

CHECKLIST FOR NEGOTIATING AN OIL AND GAS LEASE

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This article is intended to provide practical advice for landowners in negotiating oil and gas leases of their mineral interests. It is not a comprehensive list of all possible issues that may arise in negotiating leases, nor is it a survey of the law concerning interpretation or enforcement of leases. Landowners are encouraged, where possible, to consult with attorneys familiar with oil and gas law. The summary below will be helpful to landowners in discussing with their legal counsel the issues important to them in negotiating leases of their land.

Oil and gas leases have been the staple of the oil and gas industry in the U.S. since the first well was completed at Titusville, Pennsylvania in 1859. The oil and gas lease is a unique form of legal transaction with its own peculiar language and rules, and its basic terms have developed over the years to serve the needs of landowners and the oil companies who want to exploit their mineral reserves. The legal relationship established by the oil and gas lease has been remarkably successful in allowing private industry to exploit our country's mineral wealth while preserving our heritage of private ownership of mineral rights.

The development of the basic oil and gas lease form has been influenced by appellate courts, particularly in Texas, who have construed particular lease terms in an attempt to carry out the intent of the parties. Court precedent has in turn resulted in further development of and changes in the lease forms. This evolutionary process continues today. While there is no "standard" lease form, all leases contain certain essential terms. It is important, therefore, to first understand these basic lease terms.

The Basic Lease Terms.

The essential terms of an oil and gas lease, and their function, must be understood if a landowner expects to negotiate a reasonable and fair lease. Those essential terms are as follows:

The Lease Term.

In Texas, the term "lease" is in some ways a misnomer. In fact, an oil and gas lease is a conveyance by the Lessor of the fee mineral estate to the Lessee, for a term. As long as the lease is in force, the Lessee is the owner of the minerals covered by the lease, and the Lessor is the owner of a royalty interest only. Therefore, it is important to

understand how the lease term functions in the typical oil and gas lease. A lease contains a *primary term* and a *secondary term*. The primary term is usually expressed as a fixed number of years or months. The secondary term is the time period after the primary term, when the lease is held in force by production from the lease. So a typical lease will provide that "This lease shall remain in force for a term of three years and for so long thereafter as oil, gas or other mineral is produced from the leased premises." No production or exploration is necessary to keep the lease in effect during its primary term. The length of the primary term is one of the main points to be negotiated between the Lessor and Lessee.

The royalty.

The Lessor of an oil and gas lease reserves a royalty interest in all production from the lease. It is called a royalty interest because it is paid to the Lessor without deduction for the costs of drilling or production. It is typically expressed as a fraction or a percentage. For many years, almost all oil and gas leases reserved a 1/8th royalty. Today, the royalty fraction is negotiable, and is usually between 1/8th and 1/4th.

Bonus.

The bonus is the amount paid to the Lessor as consideration for his/her execution of the lease. The amount of the bonus is almost never set forth in the lease itself. It is paid when the lease is signed by the Lessor and delivered to the Lessee. The bonus is based on the number of "net mineral acres" owned by the Lessor in the property being leased. "Net mineral acres" are the number of acres in the property times the interest in the minerals owned by the Lessor. For example, if the Lessor owns a 1/2 mineral interest in a tract of 100 acres, the Lessor owns 1/2 of 100, or 50 net mineral acres. The bonus is expressed as a number of dollars per net mineral acre. If the Lessee is offering a bonus of \$100/acre, the offer is to pay the Lessor \$100 for each net mineral acre owned by the Lessor.

Delay rental.

A lease may provide for the payment of "delay rental" during the primary term. The delay rental is paid at the end of each lease year during the primary term if no production has been established on the lease, in order to keep the lease in effect during the primary term. In most leases used today, the Lessee has no obligation to pay delay rental. The lease provides that, if there is no production at the end of any lease year during the primary term, then the lease will expire *unless* Lessee pays a delay rental prior to the end of that lease year. Delay rental is expressed in the lease as a number of dollars per acre. It is typically less than the bonus amount, and typically ranges from \$1/acre to \$50/acre. Remember that, if the Lessor owns less than all of the minerals in the leased premises, then the delay rental, like the bonus, will be paid only on the number of net mineral acres owned by the Lessor.

Today, almost all leases are "paid-up" leases -- that is, they provide for no delay rental during the primary term. If a lease is a "paid-up" lease, then the lease will remain

in effect during the entire primary term with no further payments to the Lessor unless and until actual production of oil or gas is established.

Shut-in royalty.

After the primary term, a lease will expire unless oil or gas is being produced. But in some circumstances a Lessee may not be able to immediately sell production after a well has been completed, usually because the well is located at some distance from a pipeline, and a gathering line or other facilities must be constructed to transport the production to a market for sale and/or to treat the oil or gas to make it marketable. As a result, all leases contain a "shut-in royalty clause," under which the Lessee may make payments to the Lessor in lieu of actual production from a well ("shut-in" well) that has been completed but is not yet producing. Leases usually provide that these payments are made on an annual basis, and again the amount is expressed in dollars per acre. The amount of shut-in royalty is typically in the same range as delay rentals. Shut-in royalties have less importance in today's environment because wells are rarely shut in and if so only for a brief period of time.

These basic lease terms – bonus, royalty, term, delay rental (if any) and shut-in royalty --are the "deal terms" negotiated between the Lessor and Lessee. The Lessor typically wants the highest bonus, delay rental and royalty fraction he or she can get, and the shortest primary term. The Lessee wants the opposite. What terms the Lessor can get are dependent on many variables, among which are:

How "prospective" for oil and gas exploration is the area where the property is located? If there is established production in the area, bonuses and royalties are likely to be higher. If the property is miles from the nearest production, terms will likely favor the Lessor.

Is more than one company competing for leases in the area? Competition breeds higher prices.

How many net mineral acres does the Lessor own? The more the Lessor has to lease, the more likely it is that he will get better lease terms.

How much risk is the Lessor willing to take? Unless the Lessor is willing to risk losing the opportunity to lease in negotiations, he may not receive the best possible lease terms. Some Lessors cannot afford to pass up the opportunity to receive a substantial cash bonus even if, by some bargaining, he might get a larger bonus or royalty.

What is the company's strategy? In areas without established production, a company may develop an idea – a "prospect" – from geological information; the company desires to test that idea by drilling one or more exploratory wells. In order to do that, the company must first acquire oil and gas leases in the area. The company may use its own in-house staff to acquire those leases or it may

hire independent landmen who, for a fee, locate the mineral owners in the area and make lease offers on behalf of the company. The company may establish the basic lease terms it is willing to offer, and the landmen soliciting leases will be limited to those terms. For example, the company may instruct the landmen that all offers are to be for a three-year paid-up lease, with a royalty of 1/6th and a bonus of \$100/acre. Often the landmen are also given some lee-way to negotiate. The same company might instruct the landmen to offer \$100 and 1/6th, but authorize them to go up to \$150 and 1/5th. The company and its landmen will then see how many leases they can acquire using these lease terms. Any landowner unwilling to accept those terms will, at least for the first leasing effort, be passed by. Depending on what success the company has in its first leasing efforts, the company may then go back to some landowners in its area of interest and negotiate again, this time offering better terms. Or the company may decide that it has acquired enough leases to allow it to test its prospect and will not engage in further leasing activity unless and until it has drilled its exploratory well. If its prospect proves successful, it may then seek to acquire additional leases in the area, including those it could not lease in its first efforts. The more the landowner can learn about the company's strategy, the better the landowner can gauge his own strategy for negotiation of the best possible lease terms.

Finally, all leasing activity, like politics, is essentially local. That is to say, lease terms, particularly bonus amounts, may be higher in one area of the state than another for no apparent reason – simply because they are different areas of the state, and landowners in that area have come to expect a certain level of bonus payments in order to lease their land. The more a landowner can learn about what other owners are receiving for their leases in the same area, the more likely he is to receive top dollar for his lease.

Lease Forms

Most oil and gas lease forms have been developed by the oil and gas companies who want to lease minerals. Landowners should therefore understand that all lease forms offered by oil companies are drafted to protect the interests of the Lessee. In Texas, by far the most widely used lease forms for many years were published by Pound Printing & Stationery Company of Houston. Pound began printing lease forms at least as early as 1950, and it publishes up-dated forms every few years in response to comments and criticisms from oil companies. More recently, many larger independent exploration companies have developed their own lease forms. Many of these forms show at the top of the first page the words "Producers 88." Many years ago, landowners came to believe that, if they got a "Producers 88" lease, they would be protected and would get the best available lease terms for landowners. In fact, there is not one "Producers 88" lease form, and the forms named "Producers 88" were not drafted with the landowners' interest in mind.

Bank trust departments, in leasing lands they hold in trust for their clients, have also begun to develop their own lease forms, which are drafted with the interests of the

Lessor in mind. One association of mineral owners, the Texas Land and Mineral Owners' Association, has developed its own lease form for its members' use.

Landowners and the lawyers who represent them, without the benefit of a landowner-oriented lease form, have typically sought to offset the one-sidedness of industry lease forms by adding "riders" or "addendums" to the lease. These "riders" are lease provisions that are added as an exhibit to the lease form, and are intended to "override" any contrary provision in the printed lease form. Certain "standard riders" have come to be accepted by oil companies, and in fact many landmen will submit the company's lease form with certain riders already added. (A "Pugh clause," discussed below, is an example of a generally accepted rider provision.)

Oil companies differ in their willingness to accept lease forms different from their own and in their willingness to negotiate changes in their lease forms. As with the basic lease terms, the willingness of companies to negotiate other lease terms is heavily dependent on the negotiation factors listed above. The checklist given below is intended to provide landowners with a list of some, but not all, of the lease terms – those beyond the "deal" terms – that may be subject to negotiation, and to assist landowners in gauging the importance of those terms in obtaining the best possible lease of their mineral interest under their particular circumstances. One caution is in order: no checklist can cover all possible circumstances. Like all contract negotiations, each lease negotiation involves particular facts and unique personalities that cannot be covered by a single checklist. If possible, seek the assistance of legal counsel who is experienced in such negotiations.

Here, then, are some factors to consider an any lease negotiation:

A Checklist for Negotiating an Oil and Gas Lease

1. *Check out the Lessee.*

An oil and gas lease establishes a contractual relationship between the Lessor and Lessee that may last for many years. While the bonus and royalty are important issues to the landowner, the financial resources, reputation and experience of the Lessee are also important factors for the landowner to consider.

Some leases are acquired in the name of landmen or agents for the true Lessee. Insist on knowing the identity of the company acquiring the lease, and insist that the ultimate Lessee be the named Lessee in the lease. Inquire about the experience of the company in the area. Learn to use the Texas Railroad Commission website to investigate operator history.¹ Ask other landowners who have dealt with the company about their experience with the company. If the company is small and/or owned by one person, consider asking the principal for a guaranty of the lease.²

¹ <http://webapps.rrc.state.tx.us/>

² Another valuable resource for investigating the Lessee, and drilling and producing activity in the area of a proposed lease, is www.drillinginfo.com. This website compiles information from the Texas Railroad Commission

2. Agree on Deal Terms First.

Reach agreement on the "deal" terms – bonus, primary term, royalty fraction, delay rental (if any) and shut-in royalty --before negotiating the form of lease. Additional "deal" terms may include:

- granting the Lessee an option to extend the lease primary term for an agreed additional payment by the Lessee.

- a commitment from the Lessee to drill a well during the primary term, or else pay an agreed amount as liquidated damages.

- a promise to pool lands into a unit for a well to be drilled.

- an increased royalty after "payout" of a well.

- a minimum annual royalty.

The oil company is more likely to be flexible in negotiating the form of lease if the parties have agreed on the deal terms first.

3. The Lease Form.

Once "deal terms" are agreed, decide whose lease form to start with in negotiations. If possible, use your attorney's form or the TLMA form as the beginning of negotiations. The TLMA form addresses many of the issues described in this checklist.³ If the company insists on using its form, then the landowner will be negotiating the terms of the "riders" that will be added to that form.

4. Negotiate.

Remember: all lease terms are negotiable. The landman acquiring the lease may not have authority to negotiate those terms, but someone does. Don't be timid.

5. Description of Leased Premises

Be sure there is a complete legal description. If there is more than one non-contiguous tract to be leased, negotiate a separate lease for each tract.

Delete the "mother hubbard" clause in printed forms following the lease description ("This lease also covers any lands of Lessor adjacent or contiguous to the above-described lands")

(and regulatory commissions of other states), as well as county real property records of leasing activity, into a single interactive database. Drillinginfo (recently renamed Enverus) is a fee-based subscriber database. Most bank trust departments now make extensive use of this database.

³ See www.tlma.org.

6. Limit the lease to oil and gas.

Most printed form leases cover "oil, gas and other minerals." Limit the lease to petroleum and natural gas and related hydrocarbons produced in association with oil and gas.

7. The Royalty Clause

From the Lessor's point of view, the most important provision in the lease is the royalty clause. If the Lessee is successful in discovering oil or gas, how and when the Lessor's royalty is calculated and paid will be the principal issue in the lease for as long as it remains in effect. The following issues should be addressed in the royalty clause:

-- Post-Production Costs

Royalties are typically calculated based on the price received by the Lessee from its sale of the oil or gas produced. As a royalty, the payments are made without deductions for the cost of drilling or operation of the wells. The Lessee, however, may incur additional costs after production – called "post-production costs" – that may or may not be deducted from royalties, depending on the lease terms. For example, the gas may need to be transported to a remote interconnect with a pipeline, for which the Lessee incurs transportation and compression costs. Some oil and gas must be treated before sale. Post-production costs can be significant. The deductibility of post-production costs is therefore an issue that has been subject to constant litigation between Lessors and Lessees and should be addressed in the lease.

Most lease forms used by oil companies provide that royalties are to be based on the "proceeds" or "revenue" received by the Lessee, "computed at the mouth of the well." Texas courts have construed this language to mean that companies can deduct post-production costs from Lessor's royalty, because those costs are incurred beyond the "mouth of the well" – that is, after the oil or gas is produced. If the company's lease form is used, this provision must be changed to avoid post-production-cost charges to the royalty owner. In order to change this allocation of costs the lease must provide that royalties should be based on the value or proceeds calculated *at the point of sale*.

-- Affiliate Sales

Basing royalties on the Lessee's proceeds of sale of production is a fair way to value royalties *except* when the Lessee and the purchaser of production are affiliated entities. If the sale of production is between related companies, then there can be no assurance that the Lessee is receiving fair market value for its production. The lease therefore should address how to value production where there is no arms-length sale. There is no standard way to address this problem. The alternative measure of value for payment of royalty can be comparable prices of oil or gas in the vicinity, or an agreed published spot price, or any other method the parties can agree on.

-- Processing Costs

One category of post-production costs deserves special attention – gas processing costs. Natural gas, when produced, often contains several different kinds of gas. The gas burned by consumers in their homes is methane, or CH₄, the simplest form of hydrocarbon. Natural gas as produced may also contain significant quantities of ethane, propane, butane, and other hydrocarbon compounds that are gases at atmospheric temperatures and pressures. These other gases are sometimes called "heavier" hydrocarbons, because their molecular weight is greater than methane, or (misleadingly) "natural gas liquids" or "liquefiable hydrocarbons," because (unlike methane) they can be economically compressed into a gas for transportation and sale. These heavier gases have a higher heating value than methane – they produce more heat per unit of volume than methane – and therefore have a greater value per cubic foot than methane. Also, if natural gas in its produced state has significant quantities of these heavier gases, they must be removed from the gas before the methane will be accepted by a purchaser for transportation in its pipeline system, because these heavier gases may condense into their liquid form in the pipeline and cause mechanical or other problems. The process by which these heavier gases are removed from the produced gas is called natural gas processing. This processing is done in natural gas processing plants, usually located in or near the field where the gas is produced.

There are many different ways in which a company producing natural gas can arrange for its gas to be processed. Some companies construct and operate their own processing plants. Other companies contract with companies who own the processing plant. Often the plant is owned by a company that also gathers the gas from the field and transports it to a point of sale at the outlet of the processing plant. Sometimes the producer sells the gas in its unprocessed state to a gathering company which then owns the gas and processes it in its plant for its own account.

If the company that is the gas producer retains the gas and processes it, or contracts with another company to process the gas before sale, it is important to address in the oil and gas lease how royalties will be calculated on the gas and natural gas liquid products resulting from the processing. The lease must address (1) whether the Lessor receives royalties on the natural gas liquid products, and (2) what (if any) costs of processing are borne by the royalty owner. Gas processing, whether done in a plant owned by the Lessee or in a plant owned by a third party processor, is an expensive endeavor. It is almost always economical, even taking into account these processing costs, because the value of the methane and separate heavier gases, less the processing costs, will be greater than the value of the natural gas in its native state at the mouth of the well. The most common way of paying royalties on processed gas, therefore, is to calculate the royalty on the net proceeds received by the producer from the sale of the methane (the "residue gas") and the heavier gases extracted from the natural gas stream. Once again, the issue is what costs can be deducted from these proceeds in calculating the Lessor's royalty. And once again, if the natural gas processing plant is owned by the Lessee or by an affiliated company, issues arise as to how to fairly calculate the costs that are being deducted from the Lessor's royalty.

-- Due Dates of Royalty; Remedies for Default

Most royalty owners would be surprised to know that, under the typical oil and gas lease form, the Lessor may not terminate the lease as a remedy for Lessee's failure to pay royalties. Unless the lease expressly provides that the Lessor may terminate the lease if royalties are not paid, the Lessor's sole remedy is a suit to recover the royalties due.

A lease should state (a) when royalties are due, (b) that an agreed rate of interest will be paid on late payments, and (c) that, if royalties are not paid when due, the Lessor may terminate the lease after giving notice to the Lessee and an opportunity to cure the default.

It is also a good idea to include a provision granting the Lessor a security interest in the Lessee's share of production to secure the payment of royalty. This provision has two benefits to the Lessor: first, if the Lessee is not paying royalties timely, the Lessor may contact the purchaser of production directly, assert his security interest, and insist on being paid directly by the purchaser. Second, if the Lessee enters bankruptcy, the Lessor's security interest in production will make the Lessor a secured creditor for the unpaid royalties, assuring that the royalty will be paid before the Lessee's unsecured creditors.

-- Minimum Royalties

One problem often encountered by landowners is how to deal with a lease that is near the end of its life and is only marginally productive. This is especially a problem when the Lessor is also the owner of the surface estate and the Lessee's surface operations significantly detract from the value of the land. In order to keep the lease in force, the Lessee's production must be in "paying quantities," defined as production sufficient, after royalties, to pay the Lessee's cost of operating the well. It is often difficult to prove that a well is not producing in paying quantities, even if its rate of production is very low.

One possible solution to this problem is to include a minimum royalty provision in the lease. Such a provision states that the royalties paid to the Lessor under the lease for any one-year period, once production is established, will never be less than an agreed amount, usually expressed as a number of dollars per acre. At the end of each year after production is established, the total royalties paid during that year are added up, and if the amount is less than an agreed minimum amount then the Lessee must pay the difference as "minimum royalties." If the minimum royalty is set high enough, it gives the Lessee an economic incentive to plug a marginal well, since the minimum royalty will increase its cost of operation. For example: suppose that the Lessee has one producing oil well on a 100-acre lease, providing for a 1/5th royalty, and that well produces an average of ten barrels per month. At \$50 per barrel, the Lessee's revenue after royalties is \$400 per month, and the royalties are \$100 per month. If the lease

provides for a minimum royalty of \$50 per acre per year, then the minimum royalty is \$5000 per year. At the end of the year, the Lessee would owe a minimum royalty payment of \$5000 less \$1200, or \$3800. The Lessee's revenue, before operating costs, would then be \$4800 less \$3800, or \$1000. As the production continues to decline, the lease will become uneconomical to the Lessee sooner than it would without the minimum royalty, giving the Lessee an incentive to plug the marginal well sooner.

8. Define "Operations."

After the end of the primary term of a lease, the lease is held in effect only if there is production from the leased premises. But what if, at the end of the primary term, the Lessee is drilling a well? Or what if, after the end of the primary term, production from a well ceases? All leases address this problem by including provisions allowing the Lessee to maintain the lease after the end of the primary term by conducting "operations" on the lease. Sometimes that term is defined, but more often it is not. This leads to confusion and controversy. The lease should make clear what operations will maintain the lease in force. It should define "drilling operations" and "re-working operations." From the Lessor's point of view, drilling operations should not include having a bulldozer making a pad for the well location on the property, but should be limited to the actual drilling of the well with a rig capable of drilling to the permitted depth. Re-working operations should not include working on a compressor or a broken water line, but should be defined as actual work in the hole of a well in a good-faith effort to restore that well to production.

9. Pooling and Pugh Clauses

Pooling is a topic too complex to fully address in this chapter. Every oil company lease form will contain a pooling clause, and the rights granted to the Lessee by that clause can significantly affect the economic and other rights of the Lessor under the lease. Every Lessor should therefore understand the concept of pooling.

The basic idea behind pooling is a good one, and its use can benefit both parties to the lease. In all states, laws and regulations have been adopted governing the spacing of wells – how many wells can be drilled in a field and how far apart they must be from each other and from the lease line on which the well is located. These regulations have been developed to prevent the drilling of unnecessary wells and to maximize the ultimate recovery of oil and gas from a field. The spacing rules -- often called "field rules" -- may differ from field to field, depending on whether the field produces gas or oil and on the geological characteristics of the reservoir. In Texas, the Texas Railroad Commission's spacing rules require an oil company to have a minimum number of acres under lease and assigned to a well in order for the Commission to grant a permit to drill the well. The acreage assigned to the well is called a "proration unit." For most oil fields, the proration unit size is 40 acres. For gas wells, the proration unit size can range from 40 acres to 640 acres, depending on the field rules for that field.

Where mineral ownership is divided into small tracts, it may not be possible for a Lessee to obtain a permit to drill a well unless it can somehow combine the small tracts into a larger tract for purposes of assigning a proration unit to the well. For example, if the proration unit size in a field is 160 acres but all of the tracts in the field are 40 acres or less, then the Lessee must combine several tracts into a single unit in order to drill a well. Also, the tract boundaries in a field may not fit the spacing pattern for a field. The best location to drill a well may be exactly on the boundary between two tracts. In such a case, the best solution is to combine all or parts of the two adjacent tracts to form a single unit. This combining of acreage is called pooling, and the units so created are called pooled units.⁴

A lease pooling clause allows the Lessee to put all or parts of the leased premises into pooled units with other adjacent properties. The economic effect on the Lessor is that all Lessors of all of the leases included in the pooled unit will share in production from the pooled unit in proportion to the number of acres each lease contributes to the unit. For example, if the Lessee combines 60 acres from Lease A and 100 acres from Lease B to form a pooled unit, and if the royalty in Lease A is 1/5th and the royalty on Lease B is 1/4th, then:

Royalty Owner A will receive a royalty on unit production of 1/5th of 60/160, or 7.5%, and

Royalty Owner B will receive a royalty on unit production of 1/4th of 100/160, or 15.625%, and

The Lessee's share of production will be 100% minus 7.5% minus 15.625%, or 76.875%.

The idea is that each royalty owner whose lease participates in the pooled unit will receive a fair share of royalties on production from the well, because the well will drain oil or gas from all of the tracts included in the pooled unit.

Problems arise in pooling where the interests of the Lessor and Lessee do not coincide. For example, most lease clauses allow the Lessee to form pooled units for gas wells of up to 704 acres. If the wells in the field are only capable of draining 80 acres, then a well on a 704-acre pooled unit will not fairly allocate royalties among the tracts included in the pooled unit. But the Lessee has an incentive to create larger units, because production from the unit well will serve to keep all of the leases included in the unit in effect beyond their primary terms. So the Lessee's incentive is to form units as large as possible, even though such units may not be in the Lessors' best interest. In considering drafting issues related to pooling clauses, this inherent conflict of interest should be kept in mind.

-- Is a pooling clause necessary?

⁴ Remember that "proration units" and "pooled units" are two different things. Proration units are creatures of governmental regulation. Pooled units are what is created by a Lessee pursuant to the authority granted in a pooling clause.

The first question a landowner should ask in negotiating a lease is whether a pooling clause is necessary at all. If the leased premises will be 5,000 acres then there is no need to pool with other lands in order to develop wells on the property, and the pooling clause should be deleted. If the leased premises contain 80 acres, it may be appropriate to give the Lessee authority to pool for gas wells but not for oil wells.

One alternative is to leave the pooling clause in the lease but provide that the Lessor's consent must be obtained to create a pooled unit. In that way, the Lessor can have the opportunity to judge the fairness of each pooled unit on its own merits.

Pooling clauses should also be seen from the Lessee's point of view. A company may have to assemble hundreds of leases from owners of multiple tracts with multiple mineral interest owners in order to assemble a drillable prospect. It may not be reasonable to expect the company to obtain consent from all of those royalty owners every time it wants to form a pooled unit. The law implies an obligation on the Lessee to form pooled units in good faith, taking into account the interests of both parties. In most cases, pooled units benefit all parties by allowing for an efficient development of the mineral resource.

-- The "Pugh" Clause

A pooling clause has a consequence that many Lessors may not realize. Suppose that a lease covers 320 acres, and that the Lessee exercises its right under the lease to create a pooled unit containing 20 acres of the leased premises and 620 acres of an adjacent tract. So 20/620ths of production from the unit will be allocated to the 320-acre lease for royalty purposes. The pooling clause provides that production from a pooled unit will be considered production from the leased premises for purposes of maintaining the lease in effect beyond its primary term. So inclusion of 20 acres of the 320-acre lease has the effect of keeping the lease in effect beyond its primary term as to the entire 320-acre tract, even though only 20 acres of the tract was included in the pooled unit.

In order to avoid this result, the Lessor commonly insists on inclusion of a "Pugh clause." This clause provides that production from a pooled unit in which less than all of the leased premises is included will maintain the lease beyond its primary term only as to the part of the leased premises included in the pooled unit. In the example given above, if the lease contained a Pugh clause then the lease would expire at the end of its primary term as to all of the 320 acres except for the 20 acres included in the pooled unit, unless the Lessee established production from the non-pooled acreage.

-- Other Restrictions on Pooling

Depending on the circumstances, the Lessor may want to negotiate other restrictions on pooling. For example, if the lease contains 40 acres, consider requiring that all of the leased premises must be included in any pooled unit. Consider restrictions on the size of the pooled unit depending on the depth or field in which the

well is completed. If all of the wells in the area are producing from a field in which the proration unit size is 160 acres, why grant the Lessee the right to create 640-acre units for gas wells? Effective negotiation of pooling restrictions requires a knowledge of the spacing rules in effect in the area of the leased premises.

-- Allocation Wells

A recent phenomenon in Texas has caused much discussion among oil and gas practitioners - the drilling of wells that have come to be known as "allocation wells." The term refers to a horizontal well that is drilled across two or more separately leased tracts *without pooling those tracts*, or a well drilled across two or more existing pooled units. Sometimes the operator of the well will ask the royalty owners in the tracts crossed by the well to sign an agreement on how production from the well will be allocated among the tracts crossed by the well - usually called a Production Allocation Agreement or Production Sharing Agreement. But some operators will drill an allocation well without getting agreement from the royalty owners affected by the well, and will simply propose a division of royalties among the tracts by sending a division order after the well has started producing.

There are many unknown questions about allocation wells, including the very basic issue of whether an oil and gas lease authorizes the drilling of such a well. To avoid such controversies, an oil and gas lease can clearly provide that no allocation well may be drilled on the lease without the consent of the Lessor. The State of Texas has recently added such a provision to its Relinquishment Act lease form, and the current version of the TLMA lease form has such a provision.

11. Retained Acreage Clauses

For leases covering tracts of significant size, landowners have developed more sophisticated versions of Pugh clauses, usually referred to as "continuous operations" or "continuous development" or "retained acreage" clauses. The idea behind such a clause is that the Lessee, after having a reasonable time to explore and develop the leased premises, should be entitled to retain under lease only those parts of the leased premises necessary for its production of wells on the leased premises.

The importance of these provisions depends largely on the size of the tract being leased. If the tract is relatively small (less than 200 acres), such a provision is probably not necessary. For larger tracts, a continuous operations clause requires the Lessee to release portions of the leased premises not included within "production units" designated around producing wells, at some time after the end of the primary term. If the Lessee is engaged in drilling operations at the end of the primary term, the time when Lessee must designate production units is postponed for as long as the Lessee continues to drill wells on the leased premises. The continuous operations clause usually provides that, in order for the Lessee to postpone the time for designating production units, it must drill wells consecutively with no more than an agreed number of days (90 to 180) between the completion of one well and the commencement of the next well. Once the Lessee has designated production units around each producing

well and released all lands not within a production unit, each production unit stands on its own as a separate lease, and production from each well holds under lease only that part of the leased premises within its production unit. A continuous operations clause should specify maximum production unit sizes, depending on the classification of the well as oil or gas and the depth of the well. It should also address how production units can be configured (*e.g.*, as nearly in the form of a rectangle as possible, whose length is no more than twice its width).

Production units for horizontal wells should depend on the length of the productive lateral of the well. The longer the lateral, the more acreage can be retained around the well. This is an important term to negotiate in leases within areas where horizontal wells will be drilled.

Leases sometimes provide that the amount of retained acreage around a well will be based on the acreage assigned or permitted to be assigned to the well under applicable Texas Railroad Commission rules for proration purposes. Railroad Commission field rules and proration units are beyond the scope of this paper, but it is better for the Lessor if the lease does not relate the size of retained acreage to Railroad Commission regulations. Those regulations are promulgated by exploration companies and are subject to revision, and have little or no relation to how much acreage can be drained by a well in the field.

In some shale plays, particularly in the Permian Basin, operators have begun to drill multiple horizontal wells at different depths within the same formation, stacking wells on top of each other or creating a "wine-rack" drilling program. Retained acreage clauses may need to change to accommodate those different drilling patterns. Lawyers are experimenting with retained acreage clauses that do away with the "production unit" method altogether and base the amount of acreage earned by drilling horizontal wells depend on the number of feet of productive lateral drilled.

12. Depth Severance

Regardless of the number of acres leased, it is a good idea to require that the Lessee release depths below (or above and below) the depth at which its wells are producing on the leased premises at some point during the life of the lease. Leases often provide that the Lessee must release these "deep rights" one or two years after the end of the primary term. Such a lease clause is sometimes called a "depth severance clause." If the lease contains a continuous development provision, then this depth severance may be different for each production unit designated by the Lessee. The clause should carefully define the depth below which the lease will be released. The Lessee will want to retain the deepest depths possible, and will suggest that it be entitled to retain all depths down to the depth of the deepest depth drilled in any well on the lease. The depth most favorable to the Lessor will be based on the deepest perforation in the well from which it is then producing. Other alternatives are to use the deepest depth to which production casing is set in the well or the base of the producing formation.

13. Assignment

Almost all leases submitted by companies will provide that the rights of the Lessee in the lease may be assigned at any time. Landowners are often surprised to learn when a drilling rig shows up to drill a well on their property that their lease has been sold to another company without their knowledge or consent. Oil and gas leases are an exploration company's principal asset and are bought and sold, often many times during the life of a lease, as companies change the focus of their exploration activities. Some Lessees have no intent of ever drilling wells, but acquire leases solely for the purpose of selling those leases to exploration companies. Undivided interests in leases are also assigned to other persons or entities who have agreed to bear a portion of the costs of drilling a well on the lease in exchange for a share of the well's revenue. Before a well is drilled, there may have been many sales of the lease, and there may be many investors who have acquired small undivided interests in the lease. All of these assignments may be made without the knowledge or consent of the landowner.

Most oil company leases also provide that, once the Lessee has sold the lease, it has no liability for any further obligations under the lease that arise after the date of the assignment. This also can be a problem for the landowner. If, for example, the landowner has leased to a major independent oil company which has drilled and completed a well, and if that company subsequently sells the lease to Fly-by-Night Oil Company who promptly spills salt water all over the lease, the original Lessee will have no liability for the damages caused to the land and the landowner may be faced with trying to collect damages from an insolvent Lessee.

There are several ways to approach the problems caused by assignments of the lease. One alternative is to provide that the lease may not be assigned without the Lessor's consent. Because assignability is an important attribute of the lease to most Lessees, it may be difficult to get the Lessee to agree, except for leases covering significant acreage.

Another alternative is for the lease to provide that, notwithstanding any assignment by the Lessee, the original Lessee remains liable for all obligations and liabilities under the lease. This assures the landowner that, if the Lessee decides to sell its lease, it will take some care to assign to financially responsible companies. If problems with the lease arise, the landowner can call on the original Lessee to fix the problem.

Another possible solution is to allow the Lessee to assign undivided interests in the lease to other investor parties provided that the original Lessee retains a specified percentage interest in the lease and remains the operator of all wells drilled on the lease.

In any event, the lease should require the Lessee to provide to Lessor copies of all assignments of the lease to third parties. This provision is difficult to enforce, but at least gives the landowner some ability to keep track of who owns an interest in his land.

14. Delete the warranty of title.

All company leases provide that the Lessor warrants his title to the minerals being leased. This clause should always be deleted. In practice, oil companies never rely on the landowner's representation of his mineral ownership, but conduct their own investigation of the mineral title. If the Lessor gives no warranty of title, then there is no risk that he will have to return any bonus paid for the lease in the event that his title fails.

15. Limit the effect of the force majeure clause.

All leases contain what is called a "force majeure" clause. The clause is intended to relieve the Lessee of the obligation to continue producing if production is halted by a "force majeure" event – an event beyond the Lessee's control, such as flood, fire, war, strikes, or "acts of God." The problem with these clauses is their indefinite nature. It may be difficult to discern whether a four-inch rain is a "flood," or whether inability to acquire the services of a workover rig is a force majeure event. The types of events that can be described as "force majeure" should be limited as much as possible. Also, the effect of a force majeure event on the duration of the primary term should be addressed. To illustrate, suppose that in the last year of the primary term there is a hurricane on the coast and the leased premises become flooded. The land dries out before the end of the primary term, but the Lessee claims that the flood caused him delay in his efforts to drill a well, so that the primary term should be extended by the period of time the flood prevented him from drilling a well. To avoid this confusion, the force majeure clause should put a limit on the number of days that the primary term can be extended by a force majeure event. Also, the clause should require the Lessee to notify the Lessor whenever the Lessee claims that its operations have been delayed by a force majeure event, specifying the event causing the delay.

16. Provide a broad indemnity clause that satisfies the "express negligence" rule.

The purpose of an indemnity clause is to provide that one party will indemnify the other against certain claims made by third parties. It is a provision allocating risk by contract in a way different from the way the liability would be allocated absent the contract. Because the Lessor of an oil and gas lease has no control over the Lessee's activities on the property and has no expertise in oil and gas operations, it makes sense that the Lessee should agree to indemnify the Lessor against claims of third parties arising out of activities of the Lessee on the property. If a third party harmed by the Lessee's operations makes a claim against the Lessor, then under such an indemnity clause the Lessee should be required to pay any damages from such harm.

Courts do not look favorably on indemnity clauses, and such clauses are "strictly construed." Courts have adopted a rule, called the "express negligence doctrine," used to construe indemnity clauses. That rule provides that no indemnity clause will be construed to indemnify a party against the result of his own negligence or misconduct unless the clause expressly so provides, in typeface that is larger or more prominent than the balance of the agreement. The idea is that a party agreeing to indemnify

another must be made expressly aware that the indemnitee (the party being indemnified) intends that the indemnity will protect him even if his negligence caused the harm. If an indemnity clause does not satisfy this express negligence doctrine, then it has little value, because it will not be construed to shift the risk of liability from the indemnified party to the indemnifying party.

So a well drafted indemnity clause should be crafted to satisfy the express negligence doctrine. It should say that the Lessee agrees to defend and indemnify the Lessor against all claims arising out of Lessee's activities on the leased premises, **INCLUDING CLAIMS ALLEGING THAT THE LESSOR IS GUILTY OF NEGLIGENCE OR OTHER MISCONDUCT.**

16. *Address the use of division orders.*

A division order is another instrument that, like the oil and gas lease, is unique to the oil industry. Once production from a lease has been established, the Lessee must determine who is entitled to payments from proceeds of production. Typically the Lessee will hire a title attorney to examine the mineral title for the leased premises and provide a "division order title opinion," giving his legal opinion as to the ownership of royalties under the lease and how they should be paid. Based on this opinion, the company will then prepare and send to those royalty owners a division order. The division order describes the property, lists the decimal interest in production owned by the royalty owner according to the title opinion, and provides that the royalty owner agrees that this is his correct interest and that the company is authorized to make payments to him of that interest until notified otherwise by the royalty owner. The division order serves a legitimate purpose in obtaining the royalty owner's agreement that his decimal interest is correct and that the royalty owner will notify the company of any future changes in ownership of the royalty owner's interest.

Division orders have created much controversy, at least in Texas, because oil companies tried to use them for purposes not originally intended. Many division orders, in addition to setting forth the royalty owner's interest, contained language specifying how royalties were to be valued and calculated, and those provisions were often contrary to the provisions agreed to in the lease. In effect, companies were trying to use division orders as a means to amend the lease royalty clause. This controversy led to legislation in Texas (and in other states), specifying what language division orders can contain, and how they are to be used. The Texas division order statute is Texas Natural Resources Code §§ 91.401-408. The statute provides that companies are entitled to require royalty owners to sign a division order as a condition to payment of royalties, provided that the division order contains only certain provisions. This has led to the use by most companies of what is known as the "statutory form" division order. But the statute itself is not without its problems, and the statutory form of division order could be construed in some instances to modify certain terms of the oil and gas lease.

The oil and gas lease should provide that the Lessee may not require execution of a division order as a condition for payment of royalties, and that no division order signed by the Lessor will be construed to modify the terms of the lease.

17. Protection of Surface

If the Lessor owns no interest in the surface estate of the leased premises but only a mineral interest, then the oil and gas lease need not address issues of concern to the surface owner. But if the Lessor also owns the surface estate, the lease should address any concerns the Lessor may have about the Lessee's use of the surface. These provisions will vary greatly with the type of land involved and its current and prospective uses, so it is not possible to point out all of the possible issues to be addressed regarding the Lessee's surface use. Some general observations can be made:

-- Remember that, unless the lease expressly so provides, the Lessee has no obligation to compensate the surface owner for reasonable and necessary use of the surface estate to explore for and produce the minerals. As a matter of practice, most oil companies will pay some negotiated damage amounts to the surface owner for well locations and other surface uses. In return, the companies try to get the surface owner to sign a release, and the release may relieve the oil company from liability for damages that go beyond those reasonable and necessary for the development of the leased premises. It is better to specifically address these issues in the lease itself. Provide that surface owner will be compensated for all uses of and damages to the surface estate for all operations by Lessee.

-- Consider providing agreed amounts of damage payments for specific uses of the surface estate: agreed amounts for well locations, roads, pipeline easements, tank batteries, etc. If those amounts are agreed in advance, provide for escalation of the agreed amounts to account for inflation.

-- If the lease covers a small tract, the Lessee may be willing to waive the right to use the surface altogether if the Lessee knows that the tract will be put in a pooled unit and the well location will not be on the tract.

-- Are there portions of the leased premises that the landowner wants to exclude from Lessee's surface use? If there is a residence on the property, how close can a well be to that residence? Are there water wells on the property? Are there environmentally sensitive areas, such as springs, creeks, lakes or ponds?

-- If the property is farm land subject to a farming lease, how will the tenant be compensated for the mineral Lessee's surface use? The Lessee would prefer to reach one agreement with the landowner and require the landowner to share any surface damage payments with his tenant. If the landowner wants the Lessee to settle separately with the surface tenant for damages to crops or other tenant improvements, the lease should so provide. If some of the farmland is taken out of cultivation as a result of a completed well, some governmental price support payments, such as Conservation Reserve Program or "CRP" payments may be lost. Should the Lessee be required to compensate the landowner or his tenant for loss of those payments?

-- How will the Lessee obtain access to the property? Does the landowner have a preferred route of ingress and egress he wants the Lessee to use? Will the Lessee have to go through gates, and are they kept locked? Will the Lessee have to make new gates through fences, and if so, what kind of gate should the Lessee install, and should that gate be removed when the lease expires?

-- What rights will the Lessee have to use water on the property? Absent other agreement, the mineral Lessee has the right to use fresh water from wells, tanks or lakes on the property in Lessee's operations. If subsurface water is present, the Lessee will generally drill its own water well for use in drilling operations. Should the Lessee turn this well over to the landowner at the conclusion of drilling operations? In the Barnett Shale field in Texas, huge quantities of fresh water are used in fracture stimulation of the wells. What source of water will the Lessee use for such fracture treatment? Can the Lessee use fresh water for secondary recovery operations?

-- The Lessee has an implied right to drill salt water disposal wells on the lease to dispose of salt water produced from wells located on the leased premises. Should the lease limit or prohibit the Lessee from salt water disposal on the property?

-- In addition to the well location itself, the Lessee will have to construct a road to the location for the drilling operation and, if the well is completed, for subsequent well servicing activities. The lease should require the Lessee to consult with the landowner as to the best location for these lease roads and what material the road should be made of. If existing roads are used by the Lessee, the Lessee should be required to repair any damage to those roads caused by its drilling and other equipment and to maintain those roads as long as Lessee uses them.

-- Leases also grant the Lessee the right to conduct geophysical testing on the leased premises. A more complete discussion of geophysical testing is below, but here it should be noted that such testing activities may involve clearing of trees and brush, the drilling of shallow holes, and setting off small explosive charges in those holes. If structures, wells or other improvements on the surface might be disturbed or endangered by those activities, the lease should address the landowner's issues with such activities.

-- Much of the friction between landowners and mineral Lessees arises out of the behavior of the Lessee's employees that do not cause great damage but are a constant irritant – leaving gates open, leaving trash around the wells, carrying firearms on the property, driving recklessly. Mineral leases covering some large ranches include "ranch rules" that anyone present on the property must follow, including speed limits, staying on designated roads, no drinking, hunting or fishing, picking up trash, etc. Whatever rules the Lessee and its employees must follow, it is difficult for the landowner to enforce those rules because their violation causes little monetary damage. If appropriate, the landowner should consider including a lease provision allowing the landowner to exclude from the premises any employee found violating these rules. The landowner also might require any employee of the Lessee present on the leased premises to carry identification showing that he is authorized by the Lessee to be

present on the lease. Also, consider providing for an agreed amount to be paid to the landowner as liquidated damages for violations of particular covenants, such as failure to close a gate.

-- The rights granted to the Lessee include the right to lay pipelines to gather and transport oil and gas from the leased premises. Lines also may be needed to handle salt water produced from wells. Consider whether there should be agreements in advance concerning the locations of such lines. If the landowner wants the pipelines to be buried, provide the depth to which they should be buried, and provide that the Lessee must "double-ditch" all pipelines and restore and maintain the pipeline right of way. Consider whether a survey should be required for any buried pipeline so that the landowner will have a way to locate the line years later. If the landowner wants to require that pipelines be removed when the line is abandoned, the lease should so provide.

18. Access to Information

A Lessee has no obligation, absent express lease provisions, to provide the royalty owner any information about his activities on the leased premises. Information the Lessee might be required to provide includes:

-- prior notice of Lessee's activities on the property, including commencement of drilling, laying of any pipelines, logging of a well, or other activities.

-- copies of documents filed with the regulatory authorities pertaining to drilling and production, including drilling permits, completion reports and production reports.

-- copies of assignments of interests in the lease.

-- a copy of any pooled unit designation affecting the lease.

-- well logs and well tests.

-- copies of contracts by which the Lessee sells oil and gas produced from the lease.

-- records showing how the Lessee is calculating the royalties paid under the lease.

A lease should grant to the Lessor the right to inspect, copy and audit the books and records of the Lessee pertaining to the production, marketing and sale of production from the leased premises.

19. A note on the use of bank drafts

Companies like to use bank drafts to pay lease bonuses. This is convenient for the company but poses risks to the Lessor. A bank draft looks like a check, but is it not.

A bank draft is not an unconditional promise to pay the sum stated. A draft gives the Lessee a period of time – usually 30 days – after the draft is presented to its bank to decide if it wants to honor the draft and make payment. During that time the Lessee can check the Lessor's mineral title to be sure that the Lessor has not leased to someone else. But the usual practice is for the Lessor to send the lease back to the company at the same time the draft is deposited for collection. The Lessor therefore runs the risk that the Lessee will record the lease and then not honor the draft. If this happens, the only way to clear the Lessor's title may be by litigation. Most companies, if asked, are willing to pay the bonus by check. Usually the landman will bring the check to the Lessor and exchange it for the executed lease. In that way, the Lessor is assured that the signed lease is not delivered until the bonus is paid. If the Lessor has any question about whether there will be sufficient funds to pay the check, consider whether you really want to lease to that Lessee; if necessary, you can insist on a cashier's or certified check.

20. Geophysical Exploration

Seismic testing has been used for many years as a tool for oil and gas exploration. The basic method of seismic testing is to create a shock wave on the surface of the ground along a predetermined line, by some energy source such as a small dynamite charge. This shock wave travels into the earth, is reflected by subsurface formations and returns to the surface where it is recorded by receivers – similar to microphones. The shock waves are created either by small explosive charges set off in shallow holes ("shot holes"), or by large trucks that are equipped with heavy plates ("Vibroseis trucks") that vibrate on the ground. By analyzing the time it takes for the shock waves to return to the surface, the geophysicist can map subsurface formations and anomalies and predict where oil or gas may be trapped in sufficient quantities for exploration and production. Until relatively recently, these tests were conducted along a single line on the ground, and their analysis created a two-dimensional picture akin to a slice through the earth beneath that line, showing the subsurface geology along that line. This is referred to as two-dimensional or 2D seismic data.

In the last 20-30 years, with the development of computers, geophysicists have been able to take seismic testing to a new level by conducting three-dimensional, or 3D, seismic tests. The basic method of testing is the same, but instead of a single line of energy source points and receiver points, the source points and receiver points are laid out in a grid across the property. The resulting recorded reflections received at each receiver point thereby come from all directions, and sophisticated computer programs can analyze this data to create a three-dimensional image of the subsurface. Today, almost all oil and gas exploratory wells are preceded by 3-D seismic surveys. The technology has greatly improved the rate of success of exploratory wells in the continental U.S., and has extended the life of the industry.

A 3-D seismic survey may cover many square miles of land, and may cost \$40,000 per square mile or more. The data obtained from such a survey is therefore very valuable and is bought and sold as a separate commodity in the industry.

Landowners with significant acreage should consider whether, in the negotiation of their leases, they should seek rights to seismic data covering their lands that is acquired during the lease term. The Lessee may be willing to grant landowners rights to such data, but the Lessee will have a legitimate interest in protecting the confidentiality of that data and therefore may want to require the landowner's promise that the data will not be disclosed to other parties. Conversely, landowners may want to consider whether they should seek to obtain agreements from the Lessee restricting the Lessee's right to disclose the seismic data to third parties, or alternatively to share with the landowner some of the benefits that might accrue to the Lessee from licenses of that data to third parties.

CONCLUSION

Oil and gas leases can in some ways be compared to other types of leases of real property. Real property leases range from simple two-page apartment leases to commercial leases of office space or commercial buildings that run to fifty pages of text or more. Likewise, oil and gas leases can be short, two-page forms or sophisticated, heavily negotiated agreements that cover thousands of acres of land and address not only the issues outlined in the above checklist but many more as well. Every lease negotiation presents its own unique issues, and every landowner has different interests to protect and different goals to achieve in the negotiation. The more knowledge the landowner brings to the negotiation, the more likely it is that he will achieve his goals. This checklist is intended to help the landowner by providing some of that knowledge.

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Admitted to bar, 1975, Texas. Board Certified, Oil, Gas and Mineral Law, Texas Board of Legal Specialization. Briefing Attorney to the Honorable Ruel C. Walker and to the Honorable Ross E. Doughty, Supreme Court of Texas, 1975-1976. Fellow: Texas Bar Foundation.

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Recent Publications and Presentations:

Ethics for Land Professionals, San Antonio Association of Professional Landmen, February, 2000.

Conflicts Between Private Royalty Owners and Payors Over Royalty Owner Rights: Legal and Practical Solutions, National Oil and Gas Royalty Conference, Houston, Texas, November 5-6, 2001.

Conflicts Between Private Royalty Owners and Payors Over Royalty Owner Rights: Legal and Practical Solutions, Asset Management Task Force of the Texas Bankers Association/Trust Financial Services Division, San Antonio, Texas, April 19, 2002.

Issues Concerning Royalty Valuations and Deductions, Petroleum Accounting and Financial Management Journal. (Fall/Winter 2002, Vol. 21, No. 3).