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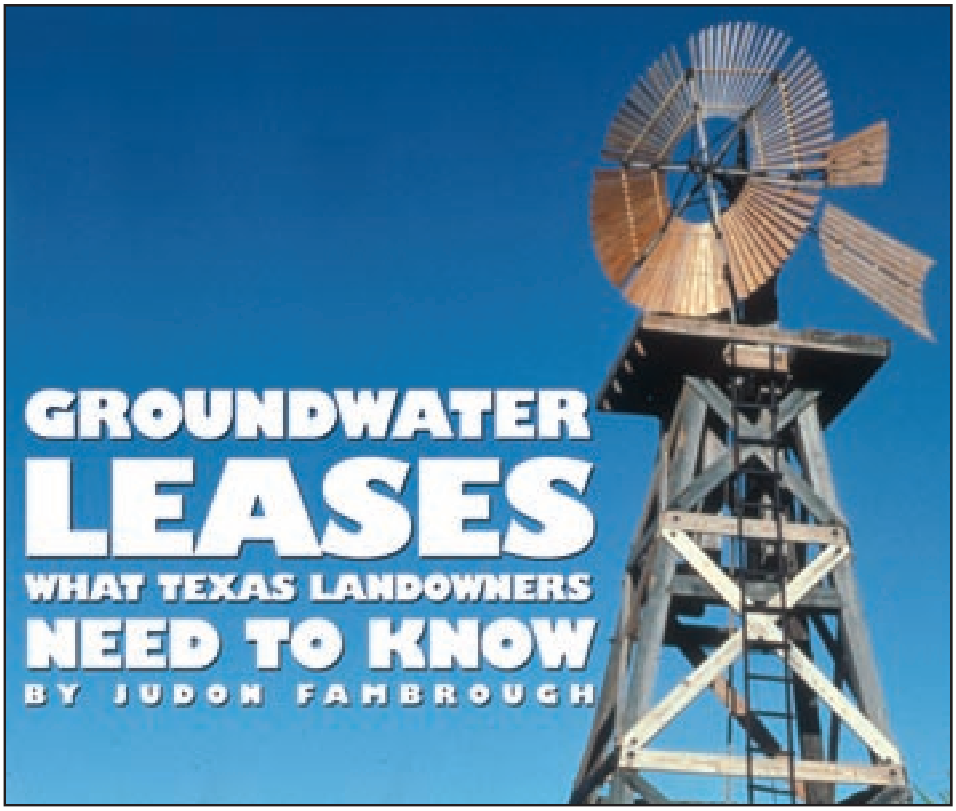

Groundwater supplies approximately 58 percent of Texas' water needs. In 1999, this amounted to 9.3 million acre-feet. With the state's population expected to double by 2050, reliance on groundwater is sure to increase.

Experts say Texas has sufficient groundwater to meet this demand. The problem is accessing — that is, leasing or buying — and transporting the water to market.

Before groundwater can be leased and produced commercially, the landowner and producer must reach an accord. Landowners familiar with oil and gas leases are at an advantage because most groundwater leases follow a similar format. The similarity may stem from the fact that the rule of capture applies to water as well as oil and gas.

The rule of capture permits oil, gas or water to be pumped from underneath adjacent property as long as the well is situated at a legal location, production is within any prescribed limits and other conditions are met. But the similarities end here.

Establishing Legal Well Locations

The Railroad Commission of Texas (RRC) designates legal locations for oil and gas production on a statewide basis while the local underground conservation district (UCD), if one exists, establishes legal locations for water wells within a district. Likewise, the RRC sets statewide pumping limits for all wells based on the size of the producer's production unit. UCDs do the same except the statute limits their authority to regulating wells capable of producing more than 25,000 gallons daily. Typically, UCDs allow groundwater producers to pump two acre-feet annually for each surface acre under lease and regulate wells capable of producing more than 50,000 gallons daily.

The RRC also regulates the maximum size of oil-gas production units. Generally, sizes depend on the type of well (vertical versus horizontal), the type of production (oil or gas) and the depth of production. Without special permission, the RRC requires all the acreage within the production unit to be contiguous to the well site. A plat of the production unit must be filed with the RRC and in the county deed records. Monthly production reports must be filed with the RRC.

While it is still unclear, UCDs may have the option to:

- limit the size of production units,
- require the pooled acreage to be contiguous,
- demand the filing of the plat in the deed records or
- mandate the filing of monthly production reports.

Because these items may not necessarily be regulated by UCDs, landowners may want to address them in the lease. As a minimum, landowners may require a plat of the production unit and certified copies of monthly production reports.

Also, landowners may require producers to comply with all local, state and federal rules governing production. The producer (lessee) should hold the landowner (lessor) harmless from any violation of these rules and regulations, including environmental ones. The penalty for a violation of any local, state or federal rule should be addressed in the lease.

$1-Million-Per-Mile Pipelines

Another similarity between the leases involves transportation of production. According to Texas statutory law, cross-country carriers of oil and gas have the power of eminent domain to condemn pipeline easements. In Texas, only cities and freshwater supply districts have the authority to condemn water pipeline easements. A district's authority to condemn a pipeline easement beyond the district's boundaries is questionable.

Groundwater producers lacking the power to condemn easements predict they can purchase and construct cross-country water pipelines for $1 million per mile. This raises a serious question for groundwater owners. Can a portion of pipeline costs be deducted from their royalties?

According to oil and gas leases, the costs of exploring, producing and transporting minerals are divided into two categories. The cost of exploring and bringing the minerals to the surface is borne solely by the lessee-producer. All costs subsequent to production, such as treating and transporting the product to market, are shared whenever the lease fixes the royalty "at the well" or "at the wellhead." The portion borne by the royalty owners corresponds to the size of the lease royalty.

For example, a landowner who reserves a 20 percent royalty in the lease pays 20 percent of all costs subsequent to production. This could include the cost of the pipeline. If so, landowners subsidize 20 percent of the pipeline costs but own no interest in the pipeline. If a city condemns the pipeline, the price it pays for the water could, in fact, reflect recoupment of pipeline costs.

Negotiate 'Cost-Free' Provision

To avoid these costs, sophisticated mineral owners began negotiating a "cost-free" provision in oil and gas leases. This freed them from both production and post-production costs. In 1999, the Texas Supreme Court held that such cost-free provisions were unenforceable when the lease fixed the royalty "at the well" or at the "wellhead."

Landowners should be aware when negotiating groundwater leases that pipeline costs may at times exceed monthly royalty payments. They should attempt to negotiate the cost-free royalty provision, and never allow the royalty to be fixed at the well or wellhead. If possible, landowners should avoid sharing any pipeline costs, either directly or indirectly, when the city condemns the line. If cost sharing is unavoidable, they should try to convert any deductions into an ownership or revenue interest in the water pipeline.

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Royalty payments for oil and gas leases are determined in one of two ways. Oil production is converted into monetary royalty payments based on market price (sometimes referred to as market value), which is the highest price purchasers will pay for the product. Royalties for gas production are based on proceeds (sometimes referred to as amount realized), meaning what the product sells for, not necessarily its fair market value.

Proceeds Determine Royalties

Most groundwater leases use proceeds to determine royalties. This is undoubtedly because of the difficulty in determining the fair market value of groundwater. The limited number of purchasers and disparity in the cost of transporting water to various buyers complicate the valuation process.

Many older groundwater leases between cities and large ranchers included a provision stating the price used to determine royalties could never be less than a specified percentage of the price the city's commercial customers paid for the water. This provision may still prove beneficial.

Another option is to include a provision for taking production "in kind." This option allows landowners to take their share of the production in actual water. Having the water may be more beneficial at times than having a royalty check.

Texas statutes govern the frequency of oil and gas payments. The law requires the first tender within 120 days after the end of the month of the first sale. Otherwise, interest accrues on the unpaid balance at two percent above the interest rate charged on loans to depository institutions by the New York Federal Reserve Bank. A different interest rate may be specified in the lease agreement.

Subsequent royalty payments are required within 60 days after the end of the month for oil sales or within 90 days after the end of the month for gas sales or interest again accrues. The lease never terminates for nonpayment.

Oil, Gas Division Orders Should Apply

No Texas statute governs the frequency of groundwater royalty payments. Consequently, landowners may address the issue in one of two ways. First, they can require that the Texas statutes governing the frequency of oil (not gas) royalty payments apply to groundwater payments. However, the landowner may require the lease to terminate after so many months of nonpayment.

Alternatively, the lease could require that, if the first royalty payment is not tendered within 90 days (or some other period) after the first production leaves the production unit, interest accrues at 15 percent (or some other negotiated rate). If the royalty payment, plus accrued interest, is not paid in 180 days (or some other period), the landowner would have the option of terminating the lease. Similar provisions could apply to the timing of subsequent royalty payments.

Groundwater lessors should attempt to negotiate a provision stating that the statutes regulating oil and gas division orders apply to groundwater division orders. Division orders indicate each royalty owner's share of the production from a well or unit. Without this document, royalty owners have no way of knowing this fact when the production unit is not filed in the county deed records. Presently, no Texas statute requires groundwater producers to send division orders in advance of the first royalty payment.

A nagging problem with oil and gas leases relates to the minimum production level needed to keep the lease in force. The answer depends on whether the lease is said to be in force "as long as production continues" or "as long as operations are conducted" with no cessation for 90 consecutive days. Both methods beg litigation. Astute mineral owners negotiate minimum royalty provisions to avoid this problem.

Whenever royalty payments drop below a certain dollar amount per acre per year, the producer must make up for the difference or the lease terminates. Minimum royalty payments cannot sustain the lease when no annual production occurs. Groundwater owners may consider a similar approach.

Overpayment Implications

Landowners should also be aware of the implications of overpayment of royalties. In Texas, royalty owners are personally liable for four years after receiving an overpayment. By then, most of the funds may have been spent or reinvested. The producer may recoup the deficit from the landowner's future royalty payments, but this source may be insufficient.

Again, landowners have two options to avoid the problem. First, they may attempt to remove all personal liability, no matter what the cause of the overpayment, and permit no recoupment from future royalty payments. Alternatively, Texas law permits the parties to reduce the statute of limitations from four years to two. Landowners may attempt to limit the statute of limitations accordingly and then allow recoupment only from future production.

Surface Damage Issues

Surface damages are another issue. Unless restricted in the lease, mineral lessees (oil companies) have the automatic right to use as much of the surface as is reasonably necessary to explore for and produce the minerals. This privilege comes without seeking independent permission from the surface owners, without having to restore the surface and without having to pay surface damages.

The same privileges do not accompany groundwater leases. Unless permitted in the lease, groundwater producers do not have the right to enter, explore and produce. Therefore, landowners must carefully detail:

- where the lessee enters and undertakes its operations or whether the parties must mutually agree on these locations,
- how damages will be determined when the parties cannot mutually agree on the amount and
- when the damages will be paid, preferably in advance of operations.

If the owner's land is used for a drill site, Texas law requires the creation of a sanitary control easement restricting certain activities within a 500-foot radius of the well. This amounts to more than 18 acres. Any compensation for surface damages should consider the affected area and not just the area used for the drill site.

Some groundwater leases authorize the lessee to take title to as much as an acre or two around each water well. Landowners should strike such a provision from the lease. Otherwise, the groundwater producer could theoretically cancel the lease and claim all the production under the rule of capture.

Finally, landowners should insert the provision "Time is of the essence." Without this language, there are no deadlines. The timing for the royalty payments discussed earlier would be rendered meaningless. "Time is of the essence" is implied in all mineral leases but not in groundwater leases.

These and many other considerations are detailed in the Center's technical report number 1593 entitled *Secrets for Negotiating Texas Groundwater Leases*. A free download is available at http://recenter.tamu.edu/pdf/1593.pdf.

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