What the Frack?
Judicial, Legislative and Administrative Responses to a New Drilling Paradigm.

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Introduction

Law must bend to science; it must accommodate technology. For nearly a century, oil and gas production was dominated by an engineering model in which a vertical well was perforated at a single downhole location in order to drain as large an area as was feasible. The most successful wells were characterized by higher pressure formations of relatively high porosity and permeability. In the mid to late 1990s, hydraulic fracturing ("fracking") in combination with horizontal drilling made possible recovery of natural gas and oil from shales and other formations with low porosity and permeability. This "fracking" process of creating fissures in tight underground formations allows natural gas and oil to flow from reservoirs that would have been uneconomic to produce under what will be here called the Standard Model. As the oil and gas industry evolved with the new technology, the courts, legislatures and agencies have had to respond to the new drilling model, accommodating or displacing existing legal principles that were founded on the Standard Model. No more than the tides would heed King Canute's commands will the earth yield up its resources in response to ill-suited legislation, mis-informed judical opinions or regulatory ukases. The shale revolution in its second decade is still contending with legal principles that were sound a century ago but must be adapted to reflect hard facts about recovering oil and gas from tight rock confines. The tools and concepts are in place but must be brought to bear to overcome common law doctrines of trespass that have no more application a mile underground than they have a mile in the air. Just as landowners now recognize that they must accept, with compensation, a utility planting a gas pipeline or hoisting an electric line across their property for the common good, so too will landowners need to come to accept the presence of a borehole a few inches in diameter a mile or more under their land, a small perforated pipe that permits the migration of fluid hydrocarbons that are essential to our national security and economic well-being .

The Standard Model

Petroleum Characteristics

We must begin with the basics. Of the many physical properties of petroleum studied by scientists, three are fundamental for an understanding of oil and gas production. First, petroleum occurs in nature in the gaseous, liquid and solid states, usually as gas or a liquid. Wherever it occurs as a liquid there is almost always some gas also present in solution. Since gas expands when pressure is reduced, there is energy

available for the propulsion of the oil to the surface. How much energy is available depends on the amount of gas present in the reservoir, at least in part. We say “in part” because other sources of energy may also be present in the reservoir.

Another important property of petroleum is its *specific gravity* or *density.* In the case of solids and liquids, specific gravity expresses the ratio between the weights of equal volumes of water and another substance measured at a standard temperature. The weight of water is assigned a value of 1. Liquid petroleum normally being lighter than water, its specific gravity is a fraction. For example, the specific gravity of octane is.7064. In the oil industry, however, the specific gravity of oil is commonly expressed in *A.P.I. degrees.* On this scale the ratio is inverted so that oil with the least specific gravity has the highest A.P.I. gravity. Most crude oils range from 27° to 35° A.P.I. gravity. Other things being equal, the higher the A.P.I. gravity the better the price for the oil.

The third property to be noticed is *viscosity,* which is an inverse measure of the ability of a fluid to flow. The less viscous the fluid the greater its mobility. There is a relationship between specific gravity and viscosity, for usually the less dense a petroleum compound is the less viscous it is. The viscosity of oil in a reservoir is also affected by the amount of gas present in solution, for gas is the less viscous of the two fluids. Production methods which permit gas to escape from solution before the oil has reached the well bore decrease ultimate recovery from the reservoir by increasing the viscosity of the oil as well as by dissipating the reservoir energy.

Petroleum Geology

To understand how petroleum is found and produced, we need to know something about petroleum geology. What follows is rudimentary. All rocks are divided into three basic classifications: *igneous* (granite is an example), *metamorphic* (slate and marble are examples), and *sedimentary,* of which three kinds are especially important in petroleum geology: sandstone, limestone and shale. The crust of the earth is composed of layers of these rocks overlain in some places with a thin coating of top soil, and any single layer (or *stratum*) will normally contain only one kind of rock. These strata having been deposited at different periods of time, the deepest layer will ordinarily be the oldest. Igneous and metamorphic rocks are also called *basement rock,* since, being older, they ordinarily occur beneath sedimentary deposits. Nearly all commercial oil and gas production is from some form of sedimentary rock. This is accounted for in one theory by the absence of source material for the manufacture of petroleum prior to the time of sedimentary deposits. According to this theory, oil and gas was formed from animal and vegetable life in the sea, and it was the sea that deposited sedimentary strata. Whether one accepts this theory of the origin of petroleum, there is another reason for its presence being confined to sedimentary rocks. Unlike igneous and metamorphic rocks, many sandstones and limestones and some shales possess two physical properties necessary for the accumulation of petroleum in commercial quantities, *viz., porosity* and *permeability.* Porosity is demonstrated every time you put oil on a whetstone to sharpen a knife. The stone soaks up the oil because there is a void between the particles that compose the rock. Permeability is the resistance rock offers to the flow of fluids through it. It is not enough that reservoir rock be capable of holding petroleum; it must also allow the petroleum to move through it. Usually porosity and permeability conjoin, but this is not invariably true. In summary, a commercial oil deposit requires the presence of a porous, permeable

rock formation containing oil of marketable A.P.I. gravity and of producible viscosity.[1]

It is the business of petroleum geologists, aided by geophysicists and other scientists, to search for these deposits. At present, however, there is no way of finding oil and gas short of drilling wells. What the geologists have traditionally looked for are *reservoir traps* —underground formations favorable to the accumulation of oil and gas. A reservoir trap can be generally described as a tilted layer of sedimentary rock overlain by an impervious substance and folded, broken, or otherwise so formed as to stop the natural migration of the petroleum upward.

Geologists recognize two fundamental types of reservoir traps, *structural* and *stratigraphic*, and a third type which combines characteristics of the other two. A trap could have resulted from a gentle uplift which produced an arch in a stratum that was probably level when laid down. Or a trap may be caused by faulting, which is the cracking and breaking of a rock plane. These breaks may be small and the displacement slight or they may extend for many miles and involve hundreds of feet of displacement. A variety of causes accounts for faulting, from violent upheavals that thrust great masses of rock upward to the gradual and gentle work of gravity. The effect of the latter is found along the Gulf Coast, where the weight of the sea and the silt washed into it caused the rock planes of the region to *dip* (*i.e.*, slope) to the south and then in places to crack and break. A stratigraphic trap results from a change in the character of reservoir rock (*e.g.*, from permeable to impermeable) or from a break in its continuity. One example of a stratigraphic trap is a lens of porous, permeable sandstone surrounded by impermeable shale. Oil and gas deposits have been found in such traps despite the absence of any structure. More common, however, are the combination traps where the upper part of a monoclinal structure "tightens up," that is, loses its porosity and permeability. The incline is the structural feature and the tightening up is the stratigraphic feature of a combination trap. In another sort of combination trap the sandstone "pinches out" between two planes of impervious rock. The East Texas pool is the largest in the lower 48 states with a capacity of about five billion barrels of recoverable oil. Salt domes are also frequently associated with petroleum reservoirs, for the intrusion of the salt plug forms traps of all three types.

Oil and gas exploration is the search for reservoir traps. Petroleum shales are blanket formations that may extend for hundreds of miles and are attractive for exploitation for that reason. But it would be a mistake to think that they are uniform. Drillers must experience much local variation—thickness, amount of sand, and natural fracturing of the rock. Increasingly, the key to more successful drilling and production of wells is "geosteering," which is made possible by enhanced downhole measurement using geophysical tools like gamma ray and resistivity meters, *aka* measurement while drilling (MWD) and logging while drilling (LWD). One source distinguishes the two as

[1] In Samedan Oil Corp., 173 IBLA 23, 42-43, 2007 IBLA LEXIS 57 (IBLA 2007), the Board identified three prerequisites for an oil and gas accumulation. They are: "1) oil or gas generation from a source rock; 2) a favorable structural configuration that allows oil and gas to migrate to a high point through permeable rock yet traps the oil and gas with impermeable rock (e.g., fault traps or anticline traps) before it seeps into the ocean; and 3) favorable reservoir rock with the capacity to store and produce oil and gas to the wellbore, which requires both porosity (pore spaces or fractures in the rock where oil or gas is stored) and permeability (naturally connected pores or fractures that will allow the oil or gas to flow through the rock to the wellbore)."

follows: "LWD [i]s the process of obtaining information about the rocks (porosity, resistivity, etc) and MWD [i]s obtaining information about the progress of the drilling operation (rate of penetration, weight on bit, wellbore trajectory, etc)."[2] The same source defines "geosteering" as "the act of adjusting the borehole trajectory (inclination and azimuth angles) as the well is being drilled, so as to reach one or more geological targets. These changes are based on geological and position gathered from measurement while drilling (MWD) techniques."

Most wells, are single completion wells. After a successful drill stem test, a new string of pipe, called casing, is run into the hole. The casing is then set by forcing oil well cement between it and the wall of the hole. After the cement hardens, the well is perforated by a special device that blows holes through the casing and cement, allowing the oil and gas to enter the well bore. Sometimes it is necessary to increase the flow of petroleum into the hole by acidizing or hydraulic fracturing the formation. Each process seeks to increase the permeability of the reservoir rock, the former by chemical treatment and the latter by pressure which cracks the rock.

Fracturing of reservoir rock is nothing new. On April 25, 1865, Civil War veteran Col. Edward A. L. Roberts received the first of his patents for an "exploding torpedo." A year later, he received the patent what would become known as the Roberts Torpedo. A Pennsylvania newspaper reported:[3]

> Our attention has been called to a series of experiments that have been made in the wells of various localities by Col. Roberts, with his newly patented torpedo. The results have in many cases been astonishing.
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> The torpedo, which is an iron case, containing an amount of powder varying from fifteen to twenty pounds, is lowered into the well, down to the spot, as near as can be ascertained, where it is necessary to explode it.
>
> It is then exploded by means of a cap on the torpedo, connected with the top of the shell by a wire.

The torpedo could be more effectively charged with nitroglycerin. The Roberts Petroleum Torpedo Company flourished as production from a fractured well might increase 1,200 percent within a week of being shot.

Akin to nitro blasting is another form of explosion that was tried but was not adopted: nuclear blasting. Three natural gas projects were part of the Plowshare program, which was designed to develop peaceful uses for nuclear energy. These were Project Gasbuggy (1967) in Rio Arriba County, New Mexico, Project Rulison (1969) near Parachute, Colorado and Project Rio Blanco (1973) in Rio Blanco County, Colorado.[4] The third involved three 33-kiloton nuclear devices that were detonated nearly simultaneously in a single emplacement well at three different depths. The gas produced

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[2] *Crain's Petrophysical Handbook***,** http://www.spec2000.net/08-mwd.htm#b3.

[3] Source: http://www.logwell.com/tales/well_shooting_history.html.

[4] Fact sheets on each of these are available from http://energy.gov/lm/office-legacy-management. See also the discussion in Russell Gold, The Boom: How Fracking Ignited the American Energy Revolution and Changed the World (2014) pp. 80-82.

from the experiments was contaminated by radiation and the results overall were not sufficiently encouraging.

Commercial hydraulic fracturing of an oil well dates from 1949. Fracking, or hydrofracturing, "is a method used to stimulate production of a well. A specially blended liquid is pumped down the well and into a formation under pressure high enough to cause the formation to crack open, forming passages through which oil or gas can flow into the wellbore."[5] One property of water is a lack of compressibility. Here the lack of permeability in a shale structure means the pressurized water will not seep into the rock. Instead the rock breaks under the water's pressure. In fracking a well, hydraulic pressure will build to 7-8000 psi. A car tire is filled to 30 psi or so. An aluminum scuba tank strapped for an hour or more on my back starts out with a filling to a bit more than 3,000 psi.

The etymology of "fracking" is given in by the author of a book of that name as follows: "hydraulic fracturing became known in the popular media as 'fracking,' with a 'k' replacing the 'c.' From the beginning, industry members detested the word because of its closeness to the common expletive, not to mention a similarity to 'fragging,' the act of attacking fellow soldiers. 'Fracking' also rhymes with 'hacking,' yet another word with a negative connotation. Energy veterans claim that 'fracking' was coined by those with a bias against the industry. In truth, the word was first used in the late 1970s in the science fiction series Battlestar Galactica as a substitute for the curse word."[6]

Fracking has made possible recovery of natural gas and oil from shales with low porosity and permeability. This "fracking" process of creating fissures in tight underground formations allows natural gas and oil to flow. The development of oil and natural gas in these shale plays has dramatically increased assessments of the long-term supplies available for domestic consumption.

Rate of production, gas-oil and water-oil ratios have traditionally been the primary factors affecting recoveries. Of less importance has been *well spacing.* The dense drilling of the '20s and early '30s was wasteful certainly, but not so much in harm done to reservoirs as in the expense of useless wells. It is now recognized that one vertically completed oil well under the Standard Model can efficiently drain twenty to eighty acres; a gas well may efficiently drain as much as eight hundred acres (depending on the reservoir). Most states have some sort of regulation requiring uniform spacing of wells within specified limits (*spacing rules*). Irregular spacing replaced overcrowding as a spacing problem. Some states have granted liberal exceptions to the uniform drilling pattern. Even this causes no serious problem by itself, but such exceptions were in the past usually accompanied by a disproportionately large production allowable for the small tract. For example, in a field drilled on a 40–acre pattern, the wells drilled on 5–acre sites as exceptions may have received ninety percent of the allowable for a standard site. Not only was this unfair to the larger site owners, it could result in damage to the reservoir. The solution to the problem is integration of small tracts into drilling units of the proper size, a process called *pooling.* Texas did not come to compulsory pooling until 1965.

[5] T.W. Phillips Gas & Oil Co. v. Jedlicka, 42 A. 3d 261, 264 (Pa. 2012).

[6] Gregory Zuckerman, The Frackers: The Outrageous Inside Story of the New Billionaire Wildcatters, p. 27 (2013).

As mentioned, new drilling and production techniques may be used to increase recovery of oil or gas. The late 1980s saw a substantial increase in the use of horizontal drilling.[7] Petroleum engineers have for many years employed directional drilling (or *whipstocking*) successfully to control the bottom hole location of a well (such as beneath a river bed) so that the surface location can be at a more favorable spot (such as the river's bank). Horizontal drilling goes well beyond directional drilling by significantly increasing the amount of reservoir open to the well bore.

Combining fracking and horizontal drilling has stimulated oil and gas drilling and development activity in the United States in recent years. Despite the fact that the United States is a high-cost area in which to produce oil and natural gas, the technical advances have allowed American producers to get more production for their dollars than would have otherwise been possible. Horizontal drilling with fracking continues to increase. This is the New Model or New Paradigm.

The New Model has faced not only controversy over its safety and impact on the environment but also the challenge of application of old rules based on outdated assumptions about the Standard Model. Our focus will be on spacing of wells, allowables for production, pooling and common law property rules.

Salient Features of Standard and New Models

Standard Model – We were concerned about too many wells and with wells too close together. We were concerned with too rapid production that prematurely depleted natural reservoir pressure and coning and fingering that allowed water intrusion. The Rule of Capture allowed a driller to drain a large area, with a neighboring landowner unable to stop production as there was no physical intrusion onto the neighbor's property. Larger units were desirable because they meant fewer wells. Pooling protected correlative rights and prevented the drilling of unnecessary wells.

New Model – The horizontal laterals drain only a few hundred feet around the borehole but the laterals extend a long way. So you need to be able to drill your well a long distance. With the New Model, the common law rule of trespass is suddenly a huge threat to efficient production. You can't drill around a holdout who owns a two acre tract, a person who says "I refuse to allow a well to drill under my property a mile or two miles down." This holdout makes it economically or physically impossible for me to extract oil or natural gas from under my own property. We are no longer worried that there will be too many wells but whether enough can be allowed. What we have to worry about is whether they will be aligned. If we cannot line up all the wells, there will be substantial gaps that will leave hydrocarbons in the ground, never to be produced. The problem here is one I introduced my first years students to in the old days when exams were written on sheets of paper. They would ask me whether they should use letter-size pads, legal pads or blue books. With no smile but with mischievous purpose, I would respond, "It doesn't matter to me so long as everyone uses the same size." Slowly a class of 50 would realize that uniformity could not be brought about voluntarily. So, too, in a shale formation. If you have six or a dozen developers and thousands of landowners/mineral owners you

[7] See Moore, Horizontal Drilling—New Technology Bringing New Legal and Regulatory Challenges, 36 Rocky Mt. Min. L. Inst. 15–1 (1990).

cannot get them to agree on lining up their wells in a uniform pattern. Compulsory pooling is desirable to overcome the recalcitrant landowner who would deny his neighbors the ability to obtain the oil and gas from beneath their property. And it is necessary for the state to superintend the most efficient and orderly pattern of development by the producing companies. Spiteful disputes between clashing personalities running their own producing companies should not be allowed to interfere with achieving maximum efficient recovery of hydrocarbons.

Traditional State Conservation Regulation

The Rule of Capture [8]

The rule stated:

> "the owner of a tract of land acquires title to the oil or gas which he produces from wells on his land, though part of the oil or gas may have migrated from adjoining lands. He may thus appropriate the oil and gas that have flowed from adjacent lands without the consent of the owner of those lands and without incurring liability to him for drainage."

This rule is followed in all producing states, whether they have adopted an "ownership in place" theory such as Texas has or have adopted a "non-ownership" approach such as Louisiana and California. The defense to the rule of capture is: the rule of capture. Thus there is a great incentive to drill wells to prevent another party from draining your property and to produce from such wells as rapidly as possible.

The rule of capture can lead to the drilling of wells that are unnecessary to drain a reservoir. It can lead to excessive rates of production of oil that may cause coning, fingering, and premature loss of reservoir energy as gas cap gas or solution gas is depleted. Surface effects may include production in excess of storage and marketing facilities.

Apart from the incentives of the rule of capture, improper practices by operators can cause waste. Incorrect plugging of a well, for example, can lead to migration of oil out of a reservoir to pollute the surface or can lead to communication between formations thus damaging a productive formation. Putting a valuable resource to inferior uses might also be regarded as a wasteful practice.

State Efforts to Promote Conservation[9]

Conservation of oil and gas is a concern essentially local in character. Each state, that is, has its own program of conservation, and there can be considerable variation in policy and statutory authority from state to state. The influence of the Federal government has been limited, though in recent years the Federal agencies and the Congress have had more involvement with the state programs. While the states may differ, their common features stand out. This is not a matter of coincidence. States consciously borrowed from one another in the development of their programs and

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[8] Kramer & Martin, *Pooling and Unitization*, §2. All citations to this work are to the chapter and section of Bruce M. Kramer & Patrick H. Martin, *Pooling and Unitization* (3rd ed., 1989, 2014) published by LexisNexis Matthew Bender.

[9] Kramer & Martin, *Pooling and Unitization*, §3.

continue to do so, both because they wish to benefit from the experience of others, and because common problems often call for common solutions. The states cooperate with one another on conservation matters through the Interstate Oil Compact Commission which was established in 1935, now named Interstate Oil and Gas Compact Commission (IOGCC – http://www.iogcc.state.ok.us). It is possible to describe the development of conservation programs as falling into several fairly distinct phases.

1. Regulation up to 1909:

Early regulation of oil and gas production and use was concerned with prevention of subsurface and surface damage that could result from improper drilling techniques. Regulation of casing of wells and plugging of wells was for this purpose. There was restriction of venting of gas, and prohibition of certain uses of gas, such as for flambeau lights and carbon black.

2. Regulation to 1919:

In this period, states enacted a number of laws to prohibit discrimination in purchases of oil or gas by pipelines and to prohibit waste through a variety of practices.

3. Regulation since 1919:

The period since 1919 has seen the development of modern conservation regulation — well-spacing, establishment of allowables, pooling and unitization. These have been based on the Standard Model described above.

4. New roles for conservation since 1976:

The state regulatory agencies responsible for conservation of oil and gas have assumed new responsibilities. These have primarily related to developments at the Federal level and increased concern for environmental protection at both the state and Federal levels. The agencies were charged with the duty of making well-status determinations for regulation of natural gas prices and reservoir determinations for purposes of price controls on oil (1976-1980) or Windfall Profit Tax implementation. The agencies have authority over underground injection of wastes and new responsibilities regarding transportation and disposal of oil field wastes and site remediation. A number of states also have given responsibility to the conservation agency for underground storage facilities for natural gas. Projects of this nature involve not only a sort of pooling but also expropriation.

5. The Fracking Revolution since 2000:

The state regulatory agencies are now having to adjust to the changes in technology that have made possible extraction of oil and gas from shale formations of low porosity and permeability. Hydraulic fracking and horizontal wells require changes in assumptions about how wells should be drilled and produced in order to prevent waste and protect correlative rights. Contrary to the regulatory presuppositions for conventional wells, most wells now extend long distances from their surface locations, are completed at many locations along their extent, and require much closer spacing than conventional wells.

Production Limitations[10]

Maximum efficient rate of recovery

Maximum efficient rate (MER) is the maximum rate at which oil can be produced without excessive decline or loss of reservoir energy. It is based on the engineering concept that each well has a rate of production that will maximize the amount of recoverable hydrocarbons by minimizing the loss of natural reservoir pressure. Because of the ever-changing nature of reservoir pressure, MER figures must change and reflect a range of options rather than a single number. MER regulation was stimulated by the federal effort to deal with wartime petroleum demand during World War II. In some states this federal effort remained after the war as a means of controlling production. MER also served as the only regulatory mechanism available to control production in those states where market demand prorationing was not authorized. Thus, MER regulation could serve either as an outer limit on production everywhere market demand prorationing existed, or as the only limit on production based on the general concept of waste prevention.

For example, in a water drive field the rate of withdrawals of oil may be limited to about 3 to 5 percent per year of the ultimate yield so as to coincide with the rate of movement of water into the structure. If this were not done, pressure would drop, gas would come out of solution in the oil rendering it more viscious and in part nonrecoverable, and water would "finger" through the producing structure, segregating pockets of unrecoverable oil. Factors considered in maximum efficient rate regulation: yardstick, depth-bracket allowables; gas-oil ratio; deliverability reports

Market Demand

The most controversial form of conservation legislation was the prorationing system. Prorationing had its greatest effect on the production of oil, rather than natural gas. Caused in part by the substantial imbalance between the demand and supply of oil, state prorationing systems attempted to stabilize the price of oil by limiting the production of oil at the wellhead. Prorationing is essentially a division of the production of hydrocarbons within a common source of supply or a specified geographic area. It normally involved a three-step procedure: (1) A determination of the maximum allowable production, which means, in a market demand system, determining how much product will be purchased on the open market; (2) An allocation of total demand among the jurisdictions various common sources of supply; and (3) A formula for dividing each common source of supplys share among the producing wells.

Oklahoma was probably the first state to impose a statewide proration order in response to a tremendous glut of oil that had driven the price of oil down substantially in a very short period of time. The order limited production in the state to 700,000 barrels and allocated that production among the settled pools and the flush pools. This order was followed by proration orders in other states, including a series of Texas orders that began in 1930.

Protection of correlative rights within a reservoir; prevention of net drainage.

[10] Kramer & Martin, *Pooling and Unitization*, §5.01.

Allowables are also established to protect correlative rights within a specified field. The doctrine of correlative rights is not a rule that a court or party can express in a flat statement. Rather, the concept of correlative rights is in the nature of a guide or precept that is to be applied to particular facts. It is simply this: that each person with a right to produce from a common source of supply ought to have a fair and reasonable opportunity to produce his or her fair share of oil or gas. That right should not be improperly defeated through the negligent or intentional actions of another party, nor should one be deprived of that right by the state without due process and just compensation. Having correlative rights in a common source of supply does not mean that each owner is guaranteed to recover a proportionate share of the oil or gas in the reservoir, but only that each owner shall be afforded the opportunity to produce or to share in production on a reasonable and fair basis. The point bears repeating for emphasis: The correlative right is having the *opportunity* to produce, not having a guaranteed share of production. Once the state has afforded that opportunity, it has protected the correlative rights of a party; it need not ensure a share of production to a party.

Well Spacing[11]

Well spacing is concerned with the location of wells and the density of drilling into a reservoir. Rules or orders of the state conservation agency may limit the proximity of wells to property lines and to other wells. Such regulations have the effect of protecting correlative rights in areas of diverse ownership and of limiting the number of wells that may be drilled into a reservoir in a given area. Well-spacing is done both by state-wide order and by individual field or reservoir rules. Exceptions may be granted on a well-by-well basis. Some examples of state-wide rules are as follows:

1. Louisiana Statewide Order No. 29-E:

> (1) No spacing shall be required for wells drilled in search of oil to depths less than 3,000 feet subsea ....
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> (2) Wells drilled in search of OIL to depths below 3,000 feet subsea shall not be located closer than 330 feet from any property line nor closer than 900 feet from any other well completed in, drilling to, or for which a permit shall have been granted to drill to, the same pool.
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> (3) Wells drilled in search of GAS shall not be located closer than 330 feet to any property line nor closer than 2,000 feet to any other well completed in, drilling to, or for which a permit shall have been granted to drill to, the same pool.

2. Texas Statewide Rule 37 (16 T.A.C. §3.37):[12]

> No well for oil, gas, or geothermal resource shall hereafter be drilled nearer than 1,200 feet to any well completed in or drilling to the same horizon on the same tract or farm, and no well shall be drilled nearer than

[11] Kramer & Martin, *Pooling and Unitization*, §5.02.

[12] History of Rule 37: Hardwicke, "Oil Well Spacing Regulations and Protection of Property Rights in Texas," 31 Tex. L. Rev. 99 (1952).

467 feet to any property line, lease line, or subdivision line; provided the commission, in order to prevent waste or to prevent the confiscation of property, may grant exceptions to permit drilling within shorter distances than prescribed in this paragraph when the commission shall determine that such exceptions are necessary either to prevent waste or to prevent the confiscation of property.

3. Texas Statewide Rule 86 (16 T.A.C. §3.86):[13]

This rule governs the drilling of horizontal drainhole wells. In general, all portions of the horizontal drainhole must comply with the applicable lease-line and between well spacing requirements for the field. If not, a Rule 37 exception must be obtained. Horizontal wells qualify for the allowables for a vertical well plus the additional acreage assignment provided in the rule. Operators must conduct a directional survey on every horizontal drainhole well. There will be special field rules for horizontal drilling in individual fields.

4. Arkansas Rule - Rule B-3: Spacing of Wells:

d. The well location for a well drilled for oil or gas production in an exploratory drilling unit established by Commission Order shall not be located closer than 280 feet from the drilling unit boundary, except that wells drilled in exploratory drilling units established by General Rule B-43, shall be governed by the well setback provisions of General Rule B-43.

e. The following applies to all wildcat well locations not drilled in exploratory drilling units:

(1) The well location for a wildcat well drilled for oil or gas production purposes, within an area not covered by Field Rules or General Rule B-43, shall not be located closer than 280 feet from a quarter, quarter division line within a governmental section.

5. Exception Wells; alternate unit wells; cross-unit wells

The state conservation agency may grant exceptional locations for drilling under the state regulations when certain conditions are present and the procedural requirements such as notice and hearing are fulfilled. Generally, an exception location may be approved when it is necessary to prevent waste or to prevent inequity or loss of property rights, and the statute may require the agency to limit the exception so as to eliminate any advantage it may give the party it grants the exception.

In addition to allowing wells at exception locations, an agency may also authorize the drilling of a substitute unit well or an alternate unit well. A substitute well replaces the well that had been designated the unit well. The alternate well is in addition to the unit well. While some statutes may provide that a unit may only have a single unit well, as that unit is the area that is efficiently and economically drained by a single well, the

[13] See generally Richard P. Marshall, Jr., "Land Problems Related To Horizontal Drilling In Texas," The Landman (July/August 2008), pp 47 et seq.

permitting of a second well will cause no loss to adjacent owners if the unit well and the alternate well together are not permitted to produce more than the unit's just and equitable share of the pool.

Spacing or Drilling Units[14]

Not only will a state agency establish general well location or spacing requirements, it will also establish special rules within a field or reservoir. Most state statutes will require the agency to establish spacing units or drilling units. This has often been described as the area which will be effectively and efficiently drained by a single well. Such an area may be a square, a rectangle, or some irregular shape. The conservation agency may rely upon subsurface geologic features, such as a fault line or water level, for establishing one or more of the boundaries of the drilling unit. Such a unit would be referred to as a geologic unit. A unit based only on surface lines for establishing boundaries would be referred to as a geographic unit. If rectangular, the unit may be described as stand-up (taller) or lay-down (wider).

Creation of a drilling unit need not be accompanied by the merger or pooling of the ownership interests in oil and gas within the unit area. The two juridical acts may be accomplished separately. For example, the state agency may establish the drilling unit and the owners of interests may then through a separate action pool their working interests and/or royalty interests. The state may in one proceeding establish a drilling unit and then later in a separate proceeding pool the interests within the drilling unit, or the state may accomplish both through a single proceeding.

Oklahoma: the establishment of the spacing unit has historically pooled a one-eighth royalty at the same time and has entitled all owners to a share of production; a separate action of the Corporation Commission has been necessary to pool the working interest for the purpose of well cost allocation.

Louisiana: it has been the practice of the Commissioner of Conservation to establish a drilling unit and pool the separate tracts in the same proceeding; i. e. a single hearing will be used to create a drilling unit and pool the separate interests through different paragraphs of the findings and order which issue from the proceeding.

Texas: the inclusion of a non-producing tract in a spacing unit/proration unit does not alter the rule of capture.

Equitable pooling: Under the so-called doctrine of "equitable pooling" establishment of a spacing unit operates to allocate production among all owners of interests within the spacing unit even without a pooling order.

Pooling

Pooling is the integration of interests in separately owned tracts for an area where a single well has been or will be drilled such that drilling and production costs are shared among the working interest owners and production is shared by all owners of rights in minerals. When compelled by the state, it is the uniting of the interests in separately owned small or irregularly shaped tracts for the purpose of integrating the minimum

[14] Kramer & Martin, *Pooling and Unitization*, §5.03.

acreage necessary for a drilling unit. Pooling may be effected for the working interest or the royalty interests or for all interests.

Unitization

Unitization, as opposed to pooling, is the consolidation of mineral or working interests covering all or part of a common source of supply. Within the unitized area there may be many spacing, drilling, or pooled units. Unitization is designed to maximize production by efficiently draining the reservoir utilizing the best engineering techniques that are economically feasible. While unitization in many cases is in the best interests of all of the parties, voluntary unitization of all the owners has been difficult to attain. As a result, all producing states, except for Texas, have adopted a compulsory unitization statute that allows the state conservation agency to unitize minority interests who have chosen not to voluntarily join in a unit agreement.[15] Unlike compulsory pooling statutes, which often encompass only one statutory provision, compulsory unitization statutes cover more sections and are lengthier and more complete. As with the compulsory pooling statutes, the compulsory unitization process is initiated by the submission to the state conservation agency of a detailed plan. In most states the minimum requirements for the petition are set out in great detail. These normally include a list of persons having interests in the unitized area, a unitization and unit operating agreement, an accurate map, and substantial geological and engineering data. In some states, compulsory unitization can be used for specific purposes only, such as recycling operations or secondary recovery operations; but the majority of states authorize compulsory unitization in order to prevent waste, increase the ultimate amount of hydrocarbons recovered, avoid the drilling of unnecessary wells, and/or protect correlative rights.

One of the requirements that must be met is the identification of the common source of supply, which is going to be unitized either partially or in its entirety. In most cases, the state conservation agency must make a specific finding that a common source of supply exists and that the unitized area encompasses that common source. Oklahoma, for example provides:[16]

> Each unit and unit area shall be limited to all or a portion of a single common source of supply. Only so much of a common source of supply as has been defined and determined to be productive of oil and gas by actual operations may be so included within the unit area.

Creation of Units[17]

Community lease

A community lease is a single lease (or multiple leases describing the same acreage) covering multiple tracts of land owned by different persons, the effect of which is to apportion royalty throughout the described acreage. It should contain an entirety

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[15] For some representative compulsory unitization statutes, see, e.g, Ark. Code Ann. § 15-72-308 to 15-72-315; Cal. Pub. Res. Code § 3640 *et seq.*; Kan. Stat. Ann. § 55-1301 *et seq.*; La. Rev. Stat. Ann. § 30:5; Miss. Code Ann. § 53-3-7; N.M. Stat. Ann. § 70-7-1 *et seq.*; Okla. Stat. Ann. tit. 52, § 287.1 *et seq.*; Wyo. Stat. § 30-5-110.

[16] Okla. Stat. Ann. tit. 52, § 287.4

[17] Kramer & Martin, *Pooling and Unitization*, §7.

clause, which overcomes the rule of nonapportionment that would otherwise obtain for property which has been divided subsequent to the creation of the lease or where the parties have been found not to intend a pooling in the granting of a joint lease.

Declared unit - The Pooling Clause[18]

The pooling clause of an oil and gas lease allows the lessee to effect the pooling of the lease, including the lessor's interest, without further consent by the lessor. Because the pooling is accomplished by filing a declaration of pooling, a pooled unit so formed is often referred to as a "declared unit." While it is a form of voluntary pooling in the sense that it is pooling by consent of the parties pooled and is not the result of the compulsion of the state, a unilateral act of the lessee invokes the pooling based on the power given in the lease. Without such a grant of authority or a separate agreement from the lessor, the lessee has no power to pool the interest of the lessor.[19] This is true whether or not the state in which the land is found authorizes the owner of the executive right the power to pool the interest of the non-executive owner.

The pooling clause will generally have an acreage limit, such as 40 acres for oil and 160 acres for gas, and provide for a larger area if a regulatory agency fixes a larger spacing pattern. The clause will generally spell out the effect of such pooling on royalty payments as well as some other effects on lease maintenance. It may include a limitation as to time for exercise of the pooling power. The pooling clause is implemented by filing a declaration of the pooling in the records of the county or parish where the land is located. The clause may make recordation of the exercise of pooling mandatory so that recordation subsequent to the end of the primary term (or past time for paying delay rentals) will not maintain the lease even though notice of the pooling was given prior to the end of the primary term. It is important to distinguish between pooling by exercise of the pooling clause and pooling accomplished by order of the state conservation agency. The agency's order for a spacing unit (or pooling) will maintain the lease even though the requirements of the pooling clause, such as recordation of the pooling, have not been fulfilled.

The pooling power granted the lessee is usually expressed in rather general terms. The precise circumstances of its exercise will be unknown at the time the power is conferred. As explained by a Texas court:[20]

> Anticipatory provisions in leases for the commitment by the lessee of such leases to unitization, of necessity must be in general terms. Neither the lessor nor the lessee has any way of knowing at the time the lease is taken the facts with respect to which it will be necessary for the lessee to apply his power. It is not practicable for the lessee to await the ascertainment of such facts. He knows from experience that because of the possibility of

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[18] Kramer & Martin, *Pooling and Unitization*, §8.

[19] As stated in a Texas case: "Absent express authority, a lessee has no power to pool interests in the estate retained by the lessor with those of other lessors." Jones v. Killingsworth, 403 S.W.2d 325, 328, 9 Tex. Sup. Ct. J. 155, 24 O.&G.R. 508 (Tex. 1966).

[20] Expando Production Co. v. Marshall, 407 S.W.2d 254, 260, 25 O.&G.R. 954 (Tex. Civ. App.—Fort Worth 1966, writ ref'd n.r.e.), quoting from Tiller v. Fields, 301 S.W.2d 185, 187-188, 7 O.&G.R. 1513 (Tex. Civ. App.—Texarkana 1957, n.w.h.).

> many changes in ownership of the lessor's interest as time goes on, it may be difficult to effect an agreement if the right to unitize is not included in the lease itself.

The Pugh Clause[21]

A Pugh clause is a lease clause whose purpose is to divide the lease when a portion of it has been included in a unit. It thus increases the burdens on the lessee who must take additional steps to maintain the lease as to the portion outside the unit; this may include a return to delay rentals or initiation of drilling operations within a specified period. Yet, the Pugh clause may also benefit the lessee in some circumstances, such as where it is coupled with a "saving provision" that allows the acreage outside the unit to be continued in force by other means. Such a clause may give a period of say three years in which to pay delay rentals beyond the primary term as to the outside acreage, when a lessee might otherwise have been forced to drill under the implied covenant of reasonable development.

Voluntary unit

A voluntary unit is a unit specifically created by joint agreement of the mineral lessee and the owners of all the other mineral or royalty interests affecting the land in question, as distinguished from a Declared unit.

Compulsory unit

A compulsory unit is one formed by order of the jurisdictional conservation agency. The process is referred to as compulsory pooling. Compulsory pooling statutes generally recite certain requirements for the entry of an order relating to compulsory or voluntary pooled or unitized operations. A pooling or unitization agreement or order usually will contain recitals which "track" the language of the applicable statute or which refer to such statute and aver the statutory requirements have been satisfied.

The Statutory Authority[22]

Each of the producing states provides for voluntary pooling where the parties have agreed upon the sharing of the costs of development and proceeds of production. They also provide for the conservation agency to establish these where the parties are unable to agree upon a sharing.

1. Louisiana.

> Where two or more separately owned tracts of land are embraced within a drilling unit which has been established by the commissioner . . . the owners may validly agree to pool their interests and to develop their lands as a drilling unit. (1) Where the owners have not agreed to pool their interests, the commissioner shall require them to do so and to develop their lands as a drilling unit, if he finds it necessary to prevent waste or to avoid drilling unnecessary wells.[23]

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[21] Kramer & Martin, *Pooling and Unitization*, §9.

[22] Kramer & Martin, *Pooling and Unitization*, §10.

[23] La. R. S. 30: 10A.

2. Oklahoma.

> When two (2) or more separately owned tracts of land are embraced within an established spacing unit, or where there are undivided interests separately owned, or both such separately owned tracts and undivided interests embraced within such established spacing unit, the owners thereof may validly pool their interests and develop their lands as a unit. Where, however, such owners have not agreed to pool their interests, and where one such separate owner has drilled or proposes to drill a well on said unit to the common source of supply, the Commission, to avoid the drilling of unnecessary wells, or to protect correlative rights, shall . . . require such owners to pool and develop their lands in the spacing unit as a unit.[24]

3. Texas: MIPA - An Act to encourage voluntary pooling

> When two or more separately owned tracts of land are embraced in a common reservoir of oil or gas for which the commission has established the size and shape of proration units, whether by temporary or permanent field rules, and where there are separately owned interests in oil and gas within an existing or proposed proration unit in the common reservoir and the owners have not agreed to pool their interests, and where at least one of the owners of the right to drill has drilled or has proposed to drill a well on the existing or proposed proration unit to the common reservoir, the commission, on the application of an owner specified in Section 102.012 of this code and for the purpose of avoiding the drilling of unnecessary wells, protecting correlative rights, or preventing waste, shall establish a unit within an area containing the approximate acreage of the proration unit, which unit shall in no event exceed 160 acres for an oil well or 640 acres for a gas well plus 10 percent tolerance.[25]

A further requirement of the Texas Mineral Interest Pooling Act is that the applicant must show he has made a fair and reasonable offer to pool voluntarily to the owners of the other interests in the proposed unit.[26]

4. What is Pooled: Specific Formation or Entire Area?

When pooling is accomplished through the exercise of the pooling clause by the lessee or through the granting of a community lease, an area often will be pooled that is designated only by a surface description. The effect of this is to pool any and all formations in which oil or gas may be found at any depth within that area. Production will be shared in the pooled area regardless of the formation from which it is produced. Costs will be shared among lessees under the agreement regardless of where the well is drilled within the area and regardless of the depth, so long as the terms of the agreement are met.

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[24] 52 O. S. §87.1.

[25] V.T.C.A. Natural Resources Code § 102.011.

[26] V.T.C.A. Natural Resources Code § 102.013.

In most orders for pooling, the state will designate a specific sand or formation (or pool or reservoir or interval or stratum) that is the subject of the spacing unit or pooling. While the order may include an exhibit that describes the surface area that is subject to the spacing or pooling, only the designated sand is actually spaced or pooled. Thus, owners of interests within the pooled area share in production from the pooled formation, but only from the pooled formation. If another formation is found to be productive within the surface area, it will have to be pooled separately, and, until the pooling is accomplished, there is no sharing of production from that separate formation.

Similarly, only the costs associated with the pooled formation will be subject to being shared. Thus, if an operator drills a well to 15,000 feet but only the sand at 10,000 feet is pooled, the other working interest owners need share in the costs of drilling only to the 10,000-foot sand (unless, of course, they have agreed otherwise with the operator).[27] If, on the other hand, the state agency pools an area without limitation of the pooling to a specific sand, formation, or depth, then the owners (royalty and working-interest) share in production from whatever source within the area, and the working-interest owners share in all costs properly incurred in the development of the pooled area. This does not happen often, because the pooling statute will often restrict the agency to spacing or pooling a "common source of supply" or a "pool" or a "common reservoir."[28]

Effects of Pooling and Unitization

Express and Implied Lease Terms [29]

1. The Habendum Clause:

Absent a clause to the contrary, where a lease lies partly within and partly without a unit, the unit production will maintain the lease in its entirety. This is the general rule, though as indicated below, several states have altered this by statute. Often, the lease will spell this out explicitly.

The 4 cases:

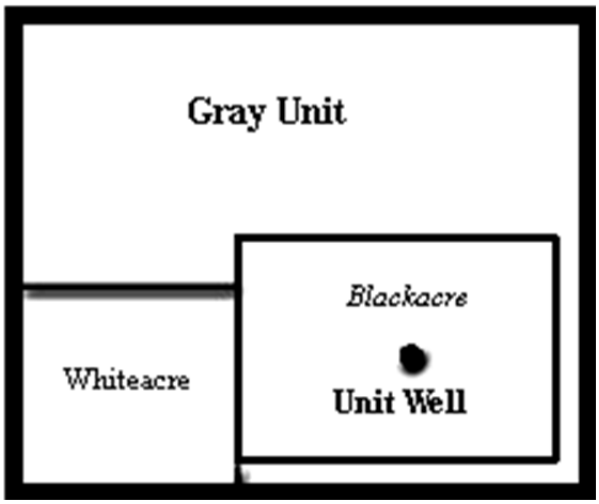
[1] Case 1

In Case 1 all of Blackacre is in Gray Unit, and the unit well is on Blackacre. This is depicted in the following diagram:

[27] *See* Sundown Energy, L.P. v. Harding & Shelton, Inc., 2010 OK 88, 245 P.3d 1226.

[28] See, e.g., La. Rev. Stat. Ann. § 30:9, 10; Okla. Stat. Ann., tit. 52 § 87.1; Tex Nat. Res. Code § 102.011. But see Wright v. State Oil & Gas Bd., 532 So. 2d 567, 103 O.&G.R. 79 (Miss. 1988).

[29] Kramer & Martin, *Pooling and Unitization*, §20.

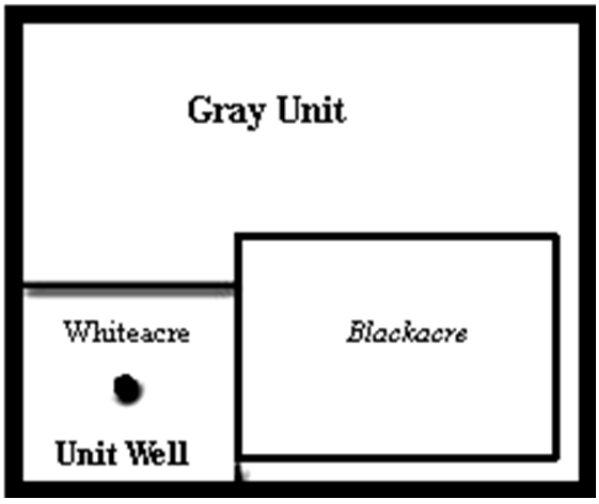


Case 1

Case 1 occasions very little controversy when the interests in Blackacre have been pooled. The unit well will maintain the lease or term interest on Blackacre, and the production will be shared among all owners of interests in Gray Unit. The only questions that might arise are whether the interests on Blackacre have been made subject to pooling. If an interest has not been effectively pooled, then that interest is not reduced by the inclusion in the unit. For example, if A is a royalty owner for of the production from Blackacre, and A's interest has not been pooled, then A would receive 1/8th of all production from the well on Blackacre, not 1/8 x 160/640 of total production.

[2] Case 2

In Case 2, all of Blackacre is included in Gray Unit, but the unit well is on Whiteacre rather than on Blackacre. This is depicted in the following diagram:



Case 2

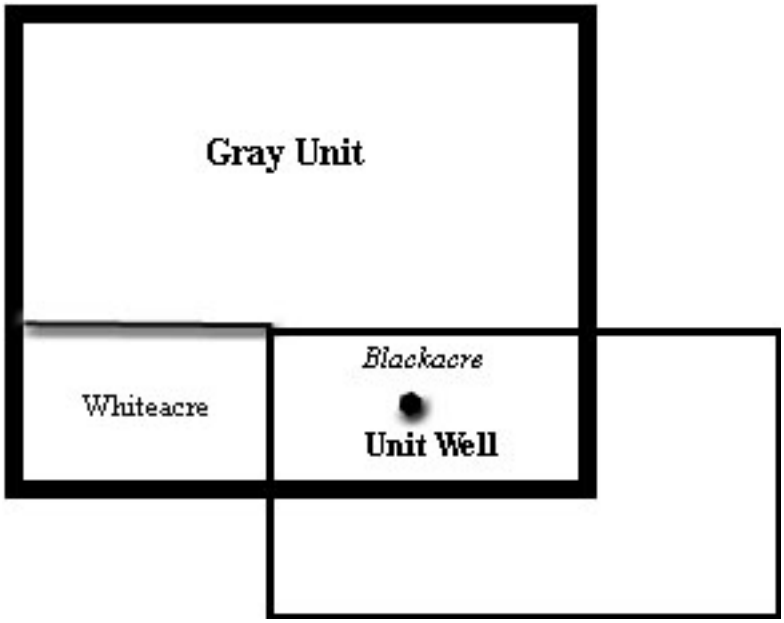
Case 2 occasions a bit more controversy than Case 1. In most circumstances the unit well on Whiteacre will maintain a lease or a term interest on Blackacre, and the

production will be shared among all owners of interest in Gray Unit. Two particular questions do arise out of Case 2. First, if an interest in Blackacre has not been pooled, is there any right of that owner to a share of production from the Gray Unit well on Whiteacre? For example, if **A** is a royalty owner for a 1/4th mineral interest on Blackacre, and **A**'s interest has not been pooled (e.g., because **A** initially refused to agree to pooling or because the owner of the executive right for **A**'s interest had no power to pool **A**'s interest), does A have a right to a share of the production from the well? The answer is clearly no. **A**'s claim to a share of production must arise by contract or by regulation; under the rule of capture there is no right to a share of production merely because the oil or gas may have migrated from beneath A's property.

The second area of controversy in Case 2 arises from interpretation of the specific language of a lease or deed for a term interest. The lease or deed may include a reference to "production from such lands as described herein" or words of similar import. Does production from a unit well on Whiteacre satisfy the requirement? The better view, as exemplified in the majority approach, holds that the unit production does maintain the interest.

[3] Case 3

In Case 3, only a portion of Blackacre is in Gray Unit and the unit well is on Blackacre. This is depicted in the following diagram:



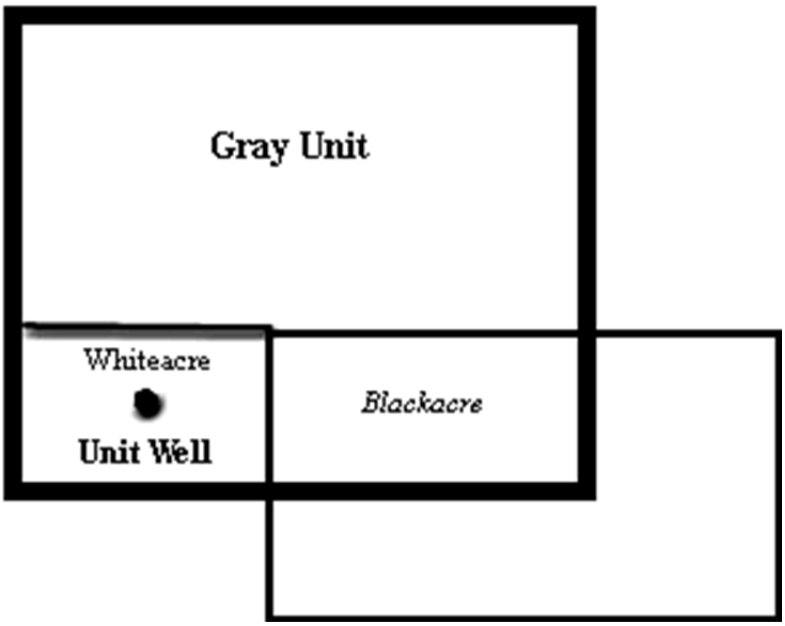
Case 3

In this circumstance, when all interests in Blackacre are pooled, the question may arise whether the unit well will serve to maintain the lease or term interest on Blackacre as to the portion not in the unit. The rule in most states is that the lease or term interest will be maintained as to both portions. There are, however, minority positions; some jurisdictions would give differing approaches whether a lease or a term interest is involved. Some jurisdictions have specifically provided by statute that a unit in a Case 3 or Case 4 situation will have the effect of dividing the lease or term interest into portions that must be

separately maintained. Parties can specifically provide for a different effect from the majority rule by contract in the lease or in the grant of the term interest.

[4] Case 4

In Case 4, only a portion of Blackacre is in Gray Unit, and the unit well is on Whiteacre. This is depicted in the following diagram:



Case 4

The same question arises in this as in the Case 3 circumstances. The majority approach does not distinguish between Case 3 and Case 4, and the statements regarding the minority jurisdictions in reference to Case 3 apply with respect to Case 4. That is to say, in most jurisdictions a lease or term interest will be continued by the unit operations or production on Whiteacre.

The four cases dealing with well placement and partial inclusion in a unit are only the beginning of the variations that can occur and that may raise issues about lease or term interest maintenance. Other variables that may affect the decision in a case include the following:

1. The specific wording of the habendum clause or the pooling clause of the lease or the wording of the term interest deed. For example, the lease may spell out the consequences of pooling, or the term interest deed may specify that the interest will continue for ten years and so long thereafter as there is production from "said described lands."

2. Other specific terms of the lease, such as the drilling operations clause or shut-in royalty clause.

3. Whether it is a lease or a term mineral interest or term royalty interest that is at issue.

4. Whether the pooling or unitization was the result of a community lease, inclusion of the acreage in a state-established drilling/spacing unit, a voluntary pooling or unitization, the exercise of the pooling clause by a lessee, or a compulsory pooling or unitization.

5. The specific terms of the agreement for pooling or unitization or the specific provisions of the order for pooling or unitization.

6. The specific wording of the statute under which pooling or unitization is effected.

7. Whether the pooling occurred before or after the well was drilled.

8. Whether the pooling occurred during or after the primary term of the interest in question, and whether all of the interests were pooled by the end of the primary term.

9. Whether the lessee or mineral interest owner of the interest in question has agreed to pay a share of costs for the well or has otherwise assumed liability for the drilling of the well.

Any of these variables, or combination of variables, may come into play within the four cases.

One can discern some underlying principles to which one returns in many or most of the cases. Principal among these are the following: Pooling and unitization are generally favored, both judicially and by statute. They are to be encouraged rather than discouraged. The Conservation Act provides that production from a unit well is treated as though it is production from each tract. The freedom to contract as one may wish remains a very high value. A court will generally seek to find the intent of the parties to the contract which is embodied in the words of the contract. Most courts remain reluctant to write new contract terms for parties.

The Effect of Pooling on Drainage and Development Obligations[30]

1. Limitation on requirements to drill additional wells.

If a lessee is prevented by the state from drilling additional wells, he generally cannot be found not to have acted as a prudent operator for not drilling additional wells. Even if there is an express lease provision for a certain drilling program, state action limiting the drilling would probably constitute force majeure under the lease. Similarly, there is no need to drill an offset well for a lessor if the pooling has the effect of allowing that lessor to participate in the production. But there are two caveats: it may be doubted that the state agency's determination that the unit constitutes the area economically and efficiently drained by a single well will be sufficient to establish that the unit well is not actually draining a larger area, bringing into play the offset well covenant or covenant to protect against drainage. Likewise, the mere existence of spacing limitations may not be enough to prevent the drilling of wells not in accordance with the spacing regulations; the lessee may be able to seek administrative relief from the agency regulations.

[30] Kramer & Martin, *Pooling and Unitization*, §20.04.

2. Development and Exploration of Outside Acreage.

An agency determination that a well economically and efficiently drains the area within the unit and hence is adequately developed may carry with it the negative implication that the area outside the unit is not adequately developed.

(a) Implied Covenant to Protect against Drainage.

In establishing a drilling unit or a spacing pattern for a particular reservoir, the conservation agency may be identifying the geological limits of the reservoir. Several units may be created adjacent to one another. If one unit is drilled and producing and another undrilled for the same formation or reservoir, there is a strong basis for concluding the undrilled unit area is being drained.

(b) Implied Covenant of Reasonable Development.

Under the implied covenant of reasonable development, the prudent operator lessee will drill to all known productive formations and produce where it can be shown that a well would produce in paying quantities. Where the state agency has established the existence of a formation and a well has been drilled into that formation and a unit has been created for that well, the same facts could easily serve as the basis for an adjacent landowner's claim that a reasonable, prudent operator would drill to the same formation on his land, just as with the drainage matter discussed under the previous heading. Many of the implied covenant of reasonable development cases have involved acreage outside of and adjacent to units established by the state. In such circumstances, a court or jury may use the implied covenant for an effect like a Pugh clause, requiring development or cancellation of the lease as to the outside acreage. Several states have enacted statutes that operate effectively as statutory Pugh clauses.

(c) Implied Covenant of Further Exploration

Some writers and courts would recognize the existence of an implied covenant of further exploration. It posits that a lessor should be able to show that a prudent operator would undertake to drill an exploratory well (one to a formation not proven to be productive in paying quantities) in some circumstances, even though the lease is being held by production from another formation or by some other lease provision, and if the lessee cannot then show a good reason for not drilling the lease will be cancelled. The existence of producing units on the leased tract or on adjacent acreage may well play a role in the court or jury's evaluation the conduct of a prudent operator, just as in the question of the implied covenant of reasonable development.

3. Limitation on requirements to produce.

If the state agency forbids a lessee to produce more than a specified amount of oil or gas or at no more than a specified rate then he cannot be required to produce more by the lessor. And if all the allowable is being made by a well, then it would be improper to require the drilling of another well which would not be able to produce any more.

Statutory Effects of Pooling and Unitization[31]

1. Louisiana: Prescription of Mineral Servitude

> Operations conducted on land other than that burdened by a mineral servitude and constituting part of a conventional or compulsory unit that includes only a part of the lands burdened by the servitude will, if otherwise sufficient to interrupt prescription according to Articles 29-32, interrupt prescription only as to that portion of the tract burdened by the servitude included in the unit provided such operations are for the discovery and production of minerals from the unitized sand or sands.[32]

The rules of use regarding interruption of prescription can be altered to allow unit operations to interrupt prescription as to the entire area burdened by the servitude.[33]

2. Oklahoma:

The Oklahoma legislature enacted a "statutory Pugh clause" in 1977. It provides that acreage of a lease which is partially in a unit will not be held as to the area outside the unit if the unit is 160 acres or more in size. The pertinent portion of the act states:[34]

> In case of a spacing unit of one hundred sixty (160) acres or more, no oil and/or gas leasehold interest outside the spacing unit involved may be held by production from the spacing unit more than ninety (90) days beyond expiration of the primary term of the lease.

The preceding statute is not to be applied retrospectively to leases executed before its enactment. It apparently will be applied to a unit formed by despacing.

3. Mississippi:

> The portion of unit production allocated to a separately owned tract within the unit shall be deemed, for all purposes, to have been actually produced from such tract, and operations with respect to any tract within the unit area shall be deemed for all purposes to be the conduct of operations for the production of oil or gas, or both, from each separately owned tract in the unit area. Provided, however, when an oil, gas and mineral lease contains land partially within and partially without said unit area, the unit agreement and production from the unit shall have no force and effect on lands lying outside of such unit area and failure of the lessee or lessees thereof to drill and develop such lands lying outside said unit area within one (1) year or during the term of the lease, whichever is a longer period of time, from the date of the determination of the unit area by the State Oil and Gas Board shall render such lease or leases on lands outside said unit

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[31] Kramer & Martin, *Pooling and Unitization*, §20.03

[32] La. R. S. 31:33; see also, articles 34 and 37.

[33] La. R. S. 31:75.

[34] 52 O. S. § 87.1(b).

area void and of no force and effect, unless otherwise held by production other than from unit production.[35]

Operating Problems

Options Afforded Owners of Interests [36]

Forced pooling requires legislators and conservation commissioners to make difficult choices as to what is just and reasonable in a variety of factual settings. When an interest owner is forced into a relation of sharing production with another there is considerable potential for depriving one or the other of his fair share of the fruits of a speculative enterprise or of oil and gas from beneath his land.

Drilling a well is a risky undertaking. The well may produce in great quantities and adjacent owners of interests will be eager to share. The well may result in a dry hole, and all expenditures on drilling will have produced absolutely no revenue, only losses, and few neighbors will be found who are willing to pick up a share of the costs. A rule which requires neighbors to share in all costs and all production on the same proportional basis may work very harshly on a landowner with little cash for speculation. A rule which requires a well operator to absorb all losses but forces him to share all profits will work very harshly on that risk taker whose efforts have led to production; indeed it will encourage people who might otherwise contribute to the costs of a well in advance to hold out until the results of the drilling are known since they can get the benefits of the well without the risks.

How does the legislature or conservation agency balance the interests of operators and non-operators? A single rule is not fine enough a measure for the purpose. Most of the producing states, either through the conservation statute or through the rules or practices of the agency, provide a mechanism allowing owners who are force pooled to share in the production on an equitable basis while still giving recognition to the risks assumed by the driller of the well through some additional compensation. Generally, this mechanism will be in the form of an election that the party being pooled can make prior to the drilling of the well in question. He will have the option to share in the risks of the venture or to forgo a portion of any production as compensation to the operator for his risk.

The problems of forced pooling are complicated by the existence of royalty owners, owners whose interests are normally not burdened by costs of production. If their lessee is subject to loss of a share of the production attributable to their lease for a time because of an election not to participate in well costs, should the royalty owner share in that loss? If royalty exists on a tract independent of any lease, does the well operator owe that royalty owner a share of the production irrespective of well costs issues? These matters are resolved by statute in some states, by agency practice in others, and in some states they have not been explicitly resolved at all.

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[35] Miss. Code Ann. § 53-3-111 [unitization].

[36] Kramer & Martin, *Pooling and Unitization*, §12. See also, Martin, *Unleased and Unjoined Owners – Forced Pooling and Cotenancy Issues*, 56 Rocky Mtn. Min. L. Inst. Ch. 18 (2010).

The Principal Alternative Approaches

There are three primary approaches that may be taken in dealing with the problem of sharing costs among owners of the right to produce who are included in a compulsory pooling unit. They may be found in combination. Within the three, there may be differing treatment of unleased owners and royalty owners.

1. Surrender of working-interest approach

The Oklahoma statute on forced pooling is not very different in wording from other state statutes. It and most such statutes require pooling on a fair and equitable basis. But the Oklahoma Corporation Commission has developed an approach that differs from many other states, and some states have borrowed features from Oklahoma. The Commission gives the pooled non-operating working-interest owner the option of assigning (or surrendering) the working interest to the operator with compensation (bonus and/or royalty) or of putting up cash (or its equivalent) for well costs in advance of drilling. The non-operator who fails to make an election to share in costs will be deemed to have elected to accept compensation for the working interest, thereby foregoing its working-interest share of production should the well be successful. A third option may also be given in which the working interest can be carried subject to a risk penalty.

Several states other than Oklahoma will give the non-operator an election like Oklahoma's, including Arkansas, Idaho, Illinois, South Dakota, and West Virginia. The surrender of working interest may be permanent or for a limited time, depending on the statute and the exercise of discretion by the agency. These states also generally provide for the non-operator being carried with a risk penalty as an alternative election.

The Oklahoma cases indicate the problems that may arise in connection with the assignment-of-interest approach. These include the valuation to be placed on the interest, the duration and extent of the assignment, and the treatment to be given to interests carved out of the interest prior to assignment.

2. The risk-penalty approach

In many states the non-operator will be given the opportunity by the administrative agency, or by the operator as authorized by statute, to put up cash (or its equivalent) for a share of drilling costs in advance of drilling; failing to do so, the non-operator will be treated as a carried interest subject to a risk penalty. That is, if the operator is successful in drilling the well, the operator may retain from production the non-operator's proportionate share of costs of drilling and completing the well plus an additional sum as compensation to the operator for its risk when the non-operator has elected to forego the drilling risks by not advancing its share of the costs. The risk penalty may be fixed by the statute, or the statute may give discretion to the agency to set the penalty within a determined range. The statute may define the costs subject to the risk penalty with some specificity, or it may leave the terms rather general, with the agency having the authority in either instance to resolve disputes as to costs. The states that follow the risk-penalty approach include, in addition to the states discussed above that allow working interest surrender or risk penalty, Alabama, Colorado, Louisiana, Michigan, Mississippi, Montana, Nebraska, Nevada, New Mexico, New York, Texas, Utah, and Wyoming.

3. The free ride

Some states have not addressed directly the treatment to be given to force-pooled non-operators who have not put up a share of the operating costs in advance. In the absence of specific legislation or regulations from the state agency, the treatment given such interests is as common-law co-tenants. That is, the compulsory unit is treated as the legal equivalent of a single lease with each pooled working interest owner having a right to an undivided share of production, subject to the operator's retention of the non-operator's proportionate share of costs until payout. The effect of such an approach is to give the non-operator a "free ride," an opportunity to let the operator drill the well at its own risk and then have the non-operator responsible for no more costs than had it put up a share of costs prior to drilling. Among the following states affording the non-operator a free ride, which will be described below, are Alaska, Arizona, Indiana and Missouri. There are several others whose statutes indicate a free-ride approach, but these states have very little oil and gas activity and will not be separately discussed.

4. Treatment of unleased interests

An owner of an unleased interest may get differing treatment within the above three approaches. Several states treat the unleased owner's interest as a royalty interest to the extent of 1/8[37] or the average of royalty [38] in the unit and the remaining 7/8 as a working interest given the same option as a leased interest. The alternative is to treat the unleased owner as having an 8/8 working or cost-bearing interest. In Louisiana, the unleased owner is not made subject to the risk penalty and is thus given treatment as a free-riding (costs to be taken out of production) 8/8 working interest. Another possible position is to treat the unleased owner in a unit as having a royalty interest until payout and as an 8/8 working interest thereafter. This, for example, is the approach in Colorado,[39] Montana,[40] and Utah. [41] In Arkansas, the Commission has given the unleased owner several options, including leasing the minerals to the pooling applicant with a designated bonus and royalty payment or staying unleased and participating or being carried with a risk penalty and royalty payments until payout is achieved. [42]

5. Treatment of royalty interests

The treatment of royalty owners has no clear pattern, owing to a lack of litigation or specific legislation on the subject. Royalty may be differentiated as to lessor royalty, overriding royalty created out of a leasehold, and non-participating royalty (royalty that exists independent of a lease). The treatment of royalty in a unit may depend on which type of royalty it is. In Oklahoma the lessor's royalty is pooled with the issuance of a spacing order in the sense that the royalty owner is entitled to a share wherever the well is

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[37] Ark. Code Ann. § 15-72-305 (a)(1); 225 Ill. Comp. Stat. § 725/22.2 (g); Ky. Rev. Stat. Ann. § 353.510.

[38] 2009 North Dakota Laws Ch. 314 (H.B. 1071); Utah Code Ann. § 40-6-6.5 (6) & (8). See also Cal. Pub. Res. Code § 3608 (tracts of one acre or less); Hunter v. Justice's Court, 36 Cal. 2d 315, 223 P.2d 465 (1950).

[39] Colo. Rev. Stat. § 34-60-116(7)(c).

[40] Mont. Code Ann. § 82-11-202(2)(c).

[41] Utah Code Ann. § 40-6-6.5(6).

[42] Lindquist v. Arkansas Oil & Gas Commission, 2000 Ark. App. LEXIS 442 (Ark. Ct. App. May 31, 2000) (unpublished opinion).

located within the unit. The royalty is paid by the operator or by the person selling the production of the royalty owner.[43] Under Louisiana's tract-allocation approach, it is the working interest on a tract that is subject to compulsory pooling, and the production is allocated back to the tract in the unit. The working-interest owner as to that tract then bears the responsibility for payment of royalty under its contract of lease.[44] The Utah pooling statute provides that if a nonconsenting owner's tract in the drilling unit is subject to a lease or other contract for the development of oil and gas, the pooling order shall provide that the consenting owners will pay any royalty interest or other interest in the tract not subject to the deduction of the costs of production from the production attributable to that tract.[45]

6. Surface (and Subsurface) Use Issues

Surface use issues can arise in a variety of circumstances in relation to unit operations for voluntary and compulsory pooling.[46] The optimum surface or bottomhole location of the unit well might be on the land of an unleased owner or an owner who has not consented to pooling or unitization. There may be need for use of land within a unit for access to the unit well and for production-related activities ranging from treatment plants to oil tanks to gathering lines. Issues can arise between the lessor and lessee and between the landowner and mineral owner (or his or her lessee) when the minerals have been severed from the land. The issues may be affected by a lease or deed provision, by the provisions of an order of the conservation agency, or by statute.

If a unit operator is unable to gain access to and unable to use the land for unit operations, the object of a grant or lease of mineral rights or the purposes sought to be attained by the state conservation order may be defeated. Pooling and unitization are generally favored, so it is not surprising that the courts frequently find that there is an implied easement to use the land for unit operations, or that an express provision of the lease or deed gives the right to such use, or that an order of the conservation agency gives the right of use for unit operations.[47] Even when a court recognizes a right of the landowner to some sort of compensation for the use of the land, the court will be reluctant to characterize the unit operations as constituting a trespass that could give rise to an order to cease the use of the land.

When oil and gas rights have been severed from the ownership of the land, a mineral interest owner ordinarily possesses the right to use so much of the surface of the land as is reasonably necessary for operations to develop the lands oil and gas.[48] May the

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[43] See Okla. Stat. Ann. tit. 52, § 87.1(e), 52 Okla. Stat. 570.1 et seq., esp § 570.4 .

[44] Caveat: Louisiana has recently modified by statute the tract allocation approach. Act No. 743 of 2012, (La. R.S. 30:10).

[45] Utah Code Ann. § 40-6-6.5(5).

[46] There probably should be no real distinction between surface and subsurface use of land though the two are very different in likely impact upon the owner of the land. Courts implicitly recognize the reality of the differing impact. On the implied right to use the subsurface for saltwater disposal and the effects of conservation agency regulation, see Colburn v. Parker & Parsley Dev. Co., 17 Kan. App. 2d 638, 842 P.2d 638 , 842 P.2d 321, 125 O.&G.R. 511 (1992).

[47] *See*, for example, Reynolds v. Amerada Hess Corp., 778 So. 2d 759, 147 O.&G.R. 89 (Miss. 2000).

[48] A number of states now regulate surface use relations in connection with oil and gas development. Such statutes are often called Surface Damage Acts. For additional coverage see Patrick H. Martin & Bruce M. Kramer, Williams &

interest owner and his or her lessee also use the surface for access to drilling operations on adjacent acreage when the land is included in the unit for which the operations are being undertaken? There is no logical reason why the mineral interest owner should not have the same implied easement rights wherever the unit well would be located when the use of the land is reasonably necessary for the enjoyment of the mineral rights.

A different question is raised when the matter is not between a surface owner and a mineral owner but rather is between an unleased landowner and the drilling party; there may be a right for surface or subsurface use under a compulsory unit order under the police power of the state rather than as a matter of implied rights under a deed. The right of use of unleased land within a unit is discussed below. The cases that have taken up the implied rights issue have almost uniformly concluded that the mineral rights owner may use the lands for unit activities whether the unit well was on or off the land burdened by the mineral interest.

A compulsory unit may contain both leased and unleased tracts. Ordinarily the lease will give the lessee the right to use the land for development of oil and gas, and this right will extend to use of the land for unit operations, even when the well is physically located off the leased tract and the lessee desires some use of the land for access or treatment facilities.[49] The question arises, however, whether the unit operator will be able to make use of the land of an unleased owner whose interest has been included in the unit and will share in the production from the unit well. Unless the unit order provides a defense, use of the surface or subsurface would be a trespass. Will the unit order insulate the operator from a trespass claim? The courts that have ruled on this issue have concluded that the unit order will prevent the unit operations from constituting a trespass. Nevertheless, damages may be available to the landowner who has been force-pooled and whose land has been used for unit activities.[50] Sharing in the hydrocarbons may be inadequate for compensation for use of the land for drilling operations. The sharing of production is to compensate for loss of the right to produce; damages for the use of the land is for that usage of the land, not for the production. The two are distinct. There is nothing inherently inconsistent in regarding the use of the land as a right arising from an order and requiring payment for the use of the land. Oil and gas leases, for example, typically provide the lessee the right to use the land but also provide for payment of damages for the use of the land. Of course, there is a distinction between payment for damages to land and payment for use. However, loss of use and damage can closely approximate one another. It is preferable that fair negotiation and agreement take place between the landowner and the users of the land.

Well Cost Disputes

In both voluntary and compulsory unitization, well cost disputes arise. When there is an operating agreement among the parties, such disputes are generally addressed

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Meyers Oil and Gas Law §§ 218-218.14 (2012).

[49] Some dispute may arise on the interpretation of a lease provision for surface use when only a part of the leased land is included in a unit. See Acree v. Shell Oil Co., 548 F. Supp. 1150, 75 O.&G.R. 85 (M.D. La. 1982).

[50] Several cases have so held or clearly indicated such an obligation. See Cormack v. Wil-Mc Corporation, 1983 OK 31, 661 P.2d 525, 77 O.&G.R. 330 (Okla. 1983), and Nunez v. Wainoco Oil & Gas Company, 488 So. 2d 955, 964-965, 91 O.&G.R. 246, n.29 (La. 1986).

in the agreement. Typically, the designated operator will be authorized to expend only an express, limited amount of money on a particular operation without securing the prior consent of the other parties to the agreement. When consent is sought for a larger expenditure, the operator will send out an "AFE," (authorization for expenditure), which will be an estimate of the cost for the proposed operation. A working interest owner is usually able to "go non-consent," to opt out of the operation with a loss of interest in the well or subject to later participation on the basis of a penalty.

Where there is compulsory unitization, the legislature generally has given the conservation agency the power to resolve well cost issues. E.g. Texas: "If there is a dispute relative to the costs, the [Railroad Commission] shall determine the proper costs and their allocation among working interest owners after due notice to interested parties and a hearing on the costs."[51] Likewise, the agency has continuing jurisdiction over orders it has entered, and this extends to well costs arising under the order. Particular problems arise in several contexts. The well costs may exceed the estimate used when a nonoperator elected to share in well costs. The reasonableness of certain costs may be questioned, such as an assertion that too much was paid to a particular drilling company. The inclusion of other costs may be challenged, such as company overhead or gas processing charges or a supervisory charge. Issue may arise as to when well costs have been fully recouped by the operator.

Several observations should be made concerning well cost disputes before the state agencies. First, the agencies are not eager to deal with well cost issues. They may be complex: some involve accounting techniques and methodologies unfamiliar to agency personnel and others question engineering decisions as to rig size, drilling methods, or well completion which agency staff have difficulty evaluating. Also, the disputes can be rancorous and involve assertions of bad faith and unfair dealing. While the courts are accustomed to dealing with such charges, the agencies are not and generally do not have the extensive discovery procedures of the courts. There are occasions when it will appear that both court and Commission will have jurisdiction over well costs.

Selected Issues of the New Drilling and Production Model

Multiple Unit Wells

Increased density orders allow the drilling of additional wells in a drilling/spacing unit. For example, the commission may have made a drilling/spacing unit order establishing 640 acres as the area effectively and economically drained by a single well. An increased density order in a Standard Model area might allow two or three wells to be drilled in the same unit in order to get more efficient production or to prevent drainage that would possibly otherwise occur. The increased density order may or may not be accompanied by a change in the allowable for the drilling/spacing unit. Thus, for example, in Louisiana the Commissioner of Conservation might enter an order for an alternate unit well in that unit. The unit would continue to have the same allowable, but the operator would be able to produce it out of either the unit well or the alternate well or could produce both, so long as the single allowable was not exceeded. The alternate unit well is to be distinguished from the substitute unit well. The substitute well replaces the

[51] Tex. Nat. Res. Code Ann. § 102.052. (b)

well that had been designated the unit well. The alternate well is in addition to the unit well. Under the New Model of horizontal drilling, it is necessary to drill anywhere from four to sixteen wells on a a 640 acre unit to adequately drain the area. This is because the conditions of the producing formation may allow drainage of only a few hundred feet around the wellbore. Long narrow units are impractical for a number of reasons.

Louisiana litigation on multiple wells on unit

Challenges have been made to the authority of the Commissioner of Conservation to allow more than one well in a unit under La. R. S. 30:9B, which provides that a "drilling unit, as contemplated herein, means the maximum area which may be efficiently and economically drained by one well." In *Walker v. J-W Operating Co*.,[52] the Louisiana appeals court upheld the Commissioner's "authority to issue permits for alternate wells pursuant to its grant of authority to prevent waste and its authority to 'make ... reasonable rules, regulations, and orders' to effect that goal," citing La. Rev. Stat. Ann. §§ 30:2, 30:3, and 30:4.The court noted that for fifty years the various Commissioners for the State of Louisiana had approved alternate wells. Moreover, it observed that the Louisiana legislature had in two acts recognized the practice of permitting alternate wells, both acts providing that 'nothing herein shall be construed as limiting the authority of the commissioner to approve the drilling of alternate unit wells on drilling units established pursuant to Section 30:9(B).'[53] The court ruled that nothing in Section 30:9 prohibits the permitting of alternate wells on a unit previously established pursuant to Section 30:9. Despite this ruling, a different panel of the same court ruled that a declaratory judgment action could go forward with the same claims that were rejected in this case.

In *Gatti v. State*,[54] plaintiffs sought, *inter alia*, a declaratory judgment to the effect that with certain limited exceptions no authority or power is prescribed by law for the Commissioner to establish a unit having an area in excess of the area drainable by one well, and the purported creation of a unit having an area in excess of the area drainable by one well is null and void. They further sought a declaration that alternate wells are not authorized by the statute, are beyond the legal authority granted to the Commissioner, and violate La. R.S. 30:9(B). The appeals court overturned the trial court judgment sustaining the peremptory, declinatory, and dilatory exceptions raising the objections of no cause of action, no right of action, prescription/peremption, lack of subject matter jurisdiction, and prematurity filed by the defendants, the State of Louisiana through the Office of Conservation and its commissioner and numerous oil and gas companies. The appeals court rejected the defendants' assertion that La. R.S. 30:12 provides the exclusive means of reviewing the orders of the Commissioner and does not permit the use of a

[52] Walker v. J-W Operating Co., 2012 La. App. Unpub. LEXIS 872; 2012 WL 6677913; *writ denied*, 2013 La. LEXIS 695 (La., Apr. 1, 2013). The author was a consultant at the trial level in this case.

[53] La. Rev. Stat. Ann. §§30:5.1A (9), 30:5.1B(13).

See also Six C Properties, LLC v. Welsh, 68 So. 3d 609, 2010-1913 (La. App. 1 Cir. 5/26/11). This case involved a challenge to a coal seam natural gas unit established under La. R.S. 30:5.2A which expressly provides the commissioner of conservation is authorized "to establish a single unit to be served by one or more wells for a coal seam natural gas producing area." The unit here included about 5,830 acres and provided for 330-foot offsets from property lines but no well spacing within the unit.

[54] Gatti v. State, 2013 0289 (La.App. 1 Cir. 01/15/14), 2014 La. App. Unpub. LEXIS 7.

declaratory judgment action to adjudicate the scope of the Commissioner's statutory authority to order forced pooling of lands that cannot be economically drained by one well.[55] The case was remanded to the trial court. If the *Gatti* decision were not overturned, it would effectively allow collateral attacks on orders via Louisiana Code of Civil Procedure article 1871 for judicial declaration of rights. On appeal, the Louisiana Supreme Court reversed, but did so without rendering an opinion, thereby leaving the issues addressed in a murky status.[56] The full decision is as follows:

> Writs granted. The court of appeal is reversed. The district court's ruling, which granted the defendants' exceptions of lack of subject matter jurisdiction, no cause of action, no right of action and prescription/peremption are reinstated. The plaintiffs' claims are dismissed without prejudice, as originally ordered by the district court.

What does this mean? Probably that the issue is mostly resolved in favor of allowing the commissioner to permit multiple unit wells. It would be desirable to modify the legislation.

Risk Penalties & Alternate Wells

Because multiple wells will be required to drain adequately a relatively large unit, the pace of development in a unit and in a large shale area can become a matter of dispute among working interest owners within a unit or in the play area. Once a successful well is drilled in a unit, there is often a 100% chance of success in drilling additional wells on the unit. With gas prices relatively low, drilling hundreds of wells almost simultaneously can be poroblematic. Joint operating agreements often contain a risk penalty provision if a working interest owner goes mon-consent on a proposed additional well subject to the joint operating agreement. This fact provides the owner of a small working interest the opportunity to propose wells on a unit which the operator may be reluctant to drill for the time-being. If the operator goes non-consent, then the small working interest can make a great deal more money by virtue of the non-consent penalty than it could if it were the majority owner. This scenario in Louisiana has led to administrative disputes, proposed legislation and apparently litigation. Let's illustrate the problem.

Where a small minority interest owner can drill a well and look to a much larger interest owner for a 200% or 300% or 400% risk penalty under a joint operating agreement, the drilling party has little incentive to seek efficient recovery of natural gas or maximum production from the entire unit. Let's imagine a 640 acre unit which with four wells can produce natural gas worth $100 million. Let's imagine each well will cost $8 million. Let's say the majority interest owner has 80% of the ownership interest and a minority owner has 3%. With maximum recovery from four wells at a cost of $32 million, the 3% owner would put up almost $1 million to get back $3 million before paying any severance tax or royalties, thus perhaps clearing $1.5 million. If on the other hand, the 3% owner could propose a second unit well with the majority owner going non-

[55] The court relied on Eads Operating Co. v. Thompson, 537 So. 2d 1187, 102 O.&G.R. 267 (La. App. 1988), *writ denied*, 538 So. 2d 614 (La. 1989), and distinguished McGowan v. Commissioner of Conservation, 92-2189 (La. App. 1st Cir. 3/11/94), 636 So.2d 920, *writ denied*, 94-1605 (La. 9/30/94), 642 So.2d 877.

[56] Gatti v. State, 2014 La. LEXIS 1804, 2014-0863 (La. 08/25/14).

consent under the joint operating agreement, the 3% owner could put up the full $8 million for a well and produce $25 million from it and keep all $25 million as risk penalty. The 3% owner could make perhaps 10 times the money from one well as he could have if all four wells had been drilled. Perhaps the third and fourth wells would never be drilled. If a small working interest owner can force this scenario, it would make the majority owners in the units hostages of every small working interest owner throughout a shale play. The incentive of the small interest owner will be to maximize the recovery from the risk penalty, not to maximize production from the entire unit.

In Order No. 361-L-122 dated February 14, 2014, for the Elm Grove Field, Bossier Parish, Louisiana, the Louisiana Commissioner of Conservation denied the application of Larchmont Resources, LLC to drill, designate and utilize three (3) alternate unit wells for three units. The application was opposed by the majority of the owners having the right to drill in said units, including the operators of each of said units. The Commissioner found that the available geological, engineering or other appropriate information indicated that approval of the applicant's request was not in the interests of conservation, nor was it necessary to prevent waste, to avoid the drilling of unnecessary wells, to allow for orderly development, or to protect the correlative rights of the owners of the tracts in said units. The Order reserved to the unit operator the ability to propose alternate unit wells for said units at a later time. To the same effect was Order No. 691-C-29 for the Swan Lake Field.

Undaunted, the parties behind Larchmont Resources sought legislation a few months later that would have required the granting of such applications by a non-operator. House Bill No. 1204 filed in the Louisiana legislature provided:

> The commissioner shall approve an increased well density within a unit's current boundaries established for stratigraphic zones which comprise the Haynesville Shale upon application by any working interest owner and the commissioner finding, after notice and a public hearing, that the geological, engineering, and other relevant evidence establishes that the developed area cannot be efficiently and economically drained by the current unit well or wells. The commissioner shall issue a permit to drill an alternate unit well to a successful applicant, upon the election of the current unit operator not to participate pursuant to R.S. 30:10 or otherwise, and in compliance with R.S. 30:28 and applicable rules and regulations.

At the hearing on the bill, the lawyer for a supporter of the bill indicated that litigation was in progress on the commissioner’s denial of the application. Thereupon no further action was taken on the bill. At last announcement the bill was still pending in the House Natural Resources committee.

Cross-unit wells

The shale revolution is taking place in some areas that have long produced oil and natural gas. There have been state-created units that have established sharing within a given geographic area. Even though the shale area is at a different depth and is not in communication with a reservoir that has produced in the past, a state agency may be reluctant to change the relative equities among the owners of mineral rights within the

pooled area. When one takes into account that a field rule may limit a well from being drilled or completed within say 330 feet of another unit boundary, the result is a gap of at least 660 feet which cannot be produced, and a borehole that might be most efficiently extended to 8,000 feet must be limited to about 4,500 feet for a 640 acre square unit. That means the unit and rules based on the Standard Model result in an inefficient well and an unproduced gap, neither of which benefits anyone; adherence to the Standard Model causes a loss of money and hydrocarbons.

1. Louisiana

One solution is to permit cross-unit wells as exceptions to the spacing requirements and to come up with special rules to allocate production that comes from the adjacent units. Attached to this paper below is one such order from Louisiana: Order No. 191-H-176, effective April 8, 2014. This pertains to alternate wells in three Haynesville Units. The diagram attached thereto illustrates how the wells cross unit boundaries.

We should note the basis for allocation between the units in finding No. 6:

> That unit production from said cross unit horizontal alternate unit wells should be allocated to each unit in the same proportion as the perforated length of the lateral, as defined in the DEFINITIONS section herein,[57] in that each unit bears to the total length of the perforated lateral, as determined by an "as drilled" survey performed after the cross unit wells are drilled and completed; and that unit production should continue to be shared on a surface acreage basis.

Mineral owners in Louisiana have been concerned that operators might use very short-segment cross-unit drilling to interrupt prescription of mineral servitudes and mineral royalties and to maintain leases without an underlying reason for conservation purposes. In Act No. 394 of 2014 the Louisiana Legislature said it has become aware of:

> the practice of granting exceptions to the spacing rules and allowing oil and gas operators to drill within the three hundred thirty feet property line and into the adjacent property. R.S. 31:16 provides that mineral rights are real rights and subject to either a prescription of nonuse for ten years or to special rules of law governing the term of their existence. One practical implication of allowing an exception to the three hundred thirty foot boundary rule is that the drilling of cross-unit wells could prevent the prescription of nonuse from running on the adjacent property.

The legislature provided for the establishment of a Cross-Unit Well Study Commission to study the issue of prescription (and presumably related matters) arising from cross-unit wells and report the commission's findings and recommendations to the Senate Committee on Natural Resources and the House Committee on Natural Resources and

[57] " 'perforated length of lateral' shall mean and is hereby defined as the length of horizontal lateral wellbore wherein perforations have been made, regardless of the number of perforated stages or individual perforations, which is measured from the lesser measured depth perforation or 'top of perforations' to the greater measured depth perforation or 'base of perforations'."

Environment not later than March 16, 2015. The Commission has held two meetings so far and is drafting an approach.

2. Arkansas

The approach to horizontal wells in Arkansas has been spelled out in a special rule of the Arkansas Oil and Gas Commission for the Fayetteville Shale, the Moorefield Shale, and the Chattanooga Shale Formations. There will be additional discussion of Arkansas's approach in another paper at this program so I will not go into the topic in depth. Briefly, Rule B-43 establishes a norm of 640 acre drilling units with a maximum of 16 wells per 640 acres for each separate unconventional source of supply within an established drilling unit. Each well location must be at least 560 feet from any other well in the same common source of supply that extends across or encroaches upon drilling unit. Each well location must be at least 448 feet, with an allowed 20% variance, from all other well locations in the same common source of supply within an established drilling unit. These setbacks may be waived if all affected owners consent in writing.

Of particular interest are cross-unit laterals which are given special treatment for allocation of production, using a "calculated area." General Rule B-43(o)(2)(E) provides:

> E. The method for sharing the costs of and the proceeds of production from one or more separately metered wells shall be based on acreage allocation as follows:
>
> > i) An area measured 560 feet along and on both sides of the entire length of the horizontal perforated section of the well, and including an area formed by a 560 feet radius from the beginning point of the perforated interval, and a 560 feet radius from the ending point of the perforated interval shall be calculated for each such separately metered well (the "calculated area").
> >
> > ii) Each calculated area shall be allocated and assigned to each drilling unit according to that portion of the calculated area occurring within each drilling unit.

A diagram using this "calculated area" approach looks like a band-aid. Apparently, the great majority of Fayetteville Shale drilled since 2010 have been cross-unit wells.

Attached is an order of the AOGC, Order No. 198-2-2014-07, dated August 5, 2014, to illustrate the authorization of a cross-unit horizontal well, the specification as to well costs, and the description of the "calculated area" (band-aid) (Finding No. 3).

Cross-lease Wells - Non-Units; Non-Pooling

Some states, such as North Dakota and Colorado, have readily adapted to the challenge of the New Model of drilling with establishment of pooled units that allow successful drilling with a minimum of reported controversy. Other states have responded with legislative or regulatory fixes that avoid pooling of interests but do allow producers to circumvent the otherwise applicable spacing regulations. Examples can be given from Texas and Pennsylvania.

The case of *Springer Ranch, Ltd. v. Jones*,[58] involved a 1956 lease on 8545 acres in Texas. Later, the area was subject to a division into 3 tracts. A 1993 contract among the parties provided:

> [the parties] contract and agree with each of the other parties, that all royalties payable under the above described Oil and Gas Lease from any well or wells on said 8,545.02 acre tract, shall be paid to the owner of the surface estate on which such well or wells are situated, without reference to any production unit on which such well or wells are located. . . .

This worked well enough for several vertical wells, but for a horizontal well the wellhead was located on one tract while the terminus was on another tract. Who was entitled to royalties? The court rejected the claim that the division between the two owners should be based on the total length of the wellbore, including the vertical segment since there is no production from that vertical segment. Instead, the court allocated production based on the length of the lateral between the first takepoint in the correlative interval to the last takepoint at the terminus of the horizontal wellbore.

The court looked to *Browning v. Luecke*.[59] The *Browning* court was faced with a jury verdict that had given a royalty owner the full value of all minerals produced from a horizontal wellbore that traversed over a portion of the lease, after the lessee had improperly pooled the royalty owner's interest into a unit. The royalty owners had a portion of both horizontal drainholes and the vertical drillsite on their acreage.

> "We decline to apply legal principles appropriate to vertical wells that are so blatantly inappropriate to horizontal wells and would discourage the use of this promising technology. The better remedy is to allow the offended lessors to recover royalties as specified in the lease, compelling a determination of what production can be attributed to their tracts with reasonably probability. …"

The court remanded for a determination of damages.

Pennsylvania statute:

The Pennsylvania Legislature in 2013 enacted the following statute that allows a lessee of adjoining lands to drill a horizontal well that traverses the property line between the two separate leases.[60]

> "Where an operator has the right to develop multiple contiguous leases separately, the operator may develop those leases jointly by horizontal drilling unless expressly prohibited by a lease. In determining the royalty where multiple contiguous leases are developed, in the absence of an agreement by all affected royalty owners, the production shall be allocated to each lease in such proportion as the operator reasonably determines to be attributable to each lease."

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[58] Springer Ranch, Ltd. v. Jones, 421 S.W.3d 273 (Tex. App.--San Antonio 2013).

[59] Browning Oil Co. v. Luecke, 38 S.W.3d 625 (Tex. App.—Austin 2000, rev. denied).

[60] "Oil and Gas Lease Act," SB 259, 58 Pa. Stat. § 34.1

Allocation of production between the two or more separate, but contiguous, leases is left to the discretion of the operator. To date, the predominant method of allocation for horizontal wells, be they allocation wells or pooled unit wells, appears to be the length of the lateral in the productive horizon under the owner's land as compared to the total length of the lateral in the productive horizon.

Conclusion

This paper has hit only a few of the many legal issues arising from the Fracking Revolution. Others have been raised by others making presentations on this program. As technology continues to change and improve, many additional legal challenges will arise. Interested persons in the producing states can watch regulatory, legislative and judicial developments in other states and learn much from those experiences – what to emulate and what to avoid.

STATE OF LOUISIANA
OFFICE OF CONSERVATION
BATON ROUGE, LOUISIANA

April 22, 2014

ORDER NO. 191-H-176

Order concerning permission to drill, designate and utilize three (3) cross unit horizontal wells as alternate unit wells at exceptional locations for **HA RA SU96,** in the **ELM GROVE FIELD**, and **HA RA SUYY** in the **CASPIANA FIELD,** and four (4) cross unit horizontal wells as alternate unit wells at exceptional locations for **HA RA SUYY** and **HA RA SU122** in the **CASPIANA FIELD**, Caddo and DeSoto Parishes, Louisiana.

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Pursuant to power delegated under the laws of the State of Louisiana, and particularly Title 30 of the Louisiana Revised Statutes of 1950, and after a public hearing held under **Docket Nos. 14-169 thru 14-171** in Baton Rouge, Louisiana, on **April 8, 2014**, upon the application of **BHP BILLITON PETROLEUM (TXLA OPERATING) COMPANY,** following legal publication of notice and notice in accordance with the rules prescribed by the Commissioner of Conservation, the following Order is issued and promulgated by the Commissioner of Conservation as being reasonably necessary to conserve the natural resources of the State, to prevent waste as defined by law, to avoid the drilling of unnecessary wells, and otherwise to carry out the provisions of the laws of this State.

DEFINITIONS

The Haynesville Zone, Reservoir A, in the Caspiana Field, Caddo, DeSoto, and Red River Parishes, Louisiana, was defined in Office of Conservation Order No. 191-H, effective August 28, 2007, and was redefined as to HA RA SU122 in Order No. 191-H-63, effective September 23, 2009.

The Haynesville Zone, Reservoir A, in the Elm Grove Field, Bienville, Bossier, Caddo, and Webster Parishes, Louisiana, was defined in Office of Conservation Order No. 361-L, effective July 29, 2008, and was redefined as to HA RA SU96 in Order No. 361-L-66, effective November 10, 2009.

For purposes outlined in the Order promulgated herewith, "perforated length of lateral" shall mean and is hereby defined as the length of horizontal lateral wellbore wherein perforations have been made, regardless of the number of perforated stages or individual perforations, which is measured from the lesser measured depth perforation or "top of perforations" to the greater measured depth perforation or "base of perforations".

FINDINGS

The Commissioner of Conservation finds as follows:

1. That Office of Conservation Order No. 191-H, effective August 28, 2007, as amended and supplemented by the 191-H Series of Orders, established rules and regulations and created drilling and production units for the exploration for and production of gas and condensate from the Haynesville Zone, Reservoir A, in the Caspiana Field, Caddo, DeSoto and Red River Parishes, Louisiana, including the units designated HA RA SUYY and HA RA SU122.

2. That Office of Conservation Order No. 361-L, effective July 29, 2008, as amended and supplemented by the 361-L Series of Orders, established rules and regulations and created drilling and production units for the exploration for and production of gas and condensate from the Haynesville Zone, Reservoir A, in the Elm Grove Field, Bienville, Bossier, Caddo and Webster Parishes, Louisiana, including the unit designated HA RA SU96.

3. That the available geological, engineering or other appropriate information indicates that it would be reasonable and in the interest of conservation to permit the applicant to drill, designate and utilize three (3) cross unit horizontal wells as alternate unit wells for HA RA SU96 and HA RA SUYY, and four (4) cross unit horizontal wells as alternate unit wells for HA RA SUYY and HA RA SU122, at the locations and in the general manner shown on the plat labeled, "BHP Billiton Petroleum (TxLa Operating) Company - Exhibit No. 2 for Docket Nos. 14-169 thru 14-171", a copy of which is attached hereto and made a part hereof, in exception to the spacing provisions of the 361-L Series of Office of Conservation Orders and the 191-H Series of Orders, respectively.

4. That the cross unit horizontal wells to be drilled as alternate unit wells for HA RA SU96, HA RA SUYY and HA RA SU122, at the locations designated in accordance with Finding No. 3 above, are necessary and in the interest of conservation and will efficiently and economically drain portions of the Haynesville Zone, Reservoir A, underlying HA RA SU96 in the Elm Grove Field, and HA RA SUYY and HA RA SU122 in the Caspiana Field, which cannot be efficiently and economically drained by any existing well within such units.

5. That with respect to the horizontal wells drilled to the Haynesville Zone, Reservoir A, within or to serve HA RA SU96 in the Elm Grove Field, and HA RA SUYY and HA RA SU122 in the Caspiana Field, where the horizontal portion of the wells are cased and cemented back above the top of the Haynesville Zone, Reservoir A, the distance to any unit boundary and any offset well(s) should be calculated based on the distance to the nearest perforation in the well, and not based on the penetration point or terminus and that the proposed cross unit laterals should be perforated no closer than 330 feet from any unit boundary of a unit other than the common unit boundary between HA RA SU96 and HA RA SUYY, and HA RA SUYY and HA RA SU122, respectively.

6. That unit production from said cross unit horizontal alternate unit wells should be allocated to each unit in the same proportion as the perforated length of the lateral, as defined in the DEFINITIONS section herein, in that each unit bears to the total length of the perforated lateral, as determined by an "as drilled" survey performed after the cross unit wells are drilled and completed; and that unit production should continue to be shared on a surface acreage basis.

7. That the operator of HA RA SU96, HA RA SUYY and HA RA SU122 should be allowed to produce the unit allowable for each unit from either the respective unit wells, the alternate unit wells, or from any combination thereof, at the discretion of the operator.

8. That the proposed cross unit horizontal alternate unit wells should be separated and metered individually and this information should be reported to the Office of Conservation in a manner to be prescribed by the Commissioner of Conservation.

9. That a majority of the owners having the right to drill in, and the operators of, HA RA SU96, HA RA SUYY and HA RA SU122 have indicated that they are in agreement with the cross unit horizontal alternate unit wells proposed to be adopted herein, and that the applicant has received no objections to said proposal.

ORDER

NOW, THEREFORE, IT IS ORDERED THAT:

1. The applicant, BHP Billiton Petroleum (TxLa Operating) Company, is hereby authorized to drill, designate and utilize three (3) cross unit horizontal wells as alternate unit wells for HA RA SU96 and HA RA SUYY, and four (4) cross unit horizontal wells as alternate unit wells for HA RA SUYY and HA RA SU122, at the locations and in the general manner shown on the plat labeled, "BHP Billiton Petroleum (TxLa Operating) Company - Exhibit No. 2 for Docket Nos. 14-169 thru 14-171", a copy of which is attached hereto and made a part hereof, in exception to the spacing provisions of the 361-L Series of Office of Conservation Orders and the 191-H Series of Orders, respectively.

2. With respect to horizontal wells drilled to the Haynesville Zone, Reservoir A, within or to serve HA RA SU96 in the Elm Grove Field, and HA RA SUYY and HA RA SU122

in the Caspiana Field, where the horizontal portion of the wells are cased and cemented back above the top of the Haynesville Zone, Reservoir A, the distance to any unit boundary and any offset well(s) shall be calculated based on the distance to the nearest perforation in the well, and not based on the penetration point or terminus, and the proposed cross unit laterals shall be perforated no closer than 330 feet to any unit boundary of a unit other than the common unit boundary between HA RA SU96 and HA RA SUYY, and HA RA SUYY and HA RA SU122, respectively.

3. Unit production from said cross unit horizontal alternate unit wells in HA RA SU96, HA RA SUYY and HA RA SU122 shall be allocated to each unit in accordance with Finding No. 6 hereof.

4. The operator of HA RA SU96, HA RA SUYY and HA RA SU122 is hereby authorized to produce each unit allowable in accordance with Finding No. 7 hereof.

5. The cross unit horizontal alternate unit wells shall be separated and metered individually and this information shall be reported to the Office of Conservation in accordance with Finding No. 8 hereof.

6. Except to the extent contrary herewith, the provisions of Office of Conservation Order No. 191-H, effective August 28, 2007, as amended and supplemented by the 191-H Series of Orders, and Order No. 361-L, effective July 29, 2008, as amended and supplemented by the 361-L Series of Orders, respectively, and all applicable Statewide Orders shall remain in full force and effect.

This Order shall be effective on and after April 8, 2014.

OFFICE OF CONSERVATION
OF THE STATE OF LOUISIANA

JAMES H. WELSH
COMMISSIONER OF CONSERVATION

SRB

BHP Billiton Petroleum (TxLa Operating) Company
Exhibit No. 2 for Docket Nos. 14-169 thru 14-171
Attached

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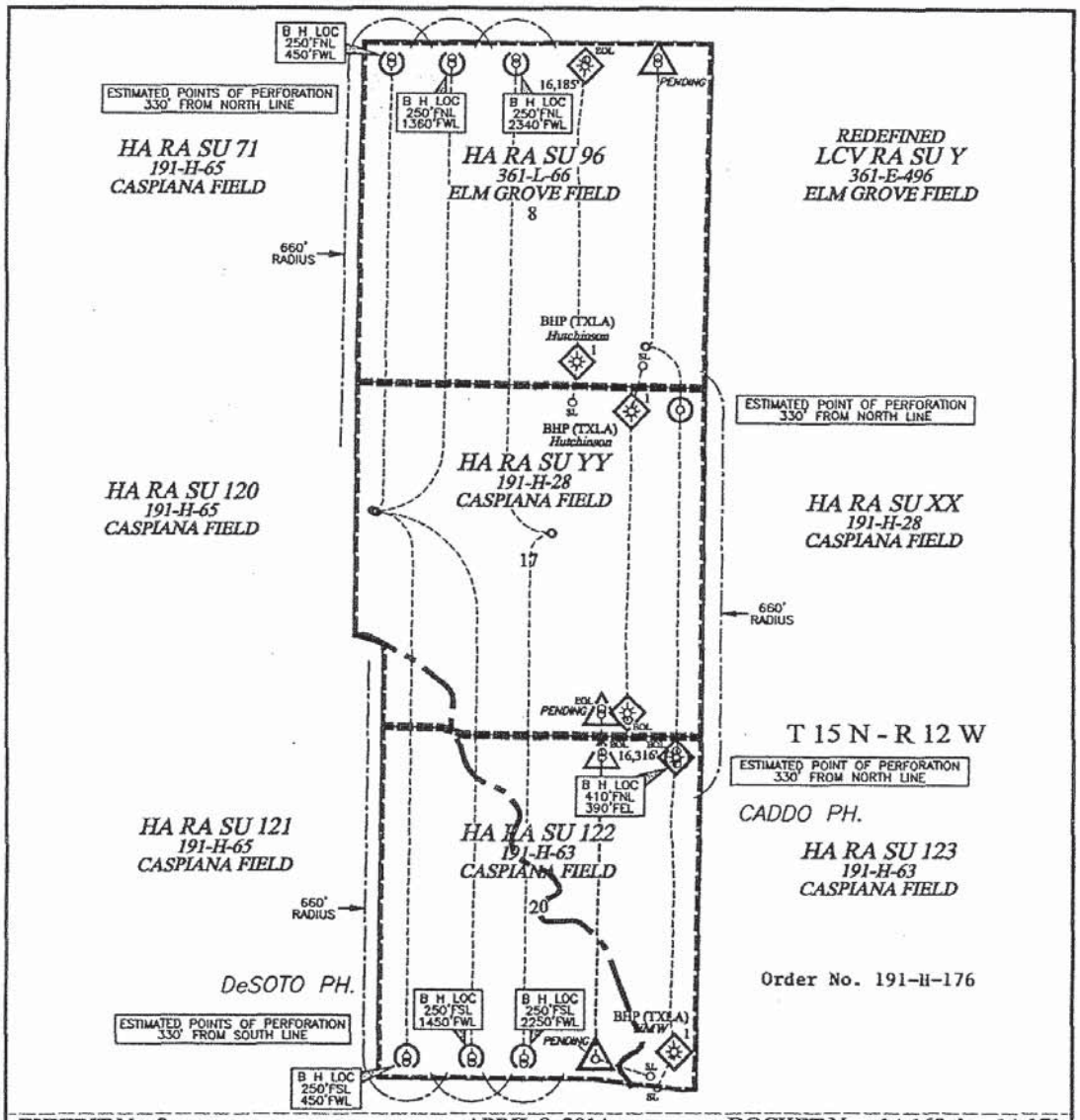

EXHIBIT No. 2 | APRIL 8, 2014 | DOCKET Nos. 14-169 thru 14-171

BHP BILLITON PETROLEUM (TXLA OPERATING) COMPANY
HOUSTON, TEXAS

CASPIANA AND ELM GROVE FIELDS
CADDO AND DeSOTO PARISHES, LOUISIANA

PROPOSED CROSS UNIT (ALTERNATE UNIT) WELLS AT EXCEPTIONAL LOCATION
FOR HA RA SU 96, HA RA SU YY, AND HA RA SU 122

- - - - - - :HAYNESVILLE RESERVOIR A UNITS
◎ :PROPOSED ALTERNATE UNIT WELLS
:HAYNESVILLE RA UNIT WELL
:HAYNESVILLE RA ALT UNIT WELL

GEOLOGIST: CRAIG C. BARCLAY

0 2000' 4000' 1 MILE
SCALE OF ORIGINAL: 1" = 2,000'

ONLY WELLS > TOP H'VILLE SHOWN

ARKANSAS OIL AND GAS COMMISSION
301 NATURAL RESOURCES DRIVE
SUITE 102
LITTLE ROCK, ARKANSAS 72205

ORDER NO. 198-2-2014-07 **August 05, 2014**

General Rule B-43 Well Spacing Area
Cleburne County, Arkansas

AUTHORITY TO DRILL AND PRODUCE WELL / SHARING COSTS AND NATURAL GAS PRODUCED

After due notice and public hearing in El Dorado, Arkansas, on July 22, 2014 the Arkansas Oil and Gas Commission, in order to prevent waste, carry out an orderly program of development and protect the correlative rights of each owner in the common source(s) of supply in this drilling unit, has found the following facts and issued the following Order.

STATEMENT OF THE CASE

SEECO, Inc., (the "Applicant"), filed its application for authority to drill and produce its proposed Green Bay Packaging 11-10 2-13H24 well, pursuant to Arkansas Oil and Gas Commission General Rule B-43 (o), and to share the costs of such well and the natural gas produced therefrom between the working interest owners and royalty interest owners of the existing units consisting of Section 24, Township 11 North, Range 10 West, and Section 13, Township 11 North, Range 10 West, Cleburne County, Arkansas.

FINDINGS OF FACT

From the evidence introduced at the hearing, the Commission finds:

1. That the Applicant is operator and owns or has the support of the majority working interest within Section 24, Township 11 North, Range 10 West, and Section 13, Township 11 North, Range 10 West, Cleburne County, Arkansas.

2. The Applicant proposes to drill a cross-unit horizontal well targeting the Fayetteville Shale and any intervening formations. The surface hole is planned in the Southeast Quarter of Section 13, Township 11 North, Range 10 West down to a bottom hole location in the Southeast Quarter of Section 24, Township 11 North, Range 10 West.

3. Utilizing an area encompassed an exterior which is defined by a distance of 560 feet measured perpendicular to both sides of the proposed well bore and a radius extending 560 feet from the first perforation (heel) and the last perforation (toe), the applicant estimates that the allocation area encompassing the perforated well bore is approximately 95.24% of Section 24, Township 11 North, Range 10 West, and 4.76% of Section 13, Township 11 North, Range 10 West.

4. The Applicant proposes that operations will be conducted under the terms of Model Form Operating Agreements adopted by the Commission, with the non-consent penalty being 400% for the proposed well; and that the above allocation of cost shall be effective for the drilling of the proposed well through the setting of production casing. The following terms will also govern the drilling and completion of the proposed well:

   (A) After the setting of production casing, but before a completion attempt is made, drilling cost will be reallocated, based upon the actual perforated interval available for completion in the as-drilled well bore. This re-allocation may result in a revision to working interest and all costs paid to that point will be adjusted.

   (B) If a well bore is lost during the drilling or completion operation and a replacement well bore is proposed with an alternate azimuth that will result in a further reallocation of working interest participation or the allocation of the production, the replacement well will be treated as a new well proposal with the revised interest. All parties that participate in the drilling and completion attempt in the initial well will be liable for their proportionate share of the actual cost of operation to the point of setting a plug for side-track operations, based on their original interest.

   (C) Should any party that elected to participate in the initial well elect to not participate in the replacement well, the penalty for a non-consent election in the replacement well will be imposed on only the

replacement well costs. A non-participating party in the initial well will not be afforded the opportunity to participate in the replacement well and their penalty will be imposed on the cumulative cost of the initial well and the replacement well.

(D) Any re-allocation after the setting of production casing will be final for the completion attempt and for the ultimate allocation of production from the well between the respective units.

5. That the granting of this application will be protective of the correlative rights of all interested parties and will prevent waste of the natural gas by permitting an efficient method of developing the resource within multiple drilling units

6. That no objections were filed.

CONCLUSIONS OF LAW

1. That due notice of public hearing was given as required by law and that this Commission has jurisdiction over said parties and the matter herein considered.

2. That this Commission has authority to grant said application under the provisions of Act No. 105 of 1939, as amended.

ORDER

It is, therefore, Ordered by the Commission:

1. The Applicant's application for authority to produce its Green Bay Packaging 11-10 2-13H24 well is hereby approved.

2. The Applicant shall share the costs of such well and the natural gas produced therefrom in the manner described in Finding Nos. 3 and 4 above.

3. That if the subject well encroaches upon but does not cross the drilling unit boundary of an adjoining drilling unit (an "encroaching well"), the Commission shall not consider the encroached-upon drilling unit to be held by production from the encroaching well.

4. That the following requirements are placed upon the drilling units from which production is allocated by applicant's well:

    a. There is at least one well located, as defined in subsection (a)(2) of General Rule B-3, at a non-exceptional well location and located entirely within each included drilling unit that is producing or capable of producing gas; or

    b. Within twelve (12) months following the date the well for which approval is granted is spud, there will be at least one well located, as defined in subsection (a)(2) of General Rule B-3, at a non-exceptional well location and located entirely within each included drilling unit that is either a well that is producing gas, or a well that is capable of producing gas and awaiting connection to a pipeline; or

    c. There is at least one well or a combination of multiple wells, including cross unit wells and/or encroaching wells located, as defined in subsection (a)(2) of General Rule B-3, within each included drilling unit that have a total combined perforated lateral length within the drilling unit of not less than 4160 feet, and are producing or are capable of producing gas; or

    d. Within twelve (12) months following the date the well for which approval is granted is spud, there will be at least one well or a combination of multiple wells, including cross unit wells and or encroaching wells located, as defined in subsection (a)(2) of General Rule B-3, within each included drilling unit that have a total combined perforated lateral length within the drilling unit of not less than 4160 feet, and are producing or are capable of producing gas and awaiting connection to a pipeline.

This Order shall be effective from and after **August 05, 2014**; and the Commission shall have continuing jurisdiction for the purposes of enforcement, and/or modifications or amendments to the provisions of this Order. This Order will automatically terminate under any of the following conditions: well drilling operations have not been commenced within one year after the effective date; or one year following cessation of drilling operations if no production is established; or, within one year from the cessation of production from the units.

ARKANSAS OIL AND GAS COMMISSION

Lawrence E. Bengal,
Director