Oil and Gas Lease Extensions

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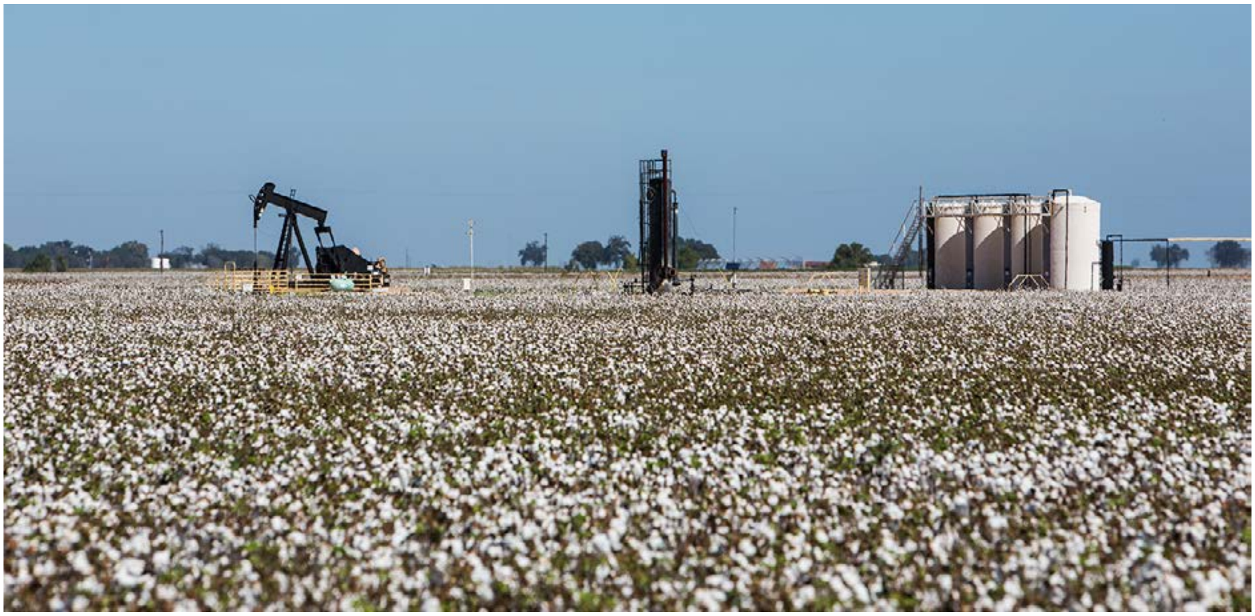

The recent downturn in oil and gas prices stymied exploration and production in many areas of the state. Presently, oil and gas companies are scrambling to find ways to hold leases with marginal or no production, awaiting the return of higher prices.

Mineral owners (lessors) tend to focus on ways to get production established when negotiating leases and often overlook provisions that prevent prolonged extensions when prices fall or production becomes marginal. The duration of the lease sets the parameters for understanding unanticipated extensions.

The Takeaway

When prices fall, oil companies may resort to inventive ways to extend leases with little or no production. Mineral owners need to be aware of these possibilities and guard against them when negotiating leases.

Paragraph two of a lease, known as the *habendum clause*, describes the length or duration of a lease. The clause divides the lease into two terms: primary and secondary. The negotiated length of the primary term averages three to five years. The lease terminates at the end of the primary term unless the operator has established production or commenced drilling operations. If so, the lease enters the secondary term and lasts for as long as production or operations continue without ceasing for more than some stated period, generally 90 consecutive days. When the cessation occurs, the lease terminates.

There are ways oil companies may extend leases within these parameters. At the same time, there are ways mineral owners may avoid these extensions when negotiating a lease.

Extensions at End of Primary Term

The length of the primary term appears straightforward, but the lack of definitions creates problems starting on the day the oil company enters the property to prepare to drill. Because the lease contains no definition of what constitutes the *commencement of drilling operations*, clarity lies in Texas case law.

The Texas courts adhere to a liberal definition of the term. According to two rulings, selecting the drill site, hauling lumber onto the premises, procuring a water supply and similar acts preliminary to the beginning of drilling, when performed with the bona fide intention to diligently proceed toward the commencement of a well, constitute the beginning of drill operations within the purview of lease terms *(Whelan v. R. Lacy Inc.* and *Peterson v. Robinson Oil & Gas Co.).* While the physical entry is quite evident, determining whether the acts are performed with the bona fide intent to begin drilling operations is not.

Obviously, mineral owners need to formulate a more exact definition. Otherwise, the oil company could conduct limited operations on the property every 60 to 90 days just to hold the lease. A violation of the bona-fide-attempt and due-diligence tests rests in litigation, which should be avoided if possible.

Some lessors define the beginning of drilling operations as the moment the drill bit begins rotating in the ground under its own power with sufficient equipment on site to drill to the depth of the permit issued by the Railroad Commission of Texas (the commission). Failing to meet this test before the end of the primary term permits the lease to terminate.

Another way to hold leases at the end of the primary term is to drill shallow wells. In Texas, the mineral estate extends to the center of the earth as does the depth of mineral leases. Consequently, any production at any depth holds the lease to the center of the earth.

The Austin Chalk lies immediately above the Eagle Ford Shale. The chalk contains proven reserves but not to the extent of the Eagle Ford Shale. The chalk can be developed less expensively with vertical wells as opposed to more expensive horizontal wells to the lower Eagle Ford Shale. Hence, oil and gas companies (lessees) drill shallow vertical wells to the chalk before the end of the primary term to hold the shale until higher prices merit development of the lower, more productive formation. The same occurs in other areas of the state with similar overlying formations.

This practice could have been avoided by negotiating a *horizontal severance clause* or *depth clause*. Typically, the clause provides that the lease terminates at the end of the primary term starting 100 feet below the stratigraphic equivalent of the deepest producing formation. If such a clause had been negotiated in the above scenario, the shallow well would hold the lease down to the Austin Chalk. The Eagle Ford Shale and all lower depths would no longer be bound after the end of the primary term.

Many oil companies agree to depth clauses starting 100 feet below the deepest drilled depth but not 100 feet below the deepest producing formation. There is quite a difference. Specify *below the deepest producing formation*.

Another possible extension is known as *continuous drilling operations*. This is not a standard clause but one negotiated by the parties on larger lease tracts where it would be impossible to develop the lease during the primary term. The clause allows continuous development based on two contingencies: (1) the lessee is drilling a well at the end of the primary term and (2) no more than 180 days elapse between the completion of one well and the beginning of drilling another.

The problem with this clause again lies with definitions. As discussed earlier, what constitutes the commencement of drilling operations? Likewise, what constitutes the completion (or abandonment) of a well? The lack of definitions opens the door for disagreements and litigation. A good definition of the completion or abandonment of a well avoids the problem. “The day the drilling rig is removed from over the borehole” is a good possibility. Never define completion as “the day the completion report is filed with the commission.”

Finally, lessees may resort to pooling before the end of the primary term to hold multiple leases with one well.

Paragraph four permits the lessee to unify the lease with other adjacent lease tracts to create what is known as a *pooled production unit*. A production unit is the area assigned to the well by the lessee to establish the amount of production allowed by the commission. Pooling enables the lessee to meet the commission’s spacing and density requirements. While this may appear innocuous, it may create problems for mineral owners.

Paragraph four goes on to say that any operations on or production from the pooled unit will be construed as operations or productions on all the leases from which the pooled unit was carved. This means that if the lessee places ten acres from a 500-acre lease in a pooled unit, any operations on or production from the pool holds the entire 500 acres with only ten in production. This permits the lessee to hold vast amounts of nonproducing acreage with one well. The practice could lead to a lawsuit for bad-faith pooling, though.

Lessors may limit the impact of this practice two ways.

First, limit the size of the pooled units to those *prescribed* by the commission. Generally, leases allow the lessee to create unit sizes *prescribed* or *permitted* by the commission. The prescribed sizes are the ones described in the commission's rules and regulations. The permitted sizes are the ones granted on request by the lessee. Lessees desire larger units to hold more nonproducing acreage with one well.

Second, place a *vertical severance* (or *Pugh Clause*) in the lease. This clause divides the pooled from the nonpooled acreage. At the end of the primary term or the end of continuous drilling operations (if one has been included), whichever is later, the lease continues only on the pooled acreage. The lease terminates on the nonpooled acreage.

On larger leases, lessees are able to create production units from one tract without resorting to pooling. The language in a standard Pugh Clause addresses only the creation of a pooled unit or units. If no pooling occurs, the Pugh Clause has no effect. Consequently, the language needs to be modified on larger tracts to separate acreage in production units (whether pooled or not) from the rest of the lease.

Litigation may still provide an option for lessors whose leases do not have Pugh Clauses. Texas courts recognize an implied duty for the lessee to continuously develop the premises when a profitable well has been drilled. Likewise, the courts prohibit a concept known as *bad-faith pooling* (mentioned earlier) when the lessee forms pooled units immediately before the end of the primary term simply to hold leases regardless of the geological aspects of a formation. Either practice may be difficult and expensive to prove in court.

Extensions During Production

The lease contains two ways to suspend or "toll" a lease while production occurs or can occur in paying quantities. These include the shut-in and the *force majeure* clauses. Both are referred to as *tolling provisions*.

The shut-in provision, contained in the royalty clause, allows the lease to remain in effect whenever the production from a well is not being sold or used by the lessee for 60 to 90 consecutive days. The well must be capable of producing in paying quantities. Lack of a pipeline to a newly completed gas well accounts for most shut-ins, but the clause is much broader than that.

The lease allows the producer to shut-in a well based on other reasons. For example, the lessee is not obligated to settle labor problems or market gas on terms *unacceptable to the lessee*. These are subjective standards.

Consequently, the lessee may shut-in a well whenever gas prices drop below a threshold unacceptable to the lessee. However, once the shut-in occurs, the lessee faces another obligation. The lessee must tender annual payments known as shut-in royalties to the royalty owners. As long as the lessee tenders the required annual payments in a timely fashion, the lease (and the shut-in) continue indefinitely.

The amount of annual shut-in royalties is negotiable. Before the late 1970s, failure to tender the payment within 90 days after the shut-in occurred terminated the lease. Later, failure resulted in a right to sue for the delinquent payments. The lease did not terminate.

Lessors cannot avoid shut-ins but may limit them. Generally, oil companies consent to limiting a shut-in to no more than 24 *consecutive* months. Lessors should counter with a limitation of no more than 24 months *in the aggregate*, which is a big difference. Also, lessors should fashion the timing of the payments as a condition, making delinquency grounds for terminating the lease.

The *force majeure* clause, much like the shut-in, protects oil companies from losing the lease whenever causes reasonably beyond their control suspend operations or production. Acts of God are good examples. However, the clause may include events such as financial problems, lack of water, lack of workers, and so on that may be within the lessee's reasonable control.

Two problems are apparent. First, which clause controls when an event could be classified as either a shut-in or a *force majeure*? The shut-in clause permits the lessee to shut-in a well if it cannot settle labor problems. Could this cause a lack of workers to be classified as a *force majeure*? Second, how soon after a *force majeure* is removed must the lessee restart operations?

To resolve these issues when negotiating a lease, first stipulate that whenever an event could be classified as either a shut-in or a *force majeure*, it will be classified as a shut-in. Shut-ins require annual payments and the duration may be limited. Not so with a *force majeure*.

Second, require the lessee to recommence operations or production within 30 to 60 days after the *force majeure* is removed. Some leases allow as many as 15 months.

Finally, review items listed as a *force majeure* and delete those that are within the lessee's control.

Extensions at End of Lease

The closing moments of a lease create a multitude of problems. Most focus on how much production is needed to hold the lease.

Generally, leases phrase the duration of the secondary term "as long as *production* continues with no cessation for 90 consecutive days." In this context, *production* means production in paying quantities. But, again, the term is not defined in the lease.

According to Texas case law, if the well returns a profit, even small, over operating expenses, it produces in *paying quantities* even though it may never repay all its costs. The enterprise as a whole may prove unprofitable yet meet the test per *Garcia v. King.*

The courts have developed a rather precise method for calculating (quantifying) production in paying quantities (see Center publication 601, "Termination of an Oil and Gas Lease"). For example, if there is more than one well on the lease, the test applies to all the wells as a whole and not to individual ones.

Case law does not dictate the length of time over which to apply the test. If the lease does not define the period, the courts resort to what is reasonable. In the past, this has varied between six and 18 months depending on the circumstances.

In *Clifton v. Koontz*, the Texas Supreme Court said, "We again emphasize that there can be no limit as to time, whether it be days, weeks, or months, to be taken into consideration in determining the question of whether paying production from the lease has ceased."

If the well or wells produce small amounts, but not in paying quantities, does the lease terminate? Again, the answer depends on the circumstances. According to the courts, the lease would not terminate if, under all the 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.

Finally, if there is a total cessation of all operations and production and the cessation continues for 60 to 90 consecutive days, the lease terminates regardless of whether it is producing in paying quantities or not. The reasonableness of the operator's actions under the circumstances becomes irrelevant.

How can these situations be avoided? One possibility lies in a provision known as required *minimum royalties* during the secondary term. Basically, the provision divides the lease into annual events starting at the end of the primary term. If during any annual period the lessor does not receive a certain amount of royalties based on the number of acres held by the lease, the lessee must make up for the difference or the lease terminates. However, the payment of minimum royalties will not hold the lease when no operations or production occurs during any 12-month period except when the lease is being held by a shut-in or a *force majeure*.

Finally, with improved technology, lessees may easily decrease the rate of production and extend the lease by reducing pump speed. Many lessors have seen their royalty checks decrease not only because of falling prices but also because of the reduced rate of production. This practice could occur anytime during the lease and appears permissible as long as the production occurs once every 90 days and continues in paying quantities. If negotiated, minimum royalties would be required during the secondary term when production drops too low.

Actual Extension Agreements

The lessee may seek an actual extension of the lease agreement rather than resort to the methods described here. While this removes any guesswork on what constitutes an extension, it does not resolve all problems.

A lease extension continues the terms and provisions of the existing lease. If the lease does not contain the recommended provisions just described, the lessor remains in the same precarious predicament.

For more information, see the updated research report *Hints on Negotiating an Oil and Gas Lease* at recenter.tamu.edu/pdf/229.pdf.

This article is for information only. For specific legal advice, consult an attorney.

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WAS THIS HELPFUL ?