

# Post-Production Deductions in Gas Royalties:

## What Are They?

## What Does the Law Say About Them?

## How Can You Minimize/Eliminate Them?

**To: Attendees of the NARO Texas Convention; Austin, Texas; July 2017**

I've spent much of the past 15 years in litigation against large oil and gas producers. The disputes have concerned upstream pricing, processing, general production issues, and all aspects of upstream-midstream marketing – specifically, how such activities affect my clients' royalty income or working-interest revenues and related expenses.

In my practice, I've focused primarily on casinghead gas (*i.e.*, the wet, low-pressure gas associated with crude oil production), crude oil, and gas-well gas, in that order. My practice has become increasingly focused on gas-well gas (*viz.*, Barnett Shale gas) over the past six years. I focus this paper and my speech mostly on gas-well gas royalties and post-production deductions thereon.

I frequently represent royalty owner groups in shale-gas litigation pending in Texas and Oklahoma state and federal courts. Much of this litigation concerns Chesapeake's, Total's or Devon's low pricing for its shale-gas royalty payments. Chesapeake, Total and Devon entities are defendants in my clients' lawsuits. Although I cannot share confidential information that I've learned via these lawsuits, I can discuss the general legal and factual concepts at play – such as the pleadings and public statements by the parties.

Most times, the royalty accounting and revenue accounting departments of large oil and gas producers consist of hard-working, conscientious personnel, who are doing their best to measure volumes for, apply prices to, report taxes on, make allocations for, and distribute money on hydrocarbon production. Each month, they have to process copious amounts of data relating to hydrocarbon production, transportation, processing and sales – in order to pay hundreds of thousands (or millions) of dollars to royalty owners, working interest owners, and taxing authorities. They may make mistakes, but generally are doing their best under the foregoing circumstances. Also, these circumstances challenge their ability to comply with lease royalty-valuation clauses.

My generosity for producers' accounting departments does not extend to companies that control gas production, gathering, and processing by way of affiliated entities – especially in Texas. Accounting for affiliated gas upstream and midstream functions is not a hurried activity leading to innocent errors; rather, it a purposeful activity to depress wellhead revenues and profits – by piling on the post-production deductions – in order to minimize gas royalties, working-interest payments to non-operators, and most importantly severance (production) taxes and ad valorem taxes. This is particularly so in Texas. Because Texas courts will not

regulate/correct this sort of accounting – by enforcing royalty owners’ and non-operators’ contractual rights standing against it – a legislative remedy is long overdue. A legislative remedy would shift hundreds of millions in value annually from large producer gas-midstream divisions to royalty owners, non-operators, and state and county taxing authorities. (Addressing the foregoing issues, in 2009 I drafted proposed supplements and amendments to Chapters 201 and 23 of the Texas Tax Code. I would welcome efforts to create a dialogue over amending these Chapters in the next Texas legislative session. Amending these Chapters will encounter significant industry resistance.)

I intend to equip Conference attendees with the fundamental principles they must understand in order to recognize and converse intelligently about post-production deductions in states following the trend of Texas law (like Pennsylvania and Louisiana) and in those following the trend of Oklahoma law (like Colorado and West Virginia).

James Holmes  
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James Holmes enjoys a diverse practice of oil and gas cases and business cases. He has substantial trial and appellate experience. James was born, raised and educated in Texas. Before practicing law in Dallas, he earned his Bachelor of Science from Trinity University in San Antonio and his Juris Doctorate from the University of Texas School of Law in Austin, where he served as an Editor on the Law Review and graduated Order of the Coif. Following law school, he clerked for Associate (now Chief) Justice Nathan Hecht on the Texas Supreme Court.

Currently, James represents a royalty owners, bank-operated royalty/mineral trusts, non-operating working interest owners, and surface-estate owners by way of various legal matters in the Barnett Shale and in the legacy oil fields of Texas and New Mexico. Also, when feasible, James will assist in the marketing of his clients’ share of production and in pursuing other transactional remedies and work-outs as alternatives to litigation. He has special experience in gas-processing arrangements; the interdependency of gas plants and mature oil reservoirs; cradle-to-grave marketing arrangements for gas-well gas, casinghead gas and crude oil; and enhanced oil recovery via CO<sub>2</sub> flooding and other reservoir-pressure management.

## EXECUTIVE SUMMARY

### What are post-production deductions?

Post-production deductions (“PPDs”) are charges against royalty payments that reflect a producer’s (lessee’s) efforts to transform newly produced oil or gas into a marketable product and then to sell the product. For gas, such charges cause the royalty payments to bear a proportionate share of the costs of gathering, transportation, processing, treating, and administrative marketing (or some part of the foregoing costs). PPDs lessen royalty payments. Royalty owners have incentives to minimize or eliminate PPDs so that they can obtain larger royalty payments.

For gas, most PPDs arise from “tariffs” – those gathering and transportation expenses imposed by pipelines, which pipelines must disclose by way of publicly filed tariff rates. Some gas-related PPDs do not result from tariffs, but instead from private contracts between a producer and a gatherer/processor. The most common example: per-MCF fees, or percentage-of-proceeds fees, for gas-plant processing.

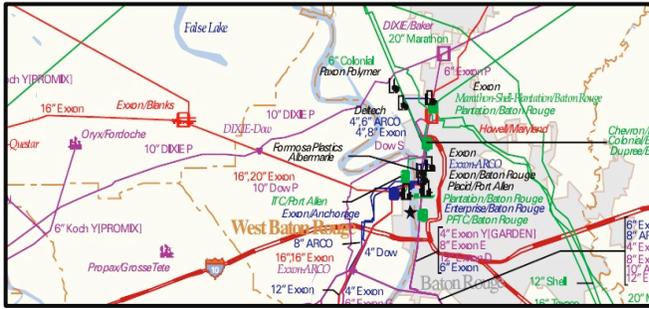
### What does the law say about post-production deductions?

In Texas and states following the Texas approach to oil and gas law and industry practice (*e.g.*, Pennsylvania, North Dakota, Louisiana, and to some extent New Mexico), the producer may charge all PPDs against royalty payments, unless the lease contract says otherwise. The Texas approach regulates PPDs little by way of the common law (*i.e.*, judge-made law arising from lawsuits and published legal opinions). Nonetheless, the Texas approach attempts to curtail excessive and unreasonable PPDs (while still allowing for some PPDs against royalty) by way of the “duty to market” in “proceeds” and “amount realized” leases, and by way of the “market value” concept in “market value” and “market price” leases. In other words, if the PPDs are excessively and unreasonably high, then the duty to market or the market value concept disallows the excessive portion of the charges against royalty.

In Oklahoma and states following the Oklahoma approach to oil and gas law and industry practice (*e.g.*, Kansas, Colorado, West Virginia, and to some extent New Mexico), the producer may not charge any PPDs against royalty payments, unless a certain PPD enables the producer to obtain a higher downstream sales price for the oil or gas than it otherwise would have obtained, and the producer shared the marketing overage with the royalty owner. The Oklahoma approach uses the common law more than the lease contract to regulate PPDs, and it generally disallows them. The Oklahoma approach is known as the “marketable condition rule”: in either proceeds leases (aka amount realized leases) or in market value leases, the producer must bear all PPDs necessary to create a marketable product and cannot charge such PPDs against royalty.

### How can a royalty owner minimize or even eliminate post-production deductions?

In Texas and like states, the royalty owner must draft the lease’s royalty-valuation clause to use a “gross proceeds” standard (or perhaps “market value” standard) and must never use the phrase “at the well” or “at the point of sale” – anywhere in the lease. The lease should include also a clause that expressly disallows PPDs against royalty. In Oklahoma and like states, such a strong lease would be helpful, but generally the marketable condition rule will disallow PPDs against royalty. Royalty owners must begin expressing their economic interests, including their goal of eliminating PPDs, in their state political process. This is especially true in Texas and New Mexico, where legislators and appellate judges – as shown by their actions in recent years – are not mindful of royalty-owner rights.



# At the Well

In the Field  
At the mouth of the wellhead  
At the Plant

Notes: \_\_\_\_\_

Post-production costs consist of operational costs occurring after production at the wellhead (that is, after the producer severs hydrocarbons from the mineral estate). Post-production costs concern the selling of hydrocarbons or rendering them able to be sold (“marketable”). Such costs for gas commonly include gathering, compression, transportation, treating, dehydration, and in some cases (for liquids-rich gas) extensive processing.

In Texas, regardless of whether the producer and royalty owner are under a “market value”-style lease or a “proceeds”-style lease (even a proceeds lease that implicates the duty to market), the parties must consider the deductibility of post-production costs against royalty. If the lease is entirely silent as to post-production costs, the Texas producer likely will deduct the royalty-proportionate share of post-production cost from royalty. To justify its position, the producer will rely on Texas law that, by default, post-production costs are deductible against royalty because the Texas definition of “royalty” itself contemplates that it bears a proportionate share of such costs. *See, e.g., Heritage Resources, Inc. v. Nationsbank*, 939 S.W.2d 118, 121-22 (Tex. 1996) (defining “royalty” and holding that “[a]lthough it is not subject to the costs of production, royalty is usually subject to post-production costs, including taxes, treatment costs to render it marketable, and transportation costs” (citations omitted)); *Blackmon v. XTO Energy, Inc.*, 276 S.W.3d 600, 604 (Tex. App. – Waco 2008, no pet.) (“Whatever costs are incurred *after* production of the gas or minerals are normally proportionately borne by both the operator and the royalty interest owners. These post-production costs include taxes, treatment costs to render the gas marketable, compression costs to make it deliverable into a purchaser’s pipeline, and transportation costs.” (citation omitted)).

Most states, including specifically North Dakota and Pennsylvania, and recently New Mexico, follow the Texas trend and allow – as a default rule – a producer (lessee) to make full deductions for post-production costs against royalty. *See Bice v. Petro-Hunt, LLC*, 768 N.W.2d 496, 502 (N.D. 2009) (adopting the “at the well rule” and rejecting “the first marketable product

doctrine”); *Kilmer v. Elexco Land Servs.*, 990 A.2d 1147, 1157 (Pa. 2010) (noting with approval that “[a]lthough the royalty is not subject to costs of production, usually it is subject to costs incurred after production, e.g., production or gathering taxes, costs of treatment of the product to render it marketable, costs of transportation to market”); *Anderson Living Trust v. Energen Resources Corp.*, 161 F.Supp.3d 1055, 1061 (D.N.M. 2016) (holding that “in accordance with New Mexico law, [the producer] is entitled to deduct post-production costs for its services in getting the gas into a marketable condition”).

If the lease includes the terms of art “at the well,” “at the wellhead,” “in the field,” “at the plant” or the like, then the knowledgeable Texas producer certainly will take post-production costs from royalty – absent other lease language forbidding such deductions. In *Heritage Resources* and other cases, Texas appellate courts have expressly held that phrases like “at the well” – when appended to words like “market value” or “amount realized” – define the royalty valuation to mean an amount *less* post-production costs necessary to market gas or render gas marketable. See *Heritage Resources*, 939 S.W.2d at 122 (faulting an intermediate Texas appellate court for not recognizing that “market value at the well” necessarily lessens the market value at the sales point by the royalty-proportionate share of post-production costs involved in marketing the gas at such sales point); *Chesapeake Exploration, L.L.C. v. Hyder*, 483 S.W.3d 870, 872-73 (Tex. 2015) (reaffirming the “at the well” rule from *Heritage Resources*).

The New Mexico Supreme Court has embraced the logic behind Texas’s treatment of “at the well” language. See, e.g., *ConocoPhillips Co. v. Lyons*, 299 P.3d 844, 850-51 (N.M. 2013) (“In oil and gas leases it is typical for the royalty clause to specify the calculation of net proceeds ‘at the well.’ When the well is specified as the point of valuation, it is generally understood that the ‘lessee is entitled to deduct all costs that are incurred subsequent to production, including those necessary to transport the gas to a downstream market and those costs, such as dehydrating, treating, and processing the gas, that are either necessary to make the gas saleable in that market or that increase the value of the gas.’”).

Disputes between Texas producers and royalty owners can arise from lease language forbidding deductions of post-production costs against royalty. Such language may appear as the following:

**Notwithstanding any foregoing language to the contrary, Lessee agrees that all gas royalties accruing under this lease shall be without deduction, directly or indirectly, for the cost of gathering, separating, treating, dehydrating, compression, transportation or other costs necessary to make the gas ready for sale or use. The parties agree that this provision is to be given full effect and is not to be construed as “surplusage” under *Heritage Resources, Inc. v. Nationsbank*, 939 S.W.2d 118 (Tex. 1996).**

If such no-deductions language appears in a lease that entirely lacks phrases like “at the well” in the royalty valuation, then the foregoing language should operate to alter the default Texas law and thereby to forbid deductions for post-production costs. See *Heritage Resources*, 939 S.W.2d at 122 (“[T]he parties may modify this general rule [allowing for the deductibility of post-production costs against royalty] by agreement.” (citation omitted)). On the other hand, if the no-deductions language appears in a lease containing “at the well”-style phrases in the royalty valuation, then *Heritage Resources* could create a conflict between (i) the no-deductions language above and (ii) the default Texas law allowing for deductions. Which side wins the

conflict depends upon the facts of each case. For instance, the foregoing language – expressly providing that *Heritage Resources* should not trouble the no-deductions language – strongly indicates that the no-deductions language should control and should forbid any deductions of post-production costs. Other leases may require courts to carefully review the facts and holding in *Heritage Resources*, as well as Texas canons of contract construction, in order to settle the conflict between a no-deductions clause and “at the well”-style phrases.

Canons of construction may play a role in settling the conflict between no-deductions clauses and “at the well”-style phrases (which implicate the default Texas law allowing for deductions). The canons settle the conflict differently when the lease language is “unambiguous” (capable of only one reasonable meaning) and when it is “ambiguous” (capable of more than one reasonable meaning).

“When the [lease] is unambiguous, the court [alone and without a jury trial] should apply the pertinent rules of construction, apply the plain meaning of the contract language, and enforce the contract as written.” *Calpine Producer Servs., L.P. v. Wiser Oil Co.*, 169 S.W.3d 783, 787 (Tex. App. – Dallas 2005, no pet.). Moreover, when construing an unambiguous lease, Texas law directs that

[t]he interpretation of an unambiguous contract is a question of law. The parties’ intent must be taken from the agreement itself and the agreement must be enforced as written. A court must favor an interpretation that affords some consequence to each part of the agreement so that none of the provisions will be rendered meaningless. No single provision taken alone will be given controlling effect. All provisions of a contract must be considered with reference to the entire instrument.

*Jacobson v. DP Partners Ltd. P’ship*, 245 S.W.3d 102, 106 (Tex. App. – Dallas 2008, no pet.) (citing *MCI Telecomms. Corp. v. Tex. Utils. Elec. Co.*, 995 S.W.2d 647, 650-51 (Tex.1999); *Coker v. Coker*, 650 S.W.2d 391, 393, 394 (Tex. 1983); other citation omitted).

When the lease is ambiguous, then a jury trial or a bench trial (*i.e.*, a trial to a judge sitting as a fact-finder) will determine whether the no-deductions clause trumps the “at the well”-style phrase. *See, e.g., Declaris Assocs. v. McCoy Workplace Sols., L.P.*, 331 S.W.3d 556, 562 (Tex. App. – Houston [14<sup>th</sup> Dist.] 2011, no pet.) (“If its meaning is uncertain, or it is reasonably susceptible to more than one interpretation, then it is ambiguous and *its meaning must be resolved by the finder of fact.* . . . [There was] [t]he portion of the agreement that the court determined to be ambiguous, and thus submitted to the jury for interpretation . . .” (emphasis added & citations omitted)).

The conflicts between no-deductions language and “at the well”-style phrases – which frequently appear in Barnett Shale leases – result from a unique concoction of (a) Texas law allowing the full deductibility of post-production costs, (b) *Heritage Resources*’s special protection for “at the well”-style phrases in Texas leases, and (c) Texas’s canons of contract construction as applied to oil and gas leases. Texas, which is not a marketable-condition rule state, probably will see many more “at the well” conflicts than states like Oklahoma and other marketable-condition rule states.

### ***Marketable-Condition Rule States (aka Marketable-Product States):***

States like Oklahoma, Kansas, Colorado and West Virginia, which adhere to the marketable-condition rule as it relates to the concepts “market value” and “proceeds,” are not as susceptible as Texas to conflicts between no-deductions language and “at the well”-style phrases in the same lease. These states by default do not permit deductions of post-production costs against royalty; rather, by default they forbid most such deductions. Therefore, when these states apply to a given lease the marketable-condition rule (namely, that the producer must bear all post-production costs necessary to render a marketable product), they generally do not allow phrases like “at the well” to impose on royalty owners the very post-production cost deductions forbidden by the states’ default law. *See Fankhouser v. XTO Energy, Inc.*, No. CIV-07-0798-L, 2012 U.S. Dist. LEXIS 22728, at \*6-\*8 (W.D. Okla. Feb. 23, 2012) (holding that the phrase “at the well” does not negate Oklahoma’s marketable-condition rule); *Sternberger v. Marathon Oil Co.*, 894 P.2d 788, 799 & 795 (1995) (holding that “[t]he lessee has the duty to produce a marketable product, and the lessee alone bears the expense in making the product marketable” – however, “transportation costs are borne proportionately by the lessor and the lessee where the royalty is to be determined at the well but no market exists at the well”); *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 890, 912 (Colo. 2001) (applying a marketable-condition rule and concluding that “[a]fter assessing the ‘at the well’ and ‘at the mouth of the well’ language in this case, we conclude that the leases at issue here are silent with respect to the allocation of costs. Moreover, we decline to adopt the rule that the ‘at the well’ language in the leases allocates transportation costs, while being silent as to other costs. Because we have determined that the leases are silent with respect to allocation of costs, we look to the implied covenant to market to determine the proper allocation of costs”).

Kansas, a leading marketable condition state with persuasive oil and gas case law, is trending towards lessening the burden of the duty to market (which gives rise to the marketable condition rule) on lessees (producers). The Kansas Supreme Court has held that the duty to market ends and is satisfied once a producer sells gas to an arm’s length purchaser, and the producer has no obligation to market the gas differently in order to create higher gas royalty payments. *Fawcett v. Oil Producers, Inc. of Kansas*, 352 P.3d 1032, 1042 (2015) (“[W]hen a lease provides for royalties based on a share of proceeds from the sale of gas at the well, and the gas is sold at the well, the operator’s duty to bear the expense of making the gas marketable does not, as a matter of law, extend beyond that geographical point to post-sale expenses. In other words, the duty to make gas marketable is satisfied when the operator delivers the gas to the purchaser in a condition acceptable to the purchaser in a good faith transaction.”). Oil and gas legal observers believe the Kansas trend will influence Oklahoma and Colorado, thereby lessening the marketable condition rule’s protectiveness for royalty owners in those states.

### ***Where Does New Mexico Fall? (Marketable-Product vs. At the Well):***

At least twice, the New Mexico Supreme Court has acknowledged that New Mexico law, like Colorado law, may embrace the marketable-product rule. In these cases, the court did not explore the details of how much post-production costs a lessee must bear in order to render a marketable product. *See generally Davis v. Devon Energy Corp.*, 218 P.3d 75 (N.M. 2009); *Ideal v. BP Am. Prod. Co.*, 180 P.3d 1182 (N.M. 2010).

In 2012, the New Mexico Supreme Court began downplaying the strength of the marketable-product rule by holding that “at the well” lease language in New Mexico state lease forms had the following effect:

In oil and gas leases it is typical for the royalty clause to specify the calculation of net proceeds “at the well.” When the well is specified as the point of valuation, it is generally understood that the “lessee is entitled to deduct all costs that are incurred subsequent to production, including those necessary to transport the gas to a downstream market and those costs, such as dehydrating, treating, and processing the gas, that are either necessary to make the gas saleable in that market or that increase the value of the gas.”

*ConocoPhillips Co. v. Lyons*, 299 P.3d 844, 850-51 (N.M. 2012) (citations omitted). The court then held open the possibility that New Mexico’s “duty to market” – an implied covenant in certain private leases – encompasses and provides for the marketable-product rule. *Id.* at 860.

One federal court applying New Mexico law has stated that New Mexico in the future likely will adopt formally the marketable-product rule: “The Court believes that when the Supreme Court of New Mexico determines that the existence of the marketable condition rule is ripe for review, it will find the reasoning of Colorado, Kansas, Oklahoma, and Wyoming more persuasive than that of Texas.” *Anderson Living Trust v. WPX Energy Prod., LLC*, 306 F.R.D. 312, 428 (D.N.M. 2015).

Another federal court applying New Mexico law has held that New Mexico law, regardless of the marketable condition rule, will allow producers (lessees) to deduct from royalty post-production costs necessary to render a marketable form of gas. *Anderson Living Trust v. Energen Resources Corp.*, 161 F.Supp.3d 1055, 1061 (D.N.M. 2016) (holding that “in accordance with New Mexico law, [the producer] is entitled to deduct post-production costs for its services in getting the gas into a marketable condition”).

### ***Back to Texas – The “At the Well” Doctrine and the Unfortunate Cases Involving Casinghead Gas Plant-Related Royalties:***

Texas courts use the *Heritage Resources* rule and “at the well” lease language to cause royalty to bear the full spectrum of gas plant activities and costs, such as inert gas removal, hydrocarbon-gas recycling, CO<sub>2</sub> recycling, and field operations. *See French v. Occidental Permian Ltd.*, 440 S.W.3d 1, 8-10 (Tex. 2014) (using “at the well” language to impose on royalty owners the various post-production activities and costs incurred by casinghead gas plant operations); *Occidental Permian Ltd. v. Helen Jones Found.*, 333 S.W.3d 392, 404-06 (Tex. App. – Amarillo 2011, pet. denied) (using “at the well” and “in the field” language to avoid a meaningful market value analysis). Consequently, there is little to no Texas litigation challenging gas plant activities and thereby attempting to improve associated gas royalties.

*Occidental Permian Ltd. v. Helen Jones Found.*, 333 S.W.3d 392 (Tex. App. – Amarillo 2011, pet. denied), is a particularly unfortunate appellate decision. It would be hard to find a case involving a more developed factual record on oil and gas royalty rights, with opportunities to apply the “duty to market” and “market value” concepts, than the *Helen Jones Foundation* case. Sadly, it would be hard to find a court demonstrably less inclined to think through the case’s issues than the Amarillo Court of Appeals, as it was comprised in 2011.<sup>2</sup> The court’s decision at every turn strives to side with the defense – in order to release two large oil producers from a multi-million dollar judgment liability. The court’s decision, as badly as any Texas case before it, rides roughshod over established Texas law seeking to protect royalty-owner rights.

*Helen Jones Foundation* involved a very important industry practice in Texas’s mature oil fields: the injection of CO<sub>2</sub> to enhance oil recovery, the recovery of that CO<sub>2</sub> (after it has been commingled with other CO<sub>2</sub>, including native CO<sub>2</sub>, in the oil-producing formation), and the *profitable selling* of the recovered CO<sub>2</sub> for further re-injection. The Amarillo Court of Appeals did not address properly the CO<sub>2</sub>-flooding and CO<sub>2</sub>-recycling issues in the case, despite extensive briefing by the royalty owners’ counsel to delineate and present such issues.

The court concluded that the producer (lessee) owns the CO<sub>2</sub> continuously throughout the recycling and never relinquishes ownership to it; so, the court concluded, the producer can charge against royalty the entire cost of CO<sub>2</sub> recycling. The court’s conclusion does not reconcile the relationship between CO<sub>2</sub> flooding and recycling (clearly, a production-related activity) and the main disputes in the case: whether the royalty owners were receiving competitive hydrocarbon-gas royalties by way of the “duty to market” in proceeds leases, and by way of the “market value” concept in market value leases.

The CO<sub>2</sub> issues were collateral to the main disputes in the case: the defendants were attempting to justify paying virtually no hydrocarbon-gas royalties because the hydrocarbon gas was “contaminated” with the CO<sub>2</sub> – a production-related “tool,” which was hardly a contaminant because defendants could re-sell it to oil producers for millions annually at roughly \$1.50/MCF. The Amarillo Court of Appeals failed to recognize that CO<sub>2</sub> usage in an oil field is necessarily a production-related (not post-production) activity. CO<sub>2</sub> injection and recycling is directly analogous to water flooding, a well-recognized example of a production activity. Therefore, royalty should not bear costs related to CO<sub>2</sub> injection and recycling.

If a producer injects its “tool” or “chemical” into a wellbore and retains ownership of the same while the tool/chemical travels around a producing formation and back to the surface in the produced hydrocarbon stream – as the *Helen Jones Foundation* court concluded – then the producer’s activity is production-related, and recovering the tool/chemical from the produced stream is a production-related cost. (For instance, producers do not charge against royalty the costs of injecting, recovering, and re-injecting water in a mature oil field. CO<sub>2</sub> recycling and water recycling are conceptually the same activity – and in fact occur by way of the *same* injection wellbores.).

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<sup>2</sup> Of the three Justice deciding *Helen Jones Foundation*, Justices James Campbell and Patrick Pirtle remain on the court. The third, Justice John Boyd, no longer serves on the court.

On the other hand, if a producer injects a tool/chemical substance into a wellbore and loses title to it, the producer may charge against royalty the costs of extracting the substance from the produced stream – but the producer simultaneously must share with royalty the benefit of extracting the substance (specifically, the producer must pay a royalty on the \$1.50/MCF the producer sells the substance for). Again, the Amarillo Court of Appeals demonstrably did not understand, or think through, the foregoing concepts.

The foregoing cases, *French* and *Helen Jones Foundation*, are very bad ones for Texas royalty owners. They effectively have caused Texas to follow Oklahoma law on this point: “As long as the [gas] contract was reasonable when entered into, and as long as our law recognizes long-term gas purchase contracts as binding in the face of escalating prices, the law should not penalize the producer who was forced into the contract in large measure by his duty to the lessor.” *Tara Petroleum Corp. v. Hughey*, 630 P.2d 1269, 1274 (Okla. 1981). In other words, if the producer (lessee) justifies entering a gas contract – in 1935, 1962 or 2017 – with certain business reasons, then the producer may calculate gas royalties based upon the out-dated and/or below-market contract. The “duty to market” in proceeds leases, and the “market value” concept in market value leases, will not allow royalty owners to challenge the producer’s long-term gas contract, despite many historical Texas cases (such as *Texas Oil & Gas Corp. v. Vela*, *Amoco Production Co. v. First Baptist Church of Pyote* and *Exxon Corp. v. Middleton*) holding to the contrary.