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Scrutinizing Royalty Payments

By Judon Fambrough

Dramatic changes occurred in the oil and gas industry in 2001. High prices at the beginning of the year spurred drilling exploration to levels not seen since the '80s. However, low prices at year's end caused drilling activities to practically cease.

During the year, Texas appellate courts decided three important cases affecting royalty owners. Mineral owners should be aware of these decisions and use them in future lease negotitions.

Production in Paying Quantities

The first case dealt with measuring production in paying quantities during the secondary term of an oil and gas lease *(Ridenour v. Herrington, 47 SW3d 117, Waco Court of Appeals, 4/25/01)*.

Oil and gas leases are divided into two terms, primary and secondary. The length of the primary term is negotiable and generally lasts three to five years. Oil companies must be drilling or have established production at the end of the primary term to enter the secondary term; otherwise, the lease terminates.

If the lease enters the secondary term, its duration depends on one of two standards given in the lease. Older leases use the production standard "for so long as production continues"; newer ones use the operations standard "for so long as operations continue." The difference is explained later.

Leases based on the production standard created confusion. It was unclear exactly how much production was necessary. Would one barrel of oil produced annually suffice?

In response, Texas courts held that the word *production* meant production in paying quantities *(Clifton v. Koontz, 325 SW2d 684)*. A lease cannot be held by little or no production for purely speculative purposes *(Garcia v. King, 164 SW2d 509)*. Likewise, when the lease does not specify the period over which the production in paying quantities is measured, the courts use a reasonable time that varies with the circumstances in each case. Texas courts say a minimum of six and a maximum of 17 months is reasonable.

After examining a series of cases, Texas courts developed a two-part test for determining production in paying quantities. The first part is mathematical, known as the *profitability test*. The second is the *prudent-operator test;* it basically examines the operator's intent when the well fails the profitability test.

The profitability test entails deducting certain charges and expenses from the gross revenue. If more than one well is located on the lease, the test applies to the gross revenue of all wells, not to each individual well. The exact deductions are detailed in Center report 601, "Termination of an Oil and Gas Lease."

If the well or wells fail the profitability test, the lease does not terminate automatically. The court must then determine whether a reasonably prudent operator would continue to operate the lease to make a profit. If the court finds the motive to be speculative, the lease terminates.

Once the Texas courts developed parameters for the production in paying quantities test, many oil companies switched to the newer operations standard. This standard nullifies the production in paying quantities test by defining operations as any endeavor to produce oil and gas, **whether or not in paying quantities.**

The *Ridenour* case involved a lease written on the production standard. The lease stipulated that the profitability test would be measured over a 60-day period during the secondary term. The oil company went 60 days **without any production** and the mineral owner filed suit to terminate the lease. The oil company argued a reasonably prudent operator would have continued to operate the lease under the circumstances to make a profit. The trial court granted the mineral owner summary judgment, and the oil company appealed.

The appellate court affirmed the summary judgment for the mineral owner, stating that the prudent-operator test applies only **when there is some production** during the measuring period for profitability. Here there was none.

Evaluating Production

The second case dealt with the complex problem of evaluating gas production for royalty payments (*Yzaguirre v. KCS Resources, Inc., Dallas Court of Appeals, 47 SW3rd 532, 6/27/01*). Royalty, as used in the oil and gas industry, means the fraction of production reserved by the mineral owner (lessor) in the lease. The reserved fraction must be converted into monetary units before royalties can be tendered. The industry uses two standards to make this

***MINERAL OWNERS SHOULD NEGOTIATE** a minimum royalty provision, regardless of whether the lease is based on the operation or production standard.*

conversion for gas: market price (market value) and amount realized (or proceeds).

The terms *market price* and *market value* are used interchangeably by Texas courts when referring to gas royalties. The terms mean the price generated by sales comparable in time, quality, quantity and availability of marketing outlets *(Texas Oil and Gas Corp. v. Vela, 429 SW2d 866, [Tex. 1966])*.

The terms *amount realized* and *proceeds* are likewise synonymous when referring to gas royalties. The terms mean the revenue the operator receives from the sale of the gas regardless of what the market value or price may be.

Evaluation of gas royalties based on amount realized or proceeds originated because of how gas was initially marketed and sold. To ensure long-term demand for the gas, producers entered long-term contracts. The contracts guaranteed the purchaser a supply of gas at a set price for a given period. During this period, the market price or value of gas might fluctuate, but the contract price (or proceeds) used to evaluate gas remained constant.

Over time, oil companies became so accustomed to using the amount realized for gas royalties that they failed to notice when the lease called for market price. This occurred in the *Vela* case cited earlier. The producer was selling gas under a traditional long-term contract and paying royalties based on the contract price (amount realized). The lease, however, required the gas royalties to be based on market price. In this instance, the market price far exceeded the contract price.

When the royalty owners discovered the discrepancy, they successfully sued the producer. The court concluded that the price paid under a gas contract was not the same as the market price provided for in the lease; they are entirely different standards.

The *Yzaguirre* case decided last year is similar to the *Vela* case. The lease required the royalties to be based on market value, but the lessee mistakenly paid royalties based on the amount realized. The contract price for gas, in this instance, far exceeded the market value. When the lessee recognized the mistake, it revoked the division orders and switched to evaluating royalties based on market price. The royalty owners sued because the division orders they signed called for royalties based on the amount realized. The case eventually reached the Texas Supreme Court, which ruled in favor of the oil company.

The high court focused on the impact of division orders containing contradictory provisions to the lease. Division orders are contracts signed both by the lessee and the lessors. They provide a means for distributing royalties by authorizing and directing to whom and in what proportion to distribute funds from the sale of production. Division orders, while in effect, temporarily rewrite or supplant contradictory lease provisions. Division orders are freely revocable at any time. Once revoked, the lease provisions again control *(Exxon Corp. v. Middleton, 613 SW2d 240 [Tex.1981])*.

The oil company was justified in making gas royalty payments based on market price once the division orders were revoked.

Cost-Free Royalties

The third case dealt with the improper deductions of costs and expenses from the lessor's royalty payments (*Wagner & Brown, Ltd. v. Horwood, 58 SW3rd 732, [Tex. 2001)*. The case clarifies a confusing issue.

A royalty (or royalty interest) is sometimes referred to as being "cost free." Some royalty owners mistakenly believe this means that no costs or expenses can be deducted from the royalty payment. Texas courts, however, construe this to mean that royalty payments are free of all preproduction costs, such as exploration, development and production needed to bring the oil or gas out of the ground.

Once out of the ground, though, the royalty bears some, if not all, of its proportionate share of postproduction costs incurred to make the oil and gas marketable and move it to market. This includes treating, transporting, dehydrating, processing, compressing, separating and scrubbing costs. The size of the royalty negotiated in the lease establishes the royalty owner's proportionate share of these costs and expenses. For example, if the lease royalty is one-sixth, the royalty payment bears one-sixth of the postproduction costs.

It is difficult to categorically state that all postproduction costs will be shared. The deductions depend on the lease terms and the circumstances surrounding each expense. However, most Texas leases place the royalty payment "at the well or wellhead." This generally means all costs incurred subsequent to production will be shared *(Heritage Resources Inc. v. NationsBank, 939 SW2d 118 [Tex. 1996])*. Any clause negotiated to negate this rule is unenforceable *(Judice v. Newbourne Oil Co., 939 SW2d 133, [Tex. 1996])*.

In the *Horwood* case decided in 2001, the lessee deducted postproduction gathering and compression charges but did so in excess of the royalty owner's proportionate share. The royalty owners suspected the overcharging occurred as early as 1982 when they hired an independent investigator. The investigator concluded the lessee was, in fact, overcharging, but the royalty owners did not file suit until 1996.

The lessee argued that the four-year statute of limitations expired. The royalty owners did not file suit within four years of the time they discovered or, by exercising reasonable diligence, should have discovered the unauthorized deductions. Eventually, the Texas Supreme Court was asked to decide if the overcharges could have been discovered prior to 1992.

The high court concluded that royalty owners have "some obligation to exercise reasonable diligence in protecting their interests . . . and determining whether charges made against payments are proper and reasonable." The court cited Sections 91.504 and 91.505 of the Texas Natural Resources Code as a mechanism for discovering overcharges.

These sections require the person making the royalty payments to explain any deductions or adjustments not explained on the check attachments. The payor must respond within 30 days after receiving a request (60 days after September 1, 2002) by certified mail. If the person fails to respond, the royalty owner may file a civil suit to compel the information and recover reasonable court costs and attorney's fees.

The Texas Supreme Court found the unauthorized deductions could have been discovered before 1992 and sent the case back to the appellate court for further proceedings.

Lessons to be Learned

Mineral owners should learn from these cases and consider the following in future lease negotiations.

First, negotiate a minimum royalty provision in the lease regardless of whether the lease is based on the production or operation standard. Any year during the secondary term of the lease that royalties do not equal or exceed the specified amount per acre, the lessee must pay the difference or the lease terminates. The size of the minimum royalty depends on the lessor's negotiating power.

Negotiating a clause that protects royalty owners in every situation is nearly impossible.

Second, it is difficult to address evaluating gas royalties in the lease because the marketing of gas is complex. Negotiating a clause that protects the royalty owner in every situation is nearly impossible. Mineral owners may require that gas royalties be based on the higher of market price or proceeds but never less than the amount the lessee receives from the gas sale.

Third, freeing the royalty from postproduction costs is difficult because of the *Heritage* and *Judice* cases, which hold that any clause in the lease attempting to free the royalty of these costs and expenses is unenforceable when the royalty is set at the well or wellhead. One solution would be to permit the deductions of postproduction costs but require the lessee to reimburse them with each royalty payment. Another possible solution is to free the royalty from postproduction costs but provide that the royalties will be set at the place of sale, not at the well or wellhead.

Finally, mineral owners should be aware of Sections 91.504 and 91.505 of the Texas Natural Resources Code. Whenever the royalty owner is uncertain or suspect about a deduction from the royalty, send an inquiry to the payor for clarification. Hesitating may allow the statute of limitations to expire.

Fambrough (judon@recenter.tamu.edu) is a member of the State Bar of Texas and a lawyer with the Real Estate Center at Texas A&M University.

***ANY CLAUSE** in the lease attempting to free the royalty of postproduction costs and expenses is unenforceable when the royalty is set at the well or wellhead.*

LOWRY MAYS COLLEGE & GRADUATE SCHOOL OF BUSINESS

Texas A&M University
2115 TAMU
College Station, TX 77843-2115

http://recenter.tamu.edu
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800-244-2144 orders only

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