TOP TEN TEXAS ENERGY CASES FROM THE PAST TWELVE MONTHS

DALLAS BAR ASSOCIATION'S
XXXIII REVIEW OF OIL AND GAS LAW

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1. ***Apache Deepwater, LLC v. Double Eagle Development, LLC*, No. 08-16-00038-CV, 2017 WL 3614298 (Tex. App.—El Paso Aug. 23, 2017).**

This case analyzed whether a retained acreage clause provided for "rolling terminations" after the expiration of a lease's primary term or "snapshot termination" at the expiration of a lease's primary term. In 1975, Apache's predecessor leased a 640-acre tract in Reagan County. The lease provided a four year primary term and a secondary term for "as long thereafter as oil, gas, or other minerals or leased substances or any of them are produced from the leased premises . . . ." The lease defined the "leased premises" as the entire 640-acre tract.

Consistent with the regulatory scheme at the time, Apache divided the lease into four 160-acre proration units. Each unit had one producing well within its boundaries. At the end of the lease's primary term, all four wells were producing. However, in the ensuing years, three of the four wells ceased production.

In 2012, the property owner leased the property within the three non-producing proration units to Double Eagle. Double Eagle then demanded Apache to execute releases for the property in the non-producing units. Apache refused, contending production from the well in the producing unit held the entire 640-acre tract. Double Eagle then sued for a declaration the lease expired within the non-producing units.

The crux of the dispute was the interplay between the lease's habendum and retained acreage clauses. The habendum clause provided

> TO HAVE AND TO HOLD the leased premises [i.e., the entire 640-acre tract] for a term of three (3) years from the date hereof, hereinafter called the 'primary term,' and as long thereafter as oil, gas or other hydrocarbons or other minerals or leased substances, or either or any of them, are produced from the leased premises or from lands with which the leased premises are pooled or unitized.

However, the lease's retained acreage clause provided

> Notwithstanding anything to the contrary in the foregoing, Lessee covenants to release this lease after the primary term except as to each producing well on said lease, operations for which were commenced prior to or at the end of the primary term and the proration units as may be allocated to said wells under the rules and regulations of the Railroad Commission of Texas or 160 acres, whichever is greater, insofar as said proration units cover from surface to base of the deepest formation penetrated by the deepest of said wells. The description of said tracts around said well shall be compiled and prepared by the Lessee for purpose of executing such release.

Apache contended this retained acreage clause provided for "snapshot termination." That is, Apache contended this clause required a single snapshot-in-time evaluation as of the end of the lease's primary term, and because each of the four proration units had a producing well in it on that date, the termination obligation in the retained acreage clause did not apply. Double Eagle contended this retained acreage clause provided for "rolling terminations." That is, Double Eagle contended that following the primary term, the lease would expire as to any proration unit that did not have a producing well within it at any time (to the extent not saved by other leave clauses).

The El Paso Court of Appeals sided with Apache. The court first noted the habendum clause unambiguously provided the entire 640-acre tract would be held by production from any well within the tract's boundaries. Thus, for the retained acreage clause to modify the habendum clause and provide for rolling proration unit terminations during the lease's secondary term, it had to contain "clear, precise, and unequivocal language" expressing a "clear intent" to do so. The court held the lease's retained acreage clause did not contain such language. Instead, the court held the retained acreage clause provided that *after* the end of the primary term, the lessor could insist that any part of the leasehold that was not within a proration unit which had either a producing well or a well under development that later came into production *at* the end of the lease's primary term, must be released. Though Double Eagle correctly pointed out the retained acreage clause used the phrase "after the primary term" not "at the expiration of the primary term," it still limited the lessor's right to demand a release "after the primary term" to acreage not within a proration unit with a producing well or continuous operations leading to a producing well "*prior to or at the end of the primary term.*" Thus, the court held the lease did not contain "clear, precise, and unequivocal" language negating the habendum clause and providing for rolling terminations, and that production from any well within the leased 640 acres would hold the lease on the entire tract.

2. ***XTO, Inc. v. Goodwin*, NO. 12-16-00068-CV, 2017 WL 4675136, (Tex. App.—Tyler Oct. 18, 2017) (pet. filed).**

In this case, the Tyler Court of Appeals reversed a jury verdict awarding a property owner damages for (i) subsurface trespass because the award was based on the value of the impeding wellbore to the trespasser rather than reduced market value of the property due to the trespass and (ii) bad-faith pooling because the trial court had previously determined the pooled leases were *void ab initio* for failure to pay the proper lease bonus.

In 2007, the plaintiff, Edwin Goodwin signed an oil and gas lease with XTO's predecessor in interest covering three tracts of land in San Augustine County. Pursuant to a contemporaneous letter agreement, the lessor paid Goodwin a lease bonus based on the parties' belief Goodwin owned a 50% mineral interest in one of the tracts and a 100% mineral interest in the remaining tracts. After XTO acquired the leases, however, the parties determined Goodwin actually owned more than a 50% mineral interest in one of the leased tracts (Tract 2). Thus, Goodwin argued XTO's lease on Tract 2 was void due to its predecessor's failure to pay Goodwin the proper lease bonus.

While this dispute was lingering, XTO formed two adjacent units in San Augustine County, the Butler Rooney and Terrapins 1H. All three of Goodwin's tracts were included in the Butler Rooney Unit. A successful well was drilled on that unit, and Goodwin began receiving proportional royalty payments. XTO then drilled a well on the Terrapins 1H unit in close proximity to Goodwin's lease line. During drilling, the wellbore "walked" (i.e., drifted horizontally) and crossed into Goodwin's tract for 2,900 linear feet between 10,000 and 13,000 feet below the surface. Prior to completing the Terrapins Well, XTO sought a subsurface easement from Goodwin, but Goodwin refused. Around the same time, XTO realized it had been overpaying Goodwin on his Butler Rooney leases. When XTO suspended Goodwin's royalty payments to account for this overpayment, Goodwin filed suit.

In the trial court, Goodwin sought a declaratory judgment that XTO's leases were void due to the failure to pay Goodwin a proper lease bonus. Goodwin also asserted claims against XTO for fraud, trespass and bad faith pooling, among other claims. XTO responded that Goodwin did not have an interest in the deep subsurface sufficient to support a trespass claim, and even if he did, he suffered no damages from XTO's trespass. XTO also argued that Goodwin ratified XTO's leases by accepting royalty payments under them, and that if he had not ratified them (and thus, the leases were void), his bad-faith pooling claim failed because no pooling ever actually occurred. The trial court granted summary judgment for Goodwin on his declaratory judgment action, and the case proceeded to trial. There, the jury sided with Goodwin on his trespass and bad-faith pooling claims, but with XTO on Goodwin's fraud claim. Altogether, Goodwin obtained a judgment against XTO for $2,088,723.80.

Subsurface Trespass but No Damages

On appeal, XTO did not dispute its wellbore crossed into the subsurface of Goodwin's property. However, XTO argued that Goodwin did not have a legally protected interest in the subsurface two miles below the surface sufficient to support a trespass claim. In fact, XTO argued that after the Texas Supreme Court's holding in *Coastal Oil & Gas Corp. v. Garza Energy Trust*[1], "subsurface trespass is no longer a viable cause of action" in Texas. XTO relied on language in the Garza Opinion stating the ancient maxim that land ownership extends to the sky above the earth's center and the earth's center below "has no place in the modern world." Based on this language, XTO claimed "Goodwin simply failed to prove an ownership interest subject to legal protection for the rock two miles below his surface."

Alternatively, XTO argued that even if Goodwin had a legally protectable interest in the deep subsurface, XTO's trespass caused Goodwin no damages. It was undisputed XTO never completed the well, and even if it did, none of the take points would be under Goodwin's tract (only the horizontal portion of the wellbore crossed into Goodwin's property). Likewise, Goodwin presented no evidence XTO's well would prevent drilling on Goodwin's tract or reduced the market value of Goodwin's property. Instead, Goodwin presented evidence of the value of the wellbore *to XTO*, contending this was a "fair trade" for XTO's trespass. XTO contended this was an improper measure of damages and was unreliable.

The Court of Appeals rejected XTO's argument on the viability of subsurface trespass generally, but sided with XTO on its argument that Goodwin's damages were unreliable. Citing the Texas Supreme Court's 2017 opinion in *Lightning Oil Co. v. Anadarko E&P Onshore, LLC*[2], the Tyler Court noted the surface owner, not the mineral owner, "owns all non-mineral 'molecules' of land, i.e., the mass that undergirds the surface estate" and that "ownership of the hydrocarbons does not give the mineral owner ownership of the earth surrounding those substances." The court further noted that in *Lightning*, the Texas Supreme Court discussed the Garza Opinion at length, "but placed no limitation on the surface owner's interest in the subsurface or implied the surface owner's rights to the underlying earth ends at some depth below the surface." Thus, the court dismissed as dicta the language XTO relied upon from *Garza*, and held XTO had committed subsurface trespass when its wellbore waked into Goodwin's tract.

1 268 S.W.3d 1 (Tex. 2008).
2 520 S.W.3d 39 (Tex. 2017).

Nonetheless, trespass is not actionable without damages. And, when a plaintiff seeks to prove damages by expert testimony, the expert's methodology must be reliable. In this case, Goodwin's damage expert arrived at his opinion by estimating the total value of XTO's well based on projections contained in XTO's SEC filings, then allocating a proportion of that value to the portion of the wellbore impeding into Goodwin's property. The court held this methodology was not reliable, and thus, the expert's testimony was inadmissible. The court found that XTO's internal forecasts of the well's production value were no more than "hopes for the future worth of the well" and that "such hopes do not establish a reliable component of a damages model." The court also noted that XTO had never produced from the well, and that if Goodwin refused to grant XTO an easement, it never could. Because Goodwin did not factor this fact into the value of the well, his testimony was likewise unreliable and inadmissible. With no admissible evidence of damages, the trial court's judgment was reversed. The court declined to address XTO's argument Goodwin presented the wrong measure of damages.

No Bad-Faith Pooling because the Leases were Void

XTO also argued the trial court's finding that its leases were void foreclosed Goodwin's bad-faith pooling claim. That is, XTO argued that if its leases were void, any attempt to pool the mineral interests failed for lack of a valid cross-conveyance of title. And, if the leases were never actually pooled, they could not have been pooled in bad-faith.

The Court of Appeals agreed with XTO and reversed the trial court's judgment on bad-faith pooling as well. The court noted a lessee has no power to pool without the lessor's express authorization, which is usually contained in the lease's pooling clause. Because Goodwin's lease with XTO was void, XTO never had contractual authority to pool it, and thus, no implied obligation to pool in good-faith. The court dismissed Goodwin's argument that a lessee can be held liable for bad-faith pooling by attempting to pool leases he or she does not have authority to pool. Instead, those actions may support a claim for fraud, but the jury sided with XTO on Goodwin's fraud claim, and Goodwin did not challenge that portion of the judgment on appeal.

3. ***ConocoPhillips Co. v. Koopmann*, 547 S.W.3d 858 (Tex. 2018) (March 23, 2018)**

In this case, the Texas Supreme Court rejected ConocoPhillips' claim that standard term NPRI reservations violate the Rule Against Perpetuities. In 1996, Lois Strieber sold 120 acres to Lorene Koopman, reserving a 15-year one-half NPRI which could be extended "as long thereafter as there is production in paying or commercial quantities." The 15-year term ended on December 27, 2011. Lorene Koopmann later gifted two-thirds of her undivided interest to her two children. She then executed an oil and gas lease in 2007 which had a three-year primary term and an option to extend the primary term two additional years for $24,000. Burlington subsequently tendered this payment to the Koopmans, thus extending the primary term to October 22, 2012. Despite pooling activity and Strieber's conveyance of a 60% interest in her NPRI to Burlington, a well site within the pooled unit was not yet producing any oil or gas. Production began in February 2012, which was two months after the expiration of Strieber's 15-year term NPRI. Prior to the expiration of the 15 year term, Burlington sent a letter to Koopmann indicating that it had a identified a well location, and along with the letter, paid "shut-in royalty payments" to the Koopmans in an effort to perpetuate the NPRI beyond its 15 year primary term. A dispute later arose as to whether the well was *capable* of producing in paying or commercial quantities as of December 27, 2011 (the NPRI's date of termination). Royalty payments were suspended, and a lawsuit ensued.

Burlington asserted the Koopmans' future interest in Strieber's NPRI violated the Rule Against Perpetuities and was therefore void. The basis for this argument was that the phrase "as long thereafter" within the reservation created a springing executory interest in favor of the Koopmanns that was not certain to vest within the period required by the Rule (21 years after the death of some life or lives in being at the time of conveyance). The Texas Supreme Court disagreed and held that Strieber actually conveyed a future interest to the Koopmanns that "vested" immediately, and therefore did not violate the Rule for two reasons:

(1) The Court strictly adheres to the rules of construction that courts should construe instruments equally open to two interpretations as valid rather than void, and that the Legislature requires courts to reform an interest that violates this Rule to effect the ascertainable general intent of the creator of the interest; and

(2) Modern scholarship supports construing the Rule based on its purpose and intent and avoiding its application when, like in the present case, doing so would not serve the Rule's purpose.

This modern approach is particularly appropriate because restraints on alienability and promoting the productivity of land is not an issue in the context of oil and gas. Because the court reasoned that Strieber reserved the NPRI for a limitation certain to occur at some point (i.e. for 15 years and as long thereafter as there is production in paying or commercial quantities), the Koopmanns' interest was more akin to a vested remainder (and not a springing executory interest) when it was created. Therefore, the court held that—in the context of a NPRI reservation—where a defeasible term interest is created by reservation, leaving an executory interest that is certain to vest in an ascertainable grantee, the Rule does not invalidate the grantee's future interest.

Having found that Koopmann's interest did not violate the Rule, the Court still had to address whether the savings clause perpetuated the NPRI beyond its term. Since no well was actually producing on December 27, 2011, Strieber's interest in the NPRI could continue beyond that date only if the savings clause's three requirements were satisfied: (1) there was a lease on the premises; (2) the lease was maintained in force and effect by payment of "shut-in royalties or any other similar payments made . . . in lieu of actual production"; and (3) there was a well "capable of producing oil, gas, or other minerals in paying or commercial quantities," but which is shut in "for lack of market or any other reason." The Court affirmed the appellate court's holding that "or any other similar payments made" was ambiguous as a matter of law. Therefore, there were unresolved fact issues as to whether Burlington's payment of "shut-in" royalties (later couched as delay rental payments on appeal) extended the term NPRI which necessitated remand to the trial court.

Burlington also unsuccessfully argued that Section 91.402 of the Texas Natural Resources Code barred Koopmanns' breach-of-contract claim and served as their exclusive remedy. That statute requires lessees to make royalty payments within 120 days after the end of the month of first sale of production, but it also allows a lessee to withhold royalty payments without interest when there is "a dispute concerning title that would affect distribution payments." Section 91.404(c) gives royalty owners a statutory cause of action for nonpayment of royalties and interest. Burlington argued the Texas Legislature intended royalty owners' cause of action for failure to pay royalties under Section 91.402 to be exclusive. Again, the Court disagreed with Burlington and held that the statute did not contain the requisite express "clear repugnance" to statutorily abrogate the

Koopmanns' common-law cause of action based on the terms of their lease. Therefore, the Koopmanns were free to pursue that breach-of-contract claim.

4. ***Endeavor Energy Resources, L.P. v. Discovery Operating, Inc.*, No. 15-0155, 2018 WL 1770290 (Tex. Apr. 13, 2018).**

Endeavor Energy Resources, L.P. v. Discovery Operating, Inc. is yet another retained-acreage case decided by the Texas Supreme Court this year. The facts were as follows: Endeavor acquired oil and gas leases covering a 640-acre tract and the north half of an adjoining 640 acre tract to the south. The leases contained retained acreage clauses and Endeavor drilled four wells on the leases. The two wells drilled on the 640 acre tract were both located in the southeast quarter of the section. The two wells drilled in the north half of the adjoining tract were both drilled in the eastern portion of that half section. After completing the wells, Endeavor filed certified proration plats with the Texas Railroad Commission ("RRC"). The plats designated approximately 81 acres for each well encompassing a total of 320 acres (two quarter sections where the wells were actually located).

After Endeavor's leases' primary terms expired, Patriot Royalty and Land, LLC reviewed the leases and proration plats Endeavor filed with the RRC and concluded that Endeavor's leases terminated as to the northwest quarter of Section 9 and the southwest quarter of Section 4. Patriot then obtained leases on that acreage and later assigned them to Discovery. Discovery then drilled producing wells on that acreage, which led to the lawsuit.

When Endeavor learned that Discovery had drilled wells on the tracts, it objected to Discovery's assertion of any leasehold interest. Relying on the retained acreage clauses, Discovery asserted that Endeavor's leases had expired as to the lands outside the 81-acre proration units Endeavor formed at the RRC. In response, Endeavor argued that it retained *160* acres around each well because the leases' references to "maximum producing allowable" meant that each proration unit automatically consists of the greatest amount of acreage permitted per RRC rules.

At the time, the RRC's rules for the Spraberry (Trend) Area allotted 80 acres to a proration unit with an additional 80 acres of "tolerance acreage" at the operator's election. The Spraberry field rules required operators to file certified plats describing their proration units. The leases' retained acreage clauses stated, "[this] lease shall automatically terminate . . . save and except those lands and depths located within a governmental proration unit assigned to a well . . . [containing] the number of acres required to comply with the applicable rules and regulations of the Railroad Commission of Texas for obtaining the maximum producing allowable for the particular well." The Texas Supreme Court concluded that the leases' use of "assigned" referred to the lessee's assignment of acreage through its regulatory filings.

Focusing on the specific lease language, the court agreed with Discovery that the retained acreage clauses required the operator to file a plat assigning only the amount of acreage necessary to obtain the maximum producing allowable as determined by the applicable field rules, which in this case was 80 acres. To retain 160 acres, Endeavor needed to actually assign 160 acres to each well, which it did not do. Having met the threshold requirement for compliance with the field rules, Endeavor retained "exactly what it bargained for: approximately 81 acres per well."

Notably, the court further indicated that "[a]lthough such an assignment would hypothetically raise each well's maximum producing allowable, when productive acreage is a component of the maximum producing allowable—as it is here—the operator must verify that additional acreage is actually necessary or required to achieve the maximum allowable" or it may "open itself up to claims that it is not acting in good faith in purporting to retain a substantially greater amount of acreage."

5. *XOG Operating, LLC v. Chesapeake Expl., Ltd. P'Ship*, No. 15-0935, 2018 WL 1770506 (Tex. Apr. 13, 2018).

This case is a companion to the Endeavor Case discussed above. Like in *Endeavor*, the Court wrestled with how much acreage was retained by a retained acreage clause. Here, the retained acreage clause in a term assignment from XOG Operating to Chesapeake stated Chesapeake would keep the leased acreage within the proration or pooled unit of each drilled well. However, the assignment contractually defined "proration unit" to include the boundaries of a proration unit "then established or prescribed by field rules." The Commission's field rules for the Allison–Britt Field applied. A "prescribed" proration unit under the Allison-Britt Rules was 320 acres per well.

Chesapeake filed its Form P-15 for each well and assigned proration units totaling 800 acres. XOG Operating sued Chesapeake after Chesapeake refused to release or reassign any acreage to XOG. Each side moved for summary judgment. XOG argued that the disputed acreage was not retained by Chesapeake pursuant to the term assignment's retained acreage provision because Chesapeake failed to "assign" that acreage to a proration unit in its P-15 filings. Chesapeake argued that it retained 320 acre units as "prescribed by field rules."

The same principles applied in *Endeavor* were applied in this case, but this time with a different result based on the alternative language in the retained acreage clause. The Court acknowledged that although retained acreage provisions are based on regulatory filings and rules, they are fundamentally contractual in nature and parties to these clauses are presumed to know the law and to have stated their agreement in light of it.

The Court held that acreage "included within the proration unit for each well … prescribed by filed rules" referred to acreage set by the field rules, not acreage "assigned" by the operator (like in *Endeavor*). At the time, the field rules defined a "prescribed" proration unit as 320 acres for the Allison–Britt Field. Therefore, under the retained acreage provision's language, Chesapeake retained 1,920 acres for its 5 wells drilled—not just 800 acres. The court distinguished *Endeavor* from this case in that the field rules in *Endeavor* referred to assignments by operators claiming acreage. The field rules in this case referred to "assigned" acreage as well, but unlike the rules in *Endeavor*, the rules here also "prescribed" proration units.

6. *Dimock Operating Co. v. Sutherland Energy Co.*, LLC, No. 07–16–00230–CV, 2018 WL 2074643 (Tex. App.—Amarillo Apr. 24, 2018, pet. filed) (mem. op.)

This case discusses the impact of certain key contractual provisions within a farmout agreement and it displays how the court will interpret such provisions based on the farmout's express language. *Dimock* yet again highlights the importance of paying close attention to your oil and gas agreements' express language, as standard provisions within oil and gas agreements frequently vary in wording.

Dimock Operating Company and Dimock entered into a Seismic Exploration and Farmout Agreement (SEFA), where Dimock (farmor) farmed out 15 sections in Hardeman County to Sutherland (farmee). The parties agreed that upon "project payout," Sutherland would assign well operations and a 51% working interest back to Dimock, and the remaining 49% would be assigned to various charities. "Project payout" was the point at which revenues equaled two times Sutherland's capital costs. A dispute subsequently arose as to whether Sutherland reached payout.

This case addresses four significant oil and gas issues. First is whether costs incurred by Sutherland after drilling its initial well constitute "capital cost[s]" and should therefore be considered in determining whether Sutherland reached "project payout." The SEFA expressly defined Sutherland's capital cost as "cost[s] incurred by Farmee [Sutherland] for land and seismic for the Hamrick Area 3D Shoot … a fifty thousand dollar ($50,000) prospect fee, and cost for drilling, testing, completing, and equipping, the Initial Earning Well." Land and seismic costs were undefined. The court found that, contrary to Dimock's argument, "land and seismic costs" were not ambiguous merely because the terms had no contractual definitions. Nor were the terms "deposit" and "prospect fee" ambiguous within the agreement. Additionally, one punctuation mark cost Dimock a financial blow: a comma. Dimock argued that the placement of the comma after the word "equipping" made the definition of "capital costs" ambiguous. The court disagreed and concluded that it was a grammatical error to contend that the comma's placement indicated a modifying element—seismic costs were "capital costs" under the SEFA.

Interestingly, at trial, Sutherland passed up the opportunity to obtain a ruling from the trial court that "project payout" had not occurred. Instead, it requested that the court find that "capital costs" included the cost of undertaking seismic operations—a fact which Sutherland assumed would resolve the question of project payout. The court of appeals did not find the solution so simple. There was a finding about whether project payout had occurred, but there was no finding on whether the capital costs claimed by Sutherland were actually proper under the SEFA. Of the sixty-six points of error Dimock raised on appeal, many were reversed and remanded to the trial court for further proceedings because there was no adjudication of these key issues.

Next, Dimock argued that the Joint Operating Agreement (JOA) executed along with the SEFA obligated Sutherland to seek the consent of the non-operators before incurring expenses associated with the seismic operations. The court disagreed. The SEFA provided Sutherland with the "sole, exclusive and irrevocable right to conduct Seismic Operations" and the right to "use its sole discretion to determine the type, nature, timing, and extent of all Seismic Exploration Operations." The operating agreement, in contrast, obligated Sutherland as the operator to seek consent from non-operators for any project reasonably estimated to cost more than $25,000. Sutherland argued that the JOA was not effective as between Dimock and Sutherland until after project payout – when Dimock actually owned an interest in the contract area. The court disagreed with Sutherland yet ruled in Sutherland's favor on this issue. The SEFA stated that the SEFA would serve as the governing agreement in the event of any conflict between the operating agreement and the SEFA. Language giving Sutherland discretion to determine when to conduct seismic operations prevailed over the subsequent operations language in the JOA.

While the trial court did not specify the reason it concluded that Sutherland had the right to conduct the seismic operations, the controlling language within the SEFA could have served as the basis for such a holding. Therefore, the court of appeals affirmed the trial court's judgment.

Dimock also brought a claim for fraud alleging Sutherland falsely represented that seismic analysis was needed to locate the proper drill site, thus, inducing Dimock to include seismic costs in the parties' agreement. Contrary to its representations, Sutherland did not undertake seismic operations prior to drilling the first well. Sutherland alleged Dimock did not reasonably rely on this alleged misrepresentation. The court concluded that Sutherland did not conclusively negate justifiable reliance, however, and that summary judgment on Dimock's fraud claim was improper and would be remanded for trial.

Finally, Dimock alleged Sutherland breached its fiduciary duty to Dimock. The JOA created a contractual fiduciary duty requiring Sutherland to properly account for the distribution of well proceeds to Dimock. Dimock alleged that Sutherland breached this duty by failing to distribute the well proceeds to Dimock and converting them for Sutherland's own use. The court recognized that while a JOA alone does not generally create a fiduciary relationship, the "Custody of Funds" provision (which is standard in the Model Form JOA) states that the agreement does not establish a fiduciary relationship between the parties "for any purpose other than to account for Non-Operator funds as herein specifically provided." This language effectively created a contractual fiduciary duty to Dimock from Sutherland to properly account for the distribution of well proceeds. Because the court identified unresolved fact issues as to this claim, summary judgment on the claim was improper as well, and would be remanded for trial.

7. *Devon Energy Production Company, L.P. v. Apache Corporation*, No. 11-16-00105-CV, 2018 WL 2022699 (Tex. App.—Eastland Apr. 30, 2018, pet. filed)

In this case of first impression, the Eastland Court of Appeals held that Section 91.402 of the Texas Natural Resources Code (the "Division Order Statute") does *not* require an operator to pay lease royalties to mineral interest owners who have leased to a different working interest owner. And, by implication, the court held that such mineral interest owners are *not* entitled to royalties under the Division Order Statute until payout of the well from which royalties are due.

Norma Jean Hester leased her undivided one-third mineral interest in a tract of land in Glasscock County to Apache, reserving a 25% royalty. The remaining mineral owners leased their combined two-thirds mineral interest to Devon, also reserving a 25% royalty (the "Devon Lessors"). Devon and Apache were unable to agree on a JOA. Apache then drilled seven producing oil and gas wells on the property, and, after payout, paid Devon its two-thirds share of the production revenue net of Apache's costs.[3] Apache left it to Devon to pay the Devon Lessors their quarter royalty.

The Devon Lessors sued Devon and Apache alleging generally that they had not been paid all royalties due under their leases with Devon, among other claims. Devon filed a cross-claim against Apache seeking a declaratory judgment the Division Order Statute required Apache to pay the Devon Lessors' royalties under Devon's leases: (i) directly and (ii) *before payout* of Apache's wells. Devon alleged Apache was then to charge those royalty payments against Devon in determining the wells' payout point.

[3] Prior to commencing drilling operations, Apache sent Devon an Authorization for Expenditure ("AFE") offering to jointly develop the property. Ultimately, Devon elected not to participate in drilling the wells.

The Eastland Court of Appeals noted the rules of equitable accounting among mineral cotenants are well established. "A cotenant has the right to extract minerals from common property without first obtaining the consent of his cotenants; however, he must account to them on the basis of the value of any minerals taken, less necessary and reasonable costs of production and marketing." It was also clear that Devon and Apache, as lessees, were cotenants in the mineral estate.

However, the question of *which* cotenant must pay royalties to the lessors of a non-participating working interest owner under the Division Order Statute has never been addressed by the Texas courts of appeal. The statute provides as follows:

> "The proceeds derived from the sale of oil or gas production from an oil or gas well located in this state must be paid to each payee by payor on or before 120 days after the end of the month of first sale of production from the well. After that time, payments must be made to each payee on a timely basis according to the frequency of payment specified in the lease or other written agreement between payee and payor."[4]

Siding with Apache, the court focused on the words "payor" and "payee" in the statute to determine Devon, not Apache, was obligated to pay the Devon Lessors. A "payor" is "the party who *undertakes* to distribute oil or gas proceeds to the payee, whether as the purchaser of the production of oil or gas generating such proceeds or as operator of the well from which such production was obtained or as lessee under the lease on which royalty is due."[5] A "payee" is "any person legally entitled to payment from the proceeds derived from the sale of oil or gas from an oil or gas well located in this state."[6]

The court held Apache and the Devon Lessees did not have a "payor-payee relationship" under the Division Order Statute because Apache did not "undertake" to pay the Devon Lessors by entering into leases with them. Thus, even though Apache was the "operator of the well from which … production was obtained," it was not a "payor" under the Division Order Statute. Thus, paying the Devon Lessor their lease royalty was Devon's obligation, not Apache's.

The court's opinion did not expressly address the issue of *when* a royalty owner who has leased to a non-participating working interest owner is entitled to royalties pursuant to their lease—before or after payout. However, the court's opinion appears to have answered that question by implication. The Division Order Statute does not require an operator to pay royalties to mineral interest owners who have leased to a different working interest owner. And, Texas cotenancy law does not require the operator to pay net production revenues to a non-participating cotenant until after payout. Thus, absent special lease provisions, a mineral estate lessor is not entitled to lease royalties from a well drilled by the lessee of a different mineral estate cotenant until after payout of the well from which royalties are due. Until that point, the operator is not required to pay net production revenue to the other lessee/non-participating cotenant, and the other lessee/non-participating cotenant has received no revenues on which royalties are due to his lessor.

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[4] Tex. Natural Res. Code § 91.402(a) (Vernon Ann. 2016).
[5] Tex. Natural Res. Code § 91.401(2) (Vernon Ann. 2016).
[6] Tex. Natural Res. Code § 91.401(1) (Vernon Ann. 2016).

8. *TRO-X, L.P. v. Anadarko Petroleum Corporation*, No. 16-0412, 2018 WL 2372805, (Tex. May 25, 2018)

This case is a cautionary tale about failing to draft robust "anti-washout" clauses. In 2007, TRO-X entered into five mineral leases covering acreage in Ward County, Texas. The leases (the "2007 Leases") contained identical terms, including a 660-foot offset well clause. TRO-X later entered into a participation agreement transferring its interest in the 2007 Leases to Eagle Oil and Gas and reserving a 5% back-in option once the 2007 Leases reached "project payout." The participation agreement contained an "anti-washout clause" providing that TRO-X's back-in option "shall extend to and be binding upon any renewal(s), extension(s), or top lease(s) taken within one year of termination of the underlying interest."

Eagle Oil and Gas eventually assigned its interest in the 2007 Leases to Anadarko. A year later, Anadarko completed a well on land adjacent to the tract covered by the 2007 Leases approximately 550 feet from the lease line. Anadarko then failed to drill an offset well within the required period. When one of the lessors alleged Anadarko breached the 2007 Leases' offset well clause, Anadarko engaged all of the lessors in negotiations that culminated in their executing new leases (the "2011 Leases"). The 2011 Leases were with the same lessors and covered the same mineral interest as the 2007 Leases, but did not release, and in fact, did not even mention the 2007 Leases. The 2011 Leases all specified an effective date of June 17, 2011, and were executed on various dates between June 15 and June 30, 2011, on which date Anadarko executed a written release of the 2007 Leases. When TRO-X later approached Anadarko to confirm that its back-in interest in the 2011 Leases was valid, Anadarko denied that it was.

TRO-X filed suit against Anadarko in February of 2014 asserting claims for breach of contract and trespass to try title. The case was tried to the bench, with the central issue being whether the 2011 Leases were "top leases" in which TRO-X retained its back-in interest, or new leases, which washed out TRO-X's interest. Anadarko argued the very act of executing of the 2011 Leases terminated the 2007 Leases. Therefore, according to Anadarko, the 2011 Leases were not top leases because they were never in effect at the same time as the 2007 Leases. TRO-X, however, argued the 2007 Leases remained in effect until Anadarko executed its release. Therefore, according to TRO-X, the 2007 and 2011 Leases were all in effect between June 17, 2011 (the 2011 Leases' effective date) and June 30, 2011 (the date Anadarko executed its release of the 2007 Leases). Thus, TRO-X alleged the 2007 and 2011 Leases were in effect at the same time, albeit briefly, and thus, the 2011 Leases were top leases subject to TRO-X's back-in interest. The trial court sided with TRO-X. The El Paso Court of Appeals reversed, holding that TRO-X had not proven the parties intended the 2011 Leases to be top leases. The Texas Supreme Court granted review.

The Court began its analysis with the familiar maxim that mineral leases are interpreted using the same rules applied to other contracts. Thus, whether the parties intended the 2011 leases to be top leases must first be determined by reviewing the 2011 Leases' plain language. If the plain language unambiguously provided the 2011 Leases were or were not top leases, the inquiry is complete. The Court then explained that, "[b]ascially, a top lease is a subsequent oil and gas lease which covers one or more mineral interests subject to a valid, subsisting lease." A top lease becomes effective only upon termination of the bottom lease.

The Court then summarized the law regarding lease termination through execution of a new lease in three parts. First, "when a lessor and lessee under an existing lease execute a new lease of the same mineral interest subject to the existing lease, the existing lease is terminated unless the new lease objectively demonstrates both parties' intent otherwise[.]" Second, "[a] party contending that a new lease did not terminate the previous one has the burden to prove and obtain a finding that the parties intended for the previous lease to survive execution of the new lease." And third, "[t]he proof must be either specific language in the new lease objectively demonstrating that intent, or an ambiguity in the new lease as to termination of the previous lease together with evidence that the parties did not intend the new lease to terminate the prior lease."

The Court found the 2011 Leases did not contain language indicating the parties intended the 2007 Leases to survive the 2011 Leases' execution. Therefore, the 2007 Leases were terminated by the 2011 Leases' execution and were never effect at the same time as the 2011 Leases. Accordingly, the 2011 Leases were not top leases and were not subject to TRO-X's back-in interest. The fact that Anadarko executed a release of the 2007 Leases a few days after some of the 2011 Leases were executed was irrelevant because the 2011 Leases were unambiguous.

One might assume that TRO-X's back-in interest could easily have been preserved if the parties had included language in the participation agreement making the anti-washout clause applicable to "new leases." However, on July 26, 2018 (after this paper was submitted for publication), the Amarillo Court of Appeals held that such a clause violates the Rule Against Perpetuities.[7] In light of the Texas Supreme Court's opinion in *TRO-X*, the Amarillo Court's opinion in *Yowell* will be one to watch in 2018-2019.

9. ***Murphy Exploration & Production Company—USA v. Shirley Adams, et al*, No. 16-0505, 2018 WL 2449313 (Tex. June 1, 2018)**

In this case, the Texas Supreme Court held that an Offset Well Clause in an operator's leases with the Plaintiffs did *not* require the operator to drill wells reasonably calculated to protect against drainage from the neighboring tract. Four justices issued a stinging dissent[8] arguing the majority disregarded the well-established meaning of the term "offset well" as used in the Texas oilfield for decades.

In 2009, Murphy Exploration & Production Company—USA ("Murphy") entered into two oil and gas leases with the Plaintiffs (the "Herbsts").[9] The leases contained identical Offset Well Clauses, which provided:

> It is hereby specifically agreed and stipulated that in the event a well is completed as a producer of oil and/or gas on land adjacent to and contiguous to the leased premises, and within 467 feet of the premises covered by this lease, that Lessee herein is obligated to . . . commence drilling operations on the leased acreage and thereafter continue the drilling of ***such off-set well or wells*** with due diligence to a depth adequate to test the same formation from which the well or wells are producing from the adjacent acreage.

[7] *See Tommy Yowell, et al v. Granite Operating Company, et al*, No. 07-17-00112-CV, 2018 WL 3596744 (Tex. App.—Amarillo, July 26, 2018).
[8] Justices Johnson, Green, Guzman and Boyd.
[9] The leases covered adjacent 302 acre tracts in Atascosa County.

When a well on a neighboring tract triggered this clause, Murphy drilled a well on the Herbts' tract . . . 2,100 feet from the triggering well. It was undisputed this well would *not* prevent drainage from the neighboring tract. Thus, the Herbsts argued the well did not satisfy the leases' Offset Well Clause because it was not designed to protect against drainage.[10] In response, Murphy argued the well satisfied the Offset Well Clause because it was drilled on the leased premises to the same depth as the triggering well, which Murphy claimed is all the leases' explicit language required. Murphy argued the notion that an offset well must actually protect against drainage or even be reasonably calculated to do so has no place in horizontal drilling in tight shale formations where drainage is minimal. The trial court sided with Murphy. The San Antonio Court of Appeals sided with the Herbsts. The Texas Supreme Court granted review.

The Texas Supreme Court began its analysis by noting the law is well-established that courts interpret oil and gas leases just like any other contract. Thus, a court must read the lease, give its terms their plain and ordinary meaning, and enforce the lease as written. Courts may not modify a lease's explicit language absent extraordinary circumstances. However, a court can consider the context in which a lease was negotiated and executed to inform its interpretation of the words used in the lease. And, a court can interpret words and phrases in a lease in accordance with any special definitions those terms have in a particular industry.

In a 5-4 opinion, the Court held Murphy's Offset Well Clause did *not* require Murphy to drill a well to protect against drainage from the neighboring tract, and that Murphy's well, some 2,100 feet from the triggering well, satisfied the leases' Offset Well Clause. The Court's opinion was based on two important premises. First, the Court held Murphy's leases provided their own definition of "offset well." That is, the leases stated that when the Offset Well Clause was triggered, Murphy had to drill a well (1) on the Herbsts' tract (2) with due diligence and (3) to the same depth as the triggering well, and the drilling of "***such offset well***" would satisfy the Offset Well Clause. Because the leases used the term "such offset well" when setting forth three criteria for a satisfactory well, but did not include a proximity requirement or an express protection requirement, the Court would not impose one.

Second, the Court considered the "surrounding circumstances" under which the leases were executed in interpreting the Offset Well Clause. The Court noted leases were executed in 2009 and were drafted with horizontal drilling in the Eagle Ford Shale in mind. The Court considered expert testimony presented by Murphy that drainage is almost non-existent from horizontal wells in tight-shale formations like the Eagle Ford. Thus, the Court concluded it would be "illogical" for an Offset Well Clause to require a well—even an "offset well" to even attempt to protect against non-existent drainage.

Four justices dissented, arguing the commonly understood definition of "offset well" required Murphy to drill its offset well at a location where a reasonably prudent operator would drill to protect the leasehold from actual or potential drainage, regardless of whether any was actually occurring. The dissent claimed the majority opinion effectively read the term "offset" out of the leases.

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[10] The Herbsts did not contend Murphy's offset well had to "actually" protect against drainage and never stated how close to the triggering well the offset well had to be. Rather, the Herbsts merely argued the offset well had to be "in close proximity to the lease line adjacent to the tract where the triggering well was drilled," and that Murphy's purported offset well was not close enough.

While the Court purported to limit its holding to the facts before it, the Murphy Opinion may have far-reaching consequences for the Texas oil and gas business. The vast majority of wells drilled in Texas today are horizontal, tight-shale wells. The Court's opinion indicates the common understanding of an "offset well" is antiquated in this context. How can operators protect against drainage that does not exist? The Murphy Opinion indicates the Texas Supreme Court believes they cannot—and that they no longer have to even try.

10. *U.S. Shale Energy II, LLC v. Laborde Properties, L.P.*, No. 17-0111, 2018 WL 318952 (Tex. June 29, 2018)

In this case, the Texas Supreme Court considered whether the royalty interest reserved to the grantor in a 1951 deed was fixed (set at a specific percentage of production) or floating (dependent on the royalty amount in the applicable oil and gas lease). In 1951, J.E. and Minnie Bryan conveyed by deed a tract of land in Karnes County to S.E. Crews. The deed reserved a NPRI to the Bryans, as follows:

> There is reserved and excepted from this conveyance unto the grantors herein, their heirs and assigns, and undivided one-half (1/2) interest in and to the Oil Royalty, Gas Royalty, and Royalty in other Minerals in and under or that may be produced or mined from the above described premises, the same being equal to one-sixteenth (1/16) of the production. This reservation is what is genaerally [sic] termed a non-participating Royalty Reservation …

Through a series of conveyances, U.S. Shale acquired a share of the Bryans' NPRI. In 2009, EOG acquired a lease on the subject tract providing for a lessor's royalty of 20%, i.e., 1/5. In 2010, Laborde acquired some of property burdened by the Bryan-U.S. Shale NPRI, and thus became a lessor under EOG's lease. EOG sent Laborde a division order crediting the Bryan heirs and U.S. Shale with 1/2 of the 1/5 royalty under EOG's lease for a total royalty of 1/10 of production. Laborde disputed the division order, alleging the Bryan heirs and U.S. Shale should only be credited with 1/16 of production by virtue of a fixed 1/16 NPRI reserved in the Bryan deed. After Laborde notified EOG of its disagreement, EOG put all parties in suspense, and litigation ensued. The trial court ruled for the Bryan heirs and U.S. Shale. The Court of appeals reversed, and the Texas Supreme Court granted review.

The Texas Supreme Court explained that a royalty may be conveyed or reserved as a "fractional" royalty interest or a "fraction of" royalty interest. A "fractional" royalty interest is referred to as a "fixed" royalty because it remains constant and is untethered to the royalty amount in a particular oil and gas lease. A "fraction of" royalty interest is referred to as a "floating" royalty because it varies depending on the royalty in the oil and gas lease in effect and is calculated by multiplying the fraction in the royalty reservation by the royalty in the lease.

Turning to the Bryan deed, the Court found that read independently, the first clause of the royalty reservation unambiguously reserved a floating royalty ("… an undivided one-half (1/2) interest in and to the Oil Royalty, Gas Royalty and Royalty in other Minerals…"). The issue was whether the second clause ("… the same being equal to one-sixteenth (1/16) of the production…") indicated an intent to fix the Bryans' NPRI at 1/16 of production. In determining that it did not, the Court noted that when the Bryan deed was executed, a 1/8 lessor's royalty was "ubiquitous".

Thus, even though no lease was in effect covering the Bryans' property at the time the deed was executed, the Bryans must have assumed that when a lease was taken on the property, it would provide for a 1/8 royalty. Of course, 1/2 of a 1/8 royalty equals 1/16. Thus, the Court reasoned the Bryans must have intended to reserve a 1/2 floating royalty, which the Bryan's must have assumed would equal 1/16 of production. Had they not, the first clause of the reservation tying the NPRI to the applicable royalty would be rendered meaningless. Accordingly, the Court reinstated the trial court's judgment finding the Bryan deed unambiguously reserved a floating 1/2 royalty interest.

Three justices dissented[11], finding the Bryan deed's reference to 1/2 of the "Oil Royalty, Gas Royalty and Royalty in other Minerals," none of which were defined terms in the deed, did not unambiguously create a floating royalty. The dissent found the reservation's second clause, however—"the same being equal to one-sixteenth of production"—could not have more plainly stated an intent to reserve a fixed 1/16 royalty. Accordingly, the dissent would have held the Bryan deed's reservation created a fixed 1/16 royalty interest.

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[11] Justices Boyd, Johnson and Blacklock.