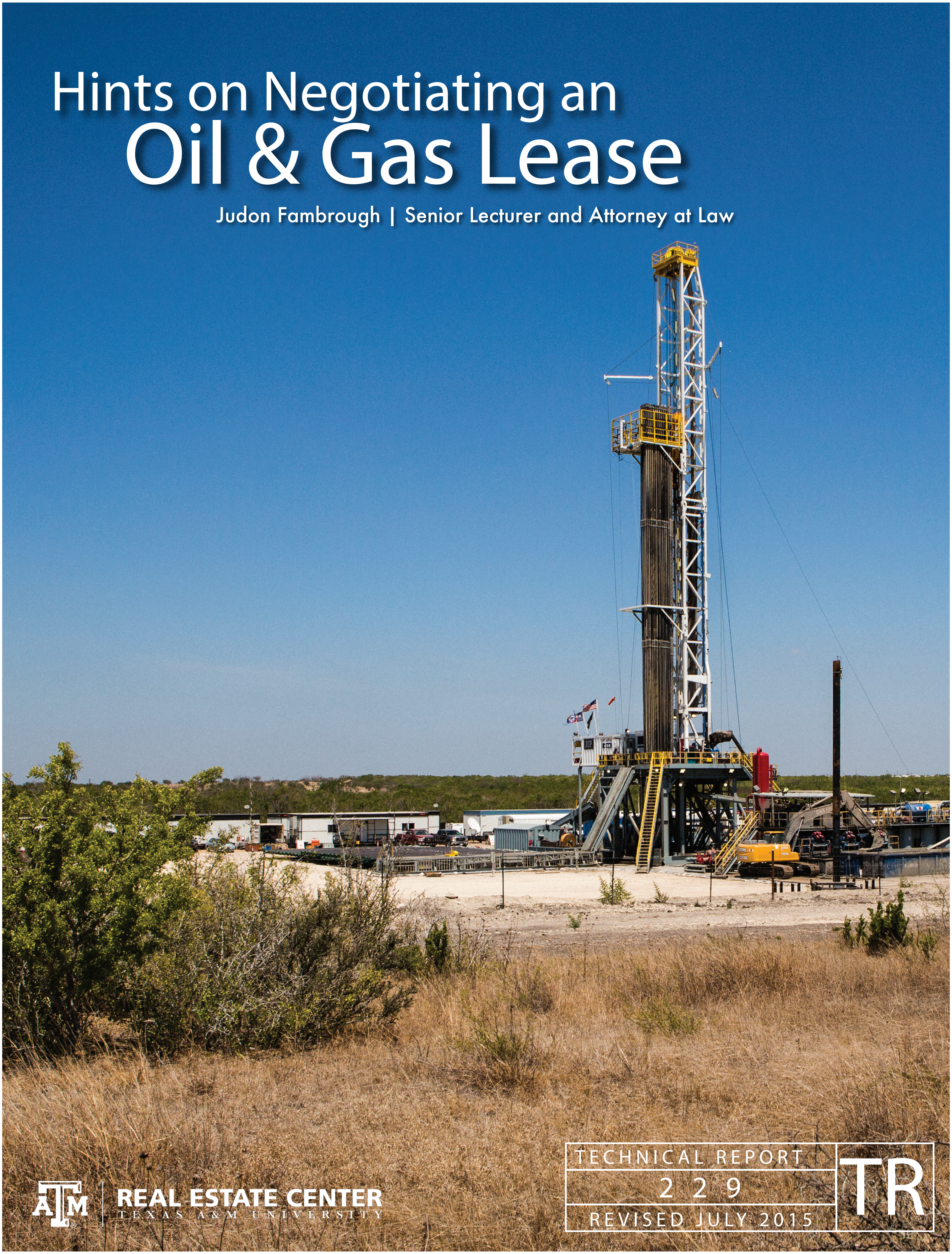
Hints on Negotiating an Oil & Gas Lease

Judon Fambrough | Senior Lecturer and Attorney at Law



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Introduction

Visions of oil wells conjure images of wealth. Consequently, mineral owners may fall victim to an oil company's bidding to sign an oil and gas lease as quickly as possible, and without changes. The quicker the signature is obtained, the quicker the drilling starts, according to the oil company. However, a hastily executed lease may turn a mineral owner's dream into a nightmare.

Before any operations commence, the mineral owner (lessor) and the oil company (lessee) must agree to certain terms and conditions regarding the rights, privileges and obligations of the respective parties during the exploration and possible drilling and production stages. Attempting to negotiate these items may be the mineral owner's first exposure to an oil and gas lease. Because of the complicated legal nature of the transaction, an inexperienced mineral owner may be somewhat at a disadvantage when dealing with an experienced representative (landman) from the oil company.

This report attempts to acquaint mineral owners with the more common provisions contained in an oil and gas lease. It explains the legal ramifications of each clause followed by suggestions to help the mineral owner protect his or her property and property rights. This report, however, is not a substitute for legal counsel.

The report focuses primarily on privately owned land in Texas. It does not cover leases on state-owned land or Mineral Classified Land where the state relinquished a portion of its mineral interest to the surface owners. To learn more about Mineral Classified Land, see *Mineral Law West of the Pecos,* Real Estate Center publication 2026.

The Mineral Estate

To better understand the lease provisions, mineral owners need to understand both the rights and the substances comprising the mineral estate in Texas.

The five rights possessed by anyone owning "*all* the minerals" are:

- right to negotiate and sign a lease (sometimes referred to as the *executive rights*),
- right to enter, explore and produce the minerals,
- right to receive *delay rentals* during the primary term of the lease (this right is offset by the current use of *paid-up leases* that require no delay rentals),
- right to receive an incentive (bonus) to sign the lease, and
- the right to reserve or retain a portion of the production, better known as a *royalty*.

A person who owns all the minerals owns 100 percent of all five rights. A person owning half the minerals owns 50 percent of these rights. To learn more about how these rights may be owned in combination with others, see Center publication 843, *Rights and Responsibilities of Mineral Cotenants*.

The following five substances are owned by mineral owners when the terms "minerals" or "oil, gas and other minerals" are used to sever the minerals from the surface:

- oil,
- gas,
- salt,
- sulfur, and
- uranium.

Coal, lignite and iron ore are included whenever they can be produced without destroying or depleting the surface.

Consequently, anyone entering an oil and gas lease may want to limit the lease to oil, gas and associated hydrocarbons that can be produced through a borehole. Prohibit mining. Otherwise, any of the hard substances could be mined or otherwise produced and sold by the lessee under the terms of the lease.

Lease Forms

Before discussing the lease provisions, mineral owners need to grasp certain facts about any proposed lease form presented to them. For example, in Texas, an oil and gas lease is not a lease but a *mineral deed*. Whenever the lessor signs the lease, he or she conveys a portion of his or her mineral interests to the oil company for the duration of the lease term. When the lease terminates, these interests revert to the mineral owner.

No standard or universal lease form exists in the oil and gas industry. Instead, each company uses a predrafted agreement, usually some version of a Producers 88 Lease form that has proven suitable in the past. The agreement may not be in the best interest of the lessor. Here are some facts to consider when presented with the form.

All provisions are negotiable. Likewise, the first offer an oil company makes may not be its best offer. Do not get in a hurry. Even though the landman soliciting the lease for the oil company may not have the authority to make immediate changes, many clauses or even the entire lease may be altered. However, the ability to negotiate favorable terms depends on the lessor's negotiating power.

Negotiating power depends primarily on three factors. The first is the amount of mineral acreage the lessor owns and controls; the second is the proximity of the acreage to proven production; and the third is the number of oil companies competing for the lease. The ideal situation would be to own a large tract next to a newly discovered field with numerous oil companies vying for the lease.

If favorable terms can be negotiated, put them in writing, and attach them to the lease form with an addendum.

The addendum begins with the wording "Notwithstanding anything to the contrary in the foregoing Oil, Gas and Mineral Lease, the following terms and provisions control. . . ." Then list the changes with the first numbered paragraph following in sequence after the last numbered paragraph in the lease. If the last numbered paragraph of the lease is 12, then the first numbered paragraph of the addendum will be 13.

Never consent to an oral change. It is what you sign that counts and not what the landman promises. Make sure all agreements are in writing and placed in the addendum.

To the extent possible, negotiate each change as a condition and not as a covenant. The difference lies with the remedies for a breach. The lessor's sole remedy when the lessee breaks a covenant is to sue for damages. If the lessee breaks a condition, the lease terminates automatically.

How can you distinguish between the two? The condition always ends with the phrase “or this lease shall terminate.”

For example, if the addendum specifies that the first royalty payment shall be tendered within 90 days after the first production leaves the leased premises, this is a covenant. If it states the first royalty payment shall be tendered within 90 days after the first production leaves the leased premises or this lease shall terminate, this language creates a condition. Oil companies abhor conditions and prefer covenants.

If the addendum contains confidential terms and provisions, ask that a *memorandum of lease* be drafted, executed and recorded in the deed records in lieu of the lease. The memorandum of lease contains the minimal information needed to give constructive notice of the lessee's ownership interests in the oil and gas lease. Generally, the memorandum recites the names and addresses of the parties, the effective date of the lease, the length of the primary term and the legal description of the property.

Mineral owners dealing with an unfamiliar oil company should research the company's history on the web. The Railroad Commission of Texas (the commission) serves as an excellent source as to the number of drilling permits issued to the oil company, the number of wells it has drilled and the daily production from its wells. An experienced oil company trumps an inexperienced one.

If possible, contact prior mineral owners who leased to the company, and find out how they were treated. See what kind of reputation the oil company has in the areas it drilled.

If the lease names an individual as the lessee and not an oil company, find out the name of the oil company that will eventually own the lease and repeat the investigative process.

Some mineral owners become concerned with the fact that an oil company refuses to sign a lease. Furthermore, the lease form does not disclose or recite the amount of the bonus payment.

First, remember an oil and gas lease in Texas is a mineral deed. Only sellers (or grantors) sign a deed. Consequently, only the grantor (the mineral owner) signs the oil and gas lease. The grantees (the oil companies) are not legally required to do so. However, getting the oil company to sign the addendum is recommended. The company cannot later claim the lessor added the addendum without its knowledge and consent.

Second, Texas is a nondisclosure state. This means the purchase price for property (the bonus in this instance) is not public record. Deeds in Texas recite the consideration as being "Ten Dollars and Other Valuable Consideration." Some simply say "Ten Dollars and OVC." Oil and gas leases contain the same recitals. Other documents in the transaction reveal the amount of the bonus, but not the lease.

However, lessors need to consider how oil companies tender bonus payments. Generally, the landman presents the mineral owner with a 30-day *sight draft*. This is not a check even though it resembles one. It is not legal tender.

Lessors endorse the back of the sight draft and deposit it in the local bank just like a check. However, the draft is not funded immediately. The local bank forwards the draft to the lessee's local bank for collection. This may be in Houston or Oklahoma City. Once the draft reaches this bank, the lessee has 30 *banking days* (not calendar days) to honor or deny payment. If denied, the lessor has no legal recourse against the lessee.

For this reason, the lessor should ask for a check, preferably a cashier's check. If this is unacceptable, sign the lease before a notary and give copies to the lessee as evidence of the signing. Give the originals to the company once the cash payment arrives. Never release the pages with the original signatures until cash is in hand. Otherwise, the lessee may record the lease without ever paying. (In Texas, only documents with the original signatures may be recorded.) In the meantime, reserve the option to sign with another oil company.

This raises another problem. In Texas, a deed requires no consideration for validation. (Remember an oil and gas lease is a deed.) Consequently, the addendum needs to state that the lease is conditioned on the receipt of the promised bonus money before it becomes effective.

Finally, mineral owners must understand that many of the problems associated with leasing spring from what the leases do *not* say in the event of production, not what they say. Here are several examples.

Unless the lessee establishes production or commences drilling operations by the end of the primary term (discussed later), the lease terminates. However, the lease does not define the term "commencement of drilling operations." Without a definition, the parties must rely on Texas case law. Case law recites a three-part test. The commencement of drilling operations occurs when (1) the lessee conducts preliminary operations on the premises leading toward drilling operations (such as the construction of a road or staking a drilling pad). Thereafter, the lessee pursues these operations (2) in good faith and (3) with due diligence to begin actual drilling.

Suppose the lessee stakes a well the day before the end of the primary term and does nothing else. Thereafter, only the lapse of time determines whether subsequent operations are pursued in good faith and with due diligence. In the meantime, no other oil company will take a lease on the property. Lessors must negotiate a more precise definition discussed later.

Another example involves surface operations and damages. In Texas, the mineral estate is dominant over the surface. This means when the mineral owner signs the lease, whether the mineral owner owns the surface or not, the oil company has the implied (automatic) right to use as much of the surface as reasonably needed to explore and produce the minerals without asking the surface owner for permission, cleaning up when operations cease or paying surface damages. This rule puts surface owners without minerals in a precarious position.

Leases do not address or even mention the dominance of the minerals over the surface. So, when mineral owners own both the surface and minerals, they must be careful to counter these implied rights with specific provisions regarding entry, cleaning up and payment of surface damages among other things as discussed in this report.

Finally, any production or operations conducted on the leased premises perpetuate the lease on all the leased premises to the center of the earth as long as any production or operations continue on the premises or on lands pooled with it. This enables the lessee to hold large amounts of nonproducing acreage. Lessors need to negotiate a vertical severance (Pugh) clause and a horizontal severance (depth) clause, both described later, to keep this from happening.

Granting Clause

The opening paragraph of the lease, better known as the granting clause, outlines the purpose of the lease, describes the substances that can be explored and produced and, to some degree, describes the surface operations allowed for exploring and producing the minerals.

Typically, the clause provides the lessee with the right to explore, drill, mine and produce oil, gas and all other minerals.

Under current Texas law, this gives the lessee the right to produce and sell oil, gas, salt, sulfur and uranium as mentioned earlier. Coal, lignite and iron ore may be produced and sold as long as it can be accomplished without depleting or destroying the surface.

Consequently, lessors may wish to limit the lease to the exploration and production of oil, gas, sulfur and associated hydrocarbons that can be produced through a borehole, and prohibit mining.

Implied Rights and Surface Damages

As mentioned earlier, the lessee has the implied right to use as much of the physical surface as is **reasonably necessary** to explore and produce the oil, gas and other minerals without asking the surface owner for permission to enter and without having to clean up or pay surface damages when operations conclude. This also includes the use of any substances owned by the surface owner such as caliche for constructing roadways and groundwater for drilling and fracking. Likewise, the lessee has the implied right to use any abandoned well(s) located on the premises for the disposal of wastewater. The lease does not discuss or even address these implied rights. They come automatically. Evidently, the mineral owners “should know this” before signing the lease.

Typically, leases contain various provisions limiting the use of the surface and requiring some payments for surface damages. For example, the lease prohibits the lessee from taking groundwater from the surface owners' existing water wells. Likewise, it restricts the lessee's operations to a minimum of 200 feet from any dwelling. Finally, the lease requires the lessee to compensate the surface owner for any damages to growing crops and timber.

If the mineral owner does not negotiate surface-protection provisions, the lessee is liable for surface damages only when it (1) uses more surface area or surface substances that are reasonably needed to explore for and produce the minerals, (2) injures the surface negligently or (3) fails to accommodate the estates. (For more information on the topic, see *Minerals, Surface Rights and Royalty Payments*, Center publication 840 and *The Accommodation of the Estates Doctrine*, Center publication 2090.)

Mineral owners who own the surface and wish to maintain some control may wish to incorporate some of these suggestions.

- Do not grant an unrestricted right for the underground disposal of wastewater in abandoned wells on the property. Instead, require prior written consent of the lessor or prohibit it entirely.
- Require the lessee to consult with the surface owner prior to entering to drill concerning the proposed locations of drill sites, roadways and pipelines. Likewise, address the location, construction and fate of any frack ponds dug by the lessee along with whether the lessee may drill water wells for its water needs. Require mutual consent on these points giving due regard to the lessor's present and future use of the surface. However, the lessor's consent cannot be unreasonably withheld.
- At the pre-entry meeting, require the lessee to tender surface damages in advance for the drilling pad based on its size and the number of potential boreholes. Let the initial payment for the drilling pad (based on the fair market value of proposed acres being used) cover payment for the pad and the first borehole. After that, require an additional advance payment for each borehole. The additional payments compensate for the additional trucks, noise, traffic and lights associated with each subsequent well.
- Do not allow the lessee to take free groundwater for drilling or fracturing. Possibly give the lessee the right to drill water wells for its water needs, then sell the water at a specified price per barrel. Detail the number of gallons in a barrel (33, 42.5 or 55) and

require metering at the wellhead. Stipulate how frequently the payments for the groundwater must be tendered and the consequences for missed or delinquent payments.

- If the lessee is given the right to drill water wells for its water needs, make sure the locations comply with the spacing requirements of any local groundwater district having jurisdiction. This is important when the lessor wants control of the water well(s) after the lessee no longer needs them. If they are at illegal locations, they must be plugged because the lessor is subject to the groundwater district's control while oil companies are not.
- Before the lessor takes control of a water well, find out its depth, quality of the water, rate of production, the screen depth and hydrostatic height of water. If these are favorable, require the lessee to file the necessary paperwork with the commission and pay any fees required to confer ownership on the lessor. Thereafter, the lessor must assume plugging responsibilities. If possible, require all pumps, casing and other supplies to be left in place for the lessor's use.
- In Texas, most *surface* water belongs to the state. If the lessee wishes to take water from the lessor's ponds or lakes, it must secure permission from the Texas Commission on Environmental Quality. The surface owner has no right to grant permission for its use.
- Never permit the lessee to use the lessor's existing roads, especially those accessing the residence. Interference and maintenance will be a constant problem.
- By the same token, restrict any drilling operations a certain distance from any inhabited dwellings or possibly other structures on the premises when drilling commences. Generally, the lease restricts operations to a minimum of 200 feet from structures existing on the premises when the lease was signed. Persons living in nearby residences may find this distance intrusive. Consequently, restrict operations to a minimum of 1,000 to 1,500 feet measured from the nearest edge of the drilling pad and not from the borehole. City ordinances typically require this offset.
- Determine the fate of the drilling pads, roads and frack ponds built and/or constructed by the lessee when the lease terminates. Some mineral-surface owners want them left in place to use in their farming operations. Others want one or more removed and the surface restored to its pre-existing condition. If restoration is desired, require the topsoil to be set aside when constructing the pads or ponds. The topsoil will be replaced as the final measure in the restoration process.
- Specify if cattle guards are required at the entry to the property. Require them to be kept shut and locked when not in use.
- To prevent erosion along roadways and around drill sites, require berm construction on slopes and culvert installation at low crossings.
- Require pipelines, telephone and water lines to be buried below plow depth (or a specified depth) in agricultural areas.
- Mineral owners wishing to cultivate or graze the area immediately above pipelines should direct the lessee to use the double-ditch method when opening and closing

trenches. This method requires the topsoil to be placed on one side and the subsoil on the other when the trench is opened. When backfilling, the subsoil is replaced first followed by the topsoil. Require the lessee to re-establish disturbed areas with a plant variety chosen by the lessor.

- In Texas, the lessee has the implied right to use caliche found on and under the leased premises free of charge for construction of drill sites and roads. As with groundwater, the mineral owner needs to stipulate the price for this material if used by the lessee. Some mineral owners require the lessee to purchase all the caliche for its needs from the lessor at a set price.
- Specify that the lessee's structures and equipment **must be removed** within a certain time after the lease expires or be forfeited. Otherwise, problems arise concerning its ownership. The same applies to any pipelines left in the ground.
- If the lessor runs livestock, require the lessee to fence any areas containing hazardous substances. Make the lessee liable for damages to livestock injured or killed by the lessee's operations, including the failure to maintain or repair fences or keeping gates closed.
- Mineral owners may require their prior consent for conducting seismic or other geophysical tests. With the advent of three-dimensional (3-D) seismic surveys, the potential for surface damages increases significantly, adding to the importance of this requirement. (See *Minerals, Surface Rights and Royalty Payments,* Center publication 840, for more details.)
- If the lessee cuts fences to build a road or install pipelines, describe the methods for bracing the fences prior to the breach.
- Describe the method or methods to be used for determining the amount of the damages. If the parties cannot mutually agree, resort to some nonjudicial means of resolving the dispute. Selecting an appraiser agreeable to both parties to determine the damages is one possibility.
- Stipulate that any groundwater use by the lessee cannot restrict the lessor's supply of fresh water for domestic, livestock or agricultural purposes. In times of drought, get permission to use water from the lessee's wells to water stock if the water is potable.
- If secondary recovery operations are undertaken for waterflood operations, deny the use of fresh potable water. State that such water must come from other sources.
- If the lessee assigns the lease, hold the assignor(s) and assignee(s) jointly and severally liable for surface damages as mentioned previously.
- A key provision that can be easily overlooked relates to the removal of litter and trash left on the property by the lessee's employees and independent contractors both during and after operations conclude. This can turn into a monumental problem and must be addressed. One solution is to require all litter and trash to be removed within 24 hours after being brought to the lessee's attention. The failure to do so could result either in a daily penalty or a set fee the lessee must pay when retrieved by the lessor or his or her employee. The fee is on an item-by-item basis (so much for a cup, bottle, can and so on).

Duration of the Lease

Leases are divided into two periods. The first period (primary term) sets the number of years (or months) in which the lessee must establish production or commence drilling operations. Older leases contained ten-year primary terms and required delay rental payments on each anniversary date when drilling operations or production were not occurring. As mentioned earlier, primary terms presently average three to five years and *paid up* leases now delay rental payments.

If the lessee establishes production or commences drilling operations by the end of the primary term, the lease continues into the secondary term and lasts as long as oil, gas and other minerals are produced with no cessation of more than 90 continuous days. Generally the full clause reads, "This lease shall remain in force and effect for a term of _____ years and as long thereafter as oil, gas or other minerals are *produced* from said land with no cessation of more than 90 consecutive days." Newer leases substitute the word *operations* for *produced.* These leases read, ". . . as long thereafter as *operations,* as herein defined, are conducted upon the said land with no cessation of more than 90 consecutive days."

For protection, lessors should consider the following:

- Strive to keep the primary term as short as possible. This spurs earlier exploration and possibly production. Avoid primary terms lasting more than five years.
- Be wary of granting an *option to extend* the primary term. Some oil companies offer a given bonus amount for a three-year primary term with the *option* to extend the primary term another two or more years by tendering the same amount of bonus on or before the initial primary term ends. Because it is an option and not a requirement, mineral owners rarely find this arrangement advantageous.
- Avoid leases using the wording *" . . . for so long as **operations** continue." Substitute "**operations**" with* **production** and include a minimum royalty provision (discussed later). *Production* means for as long as production continues in paying quantities. *Operations* means for as long as production continues whether or not in paying quantities. The latter favors the lessee. (For more information on what constitutes production in paying quantities, see *Termination of an Oil and Gas Lease,* Center publication 601.)
- Because the lease contains no definition of the term *commencement of drilling operations*, define the term to mean "whenever the drill bit is rotating in the ground under its own power with appropriate drilling equipment on site to reach the depth

specified in the drilling permit issued by the commission." No work (operations) occurring prior to this moment meets that test.

- Make sure the time between cessation-of-operation or production periods does not exceed 90 consecutive days. Some leases provide up to 180 days.

Extensions of the Primary and Secondary Terms

The primary and secondary terms of the lease may be extended via the cessation-of-operations, shut-in or *force majeure* clauses. Most leases contain all three. A fourth extension, discussed in the next section, may be added on large tracts known as *continuous drilling operation* during the secondary term.

Any time production or drilling operations cease, the lessee has 90 days (or some other stipulated period) to renew drilling operations or attempt to restore production from an existing well (sometimes collectively referred to as operations). As long as 90 consecutive days do not transpire between these operations, the lease continues.

The shut-in provision, on the other hand, allows the lease to remain in effect whenever the production from a well is not being sold or used by the lessee for 90 consecutive days, but the well must be capable of producing in paying quantities. The lack of a pipeline to newly completed gas wells account for most shut-ins. In addition, the lessee must tender an annual payment known as a shut-in royalty during the shut-in period. As long as the lease is capable of producing in paying quantities and the lessee tenders the required annual shut-in royalties in a timely manner, the lease (and the shut-in) remains in effect.

The amount of the shut-in royalties is negotiable. Generally, the amount equals the minimum royalties (discussed later) required to keep the lease in effect during the secondary term. According to some leases, failure to tender a shut-in royalty in a timely fashion terminates the lease.

Finally, the *force majeure* clause, much like the shut-in provisions, protects oil companies from loss of the lease whenever causes reasonably beyond their control suspend operations or production. Acts of God are good examples. However, the clause may include less notable events.

Two problems become apparent. First, which clause controls when an event could be classified as either the shut-in or a *force majeure*? Second, how soon after a *force majeure* is removed must the lessee recommence operations?

As a rule, mineral owners understand the rationale behind the extension provisions. The problems arise, as discussed earlier, are in what they do not say. Here are some examples and suggestions.

- Allow no more than 90 consecutive days between operations under the cessation-of-production clause. One hundred eighty days is too long.
- Because a shut-in could theoretically last forever (as long as the two conditions are met), limit it to no more than 24 to 36 months. Beware of basing the limitation on *consecutive* months versus *cumulative* months. Always base the limitation on no more than 24 to 36 cumulative months in the aggregate.
- Because the lessee prepays shut-in royalties on an annual basis, confusion arises when the lessee briefly produces the well during a prepaid shut-in period. Is the lessee entitled to credit for both the money and the months that were prepaid but not used? One possibility is to require the lessee to account to the lessor at the end of each annual prepaid period for the months that were prepaid but not used. The lessee forfeits any credits for failing to account within a certain period. Another possibility requires the lessee to prepay shut-in royalties monthly, not annually.
- Consider limiting shut-ins to gas wells. Exclude oil wells.
- Automatically terminate a shut-in whenever a well located on adjacent land, situated within a certain distance of the leased premises and completed in the same formation, begins producing and selling gas.
- Whenever an event could be considered either a shut-in or a *force majeure*, classify it as a shut-in. Why? Because a stoppage under the *force majeure* generally requires no payment and has no time limit. A shut-in should have a negotiated shut-in payment and a negotiated time limit.
- Require a timely written notice of any sustained work stoppage. Require the notice to specify whether the stoppage was pursuant to a *force majeure* or a shut-in.
- Specify how soon operations must resume after a delaying cause is removed under a *force majeure*. Some leases have no limit. Others allow up to 15 months, but 90 days is preferable.
- Consider whether financial difficulties, lack of water, lack of materials, lack of transportation, lack of drilling rigs, and so on constitute a *force majeure*. Some events may be within the reasonable control of the lessee yet classified as a *force majeure* under the lease terms. Remove events reasonably within the lessee's control.

Continuous Drilling Operations

When leases are taken on large tracts, both parties may insist on the fourth type of extension known as *continuous drilling operations*. The clause gives the lessee the opportunity to develop the entire leased premises but not necessarily during the primary term. It is similar to the 90-day cessation of operations provision discussed earlier. Here is how it works.

If the lessee is drilling a well at the end of the primary term, the lease continues as long as no more than 180 days (or some other negotiated period) transpire between the completion or abandonment of one well and the commencement of drilling operations for another. It differs from the cessation-of-operations provisions because it is longer, and the reworking of an existing well does not count. The lessee must commence drilling a new well on or before the end of the 180-day period or the lease terminates on the nonproducing acreage.

The 180 days gives the lessee the opportunity to gauge the profitability of the prior well before having to drill another. Generally speaking, if a well does not pay for itself in the first six months, it never will. Large lease tracts cannot be developed during a three-year primary term. This clause gives the lessee the opportunity to do so but in a timely manner.

Lessors must be careful when granting this clause. Definitions are critical. The terms *commencement of drilling operations* and the *completion or abandonment of a well* must be defined to an exact day for calculating the 180-day period. The completion or abandonment could be defined as the day the drilling rig is removed from over the borehole. Also, the provision needs to detail when the horizontal (depth) clause and the vertical (Pugh) clause (discussed later) take effect. Do they apply at the end of the primary term or at the end of the continuous drilling operations?

Royalty Clause

The royalty clause serves several purposes. First and foremost, it enumerates the percentage of the production retained by the lessor. In older leases, the standard was 12.5 percent or one-eighth. Today, the standard approximates 20 percent to 25 percent. It is negotiable. Second, the clause translates or converts the retained percentage of production into a monetary payment based on its market price, market value or sales price (proceeds). Some leases allow the production to be taken *in kind*. Finally, the clause describes the costs that may be deducted from the royalty payments. A discussion of this topic follows this section.

Here are the general rules on how the lease converts the retained royalty into a monetary payment.

- For oil, the conversion is based on “market price” or possibly “market value.” This means the highest posted field price for like grade and gravity of oil in the field where the production occurs.
- For gas, the conversion is based on “proceeds” or the actual revenue derived from the sale. As such, the resulting price may not necessarily equal its actual market price or market value.
- Finally, mineral owners may receive physical delivery of his or her share “in kind.” This method presents an alternative when the sale of production is based on long-term contracts. By inserting an option to take either as proceeds or “in kind,” the mineral owner can get the best of both worlds. When the market price rises above the long-term contract price, the mineral owner can take his or her share “in kind” and seek his or her marketing outlet. When the market price falls below the contract price, the lessor can revert back to proceeds.

As a general rule, lessees (and lessors) are hesitant to grant (or ask for) the “in kind” option unless the lease is in a major producing field. Otherwise, the cost of storage, accounting, delivery and other associated expenses outstrips any gain.

These items may be considered when negotiating royalty clauses.

- Specify how frequently royalty payments must be tendered because the lease does not address the issue. Pay particular attention to when the first royalty payment is due after production begins. Outline the consequences for missed or delinquent payments, such as daily penalties. Terminate the lease if the delinquency exceeds a specified period such as 180 days after the end of the month the first production leaves the premises or from land pooled with it. Once royalties are tendered, require subsequent payments every 30 to 60 days. Should the lease terminate for nonpayment, make sure the equipment, tubing, casing and other machinery used in production are forfeited so the mineral owner can use them to produce any remaining oil or gas. (According to Texas statutory law, the lessee has no obligation to tender a royalty until the payment exceeds $100. Until that threshold is met, the lessee need only tender royalties annually [Sec. 91.402, Texas Natural Resources Code]). Recognize this exception in the lease.
- Place a limit (bottom) on the valuation of royalty payments by stating that they can never be less than the contract price that could be negotiated between two disinterested parties in an arm's-length transaction on the day the purchase occurs.

- Reserve the option to take gas "in kind" if feasible.
- Consider negotiating an additional royalty (or overriding royalty) whenever the lessee recovers all or a certain percentage of the production costs.
- Determine if and when the mineral owner should have access to free gas. Many leases allow the lessor free use of natural gas for domestic (and sometimes agricultural) purposes. However, the lessor must indemnify the lessee in case of an accident. (Natural gas has no smell in its natural state.) The free gas may be limited to a certain amount per month. Make sure the connection for the gas is below any compressor site on the property.
- By the same token, decide whether the lessee should have free gas to use in its operations.
- Prohibit any division order from altering or changing the terms of the lease. (The division order discloses the lessor's interest in the production from a well, among other things.) If the division order contains terms contrary to the lease, it amends and supplants it. For protection, require all division orders to conform to the one prescribed in Section 91.402(c)(1) of the Texas Natural Resources Code. By doing so, the form provides that it does not change or amend the terms of the lease. Furthermore, Texas law provides that mineral (royalty) owners cannot be required to sign a division order as a condition for receipt of royalties as long as it does not comply with the one in the Natural Resources Code.
- Stipulate that the royalty owner faces no personal liability for receiving an overpayment. In Texas, the lessee has four years to recoup an overpayment. This means the royalty owner is not vested absolutely with the payment until four years after receipt. According to Texas statutory law, the parties may agree to limit the recoupment to two years. For the best protection, simply eliminate any personal liability for its return in the lease.
- Allow the lessee to flare the gas from an oil well for no more than 30 days in the aggregate after production commences. After that, the lessee must pay the lessor his or her share of the flared gas based on the price at Henry Hub on the day the flaring occurs. This limitation may apply only when a pipeline is available to take the gas.
- Require all long-term contracts for the sale of natural gas to have monthly (or daily) price adjustments. Try to get copies of the contracts.

Cost-Free Royalties

Because the royalty clause represents the greatest potential financial benefit to the lessor, deductions from the royalty check deserve attention. These deductions can reduce royalty payments by as much as 2 percent. The terms of the lease never address the issue directly. Instead, the deductions are based impliedly on where the royalty is set in the lease. Here are the rules in a nutshell.

Oil companies bear all the exploration and production costs necessary to get the product out of the ground. These are referred to as *production costs*. After that, the costs needed to make the product marketable and move it to the market place (sometimes referred to as *post-production costs*) are shared depending on whether the royalty is set: (1) at the well or wellhead, (2) in the pipeline or (3) at the place of sale. The shared costs include treating, dehydrating, marketing, compression and transportation, among other things.

The percentage of the post-production costs borne by the lessor depends on the size of the retained royalty. For a one-fifth royalty, the lessor bares one-fifth of the post-production costs. By negotiating a higher royalty, the mineral owner in essence agrees to shoulder a greater percentage of the post-production costs.

Obviously, mineral owners desire to avoid all post-production costs. But is this possible?

In 1997, the Texas Supreme Court resolved the issue *(Heritage Resources Inc. v. NationsBank*, *960 S.W.2d 619)*. The lessors negotiated a cost-free royalty provision, and the lessee breached the agreement. The lessor sued.

The high court held the clause unenforceable because the lease fixed the royalty "at the well" or "wellhead." In such instances, the lessor shares in all post-production costs and cannot be avoided.

The decision generated controversy. In 2014, the controversy intensified. Three appellate decisions questioned (and partially approved) ways to avoid the *Heritage* decision. Two came from the Federal Fifth Circuit Court of Appeals (to which Texas belongs), the other from the San Antonio Court of Appeals. Here is a quick synopsis of these three cases.

The two federal appellate decisions, *Warren v. Chesapeake* and *Potts v. Chesapeake*, involved changing the point for evaluating the royalties from "the well or wellhead" to "the place of sale." The courts held that the change *may* be sufficient to alter the *Heritage* outcome. The courts left the question open.

The Texas appellate decision in 2014, *Chesapeake Exploration v. Hyder,* is currently pending before the Texas Supreme Court for review. In this case, the lessor placed two limitations on the deduction of post-production costs. One stated that the royalty would be free of all post-production costs between the wellhead and point of delivery or sale. The other provided that the holding in the *Heritage* decision would have no bearing on construing the terms and provisions of the lease.

The court ruled in favor of the royalty owner and against Chesapeake. The court stated that *Heritage* ignored the "free and clear" provisions of the royalty clause. By law, the courts are required to consider the entire lease so that no provision will be rendered meaningless. Here, the appellate court recognized the parties' agreement (and intent) to exclude all post-production costs and expenses.

On a related subject, the appellate court ruled that because the royalties were set at the place of sale and not the wellhead, any gas lost or unaccounted for between the two places was not compensable. However, because the royalty owner won on the cost-free issue, the court held, "An award of reasonable attorney's fees to a plaintiff recovering on a valid claim founded on a written or oral contract is mandatory under Texas law." So, the mineral owner recovered reasonable attorney fees in addition to post-production costs.

On June 12, 2015, the Texas Supreme Court decided in favor of the royalty owners, meaning a royalty interest (and, in this case, an overriding royalty interest) may be made free of postproduction costs. However, its analysis of the case varied slightly from the appellate court's analysis.

For example, the language in the lease disclaiming any use of the *Heritage* case in construing the cost-free provision was held irrelevant. "A disclaimer of that holding, like the one in this case, cannot free a royalty of postproduction costs when the text of the lease itself does not do so."

According to the high court, the key components in the lease making the royalty free of postproduction costs were:

- The gas royalty was to be based on a percentage of the price “actually received by the lessee.” The royalty is sometimes referred to as being based on “proceeds.”
- The gas royalty was made to be expressly “free and clear of all production and postproduction costs and expenses;”
- The lease called for “a perpetual, cost-free (except only its portion of production taxes) overriding royalty of 5 percent of gross production obtained” from the wells.
- “Each lessor has the continuing right and option to take its royalty share in kind.” Both parties agreed this option could be satisfied with a monetary payment.

It was a combination of these provisions that were the factors in the court’s ruling. As it said in its conclusion, “Here, the lease text clearly frees the gas royalty of postproduction costs, and reasonably interpreted, we conclude, does the same for the overriding royalty. The disclaimer of *Heritage Resources'* holding does not influence our conclusion.”

While this case holds favorably for the gas royalty owners, a different analysis is possible for the oil royalty owners because the lease uses different language in determining oil royalties. For example, they are not based on proceeds, and generally there is no option to take in kind.

In light of these decisions, mineral owners may find it advisable to include these provisions in their leases.

- For certain, provide that the royalties will be free of both production and post-production costs.
- Require the point for evaluating the royalties to be the place of sale and not at the well or wellhead.
- Attempt to get the lessee to agree to waive the right to assert the cost-free royalty provisions as being unenforceable in a court of law having jurisdiction whether the lessee is a plaintiff or defendant.
- If no cost-free provisions can be negotiated, attempt to place a limit on post-production costs by stipulating no more than _____ can be deducted per mcf for gas and not more than _____ can be deducted per barrel of oil.
- As mentioned earlier, to lessen the problems associated with the valuation of royalties, state the royalties can never be less than the price that could be negotiated between two disinterested parties in an arm's-length transaction for the product on the day the sale occurs.

- Make the lessee liable for oil and gas lost or unaccounted for between the wellhead and the place of sale. Always make the lessee liable for any oil or gas lost or unaccounted because of the lessee's negligence.

Minimum Royalties

Leases contain no minimum royalty provisions. If one can be negotiated, it impacts the length of the secondary term of the lease. As discussed earlier, leases employ two measuring standards for the length of the secondary term. One states the secondary term lasts for so long as *production* continues, the other as long as *operations* continue. *Operations,* in this context, require very little production to keep the lease in force. However, when extended marginal production occurs, litigation may be necessary to terminate the lease under either standard.

Minimum royalties prevent a lease from being extended (held) for long periods by marginal production. If negotiated correctly, the clause avoids litigation. Minimum royalties are based on the total amount of royalties the lessor receives annually starting at the expiration of the primary term. For example, suppose a royalty owner desires a minimum of $35/mineral acre/year starting at the end of the primary term. Any year the royalties drop below this threshold, the lessee must make up the difference or the lease terminates. The requirement must be stated as a condition, not as a covenant, to make the lease’s termination automatic.

Minimum royalties are based on the number of mineral acres owned by the lease. Mineral acres are derived by multiplying the size of the lease tract times the lessor's undivided mineral interests in it. If the lessor owns an undivided one-half of the minerals in a 600-acre tract, he or she owns 300 mineral acres.

If the lessor owns a quarter of the minerals in the same tract, the annual minimum royalties required during the secondary term would be $35/mineral acre times 150 mineral acres or $5,250.

Minimum royalties are based on the combined receipt of royalties from production plus shut-in royalties. For example, in the above scenario, if the royalty owner receives an annual total of $3,000 from production and $1,000 in shut-in royalties, the lessee needs to add an additional $1,250 to perpetuate the lease for another year during the secondary term.

Pooling

Pooling represents one of the most complex clauses in the entire oil and gas lease. This occurs because the clause attempts to address and conform to several rules promulgated by the commission regarding statewide spacing and density requirements for wells. The language adds to the confusion by using the following undefined terms: *pooling*, *units*, *unitization*, *lands*, *prescribed, permitted* and *allowables*.

In essence, here is how the first part of the pooling clause reads:

> The lessee is hereby granted the right, at its option, to pool or unitize any land covered by this lease with other lands or leases, as to any and all minerals or horizons, for the establishment of units prescribed or permitted by the commission containing not more than _____ acres for oil or _____ acres for gas. Unit sizes may be established or enlarged to conform to the requirements for drilling a well at a regular location or for obtaining maximum allowables.

This means the lessee cannot pool the lease without authorization from the lessor. The opening language grants this right. Lessors of large tracts may wish to avoid pooling by striking the clause.

However, lessors must beware of subsequently *ratifying* a lease without pooling provisions with one that does. The ratification renews the lessee's right to pool. Some oil companies use this ploy against unknowing lessors. Basically, the oil company asks the lessor to ratify the lease to cure some irregularity, but the ratification contains the lessor's consent to pool. Mineral owners should never ratify a lease until they know the exact reason for the request.

Pooling involves the combining of all or a part of a lease with all or a part of an adjoining lease or leases to accumulate sufficient acreage to create a *unit (a production unit* in this context) to meet the applicable commission's spacing requirements. Currently, a well cannot be located within 467 feet of another person's property unless adjoining property is included in the production unit. Consequently, pooling represents an exception to the statewide spacing requirements.

Two types of *production units* may be created: those that are taken from more than one lease tract (called pooled units) and those that are taken from one lease tract (called tract wells or lease wells). The pooling clause authorizes the creation of *pooled production units.*

In addition to being an exception to the spacing requirements, the size of the *production units* or *units* dictates the rate of production permitted by the commission. This amount is called the *well's allowables*. The larger the unit, the larger the allowables. However, the commission places a maximum size on production units. The maximum unit size permits the maximum rate of production for the well's maximum allowables. Units less than the maximum size may still produce but at a reduced rate.

Only the land adjoining the well can be assigned to or included in a pooled unit. Likewise, the same acreage cannot be assigned to two units unless the two units (or wells) produce from different formations or horizons.

Unitization relates to the consolidation of all the operators and a certain percentage of the royalty owners in a field for a secondary or reservoir-wide recovery operation. Consent for these projects cannot be secured in a lease. It must be accomplished in accordance with the procedure outlined and supervised by the commission.

Pooling is conducted on a well-by-well basis while unitization occurs on a field-wide basis. Why unitization is even mentioned in a lease is questionable. However, the terms are used synonymously in the context of the lease to refer to pooling.

Land refers to unleased property not subject to an oil and gas lease. In Texas, unleased land may continue in a pool as long as it was subject to a lease when initially placed there. This is important because if the lease terminates on an undivided interest containing the drill site, the pool continues in effect. This could have adverse consequences on the lessor's interest *(Wagner & Brown v. Sheppard, 282 SW 3rd 419)*. To avoid this, always state that the lease can be pooled only with other leases or lease interests, never with other *lands*.

Leases, as noted previously, refers to lands under or subject to an oil and gas lease.

Notice the language in the pooling clause states that so many acres can be placed in an oil unit and so many in a gas unit. Then it adds that if additional land is needed to obtain maximum (sometimes referred to as “full”) allowables, the lessee can increase the size accordingly.

Two sets of rules exist regarding the size of production units: those *prescribed* in the commission's rules and those *permitted* by the commission upon request. Typically, mineral owners allow the creation of the *prescribed* units but deny the creation of any *permitted* ones. Alternatively, lessors may allow the creation of permitted units only after securing the mineral owner's prior written permission.

Pooling clauses include a provision that mineral owners can overlook easily. It states that any operations conducted on or production taken from any part of the pooled unit shall be considered for all purposes, *except for the payment of royalties*, as operations on or production from *said land* under the lease. *Said land* in this context means from the entire leased premises.

Therefore, if any part of the leased land is placed in a pooled unit, any operations (which includes production) conducted in the pool (and not necessarily on the lessor's land) maintains the entire lease as long as operations continue without cessation of more than 90 consecutive days. This language allows lessees to hold large amounts of nonproductive acreage outside the parameter of the pooled unit. Lessors should offset this with the inclusion of a Pugh clause (discussed later).

As noted in the prior language, the pooled unit will be considered for all purposes, *except for the payment of royalties*, as operations on the entire leased premises. This means that once the land is pooled, the formula for calculating royalty payments changes. The mineral owner's share of the production from the pooled unit is determined by multiplying the royalty reserved in the lease times the resulting fraction found by dividing the number of mineral acres the lessor has in the pooled unit by the total number of acres in the pool.

For example, assume a lessor owns an undivided one-fourth of the minerals in a 600-acre tract. She reserves a 20 percent royalty in the lease. The lessee forms a 300-acre pooled unit and places 100 acres of the lease in it. What percentage of the production will the lessor receive?

Remember, by owning one-fourth of the minerals in the 600-acre tract, the lessor owns 150 mineral acres. This means the lessor owns 25 mineral acres in 100 of the acres.

Applying the formula, the lessor will receive 1.67 percent of the production from the pool (20 percent × 25 divided by 300 = 0.0167).

Mineral owners should be cautious about giving the lessee the right to pool the property without considering the following.

- Mineral owners with large tracts may wish to withhold the consent to pool until the remaining nonproducing land outside of a unit is insufficient to form a unit for full allowables under the rules *prescribed* by the commission.
- Alternatively, because the size of gas units is so large, lessors may allow pooling for gas but deny pooling for oil without their prior written permission. Likewise, limit the size of the gas units that can be created based on the depth of completion. Allow bigger units for deeper wells.
- For mineral owners with large- to medium-size tracts, allow pooling, but state that any pooled unit must contain either a certain percentage of the lessor's land or a certain percentage of the pooled unit. The greater the number of acres placed in the unit, the greater the portion of production the lessor receives. Generally, lessees are more inclined to grant these requests when the lease serves as the drill site.
- For lessors owning smaller tracts, allow pooling but require that all of the leased premises be placed in the production unit. This is sometimes referred to as "all or nothing." This maximizes the percentage of production the royalty owner receives from the pool.
- Some oil companies withhold royalty payments from all the mineral owners placed in a pool until they cure all title problems on all the tracts in the pool. Avoid this by stating they cannot withhold royalty payments when no title problems exist on your tract. If they attempt to do so, penalize them with daily late payments.
- Consider whether the lessee may change the size of the pool once formed. The lease provisions generally grant the lessee this latitude. Consent to the change in size but stipulate that the lessor's percentage of production from the pooled unit can only increase, never decrease.

Vertical Severance (Pugh) Clause

As noted in the prior section, operations or production on any part of a pooled unit, whether or not on the leased premises, must be considered for all purposes, except for the payment of royalties, as operations or production on the entire leased premises. In fact, any operations or production anywhere on the leased premises, whether on the pooled unit or not, holds the entire lease tract. This has adverse consequences, especially on large tracts.

For example, suppose a landowner owns all the minerals on a 500-acre tract and places all of it in one lease. The lessee drills one well, completes it at 2,000 feet and creates a nonpooled 40-acre production unit. At the end of the primary term, this 40-acre unit holds the entire 500 acres even though only 40 acres is in production. No other oil company can lease the remaining 460 acres until the well on the 40 acres ceases to produce.

To avoid this, lessors need to include some form of a Pugh Clause that separates the acreage in a unit or units from the rest of the lease. This may occur at the end of the primary terms or at the end of continuous drilling operations if the clause has been added. In the purist sense, a Pugh Clause separates the pooled acreage from the rest of the lease. If the unit is not a pooled one, the clause has no effect.

On larger tracts, the Pugh Clause needs to be modified to separate the acreage in a unit, whether pooled or not, from the rest of the tract. Larger tracts give the lessee the ability to create both pooled units as well as tract wells. Without the modification, a Pugh Clause affords the mineral no protection in the event of a tract well or wells.

Here is how the clauses would read.

A pure Pugh Clause provides that at the end of the primary term or at the end of continuous drilling operations, whichever is later, the lease terminates on all acreage *not in a pooled unit.* For a modified Pugh Clause, it would state that at the end of the primary term or at the end of continuous drilling operations, whichever is later, the lease terminates on all acreage *not in a production unit, whether it has been pooled or not.*

As a final measure, another provision needs to be added in the event multiple production units are created. It stipulates that whenever the termination occurs on the land outside of the production units, the lease applies separately to each production unit. Any operations on or production from one unit shall not be construed as operations or production on or from another.

Consequently, as operations or production ceases on one unit, the lease terminates on that unit even though production or operations continue on another.

Without this clause, the lease would continue on all the production units until the last one ceases to produce.

Horizontal Severance (Depth) Clause

As alluded to earlier, leases need some type of a Pugh Clause (or vertical severance) to limit the amount of acreage one well holds at the end of the primary term or at the end of continuous drilling operations.

Likewise, leases need some form of a depth clause (or horizontal severance) to limit the depth one well holds. Without it, one well, completed at any depth, holds the entire lease to the center of the earth as long as operations or production continues. (In Texas, ownership of the minerals extends to the center of the earth.) If the property contains several producing formations, the lessee has the potential of producing each one in succession without getting a new lease. A depth clause eliminates this possibility.

Depth clauses come in several varieties. The best would be to limit the lease to a specific formation (the Eagle Ford Shale) and nothing else or to a specific depth (no more than 8,000 feet). If this cannot be accomplished, limit the lease to 100 feet below the stratigraphic equivalent of the deepest producing formation at the end of the primary term or continuous drilling operations, whichever is later. Even better, limit it to 100 feet above and below the stratigraphic equivalent of the deepest producing formation. Finally, as a last resort, limit it to 100 feet below the deepest drilled depth.

Another variation would provide the horizontal severance applies _____ years after the end of the primary term.

Assignment Clause

Typically, leases contain a provision permitting both the lessor and the lessee to assign (convey) all or a part of their lease interests to a third party. To a large extent, these provisions favor the lessee.

Oil companies would like to lease large tracts and then assign (sell) all or a part of the tracts to another oil company for a profit and reserve an overriding royalty. Consequently, the ultimate developer-producer of the lease may not necessarily be the initial lessee. To retain some control over assignments, the mineral owner may wish to incorporate these suggestions.

- State that the lessee must notify the mineral owner of any assignment. A 1989 Texas appellate case upheld the validity of a clause providing for $1,000 liquidated damages if the lessee fails to notify the lessor of an assignment.
- Do not release the original lessee from liability for a default on any portion of the assigned lease. This is particularly important when surface damages and royalties remain unpaid after an assignment occurs.

Warranty Clause

Most leases contain a provision requiring lessors to warrant and defend their mineral interests (on behalf of the lessee) should a title dispute or failure arise. This is known as the warranty clause. When the mineral owner does not own all or a part of the minerals, the lessee has three options. The lessee may force the lessor to defend the title in court. Generally this does not happen. As an alternative, the lessee may demand and sue for the return of any consideration paid the lessor, such as bonus or royalties, which he or she was not entitled to receive. In addition to getting the consideration back, the lessee reduces future payments according to actual interest owned by the lessor.

In lieu of suing for a refund of bonus and royalties, the lessee may recoup the payments from the lessor's future share of production. For example, if the lessor owns half the minerals and purports to own them all, the oil company may seek the return of half the bonus and half the royalties either directly from the lessor or from the lessor's half of future production. The lessee will also reduce the future royalty payments to the lessor accordingly.

Under the lease terms, each lessor purports to own 100 percent of the minerals even though a cotenancy exists. For this reason, lessors may wish to stipulate that they are conveying (leasing) only the minerals they own in and under the tract and not 100 percent.

To avoid litigation, mineral owners should delete any language stating that they warrant or will defend title. Simply state that the lessee takes title to the lease at its own risk. Because most oil companies conduct title searches prior to leasing, this should not present a problem.

Avoid having to return any consideration received prior to a title failure by stating that the lessor faces no personal obligation for its return. Address whether the lessee is entitled to recoup the consideration from the lessor's share of future production.

Other Provisions for the Mineral Owner's Consideration

Without going into detail, these items may be considered by mineral owners when negotiating a lease.

- Insert provisions allowing free access to books, records and drilling data accumulated pursuant to operations conducted on the leased premises.
- More importantly, obtain copies of all title opinions and abstracts of title acquired by the lessee on the property. This bolsters the lessor's negotiating power with subsequent lessees by sharing these documents in return for favorable lease provisions.
- If possible, negotiate some provisions whereby the mineral owner may assume control of the casing when the lessee abandons a well. The casing could be used to extract fresh water for domestic or agricultural purposes. However, ascertain the quality and quantity of the water before making the request. According to the commission, the mineral owner must assume the cost and liability for plugging the well.
- Always include an indemnification clause. This clause requires the lessee to indemnify, save and hold the lessor harmless from all claims, demands and causes of actions stemming from activities undertaken by the lessee or lessee's assignees, employees, agents, contractors and subcontractors during operations conducted on the leased premises. Make sure the indemnification covers infractions of environmental laws. If possible, require the lessee to post bond, carry comprehensive liability insurance of a specified amount and make the lessor an additional insured under the policy.
- When negotiating the indemnification clause, make sure it states the lessee will ***defend***, indemnify, save and hold the lessor harmless. Without the word **defend,** the indemnification is valid but the lessor must hire the attorneys to defend the lawsuit and monitor the process. The lessee will indemnify the lessor for the costs but not the hassle. Avoid this by including the word **defend** in the indemnification provision.
- Before the oil company enters to conduct drilling operations, require them to provide a name and contact information for someone from the company who is authorized to address and correct any breach in the terms of your lease agreement. Many times lessors have concerns about the conduct of the drilling company but have no one to contact concerning the matter. If no contact person is provided, assess a daily penalty until the company complies.

Conclusion

Negotiating an oil and gas lease requires knowledge, skill, foresight and common sense. This report attempts to assist inexperienced mineral owners in all four categories.

Mineral owners may not be able to include all the suggestions contained in this report. Even so, the information alerts the lessor to what may occur when the suggestions are not included. For certain, the information should foster a frank discussion between the mineral owner and the lessee prior to signing any agreements.

This report is for information only and is not a substitute for legal counsel.

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MAYS BUSINESS SCHOOL

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

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