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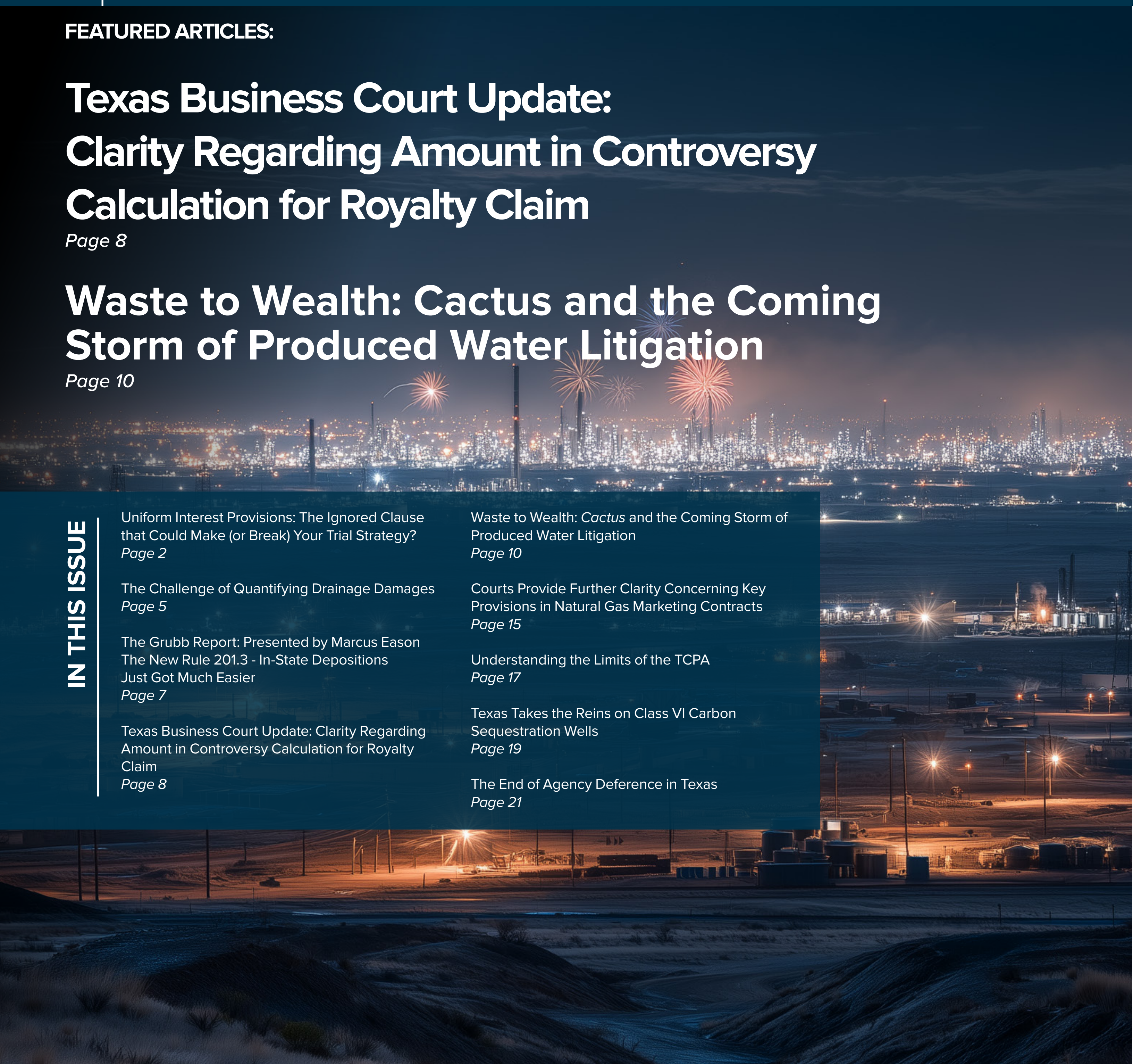
McGINNIS LOCHRIDGE

Producer's Edge

TEXAS OIL AND GAS LAW BULLETIN



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The McGinnis Lochridge Oil and Gas Practice Group publishes the *Producer's Edge* with the purpose of keeping our valued clients and contacts in the oil and gas industry updated and informed regarding interesting Texas case law and regulatory developments, as well as providing insightful articles relevant to the oil and gas community. In this print and digital publication, we also routinely welcome various other practice groups to share guest articles surveying other areas of the law important to the oil and gas industry.

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McGINNIS LOCHRIDGE

EVENTS, PUBLICATIONS, AND AWARDS

NEWS AND HONORS

- McGinnis Lochridge names Carl Galant Managing Partner effective January 1, 2026 as featured in Law360 and Texas Lawyer.
- McGinnis Lochridge was a hole sponsor at the ExxonMobil Golf Tournament on November 3, 2026.
- McGinnis Lochridge was a proud sponsor of the IEL Annual Energy Litigation Conference on November 4 in Houston, TX.
- Travis Barton and Jonathan Baughman were selected as 2026 US Litigation Stars in Benchmark Litigation while Austin Brister and Will Grubb were named to the 40 & Under List. Will Grubb was also recognized as a 2026 Future Star.
- Jonathan Baughman, Austin Brister, Will Grubb, Kevin Beiter, and Derrick Price were recognized in the Legal 500 City Elite Rankings.
- McGinnis Lochridge earned top honors from Best Law Firms® Ranked by Best Lawyers, being named a 2026 Tier 1 National Law Firm in Oil & Gas Law, as well as a 2026 Tier 1 Regional Law Firm in Oil & Gas Law in Austin, Dallas/Fort Worth, and Houston.
- Jonathan Baughman, Kevin Beiter, Tim George, and Derrick Price were selected as Texas 2025 Super Lawyers, while Alejandra Salas and Will Grubb were named to the 2025 Texas Rising Stars list.
- Austin Brister was selected to the "500 Leading Energy Lawyers" list by Lawdragon, and Will Grubb was named to Lawdragon 500 X – The Next Generation.
- Austin Brister selected as Course Director of the OGERL Section's 2026 Oil and Gas Disputes Course.
- Austin Brister selected as Co-Chair of the Permian Basin Special Institute, co-hosted by the Foundation for Natural Resources and Energy Law and the OGERL Section of the State Bar of Texas.
- Austin Brister and Jonathan Baughman appointed as Members of the Oil and Gas Pattern Jury Charge Committee, State Bar of Texas.
- Logan Jones was appointed as a new member of the IEL Advisory Board.
- Alejandra Salas was selected to join the Institute for Energy Law's 8th Leadership Class.

SPEAKING ENGAGEMENTS AND PUBLICATIONS

- Ashley Vega participated in the "A Day in the Life of a Litigator" panel at South Texas College of Law Houston on September 30, 2025.
- Jonathan Baughman moderated the panel "From Wells to Wind: Navigating the Future of Oil, Gas & Renewables," on September 18, 2025 at the SCG Legal Annual Meeting in Austin, TX. Among the panelists was the distinguished Jack Balagia, Former VP and GC of ExxonMobil Corporation.
- Marla Broaddus moderated the panel "The Client's Perspective: What Matters, What Works & What Drives Loyalty," on September 19, 2025 at the SCG Legal Annual Meeting in Austin, TX. Neal Nobles, Associate General Counsel of ExxonMobil Corporation was among the panelists.

UPCOMING

- Alejandra Salas and Austin Brister will co-present "2025 Oil and Gas Litigation Insights" at the 5th Annual U.S. Oil and Gas and Renewable Energy Law Seminar, sponsored by FNREL during NAPE 2026.
- Austin Brister will co-present "Negotiations in Renewable Energy Litigation" at the 21st Annual Renewable Energy Law Institute, co-hosted by The University of Texas School of Law and the Oil, Gas, and Energy Resources Law Section of the State Bar of Texas, January 2026.
- Austin Brister will present "Recouping Overpaid Royalties" at the 2026 Annual Oil, Gas and Mineral Law Institute, presented by The University of Texas School of Law CLE.

Uniform Interest Provisions:
The Ignored Clause that Could Make (or Break) Your Trial Strategy?

By: Austin W. Brister

Buried in most JOAs lies a provision that many ignore, but history has shown that it can cost companies hundreds of thousands in damages. And, from my own experience, it can also serve as an unsuspecting tool in litigation strategy. The provision? The Maintenance of Uniform Interest (or MUI) clause. While many practitioners view the MUI clause as forgetful boilerplate when drafting, or an administrative afterthought in transactions, I've discovered it can sometimes offer unexpected strategic leverage in litigation. From potential collateral attacks on operatorship succession to defensive positions in some preferential rights disputes, the MUI provision may be more versatile than traditional treatment suggests. This frequently-ignored provision may offer unexpected strategic leverage in complex disputes—or create unforeseen liabilities for the unwary.

The MUI: A Quick Refresher

It's worth noting that the MUI provision has been part of the AAPL forms since 1956, and despite there apparently being repeated calls for its elimination, the drafting committees retained it. For instance, the 1982 revision committee reportedly "deliberated a great deal" over whether to remove or weaken the provision, and ultimately chose not to do so. Indeed, the 1989 and 2015 forms also retain an MUI provision. Perhaps there's a message in that.

For those who haven't dusted off Article VIII.D in a while, the MUI generally requires all parties to maintain ownership uniformly across the Contract Area. According to the clause, parties cannot "sell, encumber, transfer or make other disposition" of their covered interests unless the disposition covers either their entire interest or "an equal undivided percent" across all leases, wells, equipment, and production.

Walk into just about any old legacy JOA contract area and you'll have a high chance of finding that the working interests have been carved up over the years through a series of creative dealmaking, elections, side letter agreements, and otherwise. Perhaps you'll find depth severances, selective acreage assignments, or wellbore-only assignments, among other title features that can slice and dice the leasehold ownership.

In theory, some have described the MUI clause as simply prohibiting any efforts to assign away the good assets while leaving the other parties holding dogs. Several papers have argued that the MUI clause prohibits partitioning merely as a way to avoid costs of additional measuring equipment, or to avoid marketing complications.

But are those occasional views accurate? Does the MUI truly prohibit any and all non-uniform assignment? Does the MUI really lack teeth, such that there are no damages for violating the clause beyond perhaps the cost of another meter? As we'll discuss in the *Valence* case below, those views are oversimplifications that ignore critical nuances, which the MUI clause could allow for certain types of partial transfers under the JOA. Moreover, the *Valence* case illustrates that damages for breach of the MUI clause can, in some cases, prove substantial.

The $834,299 Case Study

Before going much further, let's address the case that proved MUI violations can carry real teeth. In *ExxonMobil Corp. v. Valence Operating Co.*, 174 S.W.3d 303 (Tex. App.—Houston [1st Dist.] 2005), Valence walked away with $834,299 in damages plus attorney's fees for breach of the MUI provision.

ExxonMobil and Valence owned interests subject to an MUI. Down the road some time, ExxonMobil farmed out its interest in the Cotton Valley Sand formation while keeping its interest in the Cotton Valley Lime formation. No notice of the assignment was provided to Valence. The farmee later sent AFEs to Valence proposing the drilling of new wells, but Valence did not respond (apparently claiming they had no notice of the farmee's alleged interest). The farmee drilled the well and treated Valence as a non-consenting party subject to penalties. Valence sued for, among other things, violation of the MUI clause.

Here's where it gets interesting. ExxonMobil's counsel noticed a potential nuance in the MUI clause that they argued allowed partial transfers of certain rights. In essence, they argued that, when the MUI clause is interpreted precisely as written, its restrictions only apply to assignments that cover interests in the "wells, equipment and production." They argued that assignments that do not cover all three attributes do not trigger the MUI clause. Here, they argued that the farmout only transferred a naked leasehold, without any interest in the wells and equipment. They argued this did not trigger the MUI.

The appellate court ultimately rejected ExxonMobil's argument. But the precise rational is important. Some have incorrectly interpreted the court's holding as rejecting ExxonMobil's interpretation of the MUI. However, more precisely, the appellate court rejected ExxonMobil's argument because it found that ExxonMobil's farmout agreement transferred so broad an interest that it did transfer interests in the wells, equipment, and production—not just naked leasehold interests. Game over.

This creates an intriguing possibility for the careful drafter. Could a more surgical transfer (one that truly conveys only interests in production without any rights to wells or equipment) potentially sidestep the MUI? Of course, any party considering such an argument should recognize the risks. Courts might view attempts to parse the MUI language this finely as elevating form over substance. But for those looking for every possible angle in a high-stakes dispute, understanding these nuances could prove valuable.

The damages in *Valence* also deserve attention. The court awarded Valence its share of the difference between what it cost to drill new wells ($719,354 each) versus what it would have cost to complete the Cotton Valley Sand formation through existing wellbores ($150,000 each). Three wells later, that was serious money, and a cautionary tale for operators contemplating creative transactions.

Strategic Uses of MUI Claims

Beyond the direct enforcement scenario in *Valence*, MUI violations may provide ammunition in disputes that are not focused on uniformity of ownership. Consider these scenarios where MUI arguments could potentially shape strategy:

The Operatorship Challenge Play

Your client, a non-operator, watches as the operator sells its working interest while purporting to assign operatorship to that same buyer—no vote, no discussion, just a *fait accompli*. Maybe your client wanted to throw its hat in the ring for operatorship and a shot at accumulating sufficient votes. Or maybe the voting would result in a deadlock (another common JOA issue), and your client is frustrated by apparent streamroll rather than negotiation. Or perhaps your client has a custom provision that it believes gives it a right to succeed as operator.

Here's where the MUI might provide leverage (perhaps unexpectedly). If the operator's assignment violates the MUI provision—say, by transferring interests in only certain lands or certain depths—that violation could potentially give you an argument that might undermine the entire transaction. That is, an argument may be available that, if the underlying assignment violates the JOA's MUI clause, then the purported assignment of operatorship rights should also be invalid. Perhaps you also underscore complexities that introduces in JOA administration, or perhaps renders It's a collateral attack that could force the parties back to the negotiating table or into a proper succession of operatorship process.

The Asset-Shielding Strategy

I recently handled a case where a non-operator owned interests in seven wells under an aging JOA but believed only two remained economically viable. When the operator and other non-operators refused to plug and abandon the five marginal producers, the non-operator assigned the two best producing wells to an affiliated entity and stopped paying joint interest billings on the five marginal wells. The strategy was transparent: shield revenue from profitable wells from the operator's right to offset unpaid JIBs.

The selective assignment of only two wells out of seven arguably violated the MUI provision, giving the operator leverage to argue the transaction was ineffective under the JOA. Rather than chasing collection from the non-operator while watching revenue flow to its affiliate, an operator could consider leveraging the MUI violation to unwind the asset-shielding transaction or gain more favorable room for damages methodologies. In the right case, the MUI provision doesn't just prevent dumping bad assets, it may also prevent bad actors from strategically repositioning good assets to avoid legitimate obligations.

The AMI Complication

On the other hand, *Slawson v. Vintage*, illustrates another trap for the unwary. When Slawson sold its producing well but retained undeveloped acreage in alleged violation of the MUI, it created a mess that only surfaced years. Who had the right to participate in new acquisitions under the Area of Mutual Interest provision—the assignor who violated the MUI or the assignee who bought the well? The Tenth Circuit in that case ultimately looked to the assignment language rather than the MUI provision. But the case still demonstrates how a variety of disputes can entangle MUI clauses.

The Defensive Counter-Punch

Conversely, suppose your client faces a pref rights claim. The holder exercises rights to certain properties but not others within the contract area. Could this selective exercise itself constitute an MUI violation? Such an argument might complicate the pref rights holder's position, whether as to validity of the triggering assignment or validity of the purported assignment. How might arguments shift if the pref rights exerciser has been selective about MUI enforcement in the past?

Penalty Avoidance Deals

With some effort, one could imagine a scenario where non-operators may desire to avoid participating in a proposed operation while also desiring to avoid the JOA's non-consent penalties (hard to imagine, I know). This could be one motive underlying certain single wellbore transactions. Hypothetically, when a non-operator receives a well proposal they do not wish to accept, they face the choice of either going non-consent and incurring a non-consent penalty, or participating and paying for an unplanned and undesirable operation.

Some non-operators have sought to address this issue by posting for a quick auction a wellbore-only interest in that one proposal. By doing so, the seller non-operator sells a wellbore-only interest to a buyer that will participate, rather that merely sit around and relinquish their interest (and related value) by non-consenting. If the selling party had simply gone non-consent, the other participants would have acquired their interest subject to the penalty provisions. By farming out or selling a wellbore-only interest, they potentially avoid the relinquishment and extract some value from their interest.

In certain circumstances other JOA parties may argue these AFE deals undermine the balance of risk and reward contemplated by the JOA. For instance, it arguably deprives the other JOA parties of their rightful share of the non-consent penalty they would stand to gain when one of the other parties elects not to pay for their share of a proposed operation. These arguments will typically revolve heavily around the MUI provision.

The Enforcement Dilemma

Here's another rub: where the MUI provision is breached, the remedies for the most ordinary damages remain relatively underexplored in Texas courts. For instance, if the only damages are the need for additional measuring equipment, that may be quite nominal. If the damages are increased accounting burdens, that may also be minimal given advancements in modern computing beyond the day and age of IBM-compatibles running MS-DOS.

Yet again, even if MUIs have historically been ignored under a given JOA, that can create both opportunity and risk.

Anticipate Potential Arguments:

- Perhaps non-uniform transfers are void or at least ineffective.
- Perhaps non-consent penalties vanish if connected to an improperly transferred interest.
- Perhaps damages arise based on disrupted operations or increased accounting costs.
- Perhaps this would be a factor in operator removal.

Potential Defensive Playbook:

- Potential waiver arguments based on historical tolerance of breaches
- Potential estoppel defenses when parties have accepted benefits from non-uniform arrangements.
- Lack of damages (or merely nominal damages) where operations and allocations continue smoothly despite theoretical or technical violations.
- Perhaps the specific MUI can be read narrowly to allow the type of partial assignment at issue.

Practical Considerations

Before wielding the MUI provision as sword or shield, consider:

The Glass House. In some areas, few legacy JOAs have perfectly clean track records. Before asserting violations, consider auditing the JOA history and chain of title. Does that strengthen or weaken your case?

Other Documents. Transaction documents sometimes contain a variety of provisions that could impact this analysis. Similarly, custom JOA provisions may impact the analysis. Also, history of prior breaches from other transactions could give rise to estoppel or related defenses.

Damages. In the most routine cases, proving damages can be difficult or may only lead to nominal damages. Consider analyzing how or why the MUI provision may relate to a broader series of breaches or issues.

The Bottom Line

The MUI provision represents both a trap for the unwary and a potential tool for the creative advocate. As the Valence case demonstrates, MUI violations can result in substantial damages—this isn't just theoretical risk. The clause could provide compelling arguments in the right case, sometimes in ways you may not suspect.

Remember: Today's routine transaction could become tomorrow's litigation leverage.

The Challenge of Quantifying Drainage Damages

By: Logan B. Jones

When a lessor accuses a lessee of breaching the implied covenant to prevent drainage (a/k/a the implied covenant to drill an offset well), the complaint often sounds devastating: “The oil and gas company let my minerals drain away to neighboring properties.” The damages demand follows a seductively simple logic: the lessor wants full royalty from the offset well that they claim should have been drilled.

Luckily for oil and gas companies, Texas law doesn’t work that way anymore—and understanding why gives lessee oil and gas operators substantial leverage in both litigation and settlement negotiations when they are accused of breaching the covenant to prevent drainage.

The Old Rules That Invited Overcompensation

Before 2008, lessors had their choice of two damage theories, both of which systematically overcompensated them. Some courts awarded damages equal to the full royalty the lessor would have received from a hypothetical offset well on their property. *See, e.g., Kerr-McGee Corp. v. Helton*, 133 S.W.3d 245, 253 (Tex. 2005). Others awarded the value of all gas drained from the lessor’s tract. *See, e.g., Southeastern Pipe Line Co. v. Tichacek*, 977 S.W.2d 393, 399 (Tex. App.--Corpus Christi 1998), *aff’d in part and rev’d in part*, 997 S.W.2d 166 (Tex. 1999).

Both measures of damages risked over-compensating the lessor. If the hypothetical offset well would have produced more than was actually drained—which is highly dependent on reservoir characteristics, well spacing, and other factors—the first rule gave the lessor a windfall. If not all drainage could have been prevented by drilling an offset well—due to field-wide drainage, regulatory constraints, and other factors—the second rule did the same.

The Texas Supreme Court recognized this tension in *Coastal Oil & Gas Corp. v. Garza Energy Trust*, noting that prior formulations “would overcompensate the lessee if production from the offset well exceeded the drainage” or “if not all of the drainage could have been prevented.”

Establishing and Measuring Damages After *Coastal Oil*

The *Coastal Oil* Court’s solution established what sounds like a straightforward standard: damages should equal “the value of the royalty lost to the lessor because of the lessee’s failure to act as a reasonably prudent operator”—no more, no less.

This reformulation did more than adjust the arithmetic. It fundamentally shifted the burden of proof in drainage cases in ways that many lessors initially failed to appreciate. After the *Coastal Oil* opinion, to prosecute a drainage case the lessor must now prove, based on the Court’s opinion in that case and existing case law:

- That substantial drainage actually occurred from their specific tract.
- That a reasonably prudent operator would have drilled an offset well under the circumstances (i.e., that the offset well would have produced in paying quantities).
- The value of the royalty lost to the lessor because of the lessee’s failure to act as a reasonably prudent operator. This might involve, for example, determining the quantity of minerals that the offset well would have prevented from draining (volume for gas, barrels for oil), the market value of those minerals at the relevant time, and the resulting royalty payment under the lease terms.

Each element requires expert testimony. And here's what matters for lessees: these aren't easy questions, even for qualified experts.

Where the Proof Gets Complicated – Damages

Consider the third element—quantifying the value of royalty lost, including how much drainage the hypothetical offset well would have prevented. This requires sophisticated reservoir engineering analysis of factors such as:

- Formation characteristics such as porosity, permeability, pressure, and fluid properties.
- Reservoir conditions and variations between tracts.
- Pressure gradients and fluid migration patterns.
- Production history in the area.
- The specific location and completion design of both the draining wells and the proposed offset well.
- Regulatory constraints on well spacing and density.
- Economic considerations affecting what a reasonably prudent operator would have done.

The lessor's expert must reconstruct a counterfactual scenario: what would have happened if a well had been drilled that wasn't actually drilled. Then the lessor's expert must be able to ascertain and explain to a judge or jury what drainage could have been prevented and what drainage would have occurred regardless of the lessee's hypothetical offset well.

There are instances where a lessor's expert can confidently opine that substantial drainage occurred and a reasonably prudent operator would have drilled an offset well—satisfying the threshold liability questions—but then struggle on cross-examination when asked to quantify exactly how much of that drainage a single offset well would have prevented. Proving that substantial drainage happened establishes the breach, but the lessor still must quantify the specific royalty value lost with reasonable certainty. Vague and speculative testimony about "significant" or "substantial" losses won't carry the day on damages, which must be proven with reasonable certainty.

The Practical Defense

This expert-intensive standard creates strategic opportunities for lessees:

Early Case Evaluation Gets Sharper. When evaluating exposure in a drainage claim, the question isn't just "did drainage occur?" It's "can the lessor's expert prove, with reasonable certainty, exactly how much royalty was lost that an offset well would have captured?" Many claims that appear serious at the pleading stage may have proof problems that counsel can identify and exploit.

Expert Selection Matters More. The lessor likely needs multiple experts to carry their burden: a reservoir engineer who can quantify drainage and build a persuasive model of what the hypothetical offset well would have produced, and an operations or management expert who can testify about what a reasonably prudent operator would have done under the circumstances—addressing industry practices, economic considerations, and operational decision-making. The defense can challenge the reservoir engineer's model by showing that the assumptions are unreliable or the conclusions speculative. Additionally, the lessee may be able to use its own employees to rebut the lessor's testimony on the reasonably prudent operator standard, creating a significant cost advantage. Highlighting the range of potential outcomes—the inherent uncertainty in both the reservoir analysis and the operational judgment—serves the defense while multiplying the lessor's expert costs.

Causation Becomes the Battlefield. Even if substantial drainage occurred, the lessor must prove through expert testimony that a reasonably prudent operator would have drilled the offset well. This opens arguments about economics (would it have been profitable?), regulatory constraints (could it have been permitted?), and timing (when should it have been drilled, and does that affect the damage calculation?).

Settlement Leverage Improves. When lessors realize they face an expensive expert battle with an uncertain outcome, reasonable settlements become more achievable. The lessor who demands full royalty from a hypothetical well should be more willing to settle for a fraction once they understand what *Coastal Oil* actually requires them to prove.

The Broader Signal

Coastal Oil reflects judicial skepticism of damage rules that overcompensate plaintiffs. The Court explicitly rejected formulations that might give lessors windfalls and insisted on damages that track actual losses. This principle extends beyond offset well cases—it's worth considering how courts might apply similar reasoning to other implied covenant disputes where damage calculations have been generous to lessors.

The case also illustrates a recurring dynamic in oil and gas litigation: as operational and geological understanding becomes more sophisticated, so do the standards for proving damages. Simple rules give way to complex, expert-driven inquiries. For a lessee, that complexity can often be used to its advantage.

About the Author

Logan Jones *is an associate in our Houston office and has represented large energy companies and individual and family mineral owners across the State of Texas in complex oil and gas litigation. He has successfully handled disputes concerning mineral and leasehold title, operator/non-operator disputes, and breach of joint operating agreements among other things.*

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The Grubb Report:
Presented by Marcus Eason
The New Rule 201.3 - In-State Depositions Just Got Much Easier

By: ~~Will Grubb~~ MARCUS EASON

I am honored to continue The Grubb Report: Presented by Marcus Eason, which was started by my colleague William Grubb. Like Mr. Grubb, I am a Texas trial lawyer that focuses on commercial and oil and gas litigation. As before, The Grubb Report, Now Presented by Marcus Eason will focus on updates in Texas law and procedure, as well as my general musings, thoughts, and ideas that may appear in the head of a Texas litigator.

In this episode of The Grubb Report, I want to call the readers' attention to the recent adoption of Texas Rule 201.3 by the Supreme Court of Texas, which implements the Uniform Interstate Depositions and Discovery Act (UIDD) for depositions and document requests that occur in Texas.

In the past and under the former Texas Rule of Civil Procedure 201.2, out-of-state attorneys desiring to take oral or written depositions in the State of Texas had to first obtain some order or process (a "mandate, writ, or commission") from the jurisdiction in which the case was pending. Then, such "mandate, writ, or commission" could be used to compel a witness to comply, in the same manner as Texas subpoenas – but of course that would potentially require the out-of-state attorney to commence a Texas proceeding, which becomes complicated if the attorney is not licensed in Texas.

Now, the Supreme Court of Texas has implemented the UIDD, which streamlines the taking of depositions and requests for documents for use in out-of-state proceedings. Under the new Rule 201.3, to compel deposition attendance or the production of documents in Texas, the out-of-state attorney need only "submit [their] out-of-state subpoena to a clerk of a district or county court in the county in which the discovery is sought to be conducted in Texas." TEX. R. CIV. P. 201.3(b)(1). At that time, the clerk will issue a Texas subpoena for the discovery sought. TEX. R. CIV. P. 201.3(b)(2). No more "mandates, writs, or commissions" are needed, which potentially increases the number of foreign depositions being taken in Texas' borders. Additionally, the new Rule 201.3 specifically provides that the request for the Texas subpoena does not constitute an appearance in a Texas court – so out-of-state attorneys need not wonder if local counsel is necessary to effectuate their out-of-state process.

For some of you with wide-ranging practices, it may make compelling discovery out of state simpler. For example, several jurisdictions (including Alabama and Georgia) that have adopted the UIDD only allow attorneys from states that have similarly adopted the UIDD to take advantage of the streamlined procedure for deposition and document requests. Ala. Code 12-21-406; O.C.G.A. 35-13-112.

In my practice, determining how to compel out-of-state discovery can sometimes be a chore, but now, if I want to compel certain discovery, I will check to make sure that the receiving state has adopted their own version of the UIDD, and I will make sure that I understand whatever reciprocity provisions exist.

To date, according to the Uniform Law Commission, every state but New Hampshire, Massachusetts, and Missouri has enacted the UIDD. At the time of this writing, Massachusetts and Missouri have introduced legislation aimed at adopting the UIDD.

The Texas version of the UIDD, found in Texas Rule of Civil Procedure 201.3, is in effect as of September 1, 2025.

Texas Business Court Update:

Clarity Regarding Amount in Controversy Calculation for Royalty Claim

Black Mt. SWD, LP v. NGL Water Sols. Permian, LLC, 2025 Tex. Bus. 24; 2025 TXBC LEXIS 27; 718 S.W.3d 281; 2025 WL 1826122

By: Ashley N. Vega

The Texas Business Court has made it clear that in order to satisfy its amount in controversy jurisdictional threshold when only unpaid royalties are sought under a breach of contract claim, the amount in controversy is limited to the actual damages, meaning the royalties actually accrued and owed at the time the lawsuit was filed. This does not include the lifetime value of all royalties that might ever become due under the royalty agreement.

In *Black Mountain SWD, LP v. NGL Water Solutions Permian, LLC*, the Court remanded the lawsuit to state court after rejecting the defendant's attempt to inflate the amount in controversy by including future royalty payments that the plaintiff had not sought in its pleadings.

Key Takeaways

- It is important to assess what the petition is actually seeking. When a plaintiff sues for the amount of unpaid payments under a contract, the amount in controversy is the sum of those past-due payments and not the theoretical value of all future payments under the agreement.
- A party seeking to remove a case from state court to the Business Court bears the burden of establishing jurisdiction. If the plaintiff presents evidence that the amount in controversy falls below the Court's amount in controversy threshold, the defendant must then present controverting evidence, not just argument, raising a fact issue to avoid remand.

The Dispute

Black Mountain SWD, LP ("Black Mountain") and NGL Water Solutions Permian, LLC ("NGL") entered into a royalty agreement that was executed pursuant to a purchase and sale agreement. The royalty agreement entitled Black Mountain to a $0.03-per-barrel royalty for product transported through the pipelines the royalty agreement covered. Notably, the royalty was payable only on the volumes of product for which NGL received a transportation fee from a non-affiliated third party. The royalty was not payable for saltwater transported as a result of capacity balancing across current and future saltwater disposal assets.

NGL stopped paying royalties, after which Black Mountain believed that NGL had been avoiding paying royalties by mislabeling the transportation of saltwater and its associated fee. Black Mountain argued NGL was charging third parties a disposal fees, rather than a transportation fee, for transporting saltwater from well sites to an injection well. Specifically, Black Mountain asserted that over the span of five years, NGL categorized over 144 million barrels of saltwater as "capacity balancing" (which the royalty agreement excluded) and paid the royalty on only 22,102 barrels.

Black Mountain sued for breach of contract in Tarrant County state court, seeking actual damages exceeding $1 million. NGL then removed the case to Business Court without Black Mountain's consent, asserting that the Court had jurisdiction because the lifetime value of disputed royalties under the royalty agreement exceeded the $10 million threshold required for jurisdiction.

The Court's Analysis

This is not the first time the Business Court analyzed the amount in controversy issue. In finding that the amount in controversy was not met and therefore the Court had no jurisdiction, the Court used the following framework from C Ten 31 LLC ex rel. SummerMoon Holdings LLC v. Tarbox:

- When the petition alleges the amount in controversy, the pleading controls unless: (a) a party presents evidence that the amount is falsely asserted to wrongly obtain or avoid jurisdiction; or (b) a different amount in controversy is readily established, such as by statutory set fees.
- When a plaintiff's pleadings are silent as to the amount in controversy, but the removing party's notice of removal properly pleads that the amount is within the Court's jurisdiction, these pleadings will be given the same deference and will control absent the presence of section (a) and (b) described above.
- In either case, if a party presents evidence that the amount in controversy is outside of the Court's jurisdiction, the Court will remand the case unless another party presents controverting evidence that raises a fact issue.
- If a fact issue exists, the party asserting jurisdiction will bear the burden of proof.

While NGL argued that the lifetime value of all royalties owed to Black Mountain under the royalty agreement exceeded $10 million, the Court rejected this argument, finding NGL did not meet its burden to establish the amount in controversy threshold.

First, the amount in controversy here is the amount of past damages for unpaid royalties. Per Black Mountain's petition, the actual damages sought equal the amount of unpaid royalties per barrel of saltwater transported for unaffiliated third parties through the pipelines that are subject to the royalty agreement. Black Mountain, in turn, sought reimbursement for the non-payment of periodic royalties that had already accrued and were owed. Per the Court, the allegations did not demonstrate Black Mountain was seeking any future damages to protect non-monetary privileges or rights such as declaratory or injunctive relief.

Second, Black Mountain's evidence established that the amount in controversy was no more than $4.5 million. Black Mountain presented evidence that the amount in controversy was outside of the Court's jurisdiction. Specifically, Black Mountain presented a declaration from its CFO calculating $4,422,789.15 in royalties owed from the royalty agreement's date of execution through the date the lawsuit was filed.

Third, NGL offered no controverting evidence to raise a fact issue. Turning to the burden shifting analysis, because Black Mountain presented evidence that the amount is outside the Court's jurisdictional limits, NGL carried the burden to present controverting evidence but failed to do so. The Court indicated that while NGL's counsel explained that basis for removal based on the petitions' allegations, "counsel's interpretation of Black Mountain's allegations is not evidence establishing Black Mountain seeks more than $10 million in relief."

The Court also addressed NGL's argument surrounding the "theoretical recovery of royalties on discarded saltwater." However, Blackwater's pleadings did not bring into controversy the amount of all payments that could ever come due under the royalty agreement. The "proper inquiry is to ask what the parties seek to recover, not what they will recover or are likely to recover, when the pleadings are filed." Accordingly, the Court's analysis was limited to the amount due and owing on the contractual past-due royalties when the lawsuit was filed.

Why This Case Matters

This decision provides a roadmap for plaintiffs seeking to keep periodic-payment disputes out of the Business Court and notice to defendants hoping to remove them. The Court made clear that the amount in controversy turns on what the plaintiff actually seeks, not what the defendant believes could theoretically be at stake. For contracts involving ongoing payment obligations like royalties, the jurisdictional inquiry focuses on accrued amounts at the time of filing. Parties seeking removal must come prepared with evidence, not just arguments, if they want to establish the Court's amount in controversy threshold.

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Waste to Wealth:
Cactus and the Coming Storm of Produced Water Litigation

Cactus Water Servs., LLC v. COG Operating, LLC, 718 S.W.3d 214 (Tex. 2025)

By: Austin W. Brister

In one of the most anticipated cases of 2025, the Texas Supreme Court's decision in *Cactus Water Services, LLC v. COG Operating, LLC,* No. 23-0676, resolves—on its face—a straightforward question of first impression: who owns produced water when an oil and gas lease doesn't expressly address it? The Court delivered its answer with unusual speed following oral argument: the mineral lessee, not the surface owner. In essence, the Court held that produced water is a waste byproduct of oil and gas production, necessarily included in a mineral lease unless it expressly states otherwise.

But any practitioner who reads only the majority opinion and considers produced water to be a totally settled matter is making a serious mistake.

Justice Busby's concurrence, joined by Justices Lehrmann and Sullivan, tells a different story. It's a roadmap of unresolved issues that many believe will spawn a new wave of oil and gas litigation in Texas. The concurrence makes clear that, although the *Cactus* opinion answers that one narrow question, the Court deliberately avoided a host of thornier issues lurking just beneath the surface, such as related royalty obligations, rights to lithium extraction and beneficial reuse, and the very nature of the parties' relationship when technology and markets evolve such that this "waste" becomes wealth.

For some, *Cactus* is not the end of produced water disputes. It's the beginning.

Burden Transformed to Bonanza

To understand why this case matters, you need to understand the seismic shift that's occurring in how the industry views produced water. For over a century, produced water was simply waste—an expensive, hazardous byproduct that operators were legally obligated to dispose of properly. For example, in *Cactus*, COG Operating spent $21 million disposing of 52 million barrels of produced water between December 2018 and March 2021 alone. Operators viewed that as pure loss; or the cost of doing business in the oilfield.

But technology is rapidly changing that calculus. Produced water can now be treated and recycled for use in subsequent fracking operations. It can be mined for critical minerals like lithium. Companies like Element3 have successfully extracted lithium from Permian Basin produced water, transforming what was once a disposal problem and cost into a potential profit center. Some landowners have begun to contract around produced water, not for waste management, but with an eye toward new revenue streams.

This is where the litigation begins.

The Supreme Court's Holding: Produced Water as Incidental Waste

The facts of *Cactus* are straightforward. Between 2005 and 2014, COG Operating acquired four oil and gas leases covering approximately 37,000 acres in Reeves County. Some leases granted COG the right to explore for, produce, and keep "oil and gas" and others "oil, gas, and other hydrocarbons." None went further to describe "other minerals," or produced water, or even oil and gas waste. And three of the leases set out expressly prohibitions on COG's use of water.

Years later, in 2019 and 2020, Cactus came along and acquired "produced water lease agreements" from the surface owners, purporting to cover all right, title, and interest to "water from oil and gas producing formations and flowback water produced from oil and gas operations" on the same lands covered by COG's leases. When Cactus notified COG that it now owned the produced water, COG sued for a declaratory judgment. The trial court and appellate court sided with COG.

The Supreme Court affirmed that COG, the mineral lessee, owned the produced water. Justice Devine's majority opinion rests on several key principles. First, the Court emphasized that "produced water is an inherent and inescapable byproduct of oil-and-gas production. Hydrocarbons cannot be extracted without simultaneously generating liquid waste, and production cannot continue without disposing of this hazardous—sometimes toxic—solution."

Second, the Court held that Texas law has "long recognized that the hydrocarbon producer's possession and control over the disposition of liquid-waste byproduct is necessarily incidental to, and therefore encompassed in, a conveyance of oil-and-gas rights." The Court relied heavily on statutory and regulatory definitions that classify produced water as "oil-and-gas waste" and on longstanding industry practice placing disposal obligations squarely on operators.

Third—and this is critical—the Court rejected Cactus's argument that produced water is simply "water" that belongs to the surface estate. While acknowledging that produced water "contains molecules of water, both from injected fluid and subsurface formations," the Court held that "the solution itself is waste—a horse of an entirely different color." The Court distinguished cases like *Robinson v. Robbins Petroleum Corp.*, 501 S.W.2d 865 (Tex. 1973), which had previously held that brine remained water belonging to the owner of the surface estate notwithstanding its salt content. The Court distinguished *Robinson* on grounds that it involved saltwater extracted from a dedicated water well and used for flooding operations, whereas produced water was liquid waste generated from hydrocarbon production. The Court emphasized that produced water is subject to a specialized regulatory scheme unique to oil-and-gas waste, further distinguishing it from the groundwater at issue in *Robinson* and similar cases.

Fourth, the Court emphasized that the conveyances must be interpreted as of the time they were executed, not through a modern lens informed by new technologies. The parties contracted at a time when produced water was understood to be burdensome waste requiring disposal. "Courts cannot employ a backward-looking construction of the conveyances that is informed by new technologies offering the potential for recycling and reuse that were not within the parties' contemplation at the time of the conveyances."

Finally, the Court held that if surface owners want to retain ownership of produced water, "the reservation or exception from the mineral conveyance must be express and cannot be implied." Because the leases here contained no such express reservation, COG owns the produced water.

The majority opinion provides a bright-line rule: absent express language to the contrary, produced water goes with the minerals. Many operators saw this as a significant victory. For surface owners and would-be produced water entrepreneurs like Cactus, it could be a setback. But, as Justice Busby's concurrence illustrates, those viewpoints may not be absolute.

Justice Busby's Concurrence: The Devil in the Details

Here is where sophisticated practitioners have paid attention. Justice Busby, joined by Justices Lehrmann and Sullivan, wrote separately to emphasize that the majority opinion is narrow, and to highlight several outstanding potential issues the majority did not decide.

Semantics: Words Matter

Notably, Justice Busby deliberately uses different terminology throughout his concurrence. While the majority consistently refers to "produced water," Justice Busby repeatedly uses the term "produced groundwater" and "groundwater produced with hydrocarbons." This semantic choice is significant because it characterizes the substance as groundwater that happens to be produced alongside hydrocarbons, rather than as a waste byproduct that happens to contain water molecules. The distinction may seem subtle, but it is a distinction that could influence how future courts analyze related ownership and compensation questions.

The Default Rule: Freedom to Contract

Justice Busby's first point is foundational: the Court's holding "merely represents the default rule" and "parties are free to contract differently." This may seem obvious, but it's critical. The Court did not hold that produced water must belong to the operator as a matter of law. It held that, absent express language, produced water is included in a hydrocarbon conveyance. So sophisticated parties, going forward, may intentionally and expressly cover produced water in their agreement.

But what about the tens of thousands of existing leases that don't expressly address produced water? That is where the litigation begins.

A Big Distinction: "Oil and Gas" vs. "Oil, Gas, and Other Minerals"

Justice Busby's second point is crucial and could drive significant litigation. The leases at issue in *Cactus* conveyed rights only to "oil and gas" or "oil, gas, and other hydrocarbons." Busby's concurrence states that the majority opinion "does not apply to the production of any unleased minerals or those incidental to the leased minerals (i.e., minerals in addition to 'oil and gas' or 'oil, gas, and other hydrocarbons')."

Think about that. Most lease forms cover "oil, gas, and other minerals." If you acquired such a lease, do you now own the lithium possibly dissolved in the produced water? Justice Busby specifically flags this as an open question. The majority expressly noted this in a footnote, stating "[w]e express no view regarding ownership of any nonhydrocarbon minerals included in liquid-waste byproduct, as no such substances are in dispute here."

This distinction is going to matter—a lot. Lithium is a mineral, not a hydrocarbon. If an operator holds a lease granting "oil, gas, and other minerals," there's a plausible argument that lithium extraction rights were included in that conveyance. But if the lease grants only "oil and gas" or "oil, gas, and other hydrocarbons," there's a plausible argument that lithium extraction is outside the scope of the grant.

The Texas Legislature tried to address this issue earlier in 2025 with proposed legislation (SB 1763) that would have classified minerals contained within brine as part of the mineral estate. Significantly, the bill defined "brine" to specifically exclude groundwater, surface water, and produced water. This exclusion suggests the Legislature recognized that produced water occupies a different legal category than other brine sources—a distinction that could be relevant in future statutory interpretation arguments. The bill ultimately stalled and failed.

That legislative failure, combined with the majority's express reservation of the issue, sets the stage for significant future litigation over who owns lithium and other minerals in produced water. Expect to see discovery battles over the composition of produced water, expert testimony about whether lithium should be classified as incidental to oil-and-gas production, and sophisticated arguments about whether direct lithium extraction (DLE) technologies constitute "production" of minerals or something else entirely.

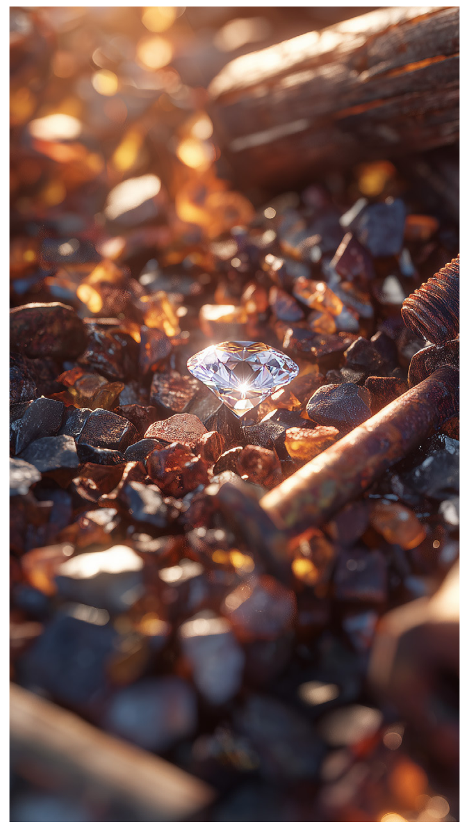
Financial Obligations: The Royalty Question

Busby's third point is perhaps most explosive: "The Court does not address the mineral lessee's obligation to a landowner for the groundwater produced with the hydrocarbons." He then poses a series of questions that could foretell an onslaught of future royalty litigation:

- Will the lessee owe royalties on the produced water it now owns?
- If so, how should the parties account for those royalties?
- What about when produced water is sold for beneficial reuse rather than disposed of?
- How should the parties account for any profit or loss realized from beneficial reuse or disposal?

These are not mere hypotheticals. Consider the economics. COG spent \$21 million disposing of 52 million barrels of produced water (roughly 40 cents per barrel). But if COG could instead sell that produced water for beneficial reuse at, say, 50 cents per barrel, that's a \$26 million swing—from a \$21 million cost to a \$5 million profit. Do mineral owners with a lease providing royalties on "oil, gas, and other hydrocarbons" get a royalty on that profit? Under what theory?

And it gets more complicated. Suppose COG can treat and reuse produced water on-site for \$25 million, compared to the \$21 million it was spending on disposal. That's a \$4 million economic loss. Does the mineral owner share in that loss through reduced royalties on hydrocarbons? Or is waste management purely an operational expense that doesn't affect royalty calculations?



Consider another complication. What if COG were to spend \$10 million on treating and handling the produced water, and then sells the treated water for \$1 million? That would be an overall loss of \$9 million, but still much better than \$25 million in disposal costs. Would the mineral owner be entitled to a royalty on the water sales, even though it was a net loss, and even though it was an alternative to the substantial disposal costs?

These questions have no bright-line answers, and the *Cactus* majority opinion doesn't attempt to provide them.

Implied Covenants and the Duty to Manage

Justice Busby's concurrence also hints at implied covenant issues that could spawn an entirely separate line of litigation. If the mineral lessee now "owns" the produced water and has the exclusive right to its "possession, custody, control, and disposition," what implied duties does that create, if any?

Traditional implied covenants in oil and gas leases include the duty to reasonably develop the lease, the duty to protect the lease, and the duty to market. Could there now be an implied covenant to maximize the value of produced water? If beneficial reuse technology exists that would generate more value than disposal, does the operator have an obligation to pursue it?

Consider the scenario where an operator continues to dispose of produced water at a cost of $0.40 per barrel when a produced water recycling company might pay $0.50 per barrel. If the operator owes royalties on produced water sales (a question Justice Busby leaves open), does the operator breach an implied covenant by disposing rather than selling?

Conversely, if the operator doesn't owe royalties on produced water, does it have any obligation whatsoever to maximize its value or to avoid disposal costs? Or can the operator dispose of it however it sees fit, regardless whether it could be monetized? How might that analysis impact other implied covenants, given that they can depend on overall profitability.

The majority doesn't answer these questions. But they're there, waiting for creative litigators.

House Bill 49: A Legislative Band-Aid on a Gaping Wound

While the *Cactus* litigation was pending, the Texas Legislature was paying attention. On June 20, 2025—just one week before the Supreme Court issued its opinion—Governor Abbott signed House Bill 49 into law.

H.B. 49 provides broad liability protections to companies that sell produced water. As of September 1, 2025, companies selling produced water can only be sued for gross negligence, failure to comply with applicable laws and standards, and other wrongful acts. Critically, the law also creates a handling-and-discharge permitting system overseen by the Texas Commission on Environmental Quality (TCEQ). While the Railroad Commission of Texas (RRC) traditionally holds regulatory oversight over oil and gas waste, H.B. 49 consolidates regulatory authority over produced water beneficial reuse under the TCEQ. The TCEQ will develop rules and effluent standards for the treatment and beneficial use of produced water, including permits for discharge and land application. Lawmakers anticipate this will streamline the permitting process for businesses seeking to monetize produced water, though it also fragments regulatory oversight between two agencies depending on whether the produced water is being disposed of (RRC jurisdiction) or beneficially reused (TCEQ jurisdiction).

This legislation is significant, but it doesn't resolve the many questions left open by *Cactus*. In fact, H.B. 49 might make some of these disputes more likely. By providing liability protections and establishing a regulatory framework for produced water sales, the Legislature has effectively greenlighted a produced water market. As that market develops and operators increasingly view produced water as a revenue source rather than a disposal cost, the economic stakes increase, and the litigation will follow.

Practical Implications

Based on *Cactus* and Justice Busby's concurrence, operators should expect a wave of produced water litigation over the next several years. The disputes will likely fall into three categories, each requiring different preparation.

Category One: Lease Interpretation Disputes

The *Cactus* default rule will generate years of litigation over whether specific lease language deviates from it—much like the steady stream of cases following *Van Dyke v. Navigator Group*, where parties continue arguing their deed language deviates from that default rule for double-fraction royalty deeds.

Review your entire lease portfolio, not just granting clauses. Cactus tells us the granting clause is critical, and the Court held that provisions merely limiting the use of water on the leased premises did not deviate from the default because they did not address ownership. But lessors will argue that other clauses—water use provisions, scope-of-rights language, surface use restrictions—are sufficient to take their lease outside the default. Identify leases with unusual language now.

Expect discovery aimed at establishing the parties' intent at execution, including course of dealing and industry custom. You may need experts on historical industry practices and what parties in a given era would have understood various lease terms to mean.

Category Two: Royalty Claims

When operators generate revenue from produced water—whether through sales, beneficial reuse, or lithium extraction—royalty claims will follow. These claims could arise from direct operator activities or even when an operator sells produced water to a third party who then extracts and sells lithium.

Review royalty clauses across your portfolio. Analyze how various provisions may create exposure—not only whether any royalty is due, but also the royalty yardstick, valuation location, and permissible deductions. Pay particular attention to catch-all provisions like "other benefits" clauses and how courts might apply them to produced water monetization.

Expect discovery into the composition of your produced water (particularly lithium content), revenues and cost savings from reuse or sales, and your accounting methodology. You may need experts on produced water composition, lithium extraction economics, and royalty accounting—including whether avoided disposal costs factor into royalty calculations.

Category Three: Implied Covenant Claims

Perhaps the most novel category: claims that operators have an implied obligation to monetize produced water rather than disposing of it. The implied covenant to market has long applied to hydrocarbons; plaintiffs will argue it extends to produced water now that *Cactus* confirms operators own it.

The theory is straightforward: if an operator disposes of produced water at significant cost when beneficial reuse, sales, or lithium extraction would generate revenue, the operator breached its duty to act as a reasonably prudent operator.

Document your decision-making on disposal versus alternatives. Maintain contemporaneous records of your analysis—disposal costs, potential revenues from alternatives, and why you chose your approach. Monitor the developing produced water market; what is defensible today may not be in two years.

Expect discovery into every aspect of your produced water management: volumes, disposal costs, alternatives you considered and rejected, and what other operators in the basin are doing. You may need experts on treatment technologies, market conditions, and what alternatives were economically feasible at the relevant time.

Across All Categories

When produced water from multiple leases is commingled for treatment, sale, or disposal, anticipate discovery and/or additional ground for disputes regarding allocation methodologies and related records.

The transformation of produced water from waste to wealth is accelerating. Conduct a portfolio-wide lease review, establish documentation protocols, and identify experts before disputes arise.

Conclusion: A Narrow Holding with Broad Implications

Cactus provides a clear answer, but only to a narrow question: under oil and gas leases that convey only "oil and gas" or "oil, gas, and other hydrocarbons," but which do not expressly address produced water, the lease includes incidental produced water. But Justice Busby's concurrence makes clear that the Court has left many crucial questions unanswered.

The coming transformation of produced water from waste to wealth is not merely an economic phenomenon—it's a potential legal earthquake that could shape oil and gas litigation in Texas for years to come. The default rule is now settled. The disputes over what that default rule means in practice are just beginning.

About the Author

Austin Brister *is a partner in our Houston office. He represents upstream operators in the issues they face every day—from JOA disputes and operatorship challenges to lease termination and title matters. When disputes head to the courthouse, Austin serves as first-chair trial counsel in complex oil and gas litigation across Texas. He regularly publishes papers and speaks at energy law conferences throughout the year.*

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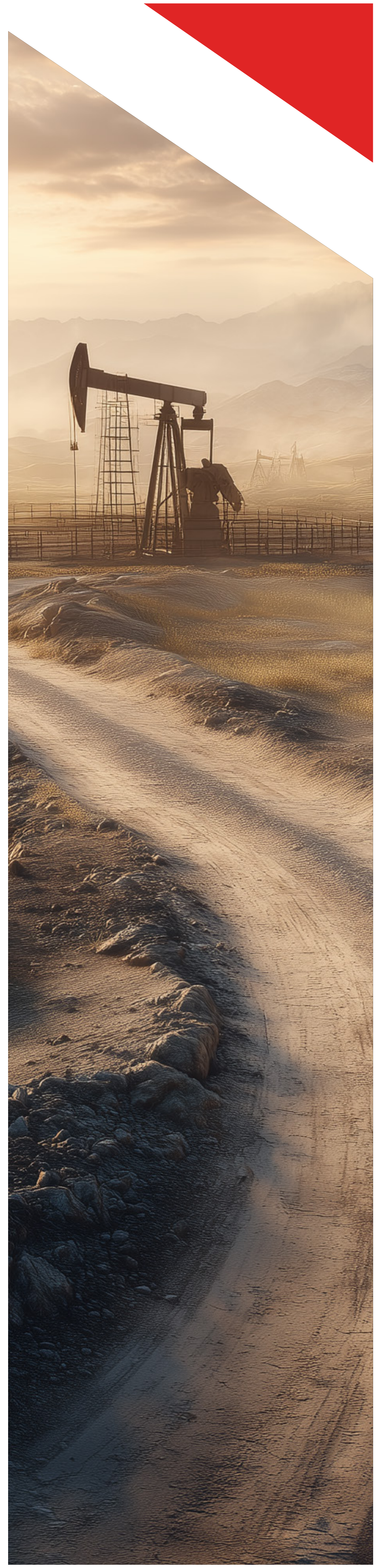

Courts Provide Further Clarity Concerning Key Provisions in Natural Gas Marketing Contracts

By: McLean Bell

In the fallout from Winter Storm Uri, Courts continue to clarify the meaning of key provisions in NAESB natural gas contracts. For decades, the check-the-box NAESB terms such as cover standards, payment methods, and force majeure provisions faced little scrutiny. But then Uri froze the Southwest, broke the energy supply chain, and sent gas prices into uncharted territories. The resulting high-dollar claims enticed industry participants to litigate the meaning of often overlooked terms.

The Eleventh Division of the Texas Business Court issued a trilogy of opinions in response to Marathon Oil's declaration under a NAESB base contract with Mercuria Energy America. Similar to other NAESB cases: the parties entered a deal that was subject to a NAESB and the added "Special Provisions." When Uri disrupted Marathon's gas production, it declared force majeure. Mercuria rejected the declaration, and the suit ensued.

Round One: Battle of the Forms

The first opinion presented a "battle of the forms" issue that arose when the parties entered an ICE deal but exchanged differing Transaction Confirmations. Gas traders often submit bids and negotiate deals on Intercontinental Exchange or "ICE." Following an agreement, the deals are usually "booked" and either one or both parties circulate a Transaction Confirmation memorializing the deal's terms.

Marathon and Mercuria's Transaction Confirmations contained the same price, quantity, delivery point, and duration terms that were agreed to over ICE. But Mercuria's Transaction Confirmation, which it sent first, denoted that the transaction was "firm," or uninterruptible without cause. Subsequently, Marathon sent a Transaction Confirmation that added a "pipeline term: "specifying", "Enable Gathering and Processing. This, it argued, designated the pipeline that would transfer its supply of gas to the trading hub.

Mercuria signed and returned Marathon's confirmation with checkmarks added to every term except the pipeline term. Mercuria argued that the pipeline term did not become a part of the deal because (1) the ICE agreement did not include the pipeline term, and the ICE agreement controls; (2) the confirmation materially differs from the NAESB; and (3) Mercuria rejected the term when it did not provide a check mark.

This issue was important, as Marathon likely had gas available on alternative pipelines. The pipeline term effectively limited the gas supply analysis to one source. Ordinarily, several pipelines transport gas to a pool or hub. Shippers may have gas transportation contracts with only some or several different pipelines. The inclusion of the pipeline term could prevent Mercuria from arguing that Marathon had gas available on alternative pipelines.

The Court rejected Mercuria's arguments. First, the parties elected for an oral transaction procedure under the NAESB. An ICE exchange qualifies as an oral transaction, but the NAESB required the "Confirming Party," here Marathon, to send Mercuria a Transaction Confirmation within three business days. Mercuria may also send its own, which it did. The NAESB further provides that Transaction Confirmations are binding unless the other party provided written notice of disagreement or the terms materially changed the terms of the NAESB or the oral agreement.

Here, neither party objected to the circulated Transaction Confirmations at the time they were circulated. The Court therefore held neither party provided the requisite written notice of disagreement. The Court further held the absence of check marks failed to provide notice of disagreement. And the Court did not agree that Marathon's confirmations materially differed from either the NAESB or the oral agreement.

In its analysis, the Court referenced NAESB Section 1.2, which distinguishes between commercial terms (i.e. price, quantity, performance obligation, delivery point, period of delivery and/or transportation conditions) versus terms that modify the NAESB (e.g., arbitration provisions or additional representations and warranties). The parties must expressly agree to the latter, whereas the parties must expressly reject the former. Therefore, the Court held that both Transaction Confirmations could be read together with the NAESB as one contract; the pipeline term became a part of the agreement, likely foreclosing Mercuria's ability to probe Marathon's alternative supply sources. Sellers that utilize several pipelines at the same hub or pool should consider specifying the pipeline in their Transaction Confirmations moving forward.

Round Two: A Special Provision that "Knocks Out" the Replacement Gas Conundrum

Judge Andrews's second opinion may solve a frequently litigated issue. That is: must a party purchase gas on the spot market to (1) meet its delivery obligations or (2) to satisfy 11.2's "reasonable efforts" condition? The Court, relying on several recent cases such as Mieco LLC v. Pioneer Natural Resources, USA, held that a party was not required to purchase gas on the spot market to satisfy its delivery obligations or to demonstrate its reasonable efforts to avoid the adverse impacts of URI.

These cases provide several key takeaways. First, the force majeure event need not render performance literally impossible, "because a buyer could always point to some gas available to the seller to buy, and the buyback method is never precluded due to a weather event." Second, a party's prior spot purchases and buybacks do not mean that such practice is a reasonable effort during a force majeure event. As the Mieco court held, in past instances where a party replaced its lack of supply through a buyout or spot purchase, the "party did not have the option to not perform because a shortage of gas without a [force majeure event] is not a force majeure occurrence." The Mieco court was especially persuaded by the fact that, in other contracts, Mieco included special provisions specifically precluding a declaration of force majeure when replacement gas was available to purchase.

In Marathon, the Court also examined the parties' Special Provisions. Relevantly, that "to the extent such failure was caused by Force Majeure [then] the party claiming excuse shall have no obligation to seek alternative Gas supplies in order to satisfy any obligation hereunder." The Court construed this provision as relieving Marathon of the obligation to purchase spot gas or buyback its position to satisfy the 11.2 "reasonable efforts to remedy the event or condition" provision. While other courts may reach the same conclusion in the absence of this provision, its addition may prevent future disputes.

Round Three: A Draw – Neither Party Conclusively Proved Actual Damage

In its last published opinion, the Court considered whether Mercuria's damages were an unlawful penalty, and whether Marathon's cost-basis theory was an appropriate measure of actual damage. This issue was raised via summary judgment where Marathon alleged Mercuria replaced its loss of supply through storage gas that was purchased before the storm. The storage gas was purchased for ~$2.00 per unit, whereas gas prices reached over $250 per unit at the West Transfer Delivery Point during the event.

The parties' NAESB provided for Spot Damages, meaning Mercuria was entitled to the difference between the contract price and the market price of gas at the delivery location, or the closest geographic location with a posted price. The contract price under the Transaction Confirmation was $2.61, so Marathon argued that Mercuria saved money when it replaced Marathon's shortfall with cheaper storage gas. Marathon argued that awarding Mercuria twenty-plus-million when Mercuria's actual damage was zero constituted an unlawful penalty.

The Court was unpersuaded. The Court held neither party had conclusively proven Mercuria's actual damage. Both parties submitted damage models that relied upon differing geographic price postings or used weighted averages. Due to the competing models, the Court held neither party conclusively established damages, which is quintessential to any penalty defense. Additionally, the Court rejected Marathon's argument that utilizing previously purchased storage gas was tantamount to Mercuria purchasing "cover gas." "Mercuria did not 'cover' – i.e., it did not 'purchase' substitute goods 'after a breach.' Instead, Mercuria used gas it already owned and purchased well before the breach."

In sum, the Court determined that Marathon's "cost-basis" damage model, which relied upon the direct cost of storage gas purchased before the breach, was the improper measure of damages for a penalty analysis. These issues were before the Court on summary judgment, and Marathon ultimately won on liability at trial. Hence, the issue of penalty remains uncertain and may be raised again.

Round Four – The Final Knockout

The first trial in Texas's new Business Courtsdelivered a final knockout blow to Mercuria. Following a four-day bench trial, the Court issued final judgment declaring that the extreme weather caused by Winter Storm Uri constituted a *force majeure*. The Court further held that Marathon made reasonable efforts to avoid the adverse impacts of *force majeure.* Therefore, Marathon's failure to deliver gas was excused.

About the Author

McLean Bell *is an associate attorney in our Austin office. McLean is a versatile trial lawyer who oversees high-stakes litigation for both individuals and the world's largest energy companies. He takes an upfront and candid approach to complex cases without sacrificing attorney's fees on antiquated approaches and inefficient practices. His methodology relies on early case evaluation, strategy, and goal setting, allowing him to accommodate the client's business goals and budget.*

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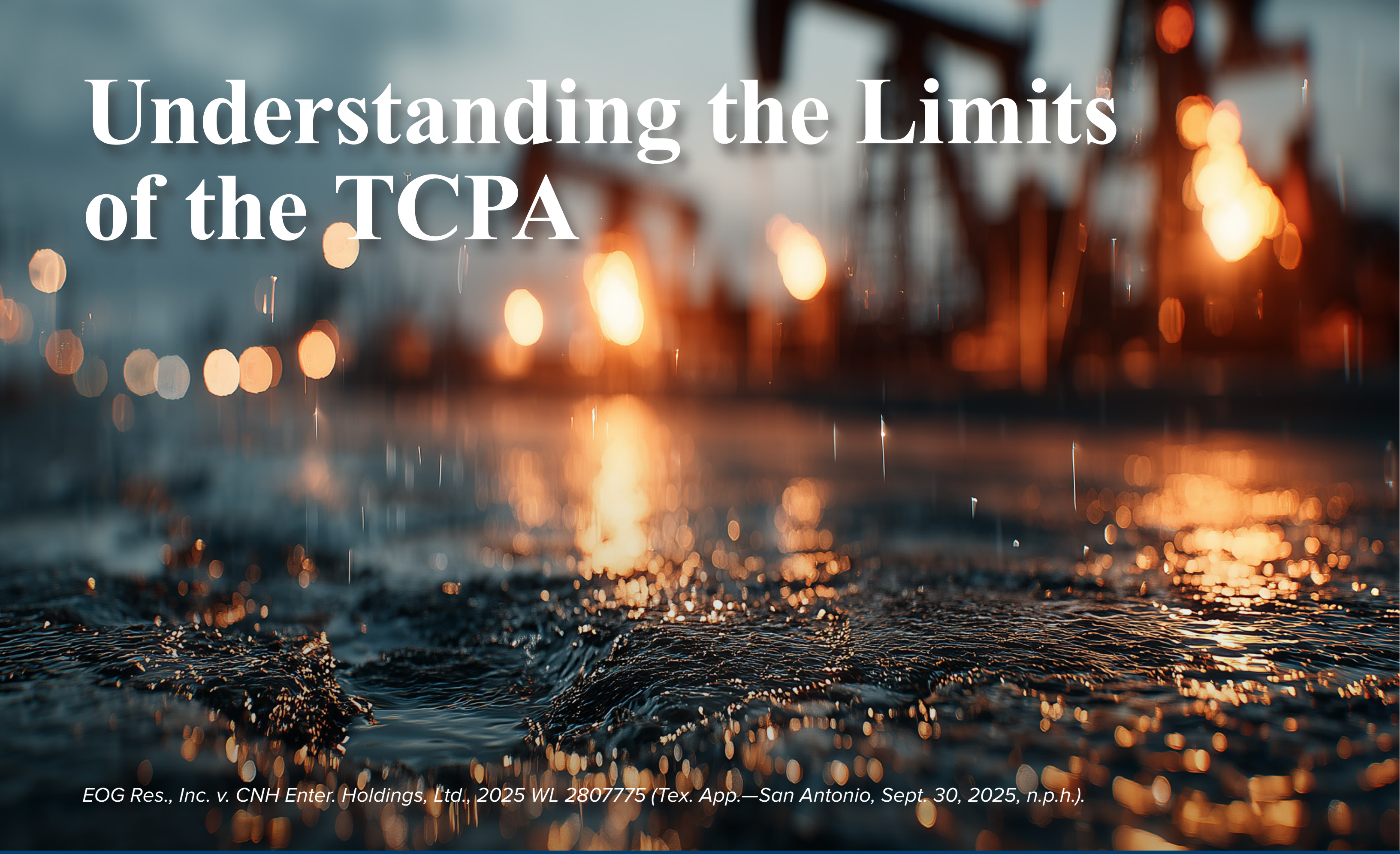
Understanding the Limits of the TCPA



EOG Res., Inc. v. CNH Enter. Holdings, Ltd., 2025 WL 2807775 (Tex. App.—San Antonio, Sept. 30, 2025, n.p.h.).

By: Alejandra Salas

The Texas Citizens Participation Act (TCPA) remains an important tool for defendants seeking early dismissal and mandatory attorney fee awards. But just how far does its reach extend when regulatory filings are involved? For oil and gas litigators, this question is hardly academic. Nearly every lease dispute, drainage claim, or development controversy involves some interaction with the Railroad Commission of Texas (RRC), creating a constant temptation for defendants to invoke the TCPA's protections based on their communications with the RRC. The San Antonio Court of Appeals' recent decision in *EOG Resources v. CNH Enterprise Holdings* sets a clear boundary, explaining that the 2019 amendments to the TCPA mean exactly what they say: mere causal connection is not enough.

In this recent case, the San Antonio Court of Appeals considered what it means for a claim to be "based on" or "in response to" a party's right to petition under the *TCPA*. *EOG Res., Inc. v. CNH Enter. Holdings, Ltd.*, No. 04-24-00160-CV, 2025 WL 2807775 (Tex. App.—San Antonio Sept. 30, 2025, no pet. h.). More specifically, it considered whether CNH Enterprise Holdings, Ltd.'s (CNH) claim for failure to protect from drainage was "based on" or "in response to" EOG Resources, Inc.'s (EOG) communications with the RRC. Generally, the TCPA allows a party who asserts that a claim was filed "based on" or "in response to" its exercise of a constitutionally protected right to file a motion to dismiss the claim and obtain an award of attorney fees.

The Dispute: Adjacent Leases and Alleged Drainage

By way of background, CNH was the lessor under two oil and gas leases, the Hundley Lease and the Gary Lease, and EOG was the lessee. The two leases share a boundary. With regard to the Hundley Lease, CNH argued that it terminated in 2014 as to certain acreage and that EOG had nevertheless drilled additional wells outside the retained acreage after the lease terminated. Alternatively, if the Hundley Lease did not terminate, CNH alleged that EOG had failed to develop the lease as a reasonable prudent operator.

Additionally, CNH alleged EOG failed to protect the Hundley Lease from drainage. Relevantly, in April 2014, EOG obtained a permit to drill the Gary 2H Well on the Gary Lease 148 feet from the boundary of the Hundley Lease. The applicable field rules, however, required a minimum lease line distance of 330 feet. According to CNH, EOG, without notice or consent from the lessors of the Hundley Lease, waived any notice or hearing on the Rule 37 exception, which would allow EOG to drill the Gary 2H Well closer than the field rules minimum lease distance of 330 feet. The Gary 2H Well was ultimately completed as a producer only 150 feet from the lease line of the Hundley Lease. The fracture stimulation operations extended over 150 feet from the wellbore. Accordingly, CNH alleged that, if the Hundley Lease did not terminate, the Gary 2H Well caused substantial drainage to the lands covered by the Hundley Lease.

EOG's Argument: RRC Filings Invoke the TCPA

EOG sought to dismiss the failure to protect from drainage claim pursuant to the TCPA, contending that it was exercising its "right to petition" when it filed its application for a drilling permit and a Rule 37 exception with the RRC and that CNH's failure to protect from drainage claim was "based on" and "in response to" EOG's exercise of its right to petition. Notably, CNH dropped the failure to protect claim, but a question remained regarding whether EOG was entitled to an award of attorney fees under the TCPA.

The appellate court explained that the purpose of the TCPA is to encourage and protect constitutional rights, including the right to petition, and also to protect the rights of a person to file legitimate claims. It noted that the three-step analysis applicable to a TCPA motion requires the movant to show that the TCPA applies by showing that the legal action or claim "is based on or in response to" the movant's exercise of its right to, in this case, petition. Once the movant establishes that the TCPA applies, the burden is on the nonmovant to show "by clear and convincing evidence a prima facie case for each essential element of its claim." If that burden is satisfied, the burden shifts back to the nonmovant to establish an affirmative defense as a matter of law. Only the first step of the TCPA analysis was at issue in this case—whether the TCPA applies to CNH's failure to protect claim. Additionally, the parties agreed that EOG's filings with the RRC, including its application for a permit and Rule 37 exception, were communications and an exercise of EOG's right to petition under the TCPA. Thus, the only remaining question was whether CNH's claim was based on or in response to EOG's communications with the RRC.

The "Gravamen" Test: What the 2019 Amendments Really Mean

The appellate court began its analysis by noting that the Legislature amended the TCPA in 2019 to narrow the required connection between the claim filed and the protected activity by deleting the "broadest connective language–'relates to.'" Relying on the Texas Supreme Court's recent Walgreens v. McKenzie, 713 S.W.3d 394, 400 (Tex. 2025) decision, the San Antonio Court of Appeals reiterated that to be "based on" or "in response to," the exercise of the protected right must be "the 'gravamen' of the claim…be 'factually predicated on' the exercise…or that the exercise be a 'main ingredient' or 'fundamental part' of the claim." Because the "gravamen" of CNH's failure to protect claim was EOG's alleged breach of its obligation to protect the Hundley Lease by failing to drill an offset well to prevent drainage, and not EOG's communications with the RRC, the appellate court found that the claim was not "based on" or "in response to" EOG's exercise of its right to petition.

Pleading Precision: The Court Rejects But-For Causation

EOG argued that CNH's failure to protect claim fell under the broader claim for breach of the implied covenant to protect the leasehold from field-wide drainage, including the duty to drill more wells, re-work existing wells, seek regulatory action, seek a Rule 37 exception from the RRC or other administrative relief, which could challenge the drilling of the Gary 2H well itself. The court rejected EOG's argument, noting that what matters is what CNH actually pled. Because CNH did not actually make that the basis for its failure to protect claim, the TCPA did not apply. Thus, although EOG's communications with the RRC led to the approval of the Gary 2H Well that allegedly caused the drainage that gave rise to CNH's claim, the court found the nexus between the action and the protected activity insufficient to invoke the TCPA.

This case clarifies the limits of the TCPA after the 2019 amendments. Specifically, it makes clear that a TCPA motion to dismiss cannot be predicated on conduct with only a tangential or indirect link to the claim, even if that conduct was a step in the sequence of events giving rise to the claim. EOG's RRC filings "started the ball rolling," but that but-for causation was too attenuated, especially where the actual complained-of conduct (failure to drill an offset well) was another step removed from the communications themselves.

EOG Resources v. CNH Enterprise Holdings offers guidance on pleading strategy for practitioners on both sides. Defendants should recognize that regulatory filings will not shield every claim touching on RRC-approved activity. Rather, the gravamen analysis demands that the protected communication itself, not merely its downstream consequences, form the heart of the plaintiff's complaint. Conversely, plaintiffs can insulate drainage and development claims from TCPA dismissal by focusing their pleadings on affirmative obligations (e.g., the duty to drill offset wells, the duty to protect) rather than on challenging the regulatory approval process itself. The decision also highlights the importance of precision in drafting a cause of action. For instance, had CNH alleged that EOG breached its duty by failing to seek administrative relief or oppose the Rule 37 exception, the outcome might have been different.

Texas Takes the Reins on Class VI Carbon Sequestration Wells

By: Logan B. Jones

The EPA's November 2025 approval granting Texas primary enforcement authority over Class VI injection wells fundamentally changes who controls permitting of carbon capture and sequestration projects across the nation's largest oil and gas state. For the 64 pending permit applications now transferring from federal to state oversight, this should improve permitting timeliness and accelerate projects tied to 45Q tax credits.

Texas became the sixth state to secure Class VI primacy, joining North Dakota, Wyoming, Louisiana, West Virginia, and Arizona. The Railroad Commission of Texas (RRC) assumes authority on December 15, 2025.

What primacy means under cooperative federalism

"Primacy" is authority granted by EPA to a state to administer and enforce a federal environmental program. Under the Safe Drinking Water Act ("SDWA"), a state assumes regulatory authority previously exercised by EPA while the federal government sets minimum standards.

Once primacy takes effect, operators apply exclusively to the state agency. The RRC becomes the permitting authority, compliance monitor, and enforcement lead. EPA retains oversight authority and can revoke primacy if Texas fails to enforce federal standards.

SDWA Section 1422 requires states seeking primacy to meet an "at least as stringent" standard across site characterization, well construction, area of review modeling, monitoring, financial assurance, post-injection site care, and emergency response. EPA conducts line-by-line regulatory comparisons.

Understanding Class VI wells and the UIC program

EPA regulates underground injection through the Underground Injection Control (UIC) program, authorized by the SDWA in 1974 to protect underground drinking water sources. Classes I through III handle industrial waste disposal, oil-and-gas-related injection (including enhanced recovery), and mineral extraction. Class IV wells—shallow hazardous waste injection into or above drinking water formations—are banned unless an injector obtains approval pursuant to 40 C.F.R. § 144.13(c). Class V covers non-hazardous injection. Class VI, added in 2010, addresses long-term geologic sequestration of carbon dioxide.

Class VI requirements are among the most stringent in the UIC program. Carbon dioxide is buoyant, mobile, and corrosive in the presence of water, and projects inject massive volumes intended to remain underground for centuries. Regulations require sophisticated computational modeling to predict CO_2 plume migration, corrosion-resistant materials, continuous monitoring, and a default 50-year post-injection site care period.

How Texas earned primacy

Texas's path to primacy began in 2009 when the legislature directed the state to pursue Class VI authority and established the legal framework for CO2 storage. The pivotal moment came in June 2021, when HB 1284 consolidated jurisdiction solely under the RRC—previously split between RRC and the Texas Commission on Environmental Quality—and mandated pursuit of primacy.

Obtaining primacy required Texas to submit six core elements to EPA: a formal letter from Governor Abbott; a comprehensive program description; an Attorney General certification of adequate legal authority; a Memorandum of Agreement with EPA Region 6; copies of applicable statutes and regulations; and documentation of public participation.

Texas adopted comprehensive regulations at 16 Texas Administrative Code Chapter 5, which EPA determined meet or exceed all federal Class VI standards. EPA's evaluation followed a four-phase process spanning three years, culminating in proposed rulemaking that received 7,534 public comments, the vast majority supportive, and final approval in November 2025.

Why industry should pay attention

The practical impact centers on speed and certainty. EPA has issued only 11 Class VI permits nationally since 2011, with applications historically taking two or more years. As of late 2025, EPA had over 175 applications under review. By contrast, North Dakota and Wyoming have nearly cut Class VI permit review times in half.

NEW ATTORNEY ANNOUNCEMENT

McGinnis Lochridge Welcomes Melanie Cruthirds

We are pleased to welcome Melanie to McGinnis Lochridge as a litigation associate in our Houston office.

Melanie represents clients in a wide range of commercial disputes, with a focus on matters involving contracts and leases, corporate governance, and employment relationships. She is known for her thoughtful, solutions-oriented approach and her dedication to helping clients navigate complex issues with clarity and confidence.

Melanie's work has earned recognition from Best Lawyers: Ones to Watch®, including honors in Commercial Litigation (2025, 2026), as well as Energy Law and Litigation Labor & Employment (2026). Her early accomplishments reflect a strong commitment to excellence and advocacy on behalf of her clients.

Melanie also participates in the Leadership Council on Legal Diversity's Pathfinder Program as a member of the Class of 2025. We are thrilled to welcome her to the McGinnis Lochridge family and look forward to the contributions she will bring to our team.

For assistance with oil and gas litigation matters, contact Melanie at (713) 615-8551 or via email at mcruthirds@mcginnislaw.com.

The End of Agency Deference in Texas

Chevron U.S.A. Inc. v. Natural Resources Defense Council, 467 U.S. 837, 842–44 (1984)

By: Alejandra Salas

Less than a year after the United States Supreme Court ended *Chevron* deference, which required federal courts to defer to agency interpretations of statutes so long as they were reasonable, Texas followed suit with Senate Bill 14, the Regulatory Reform and Efficiency Act, which similarly limits judicial deference to the legal conclusions of state agencies.

Relevantly, for nearly four decades, *Chevron U.S.A. Inc. v. Natural Resources Defense Council*, 467 U.S. 837, 842–44 (1984), overruled by *Loper Bright Enterprises v. Raimondo*, 603 U.S. 369 (2024), provided the default rule for how federal courts handled agency interpretations of statutes. At the federal level, *Chevron* deference had a major impact on the oil and gas industry, which is subject to extensive regulation.

Texas followed a very similar approach, giving "serious consideration" to a state agency's interpretation of a statute it was authorized to enforce and construe and deferring to the agency's interpretation so long as the construction was reasonable and did not conflict with statutory language. As a result, the interpretation of laws or rules relating to oil and gas by agencies like the Railroad Commission of Texas (RRC), Texas Commission of Environmental Quality (TCEQ), and Public Utility Commission (PUC) were given "serious consideration" or "substantial deference." The reasoning often echoed *Chevron's* logic that agencies are better positioned to interpret complex regulatory statutes.

Loper Bright and Senate Bill 14 shift the balance of power in regulatory interpretation. Courts will no longer be required to defer to agency interpretations, meaning that judges will have the final say on ambiguous laws. This shift will significantly affect the oil and gas industry, particularly in heavily regulated areas where state and federal agencies have shaped how oil and gas companies operate.

Chevron in a Nutshell

The United States Supreme Court's ruling in *Chevron* established a two-step test for courts reviewing agency interpretations of statutes. Under the first step, if the statute's language is clear, courts must enforce it as written, without considering agency interpretations. Under the second step, if the statute is ambiguous, courts must defer to the agency's interpretation so long as it is "based on a permissible construction of the statute," even if the court would have interpreted the statute differently. The second step embodies the *Chevron* deference principal. For decades, this framework allowed agencies to fill in gaps where Congress had not provided explicit guidance.

In the oil and gas industry, which has long been subject to regulation, agencies like the Environmental Protection Agency (EPA), Department of Interior (DOI), Bureau of Land Management (BLM), and Federal Energy Regulatory Commission (FERC) frequently relied on *Chevron* deference to justify interpretations of statutes, often imposing stricter environmental controls on the industry.

After *Loper Bright*, federal courts are scrutinizing agency interpretations, independently assessing and interpreting statutes and regulations. While in many cases the result has been a completely different interpretation than that of the agency charged with administering the relevant law, in some instances federal courts have agreed with the agency after conducting an independent analysis.

Texas Before S.B. 14: *Chevron*-like Deference in Texas

Texas never formally adopted *Chevron*, but in *Railroad Commission v. Texas Citizens for a Safe Future and Clean Water*, 336 S.W.3d 619, 625 (Tex. 2011), the Supreme Court of Texas held that when a statute is ambiguous, courts should give "serious consideration" to an agency's construction and defer to it if it is reasonable and consistent with the statute. That case involved the interpretation of the Texas Water Code and the public interest standard in the permitting of oil and gas waste injection wells by the RRC. Specifically, the issue was whether the RRC should have considered traffic-safety issues as part of its "public interest" inquiry when granting Pioneer Exploration, Ltd. a permit to convert an existing well into an injection well for oil and gas waste disposal. Because term was not defined in the statute, it was rendered ambiguous.

Following a *Chevron*-like approach, the Court held that when a statutory term is ambiguous, Texas courts should give "serious consideration" to an agency's interpretation of a statute it is authorized to enforce and construe and defer to the agency's interpretation "so long as the construction is reasonable and does not contradict the plain language of the statute." It further noted that, the deference afforded to Texas agencies "is tempered by several considerations," including that "it applies to formal opinions adopted after formal proceedings, not isolated comments during a hearing or opinions [in a court brief]," "the language at issue must be ambiguous," and that "the agency's construction must be reasonable; alternative[ly] unreasonable constructions do not make a policy ambiguous."

The Court recognized that the RRC "has long been the agency charged with regulating matters related to oil and gas production, and is given broad discretion in its administration of oil and gas laws." Thus, it needed "discretion in determining the minutiae of its statutory mandates." Ultimately, the Court emphasized that the RRC's interpretation of "public interest," which was narrowly focused on matters related to oil and gas production, was reasonable and consistent with the statutory framework of the Texas Water Code. The RRC's historical interpretation of the term in the same manner further reinforced the reasonableness of its interpretation.

The application of the "serious consideration" standard meant that agencies like the RRC, TCEQ and PUC, which regulate most aspects of oil and gas production in Texas, much like federal agencies, enjoyed broad discretion in their administration of oil and gas laws.

Critically though, in February 2025, in a concurring opinion, Justice Young joined by Justice Sullivan noted that administrative agencies in Texas have "never enjoyed the deference once endorsed by the U.S. Supreme Court." *Accident Fund Ins. Co. of Am. v. Tex. Dep't of Ins., Div. of Workers' Comp.*, No. 23-0273, 2025 WL 421009, at *4 (Tex. Feb. 7, 2025) (Young, J., concurring) (citing *Tex. Citizens for a Safe Future and Clean Water*, 336 S.W.3d at 625). He then explained that "[i]f there were a time to transform similarity into sameness . . . it is certainly not now, when the Supreme Court has decidedly abandoned *Chevron* as 'fundamentally misguided.'"

Senate Bill 14

Shortly after, in April 2025, Senate Bill 14 was signed into law. Relevant to this article, Senate Bill 14 added new Government Code provisions on judicial review. *See* Tex. Gov't Code §§ 2001.042, 2001.1721.

Under Section 2001.042, in any Texas judicial proceeding, including declaratory-judgment actions, courts are not required to give deference to a state agency's legal determination about the construction, validity, or applicability of a statute or rule the agency administers. Courts may give consideration to an agency's view only if it is reasonable and consistent with the plain language of the statute.

In contested cases, Senate Bill 14 goes further. Section 2001.1721 of the Government Code directs courts to decide all questions of law *de novo*, including the interpretation of statutes and rules, without giving deference to an agency's legal determinations. A court may still consider an agency's construction if it is reasonable and consistent with the plain language of the statute, but that would be a matter of persuasion.

Notably, factual findings remain subject to the substantial-evidence standard, so agencies will still get deference on fact disputes.

These provisions apply prospectively to petitions for review, declaratory actions, and contested cases filed after the Act's effective date of September 1, 2025.

Senate Bill 14 moves Texas away from the "serious consideration" framework and toward a standard that looks a lot like *Loper Bright*. For state agencies, the "serious consideration" standard is now replaced with a statute instructing courts to answer legal questions independently. Courts can still agree with an agency, but only after doing their own independent review. For oil and gas companies, this change might offer a new opportunity to challenge laws and rules.

Conclusion

Chevron allowed courts to favor agency interpretations when statutes were unclear. The Supreme Court ended that deference in *Loper Bright*. Senate Bill 14 does the same thing in Texas, both by instructing courts not to defer to state agencies on questions of law and by forcing agencies to justify their rules. Accordingly, while agencies like the RRC, TCEQ, and PUC will remain central to the administration of oil and gas laws in Texas, their view of what statutes or rules mean will now face additional hurdles when challenged.

About the Author

Alejandra Salas *is a litigation associate at McGinnis Lochridge, LLP. She represents oil and gas exploration and production companies, royalty owners, and mineral owners in a variety of litigation matters. Prior to joining the Firm, Alejandra served as a judicial law clerk to the Honorable David Counts of the United States District Court for the Western District of Texas, Midland/Odessa and Pecos Divisions.*

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About McGinnis Lochridge

McGinnis Lochridge is a highly experienced, multi-practice Texas law firm with more than 75 lawyers. Founded in 1927, McGinnis Lochridge has maintained strong ties to its judicial and legislative traditions for nearly a century. The Firm has been fortunate to count among its lawyers distinguished leaders in judicial and governmental positions, including state and federal trial judges, a Texas Supreme Court justice, a Fifth Circuit justice, state and federal legislators, a past president of the Texas Bar, and even a governor of Texas. The Firm has continued to grow and adapt to meet clients' needs in a changing and increasingly complex business environment.

Today, from offices in Austin, Houston, Dallas, Decatur, and McAllen, the Firm's attorneys represent energy clients throughout the country in complex litigation and arbitration. We have proven skills handling sophisticated disputes involving geology, geophysics, and petroleum engineering. Several of our lawyers have professional backgrounds and credentials in those areas. Because of the Firm's long history in handling energy disputes, the Firm's Oil & Gas Practice Group includes lawyers with a deep understanding of hydrology, seismic interpretation, log analysis, drilling, completions, hydraulic fracturing, reservoir engineering, production, transportation, hydrocarbon processing, and other related technical areas.

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