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Gas Royalty Disputes on the Rise

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Introduction

Litigation related to unconventional oil & gas plays has been steadily increasing. One of the most common types of disputes concerns the proper payment of royalties by producers to mineral rights owners. This article examines the royalty clause, the types of disputes that most commonly arise, and some of the factors leading to increases in royalty disputes, particularly in shale plays.

The Royalty Clause

Typically, the royalty rate is defined in the lease agreements as a fixed percentage point of the share of oil and gas production quantities, with 12.5% being the most common royalty rate percentage. However, royalty rates have fluctuated more in recent years, ranging from 12.5% to 25%, or even higher. In some areas of the country, bonuses have been as much as \$25,000 or more per acre and royalty rates have approached 30% and higher.

Example of a Common Royalty Cause » The royalties to be paid by Lessee are as follows: On oil, one-eighth of that produced and saved from said land, the same to be delivered at the wells or to the credit of Lessor into the pipe line to which the wells may be connected. Lessee shall have the option to purchase any royalty oil in its possession, paying the market price therefor prevailing for the field where produced on the date of purchase. On gas, including casinghead gas, condensate, or other gaseous substances, produced from said land and sold or used off the premises or for the extraction of gasoline or other products therefrom, the market value at the well of one-eighth of the gas so sold or used, provided that on gas sold at the wells the royalty shall be one-eighth of the amount realized from such sale.¹

The contract language in the example (see callout box) addresses oil and gas resources separately due to the distinct nature of each product as well as the differences in what is required to deliver each product to market. Operators can store oil tanks near the well, or they can use small pipelines or trucks to bring to a central shipping point, from which it can be transferred to a mainline crude pipeline, railroad, truck or waterway carrier that delivers the product to refinery markets. Since natural gas is a more complicated product, operators cannot store it economically at the production site. Operators typically use gathering systems to aggregate natural gas, which is often compressed and processed before it can be injected into the longer haul pipeline facilities. Consequently, oil royalties can be paid in kind, while gas royalties are paid only by money.

A royalty clause contains provisions specific to natural gas that address the increased price and additional costs that will result from the marketing efforts, transportation, and processing necessary to complete a sale. These provisions are some of the most common drivers of gas royalty litigation.

Common Types of Royalty Disputes

Royalty calculation method: market value vs. proceeds. The royalty clause contract language previously quoted distinguishes between gas sold “at the well” and gas sold beyond the production field (i.e., off- premises). Specifically, the royalty payment for natural gas sold at the well is based on **proceeds** received, while the royalty payment for gas sold off premises is based on the **market value** of the gas. This distinction has given rise to numerous lawsuits over the question of whether or not the market value can be different from the proceeds received. Essentially, if natural gas is sold off premises under the provisions of a long term contract, is the market value determined by the contract price (which may have been agreed upon months or years earlier) or the current market price (as might be evidenced by comparable transactions)?

It’s likely that producers originally intended the lease language to provide for royalties to be calculated on the contract price for natural gas sold both on and off premises while allowing for deductions of marketing, transportation, and processing when a market did not exist at the well or a better market existed elsewhere. However, royalty owners have questioned whether or not the market value could be higher than the amount realized under a contract sale.

Courts have not ruled consistently on royalty calculation methods, but rather have adopted both approaches in different cases. Most states have followed the Texas Supreme Court ruling in *Texas Oil and Gas Corp. v. Vela*, 429 S.W.2d 866 (Tex. 1968), and held that “market value” requires the lessee to pay based on the current value of the natural gas at the time of production. The “Vela Rule” raises the possibility of royalty litigation any time there is a significant increase in the price of natural gas. Courts have also held that the inverse is true; when the market price of natural gas is lower than the contract price, lessees may pay royalties on the lower price.²

Conversely, a few states follow what is called the “Tara Rule,” named after *Tara Petroleum Corp. v. Hughey*, 630 P.2d 1269 (Okla. 1981). In this case, the Oklahoma Supreme Court noted that royalties based on “market prices at the well” were inherently ambiguous given that natural gas must be sold by long term contracts whose prices could differ from current market prices. The court held that an arms-length contract established market value and could be relied upon to calculate royalties.

Disputes over the determination of market value. Once courts established that market price may be different than proceeds received, disputes over the proper determination of market value followed. In *Vela*, the court established that market value should be determined by an analysis of comparable sales, taking into account time, quality, and availability to market outlets. Disputes can easily arise over these factors as well as other variables that could be used in determining market price.

When comparable sales are not readily available or reliable, the “netback” method should be utilized to determine the market value at the wellhead. The netback method begins with the price of processed and delivered oil or gas, and then subtracts certain post-production costs incurred. In theory, a netback price subtracts the costs associated with bringing the oil or gas to market. This method has its own challenges, including, but not limited to: Can depreciation and an allowance for return on investment be deducted?; Can the cost of a processing facility be deducted?; How should those costs be allocated?; And, Can the processing facility cost be deducted even after it has been paid for?³ All of these issues are related to the next category of royalty disputes.

Disputes over proper deductions to royalty payments. The sale of natural gas usually involves significant costs to get production from the wellhead to the pipeline. Costs can include transportation, dehydration, cleaning, processing, and compressing, among other things.

While the lessee is obligated for the costs of production necessary to generate value at the well, which party bears the responsibility for costs subsequent to production? At what point has “production” occurred? And what post-production costs are deductible?

It is typically assumed that production occurs once gas has been captured and held, and the aforementioned additional expenses, as well as some taxes, depreciation, and other costs are shared proportionately by the lessor. One classic case addressing this particular issue is *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225 (5th Cir. 1984). Shell produced sour gas (gas containing significant hydrogen sulfide) on the Piney Woods lease and transported the gas to a processing plant where the impurities were removed, and then sold the processed sweet gas to a pipeline. The court stated that the lessor was entitled to “royalty based on the value or price of unprocessed or untransported gas. On royalties ‘at the well,’ therefore, the lessors may be charged with processing costs, by which we mean all expenses, subsequent to production, relating to the processing, transportation, and marketing of gas and sulfur.”⁴

The current trend is for lease clauses to specifically identify the cost categories to be deducted from natural gas transported for sale. However, states adopting the view reflected in *Piney Woods* have ruled that lessors can be charged post-production costs even in some cases where there is specific contract language to the contrary.⁵

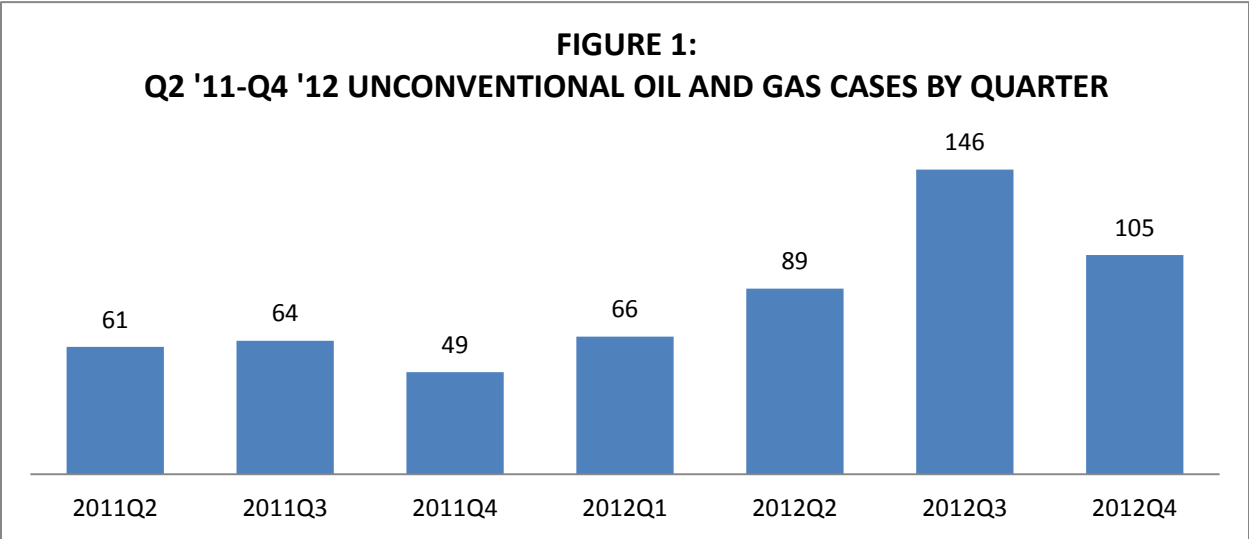
An alternative view that has been adopted in Oklahoma, Kansas, Colorado, and West Virginia relates to an implied covenant to market the natural gas. Courts in these states have ruled that production is not complete until a marketable product is held in a commercial marketplace. While some states may have adopted the marketable product rule, they don’t necessarily agree on which costs can be deducted. Some states assume initial separation of gas from oil and water is part of production, while Arkansas⁶, Kansas⁷, and Oklahoma⁸ view initial compression as a production activity.

Disputes over associated transactions. Falling natural gas prices in the latter half of the 1980s sparked a wave of litigation referred to as “take or pay litigation.” During the 1970s, the shortage of available oil and gas led buyers to enter into contracts that required buyers to either take delivery of certain quantities of gas or pay for the product at contracted rates (even if the buyer chose not to take physical possession of the product). However, when prices sharply declined in the 80s, buyers attempted to circumvent high contract price purchase obligations. Numerous lawsuits ensued, billions of dollars changed hands, and a new question was raised: Are the royalty owners entitled to a share of the take or pay proceeds and settlements? Most courts decided that royalty owners were not entitled to a share of the proceeds because “production” had not occurred.⁹ A few courts in Louisiana and Arkansas, however, ruled otherwise and held that royalty owners were entitled to a share.¹⁰

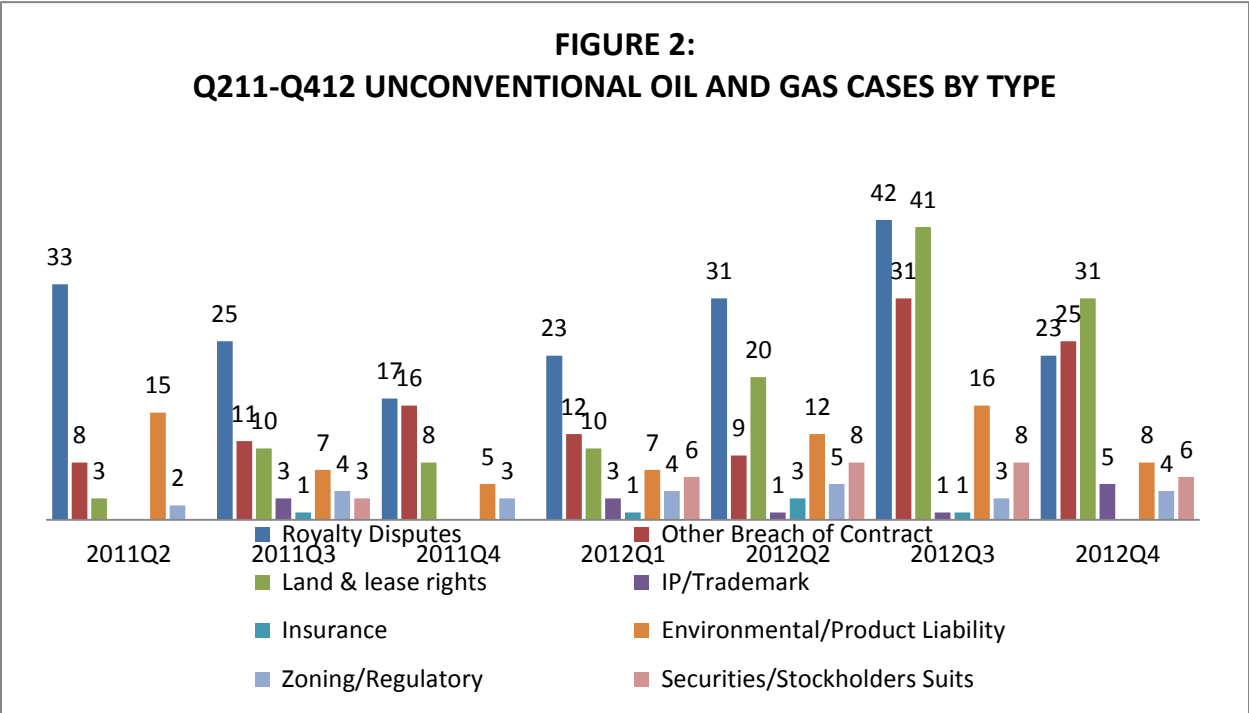
While take or pay provisions are less common today, potential questions regarding royalty owners’ rights to proceeds from transactions related to production still exist. For example, will royalty owners be entitled to a share of incentive bonuses, supply bonuses, and profits from hedges and swaps?

Trends in Royalty Litigation

Litigation related to unconventional techniques has increased significantly since early 2011 (Figure 1).¹¹



As shown in Figure 2, royalty disputes continue to be the most pervasive type of unconventional oil and gas litigation.



A number of factors have and will continue to give rise to royalty disputes in formations where unconventional methods of extracting oil and natural gas resources are being employed. The volume of new leases is significant, and some production regions include areas with smaller average parcel sizes, so pooling of leases is more prevalent, all of which can lead to more opportunities for disputed royalty calculations.

In areas where production is occurring before pooling arrangements can be formed, allocation of costs and calculation of royalty payments are further complicated. In addition, lessors are also more

sophisticated, have access to more information regarding lease terms, and are demanding more customized agreements. Greater variance in lease terms, higher volume of leases, and more complicated allocations all create a greater administrative burden for producers to accurately calculate royalty payments.

However, it is perhaps the location of these new formations that is most likely to lead to royalty litigation. Many of the new shale plays are in states where a history of oil and gas royalty case law does not exist, as it does in Texas, Oklahoma, Louisiana and other states. Courts have looked to states with more established case law for guidance, but many of the issues outlined above have not been decided. Moreover, each state ultimately acts based on the applicable state laws and rules on behalf of its constituents and thus may not rely on laws from other jurisdictions. For example, Pennsylvania's Guaranteed Minimum Royalty Act has been the source of many disputes. The statute, which was updated and amended in 2010, requires producers to pay a minimum 12.5% royalty but allows for the deduction of certain expenses. The calculation of those expenses and other issues, however, remain in debate. In fact, the Pennsylvania Attorney General recently launched an investigation into complaints that producers were over-deducting expenses, using internal sales to misrepresent values and misrepresenting other data.

Furthermore, there is still significant economic uncertainty regarding the value of shale gas and oil resources, costs to extract, level of conversion to natural gas, exporting of LNG and other factors. Economic and legal uncertainties create a challenge for operators in the drafting of leases as well as the administration of royalty payments. Since these uncertainties are likely to persist for some time, the risk of litigation over royalty issues could remain significant.

[About the Author](#) » Robert Lang is a Director in the Oil & Gas Disputes group in the Disputes and Investigations practice. He routinely provides expertise in a wide variety of oil and gas disputes dealing with matters throughout the product life cycle.

The opinions expressed in this article are those of the author and do not necessarily represent the views of Navigant Consulting, Inc.

1 American Association of Professional Landmen Form 675

2 See *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 373 (Tex. 2001).

3 One case addressing these issues is *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225 (5th Cir. 1984), where the court determined that costs for a processing facility could be allocated to lessors, but only up to the point where the facility had been paid for.

4 726 F.2d at 241

5 In *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118 (Tex. 1996), the court ruled that transportation costs could be deducted in spite of language in the lease agreement that stated "there shall be no deductions from the value of Lessor's royalty by reason of any required processing, cost of dehydration, compression, transportation, or any other matter to market such gas."

6 *Hanna Gas and Oil Co. v. Taylor*, 759 S.W.2d 563

7 *Gilmore v. Superior Oil Co.*, 388 P.2d 602

8 *Wood v. TXO Prod. Corp.*, 854 P.2d 880

9 *Diamond Shamrock Exploration v. Hodel*, 853 F.2d 1159 and *Killam Oil Co. v. Bruni*, 806 S.W.2d 264

10 *Frey v. Amoco Production Co.*, 603 So2d 166 and *Klein v. Jones*, 980 F.2d 521

11 See *Navigant Unconventional Oil & Gas Litigation Trend Reports, 2011-2012*