

**KANSAS GEOLOGICAL SURVEY**  
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Potential Applications of Horizontal Drilling  
in Kansas

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# POTENTIAL APPLICATIONS OF HORIZONTAL DRILLING IN KANSAS

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## Executive Summary

Two billion-400 million barrels of mobile oil is estimated to remain in Kansas reservoirs (DOE, 1990). On the average a third of the original-oil-in-place is extracted from oil fields. Much of the remaining two-thirds of the oil has been either bypassed because of heterogeneity in the reservoir or is immobile due to microscopic surface tension forces. Techniques such as horizontal drilling offer the opportunity to contact mobile oil that was not available to vertical wells due to the nature of the heterogeneity.

Horizontal wells have been used in a variety of situations in the past decade. These situations include intercepting fractures in reservoirs, extending contact with thin or tight reservoirs, alleviating water or gas coning, drilling drain holes into heavy oil reservoirs, and developing more efficient delivery systems of steam and miscible enhanced oil-recovery (EOR) processes into the reservoir.

The production rates of horizontal wells are often two to five times that of vertical wells. Occasionally, previous dry holes have been turned into producers. Higher productivity and increased contact with bypassed oil in the reservoir are main objectives of horizontal wells.

Horizontal drilling is a proven technology that is being rapidly extended to new applications. The risks and costs of drilling horizontal wells have decreased as the experience has increased and technology improved.

Four types of horizontal wells are in use: long, medium, short, and ultra-short radius. Drilling and completion practices associated with these types of wells are improving steadily as major research efforts by industry continue.

Planning is critical to drilling a successful horizontal well. A firm understanding of the geology of the reservoir is essential for proper design and implementation. Literally, a three-dimensional perspective of the reservoir is required. Many variables, such as whether the reservoir is fractured and the nature of the heterogeneity and anisotropy of the reservoir, will determine how the well will be designed, drilled and completed. Other options may be more feasible and should be considered before the investment and risk are committed to the horizontal well. The limits of the application of horizontal drilling are defined by the geology and economics. The geology is stressed in this report.

Several reservoirs in Kansas are likely targets for horizontal drilling, including fractured carbonate and karstic reservoirs

in the Mississippian and Arbuckle Group. Thin-bedded, lenticular sandstone reservoirs of the Middle Pennsylvanian Cherokee Group in southeastern Kansas that exhibit complex lateral heterogeneity also are prospects for horizontal drilling. This is particularly true for these reservoirs that contain heavier oil or problems with water encroachment. Lesser targets may include fractured and karstic Upper Ordovician Viola and Hunton limestones. In addition, the thicker Middle and Upper Pennsylvanian vuggy and possibly fractured cyclic carbonate reservoirs of the Marmaton Group and Lansing-Kansas City Groups may serve as drilling targets. It is possible that natural gas reservoirs of the Upper Cretaceous Niobrara Chalk in northwest Kansas will respond favorably to horizontal wells, although pressures may be insufficient at the shallow depths at which this reservoir is found. Middle Pennsylvanian Cherokee Group coals may also be targets for ultra-short radius drain holes to more efficiently extract coal-bed methane.

Regardless of the reservoir, local geologic conditions should be carefully examined and an economic analysis should be done to determine the feasibility of applying this technology.

## Background

### Generation of Interest

Positive results arose from recent horizontal drilling in the Austin Chalk in Texas and the Bakken Shale in North Dakota. Due to lowered costs and success, horizontal drilling is extending to other targets in the United States; for example, the Winnipegosis formation in the Williston basin, Tertiary strata in the Monroe gas field in Louisiana, Tertiary sandstones and heavy oil in the Kern River field in California, Cretaceous-age Fruitland Coal in the San Juan basin of New Mexico, the Permian Wolfcamp cyclic carbonates in west Texas, the Niagaran reef in Michigan, the Sadlerochit Formation in Prudhoe Bay, and Tertiary strata in Point Pedernales field, offshore California (Moritis, 1990). The application of this technology has yet to be proven in other areas.

Oil and gas productivity and cumulative hydrocarbon production can be notably higher in horizontal wells, if situations in the reservoir permit the horizontal well to contact more of the reservoir. The net result may be fewer wells and cost savings needed in field development accompanied by accelerated payout. The reintroduction of this technology is timely and should be seriously considered for oil and gas extraction as anticipated costs decrease.

## Brief History

Horizontal drilling technology developed in the 1920's, peaked during the 1950's, and has been revitalized in the 1980's. The advantage of this approach was realized as early as 1929 when R. E. Lee drilled two 5- 1/4-inch diameter horizontal drain holes, 24 feet in length, into the Lower Permian San Andres Limestone at a depth of 3,000 feet in the Big Lake oil field in west Texas. The wells were drilled using a downhole air motor with flexible drill pipe and a whipstock. Oil production was increased from 2 BOPD to 60 BOPD after wells were acidized. Reservoir development in the Lower Permian-age San Andres Limestone is stratigraphically and diagenetically controlled. Reservoirs are stacked in combination structural-stratigraphic traps.

R. E. Lee again was in the forefront of horizontal drilling technology when in 1939 he used a flexible shaft and universal socket joint accompanying a flexible drill pipe to complete horizontal wells in fractured Annona Chalk at Pine Island

field, Louisiana, and again in west Texas in the San Andres Limestone in Slaughter/Levelland field. Production increases realized in these fractured chalk wells of Stanolind (Amoco) were from 13 BOPD to 120 BOPD.

The American developments were paralleled by those in the Soviet Union where many horizontal wells were drilled in the late 1930's (Table 1). Notable development and field applications of horizontal drilling continued through the 1940's and 1950's, particularly by the international oil industry in order to solve specific production problems associated with standard vertical well completions. In the 1940's, the Eastman Corporation developed methods for precisely controlled directional wellbores that were used on the Gulf Coast and in California. Eastman used this technology to precisely locate and steer wells that were drilled in the Gladys field south of Wichita (L. Richardson, personal com., 1991).

John Zublin developed a fluid-operated turbine motor and flexible drill pipe in 1941. This approach was used to drill

Table 1. Early horizontal wells chronology (from DOE, 1990).

Year	Company	Field	No. of Wells	Depth (ft)	Reservoir Contact Length (ft)
1937	-	Yarega, USSR	many	-	1,000 max
1941	Leo Ranney et al.	McConnesville, OH	6	-	1,000
1942	-	Franklin Heavy field, Venango County, PA	4	388	1,000
1942?	-	Midway Sunset fld, CA	2	1,100	70
1946	-	Round Mtn field, CA	9	1,650	56
1952	-	Midway Sunset fld, CA	1	1,200	50
1952	Venezuelan Oil Concessions	La Pas field, Venezuela	?	10,000	50-100?
1952	Long Beach Oil Development	Los Angeles	8	3,500 to 4,800	50
1957	-	USSR	1	1,000	300
1967	-	China	1	3,600	1,600
1968	-	Marcovo, USSR	1	7,200	1,800
1977	Conoco	Tisdale, WY	6	-	1,700 max
1978	Esso, Canada	Cold Lake, Alberta	1	1,558	1,000
1979	Texaco	Fort McMurray, Alberta	3	415	1,000
1979	Esso, Canada	Wells under MacKenzie River, Alberta, Canada	1	1,603	1,860
1980-	Elf-Aquitaine	Lacq field	1	2,195	330
81	& IFP	Southwest France	1	4,100	1,214
1981-	Elf-Aquitaine	Rospo Mare,	1	4,500	1,988
83	& IFP	Offshore Italy			
	Elf-Aquitaine & IFP	Castera Lou, South France	1	9,500	1,300
1980-84	ARCO	Empire Abo Unit, NM	10	6,200	300-400
1982-84	ARCO	Southeast Douglas, Garfield County, OK	1	6,500	300-400
1985	Esso, Canada	Cold Lake, Alberta, Canada	1	1,558	3,300
1985	Petrobras	Fazenda Belam Field	1	1,000	554
1985	Sohio	McMullen County, TX	1	10,300	1,908
1985	Sohio	Glasscock, County, TX	1	-	295
1985	Sohio	Prudhoe Bay, AK	1	8,989	1,400
1985	Sohio	Prudhoe Bay, AK	1	9,000	-

horizontal wells in a heavy-oil-bearing sandstone reservoir in Kern County, California. In 1948 Zebelin developed a flexible pipe that could be used with conventional rock bit. The borehole went from vertical to horizontal over a 60-foot turning depth and was extended horizontally to an additional 50 feet at relatively shallow depths (1,800 to 2,000 feet). Oil production was increased from 1 BOPD to 25 BOPD.

This heavy oil reservoir has several unfavorable characteristics that limit its ability to produce: 1) shallow depth and consequently low reservoir energy and gravity drainage, and 2) early coning of water into the vertical borehole due to the high viscosity and low gravity oil. The horizontal drain holes took advantage of the gravity drainage and extended the exposure to the reservoir to minimize the effect of water coning.

Fourteen horizontal drain holes were drilled from a 230-foot-deep shaft in 1943 and 1944 in the Black field in Miami County, Kansas, in an attempt to economically extract remaining medium-gravity mobile oil from an abandoned lease (Abernathy and Jewett, 1946). The endeavor was unsuccessful.

During the 1950's technological developments improved horizontal drilling, including nonmagnetic drill pipe permitting compass orientation of holes and flexible slotted liners that kept horizontal sections of hole from collapsing. However, the use of shallow drain-hole drilling declined significantly by the mid-1960's, with the developments in hydraulic fracturing, introduced in the Hugoton field in western Kansas in 1947.

The decade of the eighties led to a resurgence in horizontal drilling. Between 1980 to 1984, only one or two horizontal wells were drilled worldwide. In contrast, horizontal wells drilled in search of oil and gas increased from 32 in 1985 to over 500 in 1990. Horizontal well permits increased from eight per month in 1989 to 80 per month in 1990. However, the types of applications to date have been rather limited. The Austin Chalk play in south Texas and Bakken play in the Williston basin accounted for 85% of the U.S. and 68% of worldwide horizontal well activity in 1989.

Examples of production improvements obtained by horizontal wells throughout the world are included in [Table 2](#). Decisions to drill horizontally are driven by potential benefits of higher recovery of reserves of mobile oil due to more efficient drainage, less drawdown, greater per well flow rates, low sand production (unconsolidated formations), possibly less drilling and completion costs due to fewer wells drilled to develop the reservoir, and lower logistical costs (Lang and Jett, 1990). Fewer wells may be cost effective or make development possible in areas that are environmentally sensitive, including protection of significant freshwater aquifers. The tradeoff is higher cost/well and greater risk in having mechanical problems including losing the well.

Horizontal wells are becoming an integral tool of the industry and must be considered a viable alternative to vertical wells in many future development programs.

The current rapid increase in horizontal drilling has been the result of recent technological improvements in drilling, evaluation, and completion, coupled with reevaluation and better awareness of geological conditions suited for application of this technology ([Table 3](#)). New bottom hole drilling assemblies (BHA) have made possible more precise and accurate horizontal holes ([Figures 1 through 4](#)). Measurement while drilling (MWD) has permitted monitoring of drilling progress with respect to the geological conditions by transmitting information to the surface through pulses sent through the drilling mud. Improved and more varied completion practices and integrated reservoir engineering and geological analysis have resulted in tailored, focused drilling and development programs utilizing horizontal wells. It is now possible to core short- and medium-radius wells (Eaton, 1990). Schemes for test design and interpretations are being developed (Daviau et al., 1988).

Interest in horizontal drilling has been intense worldwide and has led to what is believed to be the largest jointly funded drilling research project in the history of the industry (Petzet, 1990). For example, 95 oil and service companies from 18 countries are participating in the Drilling Engineering Association-44, a project to research literature and to develop computer programs related to drilling, completion, production, reservoir engineering, and technology transfer.

The current thrust in technological development in horizontal drilling includes improvement of completion and reservoir description, more versatile completions, reduction of permeability damage, improved stimulation techniques, and low-cost hole stability control (Lang and Jett, 1990).

Horizontal drilling usually results in elongate drainage areas, so that normal well spacing and location rules may be inapplicable or inappropriate. As the technology is applied, exceptional locations and spacing will be requested of the appropriate regulatory body. For Kansas, reconsideration of pooling, unitization, spacing and spacing unit shape and dimensions may be required for effective use of the horizontal drilling technology. Horizontal drilling in established vertical hole areas might be regarded as an enhanced oil recovery method, and thus might be eligible for favored tax treatment. Various states have experimented with both rules (North Dakota) and tax change ideas (Colorado).

#### Type of Horizontal Wells

Four basic types of horizontal wells are now in use:

1. Long radius of 1000 to 3000 feet
2. Medium radius of 300 to 700 feet
3. Short radius of 20 to 40 feet
4. Ultra-short radius of 1 to 2 feet.

Table 2. Examples of production improvements obtained by horizontal wells throughout the world (Giannesini, 1989).

Location	Operator	Horizontal length application	Production improvement (source)
Michigan	Trendwell Oil Corp.	251 ft to intersect Niagaran reef	Turned dry hole into 613.3 BOPD and 607.4 Mcfd producer. <i>Oil &amp; Gas Journal, 6/9/86</i>
Utah	Skyline Oil Co.	Two laterals, 220 ft and 476 ft into vertically fractured formations	Nonproducer made more than 85 Mbo in 2 yrs after horizontal recompletion. Six of seven nonproducing wells at the field became significant producers. <i>Western Oil World, 2/86</i>
Denmark	MAERSK	1,500 to 2,500-ft chalk formations	Initial production was 2 to 4 times as much as nearby vertical wells. <i>Varde Bank/Offshore Newsletter, 8/88</i>
UK North Sea, Cyrus	BP	1,850-ft marginal field development	Initial production tests showed 6,000 bopd, "Significantly greater than expected from a conventional well" <i>Drilling Contractor, Oct-Nov. 1988</i>
Williston basin, USA	Meridan	2,000 to 3,300-ft fractured shale	Horizontal wells produced 258 to 275 BOPD and 110 Mcf to 300 Mcf of gas compared to about 609 BOPD and 35 Mcf of gas for nearby offset wells. <i>Oil &amp; Gas Investor, 12/88</i>
Prudhoe Bay, Alaska	Standard Alaska Production Co.	Up to 1,000 to 1,600 ft to alleviate coning problems	Early productivity index for horizontal wells averaged 3.5 times conventional wells. <i>The Technical Review, Schlumberger, Vol. 1., Jan. 1988.</i> Initial production of 9,000 to 10,000 BOPD for horizontal wells compared to 3,000 to 4,000 BOPD. SPE 15372, Wilkinson, Smith, Stagg, Walters
Offshore Holland Helder	Unocal	134 to 413 m alleviate coning problems	Reduced water cut and gross fluid production and achieved slower reservoir pressure decline. <i>Offshore Engineer, 11/88</i>
Italy, Rospo Mare	Eif-Italiana	1,600 to 2,000 ft fractured, cavernous formations	Production rates, 7 to 10 times vertical wells. <i>Oil &amp; Gas Journal, 2/29/88</i> SPE 14338, L.H. Reiss, 1985
Java Sea Indonesia	Arco	1,000 to 2,500 ft to produce thin	P.I. of nine horizontal wells averaged 5.4 times greater than three vertical wells in the same field. <i>Offshore, 2/88</i>
Canada, Norman Wells Ltd.	Esso Resources Canada	Up to 4,013 ft heavy oil, with water injection	Horizontal drilling increased field production from 3,000 BOPD to 28,300 BOPD. One horizontal well had initial production of 1,250 BOPD, and stabilized at 800 BOPD. <i>Petroleum Engineer International, 9/87</i>

Table 3. Improvements in horizontal drilling during the last decade (Mahony, 1988; Lang and Jett, 1990).

1. Downhole tools now permit deviation and azimuth measurements while drilling
2. Downhole motors are now steerable and have extended lives
3. Drilling fluids can be tailored to meet most hole cleaning or formation stabilization requirements
4. Bending stresses and buckling forces that act on drill pipe in horizontal holes can now be precalculated and designed
5. Evacuation of cuttings from horizontal holes is now achieved through appropriate annular velocities and new drilling additives
6. Horizontal holes are now routinely logged, cased, perforated and selectively treated
7. A variety of techniques to isolate zones have been utilized successfully
8. Equipment and methods are available to run liners and achieve zone isolation
9. Horizontal wells have been successfully cemented
10. Multiple-zone, high-pressure, and high-rate frac jobs have been successful on horizontal wells
11. It is now possible to open and close sliding sleeves and retrieve blanking plugs horizontally

The radius of curvature is equal to the horizontal distance and the depth required to turn the borehole from vertical to horizontal. The build rate is the angle of deviation from the vertical per unit distance drilled. For these types of wells, the build rate varies from 6 degrees/100 feet for long-radius holes to 3 degrees/foot for the short-radius hole (Table 4).

There is no single optimum way to drill a horizontal well. The choice of build rate and drilling system depends on the company objectives, the driller's capability, the geologic conditions encountered while drilling, the nature and depth of the target reservoir, and the size of the lease. The decisions on which choices are optimum are not yet clearcut as new completion techniques continue to be developed, as the effectiveness of horizontal drilling in field management continues to be evaluated, and as the versatility of the various options for drilling continues to be tested.

**Long-radius Wells**

Long-radius holes represent the oldest of the horizontal drilling techniques. The wells can be drilled using conventional rotary drilling tools, drill string, and techniques or may use new steerable motor systems in all ranges of standard oil-field sizes. The older conventional approach was to insert a whipstock into the hole to force the bit to deviate from its previous course.

Today the long-radius hole is accomplished by two approaches. One uses a specially designed bottom hole assembly (BHA) to achieve the build rate of 2-6 degrees/100 feet during the turn (Figure 1) (Fritz et al., 1991). The second approach uses

Table 4. Parameters for various types of horizontal wells (Mahony, 1988).

Feature	Short	Medium	Long
Radius of curvature	30'-45'	300'-500'	1,200'-3,000'
Typical build	191°-126°/100'	18.8°-11.5°/100'	4.8°-3.8°/100'
Feet drilled to horizontal	47'-71'	471'-785'	1,885'-4,712'
Feet of horizon. hole	75'-125'	500'-2,000'	1,000'-4,000'
Drilling assemblies	Whipstock, articulated tools, knuckle joints Compressive service	Conventional rotary Inverted drill string MWD, motor assemblies	Near conventional Rotary, MWD & motor
Drilling operations	Very specialized Single-shot/	Conventional MWD	Near-conventional MWD
Surveying	multi-shot		
Directional control	Initial aim only, off whipstock	Steerable	Steerable
Logging	None	MWD	MWD
Use in existing wells	Yes	Yes	Not likely
Cased horizon.	No	Yes	Yes

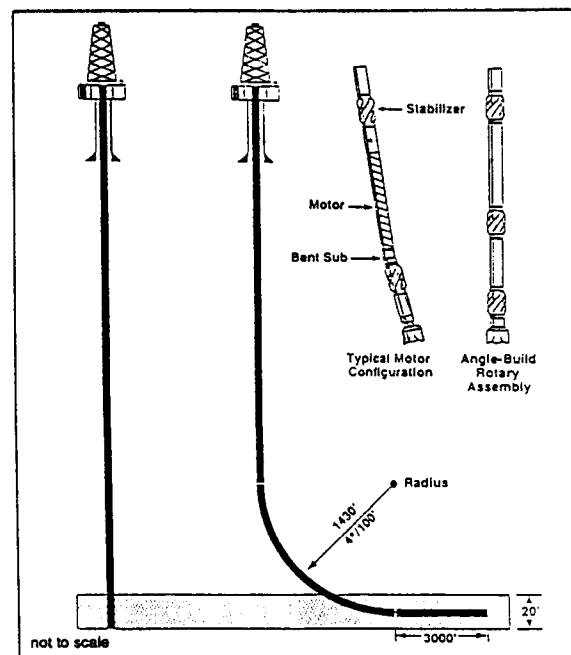


Figure 1. Long-radius horizontal hole (from DOE, 1990).

a downhole mud motor to turn only the drill bit. The build rate can be increased to 6–7 degrees/100 feet with a radius of 600 to 2,000 feet. Commonly a measurement-while-drilling device (MWD) is inserted in the drill string just above the motor. The MWD records information such as the natural gamma radiation and resistivity of the rocks being penetrated and the orientation of the bit, transmitting this information back to the surface to assist the driller in determining the location of the bit.

Long-radius holes are logged easily with standard wireline tools and can be completed selectively with standard tubulars and casing (Karlsson and Bitto, 1989). The wellbore may also be adapted to reciprocating rod pumping (Mahony, 1988). In steerable motor systems, long-radius wells can probably reach greater horizontal distances than the medium-radius method. Long-radius wells are generally used in conjunction with extended reach drilling such as offshore drilling platforms or pads to reach a target far removed from the surface location. Reaching out under lakes, rivers, townsites, or unfavorable terrain are other applications of these holes.

Application of long-radius wells in Kansas is very limited due to the minimum 1,430-foot radius or horizontal departure needed before it becomes horizontal. Small leases under 160 acres would be too limited to utilize long-radius holes (Table 5).

Table 5. Accommodation of horizontal wells by lease size (Henderson and Burge, 1990).

Lease Size (Acres)	Short 50-ft Radius	Intermediate 150-ft Radius	Medium 409-ft Radius	Long 1,430-ft Radius
20				
Min.	163	53	N/A	N/A
Max.	230	130	187	N/A
40				
Min.	550	450	191	N/A
Max.	775	675	269	N/A
80				
Min.	1,097	997	737	N/A
Max.	1,546	1,446	1,040	482
160				
Min.	1,870	1,770	1,511	490
Max.	2,637	2,537	2,131	691

Minimum = Perpendicular to the square lease  
 Maximum = Diagonal to the square lease  
 All square leases are based on 360-foot hard line from Henderson and Burge, 1990

### Medium-radius Wells

The medium-radius wells are the most popular of the horizontal options. These wells have been demonstrated to be practical and represent a proven drilling system (Henderson and Burge, 1990). The medium-radius wells have a turning radius of 300 to 700 feet (8–20 degrees/100 feet). The wells are drilled with conventional rotary equipment except for the bottom hole assembly (BHA). The BHA typically consists of a bit, a stabilizer equipped for slow speed, high torque downhole motor, an orienting bent sub, a nonmagnetic drill collar, and MWD equipment. Compressive service drill pipe and power swivels or top drives are also used (Mahony, 1988). In the horizontal portion of the well, an angle-hold assembly is used that generally consists of a bit, high-speed, low-torque, steerable downhole motor equipped with a bottom-hole or conical stabilizer, a nonmagnetic drill collar, and an MWD tool. The drill pipe is slowly rotated by means of a power swivel or top drive. The technology is more sophisticated than the long radius and accordingly is more expensive (Figure 2).

There are two approaches currently used to drill the medium-radius well. One utilizes the bent housing motor with a small preset angle within the motor section which can be rotated from the surface. This permits the correction of the azimuth of the well path during drilling. The other type is a positionally stable motor which cannot be rotated for azimuth correction. However, the turning radius of the latter is very predictable.

Special heavy-duty flexible drill pipe is used to accomplish the relatively tight turning and horizontal positions of the

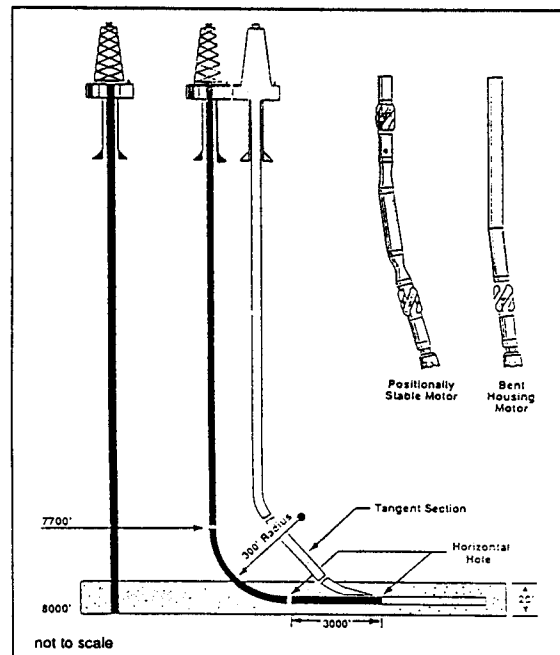


Figure 2. Medium-radius horizontal hole (from DOE, 1990).

well bore. MWD equipment is used in guidance. The turning position requires the exact knowledge of the target formation depth. Options include drilling separate segments of the turning radius until the target depth is reached.

The medium-radius horizontal wells offer more options than the long-radius holes due to the much shorter turning radius. The shorter radius means less hole below the dogleg creating less torque and drag. Hole sizes range from 4.5 inches to 12.25 inches (Henderson and Burge, 1990). The laterals can exceed 5,000 feet (J. Daniels, personal com., 1991) and can be selectively completed. The hole can also be logged using conventional equipment. Moreover, most types of artificial lifts can be used in the medium-radius wells.

The medium-radius hole is particularly well suited to Kansas. It can be used to re-enter and re-drill an existing hole no longer on production, saving the time and cost of drilling a new hole. A window is milled at the proper location above the target zone in the casing of the existing hole. Then a whipstock is positioned to initiate departure from the old well bore. The deviated hole is then drilled to completion.

The medium radius permits the hole to be drilled on small leases (Table 5). While lease size was a limiting factor for the long-radius hole, the medium-radius hole can be drilled on even a small area such as that offered by a 20-acre lease common to eastern Kansas.

The prominent position of the medium-radius hole in the industry is due in part to its practical applications to smaller reservoirs and leases. The development focus today is on improved operational efficiency and reduced costs (DOE, 1990). Slotted liners can be cemented in place to accomplish zone isolation and strength. Steerable motors are under development that are short enough or articulated to follow sharp-hole curvature permitting simultaneous correction of hole angle and azimuth. This added flexibility decreases the risk in making a successful completion.

### Short-radius Wells

The short-radius holes, also called drain holes, were the first to be attempted by using specialized tools such as universal joints, articulated drill collars, and stabilizers (Mahony, 1988). However, tools today are more sophisticated and more reliable. The turning radius varies from 20 to 40 feet. This tight turn is accomplished with two methods. The simpler method is the use of surface rotation of the bit with a special articulated drill pipe in the curved and horizontal portion of the hole (Figure 3). With surface rotation there is little directional control once the bit is advanced beyond the drill guide. Rotating friction and torque problems in the curved guide limit the horizontal hole length (DOE, 1990).

The other method to drill short-radius wells is through the use of new articulated motors and steering tools. These permit real-time course correction and extend the hole-length range.

However, MWD tools are not yet available for short-radius wells and thus the curved and horizontal portions can not be drilled as far horizontally as by the medium- and long-radius methods. Typical horizontal distances of the lateral for the short-radius hole are up to 300 feet, but 750 feet has been obtained. Horizontal holes are presently restricted to 4 3/4 to 6 inches in diameter. Wells are completed without casing or with slotted liners. Drain holes can be placed in several depths in a vertical borehole (DOE, 1990). Existing cased wells can be reentered and completed as short-radius horizontal wells using portable workover rigs (Henderson and Burge, 1990).

The geometry of short-radius holes makes them ideal for small leases and shallow reservoir applications. Critical controlled hole sections during the turn are reduced, limiting time during which problems are likely to occur. Also the short radius makes this the most precise approach to targeting the reservoir. This would be especially important in Kansas' thin reservoirs. For example, a gas cap could be drilled and cemented before lateral drilling is begun.

Vertical hole segments are closer to the pay section in short-radius wells, facilitating the use of pumping to lift oil from the well. A larger portion of the curve and horizontal hole will also remain in a single zone with a short-radius hole, potentially exposing more of the pay section.

### Ultra-short Radius Drain Holes

The ultra-short radius drain holes are a proprietary system that utilizes a water jet to drill horizontal drain holes, or radials, up to 200 feet with a turning radius of only 1 to 2 feet (Figure 4). A vertical well is drilled into the pay zone, and the

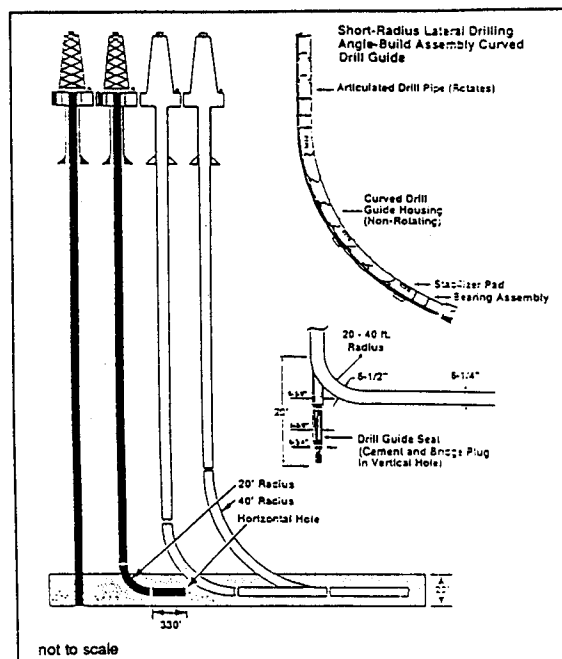


Figure 3. Short-radius horizontal hole (from DOE, 1990).

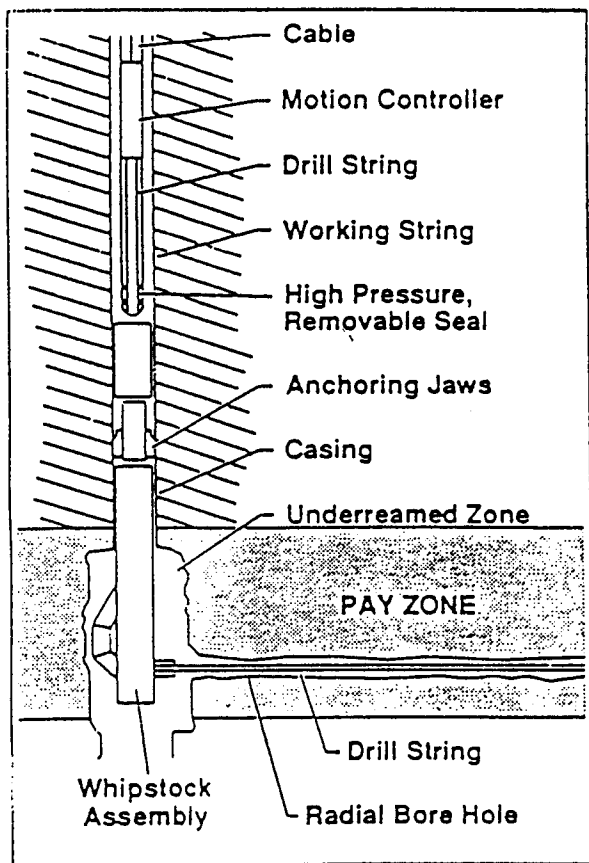


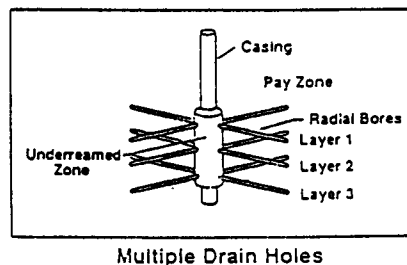
Figure 4. Ultra-short-radius horizontal hole (from DOE, 1990).

hole is under-reamed within the reservoir to a diameter of around 2 feet. The small-scale drill string with a hydraulic jet nozzle is lowered by a wire cable. The water jetting from the nozzle provides the drilling mechanism. The system's own internal hydraulic pressure pushes the drill string through a guide to advance it horizontally through the formation. The resulting hole diameter ranges from 1 1/2 to 4 inches depending on the hardness of the rock. Horizontal drain holes have been drilled out to 200 feet (Fritz et al., 1991). Several drain holes can be drilled from the same under-reamed pocket, e.g., forming spokes radiating from the vertical hole (DOE, 1990).

A potential applications limitation of the ultra-short radius drain hole is the possible reaction of water-sensitive constituents in a formation with the pressurized water. Reaction of the water with mobile or expandable clays encountered during drilling may decrease permeability near the borehole. Water reactivity also occurs in vertical holes. Employment of chemicals such as potassium or sodium chloride, water loss additives, diesel fuel or lease crude have often been used to reduce or eliminate formation damage in vertical wells and is appropriate for some of these horizontal wells.

#### Feasibility and Use of Horizontal Wells

The desirability of horizontal wells over vertical wells depends on well performance comparisons and economic considerations. Well performance improvements must be bal-



anced against the additional costs of drilling a horizontal well and any risk inherent in its completion and stimulation. Horizontal wells require careful engineering and the application of appropriate technologies (Economides, 1990).

The applications of horizontal drilling are varied and yet are quite specific. The list of applications will grow as horizontal well performance within reservoirs is better understood. **First**, horizontal wells can overcome reservoir anisotropy and reservoir heterogeneity. An example of the former is to intersect open fractures, particularly those where only one set (single orientation) of fractures is noted. In this fracture system, conventional fracture stimulation would only form additional parallel fractures. A horizontal well may encounter undrained compartments of the reservoir occurring between normal vertical well spacing. **Secondly**, horizontal wells have been used to reduce a variety of common drilling problems such as natural formation damage, pressure drawdown, coning, and production of loose sand from formations that contain moveable fines. **Thirdly**, when properly oriented, a horizontal borehole permits a controlled multi-frac operation to produce an artificial fracture zone in an otherwise unfractured reservoir. **Fourth**, horizontal wells can be used in situations where stress barriers in the seals above and/or below the reservoir are insufficient to contain an artificial vertical fracture. **Fifth**, the horizontal well provides information about the lateral heterogeneity of the reservoir. **Sixth**, a secondary recovery method is in place on the first day of production (Fritz, 1989).

In order to design horizontal wells to develop a heterogeneous reservoir, it is necessary to know the dimensions, the direction, and the occurrence of the anomaly. The effects of heterogeneities on a vertical well may be very different from those in a horizontal well. Depending on the type of heterogeneity, the horizontal well may or may not be particularly suitable (de Montigny and Combe, 1988). One must understand the three-dimensional framework of the reservoir to address this need.

Cleanup of formation damage in a horizontal well can be expensive and difficult or simply may not be possible in a horizontal well. Reservoirs particularly susceptible to formation damage may seriously limit or preclude the use of horizontal drilling. In addition, once water or gas breakthrough occurs in a horizontal well, few if any remedial options are available (Stagg, 1991).

**Fractured Reservoir**

It is common that fractures are subvertical below shallow depths. It follows that the best way of intersecting the greatest number of fractures is by drilling a horizontal well. When fractures are spaced at wide intervals, vertical wells are rarely

in contact with the network of fractures. Horizontal wells can result in high productivity gain as these vertical fractures are intersected. However, when fractures are closer together, the productivity gains of horizontal wells become lower (Figure 5).

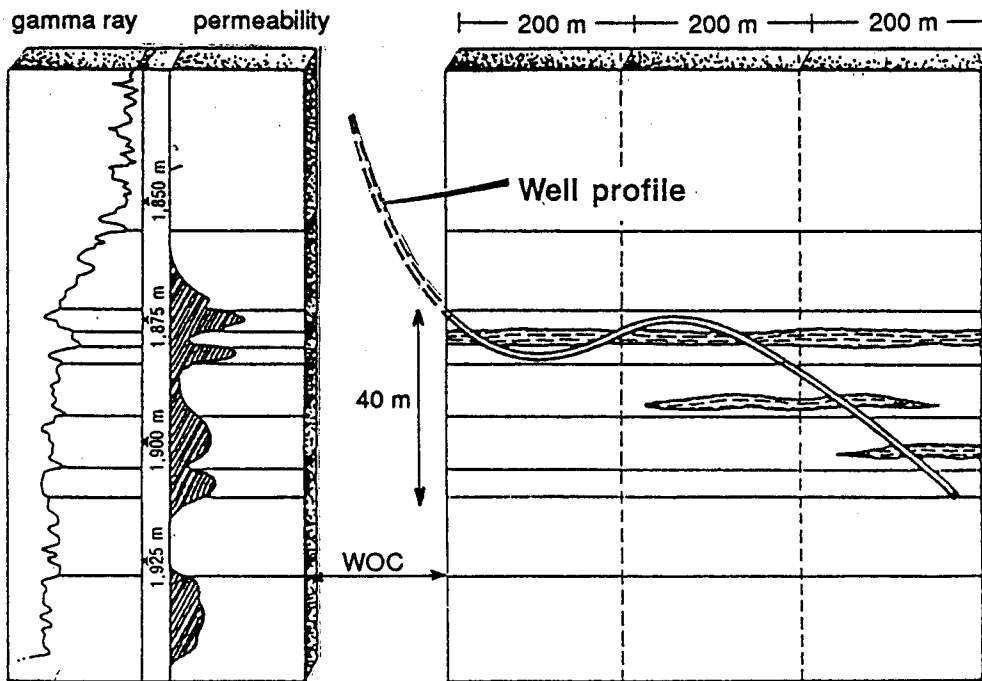
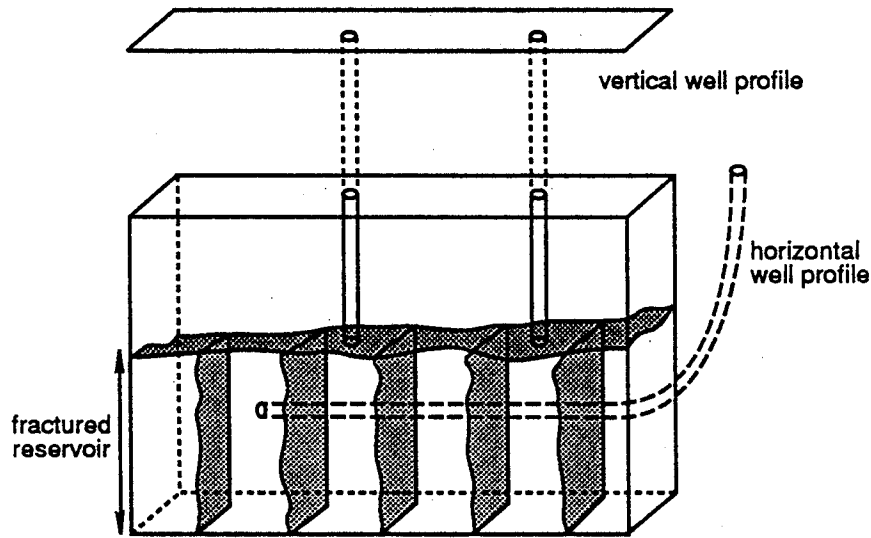


Figure 5. (a) Horizontal well intersecting vertical fractures; (b) horizontal well intersecting multiple, thin reservoirs.

The ratio of the productivity indices of a horizontal to a vertical well has been defined as follows (Giger et al., 1984),

$$J_h/J_v = \frac{\ln(r_{ev}/r_w)}{\ln\left[\frac{1+(1-L/2r_{eh})^2}{L/(2r_{eh})}\right] + (h/L) \ln(h/2\pi r_w)}$$

where:

$J_h$  = horizontal well productivity, bbl/day/psi

$J_v$  = vertical well productivity, bbl/day/psi

$r_{ev}$  = effective vertical drainage radius, ft

$r_{eh}$  = effective horizontal drainage radius, ft

$r_w$  = wellbore radius, ft

$L$  = length of horizontal well

$h$  = thickness of reservoir.

The steady state flow rate in the horizontal well,  $q_h$ , is predicted using an equation developed by Joshi (1988):

$$q_h = \frac{0.00708 k_h h \Delta p / (\mu_o B_o)}{\ln\left[\frac{a+(a^2-L/2)^2}{L/2}\right] + (\beta h/L) \ln(\beta h/2r_w)}$$

$a = L/2 [0.5 + (0.25 + (2r_{eh}/L)^4)0.5]^{0.5}$

$\beta = (k_h/k_v)$

$\mu_o$  = oil viscosity, centipoise

$k_h$ , horizontal permeability

$k_v$ , vertical permeability.

The smaller the beta term (horizontal-to-vertical permeability anisotropy), the larger estimated flow rate from a horizontal well. Thus horizontal wells are comparatively more attractive for vertically fractured reservoirs and thinner formations. Another relationship shown with the use of this equation is that an unfractured horizontal well can rarely, if ever, exceed economically the performance of a fractured vertical well in reservoirs that are obvious candidates for hydraulic fracturing (Economides, 1990). Fracture stimulation was one of the main reasons that horizontal drilling was seldom used in the period from the 1950's through the late 1970's. However, fracture stimulation introduces the risk that the induced fractures may plunge into an underlying aquifer and thus lead to rapid water breakthrough.

Fracture analysis is important in assessing the impact and design of horizontal wells. The analysis of natural fractures is based on the principle that fractures are always perpendicular to the least principal stress. In deeper wells, the least principal stress is in a horizontal plane. Induced and natural fractures are in a vertical plane. The magnitude and orientation of the least principal stress can be determined through: (a) direct measurement of microfracturing and least principal stress while drilling, (b) the use of long-spaced sonic log to estimate stress magnitude, and (c) strain relaxation studies (Soliman et al., 1990).

## Layered and Thin-bedded Reservoir

Thickness, permeability anisotropy, or stratification of the reservoir limit the potential success of horizontal wells. Thin beds (less than 50 feet) and low horizontal-to-vertical permeability anisotropy ( $\beta = k_h/k_v$ ) are better suited for horizontal drilling (Economides, 1990). The trajectory of a horizontal well can possibly be controlled to encounter different stratified layers, if their location is well understood. For example, a laterally compartmentalized sandstone or carbonate grainstone with permeable compartments separated by impermeable units all of which are confined to a particular stratigraphic interval would be a good target for horizontal drilling. The horizontal drain hole could pass from one compartment to another. The reservoir may be confined to a channel-form feature. With adequate control, the horizontal well could be placed along the axis of this channel deposit. Vertical wells may have inadequately drained the compartments.

The horizontal heterogeneity could initially be revealed by comparison of volumetric calculations of the reservoir with actual field and well performance, e.g., decline curve analysis, transient testing to detect and estimate the distance to flow barriers; or tracer tests to determine interconnection between injection and producing wells.

## Gas/Oil and Oil/Water Contacts

If a thin oil reservoir is associated with a gas cap or bottom aquifer, the situation becomes even more favorable for horizontal drilling. This involves what is called a critical flow rate. Over and above this rate an unwanted fluid, either gas or water, appears in production. The physical phenomenon associated with the increase in gas or water production is called coning. The forces of gravity tend to maintain the unwanted fluid in place, while the viscosity forces tend to cause water to rise or gas to descend towards the perforated interval as the well is produced and formation pressure around the wellbore is relieved. Above the critical rate of flow, those factors are no longer in equilibrium and breakthrough occurs.

Horizontal wells offer a solution by increasing the section of the reservoir exposed to the wellbore. The horizontal well permits fluid withdrawal over a larger volume of the reservoir. The nature of the flow path is vertical radial flow and horizontal pseudoradial or parallel flow compared to simply radial flow within a vertical well (Daviau et al., 1988) (Figure 6). The horizontal well can be placed at a maximum distance from the gas/oil or oil/water contact and productivity can likely be improved.

Controlling the vertical position of the horizontal well is mandatory. Basically it is an economics and a regulatory problem. In the absence of a gas cap or aquifer, the accuracy

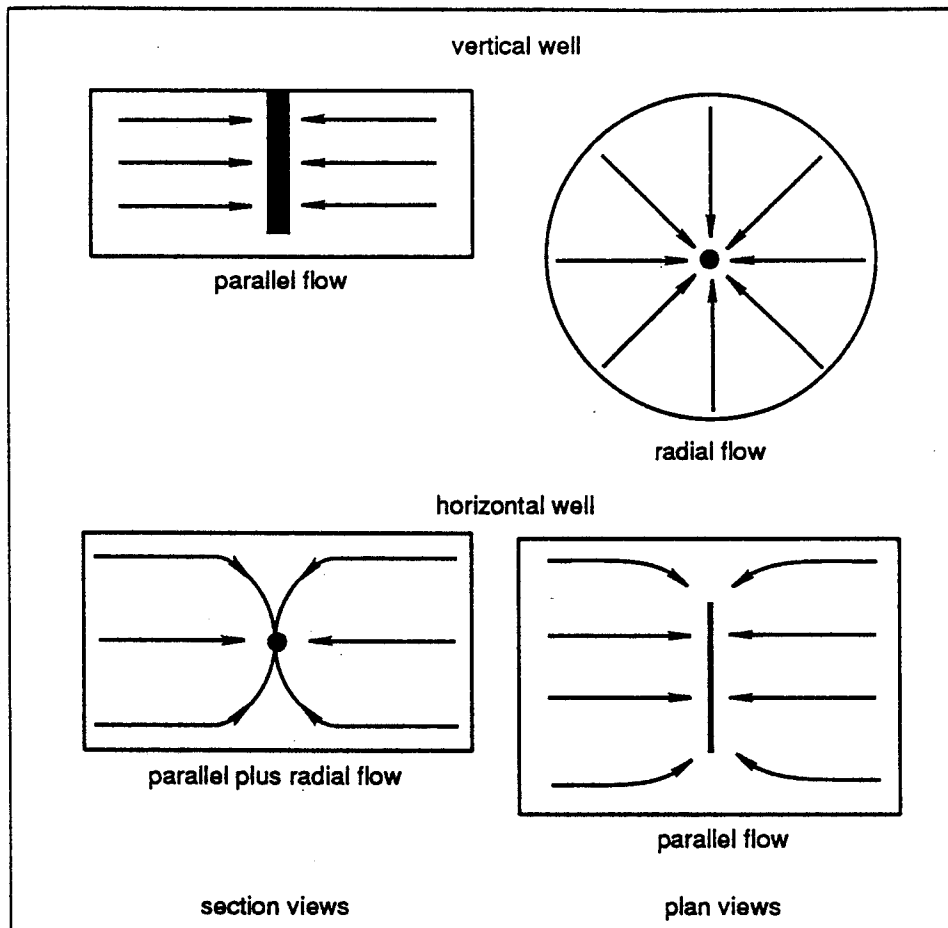


Figure 6. Flow paths to horizontal and vertical wells (from Giannesini, 1989).

is about +/- 10 feet. Existing tools can accomplish this at a reasonable cost (Gust, 1989). If there is a fluid contact, the accuracy will depend on the thickness of the oil column. If the oil column is less than 40 feet as it would be in most of the smaller Kansas fields, then the accuracy must be within +/- 3 feet. It is expensive to maintain this accuracy and may be a limiting factor for some potential applications.

Depleted reservoirs in a large field that originally had a 40+-foot-thick oil column will no longer have such an oil column. Obviously, economics and knowing details of the reservoir geometry and composition and present fluid conditions of the reservoir are imperative toward proper design and prudent evaluation.

MWD tools in long- and medium-radius wells can be used to follow a geological marker when there is structure or stratigraphic complexity that must be followed. This can assist in targeting the reservoir. It is therefore necessary to have nearby wireline log control with which to correlate.

#### Low-permeability Reservoir

A low-permeability reservoir with insufficient production may be helped by drilling a horizontal well to increase the

length of exposure to the formation. Also resistance to flow is nearly always negligible in a horizontal well (de Montigny and Combe, 1988). Production improvement provided by horizontal wells is higher for gas than for oil. With lower rate of flow per opened foot of formation, turbulence, which is typical of gas production, is practically nil in horizontal wells (Giannesini, 1989).

Holes also have been drilled with air (foam) extending the possible applications to sensitive tight gas-bearing formations. The extraction of coal-bed methane is a possible application of horizontal drilling under certain conditions.

#### Water Drive or Water Injection

In either an active water drive or a water injection program in an oil field, a water/oil interface sweeps the reservoir and displaces the oil towards producing wells. The oil producing rate may slow down considerably if rapid breakthrough of water occurs in the producing wells. As the water cut increases, the oil flow rate decreases. As a consequence, cumulative recovery flattens out in time. The well may be shut-in with a low recovery if the oil flow rate no longer covers the operating costs (de Montigny and Combe, 1988). Water breakthrough occurs faster as the water-to-oil mobility ratio increases.

A horizontal well can improve productivity by making the pressure sink less intense. The greater dispersion of the withdrawal results in a pressure sink which is no longer concentrated at a single point, hence the deformation of the oil/water contact is smaller and sweep volume is therefore increased.

Horizontal wells are particularly amenable to improving recovery from heavy oil reservoirs (de Montigny and Combe, 1988). Water is much more mobile than the heavy oil in these reservoirs (very high water-to-oil mobility ratio). Thus water cut increases very quickly after breakthrough. The water-free phase can last much longer in a horizontal well drilled into a heavy-oil reservoir. Chances are that the vertical wells would have done a poor job of removing the heavy oil by either primary or secondary recovery, leaving a significant opportunity for horizontal drilling. These exhausted vertical wells may leave a gravity drainage situation that is described further below.

In low permeability reservoirs, pressure drop in the reservoir limits the oil and water producing potential of vertical wells. The horizontal well increases the oil plus water productivity. This enables the duration of two-phase (oil/water) production to be considerably extended as large quantities of oil are recovered.

### Gravity Drainage

Horizontal drain holes can be placed low in a pressure-depleted reservoir to assist in extracting remaining oil. This should be much more effective in recovering oil compared to vertical wells. A novel operation run by Three Star Drilling and Producing in Illinois utilizes 33 horizontal drain holes extending upward from 300 to 2,000 feet into a Pennsylvanian sandstone reservoir from an excavation room. Approximately one barrel of oil per day is tapped from each 100 feet of horizontal hole. The crude is 38° gravity oil (Nation, 1990).

Another project operated by Kaycee Oil Company in Wyoming has two workrooms and 40 horizontal wells totaling 70,000 feet of hole. The wells have produced between 100 and 250 BOPD using air, water, and polymers to drive oil to the drain holes. A shallow reservoir with at least 75,000 barrels recoverable per acre is required to make such a program work (Nation, 1990).

### Enhanced Recovery

Horizontal wells also have good potential in enhanced oil recovery (EOR) procedures. For instance, steam injection rates can be increased in horizontal wells and a greater amount of oil can be heated directly.

Table 6. Present applications of horizontal drilling for various types of horizontal wells (table 2, DOE, 1990).

Applications	Horizontal Well Technology				
	Ultra-Short Radius	Short Radius	Medium Radius	Long Radius	Advanced Concepts
<b>GAS DEVELOPMENT</b>					
Naturally Fractured		X	X	X	
Low Permeability		X	X	X	X
Low Energy		X	X		X
Extended-reach			X	X	
Thin Formations		X	X	X	
Multiple Strata (Sands/Coals)		X	X		X
<b>OIL DEVELOPMENT</b>					
Naturally Fractured	X	X	X	X	X
Water Coning	X	X	X		
Low Permeability		X	X	X	X
Gas Coning	X	X	X		
Thermal Recovery	X	X	X		
Low Energy Reservoirs	X	X	X		X
Irregular Formations		X	X		
Extended-reach				X	
Thin Formations			X		
EOR Mobility Control	X	X	X	X	
<b>OTHER APPLICATIONS</b>					
Gas Storage		X	X		X
Oil Storage		X	X		X
Solution Mining	X	X	X		X
Residential Utilities	X	X			
River Crossings				X	
In-Mine Gas/Oil Production				X	
Environmental Mitigation	X	X	X	X	X

Poor injectivity of polymers is mainly due to high velocities of injection near the wellbore. These higher velocities may also cause polymer molecules to break up. Horizontal wells should reduce this risk in creating polymer instability. Horizontal wells can result in parallel flow in contrast to the radial flow of vertical wells. This can spread the chemical over a longer distance into the reservoir (Bruckert, 1989). Properly positioned, the horizontal well can help to establish a miscible slug.

### Development Drilling

In general, one would anticipate fewer horizontal wells would be needed to develop a field than vertical wells. Moreover, production rates could be accelerated above those of vertical wells. In order for this to be true, the horizontal wells need to be strategically placed in the reservoir and sited by considerations of the three-dimensional architecture of the

reservoir. Better knowledge of the fluid flow behavior in horizontal wells and methods of their completion will reduce the risk in such future endeavors.

Present applications of horizontal drilling are listed for each type of horizontal well in [Table 6](#). A survey of horizontal wells in 1990 by the *Oil and Gas Journal* indicates that the dominant type of reservoir heterogeneity identified in reservoirs to be tested was fractures (54%). The main reservoir lithology of these wells is shale (40%), followed by chalk (14%), sandstone (11%), limestone (9%), karstic limestone (8%), and unconsolidated sand (7%) (Moritis, 1990).

### Drilling A Horizontal Well

The selection of a candidate reservoir is not presently done with any hard-and-fast rules. Much depends on what the individual operator is trying to accomplish. In general, it is believed horizontal drilling will be used chiefly for production enhancement — to recover the most hydrocarbon at the smallest cost (Mahony, 1988). Parameters that are considered include: depth, pay thickness, reservoir drive mechanism, porosity, absolute permeability, formation pressure, character of reservoir rock, original fluid saturations, oil and gas characteristics, reservoir temperature, vertical restrictions in the reservoir, location of lease lines, required spacing, production history, hydrocarbons originally in place, hydrocarbons remaining, casing and hole sizes, anticipated completion and production techniques, economics, and market (Mahony, 1988).

Drilling plans include choosing an entry point into the reservoir and a minimum length of hole to be drilled inside the reservoir at a given angle. The entry point is called the target and the section inside the reservoir is the drain hole. The driller develops a designated trajectory to reach the target. This plan is typically prepared by a team of experts including the reservoir and production personnel. The phases of actual drilling of the well are the vertical drilling; deviated drilling, if any; the approach phase (when the build angle is done to the target); and the horizontal drilling phase. The approach phase is the most critical because the exact location of the target is never precisely known ([Figure 7](#)).

The driller is like a pilot landing an airplane on a runway whose altitude is not known. If the runway is lower than expected the driller will “fly over” it, if it is higher the driller will “crash” into it. The driller adjusts the trajectory to a target that is, step by step, revealing its position. The driller uses the MWD tool to read the material surrounding the borehole, much like the pilot sees around the plane. The MWD tool primarily makes use of the natural gamma ray and resistivity to identify geological markers to help the driller determine the vertical distance between the bit and the target as the drilling proceeds (Giannesini, 1989). If the well “crashes,” it is now possible to kick out higher in the existing hole and begin the build angle more sharply. Also the steerable motor can turn the lateral upwards to re-enter the

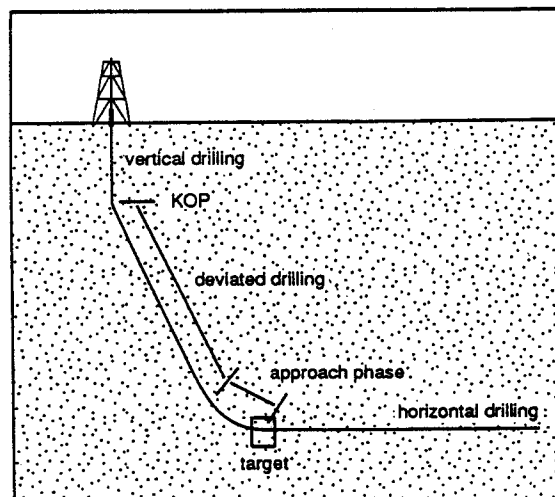


Figure 7. Trajectory and terminology of horizontal well (from Giannesini, 1989). KOP—kick-off point.

reservoir, if this distance is small. Steerable motors can also direct the bit downward to intercept the formation, if the “flyover” is shallow.

Most horizontal wells are landed this way. However, thickness between the last marker and the target may not be reliable. The solution may be to first penetrate the reservoir at some high angle to locate the target depth. Then the well is sidetracked to the proper elevation.

MWD tool selection has been growing over the last few years and offers a substantial first look at the strata encountered during drilling. The tools presently available include the gamma ray, oriented gamma ray, resistivity, temperature, neutron, density, annulus and drill pipe pressure, hole size indicator, and inclination and direction. The hole size required runs from 4 3/4 to 9 1/2 inches (Fritz et al., 1991).

### Economics of Drilling a Horizontal Well

The costs are difficult to estimate because they depend on so many factors. The average horizontal well in the United States drilled in 1990 cost \$1.2 million or \$475/horizontal foot. Austin Chalk wells with a typical 3,000-foot horizontal drain hole averaged \$360/horizontal foot (Moore, 1991). In general, the latest figures suggest that horizontal wells will cost 1.4 to 3 times more than the vertical, the longer the drain hole, the more expensive the well will be (Brown, 1991).

Seven key parameters that affect the economic success of a horizontal well were pointed out by S. Lacy (in Brown, 1991):

- 1) fracture intensity and direction,
- 2) pay thickness with a lower limit of 10 feet without a gas cap or bottom water or 20 feet otherwise,
- 3) well spacing, producible reserves per horizontal well need to be large enough to offset higher costs of drilling,

- 4) vertical permeability is necessary to ensure good communication between parallel zones for proper drainage to the horizontal well,
- 5) avoid formation damage since it is not easy to eliminate in the horizontal well,
- 6) conduct post-drilling cleanup of borehole,
- 7) have effective geological control where the horizontal well is drilled.

Joshi (in Brown, 1991) suggests that it is desirable to drill along a low quality trend in a reservoir where there had been problems with drilling.

### **Case Study Summaries**

The following are summaries of three applications of horizontal drilling, the well-publicized Austin Chalk of south-central Texas, the Bakken Shale of the Williston basin, and the Roso Mare oil field in Italy. The examples illustrate the results of drilling horizontal wells in naturally fractured chalk, brittle shale, and a karstic limestone.

#### **Case Study: Austin Chalk, a Naturally Fractured Reservoir**

A very publicized success story for horizontal drilling is the naturally fractured and, in part, cavernous Austin Chalk of south-central Texas (Holifield and Rehm, 1989). Some 4,000 new and redrilled horizontal wells are anticipated to be drilled in the Austin Chalk between 1989 and 1995. Despite large flow rates of over 5,000 BOPD in horizontal wells completed in chalk, three-fourths of the wells have IP's of under 500 with a third of these under 100 BOPD. Twelve percent have flowed initially over 1,000 BOPD (Lang and Jett, 1990).

The Austin Chalk produces along a trend that is about 10 miles wide extending from the Texas-Mexico border to just north of Houston, Texas. Oil production ranges in depth from greater than 7,000 feet (oil with water), 7,000-9,000 feet (all oil), and deeper than 9,000 feet (oil and gas). At least part of the oil is thought to be self-sourced (Fritz et al., 1991).

The Giddings field is over 60 miles long, encompassing four counties. Horizontal drain holes in Giddings field range from 300 to 1,250 feet. These were drilled from existing depleted wells in the Giddings field. Those horizontal wells have generally paid out in three to 24 months. The maximum hole length of 1,200 feet is determined by cost and return on investment. Fractures seldom lie farther apart than this distance.

The thickness of the Austin Chalk varies from 100 feet to 800 feet thick. Oil production has been almost exclusively from natural fractures and faulting. Operators have used local and regional geological models to identify fracture systems. Many of the fractures correlate to tensional, high-angle, down-to-the-coast faults. Seismic profiles have been used to

confirm faulting and presence of fault blocks. Fractured chalk is also linked to sites of rapidly changing dip. Fracture systems extending several miles are associated with vugs and larger cavities (small caverns) (Holifield and Rehm, 1989).

Horizontal medium-radius drain holes are drilled from old wells using a BHA of a special directional 4 1/2-inch polycrystalline diamond bit, downhole motor, stabilizer, wireline steering tool assembly, and 2 7/8-inch slimhole (slick) drill pipe, attached to regular drill pipe. The latter runs through the vertical section of the hole. A biopolymer mud, low bit-weights, and hydraulics for high-speed bit rotation are used. The build rate ranges from 10 to 30 degrees/100 feet. A modified double-drum, truck-mounted workover unit is used to drill the horizontal hole. Biopolymer muds have resolved some of the problems in formation damage and cleaning of the hole associated with horizontal wells (Seheult et al., 1990).

In the Giddings field both pressured and depleted fracture systems are encountered during horizontal drilling. Pressured fracture systems are isolated from depleted zones with an inflatable external cement packer run as part of a liner. Drain holes are completed through 2 7/8-inch liners slotted or perforated over the interval having the best mud log shows. Wells are completed natural or with fracture stimulation (high pump rates, large fluid volumes, and small amounts of sand). Well costs average \$350,000. Ultimate recovery from these wells averages 125,000 barrels of oil equivalent (BOE). Initial production rate usually exceeds 150 BOEPD. Decline rates are initially 40 to 50%, typical of fractured reservoirs. After this initial rapid decline, production rates become hyperbolic in shape depending on the contribution of fluid from the matrix pores. Payout comes in less than two years for the average horizontal well.

Reserves in the Austin Chalk in the Pearsall field in south Texas have shown substantial increases. Since 1936 two thousand conventional vertical wells have produced an average of 30,000 barrels of oil per well. New horizontal wells have already recovered in excess of 100,000 barrels per well. A few have also produced in excess of 300,000 barrels. Production tests of the horizontal wells have been as high as 6,400 BOPD (Moritis, 1990), while conventional vertical wells in the same field produced between five and 15 BOPD (Stayton and Peach, 1990).

#### **Bakken Shale in Williston Basin**

Meridian Oil and a number of smaller independents are revolutionizing the economic recovery of oil from the naturally fractured Bakken Shale found at a depth of 10,000 feet in the Williston basin of North Dakota. The Bakken Shale is lower Mississippian or upper Devonian age and is equivalent to Exshaw, Pilot, Woodford, Chattanooga, Antrim, and New Albany shales in other locations in North America (Fischer and Rygh, 1989). Over 25 horizontal wells have

been completed at average rates of 250 BOPD compared to only a few BOPD from earlier produced vertical wells (DOE, 1990). Productivity has been improved from two- to five-fold in the horizontal wells.

The Bakken formation is divided into an upper organic-rich black shale, a middle tight siltstone/limestone, and a lower organic-rich black shale. The combined thickness ranges from 145 feet to a feather-edge in the Williston basin. The shales are hard and fissile. The productive section ranges in thickness from a few feet up to 10 feet.

The Bakken Shale is currently productive along or adjacent to the Nesson anticline. Vertical holes generally have low potentials in this area (less than 100 BOPD). Porosity is below 5% and permeability is seldom greater than 0.2 md. Large vertical fractures occur often and greatly increase the permeability. A fractured reservoir is considered necessary for production. Tectonic fracture systems are important to creating economically viable reservoir rock including those associated with regional lineaments related to regional tectonic elements expressed in the basement (Gerhard et al., 1982) and those associated with folding over local basement structures.

An overpressure of 0.6 psi/ft is often associated with the Bakken. Microfractures are locally common and are essen-

tial for production after wells are fracture stimulated. Overpressuring and microfractures are associated with active petroleum generation from the shales (Fisher and Rygh, 1989).

The horizontal wells are medium radius with length of the drain hole around 2,500 feet. A sample comparison of vertical and horizontal wells prepared by Meridian indicates the following:

	<u>vertical well</u>	<u>horizontal well</u>
initial production	120 BOPD, 96 MCF	480 BOPD, 384 MCF
reserves	184 MBO, 148 MMCF	364 MBO, 291 MMCF
payout	1.9 years	1.0 year

**Rospo Mare Oil Field, Italy**

The Rospo Mare oil field in the offshore Adriatic contains a 400-foot-thick Lower Cretaceous karstic carbonate reservoir. The upper 230 feet consists of widened vertical fractures while the lower layer, 160 feet thick, consists of vugs and partially filled horizontal caves. An oil/water contact exists in the lower interval connected to an active aquifer. Relief on the upper surface is on the order of 100 feet (Figure 8). Porosity of the karstic voids is 1.8% with vertical fractures of the upper zone spaced some 300 feet apart. The oil is very low gravity at 11.9°. The field covers some 45,000 acres with OOIP of over one billion barrels.

Vertical wells have been nearly ineffective in recovering oil from the vertical fractures, vugs, and caves that characterize the upper portion of the reservoir. Six horizontal wells with 2,000-foot drain holes are producing 19,000 BOPD compared to 3,000 BOPD from three vertical or deviated wells (Dussert et al., 1988).

Horizontal wells intersect the vertical fractures. The ratio of the horizontal to vertical permeability is obviously very high in the upper oil-filled zone, making horizontal wells particularly attractive in spite of the significant thickness of the reservoir.

**Flatrock Field, Osage County, Oklahoma**

A medium-radius horizontal well was drilled during 1990 in the Middle Pennsylvanian Bartlesville Sandstone in the Flatrock field, Osage County, Oklahoma, by Rougeot Oil and Gas Corporation. The Flatrock field was discovered in 1904 and was fully developed by 1924 with over 1,000 development wells. Well spacing is under 10 acres. The field has produced in excess of 30 million barrels. Millions of barrels of mobile oil are still estimated to be in the ground, but have not been producible in economic quantities with currently available vertical oil-well drilling and completion technology. Problems encountered in this reservoir include water coning and thin, low permeable reservoir. Horizontal drilling provided the additional opportunity to allow for economic production. The DOE underwrote the drilling costs of a horizon-

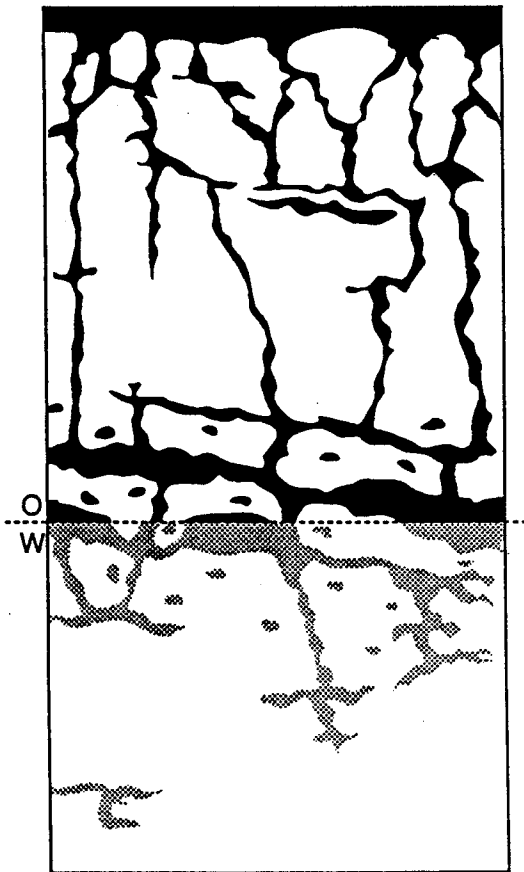


Figure 8. Sketch of Lower Cretaceous karsted, fractured reservoir in Rospo Mare oil field in Adriatic Sea (from Dussert et al., 1988).

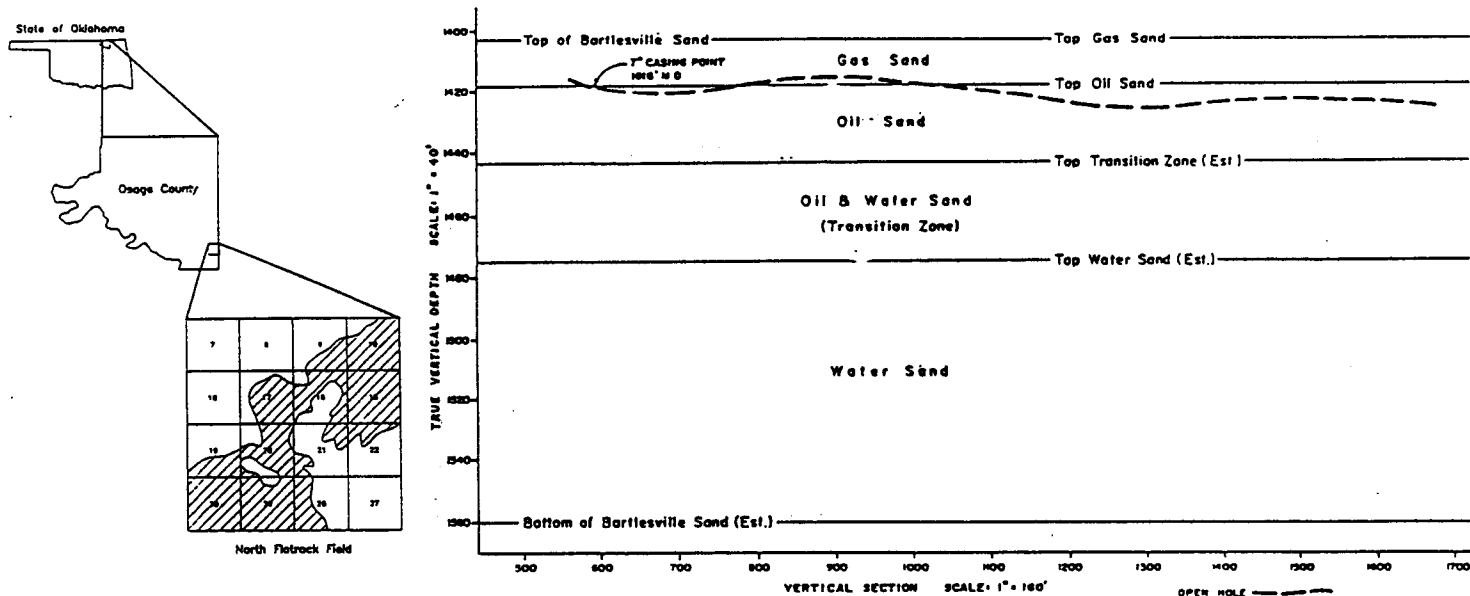


Figure 9. (a) Index map showing location of Flatrock field; (b) vertical cross section of completed horizontal well in Bartlesville Sandstone in Flatrock field (Rougeot and Lauterbach, 1991).

tal well in an effort to determine the feasibility of obtaining economic oil recovery.

The oil-bearing zone in the Bartlesville Sandstone is located at shallow depths (~1,400 ft), has low permeability, is thin (10 ft), and is underlain by a thick aquifer comprising the lower 10 to 30 feet of the sandstone below the oil/water contact. The depositional system is classed as a fluvial-dominated delta.

The horizontal portion of the well was to be 1,000 feet long at a vertical depth of 1400 feet. The target is 100 feet by 200 feet wide. A 1,050-foot horizontal well was drilled at a cost of \$150,532 (Figure 9). The production stabilized at 6 BOPD and 0.84 BWPD, some 200-600% greater than a typical unstimulated vertical well. Although this pilot well is uneconomic, it was recommended that further investigations of horizontal well-bore clean-up/stimulation and effects of selecting wellbore direction in non-fractured reservoirs are needed in order to develop the full potential for horizontal drilling in the midcontinent. Details are described in Rougeot and Lauterbach (1991).

#### **Black Field, Miami County, Kansas**

Horizontal drain holes were drilled in 1943 and 1944 in an attempt to economically extract remaining mobile oil from an abandoned lease in the Black field located in SW sec. 9, T. 19 S., R. 24 E., in Miami County, Kansas (about 4 miles north of LaCygne) (Abernathy and Jewett, 1946). The site is near where oil was first discovered in Kansas as oil seeps along Wea Creek near Paola, Kansas, in 1860.

The fourteen drain holes were drilled from a 7 foot x 7 foot shaft at a depth of 230 feet. The objective horizon was the main pay zone, the "Wayside" or "Walter Johnson" sandstone

in the Nowata Shale Formation of the Desmoinesian Marmaton Group. The shale averaged 25 to 30 feet thick and occurs at a depth of around 210 feet below the surface. The field originally discovered in 1927 had produced on the average of 600 barrels per acre.

A portable drilling machine was used to drill the shaft after initial vertical holes were shot with nitroglycerine. The shaft was cribbed and later cemented in an effort to hold back water. The water apparently later became a problem in maintaining a successful operation. The drain holes were drilled with a core-drilling machine with diameters of 3 3/4, 3 7/8, and 4 1/4 inches. The maximum horizontal drain-hole length was 700 feet and the minimum drain-hole length was 350 feet. Total footage of the drain holes amounted to over 7000 feet. Each hole was cased for the first 40 feet with 3 or 3 1/2 inch pipe. This pipe was cemented into the hole. The drain holes were connected to a small tank to catch the oil which acted like a sump for a pump that brought the oil to the surface. Each drain hole was equipped with a valve. Thomas reported the oil was 29° to 31° gravity and that the project would flow 25 to 50 BOPD (Abernathy and Jewett, 1946).

A later report indicated that the operation was not successful with little or no commercial oil produced. No reason was given why the venture was not a success (Jewett, 1954).

#### **Muhlheim Field, Trego County, Kansas**

Phillips Petroleum Company drilled a horizontal well in the Muhlheim field in an attempt to increase production from the basal Marmaton. An Arbuckle producing well, the #A-4 Muhlheim (NE SW SW sec. 14, T. 13 S., R. 21 W.) in February 1985 for 37 BOPD and no water from the Arbuckle

Group. The Marmaton Group interval including the basal conglomerate was cored in this well. The Marmaton directly overlies the Arbuckle Group. The basal portion of the Marmaton is a conglomeratic limestone and is thought to be transitional to the basal Pennsylvanian conglomerate. According to the Independent scout card, the 28-foot core contained abundant brecciated and conglomeratic chert and limestone clasts with many fractures including vertical ones and vugs. Most of the porosity had abundant oil staining.

Phillips drilled an offsetting dry hole in 1986, the #A-5 Muhlheim (NW SE SW sec. 14, T. 13 S., R. 21 W.). No cores or DST's were run. In 1988 this well was re-entered and a 179-foot horizontal borehole was cut at the level of the Marmaton within the fractured conglomeratic interval. The vertical-to-horizontal distance was only 29 feet, a short-radius hole, even though the well had been planned to have a 400-foot horizontal drain hole. The well was completed as an oil well for 67 BOPD and water.

The "A" Muhlheim lease presently has four producing wells with combined oil production of 19 BOPD. Cumulative oil production of the lease as of June 1990 is 112,930 barrels. Production is commingled between the Lansing-Kansas City, Marmaton, and the Arbuckle.

#### **Application of Horizontal Drilling to Kansas Reservoirs**

Kansas contains reservoirs that should receive further consideration as targets for horizontal drilling. The following discussion is organized according to the characteristics of these reservoirs that make them attractive to horizontal drilling. Further information on the reservoirs can be found in the Kansas Geological Survey's Subsurface Geology Series 9, *Stratigraphic and Spatial Distribution of Oil and Gas Production in Kansas*, by Newell et al., published in 1987, and studies as listed in the *Bibliography of Kansas Geology*, by Sorensen et al., Kansas Geological Survey Bulletin 221. Also the five volumes of field studies published by the Kansas Geological Society provide useful background material. A general introduction to petroleum activity in Kansas can be found in Baars et al. (1989). The reservoirs are identified on the following stratigraphic chart (Figure 10).

#### **I. Connecting Vertical Fractures/Fissures**

In general, medium- and short-radius horizontal wells would be appropriate for developing vertically fractured reservoirs. Lease size may have to be modified to accommodate the horizontal well. The length of the drain holes will vary according to the targeted reservoir and the nature of its distribution and fluid properties. The previous discussion should be helpful in beginning a screen of the reservoir and the evaluation of the feasibility of drilling a horizontal well.

**A. Niobrara Chalk.** The Upper Cretaceous Niobrara Chalk is a shallow, low-pressure, low-permeability gas reservoir in northwestern Kansas. The most productive interval in Kansas is the Smoky Hill Member. The Smoky Hill Member averages some 60 feet in thickness. Porosity is around 40%, characteristic of the chalk at these shallow depths (Lockridge and Scholle, 1978). Matrix permeability is very low. The chalk is brittle and fractures easily. Small folds and domes and faults have led to local reservoir development and gas accumulation at depths between 900 and 1,200 feet (Brown et al., 1982). This latter point is key. The structure must be studied locally to discern orientation of the folding and faulting. The horizontal well would be directed so that it would intersect a number of the dominant fracture systems.

The properties of the chalk are essentially the same as that of the Austin Chalk in south Texas. They are age-equivalent, but have undergone different structural development. However, the substantial down-to-the-basin faults that have produced a distinctive fracture pattern in Texas are lacking in Kansas. The faulting in Kansas is much more subtle and less well defined. Local studies and subsequent drilling of the Niobrara Chalk have yielded gas production in northwestern Kansas (Beene, 1990). The foam-fracture stimulated vertical wells have typically produced several hundred MCF per day and less. It is possible that horizontal wells could improve this flow rate by contacting more of the natural fractures. On the other hand, the low pressures suggest that the flow rates would not be substantial for a horizontal well and would adversely affect its economic viability.

**B. Mississippian Limestones.** The Mississippian limestones are, in part, fractured although these reservoirs are noted for significant depositional and diagenetic porosity. Possible targets for horizontal drilling may exist in the later porosity development in addition to fractured reservoirs. Linear belts of some of the thicker lobes of porous oolitic grainstone reservoirs in the St. Louis Limestone may be possible targets for horizontal drilling in southwestern Kansas (Figure 11).

Oil production has been significant from the St. Louis interval. Cores from the St. Louis Limestone from Damme field in Finney County indicate complex internal lithofacies comprise the upper portion of the St. Louis including open shelf, mobile grain shoal, tidal inlet and lagoon, intertidal mud flat, and marine sand belt (Handford, 1988). The best porosity development from the Damme field is found in the marine sand belt facies of the B-zone of the St. Louis Limestone. This oolitic marine sand belt in Damme field is an elongate and lenticular grainstone body 10 miles long, 2 miles wide, and up to 18 feet thick (Figure 12). This unit is similar in dimensions, shape, and composition to modern marine sand belts described by Ball (1967) in the Bahamas (Handford, 1988). Horizontal wells within these pods may be warranted, if barriers to fluid flow are indicated due to reservoir heterogeneity.

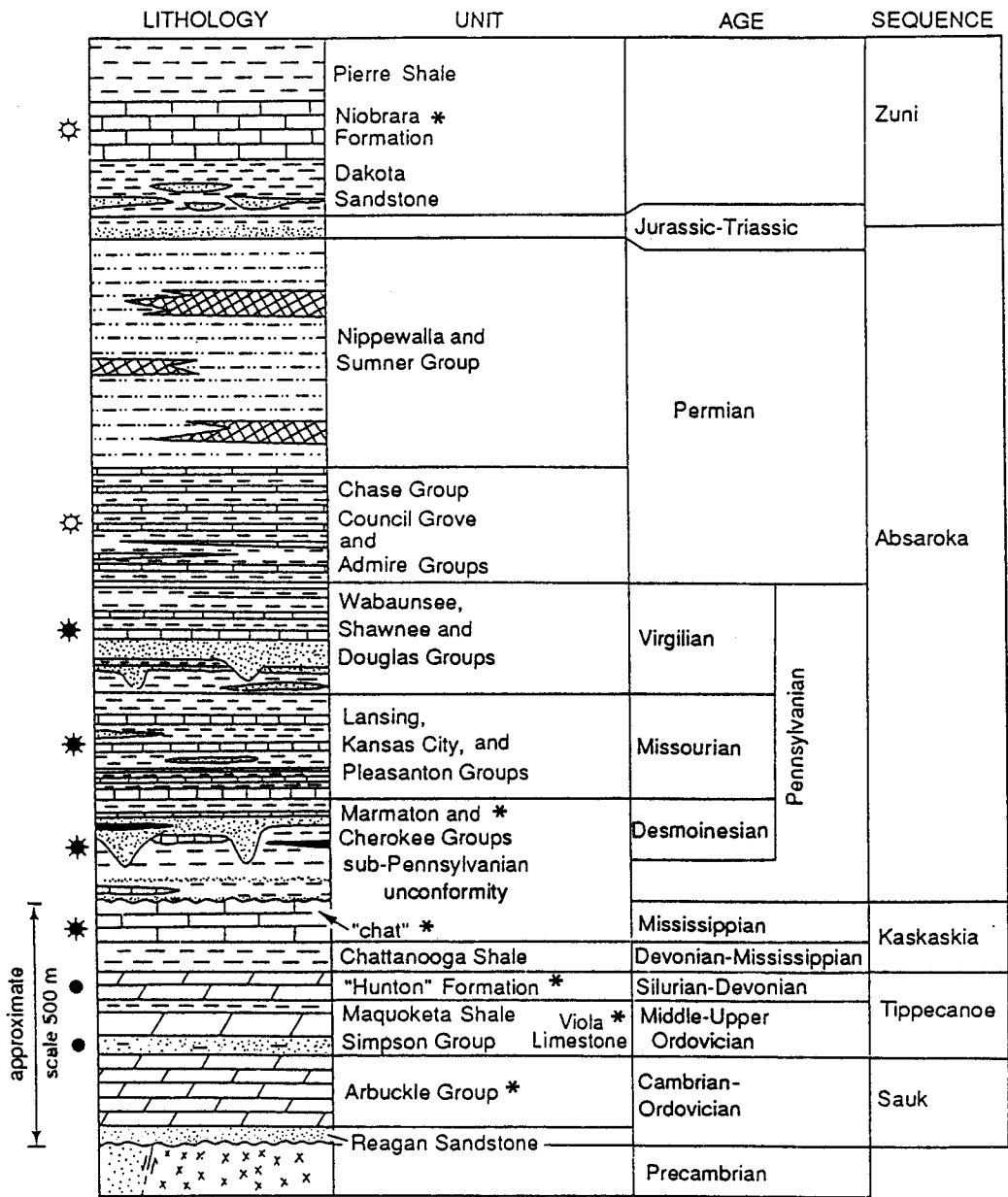


Figure 10. Stratigraphic column for Kansas identifying targets (asterisks) for horizontal drilling.

Other prospective sites for considering horizontal drilling include the porous quartzose carbonate grainstones of the Chester limestones in southwestern Kansas and porous dolomite zones of the Warsaw Limestone along the Pennsylvanian subcrop along the western flank of the Central Kansas uplift, e.g., Bindley field in Hodgeman County (Ebanks et al., 1977). Karstic weathering profiles recognized at the top of the Mississippian interval suggest additional targets for horizontal drilling. The karsting apparently resulted from prolonged weathering associated with the regional unconformity found at the top of the Mississippian (Nodine-Zeller, 1981).

Dolomitic, vuggy, and highly fractured chert is found at and near the Pennsylvanian subcrop of the Osagian Mississippian in south-central Kansas, e.g., Rhodes field in Barber County (Thomas, 1982). The dolomitic cherty facies of the Mississippian is actually quite extensive, covering a large interval of the Mississippian strata and region of extreme southern Kansas and northern Oklahoma. This chert-rich interval is commonly referred to as the "Cowley facies." The cherty interval typically consists of dark silty dolostone and dark dolomitic cherts. This cherty interval ranges up to nearly 500 feet thick in southwest Kansas and ranges from Kinderhookian

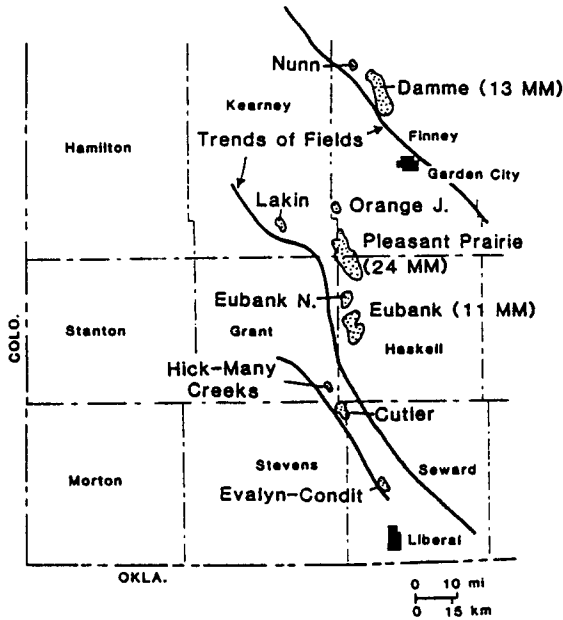


Figure 11. Mississippian fields and their trends in the Hugoton embayment (from Handford, 1988).

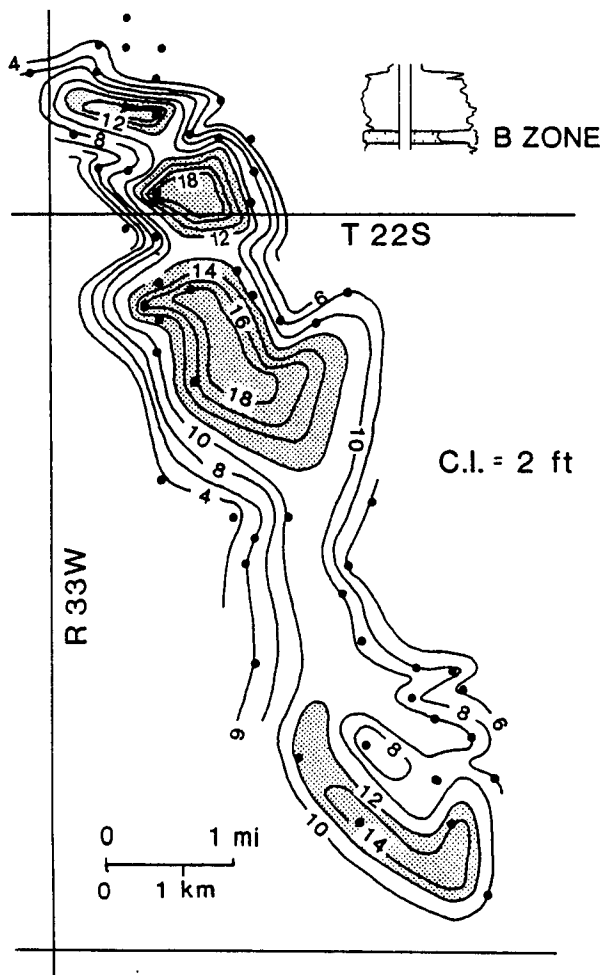


Figure 12. Typical log signature (gamma ray, neutron) and isopach map of porous St. Louis B-zone at Damme field. Isopach is of the oolitic marine sand belt facies (from Handford, 1988)

to early Meramecian in age. The Cowley facies is very difficult to correlate internally and with generally widely correlable Mississippian strata to the north.

The porosity is of secondary origin in the weathered chert of the Cowley facies. Fracturing also is developed related to the brittle deformation of the chert-rich facies (Thomas, 1982). The higher permeability along fractures apparently led to percolation of undersaturated water that led to extensive dissolution. Precursor evaporites may also have been present that were subsequently leached during subaerial exposure creating breccias and secondary porosity such as that found in the large Spivey-Grabs field (Tomasson et al., 1989).

Structural deformation appears to be important in effective porosity development in the cherty interval (Thomas, 1982). The Rhoades field in Barber County, Kansas, is situated on an anticlinal structure and may reflect increased fracturing associated with deformation of this structure (Thomas, 1982). Fields that have experienced poor primary and secondary recovery from these cherty reservoirs may present additional favorable considerations for horizontal drilling if estimates of oil reserves are sufficient. An attempt could be made to cross-cut the fracture systems that may be untapped by the vertical wells. Alternatively, the fractures may be depleted and the attempt would be to contact the less-fractured matrix areas. A structural analysis of the local area would be required to discern the orientation of the fracture systems. The fracture spacing would be an important component in order to determine the length of the drain hole.

**C. Arbuckle Group.** The Cambro-Ordovician Arbuckle Group has been a prolific oil reservoir in Kansas. Production is primarily found on the Central Kansas uplift and over the southern Nemaha uplift. Nearly half of the original oil in place in Kansas is associated with the Arbuckle Group. The reservoir is noted for its strong water-drive. The southern portion of the Central Kansas uplift also contains gas-drive reservoirs (Newell et al., 1987).

The unit is stratigraphically complex with many potential opportunities for horizontal compartmentalization of matrix permeability. In addition, the dolomitic Arbuckle Group has been severely affected by karstification and fracturing on these uplifts (Walters, 1946). Several periods of deformation have fractured, faulted, and generally modified the original stratigraphy in the Arbuckle Group over these uplifts. Orthogonal sets of cavernous porosity in the Arbuckle in El Dorado field on the Nemaha uplift apparently follow pre-existing fracture systems (Ramondetta, 1990). These solution-enhanced fracture trends are thought to be responsible for observed trends of highly productive wells.

In El Dorado field, previous severe water coning in old wells due to high rates of production led to their premature abandonment. Once abandoned, the water coning subsided, allowing oil and water to re-equilibrate. New wells have

encountered some of this remaining re-equilibrated, bypassed oil (Ramondetta, 1990).

In other areas of El Dorado field and other large fields on the Central Kansas uplift, stratification exerts considerable control on reservoir development. The nature of the stratigraphy depends on the amount of section removed by erosion and the extent of its preservation due to later karstification. Thickness of the Arbuckle varies significantly across structures. Open-hole completions and poor cement jobs in the stratified reservoirs of the Arbuckle Group often resulted in water production and thus to false condemnation of areas within the field. Moreover, old casing programs such as uncemented telescoping production strings may have led to early water breakthrough and premature abandonment. In contrast, the many old wellbores may have brought oil-bearing zones into communication with those water-bearing intervals (M. Bryan, personal com., 1991). Use of modern drilling, evaluation, and completion techniques creates opportunities for redrilling in these old fields as has been the case with El Dorado field (Ramondetta, 1990).

Horizontal drilling may be appropriate for the Arbuckle Group. Drain holes could follow the oil zone in the fractured/karsted interval above the oil/water contact. More oil could potentially be withdrawn from a horizontal well without coning water into the wells, i.e., without increasing the critical flow rate. If the zone is isolated from water encroachment, gravity drainage may be enhanced by horizontal drilling. Any consideration for horizontal drilling must consider the local orientation of fractures, fissures, and karstic development. Stratification should also be appraised as a possible control on horizontal matrix-porosity development.

Although the opportunity exists for identifying new, previously untapped reservoir compartments in the Arbuckle, many areas are heavily drilled and are near depletion with little remaining oil column. This state of development severely limits the potential size, shape, and location of these untapped areas and the reserves potentially extracted through a horizontal well. Careful economic evaluation is imperative in addition to good interpretation of geologic and engineering data from which inferences are made about such characteristics as matrix porosity, fractures and fissures, and flow barriers. Horizontal drilling may be feasible if the reserves are great enough and the risks are minimum. The recognition of prematurely plugged wells due to rapid production or mechanical problems may themselves create significant opportunities for redrilling within heavily drilled areas irrespective of the use of horizontal well technology.

**D. Viola Limestone.** Fields producing from the Upper Ordovician Viola Limestone are widespread over the central and northeastern part of the state of Kansas (Newell et al., 1987). Oil accumulation is associated with structural traps where production is situated in the upper Viola Limestone.

Horizontal stratification of porosity development occurs. The porosity varies, including intergranular, vuggy, moldic, and fracture (Caldwell and Boeken, 1985; St. Clair, 1985). Subaerial weathering on the top of the Viola has compartmentalized the Viola reservoir in El Dorado field (Ramondetta, 1990).

The Zenith field in Stafford County, producing from the Viola Limestone, Maquoketa Dolomite, and Misener sandstone and limestone exhibited extremely poor waterflood performance. Less than 2% of the estimated original-oil-in-place has been produced during waterflooding that goes back some 24 years (Newell et al., 1990). Part of this poor recovery appears to be related to fracturing that is suspected in the Viola Limestone and perhaps communication between reservoirs that occurred behind the production casing of boreholes. Fractures may have allowed the injected water to bypass oil that remained in the lower permeability portions of the reservoirs and could have permitted communication between carbonate and sandstone reservoirs (Kansas Geological Survey and Tertiary Oil Recovery Project, 1991). This communication may have occurred where these reservoirs were not separated by shale.

Drilling of horizontal injection wells to serve as water injectors in Zenith field may help to create a better waterflood sweep utilizing a fracture system. However, the presence and orientation of fractures first needs to be confirmed. Additional testing is needed to make this assessment, e.g., transient testing or wellbore strain analysis.

The first vertical derivative structure (dip) and second vertical derivative (rate of dip change) structure maps, and trend surface residual structure maps may be useful in discerning the location and orientation of fracture systems. Whether the orientation of drilling would be designed perpendicular or parallel to these systems could be tested before actual initiation of the program through the use of mass balance studies and running reservoir simulator models. These predictions could minimize the potential for costly mistakes (K. D. Newell, personal communication, 1990).

## **II. Low-permeability, Low-pressure Oil Reservoirs**

Low permeability and low reservoir pressure can limit production from vertical holes. Lateral drain holes may assist in more rapid withdrawal of fluid in shallow, low pressure wells by increasing the drainage area of wells completed in these reservoirs. Secondary and enhanced recovery may also be assisted through the use of horizontal wells for injection and production.

**A. Middle Pennsylvanian Cherokee Group Sandstones.** The Middle Pennsylvanian Cherokee Group sandstones in eastern Kansas have contributed a substantial amount of oil and gas production. Most of these major reservoirs are now nearing depletion, having undergone primary and secondary

oil recovery operations since the turn of the century. Many of the reservoirs are pressure-depleted by over production of oil wells or selective depletion of gas caps or solution gas within the oil reservoir. Shallow depths and the depleted reservoir state have left very little remaining energy to help remove the oil from the reservoir. Where there is a water aquifer, problems with water coning occur such as in the Flatrock field example discussed earlier.

There is a considerable variation in size of fields, the thickness of the reservoirs, and the gravity of the oil. Lower gravity oil reservoirs may be particularly well suited for horizontal drilling due to limited contact of existing vertical holes in the reservoir and inability of the heavy oil to readily flow to the vertical wells. Moreover, the very low oil/water mobility ratio of this heavy oil limits the success of conventional secondary recovery efforts.

The heterogeneity of these sandstone reservoirs has been demonstrated repeatedly. Sedimentary structures in the sandstone reservoirs (Hulse, 1979), cross-cutting channels (Rofheart, 1985), and development of secondary porosity (Brenner, 1989) produce significant multi-scale stratigraphic compartmentalization and anisotropic flow. This has undoubtedly led to bypassed mobile oil in many of these fields. In general, the sandstones are spatially complex and led to poor radial drainage.

The presence of natural fractures can also be important in the Cherokee sandstone reservoirs. Their presence is commonly detected as anisotropic reservoir performance. An example is from the large Burbank field in Osage and Kay counties, Oklahoma (Hagen, 1985). Natural fractures in the reservoir were indicated by the early water bypassing into producing wells located east and west of a waterflood unit in the field. Surface joints are strongly oriented North 70 East. The supposition of a fracture system in the sandstone reservoir at 3,000 feet, paralleling the surface joints, led to changing the waterflood to a north-south line drive. This led to a reduction in bypassed water and a successful waterflood. Fractures need to be considered in proper design of improved oil recovery methods in these fields, including horizontal drilling.

Properly oriented horizontal wells can potentially improve recovery of oil from these Pennsylvanian sandstone reservoirs. Ultra-short-, short-, and medium-radius drain holes should be considered in order to increase the effective contact of the boreholes in these strata. Drain holes could follow channels or could be designed to intersect with multiple channels especially those developed below the standard horizontal well spacing. Waterflooding, steam or miscible gas injection may be improved by directing fluid down the axis of a lenticular sandstone or injecting into multiple sandstone units simultaneously. This could help to improve the sweep efficiency. The presence and orientation of fractures also

need to be factored into the evaluation and design for a horizontal well into these sandstones.

**B. Coal-bed methane.** Coal beds are unconventional reservoirs, but with the tax incentives, these are now proving to be commercial. The viability of coal-bed methane is becoming more firmly established in eastern Kansas. Some 200 wells are scheduled to be producing by the end of 1990 (Stoekinger, 1990). However, horizontal drilling adds another element of risk in this endeavor and must be closely scrutinized.

Coal beds that have been identified to contain natural gas in Kansas are thin—6 feet thick and less. The Weir-Pittsburg coal in southeastern Kansas is porous and gassy due to fracturing (Stoekinger, 1990). The Weir is one of the gassiest coal seams in the country at 65 to 220 cubic feet/ton (Anonymous, 1990).

Production occurs after the water is pumped off. A small fracture stimulation of the coal bed is required, but larger ones may be warranted. The shallow depth of burial of the coal (<1,000 feet) suggests that the induced fractures would produce horizontal fractures. Horizontal fractures would be greatly effective in connecting existing fractures permitting the gas to drain to the vertical well.

If the induced fractures are horizontal, horizontal wells may not be warranted. If horizontal wells were considered, drain holes from multiple ultra-short-radius drain holes could help to increase the effective area of the borehole.

### **III. Thin, Stratigraphically Complex Reservoirs**

**A. Middle and Upper Pennsylvanian Carbonates.** The Upper Pennsylvanian Lansing-Kansas City and Middle Pennsylvanian Marmaton and Cherokee carbonate reservoirs in central and western Kansas typically are thin and often stacked in larger fields. There is a significant stratigraphic component to these reservoirs throughout Kansas. Individual carbonate units are often isolated by shales. Fractures may be locally important.

Skeletal grainstone, oolite, and fractured, vuggy carbonates comprise the porosity types. The more continuous and significant reservoirs contain primary and secondary porosity in packstones and grainstones that are located in the upper portions of separate carbonate units. The secondary porosity may locally be very erratic and unpredictable. Horizontal wells may follow the generally porous interval and contact new unswept portions of the unit within an established field. Horizontal wells may also assist in improving sweep efficiency in fields where waterflood performance of these thin, vuggy reservoirs was not good.

The economics of completing a horizontal well(s) in these thin carbonate reservoirs is a particularly critical issue. Re-

maining reserves need to be sufficiently high to make them a favorable target. In general, old structural fields with water coning or water fingering problems (poor sweep efficiency) during waterflooding may be considered potential targets for horizontal wells (Shirley, 1990).

**B. Lenticular Sandstones of the Chester (Late Mississippian), Morrow (Early Pennsylvanian), and Atoka (Middle Pennsylvanian)**

Chester, Morrow, and Atoka sandstones of southwestern and western Kansas were deposited as a southward-thickening siliciclastic and carbonate wedge consisting of marine to fluvial deposition. The Upper Morrow consists of marine shale cut by transgressive valley fill sequences (Wheeler et al., 1990). The valleys are shallow and narrow ranging from 50 to 80 feet deep and 0.5 to 2 miles wide (Krystinik and Blakeney, 1990). Reservoir units consist of estuarine sandstones, fluvial point bar deposits, and tidal-influenced point bar deposits filling narrow valleys (Figure 13).

The continuity of these reservoirs in some of these valley fill deposits can be quite high, e.g., Sorento and E Sorento fields in eastern Colorado with contiguous pressure communication through the reservoir (Krystinik and Blakeney, 1990). The resulting recovery by vertical wells is adequate and horizontal drilling is not warranted. However, other deposits are elongate and compartmentalized offering opportunity for horizontal wells to contact multiple compartments that would likely be left untapped with vertical wells. The Stateline trend (Colorado-Kansas) has marked heterogeneity due to depositional variability. Valley deposits are superimposed on one another, multiple incisions of channels isolate or connect reservoir units, and reservoir units vary markedly in grain size (Blakeney et al., 1990). Grain size strongly influences reservoir productivity (Krystinik and Blakeney, 1990). Horizontal drilling may be warranted to tap reservoir units that contact presently isolated smaller reservoir compartments that are below the present horizontal well spacing.

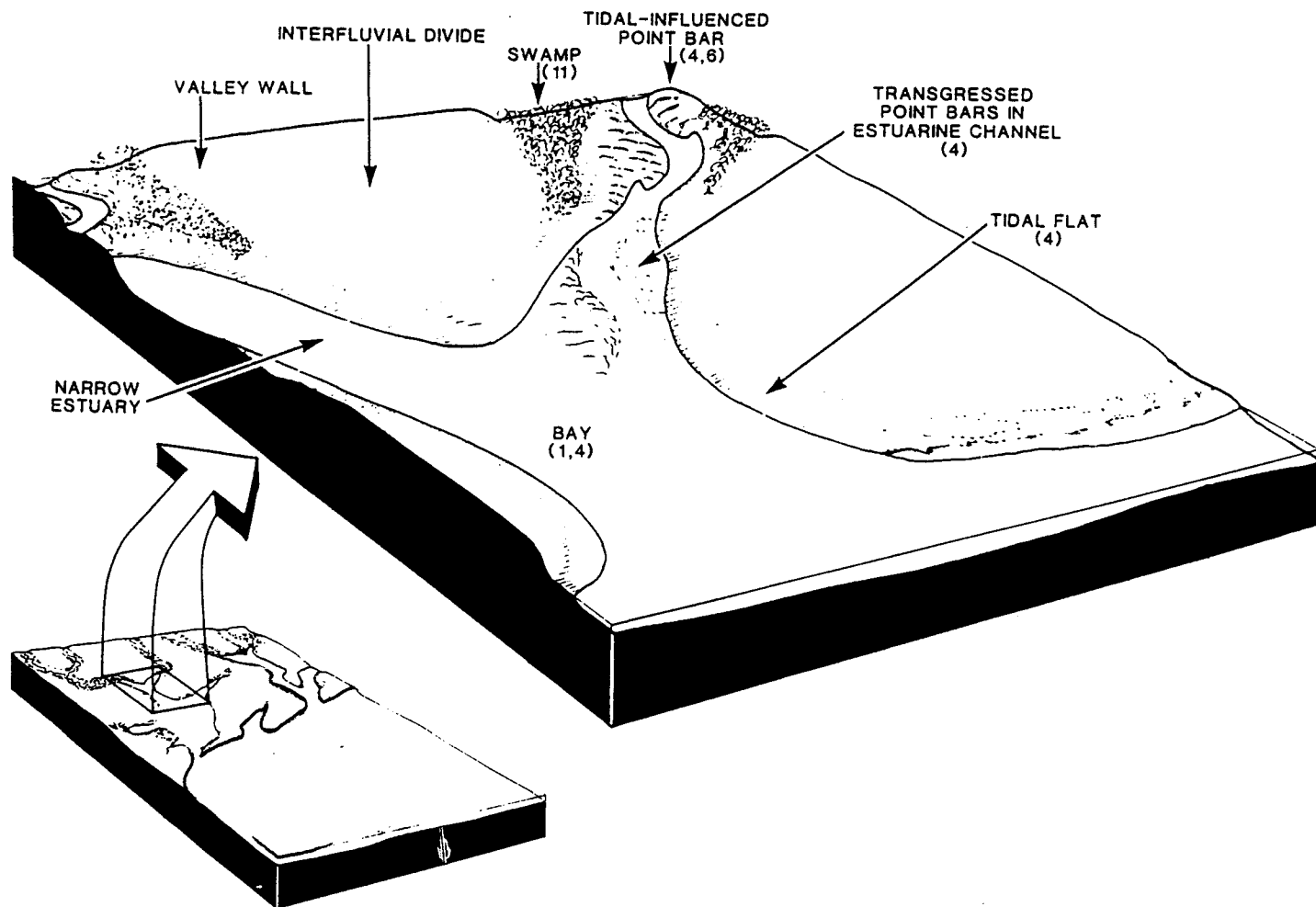


Figure 13. Estuarine depositional model for Morrow valley-fill sequences (from Wheeler et al., 1990).

## Summary

This paper is an introduction to uses of horizontal drilling. The goal is to provide enough of an understanding so that the reader can give more serious consideration for the application of horizontal drilling to their situation. The potential applications in Kansas appear to be numerous, but there remains a considerable gap between recognizing the potential application of horizontal drilling and establishing a geologic, engineering, and economically successful endeavor. The reader will need to carefully investigate the technology that is currently available and what applications have been successful coupled with a careful evaluation of their specific project. The industry is on the steep side of the learning curve and successful applications in Kansas have yet to be realized.

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