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ARTICLES

SELECTED RE-EMERGING AND EMERGING TRENDS IN OIL AND GAS LAW AS A RESULT OF PRODUCTION FROM SHALE FORMATIONS

By Jeffrey C. King[1]

I. INTRODUCTION

Unconventional hydrocarbon bearing formations have had a significant impact on the position of the United States in the global energy markets. While the United States continues to be largely dependent on foreign produced crude oil, it has re-established itself as the world's leader in recoverable natural gas reserves. In fact, many prognosticators have stated that there are enough known, recoverable natural gas reserves to meet the power requirements of the United

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States for at least 100 years. These unconventional plays are largely, if not exclusively, shale formations that are denser and less permeable than the conventional sand-based rocks that have produced the overwhelming majority of hydrocarbons in the last 130 years across the globe.

Shale formations are abundant in the United States with the most famous being the Barnett Shale (Texas), the Haynesville Shale (Texas, Louisiana), the Fayetteville Shale (Arkansas), the Woodford Shale (Oklahoma), the Bakken Shale[2] (Montana, North Dakota), the Antrim Shale (Michigan), and the Marcellus Shale (Pennsylvania, West Virginia, Ohio, New York). In addition to these proven formations, there are the newer discoveries of the New Albany Shale (Indiana, Illinois), the Utica Shale (Michigan), the Cumnock Shale (North Carolina), Niobrara Shale[3] (Colorado, Wyoming, Nebraska), and the Eagle Ford Shale[4] (Texas). One significant fact common to most, but not all, of these shale formations is that until eleven years ago, the hydrocarbons captured in shale rock were believed to be either unrecoverable or uneconomic to recover.

The industry and the U.S. Department of Energy have proclaimed these finds to be the most rapidly expanding trends in the oil and gas industry.[5] Having said that, almost everyone agrees that the exploration bonanza we have seen since 2005 has been, and will be, driven by the price of natural gas and crude oil. So long as prices remain high, exploration in and the development of shale formations will continue. Accepting that premise, the opposite should also be correct: lower prices will slow exploration and development. In that circumstance, the downstream economics of the industry may have consequences for producers, non-operating working interest owners, and royalty owners that are not being presently discussed.

Taking the statements in the above paragraph as true, there is also another consequence to these developments. There has been a proliferation of oil and gas leasing and drilling in areas that have little prior experience, or little recent experience, with such activities. This has caused a resurgence of oil and gas law and raised issues that have been either dormant or nonexistent. This Article will address some of the re-emerging and emerging oil and gas litigation issues that are the byproduct of shale development activities. Specifically, this Article will discuss:

1. Production in paying quantities and shut-in royalties;

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2. The Bakken Shale is primarily an oil producing shale.

3. This shale is projected to be an oil producer.

4. From all reports, the Eagle Ford Shale will be a large producer of both crude oil and natural gas.

5. U.S. DEP'T OF ENERGY, MODERN SHALE GAS DEVELOPMENT IN THE UNITED STATES: A PRIMER ES-1 (2009), http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf.

2. Oil and gas lease drafting, and in particular, the use of termination clauses;
3. The impact of the Uniform Electronic Transactions Act on oil and gas law; and
4. Allegations of groundwater contamination caused by hydraulic fracture stimulation.

In order to have a full appreciation of these legal issues, however, a brief commentary on the economics of the industry is helpful, as well as a short history lesson of how these economic factors evolved into their present conditions. This Article will focus on natural gas since this is the predominant commodity produced from most shale plays.

A. *Price Dependent*

Shale plays are entirely price dependent, i.e., high price dependent. A benchmark gas price for shale exploration is approximately $5.00 per mmbtu.[6] For those experienced in natural gas values, they will naturally gasp that such prices are unreasonably high for economic production and makes the entire development of shale fields completely price dependent. That begs the question: why is shale production so expensive?

Shale plays are a product of technology.[7] The rock is very dense and hydrocarbons will not flow to the wellbore simply because a hole has punctured the formation. These formations can only be produced through the application of hydraulic fracture stimulation techniques. Such an operation requires multiple perforation zones and the injection of millions of gallons of water that is mixed with sand, silica, and certain chemicals under extreme pressure that will crack the rock.[8] As a result of the high water pressure, the sand and silica is wedged between the cracks, which allows the natural gas to escape through the wellbore. Hydraulic fracturing is generally coupled with horizontal drilling so that as much of the rock as possible is exposed to the fracture stimulation. The horizontal portions of these wells are 3,000 to 5,000 feet in length.

While horizontal drilling and hydraulic fracture stimulation greatly enhance the quantity of recoverable gas, these methods are far more expensive than older, smaller fracture simulation procedures and vertical well bores. For example, in late 2003 to early 2004, a Barnett Shale horizontal well, with an expectant delivery of 1 Bcf of gas and with a bottom hole that is over one mile beneath the surface of the

6. This figure represents the consensus from multiple producers interviewed by the Author over the last five years.

7. Patrick Forbis, *Barnett Shale Development Encroaches on DFW Metroplex as Play Grows by Leaps and Bounds; Spreads South*, TEXAS DRILLING OBSERVER, April 18–22, 2002, at 1, http://www.drillingobserver.com/Regional%20Rpt.%20Sample.pdf.

8. The fluid that is injected in this technique is at least 95% water and sand, if not higher.

earth and 3,000 feet laterally from the surface well bore, cost approximately $1.8 million to drill and complete. Since at least August of 2005, the same cost for that same well is approximately $3 million.

For illustrative purposes, if it costs $3 million to drill a well that will produce one Bcf of gas, and if we assume that the quality of the gas from our Barnett Shale well is 1000 btu's per cubic foot (i.e., pipeline quality), then the market price for natural gas must yield an average of no less than $3.00 per mmbtu *simply to recoup the cost to drill and complete the well.* The producer's expenses, though, do not stop there. A producer will also have to pay the cost to move the gas to market (including the cost of compression and the capital cost for gathering lines), the cost to make the gas marketable (such as the removal of water and the heavier liquid hydrocarbons), royalties owed to the lessor, taxes, and other miscellaneous expenses. As a result, if the average price for natural gas over the production life from our hypothetical well (assuming the well actually produced one Bcf) was only $3 per mmbtu, the producer lost substantial amounts of money. Simply put, the gas from a $3 million, one Bcf well must yield a substantially higher average price in order for the producer to make money and obtain a reasonable return on its investment, a return that will take years to realize.

As a result of this simplistic cost vs. return on investment examination, many producers in shale plays use a benchmark price of $5 per mmbtu in deciding whether to drill in a particular formation. If the price is above the $5 level, the decision to drill is an easy one. At the $4.99 mark, the producer will more closely examine the proposed well. As the price falls further below the $5 benchmark, the producer is less likely to drill the well. Statistically, this benchmark has held true. As the price of natural gas hovered near or above the $5 mark, drilling within the Barnett Shale increased substantially. When the price fell into the $3 and $4 ranges, drilling declined and was only done for lease preservation.

B. *Market Volatility*

The high cost of exploration and production, and thus the need for high prices, makes shale plays very susceptible to market fluctuations. The market for natural gas is largely unregulated as far as price, and it is subject to both the effects of supply and demand, and the whimsy of Wall Street speculators. In order to fully understand why today's gas market is volatile, one need only take a brief history course in natural gas marketing. In the last eighteen years, the manner in which a producer markets its natural gas production has changed immensely. The methods have moved from a relatively simple, safe, and lower-risk system to a true free market that can make paupers into millionaires or millionaires back into paupers.

1. The Dual System

Until 1987, natural gas was sold in a dual system—the interstate market, i.e., gas sold in states other than the state of production and the intrastate market, i.e., gas sold in the state of production. A producer was simply an exploration and production company that sold its gas to a pipeline company. The pipeline company then transported the gas to its buyer, usually an end-user, and then sold the gas, usually at a price equal to its gas acquisition price plus a charge for the transportation. End-users that purchased gas from an interstate pipeline, pursuant to a contract approval process by the Federal Energy Regulatory Commission ("FERC"), were required to pay a price to the pipeline company equal to the cost of the gas plus a transportation fee.[9] This was called a minimum bill.[10] Additionally, the FERC permitted interstate pipelines to exclude other gas merchants from transporting gas on their pipeline.[11] Once the FERC approved the contract, the purchaser was, in practice, prohibited from buying gas from other sellers, even though there may have been a cheaper supply, because the interstate pipeline maintained a monopoly over the components that were allowed in its piece of pipe.[12]

The pipeline to whom a producer sold its gas, whether interstate or intrastate, was usually a product of which type of pipeline was willing to extend its infrastructure to the production area and gather the gas from the wells. Accordingly, the producer's market was usually limited to the nearest pipeline and the market into which that pipeline sold the gas. As a result, the producer's marketing activities were rather simple. Between 1978 and 1987, that would change.

2. The Natural Gas Policy Act of 1978

Prior to 1978, industry experts predicted a shortage of natural gas in the United States.[13] Partly as an incentive to spur drilling by the industry, Congress passed the Natural Gas Policy Act of 1978 (the "NGPA").[14] Under the NGPA, producers that drilled and developed future wells in unconventional formations, tight sands or shale for instance, and who sold their production in interstate commerce were entitled to be paid maximum lawful rates starting at prices above \$3.00 per mmbtu and rising as high as \$8.00 per mmbtu depending on the date of drilling. At the time of the NGPA's passage, the average price for natural gas in the United States was 0.91 cents per Mcf.[15]

9. Wis. Gas Co. v. F.E.R.C., 770 F.2d 1144, 1149 (D.C. Cir. 1985).
10. *Id.*
11. Associated Gas Distribs. v. F.E.R.C., 824 F.2d 981, 993 (D.C. Cir. 1987).
12. *Id.*
13. Fed. Power Comm'n v. La. Power & Light Co., 406 U.S. 621, 626–27 (1972).
14. 15 U.S.C. §§ 3301–3432 (2006).
15. U.S. Dep't of Energy, Annual Energy Review 2009 201 (2009), *available at* http://www.eia.gov/totalenergy/data/annual/pdf/sec6_19.pdf.

Under the dual market system, new gas sold to the interstate pipelines under the NGPA would bring a substantially higher price. So utilizing the minimum bill contracts referenced above, interstate pipelines continued to purchase new gas from producers at extremely high prices and passed that cost on to the consumer.[16]

Whether the NGPA's drilling incentive played a role in the supply of natural gas, the predicted gas shortage of 1978 changed to a surplus of gas by the early 1980s.[17] Consequently, intrastate gas was extremely cheap while interstate "new" gas, i.e., from wells drilled since 1978, was extremely expensive.[18] The minimum bill contracts saddled end-use purchasers with high price gas, and because of interstate pipeline monopolies, they could not purchase the cheaper intrastate gas.

In response to consumer complaints about high natural gas prices, FERC took action. In 1983, FERC issued Order 380, which declared minimum bill contracts between interstate pipelines and end-users to be invalid.[19] As a result of this Order, gas users were relieved of their obligation to pay the selling pipeline company its gas purchase cost, which for "new" gas was the maximum lawful rate of $3.00 or more.[20] Rather, the end-use purchaser became free to negotiate a lower price to match the much lower gas market. Then in 1985, FERC issued Order 436, which required interstate pipelines to terminate their discriminatory practice of denying pipeline access to unaffiliated transporters.[21] Thus, pipeline companies were required to allow gas into their systems that would be competing with them for gas sales, including the cheaper intrastate gas. Order 436 "unbundled" the pipelines' role of gas marketer and transporter.[22]

In 1985 and 1987 respectively, the federal courts approved Orders 380 and 436 (as modified under Order 500).[23] Since they could no longer effectively monopolize their pipe, the dual system vanished, and pipeline companies moved away from being gas purchasers and sellers to merely transporters. Hence in 1987, access between end-users and producers was opened for the first time. The pipelines'

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16. Wis. Gas Co. v. F.E.R.C., 770 F.2d 1144, 1151 (D.C. Cir. 1985).

17. Another oft-cited factor was the decline in oil prices, which reduced the demand for natural gas due to consumer consumption of heating oil. *Id.*

18. *Id.*

19. *Id.* at 1149.

20. *See* Md. People's Counsel v. F.E.R.C., 761 F.2d 768 (D.C. Cir. 1985).

21. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, FERC Stats. & Regs., Regs. Pmbls. 1982–1985 ¶ 30,665, *order on reh'g*, Order No. 436-A, FERC Stats. & Regs., Regs. Pmbls. 1982–1985 ¶ 30,675 (1985), *order on reh'g*, Order No. 436-B, 34 FERC ¶ 61,404, *order on reh'g*, Order No. 436-C, 34 FERC ¶ 61,403 (1986), *aff'd in relevant part*, Associated Gas Distribs. v. F.E.R.C., 824 F.2d 981 (D.C. Cir. 1987).

22. *Id.* at ¶ 42,437.

23. Associated Gas Distribs. v. F.E.R.C., 824 F.2d 981, 1044 (D.C. Cir. 1987); *Wis. Gas Co.*, 770 F.2d at 1149.

change in business, however, now required the producer to create new marketing models and business strategies.

3. Access to the Burner-Tip

Upon the pipelines' withdrawal from the market, producers and end-users had more access to each other. Spot markets developed at certain locations around the United States where multiple pipelines converged and large quantities of gas were available for sale. For example, in Texas, spot markets developed in Waha (West Texas), at the Houston Ship Channel, and in Carthage. At those locations, buyers and sellers would negotiate a transaction for the sale of natural gas. The arm's length negotiated prices soon began to be published in industry periodicals and were called "index prices." Soon, producers began using the published index prices as their reference for future pricing of gas, as well as for valuing their reserves. Today, most natural gas is sold in major spot markets utilizing the "index price" for that location.

4. NYMEX and its Influence on Index Prices

The most important spot market in the United States is Henry Hub, Louisiana. It is a major natural gas transmission and transaction point. More significantly, it is the location that NYMEX relies upon for the selling of futures contracts on its exchange.[24] In the late 1980s and early 1990s, NYMEX included natural gas on its exchange. With the fall of the prior, relatively riskless marketing model, producers, middleman marketers, and buyers began to rely heavily on the futures market to guarantee supply and as a method of valuing natural gas. The NYMEX futures market has also become the vehicle upon which financial hedging transactions are based to protect sellers and buyers from wild price swings in the physical market.[25] The reliance on the NYMEX futures market soon, however, began to influence the spot market since it was projecting gas values for deliveries in future months and years.

The problem with utilizing the NYMEX as a barometer for gas values is the influence speculators have upon it. While physical supply and demand figures play a role in setting that market, a major influence is speculation about what events may or may not occur around the world that impact gas supply or consumption. That means guessing or crystal ball forecasting what the future might bring. For example, NYMEX speculators try to evaluate the role of a war in the Middle East, a hurricane, the weather forecast for summer or winter,

24. Philip Budzik, *U.S. Natural Gas Markets: Relationship Between Henry Hub Spot Prices and U.S. Wellhead Prices*, U.S. ENERGY INFO. ADMIN. 1, http://www.eia.gov/oiaf/analysispaper/henryhub/pdf/henryhub.pdf (last visited July 12, 2011).

25. *Marketing*, NATURALGAS.ORG, http://www.naturalgas.org/naturalgas/marketing.asp (last visited July 12, 2011).

field discoveries, or how announced technologies may impact supply or demand in the future here in the United States. Depending upon how these speculators determine these unknown future events will affect the physical market, the price for futures contracts will rise or fall. If their guessing proves to be incorrect, later contracts will be at lower prices. If they tend to be more correct than incorrect, prices will be higher. These signals from the NYMEX market then trickle down into the physical or spot market and influence the price producers obtain for their gas.

As a practical matter, the NYMEX influence is dangerous to market stability. When guessing about the future plays a role in valuing present day supply, such speculation can make present-day supply either extremely valuable or relatively cheap. There have been, and will be, enormous price swings due to the reliance on NYMEX. As stated above, it can make paupers into millionaires or back into paupers. This phenomenon has occurred in the past, and it can happen again in a matter of mere months. A classic example is the substantial price declines the industry suffered in late 2008 and continuing into 2009.

II. Legal Issues Raised

The expense associated with unconventional formation drilling and the applicability of price fluctuations raise many legal issues. Many of these issues exceed the breadth of this Article. A select few of these will be the focus of this Article since they have not been raised before in the context in which they are presently being alleged.

A. *Production in Paying Quantities and Shut-in Royalties*

In shale areas, there has been, presently is (depending on the area), or will be a leasing frenzy. The lease "hounds" have paid record high bonus amounts, agreed to pay record high royalty percentages, agreed to lease terms that are friendlier to landowners, and have limited leases to relatively short primary terms. The days of the Producer 88 form are over. All of this activity has been driven by commodity pricing and the technological advances discussed above.

The effect of this activity on the concept of "production in paying quantities" is two-fold. First, if the area is one where there are older leases held by production from non-shale formations, those landowners with an old Producer 88 form lease may claim, and have claimed, that the old lease terminated for failure to maintain "production in paying quantities." These claims are made by the landowner in the hopes of getting a newer, friendlier lease. Second, even with the newer leases on which a well has been drilled, but from which only limited production has been obtained due to poor pricing, landowners have sought termination based on the failure of the well to produce to paying quantities.

1. Fee Simple Determinable Interest/Special Limitation on Title

One concept that is not given enough attention by landowners and their lawyers, but which permeates every aspect of the base agreement between a landowner and a producer, is the nature of an oil and gas lease under Texas law. Though it is called a lease, an oil and gas lease is not a "lease" in the traditional sense. Rather, an oil and gas lease is a *sale* of the minerals by the landowner to the lessee.[26] The lessee acquires a fee simple determinable interest.[27] In other words, the lessee owns the minerals subject to the interest terminating due to a special limitation of title. The determinable interest lasts for a stated period of years, which is called the primary term, and so long thereafter as oil or gas is produced in paying quantities.[28] The portion of the life of the lease following the primary term is the secondary term.[29] An event or non-event that will cause a lease to terminate is a special limitation on this title.[30]

2. Older Leases Held by Production from Marginal Wells

When a lease has reached the secondary term and there has been established mineral production from that lease, the lease is said to be "held by production" or "HBP." The lease will continue to be held so long as the lease has a well that is producing in paying quantities.[31] When there is new leasing and production in areas where there has previously been leasing and production (such as in the Barnett Shale, the Haynesville Shale, and Eagle Ford Shale), there are older leases that are HBP by marginal wells. Typically, the production will be from a shallower formation and from a lease with a one-eighth-royalty provision. With new leasing activity in the area for bonuses in the thousands of dollars per acre, plus royalty percentages in the one-fourth to one-fifth range, royalty owners burdened by the older leases will file suit to quiet title and have the old leases declared terminated.

In such litigation, the issue is whether the well holding the lease is producing in paying quantities. Production in paying quantities means production in quantities sufficient to yield a return in excess of operating costs, even though drilling and equipment costs may never be re-

26. Natural Gas Pipeline Co. v. Pool, 124 S.W.3d 188, 192 (Tex. 2003); Anadarko Petroleum Corp. v. Thompson, 94 S.W.3d 550, 554 (Tex. 2002); Jupiter Oil v. Snow, 819 S.W.2d 466, 468 (Tex. 1991).

27. *Jupiter Oil*, 819 S.W.2d at 468.

28. *Anadarko Petroleum*, 94 S.W.3d at 554; Prize Energy Res., Ltd. P'ship v. Cliff Hoskins, Inc., No. 04-09-00603-CV, 2011 WL 648996, at *7 (Tex. App.—San Antonio Feb. 23, 2011, no pet.); Faith Oil v. King, No. 11-10-00234-CV, 2011 WL 2204476, at *1 (Tex. App.—Eastland June 2, 2011, no pet. h.) (mem. op.).

29. *Prize Energy*, 2011 WL 648996, at *7.

30. *Anadarko Petroleum*, 94 S.W.3d at 554; Rogers v. Ricane Enters., Inc., 772 S.W.2d 76, 79 (Tex. 1989).

31. Hydrocarbon Mgmt., Inc. v. Tracker Exploration, Inc., 861 S.W.2d 427, 433–34 (Tex. App.—Amarillo 1993, no writ).

paid and the undertaking considered as a whole may ultimately result in a loss. Further, in the event an operating loss is occurring, paying quantities may still be determined by the standard of whether, under all relevant circumstances, a reasonably prudent operator would, for the purpose of making a profit and not merely for speculation, continue to operate a well in the manner in which the well in question was operated.[32]

No arbitrary timeframe exists for determining whether a lease is producing in paying quantities.[33] Additionally, if a well yields returns in excess of operating costs, there is no need to determine whether a reasonably prudent operator would continue to operate the well.[34] Furthermore, operating costs are the ordinary periodic expenses of production, such as taxes, labor, repairs, and overhead charges.[35] However, no expenses associated with the original drilling of the well are taken into consideration.[36] Other costs that are excluded from the analysis are:

1. overhead charges or other expenses that are allocated to a well but which will not be materially reduced by the elimination of the well;[37]
2. expenditures incurred in the reworking of an existing well;[38] and
3. costs associated with making a marketable quantity of gas into a marketable quality gas.[39]

If after conducting this analysis, the well on the lease is not making a profit, the analysis does not end. If a reasonably prudent operator would continue to operate the well in the same manner for the purpose of making a profit and not merely for speculation, the well is still considered to be producing in paying quantities.[40]

These types of disputes are costly, accounting-intensive cases. They require expert testimony from persons with extensive experience in oil and gas accounting and petroleum engineering. If the well in question has not been making an operational profit, expertise in the reasonably prudent operator standard is also required.

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32. *See* Clifton v. Koontz, 325 S.W.2d 684, 691 (Tex. 1959).
33. *Id.* at 690.
34. *Id.* at 690–91; Skelly Oil Co. v. Archer, 356 S.W.2d 774, 780–81 (Tex. 1961).
35. *Skelly Oil Co.*, 356 S.W.2d at 781.
36. *Id.; see also* Blackmon v. XTO Energy, Inc., 276 S.W.3d 600, 603 (Tex. App.—Waco 2008, no pet.).
37. Ladd Petroleum Corp. v. Eagle Oil & Gas Co., 695 S.W.2d 99, 108 (Tex. App.—Fort Worth 1985, writ ref'd n.r.e.).
38. Pshigoda v. Texaco, Inc., 703 S.W.2d 416, 418–19 (Tex. App.—Amarillo 1986, writ ref'd n.r.e.).
39. *Blackmon*, 276 S.W.3d at 604.
40. Anadarko Petroleum Corp. v. Thompson, 94 S.W.3d 550, 559 (Tex. 2002) (quoting Clifton v. Koontz, 325 S.W.2d 684, 691 (Tex. 1959)).

3. Newer Leases with the Shut-in Well

As discussed extensively above, wells in unconventional formations are expensive to drill and are only marginally profitable during periods of low prices. Some producers will drill a well during the primary term and then shut-in the well during low price periods. Alternatively, some producers will drill the well but not totally complete it while waiting on higher prices. In this last scenario, some producers will drill a horizontal well, perforate it, and fracture stimulate only a portion of the well so that it will produce some gas. This is called "toe fracing" because only the very end of the wellbore is fracture stimulated. The producer performs a toe frac with the intention of re-entering the well when prices are better and then perforate and fracture stimulate the remaining portions, or stages, of the wellbore. Before completing all of the operations on the well, the producer will assert that the well is "capable of producing in paying quantities" thus allowing the payment of shut-in royalties to extend the life of the lease into the secondary term. These practices sometimes raise termination issues.

Under most leases, the lessee must be engaged in drilling operations for a well or producing a well in paying quantities at the conclusion of the primary term.[41] Otherwise, the lease terminates unless there is a shut-in royalty clause. A shut-in royalty clause provides for the payment of a shut-in royalty during periods when there is a well on the lease capable of producing in paying quantities but not producing because of a lack of a market for the gas.[42] In such instances, the parties have agreed that upon the payment of the shut-in royalty, the lease will be deemed to be producing in paying quantities during the shut-in period. But, there is a catch: the well must be "capable of production in paying quantities." In other words, the well was producing in paying quantities when it was turned off and would again produce in paying quantities without the need for additional equipment or operations when turned back on.[43] As stated by the Texas Supreme Court in *Anadarko Petroleum*, "we hold that a well must be capable of producing gas in paying quantities without additional equipment or repairs."[44]

Consequently, when an operator toe fracs a well, that well must produce in paying quantities in its present condition for shut-in royalties to be an option for extending the lease.[45] Accordingly, the value of the gas to be produced from the single stage of fractionation must

41. *E.g.*, *Anadarko Petroleum*, 94 S.W.3d at 554; Hydrocarbon Mgmt., Inc. v. Tracker Exploration, Inc., 861 S.W.2d 427, 432 (Tex. App.—Amarillo 1993, no writ).
42. *Hydrocarbon Mgmt.*, 861 S.W.2d at 432.
43. *Anadarko Petroleum*, 94 S.W.3d at 558–59; *Hydrocarbon Mgmt.*, 861 S.W.2d at 432–34.
44. *Anadarko Petroleum*, 94 S.W.3d at 558.
45. *See generally id.*

exceed the operational costs to produce that amount of gas. Since the gas production will be small, relatively speaking, this may cause a problem if prices are low. Furthermore, if the well is shut-in during the primary term, it must be capable of producing in paying quantities on the date the primary term ends.[46] When the toe-fraced well is turned on, it is critical that it produce in paying quantities without the need for additional equipment or operations, such as the need for further fractionation.[47] If there is such a need, the lease terminated at the end of the primary term.[48]

A related question is whether the cost of post-production equipment is included in the calculation. In *Blackmon v. XTO Energy*, the well at issue would produce natural gas in paying quantities.[49] In order to make the gas marketable, however, an amine processing unit was needed.[50] No gas could be sold until the amine unit was installed. Thus, the plaintiff contended that the lease terminated because the well would not produce in paying quantities without additional equipment.[51] The court of appeals disagreed. It was uncontested that the well would produce a high volume of gas and that no additional equipment was needed to make the well produce.[52] In other words, the well would produce a marketable quantity of gas.[53] Post-production equipment and expenses necessary to make the gas of a marketable quality had nothing to do with making the well produce. As a result, both the need for and the cost associated with the amine processing unit was not relevant to the paying quantities analysis.[54]

B. *Lease Drafting and the Termination Clause*

With the rush to lease as much property as possible, an emerging trend in oil and gas leases is the allowance of termination clauses in the contract aside from the common termination events discussed above. Increasingly, drafters include poorly drafted early termination clauses that are triggered by vague lease breach allegations. In the hopes of securing a settlement, landowners routinely allege relatively minor breaches in reliance on these clauses. Landowners know that once a producer has drilled a well into one of these shale plays that

46. Chesapeake Exploration Ltd. P'ship v. Corine Inc., No. 10-06-00265-CV, 2007 WL 2447293, at *3 (Tex. App.—Waco Aug. 29, 2007, no pet.) (mem. op), *withdrawn*, No. 10-06-00265-CV, 2007 WL 2729576 (Tex. App.—Waco Sept. 19, 2007, no pet.).

47. *Anadarko Petroleum*, 94 S.W.3d at 558.

48. *Chesapeake Exploration*, 2007 WL 2447293, at *3.

49. Blackmon v. XTO Energy, Inc., 276 S.W.3d 600, 602 (Tex. App.—Waco 2008, no pet.).

50. *Id.* at 604.

51. *Id.* at 603.

52. *Id.* at 603–04.

53. *Id.*

54. *Id.* at 604.

producer has now committed millions of dollars of capital to that lease, which is now at risk.

Many of these claims are questionable and fail to take into account the law concerning special limitations of title and the rules concerning forfeiture. A breach of an oil and gas lease does not result in termination.[55] Failure to properly pay royalties or to reasonably develop, for example, are breaches of a covenant giving the royalty owner a cause of action for damages, not termination.[56] When a landowner drafts clauses into a lease that result in lease termination when there is a breach of a covenant, they forget that a termination clause is a special limitation of title.

A forfeiture provision in a lease is disfavored under Texas law, and "[i]f the terms of a contract are fairly susceptible of an interpretation which will prevent a forfeiture, they will be so construed."[57] The Texas Supreme Court has steadfastly held that a lease's termination provision is a special limitation on title and will not serve to terminate the lease unless it is *"clear and precise and so unequivocal that it can reasonably be given no other meaning."*[58] The court has also described forfeiture or termination provisions as "harsh and punitive in their operation."[59] In doing so, the court has stated that such provisions will not be enforced when the provisions are ambiguous in nature:

> Where a contract is so vague in its terms that a court cannot determine its meaning, it would be unjust to enforce a forfeiture under it against one whose only fault has been to possibly mistake its meaning. . . . The authority to forfeit a vested right or estate should not rest in provisions whose meaning is uncertain and obscure.
> . . . *A provision so indefinite as to the obligation imposed, is incapable of supporting a forfeiture.*[60]

Termination clauses that state the lease will terminate if there is a breach of the lease are insufficient. To be effective, a termination clause must be specific as to what type of breach will result in termination and the circumstances under which termination will occur. If

55. Anadarko Petroleum Corp. v. Thompson, 94 S.W.3d 550, 560 (Tex. 2002).

56. *Id.*; W.T. Waggoner Estate v. Sigler Oil Co., 19 S.W.2d 27, 32 (Tex. 1929).

57. *See* Henshaw v. Tex. Natural Res. Found., 216 S.W.2d 566, 570 (Tex. 1949); Vinson Minerals Ltd. v. XTO Energy, Inc., 335 S.W.3d 344, 354 (Tex. App.—Fort Worth 2010, no pet.).

58. *See* Rogers v. Ricane Enters., Inc., 772 S.W.2d 76, 79 (Tex. 1989) (emphasis added); *see also Anadarko Petroleum Corp.*, 94 S.W.3d at 554 (citing Fox v. Thoreson, 398 S.W.2d 88, 92 (Tex. 1966)) ("However, we will not hold the lease's language to impose a special limitation on the grant unless the language is so clear, precise, and unequivocal that we can reasonably give it no other meaning.").

59. Decker v. Kirlicks, 216 S.W. 385, 386 (Tex. 1919).

60. *Id.* (emphasis added); *see also* York v. McBee, 308 S.W.2d 951, 956 (Tex. Civ. App.—Waco 1957, writ ref'd n.r.e.) ("The applicable rule here is that forfeitures are not favored and will be decreed only under specific and clear provisions therefor. *If, therefore, the instant lease be ambiguous, it must be construed as not creating a special limitation terminating the estate granted.*") (emphasis added).

there is any ambiguity or uncertainty as to whether the complained of conduct is within the terms of the clause, termination is not allowed.[61]

Another point needs to be made about termination clauses. Landowners believe that in the event the lease is terminated, the landowner will get the well and all of the production from it. That is the rare exception indeed. First, if a lease is terminated, the well or wells must be plugged.[62] The operator cannot abandon the well to be operated by the landowner. That means the surface casing must be pulled from the wellbore and concrete poured into the well to prevent the escape of hydrocarbons. Second, the equipment on the lease that is essential for production is the personal property of the producer. It is not the property of the landowner. So when a lease terminates, the producer has the right to retrieve its personal property, such as the wellhead and the tanks. It follows that royalty owners need to heed the maxim: "Be careful what you ask for; you just might get it!" What the landowner may get is a plugged well and no more future revenue from it.

C. *The Applicability of the Uniform Electronic Transactions Act*

In the fast pace periods of leasing, such as has been seen recently in the Eagle Ford Shale, lease and operational type negotiations occur daily via e-mail. These negotiations via e-mail sometimes result in a signed agreement; sometimes they do not. A recent question has been whether the e-mails actually form an oil and gas agreement despite the fact there are no physically signed documents.

In 2001, the Texas Legislature passed the Uniform Electronic Transactions Act (the "UETA").[63] As of the date of this Article, the Author is unaware of any reported Texas cases interpreting this statute. The UETA was designed to promote e-commerce and legitimize internet transactions.[64] Further, the UETA was intended to provide greater ease for parties to transact business through electronic means rather than through the traditional use of the U.S. mail.[65] In doing so, the drafters did not intend to re-write contract law.[66] The drafters did, however, intend for the UETA to satisfy the statute of frauds under appropriate circumstances and facts.[67]

61. The Fort Worth court in *Vinson* recently ruled that any notice of intent to terminate and any pre-suit demands must literally comply with the express language of the lease or termination will not be permitted. *Vinson Minerals*, 355 S.W.3d at 359–60.

62. TEX. NAT. RES. CODE §§ 89.011, 89.002 (West 2011).

63. TEX. BUS. & COM. CODE §§ 322.001–322.021 (West 2009).

64. *Id.* § 322.006.

65. *Id.* § 322.007, Cmt. 1.

66. *Id.* §§ 322.006(1), 322.007, Cmt. 2.

67. *Id.* § 322.007, Cmt. 2.

For the UETA to apply to an agreement, the parties must agree to transact business electronically.[68] Whether the parties entered into such agreement is determined by the context and surrounding circumstances, including the parties' conduct.[69] Based on the wording of this statute, if the parties expressly agree to transact business by electronic means, the UETA applies. If they do not so expressly state, the UETA may still apply if the surrounding circumstances, including the parties' conduct, leads to the conclusion that they agreed to transact business electronically. This could lead to a factual dispute.

The UETA's second requirement is an electronic signature.[70] An electronic signature is a sound, symbol, or a process the party has adopted as his or her signature.[71] At least one Missouri court has ruled that a simple reply e-mail that contains the name and e-mail address of the replying party can constitute that party's electronic signature under the UETA.[72]

Oil and gas transactions require compliance with the statute of frauds. Oil and gas leases, area of mutual interest agreements, participation agreements, joint operating agreements, lease purchase agreements, and purchase and sale agreements—to name a few—concern or deal with the sale of minerals, a real property interest. Consequently, the statute of frauds applies.[73] Such transactions must be in writing, contain a description of the property with reasonable certainty, and be signed by the party against whom enforcement is sought.[74] Otherwise, the agreement is unenforceable.[75]

Oil and gas transactions are complicated. They have always been consummated in written documents that were physically signed. That has been the industry custom and practice before and since the invention of the Internet. Having said that, some parties have asserted that loosely worded e-mails discussing the types of oil and gas agreements referenced above are enforceable as a contract under the UETA and the statute of frauds. Such an argument is contrary to the established industry custom as well as the import of the statute of frauds, which is to bring certainty to agreements concerning the sale of real property interests. It would be a rare thing indeed for parties to a multi-million dollar, multi-year transaction to intend to consummate a transaction via e-mail when less than all of the material terms are spelled out in the e-mail. The issue about whether emails exchanged between par-

68. *Id.* § 322.005(b).
69. *Id.*
70. *Id.* § 322.007.
71. *Id.* § 322.002(8).
72. Int'l Casing Grp., Inc. v. Premium Standard Farms, 358 F. Supp. 2d 863, 873 (W.D. Mo. 2005).
73. Dixon v. Amoco Prod. Co., 150 S.W.3d 191, 194 (Tex. App.—Tyler 2004, pet. denied).
74. Morrow v. Shotwell, 477 S.W.2d 538, 539 (Tex. 1972).
75. *Id.*

ties, who did not enter into a physically signed, written agreement, are sufficient to form a contract that complies with the statutes of frauds will be presented to the appellate courts of Texas very soon.

D. *Groundwater Contamination by Hydraulic Fracture Stimulation*

The use of hydraulic fracture stimulation has been the key to the exploitation of unconventional shale plays. Without hydraulic fracturing, natural gas would be in short supply in the United States. There has been a great deal of publicity, however, about the effects of hydraulic fracture stimulation on groundwater. The concern is that the water used in the process is mixed with certain chemicals that may be toxic. This frac fluid, according to the concern, may seep into and contaminate the groundwater. The possibility that frac fluid will somehow migrate to the surface water is extremely remote, and the odds of this occurring are too low to calculate.[76] This is especially true since the frac water comes back through the mouth of the well when the gas is produced and captured in tanks at the well location. The frac fluid does not stay in the formation. The only reason that seepage is even a possibility is because, as any scientist will tell you, anything is possible.

What needs to be understood is that frac fluid is forced into the hydrocarbon bearing formation thousands of feet below the groundwater and usually more than one to two miles below the surface of the earth. There are a thousand feet of solid rock between the oil and gas formation and the water-bearing strata. This solid rock acts as a thick, dense barrier that prevents the frac fluid from naturally migrating to the surface.

What also needs to be understood is that frac fluid is nothing new. The industry has used various forms of frac fluid dating back to the 1940s.[77] They have used oil as frac fluid, petroleum-based gels as frac fluid, and various other chemicals. For the last forty-plus years, there have been very few, if any, reported cases of groundwater contamination as a result of frac fluid migrating to the water strata. In short, the law of physics just does not support such an occurrence.

If groundwater did contain the chemicals used in frac fluid, a possible source is a leak in the wellbore's casing. It is possible for a leak to occur if the wellbore was not properly cased and cemented back. In such instances, the landowner may have a cause of action for negligence, nuisance, or trespass. A key fact in determining whether there is a casing leak is the pressure test on the wellbore. If the wellbore

76. *Review of Hydraulic Fracturing Technology: Testimony Before the H. Comm. on Sci., Space, & Tech.*, 112th Cong. (2011) (statement of Elizabeth Ames Jones, Chairman, R.R. Comm'n of Tex.), http://www.rrc.state.tx.us/commissioners/jones/press/051211-testimony.php.

77. Alfred R. Jennings, *Fracturing Fluids – Then and Now*, 48 J. Petroleum Tech. 604, 604–10 (1996).

maintains its integrity under pressure, then the source of the contamination is something other than the oil and gas well under review.

As of the time of this Article, the first round of groundwater contamination cases have been filed in the Barnett Shale area.[78] These cases will be followed with great interest by all concerned: the producers, the landowners, and the environmentalists. There will be a mixture of geological studies, engineering analysis, and the opinions of epidemiologists.

III. CONCLUSION

Unconventional shale formations have been the most discussed topic in the oil and gas industry for the last ten years. They also represent a perfect storm for controversy. They need to be produced because of the long-term energy needs of the United States. They are expensive. They are subject to the whimsy of price fluctuation. And they involve advanced technology that some people believe may cause environmental contamination. One thing is certain; shale formations and the predicaments they present will be the subject of much litigation for the foreseeable future. This Article is by no means a complete analysis of the possible claims nor is it a complete analysis of the types of issues discussed herein. The goal of this Article was merely to spot issues that have been emerging or re-emerging in courtrooms in and around the various shale formations.

78. Several cases have been filed against Devon Energy Production Company, XTO Energy, Inc., EnCana Oil & Gas (USA), Inc., and Chesapeake Operating.