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McGINNIS LOCHRIDGE

Producer's Edge

TEXAS OIL AND GAS LAW BULLETIN



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About the *Producer's Edge*

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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EVENTS, PUBLICATIONS, AND AWARDS

NEWS AND HONORS

- Charles Gillis joined McGinnis Lochridge as Chief Operating Officer
- 21 Attorneys Named to The Best Lawyers in America® 2027
- 7 Attorneys Named to Best Lawyers: Ones to Watch in America® 2027
- Austin Brister Elected Chair of the Houston Bar Association Energy Law Section for 2026–2027
- 13 Attorneys Named to 2026 Texas Super Lawyers
- 8 Attorneys Named to 2026 Texas Rising Stars
- Jonathan Baughman and Austin Brister Named to 2026 Lawdragon 500 Global Leaders in Energy
- Will Grubb Named to The 2026 Lawdragon 500 X – The Next Generation
- *Legal500* ranked McGinnis Lochridge Tier 3 in Energy Litigation: Oil & Gas – Mid-Market ($0-500m)
- Tim George recognized in 2026 *Chambers USA* in Energy: State Regulatory & Litigation (Oil & Gas) – Texas
- Derrick Price recognized in 2026 *Chambers USA* in Oil & Gas Litigation – USA Nationwide
- 2026 *Chambers USA* rankings for Texas in the following:
  - Energy: State Regulatory & Litigation (Oil & Gas)
  - Environment
  - Water Law
  - Austin & Surrounds – Litigation: General Commercial

SPEAKING ENGAGEMENTS & PUBLICATIONS

- Austin Brister's article, "How Far Does 'Free of Cost Forever' Go? Not Far," was featured in the NADOA Q3 Newsmagazine
- Bruce M. Kramer's article, "State Preemption of Local Governmental Ordinances – The Texas Approach," was published in The Journal of the Energy Law Practitioner
- Alejandra Salas joined Julian Sharp of Haynes Boone for an in-depth conversation about her path in energy law, the work shaping her practice, and what lies ahead for the next generation of energy attorneys
- Bruce Kramer taught "Voluntary Pooling & Unitization" at the 43rd Annual Oil and Gas Law Short Course
- Marla Broaddus spoke at the TexasBarCLE live webcast on "Texas Supreme Court Update"
- Austin Brister was quoted in Law360 on *Mieco LLC v. Targa Gas Marketing LLC*
- McLean Bell's article "Measuring What Matters: How MRC Permian Reshapes Retained-Acreage Disputes in Horizontal Drilling" was featured in IEL Energy Law Advisor
- Austin Jones served as an instructor for the Contract Law module in the University of Texas at Austin's Paralegal Certificate Program
- Austin Brister presented "Shale Litigation Roundtable: Current Issues in Colorado, Texas, and Appalachia" at the IEL 25th Annual Energy Litigation Conference.
- Alejandra Salas and Austin Brister published Oil, Gas, and Energy Case Law Update – Summer 2026 in OGERL Section Report, Vol. 50, No. 3



The Next 100 Years Of Oil And Gas Law In Light Of Its Common Law, Legislative/ Regulatory And Academic History

By: Bruce Kramer

Whether one dates the source of "oil and gas law" to the successful drilling of an oil well in Ohio in 1833, or to the drilling of the more famous Drake Well in Pennsylvania in 1859, the acceptance of a body of common law, legislative/ regulatory and academic as being a standalone field known as oil and gas law followed within a generation. The goal of this paper is not to predict the role that oil and gas production will play over the next century but to try and divine, as best as one can, the issues that will need to be addressed by oil and gas law within the overall context of natural resources law.

As is evident by the title to this paper, my discussion and analysis will look at three component parts of what in the author's opinion constitutes "oil and gas law." Undoubtedly oil and gas law is shaped by common law or judicial decision-making, legislative and/or administrative decision-making and by the legal academy's acceptance of and debate over the judicial and legislative/ administrative actions. Additionally the development of any body of law cannot be shoe-horned into any post-hoc chronological order that neatly fits into 100-year eras. But it is also obvious that trends and developments that occur do not occur in isolation or in the absence of historical evidence that may illustrate that a particular issue or problem is typically not sui generis but is instead a new wrinkle in an older set of problems that oil and gas law or more broadly natural resources law has dealt with in the past. For example, how different from a natural resources law perspective is the 40-year-old concept of mine-mouth coal-burning electric generating facilities from locating natural gas and pocket atomic electric generating facilities adjacent to large-scale data centers?

The Early Years – Pre-1926

Given the fact that we are celebrating a centennial year, I have artificially designated the end of the early years of oil and gas law as being 1926. It is not surprising that the earliest period of oil and gas law development was in the Appalachian Basin states of Pennsylvania, Ohio and West Virginia from the mid-1850s through the drilling of the Spindletop Well near Beaumont, Texas in 1901. The shift in production from the Appalachian Basin to the Mid-Continent region consisting of Louisiana, Texas, Oklahoma and Kansas was reflected in the number of reported cases and a shifting in the domicile of the authors of the various oil and gas treatises that started to appear in the 1890s.

This early period was concerned with a number of important issues that form the basis of oil and gas law. Generally speaking, common law developments in oil and gas law during this time frame were concerned with the characterization of the oil and gas estate, the application of the rule of capture including the offset well rule, the severability of the oil and gas estate from the ownership of the surface, the use of the oil and gas lease as the principal written instrument authorizing the exploration for and development of the oil and gas resource, the cotenancy rule, and the implied covenant doctrine.

While the rule of capture is generally treated in hindsight as the most important development in oil and gas law, contemporary authors treated the characterization issue as the most critical issue. In my opinion characterization was the critical force in oil and gas law development since it resulted in the application of traditional notions of real property to oil and gas transactions. Courts had less to do with the widespread use of the oil and gas lease as being the written instrument which allowed the owner of the mineral estate to authorize someone else to explore for and produce the oil and gas underneath its premises. Given the fractionized ownership of land and minerals that is prevalent in many areas of the United States, an important common law development that encouraged the production of oil and gas was the adoption of the cotenancy rule whereby a single cotenant could either develop itself or lease to a third party the right to explore for and develop the oil and gas that was owned by two or more cotenants. Finally, this early period was the source of the implied covenant doctrine that would attach itself to the lessor/lessee relationship notwithstanding the general laissez-

faire approach taken by many courts in dealing with contractual and other juridicial relationships. A series of cases arising in Pennsylvania and the Mid-Continent region literally created out of whole cloth the notion that in every oil and gas lease, in the absence of express language to the contrary, there arose various implied covenants that created duties on the lessee to engage in activities or refrain from engaging in activities that would be detrimental to the interests of the lessor.

Thanks in large part to the work of the Section of Mineral Law of the American Bar Association it is relatively easy to determine the legislative/administrative response to the development of the oil and gas industry. In 1938, 1948 and 1960, the Section published three volumes that looked at legislative and administrative developments in the oil and gas industry over the decade prior to each volume's publication date. The earliest statutes relating to oil and gas conservation matters regulated the plugging and casing of wells. Within a few years of this initial spurt of legislation came more general state regulation though the adoption of conservation statutes that in broad terms were intended to prevent the waste of oil and gas caused by the haphazard and inefficient development of oil and gas fields in the Appalachian Basin, which in turn was largely caused by the widespread adoption of the rule of capture. Starting in the 1890s, Indiana took the lead in this type of anti-waste regulation which eventually led to the Supreme Court's opinion in *Ohio Oil Co. v. Indiana*, upholding the constitutionality of such provisions.

The proof of the birth of oil and gas law as a standalone jurisprudential subject comes in part from how oil and gas law was treated by the legal authors and scholars of the time. Prior to 1896 to the extent that oil and gas legal issues made their way into digests or treatises they were probably a page or two in one of the mining law treatises that dealt with hardrock mining. In 1896, George Bryan of Pennsylvania authored The Law of Petroleum and Natural Gas, a reasonably short tome on oil and gas law. This was followed in 1904 by the first edition of W.L. Thornton, The Law Relating to Oil and Gas, an even-longer one-volume tome that was the predecessor to Eugene Kuntz's multi-volume treatise. As W.L. Thornton, an Indiana resident said in 1904: "Since petroleum and natural gas became commercial products, thousands of cases concerning their production, sale and transfer, involving new and unusual questions, have been decided in our courts. . . . Cases have come before the courts involving many questions so unique a character that no precedents could be found. Necessarily, there has grown up quite a body of law, unknown to the past generations." By the 1920s, however, the need for an oil and gas treatise covering the legal developments in the Mid-Continent area was being fulfilled by attorneys who lived outside the Appalachian Basin.

The Last Century – 1926-2026

The past 100 years of oil and gas law were impacted by many events and realities that were probably unforeseeable by those oil and gas professionals who created the building blocks that formed the basis of oil and gas law. From world wars, to oil embargos, to pricing spikes and collapses to natural gas gluts, to natural gas de-regulation, to concerns about global warming, to the development of hydraulic fracturing and horizontal drilling technologies and to predictions of peak oil, the oil and gas industry and oil and gas law had new obstacles to confront. I have had the privilege of being both an eyewitness and chronicler to the last 45 years of such tumult.

From a common law perspective the past 100 years saw a refinement of the characterization efforts of the early years with most oil and gas producing states making definitive decisions as to whether oil and gas in the ground fit within the two or three ownership theories, to wit, absolute ownership or ownership-in-place, qualified ownership and non-ownership. Along with the categorization effort, state courts had to deal with the consequences of treating oil and gas in place within those three categories. Thus, state courts issued opinions regarding whether or not the rule of capture applied, and if it did how the rule could consider the correlative rights of the owners of portions of a common source of supply, whether or not the Statute of Frauds applied to various oil and gas transactions, whether the oil and gas estate was a corporeal or incorporeal hereditament, whether the oil and gas estate was an interest in real property or an interest in personal property, and whether the Rule Against Perpetuities would apply to various types of transactions involving the oil and gas estate.

> Some 25 years ago I said:
>
> When oil and gas jurisprudence was in its infancy, for better or worse, the courts chose to follow the path of applying property law precepts. The one precept which has done more to shape oil and gas jurisprudence more than any other is the borrowing of the estates system to describe the nature of the interests in the mineral and leasehold estates. Furthermore the labeling of the basic leasehold estate as a fee simple determinable with its automatic termination feature created substantial practical difficulties relating to activities of the lessee in both the primary and secondary terms of a typical oil and gas lease.

Responses to the ubiquitous adoption of the "unless" lease form through the inclusion of savings provisions in oil and gas leases ameliorated some of these unintended consequences, but more often than not were "merely the prologue to new problems."

One of the principal areas where there has been significant and consequential activity in the past 100 years involves the interpretation of the royalty clause in oil and gas leases. This activity was undoubtedly triggered by how the market for oil and gas has changed over the past century. For the first several decades of the 1926-2026 century oil was sold at the well at the posted price for the field. Pricing was local in nature. As the oil markets became both international and national in scope, the use of local posted prices disappeared and was replaced by market centers such as exist in Cushing, Oklahoma and in the Houston, Texas area. In addition, futures markets for oil were created that allowed for various hedging and other financial transactions to impact the price of oil. In addition, natural gas went from being a waste product unless it could be used locally to a national and now international commodity that can be sold not only at the wellhead but at a LNG facility that could either liquify or de-liquify the LNG. These external factors led to decades of litigation as to how a lessee is to calculate the royalty owed to the lessor. The results have

not been consistent from jurisdiction to jurisdiction including substantial differences as to how actual language used in the royalty clause should control in determining the royalty calculation methodology

Common law developments over the past 100 years have not been distributed equally throughout the United States. Up until the 1990s the lion's share of reported cases dealing with oil and gas matters arose in Texas, Louisiana and to a lesser extent in North Dakota and Colorado. With the shale revolution, Pennsylvania, West Virginia and Ohio revived their oil and gas law jurisprudence and now share top billing with Texas and Louisiana for the number of cases decided each year.

The past 100 years has entailed a maelstrom of legislative and regulatory enactments at the federal, state and local level that clearly has impacted oil and gas law. Although long forgotten, for nearly 40 years the Federal Energy Regulatory Commission and its predecessor the Federal Power Commission were in the business of regulating the pricing of natural gas that entered the interstate pipeline system. In addition, the Federal Government as owner of vast acreage in the western States and offshore not only leased its oil and gas to private operators but imposed a regulatory regime following the enactment of the major environmental statutes starting in 1969 with the National Environmental Policy Act.

One of the negative ramifications of the widespread adoption by the courts of the rule of capture is the economic incentive it creates to over drill an oil and gas reservoir in order to maximize production as quickly as possible before the oil is produced from a neighboring wellbore. Maximizing production tends to lower the price for oil and gas leading to constant boom and bust cycles. One legislative/administrative response to low commodity prices is the proration/allowable system which attempts to regulate, meaning limit, production from individual wells so that the commodity price would increase. States also responded by enacting well spacing statutes, administratively enforced by state conservation agencies, which limited the number of wells that could be drilled. Two of the leading state conservation regulatory programs, pooling and unitization, were also instituted and implemented starting in the 1930s, although the initial compulsory pooling regulations were adopted by municipalities that antedated the state statutes. Pooling is "the joining together of small tracts or portions of tracts for the purpose of having sufficient acreage to receive a well drilling permit under the relevant state or local spacing laws and regulations, and for the purpose of sharing production by interest owners in such a pooled unit. Pooling was the stepchild of well spacing since if one owned a parcel of land that would not qualify for a drilling permit the rule of capture would essentially cause the owner to have his oil or gas drained away to a well which did comply with the spacing regulations. New Mexico adopted the first state compulsory pooling statute in 1935. Unitization, on the other hand "refer[s] to the consolidation of mineral or leasehold interests covering all or part of a common source of supply. Oklahoma adopted the first compulsory unitization statute in 1945 which was found to be constitutionally valid in 1952. The role that sub-state governmental units play in the regulation of oil and gas operations has been transformed in the past 20-25 years from one where dual regulation was common to one where states are increasingly seeking to preempt sub-state units from regulating oil and gas operations even where the sub-state units are afforded home rule authority under the respective state constitutions.

The maturation of oil and gas law as a standalone subject worthy of being taught at law schools throughout the nation and written about in multi-volume treatises is evident from the record. Starting in the 1940s authors were preparing casebooks for use in standalone oil and gas law classes. Oil and gas law was treated as a special area of property law, a notion that I personally believed in when I started teaching the subject in 1980. The changing nature of oil and gas law as an academic subject is reflected in the changing emphases on subject matter areas in the two most widely-used casebooks in use today.

Oil and gas law was the subject of comprehensive, and national-in-scope multiple multi-volume treatises which have been annually updated since the earliest treatise was published in 1938. Another sign that oil and gas law had been recognized as a worthy subject of teaching, research and scholarship was the central role that oil and gas law played in the creation of three national continuing legal education institutions. The Southwestern Legal Foundation, now known as the Center for American and International Law, has from its creation in 1949 sponsored both an annual program and special programs that focus on oil and gas law. The Rocky Mountain Mineral Law Foundation, now known as the Foundation for Natural Resources and Energy Law, has from its creation in 1955 sponsored both an annual program and special institutes that include substantial segments on oil and gas law. Finally, the Eastern Mineral Law Foundation, now known as the Energy and Mineral Law Foundation, has from its creation in 1979 sponsored both an annual program and special programs that focus on oil and gas law.

The last 100 years has been a roller coaster ride for oil and gas law and the oil and gas industry. Clearly the refinement of horizontal drilling and hydraulic fracturing technologies that allowed for the economic development of known, but un-developable hydrocarbons has led to a renaissance of oil and gas law activity in states where oil and gas law had been moribund for several generations.

The Next 100 Years

Now comes the fun part of this presentation: trying to predict the future of oil and gas law over the next 100 years. In this section I will discuss several issues that I believe will confront oil and gas jurisprudence with difficult, but not impossible to answer, questions. Unlike the prior sections I will try to identify the issue and then provide my guess as to whether such issues can, or should be resolved by the common law, legislative/administrative or academic institutions, or any combination thereof.

The common law has been around since the 13th century. The evolution of the common law as a means of regulating, informing and potentially resolving societal interests and conflicts has been well documented. The common law field of torts clearly has shaped behavior by imposing minimum standards of conduct which if not met can lead to liability. Likewise, as discussed earlier, the common law of property has and continues to shape

behavior on behalf of the participants in the oil and gas industry. As we move into the next 100 years I predict that in the absence of legislative/administrative actions, courts in resolving property and tort disputes will undoubtedly change and/or shape oil and gas law to meet the demands of new technologies and new societal needs.

In my opinion, oil and gas law will deal with "micro" issues, such as conveyancing problems, royalty clause problems, joint operating agreement problems and characterization problems, notably dealing with the ownership of pore space and the potential growth for widespread development of carbon capture, utilization and sequestration (CCUS). But United States oil and gas law will also necessarily deal with "macro" issues such as global warming, climate change and the borrowing of oil and gas jurisprudence and principles into other natural resource areas such as wind, solar, and geothermal.

Whether one is a proponent of the "drill baby drill" or "keep it in the ground" dogmas, I believe that oil and gas law jurisprudence will be taking a back seat to legislative and administrative power over the next 100 years. Attempts by individuals and non-governmental organizations to use common law principles to achieve their respective goals on a macro level will likely be doomed to failure. As an example, in the past decade a number of governmental entities and NGO's have filed state common law tort and other claims against various oil and gas companies. See 8 Patrick H. Martin & Bruce M. Kramer, Williams & Meyers Oil & Gas Law 164-65 (climate change litigation) (2025). After 8 years of litigation, including a decision by the Supreme Court, almost all of the cases have been remanded back to state court for eventual trials. But we are still years, if not decades from determining if the common law rules should apply to climate change/global warming litigation as is reflected in the Supreme Court's recent grant of a writ of certiorari from a Colorado Supreme Court opinion finding that various state common law tort claims were not preempted by several federal statutes. It will probably be another decade or so before any trial court in any state begins to tackle the very difficult conceptual and foundational common law tort issues such as causation, standing and injury that will have to be overcome before liability attaches to oil and gas extraction activities.

Oil and gas jurisprudence has been developed through a combination of judicial decision-making and academic research and writing. Treatise and law review article authors have had an outsized impact on judicial decision-making as it relates to the development of oil and gas jurisprudence. But the role of the academic in the development of oil and gas law may have reached its peak with the birth of artificial intelligence (AI). As an example, it has been my experience in publishing two treatises and over 60 law review articles, that practicing lawyers and judges did not have the time, or possibly the inclination, to take the "deep dive" into the jurisprudence in order to inform those lawyers and judges what the "law" was as to a particular problem. The academic, however, can and should devote substantial time and resources to fully explore an area, or a single question, and develop a theory or explain inconsistent results that would be published in an accommodating law review. That system, however, was changed somewhat by the development of Westlaw and Lexis which made access to that information quick and easy as opposed to slow and hard. AI, however, may change that paradigm extensively by not only doing the research that the academic community would spend months delving into, but by analyzing the hundreds of legal opinions and written articles on the subject or issue at hand. For example, as part of my role as an expert in an Australian litigation it took me several months to respond to a series of 40-50 questions posed by the judge regarding an issue the parties had agreed to resolve applying Texas law. When the case settled I shipped my boxload of hard print materials to a colleague at McGinnis Lochridge who ran the cases and articles through an AI application and within 15 minutes had a written summary of what each case and article said. I perceive that over the next 100 years the role of the academic commentator on the common law will necessarily shrink and be replaced by ever-evolving AI applications. I also predict that lawyers will embrace the use of AI because of its time-saving quality but just as the episodic appearance of hallucinations and made-up case law reflect, attorneys will still be active participants in the practice of law and the development of jurisprudence even though they may be relying on AI rather than associates and paralegals in their practice.

While I have long favored the application of traditional rules or principles of property to the oil and gas estate, recent scholarship has raised some substantial questions about the continued wisdom of applying such rules or principles to resolve such questions. For example, Professor Monika Ehrman has posited the theory that property law should be divided into two areas, to wit, simple property and complex property. As to complex property such as those dealing with renewable energy supplies, pore space ownership and use and transboundary sub-surface migration, the traditional property-based principles shouldn't apply because, like the rule of capture, they lead to inefficient results and social harms.

Oil and gas law as well as common law property and tort principles may have to be changed in order to deal with the new reality that, at least for the next few decades or more, CCUS may be the most economically available technology to deal with our global warming issue. As in the past with the academic debates in oil and gas law such as the Merrill and Walker debate over whether implied covenants were implied in fact or implied in law or the Meyers and Brown debate over whether there existed an implied covenant of exploration, there is a current debate as to whether a cross-boundary migration of gas and/or fluids should be governed by the strict liability trespass rule or should be governed by an "actual harm" test. While oil and gas law has been dealing with the practice of injecting fluids and/or gases into subsurface formations for secondary recovery projects and underground natural gas storage facilities for nearly 100 years, the refinement of hydraulic fracturing and horizontal drilling technologies in the past 30 years along with CCUS have created new problems not capable of being resolved applying extant oil and gas law principles. For example, neither the Texas approach of treating the cross-boundary migration of frac fluids and/or proppants as being insulated from liability under the rule of capture, nor the Pennsylvania approach that

would find trespass liability if such a cross-boundary migration can be shown have been widely adopted or rejected in other jurisdictions. The lack of cases in jurisdictions other than Texas and Pennsylvania may in part be due to further technological advances in hydraulic fracturing techniques and the adoption by state oil and gas conservation agencies of well spacing regulations that minimize the chance for such cross-boundary migrations. This result would be similar to the minimization of drainage covenant cases following the widespread adoption of well spacing and pooling statutes and regulations for traditional oil and gas production.

Even though windmills have been used for hundreds of years, it is only in the past few decades that the commercial installation of wind farms, both onshore and offshore, has taken off. At least in the United States, the ownership principles that were developed for oil and gas, namely, the rule of capture, has become the prevalent way of describing the ownership of "wind" that allows the wind resource to be severed and then sold as a commercial commodity. But the use of oil and gas law principles relating to "ownership" may be rejected as they apparently were in New Mexico which treated the ownership of wind as different from the ownership of oil and gas in a case dealing with a partition petition among cotenants fighting over the potential use of the surface as a wind farm. Instead of treating wind as being subject to the absolute ownership doctrine, wind was treated as an ephemeral right that only became subject to ownership after it was captured.

Another problem that will need to be resolved in the next 100 years deals with the ownership of produced and/or frac water that is produced along with the oil and gas stream. The difference between naturally-occurring produced water and injected frac water may be important in resolving the ownership interest. Recently due to the possible lithium and/or other rare earth elements that might be present in the produced water, the question has arisen as to whether or not the produced and/or frac water is owned by the surface owner, the mineral owner or the mineral lessee. In the past few years, both common law and legislative/administrative developments have attempted to determine the proper owner. Given the backdrop of different groundwater ownership regimes that exists in oil and gas producing states, the resolution of who owns the produced water will undoubtedly not be uniform. Developments to date have focused on classifying the water under the relevant State's groundwater law or the specific language contained in the instrument that severs the surface and mineral estate.

What I had thought was a Texas-centric problem dealing with the Texas Supreme Court's inability to articulate a rational methodology for interpreting deeds, leases and contract, has become more widespread with other states, such as Ohio and Pennsylvania, creating rules, canons and presumptions that are sometimes contradictory to each other.

Finally, in light of the NIMBY movement (Not In My Back Yard) that has been recognized as a reality in the field of land use planning, I think that the division of power issues between federal, state and sub-state units will only be exacerbated by developments in the natural resources arena, including the oil and gas sector. While states have since the 1940s been the primary source of the regulation of oil and gas activities, sub-state units have exercised their land use and zoning powers for the past 100 years. Recent events suggest that states are becoming more jealous of sub-state units' impact on oil and gas operations so as to preempt such sub-state units from interfering with oil and gas operations.

As I have aged, I have come to the realization that oil and gas-related issues that appear to be new and/or novel are really issues that have been arising over the past 150 years of oil and gas production. Knowing where we have been is an important step in predicting where we may be in the next 100 years. In many situations, oil and gas law is flexible enough to respond to new issues without overthrowing the foundational principles that make oil and gas law a meaningful jurisprudential subject. Thus, in my opinion oil and gas law will not only survive over the next 100 years, but thrive as a source of answers to questions that will undoubtedly arise.

About The Author

***Bruce M. Kramer**, Of Counsel at McGinnis Lochridge, is a nationally recognized oil, gas, and land use scholar and a longtime professor at Texas Tech University School of Law. He co-authors Williams and Meyers Oil and Gas Law and The Law of Pooling and Unitization, two treatises widely cited by courts, including the Supreme Court of Texas and the Fifth and Tenth Circuits. He has advised energy companies for more than 40 years.*

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The Eason Report: Does a Franchisee's Texas Store Create Jurisdiction?

By Marcus V. Eason

An out-of-state franchisor with no Texas stores, no Texas leases, and no Texas employees can still find itself named in a Texas lawsuit because a franchisee's storefront carries its brand. Plaintiffs make the argument regularly, and it is usually based on the visible presence of franchised locations. Under current Texas and federal law, "visible presence" will not alone establish general jurisdiction. Franchisors should still understand why, because the answer turns on how they actually structure their relationship with franchisees in the forum.

General jurisdiction now means "at home"

The Texas long-arm statute reaches as far as federal due process allows, so in practice the constitutional analysis is the only one that matters. The Texas Supreme Court said as much in *State v. Volkswagen Aktiengesellschaft*: federal due process requirements shape the contours of Texas courts' jurisdictional reach. A plaintiff who pleads the long-arm statute and stops there has not engaged with the question.

Since the United States Supreme Court's decisions in *Goodyear Dunlop Tires v. Brown* and *Daimler AG v. Bauman*, general jurisdiction over a corporation exists where the corporation is "at home," and the paradigm forums are its place of incorporation and its principal place of business. The Fifth Circuit in *Monkton Insurance Services v. Ritter* described it as incredibly difficult to establish general jurisdiction anywhere else. The Texas Supreme Court adopted the same framework in *Searcy v. Parex Resources*: courts do not have general jurisdiction over corporate defendants that are neither incorporated in the forum nor headquartered there, absent some relatively substantial contacts with it.

How substantial is substantial? In *BNSF Railway v. Tyrrell*, more than 2,000 miles of track, over 2,000 employees, and a facility in the forum did not make a railroad at home there. A recent Western District of Texas decision, *Stambro v. Vanderhall Motor Works*, held that a major automaker with thousands of Texas employees, hundreds of Texas dealers, billions in Texas supplier spending, and a financial subsidiary headquartered in Texas was still not at home in Texas. Against that yardstick, a franchisor's brand appearing on independently owned stores is not close.

Why the franchise relationship is not a substitute

Two Texas courts of appeals have addressed the franchise question directly. In *Kumon North America v. Nguyen*, the Fourteenth Court of Appeals reversed a trial court's finding of jurisdiction over a franchisor. In *Hilton Franchise Holding v. Peguero*, the Fort Worth Court of Appeals reached a similar result. And recently, the Fourteenth Court of Appeals similarly discussed in *Hilton Franchise Holding, LLC v. Augustine* that the mere existence of a franchisor-franchisee relationship does not establish jurisdiction over the franchisor, even when there are a certain number of franchise locations in that forum.

The reason is a rule that predates the franchise cases. The contacts that count are the defendant's own, and not those of the franchisee, plaintiff, or some other party. Under *Walden v. Fiore* and *Burger King v. Rudzewicz*, conduct by plaintiffs or third parties that creates a connection between the defendant and the forum is disregarded. A franchisee is a third party. Its decision to open a store in Houston, sign a lease in Houston, and sell to Houston customers is the franchisee's contact with Texas, not the franchisor's.

The lease-assignment argument, and what it depends on

Plaintiffs who understand the at-home standard have looked for a contact that

belongs to the franchisor itself, and at times will point to franchise agreements to establish such a contact. Of course, franchise agreements can be written in a manner that permits more involvement on behalf of a franchisor than may occur in practice, so at times, franchise agreements become the main focus in a jurisdictional dispute regarding a franchisor's contacts with the forum state.

In general, courts should review what contacts the franchisor actually has with the forum state, as opposed to what contacts could arise if contractual rights are exercised. For example, a contractual right to take an assignment of a lease is not the same as holding one. If the franchisor has never taken over a Texas lease, is not party to any Texas lease, and has not acted as prime lessee in Texas, the right is unexercised and the contact is hypothetical. Franchisors defending these motions should be prepared to prove the negative in discovery or in court, because plaintiffs will use the franchise agreement to imply the opposite.

Additionally, even an exercised right would face the Texas Supreme Court's holding in *PHC-Minden v. Kimberly-Clark* that contracting with Texas residents does not by itself subject an out-of-state company to general jurisdiction. Holding a lease in the forum is a contact, but general jurisdiction requires the defendant to be at home, and one lease or a handful of leases is a long way from that.

What franchisors should take from this

The doctrine is favorable, but it rewards franchisors whose conduct matches their structure. One point matters most in practice.

Keep the franchisor out of franchisee leases in forums where it does not otherwise operate. The prime-lessee and collateral-assignment tools in a franchise agreement have real business value, but every exercise of them in a state creates a contact that the franchisor, not the franchisee, owns. While the "at-home" standard is high, a franchisor looking to avoid being haled into foreign courts should be cognizant of creating additional contacts with such a forum.

Specific jurisdiction is a separate inquiry, and a franchisor that participated in the transaction giving rise to the claim faces a different analysis. For a franchisor with no role in the underlying dispute, however, the question is general jurisdiction, and the standard is at home.

For questions about defending an out-of-state franchisor or other nonresident defendant in Texas, contact Marcus Eason.

About The Author

Marcus Eason *is a trial attorney who specializes in complex commercial, business, and partnership disputes. He practices in a wide variety of industries, and frequently represents both individuals and entities with their most pressing needs. His matters span across the State of Texas, and Marcus appears frequently in both state and federal court. Marcus' matters entail fiduciary duty disputes; partnership termination and wind up disputes; business fraud and theft; various contract actions and disputes; lien disputes; disputes over purchase and sale agreements, non-competes, and various other corporate agreements.*

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NEW ATTORNEY ANNOUNCEMENT

McGinnis Lochridge Welcomes Greg Mathews

McGinnis Lochridge welcomes Greg as Counsel. Greg is an energy lawyer with more than 45 years in the oil and gas industry, 34 of them practicing law. He joins the firm after 18 years as Senior Counsel at Chevron U.S.A. Inc., bringing an in-house perspective to energy regulatory, legislative, and governmental affairs matters.

At Chevron, Greg handled legal matters for the company's upstream assets in Texas, Oklahoma, and Kansas and led its legislative work before the Texas and New Mexico Legislatures. He helped draft and pass several major Texas oil and gas bills, including laws on Railroad Commission preemption, offset wells on state lands, reuse of treated produced water, and plugging of inactive and orphan wells.

Before Chevron, Greg spent nearly 17 years as a shareholder at Winstead PC in Houston, handling energy litigation and transactional work and serving in firm management. He began his career as an oil and gas landman for 12 years, which gives him a hands-on understanding of title, leasing, and land issues.

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Fifth Circuit Punts Key Force Majeure Question to the Texas Supreme Court

Mieco L.L.C. v. Targa Gas Mktg. L.L.C., *No. 23-20567, 2026 WL 2145869, 2026 U.S. App. LEXIS 22116* (5th Cir. July 24, 2026)

By: Michael Kabat

When Winter Storm Uri knocked out roughly a fifth of the nation's natural gas production in February 2021, it also set off years of litigation over who bears the risk when a seller cannot deliver the gas it promised. One of those disputes, *MIECO L.L.C. v. Targa Gas Marketing L.L.C.*, has now taken an unusual turn that every company operating under a NAESB base contract should watch closely: on July 24, 2026, the U.S. Court of Appeals for the Fifth Circuit withdrew its own prior opinion in the case and certified the controlling question to the Texas Supreme Court.

The facts will sound familiar to anyone who lived through Uri. MIECO and Targa bought and sold gas under a 2010 NAESB-form base contract, supplemented by two transaction confirmations. Under one, Targa agreed to sell MIECO 15,000 MMBtu per day at a fixed, first-of-month price; under the other, 30,000 MMBtu per day at a floating Gas Daily index price. For six days in February 2021, Targa delivered far less than the contracted volumes and invoked the contract's force majeure clause, citing both the weather event itself and force majeure declarations by its own affiliated suppliers.

Section 11 of the base contract excuses performance for causes "not reasonably within the control of the party claiming suspension," including weather events affecting an entire region. But it carves out an important exception: force majeure does not excuse "the loss or failure of Seller's gas supply," and economic hardship, including the ability to sell gas at a more advantageous price elsewhere, never qualifies as force majeure. The district court sided with Targa, holding that Uri was a force majeure event and that Targa had no obligation to buy replacement gas on the spot market to cover the shortfall.

The Fifth Circuit's now-withdrawn 2025 panel opinion disagreed, at least in part. The court reasoned that because Targa, a marketing company rather than a producer, had already been sourcing roughly 29 percent of its gas needs from the daily spot market before the storm, buying from 25 to 50 counterparties on a given day, that spot market was itself part of Targa's contractual "gas supply." If gas remained available there, even at dramatically inflated storm prices, force majeure did not automatically excuse Targa from continuing to buy from that market, subject to a "reasonable efforts" requirement the district court had never evaluated. The panel reversed and remanded for fact-finding on that issue.

Targa sought rehearing en banc, warning that the panel's reasoning could reshape pricing risk across the Texas gas industry during future force majeure events. No judge requested a full-court vote, so en banc rehearing was denied. But the panel granted rehearing on its own, withdrew its 2025 opinion, and, in a per curiam order, concluded the stakes were too high and the state-law question too unsettled for a federal court to resolve alone. It certified two questions to the Texas Supreme Court: whether the NAESB form contract's force majeure provisions require a non-producer seller to enter the spot market during a force majeure event if it had already been sourcing part of its supply there before the event, and, if so, how "reasonable efforts" to do so should be defined.

The upshot for now is uncertainty, not resolution. The Fifth Circuit's 2025 opinion is now withdrawn, and the rule that will ultimately govern force majeure and spot-market obligations under the standard NAESB form contract will come from Austin rather than New Orleans, on an uncertain timeline.

Companies that buy or sell gas under NAESB base contracts, particularly marketers who blend producer supply with spot-market purchases, should treat this as a live issue rather than settled law. That means revisiting how force majeure notices are drafted and documented and how "reasonable efforts" to secure replacement supply would be evidenced in real time during a weather event. Given the exposure in this one dispute, and how widely this form contract is used in Texas gas trading, the Texas Supreme Court's eventual answer is likely to matter well beyond these two parties.

About The Author

Michael Kabat's *commercial practice covers contract and fiduciary duty disputes, business torts, noncompetes, construction claims, and intellectual property litigation. In the oil and gas sector, he represents upstream, midstream, and downstream clients in disputes over wellbore damage, fracking, NAESB contracts, defective casing, and royalty and mineral interests.*

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Non-Consenting Non-Ops Owe Royalties Without Revenue?

Pioneer Nat. Res. USA, Inc. v. Elberta M. Royalty, LLC, No. 08-24-00133-CV, 2026 WL 2435350 (Tex. App.—El Paso Aug. 19, 2026, no pet. h.) (mem. op.).

By Austin Brister and Alejandra Salas

SUMMARY: The El Paso Court of Appeals affirmed summary judgment for a lessor, holding that a lease paying royalty on the "net amount received by Lessee for the sale" required a non-participating lessee to pay royalty on the operating co-tenant's production, and dated that obligation back to first production. It also affirmed the jury's award of $338,990.63 in trial-level attorney's fees and $200,000 in conditional appellate fees, even though the only damages awarded were $17,588.19 in stipulated statutory interest.

As background, under *Cox v. Davison*, 397 S.W.2d 200 (Tex. 1965), when an operating cotenant drills but some non-operators do not participate, the operating cotenant may recover its costs out of production before it accounts to its cotenants, so a non-participating cotenant receives nothing until payout. For a non-participating, non-operating working interest owner, that rule can collide with the royalty owed under its own lease. Indeed, the court in *Pioneer* described a royalty as the lessor's share of production, free of the costs of production.

That raises two questions: who owes that royalty (the operating cotenant or the non-participating lessee), and when. The parties could point to no prior Texas case on a royalty claim against a non-operating lessee for a cotenant's production. In *Pioneer*, the trial court answered who, granting the operating cotenant's summary judgment motion, which argued it had no payor-payee relationship with the lessor; the operating cotenant is not a party to the appeal. The El Paso Court of Appeals answered when, holding that the lessee owed royalty "beginning with first production" and reasoning that "net amount received by Lessee" in the royalty clause describes "the yardstick for measuring royalty" and does not delay royalty until the lessee itself is paid.

Pioneer Natural Resources USA, Inc. is the lessee, and Elberta M. Royalty, LLC now the lessor, under a lease paying "22.5% part of the net amount received by Lessee for the sale of the oil." Henry Resources, LLC, a cotenant with leases from other owners, drilled the Pearl Wells, which began producing in January 2021. By both sides' accounts, Pioneer did not participate, and no joint operating agreement governed the wells until August 2023, when the two signed one keeping Pioneer liable for royalty to its own lessors. In January 2022, Elberta sent Pioneer, and later Henry, statutory 30-day notices of nonpayment. Pioneer did not pay or respond within 30 days. Henry began paying Pioneer in November 2022, and Pioneer first paid Elberta in January 2023, reaching back to first production. The trial court granted Elberta summary judgment on liability under the lease and Chapter 91, denied Pioneer's motion, and tried attorney's fees to a jury after the parties stipulated that interest on the late royalties, measured under Elberta's reading of the lease, was $17,588.19.

Pioneer argued that "received by Lessee" means received by the lessee personally, so royalty on the Pearl Wells was not owed until Henry paid Pioneer after payout. The court disagreed for two textual reasons. First, "net amount received by Lessee for the sale" describes the yardstick for measuring royalty, and the same clause deducts post-production costs "incurred by Lessee." Pioneer did not suggest that it personally incurred those costs; it said Henry did. The clause, the court reasoned, uses "by Lessee" to refer to "the acts of whoever produces and sells the oil and gas." Second, Pioneer's reading would leave the lessor with nothing until the costs of production were recouped, contrary to "the established meaning of royalty as an interest in first production, free of the costs of production."

The court also observed that this clause, "[l]ike many royalty clauses," is written in the passive voice and "does not specify the party obligated to produce." Pioneer asked the court to extend *Cromwell v. Anadarko E&P Onshore, LLC,* 716 S.W.3d 515 (Tex. 2025), which held that the passive-voice habendum clauses before it did not require the lessee to produce personally, to require that the lessee personally receive the proceeds. The court answered in a footnote that *Cromwell* "stands for the proposition that production by a cotenant operator may be sufficient both to maintain a lease and entitle the non-operating lessee to a share of proceeds."

Pioneer also argued that making a non-operating lessee front royalty it cannot calculate is impossible and absurd. Elberta responded that any impossibility was of Pioneer's own making. In January 2021, Pioneer had

asked Henry for production data and decimal interests for royalties it acknowledged would be owed to Elberta, and after suit it sent Elberta division orders effective as of "first sales." In the court's view, that record did not show it was difficult, "much less impossible," to calculate the stipulated amount "using publicly available information and monthly reports of sales proceeds and production volume for each well." The court concluded that "the unambiguous terms of the Lease" required Pioneer to pay royalty "beginning with first production," adding that a lease "may expressly defer royalty on a cotenant's production until payout or condition payment on the lessee's receipt of proceeds. This Lease does not."

Pioneer argued that Elberta was not "legally entitled" to payment, and so not a "payee," until Henry paid Pioneer. The court held that the statutory payment obligation "is triggered by the sale of production, not by the payor's receipt of proceeds," and that a "payor" includes the lessee under the lease on which royalty is due. Pioneer's January 2023 payment came well after 120 days from the end of the month of first sale, January 2021. In a footnote, the court noted that *Devon Energy Production Co. v. Apache Corp.*, 550 S.W.3d 259 (Tex. App.—Eastland 2018, pet. denied), which held an operating cotenant was not a "payor" to its cotenant's lessors, had indicated in dicta that the non-operating lessee "is properly liable under the statute."



Two further points deserve mention. The first is measurement. The court described a proceeds royalty, citing *BlueStone Natural Resources II, LLC v. Randle*, 620 S.W.3d 380 (Tex. 2021), as measured by what the lessee "in fact receives under its sales contract," and it read "by Lessee" to mean whoever produces and sells. Where a lease is silent, *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368 (Tex. 2001), describes the implied duty to market as protecting the lessor from "the lessee's self-dealing or negligence." The opinion does not say whether all marketing performance was measured against the operating cotenant's sales, or whether a non-operating lessee answers for marketing by an operator it does not control.

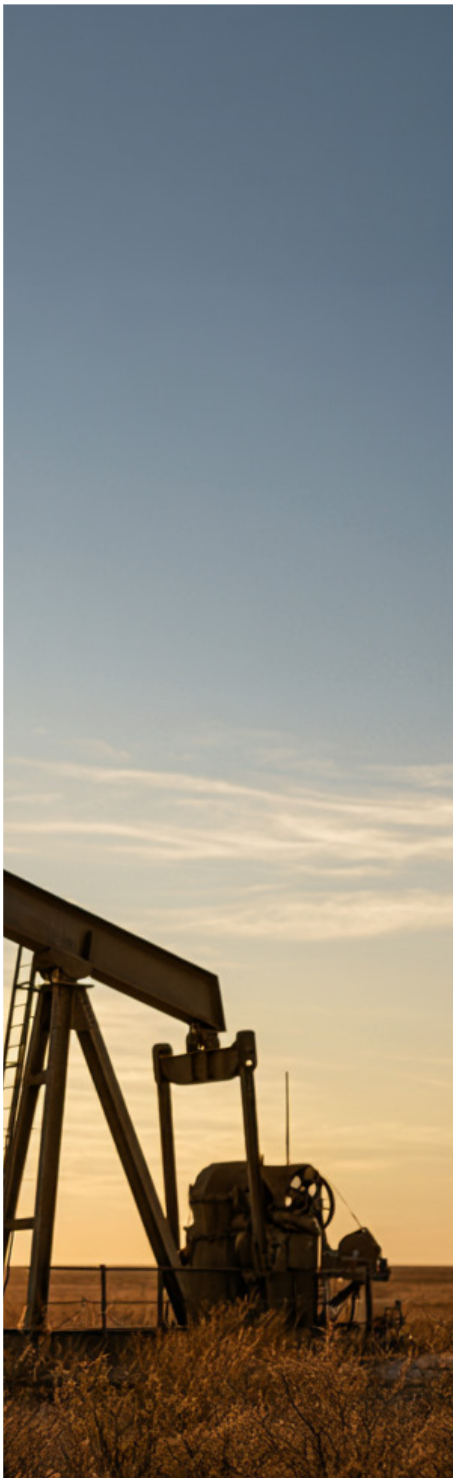
Second, the court's reminder that lessors and lessees "remain free to contract for a different rule" may sound practical, but has limited go-forward reach in reality. Most leases in effect throughout the state have been around for years, many of them for several decades. Drafting new leases to defer royalty until payout may be prudent, but it does not resolve much about the vast majority of royalty obligations due today, or in the near future.



About The Authors

***Austin Brister**, a partner in McGinnis Lochridge's Houston office, and **Alejandra Salas**, a litigation associate with the Firm, handle complex oil and gas litigation. Austin serves as first-chair trial counsel for upstream operators in disputes over JOAs, operatorship, lease termination, and title. Alejandra represents exploration and production companies, royalty owners, and mineral owners.*

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Executive Decision: Texas Courts Split on Executive Rights?

Ovintiv USA, Inc. v. High Noon Res., LLC, No. 11-21-00103-CV, 2026 WL 1992100 (Tex. App.—Eastland July 10, 2026, no pet. h.).

By Austin Brister and Alejandra Salas

SUMMARY: The Eastland Court of Appeals held that grantors who conveyed only a fractional mineral interest kept the additional executive rights they owned, disagreeing with the El Paso Court of Appeals, held that an executive right may be held as a naked interest, and held that a 1958 deed reserving "1/4th of the 1/8th royalty irrespective of the amount of royalty actually provided for in any lease" rebutted the *Van Dyke* presumption and reserved a fixed 1/32 royalty.

In this case, the Eastland Court of Appeals addressed two questions arising from Martin County mineral deeds executed in 1958 and 1962. First, the court held that grantors who conveyed only a fractional mineral interest kept the additional executive rights they owned, and that an executive right may exist as a stand-alone interest. Second, the court held that a 1958 deed reserving a double-fraction royalty "irrespective of the amount of royalty actually provided for in any lease" rebutted the presumption from *Van Dyke v. Navigator Group*, 668 S.W.3d 353 (Tex. 2023), and reserved a fixed 1/32 royalty.

In 1958, E.H. Chandler and William A. Childress conveyed to High Crest Realty Company an undivided 1/4 mineral interest in the C.C. Slaughter Ranch, a tract of over 25,000 acres, along with the executive right over the 1/4 mineral interest they kept. The deed provided that the grantors would receive one-fourth of any bonus and delay rentals and

> one-fourth (1/4th) of the usual one-eighth (1/8th) royalty (and Grantors shall be entitled to 1/4th of the 1/8th royalty irrespective of the amount of royalty actually provided for in any lease executed by Grantee, its successors or assigns) . . . .

Through later conveyances, Chandler, Childress, and Excuderunt, Inc. each came to own an undivided 1/24 mineral interest and a 1/12 interest in the executive rights. In 1962, each executed a mineral deed to General Crude Oil Company conveying "an undivided one-twenty-fourth (1/24th) interest in and to all of the oil, gas and other minerals" in about 7,000 acres. The deeds said nothing about the grantors' additional executive rights, which together amounted to a 1/8 interest.

Element Petroleum Properties LLC, later succeeded by High Noon Resources, LLC, held leases from the 1962 grantors' successors. PetroLegacy Energy II, LLC, later succeeded by Ovintiv USA, Inc., held leases from General Crude's successors. Element sued PetroLegacy, which counterclaimed for trespass to try title, and other interest owners were joined, including XTO Holdings, LLC and Jase Minerals, LP and Jase Family, Ltd. (collectively "Jase"). Jase moved for a declaration that the 1958 deed reserved only a fixed 1/32 royalty. The trial court ruled for Element on the 1962 deeds and for Jase on the 1958 deed, and rendered judgment against PetroLegacy for $471,837 in stipulated damages and $350,000 in attorney's fees.

On the 1962 deeds, Ovintiv and XTO argued that executive rights pass with a mineral conveyance unless expressly reserved, even when the executive interest is larger than the mineral interest conveyed. They relied on *Anadarko Petroleum Corp. v. BNW Property Co.*, 393 S.W.3d 846 (Tex. App.—El Paso 2012, pet. denied), which so held, and on the Texas Supreme Court's decisions in *Day & Co. v. Texland Petroleum, Inc.*, 786 S.W.2d 667 (Tex. 1990), and *Lesley v. Veterans Land Board*, 352 S.W.3d 479 (Tex. 2011). Element conceded at oral argument that *Anadarko* conflicted with the trial court's ruling. The court of appeals affirmed anyway. It explained that the grantors in *Day* and *Lesley* lost their executive rights because their deeds showed no intent to convey less than everything they owned. Under *Piranha Partners v. Neuhoff*, 596 S.W.3d 740 (Tex. 2020), a grantor can keep part of its estate either by reserving it or by granting only the part it wants to convey. Because the 1962 deeds granted only a 1/24 interest, the grantors did not need to reserve the additional executive rights to keep them. To the extent *Anadarko* requires a reservation in that situation, the court expressly disagreed with it. The court also rejected the argument that the "to have and to hold" clause carried the executive rights as appurtenances, holding that a warranty clause does not convey title or define the estate conveyed.

Ovintiv and XTO further argued that the trial court's reading left the grantors with an impermissible "naked" executive right. The court disagreed.

Relying on *Day's* statement that the executive right remains an interest in property even when severed, and noting that the Texas Supreme Court has left the question open, the court held that the executive right is severable from the other attributes of the mineral estate and may be held as a naked right. The court added that, given its reading of the 1958 deed, the executive right retained here was not naked in any event.

The court next held that the trial court did not abuse its discretion by refusing to compel joinder of everyone claiming under the 1958 deed across the full 25,000 acres. Ovintiv and XTO relied on *Longoria v. Exxon Mobil Corp.*, 255 S.W.3d 174 (Tex. App.—San Antonio 2008, pet. denied), but the court noted that the trial court in *Longoria* had ordered joinder, and it found no evidence here that the absent owners actually claimed an interest, as *Crawford v. XTO Energy*, Inc., 509 S.W.3d 906 (Tex. 2017), requires. Merely having an interest is not enough. The court also rejected the argument that no party pleaded for a construction of the 1958 deed. Element pleaded that the 1958 grantors conveyed the "excess royalty" to High Crest, PetroLegacy and XTO argued the opposite, and the trial court was required to decide all questions presented by the competing motions.

On the meaning of the 1958 deed, Ovintiv and XTO argued that the double fraction triggered the *Van Dyke* presumption and that the "irrespective" language simply guaranteed a minimum of 1/8 under future leases. They also pointed out that, unlike the deed in *Clifton v. Johnson*, 733 S.W.3d 16 (Tex. 2026), the 1958 deed never used the multiplied fraction of 1/32. Jase and High Noon responded that the "irrespective" language untethered the reserved royalty from any lease royalty, and that applying the presumption would write those words out of the deed.

The court agreed with Jase and High Noon. It acknowledged that the presumption applied and, standing alone, would produce a floating 1/4 royalty, consistent with the grantors' 1/4 shares of bonus, rentals, and shut-in royalty. But the parenthetical did two things. It showed that the parties knew future leases might carry a royalty other than 1/8, which undercuts a key basis for the presumption. And by making the grantors' share payable "irrespective of" the lease royalty, it cut the reservation loose from any lease, which is the defining feature of a fixed royalty. Because a fixed 1/4 royalty would be unreasonable when the grantors owned only a 1/4 mineral interest, the court multiplied the fractions and held that the deed reserved a fixed 1/32 royalty.

This case creates a conflict with the El Paso Court of Appeals on whether excess executive rights pass when a grantor conveys only a fractional mineral interest, and it holds that a naked executive right is permissible, a question the Texas Supreme Court has left open. It also shows that the *Van Dyke* presumption can be rebutted even when the deed never states the multiplied fraction.

About The Authors

***Austin Brister**, a partner in McGinnis Lochridge's Houston office, and **Alejandra Salas**, a litigation associate with the Firm, handle complex oil and gas litigation. Austin serves as first-chair trial counsel for upstream operators in disputes over JOAs, operatorship, lease termination, and title. Alejandra represents exploration and production companies, royalty owners, and mineral owners.*

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NEW ATTORNEY ANNOUNCEMENT

McGinnis Lochridge Welcomes Ally Duplechain

McGinnis Lochridge welcomes Alixe "Ally" Duplechain as an Associate. Ally focuses her practice on commercial litigation and appeals, representing businesses and individuals across a wide range of industries. Her practice is built on written advocacy, and she has won pre-trial resolutions through motion practice as well as favorable outcomes on appeal.

Ally has presented on state court summary judgment practice to the New Orleans Bar Association for four years running, along with programs on new evidentiary and procedural rules passed by the legislature.

Ally graduated magna cum laude and Order of the Coif from Tulane University Law School, where she served as a managing editor of the Tulane Law Review and as a senior fellow in the first-year legal research and writing program.

She earned a Certificate in Civil Law and externed for the Honorable Susie Morgan of the U.S. District Court for the Eastern District of Louisiana. She holds a B.S. in Psychology from Louisiana State University.

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Considerations for Product Storage Arrangements



By David H. Herrold

Terminal operations involving the storage, transportation and blending of crude oil or other product can be a balancing act. The operator must keep the terminal compliant with state and federal safety regulations, air emissions permits and other regulatory requirements. It must also address customer issues, whether product nominations, blending requests, or disputes concerning operations that could challenge the terminal's capabilities and regulatory compliance. Through all of it, the operator is, of course, always watching its "bottom line" to ensure the enterprise stays profitable, while still acting in a commercially reasonable manner and as a prudent operator under its customer agreements.

This article addresses an operator's storage relationships and agreements, specifically, how an operator can better protect itself and limit risk with product-storing customers.

Terminal Storage Agreements

The storage agreement is the foundational document in a crude oil (or other petroleum product) storage relationship with a terminal. Often called a 'Terminal Services Agreement,' a 'Crude Oil Storage Agreement,' a 'Storage Tank Lease,' or some variation, it is the base document governing a customer's storage of product at the operator's facility. It generally covers storage fees (usually "take or pay" – i.e., the customer pays an agreed rate multiplied by the maximum available barrel storage within the tanks being leased despite the amount of product stored), other fees charged, invoice and payment protocols, contract term and renewals, nomination and delivery protocols, agreed terminal services provided to the customer, product title requirements, force majeure, insurance and taxes, indemnification, and product shrinkage or loss, among other things.

Obviously, each party negotiates for its own interests in arriving at the ultimate agreement. The product storer (usually a 'customer,' 'lessee' or 'tenant') is most interested in facilitating its ability to move crude into and out of the terminal, depending on whether the market is in contango (a reason to store) or backwardation (a reason to sell). The operator is, of course, interested in being paid for its services, whether that be storage, blending, testing, transportation or otherwise — that's the terminal's business and what drives profitability. But other considerations are equally important, especially protecting the operator from a customer's delinquency and commercially unreasonable requests, and protecting the valuable services the terminal extends to the customer.

A separate set of terminal rules sometimes overlays this base agreement, providing further detail on the rights and duties of the parties at the terminal. If they exist separate from the agreement, they can be incorporated into it as additional terms and conditions, binding the customer to them. They tend to be one-sided (in the operator's favor), usually outlining its ability to operate the terminal in its discretion and to ensure its own commercial reasonableness in responding to customer nominations or other requests.

Protections Against Delinquency

Whether or not the storage agreement or terminal rules say so, terminal operators have strong legal protection against customer delinquency and non-payment: lien rights arising in the operator's favor and covering stored product. These rights come from the 'warehouse lien' provisions of the Uniform Commercial Code (UCC) – a standard set of laws adopted by all states (usually in uniform fashion) applicable to the storage of goods, including petroleum products. If effective as to stored goods, these lien rights plausibly give the warehouse a superior interest in the product stored by the customer at the terminal in the event of delinquency or non-payment, including when a dispute leads to the customer's withholding of payment.

The warehouse lien arises automatically in favor of a 'warehouse' (i.e., the operator) when 'goods' (such as petroleum products) are stored with it by the customer (referred to as the 'bailor') under a storage agreement or 'warehouse receipts' (documents

identifying the details of the storage relationship and the product stored). Because the relationship of the operator and storer can be viewed somewhat as an extension of credit (i.e., the operator extending substantial services in return for future payments for such services), the lien secures payment to the warehouse for the stored goods covered by the storage agreement or warehouse receipts, including storage fees, transportation costs, insurance, labor and other charges relating to the stored product. It attaches to product stored at the terminal under the agreement, usually within the tanks the operator has dedicated to customer use, although the storage agreement can extend it to the customer's product more generally.

The lien is possessory only. It extends only to the customer product the operator still possesses. If possession is relinquished, the lien falls off the released product as a matter of law. The lien also attaches only to the product identified in the storage agreement, so if the customer's product departs from its designated tanks and is held elsewhere in the facility (perhaps in other customer tanks that have been emptied), the lien likely ceases to attach to it. However, where a storage agreement provides for the lien to attach with respect to charges "in relation to other goods," the lien broadens in scope to those other goods.

A lien against stored product is an important feather in the operator's cap. But it does not automatically get the operator paid for the extent of a customer's default (over and above any letter of credit that may be posted). To convert product collateral to cash and satisfy unpaid debt owed under the storage agreement, the UCC requires the operator to foreclose its warehouse lien against that collateral by public or private sale. A customer that regularly deals in petroleum product is likely to be held out as a 'merchant' in such product, meaning the operator can use the substantially easier private sale mechanism under the UCC to foreclose its lien. It can also opt to sell the product publicly, a much more cumbersome undertaking.

For a private sale of stored product, the operator must notify its customer (and any other person with an interest in the product) of the sale, including the amount owed and the sale terms. Although the customer may not appreciate the sale of its product to satisfy unpaid sums owing to the terminal, it has the right to 'redeem' the product by paying the warehouse lien value and any expenses the operator has incurred in the proposed sale. If redemption does not occur and a sales notice is given, the operator may apply the proceeds to its lien, paying any resulting surplus over to the customer.

An operator whose customer is a product 'merchant' may sell publicly if it chooses; it *must* do so if the customer is not a 'merchant.' The public sales process is more cumbersome, requiring the operator to set a time and place for the sale and a date by which the customer may redeem its product, along with notice of that timeline to the customer and any interested parties. It also obligates the operator to comply with a host of additional requirements, including a sale by auction with pre-published advertisements that again state the customer's redemption deadline. As with a private sale, the operator may then apply sales proceeds to its lien, paying any surplus over to the customer.

Storage Agreement Suggestions

For a terminal operator, five areas deserve attention in negotiating a storage agreement with customers: [i] strong damages limitations language, [ii] broadened lien language, [iii] reasonable governing law and convenient forum requirements, [iv] broad operator discretion, and [v] product quality exceptions.

First, **damages limitations**. While the agreement should not (and likely cannot) negate all damages, a damages limitations clause should be used in the storage agreement or terminal rules. Such a clause limits the amount and types of damages a customer can seek (applied reciprocally to the operator), stripping out consequential and incidental damages, lost profits, prejudgment interest, expectation damages, punitive or exemplary damages, loss in value of the product stored, and the like. The operator can also attempt to impose caps on actual damages — for example, at the aggregate storage charges the customer has paid over a certain period (inception-to-date, year-to-date, etc.). A jury trial waiver is likewise a significant benefit, goes hand in hand with damages limitations, and should be spelled out in the storage agreement. These limitations help the operator better foresee and control the overall risk of its relationship with the storage customer.

Second, **broad lien rights**. A storage agreement need not specify the operator's UCC lien rights for them to arise — they arise 'by operation of law' — but it remains prudent to include them in the storage agreement or the terminal's rules to place the customer on direct notice. The lien rights should apply to the product stored in assigned tanks and also 'in relation to all other goods or product' of the customer, wherever located within the terminal. This gives the operator both the specific and the general liens the UCC affords, and lets it reach customer product held within the terminal but outside the assigned tanks to satisfy unpaid charges and fees. The notice of warehouse lien rights should be conspicuous within the agreement or rules; where possible, the agreement should also define the customer as a 'merchant' — one familiar with and regularly dealing in the types of goods (i.e., product) stored at the terminal. Finally, such clauses should recite that the customer exclusively owns the stored product and that, to the extent others have interests in it (such as lenders or other secured parties), they authorized the product to be in the customer's possession before storage for purposes of storing it with the terminal, or of transporting or selling it, and for the customer to pledge it to the operator for payment due under the agreement in order to procure a warehouse receipt. Terms like these advance the operator's lien claims if issues arise with a delinquent or non-compliant customer.

Third, **governing law and forum**. Parties often negotiate governing law and forum-selection clauses with an eye toward their own states of incorporation or headquarters, or land on a situs that bears no real relation to their relationship. If the relationship later becomes the subject of litigation, the parties may be forced to litigate in unfamiliar territory under unfamiliar law — though as to lien rights, the UCC's uniform nature is a straightforward benefit to lien rights and foreclosure, generally. Serious consideration should be given to choosing the law and forum of the state where the

terminal operates and the product is stored, though other business factors certainly call for a different jurisdiction to apply.

Fourth, **broad discretion**. A storage agreement cannot be so one-sided as to relieve an operator of its 'commercial reasonableness' – the obligation to act as a prudent operator with respect to a customer's stored product. The agreement or the terminal's rules can, however, define the extent of the operator's obligations and better delineate what acts are specifically permitted and, thus, commercially reasonable if the operator undertakes them. For instance, the storage agreement should directly address the operator's discretion to accept or reject nominations, or partial nominations, delivered by its customers. That relieves the operator of having to perform every nomination exactly as the customer outlined it. The agreement should also address the operator's discretion to acknowledge or accept title transfers – transfers of product ownership while the product sits *in situ* at the terminal – which, left unchecked, can work to the operator's disadvantage with respect to its lien rights. Requiring a formal title transfer process and, ultimately, the operator's approval enables the operator to better retain its lien and secured interest in the product sought to be conveyed. Other duties under the storage agreement or terminal rules may be described as discretionary as well, provided the discretion is not so one-sided as to render the customer's rights illusory.

Finally, **product quality**. An operator's duties certainly include an obligation to preserve the product the customer delivers. However, as any operator knows, contamination — whether by water, sulfur or differing grades of product passing through common piping at the facility — can diminish the overall quality of a customer's crude delivered to and stored in its leased tanks. A storage agreement should, therefore, address the operator's exculpation from liability for product quality variation or degradation, reciting the customer's acknowledgment (and acceptance) of conditions that could diminish the quality of its delivered and stored product. Such a clause may effectively reduce the customer's available remedies from the world of tort to a simpler (and more ascertainable) claim for breach of contract, which the operator would then be better able to defend and for which damages claims are somewhat more limited.



Conclusion

Terminal operations can impose significant burdens on an operator. Carefully crafted clauses — ones that protect the operator, more precisely define its obligations and its commercial reasonableness, and strip the customer of potential claims, remedies, and damages — give the operator more certainty in the operator/customer relationship and limit its risk.



Our attorneys at McGinnis Lochridge regularly assist clients in negotiating and counseling on product storage relationships. Please contact the author if you need assistance, whether as an operator or a potential storage customer.

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Can Underpayment be a "Nonpayment" Allowing Lease Cancellation?

YMC Royalty Co. LP v. WPX Energy Permian, LLC, No. 1:24-CV-00266-DAE, 2026 WL 2211771 (W.D. Tex. July 28, 2026).

By Austin Brister and Alejandra Salas



SUMMARY: On cross-motions for summary judgment, the federal district court for the Western District of Texas held that under this lease an underpayment of royalty was a "nonpayment" within the meaning of a clause that allowed for potential lease termination. However, it also held the lessor's notice had to identify the specific nonpayment, which a general refund demand did not. The court further held that a clause indicating royalties must be free of deduction for "any other costs of whatsoever nature," did not require the lessee to add back transportation and fractionation adjustments that NGL purchasers built into their index-based price, distinguishing the language from that in *Devon v. Sheppard*.

YMC Royalty Co. LP leased its Section 9 interest in Loving County to RKI Exploration & Production, LLC in 2016 for a 25% royalty, and RKI assigned the lease to WPX Energy Permian, LLC in 2019. Under the royalty clause, the lessor could give "written notice of nonpayment of royalty" and, if the royalty "is not paid on or before expiration of thirty (30) days" from the notice, "may terminate this Lease."

In 2021, WPX deducted from YMC's royalty a gathering fee that WPX attributes to an accounting error. On December 3, 2021, YMC demanded a refund of all deductions since the lease began and wrote that the lease "will terminate in 30 days from this notice date unless WPX complies with its express obligations under the Lease." WPX refunded that fee category in December and asked YMC to identify any other deductions. YMC sued in March 2024, claiming the lease had terminated because WPX had not paid royalty on plant fuel and flared gas and had made improper deductions on NGLs.

WPX argued that only an uncured "nonpayment" could trigger the clause, not an "underpayment." Reading "royalty" and "nonpayment" by their ordinary definitions, the court held that under this lease an underpayment "necessarily constitutes a nonpayment" because the underpaid lessor does not receive its share of production. The court found WPX's reading unreasonable because it added terms to the lease, so the rule favoring a reading that avoids forfeiture did not apply.

YMC contended that its December 3 letter "literally complied" with the clause, and WPX responded that it identified only the refunded fee category. The court sided with WPX. Relying on the rule, from *Reilly v. Rangers Mgmt., Inc.*, 727 S.W.2d 527 (Tex. 1987), that courts "will not declare a forfeiture unless they are compelled to do so," the court construed this lease's notice provision to require notice of "the specific way or ways in which the lessee breached the lease." It agreed with WPX that the audit clause in the same section confirmed that a general demand would not do. Under YMC's reading, the court explained, a lessor could send a general notice, find an underpayment years later, "whether that underpayment is for $1,000,000 or $1," and claim a termination dating back to 30 days after the original notice. Because the December 3 letter identified no uncured nonpayment, the court held that it did not trigger termination.

The court distinguished *Coastal Oil & Gas Corp. v. Roberts*, 28 S.W.3d 759 (Tex. App.—Corpus Christi 2000, pet. granted, judgm't set aside), on which YMC relied, on its facts and because that lease required only a "written demand of payment." The court dismissed YMC's termination-based claims, including a claim for more than $18 million under the lease's $50-per-acre-per-day surrender clause.

The gas royalty was 25% of "the amount realized from the sale thereof and any products produced therefrom to the first purchaser that is not affiliated with

or related to Lessee," and the lease barred deductions for listed costs "or any other costs of whatsoever nature." The processor sold the NGLs to unaffiliated purchasers at a Mont Belvieu index price reduced by formula adjustments for the purchasers' possible transportation and fractionation costs. YMC argued that those adjustments were prohibited deductions. The court disagreed. It reasoned that this "amount realized" lease was valued at the point of sale, that no-deductions language this broad has been treated as surplusage that does not reach post-sale costs, and that the adjustments were post-sale costs built into the price. The lease had no "add-on" provision like the one in *Devon Energy Prod. Co. v. Sheppard*, 668 S.W.3d 332 (Tex. 2023), which required price reductions for post-production costs to be "added to" gross proceeds.

WPX admitted that it paid no royalty on plant fuel, but argued there was no breach because it had overpaid the oil royalty. The lease made the oil royalty an in-kind royalty "to be delivered at the wells," yet WPX paid YMC for more than five years without deducting post-production costs, which its expert put at $2,190,812.61. The court held that an overpayment of one royalty does not negate the failure to pay another, so WPX breached the lease. But the court denied YMC summary judgment on damages. It reasoned that if YMC had made no arrangement to take or store its oil, and the parties had no other arrangement, WPX would be authorized to sell the oil for YMC and deduct post-production costs. Because the record did not establish those facts, whether YMC was overpaid and whether it suffered recoverable damages remain for trial.

On "nonpayment," the court refused to add terms to the clause. On "notice," it found a specificity requirement that the clause does not spell out, relying on the audit clause and the disfavor of forfeitures. The anti-forfeiture rule may explain the difference: the court found WPX's reading of "nonpayment" unreasonable, but it did not find YMC's reading of "notice" compelled. The court's example of a general notice reaching back years to a later-discovered $1 shortfall also traces to the clause, which did not say what a notice had to contain or how long it stayed effective.

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***Austin Brister**, a partner in McGinnis Lochridge's Houston office, and **Alejandra Salas**, a litigation associate with the Firm, handle complex oil and gas litigation. Austin serves as first-chair trial counsel for upstream operators in disputes over JOAs, operatorship, lease termination, and title. Alejandra represents exploration and production companies, royalty owners, and mineral owners.*

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NEW ATTORNEY ANNOUNCEMENT

McGinnis Lochridge Welcomes Christian Shaffer

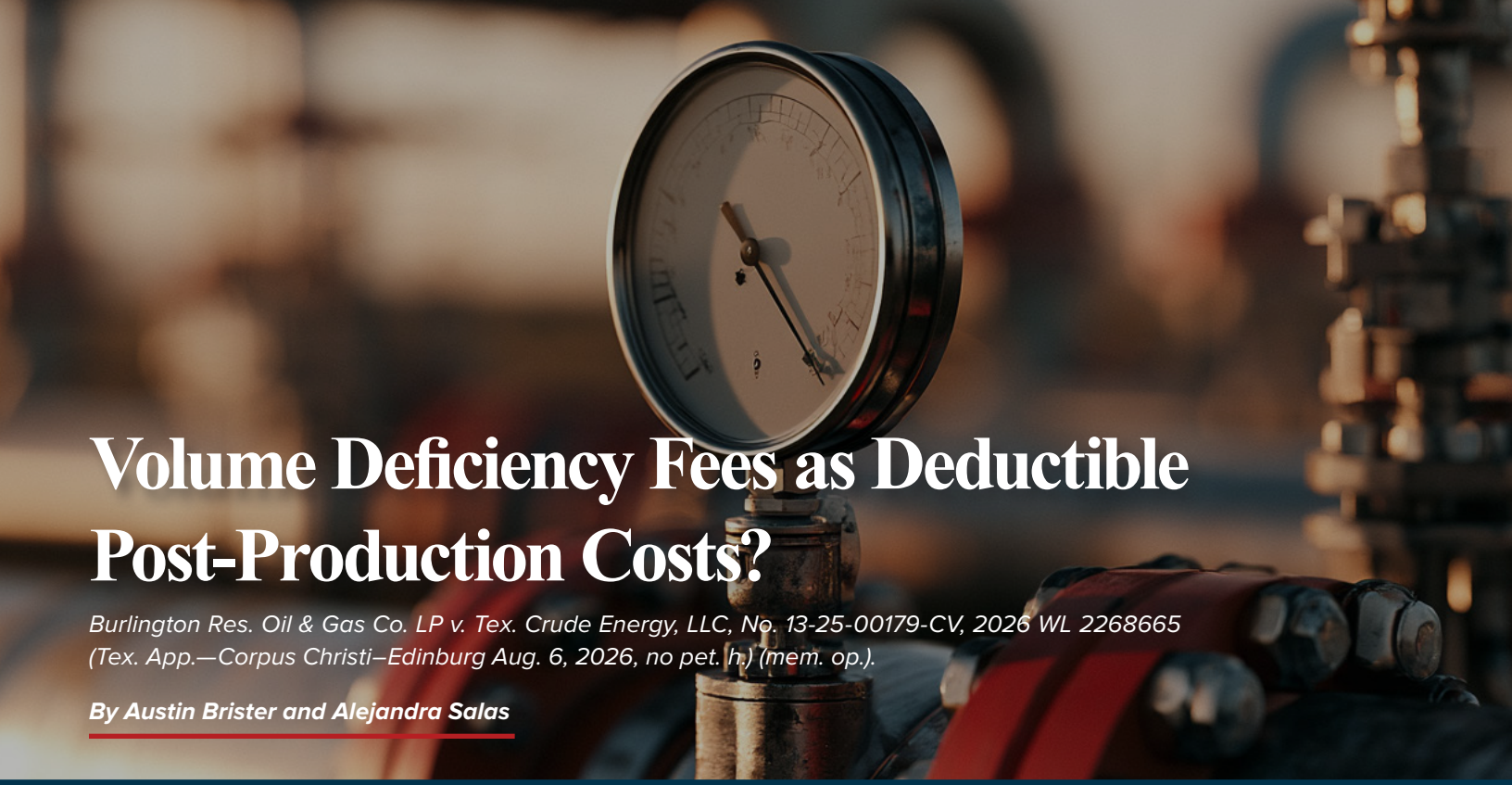
McGinnis Lochridge welcomes Christian Shaffer as an Associate in its Houston office, where he represents clients in commercial and energy-related disputes.

Christian joins the firm after two clerkships that give him both a trial-level and an appellate-level view of the disputes he handles. He clerked for the Honorable John D. Love of the U.S. District Court for the Eastern District of Texas and for the Honorable John P. Devine of the Supreme Court of Texas.

Christian earned his J.D. from Texas Tech University School of Law, where he served as Lead Articles Editor of the Texas Tech Law Review. He received several honors for his writing and appellate advocacy, including the Law Review's W.L. Penn Award for his student comment, the Dean Darby Dickerson Top Writing Award, and induction into the Order of the Barristers. He also won a national moot court championship as both an oralist and a brief writer. He holds a B.A. in Philosophy and Political Science from Washington State University.

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Volume Deficiency Fees as Deductible Post-Production Costs?

Burlington Res. Oil & Gas Co. LP v. Tex. Crude Energy, LLC, No. 13-25-00179-CV, 2026 WL 2268665 (Tex. App.—Corpus Christi–Edinburg Aug. 6, 2026, no pet. h.) (mem. op.).

By Austin Brister and Alejandra Salas

SUMMARY: The Corpus Christi–Edinburg Court of Appeals held that volume "deficiency fees" owed under minimum-volume terminal throughput agreements, and a price reduction a crude purchaser imposed when sales fell below a minimum volume, were a form of transportation cost deductible as post-production costs from an overriding royalty.

This case returned to the court of appeals after the Texas Supreme Court held, in *Burlington Resources Oil & Gas Co. LP v. Texas Crude Energy, LLC*, 573 S.W.3d 198 (Tex. 2019), that Burlington could deduct post-production costs from Texas Crude's overriding royalty. The question this time was whether "deficiency fees" count as post-production costs. An operator that commits to minimum daily volumes pays for that capacity whether or not its production fills it, and the court found "virtually no judicial authority" addressing the resulting "deficiency fees."

Texas Crude Energy, LLC owned overriding royalty interests in the Sugarloaf Wells, operated by Burlington Resources Oil & Gas Company LP, a ConocoPhillips subsidiary, and assigned them to its affiliate, Amber Harvest, LLC. This article refers to Texas Crude and Amber together as the royalty owners. The Prospect Development Agreement and Joint Operating Agreement governing the interests contain no language limiting post-production costs. After the 2019 remand, the parties agreed to stay the case, including all discovery, so the royalty owners could audit Burlington's royalty payments. In 2024 the trial court lifted the stay, and the royalty owners amended their petition to allege that Burlington improperly deducted roughly $75,000 in deficiency fees under three terminal throughput agreements and a crude oil supply agreement with BP Products.

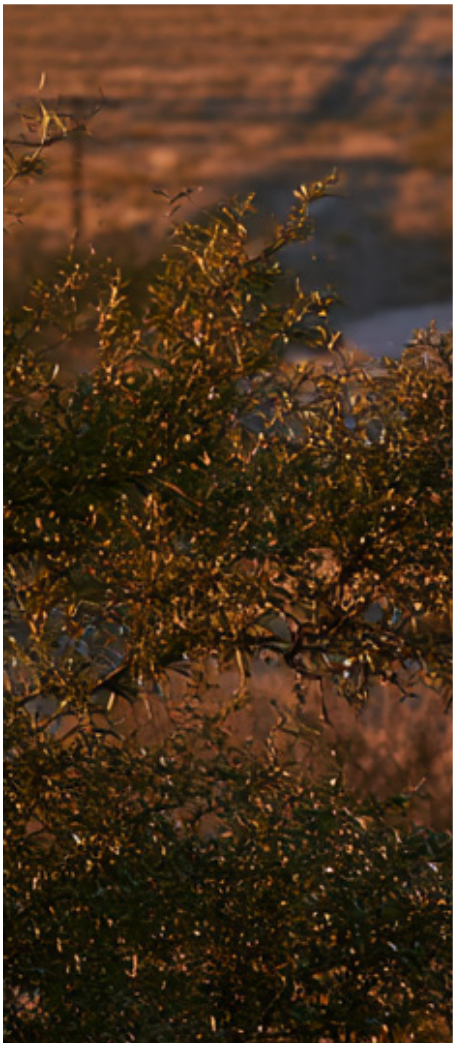
Burlington moved for summary judgment, attaching the four agreements and two affidavits. Under each throughput agreement, ConocoPhillips agreed to pay a per-barrel fee tied to a "minimum daily throughput volume" and owed the full charge even when it delivered less. The agreements called the shortfall portion a "deficiency fee." Under the supply agreement, BP paid a lower price when sales fell below a minimum volume, and the lower price flowed into the weighted average sales price used to calculate the royalty. A certified public accountant stated by affidavit that the full throughput charge, deficiency component included, was "incurred for the purpose of transporting the actual produced and delivered volumes" to ConocoPhillips's points of sale. The royalty owners argued that Burlington could not deduct fees it "chose to incur" and that paid for transportation "not actually used to transport" oil. They submitted no evidence of their own.

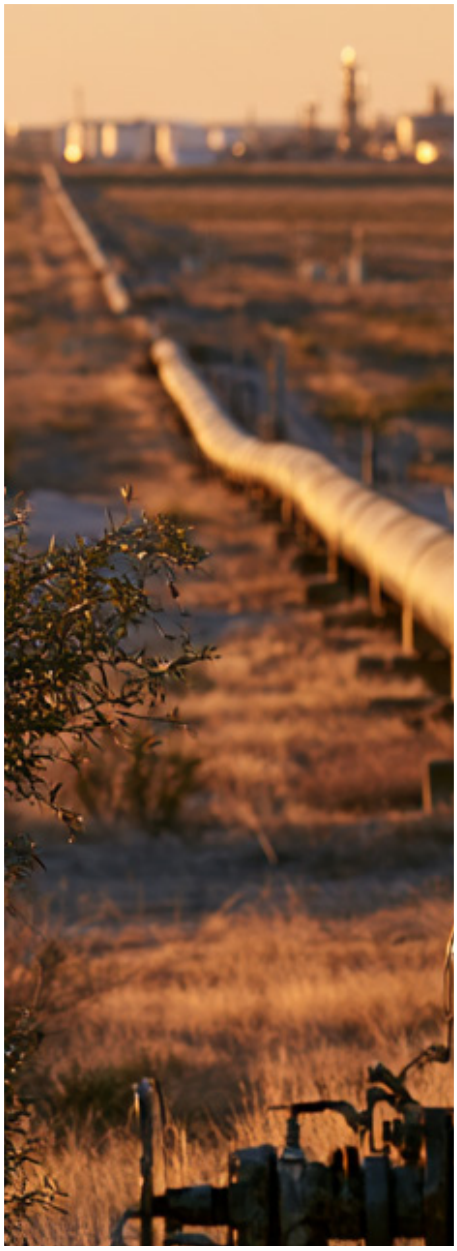
The court sided with Burlington. Reviewing the motion under the traditional summary judgment standard, it consulted the Williams & Meyers treatise, as the Supreme Court had done in the 2019 appeal. The treatise defines transportation costs as "the costs of transporting oil or gas to a market" and says nonoperating interests usually bear a proportionate share of them absent an express agreement to the contrary. Relying on the uncontroverted evidence, the court reasoned that ConocoPhillips could not have secured "firm, reliable service" for the wells' anticipated production without the minimum-volume commitment. It concluded that the entire fee, "regardless of whether the fee is labeled deficiency or throughput," was a transportation expense "because without payment of the fee, Burlington would be unable to transport the oil produced from the Sugarloaf Wells." The court also classified the BP price reduction as a transportation cost, calling it "another penalty," with little further explanation. It cited *Commissioner of the General Land Office v. SandRidge Energy, Inc.*, 454 S.W.3d 603 (Tex. App.—El Paso

2014, pet. denied), which said firm transportation charges "clearly" qualify as transportation costs.

The sanctions award fared differently. The trial court had found that Burlington abused the discovery process and awarded the royalty owners $239,003 in attorney's fees and $48,312 in expenses under Rules 215.1(d) and 215.3. The court of appeals held that both rules apply to the discovery process, and that Rule 215 "cannot be applied" where, as here, "the parties requested, and the trial court granted, a stay of the discovery process." It reversed and rendered judgment denying the motion.

This appears to be the first Texas appellate decision to treat minimum-volume deficiency fees as deductible post-production costs, and it leaves two questions open. First, the court relied on *SandRidge's* statement that firm transportation charges "clearly" qualify as transportation costs but did not discuss the rest of that opinion. The *SandRidge* leases allowed deduction only of costs "actually incurred" in transporting the gas sold, and the El Paso court held that firm transportation charges for pipeline space "not ultimately used" were not actually incurred in connection with that gas. It also left in place a fact issue on whether the charges were reasonably incurred. Because the *Burlington* court described the governing agreements as containing no language limiting post-production costs, *SandRidge* may be distinguishable, but the court did not say so. Second, whether the commitments were reasonably sized to expected production, and whether the shortfall charges were reasonably incurred, are questions the opinion never asks. The royalty owners put on no evidence about either, so the court had no occasion to draw a line, and the opinion draws none.





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What Frees a Texas Royalty From Post-Production Costs

By Kevin Colpoys

SUMMARY: After *Fasken v. Puig*, ordinary cost-free language alone generally does not free a Texas royalty from post-production costs. A royalty owner generally needs more: a valuation point downstream of the well, an add-back clause that adds the buyer's deductions to the royalty base, or other language showing the parties meant to shift those costs. Since *Sheppard*, one federal court has enforced an add-back clause, and two have declined to add back deductions where the lease had none.

Two decisions this year address when a Texas royalty owner bears post-production costs. In April, the Texas Supreme Court held in *Fasken Oil & Ranch v. Puig* that a royalty reserved "free of cost forever" is not, on that language alone, free of post-production costs. In May, a federal court in San Antonio applied the Court's 2023 decision in *Devon Energy v. Sheppard* and required a lessee to add a buyer's price deductions back into the royalty base.

Both decisions turn on the same two questions: where the instrument values the royalty, and whether it adds anything back to that value.

The General Rule

Texas values a royalty at the well unless the parties agree otherwise. Under *Heritage Resources v. NationsBank*, a royalty valued at the well bears its share of the costs incurred after production to make the product marketable, and a clause prohibiting "deductions" from that royalty does not change the result.

In *Sheppard*, the Court confirmed that parties may agree to a different allocation, but they must express that intent "plainly and in a formal way." Parties generally do so by moving the valuation point downstream, usually with gross-proceeds or amount-realized language, by specifying that something is added to the royalty base, or both.

Cost-Free Language

Fasken involved a 1960 deed reserving a nonparticipating royalty "free of cost forever." The Court held that the language did not shift post-production costs to the operator because, absent a reference to another valuation point or calculation method, "cost-free language merely restates the rule that a royalty interest is free of costs incurred in exploring for and producing the raw minerals."

The Court distinguished *Chesapeake v. Hyder*, the 2016 decision holding an overriding royalty free of post-production costs. The *Hyder* lease contained three features the *Fasken* deed did not: (i) a parenthetical excepting production taxes from the cost-free language; (ii) other royalty clauses that used downstream valuation points; and (iii) an express right for the royalty owner to choose between payment in cash and in kind.

Gross Proceeds and Add-Back Clauses

A royalty on gross proceeds at the point of sale is free of the lessee's own costs before the sale. Under *Sheppard*, it generally is not free of the buyer's costs after the sale. The buyer accounts for those costs in the price it pays, often by paying an index price less transportation, fractionation, or similar adjustments. If the lease has no add-back clause, courts have generally calculated the royalty on that reduced price, so the royalty owner bears those costs.

An add-back clause changes that result. In *Sheppard*, the Texas Supreme Court held that a lease requiring the buyer's deductions to be added back to gross proceeds required royalty on those amounts, even though the buyer incurred the costs after the sale. That holding reached only price reductions made for the purposes the lease listed. The court of appeals ruled for the producers on adjustments with no stated purpose, and because the royalty owners did not appeal that ruling, the Supreme Court did not review it.

Federal Courts and Add-Back Clauses

Since *Sheppard*, federal courts have followed the lease language. In *Gringita, Ltd. v. Ineos USA Oil & Gas*

(W.D. Tex. May 8, 2026), the add-back language appeared in the lease's definition of gross proceeds, a term the royalty clause did not use. The court held that the definitions still informed the royalty clause and that the lessee must add to the royalty base the value of sales-price deductions meant to account for post-production costs. The court construed the lease only; it did not decide whether any amount was owed.

In *YMC Royalty Co. v. WPX Energy Permian* (W.D. Tex. July 28, 2026), the court reached the opposite result because the lease "contains no language comparable to that in *Sheppard.*" *H.L. Hawkins, Jr., Inc. v. Capitan Energy* (W.D. Tex. 2023) is to the same effect. That lease had no add-back clause and protected the royalty only from costs "incurred by Lessee."

Lessees sometimes argue that a deduction built into a pricing formula is part of the price, not a cost. Before *Sheppard*, a bankruptcy court rejected that argument under a broad add-back clause in *Petty Business Enterprises v. Chesapeake Exploration* (Bankr. S.D. Tex. 2021). The purchaser there paid an index price less a transportation and fractionation fee. The court held that "[t]he fact that the reduction does not represent the purchaser's actual cost is irrelevant." The Texas Supreme Court later cited *Petty* in *Sheppard*.

Practical Considerations

For royalty owners, the first questions are where the instrument values the royalty and whether it contains an add-back clause. If the royalty is valued at the well and there is no add-back clause, cost-free language is unlikely to help after *Fasken*. If there is an add-back clause, the purchase contracts and check statements will show which adjustments relate to transportation, processing, or marketing.

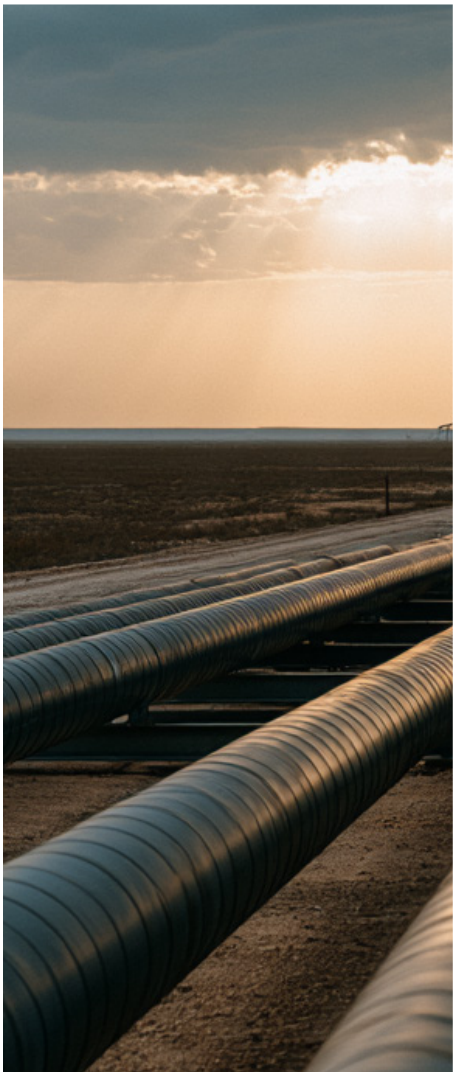
Operators and payors should run the same review. A lease with an add-back clause, particularly one reaching adjustments taken by "the purchaser," may require royalty on more than gross proceeds, and in *Petty* the argument that a deduction is simply part of the price did not succeed.

Parties drafting new instruments should state where the royalty is valued and what, if anything, is added back, rather than relying on cost-free language.

About The Author

Kevin Colpoys *is an associate in McGinnis Lochridge's Houston office whose practice focuses on commercial and oil and gas litigation. Before joining the firm, he represented landowners, operators, and service companies in Midland, Texas, in matters involving surface and mineral disputes, condemnation, trespass to try title, and conflicts arising from oilfield operations. He earned his J.D., cum laude, from Texas Tech University School of Law.*

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About McGinnis Lochridge

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