

ADOPTED RULES

Adopted rules include new rules, amendments to existing rules, and repeals of existing rules. A rule adopted by a state agency takes effect 20 days after the date on which it is filed with the Secretary of State unless a later date is required by statute or specified in the rule (Government Code, §2001.036). If a rule is adopted without change to the text of the proposed rule, then the *Texas Register* does not republish the rule text here. If a rule is adopted with change to the text of the proposed rule, then the final rule text is included here. The final rule text will appear in the Texas Administrative Code on the effective date.

TITLE 1. ADMINISTRATION

PART 15. TEXAS HEALTH AND HUMAN SERVICES COMMISSION

CHAPTER 353. MEDICAID MANAGED CARE SUBCHAPTER J. OUTPATIENT PHARMACY SERVICES

1 TAC §353.903, §353.907

The executive commissioner of the Texas Health and Human Services Commission (HHSC) adopts amendments to §353.903, concerning Definitions; and §353.907, concerning Prior Authorization Requirements.

Sections 353.903 and 353.907 are adopted with changes to the proposed text as published in the April 3, 2026, issue of the *Texas Register* (51 TexReg 2162). These rules will be republished.

BACKGROUND AND JUSTIFICATION

Previous HHSC rule amendments in the Vendor Drug Program (VDP) implemented portions of House Bill (HB) 3286, 88th Legislature Regular Session, 2023, and became effective in November 2024. These amendments elaborated on existing Preferred Drug List (PDL) exceptions regarding when a non-preferred drug can be used and added new PDL exceptions.

The adopted amendments implement the portion of HB 3286 that amended Texas Government Code §531.072 by adding subsection (h). However, effective September 1, 2025, Texas Government Code §531.072(h), was transferred to Texas Government Code, Chapter 549, and redesignated as §549.0209, as a result of HB 1620, 89th Legislature Regular Session, 2025.

Therefore, the adopted amendments implement Texas Government Code §549.0209, which requires HHSC to: (1) grant temporary non-preferred (TNP) status to new drugs that are available on the Medicaid formulary but have not been reviewed by the Drug Utilization Review (DUR) Board; and (2) establish criteria for authorizing drugs with this status. This change required HHSC to submit a Medicaid State Plan Amendment (SPA) to the Centers for Medicare & Medicaid Services (CMS), which was approved on August 29, 2024. The adopted amendments in §353.903 and §353.907 address these requirements for managed care, define TNP drugs and revise existing term definitions, and provide clarifications on application of PDL prior authorization to TNP drugs.

The adopted amendments establish a new TNP status for new drugs added to the VDP formulary that have not yet been reviewed by the DUR Board. This status will apply to new drugs upon addition to the Texas Medicaid formulary if the drugs fall

into an existing PDL class. These drugs will remain TNP until reviewed at a DUR Board meeting and approved by HHSC.

TNP status does not apply to existing PDL drugs with new label indications. The adopted amendments require a health care managed care organization (health care MCO) to have a TNP drug list prior authorization for coverage.

COMMENTS

The 31-day comment period ended May 4, 2026.

During this period, HHSC received comments regarding the proposed rules from six commenters. HHSC received comments from Navitus, Parkland Community Health Plan, Molina Health-Care, the Texas Healthcare & Bioscience Institute, the Texas Association of Health Plans, and one individual. A summary of comments and HHSC responses follows.

Comment: A commenter supported HHSC's decision to list new-to-market drugs as TNP, stating that this approach helps ensure appropriate oversight and consistency while new drugs are evaluated.

Response: HHSC acknowledges the comment of support.

Comment: A commenter recommended that all TNP national drug codes follow preferred drug list criteria, stating that one non-preferred criteria process would streamline the process and provide clarity to providers and members.

Response: HHSC disagrees and declines to revise the rule in response to this comment. Section 353.907 establishes prior authorization requirements for covered outpatient drugs with TNP status in Medicaid managed care. HHSC will administer prior authorization requirements for TNP drugs consistent with applicable state and federal Medicaid requirements.

Comment: A commenter requested clarification on whether §353.907(b) applies to a member who started a drug while it was provisionally covered, and the drug later moves to TNP status.

Response: HHSC agrees that clarification is needed and provides clarification that a drug may be assigned both provisional coverage and TNP status at the same time during weekly reviews if the drug qualifies for both statuses. If a drug has TNP status, prior authorization requirements apply according to §353.907 and applicable Medicaid managed care requirements. No changes were made to the rule in response to this comment.

Comment: A commenter asked whether VDP will list TNP products on the posted preferred drug list.

Response: HHSC will list TNP products on the Provisional Drug web search only if the drug has both active coverages, either provisional or formulary, and TNP status. The Formulary Drug search will display if a drug has both active coverage and TNP

status. The posted preferred drug list document will not include TNP products because that document lists drug products reviewed by the DUR Board and approved by HHSC. No changes were made to the rule in response to this comment.

Comment: A commenter stated that §353.907(c) should not limit submission of prior authorization requests to network providers. The commenter also stated that limiting prior authorization submissions only to network providers was not envisioned by HB 3286 and could restrict patient access.

Response: HHSC agrees with the comment as to network providers. In response to the comment, HHSC removed the definition of "network provider" in §353.903(5) and revised the definition of "covered outpatient drug" in §353.903(2) to align with the federal definition. HHSC also revised §353.907(c) to clarify that prior authorization requests for covered outpatient drugs may be submitted by a provider rather than limiting submission to a network provider. These revisions clarify that the prior authorization submission requirements are not limited to network providers and ensure consistent use of the terminology throughout the rule.

Comment: A commenter stated that limiting TNP status to drugs within existing PDL classes is not supported by Texas Government Code §549.0209 or §549.0006 and recommends removing the limitation.

Response: HHSC disagrees and declines to revise the rule in response to this comment. TNP status applies to drugs within a preferred drug list class because the preferred drug list is a subset of the formulary and the TNP designation is a precursor to preferred or non-preferred status. Drugs are not eligible for TNP status if the drugs do not fall within a current preferred drug list class, but those drugs remain subject to applicable Vendor Drug Program formulary and coverage processes.

Comment: A commenter stated that striking "electronic communications" could have unintended consequences as health care moves away from fax and toward electronic processing.

Response: HHSC agrees and revised §353.907(c) and (d) to retain "electronic communications" and remove "through the internet." These changes clarify that a provider may submit a prior authorization request by telephone, fax, or electronic communications.

Comment: A commenter stated that proposed definitions of preferred drug and non-preferred drug in §353.903 require DUR Board recommendation and may undermine the executive commissioner's authority because the DUR Board serves in an advisory capacity.

Response: HHSC agrees and revised the rule to remove language regarding a DUR Board recommendation for preferred drug and non-preferred drug status. This change clarifies that HHSC retains authority to approve preferred drug list status after DUR Board review.

Comment: A commenter expressed concern that the proposed rules may allow managed care organizations or HHSC to deny access to a TNP drug despite the drug being available on the Medicaid formulary. The commenter stated that TNP status should not operate as a barrier to access for medically necessary drugs.

Response: HHSC disagrees and declines to revise the rule in response to this comment. Section 353.907 establishes managed care prior authorization requirements, including for drugs

with TNP status. Drugs with TNP status remain subject to prior authorization requirements, and HHSC will apply the rule consistent with applicable state and federal Medicaid requirements.

Comment: A commenter recommended that the rules clarify that TNP drugs remain available through a prior authorization process based on individualized medical necessity.

Response: HHSC disagrees and declines to revise the rule in response to this comment. The rule requires prior authorization for drugs with TNP status. Medical necessity and coverage determinations will continue to be made consistent with applicable Medicaid requirements.

Comment: A commenter recommended that TNP prior authorization requests be submitted to VDP as formulary exception requests and that denial of a TNP drug not occur before VDP completes a case-by-case clinical review.

Response: HHSC disagrees and declines to revise the rule in response to this comment. The rule does not require separate VDP review before every managed care organization prior authorization decision. Managed care organizations must comply with applicable state and federal Medicaid requirements when reviewing prior authorization requests and issuing adverse benefit determinations.

Comment: A commenter requested transparency and reporting requirements regarding TNP prior authorization requests, VDP review outcomes, and managed care organization compliance.

Response: HHSC disagrees and declines to revise the rules in response to this comment. The statute does not require VDP to report on TNP drug status. TNP status requires prior authorization before approval of the drug. Managed care organizations must follow the same TNP prior authorization criteria and process as VDP.

Comment: A commenter requested that TNP status be applied to all drugs that are added to the formulary post-implementation, regardless of whether they are new to the market. HHSC appears to be applying TNP status only to drugs that are "new to market," when this limitation has no basis in the text of Texas Government Code §549.0209.

Response: HHSC disagrees and declines to revise the rule in response to this comment. The rule does not use the term "new-to-market drug" and does not establish a requirement that a drug be new to the market to qualify for TNP status. Consistent with Texas Government Code §549.0209, the rule applies TNP status to a new drug that is available on the Medicaid formulary and falls within an existing preferred drug list class.

Comment: A commenter stated that if HHSC determines that a first-in-class drug presents distinct administrative considerations, that explicit regulatory guidance is provided on how such drugs would be evaluated for and granted TNP status.

Response: HHSC disagrees and declines to revise the rule in response to this comment. HHSC will determine whether a new drug, including a first-in-class drug, qualifies for TNP based on whether the drug is available on the Medicaid formulary and falls within an existing preferred drug class that has not yet been reviewed by the DUR Board.

Comment: A commenter requested clarification that the "existing PDL class" language was not intended to exclude first-in-class drugs from TNP status under Texas Government Code §549.0209.

Response: HHSC declines to revise the rule in response to this comment. HHSC clarifies that TNP status applies to new drugs that are available on the Medicaid formulary and fall under an existing preferred drug list class that has not yet been reviewed by the DUR Board. A first-in-class drug may be eligible for TNP status if it falls within an existing preferred drug list class. If the drug does not fall within an existing preferred drug list class, it is not eligible for TNP status but remains subject to applicable Vendor Drug Program formulary and coverage processes.

HHSC made minor editorial changes in §353.903(5)(B) and §353.907(a) to correct use of acronyms.

STATUTORY AUTHORITY

The amendments are adopted under Texas Government Code §524.0151, which provides that the executive commissioner of HHSC shall adopt rules for the operation and provision of services by the health and human services system, and Texas Human Resources Code §32.021 which authorizes HHSC to administer the federal medical assistance (Medicaid) program; Texas Government Code §540.0051, which authorizes HHSC to implement the Medicaid managed care program; and §549.0202, which requires the commission to adopt preferred drug lists for the Medicaid vendor drug program and prescription drugs purchased through the child health plan program.

§353.903. Definitions.

The following words and terms, when used in this subchapter, have the following meaning, unless the context clearly indicates otherwise.

(1) Clinical prior authorization (clinical PA)--A health care managed care organization (MCO) must review and approve certain drugs before a pharmacy can dispense the drug to a Medicaid member.

(2) Covered outpatient drug--A covered outpatient drug, as defined by 42 CFR §447.502, that is included on the Texas Medicaid Formulary.

(3) Formulary--The list of covered outpatient drugs for the Texas Medicaid program.

(4) Maximum allowable cost--The highest unit price set by a health care MCO, or its subcontractor, for reimbursement of therapeutically equivalent multi-source drugs.

(5) Non-preferred drug--A covered outpatient drug on the preferred drug list (PDL) that has been:

(A) reviewed by the Drug Utilization Review Board (DUR Board);

(B) approved by the Texas Health and Human Services Commission (HHSC); and

(C) designated by HHSC as non-preferred on the preferred drug list.

(6) Pharmacy benefits manager (PBM)--An entity that administers the Medicaid outpatient drug benefit on behalf of a health care MCO.

(7) Preferred drug--A covered outpatient drug on the preferred drug list that has been:

(A) reviewed and evaluated for safety, clinical effectiveness, and cost-effectiveness compared to other drugs in the same therapeutic drug class on the market;

(B) approved by HHSC; and

(C) designated by HHSC as preferred on the preferred drug list.

(8) Preferred drug list (PDL)--The list of covered outpatient drugs defined in this section as a:

(A) non-preferred drug;

(B) preferred drug; or

(C) temporary non-preferred drug.

(9) Preferred drug list prior authorization (PDL PA)--A review a health care MCO does before a pharmacy can dispense a non-preferred drug or a temporary non-preferred drug to a Medicaid member in an outpatient setting.

(10) Temporary non-preferred drug--A covered outpatient drug on the PDL:

(A) that the DUR Board has not yet reviewed;

(B) HHSC has not approved; and

(C) that has not been designated by HHSC as preferred or non-preferred.

§353.907. Prior Authorization Requirements.

(a) Except for a temporary non-preferred drug, a health care managed care organization (health care MCO) may not require a preferred drug list prior authorization (PDL PA) for a covered outpatient drug until the Texas Health and Human Services Commission (HHSC) designates the drug as non-preferred.

(b) A health care MCO may not require a PDL PA for a covered outpatient drug that was prescribed for a member before HHSC decides the drug is non-preferred or temporary non-preferred, unless the member has used up the whole prescription, including any authorized refills.

(c) A health care MCO must allow a provider to submit a request for prior authorization for a covered outpatient drug by telephone, fax, or electronic communications.

(d) A health care MCO must respond to a request for prior authorization by telephone, fax, or electronic communications no later than 24 hours after the MCO receives the request. If the health care MCO cannot respond to the prior authorization request within this time, then the health care MCO must allow a pharmacy to dispense a 72-hour supply of the prescribed drug.

(e) A health care MCO must not require a PDL PA for a preferred drug.

(f) A health care MCO must require a PDL PA for a non-preferred drug or a temporary non-preferred drug.

(g) If a member's medical condition does not match the health care MCO's clinical criteria for dispensing a covered outpatient drug, the health care MCO may require a clinical PA for a preferred, non-preferred, or temporary non-preferred drug.

(h) A health care MCO must implement all clinical PAs that HHSC designates as "mandatory" for Medicaid managed care programs.

(i) A health care MCO must accept a standard prior authorization form for a covered outpatient drug in accordance with Texas Insurance Code Chapter 1369, Subchapter F.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on September 17, 2026.

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CHAPTER 354. MEDICAID HEALTH SERVICES
SUBCHAPTER F. PHARMACY SERVICES
DIVISION 7. TEXAS DRUG CODE INDEX--ADDITIONS, RETENTIONS, AND DELETIONS

1 TAC §354.1924

The executive commissioner of the Texas Health and Human Services Commission (HHSC) adopts an amendment to §354.1924, concerning Preferred Drug List.

Section 354.1924 is adopted with changes to the proposed text as published in the April 3, 2026, issue of the *Texas Register* (51 TexReg 2164). This rule will be republished.

BACKGROUND AND JUSTIFICATION

Previous HHSC rule amendments in the Vendor Drug Program (VDP) implemented portions of House Bill (HB) 3286, 88th Legislature Regular Session, 2023, and became effective in November 2024. These amendments elaborated on existing Preferred Drug List (PDL) exceptions regarding when a non-preferred drug can be used and added new PDL exceptions.

The adopted amendment implements the portion of HB 3286 that amended Texas Government Code §531.072 by adding subsection (h). However, effective September 1, 2025, Texas Government Code §531.072(h), was transferred to Texas Government Code, Chapter 549, and redesignated as §549.0209, as a result of HB 1620, 89th Legislature Regular Session, 2025.

Therefore, the adopted amendment implements Texas Government Code §549.0209, which requires HHSC to: (1) grant temporary non-preferred (TNP) status to new drugs that are available on the Medicaid formulary but have not been reviewed by the Drug Utilization Review (DUR) Board; and (2) establish criteria for authorizing drugs with this status. This change required HHSC to submit a Medicaid State Plan Amendment (SPA) to the Centers for Medicare & Medicaid Services (CMS), which was approved on August 29, 2024.

The adopted amendment to §354.1924 clarifies criteria HHSC uses to include a drug on the Texas Drug Code Index (TDCI) in the PDL. The rule amendment defines the term "temporary non-preferred" and adds this term to any lists of preferred drug list statuses.

The adopted amendment adds new subsection (d) to §354.1924 for HHSC to give TNP status to a new drug HHSC adds to the Vendor Drug Program formulary before the drug is reviewed by the Drug Utilization Review (DUR) Board. The adopted amendment also sets the criteria HHSC uses to add a new drug to the formulary with TNP status because the drug falls into an existing

PDL class and will remain TNP until reviewed at a DUR Board meeting.

TNP status does not apply to existing PDL drugs with new label indications. Drugs on the Texas Medicaid formulary with a TNP status will require a TNP prior authorization for coverage.

COMMENTS

The 31-day comment period ended May 4, 2026.

During this period, HHSC received comments regarding the proposed rule from 7 commenters. HHSC received comments from the Texas Healthcare & Bioscience Institute, Molina HealthCare, the Rare Disease Company Coalition, the Texas Association of Health Plans, Navitus, Parkland Community Health Plan, and an individual commenter. A summary of comments and HHSC's responses follows.

Comment: A commenter supported HHSC's decision to list new-to-market drugs as TNP, stating that this approach helps ensure appropriate oversight and consistency while new drugs are evaluated.

Response: HHSC acknowledges the comment of support.

Comment: A commenter asked whether VDP will list TNP products on the posted preferred drug list.

Response: No changes were made to the rule in response to this comment. The posted preferred drug list document will not include TNP products because that document lists drug products reviewed by the DUR Board and approved by HHSC.

Comment: A commenter stated that limiting TNP status to drugs within existing PDL classes is not supported by Texas Government Code §549.0209 or §549.0006 and recommends removing the limitation.

Response: HHSC disagrees and declines to revise the rule in response to this comment. TNP status applies to drugs within a preferred drug list class because the preferred drug list is a subset of the formulary and the TNP designation is a precursor to preferred or non-preferred status. Drugs are not eligible for TNP status if the drugs do not fall within a current preferred drug list class, but those drugs remain subject to applicable Vendor Drug Program formulary and coverage processes.

Comment: A commenter stated that proposed definitions of preferred drug and non-preferred drug require DUR Board recommendation and may undermine the executive commissioner's authority because the DUR Board serves in an advisory capacity.

Response: HHSC agrees and revised the rule to remove language regarding a DUR Board recommendation for preferred drug and non-preferred drug status. This change clarifies that HHSC retains authority to approve preferred drug list status after DUR Board review.

Comment: A commenter expressed concern that the proposed rules may allow managed care organizations or HHSC to deny access to a TNP drug despite the drug being available on the Medicaid formulary. The commenter stated that TNP status should not operate as a barrier to access for medically necessary drugs.

Response: HHSC disagrees and declines to revise the rule in response to this comment. Section 354.1924 establishes criteria for including drugs on the Texas Drug Code Index and assigning preferred drug list status, including TNP status. Drugs with TNP

status remain subject to prior authorization requirements, and HHSC will apply the rule consistent with applicable state and federal Medicaid requirements.

Comment: A commenter recommended that the rules clarify that TNP drugs remain available through a prior authorization process based on individualized medical necessity.

Response: HHSC disagrees and declines to revise the rule in response to this comment. The rule requires prior authorization for drugs with TNP status. Medical necessity and coverage determinations will continue to be made consistent with applicable Medicaid requirements.

Comment: A commenter recommended that TNP prior authorization requests be submitted to VDP as formulary exception requests and that denial of a TNP drug not occur before VDP completes a case-by-case clinical review.

Response: HHSC disagrees and declines to revise the rule in response to this comment. The rule does not require separate VDP review before every managed care organization prior authorization decision. Managed care organizations must comply with applicable state and federal Medicaid requirements when reviewing prior authorization requests and issuing adverse benefit determinations.

Comment: A commenter requested transparency and reporting requirements regarding TNP prior authorization requests, VDP review outcomes, and managed care organization compliance.

Response: HHSC disagrees and declines to revise the rules in response to this comment. The statute does not require VDP to report on TNP drug status. TNP status requires prior authorization before approval of the drug. Managed care organizations must follow the same TNP prior authorization criteria and process as VDP.

Comment: A commenter requested that TNP status be applied to all drugs that are added to the formulary post-implementation, regardless of whether they are new to the market. HHSC appears to be applying TNP status only to drugs that are "new to market," when this limitation has no basis in the text of Texas Government Code §549.0209.

Response: HHSC disagrees and declines to revise the rule in response to this comment. The rule does not use the term "new-to-market drug" and does not establish a requirement that a drug be new to the market to qualify for TNP status. Consistent with Texas Government Code §549.0209, the rule applies TNP status to a new drug that is available on the Medicaid formulary and falls within an existing preferred drug list class.

Comment: A commenter stated that if HHSC determines that a first-in-class drug presents distinct administrative considerations, that explicit regulatory guidance is provided on how such drugs would be evaluated for and granted TNP status.

Response: HHSC disagrees and declines to revise the rule in response to this comment. HHSC will determine whether a new drug, including a first-in-class drug, qualifies for TNP status based on whether the drug is available on the Medicaid formulary and falls within an existing preferred drug class that has not yet been reviewed by the DUR board.

Comment: A commenter requested clarification that the "existing PDL class" language was not intended to exclude first-in-class drugs from TNP status under Texas Government Code §549.0209.

Response: HHSC declines to revise the rule in response to this comment. HHSC clarifies that TNP status applies to new drugs that are available on the Medicaid formulary and fall within an existing preferred drug list class that has not yet been reviewed by the DUR Board. A first-in-class drug may be eligible for TNP status if it falls within an existing preferred drug list class. If the drug does not fall within an existing preferred drug list class, it is not eligible for TNP status but remains subject to applicable Vendor Drug Program formulary and coverage processes.

STATUTORY AUTHORITY

The amendment is authorized by Texas Government Code §524.0151, which provides that the executive commissioner of HHSC shall adopt rules for the operation and provision of services by the health and human services system, and Texas Human Resources Code §32.021 which authorizes HHSC to administer the federal medical assistance (Medicaid) program; Texas Government Code §540.0051, which authorizes HHSC to implement the Medicaid managed care program; and §549.0202, which requires the commission to adopt preferred drug lists for the Medicaid vendor drug program and prescription drugs purchased through the child health plan program.

§354.1924. Preferred Drug List.

(a) Purpose. This section implements the provisions of Texas Government Code §549.0202, which directs the Texas Health and Human Services Commission (HHSC) to develop and implement a preferred drug list (PDL) for the Texas Medical Assistance Program.

(b) Applicability. This section applies to drugs included in the Texas Drug Code Index (TDCI) as described in §354.1921 of this division (relating to Addition of Drugs to the Texas Drug Code Index).

(c) Selection of drugs for the PDL. HHSC includes a drug listed on the TDCI in the PDL, if the drug meets the criteria in paragraphs (1) - (5) of this subsection based on:

(1) recommendations from the Drug Utilization Review Board (DUR Board) as described in §354.1941 of this subchapter (relating to Drug Utilization Review Board);

(2) the clinical efficacy of the drug, consistent with the determination of the Food and Drug Administration and the recommendations of the DUR Board;

(3) comparison of the price of the drug and the price of competing drugs when HHSC determines the price of the drug by reviewing the reimbursement amount set in §355.8541 of this title (relating to Legend and Nonlegend Medications) and after deducting Texas and federal rebates;

(4) whether there is a program benefit offered by the manufacturer or labeler of the drug and accepted by HHSC in accordance with Texas Government Code §549.0106; and

(5) written evidence offered by a manufacturer or labeler that supports including the drug on the PDL.

(d) Temporary non-preferred status. HHSC gives a new drug a temporary non-preferred status if the drug is available but the DUR Board has not yet reviewed the drug as preferred or non-preferred and has not been approved by HHSC. HHSC sets criteria for authorizing a new drug with temporary non-preferred status, following the criteria in Texas Government Code §549.0209.

(e) Obtaining a copy of the PDL. HHSC publishes the PDL on its HHSC Vendor Drug Program website. A health care provider may view or download the PDL from the website. A health care provider

may also request a copy of the PDL by sending a written request to HHSC or its designee.

(f) Prior Authorization. If HHSC designates a drug as non-preferred or the drug has a temporary non-preferred status, prior authorization from HHSC or its designee is needed, in accordance with §354.1832 of this subchapter (relating to Prior Authorization Procedures).

(g) Supplemental Rebates or Program Benefits. HHSC includes a drug on the PDL only if the manufacturer or labeler of the drug has an agreement with HHSC to provide a supplemental rebate, as described in Texas Government Code Chapter 549, Subchapter C. HHSC may also include a drug on the PDL if HHSC enters into an agreement with a manufacturer or labeler of the drug to accept a program benefit, as described in Texas Government Code §549.0106.

(h) Notwithstanding subsection (g) of this section, the preferred drug list may contain a drug provided by a manufacturer or labeler that has not reached a supplemental rebate agreement with HHSC if HHSC determines that including the drug on the preferred drug list will not have a negative cost impact to the state, as described in Texas Government Code §549.0204.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on September 17, 2026.

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Proposal publication date: April 3, 2026

For further information, please call: (512) 289-2482



TITLE 16. ECONOMIC REGULATION

PART 2. PUBLIC UTILITY COMMISSION OF TEXAS

CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS

The Public Utility Commission of Texas (commission) adopts new 16 Texas Administrative Code (TAC) §25.61, relating to Transmission and Distribution Pole Structural Integrity Standards, a new form corresponding to §25.61(h), and amendments to 16 TAC §25.52, relating to Reliability and Continuity of Service, and §25.94, relating to Report on Infrastructure Improvement and Maintenance. Sections 25.52 and 25.61 are adopted with changes to the proposed text as published in the July 3, 2026, issue of the *Texas Register* (51 TexReg 4308) and will be republished. Section 25.94 is adopted without changes and will not be republished.

The commission adopts the new rule, new form, and amended rules under Project Number 59432 to implement Public Utility Regulatory Act (PURA) §38.006 as established, and PURA

§§38.005 and 38.101 as revised, by Senate Bill 1789 during the 89th Regular Texas Legislative Session.

New §25.61 implements PURA §38.006 by establishing structural integrity standards for transmission and distribution poles operated by electric utilities, municipally owned utilities, and electric cooperatives, and the new form corresponding to §25.61(h) establishes an annual reporting framework for those entities. Amended 16 TAC §25.52 implements PURA §38.005 by strengthening the distribution feeder performance standards for electric utilities and transmission and distribution utilities and authorizing the commission to consider distribution feeder service interruption durations when determining appropriate enforcement actions against those entities. Amended 16 TAC §25.94 implements PURA §38.101 by removing the requirement for electric utilities to include in their annual infrastructure improvement and maintenance reports a description of distribution pole inspection activities.

The commission received written comments on the proposed sections and form from the Guadalupe Valley Electric Cooperative, Inc. (GVEC), Texas Public Power Association (TPPA), City of Houston (Houston), CPS Energy (CPS), Texas Electric Cooperatives, Inc. (TEC), Oncor Electric Delivery Company, LLC (Oncor), Lower Colorado River Authority Transmission Service Corporation (LCRA TSC), CenterPoint Energy Houston Electric, LLC (CEHE), Texas-New Mexico Power Company (TNMP), Entergy Texas, Inc. (ETI), Power Line Safety Initiative (PLSI),

AEP Texas, Inc., Electric Transmission Texas, LLC, and Southwestern Electric Power Company (collectively, the AEP Companies), and Southwestern Public Service Company (SPS).

Comments on 16 TAC §25.52

Proposed §25.52(c)(4)(D) and (g)(2)

Proposed §25.52(c)(4)(D) establishes classification criteria for "major events" service interruptions. Proposed §25.52(g)(2) establishes an upper limit threshold for the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) values on an electric utility's distribution feeders.

CEHE recommended that the commission confirm that major event service interruptions, as defined under proposed §25.52(c)(4)(D), will be excluded from the SAIDI, SAIFI, and system average values referenced under proposed §25.52(g)(2).

Commission Response

The commission declines to comment on the methodologies for calculating SAIDI, SAIFI, or system average values under proposed §25.52 as recommended by CEHE because these issues are beyond the scope of this rulemaking.

Proposed §25.52(g)(3)(C)

Proposed §25.52(g)(3)(C) establishes that the commission will consider the duration of each interruption to an electric utility's distribution feeder service in determining an appropriate enforcement action under proposed §25.52(g)(3).

CEHE recommended that the commission consider service interruption durations under proposed §25.52(g)(3)(C) together with the cause of each interruption and the circumstances surrounding restoration, rather than as an isolated enforcement factor, in determining an appropriate enforcement action under proposed §25.52(g)(3).

Commission Response

The commission declines to consider CEHE's recommendations regarding criteria for enforcement action determinations, other than those addressed in proposed §25.52(g)(3), because such issues are beyond the scope of this rulemaking.

Comments on 16 TAC §25.61

General comments

Applicability

GVEC recommended that the commission consider the unique operational characteristics of electric cooperatives by ensuring that the requirements adopted under §25.61 are practical, achievable, and reflective of existing utility practices. GVEC specifically noted both that electric cooperatives often serve large geographic areas with fewer resources than investor-owned utilities and that compliance costs are ultimately borne directly by cooperative members.

Commission Response

The commission determines that the requirements under adopted §25.61 strike the appropriate balance of ensuring the consistent maintenance of systems while recognizing the diverse operating and governing characteristics of entities in the state. However, to clarify the distinct implementation requirements for electric utilities and municipally owned utilities and electric cooperatives under adopted §25.61, the commission adopts new §25.61(c) and replaces relevant references to "entity" with "electric utility" throughout the rule.

Proposed §25.61(a) and (b)(1)

Proposed §25.61(a) defines which entities and assets are subject to the rule's transmission and distribution pole structural integrity requirements. Proposed §25.61(b)(1) defines "entity" as an electric utility, municipally owned utility, or electric cooperative that operates transmission or distribution assets in Texas.

TEC asserted that the proposed rule exceeds the commission's statutory authority under PURA §38.006 by directly applying inspection, serviceability grading, corrective action, and record retention requirements to municipally owned utilities and electric cooperatives. TEC contended that PURA §38.006 authorizes the commission to impose these requirements directly on electric utilities but only requires municipally owned utilities and electric cooperatives to adopt standards through their governing bodies and submit annual reports to the commission. Accordingly, TEC recommended that the commission remove municipally owned utilities and electric cooperatives from the definition of "entity" under proposed §25.61(b)(1) or otherwise specify that proposed §25.61(c), (d), (e), and (h) applies only to electric utilities and proposed §25.61(g) applies to electric utilities, municipally owned utilities, and electric cooperatives.

Commission Response

The commission declines to adopt TEC's recommendation to modify the proposed rule to remove municipally owned utilities and electric cooperatives from the definition of "entity" under proposed §25.61(b)(1). However, to clarify the distinct implementation requirements for electric utilities and municipally owned utilities and electric cooperatives under adopted §25.61, the commission adopts new §25.61(c) and replaces relevant references to "entity" with "electric utility" throughout the rule. This modification addresses TEC's concern.

Applicability to owners versus operators

CPS, LCRA TSC, and TPPA recommended that the commission modify proposed §25.61(a) to specify that the adopted section applies to an entity that owns, rather than operates, a transmission or distribution asset. The commenters argued that this modification is consistent with the language of PURA §38.006 and would more appropriately direct the obligations for structure inspections and maintenance to the entities with financial and managerial responsibilities.

Commission Response

The commission declines to modify proposed §25.61(a) to specify that the adopted section applies to an entity that owns, rather than operates, a transmission or distribution asset as recommended by CPS, LCRA TSC, and TPPA because the recommendation is inconsistent with statute. PURA §38.006(a) specifies that "This section applies only to an [entity] that operates transmission or distribution assets" (emphasis added). However, to clarify compliance obligations for entities, the commission adopts §25.61(a)(2) to provide that "For purposes of this section, the electric utility, municipally owned utility, or electric cooperative that owns a transmission or distribution asset is presumed to operate that asset unless a different electric utility, municipally owned utility, or electric cooperative is responsible for inspections, maintenance, remediation, and replacement of that asset. An electric utility, municipally owned utility, or electric cooperative responsible for the listed functions that contracts with a third party other than an electric utility, municipally owned utility, or electric cooperative to perform those functions retains responsibility for compliance with the provisions of this section."

Compliance obligations for shared or joint assets

TEC recommended that the commission modify proposed §25.61(a) to specify that an entity with shared or joint ownership, operation, or maintenance responsibilities for a structure retains a compliance obligation consistent with the terms of any ownership, operational responsibility, maintenance responsibility, or other applicable agreement.

Commission Response

The commission declines to adopt TEC's recommendation to modify proposed §25.61(a) to specify that an entity with shared or joint ownership, operation, or maintenance responsibilities for a structure retains a compliance obligation consistent with the terms of any ownership, operational responsibility, maintenance responsibility, or other applicable agreement. TEC's recommendation is addressed by the commission's modification of adopted §25.61(a)(2) to provide that "For purposes of this section, the electric utility, municipally owned utility, or electric cooperative that owns a transmission or distribution asset is presumed to operate that asset unless a different electric utility, municipally owned utility, or electric cooperative is responsible for inspections, maintenance, remediation, and replacement of that asset. An electric utility, municipally owned utility, or electric cooperative responsible for the listed functions that contracts with a third party other than an electric utility, municipally owned utility, or electric cooperative to perform those functions retains responsibility for compliance with the provisions of this section."

Proposed §25.61(b)(2) and (3)

Proposed §25.61(b)(2) defines a coastal county as a Texas county designated as a first-tier or second-tier coastal county under Section 2201.003 of the Texas Insurance Code. Proposed §25.61(b)(3) defines a non-coastal county as any Texas

county that is not designated as a first-tier or second-tier coastal county under Section 2201.003 of the Texas Insurance Code.

CPS, GVEC, CEHE, TPPA, TNMPA, and TEC noted a typo in proposed §25.61(b)(2) and (3) and recommended that the commission replace the citations to Texas Insurance Code §2201.003 with citations to Texas Insurance Code §2210.003.

Commission Response

The commission agrees with commenters and replaces the citations to Section 2201.003 of the Texas Insurance Code in proposed §25.61(b)(2) and (3) with citations to Section 2210.003 of the Texas Insurance Code in adopted §25.61(b)(2) and (3).

Proposed §25.61(b)(4) and (5)

Proposed §25.61(b)(4) defines a non-wood structure as an in-service electrical pole or tower, including any attached crossarms, davit arms, guy wires, or supports, operating at any voltage that is constructed of composite, concrete, or steel materials. Proposed §25.61(b)(5) defines a wood structure as an in-service electrical pole or tower, including any attached crossarms, davit arms, guy wires, or supports, operating at any voltage that is constructed of wood materials

CPS, ETI, TPPA, and Oncor recommended that the commission remove the references to crossarms, davit arms, guy wires, insulators, and supports from proposed §25.61(b)(4) and (5), arguing that PURA §38.006 applies only to transmission and distribution poles, not poles and attachments.

Commission Response

The commission declines to exclude structural components, such as crossarms and guy wires, from the 'structure' definitions under adopted §25.61(b)(5) and (6) as recommended by CPS, ETI, TPPA, and Oncor because these components are referenced alongside structures in the strength factor guidelines established by the National Electrical Safety Code (NESC) and PURA §38.006 specifies that "The standards adopted under this section must...consider national guidelines such as the [NESC]."

However, for consistency with NESC Table 261-1, relating to Strength factors for structures, crossarms, braces, support hardware, guys, foundations, and anchors, the commission modifies the 'structure' definitions under proposed §25.61(b)(4) and (5) to reflect that a structure is "an in-service electrical pole or tower, including any attached crossarms, braces, support hardware, guys, foundations, and anchors, operating at any voltage" that is constructed of non-wood or wood materials (emphasis added).

TEC recommended that the commission adopt a new definition for "electrical pole or tower" that would limit the term to structures that support transmission or distribution conductors or associated line equipment. Additionally, TEC recommended that the commission remove the phrase "operating at any voltage" from proposed §25.61(b)(4) and (5). TEC argues that the proposed rule creates uncertainty as to whether the rule reaches communication structures, antenna poles, substation support structures, and other assets that do not support transmission or distribution conductors.

Commission Response

The commission declines to adopt a new definition for "electrical pole or tower" as recommended by TEC because it is unnecessary. Adopted §25.61(b)(5) and (6) are sufficiently clear that a structure to which this section applies is "an in-service elec-

trical pole or tower" (emphasis added). Accordingly, communication structures, antenna poles, substation support structures, or other assets that are not involved in, or associated with, the provision of electric service are not considered structures for the purposes of this section.

The commission also declines to remove the phrase "operating at any voltage" from proposed §25.61(b)(4) and (5) as recommended by TEC. However, to clarify the kilovolt thresholds for distribution- and transmission-level voltages as referenced throughout the rule language, the commission specifies in adopted §25.61(b)(7) and (8) that distribution-level voltage is "an operating voltage below 60 kilovolts (kV), when measured phase-to-phase" and transmission-level voltage is "an operating voltage at or above 60 kV, when measured phase-to-phase."

Proposed §25.61(c)

Proposed §25.61(c) establishes routine and post-event inspection requirements for transmission- and distribution-level structures.

CEHE recommended that the commission allow entities to satisfy the inspection requirements under proposed §25.61(c) through "an equivalent risk-based inspection methodology, supported by engineering analysis and asset condition data...provided the methodology delivers a level of structural integrity assurance reasonably equivalent to or greater than the rule's minimum frequencies."

Commission Response

The commission declines to allow entities to satisfy the inspection requirements under proposed §25.61(c) through "an equivalent risk-based inspection methodology" as recommended by CEHE. The commission has determined that it is necessary for all entities to inspect their transmission- and distribution-level voltage structures according to the same baseline standards. Provided that these standards are met or exceeded, entities are encouraged to adopt and implement inspection timelines and practices that address the individual needs and characteristics of their systems.

Oncor recommended that the commission modify proposed §25.61 to specify that entities are not required to conduct comprehensive inspections of structures that are owned by third parties, even if the entity operates equipment attached to that structure.

Commission Response

The commission declines to adopt Oncor's recommendation to modify proposed §25.61 to specify that entities are not required to conduct comprehensive inspections of structures that are owned by third parties, even if the entity operates equipment attached to that structure. Oncor's recommendation is addressed by the commission's modification of adopted §25.61(a)(2) to provide that "For purposes of this section, the electric utility, municipally owned utility, or electric cooperative that owns a transmission or distribution asset is presumed to operate that asset unless a different electric utility, municipally owned utility, or electric cooperative is responsible for inspections, maintenance, remediation, and replacement of that asset. An electric utility, municipally owned utility, or electric cooperative responsible for the listed functions that contracts with a third party other than an electric utility, municipally owned utility, or electric cooperative to perform those functions retains responsibility for compliance with the provisions of this section."

Proposed §25.61(c)(1)(A)

Proposed §25.61(c)(1)(A) establishes that a visual inspection is an inspection used to identify readily observable damage or defects to wood or non-wood structures.

Oncor and TNMP recommended that the commission modify proposed §25.61(c)(1)(A) to clarify that entities can use various inspection methodologies and technologies-including ground patrols, aerial inspections, drones, LiDAR, infrared imaging, cameras, and other technologies that collect imagery for visual analysis-to meet the visual inspection requirement under proposed §25.61(c)(1)(A).

Commission Response

The commission declines to modify proposed §25.61(c)(1)(A) to specify inspection methodologies and technologies that may be used to meet the visual inspection requirement as recommended by Oncor and TNMP because it is unnecessary. Adopted §25.61(d)(1)(A) is sufficiently clear that a visual inspection may be conducted using any inspection methodology that "allows an entity to assess any readily observable damage or defects to the physical condition of a wood or non-wood structure."

SPS recommended that the commission add the word "structural" before the phrase "damage or defects" in proposed §25.61(c)(1)(A). TNMP recommended that the commission replace the references to specific structural components in proposed §25.61(c)(1)(A) with broader references to structural damage, deterioration, or other conditions affecting structural integrity.

Commission Response

The commission declines to modify proposed §25.61(c)(1)(A) by adding the word "structural" before the phrase "damage or defects" as recommended by SPS. However, to clarify the scope of the requirement, the commission modifies the adopted rule to specify in adopted §25.61(d)(1)(A) that "A visual inspection allows an electric utility to assess any readily observable damage or defects to the physical condition of a wood or non-wood structure, including, as applicable, damage to a crossarm, pole, or tower, extreme rust or corrosion, or slacked or broken guys and anchors" (emphasis added). The commission also declines to modify proposed §25.61(c)(1)(A) by replacing the references to specific structural components with broader references to structural damage, deterioration, or other conditions affecting structural integrity as recommended by TNMP because such considerations are included in the scope of comprehensive inspections under adopted §25.61(d)(1)(B).

Oncor recommended that the commission add the phrase "indications of" before the "damaged or missing bolts" example in proposed §25.61(c)(1)(A), while SPS recommended removing the example entirely.

Commission Response

The commission agrees with SPS and removes the example of "damaged or missing bolts" from adopted §25.61(d)(1)(A). The commission accordingly declines Oncor's recommendation to modify proposed §25.61(c)(1)(A) because it is unnecessary.

Proposed §25.61(c)(1)(B)

Proposed §25.61(c)(1)(B) establishes that a comprehensive inspection includes a visual inspection as well as a detailed as-

essment of any structural damage or defects to a wood or non-wood structure.

SPS asserted that the term "comprehensive inspection" may create uncertainty regarding required inspection methods and recommended that the commission modify proposed §25.61(c)(1)(B) to exclude non-wood structures and instead refer singularly to detailed intrusive assessments of wood structures.

Commission Response

The commission disagrees with SPS' assertion that the term "comprehensive inspection" is unclear, as related to required inspection methodologies, and declines SPS' recommendations to exclude non-wood structures entirely from the scope of comprehensive inspections, or refer singularly to the detailed intrusive assessment of wood structures, in proposed §25.61(c)(1)(B). Adopted §25.61(d)(1)(B) specifies that a comprehensive inspection "allows an electric utility to conduct a visual inspection as well as a detailed assessment of any damage or defects to the structural integrity of a wood or non-wood structure." For a given wood or non-wood structure, any inspection methodology, or combination of multiple inspection methodologies, that is appropriate for assessing readily observable damage or defects to the structure's physical condition and damage or defects to the structure's structural integrity may be used to conduct a comprehensive inspection of the structure.

SPS recommended that the commission relocate the references to poor hardware condition and foundation issues in proposed §25.61(c)(1)(B) to proposed §25.61(c)(1)(A) to better reflect actual utility inspection practices.

Commission Response

The commission removes the reference to "poor hardware condition" from adopted §25.61(d)(1)(B) for clarity, rendering SPS's recommendation on the reference moot. However, the commission declines to relocate the reference to "foundation issues" in adopted §25.61(d)(1)(B) to adopted §25.61(d)(1)(A) as recommended by SPS. Adopted §25.61(d)(1)(B) establishes that a comprehensive inspection "allows an electric utility to conduct a visual inspection as well as a detailed assessment of any damage or defects to the structural integrity of a wood or non-wood structure, including, as applicable, ... foundation issues" (emphasis added). Including reference to "foundation issues" in the description of a comprehensive inspection does not preclude an entity from assessing for foundation issues as part of a visual inspection. Consistent with a previous commission response, entities are encouraged to adopt and implement inspection practices that exceed the baseline requirements of adopted §25.61(d), provided that those baseline requirements are met.

Proposed §25.61(c)(2)

Proposed §25.61(c)(2) establishes routine inspection requirements for transmission- and distribution-level voltage structures.

CEHE requested that the commission recognize and provide credit towards compliance for inspection and corrective action programs that entities already have in place before the adoption of §25.61.

Commission Response

The commission declines to recognize or provide credit towards compliance for entities' existing inspection and corrective action programs as requested by CEHE because it is unnecessary. Under adopted §25.61(d)(2), electric utilities are required to "de-

velop and implement" inspection cycles that ensure the structures they operate are inspected according to the section's requirements. Adopted §25.61 does not specify that electric utilities' existing inspection programs are defunct, nor that the inspection requirements established under adopted §25.61(d)(2) apply to an electric utility or structure retroactively.

CEHE requested that the commission clarify whether entities must file inspection timelines or methodologies for review by the commission or whether disclosure via annual reporting is sufficient.

Commission Response

The commission clarifies that, for purposes of §25.61, an entity is only required to disclose its inspection timelines or methodologies to the extent required by the commission-prescribed form under adopted §25.61(h).

GVEC recommended that the commission modify proposed §25.61(c)(2) to specify that resistograph testing for wood poles and drone/high-resolution imaging for non-wood structures are acceptable comprehensive inspection methods. Further, GVEC recommended that the commission confirm that entities may use field-validated data to refine scheduling within maximum inspection intervals.

Commission Response

The commission declines to modify proposed §25.61(c)(2) to specify methodologies or technologies that may be used to conduct comprehensive inspections as recommended by GVEC because it is unnecessary. Adopted §25.61(d)(1)(B) is sufficiently clear that a comprehensive inspection may be conducted using any inspection methodology that "allows an electric utility to conduct a visual inspection as well as a detailed assessment of any damage or defects to the structural integrity of a wood or non-wood structure."

Oncor recommended that the commission clarify whether the inspection of a structure under proposed §25.61(c)(2) may be completed any time within the calendar year in which the applicable inspection anniversary occurs, or if the structure must be inspected by the date of the applicable inspection anniversary.

Commission Response

The commission clarifies as requested by Oncor that the inspection timelines established under adopted §25.61(d) are associated with the date that a structure was last inspected, rather than the calendar year that a structure was last inspected.

TEC recommended that the commission replace the term "ensures," as used in proposed §25.61(c)(2), with a term or phrase that recognizes the potential of an entity experiencing inspection delays, such as "endeavors" or "is designed to."

Commission Response

The commission declines to replace the term "ensures" in adopted §25.61(d)(2) with another term like "endeavors" or "is designed to" as recommended by TEC because such a modification is inconsistent with the intent of the rule language. Entities are required to, at minimum, meet the inspection timelines established for transmission- and distribution-level voltage structures under adopted §25.61(d)(2).

Proposed §25.61(c)(2)(A)

Proposed §25.61(c)(2)(A) requires an entity that operates a wood or non-wood structure at transmission-level voltage to

develop and implement an inspection cycle that ensures a visual inspection of the structure is conducted annually and a comprehensive inspection of the structure is conducted at least every five years.

AEP Companies, CEHE, and SPS recommended that the commission modify proposed §25.61(c)(2)(A) to allow entities to establish risk-based inspection timelines for their own structures, rather than prescribing a standardized visual or comprehensive inspection timeline.

Commission Response

The commission declines to allow entities to establish risk-based inspection timelines for their own structures as recommended by commenters. As stated in a prior commission response, the commission has determined that it is necessary for all entities to inspect their transmission- and distribution-level voltage structures according to the same baseline standards. Provided that these standards are met or exceeded, entities are encouraged to adopt and implement inspection timelines that address the individual needs and characteristics of their systems.

TPPA recommended that the commission clarify that an under-build pole-a structure designed to carry transmission-level voltage that supports both transmission- and distribution-level voltage facilities should be inspected according to the transmission-level voltage structure timelines under proposed §25.61(c)(2)(A).

Commission Response

The commission clarifies that a structure designed to carry transmission-level voltage assets should be inspected according to the routine inspection requirements for transmission-level voltage structures under adopted §25.61(d)(2)(A) and the post-event inspection requirements for all structures under adopted §25.61(d)(3).

Proposed §25.61(c)(2)(A)(i)

Proposed §25.61(c)(2)(A)(i) requires an entity that operates a wood or non-wood structure at transmission-level voltage to develop and implement an inspection cycle that ensures a visual inspection of the structure is conducted annually.

SPS recommended that the commission modify proposed §25.61(c)(2)(A)(i) to remove the annual visual inspection requirement for transmission-level voltage structures and instead allow entities to establish risk-based inspection timelines for their own structures.

Commission Response

The commission declines to allow entities to establish risk-based inspection timelines for their transmission-level voltage structures as recommended by SPS. As intended by PURA §38.006, the requirements under adopted §25.61(d)(2)(A) establish baseline standards for the consistent inspection of transmission-level voltage structures. Entities are encouraged to adopt and implement inspection timelines and methodologies that exceed the requirements of adopted §25.61(d)(2)(A), provided that those baseline standards are met.

CPS recommended that the commission modify the visual inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A)(i) by requiring an annual inspection of structures operating at or above 345 kV and an inspection every three years for structures operating below 345 kV.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(A)(i) to establish visual inspection requirements for transmission-level voltage structures based on specific operating voltage thresholds, as recommended by CPS. The commission disagrees that structures operating at or above 345 kV warrant a different visual inspection timeline than other transmission-level voltage structures because all transmission-level voltage structures contribute to the reliability of the bulk transmission system and failures can have system-wide impacts. Accordingly, the commission has determined that the annual visual inspection requirements for transmission-level voltage structures under adopted §25.61(d)(2)(A) appropriately balance the need to regularly assess the physical condition of these structures with the costs associated with more frequent comprehensive inspections.

Oncor recommended that the commission either clarify that the use of an aerial inspection methodology qualifies as a visual inspection or extend the annual visual inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A)(i) to every two years for wood structures and every five years for non-wood structures.

Commission Response

The commission declines to extend the annual visual inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A)(i) as recommended by Oncor and instead clarifies that, as specified under adopted §25.61(d)(1)(A), a visual inspection may be conducted using any inspection methodology that "allows an entity to assess any readily observable damage or defects to the physical condition of a wood or non-wood structure."

TPPA recommended that the commission extend the annual visual inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A)(i) to every eight years and specify that the timeline begins only once a structure has been in service for eight years.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(A)(i) to extend the annual visual inspection timeline for transmission-level voltage structures to every eight years, or to specify that the timeline begins only once a structure has been in service for eight years, as recommended by TPPA. Due to the reliability risks posed by damage or defects to transmission-level voltage structures, the commission has determined that an annual visual inspection requirement for all transmission-level voltage structures is appropriate.

Proposed §25.61(c)(2)(A)(ii)

Proposed §25.61(c)(2)(A)(ii) requires an entity that operates a wood or non-wood structure at transmission-level voltage to develop and implement an inspection cycle that ensures a comprehensive inspection of the structure is conducted at least every five years.

SPS, GVEC, ETI, LCRA TSC, TNMP, TEC, AEP Companies, and Oncor recommended that the commission extend the five-year comprehensive inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A)(ii). SPS recommended an extension for all transmission-level voltage structures from every five years to every six years. GVEC recommended an extension to every seven or ten years. ETI, LCRA TSC, TNMP, and TEC recommended an extension to every 10 years. If not allowing entities to establish their own risk-based

timelines, AEP Companies recommended an extension to every six years for wood structures and every 12 years for non-wood structures. If not removing the requirement entirely for non-wood structures, Oncor recommended an extension to every 10 years for wood structures and every 15 years for non-wood structures.

Commission Response

The commission agrees with commenters that it is appropriate to extend the comprehensive inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A)(ii). Additionally, the commission agrees with AEP Companies and Oncor that it is appropriate to bifurcate the inspection requirements for wood and non-wood transmission-level voltage structures under proposed §25.61(c)(2)(A). The commission accordingly bifurcates the comprehensive inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A) and adopts a 10-year comprehensive inspection timeline for wood transmission-level voltage structures under adopted §25.61(d)(2)(A)(i)(II) and a 12-year comprehensive inspection timeline for non-wood transmission-level voltage structures under adopted §25.61(d)(2)(A)(ii)(II).

TPPA recommended that the commission specify that the five-year comprehensive inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A)(ii) begins once a structure has been in service for 10 years.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(A)(ii) to specify that the comprehensive inspection timeline for transmission-level voltage structures begins only once a structure has been in service for 10 years, as recommended by TPPA. However, the commission bifurcates the comprehensive inspection timeline for transmission-level voltage structures under proposed §25.61(c)(2)(A) and adopts a 10-year comprehensive inspection timeline for wood transmission-level voltage structures under adopted §25.61(d)(2)(A)(i)(II) and a 12-year comprehensive inspection timeline for non-wood transmission-level voltage structures under adopted §25.61(d)(2)(A)(ii)(II).

Proposed §25.61(c)(2)(B)

Proposed §25.61(c)(2)(B) establishes routine inspection requirements for distribution-level voltage structures based on the structure's construction material and geographic location.

AEP Companies, GVEC, and TEC recommended that the commission modify proposed §25.61(c)(2)(B) to prescribe a standard 10-year comprehensive inspection timeline for all distribution-level voltage structures, rather than establishing inspection timelines based on the geographic location or construction material of a structure. TEC further recommended that the commission specify that the timeline begins once a structure has been in service for 10 years.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(B) to replace the location- and material-based inspection timelines with a uniform 10-year comprehensive inspection timeline for all distribution-level voltage structures, or to specify that the inspection timeline begins when a structure has been in service for 10 years, as recommended by commenters because the commission has determined that these timelines appropriately balance the statutory objective of consistent distribution system inspection practices with the varied geographic and material considerations present on entities' distribution systems.

CPS recommended that the commission modify proposed §25.61(c)(2)(B) to require entities to conduct comprehensive inspections of structures they own, and visual inspections of structures the entities are attached to but do not own.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(B) to require entities to conduct comprehensive inspections of structures they own, and visual inspections of structures the entities are attached to but do not own, as recommended by CPS. To clarify compliance obligations for entities, the commission adopts §25.61(a)(2) to provide that "For purposes of this section, the electric utility, municipally owned utility, or electric cooperative that owns a transmission or distribution asset is presumed to operate that asset unless a different electric utility, municipally owned utility, or electric cooperative is responsible for inspections, maintenance, remediation, and replacement of that asset. An electric utility, municipally owned utility, or electric cooperative responsible for the listed functions that contracts with a third party other than an electric utility, municipally owned utility, or electric cooperative to perform those functions retains responsibility for compliance with the provisions of this section."

Houston argued that the comprehensive inspection timelines under adopted §25.61 should account for the effectiveness and lifespan of preservative treatments on wood structures, particularly fumigants that may degrade before the next scheduled inspection. Accordingly, Houston recommended that the commission modify proposed §25.61(c)(2)(B)(i)-(ii) to require inspections of wood distribution-level voltage structures at the earlier of the rule's inspection timelines or the end of a fumigant treatment's effective life.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(B)(i) or (ii) require inspections of wood distribution-level voltage structures at the earlier of the rule's inspection timelines or the end of a fumigant treatment's effective life, as recommended by Houston. There is no proven correlative relationship between fumigant treatments and shortened in-service life expectations for wood structures. Further, the inspection timelines established for wood distribution-level voltage structures under adopted §25.61(d)(2)(B)(i) are consistent with the inspection guidelines established by the United States Department of Agriculture's Rural Utility Service (USDA's RUS).

Proposed §25.61(c)(2)(B)(i)

Proposed §25.61(c)(2)(B)(i) requires an entity that operates a wood distribution-level voltage structure in a coastal county of this state to develop and implement an inspection cycle that ensures a comprehensive inspection of the structure is conducted at least every eight years.

ETI recommended that the commission modify proposed §25.61(c)(2)(B)(i) to allow entities to conduct comprehensive inspections of wood distribution-level voltage structures in coastal counties every 10 years, instead of every eight years, provided that an entity justifies the lengthened timeline in its annual report.

Commission Response

The commission declines to replace the eight-year comprehensive inspection timeline for wood distribution-level voltage structures in coastal counties under proposed §25.61(c)(2)(B)(i) with a conditional 10-year timeline, as recommended by ETI. PURA

§38.006(c) establishes that "The standards adopted under this section must...account for the geographic and weather characteristics of this state...[and] consider national guidelines such as...the guidelines developed by the [USDA's RUS]." As demonstrated by the USDA's RUS inspection guidelines, structures located in coastal areas-especially wood distribution-level voltage structures-experience higher rates of decay and deterioration than structures with the same characteristics that are located in non-coastal areas. Accordingly, the commission determines that the eight-year comprehensive inspection timeline under adopted §25.61(d)(2)(B)(i)(I) is consistent with both the USDA's RUS inspection guidelines and the geographic and weather characteristics of this state.

Proposed §25.61(c)(2)(B)(ii)

Proposed §25.61(c)(2)(B)(ii) requires an entity that operates a wood distribution-level voltage structure in a non-coastal county of this state to develop and implement an inspection cycle that ensures a comprehensive inspection of the structure is conducted at least every 10 years.

CPS recommended that the commission modify proposed §25.61(c)(2)(B)(ii) to extend the inspection timeline for wood distribution-level voltage structures in non-coastal counties from every 10 years to every 15 years.

Commission Response

The commission declines to extend the inspection timeline for wood distribution-level voltage structures in non-coastal counties under proposed §25.61(c)(2)(B)(ii) from every 10 years to every 15 years, as recommended by CPS. The 10-year inspection timeline is consistent with the inspection guidelines established by the USDA's RUS.

Houston recommended that the commission modify proposed §25.61(c)(2)(B)(ii) to incorporate the hazard zones established by the American Wood Pole Association's (AWPA's) Decay Hazard Map for Utility Poles. Specifically, Houston recommended that wood distribution-level voltage structures be inspected every eight years if located in a "severe zone" county and every 10 years if located in a "moderate zone" county.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(B)(ii) to incorporate the hazard zones established by the AWPA's Decay Hazard Map for Utility Poles as recommended by Houston. Because the hazard zones identified by the AWPA do not correspond directly to state boundaries, including those of Texas, the commission has determined that the inspection requirements established in adopted §25.61(d)(2) should be based on the existing geographic framework set forth in Section 2210.003 of the Texas Insurance Code.

Proposed §25.61 (c)(2)(B)(i) and (ii)

Proposed §25.61(c)(2)(B)(i) requires an entity that operates a wood distribution-level voltage structure in a coastal county of this state to develop and implement an inspection cycle that ensures a comprehensive inspection of the structure is conducted at least every eight years. Proposed §25.61(c)(2)(B)(ii) requires an entity that operates a wood distribution-level voltage structure in a non-coastal county of this state to develop and implement an inspection cycle that ensures a comprehensive inspection of the structure is conducted at least every 10 years.

SPS recommended that the commission modify proposed §25.61(c)(2)(B)(i) and (ii) to prescribe a 12-year comprehensive

inspection timeline for all wood distribution-level structures, rather than the proposed geographically-based inspection timelines.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(B) to replace the geographically-based inspection timelines with a standard 12-year comprehensive inspection timeline for all wood distribution-level voltage structures, as recommended by SPS. PURA §38.006(c) specifies that "The standards adopted under this section must...account for the geographic and weather characteristics of this state." The geographically-based inspection timelines established for wood distribution-level voltage structures under adopted §25.61(d)(2)(B)(i) and (ii) are consistent with that requirement.

Proposed §25.61 (c)(2)(B)(iii)

Proposed §25.61(c)(2)(B)(iii) requires an entity that operates a non-wood distribution-level voltage structure to develop and implement an inspection cycle that ensures a comprehensive inspection of the structure is conducted at least every 10 years.

CPS recommended that the commission modify proposed §25.61(c)(2)(B)(iii) to extend the comprehensive inspection timeline for non-wood distribution-level voltage structures from every 10 years to every 15 years. Oncor and SPS recommended that the commission modify proposed §25.61(c)(2)(B)(iii) to replace the comprehensive inspection requirement with a visual inspection requirement for non-wood distribution-level voltage structures. SPS additionally recommended that the commission shorten the inspection timeline from 10 years to five years.

Commission Response

The commission declines to modify proposed §25.61(c)(2)(B)(iii) to extend the comprehensive inspection timeline for non-wood distribution-level voltage structures from every 10 years to every 15 years, replace the comprehensive inspection requirement with a visual inspection requirement, or shorten the inspection timeline from 10 years to five years as recommended by commenters. However, the commission extends the proposed 10-year inspection timeline to a 12-year comprehensive inspection timeline for non-wood distribution-level voltage structures under adopted §25.61(d)(2)(B)(ii).

Proposed §25.61(c)(3)

Proposed §25.61(c)(3) requires an entity to conduct a visual inspection of a wood or non-wood structure as soon as practicable, but not later than 30 calendar days, after an event the entity reasonably expects to have impacted the physical condition of the structure.

AEP Companies recommended that the commission modify proposed §25.61(c)(3) to replace the phrase "post-event inspections" with "post-event damage assessments and restoration activities" and clarify that post-event activities include patrols, field assessments, outage evaluations, and restoration work. SPS recommended that the commission clarify that existing outage patrols may satisfy the post-event inspection requirement.

Commission Response

The commission declines to modify proposed §25.61(c)(3) to replace the phrase "post-event inspections" with "post-event damage assessments and restoration activities", as recommended by AEP Companies because it is unnecessary. Under adopted §25.61(d)(3), a post-event inspection is a visual inspection of a

structure affected by a qualifying event. Adopted §25.61(d)(1)(A) specifies that a visual inspection "allows an electric utility to assess any readily observable damage or defects to the physical condition of a...structure." A post-event inspection is therefore a damage assessment of a structure affected by a qualifying event.

The commission also declines to clarify that post-event activities include patrols, field assessments, outage evaluations, and restoration work, or to clarify that existing outage patrols may satisfy the post-event inspection requirement, as recommended by AEP Companies. The requirements under adopted §25.61(d)(3) pertain specifically to post-event inspections, not other post-event activities. To further clarify this distinction, the commission specifies in adopted §25.61(d)(3) that the 45-day post-event inspection timeline begins "after the date [a] qualifying event ends or the date service is restored at [a] structure following [the] qualifying event, whichever occurs later."

CPS and ETI recommended that the commission remove proposed §25.61(c)(3) from the adopted rule. CPS argued that post-event inspections are outside the scope of PURA §§38.006 and 38.103. ETI argued that a post-event inspection requirement would redirect entities' resources away from necessary restoration efforts following an event.

Commission Response

The commission declines to remove proposed §25.61(c)(3) from the adopted rule, as recommended by CPS and ETI. PURA §38.006(c) specifies that "The standards adopted under this section must ... require an electric utility to ... inspect ... transmission and distribution poles as necessary on a timeline established by the commission." The commission has determined that establishing a post-event inspection requirement is consistent with the intent of this directive by ensuring that structures are inspected on a routine cycle and in response to events that may result in damage to or compromise a structure's structural integrity. To clarify that the post-event inspection requirement is not intended to redirect an entity's resources away from other critical post-event activities, the commission specifies in adopted §25.61(d)(3) that the 45-day post-event inspection timeline begins "after the date [a] qualifying event ends or the date service is restored at [a] structure following [the] qualifying event, whichever occurs later."

ETI, CEHE, TPPA, TEC, and SPS recommended that the commission modify proposed §25.61(c)(3) to clarify when the post-event inspection requirement is triggered. ETI recommended that a post-event inspection only be required after a named storm. CEHE and SPS recommended that a post-event inspection only be required if objective criteria, such as severe weather, significant outages, or structural damage thresholds, are met. TNMP recommended that a post-event inspection only be required after a Major Event service interruption under §25.52, relating to Reliability and Continuity of Service.

Commission Response

The commission agrees with commenters that further clarification around the post-event inspection triggers under §25.61 is warranted. First, the commission specifies under adopted §25.61(d)(3) that "An electric utility that operates a wood or non-wood structure affected by a qualifying event must conduct a visual inspection of the structure as soon as practicable, but not later than 45 calendar days, after the date the qualifying event ends or the date service is restored at the structure following a qualifying event, whichever occurs later." Second, the commission adopts the following 'Qualifying event' definition

as §25.61(b)(4): "an event that an entity reasonably expects to affect the physical condition of a structure, including a service interruption that meets the classification criteria of a Major Events interruption under 16 TAC §25.52 (relating to Reliability and Continuity of Service) or an event that meets the criteria of a resiliency event under 16 TAC §25.62 (relating to Transmission and Distribution System Resiliency Plans).

ETI, GVEC, CEHE, LCRA TSC, TPPA, Oncor, TNMP, TEC, and SPS recommended that the commission modify the 30-day post-event inspection timeline under proposed §25.61(c)(3). Oncor and TPPA respectively recommended extending the timeline to 60 days or 120 days after the end of an event. Oncor alternatively recommended offering a mechanism by which entities can request extensions on the inspection timeline. ETI, GVEC, CEHE, TNMP, and TEC recommended that the commission clarify that any timeline will begin only after restoration efforts following an event are completed. LCRA TSC recommended that any inspection timeline begin only once safe access to a structure is available following an event. Alternatively, LCRA TSC, SPS, and CEHE recommended a flexible timeline that would permit entities to prioritize inspections on a risk- and resource-basis.

Commission Response

The commission agrees with commenters that an extension to the 30-day post-event inspection timeline under proposed §25.61(c)(3) is appropriate. Accordingly, the commission adopts a 45-day post-event inspection timeline under §25.61(d)(3) and further specifies that the 45-day post-event inspection timeline begins "after the date [a] qualifying event ends or the date service is restored at [a] structure following [the] qualifying event, whichever occurs later."

TPPA and CPS recommended that the commission modify proposed §25.61(c)(3) to clarify that entities will not be found retroactively non-compliant with the post-event inspection requirements or liable for structural issues that are identified if an entity makes a good-faith determination that no post-event inspection is needed.

Commission Response

To eliminate uncertainty related to when an entity is required to conduct a post-event inspection is required under §25.61, the commission specifies under adopted §25.61(d)(3) that "An electric utility that operates a wood or non-wood structure affected by a qualifying event must conduct a visual inspection of the structure as soon as practicable, but not later than 45 calendar days, after the date the qualifying event ends or the date service is restored at the structure following a qualifying event, whichever occurs later." Additionally, the commission adopts the following "Qualifying event" definition as §25.61(b)(4): "an event that an entity reasonably expects to affect the physical condition of a structure, including a service interruption that meets the classification criteria of a Major Events interruption under 16 TAC §25.52 (relating to Reliability and Continuity of Service) or an event that meets the criteria of a resiliency event under 16 TAC §25.62 (relating to Transmission and Distribution System Resiliency Plans).

TEC recommended that the commission clarify that entities are only required to conduct post-event inspections under §25.61(c)(3) on areas that were impacted by an event, not an entity's entire system.

Commission Response

The commission clarifies that the subject of post-event inspections under adopted §25.61(d)(3) are "[structures] affected by a qualifying event." "Qualifying event" is defined by adopted §25.61(b)(4).

Proposed §25.61(d)

Proposed §25.61(d) requires an entity to assign a structure a serviceability grade upon any inspection of the structure conducted under §25.61.

GVEC recommended that the commission allow entities to use their existing serviceability grading systems, if entities can map their systems to the serviceability grades under proposed §25.61(d). AEP Companies and SPS recommended the commission allow entities to use existing grading methodologies instead of prescribing the serviceability grading system under proposed §25.61(d).

Commission Response

The commission declines to allow entities to use existing grading methodologies instead of prescribing the serviceability grading system under proposed §25.61(d), as recommended by commenters. PURA §38.006(c) specifies that "The standards adopted under this section must ... establish a classification system to assess the serviceability of transmission and distribution poles that accounts for pole maintenance and extending the service life of [those poles]." The commission has determined that establishing a standardized serviceability grading system is consistent with the intent of this statutory requirement by ensuring that the condition of all structures is assessed and graded according to the same baseline standards.

AEP Companies, CPS, TPPA, and Oncor recommended that the commission clarify how the serviceability grading system under proposed §25.61(d) applies to components of a structure other than a pole or tower itself. GVEC, CEHE, and Oncor recommended that the commission clarify that the serviceability grading system under proposed §25.61(d) applies only to a pole or tower itself. Alternatively, GVEC recommended that hardware defects be graded only when they affect structural integrity or public safety, and CEHE recommended that equipment attached to a pole or tower be evaluated on the basis of condition instead of NESC strength requirements.

Commission Response

The commission agrees with AEP Companies, CPS, TPPA, and Oncor that further clarification around the application of the serviceability grading criteria under proposed §25.61(d) is warranted. However, the commission declines to modify proposed §25.61(d) by specifying that the serviceability grading criteria applies only to a pole or tower itself, or by establishing separate serviceability grading conditions or criteria for non-pole or -tower components, as recommended by GVEC, CEHE, and Oncor. The commission instead specifies in adopted §25.61(e)(1) that "A 'Pass' grade applies when the structure meets the applicable strength requirements established by the National Electrical Safety Code (NESC) and is otherwise absent of readily observable and structural damage or defects."

GVEC and TEC recommended that the commission modify proposed §25.61(d) to specify that the serviceability grading requirements apply only to comprehensive inspections. TEC alternatively recommended that only a 'pass' or 'fail' serviceability grade be required from visual inspections.

Commission Response

The commission declines to modify proposed §25.61(d) to specify that the serviceability grading requirements apply only to comprehensive inspections, or to establish separate serviceability grading requirements for visual inspections, as recommended by GVEC and TEC. However, to ensure the serviceability grading criteria translates clearly to both visual and comprehensive inspection, the commission specifies in adopted §25.61(e)(1) that "A 'Pass' grade applies when the structure meets the applicable strength requirements established by the National Electrical Safety Code (NESC) and is otherwise absent of readily observable and structural damage or defects."

Proposed §25.61(d)(1)

Proposed §25.61(d)(1) provides that a 'Pass' serviceability grade applies to a structure when the structure meets the applicable strength requirements established by the National Electrical Safety Code (NESC).

Oncor recommended that the commission modify proposed §25.61(d)(1) to specify that the NESC strength standards applicable to a structure are those in effect at the time of installation. Oncor alternatively recommended that the commission extend the corrective action timelines under proposed §25.61(e) for structures that received non-passing serviceability grades due to changes to the NESC standards over time.

Commission Response

The commission clarifies that the applicable NESC strength requirements referenced under adopted §25.61 are those NESC strength requirements that were in effect at the time the structure was placed in service. Accordingly, the commission declines to extend the corrective action timelines under proposed §25.61(e) for structures that received non-passing serviceability grades due to changes to the NESC strength standards over time as recommended by Oncor because it is unnecessary.

Proposed §25.61(e)

Proposed §25.61(e) establishes the corrective action requirements that an entity must take to address the condition of a structure that receives a 'Remediate,' 'Replace,' or 'Emergency' serviceability grade under proposed §25.61(d).

CPS recommended that the commission specify that the corrective action timelines under proposed §25.61(e) apply only to entities that own structures.

Commission Response

The commission declines to modify proposed §25.61(e) to specify that the corrective action timelines apply only to entities that own, rather than operate, structures because PURA §38.006(a) specifies that "This section applies only to an [entity] that operates transmission or distribution assets" (emphasis added). To provide clarification regarding compliance obligations for entities, the commission adopts §25.61(a)(2) to provide that "For purposes of this section, the electric utility, municipally owned utility, or electric cooperative that owns a transmission or distribution asset is presumed to operate that asset unless a different electric utility, municipally owned utility, or electric cooperative is responsible for inspections, maintenance, remediation, and replacement of that asset. An electric utility, municipally owned utility, or electric cooperative responsible for the listed functions that contracts with a third party other than an electric utility, municipally owned utility, or electric cooperative to perform those functions retains responsibility for compliance with the provisions of this section."

CEHE recommended that the commission clarify that the corrective action timelines under proposed §25.61(e) apply on a structure-by-structure basis, not on a systemwide basis.

Commission Response

The commission clarifies that the corrective action requirements under adopted §25.61(f) apply respectively to a structure that is assigned a 'Remediate,' 'Replace,' or 'Emergency' serviceability grade under adopted §25.61(e).

GVEC and TEC recommended that the commission modify proposed §25.61(e) to specify that the timelines for corrective actions resulting from post-event inspections are more flexible than those associated with routine inspections. TEC further recommended the addition of new §25.61(e)(4) to specify that corrective actions associated with post-event inspections are not subject to the standard corrective action timelines and must instead be completed as soon as practicable.

Commission Response

The commission declines to specify a distinction between corrective action timelines for routine and post-event inspections, as recommended by GVEC and TEC. The commission has determined that the corrective action requirements adopted under §25.61(f) strike the appropriate balance between ensuring that entities address the conditions of non-passing structures on a timely basis and providing flexibility for entities to extend the corrective action timelines for structures that cannot practicably be replaced or remediated according to those timelines.

Proposed §25.61(e)(1), (e)(2), and (e)(3)(B)

Proposed §25.61(e)(1) requires entities to restore any structure assigned a "Remediate" grade to the applicable NESC strength standards through repair, reinforcement, treatment, or other corrective measures within six months. Proposed §25.61(e)(2) requires entities to replace any structure assigned a "replace" grade with a structure that meets applicable NESC strength standards as soon as practicable, but no later than six months after the grade is assigned. Proposed §25.61(e)(3)(B) requires entities to permanently replace an "Emergency" grade structure within six months after the imminent failure or public safety risk has been resolved, ensuring the replacement structure meets applicable NESC strength standards.

TPPA and CEHE recommended that the commission modify proposed §25.61(e) to distinguish corrective action timelines by voltage and provide transmission-level voltage structures with longer corrective action timelines than distribution-level voltage structures. Specifically, TPPA recommended that the commission extend the remediation and replacement timelines for transmission-level voltage structures under proposed §25.61(e) to 18 months

Commission Response

The commission declines to adopt TPPA and CEHE's recommendation to distinguish corrective action timelines by voltage and provide transmission-level voltage structures with longer corrective action timelines than distribution-level voltage structures. However, the commission adopts an extension and notice mechanism under §25.61(f)(1)(B) and (f)(2)(B) to allow the prescribed corrective action timelines to be extended for structures that cannot be practicably replaced or remediated according to those timelines.

TEC, CEHE, AEP Companies, LCRA TSC, ETI, and GVEC recommended that the commission extend the 6-month remediation

and replacement timelines under proposed §25.61(e). TEC and CEHE respectively recommended extending the timelines to 12 months and 18 months. AEP Companies and LCRA TSC recommended extending the timelines to 24 months. ETI and GVEC recommended that entities be allowed to complete remediations and replacements as soon as practicable. GVEC alternatively recommended that entities be allowed to remediate or replace a structure within a calendar year of a non-passing serviceability grade assignment. SPS recommended that the commission remove the prescribed remediation and replacement timelines from proposed §25.61(e) entirely.

Commission Response

The commission declines to adopt SPS's recommendation to remove the prescribed remediation and replacement timelines entirely. The commission also declines to adopt the recommendations of commenters that suggested extending the 6-month remediation timeline, but adds adopted §25.61(f)(1)(B), which specifies that "An electric utility that deems it impracticable to complete the remediation of a structure within the timeline established under subparagraph (A) of this paragraph may extend the structure's remediation timeline to a date not more than 12 calendar months after the date the electric utility assigned the structure a 'Remediate' grade under subsection (d) of this section." The commission agrees with commenters that suggested extending the replacement timeline and accordingly modifies adopted §25.61(f)(2)(A) to extend the deadline to 12 calendar months. The commission further adds adopted §25.61(f)(2)(B), which provides that "An electric utility that deems it impracticable to complete the replacement of a structure within the timeline established under subparagraph (A) of this paragraph may extend the structure's replacement timeline to a date not more than 24 calendar months after the date the electric utility assigned the structure a 'Replace' grade under subsection (d) of this section." This framework appropriately balances the need for timely corrective actions with the practical realities of utility operations.

Good cause exception to timelines

Oncor, TNMP, TEC, and CEHE recommended the commission provide a mechanism for entities with good cause to exceed the remediation and replacement timelines under proposed §25.61(e). Oncor and TNMP recommended that entities be allowed to exceed the timelines if they conducted a risk assessment on the delay and document the delay in their annual report. TEC also recommended that entities be allowed to exceed the timelines if they document the delay in their annual report. CEHE recommended that entities be allowed to exceed the timelines with good cause and an accompanying corrective action plan.

Commission Response

The commission agrees with commenters and adopts an extension and notice mechanism under §25.61(f)(1)(B) and (f)(2)(B) to allow the prescribed corrective action timelines to be extended for structures that cannot be practicably replaced or remediated according to those timelines.

Proposed §25.61(e)(3)(A)

Proposed §25.61(e)(3)(A) requires an entity to make safe any structure assigned an "Emergency" grade within two calendar days by resolving the imminent failure or public safety risk.

AEP Companies, LCRA TSC, ETI, GVEC, TEC, CEHE, and TPPA recommended that the commission modify the two-day

emergency make-safe corrective action timeline under proposed §25.61(e)(3)(A). CEHE recommended specifying that the two-day timeline begins only once safe access to a structure is available. GVEC and TEC recommended extending the timeline to 10 calendar days, with TEC additionally recommending allowing extensions for good cause. AEP Companies, LCRA TSC, ETI, and TPPA recommended removing the prescribed timeline entirely and instead requiring emergency make-safe corrective actions to be completed as soon as practicable. AEP Companies and LCRA TSC alternatively recommended extending the timeline to 7 calendar days. TPPA alternatively recommended bifurcating and extending the timeline to five calendar days for distribution-level voltage structures and 14 calendar days for transmission-level voltage structures.

Commission Response:

The commission agrees with CEHE that the two-day emergency make-safe corrective action timeline should account for circumstances where it is impracticable to access a structure safely within that timeframe. Accordingly, the commission provides in adopted §25.61(f)(3)(A) that "An electric utility must resolve a structure's imminent failure or public safety risk as soon as practicable, but not more than two calendar days, after the date the electric utility assigns the structure an 'Emergency' grade under subsection (d) of this section, or the date the structure becomes safe to access, whichever occurs later" (emphasis added). The commission declines to adopt the recommendations of commenters who suggested extending, bifurcating, or removing the two-day emergency make-safe corrective action timeline. The two-day timeline is appropriate because any delay in taking corrective action to address an "Emergency" grade structure increases the structure's risk of imminent failure and risk to public safety.

Proposed §25.61(e)(3)(B)

Proposed §25.61(e)(3)(B) requires an entity to replace a structure assigned an "emergency" grade to replace the structure with another structure that meets the applicable NESC strength requirements as soon as practicable, but not more than six months, after the date the entity resolves the structure's imminent failure or public safety risk.

AEP Companies and TEC recommended that the commission extend the emergency replacement timeline under proposed §25.61(e)(3)(B). AEP Companies recommended extending the timeline to 24 months, and TEC recommended extending the timeline to 12 months and allowing extensions for good cause.

Commission Response

The commission agrees with AEP Companies and TEC that it is appropriate to extend the emergency replacement timeline. Accordingly, the commission provides in adopted §25.61(f)(3)(B)(ii) that the electric utility must replace a structure assigned an "Emergency" grade according to the requirements of adopted §25.61(f)(2), which prescribes a 12-month timeline with opportunity for extension with notice. This framework appropriately balances the need for timely corrective actions with the practical realities of utility operations.

CEHE recommended that the commission modify proposed §25.61(e)(3)(B) to specify that the emergency replacement timeline begins only once emergency make-safe measures are completed.

Commission Response

The commission declines to adopt CEHE's recommendation to modify proposed §25.61(e)(3)(B) to specify that the emergency replacement timeline begins only once emergency make-safe measures are completed because it is unnecessary. Adopted §25.61(f)(3)(B) is sufficiently clear that the emergency replacement timeline begins after a structure's imminent failure or public safety risk is resolved under adopted §25.61(f)(3)(A).

SPS recommended that the commission modify proposed §25.61(e)(3)(B) to allow entities to remediate emergency structures, rather than replacing them, if remediation would restore the structures to the applicable NESC standards.

Commission Response

The commission agrees with SPS that it is appropriate to allow for the remediation, rather than only the replacement, of a structure assigned an "Emergency" grade, if remediation would restore the structure to the applicable NESC standards. Accordingly, the commission modifies the proposed rule to delineate the requirements for replacement or remediation of "Emergency" grade structures under adopted §25.61(f)(3)(B).

Proposed §25.61(f)

Proposed §25.61(f) requires municipally owned utilities and electric cooperatives to adopt the inspection, serviceability grading, and corrective action requirements established in the rule within 120 days of its effective date.

CEHE recommended that the commission provide electric utilities with a 120-day timeline to implement the adopted section that is comparable to the timeline for adoption by municipally owned utilities and electric cooperatives under proposed §25.63(f), or provide guidance on how electric utilities should demonstrate good-faith compliance with §25.61 during the period between the rule's effective date and the completion of the utility's first full inspection cycle.

Commission Response

The commission declines to provide electric utilities with an implementation timeline similar to the 120-day adoption timeline for municipally owned utilities and electric cooperatives under proposed §25.63(f), or adopted §25.61(c)(2)(A), as recommended by CEHE. The adoption timeline for municipally owned utilities and electric cooperatives references a statutory requirement that is procedural and related to their unique governing characteristics, which are not applicable to electric utilities. Entities will have the opportunity to provide text-based information, as well as the required reporting data points, in their annual reports on their inspection, serviceability, and corrective action activities and results. Accordingly, entities are encouraged to provide relevant information related to their successes and challenges in implementing the requirements of §25.61 during a given reporting period in those text-based fields.

TEC recommended that the commission delete proposed §25.61(f)(1) from the adopted rule and make conforming modifications to the other adopted rule language to respect the jurisdictional authority of municipally owned utilities and electric cooperatives. TEC argued that PURA §38.006 imposed the adoption requirement directly on municipally owned utilities and electric cooperatives and did not authorize the commission to reflect that requirement by rule.

Commission Response

The commission agrees that the requirement for municipally owned utilities or electric cooperatives, or their governing

bodies, to adopt the standards established by the commission under PURA §38.006 is grounded in statute, rather than commission rule. However, the commission declines to remove the reference to this requirement under proposed §25.61(f)(1) because it enhances the clarity of the rule and describes how the statutory requirements will apply to each entity. The commission's recent experience in implementing emergency operations requirements validates that entities that are not typically subject to commission regulation benefit from additional guidance in coming into compliance with new requirements.

The commission disagrees that the inclusion of this provision intrudes upon the jurisdictional authority of municipally owned utilities and electric cooperatives. The direct statutory reference in the requirement makes it evident that the obligation is statutory and not an independent exercise of commission authority. Additionally, because PURA §38.006(g) provides the commission with explicit authority to enforce the statutory section, the inclusion of proposed §25.61(f)(1) does not expose municipally owned utilities or electric cooperatives to additional regulatory risk.

However, to further distinguish statutory requirements from the adopted rule requirements, the commission relocates proposed §25.61(f)(1) and (2) (adopted §25.61(c)(2)(A) and (B)) to a new subsection (c) that clarifies the distinct implementation requirements for electric utilities, municipally owned utilities, and electric cooperatives and substitutes the term "electric utility" for "entity" in adopted §25.61(d), (e), (f), and (g).

Proposed §25.61(g) and (h)

Proposed §25.61(g) requires entities to file an annual report with the commission by May 1 detailing their inspection, serviceability grading, and corrective actions for the prior calendar year. Proposed §25.61(h) requires entities to retain records of inspections, serviceability grades, and corrective actions for each structure throughout its service life.

TEC recommended that the commission remove the phrase "under subsections (c), (d), and (e) of this section" from proposed §25.61(g) and (h) because the requirements of §25.61(c), (d), and (e) apply only to electric utilities.

Commission Response

To clarify the distinct implementation requirements for electric utilities, municipally owned utilities, and electric cooperatives under adopted §25.61, the commission adopts new §25.61(c) and replaces relevant references to "entity" with "electric utility" throughout the rule. This modification addresses TEC's concern.

Proposed §25.61(g)

Proposed §25.61(g) requires entities to file an annual report with the commission by May 1 detailing their inspection, serviceability grading, and corrective actions for the prior calendar year.

AEP Companies, ETI, GVEC, TEC, and SPS recommended that the commission remove the requirement for entities to submit annual reports according to a commission-prescribed form under proposed §25.61(g) and instead allow entities to utilize existing documentation.

Commission Response

The commission declines to adopt commenters' recommendations to remove the requirement for entities to submit annual reports according to a commission-prescribed form under pro-

posed §25.61(g) and instead allow entities to utilize existing documentation. The standardization of reporting improves transparency and access to required information. The commission's responses to recommended modifications to the proposed form are discussed later in this order.

CEHE recommended that the commission provide entities with a dedicated transition period between the adoption of the proposed form accompanying §25.61(g) and the May 1, 2027, annual report deadline.

Commission Response

The commission declines to adopt CEHE's recommendation to establish a dedicated transition period between the adoption of the proposed form accompanying §25.61(g) and the May 1, 2027, annual report deadline. The commission finds that sufficient time is available for an electric utility to transition to the commission-approved form between the form's adoption date and the May 1, 2027, deadline.

PLSI recommended that the commission publish entities' annual reports on the commission's website by September 1 of each year, similarly to the practice under §25.97(i).

Commission Response

The commission declines PSLI's recommendation and clarifies that it is unnecessary for the adopted rule to expressly state that the commission will publish reports on the commission's website. Reports filed through the commission's filing system are already publicly accessible via the commission's website.

TEC recommended that the commission allow entities to fulfill the reporting requirements under both adopted §25.61 and §25.63, relating to Distribution Pole Management and Inspection Plans, by submitting a consolidated annual report.

Commission Response

The commission declines to adopt TEC's recommendation to allow entities to fulfill the reporting requirements under both adopted §25.61 and §25.63, relating to Distribution Pole Management and Inspection Plans, by submitting a consolidated annual report because these reports have different scopes and obligations. However, the commission notes that entities may use substantially similar information to fulfill reporting requirements under §25.63.

Oncor recommended that the commission clarify how entities should comply with the reporting requirements under §25.61, §25.63, and §25.94, given previous direction from commission staff to consolidate these reports.

Commission Response

The commission clarifies that the guidance regarding consolidation of reports provided in the February 2, 2026, filing by commission staff in Project Number 59287, CY 2026 Annual Reports Under PURA §§38.006(e), 38.101(a), and 38.103(c), was expressly limited to reports filed for 2026, while rulemakings to implement legislative changes to the listed statutory sections were pending. The reports required under §§25.61 and 25.63 are to be filed separately in 2027 and subsequent years.

Proposed §25.61(h)

Proposed §25.61(h) requires entities to retain records of inspections, serviceability grades, and corrective actions for each structure throughout its service life.

TPPA recommended limiting the record retention requirement under proposed §25.61(h) to poles and towers, rather than all structural components.

Commission Response

The commission declines to adopt TPPA's recommendation to limit the record retention requirement under proposed §25.61(h) to poles and towers, rather than all structural components, because structural components are included in the scope of the "structure" definitions under adopted §25.61(b).

CEHE recommended the record retention period under proposed §25.61(h) be shortened from the entire service life of a structure to 10 to 15 years, or alternatively shortened to the current inspection cycle plus one additional inspection cycle.

Commission Response

The commission declines to adopt CEHE's recommendation to shorten the record retention period under proposed §25.61(h) from the entire service life of a structure to 10 to 15 years, or to shorten the retention period to the current inspection cycle plus one additional inspection cycle, because a comprehensive record of inspection, serviceability grading, and corrective action activities and results for each structure is imperative for the assessment of changes to a structure's physical condition and structural integrity over time.

CEHE recommended that the commission specify what the record retention period is for structures that have been removed from service.

Commission Response

The commission clarifies that the record retention timeline is tied to structure's in-service life. If structure is no longer in-service, the record retention requirements under adopted §25.61(g) no longer apply.

TPPA and CEHE recommended that the commission clarify that the record retention requirement under proposed §25.61(h) will not apply retroactively.

Commission Response

The commission clarifies as recommended by TPPA and CEHE that the record retention requirements under adopted §25.61(g) expressly apply "beginning on the effective date of this section" and not retroactively. Further, to address information that may precede the section's effective date, the commission provides in adopted §25.61(g)(1) that, if the date a structure was placed into service is unavailable, an estimate of the structure's age in years is a permitted alternative data point.

Proposed §25.61(h)(1) - (3)

Proposed §25.61(h)(1) - (3) identifies the records that entities are required to retain for each structure under proposed §25.61(h), including records related to the identification of the structure, the physical and design characteristics of the structure, and the installation, inspection, serviceability grading, and corrective action history of the structure.

CPS, TPPA, and SPS recommended that the commission limit the records required for retention under proposed §25.61(h)(1) through (3). CPS recommended (h)(1) through (3) be deleted entirely and replaced with a general record retention requirement. Alternatively, CPS recommended the required records be limited to a structure's location and type, most-recent inspection date, type, and outcome, and- for structures owned by an entity

- the installation date and corrective action information. TPPA also recommended the required records be limited to information on a structure's installation, inspections, and corrective actions. SPS recommended the required records be limited to a structure's material type, voltage level, and installation information, if available.

Commission Response

The commission declines to limit the records required for retention under proposed §25.61(h) as recommended by commenters because the required information is imperative to establish a baseline record from which to assess changes to a structure's physical condition and structural integrity over time.

Proposed §25.61(h)(2)

Proposed §25.61(h)(2) requires entities to retain records related to the physical and design characteristics of a structure, including the voltage, support type, construction material, strength rating, and length.

Houston recommended that the commission modify proposed §25.61(h)(2) to additionally require entities to retain records of a structure's NESC design construction grade.

Commission Response

The commission declines to modify proposed §25.61(h)(2) to specifically require entities to retain records of a structure's NESC design construction grade as recommended by Houston because the record retention requirement under adopted §25.61(g)(3) already ensures that foundational information related to a structure's physical and design characteristics, including the operating voltage, support type, construction material, strength rating, and length, is kept for the entirety of the structure's service life.

Proposed §25.61(h)(3)(B)

Proposed §25.61(h)(3)(B) requires entities to retain records of the dates, types, and methods of inspections performed on each structure.

Houston recommended that the commission modify proposed §25.61(h)(3)(B) to require entities to retain records of a structure's inspection dates, types, and methods, as well as treatment types.

Commission Response

The commission adopts §25.61(g)(4) to require an electric utility to retain records related to the inspection, serviceability grading, and corrective action history of the structure. Among other information, these records must include documentation of the dates, types, and methods of inspections performed on a structure and, if assigned a serviceability other than 'Pass,' a description of any corrective actions taken to make-safe, remediate, or replace the structure. These requirements satisfy the recommendations made by Houston.

Proposed §25.61(h)(3)(C)

Proposed §25.61(h)(3)(C) requires entities to retain records of serviceability grades assigned to each structure, including the damage or defect and its root cause when a grade other than 'Pass' is assigned.

SPS recommended that the commission clarify whether entities are required to document or retain records related to a structure's passing serviceability grades.

Commission Response

The commission clarifies that, under adopted §25.61(g)(3)(C), an entity is required to retain records for each structure that document the serviceability grades assigned to the structure. This includes serviceability grades of 'Pass'.

CEHE recommended that the commission clarify whether the records under proposed §25.61(h)(3)(C) pertaining to the root cause of a structure's non-passing serviceability grade satisfies the proposed form's primary cause category.

Commission Response

The commission clarifies as recommended by CEHE that primary root cause information retained under adopted §25.61(g)(4)(C) may be used to inform an entity's responses to Appendix D of the adopted annual reporting form.

Comments on Proposed Form

General comments

Addition of 'Notes' sections

AEP Companies and TEC recommended that the commission add 'Notes' sections to the tables included in the proposed form to allow entities to provide additional context for reported data.

Commission Response

The commission agrees with AEP Companies and TEC and adds a 'Notes' section to Tables 1A, 1B, and 1C of the adopted Appendix B worksheet and Table 1 of the adopted Appendix C worksheet.

Events Spanning Multiple Reporting Years

TEC requested that the commission clarify how entities should report the information required by the proposed form for events that carry over from one reporting year to another.

Commission Response

The commission clarifies in the Appendix C worksheet of the adopted form that the information related to an event that spans multiple calendar years must be included in the annual report that corresponds to the calendar year the post-event inspection was completed.

Modifications to the Proposed Form

SPS recommended that the commission modify the proposed form to provide formatting and structural flexibility, limit required data fields to essential information, and establish protective safeguards for confidential information and sensitive data.

Commission Response

The commission modifies the proposed form to provide additional clarity and flexibility in the reporting data requirements and formatting, including by narrowing the reporting data requirements, simplifying the workbook format, offering clearer instructions and examples, and providing additional text-based reporting fields. These modifications to the proposed form address SPS' recommendations related to flexibility in formatting and structure and simplification of reporting data. In order to minimize conflict between §25.61 and other existing rule language relating to the confidential treatment of information, the commission declines to address in the proposed form the treatment of confidential information or sensitive data as recommended by SPS.

Reporting by Non-Wood Material Type

TPPA recommended that the commission eliminate the distinction between non-wood material types in the reporting requirements for transmission-level voltage structures under Table 1 of the proposed Entity Profile, Executive Summary, and Key Insights sheet, Table 2 of the proposed Appendix B sheet, and Tables 1 and 2 of the proposed Appendix C sheet.

Commission Response

The commission declines to eliminate the form's distinction between non-wood material types in the reporting requirements for transmission-level voltage structures as recommended by TPPA. The reporting categories for steel, concrete, and composite structures are intended solely to facilitate the collection and analysis of inspection, serviceability grading, and corrective action information and do not create additional or distinctive substantive requirements for non-wood structures under adopted §25.61. The commission finds that this additional level of reporting detail will support the ongoing evaluation of inspection outcomes, trends in serviceability grades, and corrective action activity across different non-wood structure types.

Extension Mechanism for Corrective Action Timelines

CEHE requested that the commission modify the proposed form to account for any extension mechanism that is adopted for corrective action timelines in §25.61.

Commission Response

The commission specifies the following in the Appendix B worksheet of the adopted form: "Entities may use the note sections in Section 5 (Columns M, Q, and Y) to cite extension notices that were submitted under 16 TAC §25.61(f)(1)(B) and (f)(2)(B) during the reporting year and extension notices that were not submitted during the reporting year but for which associated corrective actions continued into the reporting year. For each extension notice, the entity must identify the corresponding item number in the commission staff-designated control number under which the notice was filed. The item number(s) cited should correspond to the extension notice submitted for the applicable reporting year."

Proposed "Workbook Introduction and Glossary" Worksheet

The proposed "Workbook Introduction and Glossary" worksheet establishes the purpose of the form and provides a glossary of terms relevant to the form.

CPS and CEHE recommended that the commission update the glossary in the proposed Workbook Introduction and Glossary sheet.

Commission Response

The commission modifies the proposed Workbook Introduction and Glossary sheet for consistency with the language adopted under §25.61.

Proposed "Entity Profile, Executive Summary, and Key Insights" Worksheet, Table 2

Table 2 of the proposed "Entity Profile, Executive Summary, and Key Insights" worksheet establishes minimum executive summary requirements, including as related to inspection methodologies and administration, events triggering post-event inspections, structures replaced to higher NESC construction grades, inspection and maintenance standards, and delays in corrective action completions.

CPS recommended that the commission remove the reporting requirements related to events that trigger post-event inspections,

NESC construction grades of replaced structures, and delays to corrective action completion from Table 2 of the proposed "Entity Profile, Executive Summary, and Key Insights" worksheet. CPS argued that these requirements fall outside the scope of PURA §38.006 and will create administrative burdens for entities without a commensurate resulting benefit to the commission.

Commission Response

The commission agrees to remove the reporting requirement related to NESC construction grades of replaced structures from the proposed form as recommended by CPS. However, the commission declines to remove the requirements related to events that trigger post-event inspections or delays to completing corrective actions because these requirements directly relate to entities' implementation of the inspection, serviceability grading, and corrective action requirements established by adopted §25.61.

TPPA requested that the commission provide clarification on what level of detail is required from an inspection methodology description or explanation of corrective action delay under Table 2 of the proposed "Entity Profile, Executive Summary, and Key Insights" worksheet, including whether the commission expects systemic or structure-specific descriptions or explanations. TPPA further requested clarification on whether this reporting requirement is intended to apply at the individual structure level or only in aggregate for similar structures, events, or categories of corrective actions.

Commission Response

The commission includes in Table 2 of the adopted worksheet examples of responses that provide a level of detail and scope that is sufficient to meet the intent of the reporting requirements.

Proposed "Appendix A" Worksheet

The proposed "Appendix A" worksheet requires entities to report the actual inspection and corrective action timelines used during the reporting period.

CEHE requested that the commission modify the proposed "Appendix A" worksheet to include instructions specifying how, and with what units of measurement, entities should report the required timelines. TPPA requested that the commission modify the proposed sheet to provide additional clarification that the timelines for visual and comprehensive routine inspections should be reported separately from the timelines for post-event inspections.

Commission Response

The commission includes in the adopted worksheet additional guidance on how, and with what units of measurement, entities should report on the required inspection and corrective action timelines. These modifications to the proposed form satisfy the requests of CEHE and TPPA.

Proposed "Appendix B" Worksheet

The proposed "Appendix B" worksheet establishes reporting requirements related to routine inspections activities and results during the reporting period.

SPS recommended that the commission limit the reporting requirements under the proposed "Appendix B" worksheet to wood structures that did not pass inspection.

Commission Response

The commission declines to limit the reporting requirements under the proposed worksheet to wood structures that did not pass inspection, as recommended by SPS. This modification would prohibit insight into the non-wood structure inspections, serviceability grades, and corrective actions taken by an entity in a given reporting year. This is inconsistent with the requirements that apply to both wood and non-wood structures under adopted §25.61.

Proposed "Appendix B" Worksheet, Table 1

Table 1 of the proposed "Appendix B" worksheet establishes reporting requirements related to the root causes of non-"Pass" serviceability grades assigned following routine inspections during the reporting period.

CEHE recommended that the commission modify Table 1 of the proposed "Appendix B" worksheet to include an "Unknown/Undetermined" primary root cause category. SPS recommended that the commission clarify how the "Physical Contact" primary root cause category in Table 1 of the proposed sheet is defined with respect to wood structures.

Commission Response

The commission agrees with CEHE and SPS. Accordingly, the commission includes in the adopted "Appendix D" worksheet an "Unknown/Undetermined" primary root cause category and an example for the "Physical Contact" category.

Proposed "Appendix B" Worksheet, Table 2

Table 2 of the proposed "Appendix B" worksheet establishes reporting requirements related to routine inspection, serviceability grading, and corrective action activities and results during the reporting period.

SPS recommended that the commission remove the reporting requirement related to structures assigned a "Pass" serviceability grade from Table 2 of the proposed "Appendix B" worksheet.

Commission Response

The commission declines to remove the reporting requirement related to structures assigned a "Pass" serviceability grade from Table 2 of the proposed "Appendix B" worksheet as recommended by SPS. To simplify the requirement, the commission converts the manual entry "# of Structures Passing Inspection" fields into auto-calculated fields in Table 2 of the adopted "Appendix B" worksheet.

Proposed "Appendix B" Worksheet, Table 1, and "Appendix C" Worksheet, Table 1

Tables 1 of the proposed "Appendix B" and "Appendix C" worksheets establish reporting requirements related to the root causes of non-"Pass" serviceability grades assigned following routine and post-event inspections, respectively, during the reporting period.

TPPA recommended that the commission remove Table 1 entirely from the proposed "Appendix B" and "Appendix C" worksheets. Alternatively, TPPA recommended that the commission clarify that any causal information included in an entity's annual report is preliminary in nature and does not represent the results of a completed investigation or root cause analysis. TPPA also recommended that commission replace the manual entry of the "% of Total Non-'Pass' Structures" value in Table 1 with an embedded formula.

Commission Response

The commission declines to remove the root cause reporting requirements in Table 1 of the proposed "Appendix B" and "Appendix C" worksheets entirely as recommended by TPPA. This information provides important insights into the root causes of non-passing serviceability grades that entities observe on their transmission and distribution systems. However, the commission clarifies as recommended by TPPA that entities are not required to conduct additional, subsequent analyses or investigations into the root cause of a structure's non-passing serviceability condition. Entities may report on the primary root causes of non-passing structure's serviceability grades to the extent that this information is ascertainable upon the inspection of a structure.

To streamline reporting requirements, the commission relocates the primary root cause requirements under Tables 1 of the proposed "Appendix B" and "Appendix C" worksheets to a new "Appendix D" worksheet and, as recommended by TPPA, converts the manual entry "% of Total Non'Pass' Structures" fields to auto-calculated fields.

Proposed "Appendix C" Worksheet

The proposed "Appendix C" worksheet establishes reporting requirements related to post-event inspections activities and results during the reporting period.

CPS recommended that the commission delete the proposed "Appendix C" worksheet from the form entirely.

Commission Response

The commission declines to delete the proposed "Appendix C" worksheet from the form as recommended by CPS. However, to reduce redundancies and better reflect the practical scope of post-event inspections, the commission narrows the scope of the proposed worksheet to only require reporting on structures assigned non-passing serviceability grades.

Proposed "Appendix C" Worksheet, Table 1

Table 1 of the proposed "Appendix C" worksheet establishes reporting requirements related to the root causes of non-"Pass" serviceability grades assigned following post-event inspections during the reporting period.

SPS recommended that the commission limit the reporting requirements under Table 1 of the proposed "Appendix C" worksheet to only wood structures that did not pass inspection, emergency events associated with post-event inspections, and findings that required corrective action.

Commission Response

The commission clarifies that, consistent with SPS' recommendation, the post-event reporting requirements under the adopted "Appendix C" worksheet pertain only to those events that result in post-event inspections under adopted §25.61(d)(3) and the non-"Pass" serviceability grades and emergency make-safe corrective actions that result from a post-event inspection. The commission declines to limit the reporting requirements to only wood structures that did not pass inspection, as recommended by SPS. Such a limitation would prohibit insight into whether a post-event inspection resulted in any non-"Pass" serviceability grade assignments for non-wood structures.

Oncor recommended that the commission reconsider whether the primary root cause categories included in Table 1 of the proposed Appendix C sheet are relevant to post-event inspections.

Commission Response

The commission declines to remove the reporting requirements in Table 1 of the proposed "Appendix B" and "Appendix C" worksheets entirely as recommended by TPPA but relocates the requirements to a new "Appendix D" worksheet for clarity.

Proposed "Appendix C" Worksheet, Table 2

Table 2 of the proposed "Appendix C" worksheet establishes reporting requirements related to post-event inspection, serviceability grading, and corrective action activities and results during the reporting period.

SPS recommended that the commission clarify in Table 2 of the proposed "Appendix C" worksheet that post-event inspections are intended only to assess structures that are affected by a specific event, not entire circuits that were unaffected by the event.

Commission Response

The commission redesignates Table 2 of the proposed "Appendix C" worksheet as Table 1 of the adopted worksheet and clarifies the following to address SPS' recommendation: "Table 1 summarizes the post-event visual inspections, serviceability grades, and Emergency make-safe corrective actions taken on in-service structures affected by a qualifying event during the prior calendar year" (emphasis added).

Comments on Proposed 16 TAC §25.94

General comments

Overlapping reporting requirements

CEHE requested that the commission provide confirmation that, upon the adoption of new §25.61 and amendments to §25.94, all information related to pole inspections will be reported through the annual report required under proposed §25.61(g) and any overlapping reporting obligations between the two rule sections will be eliminated.

Commission Response

The commission confirms that electric utilities are not required to report information related to pole inspection activities under adopted §25.94.

SUBCHAPTER C. INFRASTRUCTURE AND RELIABILITY

16 TAC §25.52, §25.61

In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

This section and amendments are adopted under Public Utility Regulatory Act (PURA) §§14.001, which grants the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by this title that is necessary and convenient to the exercise of that power and jurisdiction; 14.002, which authorizes the commission to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction; 38.005, which establishes distribution feeder performance standards applicable to electric utilities and TDUs and directs the commission to consider the performance of electric utilities' and TDUs' distribution feeders in determining appropriate enforcement actions; 38.006, which directs the commission to adopt standards for the structural integrity of transmission and distribution poles; and 38.101, which requires electric utilities to annually submit to the commission a report on infrastructure improvement and maintenance activities.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.001; 14.002; 38.005; 38.006; and 38.101.

§25.52. *Reliability and Continuity of Service.*

(a) Application. This section applies to all electric utilities as defined by §25.5 of this title (relating to Definitions) and all transmission and distribution utilities as defined by §25.5 of this title. When specifically stated, this section also applies to electric cooperatives and municipally-owned utilities (MOUs). The term "utility" as used in this section means an electric utility and a transmission and distribution utility.

(b) General.

(1) Every utility must make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility must reestablish service within the shortest possible time.

(2) Each utility must make reasonable provisions to manage emergencies resulting from failure of service, and each utility must issue instructions to its employees covering procedures to be followed in the event of emergency in order to prevent or mitigate interruption or impairment of service.

(3) In the event of national emergency or local disaster resulting in disruption of normal service, the utility may, in the public interest, interrupt service to other customers to provide necessary service to civil defense or other emergency service entities on a temporary basis until normal service to these agencies can be restored.

(4) Each utility must maintain adequately trained and experienced personnel throughout its service area so that the utility is able to fully and adequately comply with the service quality and reliability standards.

(5) With regard to system reliability, a utility must not neglect any local neighborhood or geographic area, including rural areas, communities of less than 1,000 persons, and low-income areas.

(6) Each utility that provides distribution service to retail customers must maintain an accurate and publicly available online outage tracker or outage map on its website.

(A) An online outage tracker or outage map must contain a map of the utility's distribution service territory that identifies, for each active outage impacting retail distribution customers, the approximate location of the outage, the date and time the outage was reported or otherwise identified, an estimated restoration time, the general status of the restoration effort, and the date and time the outage and restoration status information was most recently updated. Information provided by the outage tracker or outage map under this subparagraph must be updated to include new or updated service addresses in the utility's service territory as soon as practicable, and be available in English and Spanish, as applicable.

(B) If a utility's outage tracker or outage map is scheduled to be taken offline or may otherwise become unavailable due to maintenance or upgrades, the utility must post details of the scheduled activity on its website and provide notice of the scheduled activity to the commission's Consumer Protection and Critical Infrastructure Security and Risk Management divisions no later than seven days prior to the scheduled activity. A utility must, as soon as reasonably practicable, notify the commission in writing if the utility's outage tracker or outage map unexpectedly becomes unavailable or if the utility determines that maintenance is required within the next seven days.

(C) An outage tracker or outage map must provide or link to information that indicates the different methods a customer may use to report an outage or hazardous condition and provide or link to information on how a customer may request to receive updates on the

status of outages and outage restoration efforts. The outage tracker or outage map must include at least one digital means for a customer to report an outage to the utility.

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

(1) Critical loads--Loads for which electric service is considered crucial for the protection or maintenance of public safety; including but not limited to hospitals, police stations, fire stations, critical water and wastewater facilities, and customers with special in-house life-sustaining equipment.

(2) Critical natural gas facility--A facility designated as a critical customer by the Railroad Commission of Texas under §3.65(b) of this title (relating to Critical Designation of Natural Gas Infrastructure) unless the facility has obtained an exception from its critical status. Designation as a critical natural gas facility does not guarantee the uninterrupted supply of electricity.

(3) Energy emergency--Any event that results in or has the potential to result in firm load shed required by the reliability coordinator of a power region in Texas.

(4) Interruption classifications:

(A) Forced--Interruptions, exclusive of major events, that result from conditions directly associated with a component requiring that it be taken out of service immediately, either automatically or manually, or an interruption caused by improper operation of equipment or human error.

(B) Scheduled--Interruptions, exclusive of major events, that result when a component is deliberately taken out of service at a selected time for purposes of construction, preventative maintenance, or repair. If it is possible to defer an interruption, the interruption is considered a scheduled interruption.

(C) Outside causes--Interruptions, exclusive of major events, that are caused by influences arising outside of the distribution system, such as generation, transmission, or substation outages.

(D) Major events--Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake or an extreme storm. These events include situations where there is a loss of power to 10% or more of the customers in a region over a 24-hour period and with all customers not restored within 24 hours.

(5) Interruption, momentary--Single operation of an interrupting device which results in a voltage zero and the immediate restoration of voltage.

(6) Interruption, sustained--All interruptions not classified as momentary.

(7) Interruption, significant--An interruption of any classification lasting one hour or more and affecting the entire system, a major division of the system, a community, a critical load, or service to interruptible customers; and a scheduled interruption lasting more than four hours that affects customers that are not notified in advance. A significant interruption includes a loss of service to 20% or more of the system's customers, or 20,000 customers for utilities serving more than 200,000 customers. A significant interruption also includes interruptions adversely affecting a community such as interruptions of governmental agencies, military bases, universities and schools, major retail centers, and major employers.

(8) Reliability indices:

(A) System Average Interruption Frequency Index (SAIFI)--The average number of times that a customer's service is interrupted. SAIFI is calculated by summing the number of customers interrupted for each event and dividing by the total number of customers on the system being indexed. A lower SAIFI value represents a higher level of service reliability.

(B) System Average Interruption Duration Index (SAIDI)--The average amount of time a customer's service is interrupted during the reporting period. SAIDI is calculated by summing the restoration time for each interruption event times the number of customers interrupted for each event and dividing by the total number of customers. SAIDI is expressed in minutes or hours. A lower SAIDI value represents a higher level of service reliability.

(d) Record of interruption. Each utility must keep complete records of sustained interruptions of all classifications. Where possible, each utility must keep a complete record of all momentary interruptions. These records must show the type of interruption, the cause for the interruption, the date and time of the interruption, the duration of the interruption, the number of customers interrupted, the substation identifier, and the transmission line or distribution feeder identifier. In cases of emergency interruptions, the remedy and steps taken to prevent recurrence must be recorded. Each utility must retain records of interruptions for five years.

(e) Notice of significant interruptions.

(1) Initial notice. A utility must notify the commission, in a method prescribed by the commission, as soon as reasonably possible after it has determined that a significant interruption has occurred. The initial notice must include the general location of the significant interruption, the approximate number of customers affected, the cause if known, the time of the event, and the estimated time of full restoration. The initial notice must also include the name and telephone number of the utility contact person and must indicate whether local authorities and media are aware of the event. If the duration of the significant interruption is greater than 24 hours, the utility must update this information daily and file a summary report.

(2) Summary report. Within five working days after the end of a significant interruption lasting more than 24 hours, the utility must submit a summary report to the commission. The summary report must include the date and time of the significant interruption; the date and time of full restoration; the cause of the interruption, the location, substation and feeder identifiers of all affected facilities; the total number of customers affected; the dates, times, and numbers of customers affected by partial or step restoration; and the total number of customer-minutes of the significant interruption (sum of the interruption durations times the number of customers affected).

(f) Priorities for power restoration to certain medical facilities.

(1) A utility must give the same priority that it gives to a hospital in the utility's emergency operations plan for restoring power after an extended power outage, as defined by Texas Water Code, §13.1395, to the following:

(A) An assisted living facility, as defined by Texas Health and Safety Code, §247.002;

(B) A facility that provides hospice services, as defined by Texas Health and Safety Code, §142.001;

(C) A nursing facility, as defined by Texas Health and Safety Code, §242.301; and

(D) An end stage renal disease facility, as defined by Texas Health and Safety Code, §251.001.

(2) The utility may use its discretion to prioritize power restoration for a facility after an extended power outage in accordance with the facility's needs and with the characteristics of the geographic area in which power must be restored.

(g) System reliability. Reliability standards apply to each utility and are limited to the Texas jurisdiction. A "reporting year" is the 12-month period beginning January 1 and ending December 31 of each year.

(1) System-wide standards. The standards must be unique to each utility based on the utility's performance and may be adjusted by the commission if appropriate for weather or improvements in data acquisition systems. The standards will be the average of the utility's performance from the later of reporting years 1998, 1999, and 2000, or the first three reporting years the utility is in operation.

(A) SAIFI. Each utility must maintain and operate its electric distribution system so that its SAIFI value does not exceed its system-wide SAIFI standard by more than 5.0%.

(B) SAIDI. Each utility must maintain and operate its electric distribution system so that its SAIDI value does not exceed its system-wide SAIDI standard by more than 5.0%.

(2) Distribution feeder performance. The commission will evaluate the performance of distribution feeders with ten or more customers after each reporting year. Each utility must maintain and operate its distribution system so that no distribution feeder with ten or more customers sustains a SAIDI or SAIFI value for a reporting year that is more than 200% greater than the system average of all feeders during any two consecutive reporting years.

(3) Enforcement. The commission may take appropriate enforcement action, including action against a utility, if the system and feeder performance is not operated and maintained in accordance with this subsection. In determining the appropriate enforcement action, the commission will consider:

- (A) the feeder's operation and maintenance history;
- (B) the cause of each interruption in the feeder's service;
- (C) the duration of each interruption in the feeder's service;
- (D) any action taken by a utility to address the feeder's performance;
- (E) the estimated cost and benefit of remediating a feeder's performance; and
- (F) any other relevant factor as determined by the commission.

(h) Critical natural gas facilities. In accordance with §3.65 of this title, critical natural gas standards apply to each facility in this state designated as a critical customer under §3.65 of this title. In this subsection, the term "utility" includes MOUs, electric cooperatives, and entities considered utilities under subsection (a) of this section.

(1) Critical customer information.

(A) In accordance with §3.65 of this title, the operator of a critical natural gas facility must provide critical customer information to the entities listed in clauses (i) and (ii) of this subparagraph. The critical customer information must be provided by email using Form CI-D and any attachments, as prescribed by the Railroad Commission of Texas.

(i) The utility from which the critical natural gas facility receives electric delivery service; and

(ii) For critical natural gas facilities located in the ERCOT region, the independent organization certified under PURA §39.151.

(B) The commission will maintain on its website a list of utility email addresses to be used for the provision of critical customer information under subparagraph (A) of this paragraph. Each utility must ensure that the email address listed on the commission's website is accurate. If the utility's email address changes or is inaccurate, the utility must provide the commission with an updated email address within five business days of the change or of becoming aware of the inaccuracy.

(C) Within ten business days of receipt, the utility must evaluate the critical customer information for completeness and provide written notice to the operator of the critical natural gas facility regarding the status of its critical natural gas designation.

(i) If the information submitted is incomplete, the utility's notice must specify what additional information is required and provide a deadline for response that is no sooner than five business days from when the critical natural gas facility receives the written notice. If the utility does not receive the additional information in a timely fashion, the utility may use its discretion to determine if it is possible to treat the natural gas facility as critical for load shed and power restoration purposes.

(ii) If the information submitted is complete, the utility's notice must notify the operator of the facility's critical natural gas status, the date of its designation, any additional classifications assigned to the facility by the utility, and notice that its critical status does not constitute a guarantee of an uninterrupted supply of energy.

(iii) A utility must provide an additional notice to the operator of the critical natural gas facility regarding any changes to the information provided in the notice required under clause (i) of this subparagraph. Notice must be provided within ten business days of the effective date of the change.

(D) A utility or an independent system operator receiving or sending critical customer information regarding a critical natural gas facility under this subsection must not release critical customer information to any person unless authorized by the commission or the operator of the critical natural gas facility. This prohibition does not apply to the release of such information to the commission, the Railroad Commission of Texas, the utility from which the critical natural gas facility receives electric delivery service, the designated transmission operator, or the independent system operator or reliability coordinator for the power region in which the critical natural gas facility is located. This prohibition also does not apply if the critical customer information is redacted, aggregated, or organized in such a way as to make it impossible to identify the critical natural gas facility to which the information applies.

(2) Prioritization of critical natural gas facilities. A critical natural gas facility is a critical load during an energy emergency. A utility must incorporate critical natural gas facilities into its load-shed and restoration planning. For purposes of this paragraph, a utility may also treat a natural gas facility that self-designated as critical using the Application for Critical Load Serving Electric Generation and Cogeneration form as a critical natural gas facility, as circumstances require.

(A) A utility must prioritize critical natural gas facilities for continued power delivery during an energy emergency.

(B) A utility may use its discretion to prioritize power delivery and power restoration among critical natural gas facilities and other critical loads on its system, as circumstances require.

(C) A utility must consider any additional guidance or prioritization criteria provided by the commission, the Railroad Commission of Texas, or the reliability coordinator for its power region to prioritize among critical natural gas facilities and other critical loads during an energy emergency.

(D) Compliance with directives of a regional transmission organization having authority over a utility outside of the ERCOT power region will be deemed compliance for that utility.

§25.61. Transmission and Distribution Pole Structural Integrity Standards.

(a) Applicability.

(1) This section applies only to an electric utility, a municipally owned utility, or an electric cooperative that operates a transmission or distribution asset in this state.

(2) For purposes of this section, the electric utility, municipally owned utility, or electric cooperative that owns a transmission or distribution asset is presumed to operate that asset unless a different electric utility, municipally owned utility, or electric cooperative is responsible for inspections, maintenance, remediation, and replacement of that asset. An electric utility, municipally owned utility, or electric cooperative responsible for the listed functions that contracts with a third party other than an electric utility, municipally owned utility, or electric cooperative to perform those functions retains responsibility for compliance with the provisions of this section.

(b) Definitions.

(1) Entity--an electric utility, a municipally owned utility, or an electric cooperative to which this section applies.

(2) County, coastal--a county in this state that is defined as a "first-tier coastal county" or "second-tier coastal county" under Section 2210.003, Texas Insurance Code.

(3) County, non-coastal--a county in this state that is not defined as a "first-tier coastal county" or "second-tier coastal county" under Section 2210.003, Texas Insurance Code.

(4) Qualifying event--an event that an entity reasonably expects to affect the physical condition of a structure, including a service interruption that meets the classification criteria of a Major Events interruption under 16 TAC §25.52 (relating to Reliability and Continuity of Service) or an event that meets the criteria of a resiliency event under 16 TAC §25.62 (relating to Transmission and Distribution System Resiliency Plans).

(5) Structure, non-wood--an in-service electrical pole or tower, including any attached crossarms, braces, support hardware, guys, foundations, and anchors, operating at any voltage that is constructed of composite, concrete, or steel materials.

(6) Structure, wood--an in-service electrical pole or tower, including any attached crossarms, braces, support hardware, guys, foundations, and anchors, operating at any voltage that is constructed of wood materials.

(7) Voltage, distribution-level--an operating voltage below 60 kilovolts (kV), when measured phase-to-phase.

(8) Voltage, transmission-level--an operating voltage at or above 60 kV, when measured phase-to-phase.

(c) Implementation. An entity is responsible for implementing the requirements of this section as follows.

(1) Electric utilities. An electric utility must comply with the requirements of subsections (d), (e), (f), (g), and (h) of this section.

(2) Municipally owned utilities and electric cooperatives.

(A) Adoption. In accordance with Public Utility Regulatory Act (PURA) §38.006(d) and Senate Bill 1789, §6(c), as enacted during the 89th Regular Texas Legislative Session, each municipally owned utility and electric cooperative must adopt the requirements established under subsections (d), (e), (f), and (g) of this section not later than 120 days after the effective date of this section.

(B) Attestation. In accordance with PURA §38.006(f), each municipally owned utility and electric cooperative must file an attestation with the first annual report under subsection (h) of this section after the municipally owned utility or electric cooperative adopts the requirements established under subsections (d), (e), (f), and (g) of this section. The attestation must be signed by the municipally owned utility's or electric cooperative's highest-ranking representative, official, or officer with binding authority over the municipally owned utility or electric cooperative.

(d) Inspections.

(1) Inspection types.

(A) Visual inspection. A visual inspection allows an electric utility to assess any readily observable damage or defects to the physical condition of a wood or non-wood structure, including, as applicable, damage to a crossarm, pole, or tower, extreme rust or corrosion, or slacked or broken guys and anchors.

(B) Comprehensive inspection. A comprehensive inspection allows an electric utility to conduct a visual inspection as well as a detailed assessment of any damage or defects to the structural integrity of a wood or non-wood structure, including, as applicable, below-groundline decay, rot, or loss of strength, structural corrosion, deterioration, or deformation, or foundation issues.

(2) Routine inspections.

(A) Structures operated at transmission-level voltage.

(i) Wood structures. An electric utility that operates a wood structure at transmission-level voltage must develop and implement an inspection cycle that ensures:

(I) a visual inspection of the structure is conducted annually; and

(II) a comprehensive inspection of the structure is conducted at least every 10 calendar years.

(ii) Non-wood structures. An electric utility that operates a non-wood structure at transmission-level voltage must develop and implement an inspection cycle that ensures:

(I) a visual inspection of the structure is conducted annually; and

(II) a comprehensive inspection of the structure is conducted at least every 12 calendar years.

(B) Structures operated at distribution-level voltage.

(i) Wood structures.

(I) Coastal counties. An electric utility that operates a wood structure at distribution-level voltage in a coastal county of this state must develop and implement an inspection cycle that ensures a comprehensive inspection of the structure is conducted at least every eight calendar years.

(II) Non-coastal counties. An electric utility that operates a wood structure at distribution-level voltage in a non-coastal county of this state must develop and implement an inspection cycle

that ensures a comprehensive inspection of the structure is conducted at least every 10 calendar years.

(ii) **Non-wood structures.** An electric utility that operates a non-wood structure at distribution-level voltage must develop and implement an inspection cycle that ensures a comprehensive inspection of the structure is conducted at least every 12 calendar years.

(3) **Post-event inspections.** An electric utility that operates a wood or non-wood structure affected by a qualifying event must conduct a visual inspection of the structure as soon as practicable, but not later than 45 calendar days, after the date the qualifying event ends or the date service is restored at the structure following a qualifying event, whichever occurs later.

(e) **Serviceability grading system.** Upon conducting any inspection of a structure required by this section, an electric utility must assign the structure a serviceability grade according to this subsection.

(1) **Pass.** A 'Pass' grade applies when the structure meets the applicable strength requirements established by the National Electrical Safety Code (NESC) and is otherwise absent of readily observable and structural damage or defects.

(2) **Remediate.** A 'Remediate' grade applies when the structure does not meet the 'Pass' grade criteria under paragraph (1) of this subsection but can reasonably be restored through repair, reinforcement, treatment, or another means of correction.

(3) **Replace.** A 'Replace' grade applies when the structure does not meet the 'Pass' grade criteria under paragraph (1) of this subsection and cannot reasonably be restored through repair, reinforcement, treatment, or by another means of correction.

(4) **Emergency.** An 'Emergency' grade applies when the structure exhibits signs of imminent failure risk or otherwise poses a risk to public safety.

(f) **Corrective actions.**

(1) **Remediation.**

(A) As soon as practicable, but not more than six calendar months, after the date an electric utility assigns a structure a 'Remediate' grade under subsection (d) of this section, the electric utility must restore the structure to the applicable NESC strength requirements, or otherwise resolve the damage or defect to the structure, through repair, reinforcement, treatment, or by other means of correction.

(B) **Extension and notice.**

(i) **Extension.** An electric utility that deems it impracticable to complete the remediation of a structure within the timeline established under subparagraph (A) of this paragraph may extend the structure's remediation timeline to a date not more than 12 calendar months after the date the electric utility assigned the structure a 'Remediate' grade under subsection (d) of this section.

(ii) **Notice.** An electric utility that extends a structure's remediation timeline under clause (i) of this subparagraph must file notice of the extension in the control number designated by commission staff for this purpose as soon as practicable, but not later than the date corresponding to the end of the timeline established under subparagraph (A) of this paragraph. The notice must state:

(I) the electric utility's reasons for deeming it impracticable to complete the remediation of the structure within the timeline established under subparagraph (A) of this paragraph; and

(II) the date that the electric utility expects to complete the remediation of the structure.

(2) **Replacement.**

(A) As soon as practicable, but not more than 12 calendar months, after the date an electric utility assigns a structure a 'Replace' grade under subsection (d) of this section, the electric utility must replace the structure with another structure that meets the applicable NESC strength requirements.

(B) **Extension and notice.**

(i) **Extension.** An electric utility that deems it impracticable to complete the replacement of a structure within the timeline established under subparagraph (A) of this paragraph may extend the structure's replacement timeline to a date not more than 24 calendar months after the date the electric utility assigned the structure a 'Replace' grade under subsection (d) of this section.

(ii) **Notice.** An electric utility that extends a structure's replacement timeline under clause (i) of this subparagraph must file notice of the extension in the control number designated by commission staff for this purpose as soon as practicable, but not later than the date corresponding to the end of the timeline established under subparagraph (A) of this paragraph. The notice must state:

(I) the electric utility's reasons for deeming it impracticable to complete the replacement of the structure within the timeline established under subparagraph (A) of this paragraph; and

(II) the date that the electric utility expects to complete the replacement of the structure.

(3) **Emergency.**

(A) **Make-safe.** An electric utility must resolve a structure's imminent failure or public safety risk as soon as practicable, but not more than two calendar days, after the date the electric utility assigns the structure an 'Emergency' grade under subsection (d) of this section, or the date the structure becomes safe to access, whichever occurs later.

(B) **Remediation or replacement.** After an electric utility resolves a structure's imminent failure or public safety risk under subparagraph (A) of this paragraph, the electric utility must, as applicable,:

(i) remediate the structure according to the requirements of paragraph (1) of this subsection; or

(ii) replace the structure according to the requirements of paragraph (2) of this subsection.

(g) **Record retention.** Beginning on the effective date of this section, an electric utility must retain the records required under this subsection for all structures the electric utility operates. At a minimum, an electric utility must retain records of the following information for the entirety of a structure's service life:

(1) The date the structure was placed into service, or, if unavailable, an estimate of the structure's age in years;

(2) The identification of the structure, including a unique identifier;

(3) The physical and design characteristics of the structure, including the operating voltage, support type, construction material, strength rating, and length; and

(4) The inspection, serviceability grading, and corrective action history of the structure, including documentation of:

(A) the dates, types, and methods of inspections performed on the structure;

(B) the serviceability grades assigned to the structure; and

(C) if assigned a serviceability grade other than 'Pass,' a description of the reason and primary root cause, if ascertainable, for the structure's serviceability grade and any corrective actions taken to make-safe, remediate, or replace the structure.

(h) Annual reports. Not later than May 1 of each year, an entity must file with the commission a report on the entity's inspection, serviceability grading, and corrective action activities and results for the prior calendar year as required by a commission-prescribed form.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Katelyn Lewis

Rules Coordinator

Public Utility Commission of Texas

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For further information, please call: (512) 936-7044



SUBCHAPTER D. RECORDS, REPORTS, AND OTHER REQUIRED INFORMATION

16 TAC §25.94

In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

This section and amendments are adopted under Public Utility Regulatory Act (PURA) §§14.001, which grants the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by this title that is necessary and convenient to the exercise of that power and jurisdiction; 14.002, which authorizes the commission to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction; 38.005, which establishes distribution feeder performance standards applicable to electric utilities and TDUs and directs the commission to consider the performance of electric utilities' and TDUs' distribution feeders in determining appropriate enforcement actions; 38.006, which directs the commission to adopt standards for the structural integrity of transmission and distribution poles; and 38.101, which requires electric utilities to annually submit to the commission a report on infrastructure improvement and maintenance activities.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.001; 14.002; 38.005; 38.006; and 38.101.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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SUBCHAPTER I. TRANSMISSION AND DISTRIBUTION

DIVISION 1. OPEN-ACCESS COMPARABLE TRANSMISSION SERVICE FOR ELECTRIC UTILITIES IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS

16 TAC §25.194

The Public Utility Commission of Texas (commission) adopts new 16 Texas Administrative Code (TAC) §25.194, relating to Large Load Interconnection Standards, with changes to the proposed text as published in the March 27, 2026 issue of the *Texas Register* (51 TexReg 1942). The new rule implements Public Utility Regulatory Act (PURA) §37.0561 as enacted by Senate Bill (SB) 6 during the Texas 89th Regular Legislative Session. The new rule requires a large load customer, before the large load customer can be included in an ERCOT interconnection study, to execute an intermediate agreement, provide certain disclosures, and post financial security in the amount \$50,000 per megawatt (MW). The new rule also requires a large load customer to execute a standard large load agreement (SLLIA), update its disclosures, post financial security, and pay contribution in aid of construction (CIAC) for direct interconnection costs. Additionally, the new rule sets forth the consequences of withdrawing all or a portion of requested peak demand or contracted peak demand and the consequences for providing false or inaccurate information. Finally, the new rule sets forth the terms for the return of financial security to a large load customer that energizes. This section is adopted under Project Number 58481. The rule will be republished.

The commission received written comments on the proposed section from Advanced Power Alliance and American Clean Power Association (APA and ACP); AEP Texas Inc. (AEP); Agentic Infrastructure (Agentic); BKV Corporation (BKV); Black Mountain Power, LLC (Black Mountain); Brazos Electric Cooperative, Inc., Golden Spread Electric Cooperative, Inc., Rayburn Country Electric Cooperative, Inc., South Texas Electric Cooperative, Inc. (collectively, TSP Cooperatives); CCNG, Inc. (CCNG); CenterPoint Energy Houston Electric, LLC (CenterPoint); Cholla, Inc. (Cholla); Cipher Digital Inc. (Cipher); CloudHQ LLC (CloudHQ); Competitive Power Ventures, Inc. (CPV); Constellation Energy Generation, LLC (Constellation); Crow Holdings; Crusoe Technologies LLC (Crusoe); Data Center Coalition (DCC); DC Energy Texas, LLC (DC Energy); Electric Hydrogen Co. (EH2); Environmental Defense Fund (EDF); Eolian L.P. (Eolian); Eolic Development Partners (Eolic); ERCOT Steel Mills; Google LLC, Lancium LLC, and TotalEnergies Renewables USA (Google, Lancium, and TotalEnergies); Guadalupe Valley Electric Cooperative, Inc. (GVEC); HIF USA LLC (HIF); Hunt Energy Network, L.L.C. (HEN); Hut 8 Corp (Hut 8); Infinium Operations, LLC; Intersect Power, LLC (Intersect Power); Jason Buster; Landmark Development Services LLC

and EcoPartner Alliance (Landmark and EcoPartner); Lower Colorado River Authority and LCRA Transmission Services Corporation (LCRA); Mission Power; Monarch Energy Development LLC (Monarch); NRG Energy, Inc. (NRG); Office of Public Utility Counsel (OPUC); Oncor Electric Delivery Company LLC (Oncor); Permian Basin Petroleum Association (PBPA); Priority Power Management LLC (PPM); Rowan Digital Infrastructure LLC (Rowan); Satoshi Energy (Satoshi); Schaper Energy Consulting LLC (Schaper Energy); Serena Power (Serena); Sierra Club, Lone Star Chapter (Sierra Club); Skybox Datacenters, LLC (Skybox); STACK Infrastructure (STACK); Steering Committees Served by Oncor and Texas Coalition for Affordable Power (OCSC and TCAP); Targa Resources LLC (Targa); Tesla, Inc. (Tesla); Texas Competitive Power Advocates (TCPA); Texas Electric Cooperatives, Inc. (TEC); Texas Energy Buyers Alliance (TEBA); Texas Industrial Energy Consumers (TIEC); Texas-New Mexico Power Company (TNMP); Texas Oil & Gas Association (TXOGA); Texas Public Policy Foundation (TPPF); Texas Public Power Association (TPPA); City of Bryan; Thor Equities; Tract Holding Company I, LLC (Tract); Trammell Crow Company (TCC); Vistra Corporate Services Company (Vistra); Voltus; Wind Energy Transmission Texas, LLC (WETT), Cross Texas Transmission, LLC (CTT), Lone Star Transmission, LLC (Lone Star), and Sharyland Utilities, LLC (Sharyland) (Collectively, Joint TSPs); and Zachary Butler, Blind Mice Labs (Zachary Butler).

General Comments

Loads included in batch zero interconnection study

Agentic, EH2, HIF, Monarch, Skybox, Targa, TEBA, and Tract recommended modifying the proposed rule to address a large load customer's eligibility for inclusion in Batch Zero as either firm load or studied load. Black Mountain Power, Targa, and Vistra recommended modifying the proposed rule to prioritize certain types of loads for inclusion in Batch Zero.

Commission Response

The commission declines to adopt commenters' recommendation to address a large load customer's eligibility for inclusion in the batch zero interconnection study as either firm load or studied load; and declines to adopt commenters' recommendation to prioritize certain types of loads for inclusion in the batch zero interconnection study. Neither is necessary because Planning Guide Revision Request (PGRR) 145, which was approved by the commission on June 18, 2026, addresses eligibility and study requirements for batch zero load.

Changes to PGRR 145

EH2, Eolic, Landmark and EcoPartner, and Monarch recommended modifying the proposed rule to direct ERCOT to make changes to PGRR 145.

Commission Response

The commission declines to adopt EH2, Eolic, Landmark and EcoPartner, and Monarch's recommendation to modify the adopted rule to direct ERCOT to make changes to PGRR 145. PGRR 145 was approved by the commission on June 18, 2026; therefore, changes to PGRR 145 are moot. Additionally, PGRR 145 establishes the eligibility criteria for large load customers to be included in the batch zero interconnection study as either base load or studied load and the process for the batch zero interconnection study. The adopted rule does not address these issues.

Loads studied in the Permian Basin Reliability Plan (PBRP)

PBPA requested the commission clarify how the proposed rule and batch process create a path for interconnection for all loads that supported the need for the PBRP, including those below 75 MW. PBPA recommended the proposed rule and batch process include appropriate safeguards to ensure transmission infrastructure is made available to serve oil and gas loads that formed the basis for the PBRP.

Commission Response

The commission declines to adopt PBPA's recommendation to clarify how the proposed rule and batch process create a path for interconnection for loads that were studied in the PBRP, including those below 75 MW. The interconnection path for loads below 75 MW is outside the scope of the adopted rule. The commission also declines to modify the adopted rule to ensure transmission infrastructure is made available to serve oil and gas loads studied in the PBRP. Neither is necessary. PGRR 145 addresses eligibility for inclusion in the batch zero interconnection study. All other large load customers must comply with the adopted rule for inclusion in a future interconnection study. The standards in the adopted rule apply equally to all large load customers.

Financial commitments for studied loads included in Batch Zero

For batch zero loads that do not qualify as "base load" i.e., projects that have not yet satisfied ERCOT Planning Guide Sections 9.4 and 9.5 through completion of required studies, execution of interconnection agreements, and demonstration of financial commitment Skybox recommended ensuring that any new financial requirements are calculated on a net basis, with full credit given to amounts already posted with or paid to the applicable distribution service provider (DSP) or transmission service provider (TSP).

Commission Response

The commission declines to adopt Skybox's recommendation to ensure that any new financial requirements required of a studied load in the batch zero interconnection study be calculated on a net basis with full credit given to amounts already posted with or paid to the applicable DSP or TSP. Instead, the commission modifies the adopted rule to ensure that a letter of credit or guaranty serving as financial security is returned to a large load customer that is included in the batch zero interconnection study and cash collateral serving as financial security is returned or credited based on the large load customer's election and notice to the applicable DSP or TSP. The commission also modifies the adopted rule to require all loads eligible for inclusion in the batch zero interconnection study to execute a Standard Large Load Interconnection Agreement (SLLIA) with new obligations to post financial security. This creates uniform treatment for large load customers that have not energized as of the effective date of the adopted rule and ensures that the circumstances allowing the DSP or TSP to draw down on the financial security contemplate payment for outstanding amounts owed as described in the adopted rule thus striking a balance between ensuring that large load customers are not posting double the financial security and protecting ratepayers against stranded infrastructure costs.

If applicable

Constellation and LCRA recommended modifying the phrase "interconnecting DSP or interconnecting TSP" throughout the rule to state "interconnecting DSP or, if applicable, interconnecting TSP" to avoid inference that the entity is discretionary.

Commission Response

The commission declines to adopt Constellation and LCRA's recommendation to modify the phrase "interconnecting DSP or interconnecting TSP" throughout the rule to state "interconnecting DSP or, if applicable, interconnecting TSP" because the division of responsibility is best addressed in a separate rulemaking to adopt a SLLIA.

Non-refundable financial security

Black Mountain Power, Skybox, TCC, and TEBA recommended modifying the proposed rule to revise the non-refundability of financial security.

Specifically, Black Mountain Power recommended revising the proposed rule to tie financial exposure to meaningful milestones. Skybox recommended that refund and credit calculations should be applied after giving effect to first-dollar crediting of existing financial security and CIAC; no portion of the required financial commitment should be subject to forfeiture for undelivered capacity or delay driven deferrals outside the customer's control; and DSPs and TSPs should retain the ability to require incremental financial commitments only to the extent necessary to cover actual interconnection related costs associated with delivered capacity.

TCC recommended modifying the proposed rule to provide that the financial security balance must be refunded when the large load customer "reaches and sustains the contracted level of operation" because the 5-year period is excessive and inconsistent with industry practice.

TEBA opposed the imposition of non-refundable security before any load studies occurred and before any transmission is confirmed to be available, or when it might materialize. TEBA recommended that non-refundability is appropriate when a developer has elected to move forward with inclusion in a transmission plan that incorporates their loads and should be limited to protecting other customers from paying for costs incurred by the utility on their behalf if the developer does not ultimately move forward. TEBA recommended that all financial security be refunded upon energization and the load transitions to minimum transmission charges. TEBA noted that the process is unclear for exercising corporate guarantee payments for projects that do not move forward in the process. To address this, TEBA recommended that the utility directly invoice a developer who leverages a parental guarantee if their project is cancelled.

Commission Response

The commission adopts Black Mountain Power, Skybox, and TEBA's recommendation to revise the non-refundability of financial security. Specifically, the commission modifies the adopted rule to allow return of all financial security after collection of outstanding amounts owed if a large load customer withdraws its interconnection request before the interconnection study begins and authorizes the return of financial security after: (1) collection of outstanding amounts owed and (2) subtraction of 20% of the financial security associated with transmission capacity allocated if a large load customer withdraws its interconnection request after ERCOT has allocated transmission capacity. The commission also adopts TEBA's recommendation to allow the interconnecting DSP or TSP to invoice a large load customer if its project is cancelled. However, the commission modifies the adopted rule to allow the interconnecting DSP or TSP to invoice the large load customer for outstanding amounts owed regardless of what manner of financial security was posted.

Limitations of financial security

CenterPoint recommended that proposed §25.194(g) through (i), each of which requires the interconnecting utility to draw down on financial security in different circumstances, are in conflict. Once financial security is drawn down is under one of these subsections, it will no longer be available for use under any of the other subsections.

Commission Response

The commission agrees with CenterPoint that once financial security is drawn down it is no longer available for use under other circumstances. However, the commission disagrees that the adopted rule results in a conflict by requiring the interconnecting DSP or TSP to draw down on financial security in different circumstances because the identified circumstances are mutually exclusive.

Framework for flow of financial security obligations

APA and ACP, BKV, CloudHQ, CPV, HEN, Infinium, Intersect Power, OCSC and TCAP, Oncor, Rowan, Schaper Energy, Tesla, and TPPA recommended modifying the framework for flow of financial security commitments and obligations.

Specifically, APA and ACP recommended modifying the proposed rule to: (1) reduce the amount that is not refundable from 80% to no more than 10% with the remainder refunded if the developer's withdrawal does not adversely affect other requests in the cluster; (2) allow the non-refundable portion to be held until the end of the study process and used only to fund underfunded upgrades or restudies; and (3) allow a one-time transfer mechanism such as the one used in the Southwest Power Pool's Consolidated Planning Process.

BKV recommended a framework whereby: (1) intermediate-stage security is released when security is posted under an interconnection agreement, unless the customer elects to carry it forward for other financial obligations; (2) CIAC and equipment-related payments are fully creditable and not duplicative of other security requirements; (3) additional financial obligations are limited to incremental, project-specific costs not already secured or funded; and (4) to the extent multiple financial instruments are retained, expressly require transparent accounting and appropriate crediting across categories.

CPV recommended applying the interconnection fee to financial security requirements after execution of the interconnection agreement. CPV also recommended requiring financial security only after the results of a feasibility study are available.

CloudHQ recommended modifying the proposed rule to require only one form of financial security at the interconnection agreement phase. HEN recommended aligning the financial obligations with expected system use and avoiding duplicative recovery for the same MW of demand.

Infinium recommended the commission clarify whether financial obligations arising under the interconnection agreement are additive to, or inclusive of obligations arising under the intermediate agreement stage.

Intersect Power and Schaper Energy generally recommended: (1) clarifying that all financial commitments are creditable on a dollar-for-dollar basis across stages and categories; (2) replacing the non-refundable interconnection fee with a creditable financial security construct, under which any security posted at the intermediate stage is maintained and applied on a dollar-for-dollar basis to actual project costs (including CIAC, equip-

ment, and system upgrades), with any additional security limited to incremental, project-specific cost exposure; (3) confirming that CIAC and equipment-related payments are not duplicative of other security requirements; and (4) maintaining independent security for system upgrades only where stranded cost risk is project-specific and demonstrable.

OCSC and TCAP recommended clarifying the particular flow of funds among the fee categories and the extent to which a large load customer will be refunded for financial security posted as part of the intermediate agreement if ERCOT does not award that customer the full amount of its requested peak demand and that customer thus decides to withdraw its requested peak demand. OCSC and TCAP also recommended including all categories of fees under one subsection so that they are readily available and easier to review.

Oncor recommended that the commission allow the required financial commitments in the interconnection agreement phase to overlap, not stack.

Rowan recommended modifying the adopted rule to provide that upon execution of the interconnection agreement, the interconnecting DSP or TSP must credit financial security posted under the intermediate agreement to financial security and obligations arising from the interconnection agreement. If the security posted under the intermediate agreement exceeds the amount required under the interconnection agreement, the excess must be refunded within 60 days.

Tesla recommended modifying the proposed rule to apply the deposit paid at the intermediate agreement stage to other project costs and financial postings as the customer moves through the interconnection process.

TPPA recommended modifying the rule to base the intermediate financial security requirement on 75% instead of 100% of requested peak demand and assess the remaining 25% during the interconnection phase.

Commission Response

The commission adopts commenters' recommendation to revise the framework for financial security. Accordingly, the commission modifies the adopted rule in a manner that allows financial security commitments and obligations to overlap rather than stack; clarifies the flow through of various financial security requirements; and clarifies the circumstances under which financial security must be returned to a large load customer.

Specifically, the adopted rule is modified to allow cash collateral posted as financial security under an intermediate agreement to be credited to the financial security requirements for significant equipment or services. A letter of credit or guaranty provided under an intermediate agreement must be returned.

The commission also clarifies that, at the end of the batch study, an interconnecting DSP or TSP must return financial security to a large load customer that is allocated 0 MW of transmission capacity after collecting outstanding amounts owed. A large load customer that withdraws its interconnection request but was allocated transmission capacity may receive the balance of its financial security after the interconnecting DSP or TSP collects payment for outstanding amounts owed and subtracts 20% of the financial security associated with the allocated transmission capacity.

The commission also modifies the adopted rule to remove the interconnection fee under the SLLIA. At the time the SLLIA is exe-

cuted, the large load customer must post financial security in an amount that is the greater of \$50,000 per MW of the contracted peak demand or the costs allocated to the large load customer for system upgrades as a result of an interconnection study. A large load customer may elect to apply cash collateral posted as financial security under an intermediate agreement as a credit towards the financial security requirements under a SLLIA.

The interconnecting DSP or TSP must invoice the large load customer for direct interconnection costs as those costs are incurred; and the interconnecting DSP or TSP must return 20% of financial security when the large load customer energizes and the remainder ratably in 20% increments as the large load customer meets the milestones identified in the customer's SLLIA for meeting its obligation to pay the large load minimum billing demand described in §25.193, relating to Distribution Service Provider Transmission Cost Recovery Factor (TCRF), for the set period of time described in §25.193.

The commission determines that this framework best balances support for business development and the need to minimize the potential for stranded infrastructure costs.

Tie payment of financial security to development milestones

Mission Power and PPM recommended modifying the proposed rule to increase financial security requirements as a project progresses through commercial development milestones. The City of Bryan stated that it supports a staged approach to financial commitments and a refundability framework tied to energization milestones.

Commission Response

The commission declines to adopt Mission Power and PPM's recommendation to modify the adopted rule to increase financial security requirements as a project progresses through commercial development milestones. Requiring financial security at the intermediate agreement stage ensures that a large load customer has access to the necessary capital to see a project through to energization. Additionally, the risk for stranded infrastructure costs is present when the large load customer is included in ERCOT's forecast for transmission planning, which going forward will be at the time that the SLLIA is executed.

Address cost causation and recovery in Project No. 58484

TPPA recommended addressing cost causation and recovery in Project No. 58484, Evaluation of Transmission Cost Recovery, but was supportive of the fees and financial security proposed throughout the rule if addressed here. Additionally, if the interconnection fee and financial security requirements in the proposed rule are retained, TPPA recommended that the commission clearly state that adoption of these provisions does not materially resolve or address the issues under consideration in Project No. 58484.

Commission Response

The commission agrees with TPPA that transmission cost recovery should be addressed in a separate rulemaking project. Therefore, the commission modifies the adopted rule to remove the requirement that an interconnecting DSP or TSP apply retained financial security as an offset to rate base and removes the prohibition for an interconnecting DSP or TSP to recover direct interconnection costs in regulated rates. The commission will address transmission cost recovery in Project No. 58000, Rulemaking to Update Wholesale and IOU Retail Transmission Cost Recovery in the ERCOT Region.

Tie financial security to cost responsibility

APA and ACP recommended tying the financial security amounts to a developer's identified cost responsibility, once established in Project No. 58484, Evaluation of Transmission Cost Recovery. This ensures that each interconnecting entity bears the direct consequences of its actual system impacts and incentivizes timely withdrawal by projects whose upgrades would impose disproportionate or uneconomic costs on the system. APA and ACP also recommended that financial security for interconnection facilities and network upgrades should remain "at-risk" only to the extent necessary to cover actual underfunded upgrades or restudies caused directly by developer withdrawals. If the load proceeds as expected, security should be refunded promptly once the load reaches commercial operation.

Commission Response

The commission declines to adopt APA and ACP's recommendation to address financial security amounts in Project No. 58484. PURA §37.0561(h) requires that the large load interconnection standards include uniform financial commitment requirements for the development of transmission infrastructure needed to serve a large load customer. Therefore, it is appropriate to address financial security amounts in the adopted rule, which also sets forth the requirements for a SLLIA. The commission disagrees that financial security should be returned once the load reaches commercial operation because the risk for stranded infrastructure remains even after commercial operation begins. Accordingly, the commission also modifies the adopted rule to specify that additional financial security relating to the large load minimum billing demand may be required.

Allocate the cost of 765-kV STEP and associated projects to large loads

TPPF recommended allocating the costs of the 765 kilovolt (765-kV) Strategic Transmission Expansion Plan (STEP) and associated projects to large loads. TPPF reasoned that loads above 75 MW are the only reason systemwide demand may rise high enough over the next 10-15 years to justify the 765-kV lines.

Commission Response

The commission declines to adopt TPPF's recommendation to allocate the costs of the 765-kV STEP and associated projects because cost allocation for specific projects is outside the scope of this rulemaking. The purpose of this rulemaking is to establish uniform, standardized interconnection standards for large load customers.

Minimum transmission/minimum demand charge

AEP, CCNG, Google, Lancium, & TotalEnergies, LCRA, Oncor, TCC, TEBA, and Thor recommended the commission modify the proposed rule to require a large load customer to pay a capacity-based charge.

Additionally, CCNG recommended adding a new subsection requiring a large load customer to pay a minimum transmission charge of no less than 50 percent of the customer's contracted peak demand for a period of five years. CCNG reasoned that this approach is more equitable than requiring large load customers to pay financial security for system upgrades.

Google, Lancium, and TotalEnergies recommended adding a new provision that requires a DSP to assess a transmission demand charge to large load customers for a period of five years based on a percentage of the customer's contracted peak demand. Google, Lancium, and TotalEnergies further

recommended modifying proposed §25.194(f)(10) to replace the requirement that a large load customer post financial security for system upgrades with a statement that the interconnection agreement should state that the large load customer will pay the minimum transmission charge following energization.

HEN recommended that any minimum demand or take-or-pay construct should be narrowly tailored to reflect actual reserved system capacity and applied only where necessary. HEN reasoned that broad application risks creating a "pay-for-readiness" model that requires large load customers to pay for transmission capacity regardless of actual usage discouraging private investment and distorting efficient market outcomes.

Oncor recommended requiring interconnection agreements to include a contractual commitment in which interconnecting large loads over 200 MW agree to pay rates proportional to the amount of capacity that they contract for, regardless of usage, for at least 10 years after interconnection.

If the proposed rule is modified to implement a minimum demand charge, OPUC recommended that the commission: (1) include cost recovery methods, including penalty fees, if the large load customer ceases operations before the end of ten or fifteen years; (2) consider the long asset life of transmission infrastructure and the depreciation value in calculating the minimum demand charge and payment period; (3) prohibit utilities from adding provisions to their tariffs or contracts that result in large load customers paying less costs than they would under any minimum demand charge rule; and (4) not presume load growth will continue at the same unprecedented rate long-term in determining the minimum demand charge structure.

TCC recommended the commission establish a minimum demand charge in a contested case. Thor recommended replacing the interconnection fee with a minimum demand charge of no less than 50% of contracted peak demand for five years.

Commission Response

The commission adopts commenters' recommendation to require a large load customer to pay transmission rates based on the demand that the large load customer places on the ERCOT system. However, the commission determines that the details of the charge should be decided in Project No. 58000. Accordingly, the commission modifies the adopted rule to require the SLLIA include a term of acknowledgment and agreement that the large load customer will pay the large load minimum billing demand described in §25.193, relating to Distribution Service Provider Transmission Cost Recovery Factor (TCRF), for the set period of time described in §25.193. The commission also modifies the adopted rule to include the large load minimum billing demand in the list identifying what constitutes an outstanding amount owed and modifies the adopted rule to specify that a large load customer may be required to post additional financial security related to the large load minimum billing demand.

ERCOT interconnection standards

Google, Lancium, and TotalEnergies recommended adding a provision requiring ERCOT to: (1) establish a process that assigns a serial number for each complete large load that is representative of the load's position in the interconnection queue; and (2) adopt administrative protocols which create clear communication between the large load customer, the DSP, the TSP, and ERCOT.

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies's recommendation to add a provision requiring ERCOT to establish a process that assigns a serial number to large load customers that identifies the customer's position in the interconnection queue. Because ERCOT is studying interconnection requests in batches, there is no positioning in the interconnection queue to identify.

The commission also declines to adopt Google, Lancium, and TotalEnergies's recommendation to add a provision requiring ERCOT to adopt administrative protocols which create clear communication between the large load customer, the DSP, the TSP, and ERCOT. Instead, the commission modifies the adopted rule to specify certain timelines and to authorize the development of other timelines through ERCOT protocols, as appropriate. Specifically, the commission modifies the adopted rule to require the interconnecting DSP or TSP to provide information to the large load customer not later than five working days after receipt of communications from ERCOT about the large load customer's interconnection request.

The commission also modifies the adopted rule to require the interconnecting DSP, the interconnecting TSP, or ERCOT to timely notify the large load customer of the transmission capacity allocated to the large load customer and to timely notify the interconnecting TSP when another TSP completes a project that is needed to interconnect a large load customer, as prescribed by ERCOT protocols. Finally, the commission modifies the adopted rule to permit ERCOT to fulfill the interconnecting DSP or the interconnecting TSP's obligations to communicate with the large load customer through a process developed in ERCOT protocols. This recognizes that ERCOT is developing software that will enable it to communicate information directly to large load customers in the future while still addressing the need for clear and timely notification in the interim.

Loads bringing their own generation

HEN recommended modifying the proposed rule to recognize that a large load may choose to self limit the maximum demand that it will place onto the grid, consistent with protocols that will be developed in the ERCOT process, by building generation to serve its load. Specifically, HEN recommended that the financial security requirements for large loads co-located with dispatchable generation be based on expected net grid usage during system peak conditions, rather than gross on-site peak demand. HEN reasoned that large load customers that are expected to be net-zero or net exporters during peak conditions should not be required to post financial security as though they are grid dependent. Similarly, HEN recommended that interconnection fees also be assessed based on expected maximum net import from the ERCOT grid during peak conditions for large loads co-located with dispatchable generation.

Commission Response

The commission declines to adopt HEN's recommendation to modify the adopted rule to reduce the financial security requirements for a large load customer that builds generation to serve its load by basing the financial security requirements on the load's expected net grid usage during the system peak conditions instead of requested peak demand and contracted peak demand. The requested peak demand and contracted peak demand are based on the amount of load that the customer seeks to interconnect to the ERCOT system. The commission determines that the appropriate input is not an estimate of what amount of demand the load might be expected to place on the ERCOT system

during peak conditions but the amount of demand that is used for transmission planning purposes. This approach better aligns with the goal of minimizing the potential for stranded infrastructure costs.

For large load customers that co-locate, credit financial obligations under a standard generation interconnection agreement (SGIA)

BKV and Intersect Power recommended modifying the proposed rule to credit financial obligations under a standard generation interconnection agreement (SGIA) to the financial security requirements under the proposed rule for large load customers that co-locate with generation resources.

Specifically, BKV recommended that the commission clarify: (1) where interconnection facilities and upgrades have been funded or secured under an executed SGIA, those investments are credited toward any obligations to the extent they correspond to the same facilities or capacity; (2) financial obligations are limited to incremental facilities and system impacts attributable to the large load; and (3) no additional security or CIAC is required for facilities that do not give rise to new or increased system upgrade costs.

Intersect Power recommended modifying the proposed rule to state that, where a large load customer is co-located with generation at the same point of interconnection and the applicable interconnection facilities and upgrades have been funded or secured under an executed standard generation interconnection agreement, such prior investments in shared or integrated infrastructure are credited toward any financial obligations under the rule to the extent they correspond to the same facilities or capacity, and that comparable investments and study-backed facilities developed under prior ERCOT interconnection processes, including the interim process, are afforded the same recognition where they reflect substantially equivalent scope and system impact.

Second, Intersect Power recommended modifying the proposed rule to limit financial security and payment obligations to incremental facilities and upgrades, required as a result of the large load's incremental impact on the system, including changes to capacity or operational characteristics, and not to modifications that do not give rise to new or increased system upgrade costs or stranded cost risk, and that were not previously studied, assigned, or funded under the standard generation interconnection agreement or other governing agreement. Third, Intersect Power recommended modifying the proposed rule to preserve flexibility in payment structures, including as-incurred billing with true-up mechanisms, to ensure that financial requirements track actual cost development and avoid over-collection.

Commission Response

The commission declines to adopt BKV and Intersect Power's recommendation to modify the adopted rule to state financial obligations under a SGIA must be credited to the financial security requirements under the rule for large load customers that co-locate with generation resources.

PURA §35.004(d-1) requires the commission to establish a reasonable allowance for transmission-owning utility costs incurred to interconnect generation resource directly with the ERCOT transmission system at transmission voltage. PURA does not similarly require an allowance for large load customers. Moreover, a large load customer should not be able to co-locate with generation as a means to avoid contributing to transmission

costs that may be incurred as a result of the need to be able to serve that customer from the ERCOT system in the event the generation resource is needed to supply power to the ERCOT system or is otherwise unable to supply power to the large load customer. Therefore, the commission determines that all large load customers should be required to meet the same standards for interconnection, which requires large load customers to post financial security to protect other ratepayers from stranded infrastructure costs that may be incurred to serve the large load customer; and requires large load customers to pay for their direct interconnection costs.

The commission declines to adopt BKV and Intersect Power's recommendation to limit financial security and payment obligations for co-located load to the incremental facilities and upgrades, required as a result of the large load's incremental impact on the system. Such a limitation does not properly account for the fact that ERCOT must be able to reliably serve the large load customer's additional demand on the system (even if co-located with generation).

The commission declines to adopt BKV's recommendation to state no additional security or CIAC is required for facilities that do not give rise to new or increased system upgrade costs. CIAC is required for direct interconnection costs, not for system upgrade costs.

The commission adopts Intersect Power's recommendation to preserve flexibility in payment structures, including as-incurred billing with true-up mechanisms, to ensure that financial requirements track actual cost development and avoid over-collection. Accordingly, the commission modifies the adopted rule to require the interconnecting DSP or TSP to invoice the large load customer for direct interconnection costs before those costs are incurred instead of requiring payment of all direct interconnection costs at the time the SLLIA is executed.

Uniformity across interconnecting utility types

Landmark and EcoPartner recommended modifying the proposed rule to provide for consistent financial and timeline obligations and refundability terms across all interconnecting utility types. Landmark and EcoPartner reasoned that requirements and process clarity differ between non-opt-in-entities (NOIEs) and investor-owned utilities.

Commission Response

The commission declines to adopt Landmark and EcoPartner's recommendation to modify the adopted rule to provide for consistent financial and timeline obligations and refundability terms across all interconnecting utility types because it is unnecessary. The adopted rule already requires all large load customers, regardless of whether they site in an investor-owned utility's service territory or a non-opt-in entity's territory in the ERCOT region, to meet the same standards for purposes of interconnection. The adopted rule neither requires nor allows for different standards based on the nature of the service territory for a large load customer that sites in the ERCOT region.

Tie fees to costs and periodically update fee amounts

EDF recommended modifying the proposed rule to include a recurring process for updating the dollar amounts for the fees required by the proposed rule, based on a future cost-of-service or similar study. EDF stated that the commission should ensure the initial fee amounts are based on actual large load interconnection costs.

Commission Response

The commission declines to adopt EDF's recommendation to modify the adopted rule to include a recurring process for updating the dollar amounts for the required fees, based on a future cost-of-service or similar study. As more data becomes available relating to study costs, the commission may amend the rule to update the study fee amount that is required. EDF's recommendation with respect to the interconnection fee is moot because the commission modifies the adopted rule to remove the interconnection fee. Financial security remains a requirement to protect against stranded infrastructure costs and is not a "fee."

Prioritize the interconnection requests of certain types of load

EDF, TCPA, and Voltus recommended modifying the proposed rule to prioritize the interconnection request of certain types of loads.

Specifically, EDF commented that it would support a process whereby a large load customer may provisionally interconnect on an accelerated track if the customer agrees to be flexible and controllable and assumes the risk of curtailment during grid constraints. EDF also suggested a process whereby a large load customer may use off-site resources, such as energy source resources or generation, to address local nodal constraints. EDF reasoned these approaches would allow a large load customer to interconnect more quickly without undermining reliability or shifting risk to ratepayers.

TCPA recommended modifying the proposed rule to direct ERCOT to give a faster preferential path to interconnection and energization for those large load customers that co-locate with generation. Additionally, TCPA recommended that the commission direct ERCOT to prioritize a forthcoming nodal protocol revision revise (NPRR) that will accomplish this goal.

Voltus recommended modifying the proposed rule to allow a large load customer to bring their own capacity (i.e., electrically proximate or adjacent grid assets) as an alternative to backup generation facilities and to expedite interconnection for large load customers that implement a bring your own program.

Commission Response

The commission declines to modify the adopted rule to prioritize the interconnection request of certain types of loads. The commission determines that such a process and prioritization must account for technical and operational characteristics that are best addressed in ERCOT protocols, which are vetted in a stakeholder process and ultimately subject to approval by the commission.

Net metered loads subject to PURA §39.169

TCPA recommended modifying the proposed rule to place loads that are subject to PURA §39.169 in a distinct category from any other large load interconnection because the commission must review those and either approve, deny, or impose conditions on them prior to interconnection moving forward. Additionally, TCPA recommended that any financial security posted by a large load customer that is subject to PURA §39.169 be refunded if the net metering arrangement is not approved by the commission.

Commission Response

The commission declines to adopt TCPA's recommendation to modify the adopted rule to place loads that are subject to PURA §39.169 in a distinct category from any other large load intercon-

nection. PURA §37.0561 does not exempt large load customers that are subject to PURA §39.169 from compliance with the requirements for large load interconnection standards that are set forth in PURA §37.0561; and the commission is not persuaded that the adopted rule should exempt those loads. PURA §39.169 governs net metering arrangements with an existing generation resource, not the large load customer's interconnection to the ERCOT system. Therefore, the applicability of PURA §39.169 is immaterial to the applicability of PURA §37.0561. Moreover, the commission determines that whether a net metering arrangement is approved is independent of whether a large load customer may interconnect to the ERCOT system and therefore should not result in the return of financial security posted under PURA §37.0561. The purpose of financial security is to protect against stranded infrastructure costs and that protection is needed if the large load customer seeks to interconnect to the ERCOT system regardless of whether a net metering arrangement with an existing generation resource is approved by the commission.

Withdrawal, milestones, and proportional risk allocation

Intersect Power recommended modifying the proposed rule to: (1) limit forfeiture of financial security to demonstrated, non-recoverable costs and committed expenditures; (2) require prompt release of remaining financial security once such costs have been satisfied regardless of fixed milestone timing; (3) retain stronger forfeiture provisions only for discrete system upgrade security, where stranded cost risk is most acute; and (4) ensure that milestone timelines and associated consequences remain commercially reasonable and account for phased energization, supply chain constraints, and practical development considerations.

Commission Response

The commission declines to adopt Intersect Power's recommendation to: (1) limit forfeiture of financial security to demonstrated, non-recoverable costs and committed expenditures; (2) require prompt release of remaining financial security once such costs have been satisfied regardless of fixed milestone timing; (3) retain stronger forfeiture provisions only for discrete system upgrade security, where stranded cost risk is most acute; and (4) ensure that milestone timelines and associated consequences remain commercially reasonable and account for phased energization, supply chain constraints, and practical development considerations.

The financial security requirements are intended to minimize the potential for stranded infrastructure costs as required by PURA §37.0561(b) by incentivizing large load customers to right size the requested peak demand for their projects and provide a mechanism for utilities to recover stranded infrastructure costs from a large load customer. However, the commission modifies the adopted rule to allow greater flexibility in the phased energization schedule by increasing the amount of time by which a large load customer may miss a milestone in its phased energization schedule before transmission capacity is reallocated. This flexibility accounts for supply chain constraints, etc. while ensuring efficient use of transmission infrastructure and available capacity.

Refund mechanics

Landmark and EcoPartner recommended the commission modify the proposed rule to clarify the mechanisms by which financial security is refunded and provide that financial security held for longer than a defined period is treated as interest-bearing. Addi-

tionally, Landmark and EcoPartner recommended the proposed rule address: (1) escrow account structure; (2) which costs may be drawn from financial security versus charged separately; and (3) the timeline for refund processing after withdrawal or project cancellation.

Commission Response

The commission declines to adopt Landmark and EcoPartner's specific recommendations to provide that financial security held for longer than a defined period is treated as interest-bearing and to address: (1) escrow account structure; (2) which costs may be drawn from financial security versus charged separately; and (3) the timeline for refund processing after withdrawal or project cancellation.

However, the commission modifies the adopted rule to specify that cash collateral posted as financial security must be held in a segregated, cash account bearing interest at a rate equal to at least the rate of the constant maturity one-month U.S. Treasury bill. The commission also modifies the adopted rule to specify that payment must be collected for outstanding amounts owed before financial security may be returned to a large load customer and that the interconnecting DSP or TSP may invoice the large load customer or draw down on financial security for outstanding amounts owed. If the large load customer fails to pay an invoice within 10 working days after receipt, the interconnecting DSP or TSP may draw down on financial security. The timeline for returning financial security associated with withdrawal or cancellation is best addressed in the rule adopting a SLLIA.

Intermediate agreement and study progression

BKV and Intersect Power recommended modifying the proposed rule to state the intermediate agreement is a threshold requirement limited to objective indicators of project readiness and, for co-located projects, is limited to load-side readiness and does not reopen or condition generation-side interconnection status; and utilities may not impose additional conditions that delay study initiation beyond those specified in the rule. BKV and Intersect Power also recommended modifying the proposed rule to state that study initiation and progression must be aligned with ERCOT-established processes, including modeling readiness and validation requirements, and for co-located load must build on existing modeling assumptions and prior study results, with any additional analysis limited to incremental load-related impacts. Finally, BKV and Intersect Power recommended modifying the proposed rule to state that entities that have fulfilled the requirements of SB 6 before batch study implementation shall be permitted to proceed without re-screening under the subsequently adopted eligibility criteria, and co-located projects with existing or approved grid-facing generation shall not be subject to revalidation, displacement, or re-underwriting of previously completed studies.

Commission Response

The commission declines to adopt BKV and Intersect Power's recommendation to state the intermediate agreement is a threshold requirement limited to objective indicators of project readiness; and that for co-located projects, the intermediate agreement is limited to load-side readiness and does not reopen or condition generation-side interconnection status because it is unnecessary. Once the large load customer executes and funds the intermediate agreement as required by the adopted rule, the interconnecting DSP or TSP is required to contact ERCOT within 60 days to initiate the interconnection study, as prescribed by ERCOT protocols. This deadline ensures that once a large load

customer complies with the adopted rule, the interconnecting DSP or TSP has an obligation to submit the necessary information to ERCOT for the large load customer's inclusion in the next interconnection study. The adopted rule only applies to large load customers and requires all large load customers to meet the same standards. The adopted rule does not apply to generation resources, including those that are co-located with a large load customer. Thus, it is not necessary to specify that the adopted rule does not reopen or condition generation-side interconnection study.

The commission declines to adopt BKV and Intersect Power's recommendation to modify the adopted rule to state that utilities may not impose additional conditions that delay study initiation beyond those specified in the rule. There may be instances in which it is appropriate to impose additional conditions. For example, ERCOT may need to require a specific type of study from the interconnecting TSP before the large load customer is included in the interconnection study.

The commission declines to adopt BKV and Intersect Power's recommendation to modify the adopted rule to state that study initiation and progression must be aligned with ERCOT-established processes, including modeling readiness and validation requirements, and for co-located load must build on existing modeling assumptions and prior study results, with any additional analysis limited to incremental load-related impacts. The commission does not need to require, in this rule, that an interconnecting DSP or TSP comply with ERCOT protocols. Additionally, ERCOT is best positioned to determine from a reliability and technical perspective whether additional analysis is appropriate for co-located loads.

The commission declines to adopt BKV and Intersect Power's recommendation to modify the adopted rule to state that entities that have fulfilled the requirements of SB 6 before batch study implementation is permitted to proceed without re-screening under the subsequently adopted eligibility criteria, and co-located projects with existing or approved grid-facing generation should not be subject to revalidation, displacement, or re-underwriting of previously completed studies. PGRR 145 established the criteria for these loads to be included in the batch zero interconnection study and a future ERCOT protocol revision will address any needed changes to criteria for inclusion in future interconnection studies. At the conclusion of the batch zero interconnection study, it is appropriate for those loads to comply with the adopted rule's requirements for a SLLIA because these loads have not yet energized, but are being allocated transmission capacity.

Ratemaking treatment

Cholla recommended that ratemaking determinations for retained funds exceed the commission's statutory authority and depart from cost causation principles.

Commission Response

The commission disagrees with Cholla that ratemaking determinations for retained funds exceed the commission's statutory authority and depart from cost causation principles. However, the commission removes ratemaking treatment from the adopted rule to address in Project No. 58000 and therefore does not address Cholla's arguments.

PURA §37.0561 in conjunction with PURA §§14.001 and 14.002 give the commission broad authority to develop a framework for interconnecting large load customers. PURA §37.0561(i)

contemplates that a portion of financial security may be retained after the financial security is applied to any outstanding amounts owed. PURA §37.0561(i)(2)-(3) states that financial security must be refunded, in whole or in part, after the security is applied to outstanding amounts owed if the large load customer withdraws the customer's request for all or a portion of the requested capacity or if capacity subject to a financial commitment will be reallocated to one or more other customers.

The framework set forth in the adopted rule fits within this statutory framework. If a large load customer withdraws its request for all or a portion of the requested capacity before the interconnection study begins, financial security must be returned, in whole. If a large load customer withdraws its request for all or a portion of the requested capacity after the interconnection study begins, a portion of the financial security must be returned after the financial security is applied to any outstanding amounts owed. Specifically, the portion of financial security that is not associated with allocated transmission capacity must be returned and 80% of the financial security associated with allocated transmission capacity must be returned. The transmission capacity will then be reallocated in a future interconnection study. The transmission capacity cannot be reallocated to a large load customer in the same interconnection study because to do so would require a restudy of all the loads in the interconnection study. Therefore, it is appropriate to attach some level of consequence to a decision not to continue with the interconnection process when transmission capacity has been allocated and is therefore unavailable to others until a future interconnection study.

Behind-the-meter power

Landmark and EcoPartner recommended modifying the adopted rule to address specifications relating to curtailment and the contributions of behind-the-meter generation to grid reliability. Specifically, Landmark and EcoPartner recommended: (1) codifying a 30-minute curtailment capability requirement, noting that PGRR145 Section 9.2.5 requires breakers under remote transmission operator control, but does not specify a time window; (2) clarifying and formalizing the methods by which developers can demonstrate 30-minute curtailment capability; (3) explicitly defining what type of resources qualify to provide a percentage match between grid load and behind-the-meter (BTM) generation, if statute requires such a match, and including battery storage as a qualifying resource; and (4) acknowledging in the proposed rule that BTM generation contributes to grid reliability.

Commission Response

The commission declines to adopt Landmark and EcoPartner's recommendation to modify the adopted rule to address specifications relating to curtailment and the contributions of behind-the-meter generation to grid reliability. Technical specifications, including those for curtailment, are best addressed in ERCOT protocols, which are vetted in a stakeholder process and ultimately subject to approval by the commission. Behind-the-meter generations' contributions to grid reliability are outside the scope of this rulemaking.

Alignment with ERCOT planning process

Intersect Power recommended modifying the proposed rule to state that satisfaction of the rule requirements constitute evidence of project maturity and commitment for ERCOT planning purposes. Second, Intersect Power recommended modifying the proposed rule to ensure that projects meeting ERCOT Planning Guide Section 9 milestones are not subject to duplicative screening or reclassification, and that projects which satisfied

substantially equivalent study, agreement, and financial commitment milestones under prior ERCOT processes are treated consistently for planning and classification purposes. Third, Intersect Power recommended modifying the proposed rule to ensure that ERCOT Planning Guide Section 9 milestones clearly articulate criteria applicable to integrated project configurations such that prior investments and commitments under executed interconnection agreements required under ERCOT Planning Guide Section 9.5 are fully recognized, duplicative financial security is avoided, and cost responsibility remains aligned with actual cost incurrence, and that such recognition extends to projects developed under prior ERCOT interconnection processes, including the interim process, where comparable study completion, ERCOT review, and system impact determinations were achieved.

Commission Response

The commission declines to adopt Intersect Power's recommendation to modify the adopted rule to state that satisfaction of the rule requirements constitute evidence of project maturity and commitment for ERCOT planning purposes because it is unnecessary. The adopted rule sets forth the requirements for a large load customer to be included in an interconnection study and allocated transmission capacity. Moreover, the purpose of the adopted rule is to standardize the criteria used for those two purposes so that large load customers that are similarly situated must meet the same criteria regardless of the utility involved.

The commission declines to adopt Intersect Power's recommendation to modify the adopted rule such that projects meeting ERCOT Planning Guide Section 9 milestones are not subject to duplicative screening or reclassification, and that projects which satisfied substantially equivalent study, agreement, and financial commitment milestones under prior ERCOT processes are treated consistently for planning and classification purposes. The adopted rule does not require duplicative screening or reclassification. Rather, PGRR 145 establishes the requirements for inclusion in the batch zero interconnection study, recognizing that some large load customers may be in advanced stages of the interconnection process and therefore included as base load as opposed to studied load. The adopted rule appropriately requires that a large load customer included in the batch zero interconnection study execute and fund a SLLIA to secure the transmission capacity that is allocated to them at the conclusion of the batch zero interconnection study. This ensures that the loads that are driving the need for significant transmission investment in the state are appropriately securitizing costs and contributing to transmission cost recovery. It also ensures uniformity in the standards that are applied to large load customers that have not yet energized as of the effective date of the adopted rule.

The commission declines to adopt Intersect Power's recommendation to require changes to ERCOT Planning Guide Section 9. ERCOT Planning Guide Section 9 went through an extensive stakeholder process and was approved by the commission on June 18, 2026. The commission determines that ERCOT Planning Guide Section 9 appropriately resolves Intersect Power's recommendation to ensure that prior investments and commitments under executed interconnection agreements required under the pre-PGRR 145 ERCOT Planning Guide Section 9.5. However, the commission modifies the adopted rule to specify the conditions under which the interconnecting DSP or TSP may return financial security to a batch zero load to ensure that duplicative financial commitments are not required of a batch zero load.

Large load customer and generation facility that share the same interconnection facilities

TSP Cooperatives recommended clarifying the rule's applicability to a large load and a generation facility, which are not operating together as a private use network, will share the same interconnection facilities but will have separate metering and be separate transmission customers. Specifically, TSP cooperatives recommended that the rule should address how the transmission costs should be apportioned.

Commission Response

The commission declines to adopt TSP Cooperatives's recommendation to specify how transmission costs should be apportioned between a large load customer and a generation facility that are not operating together as a private use network but share the same interconnection facilities because it is not necessary. The large load customer and the generation facility must each comply with the laws and rules applicable to their interconnection request.

Require use of a pro forma agreement

AEP, CenterPoint, GVEC, and Oncor recommended modifying the proposed rule to require that the intermediate and interconnection agreements must be based on a commission-approved pro forma agreement.

Google, Lancium, and TotalEnergies recommended making the intermediate agreement a standard form attachment to a full interconnection agreement, negotiated on the front end prior to batch submission, that defines the financial commitments and makes clear the exit provisions and refundability of securities throughout the batch process.

Commission Response

The commission agrees with commenters that recommended the commission adopt a standard interconnection agreement to promote uniformity across ERCOT. Accordingly, the commission modifies the adopted rule to replace "an interconnection agreement" with "a SLLIA" (standard large load interconnection agreement) and adds the following definition for SLLIA: "a commission-approved pro forma agreement that is executed by a large load customer, the interconnecting DSP, and, if different from the interconnecting DSP, the interconnecting TSP and that, at a minimum, complies with this section." The commission plans to adopt a pro forma SLLIA in a future rulemaking project.

The commission declines, at this time, to adopt commenters' recommendation to adopt a standard intermediate agreement because it is unnecessary. The requirements for an intermediate agreement and SLLIA are substantially similar such that, once adopted, the pro forma SLLIA may be modified to serve the purpose of an intermediate agreement.

Expressly assign roles and responsibilities

GVEC, Joint TSPs, TEC, TPPA, and TSP Cooperatives recommended modifying the adopted rule to expressly assign, by rule, the roles and responsibilities identified in the intermediate agreement to the electric utility or electric utilities making the relevant upgrades or providing the relevant interconnection or services.

GVEC specifically recommended that the DSP receive distribution-level CIAC, administer true ups for distribution-level facilities, provide retail delivery service, provide operational coordination, and billing of transmission and distribution costs. GVEC recommended that the TSP must coordinate with ERCOT to ini-

tiate and monitor the interconnection study, remit ERCOT study costs on behalf of the large load customer, and receive and hold financial security posted by the large load customer for transmission equipment and upgrades. Additionally, the TSP should receive transmission-level CIAC, administer true ups for transmission-level facilities, and notify ERCOT of withdrawal, amendments, and non-utilized transmission capacity.

TSP Cooperatives specifically recommended modifying proposed §25.194(d) to clarify which entities will perform which studies or direct ERCOT to adopt procedures to identify those responsibilities. Additionally, TSP Cooperatives recommended that each TSP should be required to interface directly with the large load customer, absent an agreement with the other TSP, to collect financial security, contribution in aid of construction, or other financial commitment from the large load that is necessary to secure its expected costs.

TPPA recommended modifying the proposed rule to specify: (1) which entity the large load customer must notify in the event of a withdrawal of all or a portion of its requested or contracted peak demand, and (2) which entity, whether the DSP or TSP, is responsible for notifying the large load customer of a failure to utilize capacity in accordance with its phased energization schedule.

TEC recommended more broadly that the commission clarify which entity is to perform particular studies to avoid additional costs and duplicative work.

Conversely, Oncor recommended that the proposed rule not dictate the specific split of responsibilities between DSPs and TSPs, but instead simply require that utilities in these multi-utility scenarios execute an agreement that allocates relevant critical interconnection responsibilities as the parties see fit. If its recommendation for a pro forma agreement is adopted, Oncor recommended modifying proposed §25.194(d) and proposed §25.194(f) to remove the statement that requires the parties to the intermediate and interconnection agreements to specifically identify each entity's responsibilities, including which entity will accept the study fee and financial security.

Commission Response

The commission declines to adopt GVEC, Joint TSPs, TEC, TPPA, and TSP Cooperatives' recommendation to modify the adopted rule to expressly assign, by rule, the roles and responsibilities of the interconnecting DSP and TSP. The commission determines that assignment of roles and responsibilities is best addressed in the rulemaking project to adopt a SLLIA. The commission declines to adopt Oncor's recommendation to modify the adopted rule to remove the statement in §25.194(d) that requires the parties to the intermediate agreement to specifically identify each entity's responsibilities but does adopt the recommendation as it relates to §25.194(f) because the commission plans to adopt a pro forma large load interconnection agreement, which renders the language unnecessary for a SLLIA.

Require attestation that the rule's requirements are met

AEP recommended modifying the proposed rule to require large load customers to attest that they meet the requirements of the rule thereby ensuring that the large load customer acknowledges and accepts their obligations under the commission's large load interconnection standards. AEP noted that the attestation requirements proposed in §25.194(d)(4) and proposed §25.194(f)(4) should be expanded.

Commission Response

The commission adopts AEP's recommendation to modify the adopted rule to require large load customers to attest that they meet the requirements of the rule. Accordingly, the commission modifies the adopted rule to require that an intermediate agreement and SLLIA must be executed by an officer or official with binding authority over the large load customer and include an attestation that supports all disclosures required under the applicable agreement.

Unused funds

CenterPoint recommended modifying the proposed rule to require that any funds not used to cover the cost of the interconnection be returned to the customer rather than used to offset rate base.

Commission Response

The commission declines to adopt CenterPoint's recommendation to modify the adopted rule to require that any funds not used to cover the cost of the interconnection be returned to the customer. In instances where a large load customer is allocated transmission capacity but withdraws its interconnection request, it is appropriate for the interconnecting DSP or TSP to retain some portion of financial security. At a time when ERCOT is experiencing significant growth, the magnitude of which is expected to require significant transmission infrastructure, it is appropriate to disincentivize loads from submitting an interconnection request for requested peak demand that is not needed by the large load customer. However, the commission modifies the adopted rule to remove the requirement to apply the unused funds as an offset to rate base. The appropriate treatment of unused funds will be addressed in Project No. 58000.

Escrow account for refundable capital

TEBA recommended that refundable funds be kept in an escrow account rather than held by the utility and released upon satisfaction of specific agreed-upon conditions and promptly returned to the depositing party.

Commission Response

The commission declines to adopt TEBA's recommendation that refundable funds be kept in an escrow account rather than held by the utility. However, the commission modifies the adopted rule to specify that cash collateral posted as financial security must be held in a segregated, cash account bearing interest at a rate equal to at least the rate of the constant maturity one-month U.S. Treasury bill. The commission also modifies the adopted rule to more specifically describe the circumstances for returning financial security posted by a large load customer.

Domestic industrial metal production facility

Eolian recommended modifying the proposed rule to account for impacts to a domestic industrial metal production facility that is needed to address critical U.S. security issues and whether this facility will be able to locate in the ERCOT region under the proposed framework and ERCOT's batch study interconnection process.

Commission Response

The commission declines to adopt Eolian's recommendation to modify the adopted rule to account for impacts to a domestic industrial metal production facility. Exemptions based on customer type could result in preferential treatment based on the

industry served and run contrary to the objective of standardizing the large load interconnection process.

Thermal Performance, Roof Membrane Data, and Biennial Spectral Monitoring

Zach Bulter and EnerShield AI recommended the commission require facilities exceeding 75 MW to demonstrate ongoing roof thermal performance monitoring, require roof membrane data in the spring water usage survey, establish biennial spectral monitoring for data centers, and direct the Texas Water Development Board (TWDB) to incorporate roof degradation as a variable in water demand projections. Zach Bulter and EnerShield AI also requested that the commission set this matter for public hearing under the commission's standing rules, designate EnerShield AI as a party with standing to present testimony and respond to questions, and accept a research paper into the evidentiary record.

Commission Response

The commission declines to modify the rule in response to the comments of Zach Butler and EnerShield. The physical construction, monitoring, and passive energy use of the buildings themselves is beyond the noticed scope of this rulemaking, as is the spring water usage survey. The commission also declines to direct the Texas Water Development Board (TWDB) to incorporate roof degradation as a variable in water demand projections, because the commission does not have jurisdiction over the actions of TWDB.

The commission also declines to set this matter for public hearing, as requested by Zach Butler and EnerShield, because setting a hearing would not accomplish the requested outcome. As described, the requested hearing contemplates named parties, sponsored testimony, and cross examination of witnesses. A public hearing in a rulemaking proceeding is not a contested case-style proceeding or an active exchange between named parties and commission staff. It is an opportunity for interested persons to offer oral comments on a proposed rule to be considered along with written comments.

Proposed §25.194(a) -- Purpose and Scope

Proposed §25.194(a) states the purpose of the rule is to set forth the standards and criteria for an electric utility, municipally owned utility, and electric cooperative to interconnect a large load customer to the ERCOT system. Additionally, nothing in the rule limits the authority of a municipally owned utility or an electric cooperative to impose electric service requirements for large loads on their systems in addition to the standards adopted under the rule.

Interconnections to the ERCOT transmission system versus a utility's distribution system

CenterPoint recommended modifying proposed §25.194(a) to reflect that the rule applies to interconnections to the ERCOT transmission system and not to interconnections to distribution systems within ERCOT. CenterPoint recommended conforming changes to proposed §25.194(b).

Commission Response

The commission declines to adopt CenterPoint's recommendation to modify proposed §25.194(a) to reflect that the rule applies to interconnections to the ERCOT transmission system and not to interconnections to distribution systems within ERCOT. Limiting the rule's applicability to interconnections at transmission voltage would not appropriately capture all entities involved in

large load interconnections. Further, it is the size of the load, and not whether such load is interconnected at transmission voltage, that causes transmission system impacts.

Proposed §25.194(b) -- Applicability

Proposed §25.194(b) specifies that the rule applies to a large load customer that seeks: (1) a new interconnection that is equal to or exceeds 75 megawatts (MW); (2) an expanded interconnection that equals or exceeds 75 MW for the first time; and (3) an expanded interconnection that exceeds 75 MW by 75 MW or more.

Replace "and" with "or"

PPM recommended modifying proposed §25.194(b)(2) by replacing "and" with "or" to clarify the rule applies to a large load customer meeting any of the three conditions in proposed §25.194(b).

Commission Response

The commission adopts PPM's recommendation to modify adopted §25.194(b)(1) by replacing "and" with "or" to clarify that the rule applies to a large load customer meeting any of the listed conditions in adopted §25.194(b).

Large load interconnection requests at a single site

Constellation recommended modifying proposed §25.194(b) to clarify that each subsection of applicability relates to large load interconnection requests at a single site to avoid any misinterpretation that a single large load customer entity that seeks various interconnection requests at separate sites (for distinct loads) totaling 75 MW or more could be subject to the rule.

Commission Response

The commission adopts Constellation's recommendation to clarify that each subsection of applicability relates to a large load interconnection request at a single site.

Future action to lower the threshold of applicability

Sierra Club recommended modifying proposed §25.194(b) to add a statement that the commission may, through future action, lower the threshold of applicability of this rule.

Commission Response

The commission declines to adopt Sierra Club's recommendation to add a statement that the commission may, through future action, lower the threshold of applicability of this rule because it is unnecessary. PURA §37.0561 authorizes the commission to use a lower threshold and nothing in the adopted rule limits the commission's ability to exercise that authority in the future.

Limit applicability to incremental load additions at sites exceeding 75 MW for the first time

ERCOT Steel Mills, PPM, and TXOGA, recommended modifying proposed §25.194(b) to limit the rule's applicability to incremental load additions at sites equaling or exceeding 75 MW for the first time.

Specifically, ERCOT Steel Mills recommended modifying proposed §25.194(b)(2) to state the proposed rule applies to existing customers below 75 MW only when the customer adds at least 75 MW of new load through an expansion.

PPM recommended modifying proposed §25.194(b)(2) to read: "an expanded interconnection that would equal or exceed 75 MW within 10 years of the customer's initial energization." PPM

reasoned that this change recognizes slow-growing nature of midstream oil and gas facilities while preventing gamesmanship, noting that midstream oil and gas facilities may have multiple meters or distributed equipment that collectively exceed 75 MW if components are netted as they are installed over time.

TXOGA recommended modifying proposed §25.194(b)(2) to read "an expanded interconnection for a facility that started operation after June 1, 2025, that equals or exceeds 75 MW for the first time."

Commission Response

The commission declines to adopt ERCOT Steel Mills, PPM, and TXOGA's recommendation to limit the adopted rule's applicability to incremental load additions at sites equaling or exceeding 75 MW for the first time. Consistent with PURA §37.0561(c), the commission determines that an expansion exceeding 75 MW for the first time and an expansion by 75 MW or more significantly impacts transmission needs. Therefore, it is appropriate to subject these loads to the interconnection standards set forth in the adopted rule. The adopted rule strikes an appropriate balance of ensuring that interconnection requests significantly impacting transmission needs are required to comply with the adopted rule while not requiring compliance for incremental requests that do not significantly impact transmission needs in that the adopted rule does not require compliance for loads that expand by less than 75 MW unless the load is surpassing 75 MW for the first time.

Clarify applicability to expansions at sites already exceeding 75MW

ERCOT Steel Mills, GVEC, TEC, and Vistra recommended modifying proposed §25.194(b)(3) to clarify that the rule applies to an expanded interconnection that exceeds 75 MW and is expanding by 75 MW or more.

Commission Response

The commission adopts ERCOT Steel Mills, GVEC, TEC, and Vistra's recommendation to modify adopted §25.194(b)(1)(C) to clarify that the rule applies to an expanded interconnection that exceeds 75 MW and is expanding by 75 MW or more.

Broaden applicability to incremental load additions

OPUC and TSP Cooperatives recommended modifying proposed §25.194(b) to require all increases or expansions of large loads to meet the requirements of the rule if the load is greater than 75 MW to avoid unintended consequences of loads growing piecemeal or dividing end-user sites into less than 75 MW parcels to avoid the rules. Alternatively, OPUC recommended including some type of evaluation on transmission needs at each request for interconnection.

Commission Response

The commission declines to adopt OPUC and TSP Cooperative's recommendation to modify adopted §25.194(b) to require all increases or expansions of large loads to meet the requirements of the rule if the load is greater than 75 MW. Consistent with PURA §37.0561(c), the adopted rule strikes an appropriate balance of ensuring that interconnection requests significantly impacting transmission needs are required to comply with the adopted rule's requirements while not requiring compliance for incremental requests that do not significantly impact transmission needs.

Critical gas load not subject to rule requirements

Targa recommended modifying proposed §25.194(b) to add a provision stating that the rule does not apply to a large load customer that, prior to June 1, 2026, whose large load would be considered a Critical Gas Load under 16 Texas Administrative Code §3.65(b), has executed an interconnection agreement with an interconnecting DSP or an interconnecting TSP, and has satisfied all CIAC and financial security requirements as stipulated in the previously executed interconnection agreement.

Commission Response

The commission declines to adopt Targa's recommendation to modify adopted §25.194(b) to exempt certain critical gas loads from the requirements of the adopted rule. Exemptions based on customer type could result in preferential treatment based on the industry served and run contrary to the objective of standardizing the large load interconnection process.

Applicability to loads currently in the interconnection queue

APA and ACP, BKV, Constellation, Crow, DCC, HIF, Hut 8, Intersect Power, Landmark and EcoPartner, Schaper Energy, TEC, Thor, TIEC, Tract, and TSP Cooperatives recommended modifying proposed §25.194(b) to address the rule's applicability to large load customers that are in the interconnection queue (i.e., submitted an interconnection request and are not yet approved to energize).

Specifically, TEC and TSP Cooperatives recommended clarifying which large load customers currently under development will be subject to the new rules and on what date; and whether the standards will apply to large load customers currently in the interconnection queue.

Commission Response

The commission agrees with commenters that recommended modifying the adopted rule to identify which large load customers currently in the interconnection queue are subject to the rule and on what terms. Accordingly, the commission modifies the adopted rule to clarify that the rule applies to a large load customer that has not energized as of the effective date of the adopted rule. The commission also modifies the adopted rule to add definitions for batch zero load and batch zero interconnection study; and adds a new subsection addressing treatment of batch zero load.

Adopted §25.194(h)(3) requires a batch zero load to execute a SLLIA to reserve ERCOT's allocation of capacity as contracted peak demand and provides that a batch zero load that executed an interconnection agreement on or before June 1, 2025 must pay for direct interconnection costs in accordance with the previously executed interconnection agreement and is not subject to additional costs under adopted §25.194(f)(2)(C). All other financial commitments and obligations under adopted §25.194(f) apply to a batch zero load.

The commission further adds adopted §25.194(h)(1)(D), which provides that any previously posted financial security or cash payment may be credited on a dollar-for-dollar basis to a large load customer's financial commitments and obligations under adopted §25.194(f). The commission also modifies the adopted rule to specify the consequences if a batch zero load fails to execute a SLLIA in compliance with the rule and specifies the circumstances under which financial security may be returned to a batch zero load.

Finally, the commission modifies the adopted rule to specify that all information provided or attested to by a large load customer

under ERCOT Planning Guide Section 9, as of the effective date of this section, is subject to audit and verification by ERCOT and commission staff. A large load customer or its interconnecting TSP or interconnecting DSP that fails to comply with ERCOT or commission staff's audit process or that fails to produce responsive documentation supporting the completeness and accuracy of information provided under an intermediate agreement may be found in violation of commission rules and subject to enforcement action, including the imposition of administrative penalties or loss of transmission capacity allocated to the large load customer.

Execution of an agreement prior to effective date of rule

APA and ACP, Crow, DCC, Google, Lancium, and TotalEnergies, HIF, Hut 8, Landmark and EcoPartner, Thor, and TIEC recommended modifying proposed §25.194(b) such that the rule does not apply to, or otherwise exempts, large load customers that executed an interconnection agreement prior to the effective date of the rule provided the large load customer satisfied all CIAC and financial security obligations under that agreement.

Specifically, TIEC recommended modifying proposed §25.194(b) to create an exception to the rule's applicability for large load customers who were fully studied under the requirements in place at the time and who executed an interconnection agreement prior to the effective date of the rule. TIEC reasoned that in many instances, the only reason a site has not been able to energize is because it is waiting for the completion of transmission facilities. TIEC further asserted that this is particularly true for many large loads included in the Permian Basin Reliability Plan, who may not be allowed to energize until upgrades are completed in 2030.

Similarly, APA and ACP recommended explicit grandfathering treatment for projects with an executed interconnection agreement prior to adoption of the proposed rule. Landmark and EcoPartner recommended that a large load customer should be exempt from new costs or financial security requirements imposed by the proposed rule if the customer has executed an interconnection agreement prior to the effective date of the rule and has satisfied all CIAC and financial security obligations.

Crow recommended adding language expressly stating the rule requirements do not apply to a large load customer that has executed an interconnection agreement, posted financial security, demonstrated site control, and demonstrated project advancement through other financial commitments, such as long lead equipment deposits. HIF recommended adding language expressly stating the intermediate agreement financial security in proposed §25.194(d)(10) and the interconnection agreement fee in proposed §25.194(f)(7) do not apply to a large load customer with an executed interconnection agreement, posted security, funded CIAC, and demonstration of site control, and that these financial obligations do not apply retroactively. Hut 8 recommended that large load customer is not required to post further financial security or the interconnection fee in proposed §25.194(f)(7) if the customer has executed an interconnection agreement and funded CIAC on schedule, and if all studies are completed and confirmed by ERCOT.

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(a) to state that any projects that have executed a signed agreement with the TSP prior to the effective date of the rule and have satisfied all CIAC and financial security payment obligations in accordance with the timelines specified in that agreement by the effective date of the rule should be ex-

empt from additional costs or financial security required by the standards in the rule.

Thor further recommended that the rule should not apply to a large load customer that has executed an intermediate agreement prior to the effective date of the rule.

Commission Response

The commission declines to adopt commenters' recommendations to exempt from the adopted rule's requirements large load customers that executed an agreement, including an interconnection agreement, and satisfied financial obligations prior to the effective date of the adopted rule. Agreements executed prior to the adoption of this rule and the financial obligations under those agreements lack uniformity. Exempting a large load customer with an executed agreement, regardless of the form or terms of that agreement, would run contrary to the statutory objective of standardizing the large load interconnection process. Further, the Legislature expressly imposed an applicability limitation in one section of SB 6 (Section 7, stating that PURA §35.004(c-1) applies only to an interconnection agreement entered into on or after the effective date of this Act), but declined to include a similar provision limiting the applicability of PURA §37.0561. Therefore, stating that the rule does not apply to, or otherwise exempting, large load customers that executed agreements and satisfied financial obligations prior to the effective date of the adopted rule from the rule's requirements would be inconsistent with statute.

However, the commission agrees the adopted rule should not require a large load customer to post financial security or pay costs a second time for obligations already satisfied. Accordingly, the commission modifies the adopted rule to add a new subsection addressing treatment of batch zero load, as described in the commission's response above to commenters that recommended the commission identify which large load customers currently in the interconnection queue are subject to the rule and on what terms.

Request for interconnection as of the effective date of the rule

BKV, Constellation, Intersect Power, Schaper Energy, and Tract recommended modifying proposed §25.194(b) such that the rule applies only to large load customers requesting a new or expanded interconnection as of the effective date of the rule. Constellation asserted that this approach is consistent with legislative intent and that applicability to all pending interconnection requests which have not energized or reached their peak requested demand as of the effective date of the rule would impose retroactive rulemaking on large load applicants which have been operating under the existing ERCOT Protocols and Planning Guide requirements for large load interconnection, including rules which pre-date Senate Bill (SB) 6.

Intersect Power and Schaper Energy recommended including an explicit statement that the rule applies prospectively to large load interconnection requests initiated on or after the effective date, and does not require re-evaluation of projects that are already subject to an executed interconnection agreement, including an SGIA governing a co-located configuration, where such agreements were executed and materially relied upon prior to the implementation of PGRR 115 on December 15, 2025.

Commission Response

The commission declines to adopt BKV, Constellation, Intersect Power, Schaper Energy, and Tract's recommendation to modify adopted §25.194(b) such that the rule applies only to large

load customers requesting a new or expanded interconnection as of the effective date of the rule. PURA §37.0561 directs the commission to establish interconnection standards applicable to large load customers "requesting" a new or expanded interconnection. The use of the present participle as a verb tense shows an ongoing or continuous action. The statute does not distinguish between a large load customer that submits an interconnection request before or after the effective date of the commission's rules. The Legislature's use of the term "requesting" encompasses an ongoing action and therefore includes large load customers that have initiated the interconnection process but not yet energized.

The commission also declines to adopt Intersect Power and Schaper Energy's recommendation to include an explicit statement that the adopted rule should not require re-evaluation of projects that are already subject to an executed interconnection agreement because any determination of whether re-evaluation is necessary should be made by ERCOT based on reliability.

Request for interconnection as of June 20, 2025

Cholla recommended that application to loads that submitted interconnection requests prior to June 20, 2025 is retroactive.

Commission Response

The commission declines to adopt Cholla's recommendation to limit the rule's applicability only to large load customers requesting a new or expanded interconnection as of June 20, 2025. PURA §37.0561 directs the commission to establish interconnection standards applicable to large load customers "requesting" a new or expanded interconnection. The use of the present participle as a verb tense shows an ongoing or continuous action. The statute does not distinguish between large load customers based on when the large load customer submitted an interconnection request. Moreover, Legislature's use of the term "requesting" encompasses an ongoing action and therefore includes large load customers that have initiated the interconnection process but not yet energized.

Applicability to large load customers included in 2026 Regional Transmission Plan (RTP) compliance plan

LCRA recommended modifying the proposed rule to recognize agreements signed with large load customers that were in effect ahead of the 2026 RTP compliance plan date of April 1, 2026. LCRA reasoned that projects LCRA reported in this category are in advanced stages of development and should not be subject to any activities that reset progress.

Commission Response

The commission declines to adopt LCRA's recommendation to modify the adopted rule to recognize agreements signed with large load customers that were in effect ahead of the 2026 RTP compliance plan date of April 1, 2026 for the same reasons addressed in responses to other commenters recommending applicability limitations. However, the commission agrees with LCRA that this subset of large load customers should not lose the benefit of obligations already satisfied. Accordingly, the commission modifies the adopted rule to add a subsection addressing the treatment of large load customers included in the 2026 RTP compliance plan.

Specifically, the commission modifies the adopted rule to provide that an interconnecting DSP or TSP that executed an agreement with a large load customer under §25.370(g), relating to ERCOT Large Load Forecasting Criteria, must return any financial secu-

ity that was previously posted by the large load customer, and either return or credit any cash payment that was previously provided by the large load customer on a dollar-for-dollar basis to the large load customer's financial commitments and obligations under this section. Additionally, the commission modifies the adopted rule to provide that a large load customer that executed an agreement under §25.370(g) must withdraw its interconnection request or execute a superseding intermediate agreement or SLLIA, as applicable. For a large load customer that executed an agreement under §25.370(g) and is also a batch zero load, the large load customer must comply with the adopted rule's requirements for a batch zero load.

Provide advance notice before new requirements for applicants in the interconnection queue

Thor recommended the commission provide that large load customers already in the interconnection queue receive at least 12 months' advance notice before any new regulation or material modification affecting transient behavior, ramp rate constraints, or interconnection procedures take effect.

Commission Response

The commission declines to adopt Thor's recommendation to add a provision requiring 12-month advance notice before any new regulation or material modification affecting transient behavior, ramp rate constraints, or interconnection procedures take effect for large load customers in the interconnection queue. Large load customers had more than 12 months of notice that regulatory changes to large load interconnection requirements were forthcoming. SB 6 took effect on June 1, 2025, more than 12 months prior to the adoption of §25.194. Moreover, commission staff has actively engaged with the public during that period of time, holding workshops and taking public comment on more than one discussion draft of the proposed rule. Further, it is not unusual for regulatory changes to affect existing contracts or pending projects. Contracts commonly address this possibility through change-in-law provisions that allocate the risks and responsibilities associated with future legal or regulatory changes.

Proposed §25.194(c) -- Definitions

Proposed §25.194 sets forth definitions that are specific to the proposed rule.

Add definition for financial security threshold

Google, Lancium, and TotalEnergies recommended adding a definition for financial security threshold and defining the phrase to mean the maximum financial security required through the interconnection process shall not exceed \$50,000 per MW.

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies' recommendation to add a definition for financial security threshold to mean the maximum financial security required through the interconnection process shall not exceed \$50,000 per MW because it is unnecessary. The financial security requirements are detailed elsewhere in the adopted rule and substantive requirements should not be included in a definition.

Add definition for required disclosures

CenterPoint recommended adding a definition for required disclosures and including the requirements from proposed §25.194(d)(1) through (8). If its recommended change is adopted, CenterPoint also recommended striking proposed

§25.194(d)(1) through (8) and proposed §25.198(f)(1) through (8) because those separate provisions would be redundant.

Commission Response

The commission declines to adopt CenterPoint's recommendation to add a definition for required disclosures. Instead, the commission adds the title "Required disclosures" as a paragraph before adopted §25.194(d)(1)(A)-(I) and adopted §25.194(f)(1)(A)-(I), which set forth the disclosures a large load customer must make to the interconnecting DSP or interconnecting TSP as part of a large load interconnection request. This approach provides greater clarity and notice of what information the large load customer must disclose.

Proposed §25.194(c)(1) -- Definition for backup generating facilities

Proposed §25.194(c)(1) defines backup generating facilities as generation facilities or energy storage facilities that are not capable of operating, or are not configured to operate, in parallel with the ERCOT system and cannot export energy to the ERCOT system.

Threshold of on-site demand served

CenterPoint recommended modifying proposed §25.194(c)(1) to define backup generating facilities as those that serve at least 50 percent of on-site demand consistent with the definition in PURA §37.0561(e).

Commission Response

The commission declines to adopt CenterPoint's recommendation to modify the adopted rule to define backup generating facilities as those that serve at least 50% of on-site demand. PURA §37.0561(e) defines "on-site backup generating facilities" as "generation that is not capable of exporting energy to the ERCOT system and that, in the aggregate, can serve at least 50% of on-site demand. The statute's 50% threshold applies to the narrower category of on-site backup generating facilities and is relevant to the statutory provisions directing ERCOT to establish thresholds and procedures under which large load customers may be directed to deploy on-site backup generating facilities or curtail load during an energy emergency. However, it is appropriate to distinguish between the broader category of backup generating facilities and the narrower category of on-site backup generating facilities. Accordingly, the commission modifies the adopted rule to add a definition for on-site backup generating facilities.

Proposed §25.194(c)(2) -- Definition for competitively sensitive information

Proposed §25.194(c)(2) defines competitively sensitive information to include exact site locations, such as parcel identifiers or property boundaries; commercial terms, such as pricing or internal development prioritization; proprietary architectural, operational, or compute-deployment strategies; and financing structures. The definition for competitively sensitive information excludes the identity of a large load customer; general site location, such as load zone; requested or contracted peak demand; timing of energization; or whether an interconnection request is associated with the same applicant or affiliated entities.

Align with definition of proprietary customer information

CenterPoint recommended modifying proposed §25.194(c)(2) to align with the definition of "proprietary customer information" under §25.272, relating to Code of Conduct for Electric Utilities and

Their Competitive Affiliates, by removing the statement of what competitive sensitive information does not include and replacing it with a statement that competitive sensitive information is a subset of proprietary customer information.

Commission Response

The commission declines to adopt CenterPoint's recommendation to align the definition for competitively sensitive information with the definition for proprietary customer information under §25.272, relating to Code of Conduct for Electric Utilities and Their Competitive Affiliates. Instead, the commission removes the definition for competitively sensitive information to ensure that competitively sensitive information may be evaluated based on the specific information and consistent with applicable laws.

Modify the list of competitively sensitive information

Constellation, DCC, DC Energy, Google, Lancium, and TotalEnergies, and Targa recommended modifying proposed §25.194(c)(2) by revising the list of information that is included in and the list of information that is excluded from the definition for competitively sensitive information.

Specifically, Constellation recommended: (i) specifying that load ramp information (if designated as confidential by the interconnecting large load entity) is competitively sensitive information, (ii) removing requested or contracted peak demand from the list of information that is not competitively sensitive, and (iii) modifying to reflect that it is the timing of initial energization that is not competitively sensitive information. Constellation also recommended adding a statement that for large load customers impacted by the requirements of PURA §39.169, the following information, if so determined by the commission, is not considered competitively sensitive: requested or contracted peak demand or load ramp.

DC Energy and Targa recommended including rather than excluding, the specific identity of the large load, site location, peak demand, and anticipated energization date. Targa also recommended removing the list of information that is not competitively sensitive. Targa reasoned that the Texas Public Information Act, Chapter 552 of the Texas Government Code, excepts from disclosure commercial or financial information for which it is demonstrated based on specific factual evidence that disclosure would cause substantial competitive harm to the person from whom the information was obtained.

DCC recommended striking "contracted peak demand" from the list of exclusions because this information reflects core business decisions and could be considered competitively sensitive.

Google, Lancium, and TotalEnergies recommended removing from the list of competitively sensitive information: commercial terms, such as pricing or internal development prioritization, proprietary architectural, operational, or compute-deployment strategies. Google, Lancium, and TotalEnergies also recommended specifying that financing structure is competitively sensitive information as it relates to financial viability for creditworthiness.

Commission Response

The commission declines to adopt Constellation, DCC, DC Energy, Google, Lancium, and TotalEnergies, and Targa's recommendation to revise the list of information that is included in and the list of information that is excluded from the definition for competitively sensitive information. Instead, the commission removes the definition for competitively sensitive information to

ensure that competitively sensitive information may be evaluated on the specific information and consistent with applicable laws.

Proposed §25.194(c)(3) -- Definition for contracted peak demand

Proposed §25.194(c)(3) defines contracted peak demand as the total non-coincident peak demand that a large load customer requests that an interconnecting DSP or an interconnecting TSP serve at a site as stated in the interconnection agreement.

Calculation for co-located loads

CCNG recommended modifying proposed §25.194(c)(3) to provide that contracted peak demand for co-located loads is calculated based on the net demand impact. CCNG reasoned that making this modification would more appropriately account for the reliability benefits of co-located generation. CCNG also recommended conforming changes to proposed §25.194(c)(10).

Commission Response

The commission declines to adopt CCNG's recommendation to modify the adopted rule to provide that contracted peak demand for co-located load is calculated based on the net demand impact because the transmission system must account for the load's maximum non-coincident peak demand in various transmission planning scenarios which may or may not include the generation resource. Moreover, in the event that the generation resource that is co-located with the large load customer is not available to supply power to the large load customer, the large load customer could consume power from the ERCOT system up to its maximum non-coincident peak demand thus utilizing transmission infrastructure.

Equivalent service extension or other agreement and demand not requested to be served

Constellation recommended modifying proposed §25.194(c)(3) to state that the contracted peak demand is the total non-coincident peak demand a large load customer requests service for as stated in an interconnection agreement and/or equivalent service extension or other agreement. Constellation also recommended adding a sentence that states any demand at the site for which a large load customer does not request to be served by an interconnecting DSP or TSP shall not be included in the definition of "contracted peak demand."

Commission Response

The commission declines to adopt Constellation's recommendations to modify the definition for contracted peak demand. PURA §37.0561 does not distinguish between large load customers based on whether they co-locate with generation and the commission is not persuaded that the adopted rule should distinguish between large load customers that co-locate and those that do not. The transmission system must account for the load's maximum non-coincident peak demand in various transmission planning scenarios which may or may not include the generation resource. Moreover, in the event that the generation resource that is co-located with the large load customer is not available to supply power to the large load customer, the large load customer could consume power from the ERCOT system up to its maximum non-coincident peak demand thus utilizing transmission infrastructure.

Replace amount requested with amount ultimately approved

TPPA recommended modifying proposed §25.194(c)(3) to state that contracted peak demand may not always reflect the amount

initially requested, but instead the amount ultimately approved by the interconnecting DSP, interconnecting TSP, and the large load customer at the time the interconnection agreement is executed.

Commission Response

The commission agrees with TPPA that the contracted peak demand may not always reflect the amount requested. Accordingly, the commission modifies the adopted rule to add "and is ultimately allocated by ERCOT, as stated in the SLLIA" to the definition of contracted peak demand.

Proposed §25.194(c)(4) -- Definition for interconnecting distribution service provider (DSP)

Proposed §25.194(c)(4) defines interconnecting DSP as the electric utility, municipally owned utility, or electric cooperative that is certificated to provide retail electric delivery service at the location in which the large load customer seeks to interconnect.

Clarify interconnecting DSP is certificated to provide retail electric delivery service at the location of the consuming facility

TNMP recommended modifying proposed §25.194(c)(4) to state that the interconnecting DSP is the electric utility, municipally owned utility, or electric cooperative that is certificated to provide retail electric delivery service at the location in which the large load customer's consuming facility is located instead of the location in which the large load customer seeks to interconnect.

Commission Response

The commission adopts TNMP's recommendation to modify the adopted rule to specify that the interconnecting DSP is one that provides retail electric delivery service at the location in which the "large load customer's consuming facility is located" rather than the location the large load customer "seeks to interconnect."

Recognize not every large load customer will take service from an interconnecting DSP

Vistra recommended modifying proposed §25.194(c)(4) to recognize that not every large load customer will take service from an interconnecting DSP. As an example, Vistra cited self-service, self-generators, incidence of employment or tenancy, electric generation equipment lessor or operator arrangements, non-settled generators, connected island, and export only approaches to self-limiting new co-located generation facilities. Additionally, Vistra recommended that the proposed rule allow flexibility for a co-located generator to be a party to the intermediate and/or interconnection agreement. Vistra also recommended conforming changes to proposed §25.194(c)(6), (c)(8), (d), (d)(2)(A), (e)(1) through (4), (f), and (f)(2)(A).

Commission Response

The commission declines to adopt Vistra's recommendation to modify the adopted rule by recognizing that not every large load customer will take service from an interconnecting DSP. All large load customers that interconnect to the ERCOT system must take service from an interconnecting DSP.

Proposed §25.194(c)(5) -- Definition for interconnecting transmission service provider (TSP)

Proposed §25.194(c)(5) defines interconnecting TSP as the electric utility, municipally owned utility, or electric cooperative that owns and operates the facilities necessary to interconnect the large load customer to the ERCOT system.

Clarify interconnecting TSP owns and operates facilities necessary for transmission of electricity

TNMP recommended modifying proposed §25.194(c)(5) to state that the interconnecting TSP is the electric utility, municipally owned utility, or electric cooperative that owns and operates the facilities necessary for transmission of electricity within ERCOT instead of the facilities necessary to interconnect the large load customer to the ERCOT system. TNMP reasoned that this change harmonizes the new rule with PURA and existing commission rules, which require the customer be served by the retail electric utility certificated for the territory in which the customer's consuming facility is located.

Commission Response

The commission declines to adopt TNMP's recommendation to modify the adopted rule to state that the interconnecting TSP is the electric utility, municipally owned utility, or electric cooperative that owns and operates the facilities necessary for transmission of electricity within ERCOT instead of the facilities necessary to interconnect the large load customer to the ERCOT system. Instead, the commission modifies the definition for interconnecting TSP to state an interconnecting TSP is the electric utility, municipally owned utility, or electric cooperative that owns or operates the equipment or facilities necessary to transmit or distribute electricity to the large load customer. This approach aligns with the definition in §25.5, relating to Definitions, as recommended by TNMP, but also distinguishes between a TSP involved in providing service to a large load customer from other TSPs in the ERCOT region.

Recognize more than one entity may meet the definition for interconnecting TSP

Constellation recommended modifying proposed §25.194(c)(5) to add that the interconnecting TSP may not be same entity as the applicable DSP and may not be the TSP providing generation and/or transmission service to the applicable DSP.

Commission Response

The commission declines to adopt Constellation's recommendation to add to the definition for interconnecting TSP that the interconnecting TSP may not be the same entity as the applicable DSP and may not be the TSP providing generation or transmission service to the applicable DSP because it is unnecessary. The adopted rule already distinguishes between and separately defines the interconnecting DSP and the interconnecting TSP.

Large load co-located with a generation resource

Vistra recommended modifying proposed §25.194(c)(5) by specifying that for large load customers co-located with a generation resource, the interconnecting TSP is the TSP that interconnects the generation resource to the ERCOT system.

Commission Response

The commission declines to adopt Vistra's recommendation to modify the adopted rule to specify that for large load customers co-located with a generation resource, the interconnecting TSP is the TSP that interconnects the generation resource to the ERCOT system because this may not always be the case. The adopted rule appropriately recognizes this fact.

Proposed §25.194(c)(6) -- Definition for interconnection agreement

Proposed §25.194(c)(6) defines interconnection agreement as an agreement that is executed by a large load customer, the interconnecting DSP, and, if different from the interconnecting DSP, the interconnecting TSP after completion of the intercon-

nection study and that, at a minimum, satisfies proposed subsection (f) of the rule.

Circumstances in which retail electric delivery service is not provided by DSP

Vistra recommended modifying proposed §25.194(c)(6) by adding a sentence stating that a large load customer that will not take retail electric delivery service from a DSP must execute an interconnection agreement with only the interconnecting TSP.

Commission Response

The commission declines to adopt Vistra's recommendation to modify the proposed rule to add a sentence stating that a large load customer that will not take retail electric delivery service from a DSP must execute an interconnection agreement with only the interconnecting TSP. Consistent with the overall framework of PURA and existing commission rules in place since the deregulation of the ERCOT market, a DSP is the appropriate entity with the customer relationship and must necessarily be a party to the SLLIA. The commission declines to adopt a policy that departs from this longstanding framework.

Proposed §25.194(c)(7) -- Definition for interconnection study

Proposed §25.194(c)(7) defines interconnection study as the set of studies that are required by ERCOT before a large load customer may be interconnected.

Reference ERCOT Protocols and Planning Guide

Constellation and Vistra recommended modifying proposed §25.194(c)(7) to reference the ERCOT Protocols and Planning Guide. Vistra also recommended similar changes to proposed §25.194(f) and (g).

Commission Response

The commission agrees with Constellation and Vistra that the definition for interconnection study should reference the ERCOT protocols and modifies the adopted definition accordingly. The commission declines to reference the Planning Guide because it is unnecessary. The definition for ERCOT protocols in §25.5(47) includes the Planning Guide.

Proposed §25.194(c)(8) -- Definition for intermediate agreement

Proposed §25.194(c)(8) defines an intermediate agreement as an agreement that is executed by a large load customer, the interconnecting DSP, and, if different from the interconnecting DSP, the interconnecting TSP before the interconnection study is initiated and that, at a minimum, satisfies proposed subsection (d) of the rule.

Circumstances in which retail electric delivery service is not provided by DSP

Vistra recommended modifying proposed §25.194(c)(6) by adding a sentence stating that a large load customer that will not take retail electric delivery service from a DSP must execute an intermediate agreement with only the interconnecting TSP.

Commission Response

The commission declines to adopt Vistra's recommendation to modify the proposed rule to add a sentence stating that a large load customer that will not take retail electric delivery service from a DSP must execute an intermediate agreement with only the interconnecting TSP for the same reasons the commission declines to adopt Vistra's recommendation for this change to the definition for interconnection agreement.

Proposed §25.194(c)(9) -- Definition for large load customer

Proposed §25.194(c)(9) defines a large load customer as an entity requesting a new or expanded interconnection where the customer's total expected non-coincident peak demand at a single site is equal to or exceeds 75 MW.

Additional non-coincident peak demand

ERCOT Steel Mills recommended modifying proposed §25.194(c)(9) to state that a large load customer is an entity requesting a new or expanded interconnection where the customer's total expected additional non-coincident peak demand at a single site is equal to or exceeds 75 MW.

Commission Response

The commission declines to adopt ERCOT Steel Mills' recommendation to modify the adopted rule to state that a large load customer is an entity requesting a new or expanded interconnection where the customer's total expected additional non-coincident peak demand at a single site is equal to or exceeds 75 MW. The commission determines that loads that exceed 75 MW significantly impact transmission needs and it is therefore appropriate for loads exceeding 75 MW for the first time to comply with the adopted rule regardless of the incremental amount of non-coincident peak demand that these loads are seeking to be served. Moreover, this disincentivizes gamesmanship.

Large load customer is an Interconnecting Large Load Entity (ILLE)

Constellation recommended modifying proposed §25.194(c)(9) to specify that a large load customer is the Interconnecting Large Load Entity (ILLE) as that term is defined in the ERCOT Protocols and Other Binding Documents.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to specify that a large load customer is the ILLE as that term is defined in the ERCOT Protocols and Other Binding Documents because it is unnecessary to rely on the definition in the ERCOT protocols. The terms "large load customer" and "ILLE" are not technical in nature such that the commission's rules should rely on the definition used in ERCOT protocols. ERCOT protocols may cite back to the terminology and definition in commission rules.

Replace site with ESI ID

CenterPoint recommended modifying proposed §25.194(c)(9) by replacing "site" with "ESI ID." CenterPoint noted that a single premise may have more than one service delivery point that is nevertheless served by a shared or common transmission circuit, in which case all service delivery points on the premises that are served by a common transmission circuit under a single ESI ID should be counted as a single large load customer for study purposes. CenterPoint recommended similar modifications to proposed §25.194(b).

Commission Response

The commission declines to adopt CenterPoint's recommendation to modify adopted §25.194(c) by replacing "site" with "ESI ID." The commission determines that the demand at a single site is the appropriate measurement of demand in recognition of the fact that large loads are able to establish campuses with multiple ESI IDs, which would allow them to avoid compliance with the adopted rule.

Single site includes interconnection through the same Facilities Extension Agreement

PPM recommended modifying proposed §25.194(c)(9) to clarify that a single site includes the load interconnected through the same Facilities Extension Agreement (FEA). PPM reasoned that some loads may have multiple meters or distributed equipment that collectively exceed 75 MW if components are netted as they are installed over time.

Commission Response

The commission declines to adopt PPM's recommendation to modify the adopted rule to clarify that a single site includes the load interconnected through the same FEA. The modification would establish the FEA, rather than the site, as the measure of the large load customer's total expected non-coincident peak demand. This could open the door to gamesmanship whereby a customer could add load incrementally under a separate agreement and avoid becoming subject to the rule's requirements, regardless of the total demand at the location.

Proposed §25.194(c)(10) -- Definition for requested peak demand

Proposed §25.194(c)(10) defines requested peak demand as the total non-coincident peak demand that a large load customer requests, prior to executing an interconnection agreement, that an interconnecting DSP or an interconnecting TSP serve at a site.

Clarify how demand is measured for behind-the-meter, self-limiting, and co-located loads

AEP recommended modifying proposed §25.194(c)(10) to clarify how demand is measured for behind-the-meter loads, self-limiting loads, and co-located loads. Specifically, AEP recommended modifying proposed §25.194(c)(10) by replacing non-coincident peak demand with gross demand to clarify that the definition for requested peak demand includes behind-the-meter load and peak demand for self-limiting loads should be determined based on the total gross demand that the large load customer can draw from the ERCOT system.

Commission Response

The commission declines to adopt AEP's recommendation to modify the adopted rule to replace non-coincident peak demand with gross demand. Non-coincident peak demand is a more precise and commonly used industry term.

Proposed §25.194(d) -- Intermediate agreement

Proposed §25.194(d) states that, before a large load interconnection request is submitted to ERCOT for study, the large load customer must execute an intermediate agreement with the interconnecting DSP and, if different from the interconnecting DSP, the interconnecting TSP. If the interconnecting DSP and the interconnecting TSP are different entities, the intermediate agreement must specifically identify each entity's responsibilities under this section, including which entity will accept the study fee and financial security from the large load customer. The intermediate agreement must meet the requirements of this rule.

Deadline to execute an intermediate agreement

Joint TSPs recommended modifying proposed §25.194(d) to define a timeline of 60 days by which a large load customer, interconnecting DSP, and interconnecting TSP must enter an intermediate agreement after the large load customer requests execution of an intermediate agreement.

Commission Response

The commission declines to adopt Joint TSPs' recommendation to modify adopted §25.194(d) to define a timeline of 60 days by which a large load customer, interconnecting DSP, and interconnecting TSP must enter an intermediate agreement after the large load customer submits an interconnection request. Execution of an intermediate agreement should be based on compliance with providing the necessary information and financial commitments for an intermediate agreement rather than on a strict deadline that disregards whether the necessary information and financial commitments are provided by the large load customer.

Permit utilities to enter independent discretionary service agreements

Joint TSPs recommended modifying proposed §25.194(d) to permit utilities to enter into independent discretionary service agreements directly with the retail load for collecting financial security or CIAC for the facilities they are constructing or for any services being performed. Joint TSPs also recommended conforming changes to proposed §25.194(f), relating to interconnection agreement.

Commission Response

The commission declines to adopt Joint TSPs' recommendation to modify the adopted rule to permit utilities to enter into independent discretionary service agreements directly with the retail load for collecting financial security or CIAC. The commission determines that a standardized pro forma agreement setting forth each entity's responsibilities is a better approach than varying independent discretionary service agreements across utilities. Adopted §25.194(f) requires the large load customer and interconnecting DSP or interconnecting TSP to execute a commission-approved pro forma agreement (a SLLIA). The commission plans to adopt a SLLIA in a future rulemaking project; therefore, it is unnecessary to detail the content and types of agreements in this rulemaking beyond the minimum requirements described in the adopted rule consistent with PURA §37.0561.

Recognize right to provide retail electric delivery service

TNMP recommended modifying proposed §25.194(d) to eliminate the mandatory three-party intermediate agreement requirement or, at a minimum, strictly limit its purpose to administrative coordination, with no authority to violate retail service rights, retail obligations, or tariff responsibility by agreement. TNMP reasoned that, even if a TSP could collect fees from a retail customer under a TSP's tariff, this requirement represents a significant departure from established statutes, tariff regulations, and existing framework. Additionally, TNMP recommended modifying proposed §25.194(d) to state that the rule does not authorize any utility to provide retail electric delivery service outside its certificated territory or to impose or collect retail tariff charges (including CIAC) from a customer not served under that utility's commission-approved retail tariff.

Commission Response

The commission declines to adopt TNMP's recommendation to modify the adopted rule to explicitly recognize that DSPs, not TSPs, must serve retail customers because it is not necessary. The adopted rule does not contravene the framework under PURA and existing commission rules. Moreover, the level of detail that TNMP proposed will be addressed in a separate rulemaking to adopt a SLLIA, which will set forth each entity's responsibilities.

Identify ownership and control of distribution infrastructure

TEC recommended modifying proposed §25.194(d) to add a statement that the interconnecting DSP, if different from the interconnecting TSP, may retain ownership and control over any distribution assets necessary to interconnect the large load customer, excluding distribution equipment and transformers owned by a large load. TEC also recommended a conforming change to proposed §25.194(f).

Commission Response

The commission declines to adopt TEC's recommendation to modify the adopted rule to add a statement that the interconnecting DSP, if different from the interconnecting TSP, may retain ownership and control over any distribution assets necessary to interconnect the large load because it is not necessary. Nothing in the rule suggests that a DSP would not retain ownership and control over distribution assets necessary to interconnect the large load customer.

Add additional operational disclosure requirements

EDF recommended the commission modify the rule to add additional operational disclosure requirements. Specifically, EDF recommended requiring: (1) the average amount of energy consumption used during a normal set of circumstances; (2) any factors or events that would cause the large load customer or flexible large load customer to increase or decrease the energy consumption or demand; (3) real or reactive power consumption changes and recovery time; (4) how long the customer remains connected to the grid during a given voltage and/or frequency disturbance; (5) grid connection level; (6) request for firm or flexible load, and how much; and (7) the name and contact information of at least two individuals with decision-making authority for ERCOT to have a direct open line of communication in the event of an energy emergency alert or grid disturbance.

Commission Response

The commission declines to adopt EDF's recommendation to modify the adopted rule to add additional operational disclosure requirements. The purpose of the disclosure requirements is to demonstrate project viability and provide inputs for interconnection studies. However, the commission notes that ERCOT may still request the operational disclosures recommended by EDF.

Require disclosure of whether applicant is end-use customer

EDF recommended modifying proposed §25.194(d) to require disclosure of whether the large load customer is the end-use customer or a third-party developer, reasoning that this situational awareness would support the accuracy and reliability of large load forecasting.

Commission Response

The commission declines to adopt EDF's recommendation to modify the adopted rule to require disclosure of whether the large load customer is the end-use customer or a third-party developer because transmission planning does not differentiate based on who requests interconnection. Therefore, whether the large load customer is an end-use customer or a third-party developer is not a meaningful input to ERCOT's large load forecast.

Require disclosure of water usage

OPUC and TPPA recommended modifying proposed §25.194(d) to require disclosures related to water. Specifically, OPUC recommended requiring a large load customer to disclose detailed information as to their anticipated water usage, the source of

water supply, and whether such supply is sourced within Texas. Additionally, OPUC recommended that large load customers relying on Texas-based water supplies be required to identify and disclose contingency plans or alternative water sources in the event of drought conditions or other constraints limiting availability. OPUC recommended similar changes to proposed §25.194(f)(1). Similarly, TPPA recommended requiring disclosure about how the large load will procure water, including whether the large load's water needs will differ substantially year-to-year. TPPA recommended conforming changes to §25.194(f)(1).

Commission response

The commission agrees with OPUC and TPPA that a large load customer's access to water impacts a customer's interconnection and energization plans. Issues with a large load customer's water access could result in a customer materially changing, delaying, or withdrawing the interconnection request. Therefore, the commission modifies the adopted rule to require a large load customer to disclose to the interconnecting DSP or interconnecting TSP the anticipated volume of water needed, the type of water source that will be used, the entity that will supply water, the cooling technology that will be used, and any other related information prior to the execution of the intermediate agreement and prior to the execution of the SLLIA. Further, the commission modifies the adopted rule to specify under adopted §25.194(d)(1)(D) and §25.194(f)(1)(D), relating to disclosure of state and local regulatory milestones, that such milestones may include water permit approvals. The commission declines to adopt OPUC's recommendation to modify the rule to require large load customers relying on Texas-based water supplies to disclose contingency plans in event of water supply constraints because the details of the required water disclosure are best addressed in a future rulemaking to adopt a SLLIA.

Require disclosure of and prioritize certain cooling technologies

Jason Buster recommended the Commission modify the proposed rule to require disclosure of the large load project's primary cooling type and provide priority or preference to projects implementing non-per- and polyfluoroalkyl substances (non-PFAS) immersion cooling. Jason Buster further recommended the Commission share data or relevant findings with the Texas Commission on Environmental Quality (TCEQ) and consider working with TCEQ on rulemaking or guidance to prioritize or streamline approvals for non-PFAS immersion cooling technologies.

Commission Response

The commission adopts Jason Buster's recommendation to modify the adopted rule to require disclosure of the large load customer's primary cooling type. The commission declines to adopt Jason Buster's recommendation to modify the adopted rule to provide priority to large load customers implementing non-PFAS immersion cooling because preferential treatment based on this type of operating characteristic is beyond the scope of SB 6.

Clarify use of disclosed information

EDF and Infinium recommended modifying proposed §25.194(d) to clarify how the disclosed information will be used. Specifically, EDF recommended clarifying how ERCOT will use disclosed information for transmission planning versus resource adequacy modeling. Infinium recommended clarifying how additional studies, permitting, and operational information will be used by the

interconnecting DSP or the interconnecting TSP in the screening and interconnection process. Infinium noted that providing the required disclosures is burdensome and that, without clear guidance, there is risk of inconsistent application by DSPs and TSPs.

Commission Response

The commission declines to adopt EDF and Infinium's recommendations to modify the adopted rule to clarify how disclosed information will be used for transmission planning, resource adequacy modeling, and project screening. The purpose of the disclosure requirements is to demonstrate large load project viability and provide inputs for interconnection studies.

Proposed §25.194(d)(1) -- Site control

Proposed §25.194(d)(1) requires a large load customer to demonstrate site control for the proposed load location.

Allow updated documentation for site control to be provided

Constellation recommended modifying proposed §25.194(d) to add a statement that notwithstanding any other provisions of the rule, if a change in fact requires modification to the underlying site control documentation, a large load customer is permitted to provide updated documentation to the interconnecting DSP or TSP and such update will not delay or adversely impact the large load interconnection request.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to add a statement that a large load customer is permitted to provide updated site control documentation and such update will not delay or adversely impact the large load customer's interconnection request. Explicitly stating a large load customer may provide updated site control documentation is unnecessary, and whether changes in site control circumstances would delay or adversely impact an interconnection request depends on the nature and specific facts of the change.

Information deemed to satisfy rule requirements

Constellation recommended modifying proposed §25.194(d)(1) to add a statement that each form of documentation listed will be deemed to satisfy requirements of the rule if the large load customer provides written confirmation to the TSP addressing each relevant issue.

Commission Response

The commission agrees with Constellation that it is appropriate to specify the format by which a large load customer can provide site control demonstration. The commission declines to adopt Constellation's recommendation to add a statement that each form of documentation listed will be deemed to satisfy requirements of the adopted rule if the large load customer provides written confirmation to the TSP addressing each relevant issue because written confirmation alone does not provide sufficient assurance of information accuracy and completeness. Instead, the commission modifies the adopted rule to require the intermediate agreement and SLLIA to include an attestation by the large load customer supporting all required disclosures, including site control demonstration.

Further, the commission modifies the adopted rule to clarify that: (1) all information provided or attested to is subject to audit and verification; (2) a large load customer or its interconnecting TSP or interconnecting DSP that fails to comply with ERCOT or com-

mission staff's audit process or that fails to produce responsive documentation supporting the completeness or accuracy of information provided under an intermediate agreement or SLLIA may be found in violation of commission rules and subject to enforcement action, including the imposition of administrative penalties or loss of transmission capacity allocated to the large load customer; and (3) if a large load customer is determined to have provided false or inaccurate information, or if information cannot be verified, the customer may be deemed to have forfeited any financial security and may be subject to transmission capacity reallocation.

Require developers to show contract with end-use customer

OPUC recommended modifying proposed §25.194(d)(1) to require a large load customer that is a developer rather than the end-use customer to produce to the interconnecting utility and ERCOT proof of contracts with an end-use customer or demonstration of good faith efforts to procure contracts. OPUC recommended a similar change to proposed §25.194(f)(1).

Commission Response

The commission declines to adopt OPUC's recommendation to require a large load customer that is a developer rather than the end-use customer to produce proof of contracts with an end-use customer or demonstration of good faith efforts to procure contracts because there may be legitimate reasons a developer does not enter into a contract with an end-use customer before the intermediate agreement or SLLIA is executed.

Permit demonstration through an affiliate

Schaper Energy recommended modifying proposed §25.194(d)(1) to permit a large load customer to demonstrate site control through an affiliate. Schaper Energy also recommended a similar change to proposed §25.194(f)(1).

Commission Response

The commission adopts Schaper Energy's recommendation to permit a large load customer to demonstrate site control through an affiliate and modifies the adopted rule accordingly. The commission also modifies the adopted rule to include a definition for affiliate.

Exclusivity agreement with generator subject to PURA §39.169

Vistra recommended modifying proposed §25.194(d)(1) to add a new provision that allows a large load customer to demonstrate site control through the provision of a signed and executed exclusivity agreement with a generator subject to PURA §39.169 and Section 205 of this Chapter to enter into a net metering arrangement sufficient to accommodate the customer's planned facilities at the proposed location for a duration of at least five years from the date the large load customer is expected to reach the contracted peak demand.

Commission Response

The commission declines to adopt Vistra's recommendation to add a new provision that allows a large load customer to demonstrate site control through an exclusivity agreement with a generator to enter into a net metering arrangement. It is reasonable to expect that a large load customer that can produce an exclusivity agreement can also produce the legally binding property interests to demonstrate site control as required by the adopted rule.

Proposed §25.194(d)(1)(A) -- Site control demonstrated through signed and executed lease agreement

Proposed §25.194(d)(1)(A) states that a large load customer may demonstrate site control through provision of a signed and executed lease agreement for one or more parcels of land sufficient to accommodate the customer's planned facilities at the proposed load location for a duration of at least five years from the date the large load customer is expected to reach the contracted peak demand.

Replace contracted peak demand with requested or planned peak demand

Rowan recommended modifying proposed §25.194(d)(1)(A) by replacing "contracted peak demand" with "requested peak demand" because the contracted peak demand is not an available data point at the intermediate agreement stage.

Similarly, Constellation recommended modifying proposed §25.194(d)(1)(A) by replacing "contracted peak demand" with "planned peak demand."

Commission Response

The commission adopts Rowan's recommendation to replace the reference to "contracted peak demand" with "requested peak demand" because the contracted peak demand is not an available data point at the intermediate agreement stage. This change also addresses Constellation's recommendation.

Extend the timeline for the agreement to 15 years

TPPA recommended modifying proposed §25.194(d)(1)(A) to extend the requirement for the agreements from 5 years to 15 years from the date the large load customer is expected to reach contracted peak demand, with options to renegotiate terms at the five-year mark. TPPA also recommended a conforming change to proposed §25.194(d)(1)(C).

Commission Response

The commission declines to adopt TPPA's recommendation to extend the requirement for the lease agreements to obligate the large load customer for a period of 15 years instead of 5 years from the date that the large load customer is expected to reach contracted peak demand, with options to renegotiate terms at the five-year mark. Five years strikes an appropriate balance demonstrating project viability and allowing businesses to enter into contract terms of their choosing.

Proposed §25.194(d)(2) -- Substantially similar interconnection request

Proposed §25.194(d)(2) requires a large load customer to disclose to the interconnecting DSP or the interconnecting TSP whether the customer is pursuing a substantially similar interconnection request for electric service, the approval of which would result in the customer materially changing, delaying, or withdrawing the interconnection. A material change or delay includes a delay of one or more years to the project's projected date to realize its requested or contracted peak demand, a 20% or greater change in the contracted peak demand, or a change in the location of the point of interconnection.

Add end user that the customer has contracted to host

Oncor recommended modifying proposed §25.194(d)(2) to require the large load customer to disclose whether the customer or the end user that the customer has contracted to host is pursuing a substantially similar interconnection request for electric service either directly or through a third-party developer. Oncor also recommended a conforming change to proposed §25.194(f)(2).

Commission Response

The commission adopts Oncor's recommendation to modify the adopted rule to require the large load customer to disclose whether the customer or end-use customer the large load customer has contracted to host is pursuing a substantially similar request directly or through a third-party developer. Further, the commission modifies the adopted rule to require disclosure of whether an affiliate of the large load customer is pursuing a substantially similar request.

Substantially similar means same amount of planned peak demand

Constellation recommended modifying proposed §25.194(d)(2) to add a statement that substantially similar means a large load interconnection request for the same amount of planned peak demand, having the same load and ramp characteristics as an existing interconnection request, intended for the same end-use customer. Constellation also recommended a conforming change to proposed §25.194(f)(2).

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to further define "substantially similar." The relevant consideration is not whether two interconnection requests share the same specific characteristics, but whether approval of one request could result in the other being materially changed, delayed, or withdrawn.

Facilities study

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(d)(2) to require the TSP to conduct a facilities study prior to the batch process and include it as a criteria for the intermediate agreement.

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies recommendation to modify the adopted rule to require the TSP to conduct a facilities study prior to the batch process and include it as a criterion for the intermediate agreement because it is unnecessary. To the extent that ERCOT requires the TSP to conduct a facilities study prior to the batch process, that specific requirement is more appropriately addressed in ERCOT protocols, which relate to technical requirements.

Proposed §25.194(d)(2)(D) -- ERCOT request of competitively sensitive information

Proposed §25.194(d)(2)(D) authorizes ERCOT to request and requires a large load customer to provide any competitively sensitive information that ERCOT deems necessary to complete any analysis required as part of the interconnection process. ERCOT must treat disclosed competitively sensitive information as Protected Information under ERCOT protocols.

Broaden the circumstances for ERCOT to request competitively sensitive information

TPPA recommended modifying proposed §25.194(d)(2)(D) by moving it to its own separate provision and thereby clarifying that ERCOT may request competitively sensitive information at any point during the interconnection process and with respect to any relevant information, not solely information concerning substantially similar interconnection requests.

Commission Response

The commission adopts TPPA's recommendation to move the provision authorizing ERCOT to request competitively sensitive information to its own separate subsection and thereby clarify that ERCOT may request competitively sensitive information at any point during the interconnection process and with respect to any relevant information, not solely information concerning substantially similar interconnection requests. Accordingly, for clarity and consistency with PURA §37.0561(k), the commission modifies the adopted rule to remove the language in proposed §25.194(d)(2)(D) and add adopted §25.194(j), detailing the procedure by which ERCOT and commission staff may request information (including competitively sensitive information) to conduct an audit, complete analysis, or verify any information attested to by the large load customer.

Limit ERCOT's authority to access information

Constellation, Google, Lancium, and TotalEnergies recommended modifying the proposed rule to limit ERCOT's authority to access information.

Specifically, Constellation recommended striking proposed §25.194(d)(2)(D) because it is not contemplated in PURA §37.0561 that ERCOT should have such broad discretion to solicit confidential information from large load customers. Instead, Constellation recommended modifying proposed §25.194(d)(2)(C) by adding "subject to appropriate confidentiality protections" to align with PURA §37.0561(d). Constellation also recommended conforming changes to proposed §25.194(f)(2)(D) and proposed §25.194(f)(2)(C).

Similarly, Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(d)(2)(D) to remove the first sentence, which states ERCOT may request and the large load customer must provide any competitively sensitive information ERCOT deems necessary to complete any analysis required as part of the interconnection process.

Commission Response

The commission declines to adopt Constellation, Google, Lancium, and TotalEnergies' recommendations to modify the adopted rule to remove ERCOT's authority to request competitively sensitive information from a large load customer. PURA §37.0561(k) explicitly states that ERCOT may access any information to ensure compliance with the standards for transmission planning analysis.

However, for clarity and consistency with PURA §37.0561(k), the commission modifies the adopted rule to remove the language in proposed §25.194(d)(2)(D) and adds adopted §25.194(j), detailing the procedure by which ERCOT and commission staff may request information (including competitively sensitive information) to conduct an audit, complete analysis, or verify information attested to by the large load customer.

Reasonably necessary standard

Targa recommended modifying proposed §25.194(d)(2)(D) to require ERCOT to demonstrate that its request is reasonably necessary to complete any analysis required. Targa also recommended conforming changes throughout the rule.

Commission Response

The commission declines to adopt Targa's recommendation to modify the adopted rule to require ERCOT to demonstrate that its request is reasonably necessary to complete any analysis required. The adopted rule is consistent with PURA §37.0561(k), which states ERCOT may access any information to ensure

compliance with the standards for transmission planning analysis.

Proposed §25.194(d)(3) -- Site-related studies and engineering services

Proposed §25.194(d)(3) requires a large load customer to submit to the interconnecting DSP or the interconnecting TSP the large load customer's plans, expected timing, and progress for site-related studies and engineering services required for project development before energization (e.g., geotechnical survey, water, wastewater, or gas). The submission must be accompanied by an attestation by an officer or official with binding authority over the large load customer stating that the information contained in the submission is complete and accurate at the time the attestation is signed. A large load customer must provide updates or progress reports to the interconnecting DSP or the interconnecting TSP when requested, but no more frequently than quarterly.

Protected information and competitively sensitive information not subject to disclosure

Constellation recommended modifying proposed §25.194(d)(3) to add a statement that all information subject to this subsection shall be considered Protected Information under the ERCOT Protocols and any competitively sensitive information shall not be subject to disclosure under Chapter 552, Government Code. Constellation also recommended a conforming change to proposed §25.194(d)(4).

Commission Response

The commission declines to adopt Constellation's recommendation to modify the provisions relating to site-related studies and engineering services to state that all information subject to these provisions shall be considered Protected Information under the ERCOT Protocols. The commission determines that the appropriate treatment of information as either Protected Information or as competitively sensitive information is best addressed on a case-by-case basis that considers the specific information and applicable laws. However, the commission adopts Constellation's recommendation to specify that ERCOT and commission staff must treat disclosed competitively sensitive information as Protected Information under ERCOT protocols, and that this information is not subject to disclosure under Chapter 552, Government Code. This approach is consistent with PURA §37.0561(k) and is reflected in adopted §25.194(j)(3).

Eliminate requirement for underlying documentation and rely solely on attestation

Targa recommended modifying proposed §25.194(d)(3) to eliminate the requirement for submission of underlying plans, studies, or permit applications and instead rely solely on the officer attestation. Targa also recommended removing the reporting requirements. Targa recommended similar changes to proposed §25.194(d)(4), (f)(3) and (f)(4).

Commission Response

The commission adopts Targa's recommendation to eliminate the requirement for submission of underlying plans, studies, or permit applications. However, the commission modifies the adopted rule to require disclosure of the plans, studies, or permit applications supported by an officer attestation and clarifies that the underlying plans, studies, or permit applications may be requested by ERCOT or commission staff to verify the completeness and accuracy of the information disclosed. Accordingly,

the commission modifies the adopted rule to require the intermediate agreement and SLLIA to include an attestation by the large load customer supporting all required disclosures. Further, the commission modifies the adopted rule to clarify that all information provided or attested to is subject to audit and verification.

The commission declines to adopt Targa's recommendation to modify the adopted rule to eliminate the requirement to provide updates or progress reports. It is appropriate for the interconnecting DSP or TSP to request updates as needed because site-related, engineering, and regulatory approval information evolves throughout the development of a large load project, and changes may affect the interconnection request. Moreover, the interconnecting DSP or TSP must coordinate with ERCOT and commission staff to obtain information from the large load customer that is requested by ERCOT or commission staff for purposes of an audit. Therefore, the commission modifies the adopted rule to remove the limitation that requests are limited to a quarterly basis.

Require ongoing progress reports

OPUC recommended modifying proposed §25.193(d)(3) to require ongoing progress reports as a matter of due course rather than to require ongoing progress reports upon request. OPUC recommended similar changes to proposed §25.194(d)(4), (f)(3), and (f)(4).

Commission Response

The commission declines to adopt OPUC's recommendation to modify the adopted rule to require ongoing progress reports as a matter of due course, rather than upon request. Requiring reports regardless of whether the information is needed by the interconnecting DSP or TSP creates an unnecessary administrative burden.

Strike subsection

DCC recommended striking proposed §25.194(d)(3) because site-related studies and engineering services do not reliably indicate project commitment. DCC recommended similar changes to proposed §25.194(f)(3).

Commission Response

The commission declines to adopt DCC's recommendation to modify the adopted rule to remove the requirement that a large load customer provide information regarding site-related studies and engineering services. Information about progress in these areas is useful to understanding the viability of a proposed project because these activities help identify and resolve issues that could affect the feasibility, scope, or timing of a project. Although the timing of such activities will vary among projects, that variability does not diminish the usefulness of the information to the point of justifying elimination of the requirement.

Proposed §25.194(d)(4) -- State and local regulatory approvals

Proposed §25.194(d)(4) requires a large load customer to submit to the interconnecting DSP or the interconnecting TSP the large load customer's plans, expected timing, and current progress for obtaining non-ministerial discretionary approvals from state and local regulatory authorities required for development before energization (e.g., water, air, or backup generation permits). The submission must be accompanied by an attestation by an officer or official with binding authority over the large load customer attesting that the information contained in the submission is complete and accurate at the time the attestation is signed. A

large load customer must provide updates or progress reports to the interconnecting DSP or the interconnecting TSP when requested, but no more frequently than quarterly.

Replace reference to milestones with approvals

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(d)(4) by replacing reference to approvals with milestones and specifying that the large load customer's plans must identify the project milestones, which include the listed information. Google, Lancium, and TotalEnergies also recommended a conforming change to proposed §25.194(f)(4).

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies' recommendation to modify the adopted rule to replace reference to approvals with milestones. However, the commission modifies the adopted rule to clarify that disclosure of project milestones and regulatory approvals is required; and to specify that the large load customer's plans must identify the project milestones, including expected timing and current progress for obtaining non-ministerial discretionary approvals from state and local regulatory authorities required for development before energization. The commission also modifies the adopted rule to specify that such approvals must include, as applicable, permits for water, wastewater, air, or backup generation; abatements for noise, light pollution, or traffic impacts; and agreements related to emergency response or site security.

Strike subsection

DCC recommended striking proposed §25.194(d)(4) because permitting progress does not reliably indicate project commitment. DCC recommended similar changes to proposed §25.194(f)(4).

Commission Response

The commission declines to adopt DCC's recommendation to modify the adopted rule to remove the requirement that a large load customer provide information regarding state and local regulatory approvals. Information regarding the status of regulatory approvals is useful to understanding the viability of a proposed project because such information may affect the feasibility, scope, or timing of the project. Although the timing and types of approvals required will vary among projects, that variability does not diminish the usefulness of the information to the point of justifying elimination of the requirement.

Proposed §25.194(d)(5) -- Schedule for phased energization of contracted peak demand

Proposed §25.194(d)(5) requires a large load customer to disclose to the interconnecting DSP or the interconnecting TSP the expected schedule, including the quarter and year, for phased energization of the contracted peak demand expressed in MW, power factor (PF), and megavolt-ampere reactive (MVAR) units.

Insert load ramp

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(d)(5) by inserting "load ramp" after "expected" and before "schedule." Google, Lancium, and TotalEnergies also recommended a conforming change to proposed §25.194(f)(5).

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies' recommendation to replace "expected schedule" with "expected load ramp schedule." Instead, the commission mod-

ifies the adopted rule to replace "expected schedule" with "expected phased energization schedule." This approach adds the recommended clarity and uses more precise language that is consistent with the rest of the adopted rule.

Proposed §25.194(d)(6) -- Backup generating facilities

Proposed §25.194(d)(6) requires a large load customer to disclose to the interconnecting DSP or the interconnecting TSP whether the customer plans to have on-site backup generating facilities. And, if the large load customer does, the large load customer must disclose: (A) the number of backup generating facilities; (B) the nameplate capacity of each of the backup generating facilities; (C) the fuel source and operational characteristics of each of the backup generating facilities, including any run hour limitations and any fuel storage limitations under the existing environmental permits; and (D) how quickly each of the backup generating facilities can reach their full capacity to serve the load.

Remove reference to interconnecting TSP

AEP recommended modifying proposed §25.194(d)(6) to remove the reference to interconnecting TSP because the DSP is the entity providing certificated retail delivery service and the large load customer should notify the interconnecting DSP if its plans for backup generating facilities materially changes as this information is needed to meet its obligations as the transmission operator of the load.

Commission Response

The commission declines to adopt AEP's recommendation to modify the adopted rule to remove the reference to the interconnecting TSP because there may be circumstances in which the interconnecting TSP should also be made aware of this information.

Scope of disclosure requirement

DCC, Google, Lancium, and TotalEnergies, and TPPA recommended modifying proposed §25.194(d)(6) to change the scope of what must be disclosed. Specifically, DCC recommended requiring only the disclosure of total nameplate capacity. DCC reasoned that other details of backup generating facilities are subject to change and requiring disclosure of these details could produce outdated information. DCC further reasoned that nameplate capacity is "the most critical data point and is sufficient for reliability planning purposes." DCC recommended a similar modification to proposed §25.194(f)(6).

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(d)(6) to require the disclosure of only the percentage of load expected to be served with backup generation, expressed as nameplate megawatt capacity of backup generation facilities divided by megawatts of contracted peak demand at the conclusion of the load ramp. Google, Lancium, and TotalEnergies also recommended a conforming change to proposed §25.194(f)(6).

Constellation recommended changing the requirement to identify the number of backup generating units to a requirement to identify an estimate of the total nameplate capacity of backup generating units; and require the large load customer to disclose the expected fuel source, anticipated instead of existing environmental permits, and how quickly each backup generating facility can reach fully capacity to serve the load if known.

Conversely, TPPA recommended modifying proposed §25.194(d)(6) by broadening the disclosure requirement to

include reporting of plans for backup generation capable of exporting to the grid, as well as plans for co-located generation.

Commission Response

The commission adopts the recommendation of commenters that suggested removing the requirement to provide the number of backup generating facilities. However, the commission declines to adopt the additional changes recommended by Constellation, DCC, Google, Lancium, and Total Energies, and TPPA. Specifically, the commission declines to adopt DCC's recommendation to require only disclosure of total nameplate capacity, and Google, Lancium, and TotalEnergies' recommendation to require disclosure of only the percentage of load expected to be served with backup generation because the data points in the adopted rule are needed by ERCOT to verify which facilities serve at least 50 percent of on-site demand, the verification of which is needed to effectuate the requirements of PURA §37.0561(e).

The commission further declines to adopt Constellation's recommendation to include qualifiers ahead of the required disclosure data points because the clarification is unnecessary. While the details of the backup generation or on-site backup generation may change as the project evolves, nothing precludes the large load customer from providing updated information when making the same disclosure at the time of SLLIA execution or at any time before execution. The commission further declines to adopt TPPA's recommendation to broaden the disclosure requirement to include reporting of plans for backup generation capable of exporting to the grid, as well as plans for co-located generation, because it is moot. The commission's modifications to adopted §25.194(d)(1)(H) and §25.194(f)(1)(H) substantively address TPPA's recommendation.

Use of disclosed backup generation information

DCC recommended modifying proposed §25.194(d)(6) by adding a statement that information disclosed about a customer's backup generation must not be used by a DSP or TSP to discriminate in curtailment decisions and that a utility cannot direct a customer to operate backup generation in a manner that would put the customer out of compliance with applicable environmental permits. DCC recommended a similar modification to proposed §25.194(f)(6).

Commission Response

The commission declines to adopt DCC's recommendation to add a statement that information disclosed about a customer's backup generation must not be used by a DSP or TSP to discriminate in curtailment decisions and that a utility cannot direct a customer to operate backup generation in a manner that would put the customer out of compliance with applicable environmental permits. Curtailment decisions and operation of backup generation should consider safe and reliable operation of the ERCOT system, which is best addressed in ERCOT protocols.

Allow information to be supplemented

Constellation recommended modifying proposed §25.194(d)(6) to state that the disclosure may be revised as updated information becomes available.

Commission Response

The commission declines to adopt Constellation's recommendation to add a statement that disclosure of backup generating information may be revised as updated information becomes available. Instead, the commission modifies the adopted rule to add

a statement to the SLLIA requirements that a large load customer must timely disclose to the interconnecting DSP or the interconnecting TSP any material changes to the large load customer's plans for on-site generation that is capable of being synchronously interconnected to the ERCOT system and will provide power to the large load customer. Although the requirement is specific to on-site generation capable of being synchronously interconnected to the ERCOT system for purposes of the adopted rule, the commission notes that ERCOT, the interconnecting DSP, and the interconnecting TSP may still require updates relating to backup generating information. Moreover, nothing in the adopted rule prevents a large load customer from voluntarily providing such updates related to backup generating information.

Proposed §25.194(d)(7) -- Power supply

Proposed §25.194(d)(7) requires a large load customer to disclose how it plans to procure power and whether the large load customer has on-site generation that will provide power exclusively to the large load customer.

Allow notification of material changes

AEP recommended modifying proposed §25.194(d)(7) to allow large load customers to notify ERCOT of material changes to on-site generation plans and permitting updates to study parameters as projects evolve, improving planning accuracy and coordination while allowing projects to continue through the interconnection process.

Commission Response

The commission declines to adopt AEP's recommendation to allow large load customers to notify ERCOT of material changes to on-site generation plans and permitting updates to study parameters as projects evolve while allowing projects to continue through the interconnection process. Nothing in the rule prevents a large load customer from voluntarily providing updates and explicit allowance is unnecessary. Whether a material change to on-site generation plans and permitting impacts a large load customer's status in the interconnection process should be determined based on considerations relating to safe and reliable operation of the ERCOT system. However, the commission agrees that a large load customer must timely disclose to the interconnecting DSP or the interconnecting TSP any material changes to the large load customer's plans for on-site generation that is synchronously interconnected to the ERCOT system and will provide power to the large load customer. The commission modifies the adopted rule's requirements for the SLLIA accordingly.

Replace procurement disclosure with source of consumed power disclosure

Constellation recommended modifying proposed §25.194(d)(7) to replace the requirement to disclose how a large load customer plans to procure power with a requirement to disclose whether a large load customer plans to consume power exclusively sourced from the ERCOT grid or produced by a co-located generation resource.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to replace the requirement to disclose how a large load customer plans to procure power with a requirement to disclose whether a large load customer plans to consume power exclusively sourced from the ERCOT grid or

produced by a co-located generation resource. Given the unprecedented growth on the ERCOT system, it is important to understand from a broader perspective how a large load customer plans to procure power, which will have system planning and reliability implications.

On-site generation

Constellation, LCRA, NRG, Sierra Club, and TNMP recommended modifying proposed §25.194(d)(7) to require disclosure of greater detail relating to a large load customer's on-site generation.

Specifically, Constellation recommended disclosure of on-site, non-grid interconnected generation that will not provide power to other loads. LCRA recommended disclosure of whether on-site generation is in front of or behind the meter.

NRG and Sierra Club recommended disclosure as to whether the large load customer plans to bring its own on-site generation to run in parallel with the grid (as compared to backup generation only) and whether that generation will be sufficient to meet the large load customer's peak demand. Sierra Club also recommended disclosure of the type and amount of generation.

TNMP recommended disclosure of planned future onsite generation additions, including backup or self-generation resources, over a defined five-year planning horizon, triggered only upon material change.

Commission Response

The commission declines to adopt the redline recommendations of commenters suggesting adding details to the disclosure of whether the large load customer has on-site generation because the technical nature of the details recommended by commenters is more appropriately addressed in ERCOT protocols. However, the commission agrees with commenters who suggested it is appropriate for the disclosure to identify whether the on-site generation is (or will be) synchronously interconnected to the ERCOT system, whether the on-site generation will provide power to the large load customer, and whether the large load customer plans to have on-site generation.

The commission modifies the adopted rule accordingly and notes that disclosure of any on-site generation providing power exclusively to the large load customer is already captured in the broader requirement to disclose whether the on-site generation capable of being synchronously interconnected to the ERCOT system will provide power to the large load customer. Moreover, the commission modifies the adopted rule to more clearly require disclosure of backup generating facilities and on-site backup generating facilities, which are not capable of being synchronously interconnected to the ERCOT system and thus would provide power exclusively to the large load customer.

The requirements to disclose backup generating facilities, on-site backup generating facilities, and on-site generation capable of being synchronously interconnected to the ERCOT system substantively address LCRA's recommendation to require disclosure of whether the generation is in front of or behind the meter.

Require disclosure of demand served by new generation

EDF recommended modifying proposed §25.194(d)(7) to require disclosure of the amount of anticipated demand that will be served by new generation, the availability of generation during peak system conditions, and expected changes to power supply

over time. EDF reasoned that this information would support ERCOT's resource adequacy modeling.

Commission Response

The commission declines to adopt EDF's recommendation to require disclosure of the amount of anticipated demand that will be served by new generation, the availability of generation during peak system conditions, and expected changes to power supply over time. This information is substantively captured by the broader requirement to disclose backup generating facilities; on-site backup generating facilities; how the large load will procure power; and whether the large load has or plans to have on-site generation that is capable of being synchronously interconnected to the system and will provide power to the large load customer. Additionally, the commission modifies the adopted rule to require the large load customer to disclose material changes to the large load customer's plans for on-site generation that is capable of being synchronously interconnected to the ERCOT system and will provide power to the large load customer. Moreover, the commission notes that additional, more detailed criteria may still be developed through ERCOT protocols.

Require disclosure of co-located generation

Vistra recommended modifying proposed §25.194(d)(7) to require a large load customer to disclose whether it has or will have co-located generation and whether the large load customer will also take retail electric delivery service from a DSP.

Commission Response

The commission declines to adopt Vistra's recommendation to require disclosure of whether the large load customer has or will have co-located generation because the recommendation is substantively addressed by the commission's modification of the adopted rule to require disclosure of whether the large load customer has or plans to have on-site generation that is synchronously interconnected to the ERCOT system and will provide power to the large load customer.

The commission also declines to adopt Vistra's recommendation to require disclosure of whether the large load customer will also take retail electric delivery service from a DSP because such a requirement suggests that a large load customer that co-locates with a generation resource does not have to take retail electric delivery service from a DSP, which would be contrary to PURA and existing commission rules.

Strike subsection

Google, Lancium, and TotalEnergies and TPPA recommended striking proposed §25.194(d)(7). TPPA reasoned that Texas law provides that end-use customers cannot directly procure power except under limited circumstances; instead, power is provided through either a retail electric provider (REP) in competitive areas or the NOIE serving the customer's territory.

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies, and TPPA's recommendation to strike the subsection. The fact that an end-use customer cannot directly procure power except under limited circumstances does not mitigate the need for a large load customer to disclose how it will procure power.

Proposed §25.194(d)(8) -- Controllable load

Proposed §25.194(d)(8) requires a large load customer to disclose whether it can be modeled as a controllable load resource, as the term is defined in ERCOT protocols, in ERCOT's study.

Specify who must receive the disclosure

Constellation recommended modifying proposed §25.194(d)(8) to require the disclosure be made to the interconnecting DSP or interconnecting TSP, as applicable.

Commission Response

The commission adopts Constellation's recommendation to modify the adopted rule to require the disclosure be made to the interconnecting DSP or interconnecting TSP.

Require disclosure of plans to pursue registration

TPPA and Vistra recommended modifying proposed §25.194(d)(8) to require a large load customer to indicate whether it intends to pursue registration with ERCOT as a controllable load resource rather than require the load to indicate whether it can be modeled as a controllable load resource. Similarly, Sierra Club recommended modifying proposed §25.194(d)(8) to require disclosure of whether the facility plans to register as a full or partial controllable resource and the parameters thereof.

Commission Response

The commission agrees with TPPA and Vistra that it is appropriate to require a large load customer to indicate whether it intends to pursue registration with ERCOT as a controllable load resource, rather than whether the load can be modeled as a controllable load resource. The commission modifies the adopted rule accordingly.

The commission declines to adopt Sierra Club's recommendation to modify the adopted rule to require disclosure of whether the facility plans to register as a full or partial controllable resource and the parameters thereof because that level of detail is unnecessary in the adopted rule and is better addressed in ERCOT protocols.

Strike subsection

Google, Lancium, and TotalEnergies recommended striking proposed §25.194(d)(8) because no allocation for capacity should be considered in the planning study for controllable load resources that have not been validated by the ERCOT process. Controllable load resource designation should be considered a pathway to expedite energization of already-approved loads but not as a pathway to grid capacity allocation when controllability has not been substantiated.

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies' recommendation to strike the paragraph. The disclosure required under this section informs ERCOT's study; it does not establish a large load customer's eligibility for designation as a controllable load resource. The requirements a large load customer must satisfy to be treated as a controllable load resource are established in ERCOT protocols.

Proposed §25.194(d)(9) -- Study fee

Proposed §25.194(d)(9) requires a large load customer to pay a study fee to the interconnecting DSP or the interconnecting TSP for the costs to conduct the interconnection study

Entity collecting the study fee

AEP recommended modifying proposed §25.194(d)(9) to remove the interconnecting TSP as an entity that may collect the study fee because the DSP maintains the direct customer relationship and serves as the primary point of contact. AEP also reasoned that this change reduces administrative complexity and facilitates timely coordination within batch study timelines.

Commission Response

The commission declines to adopt AEP's recommendation to modify the adopted rule to remove the interconnecting TSP as an entity that may collect the study fee because the issue is better addressed in a future rulemaking to adopt a SLLIA.

Additional adjustments

TPPA recommended modifying proposed §25.194(d)(9) to allow for additional adjustments where study costs have historically increased at a rate greater than the consumer price index.

Commission Response

The commission declines to adopt TPPA's recommendation to modify the adopted rule to allow for additional adjustments where study costs have historically increased at a rate greater than the consumer price index because it is unnecessary. The commission may increase the study fee by amending the rule if study costs increase at a rate greater than the consumer price index.

Request for additional capacity

OPUC recommended modifying proposed §25.194(d)(9) to clarify that any large load requesting additional capacity after the interconnection study is completed must pay an additional study fee.

Commission Response

The commission declines to adopt OPUC's recommendation to modify the adopted rule to clarify that any large load requesting additional capacity after the interconnection study is completed must pay an additional study fee because it is unnecessary. Adopted §25.194(e)(4) provides that a large load customer that materially changes its requested peak demand following the initiation of the interconnection study must submit a new interconnection request, which would necessarily require a new study fee. Moreover, capacity is allocated upon completion of the interconnection study. Additional capacity cannot be allocated after the interconnection study is completed and would, as a practical matter, require a new interconnection request.

Unused study fee funds

LCRA recommended modifying proposed §25.194(d)(9) to require refundability of any unused study fee funds. LCRA reasoned that requiring the interconnecting TSP to keep track of and apply unused study fee funds towards significant equipment or services would be an administratively burdensome task, with no apparent benefit for any party. If its recommendation to modify proposed §25.194(d)(9) is adopted, LCRA also recommended conforming proposed §25.194(d)(11) by removing proposed §25.194(d)(11)(B).

Commission Response

The commission adopts LCRA's recommendation to require that any unused study fee be returned to the large load customer.

Use four tiers

Sierra Club recommended that the study fee be broken out into four tiers with range between \$100,00 and \$400,000.

Specifically, Sierra Club recommended that for tier 1, comprised of loads that are 75 MW to 150 MW, the study fee be set to \$100,000. For tier 2, comprised of loads between 150 MW and 300 MW, the study fee be set to \$200,000. For tier 3, comprised of loads between 300 MW and 500 MW, the study fee be set to \$300,000. And for tier 4, comprised of loads above 500 MW, the study fee be set to \$400,000.

Commission Response

The commission declines, at this time, to adopt Sierra Club's recommendation that the study fee be broken out into four tiers. As data becomes available indicating that the costs for studies differ based on the size of a large load customer, the commission may revisit the study fee by amending the rule.

Strike subsection

CenterPoint recommended striking proposed §25.194(d)(9) because the study fee has always been and continues to be covered by a separate study fee agreement.

Commission Response

The commission declines to adopt CenterPoint's recommendation to strike the requirement that a large load customer must pay a study fee. PURA §37.0561 provides that the large load interconnection standards adopted by the commission must set a flat study fee, and it is unnecessary to maintain separate agreements solely to preserve a historical practice. Moreover, the commission determines that implementation of PURA §37.0561 should result in greater standardization of utility practices, which is better served by clearly delineating the requirements for the study fee.

Study fee amount and study costs upper bound

If its recommendation to reduce the financial security at the intermediate agreement stage to \$10,000 per MW is adopted, Thor recommended setting the study fee at \$300,000 for projects requesting peak demand above 150 MW. Further, Thor recommended that if costs exceed the study fee amount, excess costs should be paid by the large load customer only up to cap agreed to before the commencement of the study.

Commission Response

The commission declines, at this time, to adopt Thor's recommendation to modify the study fee amount for projects above 150 MW. As data becomes available indicating that the costs for studies differ based on the size of a large load customer, the commission may revisit the study fee by amending the rule. The commission also declines to adopt Thor's recommendation to provide that if costs exceed the study fee amount, excess costs should be paid by the large load customer only up to an agreed-to cap because PURA §37.0561 requires a flat study fee.

Proposed §25.194(d)(9)(A) -- \$100,000 study fee

Proposed §25.194(d)(9)(A) requires a large load customer with requested peak demand that is equal to or greater than 75 MW and less than 250 MW to pay a study fee of not less than \$100,000 to the interconnecting DSP or the interconnecting TSP for transmission studies performed by the interconnecting DSP, the interconnecting TSP, and ERCOT, as applicable.

Cap study fee at actual study costs

DCC recommended modifying proposed §25.194(d)(9)(A) to provide that the fee paid by the customer must not exceed the

actual study costs incurred by the DSP, TSP, and ERCOT. DCC recommended similar changes to proposed §25.194(d)(9)(B).

Commission Response

The commission declines to adopt DCC's recommendation to modify the adopted rule to provide that the fee paid by the customer must not exceed the actual study costs incurred because it is moot. The addition of a provision stating that any unused amount of the study fee must be returned to the large load customer substantively addresses DCC's concern.

Applicability to incremental increase in requested peak demand

TIEC recommended modifying proposed §25.194(d)(9)(A) to apply to a large load customer with incremental increase in requested peak demand. TIEC reasoned that this change avoids imposing different fees based on the size of an existing site. TIEC also recommended conforming changes to proposed §25.194(d)(9)(B).

Commission Response

The commission declines to adopt TIEC's recommendation to modify the adopted rule to provide that the \$100,000 study fee applies to a large load customer with incremental increase in requested peak demand. However, the commission modifies the adopted rule to state that, for a large load customer that seeks an expanded interconnection, the rule applies to the incremental load addition.

Convert to a flat fee

Constellation recommended modifying proposed §25.194(d)(9)(A) to convert the study fee to a flat fee by removing "not less than" so that a higher amount cannot be charged. Constellation also recommended conforming changes to proposed §25.194(d)(9)(B). If its recommendation is adopted, Constellation also recommended striking proposed §25.194(d)(9)(D).

Commission Response

The commission adopts Constellation's recommendation to convert the study fee to a flat fee and modifies the adopted rule accordingly. The commission also modifies the adopted rule to specify that ERCOT protocols may establish an additional flat study fee that must be paid by the large load customer.

Proposed §25.194(d)(9)(B) -- \$300,000 study fee

Proposed §25.194(d)(9)(B) requires a large load customer with requested peak demand that is equal to or greater than 250 MW to pay a study fee not less than \$300,000 to the interconnecting DSP or the interconnecting TSP for transmission studies performed by the interconnecting DSP, the interconnecting TSP, and ERCOT, as applicable.

Strike subsection

PPM recommended striking proposed §25.194(d)(9)(B). PPM reasoned that increasing the fee when a customer exceeds a base load of 250 MW is not based on cost-causation. PPM also noted that proposed §25.194(d)(9)(B) is unnecessary to ensure study costs are covered because proposed §25.194(d)(9)(D) ensures the customer will pay the actual study costs if costs exceed \$100,000.

Commission Response

The commission agrees with PPM's recommendation and strikes the provision requiring a large load customer requesting peak

demand equal to or greater than 250 megawatts to pay a study fee of \$300,000.

Proposed §25.194(d)(9)(C) -- Adjustment to study fee values

Proposed §25.194(d)(9)(C) states that beginning in 2027, the commission will adjust the study fee values on January 1 every five years. The annual adjustment will be proportional to the third quarter percentage change in the national Consumer Price Index (CPI) published by the United States Department of Labor, Bureau of Labor Statistics. If the CPI becomes unavailable, the executive director must designate a substitute index to be used as a reference for adjustments.

Remove reference to annual

Constellation recommended modifying proposed §25.194(d)(9)(C) to remove the reference to "annual" since the adjustment will be made every five years and to clarify that the Consumer Price Index that is used for the adjustment will be that from the prior year. Constellation also recommended conforming changes to proposed §25.194(d)(10)(A).

Commission Response

The commission adopts Constellation's recommendation to modify the adopted rule to remove the reference to "annual" in the provisions relating to inflationary adjustments. The commission also modifies the adopted rule to clarify that the adjustment will be based on the percentage change in the CPI from the third quarter in the first year to the third quarter in the fifth year, rather than the third quarter change from the prior year as recommended by Constellation. This more accurately reflects the appropriate adjustment for inflation.

Proposed §25.194(d)(10) -- Financial security on a dollar per MW basis

Proposed §25.194(d)(10) requires a large load customer to post financial security in the amount of \$50,000 per MW of the requested peak demand at the time that the intermediate agreement is executed.

Increase dollar amount of financial security

OPUC recommended modifying proposed §25.194(d)(10) to increase the financial security from \$50,000 per MW to \$100,000 per MW. OPUC reasoned that \$50,000 is inadequate to cover the costs of transmission projects in the billions of dollars if a large load customer withdraws its interconnection request. Alternatively, OPUC supported a phased financial security amount based on estimated interconnection and transmission requirements paired with a requirement for increased proof of financial capability.

Commission Response

The commission declines to adopt OPUC's recommendation to increase the financial security required from \$50,000 per MW to \$100,000 per MW. The commission determines that the \$50,000 per MW amount at the intermediate agreement stage appropriately balances the statutory objectives of PURA §37.0561 to support business development while minimizing the potential for stranded infrastructure costs.

The commission also declines to adopt OPUC's recommendation to implement a phased financial security amount based on estimated interconnection and transmission requirements paired with a requirement for increased proof of financial capability because this information cannot be determined before an interconnection study is conducted. Moreover, the purpose of financial

security in the amount of \$50,000 per MW at the time the intermediate agreement is executed is to demonstrate a large load customer's access to the necessary capital to finance the project. Stranded infrastructure costs are unlikely before an interconnection study is completed because the interconnection study informs the necessary infrastructure to serve a load. That said, before any financial security is returned by the interconnecting DSP or interconnecting TSP prior to the completion of the interconnection study, the large load customer must pay the outstanding amounts enumerated under adopted §25.194(d)(3)(A)(iii).

To the extent some limited costs for significant equipment and services may be determined before the interconnection study is completed, the commission modifies the adopted rule to require that large load customer post additional financial security if the costs of significant equipment and services exceed the \$50,000 per MW, thereby protecting against the potential for stranded infrastructure costs.

However, the commission modifies the adopted rule to require a large load customer to post financial security under the SLLIA in an amount that is the greater of \$50,000 per MW of the contracted peak demand or the costs allocated to the large load customer for system upgrades as a result of a batch zero interconnection study or an interconnection study.

Reduce dollar amount of financial security

APA and ACP, CCNG, CenterPoint, CPV, HIF, Infinium, PPM, Rowan, Satoshi, TEC, Thor, TIEC, and TXOGA recommended modifying proposed §25.194(d)(10) to reduce the required financial security.

Specifically, Thor recommended reducing the financial security to \$10,000 per MW. CPV recommended an amount between \$10,000 and \$15,000. APA and ACP recommended an amount between \$10,000 and \$20,000. Rowan, TIEC, and TXOGA recommended \$20,000. CCNG recommended \$22,500. Satoshi and TCC recommended \$25,000. CenterPoint recommended \$30,000.

Commission Response

The commission declines to adopt commenters' recommendations to reduce the amount of financial security required. The commission determines that the \$50,000 per MW amount appropriately balances the statutory objectives of PURA §37.0561 to support business development while minimizing the potential for stranded infrastructure costs.

Tiered or bifurcated approach

Sierra Club, TIEC, and Vistra recommended modifying proposed §25.194(d)(10) to implement a tiered approach. Specifically, Sierra Club recommended modifying proposed §25.194(d)(10) to implement a tiered structure whereby loads between 75 MW and 150 MW are subject to a financial commitment of \$30,000 per MW; loads between 150 MW and 300 MW are subject to a financial commitment of \$45,000 per MW; loads between 300 MW and 500 MW are subject to a financial commitment of \$60,000 per MW; and loads above 500 MW are subject to a financial commitment of \$75,000 per MW.

As an alternative to its primary recommendation to reduce the financial security to \$20,000 per MW, TIEC recommended a bifurcated approach by which large load customers requesting peak demand that is equal to 75 MW and less than 250 MW would be subject to a \$20,000 per MW financial security requirement and a large load customer with an incremental increase in requested

peak demand that is equal to or greater than 250 MW would be required to pay \$50,000 per MW. Vistra recommended a bifurcated approach with a higher refundability provision to recognize the capital intensiveness and therefore risk associated with very large loads.

Commission Response

The commission declines to adopt Sierra Club, TIEC, and Vistra's recommendations to implement a tiered approach to the financial security. The financial security appropriately scales with the size of the load because the total dollar amount is based on the size of the load. Moreover, loads that are between 75 MW and 250 MW are significant and capital intensive. These loads, in the aggregate with other extremely large loads, contribute significantly to the need for transmission infrastructure. Therefore, the commission determines that a uniform, standardized dollar amount that scales with the size of the load best serves the statutory objective of supporting business development while minimizing the potential against stranded infrastructure costs.

Base financial security on estimated net contribution

NRG recommended modifying proposed §25.194(d)(10) to incentivize large load customers to bring their own generation by basing the financial security requirement on the estimated net contribution during summer peak.

Commission Response

The commission declines to adopt NRG's recommendation to modify the adopted rule to base the financial security requirement on the estimated net contribution during summer peak. Securitizing the cost of transmission infrastructure based on the net import or export of power at a private use network does not adequately capture the potential for the large load customer to consume its maximum non-coincident peak demand from the ERCOT system if the generation resource that is part of the private use network is unavailable to supply power to the large load customer.

Apply security for significant equipment or services as an offset

TIEC recommended modifying proposed §25.194(d)(10) to state that the financial security amount(s) shall be reduced by the amount of security provided for significant equipment or services procured prior to executing an interconnection agreement. TIEC reasoned that the dollar per MW security is a proxy; it is not based on the actual costs of serving the large load. Therefore, when some costs of serving the load are actually known and can be individually secured, this should reduce the "proxy" security under the rule. For example, if the security for long-lead time equipment is greater than the generic security, the large load customer should not be required to post additional security. Alternatively, if the long-lead time equipment is less than the generic security, the customer would post the difference between the actual cost of the long lead-time equipment and \$50,000 per MW (or \$20,000 per MW if TIEC's recommendation is adopted).

Commission Response

The commission substantively adopts TIEC's recommendation to modify the adopted rule to state that the financial security amount(s) must be reduced by the amount of security provided for significant equipment or services procured prior to executing an interconnection agreement. Specifically, the commission modifies adopted §25.194(d)(2)(C) to state that the interconnecting DSP or TSP must credit the intermediate financial security to the costs of significant equipment or services, and that the

customer must post additional security only if costs exceed the financial security balance amount.

Require only of new large load customers

Crusoe recommended modifying proposed §25.194(d)(10) to require only new large load customers and not existing customers with incremental capacity additions to post financial security in the amount of \$50,000 per MW. Crusoe recommended similar changes to proposed §25.194(f)(7) relating to interconnection fee.

Commission Response

The commission declines to adopt Crusoe's recommendation to exempt existing customers with incremental capacity additions from posting financial security. Posting financial security demonstrates the customer has access to the necessary capital to complete the project and pay the large load minimum billing demand. The potential for stranded infrastructure costs exists regardless of whether the customer is requesting a new or expanded interconnection. Moreover, exempting existing customers with incremental capacity additions has the potential to introduce gamesmanship and is inconsistent with the requirement in PURA §37.0561 to develop uniform financial commitment requirements for large load customers requesting a new or expanded interconnection request.

Deadline to post financial security

Constellation recommended modifying proposed §25.194(d)(10) to require financial security be posted not less than 60 days but no more than 90 days following execution of the intermediate agreement instead of at the time the intermediate agreement is executed.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to require financial security be posted not less than 60 days but no more than 90 days following execution of the intermediate agreement. The commission determines that a large load customer should be able to demonstrate financial commitment at the time that the intermediate agreement is executed to ensure that only loads that demonstrate financial commitment are included in an interconnection study.

Add new requirement

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(d)(10) to add a new requirement that ERCOT and the TSP provide initial screening results to the large load customer within 30 days from the start of the steady state analysis at which point the large load customer has 14 days to decide whether to stay in the interconnection process and \$6.5 million of financial security becomes non-refundable.

Commission Response

The commission declines to adopt Google, Lancium and TotalEnergies' recommendation to add an initial screening requirement because the particular studies that are needed to determine whether a large load customer can safely and reliably be served by the ERCOT system is best addressed in ERCOT protocols.

Allocate financial security proportionally between DSP and TSP

AEP recommended modifying proposed §25.194(d)(10) to recognize that the DSP and TSP may each hold a proportional al-

location of financial security that is commensurate with the risk and costs each entity is responsible for incurring.

Commission Response

The commission declines to adopt AEP's recommendation to modify the adopted rule to recognize that the DSP and TSP may each hold a proportional allocation of financial security that is commensurate with the risk and costs each entity is responsible for incurring because it is unnecessary. This approach is consistent with existing practices and the adopted rule does not prohibit this outcome.

Proposed §25.194(d)(10)(A) -- Adjustment to dollar value

Proposed §25.194(d)(10)(A) states that beginning in 2027, the commission will adjust the \$50,000 value on January 1 every five years. The annual adjustment will be proportional to the third quarter percentage change in the national CPI published by the United States Department of Labor, Bureau of Labor Statistics. If the CPI becomes unavailable, the executive director must designate a substitute index to be used as a reference for adjustments.

Annual updates

OPUC recommended modifying proposed §25.194(d)(10)(A) to require evaluation and adjustment of the \$50,000 value annually instead of every five years.

Commission Response

The commission declines to adopt OPUC's recommendation to modify the adopted rule to require evaluation and adjustment of the \$50,000 per MW financial security value annually instead of every five years. A 5-year adjustment schedule balances the need for an accurate tracking of inflation with the efficient use of commission staff resources.

Proposed §25.194(d)(10)(C) -- Acceptable forms of financial security

Proposed §25.194(d)(10)(C) states that the interconnecting DSP or the interconnecting TSP may accept financial security in the form of: (i) cash collateral; (ii) corporate or parental guaranty, only if the corporation or parent corporation has a credit rating equivalent of BBB-/Baa3 or higher from Standard & Poor's or Moody's; or (iii) a letter of credit issued by a major U.S. commercial bank, or a U.S. branch office of a major foreign commercial bank, with a credit rating of at least "A-" by Standard & Poor's or "A3" by Moody's Investor Service.

DSP or TSP acceptance of forms of financial security

Constellation recommended modifying proposed §25.194(d)(10)(C) to require the interconnecting DSP or the interconnecting TSP to accept the listed forms of financial security instead of allowing discretion.

Conversely, TPPA, GVEC, and TEC recommended modifying the proposed rule to provide the interconnecting DSP or TSP explicit discretion. Specifically, TPPA recommended modifying proposed §25.194(d)(10)(D) to add a statement that if the interconnecting DSP or interconnecting TSP determines that the guaranty does not provide sufficient assurance, it is not required to accept that form of financial security. GVEC and TEC recommended modifying proposed §25.194(d)(10)(E) to require that the letter of credit be acceptable to the interconnecting DSP or interconnecting TSP and that acceptance include approval of the bank, rather than just the credit requirements for a bank. GVEC

and TEC also recommended a conforming change to proposed §25.194(f)(8)(C) and (f)(10)(A).

Commission Response

The commission declines to modify the adopted rule to require the interconnecting DSP or TSP to accept the listed forms of financial security or to detail circumstances in which the DSP or TSP may decline to accept a form of financial security. The purpose of financial security is to demonstrate the customer has access to the necessary capital to complete the project and satisfy the obligations established by the adopted rule, and to securitize interconnection and transmission infrastructure costs. Therefore, it is not appropriate to require a DSP or TSP to accept a form financial security from a customer if the DSP or TSP finds it does not provide sufficient assurance.

Specify how cash collateral is to be held

Constellation also recommended adding that cash collateral must be held in a segregated, interest-bearing cash account. Constellation recommended conforming changes to proposed §25.194(d)(11)(C), (f)(8)(C), and (f)(10)(A). Similarly, PPM recommended modifying the adopted rule to specify that refunded cash collateral must include interest.

Commission Response

The commission agrees with Constellation and PPM that cash collateral should be held in a segregated, interest-bearing account. However, the commission declines to adopt Constellation's recommended redline change and instead adds a subclause stating that cash collateral is to be held in a segregated, cash account bearing interest at a rate equal to at least the rate of the constant maturity one-month U.S. Treasury bill.

Expand guaranty beyond corporation

TIEC recommended modifying proposed §25.194(d)(10)(C) to allow a guaranty from any entity with a high enough credit rating from S&P or Moody's to qualify as an acceptable form of financial security, rather than accept a guaranty only from a corporation. TIEC also recommended conforming changes to proposed §25.194(d)(11)(C), (f)(8)(C), and (f)(10)(A).

Commission Response

The commission adopts TIEC's recommendation to modify the adopted rule to allow a guaranty from any entity with a high enough credit rating to qualify as an acceptable form of financial security, rather than accept a guaranty only from a corporation.

Allow a third-party guaranty or designated sponsor

CloudHQ, NRG, and Rowan recommended modifying proposed §25.194(d)(10)(C) to permit a party other than the large load customer to submit a guaranty. Specifically, CloudHQ and Rowan recommended permitting a third-party, such as a large load customer's tenant, to post financial security on behalf of the customer. CloudHQ reasoned that the commission "should be agnostic to the source of the guaranty." Rowan asserted this arrangement is common practice and reduces the burden on developers. CloudHQ recommended similar changes to proposed §25.194(d)(11)(C), (f)(8)(C)(ii), and (f)(10)(A). Rowan recommended similar changes to proposed §25.194(f)(8)(C)(ii).

NRG recommended allowing a designated sponsor to provide the parental guaranty, as an alternative to the large load customer. NRG also recommended conforming changes to proposed §25.194(d)(10)(D), (d)(11)(C) through (D), (f)(8)(C) through (D), and (f)(10)(A) through (B).

Commission Response

The commission adopts CloudHQ, NRG, and Rowan's recommendation to modify the adopted rule to permit a party other than the large load customer to provide a guaranty.

Credit rating and submission of financial records

AEP recommended modifying proposed §25.194(d)(10)(C) to state that the credit rating requirement is based on ratings issued by both Standard & Poor's and Moody's, unless the large load customer is only rated by one agency. AEP reasoned that the interconnecting DSP or TSP should not be required to accept the corporate or parental guaranty or letter of credit if an entity has a credit rating from one of the agencies that is below the standard in the rule. AEP also recommended conforming changes to proposed §25.194 (d)(11)(C) and (f)(10)(B).

Commission Response

The commission declines to adopt AEP's recommendation to modify the adopted rule to state that the credit rating requirement is based on ratings issued by both Standard & Poor's and Moody's, unless the large load customer is rated by only one agency. AEP's recommendation is substantively addressed by the commission's modification of the adopted rule to provide that the required credit rating is based on a specified rating from Standard & Poor's, Moody's Investor Service, or Fitch, and if the entity providing the guaranty or bank issuing the letter of credit is rated by more than one of these agencies, creditworthiness must be determined by the second-highest rating.

Add surety bonds

NRG and Tract recommended modifying proposed §25.194(d)(10)(C) to allow the interconnecting DSP or TSP to accept surety bonds as a form of financial security. Tract reasoned that surety bonds are proven instruments. NRG reasoned that the commission recognizes surety bonds as acceptable financial security in other similar contexts. NRG and Tract recommended similar modifications to proposed §25.194(d)(11)(C) and (f)(10)(A).

Commission Response

The commission declines to adopt NRG and Tract's recommendation to modify the adopted rule to allow surety bonds as a form of financial security at this time. Surety bonds may contain varying terms, conditions, and remedies, which could create uncertainty regarding the availability and collection of funds and complicate the administration of the financial security requirements. Moreover, the commission determines that the forms of financial security available in the adopted rule provide sufficient options.

Extend the unsecured credit to all market participants

TPPA recommended modifying proposed §25.194(d)(10)(C)(ii) to permit the extension of unsecured credit to all ERCOT market participants in all ERCOT credit report situations, where the market participant or its guarantor meets appropriate credit rating requirements.

Commission Response

The commission declines to adopt TPPA's recommendation to modify the adopted rule to permit the extension of unsecured credit to all ERCOT market participants in all ERCOT credit report situations, where the market participant or its guarantor meets appropriate credit rating requirements because it is outside the scope of this rulemaking.

Proposed §25.194(d)(10)(D) -- Submission of financial records or statements

Proposed §25.194(d)(10)(D) authorizes the interconnecting DSP or the interconnecting TSP to require financial records or statements to determine a large load customer's financial stability if the large load customer provides a corporate or parental guaranty.

Eliminate requirement

AEP recommended modifying proposed §25.194(d)(10)(D) to state that the customer should simply be required to provide proof of its credit ratings to demonstrate financial stability. AEP asserted there is no need for a separate review of financial records or statements because the financial evaluation contemplated by this requirement is already encompassed within the applicable credit ratings of the customer or guarantor. AEP also recommended conforming changes to proposed §25.194(d)(11)(d).

Commission response

The commission declines to adopt AEP's recommendation to modify the adopted rule to remove the language stating that the interconnecting DSP or TSP may require the submission of financial records or statements to determine the customer's financial stability. A credit rating reflects an assessment made at a point in time and may not capture a change in financial conditions that may be identified through review of additional financial documentation.

Financial records submitted to U.S. Securities and Exchange Commission

Constellation recommended modifying proposed §25.194(d)(1)(D) to add a statement that financial records submitted to the U.S. Securities and Exchange Commission are deemed to satisfy any such request for publicly-traded companies.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to add a statement that financial records submitted to the U.S. Securities and Exchange Commission are deemed to satisfy any such request for publicly traded companies because the explicit inclusion is unnecessary.

Proposed §25.194(d)(10)(E) -- Refund of financial security posted on a dollar per MW basis

Proposed §25.194(d)(10)(E) states that financial security posted on a dollar per MW basis is subject to refund under proposed §25.194(g).

Applicability of proposed subsections (h) and (i)

Crusoe and NRG recommended modifying proposed §25.194(d)(10)(E) to include reference to proposed subsections (h) and (i).

Commission Response

The commission declines to adopt Crusoe and NRG's recommendations because they are moot, given the commission's organizational modifications to the adopted rule.

Refund treatment

CenterPoint, Cholla CloudHQ, Crusoe, DCC, Eolian, Hut 8, Infinium, Landmark and EcoPartner, Satoshi, Skybox, TCC,

TCPA, TEC, TPPF, and Tract recommended modifying proposed §25.194(d)(10)(E) to change what amount is refundable.

Specifically, Cholla CloudHQ, Crusoe, DCC, Eolian, Infinium, Satoshi, TCC, and Tract recommended that the financial security be refunded less actual incurred costs. CloudHQ reasoned that a full refund of the remaining security is required by statute. CenterPoint recommended modifying proposed §25.194(d)(10)(E) to provide that the financial security is fully refundable. TEC and TPPF stated that the security should be refundable. Relatedly, DCC and Tract recommended that the financial security should not be converted into a forfeiture. Tract recommended that if the commission adopts a non-refundable security, it should be imposed at the time of interconnection agreement execution after batch study and should be refundable to a large load customer that is not considered Batch Zero Base Load.

TIEC recommended modifying proposed §25.194(d)(10)(E) to require the release of the remaining balance after applying the financial security posted on a dollar per MW basis to any outstanding amounts owed and when the large load customer executes an interconnection agreement and provides the required financial obligations. TIEC also recommended conforming changes to proposed §25.194(d)(11)(E).

Landmark and EcoPartner recommended that the financial security should remain initially fully refundable, less documented engineering costs, until the 30-day steady state screening window is complete and then \$6.5 million should become non-refundable. Further, Landmark and EcoPartner suggested the balance should be fully refunded after applying outstanding costs.

TCPA recommended that 80% to 90% should be refundable during the intermediate agreement phase during which ERCOT is evaluating its ability to interconnect the requested peak demand. Skybox recommended 85% be refundable at the intermediate agreement stage and that the financial security transition to a non-refundable structure after the interconnection agreement is executed.

HIF commented that any financial security posted as part of the intermediate agreement stage should be fully refundable because project viability may not be meaningfully measurable at the intermediate stage. Similarly, TXOGA commented that the security should be refundable because it is likely that many projects will be allocated less capacity than requested.

Commission Response

The commission declines to adopt the recommendation of commenters that suggested the financial security under the intermediate agreement should remain fully refundable in all circumstances, or refundable less only actual costs, but agrees there are circumstances in which the full amount of financial security posted under the intermediate agreement should be returned to the large load customer. The commission also agrees that the adopted rule should differentiate the terms for returning financial security posted by large load customers included in the batch zero interconnection study, based on the maturity of the proposed project.

Posting financial security at the intermediate agreement phase serves two purposes. The first is to ensure that other consumers will not bear the cost of any large load project costs that interconnecting utilities incur early in the development process. The second is to ensure that the large load customer has access to the financial capital necessary to complete the project and satisfy the obligations established under the adopted rule, including

paying the large load minimum billing demand. This demonstration should occur before ERCOT conducts an interconnection study, forms planning assumptions, or allocates transmission capacity to the customer. Once ERCOT has allocated transmission capacity, a withdrawal or failure to execute a SLLIA has consequences the adopted rule must account for.

Allocated transmission capacity is unavailable to other customers, and the withdrawal of the request or failure to execute an SLLIA affects transmission planning assumptions. To reflect these consequences, it is appropriate to maintain some level of financial security forfeiture when a large load customer is allocated some portion of requested peak demand in a batch study and subsequently withdraws or fails to execute a SLLIA. The commission agrees with commenters that suggested 80% is a reasonable figure to return but finds it appropriate to set a different amount for certain large load customers included in the batch zero interconnection study.

Accordingly, the commission declines to adopt commenters' recommended redline changes and instead modifies the adopted rule to provide the following framework to return financial security posted by a large load customer that is included in the batch zero interconnection study, is allocated some portion of requested peak demand, and withdraws prior to the deadline to execute a SLLIA:

For batch zero loads that meet the criteria in ERCOT Planning Guide Section 9.2.1.1(1)(f), the financial security balance must be returned, less outstanding amounts owed and less 50% of the security associated with the allocated capacity.

For batch zero loads that meet the criteria in ERCOT Planning Guide Section 9.2.1.2(1), or loads included in an interconnection study other than the batch zero interconnection study, the financial security balance must be returned, less outstanding amounts owed and less 20% of the security associated with the allocated capacity.

The commission further modifies the adopted rule to identify circumstances where the full remaining balance of financial security is returned after the interconnecting DSP or TSP collects payment for outstanding amounts owed, including circumstances where:

the large load customer withdraws its request before ERCOT begins the interconnection study;

a large load customer, including a batch zero load that meets the criteria in ERCOT Planning Guide Section 9.2.1.2(1), is allocated zero MW across all study years and withdraws its interconnection request before the deadline to execute a SLLIA; and

a batch zero load that meets the criteria in ERCOT Planning Guide Section 9.2.1.1(1)(e) or 9.2.1.1(1)(g) withdraws its interconnection request before the deadline to execute a SLLIA.

The commission further modifies the adopted rule to provide that a large load customer that does not withdraw before the deadline to execute a SLLIA and does not execute a SLLIA is deemed to have forfeited any financial security posted under an intermediate agreement. Incentivizing a large load customer to affirmatively withdraw will reduce confusion about the status of the interconnection request if the SLLIA is not executed by the deadline. It is also not necessary to provide a separate set criteria for returning financial security to a large load customer that does not execute an SLLIA when the withdrawal option is available at any time after ERCOT allocates transmission capacity and before the deadline to execute the SLLIA. The commission also

modifies the adopted rule to clarify that a batch zero load may withdraw all or a portion of its requested peak demand by submitting written notice; and the interconnecting DSP or TSP may process the written notice only after ERCOT issues a study report that allocates transmission capacity and prior to the deadline to execute a SLLIA.

The commission declines to adopt Skybox's recommendation that 85% should be returned during the intermediate agreement phase. The commission determines that the figures and framework described above reflect a balance appropriate to effectuate the statutory objectives of PURA §37.0561 to support business development while minimizing the potential for stranded infrastructure costs and maintaining system reliability.

Refund if load cannot be served

Cipher, Crusoe, Hut 8, Rowan, Thor, Serena, Sierra Club, and Skybox recommended modifying proposed §25.194(d)(10)(E) to require that financial security be refunded if a large load customer's requested peak demand cannot be served. Specifically, Hut 8 recommended the financial security at the intermediate stage remain fully refundable until the completion of the interconnection study under proposed §25.194(e). Within 60 days of study completion, the large load customer should have the option to withdraw the project for full refund or proceed and receive a refund only for any portion of the requested capacity not allocated to the project based on the results of the study.

Cipher, Rowan, and Skybox recommended adding language stating that in the event a large load customer is allocated less capacity than requested during a batch study, the portion of the interconnection fee attributable to the MW not allocated is refundable. Skybox suggested this could be implemented by applying a pro rata adjustment consisting of: $\text{Adjusted Obligation} = (\text{Deliver MW} \div \text{Requested MW}) \times \text{Total Required Financial Commitment}$; and $\text{Refund/Credit} = \text{Total Amount on Deposit} - \text{Adjusted Obligation}$.

Sierra Club recommended that for large loads not fully allocated their requested capacity, that they receive a proportional refund for the capacity not allocated.

Serena recommended modifying proposed §25.194(g)(3) to add "financial security posted for requested peak demand that the large load customer withdraws after ERCOT determines the demand cannot be served 5 Years after the Batch Study must be refunded at 100%" to the end of the subsection. Serena reasoned this addition would mitigate the impact to the large load customer if the project becomes commercially inviable due to inadequate capacity.

Commission Response

The commission substantively adopts the recommendations of commenters that suggested modifying the adopted rule to provide a framework for returning financial security associated with requested peak demand that is not allocated by ERCOT during an interconnection study. Specifically, the commission modifies the adopted rule to: (1) provide in adopted §25.194(d)(3)(B)(ii) that, if a large load customer is included in an interconnection study, is allocated zero MW across all study years, and withdraws before the SLLIA execution deadline, a full return of the financial security balance is required, less outstanding amounts owed; and (2) provide in adopted §25.194(d)(3)(C) that, after collecting payment for outstanding amounts owed and before the interconnecting DSP or TSP returns financial security posted by a large load customer, the interconnecting DSP or TSP must

subtract 20% of the financial security associated with the transmission capacity that is allocated and withdrawn.

Further, the commission finds it is appropriate to separately specify treatment of financial security posted by batch zero loads, based on project maturity. Accordingly, the commission modifies the adopted rule to provide in adopted §25.194(h)(1)(B)(iii) that a full return of the financial security balance, less amounts owed, is required when: (1) a large load customer meets the criteria in ERCOT Planning Guide Section 9.2.1.1(1)(e) or 9.2.1.1(1)(g), is included in the batch zero interconnection study, and withdraws its interconnection study before the deadline to execute a SLLIA; or (2) a large load customer meets the criteria in ERCOT Planning Guide Section 9.2.1.2(1), is allocated zero MW across all study years, and withdraws before the SLLIA execution deadline.

The commission also modifies the adopted rule to provide in §25.194(h)(3)(C)(i) that, if a large load customer that is included in the batch zero interconnection study meets the criteria in ERCOT Planning Guide Section 9.2.1.1(1)(f), is allocated some portion of requested demand, and withdraws before the SLLIA execution deadline, the interconnecting DSP or TSP must return the balance, less outstanding amounts owed and less 50% of the financial security associated with the allocated transmission capacity that is withdrawn.

Finally, the commission modifies the adopted rule to provide in adopted §25.193(h)(1)(C)(ii) that, if a large load customer that is included in the batch zero interconnection study, meets the criteria in ERCOT Protocol Section 9.2.1.2(1), is allocated some portion of requested demand, and withdraws before the SLLIA execution deadline, the interconnecting DSP or TSP must return the balance less outstanding amounts owed and less 20% of the security associated with the allocated that is withdrawn.

The commission declines to adopt Cipher, Rowan, and Skybox's recommendation to add language stating that, in the event a large load customer is allocated less transmission capacity than requested during a batch study, the portion of the interconnection fee attributable to the MW not allocated is refundable because the recommendation is moot, given the commission's modifications to remove the interconnection fee.

The commission declines to adopt Hut 8's recommendation to provide that financial security remains fully refundable until 60 days after the interconnection study and to allow the large load customer to withdraw the project for full refund or proceed and receive a refund only for any portion of the requested capacity not allocated to the project based on the results of the study. Allowing for a full refund after completion of a batch study where the customer is allocated some portion of requested peak demand would effectively allow for the reservation of capacity through the batch study without consequence. Once ERCOT has allocated transmission capacity, the withdrawal of an interconnection request affects transmission planning assumptions and the adopted rule should account for this consequence by providing for the forfeiture of some portion of financial security.

Refundability where service delivery is materially delayed

Skybox recommended modifying proposed §25.194(d)(10)(E) to address refundability in circumstances where service delivery is materially delayed beyond the requested interconnection load ramp date such that a defined portion reverts to refundable status or the customer is entitled to a full refund or credit with formal withdrawal of its request less actual costs incurred by the TSP

for engineering studies and procurement efforts that cannot be repurposed.

Commission Response

The commission declines to adopt Skybox's recommendation to add a provision addressing refundability in circumstances where service delivery is materially delayed beyond the requested interconnection load ramp date. At the intermediate agreement stage, the requested interconnection load ramp date is the large load customer's representation of when it expects to energize, not a commitment by an interconnecting or TSP to deliver service by this date. Further, transmission capacity is only allocated to a large load customer after the completion of ERCOT's batch study. It is therefore not appropriate to condition the refundability of financial security at the intermediate agreement phase to the requested interconnection load ramp date. Moreover, Skybox's underlying concern is addressed by the commission's modification to the adopted rule to provide that a large load customer that is allocated zero MW across all study years and withdraws its interconnection request before the deadline to execute a SLLIA may receive a full return of financial security less outstanding amounts owed.

Proposed §25.194(d)(11) -- Financial security for significant equipment of services

Proposed §25.194(d)(11) prohibits an interconnecting DSP and an interconnecting TSP from procuring equipment or services before a large load customer posts financial security in an amount equal to the estimated costs for the equipment with a lead time of at least six months and services necessary to interconnect the large load customer.

Cap total financial security

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(d)(11) to add a statement that the total financial security posted as part of the intermediate agreement should not exceed the financial security threshold (\$50,000 per MW).

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies' recommendation to modify the adopted rule to state that the total financial security posted as part of the intermediate agreement should not exceed the financial security threshold because it is moot. The commission's modification of adopted §25.194(d)(2)(C) to state that the interconnecting DSP or TSP must credit the intermediate financial security to the costs of significant equipment or services (if procured before a SLLIA is executed) substantively addresses Google, Lancium, and TotalEnergies' concern.

Define significant equipment or services

Constellation recommended modifying proposed §25.194(d)(11) to add a statement that as used in this rule, "significant equipment" or "significant services" means a singular item of equipment or a singular service with a total cost of not less than \$5 million.

Commission Response

The commission agrees it is appropriate to define "significant equipment and services" in the adopted rule. However, the commission declines to adopt Constellation's recommended redline change because the significance of equipment is better measured by the amount of time it takes to procure the equipment and its impact on the interconnection timeline rather than by a

specific dollar threshold. Accordingly, the commission modifies the adopted rule to add a provision stating significant equipment is equipment with a lead time of at least 18 months and services are those necessary to interconnect the large load customer.

Financial security separately required for interconnecting DSP and interconnecting TSP

LCRA recommended modifying proposed §25.194(d)(11) to state that if both the interconnecting DSP and the interconnecting TSP are parties to the intermediate agreement, each may require separate financial security from the large load customer for their respective estimated costs for equipment or services.

Commission Response

The commission declines to adopt LCRA's recommendation to modify the adopted rule to state that, if both the interconnecting DSP and TSP are parties to the intermediate agreement, each may require separate financial security because it is unnecessary. The adopted rule does not prevent the interconnecting DSP and the interconnecting TSP from each requiring separate financial security from the large load customer for their respective estimated costs for equipment or services. Moreover, whether the interconnecting DSP, the interconnecting TSP, or both entities hold the financial security is a matter that should be addressed in the intermediate agreement based on the applicable facts of each set of circumstances.

Clarity regarding final treatment of significant equipment or services costs

TEC and TSP Cooperatives recommended modifying proposed §25.194(d)(11) to clarify the final treatment of the cost of significant equipment or services once facilities are completed and energized. Specifically, whether the equipment should be assessed to the large load customer. TEC and TSP Cooperatives also recommended conforming changes to proposed §25.194(f)(8).

Commission Response

The commission substantively adopts TEC and TSP Cooperatives' recommendation to modify the adopted rule to clarify the final treatment of the cost of significant equipment or services once facilities are energized. Specifically, the commission modifies the adopted rule to clarify that a large load customer must post financial security for significant equipment or services. However, where the significant equipment or services meet the definition for direct interconnection costs under §25.192, relating to Transmission Service Rates, the large load customer must pay CIAC in the form of a direct cash payment.

Equipment procured by a large load customer or subsequently reused

NRG, Constellation, APA and ACP, Tract, Targa, and Thor recommended changes to address the treatment of equipment that is procured by the large load customer itself or equipment that is subsequently reused by the interconnecting DSP or TSP to serve a different customer.

Specifically, NRG recommended modifying proposed §25.194(d)(11) to provide an offset against any financial security requirements for long-lead time equipment that the large load customer procures itself, subject to the acceptance of that equipment by the interconnecting DSP or interconnecting TSP. NRG also recommended conforming changes to proposed §25.194(f)(8). Similarly, Constellation recommended adding a statement that the interconnecting DSP or the interconnecting

TSP shall not require security to cover the cost of any equipment or services which will be procured or provided by the large load customer for the benefit of the interconnecting DSP or the interconnecting TSP (as applicable). Constellation recommended conforming changes to proposed §25.194(f)(8).

APA and ACP recommended modifying proposed §25.194(g)(2) to reflect that while some sunk costs should be borne by the load that caused them, utilities should not be permitted to charge developers for equipment that is subsequently reused for another project. APA and ACP reasoned that given long equipment lead times, a withdrawal may not delay interconnection for another developer, and capacity may be reassigned. APA and ACP also recommended a conforming change to proposed §25.194(h)(2). Similarly, Tract recommended requiring utilities to refund security for significant equipment or services where equipment is reusable, less a cost or percentage to cover facilitation and depreciation. Targa recommended modifying proposed §25.194(g)(2)(B) to state that amounts owed include costs for equipment that the interconnecting DSP or the interconnecting TSP procured and that cannot be returned or used for another pending interconnection request instead of equipment that cannot be canceled. Targa recommended similar changes to proposed §25.194(h)(2).

Thor recommended the Commission provide that if a large load customer has funded long-lead time equipment, the customer retains the right to deploy equipment at an alternative site with the same interconnecting TSP or DSP within 36 months. Thor further recommended the interconnecting TSP or DSP be authorized to charge the customer for storage costs and that the customer be required to provide written notification within 30 days of cancelling the redeployment intention.

Commission Response

The commission declines to adopt NRG's recommendation to modify the adopted rule to provide an offset against any financial security requirements for long-lead time equipment that the large load customer procures itself. The commission also declines to adopt Constellation's recommendation to add language clarifying that a large load customer is not required to provide security to cover the cost of any equipment or services which will be procured or provided by the large load customer for the benefit of the interconnecting DSP or TSP. The purpose of the financial security requirements is to minimize the potential for stranded infrastructure costs. Only costs incurred by the interconnecting DSP or TSP are at risk of being stranded in this context. The adopted rule does not require the large load customer to post financial security for costs that the large load customer incurs.

The commission declines to adopt APA and ACP, Targa, and Tract's recommendation to address the treatment of equipment that is reusable. The commission also declines to adopt Thor's recommendation to modify the adopted rule to provide a framework for redeployment of significant equipment funded by a large load customer. This level of detail is more appropriately addressed in the rule to adopt a SLLIA.

Impact of demand not allocated on significant equipment and services

Rowan recommended that if a reduced allocation results in reduced costs for significant equipment and services, the interconnecting DSP or the interconnecting TSP must refund the balance of the corresponding financial security under proposed §25.194(d)(11) after application to other interconnection agreement obligations.

Commission Response

The commission declines to adopt Rowan's recommendation to modify the adopted rule to provide that, if a reduced allocation results in reduced costs for significant equipment and services, the interconnecting DSP or the TSP must refund the balance of the corresponding financial security after application to other agreements. When an interconnecting DSP or TSP has already procured equipment or services that cannot be returned for a full refund, a refund of those costs to the large load customer would shift the cost to other customers. Moreover, it is up to the large load customer to decide whether it wants to take on the risk of bearing the costs of significant equipment before the batch study is completed when the results of that study could impact the allocation of transmission capacity and thus the costs for significant equipment. Nothing in the adopted rule requires significant equipment to be ordered and the costs for such to be incurred before the results of the batch study are available.

Proposed §25.194(d)(11)(A) -- Amendment to intermediate agreement

Proposed §25.194(d)(11)(A) allows a large load customer to amend its intermediate agreement with the interconnecting DSP and the interconnecting TSP to post financial security for significant equipment or services prior to executing an interconnection agreement.

Clarify option to post financial security

NRG recommended modifying proposed §25.194(d)(11)(A) to clarify that a large load customer may include an option to post financial security for significant equipment or services in its intermediate agreement rather than elect to amend its intermediate agreement to post financial security for significant equipment or services.

Commission Response

The commission declines to adopt NRG's recommendation to clarify that a large load customer may include an option to post financial security for significant equipment or services in its intermediate agreement rather than elect to amend its intermediate agreement to post financial security for significant equipment or services. The commission's modification of the adopted rule to replace the requirement to post separate financial security for significant equipment or services with a requirement that the interconnecting DSP or TSP credit the financial security posted under the intermediate agreement to the costs of significant equipment or services if procured before a SLLIA is executed renders NRG's recommendation unnecessary. Further, as a result of these modifications, the provision specifically authorizing a large load customer to amend its intermediate agreement is no longer necessary, and the commission modifies the adopted rule to remove it.

Allow requests for additional financial security

LCRA recommended modifying proposed §25.194(d)(11)(A) to allow for additional financial security to be requested through an amended intermediate agreement should the amount required under proposed §25.194(d)(10) be deemed insufficient. LCRA reasoned that the interconnecting DSP and interconnecting TSP that are party to the agreement with the large load customer each have separate and distinct costs for the project. If required and necessary, both entities should be able to amend the intermediate agreement to request posting of additional financial and security equipment or services under proposed §25.194(d)(11)(A).

Commission Response

The commission substantively adopts LCRA's recommendation to allow for additional financial security to be requested through an amended intermediate agreement. Specifically, the commission modifies the adopted rule to state that if the financial security provided under an intermediate agreement (i.e., \$50,000 per MW) is less than the costs of significant equipment or services being procured before a SLLIA is executed, then the large load customer must post additional financial security for the difference in the costs of significant equipment or services and the amount of financial security already posted before the interconnecting DSP or the interconnecting TSP procures the significant equipment or services.

Proposed §25.194(d)(11)(E) -- Refund of financial security for significant equipment or services

Proposed §25.194(d)(11)(E) states that financial security for significant equipment or services is subject to proposed subsections (g) through (i).

Draw down for costs incurred

CenterPoint recommended modifying proposed §25.194(d)(11)(E) to require financial security posted for significant equipment or services to be drawn down to pay the cost of any significant equipment or services incurred in the event that the customer's interconnection request is withdrawn prior to the execution of an interconnection agreement.

Commission Response

The commission declines to adopt CenterPoint's recommendation to modify the adopted rule to require financial security posted for significant equipment or services to be drawn down to pay the cost of any significant equipment or services incurred in the event that the customer's interconnection request is withdrawn prior to the execution of an interconnection agreement. CenterPoint's recommendation is substantively addressed by the commission's modification of the adopted rule to provide that, prior to returning financial security after a withdrawal, the interconnecting DSP or TSP must collect payment or draw down on the financial security balance to cover outstanding amounts owed, including costs for equipment that cannot be canceled or returned.

Proposed §25.194(e) -- Interconnection study

Proposed §25.194(e) requires the interconnecting DSP or the interconnecting TSP to coordinate with ERCOT to initiate an interconnection study not later than 60 days after an intermediate agreement is executed.

60-day timeline to coordinate with ERCOT

AEP, NRG, Oncor, and TXOGA recommended modifying proposed §25.194(e) to change the 60-day timeline. Specifically, AEP recommended replacing the 60-day timeline with a broader requirement to coordinate with ERCOT following the execution of an intermediate agreement. NRG recommended reducing the 60-day timeline to coordinate with ERCOT to 30 days. Oncor recommended requiring the interconnecting utility to either complete a utility-driven initial study or submit information necessary for inclusion of the large load customer in an initial study to ERCOT within 30 days of executing the large load interconnection screening agreement, whichever is applicable. TXOGA recommended aligning the 60-day timeline with timelines and frequency of large load batch studies at ERCOT.

Commission Response

The commission declines to adopt the recommendations of commenters who suggested modifying the 60-day timeline. The 60-day timeline is appropriate to support timely coordination while preserving flexibility for the procedures governing future batch studies beyond batch zero. Further, it is not necessary to pair the 60-day timeline with the cadence of ERCOT batch studies; the provision does not require that the batch study commence 60 days after the intermediate agreement is executed. Nor does the 60-day timeline require the interconnecting DSP or TSP to wait 60 days to contact ERCOT to ensure that the large load customer is included in the next batch study.

For organizational clarity, the commission modifies the adopted rule to add a paragraph titled "communications with large load customer" and breaks the provisions into subparagraphs titled "initial contact to ERCOT," "commencement of interconnection study," "communications with ERCOT," and "transmission capacity allocated." The commission also modifies the adopted rule to add a subparagraph titled "ERCOT communications directly with large load customer" which provides that notwithstanding this paragraph, ERCOT may fulfill the interconnecting DSP or TSP's obligations to communicate with the large load customer through a process developed in ERCOT protocols.

Require both execution and funding

Oncor recommended modifying proposed §25.194(e) to require an interconnecting large load to both execute and fund an intermediate agreement, including providing all financial commitments under the agreement, before the interconnecting utility begins its study of proposed large load interconnection or ERCOT includes it in a study batch.

Commission Response

The commission adopts Oncor's recommendation to modify the adopted rule to require a large load customer to both execute and fund an intermediate agreement, including providing all financial commitments under the agreement, before the interconnecting DSP or TSP begins its study of proposed large load interconnection or ERCOT includes the large load customer in an interconnection study.

Expressly recognize the interconnecting DSP's role

TNMP recommended modifying proposed §25.194(e) to expressly recognize the interconnecting DSP as the coordinating entity for interconnection studies, while preserving appropriate TSP participation.

Commission Response

The commission declines to adopt TNMP's recommendation to modify the adopted rule to expressly recognize the interconnecting DSP as the coordinating entity for interconnection studies. Whether the interconnecting DSP, the interconnecting TSP, or both entities coordinate with ERCOT is a matter that should be addressed in the intermediate agreement based on the applicable facts of each set of circumstances.

Large load customer subject to PURA §39.169

Vistra recommended modifying proposed §25.194(e) to add a new provision that states an interconnection study conducted by ERCOT for a large load subject to PURA §39.169 and Section 205 of this Chapter must be completed not later than the 120th day after ERCOT receives all required information regarding the arrangement that is subject to PURA §39.169 and Section 205 of this Chapter.

Commission Response

The commission declines to adopt Vistra's recommendation to modify the adopted rule to add a new provision that states an interconnection study conducted by ERCOT for a large load subject to PURA §39.169 and Section 205 of this Chapter must be completed not later than the 120th day after ERCOT receives all required information regarding the arrangement that is subject to PURA §39.169 and Section 205 of this Chapter. The timeline for the interconnection study should be driven by the time it takes for ERCOT to study whether it can safely and reliably serve an interconnection request. Moreover, the statutory deadline of 120 days that is set forth in PURA §39.169 is related to studying the system impacts of a net metering arrangement, which is outside the scope of this rulemaking.

Proposed §25.194(e)(1) -- Notification of coordination

Proposed §25.194(e)(1) requires the interconnecting DSP or the interconnecting TSP to notify the large load customer when the interconnecting DSP or the interconnecting TSP coordinates with ERCOT to initiate an interconnection study.

Require notification of date interconnection study is initiated

Constellation recommended modifying proposed §25.194(e)(1) to require an interconnecting DSP or interconnecting TSP to communicate the date on which it initiates an interconnection study with ERCOT because a general requirement to communicate "coordination" could result in varying interpretations among utilities.

Commission Response

The commission adopts Constellation's recommendation to modify the adopted rule to replace "coordinates" with "contacts" to clarify that the interconnecting DSP or TSP must timely notify the large load customer when the interconnecting DSP or TSP contacts ERCOT to initiate an interconnection study.

Proposed §25.194(e)(2) -- Notification of study commencement and conclusion

Proposed §25.194(e)(2) requires the interconnecting DSP or the interconnecting TSP to notify the large load customer when the interconnection study commences and concludes.

Require ERCOT to identify specific information

Constellation recommended modifying proposed §25.194(e)(2) to require ERCOT to identify specific studies required, the expected timing for completion of the studies, and additional notification of study completion within two business days of the study completion.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to require ERCOT to identify specific studies required, the expected timing for completion of the studies, and additional notification of study completion within two business days of the study completion. The commission's modifications to the adopted rule to set forth for communication between ERCOT, the interconnecting TSP or DSP, and the large load customer in adopted §25.194(e)(2) strike the appropriate balance to facilitate timely communication without being overly prescriptive on matters that are better addressed in ERCOT protocols.

Proposed §25.194(e)(3) -- Requirement for timely information

Proposed §25.194(e)(3) requires the interconnecting DSP or the interconnecting TSP to provide a large load customer with timely information related to communications received from ERCOT about the customer's interconnection request.

Timeline for notification

Constellation recommended modifying proposed §25.194(e)(3) to require the interconnecting DSP or interconnecting TSP to provide information to the large load customer within one business day of receipt.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to require the interconnecting DSP or TSP to provide information to the large load customer within one business day of receipt. Instead, the commission modifies the adopted rule to require the interconnecting DSP or TSP to provide information to the large load customer within five working days of receipt. This approach strikes the appropriate balance to facilitate efficient communication without being administratively burdensome.

Proposed §25.194(e)(4) -- Requests for additional capacity

Proposed §25.194(e)(4) requires a large load customer requesting additional capacity following the initiation of the interconnection study to submit a new interconnection request.

Material change to load ramp schedule

Oncor recommended modifying proposed §25.194(e)(4) to require an interconnecting large load customer that materially changes its load ramp schedule during the study process to submit a new interconnection request to the interconnecting utility.

Commission Response

The commission substantively adopts Oncor's recommendation to require an interconnecting large load customer that materially changes its load ramp schedule during the study process to submit a new interconnection request. The commission also modifies the adopted rule to recognize that other types of material changes exist that would also necessitate the submission of a new interconnection request because such changes would have an impact on the findings of an interconnection study, the accurate modeling of the load, or the reliable operation of the load. Specifically, the commission modifies the adopted rule to provide that a large load customer that materially changes its interconnection request, as described in ERCOT protocols, including by changing its requested peak demand, phased energization schedule, point of interconnection, site configuration, load composition, load type, or any other material modification, must submit a new interconnection request.

Allow discretion to determine necessity for a new interconnection request

Constellation and NRG recommended modifying proposed §25.194(e)(4) to allow the interconnecting DSP or the interconnecting TSP to determine whether a new interconnection request is necessary.

Commission Response

The commission declines to adopt Constellation and NRG's recommendation to modify the adopted rule to allow the interconnecting DSP or the interconnecting TSP to determine whether a new interconnection request is necessary. Allowing

discretion would result in inconsistent application of the rule and run contrary to the policy objective of standardizing the large load interconnection process. Further, it is ERCOT, not the interconnecting DSP or TSP that is best situated to determine whether a material change would impact the findings of an interconnection study. For clarity regarding the meaning of a material change, the commission modifies the adopted rule to specify that a large load customer that materially changes its interconnection request, as described in ERCOT protocols, including by changing its requested peak demand, phased energization schedule, point of interconnection, site configuration, load composition, load type, or any other material modification, must submit a new interconnection request.

Require amendment to interconnection agreement for added, unplanned load

GVEC and TEC recommended modifying proposed §25.194(e)(4) to add that the large load customer must apply for an increase in its contracted peak demand and ramp rates through an amendment to its interconnection agreement, recognizing that any demand that exceeds its contracted peak demand or ramp schedule is subject to load shed by ERCOT or the interconnecting TSP or DSP.

Commission Response

The commission declines to adopt GVEC and TEC's recommendation to modify the adopted rule to add that the large load customer must apply for an increase in its contracted peak demand and ramp rates through an amendment to its interconnection agreement because the concerns are addressed by the commission's modification to the adopted rule to specify circumstances requiring a new interconnection request. A change in contracted peak demand or ramp rates necessitates a new interconnection request because the change would impact the accurate modeling of the load by ERCOT and could invalidate the interconnection study. It is therefore not appropriate for such changes to be effectuated through a SLLIA amendment, or through any method other than a new interconnection request.

Allow minor modification to capacity requests

CPV recommended the Commission modify the rule to allow a large load customer to adjust its capacity request by 10% or less during the interconnection study phase without requiring a new interconnection request. CPV reasoned that minor modifications are common in the development process.

Commission Response

The commission declines to adopt CPV's recommendation to modify the rule to allow a large load customer to adjust its transmission capacity request by 10% or less during the interconnection study phase without requiring a new interconnection request because the change could impact the accurate modeling of the load by ERCOT and could invalidate the interconnection study. However, the commission modifies the adopted rule to clarify that a large load customer that materially changes its interconnection request, as described in ERCOT protocols, including by changing its requested peak demand, phased energization schedule, point of interconnection, site configuration, load composition, load type, or any other material modification must submit a new interconnection request.

Proposed §25.194(f) -- Interconnection agreement

Proposed §25.194(f) requires a large load customer to execute an interconnection agreement not later than 30 days after

completion of the interconnection study. Additionally, the interconnection agreement must specifically identify each entity's responsibilities, including which entity will accept financial security and CIAC from the large load customer. The interconnection agreement must meet the requirements of proposed §25.194(f) and the interconnecting DSP or the interconnecting TSP must cancel the interconnection request and notify ERCOT if the large load customer fails to execute an interconnection agreement within 30 days of receipt of notice that all necessary transmission studies as defined in ERCOT protocols are complete.

30-day deadline to execute interconnection agreement

CCNG, CenterPoint, CloudHQ, Constellation, CPV, DCC, GVEC, Hut 8, Infinium, LCRA, NRG, Oncor, TCC, TEC, TIEC, TPPA, and TXOGA recommended modifying proposed §25.194(f) to extend the timeline associated with executing an interconnection agreement and providing the required financial security.

Specifically, CCNG, CenterPoint, Constellation, CPV, DCC, GVEC, LCRA, NRG, Oncor, TEC, and TIEC recommended extending the timeline from 30 days to 60 days. Hut 8 recommended a minimum of 60 days. CloudHQ recommended extending the deadline to between 60 and 90 days. TXOGA recommended at least 90 days. TPPA recommended 120 days.

Infinium commented that 30 days is workable for execution of the interconnection agreement, but the commission should modify the proposed rule to allow an additional 60 days to post financial security and CIAC. Alternatively, Infinium suggested a simpler approach could be to use the interconnection fee as an interim financial security, which could be refunded if the developer makes CIAC and financial security payments within the specified timeline. TCC recommended allowing 90 days to post financial security.

If its recommendation to extend the 30-day deadline to 90 days is not adopted, TXOGA recommended modifying proposed §25.194(f) to provide a process for a deadline extension if the customer capacity allocation is less than the amount requested.

Commission Response

The commission adopts the recommendation of commenters who suggested extending the timeline to enter into an interconnection agreement and post the associated financial security to 60 days. Specifically, the commission modifies the adopted rule to state that not later than 60 days after ERCOT notifies the interconnecting DSP or the interconnecting TSP of the large load customer's allocated transmission capacity, the large load customer must execute a SLLIA with the interconnecting DSP and, if different from the interconnecting DSP, the interconnecting TSP. The 60-day timeline appropriately balances the realities of large load project financing timelines with the need to process interconnection requests efficiently to provide certainty for the large load customer, ERCOT, and the interconnecting TSP or DSP. Furthermore, the commission's interest in developing a standardized interconnection agreement for large loads mitigates concerns of commenters who advocated for a timeline longer than 60 days.

The commission declines to adopt Infinium's recommendation to use the interconnection fee as an interim financial security because it is moot, given the commission's modifications to the adopted rule to remove the interconnection fee.

The commission declines to adopt TXOGA's recommendation to modify the adopted rule to provide a process for a deadline ex-

tension if the customer's transmission capacity allocation is less than the amount requested. Delays in a deadline following the batch study impact the timeline of ERCOT's refinement study and ultimately impacts the timeline for all large load customers. Extending the deadline from 30 days to 60 days strikes an appropriate balance to efficiently complete the interconnection study and allow large load customers a reasonable amount of time to fund the SLLIA.

Extend timeline to notify ERCOT of cancellation

If its recommendation to extend the 30-day deadline to execute an interconnection agreement to 60 days is adopted, LCRA recommended modifying proposed §25.194(f) to also increase the deadline to cancel an interconnection request by 60 days to a total of 90 days after all necessary transmission studies have been completed.

Commission Response

The commission declines to adopt LCRA's recommendation to modify the adopted rule to extend the deadline to cancel an interconnection request to 90 days after all studies have been completed because LCRA's recommendation is addressed by the commission's modification to the adopted rule to remove the deadline to notify ERCOT of the cancellation. The commission determines that a specific timeline to notify ERCOT of a canceled interconnection request is best addressed in ERCOT protocols describing the process and timeline for ERCOT to move forward with a refinement study after the deadline to execute a SLLIA passes.

Timely provision of interconnection agreement cost and timeline

TXOGA recommended modifying proposed §25.194(f) to add a requirement that the large load customer receive information about the timeline and costs for the interconnection agreement "in a timely manner."

Commission Response

The commission declines to modify the adopted rule to add a requirement that the customer receive information about the timeline and costs for the interconnection agreement "in a timely manner" because it is unnecessary. The commission's modifications to the adopted rule require the interconnecting DSP or TSP to provide a large load customer information related to communications that the interconnecting DSP or TSP receives from ERCOT about the large load customer's interconnection request within five working days substantively addresses TXOGA's concern. Moreover, the commission determines that specific details about the process and timeline for providing information that will inform the timeline and costs associated with the SLLIA is best addressed in ERCOT protocols describing the process and timeline for ERCOT to move forward with a refinement study after the deadline to execute a SLLIA passes.

Power supply and controllable load

LCRA and TPPA recommended modifying proposed §25.194(f) to include two new provisions requiring disclosures related to power supply and controllable load for with the disclosure requirements at the intermediate agreement stage.

Commission Response

The commission adopts LCRA and TPPA's recommendation to modify the adopted rule to require disclosures related to power supply and controllable load for symmetry with the disclosure requirements at the intermediate agreement stage.

Designation of coordinating entity

TNMP recommended modifying proposed §25.194(f) to specifically designate a single coordinating entity for ERCOT notifications to avoid duplication or inadvertent miscommunication.

Commission Response

The commission declines to adopt TNMP's recommendation to modify the adopted rule to designate a single coordinating entity for ERCOT notification because the recommendation is better addressed in a separate rulemaking to adopt a SLLIA, which will set forth each entity's responsibilities.

Allow for the use of a similar agreement

Constellation recommended modifying proposed §25.194(f) to indicate that the relevant agreement can be an "interconnection agreement" or similar agreement since the applicable form of agreement will vary based on whether or not the large load is co-locating with a generation resource.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to indicate that the relevant agreement can be an "interconnection agreement" or similar agreement. The commission determines that a standardized pro forma agreement setting forth each entity's responsibilities is a better approach to varying independent discretionary service agreements across utilities. Adopted §25.194(f) requires the large load customer and interconnecting DSP or interconnecting TSP to execute a commission-approved pro forma agreement (a SLLIA). The commission plans to adopt a SLLIA in a future rulemaking project.

Protection from reallocation

STACK recommended modifying proposed §25.194(f) to add a new subsection stating that a large load customer that satisfies its obligations under its interconnection agreement shall not be subject to any reallocation of its capacity.

Commission Response

The commission declines to adopt STACK's recommendation to modify the adopted rule to state that a large load customer that satisfies its obligations under its interconnection agreement shall not be subject to any reallocation of its transmission capacity. Adopted §25.194(k) provides that ERCOT may reallocate transmission capacity associated with a large load customer that fails to comply with its SLLIA. Allowing a large load customer to retain unused transmission capacity in perpetuity in all circumstances would represent an inefficient use of vital electric energy infrastructure, likely resulting in an inefficient use of financial and geographic resources for consumers and industry.

Proposed §25.194(f)(1) -- Site control

Proposed §25.194(f)(1) requires a large load customer to demonstrate site control for the load location.

Previous demonstration of site control

Constellation recommended modifying proposed §25.194(f) to add a statement that if a large load customer previously demonstrated site control at the intermediary agreement phase consistent with one of the listed requirements, additional demonstration of site control is not required.

Commission Response

The commission declines to adopt Constellation's recommendation to modify the adopted rule to add a statement that if a large load customer previously demonstrated site control at the intermediate agreement phase consistent with one of the listed requirements, additional demonstration of site control is not required because the commission modifies the adopted rule to require disclosure of the property interest rather than the underlying documentation demonstrating the property interest. However, the commission modifies the adopted rule to clarify that ERCOT and commission staff may request the underlying documentation as part of an audit and verification process. Ultimately, the provision of an additional attestation or documentation is not overly burdensome and maintaining the requirement for what is effectively an update to the information provided under the intermediate agreement promotes accuracy in the disclosure of information required by the adopted rule and ensures the large load customer continues active development of its project through the pendency of the interconnection process.

Option to purchase or lease

APA and ACP, EH2, Google, Lancium, and TotalEnergies, and TIEC recommended modifying proposed §25.194(f)(1) to allow a large load customer to demonstrate site control through a purchase and lease option. Alternatively, APA and ACP recommended allowing a large load customer to demonstrate site control through a purchase and lease option if the large load customer commits to converting the option into a purchase as a contractual milestone.

Commission Response

The commission declines to modify the adopted rule to allow a large load customer to demonstrate site control through a purchase and lease option at the SLLIA stage. Options are appropriate instruments early in the development process but do not provide sufficient assurance at the SLLIA stage. An option must generally be exercised and converted to a lease or purchase agreement within 1-2 years and is unlikely to extend through the time needed for the customer to satisfy all milestones in its phased energization schedule.

The commission declines to adopt APA and ACP's recommendation to allow a large load customer to demonstrate site control through a purchase and lease option if the large load customer commits to converting the option into a purchase as a contractual milestone. If the customer intends to convert the option into a purchase after execution of a SLLIA, it is reasonable to expect the customer could instead exercise the option prior to the deadline to execute a SLLIA. If the large load customer does not want to exercise the option, the customer can withdraw its interconnection request with limited financial penalty and submit a new request once its project has more fully developed.

Proposed §25.194(f)(1)(C) -- Purchase and sales agreement

Proposed §25.194(f)(1)(C) allows a large load customer to demonstrate site control by providing a signed and executed purchase and sales agreement.

Strike subsection

Tract recommended striking proposed §25.194(f)(1)(C) because a purchase and sale agreement is insufficient to demonstrate project commitment.

Commission Response

The commission declines to adopt Tract's recommendation to modify the adopted rule to remove a purchase and sale agreement as an option for demonstrating site control. A signed and executed purchase or sale agreement typically includes binding commitments, detailed property descriptions, and enforceable closing conditions, which provide meaningful assurance that the large load customer has secured the right to the land necessary for the project. Therefore, the commission determines that a signed and executed purchase or sale agreement presents a valid legal interest demonstrating site control in compliance with PURA §37.0561(g).

Proposed §25.194(f)(2) -- Substantially similar request

Proposed §25.194(f)(2) requires a large load customer to disclose whether the customer is pursuing a substantially similar interconnection request for electric service, the approval of which would result in the customer materially changing, delaying, or withdrawing the interconnection request. A material change or delay includes a delay of one or more years to the project's projected date to realize its requested or contracted peak demand, a 20% or greater change in the requested or contracted peak demand, or a change in the location for the point of interconnection.

Strike subsection

LCRA recommended removing proposed §25.194(f)(2) because it is unnecessary. LCRA reasoned that the disclosure requirement for a substantially similar request was incorporated at the intermediate agreement stage to reduce speculative and duplicative requests that lead to inaccurate load forecasting.

Commission Response

The commission declines to adopt LCRA's recommendation to remove the requirement that a large load customer disclose a substantially similar interconnection request at the SLLIA stage because the information is equally valuable at the SLLIA stage as it is at the intermediate agreement stage.

Proposed §25.194(f)(4) -- State and local regulatory approvals

Proposed §25.194(f)(4) requires a large load customer to submit the large load customer's plans, expected timing, and current progress for obtaining non-ministerial discretionary approvals from state and local regulatory authorities required for development before energization (e.g., water, air, or backup generation permits). The submission must be accompanied by an attestation and the large load customer must provide updates or progress reports upon request.

Require proof of zoning approval

Tract recommended adding a new subsection requiring a large load customer to provide proof of local zoning approval prior to interconnection agreement execution as demonstration of project commitment.

Commission Response

The commission declines to adopt Tract's recommendation to add a new subsection requiring a large load customer to provide proof of local zoning approval prior to the interconnection agreement execution as demonstration of project commitment because not all large load projects will require local zoning approval. Moreover, it is substantively captured by the requirement to disclose state and local regulatory milestones and approvals.

Proposed §25.194(f)(7) -- Non-refundable interconnection fee

Proposed §25.194(f)(7) requires a large load customer to pay a non-refundable interconnection fee in the amount of \$50,000 per MW of contracted peak demand.

Provide interconnection fee to interconnecting DSP

TNMP recommended modifying proposed §25.194(f)(7) to require that the interconnection fee be provided to the interconnecting DSP.

Commission Response

The commission declines to adopt TNMP's recommendation to modify the adopted rule to require that the interconnection fee be provided to the interconnecting DSP because it is moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Interconnection fee refundability

CloudHQ, DCC, and Rowan recommended modifying proposed §25.194(f)(7) to allow for the refund of the interconnection fee. Specifically, DCC recommended modifying proposed §25.194(f)(7) to require that the interconnection fee be applied against actual costs incurred by the interconnecting DSP or interconnecting TSP with the excess refunded to the customer within 60 days of interconnection. CloudHQ and DCC reasoned that imposing a non-refundable fee that is not tied to actual costs incurred is inconsistent with statute. DCC further noted that the inclusion of a non-refundable fee at the interconnection agreement stage would have the effect of converting the partially refundable security proposed in proposed §25.194(d)(10) into a non-refundable forfeiture. Rowan recommended allowing for a whole or partial refund of the interconnection fee upon achievement of energization milestones, or, at a minimum, a refund of any portion of the fee exceeding the TSP's actual interconnection costs.

If the interconnection fee is retained, CenterPoint recommended modifying proposed §25.194(f)(7) to apply a graduated structure to refund the interconnection fee based on completion of commercial development milestones. Specifically, CenterPoint recommended that upon initial energization of the project, 50% of the total interconnection fee paid should be refunded; upon achievement of half of the large load customer's contracted peak demand, 25% of the total interconnection paid should be refunded; and upon achievement of the other half of the large load customer's contracted peak demand, the remaining 25% of the total interconnection fee paid should be refunded. If a large load customer does not achieve a milestone, the amount that would have been refunded had the milestone been reached should be applied by the utility to cover any outstanding amounts owed for system upgrade costs and thereby reduce the amount of such that would otherwise be eligible for recovery in rate base. Similarly, EH2 recommended applying a staged refundability framework consistent with typical development project milestones, with a portion remaining refundable if the project is not constructed.

Constellation recommended modifying proposed §25.194(f)(7) to add a statement that a portion of the interconnection fee becomes non-refundable at each stage of the large load interconnection study process and ultimately the entire interconnection fee is refundable upon execution of an interconnection or similar agreement.

Constellation also recommended adding a new provision that states immediately on ERCOT's commencement of the large load interconnection studies, 10% of the total posted financial se-

curity shall be non-refundable. The remaining security becomes non-refundable in equal percentages divided by the total number of studies, as each study concludes. If the large load customer completes all studies but does not execute an interconnection agreement or similar agreement, the applicable interconnecting DSP or TSP shall refund all but 10% of the interconnection fee. Following completion of all studies and execution of an interconnection agreement or similar agreement, no amount of the interconnection fee is refundable.

Commission Response

The commission declines to adopt commenters' recommendations to modify the refundability of the interconnection fee because they are moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Separate treatment for large load customer subject to PURA §39.169

Vistra recommended modifying proposed §25.194(f)(7) to add a new provision that states, notwithstanding proposed §25.194(f)(7)(A) and (B), a large load customer that will be subject to PURA §39.169 and Section 205 of this Chapter must pay the interconnection fee to the interconnecting TSP following commission approval under Section 205 of this Chapter. If the commission approves the application, the interconnection fee is due within 15 business days of the order becoming final. If the commission denies the application, no interconnection fee is owed.

Commission Response

The commission declines to adopt Vistra recommendation to modify the adopted rule to add a new provision that states a large load customer subject to PURA §39.169 must pay the interconnection fee after receiving commission approval for its net metering arrangement because it is moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Eliminate the interconnection fee

AEP, APA and ACP, CCNG, Google, Lancium, and TotalEnergies, Hut 8, Joint TSPs, LCRA, Satoshi, Tesla, Thor, TIEC, and Tract recommended striking proposed §25.194(f)(7) in its entirety. Joint TSPs reasoned that the interconnection fee conflicts with PURA §37.0561, which requires a dollar per megawatt security to be refunded, in whole or in part, after the security is applied to any outstanding amounts owed. Thor and Tract reasoned that the interconnection fee is not consistent with cost-causation principles.

Commission Response

The commission adopts commenters' recommendation to eliminate the non-refundable interconnection fee and modifies the adopted rule accordingly.

Acceptable forms of payment for the interconnection fee

To provide certainty, Rowan recommended adding a new subsection specifying that the interconnection fee may be satisfied through the same forms of financial security listed in proposed §25.194(d)(10)(C), (d)(11)(C), (f)(8)(C), and (f)(10)(A).

Commission Response

The commission declines to adopt Rowan's recommendation to add a new subsection specifying that the interconnection fee may be satisfied through the same forms of financial security

listed in other provisions of the rule because it is moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Reduce the dollar amount of the interconnection fee

If the requirement for an interconnection fee is retained, CenterPoint recommended modifying proposed §25.194(f)(7) to apply a tiered structure for the interconnection fee: \$10,000 per MW for loads that are 75-250 MW; \$20,000 per MW for loads that are 251-1,000 MW; and \$30,000 per MW for loads that are greater than 1,000 MW. Additionally, CenterPoint recommended capping the interconnection fee at \$50 million. Similarly, EH2 recommended lowering the dollar amount.

Commission Response

The commission declines to adopt CenterPoint's recommendation to reduce the dollar amount of the interconnection fee because it is moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Tie to costs

BKV recommended modifying proposed §25.194(f)(7) to make the interconnection fee either fully creditable toward actual interconnection-related costs, or limited to a narrowly defined, non-refundable component demonstrably tied to administrative or early-stage costs that are not otherwise recoverable.

Commission Response

The commission declines to adopt BKV's recommendation to make the interconnection fee either fully creditable toward actual interconnection-related costs, or limited to a narrowly defined, non-refundable component demonstrably tied to administrative or early-stage costs that are not otherwise recoverable because it is moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Proposed §25.194(f)(7)(B) -- Offset to rate base

Proposed §25.194(f)(7)(B) requires the interconnection fee to be used as an offset to the interconnecting TSP's rate base in the earlier of the interconnecting TSP's next interim rate proceeding or comprehensive rate proceeding.

Additional detail

TNMP and TXOGA recommended modifying proposed §25.194(f)(7)(B) to include additional details. Specifically, TNMP recommended clarifying how the proposed rate base offset is intended to apply in light of nondiscrimination obligations and existing recovery practices. TXOGA recommended additional detail on the methodology for applying funds to offset the interconnecting TSP's rate base.

Commission Response

The commission declines to adopt TNMP and TXOGA's recommendations to include additional details regarding the offset to rate base because they are moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Eliminate requirement to apply the interconnection fee as an offset rate base and suggested alternatives

Constellation, GVEC, Joint TSPs, NRG, OCSC and TCAP, TCPA, TEC, TPPA, and TSP Cooperatives recommended modifying proposed §25.194(f)(7)(B) to eliminate the requirement to offset rate base.

Specifically, TPPA recommended that the funds collected through this mechanism be issued to DSPs as a bill credit for further allocation to benefit end-use customers, rather than being used to reduce a TSP's rate base. OCSC and TCAP recommended using funds provided by large load customers to offset the overall transmission cost of service in ERCOT rather than an individual TSP's rate base.

Constellation recommended replacing the requirement to offset rate base with a requirement to apply the fee to customer assistance programs which benefit low-to-moderate income retail customers. Similarly, TCPA recommended crediting the non-refundable amount to residential consumers against their portion of the total revenue requirement. NRG recommended replacing the requirement to offset rate base with a requirement to offset annual revenue requirement.

If their primary recommendation to eliminate the interconnection fee is not adopted, then Joint TSPs recommended requiring large load customers to: (1) pay a flat fee to be applied to ERCOT-wide wholesale transmission costs with the fees credited to other retail customers across the four coincident peak transmission charge matrix; or (2) pay a fee to be credited directly to retail customers through a TSP Wholesale Transmission Tariff Credit Rider amortized across a period of time approved by the commission.

Commission Response

The commission declines to adopt commenters' recommendations to eliminate the requirement to apply the interconnection fee as an offset to rate base because they are moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Proposed §25.194(f)(8) -- Financial security for significant equipment or services

Proposed §25.194(f)(8) requires a large load customer to post financial security for significant equipment or services not later than the date that the interconnection agreement is executed if the interconnecting DSP or the interconnecting TSP needs to procure significant equipment or services to interconnect the large load customer. An interconnecting DSP or an interconnecting TSP is prohibited from procuring equipment or services before a large load customer posts financial security in an amount equal to the estimated costs for equipment with a lead time of at least six months and services necessary to interconnect the large load customer.

Strike subsection

AEP and CenterPoint recommended striking proposed §25.194(f)(8) because it is unnecessary. AEP reasoned that proposed §25.194(f)(9) already requires a large load customer to pay all direct interconnection costs, which includes long lead-time materials. CenterPoint reasoned that all equipment procurement costs are either included in the CIAC or covered by the system upgrade security. AEP further recommended modifying proposed §25.194(f)(9) to add a new provision that states long-lead time security, if collected at the time of the intermediate agreement, should be released once the interconnection agreement is executed.

Commission Response

The commission adopts AEP and CenterPoint's recommendation to modify the adopted rule to remove the subsection requiring the posting of separate financial security for significant

equipment or services at the time of interconnection agreement execution. However, the commission modifies the adopted rule to provide that the interconnecting DSP or TSP must credit the financial security provided at the intermediate agreement stage to the costs of significant equipment or services, if procured before a SLLIA is executed. If the financial security posted under the intermediate agreement is less than the costs of significant equipment or services being procured before a SLLIA is executed, then the large load customer must post additional financial security for the difference in the costs of significant equipment or services and the amount of financial security already posted before the interconnecting DSP or the interconnecting TSP procures the significant equipment or services. The commission also modifies the adopted rule to include a clarifying statement that a large load customer must pay CIAC in the form of a direct cash payment for significant equipment or services that meet the definition for direct interconnection costs under §25.192, relating to Transmission Service Rates.

Flexibility to use CIAC or financial security in alignment with existing business practices

LCRA recommended modifying proposed §25.194(f)(8) to authorize the interconnecting DSP or TSP to require a large load customer to post additional financial security or CIAC, in accordance with the interconnecting DSP or TSP's requirements, if the amount posted during the intermediate agreement phase is not sufficient. LCRA reasoned TSPs should retain authority to operate within existing business practices such as choosing to only require non-refundable CIAC in situations where requests are made by interconnecting customers that go above and beyond the standard interconnection practices, such as requests to underground transmission lines. If its recommendation is adopted, LCRA recommended striking proposed §25.194(f)(9) as a conforming change.

Commission Response

The commission declines to adopt LCRA's recommendation to modify the adopted rule to

explicitly authorize the interconnecting DSP or TSP to require a large load customer to post additional financial security or CIAC, in accordance with the interconnecting DSP or TSP's requirements, if the amount posted during the intermediate agreement phase is not sufficient. Instead, the commission modifies the adopted rule to specify that additional financial security may be required if the costs of significant equipment or services exceed the previously posted financial security under the intermediate agreement and modifies the adopted rule to specify that significant equipment and services meeting the definition for direct interconnection costs must be paid for with cash. Moreover, the commission specifies in the adopted rule that additional financial security associated with the large load minimum billing demand may be required.

Proposed §25.194(f)(8)(B) -- Balance of unused financial security

Proposed §25.194(f)(8)(B) requires an interconnecting DSP or an interconnecting TSP, after drawing down for payment of the interconnection fee, to apply the balance of any unused financial security to satisfy the financial security for significant equipment or services.

Clarify interconnection fee obligation arises under the interconnection agreement

Rowan recommended modifying proposed §25.194(f)(8)(B) to clarify that the interconnection fee is an obligation arising under the interconnection agreement pursuant to (f)(7), rather than an obligation under the intermediate agreement.

Commission Response

The commission declines to adopt Rowan's recommendation to clarify that the interconnection fee is an obligation arising under the interconnection agreement rather than an obligation under the intermediate agreement because it is moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Remove reference to drawing down for payment of interconnection fee

NRG recommended modifying proposed §25.194(f)(8)(B) to remove reference to drawing down on financial security posted under an intermediate agreement for payment of the interconnection fee because the interconnection fee matches the financial security posted under an intermediate agreement on a dollar-for-dollar basis and therefore there will not be financial security to draw down on after payment of the interconnection fee.

Commission Response

The commission declines to adopt NRG's recommendation to remove reference to drawing down on financial security posted under an intermediate agreement for payment of the interconnection fee because it is moot, given the commission's modifications to eliminate the non-refundable interconnection fee.

Proposed §25.194(f)(9) -- Contribution in aid of construction (CIAC)

Proposed §25.194(f)(9) requires a large load customer to pay all direct interconnection costs through CIAC, with no standard or other allowance offered to offset the customer's CIAC payments. A large load customer must pay CIAC not later than the date the interconnection agreement is executed. An interconnecting DSP and interconnecting TSP must not begin construction of facilities to interconnect a large load customer before a large load customer pays CIAC in an amount that is equal to the direct interconnection costs associated with the large load customer.

Clarify cost allowance prohibition

TPPA recommended modifying proposed §25.194(f)(9) to add clarity by stating that a large load customer must pay all direct interconnection costs through CIAC and no TSP may offer any allowance or other mechanism to reduce a large load customer's interconnection costs instead of stating a large load customer must pay all direct interconnection costs through CIAC with no standard or other allowance offered to offset the customer's CIAC payments.

Commission Response

The commission declines to adopt TPPA's recommendation to add clarity by stating that no TSP may offer any allowance or other mechanism to reduce a large load customer's interconnection costs because it is moot, given the commission's modification to remove the language TPPA recommended modifying. The specificity recommended by TPPA is better addressed in the pending rulemaking in Project No. 58000.

Itemization of CIAC costs

PPM recommended modifying proposed §25.194(f)(9) to require utilities to itemize costs for CIAC because itemization will facilitate the true-up process in proposed §25.194 (f)(9)(C).

Commission Response

The commission declines to adopt PPM's recommendation to modify the adopted rule to require itemization of CIAC to assist in the true-up process because it is unnecessary to prescribe the process by which an interconnecting DSP or TSP performs the true up. The adopted rule requires CIAC be trueed up to reflect actual costs. The manner in which an interconnecting DSP or TSP satisfies that requirement does not affect the amount a large customer owes or is owed.

Timeline for CIAC payment

CenterPoint, Constellation, DCC, EH2, and Targa recommended modifying the timeline by which a large load customer must pay CIAC. Specifically, CenterPoint recommended modifying proposed §25.194(f)(9) to extend the deadline to pay CIAC to 30 days after the interconnection agreement is executed. DCC recommended modifying proposed §25.194(f)(9) to allow the large load customer at least 60 days to pay CIAC because making payment the day of interconnection agreement signing is not feasible. EH2 asserted that requiring full CIAC payment on the day of interconnection agreement is unjust and unnecessary.

Constellation recommended modifying proposed §25.194(f)(9) to require CIAC paid in amounts and at the times required to facilitate construction of the facilities directly attributable to the large load interconnection request as established in the interconnection agreement, which may include making an initial payment not later than the date that the interconnection agreement is executed instead of requiring the full amount paid at the time the interconnection agreement is executed.

Targa recommended modifying the proposed rule to allow for a graduated, phased payment structure based on construction milestones rather than requiring all direct interconnection costs to be paid at the time the interconnection agreement is executed.

Commission Response

The commission declines to adopt CenterPoint, DCC, EH2, Constellation, and Targa's recommendations to modify the timeline to pay CIAC because the recommendations are moot, given the commission's modifications to the adopted rule to eliminate the deadline to pay CIAC. To address the timing of CIAC payment, the commission modifies the adopted rule to require an interconnecting DSP or TSP to invoice a large load customer before incurring costs, and to require the customer to pay invoices within 10 days. If the large load customer fails to pay an invoice from the interconnecting DSP or TSP within 10 working days after the receipt of an invoice, the interconnecting DSP or TSP may draw down on the large load customer's financial security for the invoiced amount and cancel the large load customer's interconnection request.

Long-lead time security in relation to CIAC

NRG recommended modifying proposed §25.194(f)(9) to allow for the use of financial security for long-lead time equipment to be drawn down for the payment of CIAC, to the extent that the long-lead time equipment relates to direct interconnection costs. Additionally, NRG recommended modifying proposed §25.194(f)(9) to require a refund, within 30 days of executing the interconnection agreement, financial security that was collected in ex-

cess of the direct interconnection costs required under proposed §25.194(f)(9).

Commission Response

The commission declines to adopt NRG's recommendation to allow for the use of financial security for long-lead time equipment to be drawn down for the payment of CIAC, to the extent that the long-lead time equipment relates to direct interconnection costs because it is moot, given the commission's modification to eliminate the requirement to post separate financial security for significant equipment and services at the time of SLLIA execution.

Optionality for electric cooperatives and municipally owned utilities

GVEC, TEC, and TSP Cooperatives recommended modifying proposed §25.194(f)(9) to allow optionality for electric cooperatives and municipally owned utilities with respect to CIAC billings. Specifically, GVEC and TEC recommended modifying proposed §25.194(f)(9) to add a statement that the proposed rule is optional for electric cooperatives and municipally owned utilities; and that electric cooperatives and municipally owned utilities shall pass along the costs of direct interconnection to the large load consumer in an appropriate manner solely determined by the electric cooperative or municipally owned utility.

Commission Response

The commission declines to adopt GVEC, TEC, and TSP Cooperatives' recommendation to allow optionality for electric cooperatives and municipally owned utilities with respect to CIAC. PURA §35.004(c-2) states an electric cooperative or municipally owned utility that has not adopted customer choice shall pass through to a large load customer who is subject to the standards adopted under PURA §37.0561 the reasonable costs to interconnect the large load in a manner determined by the electric cooperative or municipally owned utility. The adopted rule does not contravene this statutory requirement and it is not necessary to restate the statute. However, the commission notes that wholesale transmission rates are subject to the commission's jurisdiction and therefore the commission has jurisdiction to determine what costs should and should not be recovered in wholesale transmission rates.

Strike subsection

If its recommendation to replace the interconnection fee with a capacity-based charge is adopted, Oncor recommended striking proposed §25.194(f)(9) because CIAC does not appropriately socialize the costs of standard interconnection facilities across ERCOT customers or allow utilities to earn a fair rate of return on their facilities. Oncor asserted that electric utilities are legally entitled to earn a return on the value of the assets employed for public convenience.

Commission Response

The commission declines to adopt Oncor's recommendations to strike the subsection relating to CIAC. It is not appropriate to socialize costs associated with equipment, facilities, and services that do not benefit the public as a whole. Moreover, a rate of return is a statutory requirement that allows a utility the opportunity to earn a rate of return on capital investment as a means to attract shareholder investment to pay the significant costs to construct new equipment or facilities, the cost of which cannot be recovered in rates until the equipment and facilities are used and useful in providing service to the public.

Proposed §25.194(f)(9)(A) -- Direct interconnection costs

Proposed §25.194(f)(9)(A) specifies that direct interconnection costs include all costs associated with facilities built to interconnect the large load customer to the existing ERCOT system, including radial lines and substation upgrades necessary to interconnect the new large load customer. CIAC must be paid in the form of a direct cash payment.

Acceptable forms for CIAC payment

PPM recommended modifying proposed §25.194(f)(9)(A) to provide that CIAC may also be paid in the form of project level escrow accounts, standby letters of credit, or affiliate guarantees. PPM reasoned that limiting the payment form to direct cash could exclude otherwise viable projects.

Commission Response

The commission declines to adopt PPM's recommendation to modify the adopted rule to allow non-cash forms of CIAC payment because the recommendation is inconsistent with the purpose of CIAC. The large load customer is required to pay the direct interconnection costs associated with its interconnection request, and CIAC is the mechanism through which those costs are paid. CIAC does not function as a form of financial security for future payment obligations and therefore it must be paid in cash.

Carry previous payments forward to apply to CIAC

Hut 8 stated CIAC should be paid through the financial security posted at the time of intermediate agreement execution. EH2 stated that the interconnection fee should be carried forward to apply toward any CIAC payments.

Commission Response

The commission declines to adopt Hut 8's recommendation to modify the adopted rule to provide that CIAC is paid through the financial security posted at the time of intermediate agreement execution because CIAC and financial security serve different functions under the adopted rule. Financial security demonstrates the large load customer has access to the necessary capital to complete the project and satisfy the obligations established by the adopted rule. Financial security also minimizes the potential for stranded infrastructure costs. CIAC is the mechanism through which a large load customer's direct interconnection costs are paid. Applying financial security to CIAC would reduce the amount securitizing the large load customer's future obligations and thereby increase the risk of stranded infrastructure costs. The commission notes that the adopted rule permits the interconnecting DSP or TSP to draw down on the large load customer's financial security if the customer fails to pay an invoice within 10 working days and cancel the interconnection request. However, this mechanism applies only when a large load customer fails to pay an invoice; it does not establish financial security as the means by which CIAC is paid.

The commission declines to adopt EH2's recommendation to provide that the interconnection fee should be carried forward to apply toward any CIAC payments because it is moot, given the commission's modifications to the adopted rule to eliminate the interconnection fee.

Definition of direct interconnection costs

OPUC recommended modifying proposed §25.194(f)(9)(A) to broaden what constitutes direct interconnection costs by adding "equipment and other infrastructure built at or adjacent to the point of interconnection necessary to interconnect the large load

customer to the ERCOT system, including but not limited to new or upgraded radial lines and substations."

Joint TSPs recommended modifying proposed §25.194(f)(9) to define direct interconnection costs as radial transmission line extensions and any necessary bay at the first station needed to interconnect the customer to the transmission system and to explicitly exclude system upgrades that may be only incidentally triggered by a large load, including networked transmission lines or reinforcements that become part of the broader transmission network rather than a single interconnection.

AEP recommended modifying proposed §25.194(f)(9) to state that: (1) CIAC applies only to customer-specific interconnection facilities constructed solely to serve a large load, and (2) network upgrades that maintain system reliability or are required to meet planning criteria are not "direct interconnection costs." Similarly, CenterPoint recommended modifying proposed §25.194(f)(9) to state that CIAC costs are the engineering, procurement, and construction costs of facilities need to interconnect the customer that are beneficial or used and useful only for that customer.

Commission Response

The commission declines to adopt commenters' recommendation to modify the definition of direct interconnection costs because they are moot, given the commission's modification to the adopted rule to remove the language describing direct interconnection costs. To address which costs constitute direct interconnection costs, the commission modifies the adopted rule to include a definition that cites to §25.192, relating to Transmission Service Rates. The commission determines that the definition for direct interconnection costs, and therefore the costs covered by CIAC, is better addressed in the pending rulemaking in Project No. 58000.

Clarify tax gross up treatment

For clarity, EDF recommended modifying proposed §25.194(f)(9)(A) to explicitly state that CIAC obligations include tax gross-ups and franchise fees. Similarly, CenterPoint recommended explicitly allowing the interconnecting utilities to gross up the interconnection fee and CIAC amounts to the extent necessary to cover their tax liability.

Commission Response

The Commission declines to adopt EDF and CenterPoint's recommendation to explicitly state that CIAC and the interconnection fee include tax gross-ups because the clarification is more appropriately addressed in Project No. 58000.

Proposed §25.194(f)(9)(C) -- True up

Proposed §25.194(f)(9)(C) requires a true up of CIAC to reflect the actual costs once the facilities are completed, and allows a large load customer to receive a credit or surcharge on their bill, as applicable, for the difference in actual costs relative to the estimate.

Deadline for true ups and form of true up

Targa recommended modifying proposed §25.194(f)(9)(C) to require all CIAC true ups be made through direct cash payment not later than 60 days after the completion of all direct interconnection facilities instead of through a credit or surcharge on the customer's bill.

Commission Response

The commission declines to adopt Targa's recommendation to require CIAC true ups to be made through direct cash payment within 60 days after the completion of all direct interconnection facilities rather than through credit or surcharge on a customer's bill. A direct cash payment requirement would establish a separate settlement process when the amount can be resolved through the existing billing relationship. Further, establishing a fixed deadline is not appropriate because the time needed to determine the actual costs and true-up amount may vary.

Proposed §25.194(f)(10) -- Financial security for system upgrades

Proposed §25.194(f)(10) requires a large load customer to post financial security, not later than the date that the interconnection agreement is executed, for system upgrades that are necessary to reliably serve the large load customer.

Define system upgrade costs and identify allocation method

CenterPoint recommended modifying proposed §25.194(f)(10) to state system upgrade costs include all engineering, procurement, and construction costs associated with facilities built to interconnect the large load customer to the existing ERCOT transmission system that are also beneficial and used and useful to the transmission system, or for the reliability or availability of transmission service, generally. System upgrade costs do not include direct interconnection costs.

Similarly, TEC recommended the commission clarify what system upgrade costs encompass and whether those costs are allocated on a load ratio share to all loads in a batch study or by some other means. Additionally, TEC recommended that the rule address how system upgrade costs should be allocated if a large load and a generator which will operate independently of each other are both being built at the same interconnection point.

OPUC recommended modifying proposed §25.194(f)(10) to broaden what constitutes system upgrades to include all transmission infrastructure built or upgraded through the ERCOT grid necessary to interconnect and reliably serve large load customers.

Oncor recommended modifying proposed §25.194(f)(10) to require ERCOT to allocate the amounts of financial security that is required from each interconnecting large load to securitize system upgrades that are necessary to reliably serve the large load customer and clarify how the security amounts will be calculated.

Commission Response

The commission declines to adopt commenters' recommendations to specify in the adopted rule what encompasses system upgrades. Instead, the commission modifies the adopted rule to add a definition for system upgrades that cites to §25.193, relating to Transmission Service Rates.

The commission also declines to adopt commenters' recommendations to specify an allocation methodology in the adopted rule. A specific allocation methodology is outside the scope of this rulemaking.

Eliminate requirement to pay financial security for system upgrades

CCNG, Constellation, LCRA, Monarch, PPM, and Serena recommended striking proposed subsection §25.194(f)(10) in its entirety. LCRA and Serena reasoned that who should pay for system upgrades is best determined in Project No. 58484, Evalua-

tion of Transmission Cost Recovery. Monarch, PPM, and Serena reasoned that assigning financial responsibility for transmission upgrades to specific customers is an alteration of the foundational "postage stamp" transmission cost allocation policy and could be disruptive and have unintended consequences. Serena further reasoned that the language "for system upgrades that are necessary to reliably serve the customer" is overly vague and could lead to imprecise and discriminatory apportionment of financial responsibility.

Commission Response

The commission declines to adopt commenters' recommendations to modify the adopted rule to strike the subsection related to financial security for system upgrades. PURA §37.0561 directs the commission to establish large load interconnection standards in a manner designed to support business development while minimizing the potential for stranded infrastructure costs and maintaining system reliability. System upgrades represent a component of stranded cost exposure, because these facilities are planned and constructed based on a large load customer's contracted peak demand and the representation that the customer will energize. Eliminating the financial security requirement would eliminate a key protection by exposing ratepayers to the costs required for system upgrades to reliably serve the customer, if that customer fails to materialize. Further, eliminating the provision would leave a statutory objective unimplemented. However, for clarity, the commission modifies the adopted rule to provide that a large load customer must post financial security with the interconnecting DSP or TSP in an amount that is the greater of: (1) \$50,000 per MW of the contracted peak demand, or (2) the costs allocated to the large load customer for system upgrades as a result of a batch zero interconnection study or an interconnection study.

Deadline to post financial security for system upgrades

CenterPoint recommended modifying proposed §25.194(f)(10) to extend the deadline to post financial security for system upgrades to 30 days after the interconnection agreement is executed.

Commission Response

The commission declines to adopt CenterPoint's recommendation to extend the deadline to post financial security for system upgrades to 30 days after the interconnection agreement is executed. The execution and funding of a SLLIA is needed prior to the start of the refinement study to ensure load is accurately modeled. Extending the timeline to post financial security would impact the timeline to begin the refinement study and thus delay the results of the interconnection study. The commission modifies the adopted rule to specify that the SLLIA must be executed and funded not later than 60 days after ERCOT issues a study report that allocates transmission capacity.

Limit financial security for system upgrades

AEP recommended modifying proposed §25.194(f)(10) to state that a large load customer must post financial security for system upgrades that are necessary to directly interconnect the large load customer rather than for system upgrades that are necessary to reliably serve the large load customer. AEP reasoned that network upgrades that provide broader system benefits should be addressed through transmission cost-allocation mechanisms.

Commission Response

The commission declines to adopt AEP's recommendation to modify the adopted rule to state that a large load customer must post financial security for system upgrades that are necessary to directly interconnect the large load customer rather than for system upgrades that are necessary to reliably serve the large load customer because the costs to directly interconnect the large load customer are already covered by CIAC. This modification would have the same effect as striking the subsection, which the commission declines to do for the reasons stated in the commission's response to commenters that recommended striking the subsection.

Proposed §25.194(f)(10)(C) -- Refund

Proposed §25.194(f)(10)(C) states that financial security posted for system upgrades is subject to refund under proposed subsection (g) through (i).

Strike subsection

AEP recommended removing proposed §25.194(f)(10)(C) because it is an unnecessary restatement of other rule provisions and potentially creates confusion with the language in proposed §25.194(f)(7) if that language is retained.

Commission Response

The commission declines to adopt AEP's recommendation to remove the provision stating that financial security posted for system upgrades is subject to refund under proposed subsection (g) through (i) because it is moot, given the commission's modifications to the organizational structure of the adopted rule regarding the return of financial security to the large load customer.

Subject to true up

OPUC recommended modifying proposed §25.194(f)(10)(C) to require that a refund be delayed until there is a true up to reflect the actual costs once the transmission infrastructure to interconnect and energize the large load customer is completed. Once a decision is rendered and approved in a base rate or transmission cost of service proceeding, then the large load customer may receive a credit or surcharge on their bill, as applicable, for the difference in actual transmission costs compared to the estimate. Consistent with this recommendation, OPUC also recommended removing all other refund provisions.

Commission Response

The commission declines to adopt OPUC's recommendation to require that a refund be delayed until there is a true up to reflect the actual costs once the transmission infrastructure to interconnect and energize the large load customer is completed. The commission's modification of the adopted rule to provide that return of financial security is tied to the large load customer's payment of the minimum billing demand for a set period of time as described in §25.193 serves the same goal as that served by OPUC's recommendation.

Proposed §25.194(g) -- Withdrawal of all or a portion of requested peak demand or contracted peak demand

Proposed §25.194(g) authorizes a large load customer to withdraw all or a portion of requested peak demand or contracted peak demand for interconnection by submitting the request in writing to the interconnecting DSP or the interconnecting TSP.

Partial withdrawal

TNMP recommended modifying proposed §25.194(g) to address how refunds are calculated when contracted peak demand is reduced but not fully eliminated.

Commission Response

The commission agrees with TNMP that the adopted rule should address how the portion of financial security subject to return to the large load customer is calculated when contracted peak demand is partially but not fully withdrawn. Accordingly, the commission modifies the adopted rule to provide that if a large load customer withdraws the customer's request to interconnect all or a portion of its contracted peak demand, the interconnecting TSP or DSP must collect payment for outstanding amounts owed and then subtract 20% of the financial security associated with the contracted peak demand that is withdrawn before the interconnecting DSP or the interconnecting TSP returns the remaining balance of financial security posted by a large load customer.

New load receiving reallocated capacity

TEC recommended modifying proposed §25.194(g) to require new load to which underutilized capacity is allocated to post surety to avoid leaving a gap in posted security for system upgrades.

Commission Response

The commission declines to adopt TEC's recommendation to modify the adopted rule to require a new load to which underutilized transmission capacity is allocated to post surety because it is moot. Each large load customer must separately comply with the requirements of the adopted rule. Transmission capacity that is reallocated must be reallocated by ERCOT in a future interconnection study and cannot be reallocated to a large load customer that is not included in an interconnection study.

Proposed §25.194(g)(2) -- Outstanding amounts owed

Proposed §25.194(g)(2) requires the interconnecting DSP or the interconnecting TSP to draw down on the large load customer's financial security and apply the financial security to any outstanding amounts owed, including: (A) costs incurred; (B) costs for equipment procured that cannot be canceled with a full refund; (C) costs for construction that cannot be canceled with a full refund; and (D) costs for services that cannot be canceled with a full refund.

Purpose of financial security for system upgrades

CenterPoint recommended modifying proposed §25.194(g)(2) to remove reference to amounts owed and to require the interconnecting DSP or the interconnecting TSP to draw down on the large load customer's financial security for system upgrade costs and apply proceeds to the system upgrade costs incurred that are associated with the amount of the contracted peak demand. CenterPoint reasoned that system upgrade costs should not be "amounts owed" by the customer who successfully energizes and utilizes the interconnection capacity it requested. Rather, system upgrade costs should be allowed to be recovered through the interconnecting utility's rates for delivery services provided to all customers. CenterPoint also reasoned that the purpose of financial security for system upgrades should be to pay for system upgrade costs in the event that those costs are determined to be ineligible for rate base inclusion.

Commission Response

The commission declines to adopt CenterPoint's recommendation to remove reference to outstanding amounts owed. The in-

terconnecting DSP or TSP is required to draw down on the financial security to recover outstanding amounts owed in the event that those costs have been incurred but will not ultimately be recovered by the large load customer driving the need for those costs to be incurred in the first place. Removing this requirement would remove an important mechanism for minimizing the potential for stranded infrastructure costs. Moreover, a large load customer that successfully energizes and utilizes the interconnection capacity is still subject to the large load minimum billing demand for a set period of time, which should be explicitly identified to provide clarity and notice to large load customers.

Invoice

LCRA and TEC recommended modifying proposed §25.194(g)(2) to allow the interconnecting DSP or, if applicable, the interconnecting TSP to elect to either issue an invoice or draw down on the large load customer's financial security in order to cover outstanding amounts owed. Additionally, LCRA recommended adding a requirement for the interconnecting DSP or, if applicable, the interconnecting TSP to draw down on the large load customer's financial security for amounts covered by an invoice that is not paid within ten business days. LCRA also recommended conforming changes to proposed §25.194(h)(2).

Commission Response

The commission adopts LCRA's recommendation to modify the adopted rule to allow the interconnecting DSP or TSP to elect to either issue an invoice or draw down on the large load customer's financial security in order to cover outstanding amounts owed, and add a requirement for the interconnecting DSP or TSP to draw down on the large load customer's financial security for outstanding amounts owed that are invoiced but not paid within 10 working days.

Proposed §25.194(g)(3) -- 20% refund

Proposed §25.194(g)(3) requires the interconnecting DSP or the interconnecting TSP to refund 20% of the balance, within 60 days, after applying the large load customer's financial security to any outstanding amounts owed.

Distinguish refundability based on when the withdrawal occurs

NRG recommended modifying proposed §25.194(g)(3) such that 80% of financial security is refundable if the large load customer withdraws after the intermediate agreement is signed but before the interconnection agreement is signed and none of the financial security is refundable if the large load customer withdraws after the interconnection agreement is signed but before initial energization. NRG also recommended a conforming change to proposed §25.194(g)(4).

Commission Response

The commission agrees with NRG that it is appropriate to delineate the terms for return of financial security based on when the withdrawal occurs but declines to adopt the specific framework recommended by NRG.

The commission finds that it is reasonable to return 80% of the financial security associated with allocated transmission capacity to the large load customer in circumstances where a large load customer is included in a batch study, is allocated some portion of requested peak demand, and withdraws prior to SLLIA execution. However, a large load customer that withdraws after execution of an intermediate agreement but prior to inclusion in a batch study has not been allocated any transmission capacity

and therefore should not forfeit any portion of financial security. The same reasoning applies to a large load customer that is included in a batch study and is allocated zero megawatts.

Accordingly, the commission makes the following modifications: (1) provides in adopted §25.194(d)(3)(B)(i) that, if a large load customer withdraws its request before ERCOT begins the interconnection study, a full return of the financial security balance is required, less amounts owed; (2) provides in adopted §25.194(d)(3)(B)(ii) that, if a large load customer is included in an interconnection study, is allocated zero MW across all study years, and withdraws before the SLLIA execution deadline, a full return of the financial security balance is required, less amounts owed; (3) provides in adopted §25.194(d)(3)(C) that, if a large load customer is included in a batch study, is allocated some portion of requested demand, and withdraws before the SLLIA execution deadline, the interconnecting DSP or TSP must return the balance, less amounts owed and less 20% of the security associated with the transmission capacity allocated by ERCOT.

Further, the commission finds it is appropriate to separately specify terms for the return of financial security for batch zero loads, based on project maturity and modifies the adopted rule as previously described. To address circumstances where a large load customer withdraws after the execution of a SLLIA, the commission modifies the adopted rule to provide in adopted §25.194(f)(3)(B) that, if a large load customer withdraws all or a portion of its contracted peak demand, the interconnecting DSP or TSP must return the balance, less amounts owed and less 20% of the financial security associated with the contracted peak demand that is withdrawn. The commission's modification of the adopted rule to require that the SLLIA include an acknowledgement and agreement that the large load customer will pay the large load minimum billing demand mitigates stranded cost risk associated with withdrawal after SLLIA execution. It is therefore appropriate to return a portion of the financial security balance to the large load customer.

Modify the amount that is refundable

CCNG, Monarch, DCC, Google, Lancium, and TotalEnergies, Targa, Thor, TIEC, and Rowan recommended modifying proposed §25.194(g)(3) to provide that the financial security balance is fully refundable after application to any amounts owed. The commenters reasoned that retaining a portion of the financial security lacks a basis in cost-causation principles and that the magnitude could deter development. CCNG, Monarch, DCC, and Rowan also recommended striking proposed §25.194(g)(4) as a conforming change. CCNG, Monarch, Thor, and Rowan recommended similar changes to proposed §25.194(h)(3) and conforming changes to §25.194(h)(4).

DCC stated that if the Commission determines a portion of the financial security should be non-refundable, the non-refundable portion should be justified by a demonstrated expense or risk.

Monarch and PPM commented that if the Commission determines a portion of the financial security should be non-refundable, the Commission should tie the required financial security amounts and schedule to development milestones.

Constellation and Targa recommended increasing the portion subject to refund from 20% to 50%. Targa recommended similar changes to proposed §25.194(h)(3).

Rowan commented that if the Commission does not adopt its recommendation to modify proposed §25.194(g)(3) to provide for full refundability, the portion subject to refund should be

increased to more than 20%. Rowan recommended similar changes to proposed §25.194(h)(3).

CloudHQ commented that it is supportive of requiring some level of at-risk financial security but the Commission should justify the 20% refundability figure. CloudHQ made similar comment on proposed §25.194(g)(4), proposed §25.194(h)(3), and proposed §25.194(h)(4),

PPM commented that if the commission does not adopt its recommendation to modify the proposed rule to tie the required financial security amounts and schedule to development milestones, the commission should modify §25.194(g)(3) to provide that that 80% of the balance is refundable. PPM also recommended conforming changes to proposed §25.194(g)(4). PPM recommended similar changes to proposed §25.194(h)(3).

Serena recommended that if the Commission does not modify the proposed rule to limit the non-refundable portion to \$6.5 million, as recommended by Google and Lancium, the commission should modify proposed §25.194(g)(3) to provide that 80% of the financial security balance is subject to refund. Serena reasoned either of these two approaches would mitigate impact to the large load customer if the project becomes commercially inviable due to inadequate capacity. Serena also recommended the commission provide guidance to ERCOT that this framework should be incorporated into proposed PGRR 145 and also recommended conforming changes to proposed §25.194(g)(4). Serena recommended similar changes to proposed §25.194(h)(3).

TCC recommended the commission authorize the utility to retain a non-refundable amount of up to 10% to cover administrative and indirect costs and refund the balance to the large load customer, after application to actual costs.

CPV recommended the Commission increase the portion of financial security subject to refund to 50% to avoid disincentivizing development. CPV also recommended conforming changes to proposed §25.194(g)(4). Serena recommended similar changes to proposed §25.194(h)(3).

Oncor recommended modifying proposed §25.194(g)(4) to allow interconnecting customers that withdraw all or a portion of requested peak demand or contracted peak demand to receive a refund of the balance of their security after applying it to any outstanding amount owed. Oncor also recommended conforming changes to proposed §25.194(h)(4).

Commission Response

The commission declines to adopt the recommendations of commenters that suggested the financial security balance should be fully refundable, less amounts owed, to a large load customer that withdraws, for the reasons described in the commission's response to commenters that suggested changes to the refund treatment under proposed §25.194(d)(10)(E). The commission instead modifies the adopted rule to provide for criteria that distinguishes treatment of financial security subject to return based on when a withdrawal occurs, as described in the commission's response to commenters that suggested changes to the refund treatment under proposed §25.194(d)(10)(E) and in the commission's response to NRG regarding the company's recommendation to distinguish refundability based on when the withdrawal occurs.

The commission also declines to adopt the recommendation of commenters who suggested replacing "20%" with a different figure, because the recommendations are moot, given the commission's modifications to the overall framework for return of fi-

nancial security. The commission's modifications to increase the portion of financial security subject to return substantively addresses commenters' recommendations.

Proposed §25.194(g)(4) -- Remaining 80% of balance used to offset rate base

Proposed §25.194(g)(4) requires the remaining balance (i.e., 80% of the financial security), after application to any outstanding amounts owed and refunding 20%, to be paid to the interconnecting TSP and applied by that TSP as an offset to its rate base in the earlier of the interconnecting TSP's next interim rate proceeding or comprehensive rate proceeding.

Strike subsection

If its recommended changes to proposed §25.194(g)(2) are adopted, LCRA recommended striking proposed §25.194(g)(4). Constellation, Google, Lancium, and TotalEnergies, Joint TSPs, and TIEC also recommended striking §25.194(g)(4).

Commission Response

The commission adopts commenters' recommendation to strike the subsection requiring application of the remaining financial security balance as an offset to the interconnecting TSP's rate base. The commission determines that the treatment of any forfeited financial security balance is better addressed in Project No. 58000.

Use of financial security balance to offset rate base

PPM recommended modifying proposed §25.194(g)(4) to replace "rate base" with "rates" to incorporate a preference expressed by Chairman Gleeson in an open meeting. NRG recommended modifying proposed §25.194(g)(4) to replace "rate base" with "annual revenue requirement." NRG also recommended a conforming change to proposed §25.194(h)(4).

Commission Response

The commission declines to adopt PPM's recommendation because it is moot, given the commission's modification to remove the requirement to apply the remaining financial security balance as an offset to the interconnecting TSP's rate base. The commission determines that the treatment of any forfeited financial security balance is better addressed in Project No. 58000.

Defer decision on use of retained amounts for ratemaking purposes

TCC recommended the Commission determine the ratemaking treatment of retained funds in a PURA Chapter 36 proceeding to avoid predetermining the treatment by rule.

Commission Response

The commission declines to adopt TCC's recommendation to defer determination of the treatment of retained funds to ratemaking proceedings. The commission determines that the treatment of any forfeited financial security balance is better addressed in Project No. 58000.

Proposed §25.194(g)(5) -- CIAC not refundable

Proposed §25.194(g)(5) states that CIAC is not refundable.

Refund CIAC exceeding actual interconnection costs

DCC, EH2, Monarch, PPM, Targa, and TIEC, recommended modifying proposed §25.194(g)(5) to provide that the remaining CIAC balance after actual interconnection costs are covered is refundable. DCC further recommended specifying that the in-

terconnecting DSP or TSP must refund the large load customer within 60 days of interconnection agreement execution. DCC reasoned that retaining funds in excess of actual costs is inconsistent with statute because it lacks cost recovery justification. PPM asserted that a large load customer should be refunded for CIAC payments exceeding actual costs regardless of whether the customer interconnected or not. PPM noted that proposed §25.194(f)(9)(c) includes a CIAC true-up provision for large loads that interconnect. Commenters recommended conforming changes to proposed §25.194(h)(5).

Similarly, Targa recommended modifying proposed §25.194(g)(5) to require the interconnecting DSP or the interconnecting TSP, within 60 days, to refund of any CIAC not yet expended on direct interconnection costs at the time the large load customer provides notice of withdrawal. Targa also recommended a conforming change to proposed §25.194(h)(5).

TEC and TSP Cooperatives noted that there may be inconsistent treatment of CIAC in proposed §25.194(f)(9)(C) as compared to proposed §25.194(g)(5) and (h)(5). If the CIAC is subject to true up, it looks more like a cash deposit. If the intent is that CIAC is nonrefundable, except in the situation where facilities are completed and energized, that should be clearly stated.

Commission Response

The commission declines to adopt commenters' recommendations to provide that the remaining CIAC balance after actual interconnection costs are covered is refundable because doing so would be at odds with the mechanics of CIAC. CIAC as a whole is non-refundable because the purpose is to pay actual costs. The true-up process is included because the CIAC amount is initially based on an estimate. The commission finds that to ensure clarity and certainty, it is appropriate to retain the language stating that CIAC is not refundable in the adopted rule.

Strike subsection

Joint TSPs and TIEC recommended striking proposed §25.194(g)(5).

Commission Response

The commission declines to adopt Joint TSPs and TIEC's recommendation to strike the provision that CIAC is not refundable for the reasons described in the commission's response to commenters that suggested modifying the proposed rule to provide that the remaining CIAC balance after actual interconnection costs are covered is refundable.

Proposed §25.194(g)(6) -- Requirement to reallocate contracted peak demand

Proposed §25.194(g)(6) requires ERCOT to reallocate contracted peak demand that is withdrawn by a large load customer.

Reallocation pursuant to ERCOT Protocols and Other Binding Documents

Constellation recommended modifying proposed §25.194(g)(6) to state that reallocation must be pursuant to the requirements of the ERCOT Protocols and Other Binding Documents. Constellation recommended similar changes to proposed §25.194(g)(6) and proposed §25.194(h)(6). Similarly, TPPA recommended modifying proposed §25.194(h)(6) to require any reallocation be conducted through a formal ERCOT-administered process and that such process not permit the reassignment of load or capacity to entities without the agreement of the affected TSP.

Commission Response

The commission declines to adopt Constellation and TPPA's recommendations because they are moot. The commission's modification of the adopted rule to provide that reallocation of transmission capacity must be in a manner consistent with ERCOT protocols substantively addresses the recommendations. The commission also modifies the adopted rule to clarify that an interconnecting DSP or TSP is prohibited from reallocating transmission capacity.

Proposed §25.194(h) -- Non-utilized capacity

Proposed §25.194(h) sets forth the requirements for non-utilized capacity.

Strike subsection

DCC and Cloud HQ recommended striking proposed §25.194(h) in its entirety because the requirements are unclear, ambiguous, and disproportionate. DCC and Skybox recommended the commission "defer development of non-utilized capacity rules to a subsequent proceeding."

Commission Response

The commission declines to adopt Cloud HQ and DCC recommendations to strike the provision setting forth the requirements for non-utilized transmission capacity, and declines Skybox's recommendation to defer the development of rules for non-utilized transmission capacity to a subsequent proceeding.

The commission's modification of the adopted rule to require that the SLLIA include an acknowledgement and agreement that the large load customer will pay the large load minimum billing demand mitigates risk to ratepayers associated with delayed energization. However, permitting a large load customer to indefinitely reserve transmission capacity without utilizing it would foreclose other customers from interconnecting to a system that has been planned and built to serve demand that has not materialized. This outcome would be contrary to both aspects of the Legislature's direction under PURA §37.0561 to support business development and minimize the potential for stranded infrastructure costs. Moreover, PURA §37.0561 directs the commission to establish uniform standards addressing the circumstances under which transmission capacity subject to an outstanding financial commitment may be reallocated, and eliminating these requirements would leave the directive unimplemented.

To balance this policy objective while recognizing the risk-mitigating effects of the large load minimum billing demand, the commission modifies the adopted rule to extend the timeline by which a large load customer must satisfy a milestone in its phased energization schedule and modifies the framework for return of financial security in circumstances where the deadline is missed. Specifically, the commission modifies the adopted rule to provide in adopted §25.194(k) that ERCOT may reallocate, in a future interconnection study, transmission capacity associated with a large load customer that fails, by 24 months, to satisfy a milestone in its schedule for phased energization. The 24-month timeline affords a large load customer substantial opportunity to satisfy energization milestones before reallocation is triggered, while addressing the policy goal of ensuring infrastructure constructed is utilized. The commission also modifies the adopted rule to clarify that the 24-month period applies to the energization schedule as a whole, and not for each energization milestone individually.

To address the return of financial security, the commission modifies the adopted rule to provide that not later than 30 days after

a large load customer fails, by 24 months, to satisfy a milestone in its schedule for phased energization, the interconnecting DSP or the interconnecting TSP must notify ERCOT of the large load customer's non-utilized capacity. Within 60 days of providing the notice to ERCOT, the interconnecting DSP or TSP must apply the large load customer's financial security to any outstanding amounts owed, and then return the balance to the large load customer.

Partial energization

TNMP recommended modifying proposed §25.194(h) to address how, in circumstances of partial energization, financial security is allocated between the portion of load that is energized and the portion that is not.

Commission Response

The commission declines to adopt TNMP's recommendation to address the allocation of financial security in circumstances of partial energization because the commission's modification of the adopted rule at §25.194(f)(3)(B) to specify the treatment of financial security when a large load customer withdraws all or a portion of contracted peak demand substantively addresses TNMP's recommendation.

Successor in interest

OPUC recommended modifying proposed §25.194(h) to establish clear procedures for when a large load customer's outstanding financial commitment may be reallocated to a successor in interest or, assuming the batch study process is adopted, other large load customers within the same batch group.

Commission Response

The commission declines to adopt OPUC's recommendation to establish procedures for when a large load customer's outstanding financial commitment may be reallocated to a successor in interest or, assuming the batch study process is adopted, other large load customers within the same batch group because the concept of allocating transmission capacity to customers within the same batch group is at odds with the purpose of the batch study process as it would require restudies. Accordingly, the commission modifies the adopted rule to clarify that only ERCOT is able to reallocate transmission capacity and reallocation must occur in a future interconnection study. Further, PURA §37.051 addresses reallocation of capacity, not reallocation of financial commitment.

Proposed §25.194(h)(1) -- Failure to satisfy milestone by six months

Proposed §25.194(h)(1) requires the interconnecting DSP or the interconnecting TSP, not later than 30 days after a large load customer fails to satisfy a milestone in its schedule for phased energization by six months, to notify ERCOT of the large load customer's non-utilized capacity.

Ability to amend

Constellation recommended modifying proposed §25.194(h)(1) to specify that the milestone dates relevant for assessing non-utilized capacity are those clearly set forth in a ramp schedule to the currently effective interconnection or equivalent agreement, which the interconnecting TSP or DSP and the large load customer should be free to amend, as necessary, by agreement.

Similarly, NRG recommended modifying proposed §25.194(h)(1) to state that the schedule for phased energization may be amended up until notice-to-proceed is provided.

Commission Response

The commission declines to adopt Constellation and NRG's recommendations because the level of detail recommended is better addressed in a future rulemaking to adopt a SLLIA.

Window for meeting energization milestones

CCNG, Google, Lancium, and TotalEnergies, Hut 8, Serena, Monarch, PPM, STACK, Targa, TIEC, TEBA recommended modifying proposed §25.194(h)(1) to extend the 6-month window in which a large load customer must meet scheduled energization milestones. Hut 8, Serena, and TEBA recommended 12 months. Monarch and TIEC recommended a minimum of 12 months. CCNG, Google, Lancium, and TotalEnergies, and Targa recommended 18 months. PPM recommended 48 months. STACK recommended a large load customer have 3 years to satisfy more than 80% of a milestone before the DSP or TSP is required to notify ERCOT of the non-utilized capacity.

Commission Response

The commission substantively adopts commenters' recommendation to extend the 6-month window in which the large load customer must meet scheduled energization milestones. Specifically, the commission modifies the adopted rule to provide that ERCOT may reallocate, in a future interconnection study, transmission capacity associated with a large load customer that fails, by 24 months, to satisfy a milestone in its schedule for phased energization. The 24-month timeline affords a large load customer substantial opportunity to satisfy energization milestones before reallocation is triggered, while addressing the policy goal of ensuring infrastructure constructed is utilized. To address the return of financial security, the commission modifies the adopted rule to provide that not later than 30 days after a large load customer fails, by 24 months, to satisfy a milestone in its schedule for phased energization, the interconnecting DSP or the interconnecting TSP must notify ERCOT of the large load customer's non-utilized capacity. Within 60 days of providing the notice to ERCOT, the interconnecting DSP or TSP must apply the large load customer's financial security to any outstanding amounts owed, and then return the balance to the large load customer.

Good cause extension, good faith efforts, or cure period

CCNG, Monarch, PPM, and STACK recommended modifying proposed §25.194(h)(1) to provide that the TSP or DSP may extend the 6-month window if a large load customer demonstrates good faith effort to satisfy the scheduled energization milestones. Serena recommended similar modifications to proposed §25.194(h)(2) and proposed §25.194(h)(3). CCNG further recommended providing an opportunity to extend the 6-month window if the customer provides notice of force majeure and a revised energization schedule. TIEC recommended the adopted rule provide for a commission-led process for a large load customer to obtain a good cause exception if the timeline will slip further than a year. Similarly, Hut 8 asserted that if a large load customer can show good faith proof of continued development, "it should be left to the discretion of the TSDP as to whether reallocation of the load is necessary or appropriate"

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(h) by adding a provision that states delays to the phased energization schedule may be allowed by the interconnecting DSP or interconnecting TSP as long as the large load customer demonstrates good faith efforts to satisfy the milestones in its schedule for phased energization or provides notice of force majeure and a revised schedule for phased energization.

NRG recommended modifying proposed §25.194(h)(1) to create an exception to the requirement to notify ERCOT of non-utilized capacity if the large load customer is making reasonable efforts to continue development of the site.

If its recommendation to defer the development of rules for non-utilized transmission capacity to a subsequent proceeding is not adopted, Skybox recommended that the rule include an initial three-year buffer from the commencement of phased energization and a six month cure period for the large load customer to remedy any milestone deficiency, including by demonstrating progress toward the applicable milestone, revising the phased energization schedule with supporting justification, or otherwise curing the deficiency.

APA and ACP recommended modifying proposed §25.194(h)(1) to allow for a cure period and consideration of cause, including delays attributable to utilities or third-party vendors, before capacity is reallocated.

Commission Response

The commission declines to adopt commenters' recommendations to establish a good cause exception process, cure period, or similar mechanism because establishing such a process is unnecessary, given the extension to 24 months described in the commission's response to commenters that recommended striking proposed §25.194(h) in its entirety. The 24-month timeline affords a large load customer substantial opportunity to satisfy energization milestones before reallocation is triggered, and therefore a cure period or extension framework is both unnecessary and at odds with the commission's stated intent to support business development and minimize the potential for stranded investments.

Replace milestone with percentage of contracted peak capacity energized

Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(h)(1) to require reallocation of non-utilized capacity based on a failure to energize a percentage of the contracted peak capacity by 18 months rather than a failure to satisfy a milestone in the schedule for phased energization.

Commission Response

The commission declines to adopt Google, Lancium, and TotalEnergies' recommendation to modify the adopted rule to require reallocation of non-utilized transmission capacity based on a failure to energize a percentage of the contracted peak capacity by 18 months. The phased energization schedule is disclosed by the large load customer based on the timeline on which the customer expects to energize. Applying a uniform percentage of the contracted peak demand would bear no relationship to the disclosed schedule and could penalize large load customers that are proceeding on schedule but have disclosed longer energization schedules.

Compensatory payment

TSP Cooperatives recommended modifying proposed §25.194(h)(1) to allow a large load that is de minimis below its contracted peak demand six months after its required contract peak demand deadline or milestone ramp deadline to make a compensatory payment for other customers reflecting the slightly reduced use of the system rather than to require a full forfeiture of the capacity.

Commission Response

The commission declines to adopt TSP Cooperatives' recommendation because the commission's modifications to the adopted rule described in the commission's response to commenters that recommended striking proposed §25.194(h) address the circumstance TSP Cooperatives identified.

Phased energization

TPPA recommended modifying proposed §25.198(h)(1) to clarify that the requirement applies only to the initial interconnection agreement established by the large load and does not toll for any amended interconnection agreement that may revise the energization schedule. TPPA also recommended defining "phased energization" as it is unclear whether the phrase references the interconnection process, building timelines, or a large load's energization ramp schedule.

Commission Response

The commission declines to adopt TPPA's recommendation to clarify that the requirement applies only to the initial interconnection agreement because it is moot. The adopted rule requires the execution of a commission-approved SLLIA, and any details related to amendment of a SLLIA are better addressed in a future rulemaking to adopt a SLLIA.

The commission declines to adopt TPPA's recommendation to define phased energization because the meaning is sufficiently clear from the language in adopted §25.198(d)(1)(E) and adopted §25.198(f)(1)(E), titled "schedule for phased energization of requested peak demand" and "schedule for phased energization of contracted peak demand," respectively. The provisions state that a large load customer must disclose to the interconnecting DSP or the interconnecting TSP the expected schedule, including the month and year, for phased energization of the requested (or contracted) peak demand expressed in MW, power factor (PF), and megavolt-ampere reactive (MVar) units.

Proposed §25.194(h)(3) -- Refund 20% of balance

Proposed §25.194(h)(3) requires the interconnecting DSP or the interconnecting TSP, within 60 days of providing notice of non-utilized capacity to ERCOT, to refund the large load customer 20% of the balance of financial security after applying to any outstanding amounts owed.

50% refundable

Constellation recommended modifying proposed §25.194(h)(3) to make 50% instead of 20% of the balance refundable.

Commission Response

The commission declines to adopt Constellation's recommendation because it is moot. Constellation's recommendation is addressed by the commission's modifications to the adopted rule to provide that not later than 30 days after a large load customer fails, by 24 months, to satisfy a milestone in its schedule for phased energization, the interconnecting DSP or the interconnecting TSP must notify ERCOT of the large load customer's non-utilized capacity. Within 60 days of providing the notice to ERCOT, the interconnecting DSP or TSP must apply the large load customer's financial security to any outstanding amounts owed, and then return the balance to the large load customer.

Make fully refundable

If its recommendation to strike proposed §25.194(h) in its entirety is not adopted, DCC recommended modifying proposed §25.194(h)(3) to provide that the security is fully refundable af-

ter application to amounts owed. Similarly, Hut 8 recommended ERCOT apply the financial security to any outstanding amounts and refund the remaining balance to the large load customer.

Commission Response

The commission adopts DCC and Hut 8's recommendation to modify the adopted rule to provide that the financial security balance may be returned to a large load customer after the interconnecting DSP or TSP collects payment for outstanding amounts owed in circumstances where a large load customer fails to satisfy an energization milestone by the deadline established in the adopted rule. Specifically, the commission modifies the adopted rule to provide that not later than 30 days after a large load customer fails, by 24 months, to satisfy a milestone in its schedule for phased energization, the interconnecting DSP or the interconnecting TSP must notify ERCOT of the large load customer's non-utilized capacity. Within 60 days of providing the notice to ERCOT, the interconnecting DSP or TSP must apply the large load customer's financial security to any outstanding amounts owed, and then return the balance to the large load customer.

Proposed §25.194(h)(4) -- 80% of balance

Proposed §25.194(h)(4) requires the interconnecting DSP or the interconnecting TSP to pay the balance (i.e., 80% of the financial security remaining), after applying to any outstanding amounts owed and refunding 20% to the large load customer, to the interconnecting TSP to be used as an offset to the TSP's rate base in the earlier of the interconnecting TSP's next interim rate proceeding or comprehensive rate proceeding.

Strike subsection

If its recommended changes to proposed §25.194(h)(2) are adopted, LCRA recommended striking proposed §25.194(h)(4). Constellation also recommended striking proposed §25.194(h)(4).

Commission Response

The commission adopts commenters' recommendation to strike the subsection requiring application of the remaining financial security balance as an offset to the interconnecting TSP's rate base. The commission determines that the treatment of any forfeited financial security balance is better addressed in Project No. 58000.

Proposed §25.194(h)(5) -- CIAC not refundable

Proposed §25.194(h)(5) states that CIAC is not refundable.

Refund if capacity assigned to another customer

Monarch and PPM recommended modifying proposed §25.194(h)(5) to provide that CIAC must be refunded within 60 days if some or all of the large load customer's capacity is reassigned to another customer. Monarch and PPM reasoned that the payment made by the original large load customer will be used to support the interconnection of the subsequent customer.

Commission Response

The commission declines to adopt Monarch and PPM's recommendation to provide that CIAC is refundable if the large load customer's capacity is reassigned to another customer because reassignment is not permitted. Only ERCOT can reallocate transmission capacity and reallocation must be in a future interconnection study.

Proposed §25.194(h)(6) -- Requirement for ERCOT to reallocate non-utilized capacity

Proposed §25.194(h)(6) requires ERCOT to reallocate non-utilized capacity.

Procedures prior to reallocation

If its recommendation to strike proposed §25.194(h) in its entirety is not adopted, DCC recommended modifying proposed §25.194(h)(6) to add procedures before reallocation is triggered because loss of capacity is a severe consequence.

Commission Response

The commission declines to adopt DCC's recommendation to add procedures before reallocation is triggered. The 24-month timeline affords a large load customer substantial opportunity to satisfy energization milestones before reallocation is triggered and further, procedures for reallocation are more appropriately addressed in ERCOT protocols than in the adopted rule.

Discretion for determining whether to reallocate non-utilized capacity

Targa recommended modifying proposed §25.194(h)(6) to allow the interconnecting DSP or the interconnecting TSP to exercise discretion in determining, in consultation with the large load customer, whether non-utilized capacity should be reallocated.

Commission Response

The commission declines to adopt Targa's recommendation to allow the interconnecting DSP or TSP to exercise discretion in determining, in consultation with the large load customer, whether non-utilized capacity should be reallocated. Allowing discretion could result in inconsistent treatment. Instead, the commission modifies the adopted rule to introduce more flexibility by requiring that non-utilized capacity be reallocated if a milestone is missed by 24 months or more instead of six months.

Refund after capacity reallocation

CloudHQ recommended modifying proposed §25.194(h)(6) to incorporate procedures for refunding the large load customer, after costs are paid, in the event ERCOT successfully reallocates capacity. CloudHQ reasoned that retaining the original customer's security would result in double recovery for the same costs. CloudHQ recommended similar changes to proposed §25.194(g)(6).

Commission Response

The commission declines to adopt CloudHQ's recommendation to incorporate procedures for refunding the large load customer, after costs are paid, in the event ERCOT successfully reallocates capacity. CloudHQ's recommendation is addressed by the commission's modification to the adopted rule to provide that not later than 30 days after a large load customer fails, by 24 months, to satisfy a milestone in its schedule for phased energization, the interconnecting DSP or the interconnecting TSP must notify ERCOT of the large load customer's non-utilized capacity. Within 60 days of providing the notice to ERCOT, the interconnecting DSP or TSP must apply the large load customer's financial security to any outstanding amounts owed, and then return the balance to the large load customer.

Proposed §25.194(i) -- Terms for refund of financial security for a large load customer that energizes

Proposed §25.194(i) requires an interconnecting DSP or an interconnecting TSP to draw down on the large load customer's financial security and apply the financial security to any outstanding amounts owed for costs incurred by the interconnecting DSP or the interconnecting TSP to fulfill the large load customer's request for interconnection of the contracted peak demand.

Purpose of financial security and return

CenterPoint recommended modifying proposed §25.194(i) to clarify that the financial security for system upgrades is intended to secure the customer's contingent cost reimbursement obligation for system upgrade costs and thus the customer's reimbursement obligation terminates at the time of energization and the financial security for system upgrade costs should be returned at that time.

Commission Response

The commission declines to adopt CenterPoint's recommendation to modify the adopted rule to clarify that the financial security for system upgrades is intended to secure the customer's contingent cost reimbursement obligation for system upgrade costs and thus the customer's reimbursement obligation terminates at the time of energization and the financial security for system upgrade costs should be returned at that time. The large load customer's obligation continues for the set period of time that the large load minimum billing demand applies, and the adopted rule is modified accordingly.

Permanent load reductions

TNMP recommended modifying proposed §25.194(i) to address how reductions occurring after initial energization but before the five-year sustainment milestone are to be calculated and allocated.

Commission Response

The commission declines to adopt TNMP's recommendation to modify the adopted rule to address how reductions occurring after initial energization but before the five-year sustainment milestone are to be calculated and allocated because it is unnecessary. The commission's modification of adopted §25.194(f)(3)(B) specifies the treatment of financial security when a large load customer withdraws all or a portion of contracted peak demand and substantively addresses TNMP's recommendation.

Partial refundability of interconnection fees

NRG recommended modifying proposed §25.194(i) to state that 50% of interconnection fees are non-refundable and the other 50% must be applied as an offset to the interconnecting TSP's annual revenue requirement. NRG also recommended a conforming change to proposed §25.194(i)(1).

Commission Response

The commission declines to adopt NRG's recommendation to state that 50% of the interconnection fee is non-refundable and the other 50% must be applied as an offset to the interconnecting TSP's annual revenue requirement because the recommendation is moot, given the commission's modifications to eliminate the interconnection fee.

Proposed §25.194(i)(1) -- Refund after energization

Proposed §25.194(i)(1) requires the interconnecting DSP or the interconnecting TSP, after applying financial security to any outstanding amounts owed, to refund 20% of the remaining balance when the large load customer energizes and ratably as the large

load customer meets the milestones identified in the customer's schedule for phased energization of its contracted peak demand.

Refund schedule

Rowan recommended modifying proposed §25.194(i)(1) to read that the interconnecting DSP or interconnecting TSP must refund 60% of the balance upon the large load customer's initial energization, 20% upon energization of half of the customer's contracted demand, and the remainder upon energization of full contracted demand. Rowan recommended conforming changes to §25.194(i)(2).

Similarly, Crusoe recommended modifying proposed §25.194(i)(1) to refund 50% upon energization and the remainder as the customer meets the load ramp milestones established in its interconnection agreement so that the customer receives a full refund once it reaches contracted peak demand.

Assuming large load customers will be subject to a minimum demand charge, Sierra Club indicated it was unopposed to 20% of financial security being refunded the first year of energization and 10% per year for the first three years.

Commission Response

The commission declines to adopt the recommendations of commenters suggesting changes to the refund schedule in relation to the energization timeline because the recommendations are moot, given the commission's modifications to the adopted rule to remove the provision stating that the balance is returned ratably as the large load customer achieves milestones in its schedule for phased energization.

Instead, to address the treatment of the remaining financial security balance, the commission modifies the adopted rule to provide that the interconnecting DSP or TSP must return 20% of the remaining balance of financial security when the large load customer energizes and the remainder ratably in 20% increments as the large load customer meets the milestones identified in the customer's SLLIA for meeting its obligation to pay the large load minimum billing demand. This approach ensures that the return of financial security corresponds to the reduction in risk that the financial security is intended to secure. Payment of the large load minimum billing demand ensures the large load customer is paying for the capacity it is reserving. As that obligation is paid, the risk for stranded infrastructure is reduced, and a commensurate amount of the security can be released. This approach appropriately balances the statutory objectives of PURA §37.0561 to support business development while minimizing the potential for stranded infrastructure costs and maintaining system reliability.

Clarification

Constellation, LCRA, and TPPA recommended modifying proposed §25.194(i)(1) to reflect that the remainder balance is refunded ratably as the large load customer achieves milestones in its schedule for phased energization. If its recommendation is adopted, Constellation and LCRA recommended striking proposed §25.194(i)(2) as a conforming change.

Commission Response

The commission declines to adopt Constellation, LCRA, and TPPA's recommendation to modify the adopted rule to reflect that the remainder balance is refunded ratably as the large load customer achieves milestones in its schedule for phased energization because it is moot, for the reasons described in

the commission's response to commenters who recommended modifying the refund schedule in relation to the energization schedule.

Refund upon reaching contracted peak demand

Targa recommended modifying proposed §25.194(i)(1) to refund all remaining funds once the project has reached the customer's contracted peak demand for loads under 250 MW. Alternatively, if a holding period is retained, Targa recommended that the interconnecting DSP or TSP should be required to pay interest on the held deposits at the commission's annual interest rate.

Commission Response

The commission declines to adopt Targa's recommendation to refund all remaining funds once the project has reached the customer's contracted peak demand for loads under 250 MW because it is moot, for the reasons described in the commission's response to commenters who recommended modifying the refund schedule in relation to the energization schedule.

The commission also declines to adopt Targa's recommendation to provide that the interconnecting DSP or TSP pay interest on the held deposits at the commission's annual interest rate. The commission's modification to the adopted rule to provide that cash collateral be held in a segregated, cash account bearing interest at a rate equal to at least the rate of the constant maturity one-month U.S. Treasury bill substantively addresses Targa's recommendation for cash collateral. It is not appropriate to apply the same provision to financial security posted in the form of a letter of credit or guaranty because these instruments do not involve a transfer of funds to the interconnecting DSP or TSP.

Proposed §25.194(i)(2) -- Refund balance after sustainment of operations for five years

Proposed §25.194(i)(2) requires the interconnecting DSP or the interconnecting TSP to refund any remaining balance when the large load customer sustains operations for five years at the customer's contracted peak demand.

Timeline for refund

PPM recommended modifying proposed §25.194(i)(2) to state that the balance must be refunded when the customer sustains operations for one year at a minimum of 95% of the customer's peak demand. PPM reasoned that delaying the refund for five years is not based in cost causation and that "unforeseen circumstances could preclude full use of capacity."

Schaper Energy recommended modifying proposed §25.194(i)(2) to require releasing 20% of the financial security upon energization beginning on year one after the in-service date, and full release not later than five years after the in-service date.

Tract recommended modifying proposed §25.194(i)(2) to provide that the balance must be refunded before five years if transmission charges paid by the large load customer exceed the financial security provided before the five-year mark.

Vistra recommended modifying proposed §25.194(i)(2) to increase the timeline for refunding financial security. Google, Lancium, and TotalEnergies recommended modifying proposed §25.194(i)(2) to require the refund of 20% of any remaining balance each anniversary after the large load customer sustains operations for five years.

Commission Response

The commission declines to adopt the recommendations of commenters that suggested modifications to the refund timeline in relation to a period of sustained operations because the recommendations are moot, for the reasons described in the commission's response under proposed §25.194(i)(1) to commenters who recommended modifying the refund schedule in relation to the energization schedule.

Clarify

PPM recommended the Commission clarify proposed §25.194(i)(2) because it is inconsistent with proposed §25.194(i)(1). PPM asserted proposed §25.194(i)(1) suggests the financial security balance must be refunded upon energization.

Commission Response

The commission declines to adopt PPM's recommendation to clarify proposed §25.194(i)(2) in relation to proposed §25.194(i)(1) because the recommendation is moot, for the reasons described in the commission's response under proposed §25.194(i)(1) to commenters who recommended modifying the refund schedule in relation to the energization schedule.

In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

This section is adopted under the following provisions of Public Utility Regulatory Act (PURA): §14.001, which grants the commission the general power to regulate and supervise the business of each public utility within its jurisdiction and to do anything specifically designated or implied by this title that is necessary and convenient to the exercise of that power and jurisdiction; §14.002, which authorizes the commission to adopt and enforce rules reasonably required in the exercise of its powers and jurisdiction; §35.004, which requires the commission to ensure that a large load customer who is subject to the standards adopted under PURA §37.0561 contributes to the recovery of the interconnecting utility's costs to interconnect the large load customer to the utility's system; §37.0561, which requires the commission to establish standards for interconnecting large load customers in the ERCOT region in a manner designed to support business development in this state while minimizing the potential for stranded infrastructure costs and maintaining system reliability; and §39.151, which grants the commission authority to oversee ERCOT.

Cross Reference to Statutes: PURA §14.001; §14.002; §35.004; §37.0561; and §39.151.

§25.194. Large Load Interconnection Standards.

(a) Purpose and Scope. This section sets forth the standards and criteria for an electric utility, a municipally owned utility, and electric cooperative to interconnect a large load customer to the ERCOT system. Nothing in this section limits the authority of a municipally owned utility or an electric cooperative to impose electric service requirements for large load customers on their systems in addition to the standards adopted under this section.

(b) Applicability.

(1) This section applies to a large load customer that has not energized as of the effective date of this section and that seeks:

(A) a new interconnection at a single site that is equal to or exceeds 75 megawatts (MW);

(B) an expanded interconnection at a single site that equals or exceeds 75 MW for the first time; or

(C) an expanded interconnection at a single site that exceeds 75 MW and is expanding by 75 MW or more; or

(D) to co-locate with a generation resource.

(2) For a large load customer that seeks an expanded interconnection, this section applies to the incremental load addition.

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

(1) Affiliate--means:

(A) a person who directly or indirectly owns or holds at least 5.0% of the voting securities of a large load customer;

(B) a person in a chain of successive ownership of at least 5.0% of the voting securities of a large load customer;

(C) a corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by a large load customer;

(D) a corporation that has at least 5.0% of its voting securities owned or controlled, directly or indirectly, by:

(i) a person who directly or indirectly owns or controls at least 5.0% of the voting securities of a large load customer; or

(ii) a person in a chain of successive ownership of at least 5.0% of the voting securities of a large load customer; or

(E) a person who is an officer or director of a large load customer in a chain of successive ownership of at least 5.0% of the voting securities of a large load customer.

(2) Backup generating facilities--Generation facilities or energy storage facilities that are not capable of operating, or are not configured to operate, in parallel with the ERCOT system and cannot export energy to the ERCOT system.

(3) Batch zero interconnection study--The set of studies, including the batch study and refinement study, that are required by ERCOT protocols before a large load customer meeting the requirements of ERCOT Planning Guide Section 9, as of the effective date of this section, can be interconnected.

(4) Batch zero load--A large load customer meeting the requirements of ERCOT Planning Guide Section 9, as of the effective date of this section.

(5) Contracted peak demand--The total non-coincident peak demand that a large load customer requests that an interconnecting DSP or an interconnecting TSP serve at a single site and is ultimately allocated by ERCOT, as stated in the SLLIA.

(6) Controllable load resource--Controllable load resource as that term is defined in ERCOT protocols.

(7) Direct interconnection costs--Direct interconnection costs, as that term is defined in §25.192 of this title (relating to Transmission Service Rates).

(8) End-use customer--The entity that ultimately consumes power.

(9) Interconnecting distribution service provider (DSP)--The electric utility, municipally owned utility, or electric cooperative that is certificated or otherwise authorized to provide either retail electric service or retail electric delivery service at the location in which the large load customer's consuming facility is located.

(10) Interconnecting transmission service provider (TSP)--The electric utility, municipally owned utility, or electric cooperative that owns or operates the equipment or facilities necessary to transmit or distribute electricity to the large load customer.

(11) Interconnection agreement--An agreement that was executed, before June 1, 2025, by a large load customer and the interconnecting DSP after completion of an interconnection study that was validated by ERCOT; and that, at a minimum, sets forth the obligations of a large load customer to pay its direct interconnection costs.

(12) Interconnection study--The set of studies, including the batch study and refinement study, that are required by ERCOT protocols before a large load customer may be interconnected.

(13) Intermediate agreement--An agreement that is executed by a large load customer, the interconnecting DSP, and, if different from the interconnecting DSP, the interconnecting TSP before a large load customer's load is included in an interconnection study and that, at a minimum, satisfies subsection (d) of this section.

(14) Large load customer--An entity requesting a new or expanded interconnection where the customer's total expected non-coincident peak demand at a single site is equal to or exceeds 75 MW, whether at transmission voltage or distribution voltage.

(15) On-site backup generating facilities--Generation that is not capable of exporting energy to the ERCOT system and that, in the aggregate, can serve at least 50% of on-site demand.

(16) Requested peak demand--The total non-coincident peak demand that a large load customer requests, prior to executing an interconnection agreement, that an interconnecting DSP or an interconnecting TSP serve at a single site.

(17) Standard large load interconnection agreement (SLLIA)--A commission-approved pro forma agreement that is executed by a large load customer, the interconnecting DSP, and if different from the interconnecting DSP, the interconnecting TSP; and that, at a minimum, complies with this section.

(18) System upgrades--System upgrades as that term is defined in §25.192 of this title.

(d) Intermediate agreement. Before a large load customer's interconnection request is included in an interconnection study, the large load customer must execute and fund an intermediate agreement with the interconnecting DSP and, if different from the interconnecting DSP, the interconnecting TSP. If the interconnecting DSP and the interconnecting TSP are different entities, the intermediate agreement must specifically identify each entity's responsibilities under this section, including which entity will accept the study fee and financial security from the large load customer. The intermediate agreement must meet the requirements of this subsection.

(1) Required disclosures.

(A) Demonstration of site control.

(i) A large load customer must disclose to the interconnecting DSP or the interconnecting TSP the type of property interest that the large load customer holds for the proposed site of the load location. The large load customer must be able to demonstrate control of the proposed site of the load location through provision of one of the following legally binding property interests linking the large load customer and the proposed site of the load location:

(I) a lease agreement, signed and executed by the large load customer or an affiliate of the large load customer, for one or more parcels of land sufficient to accommodate the customer's planned

facilities at the proposed site of the load location for a duration of at least five years from the date the large load customer is expected to reach the requested peak demand;

(II) a deed, transferring ownership to the large load customer or an affiliate of the large load customer, for one or more parcels of land sufficient to accommodate the customer's planned facilities at the proposed site of the load location; or

(III) a signed and executed agreement with an option to purchase or lease one or more parcels of land sufficient to accommodate the customer's planned facilities at the proposed site of the load location. An agreement with an option to lease land must obligate the large load customer to lease the land for a duration of at least five years from the date the large load customer is expected to reach the requested peak demand.

(ii) If the property interest is held by an affiliate, the large load customer must be able to demonstrate an existing legally binding connection linking itself, the affiliate, and the proposed site of the load location.

(B) Substantially similar interconnection request. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP whether the large load customer, an affiliate of the large load customer, or the end-use customer the large load customer has contracted to host is pursuing a substantially similar interconnection request for electric service in Texas either directly or indirectly through a third-party developer, the approval of which would result in the customer materially changing, delaying, or withdrawing the interconnection request. A material change or delay includes a delay of one or more years to the project's projected date to realize its requested peak demand, a 20% or greater change in the requested peak demand, or a change in the location for the point of interconnection.

(i) A large load customer that is pursuing a substantially similar interconnection request for electric service the approval of which would result in the customer materially changing, delaying, or withdrawing the interconnection request, whether directly or indirectly through an affiliate, third-party developer, or end-use customer that the large load customer has contracted to host, must disclose the following information to the interconnecting DSP or the interconnecting TSP:

(I) the ERCOT-assigned serial number for the substantially similar interconnection request, as applicable;

(II) the location, including the power region and, if in the ERCOT region, the load zone, of the substantially similar interconnection request;

(III) the requested peak demand of the substantially similar interconnection request;

(IV) the anticipated timing of energization of the substantially similar interconnection request; and

(V) the interconnecting DSP and, if different from the interconnecting DSP, the interconnecting TSP associated with the substantially similar interconnection request.

(ii) A large load customer that discloses a substantially similar interconnection request under this subsection may anonymize competitively sensitive information in its disclosure to the interconnecting DSP or the interconnecting TSP.

(iii) An interconnecting DSP and an interconnecting TSP must not sell, share, or disclose information submitted to the interconnecting DSP or the interconnecting TSP under this subsection other than a disclosure to the commission or ERCOT.

(C) Site-related studies and engineering services. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP the large load customer's expected development schedule and progress on site-related studies and engineering services required for project development before energization (e.g., geotechnical survey, water, wastewater, or gas). A large load customer must provide updates or progress reports to the interconnecting DSP or the interconnecting TSP when requested.

(D) State and local regulatory milestones and approvals. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP the large load customer's plans, identifying project milestones including expected timing and current progress for obtaining non-ministerial discretionary approvals from state and local regulatory authorities required for development before energization. Such approvals must include, as applicable, permits for water, wastewater, air, or backup generation; abatements for noise, light pollution, or traffic impacts; and agreements related to emergency response or site security. A large load customer must provide updates or progress reports to the interconnecting DSP or the interconnecting TSP when requested.

(E) Schedule for phased energization of requested peak demand. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP the expected schedule, including the month and year, for phased energization of the requested peak demand expressed in MW, power factor (PF), and megavolt-ampere reactive (MVAR) units.

(F) Water. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP:

(i) the anticipated volume of water needed by the large load customer or end-use customer the large load customer has contracted to host;

(ii) the type of water source that will be used (e.g., potable, non-potable, groundwater);

(iii) the entity that will supply water to the large load customer or end-use customer the large load customer has contracted to host (e.g., municipally owned utility, investor owned utility, self-provided);

(iv) the cooling technology that will be used; and

(v) any other related information.

(G) Backup generating facilities and on-site backup generating facilities. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP whether the customer has or plans to have backup generating facilities or on-site backup generating facilities. If the large load customer has or plans to have backup generating or on-site backup generating facilities, the large load customer must also disclose the following information:

(i) the nameplate capacity of each of the backup generating facilities and on-site backup generating facilities, as applicable;

(ii) the fuel source and operational characteristics of each of the backup generating facilities and on-site backup generating facilities, as applicable, including run hour limitations and fuel storage limitations under the existing environmental permits; and

(iii) how quickly each of the backup generating facilities and on-site backup generating facilities, as applicable, can reach their full capacity to serve the load.

(H) Power supply. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP how the large load customer plans to procure power and whether the large load cus-

tomer has or plans to have on-site generation that is capable of being synchronously interconnected to the ERCOT system and will provide power to the large load customer.

(I) Controllable load resource. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP whether the large load customer plans to register and operate as a controllable load resource.

(2) Intermediate financial commitments and obligations. A large load customer must provide satisfactory proof of financial commitment by meeting the requirements described in this subsection.

(A) Study fee.

(i) A large load customer must pay a study fee of \$100,000 to the interconnecting DSP or the interconnecting TSP for transmission studies performed by the interconnecting DSP, the interconnecting TSP, and ERCOT, as applicable.

(ii) Beginning in 2032, the commission will adjust the \$100,000 value on January 1 every five years in accordance with this clause. The commission will publish the new values of the allowance to be used in the subsequent year on or around November 1 based on the 2026 values of \$100,000.

(I) The adjustment will be based on the third quarter percentage change in the national Consumer Price Index (CPI) published by the United States Department of Labor, Bureau of Labor Statistics from the third quarter in the first year to the third quarter in the fifth year.

(II) The executive director must designate a substitute index to be used as a reference for adjustments if the CPI becomes unavailable.

(iii) Notwithstanding this subparagraph, ERCOT protocols may establish an additional flat study fee that must be paid by the large load customer.

(iv) The study fee is due not later than the date that the intermediate agreement is executed.

(v) The interconnecting DSP or the interconnecting TSP must remit payment to ERCOT, on behalf of the large load customer, for ERCOT's costs to conduct the interconnection study.

(vi) Any unused study amount of the study fee must be returned to the large load customer not later than 60 days after the conclusion of the interconnection study.

(B) Intermediate financial security on a dollar per MW basis. A large load customer must post financial security with the interconnecting DSP or the interconnecting TSP in the amount of \$50,000 per MW of the requested peak demand for new interconnection requests or \$50,000 per MW of the incremental increase in the peak demand for expanded interconnection requests. Financial security under this subsection must be posted with the interconnecting DSP or the interconnecting TSP not later than the date that the intermediate agreement is executed.

(i) Inflation adjustment. Beginning in 2032, the commission will adjust the \$50,000 value on January 1 every five years in accordance with this clause. The commission will publish the new values to be used in the subsequent year on or around November 1 based on the 2026 value of \$50,000.

(I) The adjustment will be based on the third quarter percentage change in the national CPI published by the United States Department of Labor, Bureau of Labor Statistics from the third quarter in the first year to the third quarter in the fifth year.

(II) The executive director must designate a substitute index to be used as a reference for adjustments if the CPI becomes unavailable.

(ii) Accepted forms of financial security. The interconnecting DSP or the interconnecting TSP may accept only the following forms of financial security:

(I) cash collateral to be held in a segregated, cash account bearing interest at a rate equal to at least the rate of the constant maturity one-month U.S. Treasury bill;

(II) guaranty, only if the guarantor has a U.S. or international credit rating of at least "BBB-" from Standard & Poor's, "Baa3" from Moody's Investor Service, or "BBB-" from Fitch. If the guarantor is rated by more than one of these agencies, creditworthiness must be determined by the second-highest rating; or

(III) a letter of credit issued by a major U.S. commercial bank, or a U.S. branch office of a major foreign commercial bank, with a U.S. or international credit rating of at least "A-" from Standard & Poor's, "A3" from Moody's Investor Service, or "A-" from Fitch. If the issuing bank is rated by more than one of these agencies, creditworthiness must be determined by the second-highest rating.

(iii) If the large load customer provides a guaranty or letter of credit under this subsection, the interconnecting DSP or the interconnecting TSP may require the submission of financial records or statements to determine the customer's financial stability.

(C) Significant equipment or services.

(i) The interconnecting DSP or the interconnecting TSP must credit the financial security provided under this subsection to the costs of significant equipment or services if significant equipment or services are procured before a SLLIA is executed.

(ii) If the financial security provided under this subsection is less than the costs of significant equipment or services being procured before a SLLIA is executed, then the large load customer must post additional financial security for the difference in the costs of significant equipment or services and the amount of financial security already posted before the interconnecting DSP or the interconnecting TSP procures the significant equipment or services.

(iii) For purposes of this section, significant equipment or services is equipment with a lead time of at least 18 months and services are those necessary to interconnect the large load customer.

(iv) Notwithstanding this subparagraph, a large load customer must pay contribution in aid of construction (CIAC) in the form of a direct cash payment for significant equipment or services that meet the definition for direct interconnection costs. CIAC is not refundable.

(3) Return, credit, and forfeiture of financial security.

(A) Outstanding amounts owed.

(i) In all instances under this subsection, the large load customer must pay outstanding amounts owed before the interconnecting DSP or interconnecting TSP returns financial security to the large load customer.

(ii) The interconnecting DSP or the interconnecting TSP may elect to either invoice the large load customer for outstanding amounts owed; or draw down on the large load customer's financial security and apply the financial security to outstanding amounts owed. If the large load customer fails to pay an invoice from the interconnecting DSP or the interconnecting TSP within 10 working days after the receipt of an invoice, the interconnecting DSP or the interconnecting

TSP must draw down on the large load customer's financial security for the amounts invoiced.

(iii) Outstanding amounts owed include the following:

(I) costs incurred by the interconnecting DSP or the interconnecting TSP to fulfill the large load customer's request for interconnection;

(II) costs for equipment that the interconnecting DSP or the interconnecting TSP procured and that cannot be canceled or returned with a full refund;

(III) costs for construction that the interconnecting DSP or the interconnecting TSP started and that cannot be canceled or returned with a full refund; and

(IV) costs for services that the interconnecting DSP or the interconnecting TSP initiated and that cannot be canceled with a full refund.

(B) Full return after collection of outstanding amounts owed. After collecting payment for outstanding amounts owed, the interconnecting DSP or interconnecting TSP must return to the large load customer the remaining balance of financial security under the following circumstances:

(i) the large load customer withdraws its requests for interconnection before ERCOT begins the interconnection study; or

(ii) the large load customer is included in an interconnection study, is allocated zero MW across all study years by ERCOT, and withdraws its interconnection request before the deadline to execute a SLLIA that is set forth in subsection (f) of this section.

(C) Partial return after collection of outstanding amounts owed. After collecting payment for outstanding amounts owed and before the interconnecting DSP or the interconnecting TSP returns financial security posted by a large load customer, the interconnecting DSP or interconnecting TSP must subtract 20% of the financial security associated with the transmission capacity allocated by ERCOT to a large load customer that is included in an interconnection study, is allocated some portion of its requested peak demand, and withdraws its interconnection request before the deadline to execute a SLLIA that is set forth in subsection (f) of this section.

(D) Option for return or credit of financial security if a SLLIA is executed. A large load customer that is allocated transmission capacity that is equal to some portion of its requested peak demand and executes a SLLIA may opt to have financial security that the large load customer posted under an intermediate agreement either returned or credited by the interconnecting DSP or the interconnecting TSP, as described in subsection (f) of this section.

(E) Forfeiture. A large load customer that does not withdraw its interconnection request before the deadline to execute a SLLIA and does not execute a SLLIA before the deadline set forth in subsection (f) of this section is deemed to have forfeited any financial security that the large load customer posted under an intermediate agreement.

(4) Attestation and statement by officer or official with binding authority. The intermediate agreement must be executed by an officer or official with binding authority over the large load customer and include:

(A) an attestation that supports all disclosures required under the intermediate agreement; and

(B) a statement acknowledging that the information the large load customer submitted under the intermediate agreement meets the requirements of this section and is complete and accurate at the time the intermediate agreement is executed by the large load customer.

(5) Subject to audit and verification.

(A) All information provided or attested to by a large load customer under this subsection is subject to audit and verification by ERCOT and commission staff. The interconnecting DSP or the interconnecting TSP must coordinate with ERCOT and commission staff to obtain information from a large load customer, including supporting documentation, that is responsive to a request for information submitted by ERCOT or commission staff.

(B) A large load customer or its interconnecting DSP or interconnecting TSP that fails to comply with ERCOT or commission staff's audit process or that fails to produce responsive documentation supporting the completeness or accuracy of information provided under an intermediate agreement may be found in violation of commission rules and subject to enforcement action, including the imposition of administrative penalties or loss of transmission capacity allocated to the large load customer.

(6) Withdrawal of all or a portion of requested peak demand.

(A) Submission of written notice. A large load customer may withdraw all or a portion of its requested peak demand by submitting notice in writing to the interconnecting DSP or the interconnecting TSP. Written notice may be processed by the interconnecting DSP or the interconnecting TSP before ERCOT begins the interconnection study or after ERCOT allocates transmission capacity but prior to the deadline to execute a SLLIA that is set forth in subsection (f) of this section.

(B) Notice to ERCOT. Not later than 14 days after receipt of a large load customer's notice to withdraw all or a portion of requested peak demand, the interconnecting DSP or the interconnecting TSP must notify ERCOT via a method prescribed by ERCOT.

(c) Interconnection study.

(1) Initiation of interconnection study. Not later than 60 days after an intermediate agreement is executed and funded under subsection (d) of this section, the interconnecting DSP or the interconnecting TSP must contact ERCOT to initiate an interconnection study, as prescribed by ERCOT protocols. Notwithstanding this paragraph, ERCOT protocols may establish a process that allows a large load customer to submit its interconnection request directly to ERCOT.

(2) Communication with large load customer.

(A) Initial contact to ERCOT. The interconnecting DSP or the interconnecting TSP must notify the large load customer not later than five working days after the interconnecting DSP or the interconnecting TSP contacts ERCOT to initiate an interconnection study.

(B) Commencement of interconnection study. The interconnecting DSP or the interconnecting TSP must notify the large load customer not later than five working days after the interconnection study commences.

(C) Communications with ERCOT. The interconnecting DSP or the interconnecting TSP must provide a large load customer information related to communications that the interconnecting DSP or the interconnecting TSP receives from ERCOT about the large load customer's interconnection request. The interconnecting DSP or the interconnecting TSP must provide information to the large load customer

not later than five working days after receipt of communications from ERCOT about the large load customer's interconnection request.

(D) Transmission capacity allocated. The interconnecting DSP, the interconnecting TSP, or ERCOT must timely notify the large load customer of the transmission capacity allocated to the large load customer, as prescribed by ERCOT protocols.

(E) ERCOT communications directly with the large load customer. Notwithstanding this paragraph, ERCOT may fulfill the interconnecting DSP or the interconnecting TSP's obligations to communicate with the large load customer through a process developed in ERCOT protocols.

(3) ERCOT communication with interconnecting TSP. ERCOT must timely notify the interconnecting TSP when another TSP completes a project that is needed to interconnect a large load customer, as prescribed by ERCOT protocols.

(4) New interconnection request required. A large load customer that materially changes its interconnection request, as described in ERCOT protocols, including by changing its requested peak demand, phased energization schedule, point of interconnection, site configuration, load composition, load type, or any other modification, must submit a new interconnection request to the interconnecting DSP or the interconnecting TSP.

(f) SLLIA. Not later than 60 days after ERCOT issues a study report that allocates transmission capacity, the large load customer must execute and fund a SLLIA with the interconnecting DSP and, if different from the interconnecting DSP, the interconnecting TSP. The SLLIA must meet the requirements of this subsection. The interconnecting DSP or the interconnecting TSP must cancel the interconnection request and notify ERCOT of the cancellation if the large load customer fails to execute a SLLIA under this subsection.

(1) Required disclosures.

(A) Site control.

(i) A large load customer must disclose to the interconnecting DSP or the interconnecting TSP the type of property interest that the large load customer holds for the site of the load location. The large load customer must be able to demonstrate control of the site of the load location through provision of one of the following legally binding property interests linking the large load customer and the site of the load location:

(I) a lease agreement, signed and executed by the large load customer or an affiliate of the large load customer, for one or more parcels of land sufficient to accommodate the customer's planned facility at the proposed load location for a duration of at least five years from the date that the large load customer is expected to reach the contracted peak demand;

(II) a deed, transferring ownership to the large load customer or an affiliate of the large load customer, for one or more parcels of land sufficient to accommodate the customer's planned facility at the proposed load location; or

(III) a purchase and sale agreement, signed and executed by the large load customer or an affiliate of the large load customer.

(ii) If the property interest is held by an affiliate, the large load customer must be able to demonstrate an existing legally binding connection linking itself, the affiliate, and the site of the load location.

(B) Substantially similar interconnection request. A large load customer must disclose to the interconnecting DSP or the

interconnecting TSP whether the customer, an affiliate of the large load customer or the end-use customer the large load customer has contracted to host is pursuing a substantially similar interconnection request for electric service in Texas either directly or indirectly through a third-party developer, the approval of which would result in the customer materially changing, delaying, or withdrawing the interconnection request. A material change or delay includes a delay of one or more years to the project's projected date to realize its contracted peak demand, a 20% or greater change in the contracted peak demand, or a change in the location for the point of interconnection.

(i) A large load customer that is pursuing a substantially similar interconnection request for electric service, the approval of which would result in the customer materially changing, delaying, or withdrawing the interconnection request, whether directly or indirectly through an affiliate, third-party developer, or end-use customer that the large load customer has contracted to host, must disclose the following information to the interconnecting DSP or the interconnecting TSP:

(I) the ERCOT-assigned serial number for the substantially similar interconnection request, as applicable;

(II) the location, including the power region and if in the ERCOT region the load zone, of the substantially similar interconnection request;

(III) the requested peak demand of the substantially similar interconnection request;

(IV) the anticipated timing of energization of the substantially similar interconnection request; and

(V) the interconnecting DSP and, if different from the interconnecting DSP, the interconnecting TSP associated with the substantially similar interconnection request.

(ii) A large load customer that discloses a substantially similar interconnection request under this subsection may anonymize the competitively sensitive information in its disclosure to the interconnecting DSP or the interconnecting TSP.

(iii) An interconnecting DSP and an interconnecting TSP must not sell, share, or disclose information submitted to the interconnecting DSP or the interconnecting TSP under this subsection other than a disclosure to the commission or ERCOT.

(C) Site-related studies and engineering services. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP the large load customer's expected development schedule and progress on site-related studies and engineering services required for project development before energization (e.g., geotechnical survey, water, wastewater, or gas). A large load customer must provide updates or progress reports to the interconnecting DSP or the interconnecting TSP when requested, but no more frequently than quarterly.

(D) State and local regulatory milestones and approvals. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP the large load customer's plans, identifying project milestones including expected timing and current progress for obtaining non-ministerial discretionary approvals from state and local regulatory authorities required for development before energization. Such approvals must include, as applicable, permits for water, wastewater, air, or backup generation; abatements for noise, light pollution, or traffic impacts; and agreements related to emergency response or site security. A large load customer must provide updates or progress reports to the interconnecting DSP or the interconnecting TSP when requested.

(E) Schedule for phased energization of contracted peak demand. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP the expected phased energization schedule, including the month and year, for phased energization of the contracted peak demand expressed in MW, PF, and MVAR units.

(F) Water. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP:

(i) the anticipated volume of water needed by the large load customer or end-use customer the large load customer has contracted to host;

(ii) the type of water source that will be used (e.g., potable, non-potable, groundwater);

(iii) the entity that will supply water to the large load customer or end-use customer the large load customer has contracted to host (e.g., municipally owned utility, investor owned utility, or self provided);

(iv) the cooling technology that will be used; and

(v) any other related information.

(G) Backup generating facilities and on-site backup generating facilities. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP whether the customer has or plans to have backup generating facilities or on-site backup generating facilities. A large load customer must timely disclose to the interconnecting DSP or the interconnecting TSP any material changes to the large load customer's plans for backup generating facilities or on-site backup generating facilities. If the large load customer has or plans to have backup generating facilities or on-site backup generating facilities, the large load customer must also disclose the following information:

(i) the nameplate capacity of each of the backup generating facilities and on-site backup generating facilities, as applicable;

(ii) the fuel source and operational characteristics of each of the backup generating facilities and on-site backup generating facilities, as applicable, including run hour limitations under the existing environmental permits; and

(iii) how quickly each of the backup generating facilities and on-site backup generating facilities, as applicable, can reach their full capacity to serve the load.

(H) Power supply. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP how the large load customer plans to procure power and whether the large load customer has or plans to have on-site generation that is capable of being synchronously interconnected to the ERCOT system and will provide power to the large load customer. A large load customer must timely disclose to the interconnecting DSP or the interconnecting TSP any material changes to the large load customer's plans for on-site generation that is capable of being synchronously interconnected to the ERCOT system and will provide power to the large load customer.

(I) Controllable load resource. A large load customer must disclose to the interconnecting DSP or the interconnecting TSP whether the large load customer plans to register and operate a controllable load resource.

(2) SLLIA financial commitments and obligations. A large load customer must provide satisfactory proof of financial commitment by meeting the requirements described in this subsection.

(A) Credit and return of financial commitments provided under an intermediate agreement.

(i) Notification of election to return or credit cash collateral. Not later than 30 days after the interconnecting DSP, the interconnecting TSP, or ERCOT notifies a large load customer of its allocated transmission capacity, the large load customer must notify the interconnecting DSP or the interconnecting TSP in writing whether the large load customer elects to have cash collateral provided under subsection (d) of this section:

(I) returned to the large load customer; or

(II) credited toward the financial security requirements under this subsection.

(ii) Failure to notify of election to return or credit cash collateral. If a large load customer fails to timely notify the interconnecting DSP or the interconnecting TSP in writing whether the large load customer elects to have the cash collateral returned or credited under this subsection, the interconnecting DSP or the interconnecting TSP must credit the cash collateral to the financial security requirements under this section.

(iii) Return of guaranty and letter of credit. Not later than 30 days after ERCOT notifies the interconnecting DSP or the interconnecting TSP of a large load customer's allocated transmission capacity, the interconnecting DSP or the interconnecting TSP must return a guaranty or letter of credit provided by a large load customer under subsection (d) of this section.

(B) SLLIA financial security.

(i) A large load customer must post financial security with the interconnecting DSP or the interconnecting TSP in an amount that is the greater of:

(I) \$50,000 per MW of the contracted peak demand; or

(II) the costs allocated to the large load customer for system upgrades as a result of a batch zero interconnection study or an interconnection study.

(ii) Notwithstanding this subparagraph, a large load customer may be required to post additional financial security related to the large load minimum billing demand, described in §25.193 of this title (relating to Distribution Service Provide Transmission Cost Recovery Factor (TCRF)).

(iii) Deadline to post financial security. Financial security under this subsection must be posted at the time the SLLIA is executed.

(iv) Inflation adjustment. Beginning in 2032, the commission will adjust the \$50,000 value on January 1 every five years in accordance with this clause. The commission will publish the new values to be used in the subsequent year on or around November 1 based on the 2026 value of \$50,000.

(I) The adjustment will be based on the percentage change in the national CPI published by the United States Department of Labor, Bureau of Labor Statistics from the third quarter in the first year to the third quarter in the fifth year.

(II) The executive director must designate a substitute index to be used as a reference for adjustments if the CPI becomes unavailable.

(v) Accepted forms of financial security. The interconnecting DSP or the interconnecting TSP may accept only the following forms of financial security:

(I) cash collateral to be held in a segregated, cash account bearing interest at a rate equal to at least the rate of the constant maturity one-month U.S. Treasury bill;

(II) guaranty, of if the guarantor has a U.S. or international credit rating of at least "BBB-" from Standard & Poor's, "Baa3" from Moody's Investor Service, or "BBB-" from Fitch. If the guarantor is rated by more than one of these agencies, creditworthiness must be determined by the second-highest rating; or

(III) a letter of credit issued by a major U.S. commercial bank, or a U.S. branch office of a major foreign commercial bank, with a U.S. or international credit rating of at least "A-" from Standard & Poor's, "A3" from Moody's Investor Service, or "A-" from Fitch. If the issuing bank is rated by more than one of these agencies, creditworthiness must be determined by the second-highest rating.

(vi) If the large load customer provides a guaranty or letter of credit under this subsection, the interconnecting DSP or the interconnecting TSP may require the submission of financial records or statements to determine the customer's financial stability.

(C) CIAC for direct interconnection costs. A large load customer must pay all direct interconnection costs through CIAC, with no standard or other allowance offered to offset the customer's CIAC payments.

(i) CIAC must be paid in the form of a direct cash payment.

(ii) An interconnecting DSP and an interconnecting TSP must invoice a large load customer for direct interconnection costs before incurring direct interconnection costs.

(iii) If the large load customer fails to pay an invoice from the interconnecting DSP or the interconnecting TSP within 10 working days after the receipt of an invoice, the interconnecting DSP or the interconnecting TSP may draw down on the large load customer's financial security for the invoiced amount and cancel the large load customer's interconnection request.

(iv) The CIAC must be trued-up to reflect the actual costs once the facilities are completed, and a large load customer may receive a credit or surcharge on their bill, as applicable, for the difference in actual costs relative to the estimate.

(v) CIAC is not refundable.

(D) Large load minimum billing demand. The SLLIA must include a term of acknowledgment and agreement that the large load customer will pay the large load minimum billing demand described in §25.193 of this title for the set period of time described in §25.193.

(3) Return and forfeiture of financial security.

(A) Outstanding amounts owed.

(i) In all instances under this subsection, the large load customer must pay outstanding amounts owed before the interconnecting DSP or the interconnecting TSP returns financial security to the large load customer.

(ii) The interconnecting DSP or the interconnecting TSP may elect to either invoice the large load customer for outstanding amounts owed; or draw down on the large load customer's financial security and apply the financial security to outstanding amounts owed. If the large load customer fails to pay an invoice from the interconnecting DSP or the interconnecting TSP within 10 working days after the receipt of an invoice, the interconnecting DSP or the interconnecting

TSP must draw down on the large load customer's financial security for the amounts invoiced.

(iii) Outstanding amounts owed include the following:

(I) costs incurred by the interconnecting DSP or the interconnecting TSP to fulfill the large load customer's request for interconnection;

(II) costs for equipment that the interconnecting DSP or the interconnecting TSP procured and that cannot be canceled or returned with a full refund;

(III) costs for construction that the interconnecting DSP or the interconnecting TSP started and that cannot be canceled or returned with a full refund;

(IV) costs for services that the interconnecting DSP or the interconnecting TSP initiated and that cannot be canceled or returned with a full refund; and

(V) the large load minimum billing demand described in §25.193 of this title for the set period of time described in §25.193.

(B) Partial return required less outstanding amounts owed. If a large load customer withdraws the customer's request to interconnect all or a portion of its contracted peak demand, the interconnecting DSP or the interconnecting TSP must collect payment for outstanding amounts owed and then subtract 20% of the financial security associated with the contracted peak demand that is withdrawn before the interconnecting DSP or the interconnecting TSP returns the remaining balance of financial security posted by a large load customer.

(C) Terms for return of financial security for a large load customer that energizes. The interconnecting DSP or the interconnecting TSP must return 20% of the remaining balance of financial security when the large load customer energizes and the remainder ratably in 20% increments as the large load customer meets the milestones identified in the customer's SLLIA for meeting its obligation to pay the large load minimum billing demand described in §25.193 of this title for the set period of time described in §25.193.

(D) Forfeiture. A large load customer that fails to comply with the terms of the SLLIA may be deemed to have forfeited financial security posted under the SLLIA.

(4) Attestation and statement by officer or official with binding authority. The SLLIA must be signed by an officer or official with binding authority over the large load customer and include:

(A) an attestation that supports all disclosures required under the SLLIA; and

(B) a statement acknowledging that the information the large load customer submitted under the SLLIA meets the requirements of this section and is complete and accurate at the time the SLLIA is executed by the large load customer.

(5) Subject to audit and verification.

(A) All information provided or attested to by a large load customer under this subsection is subject to audit and verification by ERCOT and commission staff. The interconnecting DSP or the interconnecting TSP must coordinate with ERCOT and commission staff to obtain information from a large load customer, including supporting documentation, that is responsive to a request for information submitted by ERCOT or commission staff.

(B) A large load customer or its interconnecting DSP or interconnecting TSP that fails to comply with ERCOT or commission staff's audit process or that fails to produce responsive documentation supporting the completeness and or accuracy of information provided under a SLLIA may be found in violation of commission rules and subject to enforcement action, including the imposition of administrative penalties or loss of transmission capacity allocated to the large load customer.

(6) Withdrawal of all or a portion of contracted peak demand.

(A) Submission of written notice. A large load customer may withdraw all or a portion of its contracted peak demand by submitting its notice in writing to the interconnecting DSP or the interconnecting TSP.

(B) Notice to ERCOT. Not later than 14 days after receipt of a large load customer's notice to withdraw all or a portion of contracted peak demand, the interconnecting DSP or the interconnecting TSP must notify ERCOT via a method prescribed by ERCOT.

(g) Non-utilized transmission capacity.

(1) Not later than 30 days after a large load customer fails, by 24 months, to satisfy a milestone in its schedule for phased energization, as described in the SLLIA at the time of execution, the interconnecting DSP or the interconnecting TSP must notify ERCOT of the large load customer's non-utilized capacity. The 24-month period applies to the energization schedule as a whole, and not for each energization milestone individually.

(2) Within 60 days of providing notice to ERCOT under this subsection, the interconnecting DSP or the interconnecting TSP must draw down on the large load customer's financial security and apply the financial security to any outstanding amounts owed. Outstanding amounts owed include the following:

(A) costs incurred by the interconnecting DSP or the interconnecting TSP to fulfill the large load customer's request for interconnection;

(B) costs for equipment that the interconnecting DSP or the interconnecting TSP procured and that cannot be canceled or returned with a full refund;

(C) costs for construction that the interconnecting DSP or the interconnecting TSP started and that cannot be canceled with a full refund;

(D) costs for services that the interconnecting DSP or the interconnecting TSP initiated and that cannot be canceled with a full refund; and

(E) the large load minimum billing demand described in §25.193 of this title for the set period of time described in §25.193.

(3) Within 60 days of providing notice to ERCOT under this subsection and after applying the large load customer's financial security to any outstanding amounts owed, the interconnecting DSP or the interconnecting TSP must subtract 20% of the financial security associated with the non-utilized transmission capacity and then return the balance to the large load customer.

(4) CIAC is not refundable.

(h) Batch zero load.

(1) Financial security posted under ERCOT Planning Guide Section 9, as of the effective date of this section.

(A) Outstanding amounts owed.

(i) In all instances under this subsection, the large load customer must pay outstanding amounts owed before the interconnecting DSP or interconnecting TSP returns financial security to the large load customer.

(ii) The interconnecting DSP or the interconnecting TSP may elect to either invoice the large load customer for outstanding amounts owed; or draw down on the large load customer's financial security and apply the financial security to outstanding amounts owed. If the large load customer fails to pay an invoice from the interconnecting DSP or the interconnecting TSP within 10 working days after the receipt of an invoice, the interconnecting DSP or the interconnecting TSP must draw down on the large load customer's financial security for the amounts invoiced.

(iii) Outstanding amounts owed include the following:

(I) costs incurred by the interconnecting DSP or the interconnecting TSP to fulfill the large load customer's request for interconnection;

(II) costs for equipment that the interconnecting DSP or the interconnecting TSP procured and that cannot be canceled or returned with a full refund;

(III) costs for construction that the interconnecting DSP or the interconnecting TSP started and that cannot be canceled or returned with a full refund; and

(IV) costs for services that the interconnecting DSP or the interconnecting TSP initiated and that cannot be canceled with a full refund.

(B) Full return after collection of outstanding amounts owed. After collecting payment for outstanding amounts owed, the interconnecting DSP or the interconnecting TSP must return to the large load customer the remaining balance of financial security under the following circumstances:

(i) the large load customer meets the criteria in ERCOT Planning Guide Section 9.2.1.1(1)(e), as of the effective date of this section, is included in the batch zero interconnection study, and withdraws its interconnection request before the deadline to execute a SLLIA that is set forth in subsection (f) of this section;

(ii) the large load customer meets the criteria in ERCOT Planning Guide Section 9.2.1.1(1)(g), is included in the batch zero interconnection study, and withdraws its interconnection request before the deadline to execute a SLLIA that is set forth in subsection (f) of this section; or

(iii) the large load customer meets the criteria in ERCOT Planning Guide Section 9.2.1.2(1), is included in the batch zero interconnection study, is allocated zero MW across all study years by ERCOT, and withdraws its interconnection request before the deadline to execute a SLLIA that is set forth in subsection (f) of this section.

(C) Partial return after collection of outstanding amounts owed. After collecting payment for outstanding amounts owed, the interconnecting DSP or the interconnecting TSP must subtract the following before the interconnecting DSP or the interconnecting TSP returns the remaining balance of financial security posted by a large load customer:

(i) 50% of the financial security associated with the transmission capacity allocated by ERCOT to a large load customer that meets the criteria in ERCOT Planning Guide Section 9.2.1.1(1)(f), is included in the batch zero interconnection study, is allocated some portion of its requested peak demand, and withdraws its intercon-

tion request before the deadline to execute a SLLIA that is set forth in subsection (f) of this section; or

(ii) 20% of the financial security associated with the transmission capacity allocated by ERCOT to a large load customer that meets the criteria in ERCOT Planning Guide Section 9.2.1.2(1), is included in the batch zero interconnection study, is allocated some portion of its requested peak demand, and withdraws its interconnection request before the deadline to execute a SLLIA that is set forth in subsection (f) of this section.

(D) Option for return or credit of financial security if a SLLIA is executed. A large load customer that is allocated transmission capacity that is equal to some portion of its requested peak demand and executes a SLLIA may opt to have financial security that the large load customer previously posted either returned or credited by the interconnecting DSP or the interconnecting TSP, as described in subsection (f) of this section. The interconnecting DSP or the interconnecting TSP must credit the large load customer's previous cash payments on a dollar-for-dollar basis.

(E) Forfeiture. A large load customer that does not withdraw its interconnection request before the deadline to execute a SLLIA and does not execute a SLLIA before the deadline set forth in subsection (f) of this section may be deemed to have forfeited any financial security that the large load customer posted under an intermediate agreement.

(2) Subject to audit and verification.

(A) All information provided or attested to by a large load customer under ERCOT Planning Guide Section 9, as of the effective date of this section, is subject to audit and verification by ERCOT and commission staff. The interconnecting DSP or the interconnecting TSP must coordinate with ERCOT and commission staff to obtain information from a large load customer, including supporting documentation, that is responsive to a request for information submitted by ERCOT or commission staff.

(B) A large load customer or its interconnecting or its interconnecting DSP or interconnecting TSP that fails to comply with ERCOT or commission staff's audit process or that fails to produce responsive documentation supporting the completeness or accuracy of information provided under ERCOT Planning Guide Section 9 may be found in violation of commission rules and subject to enforcement, including the imposition of administrative penalties or loss of transmission capacity allocated to the large load customer.

(3) SLLIA.

(A) A batch zero load must execute a SLLIA in compliance with subsection (f) of this section to reserve ERCOT's allocation of transmission capacity as contracted peak demand.

(B) A batch zero load that executed an interconnection agreement on or before June 1, 2025 must pay for direct interconnection costs in accordance with a previously executed interconnection agreement and is not subject to additional costs under subsection (f)(2)(C) of this section. All other financial commitments and obligations under subsection (f) of this section apply to a batch zero load. Any previously posted financial security or cash payment may be credited on a dollar-for-dollar basis to a large load customer's financial commitments and obligations under subsection (f) of this section.

(C) If a batch zero load fails to execute a SLLIA in compliance with this section, the interconnecting DSP or the interconnecting TSP must cancel the request for interconnection and notify ERCOT not later than 14 days after the deadline to execute a SLLIA.

(4) Withdrawal of all or a portion of requested peak demand.

(A) Submission of written notice. A batch zero load may withdraw all or a portion of its requested peak demand by submitting notice in writing to the interconnecting DSP or the interconnecting TSP. Written notice may be processed by the interconnecting DSP or the interconnecting TSP only after ERCOT issues a study report that allocates transmission capacity and prior to the deadline to execute a SLLIA that is set forth in subsection (f) of this section.

(B) Notice to ERCOT. Not later than 14 days after receipt of a large load customer's notice to withdraw all or a portion of requested peak demand, the interconnecting DSP or the interconnecting TSP must notify ERCOT via a method prescribed by ERCOT.

(i) 2026 regional transmission plan compliance plan.

(1) A large load customer that executed an agreement with an interconnecting DSP or an interconnecting TSP under §25.370(g) of this title (relating to ERCOT Large Load Forecasting Criteria) must:

(A) withdraw its interconnection request; or

(B) execute a superseding intermediate agreement or SLLIA, as applicable, that complies with this section.

(2) An interconnecting DSP or an interconnecting TSP must collect payment for outstanding amounts owed before the interconnecting DSP or the interconnecting TSP returns financial security to a large load customer that withdraws its interconnection request under this subsection.

(A) The interconnecting DSP or the interconnecting TSP may elect to either invoice the large load customer for outstanding amounts owed; or draw down on the large load customer's financial security and apply the financial security to outstanding amounts owed. If the large load customer fails to pay an invoice from the interconnecting DSP or the interconnecting TSP within 10 working days after the receipt of an invoice, the interconnecting DSP or the interconnecting TSP must draw down on the large load customer's financial security for the amounts invoiced.

(B) Outstanding amounts owed include the following:

(i) costs incurred by the interconnecting DSP or the interconnecting TSP to fulfill the large load customer's request for interconnection;

(ii) costs for equipment that the interconnecting DSP or the interconnecting TSP procured and that cannot be canceled or returned with a full refund;

(iii) costs for construction that the interconnecting DSP or the interconnecting TSP started and that cannot be canceled or returned with a full refund; and

(iv) costs for services that the interconnecting DSP or the interconnecting TSP initiated and that cannot be canceled with a full refund.

(3) A large load customer that executed an interconnection agreement on or before June 1, 2025 must pay for direct interconnection costs in accordance with a previously executed interconnection agreement and is not subject to additional costs under subsection (f)(2)(C) of this section. All other financial commitments and obligations under this section apply. Any previously posted financial security or cash payment may be credited on a dollar-for-dollar basis to a large load customer's financial commitments and obligations under this section.

(4) Notwithstanding this subsection, a large load customer that executed an agreement with a large load customer under §25.370(g) of this title and is a batch zero load must comply with subsection (h) of this section.

(j) Audit and verification. ERCOT and commission staff may submit a request for information to the interconnecting DSP or the interconnecting TSP for information that ERCOT or commission staff deems necessary to conduct an audit, complete any analysis required as part of a batch zero interconnection study or an interconnection study, or to enforce this section, including to verify the accuracy and completeness of information attested to by a large load customer. The interconnecting DSP or the interconnecting TSP must coordinate with ERCOT and commission staff, as applicable, to obtain from a large load customer and produce to ERCOT or commission staff, as applicable, information, including supporting documentation, that is responsive to a request for information submitted by ERCOT or commission staff under this section.

(1) A large load customer or its interconnecting DSP or interconnecting TSP that fails to comply with ERCOT or commission staff's audit process or that fails to produce responsive documentation supporting the completeness and accuracy of information provided under this section may be found in violation of commission rules and subject to enforcement action, including the imposition of administrative penalties or loss of transmission capacity allocated to the large load customer.

(2) If the information provided by a large load customer under this section or ERCOT Planning Guide Section 9, as of the effective date of this section, is determined to be false or inaccurate or if the accuracy or completeness of the information cannot be verified through supporting documentation:

(A) the large load customer may be deemed to have forfeited any financial security that the large load customer posted under this section or ERCOT Planning Guide Section 9, as of the effective date of this section; and

(B) any transmission capacity allocated to the large load customer may be reallocated by ERCOT in a future interconnection study and in a manner consistent with ERCOT protocols.

(3) ERCOT and commission staff must treat competitively sensitive information that is disclosed under this section by a large load customer as Protected Information under ERCOT protocols. Customer-specific or competitively sensitive information disclosed by a large load customer and obtained by ERCOT or commission staff under this section is confidential and not subject to disclosure under Chapter 552 of the Texas Government Code.

(k) Reallocation of transmission capacity.

(1) In a future interconnection study, ERCOT may, in a manner consistent with ERCOT protocols reallocate transmission capacity, including transmission capacity associated with:

(A) a canceled request for interconnection;

(B) a withdrawn request for interconnection;

(C) a batch zero load that fails to execute a SLLIA in compliance with this section;

(D) a large load customer that fails, by 24 months, to satisfy a milestone in its schedule for phased energization;

(E) a large load customer that fails to comply with its SLLIA;

(F) a large load customer that fails to comply with ERCOT or commission staff's audit; or

(G) a large load customer that is determined to have provided false or inaccurate information; or the information provided under this section cannot be verified through supporting documentation.

(2) An interconnecting DSP is prohibited from reallocating transmission capacity.

(3) An interconnecting TSP is prohibited from reallocating transmission capacity.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on September 18, 2026.

TRD-202604027

Katelyn Lewis

Rules Coordinator

Public Utility Commission of Texas

Effective date: October 8, 2026

Proposal publication date: March 27, 2026

For further information, please call: (512) 936-7044



TITLE 22. EXAMINING BOARDS

PART 22. TEXAS STATE BOARD OF PUBLIC ACCOUNTANCY

CHAPTER 511. ELIGIBILITY

SUBCHAPTER C. EDUCATIONAL REQUIREMENTS

22 TAC §511.57

The Texas State Board of Public Accountancy adopts an amendment to §511.57 concerning Courses in an Accounting Concentration to Take the UCPAE, without changes to the proposed text as published in July 24, 2026 issue of the *Texas Register* (51 TexReg 4797) and will not be republished.

A typographical error misnamed the reference as a subparagraph when it should have been identified as a paragraph.

No comments were received regarding adoption of the amendment.

The amendment is adopted under the Public Accountancy Act (Act), Texas Occupations Code, §901.151 and §901.655 which provides the agency with the authority to amend, adopt and repeal rules deemed necessary or advisable to effectuate the Act.

No other article, statute or code is affected by the adoption.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on September 17, 2026.

TRD-202604011
J. Randel (Jerry) Hill
General Counsel
Texas State Board of Public Accountancy
Effective date: October 7, 2026
Proposal publication date: July 24, 2026
For further information, please call: (512) 305-7848



CHAPTER 523. CONTINUING PROFESSIONAL EDUCATION

SUBCHAPTER D. STANDARDS FOR CONTINUING PROFESSIONAL EDUCATION PROGRAMS AND RULES FOR SPONSORS

22 TAC §523.147

The Texas State Board of Public Accountancy adopts an amendment to §523.147 concerning Sponsor Review Program, without changes to the proposed text as published in July 24, 2026 issue of the *Texas Register* (51 TexReg 4799) and will not be republished.

To maintain the competence of Texas licensees offering accounting services, the Board's Presiding Officer currently appoints three committee members responsible for monitoring Board approved Sponsors offering continuing education to licensees. The Board staff has been administratively monitoring the Sponsor Review Program. By the staff working directly with the sponsors, concerns are addressed immediately and more efficiently. The Sponsor Review Program Committee is no longer necessary.

No comments were received regarding adoption of the amendment.

The amendment is adopted under the Public Accountancy Act (Act), Texas Occupations Code, §901.151 and §901.655 which provides the agency with the authority to amend, adopt and repeal rules deemed necessary or advisable to effectuate the Act.

No other article, statute or code is affected by the adoption.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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General Counsel
Texas State Board of Public Accountancy
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TITLE 25. HEALTH SERVICES

PART 1. DEPARTMENT OF STATE HEALTH SERVICES

CHAPTER 40. STOCK MEDICATION IN SCHOOLS AND OTHER ENTITIES

The executive commissioner of the Texas Health and Human Services Commission (HHSC), on behalf of the Texas Department of State Health Services (DSHS), adopts amendments to §§40.1 - 40.8, 40.11 - 40.18, 40.61 - 40.71, and 40.81 - 40.89; and the repeal of §§40.21 - 40.28, concerning Stock Medication in Schools and Other Entities.

Sections 40.1 - 40.8, 40.11 - 40.18, 40.21 - 40.28, 40.61 - 40.71, and 40.81 - 40.89 are adopted without changes to the proposed text as published in the July 3, 2026, issue of the *Texas Register* (51 TexReg 4339). These rules will not be republished.

BACKGROUND AND JUSTIFICATION

The amendments and repeal are necessary to implement House Bill (HB) 163 and Senate Bill (SB) 1619, 89th Legislature, Regular Session, 2025. HB 163 amended Texas Health and Safety Code (HSC) §773.0145 by removing the statutory list of specific entities authorized to adopt a policy regarding the maintenance, administration, and disposal of epinephrine delivery systems and instead authorizing any entity in Texas to adopt such a policy. SB 1619 amended Texas Education Code Chapter 38 by replacing the term "epinephrine auto-injector" with "epinephrine delivery system" throughout relevant statutes.

The statutory changes require DSHS to update the rules to expand the entities allowed to implement an unassigned epinephrine delivery system policy and to update the medication and terminology allowed in the unassigned epinephrine delivery system policy. The amendments to 25 TAC Chapter 40, Subchapters A, B, E, and F also align definitions across Chapter 40 and comply with DSHS rule standards for plain language. The repeal of Subchapter C removes duplicative rules because the content in those rules has been incorporated into the amendments in Subchapter B.

COMMENTS

The 31-day comment period ended August 3, 2026.

DSHS received comments regarding the proposed rules from one individual commenter. A summary of comments relating to the rules and DSHS's responses follows.

Comment: A commenter expressed support for the overall rule language, including clarifying which individuals may support implementation of the rules and expanding the use of "personnel" to include volunteers and other non-paid or non-staff roles.

Response: DSHS acknowledges the comment. No amendments are necessary based on this comment.

Comment: A commenter recommended defining and including stipulations for "afterschool program" or "Out-of-School Time," noting that these programs may operate in community centers not under the management and control of an educational institution and may no longer be clearly captured after removal of "off-campus" and "secondary sites" language.

Response: DSHS disagrees with the comment. HB 163 amends HSC §773.0145 to remove the list of specific entities and authorizes any entity in Texas to adopt a policy regarding the maintenance, administration, and disposal of epinephrine delivery systems. The rules are intended to implement the statutory framework enacted by HB 163 and generally apply to entities that adopt such policies. The statute and rules do not require separate definitions or requirements for "afterschool"

or "Out-of-School Time" programs. Programs that meet the applicability provisions of the statute and rules are covered regardless of whether they operate on or off a school campus. Adding a definition for only one subset of entities could unintentionally narrow or complicate implementation of a statute that was amended specifically to move away from enumerated categories of entities. Therefore, DSHS declines to amend the rules in response to this comment.

Comment: A commenter encouraged further examination of the voluntary stocking language for youth facilities and recommended requiring youth programs to stock epinephrine delivery systems, with funding support, particularly for programs serving low-income populations with barriers to allergy diagnosis, medical care, and medication access.

Response: DSHS disagrees with the comment. HB 163 authorizes entities to adopt policies regarding the maintenance, administration, and disposal of epinephrine delivery systems but does not require youth facilities or other entities to stock epinephrine delivery systems. The statute does not provide authority for DSHS to require youth programs to obtain or maintain epinephrine delivery systems or to establish a funding mechanism for such purchases. DSHS declines to make changes to the rules in response to this comment.

SUBCHAPTER A. EPINEPHRINE DELIVERY SYSTEM POLICIES IN INSTITUTIONS OF HIGHER EDUCATION

25 TAC §§40.1 - 40.8

STATUTORY AUTHORITY

The amendments are adopted under Texas Government Code §524.0151, which provides that the executive commissioner of HHSC shall adopt rules for the operation and provision of services by the health and human services system, and Texas Health and Safety Code §1001.075, which authorizes the executive commissioner of HHSC to adopt rules for the administration of Texas Health and Safety Code Chapter 1001; Texas Education Code Chapter 38 and Chapter 51, Subchapter Y-1; and Texas Health and Safety Code Chapter 773, Subchapter A.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on September 17, 2026.

TRD-202604020
Cynthia Hernandez
General Counsel
Department of State Health Services
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For further information, please call: (512) 915-8078



SUBCHAPTER B. EPINEPHRINE DELIVERY SYSTEM POLICIES IN CERTAIN ENTITIES

25 TAC §§40.11 - 40.18

STATUTORY AUTHORITY

The amendments are adopted under Texas Government Code §524.0151, which provides that the executive commissioner of HHSC shall adopt rules for the operation and provision of services by the health and human services system, and Texas Health and Safety Code §1001.075, which authorizes the executive commissioner of HHSC to adopt rules for the administration of Texas Health and Safety Code Chapter 1001; Texas Education Code Chapter 38 and Chapter 51, Subchapter Y-1; and Texas Health and Safety Code Chapter 773, Subchapter A.

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Cynthia Hernandez
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For further information, please call: (512) 915-8078



SUBCHAPTER C. EPINEPHRINE AUTO-INJECTOR POLICIES IN YOUTH FACILITIES

25 TAC §§40.21 - 40.28

STATUTORY AUTHORITY

The repeals are adopted under Texas Government Code §524.0151, which provides that the executive commissioner of HHSC shall adopt rules for the operation and provision of services by the health and human services system, and Texas Health and Safety Code §1001.075, which authorizes the executive commissioner of HHSC to adopt rules for the administration of Texas Health and Safety Code Chapter 1001; Texas Education Code Chapter 38 and Chapter 51, Subchapter Y-1; and Texas Health and Safety Code Chapter 773, Subchapter A.

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SUBCHAPTER E. EPINEPHRINE DELIVERY SYSTEM POLICIES IN SCHOOLS

25 TAC §§40.61 - 40.71

STATUTORY AUTHORITY

The amendments are adopted under Texas Government Code §524.0151, which provides that the executive commissioner of HHSC shall adopt rules for the operation and provision of services by the health and human services system, and Texas Health and Safety Code §1001.075, which authorizes the executive commissioner of HHSC to adopt rules for the administration of Texas Health and Safety Code Chapter 1001; Texas Education Code Chapter 38 and Chapter 51, Subchapter Y-1; and Texas Health and Safety Code Chapter 773, Subchapter A.

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Cynthia Hernandez

General Counsel

Department of State Health Services

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For further information, please call: (512) 915-8078



SUBCHAPTER F. OPIOID ANTAGONIST MEDICATION REQUIREMENTS IN SCHOOLS

25 TAC §§40.81 - 40.89

STATUTORY AUTHORITY

The amendments are adopted under Texas Government Code §524.0151, which provides that the executive commissioner of HHSC shall adopt rules for the operation and provision of services by the health and human services system, and Texas Health and Safety Code §1001.075, which authorizes the executive commissioner of HHSC to adopt rules for the administration of Texas Health and Safety Code Chapter 1001; Texas Education Code Chapter 38 and Chapter 51, Subchapter Y-1; and Texas Health and Safety Code Chapter 773, Subchapter A.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Cynthia Hernandez

General Counsel

Department of State Health Services

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For further information, please call: (512) 915-8078



TITLE 28. INSURANCE

PART 1. TEXAS DEPARTMENT OF INSURANCE

CHAPTER 3. LIFE, ACCIDENT, AND HEALTH INSURANCE AND ANNUITIES

The commissioner of insurance adopts amendments to 28 TAC §§3.205, 3.3403, 3.3703, 3.9208, and 3.9210, concerning certain participating policy forms, health coverage of newborn children, and preferred and exclusive provider benefit plans. The amendments to §§3.205, 3.3403, 3.9208, and 3.9210 are adopted without changes to the proposed text published in the May 8, 2026 issue of the *Texas Register* (51 TexReg 3043). These sections will not be republished. The amendments to §3.3703 are adopted with a nonsubstantive change to the proposed text to correct a reference to a section heading. This section will be republished.

REASONED JUSTIFICATION. The amendments to §§3.205, 3.3403, 3.3703, 3.9208, and 3.9210 are necessary to implement the following legislation.

- House Bill 388, 89th Legislature, 2025, requires health benefit plans to use a uniform coordination of benefits questionnaire that is adopted by TDI.

- House Bill 1620, 89th Legislature, 2025, revises Government Code references throughout the Insurance Code to reflect statutory amendments relating to Medicaid enacted in HB 4611, 88th Legislature, 2023, which made nonsubstantive revisions to various health and human services laws.

- House Bill 2221, 89th Legislature, 2025, moves requirements concerning unlawful rebates and inducements to new Insurance Code Chapter 1702.

- Senate Bill 493, 89th Legislature, 2025, prohibits certain pharmacy benefit manager contract provisions.

- Senate Bill 896, 89th Legislature, 2025, extends the enrollment period for newborn children from 31 days to 60 days.

- Senate Bill 1236, 89th Legislature, 2025, expands requirements for pharmacy benefit network contracts.

Separate adoption orders amend or repeal sections in 28 TAC Chapters 11 and 26 to implement the previously referenced legislation. The adopted amendments and repeal are also published in this issue of the *Texas Register*. TDI also adopted by reference LHL138 (Patient Health Plan Coverage Form) and LHL139 (Enrollee's Other Health Plan Coverage Form), which contain two versions of a uniform coordination of benefits questionnaire, effective January 1, 2026, in 28 TAC Chapter 3, Subchapter V, to implement HB 388. TDI has proposed amendments to 28 TAC Chapter 21 to implement provisions in HB 2221 and SB 1236, and the proposal was published in the July 31, 2026 issue of the *Texas Register*.

The adopted amendments are described in the following paragraphs.

Section 3.205. An amendment to §3.205 replaces the reference to Insurance Code §541.056(c), which was repealed by HB 2221, with new Insurance Code §1702.102(c), which was added by HB 2221.

Section 3.3403. The amendments to §3.3403 implement SB 896. Subsections (a), (b), and (d) are amended by striking general references to "for a period of time" for newborn coverage

and replacing them with the concrete time period of "before the 61st day after the child's birth." Subsection (e) is amended by replacing references to a 31-day initial coverage period with a 60-day initial coverage period.

Subsections (f) - (h), addressing the original implementation period of Insurance Code §1367.003, are deleted because they are no longer relevant. Subsection (i) is redesignated as subsection (f), and a title is added to the statutory reference in the subsection to conform to agency style.

Section 3.3703. The amendments to §3.3703 implement HB 388, HB 493, and SB 1236. Subsection (a)(21) is amended by adding a reference to Insurance Code §1203.153. Consistent with SB 1236, new subsection (a)(31) requires a contract between an insurer and a pharmacy or pharmacist to comply with Insurance Code Chapter 1369. New subsection (a)(32) prohibits certain contract provisions in a contract between an insurer and a pharmacy or pharmacist, consistent with Insurance Code §4151.155 as added by SB 493. Although §4151.155 affects contracts involving a pharmacy benefit manager, subsection (a)(32) applies to contracts involving an insurer to ensure requirements for insurers and their pharmacy benefit managers are consistent. New subsection (a)(33) is added to cross-reference 28 TAC §7.1613, which addresses requirements for a contract between an issuer and a third-party administrator (TPA), including a requirement for a TPA to be contractually obligated to comply with all statutory and regulatory requirements related to a function carried out by the TPA. This makes clear that the requirements of §3.3703 apply to health plan contracts with physicians or providers, whether the plan contracts directly or relies on a TPA such as a pharmacy benefit manager to contract.

Subsection (a)(32) as proposed has been changed to correct the reference to Insurance Code §4151.155 by replacing the word "of" with "or" in the statute's heading.

Section 3.9208. The amendment to §3.9208 replaces the reference to Government Code Chapter 533 with Government Code Chapter 540, as repealed and replaced by HB 4611, and consistent with HB 1620.

Section 3.9210. An amendment to §3.9210(a) replaces the reference to Government Code Chapter 533 with Government Code Chapter 540, as repealed and replaced by HB 4611 and consistent with HB 1620.

In addition, the amendments include nonsubstantive editorial and formatting changes to conform the sections to TDI's current drafting style and plain language preferences, and to improve the rule's clarity. These changes appear throughout the amended sections and include adding titles to cited statutes; nonsubstantive text edits, including the addition of necessary words such as "to" and replacing the word "which" with "that"; deleting a catchline for consistency; and other grammatical, punctuation, and format changes.

SUMMARY OF COMMENTS. TDI provided an opportunity for public comment on the rule proposal for a period that ended on June 8, 2026.

Commenters: TDI received written comments from one commenter. No commenters spoke at the public hearing on the proposal held on June 1, 2026. The commenter in support of the proposal was the Texas Hospital Association.

Comment. One commenter supports TDI's proposed amendments to §3.3403 to implement SB 896 relating to health coverage of newborn children and requests TDI's guidance on two

recent cases in which coverage is being denied for newborns whose mothers are listed as dependents on their parents' health insurance coverage. The commenter also supports TDI's added paragraphs at §3.3703(a)(31) - (33), which implement SB 1236 relating to requirements for pharmacy benefit network contracts.

Agency Response. TDI appreciates the commenter's support. Concerns about a violation of health insurance law or regulation can be reported via the complaint submission process described on TDI's website.

SUBCHAPTER C. APPROVAL, DISAPPROVAL, AND WITHDRAWAL OF APPROVAL OF CERTAIN PARTICIPATING POLICY FORMS

28 TAC §3.205

STATUTORY AUTHORITY. The commissioner adopts amendments to §3.205 under Insurance Code §1702.006 and §36.001.

Insurance Code §1702.006 authorizes the commissioner to adopt reasonable rules necessary to implement Insurance Code Chapter 1702.

Insurance Code §36.001 provides that the commissioner may adopt any rules necessary and appropriate to implement the powers and duties of TDI under the Insurance Code and other laws of this state.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on September 21, 2026.

TRD-202604063

Jessica Barta

General Counsel

Texas Department of Insurance

Effective date: October 11, 2026

Proposal publication date: May 8, 2026

For further information, please call: (512) 656-6777



SUBCHAPTER U. NEWBORN CHILDREN COVERAGE

28 TAC §3.3403

STATUTORY AUTHORITY. The commissioner adopts amendments to §3.3403 under Insurance Code §1367.002 and §36.001.

Insurance Code §1367.002 states that certain provisions of Insurance Code Chapter 1201, including provisions relating to rulemaking under Insurance Code Chapter 1201, apply to Insurance Code Chapter 1367, Subchapter A.

Insurance Code §36.001 provides that the commissioner may adopt any rules necessary and appropriate to implement the powers and duties of TDI under the Insurance Code and other laws of this state.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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TRD-202604064

Jessica Barta

General Counsel

Texas Department of Insurance

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For further information, please call: (512) 656-6777

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SUBCHAPTER X. PREFERRED AND EXCLUSIVE PROVIDER PLANS

DIVISION 1. GENERAL REQUIREMENTS

28 TAC §3.3703

STATUTORY AUTHORITY. The commissioner adopts amendments to §3.3703 under Insurance Code §§1203.152, 1301.007, 4151.006, and 36.001.

Insurance Code §1203.152 requires the commissioner to adopt rules establishing a uniform coordination of benefits questionnaire to be used by all health benefit plan issuers in Texas.

Insurance Code §1301.007 directs the commissioner to adopt rules as necessary to implement Insurance Code Chapter 1301 and to ensure reasonable accessibility and availability of preferred provider services to Texas residents.

Insurance Code §4151.006 authorizes the commissioner to adopt rules that are fair, reasonable, and appropriate to augment and implement Insurance Code Chapter 4151.

Insurance Code §36.001 provides that the commissioner may adopt any rules necessary and appropriate to implement the powers and duties of TDI under the Insurance Code and other laws of this state.

§3.3703. Contracting Requirements.

(a) An insurer marketing a preferred provider benefit plan must contract with physicians and health care providers to ensure that all medical and health care services and items contained in the package of benefits for which coverage is provided, including treatment of illnesses and injuries, will be provided under the plan in a manner that ensures both availability and accessibility of adequate personnel, specialty care, and facilities. Each contract must meet the following requirements.

(1) A contract between a preferred provider and an insurer may not restrict a physician or health care provider from contracting with other insurers, preferred provider plans, preferred provider networks or organizations, exclusive provider benefit plans, exclusive provider networks or organizations, health care collaboratives, or HMOs.

(2) Any term or condition limiting participation on the basis of quality that is contained in a contract between a preferred provider and an insurer is required to be consistent with established standards of care for the profession.

(3) In the case of physicians or practitioners with hospital or institutional provider privileges who provide a significant portion of care in a hospital or institutional provider setting, a contract between a preferred provider and an insurer may contain terms and conditions that include the possession of practice privileges at preferred hospitals

or institutions, except that if no preferred hospital or institution offers privileges to members of a class of physicians or practitioners, then the contract may not provide that the lack of hospital or institutional provider privileges may be a basis for denial of participation as a preferred provider to the physicians or practitioners of that class.

(4) A contract between an insurer and a hospital or institutional provider must not, as a condition of staff membership or privileges, require a physician or practitioner to enter into a preferred provider contract. This prohibition does not apply to requirements concerning practice conditions other than conditions of membership or privileges.

(5) A contract between a preferred provider and an insurer may provide that the preferred provider will not bill the insured for unnecessary care, if a physician or practitioner panel has determined the care was unnecessary, but the contract may not require the preferred provider to pay hospital, institutional, laboratory, X-ray, or like charges resulting from the provision of services lawfully ordered by a physician or health care provider, even though such service may be determined to be unnecessary.

(6) A contract between a preferred provider and an insurer may not:

(A) contain restrictions on the classes of physicians and practitioners who may refer an insured to another physician or practitioner; or

(B) require a referring physician or practitioner to bear the expenses of a referral for specialty care in or out of the preferred provider panel. Savings from cost-effective utilization of health services by contracting physicians or health care providers may be shared with physicians or health care providers in the aggregate.

(7) A contract between a preferred provider and an insurer may not contain any financial incentives to a physician or a health care provider that act directly or indirectly as an inducement to limit medically necessary services. This subsection does not prohibit the savings from cost-effective utilization of health services by contracting physicians or health care providers from being shared with physicians or health care providers in the aggregate.

(8) An insurer's contract with a physician, physician group, or practitioner must have a mechanism for the resolution of complaints initiated by an insured, a physician, physician group, or practitioner. The mechanism must provide for reasonable due process, including, in an advisory role only, a review panel selected as specified in §3.3706(b)(2) of this title (relating to Designation as a Preferred Provider, Decision to Withhold Designation, Termination of a Preferred Provider, Review of Process).

(9) A contract between a preferred provider and an insurer may not require any health care provider, physician, or physician group to execute hold harmless clauses that shift an insurer's tort liability resulting from acts or omissions of the insurer to the preferred provider.

(10) A contract between a preferred provider and an insurer must require a preferred provider that is compensated by the insurer on a discounted fee basis to agree to bill the insured only on the discounted fee and not the full charge.

(11) A contract between a preferred provider and an insurer must require the insurer to comply with all applicable statutes and rules pertaining to prompt payment of clean claims with respect to payment to the provider for covered services rendered to insureds.

(12) A contract between a preferred provider and an insurer must require the provider to comply with the Insurance Code §§1301.152 - 1301.154, which relates to Continuity of Care.

(13) A contract between a preferred provider and an insurer may not prohibit, penalize, permit retaliation against, or terminate the provider for communicating with any individual listed in Insurance Code §1301.067, concerning Interference with Relationship Between Patient and Physician or Health Care Provider Prohibited, about any of the matters set forth in the contract.

(14) A contract between a preferred provider and an insurer conducting, using, or relying on economic profiling to terminate physicians or health care providers from a plan must require the insurer to inform the provider of the insurer's obligation to comply with Insurance Code §1301.058, concerning Economic Profiling.

(15) A contract between a preferred provider and an insurer that engages in quality assessment is required to disclose in the contract all requirements of Insurance Code §1301.059(b), concerning Quality Assessment.

(16) A contract between a preferred provider and an insurer may not require a physician to issue an immunization or vaccination protocol for an immunization or vaccination to be administered to an insured by a pharmacist.

(17) A contract between a preferred provider and an insurer may not prohibit a pharmacist from administering immunizations or vaccinations if they are administered in accordance with the Texas Pharmacy Act, Chapters 551 - 566 and Chapters 568 - 569 of the Occupations Code, and implementing rules.

(18) A contract between a preferred provider and an insurer must require a provider that voluntarily terminates the contract to provide reasonable notice to the insured, and must require the insurer to provide assistance to the provider as set forth in Insurance Code §1301.160(b), concerning Notification of Termination of Participation of Preferred Provider.

(19) A contract between a preferred provider and an insurer must require written notice to the provider on termination of the contract by the insurer, and in the case of termination of a contract between an insurer and a physician or practitioner, the notice must include the provider's right to request a review, as specified in §3.3706(d) of this title.

(20) A contract between a preferred provider and an insurer must include provisions that will entitle the preferred provider on request to all information necessary to determine that the preferred provider is being compensated in accordance with the contract. A preferred provider may make the request for information by any reasonable and verifiable means. The information must include a level of detail sufficient to enable a reasonable person with sufficient training, experience, and competence in claims processing to determine the payment to be made according to the terms of the contract for covered services that are rendered to insureds. The insurer may provide the required information by any reasonable method through which the preferred provider can access the information, including email, computer disks, paper, or access to an electronic database. Amendments, revisions, or substitutions of any information provided in accordance with this paragraph are required to be made under subparagraph (D) of this paragraph and, when applicable subparagraph (J) of this paragraph. The insurer is required to provide the fee schedules and other required information by the 30th day after the date the insurer receives the preferred provider's request.

(A) This information is required to include a preferred provider specific summary and explanation of all payment and reimbursement methods that will be used to pay claims submitted by the preferred provider. At a minimum, the information is required to include:

(i) a fee schedule, including, if applicable, CPT, HCPCS, ICD-9-CM codes or successor codes, and modifiers;

(I) by which all claims for covered services submitted by or on behalf of the preferred provider will be calculated and paid; or

(II) that pertains to the range of health care services reasonably expected to be delivered under the contract by that preferred provider on a routine basis along with a toll-free number or electronic address through which the preferred provider may request the fee schedules applicable to any covered services that the preferred provider intends to provide to an insured and any other information required by this paragraph that pertains to the service for which the fee schedule is being requested if that information has not previously been provided to the preferred provider;

(ii) all applicable coding methodologies;

(iii) all applicable bundling processes, which are required to be consistent with nationally recognized and generally accepted bundling edits and logic;

(iv) all applicable downcoding policies;

(v) a description of any other applicable policy or procedure the insurer may use that affects the payment of specific claims submitted by or on behalf of the preferred provider, including recoupment;

(vi) any addenda, schedules, exhibits, or policies used by the insurer in carrying out the payment of claims submitted by or on behalf of the preferred provider that are necessary to provide a reasonable understanding of the information provided under this paragraph; and

(vii) the publisher, product name, and version of any software the insurer uses to determine bundling and unbundling of claims.

(B) In the case of a reference to source information as the basis for fee computation that is outside the control of the insurer, such as state Medicaid or federal Medicare fee schedules, the information provided by the insurer is required to clearly identify the source and explain the procedure by which the preferred provider may readily access the source electronically, telephonically, or as otherwise agreed to by the parties.

(C) Nothing in this paragraph may be construed to require an insurer to provide specific information that would violate any applicable copyright law or licensing agreement. However, the insurer is required to supply, in lieu of any information withheld on the basis of copyright law or licensing agreement, a summary of the information that will allow a reasonable person with sufficient training, experience, and competence in claims processing to determine the payment to be made according to the terms of the contract for covered services that are rendered to insureds as required by subparagraph (A) of this paragraph.

(D) No amendment, revision, or substitution of claims payment procedures or any of the information required to be provided by this paragraph will be effective as to the preferred provider, unless the insurer provides at least 90 calendar days' written notice to the preferred provider identifying with specificity the amendment, revision, or substitution. An insurer may not make retroactive changes to claims payment procedures or any of the information required to be provided by this paragraph. Where a contract specifies mutual agreement of the parties as the sole mechanism for requiring amendment, revision, or substitution of the information required by this paragraph, the written

notice specified in this section does not supersede the requirement for mutual agreement.

(E) Failure to comply with this paragraph constitutes a violation as set forth in subsection (b) of this section.

(F) This paragraph applies to all contracts entered into or renewed on or after the effective date of this paragraph. Upon receipt of a request, the insurer is required to provide the information required by subparagraphs (A) - (D) of this paragraph to the preferred provider by the 30th day after the date the insurer receives the preferred provider's request.

(G) A preferred provider that receives information under this paragraph:

(i) may not use or disclose the information for any purpose other than:

(I) the preferred provider's practice management;

(II) billing activities;

(III) other business operations; or

(IV) communications with a governmental agency involved in the regulation of health care or insurance;

(ii) may not use this information to knowingly submit a claim for payment that does not accurately represent the level, type, or amount of services that were actually provided to an insured or to misrepresent any aspect of the services; and

(iii) may not rely on information provided in accordance with this paragraph about a service as a representation that an insured is covered for that service under the terms of the insured's policy or certificate.

(H) A preferred provider that receives information under this paragraph may terminate the contract on or before the 30th day after the date the preferred provider receives information requested under this paragraph without penalty or discrimination in participation in other health care products or plans. If a preferred provider chooses to terminate the contract, the insurer is required to assist the preferred provider in providing the notice required by paragraph (18) of this subsection.

(I) The provisions of this paragraph may not be waived, voided, or nullified by contract.

(J) No adverse material change to a preferred provider contract will be effective as to the preferred provider unless the adverse material change is made in accordance with Insurance Code §1301.0642, concerning Contract Provisions Allowing Certain Adverse Material Changes Prohibited, to the extent applicable.

(21) An insurer may require a preferred provider to retain in the preferred provider's records updated information concerning a patient's other health benefit plan coverage, consistent with Insurance Code §1203.153, concerning Uniform Coordination of Benefits Questionnaire Required.

(22) Upon request by a preferred provider, an insurer is required to include a provision in the preferred provider's contract providing that the insurer and the insurer's clearinghouse may not refuse to process or pay an electronically submitted clean claim because the claim is submitted together with or in a batch submission with a claim that is deficient. As used in this section, the term "batch submission" is a group of electronic claims submitted for processing at the same time within a HIPAA standard ASC X12N 837 Transaction Set and identi-

fied by a batch control number. This paragraph applies to a contract entered into or renewed on or after January 1, 2006.

(23) A contract between an insurer and a preferred provider other than an institutional provider may contain a provision requiring a referring physician or provider, or a designee, to disclose to the insured:

(A) that the physician, provider, or facility to which the insured is being referred might not be a preferred provider; and

(B) if applicable, that the referring physician or provider has an ownership interest in the facility the insured is being referred to.

(24) A contract provision that requires notice as specified in paragraph (23)(A) of this subsection is required to allow for exceptions for emergency care and as necessary to avoid interruption or delay of medically necessary care and may not limit access to nonpreferred providers.

(25) A contract between an insurer and a preferred provider must require the preferred provider to comply with all applicable requirements of Insurance Code §1661.005, concerning Refund of Overpayment.

(26) A contract between an insurer and a facility must require that the facility give notice to the insurer of the termination of a contract between the facility and a facility-based physician or provider group that is a preferred provider for the insurer as soon as reasonably practicable, but not later than the fifth business day following termination of the contract.

(27) A contract between an insurer and a preferred provider must require, except for instances of emergency care as defined under Insurance Code §1301.0053, concerning Exclusive Provider Benefit Plans: Emergency Care and §1301.155(a), concerning Emergency Care, that a physician or provider referring an insured to a facility for surgery:

(A) notify the insured of the possibility that out-of-network providers may provide treatment and that the insured can contact the insurer for more information;

(B) notify the insurer that surgery has been recommended; and

(C) notify the insurer of the facility that has been recommended for the surgery.

(28) A contract between an insurer and a facility must require, except for instances of emergency care as defined under Insurance Code §1301.0053 and §1301.155(a), that the facility, when scheduling surgery:

(A) notify the insured of the possibility that out-of-network providers may provide treatment and that the insured can contact the insurer for more information; and

(B) notify the insurer that surgery has been scheduled.

(29) A contract between an insurer and a preferred provider must comply with Insurance Code §1458.101, concerning Contract Requirements, to the extent applicable.

(30) A contract between an insurer and a preferred provider that is an optometrist or therapeutic optometrist must comply with Insurance Code Chapter 1451, Subchapter D, concerning Access to Optometrists Used Under Managed Care Plan.

(31) A contract between an insurer and a pharmacy or pharmacist must comply with Insurance Code Chapter 1369, concerning

Benefits Related to Prescription Drugs and Devices and Related Services.

(32) A contract between an insurer and a pharmacy or pharmacist may not include a provision that is prohibited under Insurance Code §4151.155, concerning Certain Disclosures and Communications by Pharmacist or Pharmacy Protected.

(33) A contract between an insurer and a third-party administrator, including a pharmacy benefit manager, must comply with §7.1613 of this title (relating to Written Agreements Between Administrators and Insurers).

(b) In addition to all other contract rights, violations of these rules will be treated for purposes of complaint and action in accordance with Insurance Code Chapter 542, Subchapter A, concerning Unfair Claim Settlement Practices, and the provisions of that subchapter will be employed to the extent practicable, as it relates to the power of the department, hearings, orders, enforcement, and penalties.

(c) An insurer may enter into an agreement with a preferred provider organization, an exclusive provider network, or a health care collaborative for the purpose of offering a network of preferred providers, provided that it remains the insurer's responsibility to:

(1) meet the requirements of Insurance Code Chapter 1301, concerning Preferred Provider Benefit Plans, and this subchapter;

(2) ensure that the requirements of Insurance Code Chapter 1301 and this subchapter are met; and

(3) provide all documentation to demonstrate compliance with all applicable rules on request by the department.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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Jessica Barta

General Counsel

Texas Department of Insurance

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For further information, please call: (512) 656-6777



SUBCHAPTER KK. EXCLUSIVE PROVIDER BENEFIT PLAN

28 TAC §3.9208, §3.9210

STATUTORY AUTHORITY. The commissioner adopts amendments to §3.9208 and §3.9210 under Insurance Code §36.001.

Insurance Code §36.001 provides that the commissioner may adopt any rules necessary and appropriate to implement the powers and duties of TDI under the Insurance Code and other laws of this state.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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CHAPTER 5. PROPERTY AND CASUALTY INSURANCE

SUBCHAPTER W. CONSUMER RIGHTS NOTICES

28 TAC §5.9970, §5.9971

(Editor's note: In accordance with Texas Government Code, §2002.014, which permits the omission of material which is "cumbersome, expensive, or otherwise inexpedient," the figures in 28 TAC §5.9970(b) and §5.9971(b) are not included in the print version of the Texas Register. The figures are available in the on-line version of the May 15, 2026, issue of the Texas Register.)

The commissioner of insurance adopts amendments to 28 TAC §5.9970 and §5.9971, concerning the Consumer Bills of Rights for personal automobile insurance and residential property insurance. The amendments are adopted with changes to the proposed text published in the May 15, 2026 issue of the *Texas Register* (51 TexReg 3315). In addition, changes have been made to the figures adopted by reference in both sections in response to comments. The sections will be republished.

REASONED JUSTIFICATION. The amended sections are necessary to inform insurance consumers of their updated rights following the 89th Legislature. Under Insurance Code Chapter 501, Office of Public Insurance Counsel (OPIC) represents the interest of insurance consumers in Texas. OPIC is required by Insurance Code §501.156 to submit to TDI for adoption a consumer bill of rights appropriate to each personal line of insurance TDI regulates. These bills of rights explain to consumers how their rights are affected by applicable statutes and rules and are to be distributed by insurers to each policyholder on issuance of a policy.

TDI received a petition from OPIC on August 27, 2025, requesting adoption of a revised Consumer Bill of Rights for Personal Automobile Insurance (Auto Bill of Rights) and Consumer Bill of Rights for Homeowners, Dwelling, Renters Insurance (Homeowners Bill of Rights). OPIC's petition provided updated bills of rights to reflect multiple changes made by bills from the 89th Legislature. The text of §5.9970 and §5.9971 as adopted has been changed to reference January 1, 2027, instead of November 1, 2026, as the beginning date for insurers to provide the adopted figures. This change will allow insurers additional lead time to incorporate the adopted changes. A nonsubstantive change has been made to §5.9971 as proposed to correct an error so that the text correctly references the Homeowners Bill of Rights. Changes have also been made to the figures to better track the statutory language of Insurance Code §559.058(b)(1) and clarify that an insurer's re-underwriting and re-rating obli-

gation at renewal is upon request. The figures adopted by reference in both sections have been changed to provide more clarity to consumers about how they may exercise their rights and to ensure a complete translation of each figure into Spanish.

Since the last amendment to the bills of rights, the following legislation has been passed, affecting the rights of insurance consumers:

- HB 2067 amended Insurance Code §551.109, which requires insurance companies to tell policyholders or applicants in writing why an insurance policy was declined, canceled, or nonrenewed.

- SB 1238 amended Insurance Code §544.002, which prohibits insurance companies from discrimination based on an insured's marital status following a spousal death.

- SB 1644 created Insurance Code §559.058, which requires insurance companies to review and update an insured's credit reports, reassess the insured's policy rating, and adjust premiums on the basis of the insured's updated credit score at least every three years. Insurance Code §559.058 also allows an insured to request that the insurance company re-underwrite and re-rate the policy on the basis of a current credit report or insurance score once per year.

- SB 458 created Insurance Code Chapter 1813. Chapter 1813 requires certain personal auto and residential property insurance policies to include an appraisal provision to resolve disputes about loss amounts.

Personal lines insurers must distribute the Auto Bill of Rights and the Homeowners Bill of Rights to each policyholder on issuance of a new policy or on renewal if the updated bill of rights was not previously sent. Amending the Auto Bill of Rights and Homeowners Bill of Rights ensures that insurers distribute current consumer rights information to policyholders.

Descriptions of the sections' adopted amendments follow.

Section 5.9970. The amendments to §5.9970 update the English and Spanish translation of the Auto Bill of Rights included in subsection (b) as Figure 1: 28 TAC §5.9970(b) and Figure 2: 28 TAC §5.9970(b).

The adopted new English and Spanish translation versions of the Auto Bill of Rights contain changes from the previous versions resulting from legislative actions that affect the rights of insurance consumers. The changes, resulting from recent bills and reflecting new information for policyholders, include:

- the right to request appraisal to resolve disputes about loss amounts (SB 458);

- the right to a written explanation for a cancellation or nonrenewal of an insurance policy (HB 2067);

- how insurers must use updated credit information and the right to request an insurer to re-underwrite and re-rate the policy based on current credit information (SB 1644); and

- the right to not be discriminated against following a spousal death (SB 1238).

These amendments will ensure that the Auto Bill of Rights is consistent with the law and that consumers are informed of their rights related to their personal automobile insurance policies.

Section 5.9971. The amendments to §5.9971 update the English and Spanish translation of the Homeowners Bill of Rights

included in subsection (b) as Figure 1: 28 TAC §5.9971(b) and Figure 2: 28 TAC §5.9971(b).

The adopted new English and Spanish translation versions of the Homeowners Bill of Rights contain changes from the previous versions resulting from legislative actions that affect the rights of insurance consumers. The changes, resulting from recent bills and reflecting new information for policyholders, include:

- the right to request appraisal to resolve disputes about loss amounts (SB 458);

- the right to a written explanation for a cancellation or nonrenewal of an insurance policy (HB 2067);

- how insurers must use updated credit information and the right to request an insurer to re-underwrite and re-rate the policy based on current credit information (SB 1644); and

- the right to not be discriminated against following a spousal death (SB 1238).

These amendments will ensure that the Homeowners Bill of Rights is consistent with the law and that consumers are informed of their rights related to their personal automobile insurance policies.

SUMMARY OF COMMENTS AND AGENCY RESPONSE. TDI provided an opportunity for public comment on the rule proposal for a period that ended on June 15, 2026.

Commenters: TDI received comments from three commenters. Commenters in support of the proposal with changes were the Insurance Council of Texas (ICT) and one individual. A third commenter was an individual who was neither in support of nor against the proposal.

Comment on §5.9970 and §5.9971

Comment. A commenter supports the rule but suggests that the proposed date for the updated consumer bills of rights should be extended.

Agency Response. TDI agrees and has changed the language as proposed to require insurers to provide the update consumer bill of rights beginning on January 1, 2027.

Comment on §5.9971

Comment. A commenter supports the rule but suggests that the proposed rule text be changed to fix a technical error in a reference. The proposed text in §5.9971(f) references "Auto Bill of Rights" in error and should instead reference "Homeowners Bill of Rights."

Agency Response. TDI agrees and has changed the language as proposed to correct the error.

Comment on Figures in §5.9970 and §5.9971

Comment. A commenter supports the rule but suggests changes concerning the appraisal information in the consumer bills of rights. Specifically, the commenter suggests including any deadlines to demand or complete appraisal. The commenter also suggests stating that either the policyholder or the insurer may demand appraisal when the amount of the loss is in dispute and that the resulting appraisal award is binding.

Agency Response. TDI appreciates the input but declines to make the suggested changes. TDI has proposed rules relating to appraisal in Chapter 1813. Addressing the specific information about appraisal deadlines in this rule would be confusing because the consumer bill of rights covers multiple consumer

matters and does not establish those deadlines. The relevant information is better suited for the rules directly relating to appraisal.

The appraisal information in the consumer bills of rights already expresses that either the policyholder or the insurer may demand appraisal when the amount of loss is in dispute. The text in the consumer bills of rights also sufficiently conveys that the result of appraisal is binding because it states that appraisal is a means "to resolve" the dispute.

Comment. A commenter supports the rule but suggests changes concerning information in the bills of rights about the use of credit information to determine policy premiums. The commenter suggests revising the consumer bills of rights to better track the statutory language in Insurance Code §559.058(b)(1) and clarify that an insurer's re-underwriting and re-rating obligation at renewal is upon request. The commenter suggests adding "If requested," before the sentence "Your company must reassess your policy rating and adjust premiums at renewal based upon the current credit report or insurance score."

Agency Response. TDI agrees and has added the suggested language.

Comment on enforcement of the Consumer Bill of Rights

Comment. A commenter was neither in support nor against the proposed rule but raised concern over the enforcement of the rights for consumers against insurers. The commenter did not provide any suggested changes to the proposed rule.

Agency Response. TDI acknowledges the commenter's concerns.

STATUTORY AUTHORITY. The commissioner adopts the amendments to §5.9970 and §5.9971 under Insurance Code §§501.156, 551.112, 559.004, 1813.002, and 36.001.

Insurance Code §501.156 requires OPIC to submit to TDI for adoption a consumer bill of rights appropriate to each personal line of insurance TDI regulates.

Insurance Code §551.112 authorizes the commissioner to adopt rules relating to the cancellation and nonrenewal of insurance policies.

Insurance Code §559.004 authorizes the commissioner to adopt rules necessary to implement Insurance Code Chapter 559.

Insurance Code §1813.002 directs the commissioner to adopt rules necessary to implement Insurance Code Chapter 1813.

Insurance Code §36.001 authorizes the commissioner to adopt any rules necessary and appropriate to implement the powers and duties of TDI under the Insurance Code and other laws of this state.

§5.9970. *Personal Automobile Insurance Consumer Bill of Rights.*

(a) For purposes of this section, "insurer" means an insurance company, reciprocal or interinsurance exchange, mutual insurance company, capital stock company, county mutual insurance company, Lloyd's plan, or other legal entity authorized to write personal automobile insurance in this state. The term includes an affiliate, as described by Insurance Code §823.003(a), if that affiliate is authorized to write and is writing personal automobile insurance in this state.

(b) The Texas Department of Insurance adopts the 2026 version of the Consumer Bill of Rights - Personal Automobile Insurance (Auto Bill of Rights), and the Spanish language translation, as developed and submitted by the Office of Public Insurance Counsel:

Figure 1: 28 TAC §5.9970(b)

Figure 2: 28 TAC §5.9970(b)

(c) All insurers writing personal automobile insurance policies must provide with each new policy of personal automobile insurance a copy of the 2026 version of the Auto Bill of Rights. At the consumer's request, the insurer may provide an electronic copy of the Auto Bill of Rights instead of a hard copy. The insurer must provide the Auto Bill of Rights with each renewal notice for personal automobile insurance unless the insurer has previously provided the policyholder with the 2026 version of the Auto Bill of Rights.

(d) The Auto Bill of Rights must appear in no less than 10-point type and be on separate pages with no other text on those pages.

(e) Insurers must provide the Spanish language version of the 2026 version of the Auto Bill of Rights to any consumer who requests it.

(f) Insurers must provide the applicable Auto Bill of Rights included in this section beginning January 1, 2027. Before that date, insurers may provide the Auto Bill of Rights either as it currently is included in this section or as it was included in the section as the section was amended to be effective November 1, 2024.

§5.9971. *Homeowners, Dwelling, and Renters Insurance Consumer Bill of Rights.*

(a) For purposes of this section, "insurer" means an insurance company, reciprocal or interinsurance exchange, mutual insurance company, capital stock company, county mutual insurance company, Lloyd's plan, or other legal entity authorized to write residential property insurance in this state. The term includes an affiliate, as described by Insurance Code §823.003(a), if that affiliate is authorized to write and is writing residential property insurance in this state. The term does not include the Texas Windstorm Insurance Association or the Texas Fair Plan Association.

(b) The Texas Department of Insurance adopts the 2026 version of the Consumer Bill of Rights - Homeowners, Dwelling, and Renters Insurance (Homeowners Bill of Rights), and the Spanish language translation, as developed and submitted by the Office of Public Insurance Counsel:

Figure 1: 28 TAC §5.9971(b)

Figure 2: 28 TAC §5.9971(b)

(c) All insurers writing homeowners, dwelling, or renters insurance must provide with each new policy of any such insurance a copy of the 2026 version of the Homeowners Bill of Rights. At the consumer's request, the insurer may provide an electronic copy of the Homeowners Bill of Rights instead of a hard copy. The insurer must provide the Homeowners Bill of Rights with each renewal notice for any such insurance unless the insurer has previously provided the policyholder with the 2026 version of the Homeowners Bill of Rights.

(d) The Homeowners Bill of Rights must appear in no less than 10-point type and be on separate pages with no other text on those pages.

(e) Insurers must provide the Spanish language version of the 2026 version of the Homeowners Bill of Rights to any consumer who requests it.

(f) Insurers must provide the applicable Homeowners Bill of Rights included in this section beginning January 1, 2027. Before that date, insurers may provide the Homeowners Bill of Rights either as it currently is included in this section or as it was included in the section as the section was amended to be effective November 1, 2024.

The agency certifies that legal counsel has reviewed the adoption and found it to be a valid exercise of the agency's legal authority.

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