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ABSTRACT

Slimhole drilling provides an opportunity to significantly reduce overall drilling costs for exploration and development of oil fields. Cost reductions of 40–60% (or more) for exploration and appraisal wells and 25–40% (or more) for production and injection wells compared to conventional wells are possible. The savings are achieved by the use of smaller drilling and workover rigs, smaller locations, reduced casing sizes, reduced cutting volumes, less mud and cement, reduced fuel costs, and lower other costs associated with hole size. In addition, slimhole technology also provides an opportunity to minimize the effect of drilling operation on the environment and to improve working conditions. The effect of slimhole drilling on the environment includes minimized drilling wastes, reduced noise and air pollution, and less transportation for mobilization and demobilization of drilling equipment.

Typical applications for slimhole drilling are exploration wells in remote areas and reentry operations such as deepening or sidetracking in existing wells. Other applications of slimhole technology include low-cost development wells and horizontal and multilateral slimholes. In this report, the limitations and disadvantages of slimhole drilling are also discussed. The cost savings achieved from slimhole drilling may be offset by mechanical failures, problems associated with preventing kick-out, lack of directional control, and reduced lateral hole length in horizontal drilling.

Currently, slimhole drilling is being used more and more for reentry drilling, multiple horizontal drilling, and underbalanced drilling, and with coiled tubing and geosteering. Slimhole reentry and multiple horizontal drilling may offer the only opportunity to effectively develop new reserves, access by-passed oil, and effectively convert existing wells to horizontal wells. Geosteering techniques allows drillers to accurately steer downhole motors and bits so that they stay within pay zones and hit targets. Underbalanced drilling can reduce or eliminate formation damage and improve drilling performance. Production rates seven times higher than that of overbalanced drilling have been realized when underbalanced conditions were achieved. In addition, underbalanced drilling tends to increase rates of penetration.

Several areas require development and optimization in the near term. These areas include development of a sophisticated early kick-detection system, development of a reliable downhole steering system, development of downhole motors for underbalanced drilling, optimization of underbalanced drilling operations, and development of top-drive drilling system for slimhole drilling.

Slimhole drilling is still in its early development stage. At the present time, slimhole drilling cannot offer consistent results, especially in drilling horizontal and extended-reach wells. Slimhole drilling technology is still not an industry-accepted practice. With involvement from all areas to overcome its limitations, slimhole drilling will become industry standard.

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1.0 INTRODUCTION

The challenges for the oil industry in the late 1990s are to maximize the upstream potential value of discovered reserves and to optimize future investments to reduce risk in both exploration and exploitation. Increasingly, operators, petroleum engineers, and geologists must evaluate options together for exploration drilling to ensure that discoveries are economically developed (Pink 1992).

Drilling and completing new wells are costly. Those costs account for between 30% and 70% of initial capital costs for oil and gas field developments (Ross et al. 1992). If oil and gas development is to continue in mature areas, capital and operating costs must be reduced. In particular, given the current costs of drilling, completing, and working over wells in the United States, even a small percentage reduction in these expenditures will yield an immediate benefit. Fortunately, the successful development of slimhole drilling technology has created opportunities for the oil industry to cut drilling and completion costs. A slimhole saves money through the use of smaller surface casings and intermediate casing strings. The smaller upper hole sections are drilled with improved penetration rates, cement and mud costs are reduced, and the environmental impact is lessened. With increasing confidence, rig size could also be reduced. Although sometimes only the bottom 5% of a well is slimhole, cost reductions apply to the whole well.

Slimhole drilling has been actively used since the early 1920s and was studied in depth in the 1950s. Both research and field data have shown that slimhole drilling vertical wells can be very cost effective. In the 1950s, Carter Oil Co. drilled slimhole exploitation wells in Utah, Louisiana, Mississippi, Arkansas, Oklahoma, Illinois, and Wyoming, and concluded that slimhole wells could be cost effective (Flatt 1959). The company recorded savings of 3–25% in 108 slimholes drilled in 1957. From 1944 to 1959, Stekoll Petroleum completed more than 1,000 slimhole wells with depths up to 5,000 ft in Kansas and Texas (Stekoll and Hodges 1959). These wells were completed with 2 7⁄8-in. casing and 1-in. diameter tubing. Cost savings of approximately 17% were reported. Arnold (1955) noted that Wolfe and Majee drilled 34 slimhole wells with 4 3⁄4-in. and 6 1⁄8-in. diameters in Louisiana and Mississippi. The slimhole wells cost 15–20% less than conventional wells. Portability, smaller capital investment, reduced trucking costs, and reduced daily operating expense were cited as reasons for the reduced costs. Huber (1956) reported that Humble Oil and Refining Company had cost savings up to 35% with 5 5⁄8-in. diameter slimholes completed with 4 1⁄2-in. O.D. casing. Humble stated that slimholes can be drilled, fished, logged, completed, produced, and reworked without undue difficulty.

The increasing use of slimhole drilling caused the oil industry to develop special tools for logging, perforating, completion, and workover. The special logging and perforating tools included (Scott 1962a, b):

- Modified gamma ray, neutron, and gamma ray–neutron log tools for passing through tubing
- Expendable jet perforators and steel-cased retrievable jet perforators
- Sectionalized-type bullet guns containing one shot per 4-in. segment.

Special cementing tools were developed for use in slimholes. These included (Scott 1961b):

- Guide shoes and float shoes
- Latch-type pump-down plugs
- Stage-cementing equipment
- Basket and packer-type cementing shoes.

Special completion and workover tools included (Scott 1962c, d):

- Macaroni strings (3⁄4- to 1 1⁄2-in. nominal diameter) as inner tubing strings
- Small gas lift tools (1 1⁄4- and 1 1⁄2-in. tubing) for artificial lift
- Drillable and retrievable production packers
- Well stimulation treating equipment
- Retrievable straddle tools
- Aluminum swab assemblies
- Drillable and wireline retrievable plugs or bridge plugs and retainer type packers
- Wireline and positive-displacement dump bailers.

By 1961, 131 companies had drilled 3,216 slimhole wells with wellbores 6 3⁄4-in. or smaller (Scott 1961a). The depth of these slimholes ranged from an average minimum of 3,115 ft to an average maximum of 6,580 ft; the average depth was 4,515 ft. Penetration rates were approximately the same as with conventional holes.

Because of operational problems such as poor bit and drillpipe performance and standpipe pressures resulting from inappropriate mud systems, however, the rate of penetration decreased with sizes below 7 7⁄8-in. (Figure 1–1) (Worrall et al. 1992). In addition, a lack of understanding of the drilling process led to snowballing operational problems. As a result, interest in slimhole drilling waned in the 1960s.

With current conditions in the petroleum industry, where exploration activity is moving to more remote areas, and current conditions in maturing developed areas, where margins are declining, the need to reduce costs has become more critical. In the current economic climate, slimhole drilling is being proposed as a method to reduce capital investment. The petroleum industry has reviewed many slimhole techniques (such as those used in the mining industry) for ideas to improve slimhole drilling and further its use. Recent advances in slimhole drilling technology

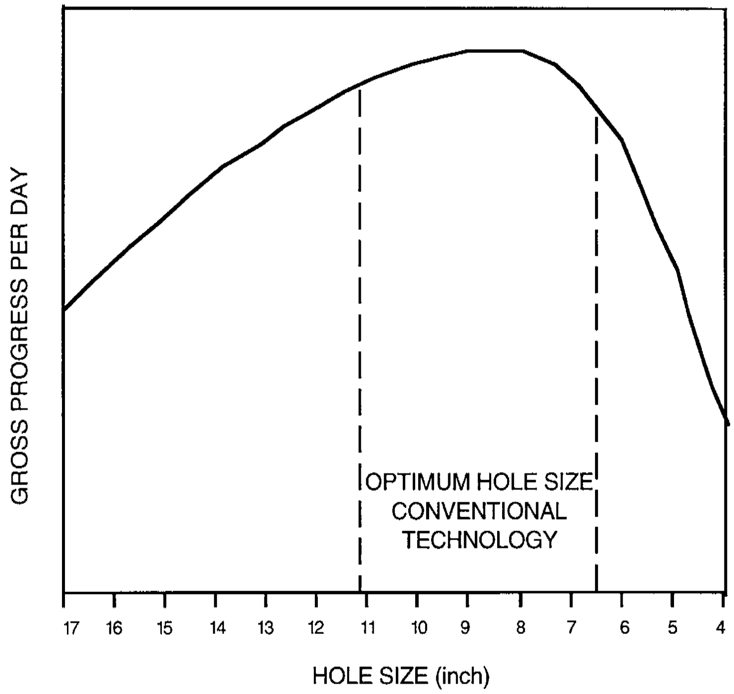


Figure 1–1 Effects of Hole Size on Overall Drilling Efficiency (McLaughlin 1959)

have improved the application of this drilling technique to oil and gas exploration and development wells. Slimhole drilling is becoming more accepted as a viable drilling method, especially as exploration budgets become smaller.

2.0 APPLICATIONS AND BENEFITS OF SLIMHOLE DRILLING

Typical applications for slimhole drilling include exploration wells in remote areas, where logistics can be a problem, and reentry operations in which the existing well has a small diameter. In addition, slimhole drilling technology offers the potential for major reductions in cost for production wells, existing wells being deepened or side-tracked, horizontal wells, and multilateral wells.

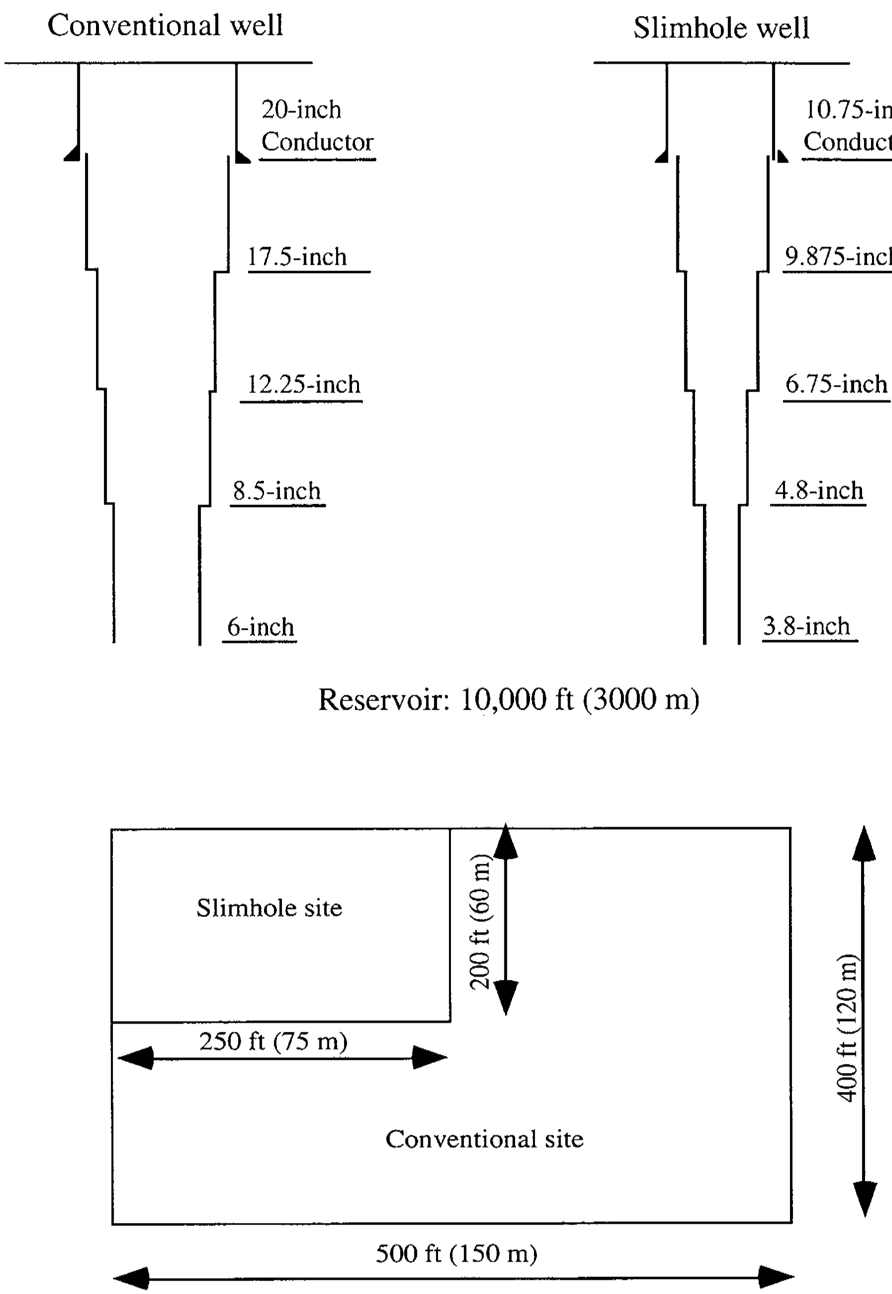
2.1 Slimhole Technology for Exploration in Remote Area

Slimhole wells may be very useful in remote exploratory areas (Deliac et al. 1991; Gunn 1991; Dachary and Vighetto 1992). Such areas may lack infrastructure or an established industry presence, and road construction and logistics can be expensive. In this situation, a slimhole well may be designed as an exploration well without consideration for its productive capabilities. The slimhole, while not the most advantageous wellbore for production, would reduce the capital requirements in a high-risk, high-cost operation.

Slimhole wells use less mud, casing, cement, water, and diesel fuel; they generate smaller volumes of cutting; and they need a smaller crew to operate and support the drilling system. For example, if the hole diameter is reduced by 50%, mud consumption and cuttings are reduced by 75%, and well-site area is reduced by 75% (Figure 2–1). The overall cost is reduced 40–60% (Murray et al. 1993).

Conoco drilled slimhole wells in Irian Jaya, Indonesia, using helicopter-portable rigs (Macfadyen et al. 1986). The operational area in Irian Jaya is one of Indonesia's most remote areas, 1,900 miles from Singapore (the point of mobilization), and 1,740 miles from the head office. Slimhole drilling allowed Conoco to use smaller rigs and a smaller rig platform layout to reduce the very high costs of such activities as field surveys, mobilization/demobilization, and base camp construction. The slimhole rig was only required about 100 airlifts to move compared with 330 airlifts (plus a further 220 airlifts to move the rig camp and tubulars) for a conventional heli-rig. The slimhole rig was transported in 5 days by helicopter compared to more than 16 days for a conventional rig.

Recently, BP Exploration, Inc. (Alaska) identified slimhole drilling as an important technology in its exploration strategy in the 1990s. BP Exploration drilled 6 slimhole wells in Plungar field, England, with the Micro-Drill MD3 rig (Floyd 1987). The MD3 rig weighs only 13 tons. It is 36 ft (11 m) tall compared to 116 ft (35.4 m) for a conventional rig. The rig requires a 70% smaller rig site than a conventional rig. The time savings on rigging up and down reduced costs by 60–70 %.



- Hole diameter reduced by 50%
- Mud consumption reduced by 75%
- Cuttings reduced by 75%
- Well site reduced by 75%
- Overall costs cut 40 to 60%

Figure 2–1 Slimhole Drilling Reduces Both Well and Site Costs (Dachary and Vighetto 1992)

resulted in a six-fold decrease in cuttings volume and a corresponding reduction in mud volume. Murray et al. (1993) indicated that cost savings of more than 40% were achieved in the BP slimhole exploration project.

Since 1983, Total Exploration Production has drilled more than 230 slimhole wells in the Paris basin (Dachary and Vighetto 1992). More than 80% of the footage (drilled to an average true vertical depth of 1,950 m or 6,400 ft) was drilled with a 6-in. diameter bore. During the first quarter of 1990, 14 wells of 4 1/2-in. diameter were drilled to 800 m (2,625 ft). By the end of October 1990, Total successfully drilled an exploration well to a depth of 1,829 m (6,000 ft) with the Foramatic II rig (Deguillaume and Johnson 1990).

During the second half of 1991, Total Exploration conducted a slimhole drilling project in the Gabon tropical rain forest (Dachary and Vighetto 1992). Two wells were drilled: one to 2,747 m (9,010 ft) ending with a 3-in. hole, and one to 418 m (1,371 ft) ending with a 5 7/8-in. hole. With conventional drilling the first well would have required a 36-in. hole and 30-in. surface casing, and the well would have ended with a diameter of 8 1/2-in. Continuous coring operations recovered 1,868 m (6,127 ft) or 59% of the total length drilled.

Total Exploration reported that the use of a slimhole rig rather than a conventional rig allowed a substantial reduction in the rig volume and weight, consumable goods, access, and installation. The direct logistic improvements include a reduction in the quantity and specification of transport equipment, a reduction in the access and location sizes and specifications, and easy organization of helicopter transportation, if necessary.

The overall cost of Total's Gabon project was $12.8 million. The same program conducted with a conventional drilling approach was estimated to cost 15% more. The approximate cost breakdown for the project was logistic and civil works, 39.5%; consumable items, 8%; all drilling contracts, 29%; logging and mud logging, 8.5%; and miscellaneous (e.g., supervision, feasibility studies), 15%.

Total Exploration estimated that a slimhole operation would cost about 30% less than a conventional operation and would take less time with an efficient and tough new slimhole drilling rig. Total Exploration concluded that the conventional 8 1/2-in. diameter bore commonly used in most wildcat wells could be replaced with a 6-in. slimhole with the possibility for a 4 1/2-in. hole (Dachary and Vighetto 1992).

2.2 Slimhole Technology for Reentering of Existing Wells

There are two ways to reenter wells: sidetracking existing wells to horizontal and deepening existing wells. In sidetracking, a portion of the existing casing is milled out by either section milling (Figure 2–2) or window milling (Figure 2–3), and then the hole is sidetracked to horizontal. Window milling does not require a cement plug for kicking off, and less casing is

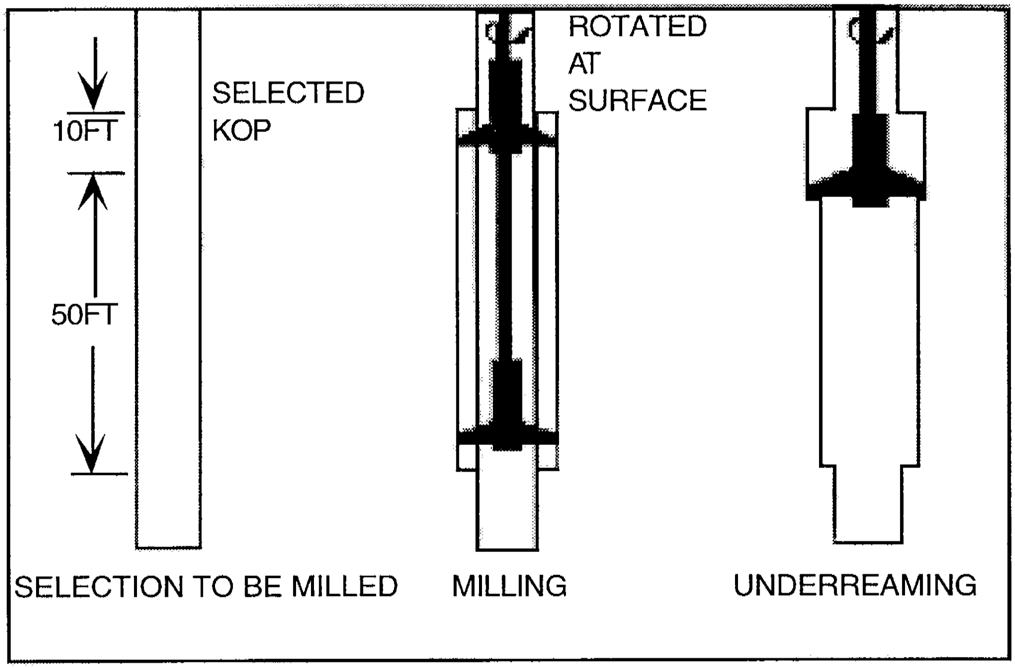


Figure 2–2 Schematic of Section Milling (Grove and Vervloet 1993)

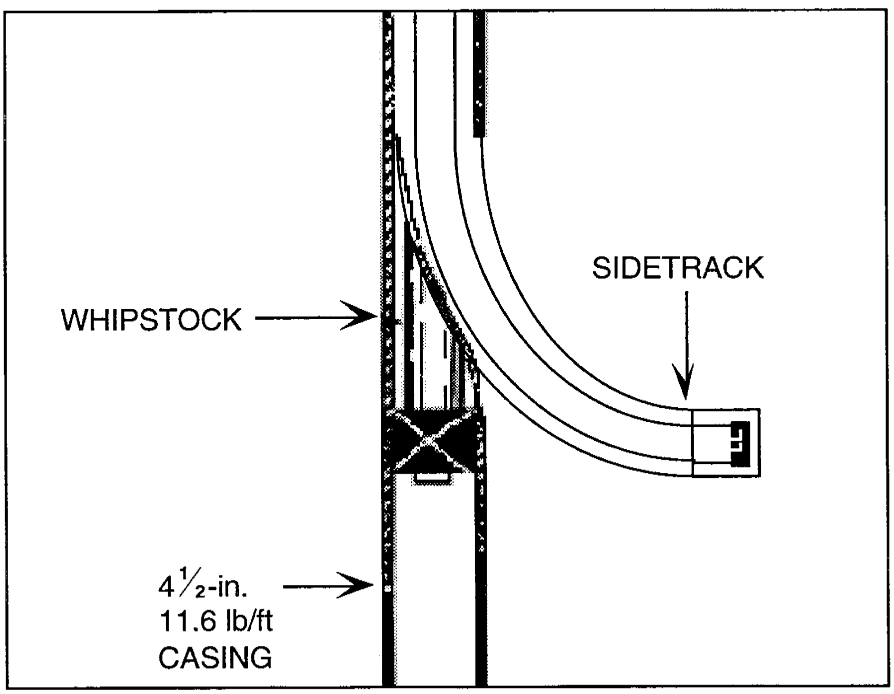


Figure 2–3 Schematic of Window Milling (Grove and Vervloet 1993)

removed. In addition, the sidetracking is accomplished while cutting out the window. Window milling, therefore, can reduce the time required for sidetracks.

Horizontal reentry operations are being used in the Austin Chalk trend (Pittard et al. 1992; Califf and Kerr 1993). There are a large number of reports on slimhole horizontal reentries. SlimDril International Inc. (Pittard et al. 1992) has successfully performed several hundred reentries out of 4 1/2- and 5 1/2-in. casings. SlimDril noted that advancements in slimhole technology have made small diameter drilling rates competitive to large hole results, and workover rigs with lower day-rate costs are being used on 4 1/2-in. reentries with no significant problems.

In 1989, Oryx Energy Company determined that a slimhole reentry program was needed to utilize existing wells in marginally productive areas of Pearsall field in Frio, Dimmitt, LaSalle, and Zavala counties, Texas (Figure 2–4) (Hall and Ramos 1992). It is an area where Oryx has had an extensive horizontal drilling program in the fractured Austin Chalk with over 150 company operated horizontal wells drilled since 1987. The typical newly drilled well is about 6,500–7,500 ft true vertical depth and has a lateral departure of 2,000–2,500 ft. The field has been also extensively drilled vertically for production in the Austin Chalk and other formations. Therefore, opportunities existed for reentering existing wells. For example, in 1991 and 1992 because of the large amount of production from the Austin Chalk in marginal areas, several reentry slimhole horizontal wells were drilled by milling a section on the 5 1/2-in. production casing to drill 4 1/2-

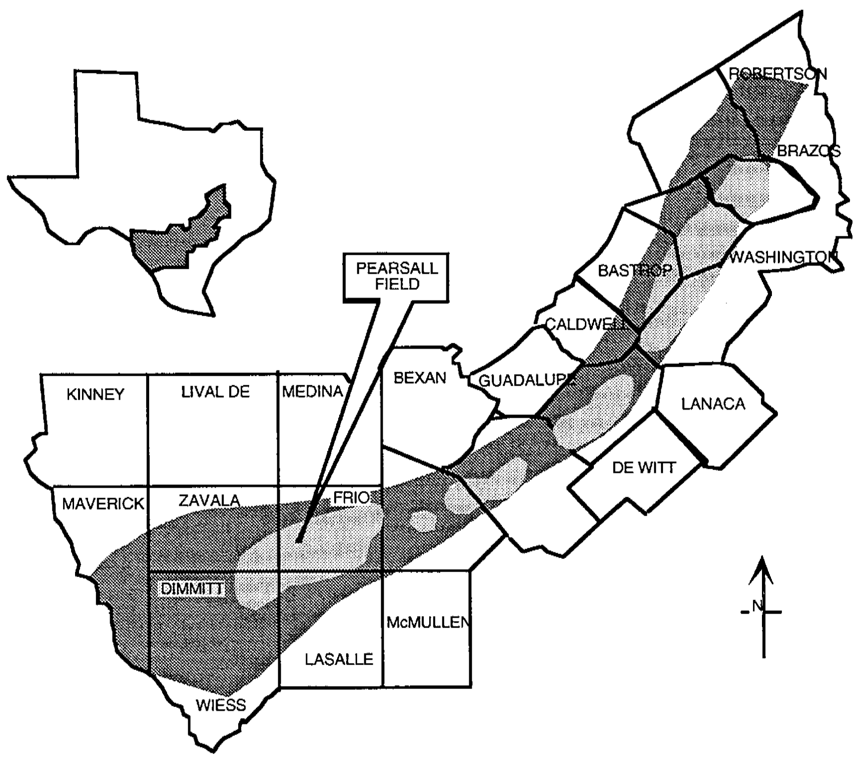


Figure 2–4 Austin Chalk Trend in South Texas

Table 2–1 Austin Chalk Slimhole Reentries 1990–1992* (after Hall and Ramos 1992)

Well	Days	Departure	Total Cost Index**	Lateral Cost Index†
1	18	1458††	0.50	1.28
2	38	2018	0.58	1.09
3	24	2002	0.32	0.61
4	21	2692	0.34	0.48
5	20	2242	0.36	0.60
6	18	1927	0..40	0.78
7	14	1600	0.25	0.58
8	22	1900	0.43	0.86
Average	22	1980	0.40	0.79

*Assumes cost for 1990 conventional well = 1.00 for both total well and lateral hole.

**Total cost index refers to total well costs.

†Lateral cost index refers to costs associated with lateral holes.

††Coiled tubing well

in. lateral holes and kicking off out of the section. All work was done with a continuous operation (24-hr) workover rig.

The savings were significant (Table 2–1) (Hall and Ramos 1992). The costs of reentries drilled were significantly less than that of conventional wells being drilled in other parts of the field. The average costs of a reentry slimhole horizontal well in 1991–1992 were only 40% of the conventional horizontal drilling costs on a per-foot basis compared to 1990 newly drilled wells. The cost savings resulted from time savings and less hole drilled. Oryx claimed a 31% decrease in the number of drilling days (Hall and Ramos 1992).

In addition to Austin Chalk fields, horizontal reentries were performed elsewhere in the United States. For example, a well with 4 1⁄2-in. casing in Logan County, Oklahoma was drilled by reentry technique. A section of the 7-in. casing was milled, and a lateral was sidetracked with a 6 1⁄8-in. bit and 4 1⁄2-in. motor assembly (Figure 2–5). A 4 1⁄2-in. casing string was run and cemented to the surface. The lateral portion was drilled with a 3 3⁄4-in. bit to a total horizontal displacement of 1,863 ft. A significant cost reduction was recognized.

Recently, BP Exploration, Inc. reported that sidetracking techniques reduced the drilling costs from $2.2 to $1 million for marginal areas of the Prudhoe Bay reservoir, a savings of up to 55% (Journal of Petroleum Technology 1994a). The company has drilled 50 sidetrack wells by drilling new wellbores from damaged or low-yield wells. Sidetracking also increased the reserve

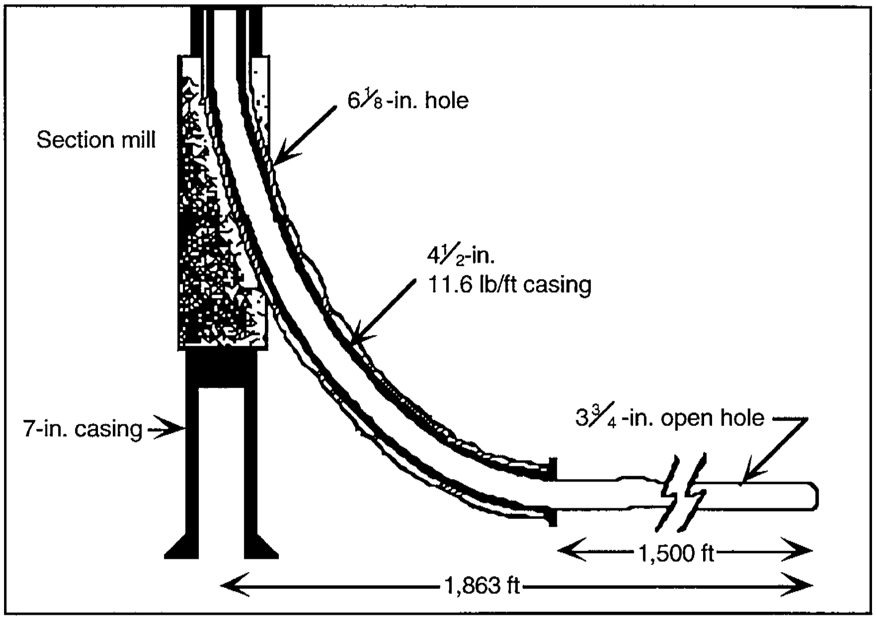


Figure 2–5 Section Mill and Sidetrack in a Well with 7-in. Casing in Logan County, Oklahoma (Grove and Vervloet 1993)

estimates for the Prudhoe Bay reservoirs. For example, one horizontal sidetrack drilled into Ivishak field's zone one is producing about 800 BOPD from a previously unproductive well because the horizontal sidetracking allows access to thin, segregated layers of oil that previously have been uneconomic to produce (Journal of Petroleum Technology 1994a).

Another application of slimhole reentry techniques is deepening existing wells. From 1982 to 1985, Tri-State Well Service (Oil & Gas Journal 1985) drilled 20 slimhole-deepened wells in Kentucky, Virginia, West Virginia, Ohio, Pennsylvania, and New York with 3 3⁄8-in. bits from existing 4 1⁄2-in. production casing. The holes were deepened with air drilling, logged, and then 2-in. production tubing was run and cemented to surface. Slimhole drilling resulted in costs that were only 40–50% of estimated new well costs to the same depths (Drilling Contractor 1985). For example, a 2,260-ft West Virginia well was deepened to 4,823 ft at a cost of $78,641, or about $31/ft, compared to approximately $165,000 for a new well from surface, providing a savings of 52%. The deepening resulted in recoverable reserves of 133.7 MMcf natural gas.

Union Pacific Resources Co. (UPRC) reported that the average drilling cost for a reentry horizontal well in Pearsall field, south Texas, was about $100/ft of exposed formation compared to an average $162/ft for a new horizontal well in the same area, a savings of 38% (Califf and Kerr 1993). The cost savings for different types of reentries is shown in Figure 2–6.

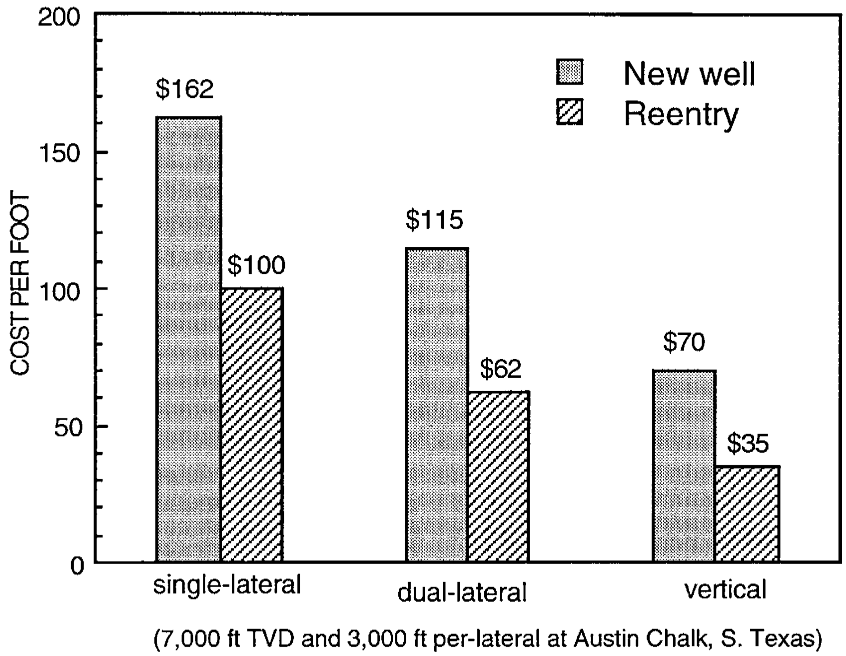


Figure 2–6 Cost Savings for Different Types of Reentries (Pittard et al. 1992)

2.3 Slimhole Technology for New Horizontal Wells

Horizontal drilling has proven to be cost effective and provides a means for improving oil recovery and production, particularly in thin reservoirs, naturally fractured reservoirs, tight reservoirs, and reservoirs with gas and water coning problems.

In recent years, operators have drilled slimhole horizontal wells where larger diameter laterals were considered marginal. The need for larger wellbores to handle high flow rates has been replaced with the need to drill a smaller diameter wellbore to reduce costs. Even though the smaller diameter wellbore limits the well production potential, practical applications proved that other factors (e.g., depletion or low rock permeability) also are limiting factors. Therefore, well cost, not productivity, can become the deciding factor in deciding on horizontal lateral length and diameter. For example, in areas where it is desired that a lateral intersect a large number of fractures to improve production, but rapid production is not required, or production rates and reserves are not enough to pay for the additional costs of a larger lateral hole, a slimhole completion can be efficient. Because of these developments, operators are willing to take the greater risks and limitations associated with slimhole horizontal wells to achieve the possible savings.

In 1991, Oryx developed a slimhole horizontal drilling program in Pearsall field, south Texas (Figure 2-4) in order to reduce costs in an area where productive rates were not contingent on the size of the lateral wellbore. Two wells were drilled using a smaller drilling rig to the intermediate casing point. Intermediate casing was then run and cemented. The drilling rig was released, and a workover rig moved on location to drill the curve and lateral section. This provided two benefits. The first was that by using a small drilling rig, the upper hole could be drilled more rapidly than with a workover rig, and at a lower cost than if a conventional drilling rig was used. The second benefit was provided by the workover rig. It more easily manipulated the tubing used for the drillstring (Hall and Ramos 1992). In addition, the workover rig was used to complete the wells prior to its release.

Results from Oryx showed significant cost reductions. After a learning experience, the second well performed under very typical conditions seen in drilling operations in Pearsall field (Hall and Ramos 1992). It had complete lost circulation, it drilled while the well was flowing, and it drilled through unconsolidated volcanic ash intervals with few problems. The hourly penetration rates were equivalent to those in larger conventional wellbores. Savings of nearly 32% from the conventional design and 17% from the reduced hole designed were achieved (Hall and Ramos 1992).

Slimhole horizontal drilling offers significant potential for cost savings. Table 2–2 shows the actual cost savings achieved in Oryx's Pearsall field operations.

2.4 Slimhole Technology for Developing Multilateral Wells

Drilling several horizontal sections from a single vertical wellbore has improved the drilling and production economics on many wells, especially in south Texas. A multilateral well consists of

Table 2–2 Slimhole vs. Larger Hole Comparative Drilling Costs (after Hall and Ramos 1992)

	Hole Size (in.)	Depth/ Displacement (ft)	TotalCost Index*	LateralCost Index**
Conventional	8 1⁄2	10,289/3741	1.00	1.00
Reduced hole	6 1⁄8	9,698/3257	0.82	0.87
Slimhole reentry	3 7⁄8	—/1,980	0.40	0.79
New well	4 3⁄4	9,697/3154	0.68	0.73

*Total cost index refers to total cost of well.

**Lateral cost index refers to costs associated with lateral hole.

two or more horizontal drainholes. There are several types of multilateral wells, including dual-opposing lateral, dual-stacked lateral, dual-opposing-stacked lateral, and Y-shaped lateral drain holes (Figures 2-7 to 2-10). Recently, a new multilateral approach has been developed which involves drilling horizontally through a pay zone and then drilling (with coiled tubing) drainholes out laterally from the horizontal section into the reservoir (Figure 2-11) (Journal of Petroleum Technology 1994b).

Generally, multilateral wells can be used under one of the following conditions (Graves 1994):

- One or more vertical permeability barriers are present.
- The planned displacement is large.
- The lease has an irregular shape.
- Topography prevents multiple surface locations.
- The surface is environmentally sensitive.
- An existing wellbore is planned for reentry.
- The offshore platform has a limited number of slots.
- The zones are laminated and have various reservoir characteristics.

In 1990, Petro-Hunt Corp. drilled two medium-radius horizontal bores in opposite directions from a single vertical hole (Cooney et al. 1991). The 7-in. casing was completed for the vertical

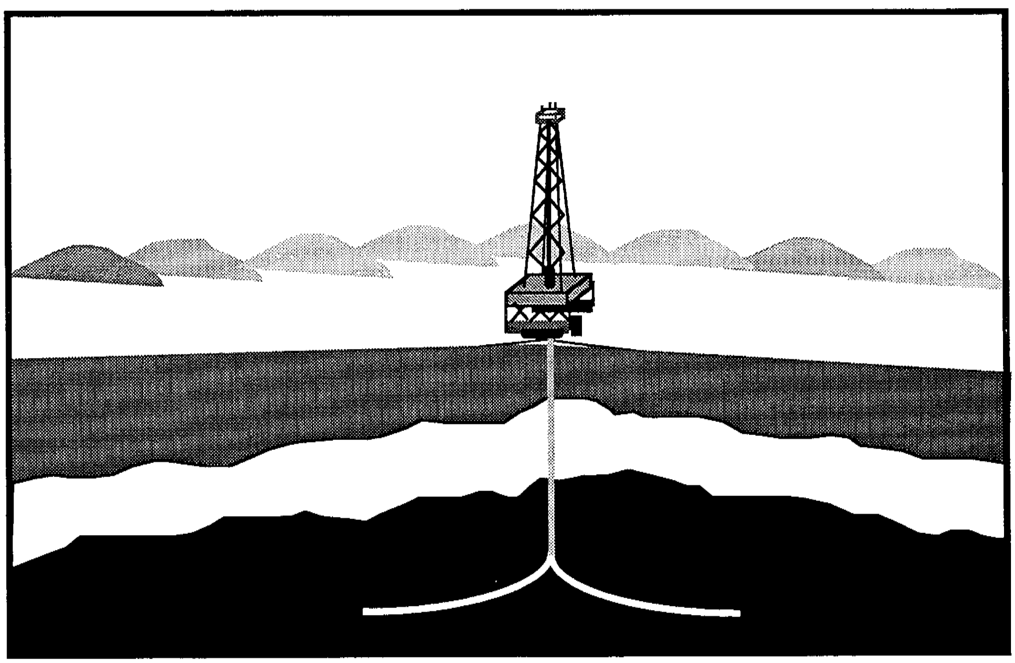


Figure 2–7 Schematic of Dual-Opposing Horizontal Well

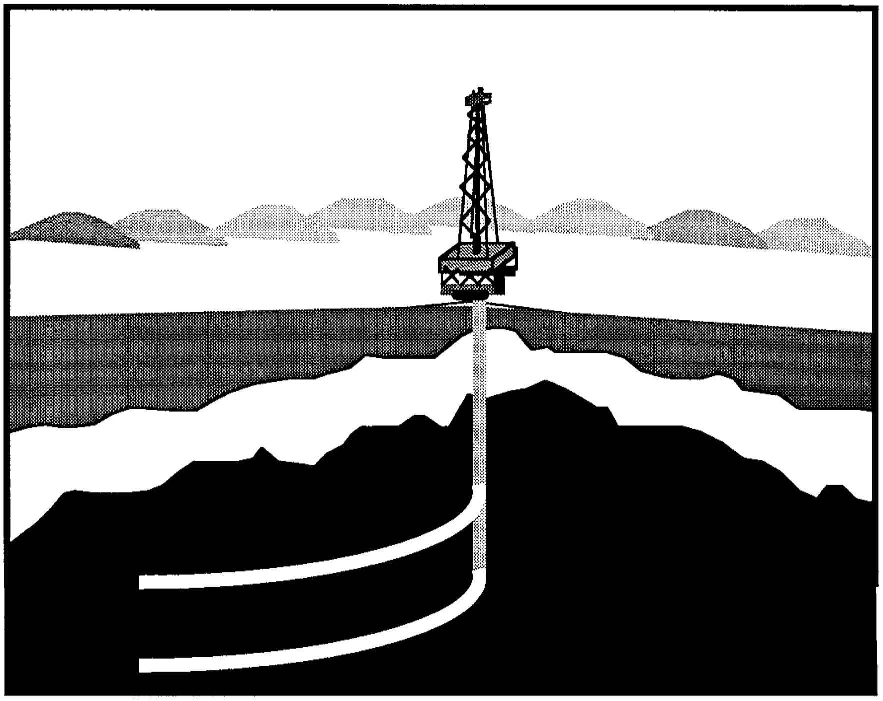


Figure 2–8 Schematic of Dual-Stacked Horizontal Well

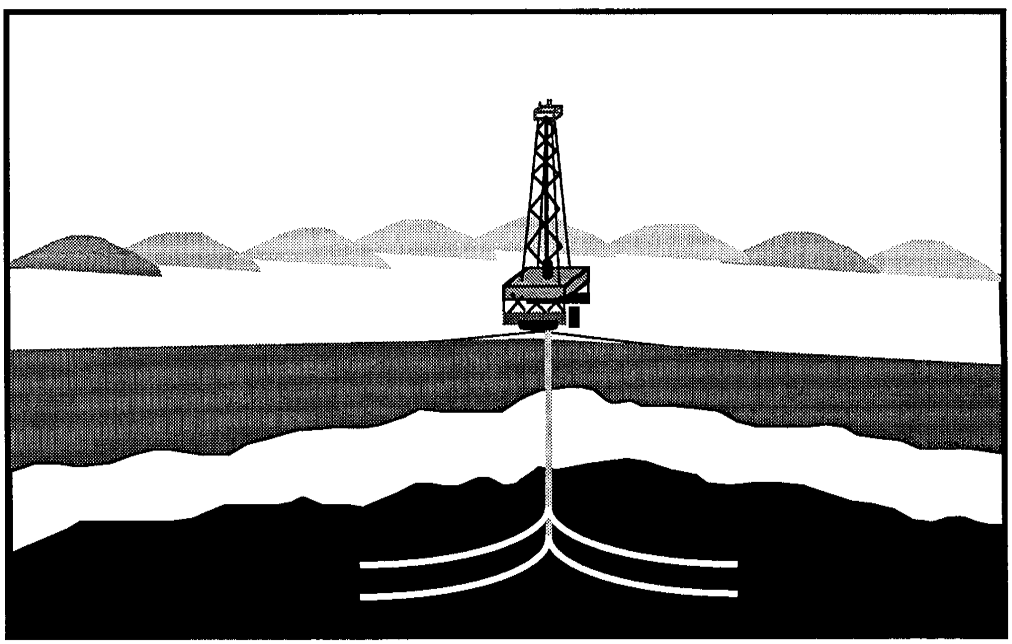


Figure 2–9 Schematic of Dual-Opposing-Stacked Horizontal Well

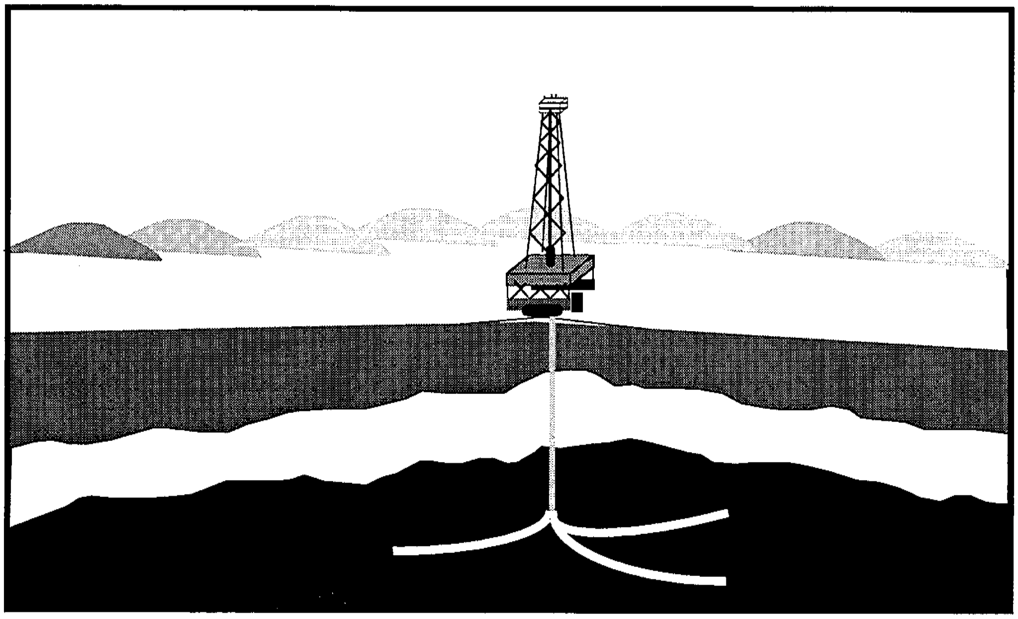


Figure 2–10 Schematic of Y-Shaped Horizontal Well

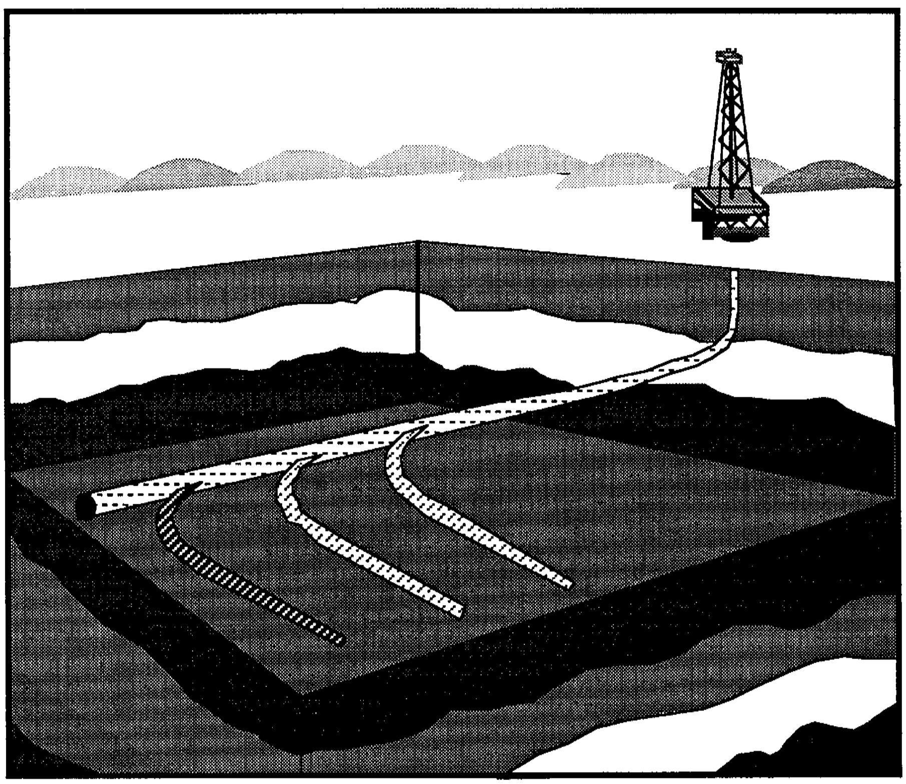


Figure 2–11 Schematic of Lateral Tie-Back System

hole to a depth of about 6,510 ft. Total length for the two laterals was 5,469 ft. The drilling cost for this dual-opposing lateral well was $183/ft of exposed formation compared to the average cost of $227/ft for a conventional single-lateral well in the same area, a savings of about 21%. By early 1993, Texaco had drilled eight dual-opposed lateral Austin Chalk wells in Brookeland, claiming a cost savings of $500,000–700,000 per well compared to single lateral horizontal wells (McMann et al. 1993).

UPRC completed the first quad-lateral well in the Austin Chalk by combining the dual-stacked lateral with dual-opposing lateral horizontal wellbores (Califf and Kerr 1993). The original well was no longer producing when it was reentered. The company said that overall cost per foot of exposed formation was $46.50, 75% less than accepted current standards. UPRC's average cost to drill a single horizontal well in Pearsall field, south Texas, was about $162/ft of exposed formation. Estimated cost for dual-stacked lateral horizontal well in the same region was $115/ft of exposed formation, a savings of about 30%. The average cost for UPRC to reenter a well and drill a single lateral was about $100/ft of exposed formation. Using a dual-lateral profile to reenter a well, an average cost of $62.11/ft was achieved, a savings of 38%. Figure 2–12 shows the cost comparison between reentry and new horizontal wells, and single-lateral and dual-lateral horizontal wells.

Dickinson et al. (1991, 1992) discussed using water jets to drill ultra-short radius multiple laterals in a single zone from a single vertical wellbore in order to penetrate near wellbore damage. The horizontal sections are 100–200 ft long. These wells include heavy oil wells in California and

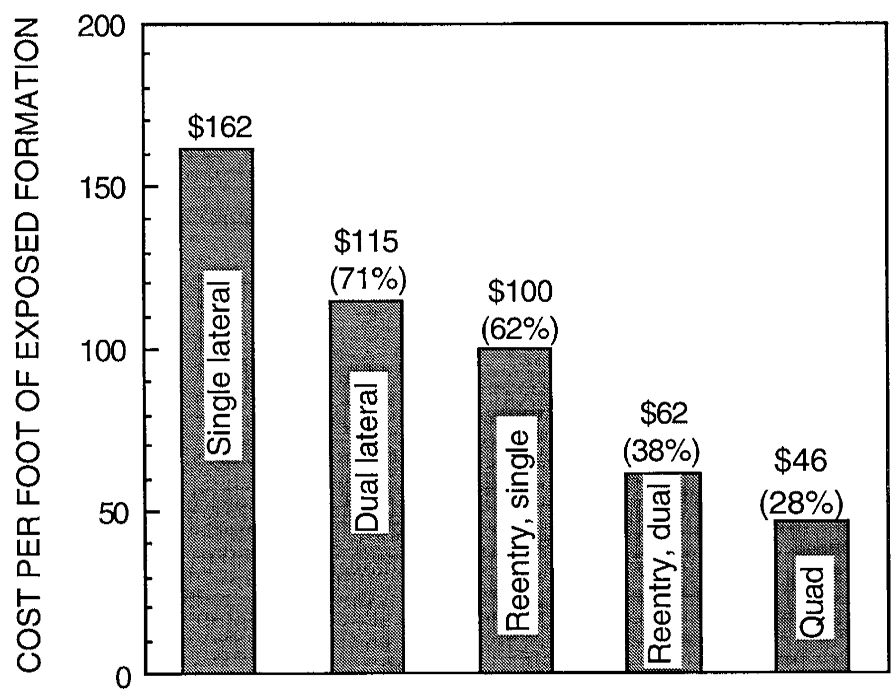


Figure 2–12 Cost Comparison of Different Types of Horizontal Wells (data from Pittard et al. 1992)

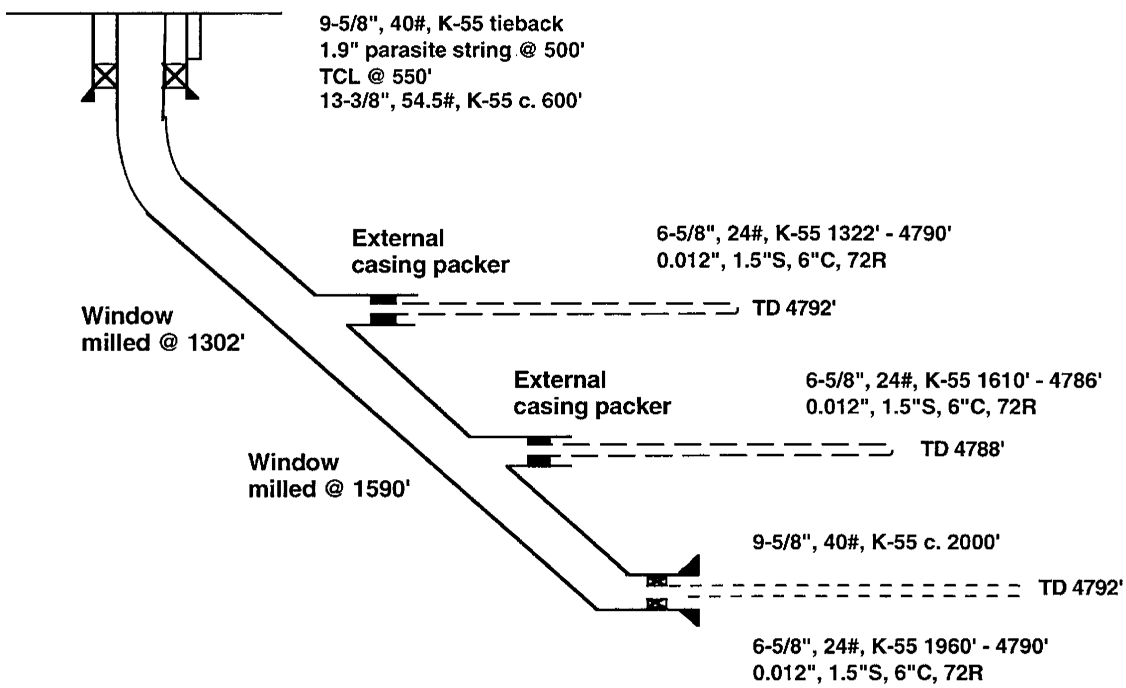


Figure 2–13 Cross Section of Dos Cuadras Field Showing Unocal's Trilateral Wells Tapping DP, D1P, and D2P Producing Zones to reverse the Decline of the Field (Dickenson et al. 1991)

light oil wells in Wyoming and Louisiana. The authors noted that production increased 2 to 10 times and the water-oil ratio decreased 10 times in strong water-drive reservoirs compared to vertical wells (Dickinson 1991).

Recently, Unocal claimed that it added more than 10 million bbl of recoverable crude oil in Dos Cuadras field, offshore California, through the use of trilateral horizontal drilling (Figure 2–13) (Offshore 1993). By September 1993, Unocal had completed four trilateral wells in Dos Cuadras field. The average per-well production rate for trilateral wells is about 800 bbl/d compared to an average per-well production rate of 50–60 bbl/d for conventional vertical wells. The total cost for a trilateral well is about $2 million vs. $3 million for a standard horizontal well (Offshore 1993).

Very recently, Sperry-Sun Drilling Services and CS Resources, Ltd. of Canada developed a new multilateral approach (Figure 2–11) to drill and case multiple wellbores from a single primary wellbore (Smith et al. 1994). The lateral tie-back system (LTBS) allows the driller to case and tie back multiple lateral branches and to seal the branches to the main casing string without milling the casing. LTBS provides for the complex interconnection of individual production liners. The lateral branch can be completed with liner or open hole. Each lateral branch can be sealed from the main wellbore and selectively reentered for servicing multiple liners. BP is considering the LTBS approach in completing its North Slope wells (Journal of Petroleum Technology 1994a). BP said that these drilling and completion methods, along with other drilling technology developments, could reduce the average cost of North Slope wells from $2.2 to $1 million.

One disadvantage of the multilateral wellbore is the potential complication during well control because two or more wellbores are open. Also, servicing a particular wellbore is more complex. To prevent future wellbore service problems, each drainhole must be designed for later reentry.

2.5 Benefits of Slimhole Drilling

Slimhole wells offer significant potential to reduce drilling costs. This cost savings is especially important because of reduced capital budgets due to current economic conditions in the oil industry. In addition, slimhole drilling can help minimize waste and improve general environmental impact.

2.5.1 Cost Savings

The cost savings from slimhole drilling are achieved by reducing drilling and disposal costs.

2.5.1.1 Reduced Drilling Costs

Savings in drilling costs can be achieved by (Hall and Ramos 1992):

- Use of smaller drilling rigs and/or workover rigs
- Reduced casing sizes and costs
- Smaller locations
- Reduced cutting, bits, mud, cementing, and fuel oil costs, and other costs associated with hole size.

Analysis by Shell of well data in three fields showed that due to improved performance, the drilling cost per foot of 4 1⁄8-in. hole drilled is between 19% and 41% lower than that of conventional 5 7⁄8-in. drilling (Figure 2–14) (Worrall et al. 1992). On an individual well basis, it is estimated that if the final hole size of a 16,000-ft gas well is reduced from 5 7⁄8 to 4 1⁄8 in., the cost is reduced by 24% (Figure 2–15) and the cuttings volume is reduced by 50%.

The total well costs for 30 wells in 25 different fields (including 13 slimhole wells with 5 7⁄8-in. and sometimes 4 1⁄8-in. holes) drilled by Shell between 1987 and 1992 were plotted against drilled depth to see what effect slimhole drilling had on costs (Worrall et al. 1992). Data were not corrected to account for variables such as location, sidetracks, geology, testing, whether the well was completed or abandoned, and so on. Only an annual inflation correction of 2.5% was made. The plot shows that the total well costs for slimhole drilling were mostly below the depth-cost trend line for conventional wells (Figure 2–16).

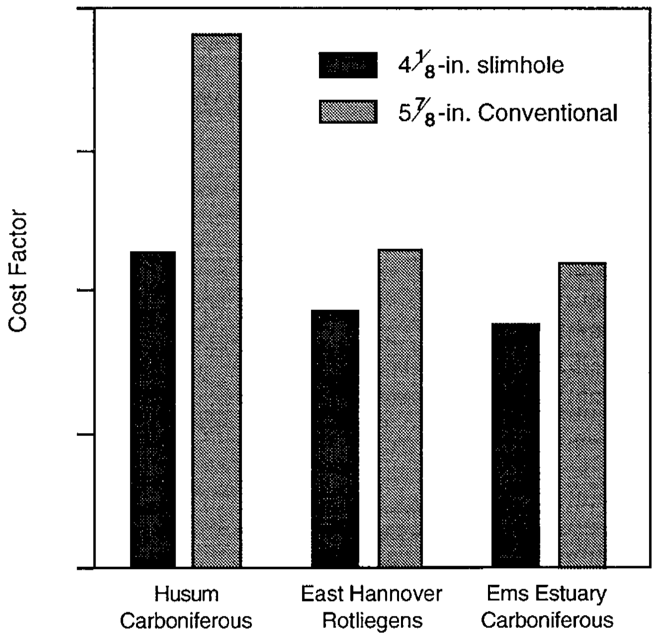


Figure 2–14 Cost Comparison of Standard vs. Slimhole Drilling for Three German Fields (after Worrall et al. 1992)

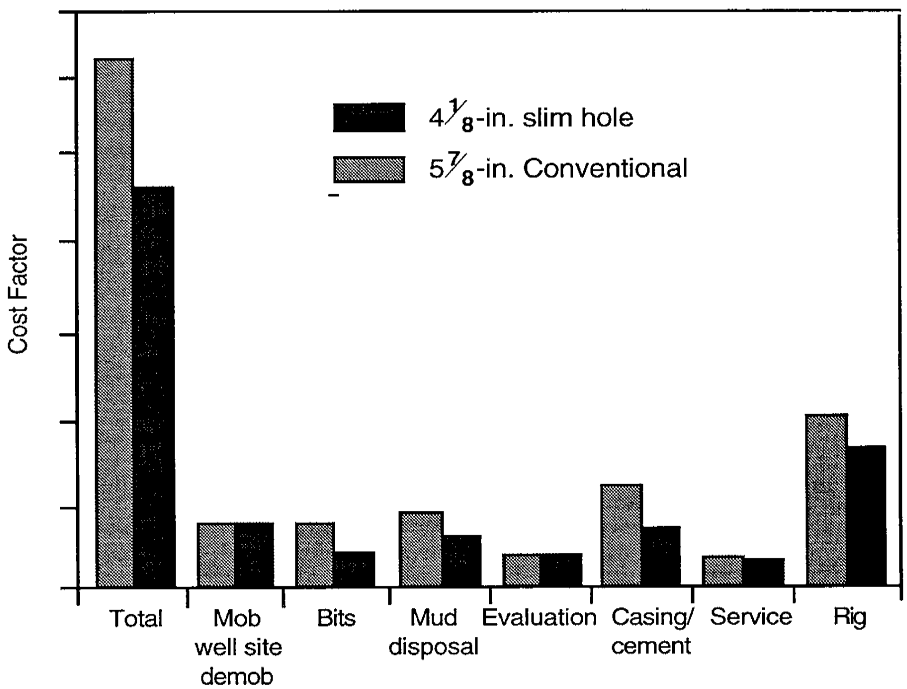


Figure 2–15 Cost Comparison of Standard vs. Slimhole Drilling for a 16,000-ft Gas Well (after Worrall et al. 1992)

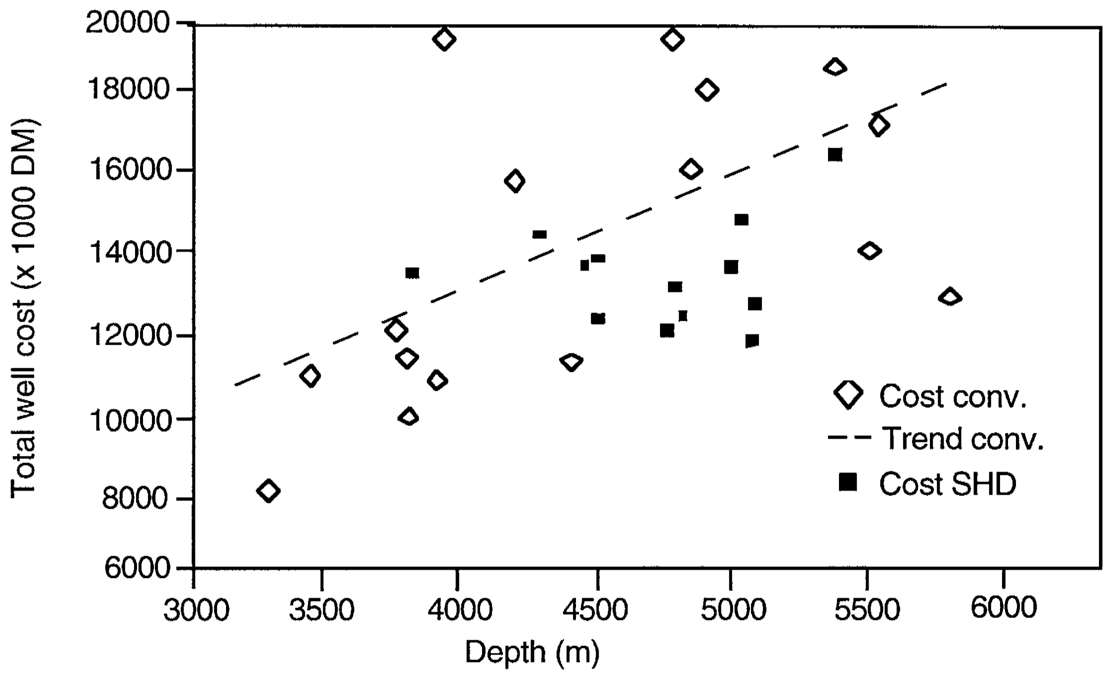


Figure 2–16 **Total Well Cost vs. Depth for Slimhole and Conventional Drilling for 25 Fields in Germany, 1987–1992 (2.5% annual inflation factor) (after Worrall et al. 1992)**

Slimhole drilling may increase the ability to exploit small, otherwise uneconomic reserves, including infill drilling for bypassed oil and thin oil rims. A slimhole drilling system was developed in Sweden to explore and exploit small shallow reservoirs. The system was used to drill 207 slimhole wells (approximately 2 1/2-in. in diameter) to depths of 650–8,000 ft. The slimhole drilling reduced costs by 75% compared with conventional drilling. The cost comparison between slimhole and conventional wells is shown in Table 2-3 (Dahl 1982).

Table 2–3 **Drilling Cost Comparison (Dahl 1982)**

Rig	Hole	Result	Depth (m)	Year	Cost (Swedish Krona)
Conventional	Bonsarve-1	Producer	493	1974	817,570
	Hamra-8A	Producer	640	1975	875,640
	Grunnet-3	Dry	536	1975	329,825
Diamec-700	Austre-1	Dry	495	1978	115,000
(slimhole)	Nors-1	Dry	359	1979	105,938
	Fardume-1	Producer	243	1979	235,741
	Stengrinde-1	Producer	249	1980	156,859
	Ojnaremyr	Dry	267	1980	86,000

Slimhole drilling techniques are being used by Unocal Corp. to drill shallow steam injectors in the San Joaquin Valley area near Bakersfield, California (Grove and Vervloet 1993). Many of the fields on the west side of the San Joaquin Valley near Bakersfield use continuous steam injection as a means of secondary recovery for the low gravity crude in the area. In the past, the injectors were normally drilled with a conventional drilling rig. These injectors are now being drilled to true depth using workover rigs and slimhole completion techniques with 2 3⁄8-in. tubing to surface. Unocal indicated that the injectors were drilled with no major problems. Unocal said that, compared to a conventional injector, there is no appreciable change in injection pressure or rates. The economics of slimhole steam injectors, however, are far superior to conventional injectors. The total well cost was reduced approximately 50%. Unocal stated that the potential now exists for either increasing existing steam injector density or initiating steam drives in previously uneconomic areas because this new method of drilling and completion has resulted in significantly lower project costs.

In general, slimhole wells reduce costs by 40–60% for remote exploration wells and 25–40% for development wells compared to conventional wells (Abrant 1992; Drilling Contractor 1993). McLaughlin (1959) reviewed time and cost savings of slimhole drilling. Although the 1950s costs were low by today's standards, the relative cost and time savings are probably still valid. The results of McLaughlin's review are summarized in Figures 2-17 through 2-21.

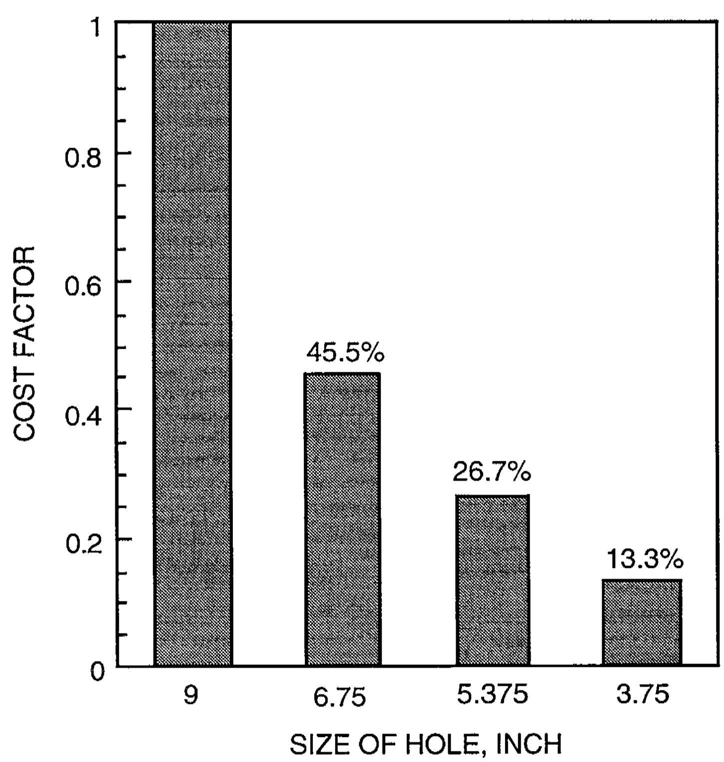


Figure 2–17 Moving Cost Factor (McLaughlin 1959)

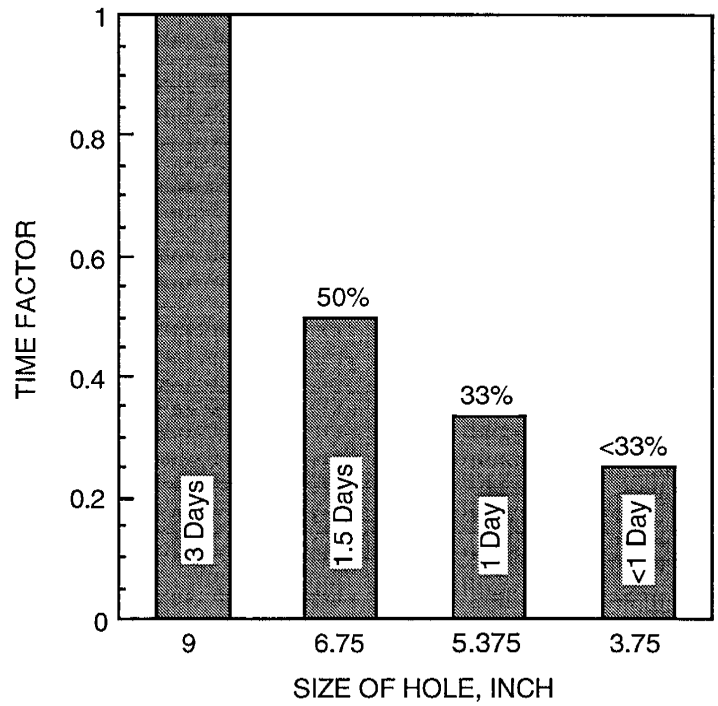


Figure 2–18 Rig-Up Time Factor (McLaughlin 1959)

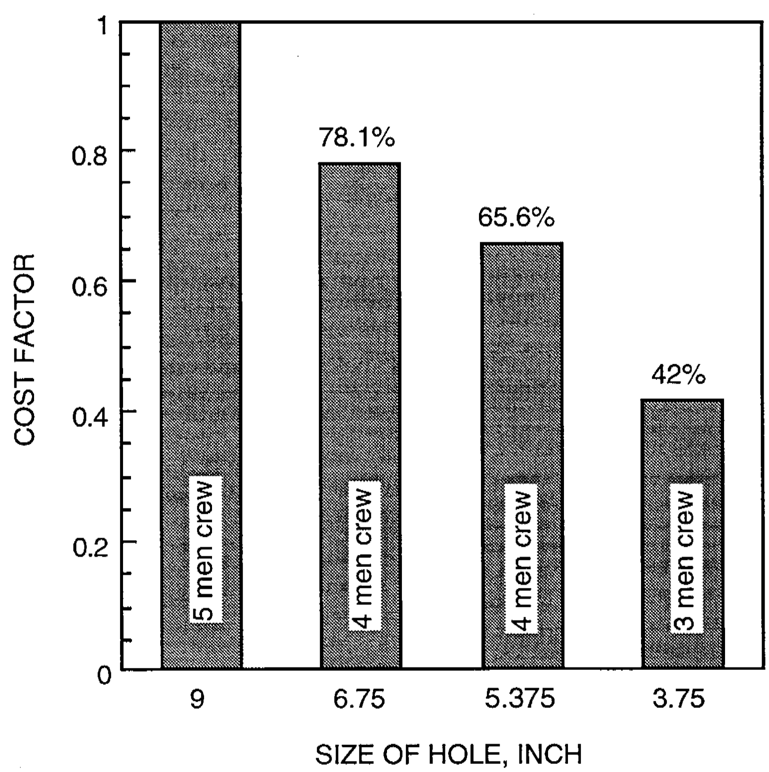


Figure 2–19 Daily Rig Cost Factor (Including Drilling String) (McLaughlin 1959)

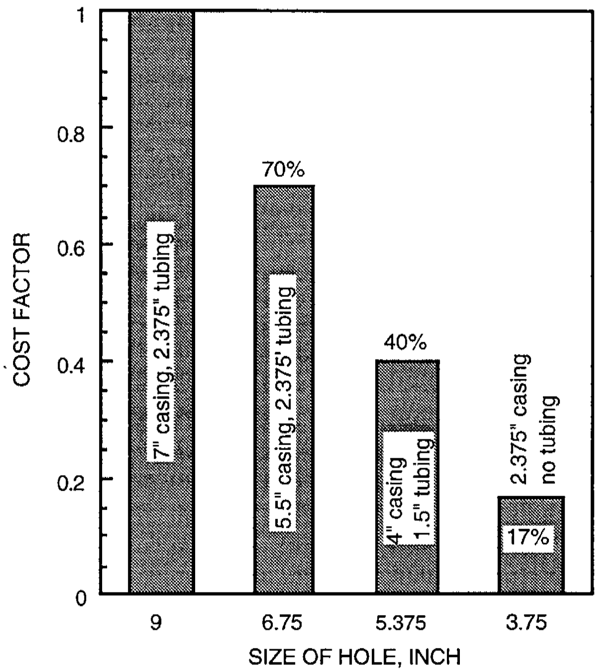


Figure 2–20 Casing-Tubing Cost Factor (McLaughlin 1959)

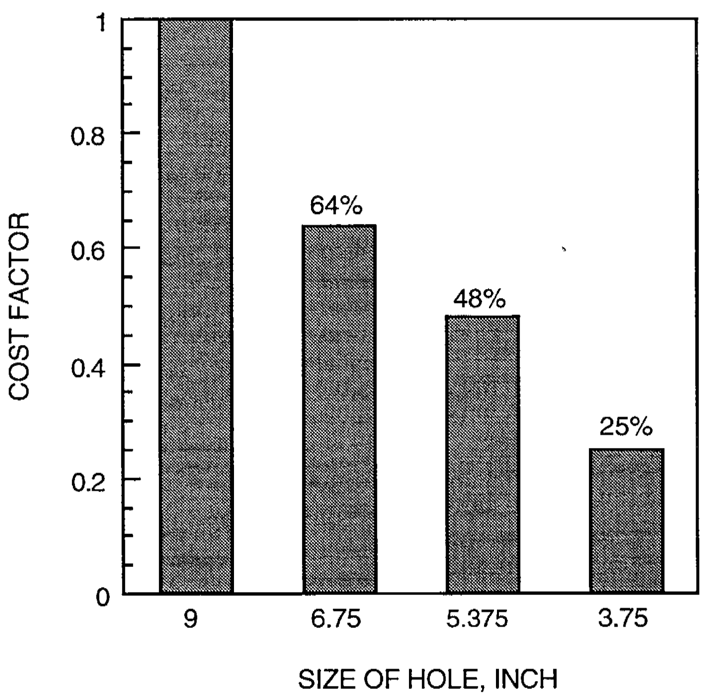


Figure 2–21 Cost per Foot Factor (McLaughlin 1959)

2.5.1.2 Reduction in Disposal Cost

During the process of drilling, considerable amounts of cuttings, drilling mud, and completion fluids have to be disposed of. With the rising costs associated with waste disposal, the oil and gas industry has emphasized reducing the generation of waste. This can be achieved by reducing the hole size drilled to less than that of a conventional well. If the size of slimhole is half of a conventional one, the cuttings and mud volume will be 25% of conventional volume. This will greatly reduce disposal cost. In addition, transportation and environmental concerns associated with the use and disposal of cuttings, drilling mud, and completion fluids are significantly reduced. Floyd (1987) noted a smaller hole size resulted in a six-fold decrease in cuttings volume and a corresponding reduction in mud volume. In general, the annular volume of a slimhole well is an order of magnitude smaller than the annular volume of a conventional hole (Randolph et al. 1991).

2.5.2 Minimizing Environmental Impact and Nuisance

As the environment becomes more and more important, reducing the environmental impact of drilling becomes more of a priority. Slimhole drilling can contribute to reduced noise levels, pollution risks, exhaust emission, and drilling waste. Slimhole technology provides opportunities to improve the overall environmental impact of drilling (Pink 1992, Teurlai et al. 1994).

The scaled-down equipment used in slimhole drilling makes operations particularly suitable for sites demanding a low impact on the environment. A conventional rig requires at least four times the area of a slimhole drilling rig (Table 2–4). The rig weight and drillstring weight for slimhole drilling are much less than for conventional drilling. This, and the relatively small size of the equipment involved with slimhole operations, results in a reduction in transportation for mobilization and demobilization of drilling equipment, reducing the overall impact and the risk

Table 2–4 Comparison of Conventional and Slimhole Rigs (Randolph et al. 1991)

Type of Rig	Conventional	Slimhole
Hole diameter (in.)	8.5	3–4
Drillstring weight (tons)	40	5–7
Rig weight (tons)	65	12
Drill site area (%)	100	25
Installed power (kW)	350	75–100
Mud pump power (kW)	300	45–90
Mud tank capacity (bbl)	470	30
Hole volume (bbl/1000 ft)	60	6–12

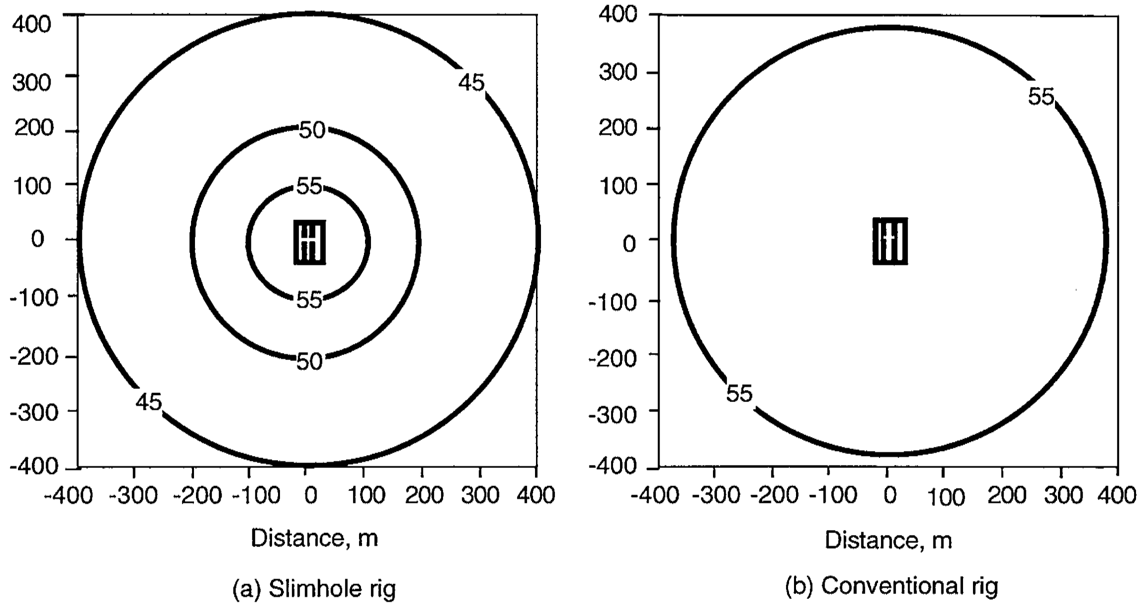


Figure 2–22 Noise Contour Maps of Typical Slimhole Rig (a) and Conventional Rig (b). Horizontal and Vertical Axes are Distances (in meters) from Rig Center. Contours are Noise Levels (in decibels).

of incidents linked to equipment transportation. Air pollution is also reduced because less power is required for slimhole drilling.

Another major benefit from slimhole drilling is noise reduction compared to conventional rigs. This is particularly advantageous when drilling near residential areas. Figure 2–22 shows an overall comparison of sound levels between a slimhole rig (or a coiled tubing unit) and a conventional rig (Faure et al. 1994).

With the ever-rising costs associated with remediation of waste streams, reducing waste generation gets more and more important. By reducing the hole size drilled compared to a conventional well, cuttings and mud volume are significantly reduced. A reduction of 70% is easily achievable (Faure et al. 1994, Teurlai et al. 1994). Transportation and environmental problems associated with the use and disposal of drilling fluids are also significantly reduced.

Another advantage of slimhole technology is emission reduction. Since the equipment needed for slimhole drilling is smaller than a conventional rig, fuel consumption and emission of gases to the atmosphere are proportionately reduced. Table 2-5 shows a comparison of fuel consumptions for a slimhole rig, a coiled tubing unit, and a conventional rig (Faure et al. 1994).

Table 2–5 Fuel Consumption and Gas Emissions (Faure et al. 1994)

		Coiled-Tubing Drilling Unit	Slimhole or Workover Rig	Land Drilling Rig
Diesel fuel used (m^3/month)		25	35	160
Gas emission (kg/day)	CO_2	2122	3293	15055
	CO	2.5	3.7	16.8
	NO_X	2.1	4.6	21
	HC	2.8	3.9	17.8
	HC (gas)	1.1	1.83	8.4
	SO_2	2.2	4.2	19.4

3.0 LIMITATIONS OF SLIMHOLE DRILLING

Slimhole drilling technology can cut drilling and completion costs significantly. However, the savings achieved from slimhole drilling can be offset by increased mechanical failures, reduced lateral hole length, and lack of directional control. Factors that affect operations and economics in slimhole drilling are described in this section.

One limitation of slimhole drilling is drillstring failure associated with the use of small-diameter tubulars. The reduced size of slimhole drill pipe makes the drillstring mechanically weaker than its conventional equivalent. For example, changing drill pipe from 5 1/2-in. to 3 1/2-in. will reduce the torque transmission capability by a factor of five. Therefore, the strength of a small-diameter drillstring is always a concern, especially in a milling operation, where high torque is encountered. In addition, bit speed has to be raised in order to maintain power. Higher rotating speeds are required to maintain cutter linear speed as bit diameter is reduced. High bit speed may create reliability problems.

Tool joint failure is another problem for slimhole drilling. Because of small and thin tubulars and joints, tool joints are inherently weaker and have a tendency to bell and twist off, particularly in deeper holes. It is necessary to design and develop high-torque tool joints and premium pipe to reduce the incidence of failures.

Kick detection is a difficult issue for slimhole drilling because a unit of reservoir gas entering a slimhole annulus will occupy a much greater height than in conventional wells. This can result in maximum allowable pressure in the casing being approached faster than in a conventional well. For example, the containment of a kick within 10–15 bbl is considered reasonable in a conventional well. However, this volume of gas in a slimhole would blow out. Early kick detection, is therefore essential. It is necessary to detect a kick to within 1 bbl to be sure of retaining safe control in slimhole drilling (Bode et al. 1989). Also, unlike conventional hole drillstrings, the frictional pressure losses in slimholes are very sensitive to the rotation speed of the pipe. The pressure measured at the standpipe will be affected by other operational changes such as pump rate, pipe movement, and coring. The cause of an increase in return mud flow rate is more difficult to identify when the effects of more than one of these operations occur simultaneously (Shields and Taylor 1992). All these factors make kick detection more difficult. Also, the most likely time for a kick to happen is during a connection, when the pumps are switched off and pressure exerted against the formation is reduced to mud hydrostatic.

Another disadvantage for slimhole drilling is a decrease in penetration rates, especially for roller cone bits. As shown in Figure 1-1, penetration rates are optimum when the hole size is between 6 1/2 and 11 1/4 in. When using roller cone bits, penetration rates tend to decrease as the hole size decreases below 6 1/2 in. due to reduced cutting structure and the smaller bearings of slimhole roller cone bits. To describe the effect of the bit size on penetration rate, compare a 6-in. diameter roller cone bit with 12-in. one. The area space available for the bearing in the 6-in. bit is about one quarter that of the 12-in. bit. Generally, the permissible bit loading is proportional to the cross sectional area of the bit (or bearing). In other words, the permissible unit loading of diameter (i.e., permissible loading per inch diameter) on a 12-in. bit will be twice that on a 6-in. bit. On the other hand, the required bit loading, for equal rates of penetration, is proportional to the diameter of the bit (Moore 1981, p.144). Neglecting other effective factors, we may assume that the penetration rate of the 12-in. bit will be double that of the 6-in bit, or proportional to bit diameter. The lower penetration rate can offset the cost savings achieved from slimhole drilling. Indeed, the main operating problems for slimhole drilling in the 1950s were low penetration rates.

Compared to roller cone bits, diamond bits have the advantage of lacking rolling parts, which require strong, clean bearing surfaces. This is especially important in small hole sizes, where space is not available. Diamond bits perform best in nonbrittle formations, especially in the bottom part of a deep well, where the cost of tripping is high and hole size becomes small. The small hole size requires a simple mechanical structure and, since diamond bits can be made from one solid piece, they are the simplest type of drilling bit.

Depth is a key limiting factor when considering slimhole well design, especially in exploration. Using available technology, slimhole drilling can reach to about 15,000 ft. Conoco recently reported that a reentry well in the southern North Sea was drilled to 12,300 ft; the last 3,000 ft were 4.7-inch hole (Murray 1994). Arco's F 4/3 well was completed with a 4 1/8-in. hole to a depth of 15,000 ft; the last 2,000 ft was a slimhole (Murray 1994). In horizontal wells, horizontal displacements are also less than with bigger holes due to the reduced drillstring weight available (Pittard et al. 1992).

Borehole integrity and instability are other concerns for slimhole drilling. Because of the small annular space between the drillstring and the wellbore, the amount of pressure lost is greater than in conventional drilling. When a mining drilling technique is used, the annular pressure losses can reach up to 90% of the total pressure losses (Sheridan 1993; Burban and Delahaye 1994). This additional pressure loss reduces the ability to control lost circulation and elevated pore pressures. A special mud system is necessary to raise weighting capability and reduce friction force. In addition, the potential for stuck pipe increases in a slimhole.

Production from slimholes has been questioned (especially with regard to limitations on the reuse of exploration and appraisal wells as producers) because of the possibility that hole size might effectively act as a choke. In artificial lift wells, the reduction in primary casing sizes used in slimholes tends to narrow options available. Field studies conducted in Pearsall field indicate that the productivity of a well may potentially be inhibited by as much as 60–80% when reducing the casing size from 9 5/8 in. to 4 1/2 in. (Hall and Ramos 1992). These estimates were based on the rod-pump intake pressure available, and the oil cut and the gas-to-oil ratio (GOR) of a specific well. The GOR tends to be the largest factor. For wells with comparable GOR, the use of smaller casing sizes limits the size of the gas separation equipment that can be used. With this reduction in equipment size, the efficiency of gas separation is reduced, leading to some loss of productivity when using conventional rod-pumping techniques. As the GOR decreases during the course of the well's productive life, this effect becomes less pronounced. Submersible lift is a viable alternative that is more tolerant of the gas interference effect during the early life of the well when the GOR is high. At some point in the production schedule, the GOR may decrease to a level where sufficient rod-pump efficiency can be maintained. However, the change of lift system will increase costs. Additionally, slimholes may limit the angle, causing a limit to the depth to which artificial lift equipment may be placed in the wellbore. Smaller equipment generally has closer internal tolerances. Therefore, it may not be able to operate as well or may experience accelerated wear and failure in comparison to larger equipment. Ultimately, the impact of slimhole casing sizes on a production schedule and operation parameters must be weighed against the initial savings of drilling a slimhole well.

Another major limitation of slimhole horizontal drilling has been the inability to effectively transmit weight to the bit. Figures 3–1 and 3–2 show the available weight on bit vs. lateral displacement for three sizes (8 1/2 in., 6 1/4 in., and 4 1/2 in.) of bottomhole assemblies (Hall and Ramos 1992). As shown in Figures 3-1 and 3-2, a larger drillstring can provide much more weight on the bit than a smaller one. It is this additional weight offered by the larger drillstrings that provides the ability to correct for angle changes or problems. As the lateral extent increases, available weight from the small diameter tubing used to drill the slimhole well is reduced to the point that side drilling to make angle corrections becomes difficult or even impossible.

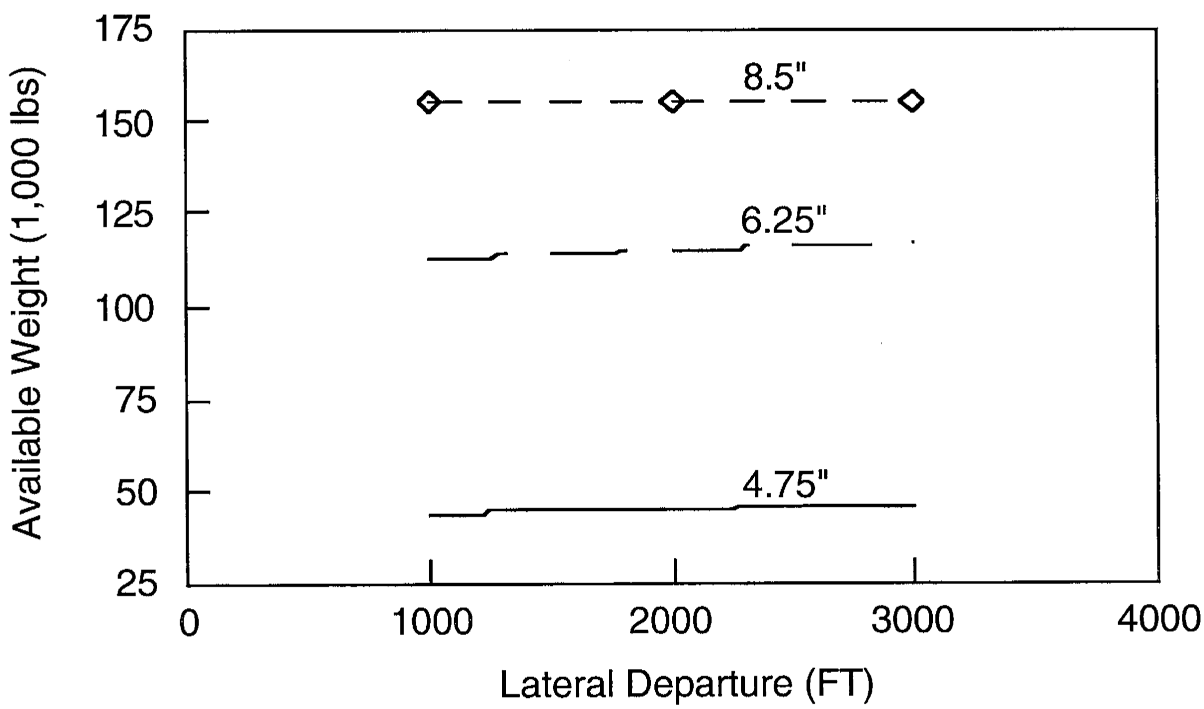


Figure 3–1 Available Weight on Bit vs. Lateral Departure for Typical Bottomhole Assemblies with Rotation (Hall and Ramos 1992)

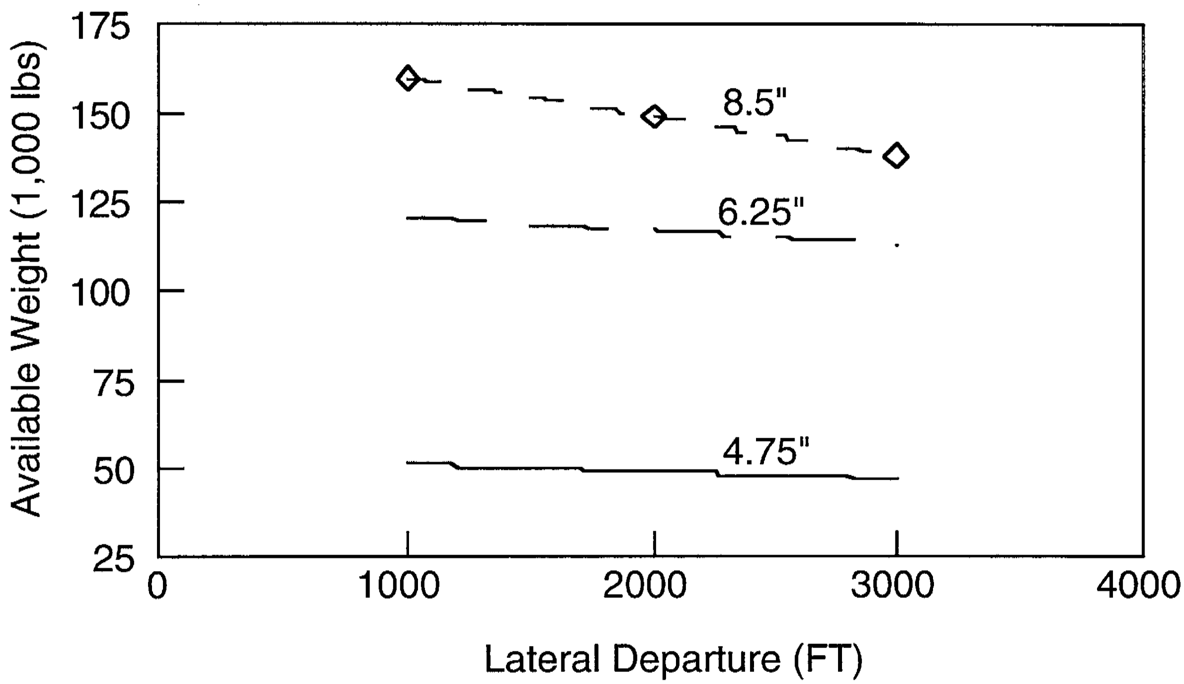


Figure 3–2 Available Weight on Bit vs. Lateral Departure for Typical Bottomhole Assemblies Without Rotation (Hall and Ramos 1992)

Therefore, the slimhole horizontal well is effectively limited to a maximum departure of 2,500 ft or less compared to more than 4,000 ft for larger wellbores (Hall and Ramos 1992).

Torsional and axial vibration of the bit in slimhole drilling can reduce bit life significantly. This problem, however, can be minimized by the shock absorbers in the bottomhole assembly (Randolph and Boyington 1991) and by combining the downhole motor with a thruster that helps limit torsional vibration in the drillstring.

The lack of tools for slimholes, especially more sophisticated tools for slimhole horizontal technology, is another barrier to slimhole application. It is easier and more economically advantageous to develop tools for the larger diameter (greater than 6-in.) wellbores. Because larger size tools have had better technology for horizontal drilling, it has been preferable to drill larger wellbores. In slimhole horizontal drilling, small tubulars are needed due to the small lateral size. Generally this will result in poorer reliability than using larger equipment because the slimhole equipment does not have capacity for the engineering safety factors that larger tools possess. In addition, there are only limited tools available for slimholes less than 4 in. MWD equipment can be run in hole sizes down to 4 1⁄8 in. Directional drilling equipment, such as steering tools, is available for 4 3⁄4-in. or 4 1⁄8-in. holes (Murray 1994). All standard logs can be run in hole sizes down to 3 3⁄4 in.

Other arguments against drilling a slimhole are the difficulty in working over such wells, the difficulty of cementing the small hole, the difficulty in testing, and problems with availability of slimhole rigs. Because of the high pump pressures required to overcome the increased friction in the small annulus, cementing operations may become difficult. The high pump pressure can cause channeling behind pipes and fracturing of weak formations. However, the biggest barrier to the use of slimholes is that the technology is new and different. It causes change, and change takes time as well as accurate communication of the technology (World Oil 1994).

4.0 CURRENT TRENDS IN SLIMHOLE DRILLING

In both frontier and mature oil fields, slimhole wells have proven savings of 15–40% over conventional drilling. In the current economic climate, slimhole horizontal wells will continue to play a role in exploration and development of reserves. The trend is also for increased slimhole reentry drilling and multiple horizontal drilling, an increased use of coiled tubing and geosteering, and an increase in underbalanced drilling.

4.1 Slimhole Reentry Drilling

In the United States, there are approximately 500,000 wells, most of them in mature areas, with 4 1/2-in., 5-in., and 5 1/2-in. casings. In these wells, slimhole reentry and horizontal drilling may offer the only opportunity to effectively develop new reserves, to access bypassed oil, or to realize the benefits of converting existing wells to horizontal wells.

The predominant reason for performing a reentry instead of drilling a new well is cost reduction. Less rig time, mud equipment rental, and associated drilling costs are incurred. However, the biggest economic benefits are the reduced costs for lease preparation and the reduced impact on the environment. In addition, well head, surface equipment, pipelines, and metering equipment are in place from previous production. Other technical benefits include the availability of drilling records and logs, which can aid the operator in reentering. In a horizontal reentry, cement bond logs can indicate areas where milling problems could occur and where cement squeeze operations may be necessary. Lithology logs, such as gamma-ray and neutron logs, can show the operator the depth intervals of the formations and help pinpoint target zones. Existing logging information from the original well also can help the operator determine the preferred azimuth for intersecting the most productive areas of the formation. Existing logs also can determine kick-off points. Knowledge gained from existing logs can reduce the chance of unexpected conditions during drilling operations in less known regions.

4.2 Slimhole Multiple Horizontal Drilling

Multiple horizontal wells are drilled to improve oil recovery and productivity. Multiple horizontal drainholes allow a well to be completed in layered reservoirs with contrasting reservoir properties or where the possibility of water or gas coning prevents the use of conventional stimulation techniques. In addition, if the horizontal penetration is restricted, multiple horizontal wells can be employed to increase the effective producing length.

There are other advantages to multilateral drainholes. Multilateral drainholes reduce drilling and completion costs because only one vertical wellbore is drilled. The use of a single vertical

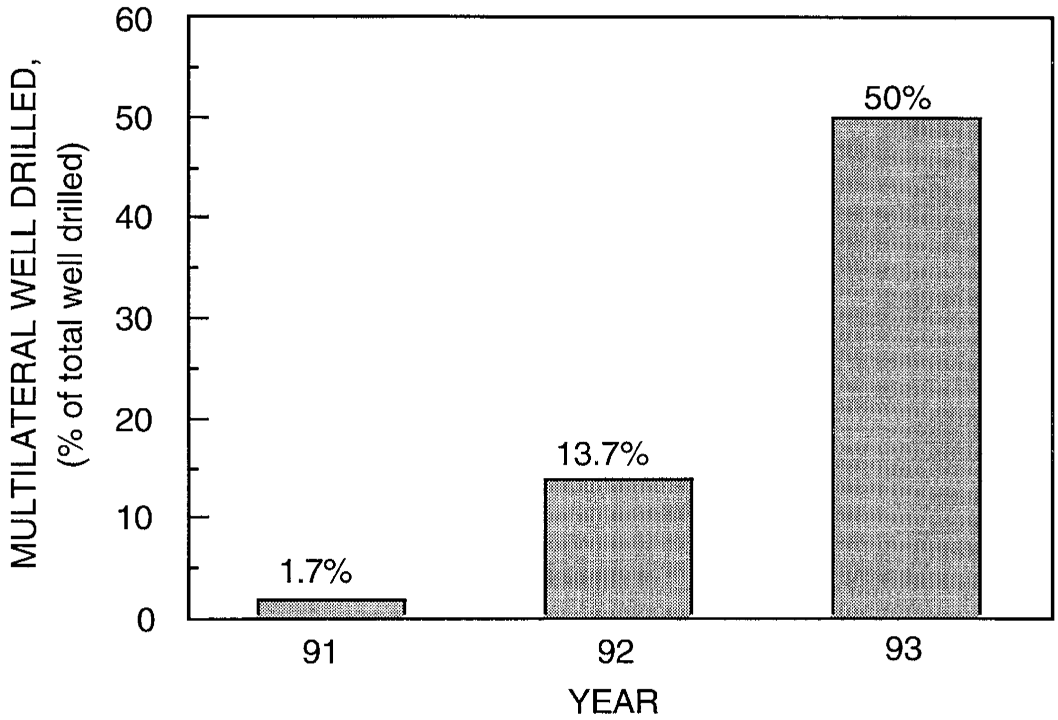


Figure 4–1 Multilateral Drilling Activity in South Texas (Graves 1994)

wellbore minimizes location, access road, and clean-up costs. Also, fewer facilities may be needed for production. This is particularly beneficial for offshore production because a platform has only a fixed number of well slots. Of primary importance, an increase in contact with the producing zone will likely yield higher production rates. Therefore, the productivity of multilateral wells is usually higher than similar single horizontal or vertical wells.

Multilateral drainhole drilling has increased rapidly in recent years. For example, multilateral drainhole technology was used in only 1.7% of the wells that Baker Hughes helped to drill in south Texas in 1991 (Graves 1994). By 1992, the number rose to 13.7%, and reached 50% in 1993 (Figure 4-1) (McMann et al. 1993; Graves 1994). Other service companies show similar trends toward multilateral wells in south Texas.

4.3 Slimhole Coiled Tubing Drilling

Coiled tubing drilling has the potential to deliver cost-effective slimhole wells (Ackers et al. 1992; Ramos et al. 1992; Tronmilin and Newman 1992; Faure et al. 1993). A coiled-tubing unit (CTU) is smaller than a slimhole rig and easier to mobilize. The CTU requires less equipment and personnel. Its smaller site requirement allows decreased civil engineering costs, and CTUs have a reduced environmental impact. Smaller surface site and lease requirements allow wells to be drilled in environmentally-sensitive areas and in remote areas where location size and logistics are critical. The noise from normal pipe handling is almost eliminated. Use of continuous tubing alleviates the need for connections and speeds up trip times. In addition, CTUs have pressure control equipment designed to allow the tubing to be safely run in and out of live wells. In summary, drilling with coiled tubing has the following advantages:

- Less environmental impact
- Increased safety on site
- Ability to drill underbalanced
- Less equipment and personnel, and a smaller surface site
- Time and cost savings.

In conventional drilling, there is always some drilling fluid spilled while making each connection. The use of a continuous string eliminates drillstring connections and thus minimizes drilling fluid spills. The continuous drillstring also significantly improves safety for rig crews because of reduced interaction between people and equipment. In addition, coiled tubing permits drilling and tripping continuously while circulating drilling fluid. This reduces the risk of blowout and results in time saving.

Another benefit of coiled tubing drilling is the ability to perform underbalanced drilling. Coiled tubing is smooth and has no external upsets. Therefore, a sliding pressure seal can be made at the surface while drilling and tripping to shut off the pressure in the annulus. Drilling underbalanced can reduce reservoir damage from invading mud particles and thus can improve production rates. In addition, lower mud weights can improve penetration rates. Tracy and Rike (1994) reported that penetration rates of 100 ft/hour and initial production rates 300% higher than anticipated were realized when underbalanced conditions were achieved.

4.4 Slimhole Drilling with Geosteering

Geosteering is another technology that will significantly affect future slimhole horizontal drilling. Geosteering enables the geological markers above the reservoir to be recognized and the final build to horizontal to be adjusted accordingly. By using this technique, decisions on well path adjustments can be made based on real-time geological and reservoir information.

In recent years, horizontal drilling has been used in thinner reservoirs. Because the successful drilling of horizontal wells is directly related to the wellbore's placement within the formation, one of the major problems in thin formations or when using slimhole horizontal technique is to establish the horizontal wellbore inside the targeted formation. In addition, excess tortuosity of the drill stem and the difficulty in effectively transmitting weight to the bit make slimhole horizontal drilling even more challenging.

In conventional horizontal drilling, the well path is steered according to a predetermined geometric plan. Formation evaluation measurements in conventional steering systems lag about

30–100 ft behind the bit. This data lag can result in changes being made only after significantly more hole has been drilled. In critical situations, the data lag may mean the difference between maintaining the wellbore within the objective formation and losing a valuable, productive hole. Geosteering, on the other hand, uses logging instruments to obtain geological and geophysical information while drilling to allow drillers to accurately steer downhole motors so that they stay within pay zones and hit targets. In addition, these geological and geophysical data can be used to reduce vertical depth uncertainty, permitting the use of tighter target entry.

The literature includes many successful geosteering cases. Goldman (1992) reported that Baker Hughes Inteq geosteered a horizontal well for Chevron in California. This horizontal well was drilled near the base of the sand formation and between a large number of vertical wells. Initial tests showed that this well produced a 3 to 5–fold increase in rate of oil production compared to vertical offset wells. Chevron used geosteering technology to:

- Confirm penetration into the target interval
- Avoid intersection with the oil/water contact
- Avoid exiting the target formation
- Position the wellbore optimally within the producing interval
- Extend the horizontal section length
- Assess the extent of invasion

Taylor (1990) reported several horizontal wells successfully geosteered within lateral heterogeneous reservoirs. For example, during the drilling of Atlantic Richfield Indonesia's ZUB-9 well in Bima field, the well–site geologist realized that the lateral was reapproaching the top of the Batu Raja Limestone. Drilling ceased, the steerable drilling system was pulled back to an appropriate location, and the well sidetracked to the low side. The well stayed within the reservoir (Barrett and Lyon 1988). LeBlanc (1993) reported that Baker Hughes Inteq used geosteering in a horizontal well where the bit exited the upper boundaries and was then steered back into the formation.

Computer modeling of the well profile prior to drilling can enhance geosteering. Using offset logging information, geological data are input into a model for the planned well profile to simulate the expected log response. Model logs have proven useful while drilling as an aid to interpretation of MWD logs.

4.5 Slimhole Underbalanced Drilling

In many oil fields, formation pressures are partially or completely depleted, so much natural gas and oil cannot be recovered because of formation damage from drilling fluids. To improve future oil and gas recovery, underbalanced drilling seems like a promising technology to reduce or eliminate formation damage and improve drilling operation.

Formation damage is of particular concern in horizontal and extended-reach wells because boreholes are exposed to drilling and completion fluid for significantly longer periods of time. Another reason is that open-hole completion is the norm in horizontal and extended-reach wells, resulting in a greater drilling fluid invasion. Also, effective stimulation in horizontal and extended-reach wells is often difficult and expensive due to the size of the damaged zone. As a result, underbalanced drilling has been used as a technique to minimize and eliminate such formation damage. In addition to preventing formation damage, underbalanced operations are also a practical and effective way to prevent lost circulation and differential sticking.

Underbalanced drilling also tends to increase the penetration rate. Reduced hydrostatic pressure at the bottom of the hole reduces the effective stress acting on the element of rock subjected to the bit cutter. Reducing the effective stress results in a decrease in apparent rock strength, which reduces the resistance of the rock to the action of the bit cutter. This results in an increased penetration rate. Compared with overbalanced drilling, an increase by a factor of 2 to 4 is not unusual, and sometimes the increase is by a factor of 10. Increased penetration rates help lower total well costs by cutting drilling time and reduce formation damage by shortening the time that the formation is exposed to the drilling fluid.

Stuck pipe incidents caused by differential pressure are eliminated because the pressure in the formation is actually higher than the pressure in the wellbore. Mud requirements are reduced because formation fluids are produced during underbalanced drilling, reducing mud costs and environmental impact. In addition, reduced formation damage can minimize expensive stimulation and lower ultimate completion/stimulation costs. Gregory (1995) reported that the production rates seven times higher than anticipated have been realized when underbalanced conditions were achieved.

Underbalanced drilling conditions are obtained when the effective downhole circulating pressure of the drilling fluid is less than the formation pore pressure. In many cases, particularly in pressure-depleted formations, it is necessary to artificially reduce the mud density and the hydrostatic pressure in order to generate underbalanced conditions. This is done by injecting gas (e.g., nitrogen, air, or natural gas) into the circulating mud system by either two-phase injection, parasite string injection, or microannulus injection.

As reservoirs become mature, underbalanced drilling activities will increase. In the future, underbalanced drilling advancements will focus on four areas: well control, drilling fluids, downhole tools, and accurate predictive models.

5.0 REQUIREMENTS FOR DEVELOPMENT OF SLIMHOLE DRILLING TECHNOLOGY

Development of slimhole drilling technology is clearly cost driven. The technology has been proven to be feasible and economical. A the present time, however, slimhole drilling cannot offer consistent results, especially for drilling horizontal and extended-reach wells because it is still in the early development stage and waiting for a push to become an industry-accepted practice.

5.1 Slimhole Early Kick Detection

One of the major barriers to the application of slimhole drilling technology to oil field operations is kick detection (Orban and Zanker 1988, Hytten and Parigot 1991, Hage et al. 1992, Prince and Cowell 1993). Conventional well-kill techniques, such as the wait and weight method, are often not valid in slimhole wells because the circulating pressure loss distribution is different. In slimhole drilling, the reduced kick tolerance in a small annular capacity well dictates that the kick detection system be able to detect a small kick volume. A kick detection system, therefore, should detect gas influxes early and shut in rapidly. In addition, it is important that any kick detection system be active during drilling and connecting operations and be capable of differentiating a kick from the additional noise introduced by drilling operations.

The annular volumes of slimhole geometries severely limit the maximum allowable kick in a slimhole compared with a conventional wellbore. From a well control standpoint, the height of an influx when a kick is taken, is critical to the severity of the situation. The greater the height of the influx, the more serious the well control problem.

Use the following equation to determine the annular volume:

$$V = \frac{d_i^2 - d_o^2}{1029.4} \text{ bbl / ft,} \tag{5–1}$$

where d_i = inside diameter (in inches) of the casing, and d_o = outside diameter (in inches) of the drillstring.

Using the equation on an 8,000-ft well, the annular volume between a conventional 8 1⁄2-in. hole and 4 1⁄2-in. drillstring is 50.5 bbl/1000 ft. The slimhole annular volume between a 4 3⁄8-in. hole and 3.7-inch drillstring is only 5.3 bbl/1000 ft.

Consider the consequence of a 1-bbl gas kick in a conventional well and a slimhole well. In the annulus between a conventional 8 1⁄2-in. hole and 4 1⁄2-in. drillstring, a 1-bbl influx will occupy a length of 19.7 ft at bottom-hole conditions. The same volume in the annulus between a 4 3⁄8-in. hole and a 3.7-in. drillstring will occupy about 190 ft at bottom–hole conditions. For 10.8-ppg mud in this hole geometry, this increase represents an additional 77 psi at surface on shut in.

As the gas expands when circulated out of the hole, the influxes of gas stretch out much more in slimholes than in larger diameter conventional wells, thus having a larger effect on wellbore pressure.

Consider 8,000-ft conventional and slimhole wells, as shown in Figure 5-1. If the gas is circulated to 1,500 ft, where a casing shoe is located, 1-bbl of gas in a conventional hole would only occupy 95 ft in the annulus and reduce the hydrostatic pressure by about 52 psi with a 10.8 ppg mud. The same 1 bbl in the slimhole annulus, however, would occupy 665 ft and reduce the hydrostatic pressure by about 3600 psi. The casing pressure must increase to maintain a constant bottom–hole pressure, as shown in Figure 5-2.

To ensure shut-in gas volumes in slimholes do not exceed the maximum allowable kick volume requires the use of a kick detection system with sufficient sensitivity to detect kicks considerably smaller than those identified by conventional technology. In conventional wells, kick detection commonly is based on a pit volume increase of between 10 and 25 bbl (Delwiche et al. 1992). A detection resolution of this size would have potentially hazardous consequences in slimholes. Therefore, the kick detection system needs to be very sensitive to kick volume. A detection limit

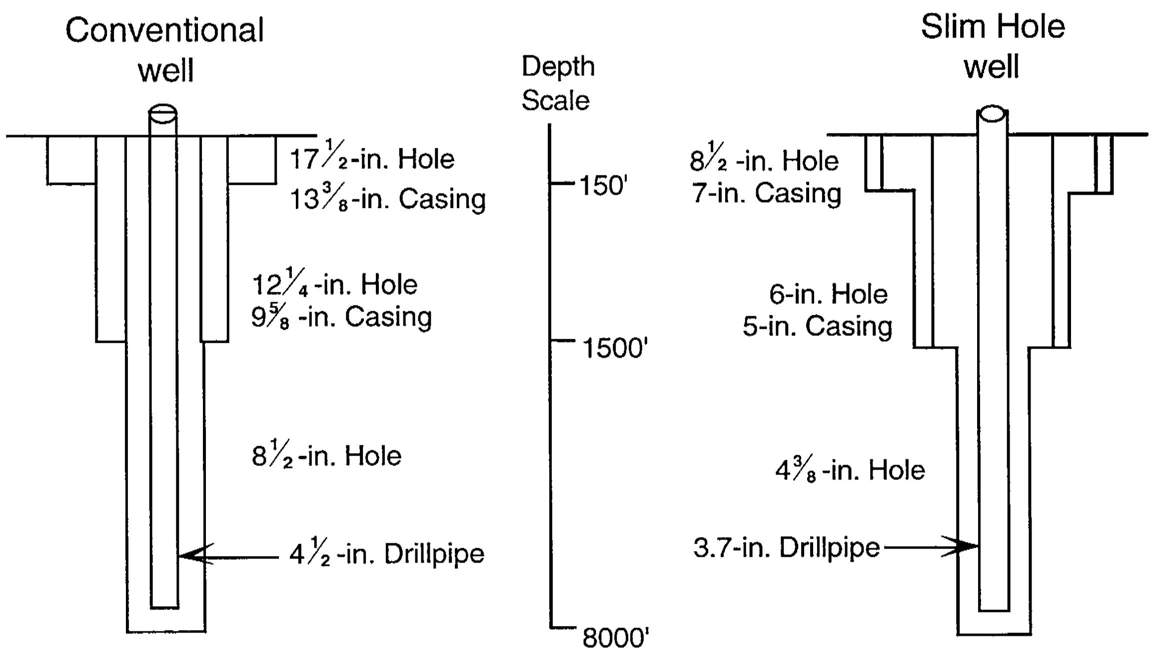


Figure 5–1 Wellbores of Conventional and Slimhole Wells

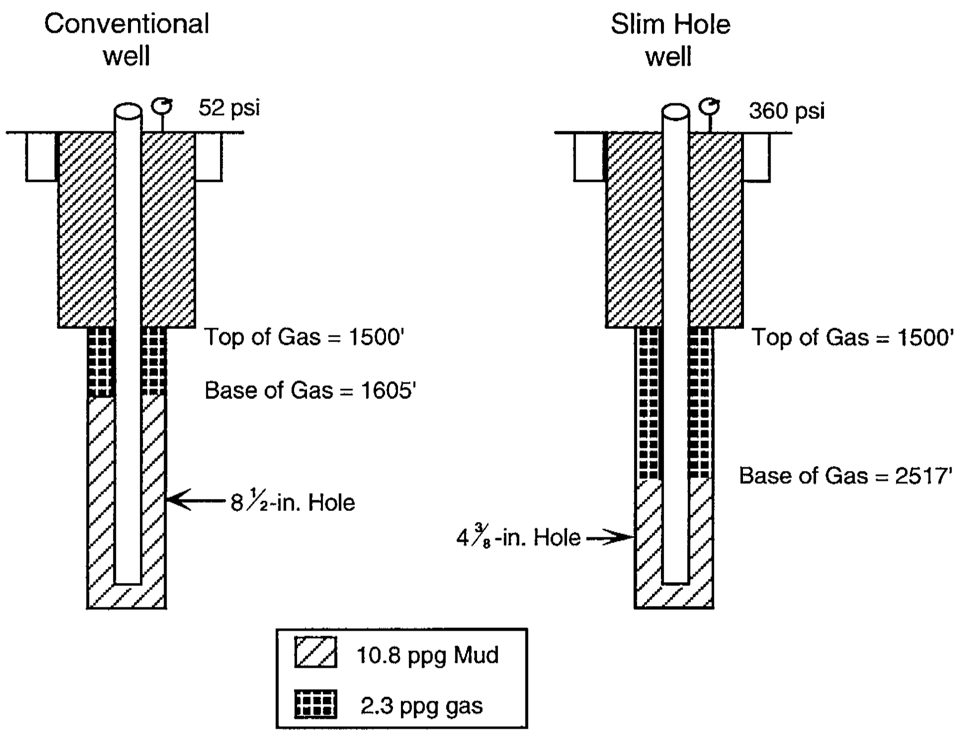


Figure 5–2 Conventional and Slimhole Wells with Initial 1-bbl Gas Kick Circulated with Drillers Method to a Maximum Position Using Shoe Pressure

of a 1-bbl influx would be considered as appropriate kick detection for a slimhole (Lejeune et al. 1992).

System pressure losses are the key to slimhole well control because, in slimhole drilling, the circulating pressure is dominated by the annular pressure drop. A result calculated by Bode et al. (1989) indicates that 90% of pressure losses takes place in the slimhole wellbore annulus compared to conventional drilling where 90% of pressure losses takes place in the drill pipe and bit nozzles. The high annular pressure losses can result in high equivalent circulating-mud density. Small changes in flow rate can produce large changes in annular pressure loss and consequent high equivalent circulating-mud density, as shown in Table 5-1 and Figure 5-3. In Table 5-1, the pump pressure is the system pressure loss, which is the sum of the pressure loss in the surface system, the drillstring and bit, and the annulus. The annular pressure loss is calculated according to the wellbore gauge diameter and flow rate. The equivalent circulating-mud density is calculated from the bottom-hole pressure, which is the sum of the hydrostatic pressure of the mud and the annular friction pressure (or the annular pressure loss).

The annular pressure loss will depend on mud properties, drillpipe size, pump performance, depth, and hole diameter, which is determined by the bit size and hole washout. Annular pressure loss can be very sensitive to hole washout. For example, the annular pressure loss difference between a gauge 4 3⁄8-in. hole and a 4 3⁄4-in. hole at 50 gpm in the example 8,000-ft

Table 5–1 Slimhole Annular Pressure Losses (Bode et al. 1989)*

Flow Rate (gpm)	Pump Pressure (psi)	Calculated Annular Pressure Loss (psi)	Equivalent Circulating-Mud Density (ppg)
11	121	106	7.8
13	164	145	7.9
16	241	214	8.1
19	331	294	8.3
23	471	420	8.7
27	634	566	9.1
31	820	732	9.5
35.5	1055	947	10.1
40	1323	1176	10.7

*For 7,010 ft total depth, with 3,219 ft of 3.27-in. (inside diameter) casing, a 3.06-in. bit, and 7.5-ppg mud weight.

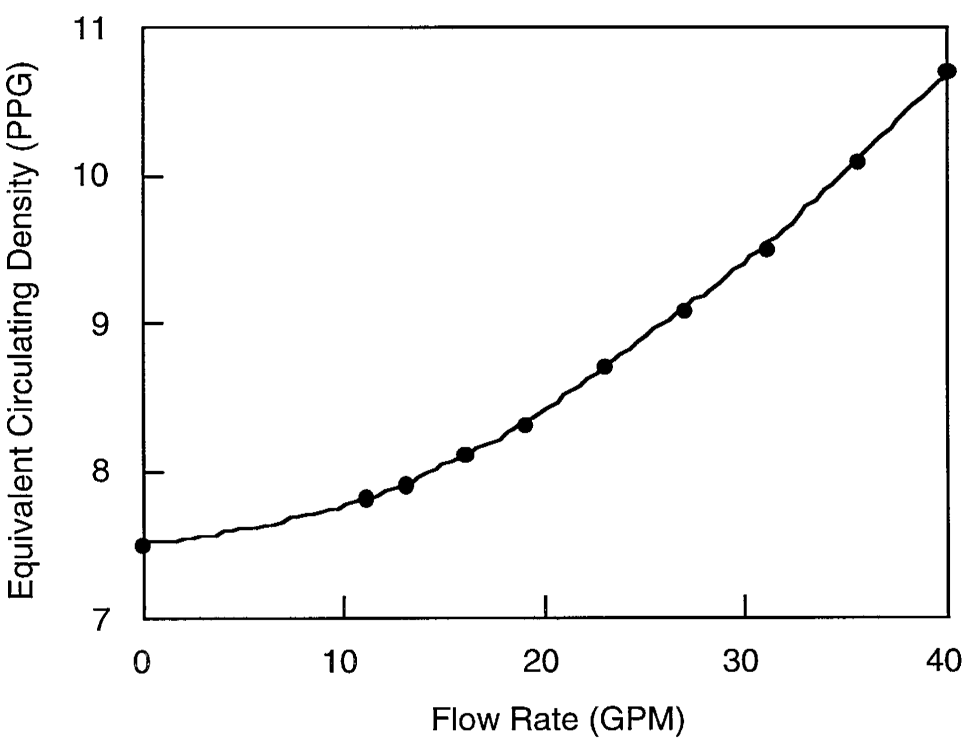


Figure 5–3 Example of Annular Pressure Loss Test (Bode et al. 1989)

slimhole well is 269 psi or 0.65 ppg equivalent (Teurlai et al. 1994). Due to the sensitivity of annular pressure loss to hole size, it is necessary to develop a new method of well control for slimhole drilling.

The annular pressure drops are also very sensitive to the rotation speed of the drill pipe. Some authors (e.g., Ferrell et al. 1958, Kardysh and Molchanov 1974) have demonstrated the dramatic increase in annular pressure caused by drill pipe rotation at high speed. The annular pressure losses induced by drillstring rotation were measured on a test well by Amoco (Bode et al. 1989). The test results (shown in Figure 5-4) indicated that the ratio of annular pressure losses with rotation to annular pressure losses without rotation ranged from 1.1 to 2.9. As an example of the effect rotation has on annular pressure loss, the 8,000-ft slimhole well in Figure 5-1 has an incremental annular pressure loss of 485 psi or an increased mud weight of 9.4 ppg equivalent when circulating 8.5-ppg mud at 50 gpm without rotation. When rotating at 600 rpm, an additional pressure loss of 580 psi is created. The total annular pressure drop would therefore be 1065 psi or 11.1-ppg equivalent (Bode et al. 1989). A kick detection system therefore, should be capable of differentiating a kick from the additional noise introduced by drill pipe rotation.

Currently, dynamic kill is commonly used to control wells in slimhole drilling. Dynamic kill is the controlling of formation pressure using the friction loss in the annulus when circulating. Typical equivalent circulating densities while circulating at 50 gpm in an 8,000-ft slimhole are approximately 9.6 ppg. Equivalent circulating densities of 12.1 ppg can be achieved on the bottom of the hole by increasing the circulation rate to 100 gpm. Rotating while circulating at 100

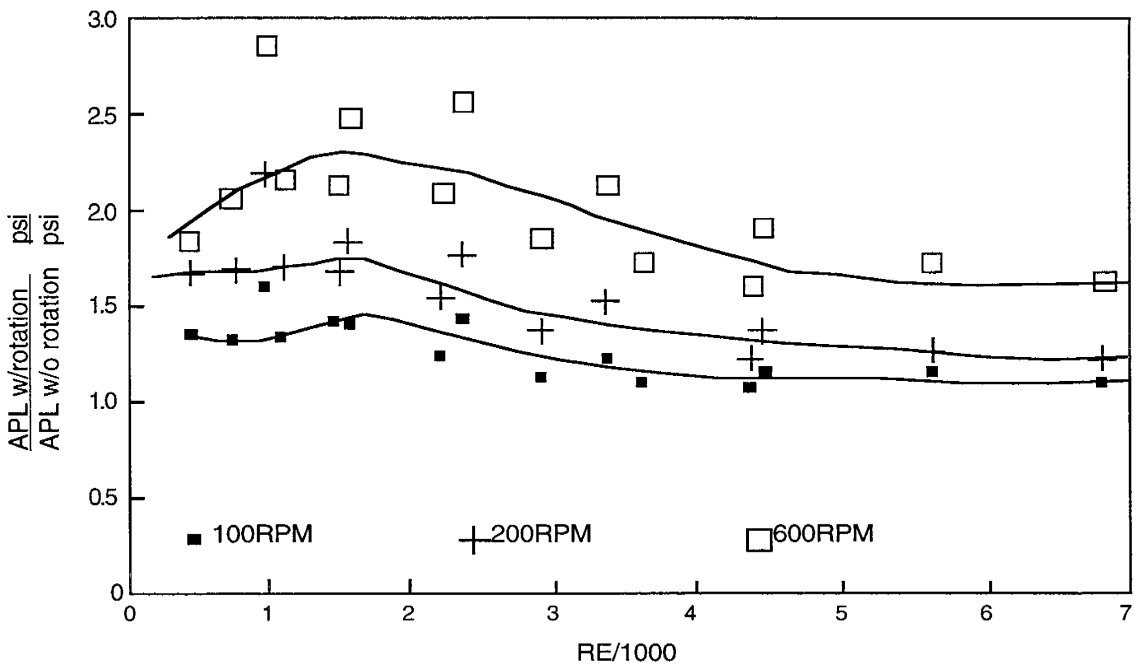


Figure 5–4 Ratio of Annular Pressure Loss with Rotation to Annular Pressure Loss Without Rotation vs. Reynolds Number (Bode et al. 1989)

gpm will increase the equivalent circulating densities to 16.1 ppg (Bode et al. 1989). Dynamic kill, however, depends on the pressure loss due to friction in the annulus. With a gas influx, the friction pressure loss will be small in comparison to the drilling mud. Therefore, the larger the gas influx volume, the more difficult a kill is with a dynamic kill method. For a large volume gas kick, the reduction in annular pressure loss due to the gas column may make dynamic kill difficult or impossible. For that reason, it is necessary to develop a new well control method for slimhole drilling.

High equivalent circulating-mud density also causes pipe-connecting operations to be more hazardous than in conventional drilling. The high circulating-mud density in slimholes can mask the presence of an overpressured formation. During a pipe-connecting operation, both mud circulation and pipe rotation stop, which will result in a large reduction of bottom wellbore pressure. If the formation had been close to balance while circulating, this pressure reduction may be sufficient to cause the well to kick. It is important, therefore, to develop a kick detection system that is active during pipe-connecting operations.

The small annulus and relatively low flow rates used in slimhole drilling also introduce a source of noise not normally a problem in conventional drilling. In slimholes, air entrained in the drill pipe during a connection will produce appreciable changes in flow as it appears at the flow line. Therefore, a slimhole kick detection system should be able to differentiate between a real influx and an artificial influx.

The demand for more sensitive and faster kick detection systems has become more important with increased slimhole drilling. Gas kicks create the greatest safety hazard in slimhole drilling. Improving kick detection systems will have a positive impact on slimhole well design as well as making the drilling operation safer. Greater effort should be made to pursue this matter.

5.2 Slimhole Directional-Drilling Steering Systems

Another necessity for slimhole horizontal drilling is the development of a reliable downhole steering system. During slimhole horizontal drilling, excess tortuosity occurs when a bottom-hole assembly drifts away from the planned profile and must be adjusted to keep the well on course. Current directional-drilling technology using steerable motors, operated with either pressure or flow changes from surface pumps, can produce numerous discrete deviations in the wellbore course. Such deviations limit the achievable lateral drilling range in many situations. In particular, elimination of excessive tortuosity is critical to extend the lateral distance in horizontal slimholes. Therefore, there is a need to develop downhole guidance systems that can minimize excess curvature.

As previously mentioned, there are approximately 500,000 wells in the United States. Because a large number of them in mature areas have 4- to 5-in. casing, slimhole reentries may be the only economic way to find new reserves or to increase oil and gas recovery. Currently available MWD tools and magnetically oriented directional tools, however, can not operate normally near the cased wellbore because of magnetic interference. The only available directional tools not affected by magnetic interference are conventional gyro-guidance systems. Since tripping gyro-guidance tools increases rig time significantly, drilling cost will increase. Therefore, it is necessary to develop new technology to locate the tool face and position of the well when exiting the milled casing.

5.3 Downhole Motors for Underbalanced Drilling

Rapid advances are being made in downhole motors, including improved adjustable housings, improved sealed as well as diamond-thrust bearings, and higher power motors. However, current slimhole downhole motors for underbalanced drilling are limited to pure nitrogen, natural gas, or air with small liquid addition for rotor-stator lubrication. Underbalanced drilling will need reliable performance from these motors for a variety of gas and liquid combinations.

5.4 Slimhole Drilling with Coiled Tubing

Coiled tubing drilling is a viable technique for drilling shallow to medium slimhole development and exploration wells. Field experiments have proven the technical feasibility of coiled tubing drilling for both new wells and reentries. In addition to the benefits of environment protection and personnel safety, coiled tubing drilling appears to be a promising technology for reducing drilling costs. The challenge is for the industry to develop this technology as an alternative to conventional drilling techniques.

A CTU can not be used to run casing. Normally, the top-hole section is not drilled with CTUs because the maximum achievable hydraulics are insufficient to clean a large borehole or to operate the required downhole motors. A conventional drilling rig has to be used to drill the top-hole and set the surface casing. Therefore, there is a need to develop a comprehensive coiled tubing drilling system that is able to carry out all phases of drilling without conventional rig intervention.

Another disadvantage of coiled tubing is tubing fatigue. Low-cycle fatigue is induced by plastic deformation of the coiled tubing through the surface equipment. It can become a significant factor in lateral drilling applications where the tubing is cycled several times to work through tight spots or during repeated trips to modify bottom-hole-assembly configuration, especially in short-radius horizontal wells. Better materials or alternative surface equipment design may help to solve or ease the low-cycle fatigue problem.

Recently, larger sizes of coiled tubing (up to 3 1/2 in.) have been developed. It is theoretically possible to drill holes of up to 9 7/8 in. (Faure et al. 1994). However, this will require new tubing materials with enhanced low-cycle fatigue life. The transport of long lengths of large-size tubing can be a problem, particularly for remote area operations. There is a need, therefore, to develop new techniques to connect or assemble small reels to bigger drums on-site at drilling operations.

With a connecting technique, coiled tubing could be transported on relatively small reels. In addition, new techniques for the development of composite coiled tubing should provide further improvement of the continuous drill-stem system.

Pipe buckling is another major problem. Buckling can lead to lock-up and horizontal displacement, as well as complicate weight-on-bit control and monitoring. The limitations of coiled tubing with regards to buckling must be addressed before the full potential of coiled tubing drilling operations can be realized.

5.5 Top Drive Drilling Systems

Top drive drilling systems were introduced to the oil industry in the early 1980s. Approximately 60–70% of all offshore wells are currently drilled with top drive drilling systems (Loland 1994). Unlike the conventional way of rotating the drillstring with a kelly and rotary table, top drive drilling systems drive the drillstring from the top, up in the derrick, by means of hydraulics or electrical motors.

The top drive drilling system has several advantages over conventional kelly drilling. The first benefit is that a top drive drilling system drills with triples, which consequently reduces the number of connections by two-thirds. This reduces the connection time and increases crew safety. Another benefit is its ability to back ream with 90-ft stands. In directional or horizontal drilling, this ability drastically reduces the trip time as well as the risk of getting stuck in the hole, and so reduces the chance of having to perform a time-consuming fishing operation. Well safety is also increased by the use of a top drive. If a kick should appear while tripping out of the hole, the system can be put back to work at any position in the derrick.

Top drive drilling systems were designed for installation on offshore units, however. They are permanently installed in a 160-ft derrick and powered with the vessel's or platform's power generation system. Such a system is not applicable on land rigs with small and short masts, which have to be rigged up and down for each well.

Recently, a portable top drive drilling system was developed for onshore drilling (Loland 1994). The basic model is equipped with two hydraulic drivers, giving a continuous drilling torque of 31,400 ft-lb at 200 rpm. The high-speed model for slimholes has speeds of up to 600 rpm, and the high-torque model gives a continuous drilling torque of 39,800 ft-lb.

There are still several barriers to the use of top drive drilling systems on land. The systems are expensive and costly to install. For example, it takes 8–12 hours to install a portable top drive drilling system (Loland 1994). In addition, the derrick or mast needs to be modified to install the system. The top drive drilling system, however, has the potential to provide the oil industry with greater drilling efficiency and higher performance, especially for extended-reach and horizontal drilling. If the previously mentioned barriers can be solved or eased, it is likely that top drive drilling systems will be the industry standard on land rigs in the near future.

6.0 CONCLUSION

Slimhole drilling technology has been proven a technologically and economically viable method of reducing drilling costs for exploration and development of oil fields. Slimhole drilling provides tremendous opportunities to significantly reduce overall drilling costs. Cost reductions of 40–60% (or more) for exploration and appraisal wells and 25–40% (or more) for production and injection wells compared to conventional wells are possible. The savings are achieved by using smaller drilling rigs and/or workover rigs, smaller surface drilling sites, reduced casing sizes, reduced cutting volumes, and less mud cement, and by reduced fuel costs, disposal costs, and other costs associated with hole size. In addition, slimhole drilling can minimize the impact of drilling operations on the environment and improve working conditions. The reduced environmental impact and improved working conditions are achieved from reduced waste generation, scaled-down equipment, reduced air pollution (because less power is required), reduced noise, and reduced risk of incidents linked to equipment transportation.

Typical applications for slimhole drilling include exploration wells in remote areas, where logistics can be a problem, and reentry operations, such as deepening or and sidetracking existing wells of small diameters. In addition, slimhole drilling technology offers the potential for major reductions in costs for production and development wells (including infill drilling for bypassed oil and thin oil rims) and for newly drilled horizontal and multilateral drainhole wells.

The current trend in slimhole drilling is to increase the number of slimhole reentries and multiple horizontal wells. Slimhole drilling is increasingly using coiled tubing and geosteering, and more and more of it is underbalanced. Because very many wells in mature areas in the United States have 4 1/2-in., 5-in., and 5 1/2-in. casing, slimhole reentry and multiple horizontal drilling may offer the only opportunity to effectively develop new reserves, to access bypassed oil, or to realize the benefits of converting existing wells to horizontal wells. On the other hand, the successful drilling of a horizontal well is directly related to its placement within a formation. Geosteering techniques allow drillers to accurately steer downhole motors and bits so that they stay within pay zones and hit targets. Underbalanced drilling can reduce or eliminate formation damage and improve drilling performance. Reduced formation damage can improve oil recovery and increase production. Production rates seven times higher than anticipated have been realized when underbalanced conditions were achieved. Reduced formation damage can also minimize expensive stimulation and lower ultimate completion costs. In addition, underbalanced drilling tends to increase the rate of penetration.

The cost savings achieved from slimhole drilling may be offset by increased mechanical failures, reduced lateral hole length, and lack of directional control. Factors that affect operations and economics in slimhole drilling include drillstring and tool joint failures, ineffectively transmitted weight to the bit, lack of directional steering tools and other slimhole measurement tools, reduced penetration rates, borehole integrity and instability problems, and difficulty in controlling a kick-out. In addition, the limited productivity of a slimhole also limits its application in many areas. The decision to drill a slimhole well, therefore, must consider the long-term effects as well as the short-term cost savings. The impact of smaller holes on long-term production and operation costs must be weighed against the initial savings of drilling a slimhole well.

Slimhole drilling is still in its early development stage. At the present time, slimhole drilling cannot offer consistent results, especially for drilling horizontal and extended-reach wells. Slimhole drilling technology is waiting for the push that will make it an accepted industry practice. Several areas require development and optimization in order to allow it rapid advancement in the near future: sophisticated early kick detection systems that can be active during pipe-connecting operations and capable of differentiating a kick from the additional noise introduced by drilling operations, a reliable downhole steering system to minimize excess curvature and to operate without magnetic interference, downhole motors for underbalanced drilling and optimization of underbalanced drilling operations, and top drive drilling systems.

Slimhole drilling with coiled tubing is an emerging technology that provides great opportunities for reducing drilling costs, improving working conditions, and reducing environmental impact. The main benefit it offers, however, is the enhanced ability to achieve effective underbalanced drilling without compromising safety. Priority should be given to development of an integrated coiled tubing drilling system that would be able to perform drilling or reentry operations without external assistance.

In summary, slimhole technology offers great opportunities for cost reduction and waste minimization. Slimhole drilling technology, however, is still under development. It requires effective communication and involvement from all areas, including operators, service companies, manufacturers, and authorities to overcome the limitations of slimhole drilling.

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