TEXAS OIL & GAS ASSOCIATION | SINCE 1919

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Office of General Counsel
Railroad Commission of Texas
P.O. Box 12967
Austin, Texas 78711-2967
Via email: rulescoordinator@rrc.texas.gov

Re: Comments of the Texas Oil & Gas Association on Proposed Amendments to 16 Texas Administrative Code §3.15, relating to Surface Equipment Removal Requirements and Inactive Wells, and §3.58, relating to Certificate of Compliance and Transportation Authority; Operator Reports, Implementing Senate Bill 1150

Dear Rules Coordinator:

The Texas Oil & Gas Association (TXOGA) appreciates the opportunity to comment on the Railroad Commission of Texas's (Commission) proposed amendments to 16 Texas Administrative Code §§3.15 and 3.58 implementing Senate Bill 1150.

The Texas Oil & Gas Association is a statewide trade association representing every facet of the Texas oil and gas industry including small independents and major producers. Collectively, the membership of TXOGA produces approximately 90 percent of Texas' crude oil and natural gas, operates the vast majority of the state's refineries, LNG export capacity and pipelines, and includes a broad array of service companies integral to the industry. In fiscal year 2025, the Texas oil and natural gas industry supported over 495,000 direct jobs and paid $27 billion in state and local taxes and state royalties, funding our state's schools, roads and first responders.

TXOGA supports the Commission's objective of reducing the population of long-term inactive wells while maintaining a regulatory framework that encourages operators to responsibly return viable wells to productive service. TXOGA's members are committed to the goals of Senate Bill 1150, and the comments below are intended to make the rule workable in practice, reduce compliance uncertainty, and promote consistent interpretation among operators and Commission staff. TXOGA respectfully submits the following comments, organized by subject.

I. Definitions and Classification of 15/25 Wells — §3.15(a)(1)

A. Consistent use of the terms "inactive well" and "15/25 well"

Proposed §3.15(a)(1) defines a "15/25 well" as an inactive land well that has been inactive for more than fifteen years and was completed more than twenty-five years ago. Accordingly, every 15/25 well is an inactive well, but not every inactive well is a 15/25 well. Throughout the proposal,

however, the two terms are at times used in a manner that creates ambiguity as to whether a given requirement applies only to 15/25 wells or to all inactive wells. Examples include:

1. The compliance plan provisions of proposed §3.15(h)(4)(C), which authorize extensions for 15/25 wells but refer to inactive wells more broadly in several subsections;
2. The financial hardship provisions of proposed §3.15(h)(4)(B) and §3.15(i)(1)(B), which alternate between references to individual inactive wells and an operator's total population of 15/25 wells; and
3. The transfer provisions of proposed §3.58(a)(5) and (a)(6), which refer to inactive wells generally while also imposing restrictions applicable specifically to the 15/25-well extension pathways.

Requested action: TXOGA requests that the Commission review the proposal for consistent use of these terms and revise the rule text so that it is clear which requirements apply only to 15/25 wells and which apply to all inactive wells.

II. Commission Action on Applications for Plugging Extensions for 15/25 Wells — §3.15(i)

A. The Commission should retain discretion to approve extensions outside the enumerated criteria

Proposed §3.15(i)(1) provides that approval of a plugging extension for a 15/25 well is warranted if the operator meets the criteria set forth in one of subparagraphs (A), (B), (C), or (D). Operators' circumstances vary widely, and some operators will make substantial, demonstrable progress toward compliance without fitting squarely within one of the four enumerated pathways.

Requested action: TXOGA requests that the Commission add a sentence following the enumerated criteria providing that the Commission may also approve a plugging extension under other circumstances, at its discretion, if the operator satisfactorily demonstrates progress toward compliance.

B. The restoration-to-production criterion is overly restrictive

Under proposed §3.15(i)(1)(A)(ii), an operator with more than ten inactive wells must have restored at least ten percent of its total inactive well population to active operation during the preceding year for approval to be warranted. For many operators, particularly those with large and geographically diverse portfolios, this threshold will be exceptionally difficult to achieve. Because the rule measures restoration activity at the operator level rather than the lease, field, or asset level, significant reactivation efforts on a particular lease or asset may represent only a small percentage of the operator's overall inactive well inventory and receive little recognition. A single percentage applied to every operator with more than ten inactive wells may also discourage acquisitions of large inactive well inventories, because each acquisition raises the number of restorations needed to qualify. As drafted, this pathway may exist in theory but be unattainable in practice for most operators, which is inconsistent with the legislative intent of giving operators a meaningful opportunity to pursue reactivation rather than immediate plugging.

Requested action: TXOGA requests that the Commission revise the criterion to:

1. Consider restoration activity over a multi-year period rather than only the immediately preceding year;
2. Provide flexibility to look at restoration activity by lease, field, or asset level rather than solely at the operator level.
3. Provide flexibility when an operator demonstrates that operational, market, or financial conditions temporarily delayed planned reactivation efforts; and
4. Scale the threshold to the size of the operator's inactive well inventory rather than applying a single percentage to every operator with more than ten inactive wells;
5. Count both well reactivations and permanent plugging and abandonment toward the qualification threshold, as both outcomes directly advance the Commission's objective of reducing the inventory of aging inactive wells.

C. Operators should be able to use more than one extension pathway

Proposed §3.15(h)(4)(A)–(D) establishes four mechanisms for obtaining plugging extensions for 15/25 wells: (1) a prior history of restoring inactive wells to active operation; (2) financial hardship; (3) a compliance plan; and (4) an individual performance bond. Because proposed §3.15(h)(4) directs the operator to submit "one of the following" for Commission approval, and §3.15(i)(1) ties approval to the criteria in "one of" subparagraphs (A)–(D), the proposal could be read to limit an operator to a single pathway for its entire portfolio rather than allowing different pathways for different wells. For operators with diverse assets at different stages of development, a single approach is often not the most effective solution for every well. Certain leases, fields, or assets may be strong candidates for a long-term compliance plan due to ongoing reactivation efforts, while other wells may be better addressed through the performance bond option because of unique operating conditions or anticipated future development. TXOGA's request is limited to the restoration-history, compliance plan, and individual performance bond pathways.

Requested action: TXOGA requests that the Commission clarify, in the rule text or the adoption preamble, that an operator may use a combination of the restoration-history, compliance plan, and individual performance bond pathways on a lease, field, asset, or well-specific basis, provided all applicable requirements for each pathway are satisfied, and that the Commission revise the phrase "one of the following" in §3.15(h)(4) accordingly.

III. Compliance Plans — §3.15(h)(4)(C) and §3.15(i)(1)(C)

A. Compliance plans should allow flexibility between plugging and restoration

Proposed §3.15(h)(4)(C)(i), in the second of two subclauses designated (II), requires a compliance plan to specify whether each included inactive well will be plugged or restored to active operation and, if applicable, how the well will be restored. Operators need more flexibility than a single fixed

designation allows. In enhanced oil recovery projects in particular, operators may need to preserve the option to either restore or plug high-potential utility wells as the project develops.

Requested action: TXOGA requests that the Commission allow an operator to designate a well as subject to either plugging or restoration, with the final designation to be made or revisited during the annual compliance plan update.

B. Technical correction: subclause numbering in §3.15(h)(4)(C)(i)

The subclauses of proposed §3.15(h)(4)(C)(i) are numbered (I), (II), (II), (III), (IV), (V), and (VI), so two different requirements are both designated (II). The preamble's description of subclauses (I)–(VI) omits the requirement to specify whether each well will be plugged or restored.

Requested action: TXOGA requests that the Commission renumber the subclauses of §3.15(h)(4)(C)(i) as (I)–(VII) and conform any cross-references.

C. Operators should be able to adjust compliance plans and report the changes annually, and renewal and deviation standards should be defined

A compliance plan under proposed §3.15(h)(4)(C) commits an operator to a schedule that may run until September 1, 2042. Well economics, commodity prices, rig availability, and field development plans cannot be predicted reliably over that period, and operators will need to adjust their plans. The proposal does not say whether an operator may adjust an approved plan during the year or how such changes are to be reported. Requiring a formal amendment and Commission approval for each change would burden operators and Commission staff alike, and proposed §3.15(h)(4)(C)(iii) already requires an annual status report for every well in an approved plan. It addresses renewal only indirectly: extensions are renewed annually under §3.15(h)(2); §3.15(i)(1)(C)(v) allows the Commission to consider wells plugged or restored above the annual minimum; and §3.15(i)(2)(F) requires denial if, in renewing, the operator "deviated from the previous year's approved compliance plan in bad faith." The term "bad faith" is not defined, and the rule does not distinguish a bad-faith deviation from one caused by operational constraints.

The proposal could also be read to require more well-specific detail than a long-range plan can reliably provide. Proposed §3.15(h)(4)(C)(i)(III) requires the plan to "provide a schedule for plugging or restoring to active operation for all included inactive wells," and proposed §3.15(i)(1)(C)(iv) requires the operator to reasonably prioritize the wells to be plugged or restored each year. Read together, these provisions could require an operator to commit, years in advance, to the specific wells, that it will plug or restore in each year of the plan. Which wells are addressed in a given year depends on rig availability, site access, field development, reactivation results, and the condition of each well when work begins. A well-by-well list would therefore be out of date soon after it was filed and would generate constant changes for operators and Commission staff. An explanation of the operator's prioritization process, together with the number of wells it will plug or restore each year, gives the Commission what it needs to evaluate the plan under §3.15(i)(1)(C)(ii)–(iv), and the annual status report under §3.15(h)(4)(C)(iii) shows which wells were actually plugged or restored.

Compliance plans and annual status reports should also be filed in a uniform format. Free-form plans and reports would be difficult for operators to prepare consistently and for Commission staff to review. The Commission's LoneSTAR online system already handles related filings, including Forms P-5 and W-3X, and could pre-populate well information the Commission already has on file.

Requested action: TXOGA requests that the Commission:

1. Provide that a compliance plan satisfies §3.15(h)(4)(C)(i)(III) and §3.15(i)(1)(C)(iv) if it explains the operator's prioritization process and states the number of wells the operator will plug or restore each year, and that the operator is not required to list each well it plans to plug or restore in each year of the plan;
2. Aligning with the previous recommendation the RRC should allow an operator to make changes to an approved compliance plan during the year, such as substituting wells, re-sequencing work, or changing a well's designation between plugging and restoration, without filing an amendment or obtaining prior Commission approval, provided the operator still meets the plan's annual minimum under §3.15(i)(1)(C)(iii); and require the operator to report those changes at the end of the year with the annual status report under §3.15(h)(4)(C)(iii), showing that the plan's goals were still met;
3. Accept compliance plans and annual status reports through LoneSTAR, using a standardized format that pre-populates well information already on file with the Commission, rather than free-form submissions;
4. Set out the procedures and timing for renewing a compliance plan; and
5. Define "bad faith" in §3.15(i)(2)(F) and provide that a deviation caused by rig or equipment availability, weather, site access, regulatory delays, or other operational constraints beyond the operator's reasonable control is not a bad-faith deviation.

IV. Conversion of Inactive Wells to Injection, Disposal, Monitoring, or Other Service — §3.15(a), (h)(4)(C), (i), and (n)

A. The rule should conform to the statute by treating conversion as a way to bring a 15/25 well back into operation

Senate Bill 1150 does not limit compliance plans to plugging or returning a well to production. Texas Natural Resources Code §89.023(c)(2) allows an operator to commit in a compliance plan to plug the well or to put it into production or operation as an injection well or other type of operation by September 1, 2042. Proposed §3.15(h)(4)(C) tracks that language, but the provisions that implement it do not. Proposed §3.15(h)(4)(C)(i)(II), (III), and (V), §3.15(i)(1)(C)(i)–(iii) and (v), and §3.15(i)(1)(A) refer only to plugging or to "restoring" or "returning" a well to "active operation," and the preamble describes the compliance plan the same way.

That narrowing matters because "active operation" is defined in §3.15(a)(2) by reference to "activities related to the production of oil and gas," and the proposal does not define "restored to active operation." A well converted to a Class II disposal or injection well, an acid gas injection

well, a monitoring or observation well, or a Class VI well is put to a use the Legislature expressly contemplated. Although the definition of "inactive well" in §3.15(a)(8) excludes a well with reported disposal, injection, or other permitted activity, the compliance plan and restoration-history provisions measure progress only by plugging or restoration to active operation. As proposed, it is therefore unclear whether conversion counts toward the plan's annual minimum under §3.15(i)(1)(C)(iii) or toward an operator's restoration history under §3.15(i)(1)(A). The exclusion of water disposal projects from the EOR definition in §3.15(a)(5) means the EOR provisions cannot fill the gap.

Requested action: TXOGA requests that the Commission add a definition of "restored to active operation" that includes conversion to and commencement of operation as a disposal, injection, monitoring, or other service well under all required Commission permits or authorizations. The definition should rely on objective markers (permit issuance, any required testing, and commencement of operation), and the Commission should conform the provisions listed above. TXOGA's proposed definition is provided in Attachment B.

VI. Performance Bonds and Financial Assurance

A. Performance bonds issued by qualified sureties should be accepted

Proposed §3.15(i)(1)(D)(iii) and §3.15(i)(2)(G) require that a qualifying performance bond be issued by and drawn on by a third-party bank authorized under state or federal law to do business in Texas. This requirement departs from the Commission's existing financial security rule. Section 3.78(a)(4) defines financial security to include individual performance bonds, blanket performance bonds, letters of credit, and cash deposits, and §3.78(a)(10) defines a bond as a surety instrument issued by a third-party corporate surety authorized under state law to issue surety bonds in Texas. The proposal's reference to "a third-party bank authorized under state or federal law to do business in Texas" tracks the §3.78(a)(9) definition of a letter of credit, not of a bond. It is unclear whether the Commission intends to limit acceptable performance bonds to bank-issued instruments. Performance bonds are commonly issued by sureties. Limiting qualifying bonds to bank-issued instruments would significantly reduce the availability of the performance-bond pathway and increase operators' costs by excluding many established surety providers that routinely issue performance bonds throughout the industry.

Requested action: TXOGA requests that the Commission revise proposed §3.15(i)(1)(D)(iii) and §3.15(i)(2)(G) to conform to the definition of a bond in §3.78(a)(10), so that a performance bond issued by a third-party corporate surety authorized to issue surety bonds in Texas satisfies the rule's requirements.

B. The rule should address how bond coverage is maintained when a well changes operators

Proposed §3.15(h)(4)(D) and §3.15(i)(1)(D)(ii) require that an individual performance bond run with and cover the lifetime of the well "regardless of a change in operator." Under the Commission's existing rules, however, financial security does not transfer from one operator to another. Section 3.78(j) provides that the Commission will not approve a transfer unless the acquiring operator has its own financial security on file, and that the existing financial security

remains in effect until the transfer is approved. Proposed §3.15(p)(2) (current subsection (n)(2)) likewise provides that supplemental financial assurance may not be transferred to a new operator. The proposal does not say whether the "regardless of a change in operator" language is intended to change that practice. It also does not address an operator name change or merger, where the operator's identity changes but the well is not sold to a new operator.

Requested action:

TXOGA requests that the Commission clarify, in the rule text or adoption preamble, that consistent with §3.78(j), the requirement is satisfied when the acquiring operator files an equivalent individual performance bond covering the 15/25 well before the Commission approves the transfer under §3.58(a)(5), with the selling operator's bond remaining in effect until then and released afterward. TXOGA also requests that the Commission confirm that, after an operator name change or merger, a rider to the existing bond reflecting the change is sufficient and a new bond need not be issued, consistent with §3.15(l)(3) and (m)(3), which allow abeyance of plugging reports and EOR statements to carry over on a change of operator name.

C. The rule should address bond amounts, adjustments, and release

Proposed §3.15(h)(4)(D) requires a performance bond in an amount "not less than" the full cost calculation, while §3.15(i)(1)(D)(i) provides that approval is warranted if the bond is "equal to" the full cost calculation. The full cost calculation will change over time, but the proposal does not say whether or how an existing bond must be adjusted when it changes, or when a bond will be released.

Requested action: TXOGA requests that the Commission conform §3.15(h)(4)(D) and §3.15(i)(1)(D)(i) to a single "not less than" standard; specify whether and how bond amounts must be adjusted when the full cost calculation changes; and provide for release of the bond when the well is plugged, restored to active operation, or covered by a replacement bond filed by a new operator.

VII. Inactive Well Transfers — §3.58(a)(5) and (a)(6)

A. Transfer filing requirements and affirmations should be clarified

Proposed §3.58(a)(5) requires a Form P-4 signed by each operator, accompanied by a written affirmation jointly signed by both operators stating that (A) the well is in compliance with Texas Natural Resources Code §89.023 and §3.15; (B) the transfer was a business practice performed in good faith; and (C) the operator receiving the well will ensure continued compliance. The preamble states that the transfer is to be filed on a Commission form, but no form has been published, and the rule does not specify any supporting documentation or the timing of the filing. These requirements will increase transaction diligence and coordination, and their scope is unclear.

Requested action: TXOGA requests that the Commission:

1. Publish the affirmation form and specify what supporting documentation, if any, must accompany it and when it must be filed relative to closing and the Form P-4 filing;

2. Clarify that the compliance affirmation in §3.58(a)(5)(A) is based on the operators' knowledge after reasonable inquiry, and specify which operator is responsible for which statements, because an acquiring operator generally cannot verify the well's compliance before closing;
3. Clarify that the affirmation in §3.58(a)(5)(C) commits the acquiring operator to comply with Texas Natural Resources Code §89.023 and §3.15 going forward, not to broader or open-ended liability, and describe the diligence the Commission expects; and
4. Confirm that the new requirements will not delay the processing of Form P-4 change-of-operator filings.

B. Acquiring operators need time to requalify for extensions that do not transfer

Proposed §3.58(a)(6) provides that an extension granted under Texas Natural Resources Code §89.023(c)(1) and §3.15(h)(4)(A)–(B), based on the operator's restoration history or financial hardship, does not transfer to another operator. TXOGA recognizes that this provision implements SB 1150. The rule does not, however, address the status of those wells at closing. If the acquiring operator must requalify immediately, the wells may be treated as lacking a valid extension on the day of transfer. This creates transaction uncertainty and reduces the marketability of inactive assets, including transfers to operators better positioned to restore them. The Commission's existing rules give a new operator six months to come into compliance in comparable situations: §3.15(l)(2) for abeyance of plugging reports, §3.15(m)(2) for EOR project statements, and §3.15(p)(2) for supplemental financial assurance.

Requested action: TXOGA requests that the Commission give an acquiring operator six months after approval of its Form P-4 to apply for an extension under §3.15(h) for any 15/25 well whose extension does not transfer, and provide that the well is not treated as delinquent during that period.

VIII. Transition Period for Acquired Inactive Wells — §3.58(a)(5)

Under proposed §3.58(a)(5)(C), the operators must jointly affirm at the time of transfer that the acquiring operator will ensure continued compliance with Texas Natural Resources Code §89.023 and §3.15. In many acquisitions, operators assume responsibility for large inventories of wells spread across multiple leases and assets. When a transaction brings a large number of 15/25 wells into an operator's inventory, the operator's minimum plugging or restoration requirement for the following years increases dramatically, and the operator would be required to begin plugging many of those wells before it has had time to evaluate them for return to production or for conversion to monitoring or injection wells as part of a revised recovery strategy for the acquired field.

Following closing, substantial technical, operational, and economic review is typically required to:

1. Evaluate the condition of inherited wells;
2. Review historical operational records;
3. Assess reactivation potential;

4. Prioritize wells for plugging or restoration;
5. Develop lease, field, or asset-specific compliance strategies; and
6. Forecast the population of wells that may become 15/25 wells in the near future.

Operators evaluating acquisitions must consider not only existing 15/25 wells but also inactive wells that will become 15/25 wells within the next one to three years. Those future obligations materially influence reactivation, plugging, and capital-allocation decisions and are often not fully understood when a transaction closes. Without a transition mechanism, the market for legacy assets is likely to be suppressed, which would slow, rather than accelerate, the return to production or plugging of those wells.

This need is not limited to the period before the September 1, 2042 compliance-plan deadline in proposed §3.15(h)(4)(C) and §3.15(i)(1)(C). After that date, operators acquiring legacy assets will face the same issue and should continue to have an opportunity to request one to three years from the Commission to conduct field studies and test new recovery strategies.

Requested action: TXOGA requests that the Commission add a provision authorizing operators to petition for a temporary stay, not to exceed three annual compliance periods, of the inclusion of recently acquired inactive wells in the calculation of the operator's minimum plugging or restoration requirement. The stay would be granted at the Commission's discretion, conditioned on continued compliance with all applicable safety, testing, reporting, and financial assurance requirements, and available both before and after September 1, 2042. TXOGA's proposed rule language is provided in Attachment A.

IX. Full Cost Calculation and Economic Impact — §3.15(a)(6)

A. Commission staff and indirect administrative costs should not be included in the full cost calculation

The proposed definition of "full cost calculation for plugging an inactive well" in §3.15(a)(6) includes Commission monitoring and administrative costs in addition to plugging costs. Specifically, proposed §3.15(a)(6)(D) and (E) include the cost of Commission staff time for directly monitoring plugging and site remediation, and Commission indirect administration calculated using the most recent Negotiated Indirect Cost Rate Agreement used for federal grants. At the same time, the definition expressly excludes the operator's own overhead and internal costs. Commission staff and indirect costs are regulatory costs, not costs of plugging the well, and including them inflates every calculation that relies on the definition.

Requested action: TXOGA requests that the Commission remove subparagraphs (D) and (E) from the definition or, alternatively, explain the statutory basis for requiring operators to bear Commission staff time and indirect administrative costs as part of the full cost calculation.

B. The calculation methodology should be published before operators must elect a pathway

The methodology and resulting values for the full cost calculation have not yet been published. The full cost calculation drives several pathways: the bond amount under proposed §3.15(h)(4)(D)

and §3.15(i)(1)(D)(i), the financial hardship tests under §3.15(i)(1)(B)(i)–(v), and the cost figure required in a compliance plan under §3.15(h)(4)(C)(i)(V). Without the methodology and values, operators cannot evaluate these options or make informed compliance decisions.

Requested action: TXOGA requests that the Commission publish the methodology, assumptions, and anticipated values for the full cost calculation as soon as practicable; state how often the values will be updated; establish a process for an operator to review and seek correction of the calculation for a particular well; and provide operators sufficient lead time to evaluate compliance alternatives and obtain any required financial assurance instruments.

C. The proposal understates administrative and compliance costs to operators

TXOGA respectfully disagrees with the preamble's determination that there will be no additional economic costs for persons required to comply with the proposed amendments. The preamble reasons that the 15/25 well extensions are optional. An operator that does not obtain an extension, however, must plug its 15/25 wells, so the realistic choice is between the cost of an extension pathway and the cost of plugging. Each pathway also requires significant administrative effort and resources, including:

1. Development and annual maintenance of compliance plans under proposed §3.15(h)(4)(C);
2. Annual status reporting for wells included in approved compliance plans under proposed §3.15(h)(4)(C)(iii);
3. Collection and submission of extensive historical well information under proposed §3.15(h)(4)(A);
4. Preparation of CPA-certified financial statements and supporting financial analyses under proposed §3.15(h)(4)(B);
5. Fluid level or hydraulic pressure testing of every inactive well more than 15 (rather than 25) years old, and annual submission of hydraulic pressure test results, under proposed §3.15(c)(4), (e)(5), (n)(3), and (n)(6). These costs are mandatory whether or not an operator seeks a 15/25 well extension; and
6. The Commission staff and administrative costs included in the full cost calculation discussed above.

Requested action: TXOGA requests that the Commission reevaluate its conclusion that the proposed amendments impose no additional economic costs on operators.

X. Fluid Level and Hydraulic Pressure Testing — §3.15(c)(4), (e)(5), and (n)

The proposal lowers the well-age threshold for fluid level and hydraulic pressure testing from 25 years to 15 years in §3.15(c)(4), §3.15(e)(5), and §3.15(n), and deletes from §3.15(n)(3) the condition that the well have been inactive for more than 10 years. As a result, every inactive well more than 15 years old must undergo a fluid level test every 12 months or a hydraulic pressure test

every five years, and under §3.15(n)(6) the results must be submitted annually even when an approved hydraulic pressure test remains valid. TXOGA recognizes that the annual reporting requirement reflects Texas Natural Resources Code §89.050. The change substantially enlarges the population of wells that must be tested, increasing field and reporting burden, and the proposal offers no risk-based justification for applying the same schedule to every well. Demand for testing may also exceed the testing resources available to operators and to Commission district offices.

Requested action: TXOGA requests that the Commission:

1. Phase in the expanded testing requirement, beginning with higher-risk wells, rather than requiring every newly covered well to be tested in the first year. One way to accomplish this is by phasing in testing of newly covered wells over three years based on well age, similar to how the original H-15 program was phased in. For example, wells more than 20 years old could be tested in year one, wells 17 to 20 years old in year two, and wells 15 to 17 years old in year three. The schedule should be based on the actual number and ages of the wells that will become subject to the new requirement, and wells that are inactive and more than 25 years old after the effective date would still be tested within one year;
2. Allow engineering alternatives that demonstrate mechanical integrity, subject to district approval, including by confirming that the district director may approve alternative tests under §3.15(n)(2);
3. Clarify what must be submitted annually under §3.15(n)(6) when a previously approved hydraulic pressure test remains valid, such as a certification referencing the prior test rather than a new filing;
4. Explain how newly covered wells will be added to testing schedules. The Commission has already begun issuing 2027 Form H-15 testing schedules based on the 25-year threshold, and operators need to know whether wells not on those schedules will be assigned testing months later in 2027 and how much notice they will receive.

Conclusion

TXOGA appreciates the Commission's consideration of these comments and looks forward to continued engagement as the rulemaking proceeds. Please contact Tulsi Oberbeck at toberbeck@txoga.org with any questions.

Respectfully submitted,



Tulsi Oberbeck
Vice President of Government and Regulatory Affairs
Texas Oil & Gas Association

ATTACHMENT A

Proposed Rule Language: Stay for Acquired Inactive Wells in Compliance Plan Calculations

[Suggested placement: new §3.15(i)(4). The minimum plugging or restoration requirement referenced below is the annual minimum in proposed §3.15(i)(1)(C)(iii).]

(1) An operator may file a petition with the Commission requesting a stay of the inclusion of acquired inactive wells and associated facilities in the calculation of the operator's minimum plugging or restoration requirement under subsection (i)(1)(C)(iii) of this section. A well or facility is eligible only if the Commission approved the operator's Form P-4 (Certificate of Compliance and Transportation Authority) for it within the 12-month period preceding the date the petition is filed.

(2) The Commission may grant a stay by order. An order under this paragraph:

(A) shall identify each well subject to the stay by API number and each facility subject to the stay by permit or identification number; and

(B) shall remain in effect for the period specified in the order, not to exceed three consecutive annual compliance periods.

(3) In determining whether to grant a petition under this paragraph, the Commission shall consider:

(A) the operator's plan for the development, redevelopment, or return to active operation of the acquired wells and facilities;

(B) the operator's record of compliance with Commission rules and orders; and

(C) the operator's history of revitalizing previously developed fields.

(4) A stay granted under this paragraph:

(A) does not extend any deadline established under Texas Natural Resources Code §89.023; and

(B) does not relieve the operator of the obligation to plug any well that the Commission or its delegate determines is leaking or otherwise poses a threat to public health, safety, or the environment.

(5) A stay granted under this paragraph is not transferable. If a well or facility subject to the stay is transferred to another operator, the stay terminates as to that well or facility.

(6) Upon expiration or termination of a stay, each well or facility subject to the stay that has not been plugged or restored to active operation shall be included in the calculation of

the operator's minimum plugging or restoration requirement for the next compliance period.

(7) A petition under this paragraph may be filed and granted both before and after September 1, 2042.

ATTACHMENT B

Proposed Rule Language: Definition of "Restored to Active Operation"

[Suggested placement: new §3.15(a)(11), following §3.15(a)(10) in the alphabetical list of definitions.]

(11) Restored to active operation--With respect to an inactive well:

(A) returned to active operation as defined in paragraph (2) of this subsection; or

(B) converted to and placed in operation as a disposal, injection, monitoring, or other service well for which the Commission has issued all required permits or authorizations, as evidenced by:

(i) the Commission's issuance of the permit or authorization;

(ii) successful completion of any mechanical integrity or other testing required by the permit or authorization; and

(iii) commencement of the authorized operation, as shown by a report filed with the Commission or other documentation of operation, as applicable to the type of well.