NIPER/BDM-0059

Status Report

A REVIEW OF SLIMHOLE DRILLING

by
Tao Zhu and Herbert B. Carroll

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Work Performed Under Contract No.
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Rhonda Lindsey, Program Manager
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ABSTRACT

Slimhole drilling provides an opportunity to significantly reduce overall drilling costs for exploration and development of oil fields. This cost savings is especially important with the reduced capital budgets under current economic conditions in the oil industry. Cost reduction of 40 to 60% (or more in some cases) for exploration/appraisal wells and 25% to 40% (or more in some cases) for production/injection wells comparing to conventional wells is possible. The savings are achieved by the use of smaller drilling rigs and/or workover rigs, smaller locations, reduced casing sizes, reduced cutting volumes, less mud and cement, reduced fuel costs, and other costs associated with hole size.

Slimhole technology also provides an opportunity to minimize the effect of drilling operation on the environment and improve working conditions. The environmental impact of the oil industry activities is playing an increasing role. The oil industry is facing the challenge to minimize the environmental impact. Slimhole drilling is contributing towards this target. The improvement of slimhole drilling on environment includes minimized drilling wastes, reduced noise, less transportation for mobilization and demobilization of drilling equipment.

This report reviews the various applications of slimhole technology including for exploration in remote areas, low-cost development wells, reentering of existing wells, and horizontal and multilateral slimhole drilling. The advantages provided by slimhole as compared to conventional drilling are also presented.

This report also discusses the limitations and disadvantages of slimhole drilling. The cost savings achieved from slimhole drilling can be offset by mechanical failures, problems associated with preventing kick-out, lack of directional control, and reduced lateral hole length in horizontal drilling. In addition, this report presents recent advances in slimhole technology, including coiled tubing drilling, drilling bit improvement, development of hydraulic thrusters, improvement of slimhole early kick detection, development of slimhole directional control tools. The improvement of slimhole technology has increased its activities in the past two to three years.

Based on the view of the literature, it is concluded that slimhole drilling offers great opportunity for cost reduction and waste minimization. However, slimhole drilling is still a ongoing development technology. It requires involvement from all areas to overcome the limitation of slimhole drilling. The slimhole technology is waiting for the push to become an industry accepted practice.

ACKNOWLEDGMENTS

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1.0 INTRODUCTION

The challenge for the oil industry in the 1990s is to identify strategies for maximizing the upstream potential value of the discovered reserves and for optimizing future investments to rescue risk in both exploration and exploitation activities. Hence, increasingly the operators, the petroleum engineer, and the geologist must evaluate together the options for exploration drilling to ensure that the discovery has the potential of being economically developed.[1]

Drilling and completing new wells are costly. Those costs accounted for between 30% to 70% of initial capital cost for oil and gas field developments.[2] Clearly, if oil and gas development is to continue in mature area, capital and operating cost must be reduced. In particular, when it is considered the currently spends on 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 the drilling and completion costs. Cost saving of a slimhole would accrue through the use of smaller surface casing and the substitution of liners for intermediate casing strings. The smaller upper hole sections could be drilled with improved penetration rates, reductions in cement and mud costs and in environmental impact would be achieved, and rig size could also be reduced with increasing confidence. Although sometimes only the bottom 5% of the well is slimhole, cost reductions apply to the whole well.

Slimhole drilling has been actively utilized 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. launched an initiative to drill slimhole exploitation wells in Utah, Louisiana, Mississippi, Arkansas, Oklahoma, Illinois, and Wyoming. The company concluded that slimhole wells could be cost effective.[3] The company recorded 3% to 25% savings in 108 slimholes drilled in 1957. From 1944 to 1959, Stekoll Petroleum completed over 1,000 slimhole wells with depth up to 5,000 feet in Kansas and Texas.[4] These wells were completed with 2⅞-inch casing and 1-inch diameter tubing. Cost saving of approximately 17% were reported. Arnold cited that Wolfe and Majee drilled 34 slimhole wells with 4¾-inch and 6⅛-inch diameters in Louisiana and Mississippi.[5] The slimhole wells cost 15% to 20% less than conventional wells. Portability, smaller capital investment, reduced trucking costs, and reduced daily operating expense were as reasons for the reduced costs. Huber reported that Humble Oil and Refining Company had cost savings up to 35% with 5⅝-inch diameter slimholes completed with 4½-inch O.D. casing.[6] They stated that slimholes can be drilled, fished, logged, completed, produced and reworked without undue difficulty. The growing slimhole drilling had resulted oil industry to develop special tools in logging, perforating, completion and workover. Special logging and perforating tools included.[7,8]

- 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-inch segment

Special cementing tools developed for use in slimholes included:[9]

- 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:[10,11]

- Macaroni strings (¾- to 1½-inch nominal diameter) as inner tubing strings
- Small gas lift tools (1¼- and 1½-inch 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 6¾-inch or smaller.[12] The depth of these slimholes ranged from an average minimum of 3,115 feet to an average maximum of 6,580 feet, with an average depth of 4,515 feet. Penetration rates were approximately the same as with conventional holes.

However, because of operational problems such as poor bit and drillpipe performance, and standpipe pressures resulting from inappropriate mud systems, the rate of penetration decreased with sizes below 7⅞-inch (as shown in Fig. 1–1). In addition, a lack of understanding of the drilling process led to snowballing operational problems. As a result, the interest in slimhole drilling waned in the sixties.

With exploration activity moving to more remote areas and 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 various slimhole techniques such as those used in the mining industry for ideas to improve slimhole drilling operations and to promote its use. Recent advances in slimhole drilling technology 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.

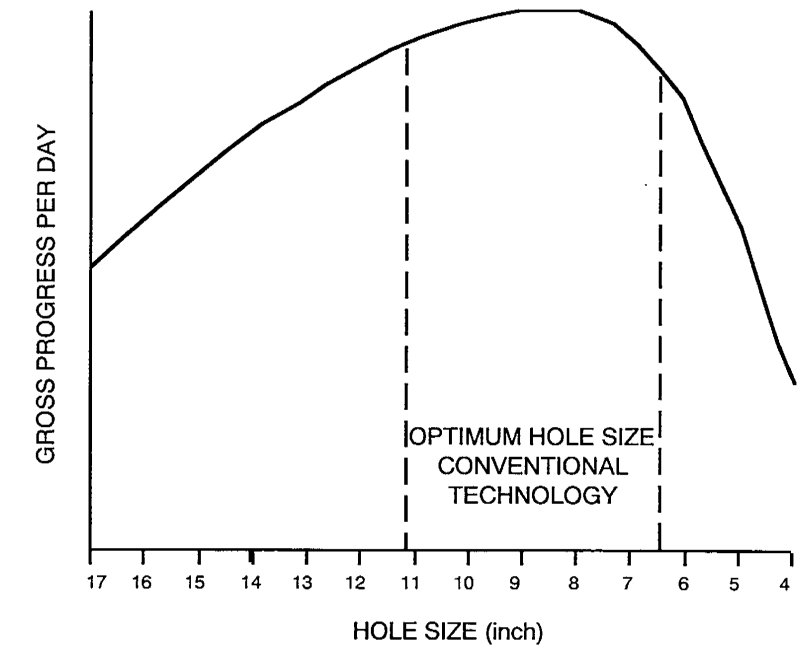


Figure 1–1 Effects of hole size on overall drilling efficiency.[44]

In this report, the following definitions will be used. For vertical wells, definitions of slimholes vary from a well with 90% or more of the length drilled with a diameter of less than 7 inches to a well with 70% drilled with less than 5 inches in diameter.[13,14] For horizontal wells, wells with lateral wellbore diameters greater than 8 inches will be called "conventional" wellbores. Wells with a lateral diameter between 6 inches and 8-inch will be called "reduced hole" wells.[15] For wells where the lateral hole is less than 6-inch will be call "slimhole" wells. Table 1–1 compares the various designs mentioned above for lateral holes.[15] In general, a slimhole is the drilling of a well with a diameter smaller than that used on conventional wells on the area.

Table 1–1 Comparison of Lateral Hole Designs[15]

	Hole Design		
Item	**Conv.**	**Red.**	**Slim**
Lateral Diameter	8.5"	6.125"	3.875"
Build Rates (Deg/100')	10–12	13–15	16–20+
Radius of Build (Feet)	573–477	440–382	358–287
Casing Designs			
Surface	13.375"	10.75"	8.625"
Intermediate	9.625"	7.00"	4.50"

2.0 APPLICATIONS FOR 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 reduction in costs for production wells, deepening and sidetracking existing wells, horizontal drilling and multilateral wells.

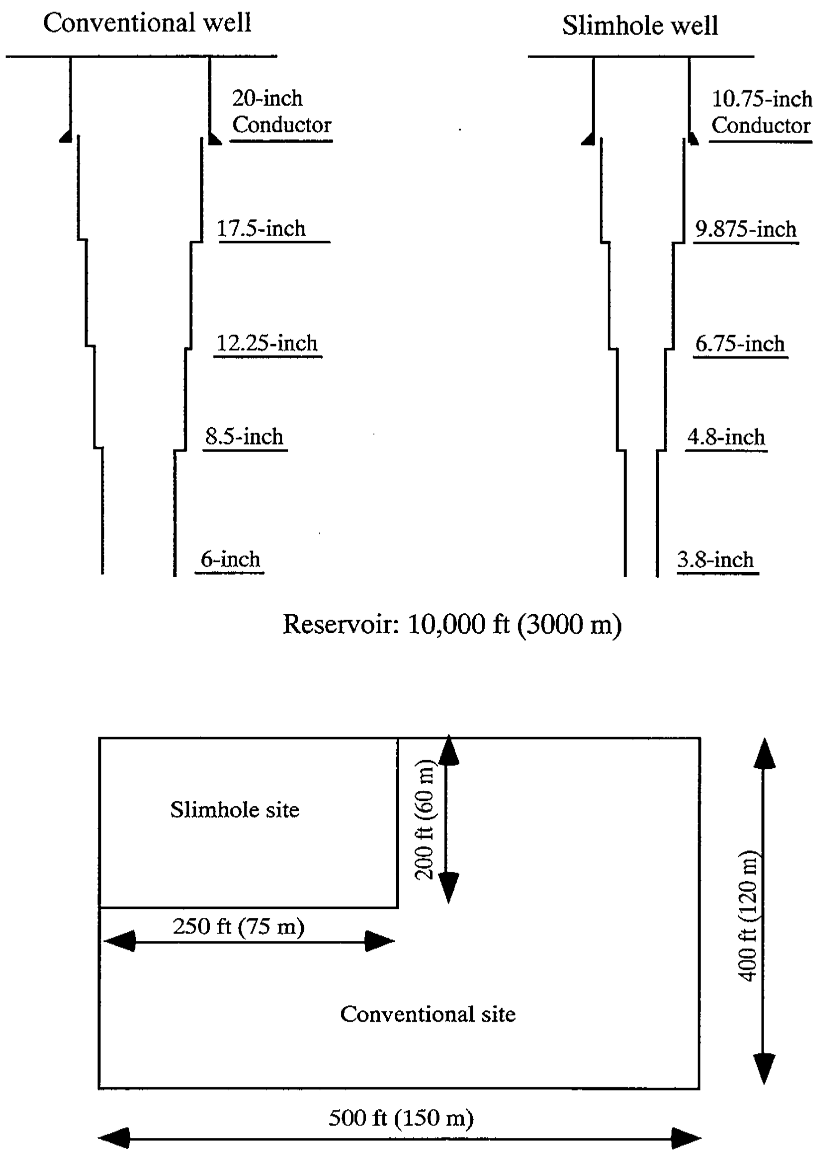
2.1 Slimhole Technology for Exploration in Remote Area

An area where slimhole wells may become very beneficial is in remote exploratory areas, where the risks are increasing.[13,16-20] Such areas may lack infrastructure or an established industry presence, where the road construction and logistics can be expensive. In this situation, the slimhole well may be simply 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 for a high-risk, high-cost operation.

Slimhole wells use less mud, casing, cement, water, diesel; generate smaller volumes of cutting; and need fewer crew to operate and support the drilling system. For example, if the hole diameters reduce by 50%, mud consumption and cuttings will reduce by 75%, and the size of well site will reduce 75% (shown in Fig. 2–1). The overall costs will reduce 40% to 60%.[21]

Conoco drilled slimhole wells in Irian Jaya, Indonesia, using helicopter portable rigs.[19] The operational area in Irian Jaya is one of Indonesia's, most remote area, which is 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 smaller rig platform layout to reduce the very high costs of field surveys, mobilization/demobilization, base camp construction, etc. The slimhole rig was only required about 100 airlift to move compared with 330 airlift (plus a further 220 to move the rig camp and tubulars) for a conventional helirig. The slimhole rig was transported in five days by helicopter compared to over 16 days for conventional rigs.

In recently, BP identified slimhole drilling as a technology for its exploration strategy in the 1990s. BP Exploration drilled six slimhole wells on Plungar field, England with the Micro-Drill MD3 rig.[22] The MD3 rig is only 13 metric tons in weight and 36 feet (11 m) tall compared to 116 feet (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% to 70 %. In BP's slimhole program, the $3\frac{7}{8}$-inch diameter slimholes were cased with 2.91-inch OD casing compared to $8\frac{1}{2}$-inch holes with $5\frac{1}{2}$-inch casing in conventional wells (shown in Fig. 2–2). The smaller hole size resulted in a sixfold decrease in cutting volume and a corresponding reduction in mud volume. Murray et al. cited that cost savings in excess of 40% were achieved in the BP slimhole exploration project.[21]



- 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 reduces both well and site costs.[21]

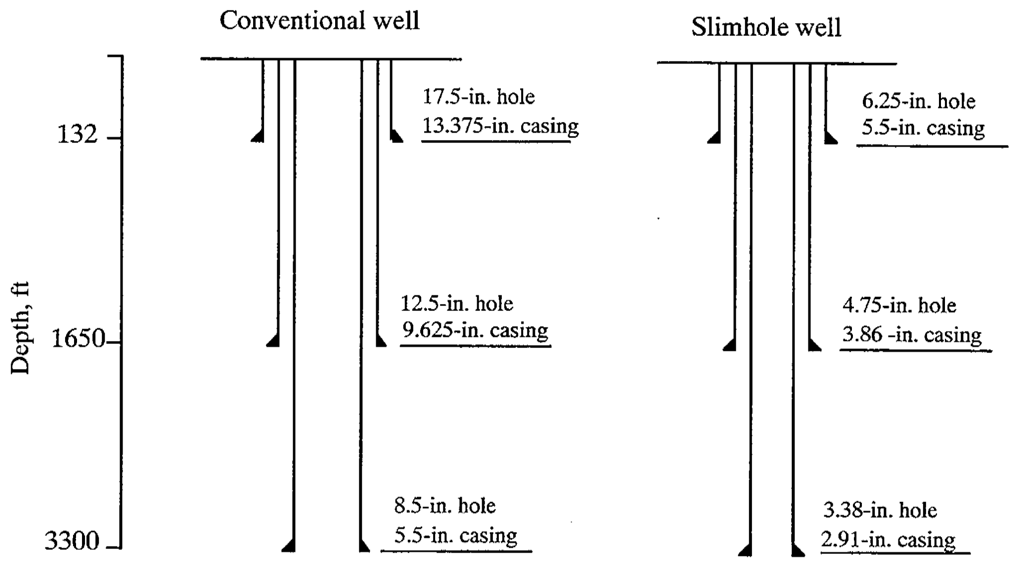


Figure 2–2 BP slimhole completion on Plungar Field.[22]

Since 1983, Total Exploration Production has drilled more than 230 slimhole wells in the Paris basin.[18] More than 80% of the meterage was drilled in 6-inch diameter. The formation is at an average depth of 6,400 feet true vertical depth. During the first quarter of 1990, 14 wells with a 4½-inch diameter were drilled to 2,625 feet. By the end of October 1990, Total successfully drilled an exploration well to a depth of 6,000 feet with the Foramatic II rig.[23]

During the second half of 1991, Total Exploration[18] conducted a slimhole drilling project in the Gabonese tropical rain forest. Two wells were drilled: one to 9,010 feet ending with a 3-inch hole and one to 1,371 feet ending with a 5⅞-inch hole. Continuous coring operations recovered 6,127 feet, or 59% of the total length drilled.

The casing design for Total's Gabonese project was set up as follows (also as shown in Fig. 2–3):[18]

- 10¾-inch casing set in a 15 inch hole drilled to a depth of 131 feet
- 8⅝-inch casing set in a 9⅞-inch drilled hole to 1,181 feet
- 6⅝-inch casing set in a 7⅞-inch drilled hole to 3,074 feet
- 5 inch casing set in a 5⅞-inch cored hole cored to 3,983 feet
- 3.7-inch drill rod as casing in a 4¼-inch hole cored to 8,593 feet
- 3-inch hole cored to total depth 9,012 feet

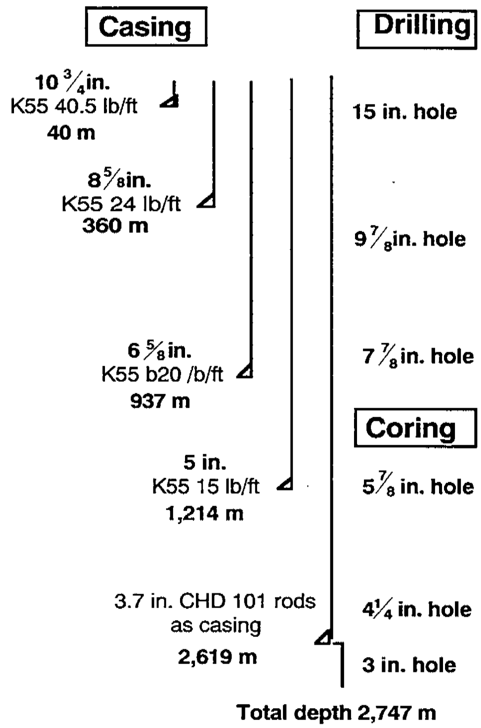


Figure 2–3 Nyangou-1 well schematic.[18]

With conventional drilling the well would have required a 36-inch hole and 30-inch surface casing, and the well would have ended with a diameter of 8 ½ inches.

Total Exploration reported that the use of a slimhole rig rather than a conventional rig allows a substantial reduction in the rig volume and weight, consumable goods, access, and installations. 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 project for Total's Gabonese project cost $12.8 million. The same program conducted with a conventional drilling approach is estimated to cost 15% more. Moreover, the potential cost savings for the same operation reaches 25%.[18]
The following is the approximate cost breakdown for the project:[18]

- Logistic and civil works, 39.5%
- Consumable items, 8%
- All drilling contracts, 29%
- Logging and mud logging, 8.5%
- Miscellaneous (supervision, feasibility studies, etc.), 15%

Total Exploration cited 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 8½-inch diameter commonly used in most wildcat wells could be replaced with a 6-inch slimhole with the possibility for a 4½-inch hole.[18]

2.2 Slimhole Technology for Low-Cost Development Wells

In many mature oil and gas field, the reserves are generally a function of the number of wells drilled. By the current recovery technology, about 40% of the original oil in place would be recovered, 20% of the oil would be unswepted in macro-scale, 20% would be bypassed in microscale and 20% was residual oil saturation. If one-half of the unswept and bypassed oil could be economically recovered, reserves of recoverable oil would be increased by 50% in the United States. Infill wells in matured areas are common to recover unsweeped and bypassed oil.

Drilling and completing new wells are costly. Slimhole drilling technology, fortunately, offers opportunities to cut drilling and completing costs. Slimhole wells may offer opportunities to access bypassed oil and gas, giving cheap production.

Slimhole completions cut development costs were reported as early as in fifties. Hudson's Bay Oil and Gas Company drilled 36 slimhole wells in Canada in the 1950s to depths of 2,600 to 6,900 feet, single and dual strings of 2⅞-inch tubing were cemented in 6¼-inch holes.[24] The slimhole wells cost 35% less than conventional completions. Most of the cost savings were from a reduction in material costs. A detailed cost comparison between typical 5,000-foot slimhole and conventional wells is listed in Table 2–1.[24] According to operators, a carefully planned slimhole development program may result in 25% savings on producing wells and 30% on injection wells, compared with conventional drilling and completion methods.[12]

Table 2–1 Cost Comparison for 5,000-foot Wells in Canada[24]

	Slimhole, $	Conventional hole, $
Casing	1,300	2,100
Tubing	5,300	5,300
Wellhead	1,100	2,200
Miscellaneous materials: (Float equipment, centralizers, etc.)	800	1,200
Contract drilling & day work	15,800	16,600
Company Overhead Expense	900	900
Trucking	900	1,800
Outside Labor	120	120
Cementing	2,800	2,000
Acid	150	600
Logging	850	850
Perforating	450	350
Fracturing	3,300	4,500
Location Expens	2,500	2,500
Mud	1,000	1,000
Core Analysis	200	200
TOTAL:	37,470	52,220
Savings:	$14,750 or 28 %	

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 some of the small shallow reservoirs. The system was used to drill 207 slimhole wells to depths of 650 to 8,000 feet with an approximately 2½-inch in diameter. The slimhole drilling reduced costs by 75% compared with conventional drilling. Cost comparison between slimhole and conventional wells are listed in Table 2–2.[25]

Table 2–2 Drilling Cost Comparison[25]

Rig	Hole	Result	Depth, m	Year	Cost[1]
Conventional Rig	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
	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

[1] In Swedish Krona.

Slimhole drilling techniques are being used by Unocal to drill shallow steam injectors in the San Joaquin valley area near Bakersfield, California.[26] 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 2⅜-inch tubing to surface. Unocal indicated that the injector was drilled with no major problems. The 2⅜-inch tubing was cemented with thermally stable cement from TD to surface to insure that there was no steam breakthrough to the surface and to isolate the tubing form formation water, thereby reducing heat loss. The tubing then was perforated and placed in service for continuous steam injection. 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 to approximately 50% of a conventional injector.[26] Unocal cited that the potential now exists for either increasing existing steam injector density or initiating steam drives in previously uneconomic areas, because this new methods of drilling and completion has resulted in significantly lower project costs.

Unocal indicated that using slimhole wells as shallow steam injectors has the following advantages:

- Total well cost reduction from 25% to 50% of a conventional injector
- Reduced location size
- Less directional drilling (smaller locations permit easier placement)
- Reduced tubular costs (no 5½-inch casing necessary)

- Expanding or initiating steam drives in otherwise uneconomic areas
- Economically increasing injector to producer ratios in existing steam drives

Unocal also pointed out the following disadvantages to using slimhole wells as shallow steam injectors:[26]

- Increased functional pressure in small ID tubulars
- Difficult to conduct workover operations inside 2⅜-inch tubing
- Cannot use insulated tubing and packer to control heat loss

2.3 Slimhole Technology for Reentering Existing Wells

The use of slimhole drilling for reentering existing wells has been provided opportunities to develop reserves through drilling deeper to find new reserves below the old reservoirs and horizontal drilling that would otherwise be unprofitable to develop.[27-41] In the United States, there are approximately 500,000 wells, many with 4½-inch (11.4 cm), 5-inch (12.7 cm), and 5½-inch (14.0 cm) casing. In mature areas, 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. Slimhole reentry technique will increase its activities in the future due to the large number of existing wells.

The predominant reason for performing a reentry instead of a new drill is cost reduction. Less rig time, mud equipment rental, and associated drilling costs are incurred because no vertical drilling is required. In addition, well head, surface equipment, pipelines, and metering equipment are also in place from previous production. Other technical benefits include the availability of drilling records and logs which aid the operator in reentering. In 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 can show the operator the depth intervals of the formations and help pinpoint target zones, and 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 point. The knowledge from existing logs can reduce the chance of unexpected conditions during drilling operations in less known regions.

One type of slimhole reentry is sidetracking the existing wells to horizontal. In this technique, a portion of the existing casing is milled out and the hole is sidetracked to horizontal. Two types of milling operations are used for reentries: section milling and window milling. The section milling operation uses a drill string with a blade type mill that is rotated from the surface (Figure 2–4).[27] The milling operation begins about 10 feet above the selected kick-off-point. This allows sufficient space to clear the casing with the motor and bit while sidetracking.

Another type of milling operations is window milling. Instead of removing the entire circumference of casing, only a small strip of the casing is removed, parallel to the casing centerline and on the side of the casing on which the horizontal wellbore extended. This is achieved by setting an oriented whipstock in the casing below the kickoff point and then running a bottomhole assembly which mills the casing and sidetracks the existing hole in the desired direction (Fig. 2–5). Comparing

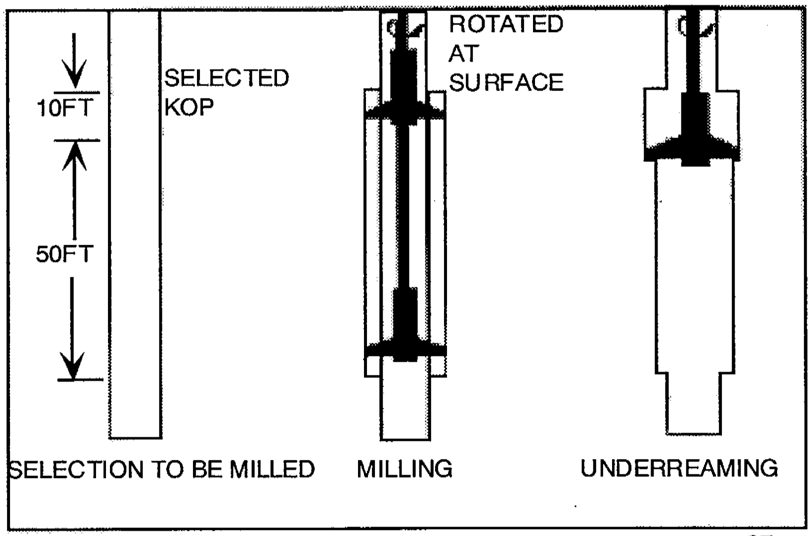


Figure 2–4 Schematic of the section milling operation.[27]

to section milling operations, window milling operations do not require cement plug for kicking off and less casing is removed. In addition, the sidetracking procedure is accomplished while cutting out the window. Window milling operations can reduce the time required for sidetracks.

There are a large number of reports on slimhole reentries. SlimDril International has successfully performed several hundred reentries out of 4½- and 5½-inch casings.[27] SlimDril cited 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 4½-inch reentries with no significant problems.

Reentry operations are now being used for numerous 4½-inch casing completions in the Austin chalk trend.[27,28] One of the 4½-inch casing reentries performed was for Gemini Exploration in the Austin Chalk in Lee County, Texas. A conventional workover rig was used with only minor

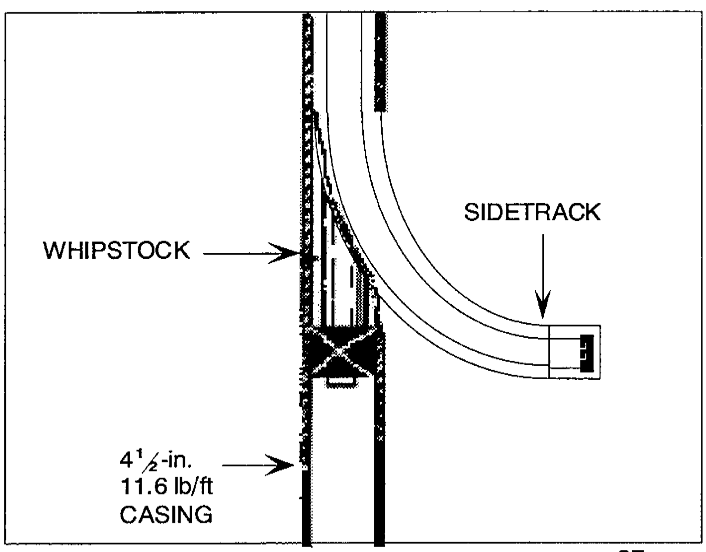


Figure 2–5 Schematic of window milling.[27]

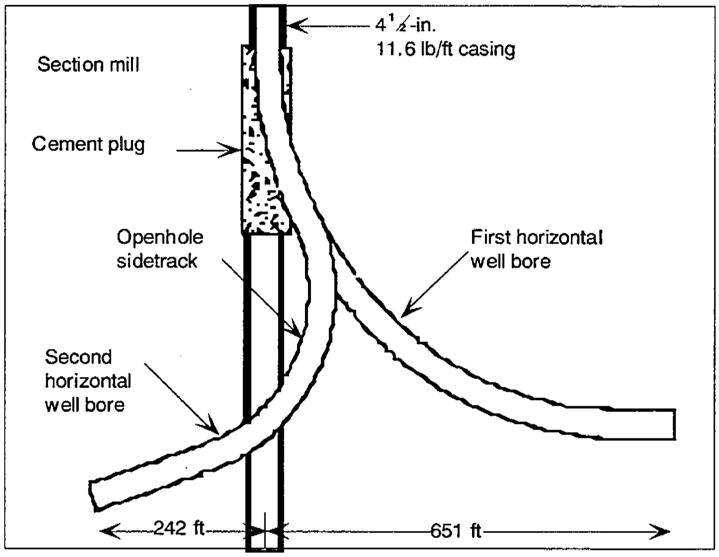


Figure 2–6 **Slim Drill used a conventional workover rig to perform a 4 1/2-in. reentry.**[28]

modifications to give it drilling capability. This reentry was a dual drain hole and was completed by using section milling operation as shown in Figure 2–6.[27] The entire dual drain hole operation was finished in nine days and cost considerably less than big hole operation.

Another reentry example is a well with 4½-inch casing run from reentry for Oklahoma Natural Gas in Logan County, Oklahoma. A section mill was performed on the 7-inch casing, and the hole was sidetracked with a 6⅛-inch bit and 4½-inch motor assembly (Fig. 2–7). A 4½-inch string of casing was run and cemented to surface. The lateral portion was drilled with a 3¾-inch bit to a total horizontal displacement of 1,863 feet. A significant cost reduction was recognized.

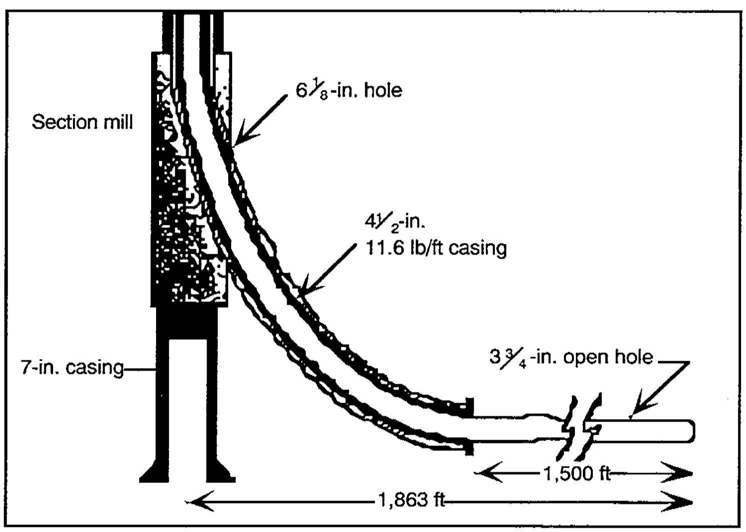


Figure 2–7 **A section mill was performed on a 7-in. casing well and sidetracked in Logan County, Oklahoma.**[27]

Union Pacific Resources Company (UPRC) has reported that the average drilling cost for a reentry horizontal well was about $100 per feet of exposed formation compared to average $162 per feet in Pearsall field of South Texas, or 38% savings.[28] The cost saving for different type of reentries is shown in Figure 28.

Recently, BP Exploration (Alaska) reported that sidetracking technique reduced the drilling costs from $2.2 to $1 million for marginal areas of the Prudhoe Bay reservoir, up to 55% savings.[30] The company has drilled 50 sidetrack wells by drilling new wellbores from damaged or low-yield wells. The sidetracking technology also increased the reserve for the Prudhoe Bay reservoirs. For example, one horizontal sidetrack drilled recently into the Ivishak field's Zone One is producing about 800 B/D from a previously unproductive well, because the horizontal sidetracking allows to access those thin, segregated layers of oil that previously have been uneconomic to produce.[29]

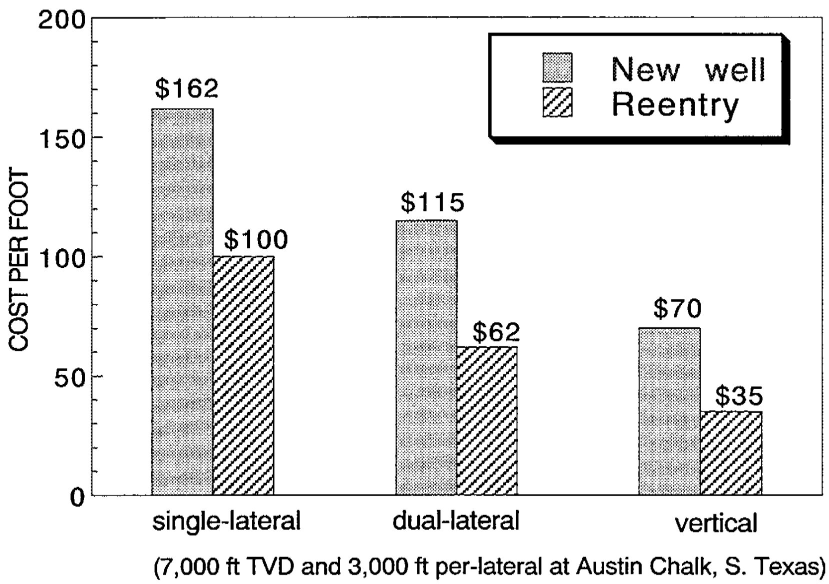


Figure 2–8 Cost saving for different types of reentries.[28]

In 1989, Oryx Energy Company determined that a slimhole reentry program was needed to utilize existing wells in marginally productive areas of the Pearsall Field.[15] The Pearsall Field is located in southern Texas. It covers an area in four counties: Frio, Dimmitt, LaSalle, and Zavala (Fig. 2–9). It is an area where Oryx has had an extensive horizontal drilling program in the fractured Austin Chalk formation with over 150 company-operated horizontal wells drilled since 1987. The field has been also extensively drilled vertically for production in the Austin Chalk and other formations. Therefore, opportunities existed for reentering existing wells. Figure 2–10 shows a typical reentry horizontal Austin Chalk well. Due to the large amount of production acreage in certain parts of the field, several reentry slimhole horizontal wells were drilled by milling a section on the 5½-inch production casing and kickoff out of the section in 1991 and 1992. All work was to be done with a continuous operation (24 hour) workover rig.

The savings were significant (as shown in Table 2–3).[15] The costs of reentries drilled were significantly less than that of conventional wells being drilled in other parts of the field. The average

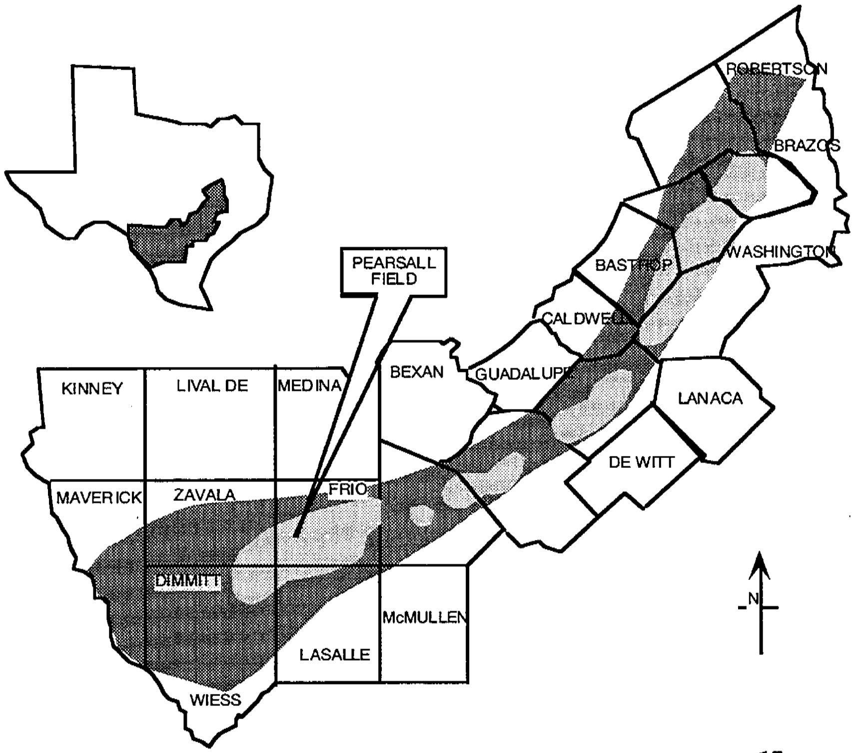


Figure 2–9 **Austin Chalk Trend Map of South Texas.**[15]

costs of a reentry slimhole horizontal well are only 50% of the conventional horizontal drilling costs. It was even more remarkable that conventional well drilling costs had been reduced by 21% through improved operations and the conventional hole lateral costs had been reduced a dramatic 67% from the previous year (Table 2–4).[15]

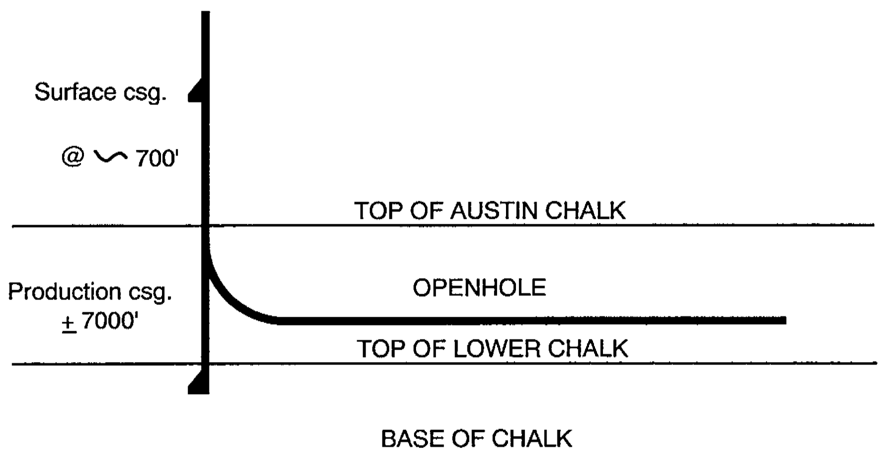


Figure 2–10 **Typical Oryx reentry wellbore configuration.**[15]

Table 2–3 Austin Chalk Slimhole (after Hall et al. 1992)

Reentries, 1990*

Well	Days	Departure	Total Cost Index	Lat. Cost Index
1	44	1901	1.09	2.17
2	39	2316	1.12	1.83
3	25	2226	0.79	1.34
4	33	1419	0.63	1.68
5	18	1460	0.60	1.57
Avg.	32	1864	0.85	1.72

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

Reentries, 1991*

Well	Days	Departure	Total Cost Index	Lat. Cost Index
1	18	1458+	0.63	3.88
2	38	2018	0.74	3.31
3	24	2002	0.41	1.84
4	21	2692	0.43	1.46
5	20	2242	0.45	1.83
6	18	1927	0.50	2.36
7	14	1600	0.31	1.75
8	22	1900	0.54	2.60
Avg.	22	1980	0.50	2.38

*Assumes cost for 1991 Conventional Well = 1.00 for both total well cost and lateral hole cost. 1991 Conventional cost was 21% less than 1990 Conventional Cost. 1991 Lateral Cost was 67% less than 1990.

+Coiled Tubing Well

Table 2–4 Austin Chalk Slimhole Reentries (1990 vs. 1991–92*).[15]

Item	1990	1991
Total Well Cost Index*	0.85	0.40
Avg. Lateral Departure	1864	1980
Days	32	22
Lat. Cost/Feet Index	1.72	0.79

*Using 1990 Conventional Well Costs = 1.00.

Another application of slimhole reentry techniques is deepening the existing wells. From 1982 to 1985, Tri-State Well Service drilled 20 slimhole deepening wells in Kentucky, Virginia, West Virginia, Ohio, Pennsylvania, and New York, with 3⅞-inch bits from existing 4½-inch production casing.[30] The holes were deepened with air drilling, logged, and then 2-inch production tubing was run and cemented to surface. The slimhole drilling technique resulted in large cost savings, which were only 40% to 50% of estimated new well costs to the same depths.[31] For example, a 2,260-foot West Virginia well was deepened to 4,823 feet at a cost of $78,641, or about $31 per feet, compared to approximately $165,000 for a new well from the surface, which was equivalent to 52% savings. The respective deepening resulted in recoverable reserves of 133.7 MMcf natural gas.

Coiled tubing used for slimhole reentry could significantly reduce costs even more significantly. Elf and Dowell Schlumberger drilled a 3⅞ inch vertical open hole from the total depth of 2,100 feet down to 4,225 feet.[32] The use of existing wells avoided the problem and cost of having set casing.

2.4 Slimhole Technology for Horizontal Wells

In recent years, operators have seen the need to drill the slimhole horizontal wells where larger diameter laterals were considered too marginal. The need for larger wellbores to handle the high flowrates has been replaced with the need to drill a smaller diameter wellbore to reduce costs. Even though the smaller diameter wellbore could limit the potential ability of the well to produce, practical applications proved that other factors such as depletion or low rock permeability can also be limiting factors. Therefore, well cost, not productivity, can become the deciding factor in the horizontal lateral length and diameter. For example, in areas where the lateral extent is desired to 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 provide efficient method of production. Because of these developments, operators are willing to take the greater risk and limitations associated with slimhole horizontal wells to achieve the savings which are possible.

In 1991, Oryx developed a slimhole horizontal drilling program in Pearsall Field located in Southern Texas (Fig. 2–9). The idea was 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 then was run and cemented. The drilling rig was released, and a workover rig moved on location to drill the curve and lateral section. This would provide 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 that required by the larger drilling rig used to drill conventional wells. The second benefit was that the workover rig could more easily manipulate the tubing used for the drillstring.[15] In addition, the workover rig could be used to complete the wells prior to its release. Figure 2–11 shows a typical newly drilled horizontal well in Austin Chalk.

Results from Oryx show a significant cost reduction. After learning experience, the second well performed under very typical conditions seen in drilling operations in the Pearsall Field.[15] It experienced complete lost returns, drilled while the well was flowing, and drilled through

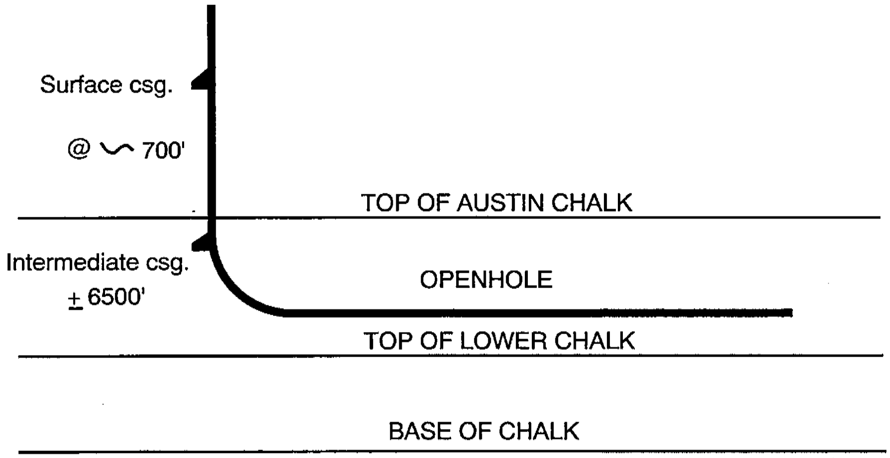


Figure 2–11 Typical newly drilled wellbore configuration in Austin Chalk.[15]

unconsolidated volcanic ash intervals with little problems. The hourly penetration rates were the equivalent of those seen in larger conventional wellbores. Savings of nearly 32% from the conventional design and 17% from the reduced hole designed were seen (Table 2–5).[15]

Table 2–5 Comparative Drilling Costs for Newly Drilled Wells[16]

	Hole Size	Depth/ Displacement	Total Cost Index	Lateral Cost Index
Conventional	8-1/2"	10,389'/3,741'	1.00	1.00
Reduced Hole	6-1/8"	9,698'/3,257'	0.82	0.87
Slimhole	4-3/4"	9,697'/3,154'	0.68	0.73

Cost index refers to total well costs. Lateral cost index refers to costs associated with lateral hole.

It can be seen that slimhole horizontal drilling offers significant potential for cost savings. Table 2–6 shows the actual cost savings which were seen from the use of slimhole technologies in Oryx's Pearsall Field operations.[15]

Table 2–6 Comparative Drilling Costs—Slimhole vs. Larger Design[15]

	Hole Size	Depth/ Displacement	Total Cost Index	Lateral Cost Index
Conventional	8-1/2"	10,289'/3,741'	1.00	1.00
Reduced Hole	6-1/8"	9,698'/3,257'	0.82	0.87
Slimhole Reentry	3-7/8"	------/1,980'	0.50	2.38
Slimhole New Well	4-3/4"	9,697'/3,154'	0.68	0.73

Cost index refers to total cost of well. Lateral cost index refers to costs associated with lateral hole.

2.5 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 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 (Figs. 2–12 to 2–15) from a vertical hole,[29,33] and a new multilateral approach which involves drilling horizontally through pay zone and drilling drain holes out laterally from the horizontal section into reservoir with coiled tubing (Fig. 2–16).[35]

There are a number of advantages to drilling multilateral drainholes. Multilateral drainholes reduce drilling and completion costs because only one vertical wellbore is drilled. The use of a single vertical wellbore minimizes location, access road, and cleanup costs. Also, fewer facilities may be needed for production, which has particularly benefit for offshore because a platform gives a fixed number of well slots. Of primary important, increase contact with the producing zone most likely will yield higher production rates. Therefore, the productivity of multilateral wells is usually higher than similar single horizontal wells and vertical wells.

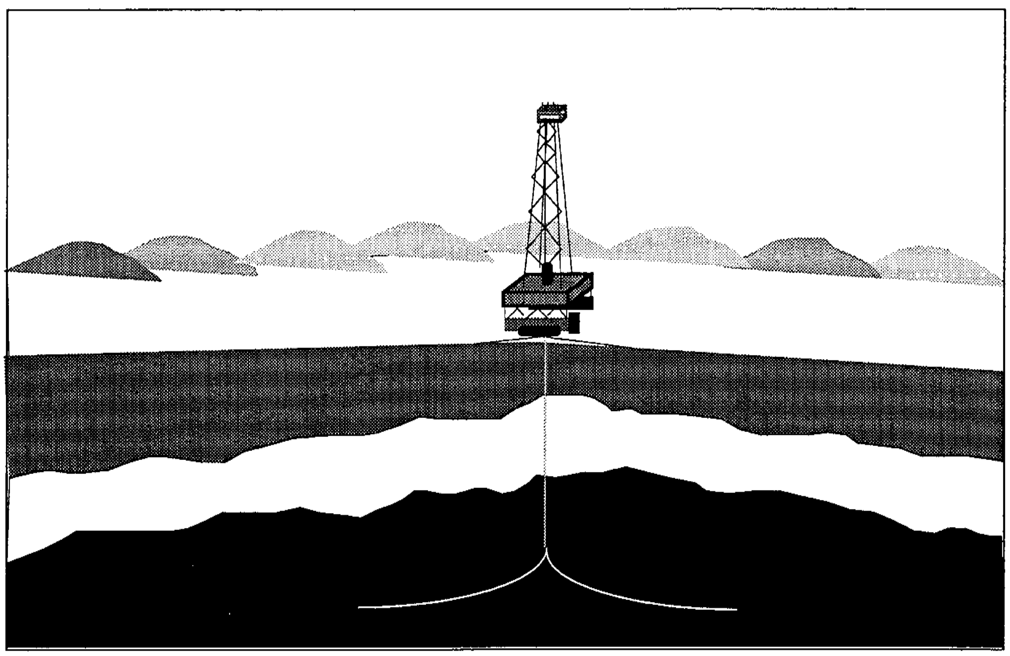


Figure 2–12 Schematic of dual-opposing horizontal well.

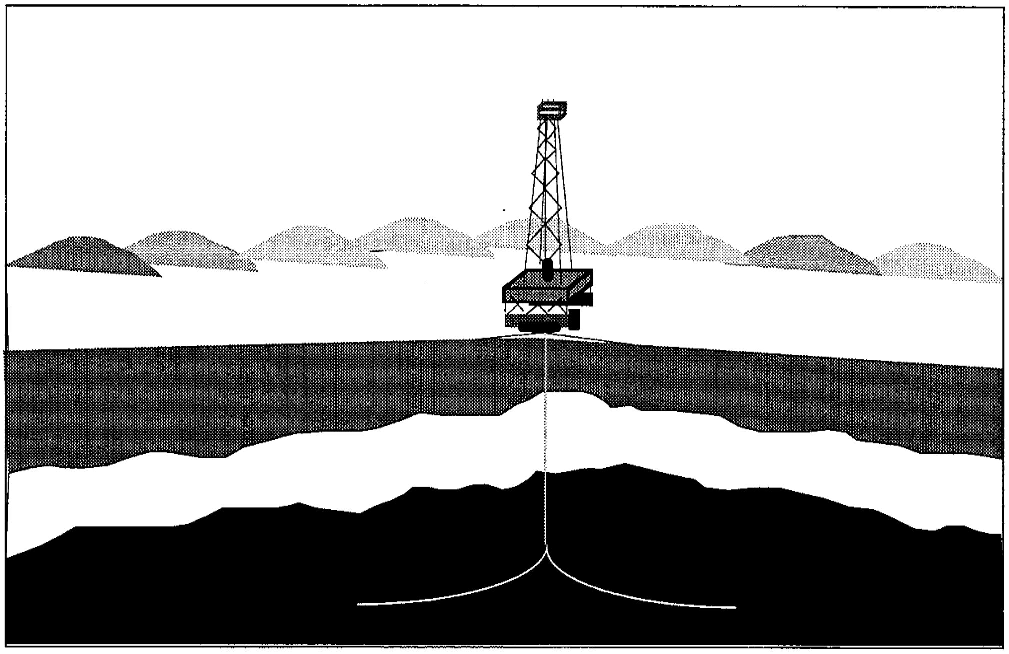


Figure 2–13 Schematic of dual-stacked horizontal well.

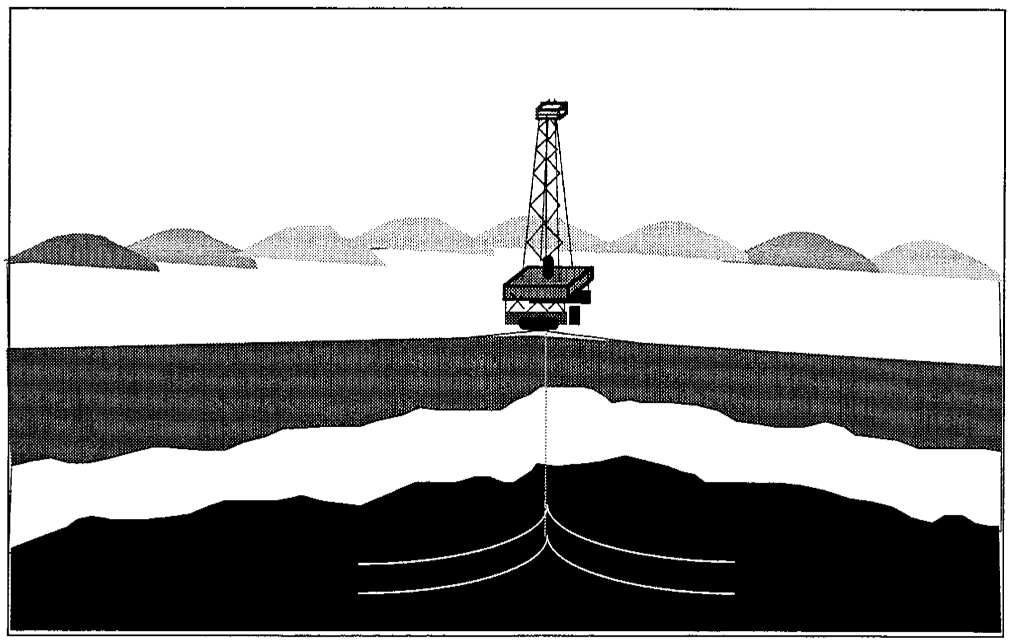


Figure 2–14 Schematic of dual-opposing-stacked horizontal well.

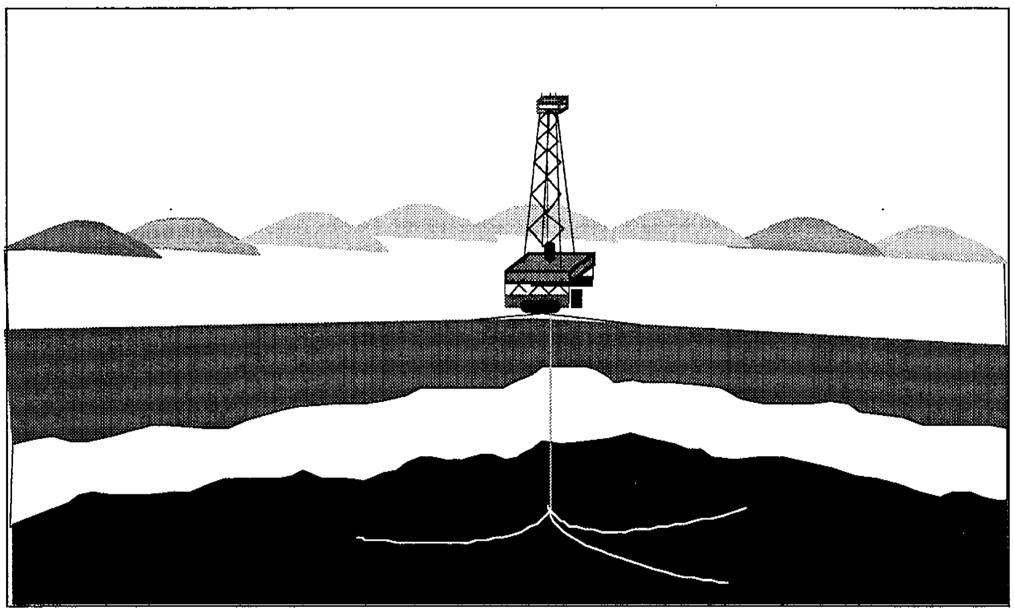


Figure 2–15 Schematic of Y-shaped horizontal well.

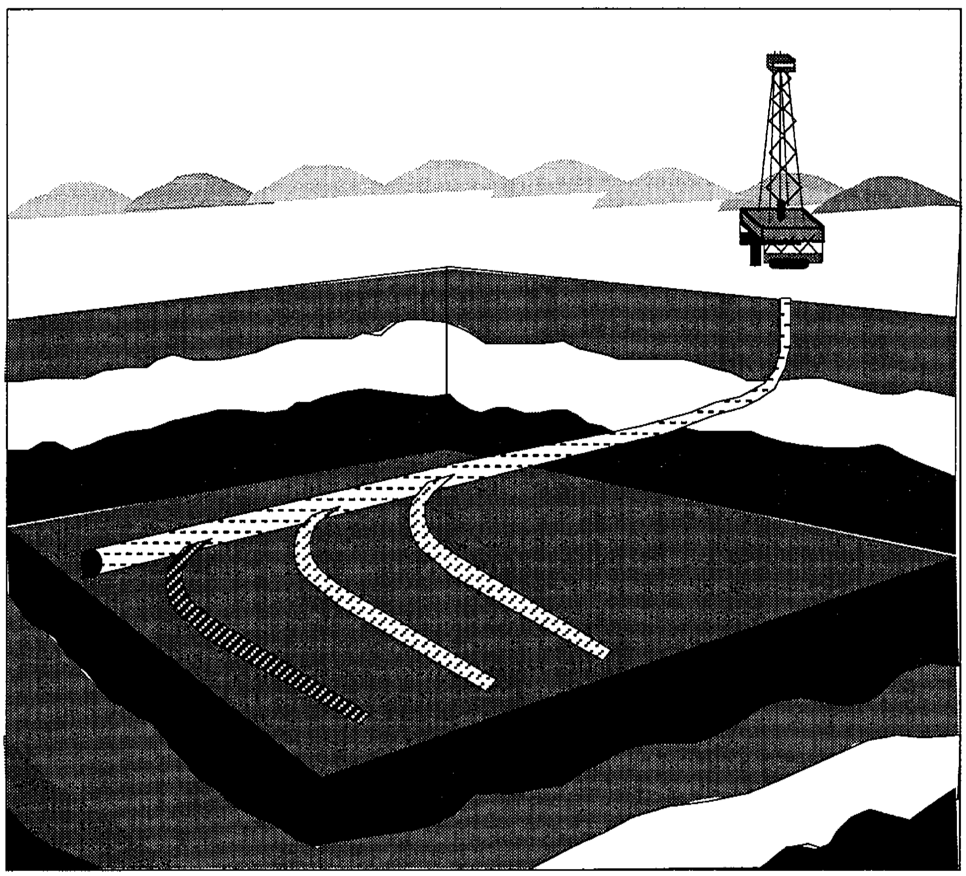


Figure 2–16 Schematic of the lateral tie-back system.[40]

The activity for drilling multilateral drainhole has increased rapidly in recent years. For example, multilateral drainhole technology was used in only 1.7% of the wells that Baler Hughes helped to drill in South Texas in 1991.[33] By 1992, the number had risen to 13.7% and reached 50% for 1993 (Fig. 2–17).[33, 34] Other service companies show similar trends toward multilateral wells in South Texas.

Generally, multilateral wells can be applied to the following conditions:[33]

- 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.

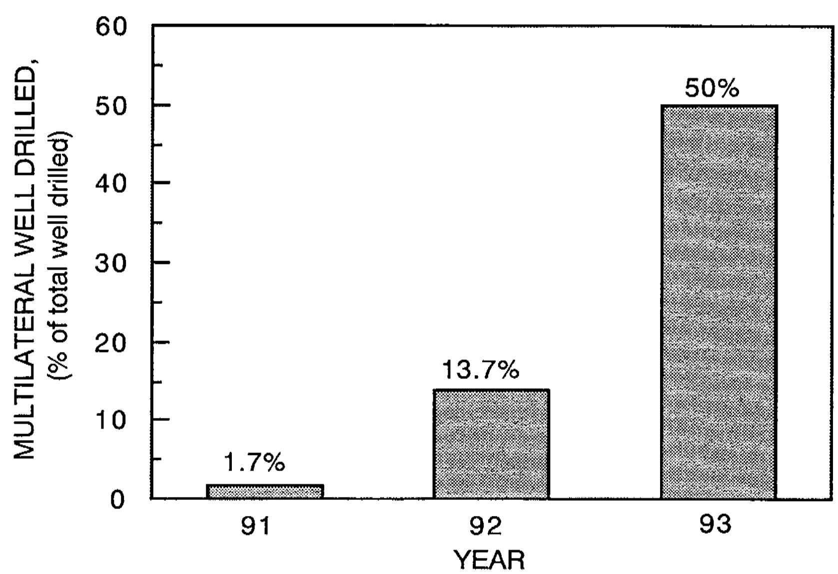


Figure 2–17 Multilateral drilling activities increase in South Texas.[33]

In 1990, Petro-Hunt Corporation drilled two medium radius horizontal bores in opposite direction from a single vertical hole.[36] The 7-inch casing was completed for vertical hole to a depth of about 6,510 feet. The two horizontal intervals were a total of 5,469 feet. The drilling cost for this dual-opposing lateral well was $183 per feet compared to the average cost of $227 per feet for a conventional single lateral well in the same area, or about 21% savings. By early 1993, Texaco drilled eight dual-opposed lateral Austin Chalk wells in Brookeland, and cited that a cost savings of $500,000–$700,000 per well has been realized compared to single lateral horizontal wells.[34]

UPRC has recently completed the first quad-lateral well in the Austin Chalk by combining the dual-stacked lateral with dual-opposing lateral horizontal wellbores.[28] The original well was no longer producing, and was reentered on January 14, 1993. The company cited that overall cost per feet of exposed formation was $46.50, or 75% less than accepted current standards. UPRC's average cost to drill a single horizontal well in the Pearsall field of South Texas was about $162 per feet of exposed formation. Estimated cost for dual-stacked lateral horizontal well in the same region was $115 per feet, or about 30% savings. The average cost for UPRC to reenter a well and to drill a single lateral was about $100 per feet of exposed formation. Using a dual lateral profile to reenter a well, an average cost of $62.11 per feet was achieved, corresponding to 38% savings. Figure 2–18 shows the cost comparison between reentry and new horizontal wells, and single lateral and dual lateral horizontal well.

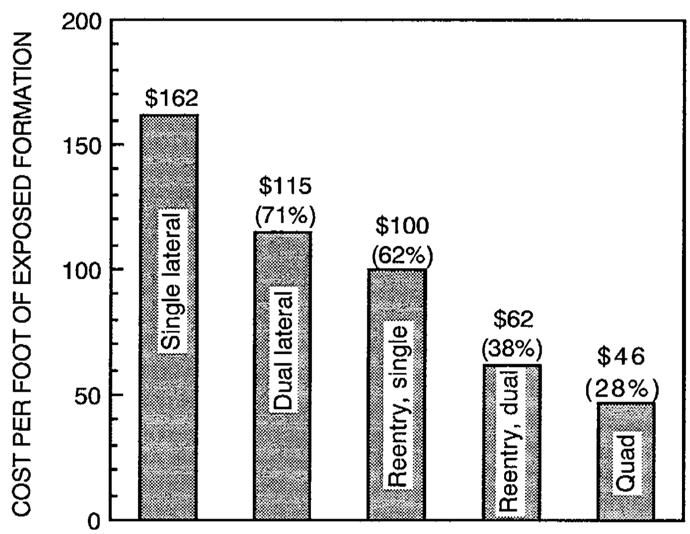


Figure 2–18 Cost comparison of different types of horizontal wells.[28]

Dickinson et al. discussed using water jet to drill ultrashort radius, multiple laterals on a single horizon from a single vertical wellbore to penetrate near wellbore damage. The horizontal sections are 100 to 200 feet. long.[37,38] These wells include heavy oil wells in California and light oil wells in Wyoming and Louisiana. The authors cited that the production is increased by 2 to 10 times and water-oil ratio is decreased by 10 times in strong waterdrive reservoirs as compared to vertical wells.[38]

Unocal has added over 10 million bbl of recoverable crude oil in the Dos Cuadras field of California through the use of trilateral horizontal drilling (Fig. 2–19).[39] By September 1993, Unocal completed four trilateral wells in the Dos Cuadras Field. The average per-well production rate for trilateral wells is about 800 b/d compared to an average per-well production rate of 50–60 b/d for conventional vertical wells. The total cost for a trilateral well is about $2 million, compared to $3 million for a standard horizontal well.[37]

Figure 2–20 corresponds to a reservoir profile of the well completed as shown in Figure 2–19.

Most recently, Sperry-Sun Drilling Services and CS Resources of Canada have developed a new multilateral approach (as shown in Fig. 2–16), the lateral tie-back system (LTBS), to drill and case multiple wellbores from a single primary wellbore.[40] The LTBS allows the driller to case and tie back multiple lateral branches and 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 new multilateral approach in completing its North Slope wells.[29] 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.

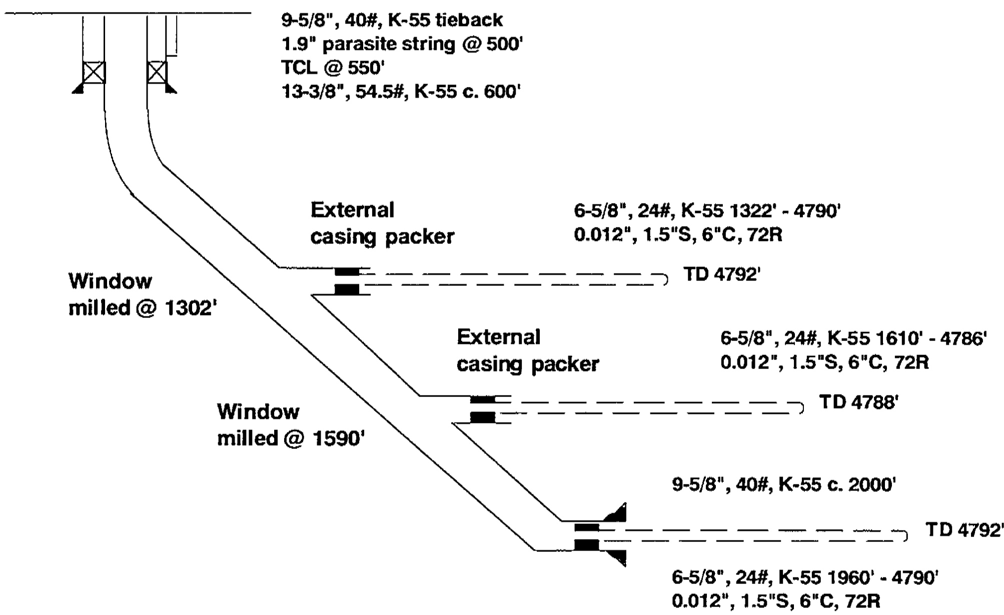


Figure 2–19 **A cross-section of the Dos Cuadras Field shows how Unocal's trilateral wells tapped the DP, D1P, and D2P producing zones to reverse decline of the field.[39]**

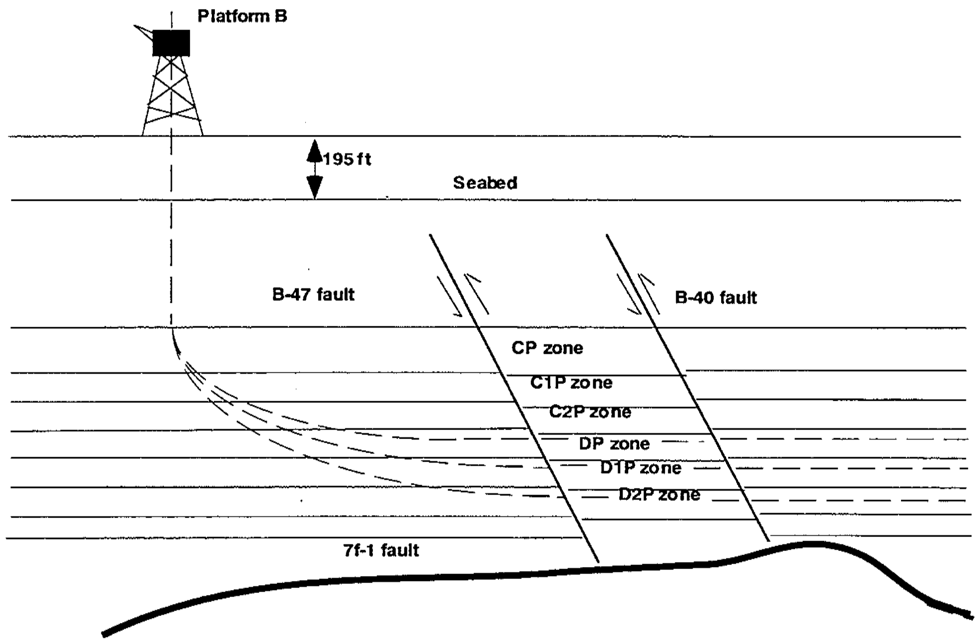


Figure 2–20 **A profile of the B-34 well completions into the reservoirs at the 900–1,000 feet depth range.**[39]

One disadvantage of the multilateral wellbore is the potential complications during well control because two or more wellbores are open. Also, the ability to service a particular wellbore is more complex. To prevent future wellbore service problems, each drainhole must be designed for later reentry.[33]

3.0 ADVANTAGES OF SLIMHOLE DRILLING

3.1 Cost Savings

Slimhole wells offer significant potential to reduce drilling costs. This cost savings is especially important because of the reduced capital budgets under current economic conditions in the oil industry. Slimhole wells reduced costs by 40% to 60% for remote exploration wells and 25% to 40% for development wells compared to conventional wells.[21,42] The savings can be achieved for the following reasons:[15]

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

McLaughlin reviewed time and cost savings of slimhole drilling.[43] Although his costs were in 1950s and are 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 3–1 through 3–5.

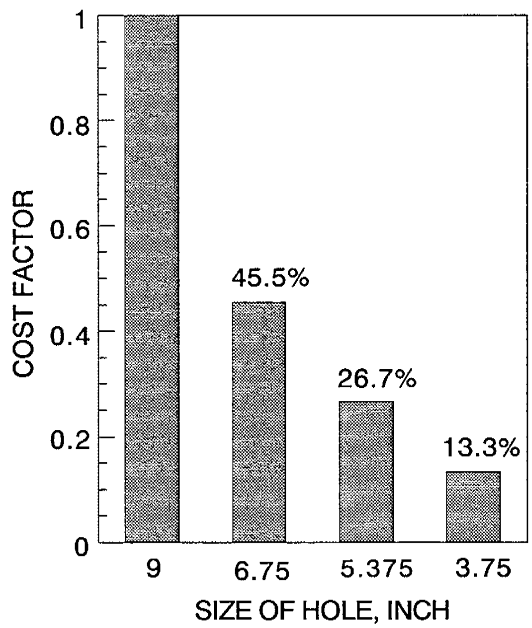


Figure 3–1 Moving cost factor (100 miles).[43]

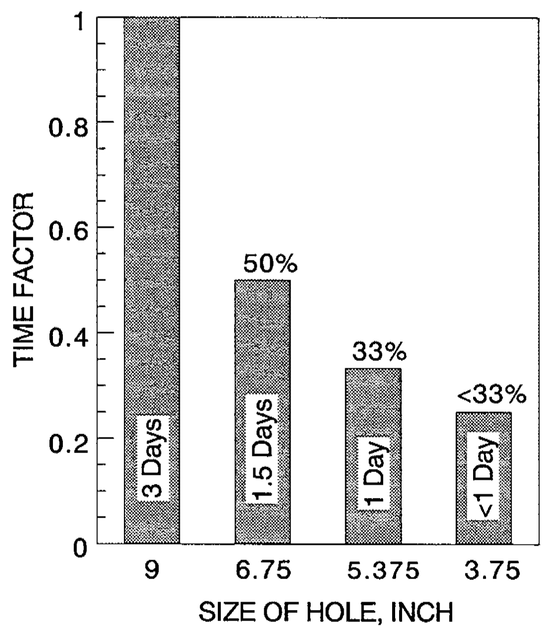


Figure 3–2 Rig-up time factor.[43]

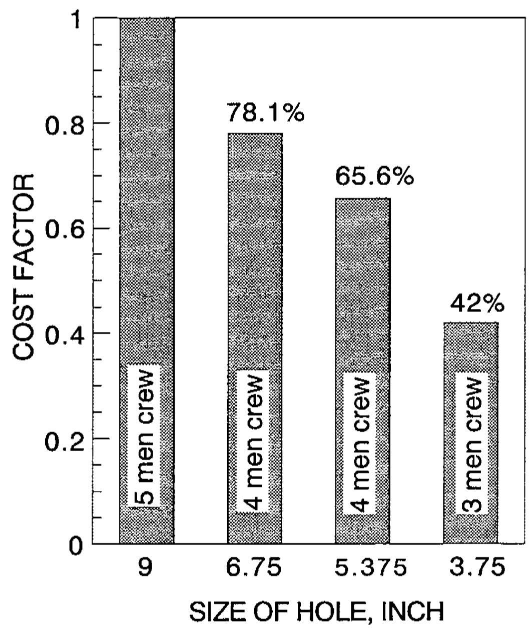


Figure 3–3 Daily rig cost factor (including drilling string).[43]

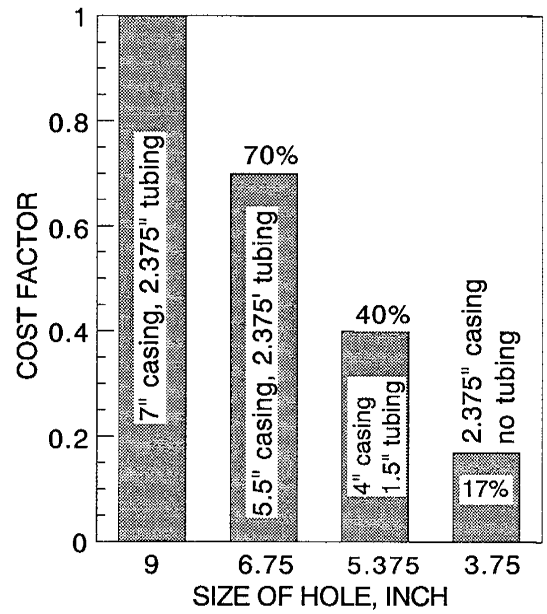


Figure 3–4 Casing-tubing cost factor.[43]

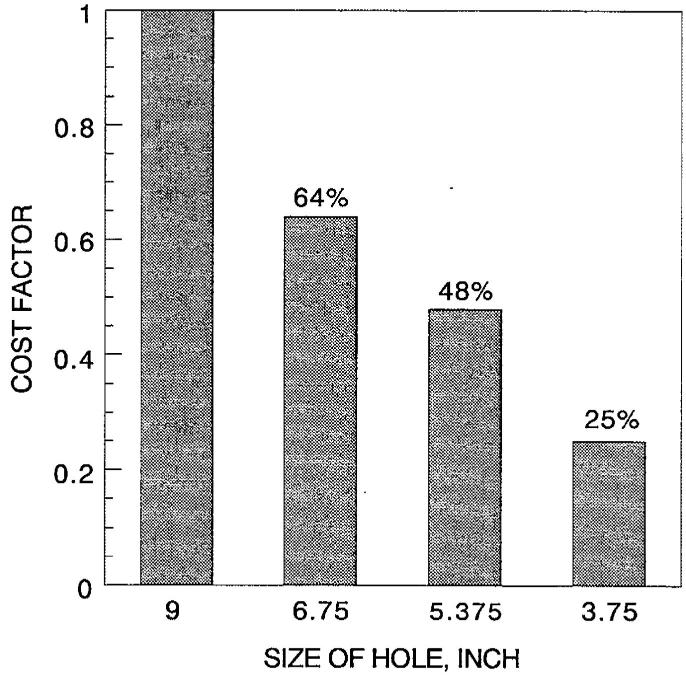


Figure 3–5 Cost per feet factor.[43]

Recently, analysis of well data in three fields by Shell shows that, due to improved performance, the drilling cost per meter of 4⅛-inch hole drilled is between 19% and 41% lower than that of conventional 5⅞-inch drilling (Fig. 36).[44] On an individual well basis, it is estimated that when the final hole size of 4800 meter gas well is reduced from 5⅞-inch to 4⅛-inch, the cost is reduced by 24% (Fig. 3–7) and theoretical cuttings volume halved.

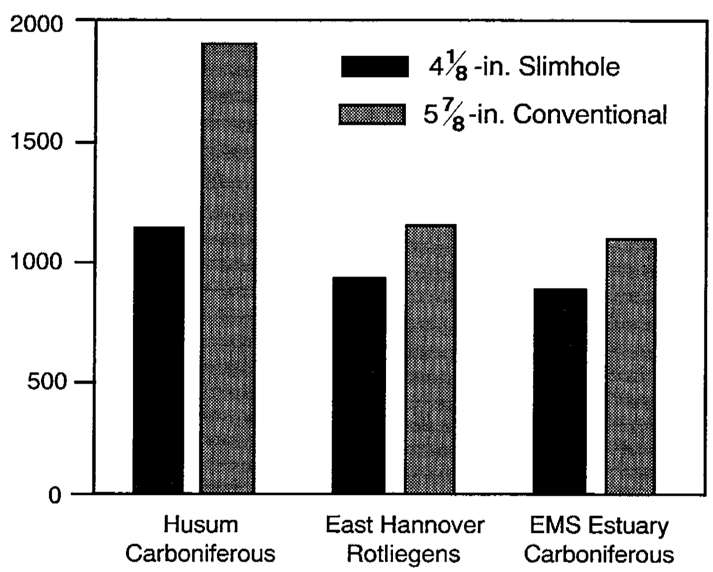


Figure 3–6 Cost/meter (after Worrall et al.).[44]

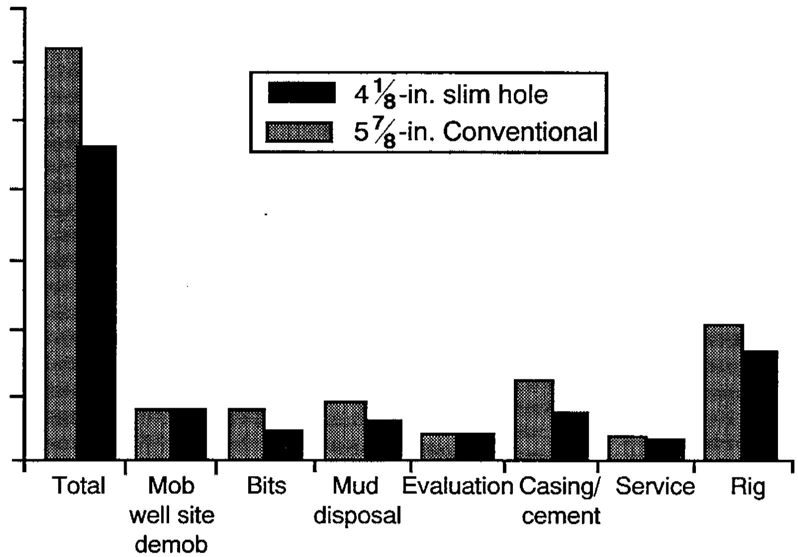


Figure 3–7 **Cost comparison-standard vs. slimhole. Hole size at total depth 5 7/8-in. vs .4 1/8-in. Depth 4,800 meters.[44]**

The total well costs for 30 wells in 25 different fields (including 13 slimhole wells with 5 7/8-inch and sometimes 4 1/8-inch holes) drilled by Shell between 1987 and 1992 were plotted against drilled depth to see what effect slimhole has had on costs. Data has not been corrected to account for variables such as location, sidetracks, geology, testing, whether the well was completed or abandoned, and so on.[44] Only an inflation correction of 2.5% per year has been made. The plot shows that the total well costs for slimhole drilling are mostly below the depth-cost trend line for conventional wells (Fig. 3–8).

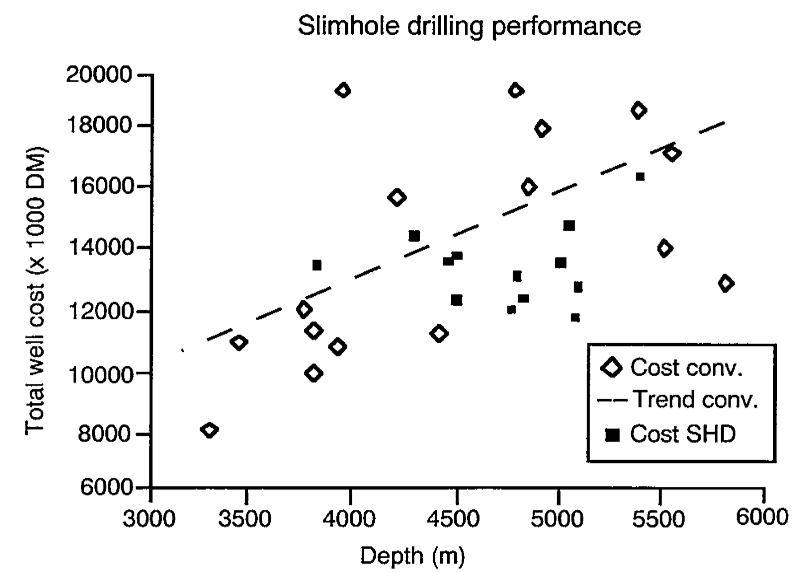


Figure 3–8 **Total well cost vs. depth, Germany. Slimhole vs. conventional (2.5% inflation 1987–1992, 25 different fields). (After Worrall et al.)[44]**

3.2 Reduction in Disposal Cost

If the size of a slimhole is half that of a conventional one, the cutting volume will reduce to 25% of conventional volume. This will greatly reduce in disposal cost. Floyd cited the smaller hole size resulted in a sixfold decrease in cuttings volume and a corresponding reduction in mud volume.[22] In general, the annular volume of a slimhole well is an order of magnitude smaller than conventional volume.[45]

3.3 Minimizing Environmental Impact and Nuisance

As the environment becomes more and more important, to reduce environmental impact is one of the major issues to drill wells. Slimhole technology can provide opportunities to minimize waste and improve general environmental impact.[46-48]

The scaled-down equipment 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 (as shown in Table 3–1). The rig weight and drill string weight for slimhole drilling are much less than convention drilling. Air pollution is also reduced because less power is required for slimhole drilling.

Table 3–1 Comparison of Conventional and Slimhole Rigs.[45]

Type of Rig	Conventional	Slimhole
Hole Diameter, in	8.5	3 to 4
Drillstring Weight, metric tons	40	5 to 7
Rig Weight, metric tons	65	12
Drillsite Area, %	100	25
Installed Power, kW	350	75 to 100
Mud Pump Power, kW	300	45 to 90
Mud Tank Capacity, bbl	470	30
Hole Volume, bbl/1,000 feet	60	6 to 12

Another aspect of major benefits of slimhole drilling over conventional rigs is noise reduction. This is particularly advantageous when drilling near residential areas. Figure 3–9 shows an overall comparison of sound levels between a slimhole rig (or a coiled tubing unit) and a conventional rig.[47]

The relatively small size of the equipment involved with slimhole operations also results reduction in transportation for mobilization and demobilization of drilling equipment. This reduces the overall impact and the risk of incidents linked to equipment transportation.

With the ever-rising costs associated with remediation of waste streams, it is realized that the emphasis should put on reduction of waste generation. By reducing the hole size drilled, reduction of cutting and mud volume is significant. A reduction of 70% of the waste is easily achievable.[47,48]

Transportation and environmental problems associated with the use and disposal of drilling fluids are also significantly reduced.

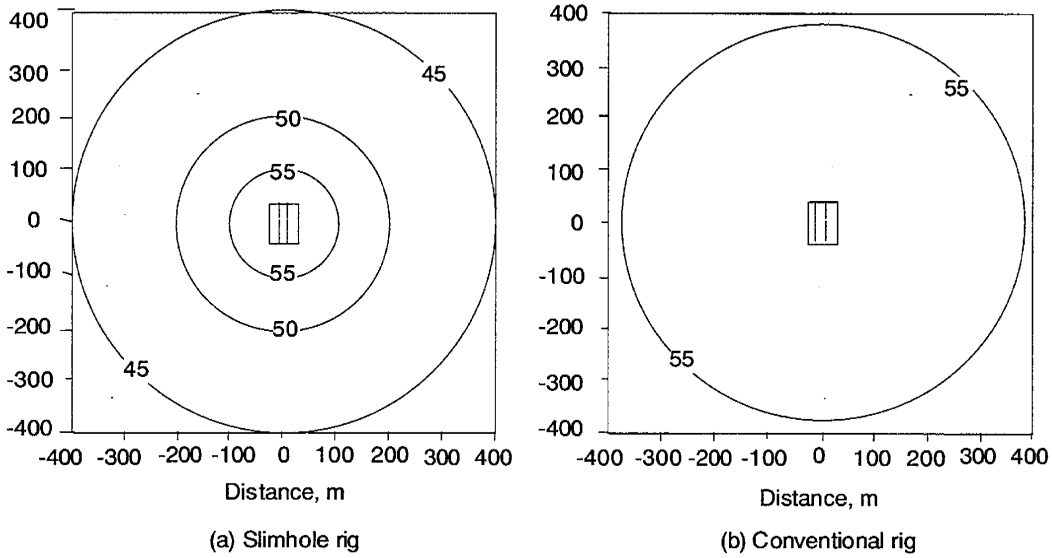


Figure 3–9 **Noise contour maps of a typical slimhole rig (a) and a conventional rig (b). The horizontal and vertical axes represent distances in meters from center of rig. The contours represent noise levels in dB.**

Another advantage of slimhole technology is emission reduction. Since the equipment needed for slimhole drilling is smaller than a conventional rig, fuel consumption and gas emissions to the atmosphere can be proportionately reduced. Table 3–2 shows a comparison of fuel consumption for slimhole rig, coiled tubing unit and conventional rig.[47]

Table 3–2 **Fuel Consumption and Gas Emissions of a CTD Unit, Slimhole Rig and Conventional Rig (Faure et al. 1994).**

		CTD Unit	Slimhole Rig or Workover Rig	Land Drilling Rig
	Diesel m^3/month	25	35	160
Gas Emissions kg/day	CO_2	2,122	3,293	15,055
	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

4.0 LIMITATIONS AND DISADVANTAGES OF SLIMHOLE DRILLING

Slimhole drilling technology can cut the drilling and completing costs significantly. However, the cost 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 as following.

One of the disadvantages for slimhole drilling is drillstring failures associated with use of small diameter tubulars. The reduced weight of slimhole drillpipe makes the drillstring mechanically weaker than its conventional equivalent. For example, when changing drillpipe from 5½-inch to 3½-inch, the torque transmission capability will be reduced by a factor of five. Therefore, the strength of the smaller diameter drillstring is always a concern, especially in the milling operation where high torque is encountered. To maintain power, bit speed has to be raised. In addition, higher rotating speeds are required to maintain cutter linear speed as reducing bit diameter. High bit speed may create reliability problems.

Tool joint failure is another problem for slimhole drilling. Because of small and thin tubulars and joints, they are inherently weaker and have a tendency to bellying and twist-offs, particularly in deeper holes. The industry now has designed and tested 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 to 15 bbl on a conventional well is considered reasonable. However, this volume of gas in a slimhole would blow out. The capability of early kick detection is therefore essential.[49] Therefore, it is necessary to defect a gain within one barrel for slimhole drilling to be sure of retaining safe control. Unlike conventional-hole drillstring geometric, the frictional pressure losses in slimholes are very sensitive to rotation speed of the pipe. In addition, 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 the above operations occur simultaneously.[50] All of these factors make kick detection more difficult. Also, the most likely time for the occurrence of a kick 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 decreasing in penetration rates, especially for roller cone bits. As shown in Figure 1–1, penetration rates reach to optimum as hole size is between 11¼ inches to 6½ inches. When using roller cone bit, penetration rates tend to decrease as hole size decreasing below 12¼ inches, due to reduced cutting structure and smaller bearing of slimhole roller cone bits. Decreasing in penetration rate can offset the cost savings achieved from slimhole drilling. The low rates of penetration were the main inherent operating problems for slimhole drilling in the 1950s.

Depth is a key limiting factor when considering slimhole well design, especially in exploration. By the available technology, slimhole drilling can reach to about 15,000 feet. Conoco recently reported that a reentry well in the southern North Sea was drilled to 12,300 feet; and the last 3,000 feet were 4.7-inch hole.[51] Arco's F 4/3 was completed with 4⅛-inch section of 15,000 feet; the last 2,000 feet were slimhole.[51] In horizontal wells, horizontal displacements are also less than with bigger holes due to the reduced drill string weight available.[27]

Borehole integrity and instability are other concerns for slimhole drilling. Because of small annul space between drillstring and wellbore, the pressure loss is larger than conventional drilling. When mining drilling technique is used, the annular pressure losses can reach up to 90% of the total pressure losses.[52,53] This additional pressure loss reduces the ability to control lost circulation and elevated pore pressures. Special mud system is necessary to raise weighting capability and reduce friction force. In addition, the potential for stuck pipe increases for slimhole's.

Production from slimhole's has been questioned, especially in regard to the major concern about limitations on reuse of exploration and appraisal wells as producers, because of the possibility that hole size might effectively act as a choke. In the artificial-life wells, the reduction in primary casing sizes used in slimholes tends to narrow options available. Field studies conducted in the Pearsall Field indicate that the productivity of a well may potentially be inhibited by as much as 60% to 80% when reducing the casing size from 9⅝-inch (24.45 cm) to 4½-inch (11.4 cm).[15] These estimates are based on the rod pump intake pressure available, oil cut, and the gas-oil ratio (GOR) of a specific well. The GOR tends to be the largest contribution 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 gas separation efficiency 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 producing 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 resulting the limitation of 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 as compared to larger equipment. Ultimately, the impact of slimhole casing sizes on the production schedule and operation parameters must be weighed against the initial savings of drilling a slimhole well.

One major limit of slimhole horizontal drilling has been the inability to effectively transmit weight to the bit. Figures 4–1 and 4–2 show the available weight on bit versus lateral displacement for three sizes (8½-, 6¼- and 4¾-inch) of bottomhole assemblies.[15] As shown in Figures 4–1 and 4–2, the larger drillstring can provide much more weight on bit than the smaller one does. 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 increased, available weight from the small diameter tubing used to drill the slimhole well was reduced to the point that slide drilling to make angle corrections became difficult or even impossible. Therefore, the slimhole horizontal well was effectively limited to a maximum departure of 2,500 feet. (762 m) or less comparing to over 4,000 feet. (1,219 m) for larger wellbores.[15]

In addition, 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 BHA and by combining the downhole motor with a thruster which helps limit torsional vibration in the drillstring.[45]

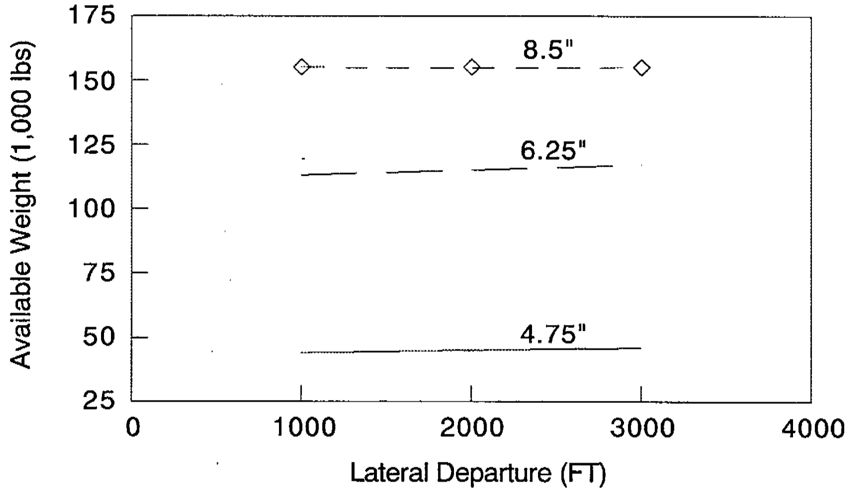


Figure 4–1 **Available weight on bit vs. lateral departure typical BHAS with rotation.**[15]

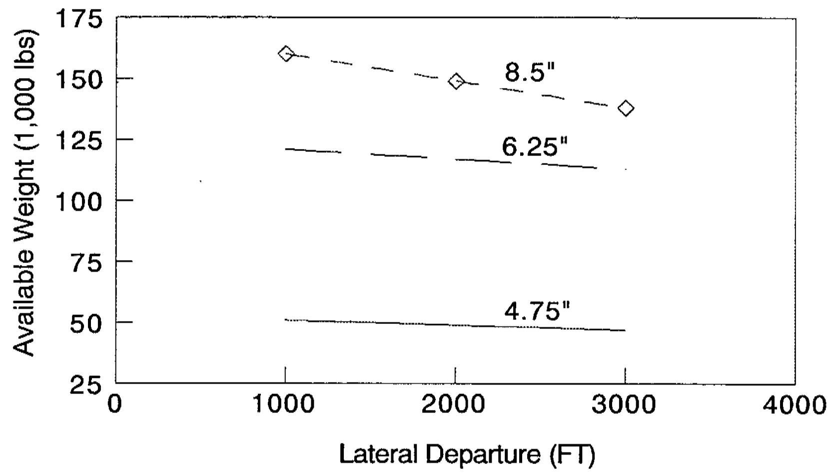


Figure 4–2 **Available weight on bit vs. lateral departure typical BHAS without rotation.**[15]

The lack of tools for slimhole, drilling especially more sophisticated tools for slimhole horizontal technology, is another barrier for slimhole application. It is easier and more economically advantageous to develop tools for the larger diameter (greater than 6-inch or 15.2 cm) wellbores. For horizontal drilling, since the larger size tools had the better technology, it was preferential to drill larger wellbores. In slimhole horizontal drilling, due to the small lateral size, small tubulars are needed. Generally this will result poorer reliability than in larger equipment because the slimhole equipment does not have capacity for the engineering safety factors that larger tools possessed. In addition, there are only limited tools running in slimholes less than 4-inches. MWD equipment can be run in hole sizes down to 4⅛-inches. Directional drilling equipment such as steering tools is available in 4¾- or 4⅛-inch holes.[51] However, all standard logs can be run in hole sizes down to 3¾-inches.

Slimhole fishing and jarring are other concerns. However, several fishing tools and jars have been designed and tested. For example, a 4 1/16-inch overshot is available for fishing 3¾-inch and 3½-inch tools.[54] In addition, 4¾-inch and 3½-inch drilling jars are available. For slimholes from 5⅞-

inch to 6 ¼-inch, a 4 ¾-inch OD hydraulic double-acting jar can be run in compression as well as tension. For hole sizes from 4 ⅛-inch to 4 ¾-inch, a single-acting hydraulic jar is available.[54]

Other arguments against drilling a slimhole well are the difficulty to work over such wells, the difficulty of cementing the small hole, the difficulty to test and the availability of slimhole rigs. Because of the high pump pressures required to overcome the increased friction in the small annulus, cementing operations might become difficulty. The high pump pressure can cause channeling behind pipe and fracturing of weak formations. However, the biggest barrier to the use of the slimhole is that it is new and different. It causes change, and change takes time and accurate communication of the technology.[54]

5.0 RECENT ADVANCES IN SLIMHOLE DRILLING

Two industry approaches to drilling slimholes have evolved in recent years: the Shell/Eastman Teleco (retrofit) approach using high-speed downhole motors, and the modified mining drilling approach.

5.1. Retrofit Slimhole Drilling System

The Shell/Eastman Teleco approach is a retrofit concept that can be brought onto any conventional drilling system to drill the required hole section. The basic principle of the Shell/Eastman Teleco system is the use of conventional geometry drillpipe, shear thinning muds, sensitive kick detection, small drag bits (PDC, TSD, Natural Diamond), downhole mud (Moineau) motors and a thruster.[51] The system was to be retrofitted to existing rigs and to be compatible with conventional practices such as full directional capability, the use of standard API casing, tubing, and drillpipe sizes, wireline logging formation evaluation, etc.

The PDC bit is crucial to Shell/Eastman Teleco system.[55] However, the dynamics of drag bits and the interaction between the bit and drillstring can lead to significant vibration.[56,57] As mentioned previously, bottomhole assemblies are very sensitive to weight on bit (WOB). The bit can be damaged if WOB is too much. Therefore minimizing these vibration is critical to the Shell/Eastman slimhole drilling system. In addition, minimization or control of these vibrations permits more power to be applied to the bit and extends bit life. The reduced vibrations also have a beneficial effect on hole stability as well as reducing the fatigue loading on the drillstring.[58]

To minimizing vibrations, an integrated approach was developed by Shell and Eastman Teleco as follow:

- A "soft-torque" rotary table or top drive which damps out "stick-slip" torsional drillstring vibrations by modifying the characteristics of the drive system[59]
- A mud motor as a partial isolator for torsional vibrations between the bit and the drillstring
- A thruster that decouples the mud motor and bit from axial vibrations in the remainder of the drillstring.

The thruster was designed to maintain accurate control of WOB. It is this fine control on weight and torque at high rotary speeds that is the key to successful slimhole drilling. Insensitive weight on bit and wild fluctuation of weight on bit can destroy slimhole bottomhole assemblies and bits. Thruster device helps reduce damaging vibrations. When drilling with a thruster the drillstring is decoupled from the BHA. This eliminates the neutral point movements.

Annular pressure losses become increasingly important in slimhole wells, especially for the areas where the pore pressure gradient is close to formation strength. To minimize annular pressure losses, a shear thinning/solids-free heavy brine-based mud system that has which have sufficient viscosity in the annulus at bottomhole temperature to carry the cuttings and have a low viscosity inside the drillstring, was developed for Shell/Eastman Teleco system. The experience shows that deep 4 ⅛-inch holes will be best drilled and logged with low solids heavy brine-based mud systems.[44,60]

In order to maximize cost savings, gross penetration rates per day had to be good as or better than that achieved with conventional hole sizes. The following different bottomhole assembly sizes were developed for the Shell/Eastman Teleco system to achieve better penetration rates:

Host liner (inches)	3 ½	4 ½	5	5 ½	7
Hole size (inches)	2 ⅝	3 ⅞	4 ⅛	4 ¾	5 ⅞
BHA size (inches)	2 ⅜	3 ⅛	3 ¾	3 ¾	4 ¾

The results from 13 slimhole wells drilled by the Shell/Eastman Teleco system in several different fields confirm that drilling progress per day no longer decreases with hole size below 7 ⅞ inches, as shown in Figure 5–1.[44]

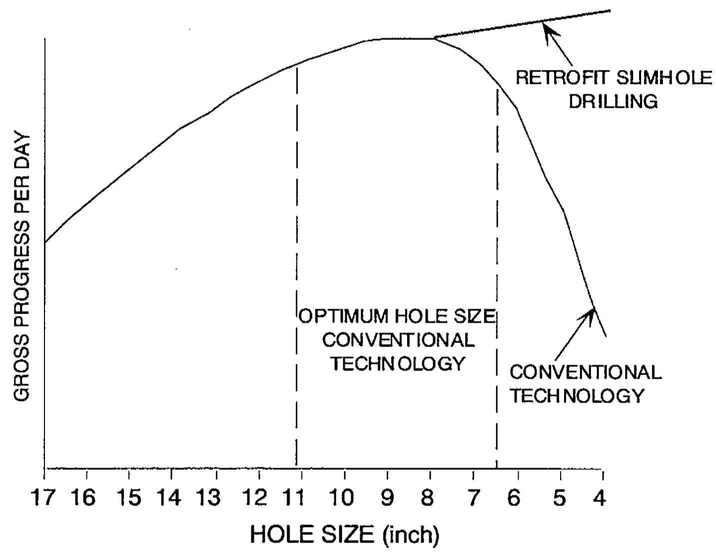


Figure 5–1 Effects of hole size on overall drilling efficiency.[44]

Shell and Baker Hughes INTEQ recently developed a slimhole drilling system that employs conventional oilfield equipment and drilling rigs (Fig. 5–2).[54] The companies redesigned the Shell/Eastman Teleco system and optimized bottomhole assemblies to greatly improve drillstring integrity. The system employs improved fixed cutter bit designs and high-strength drillpipe. The system also includes the advanced Kick Detection System (KDS) and safe and efficient Clear Drill format-based drilling fluids. Sophisticated computer modeling provides a reliable kick detection system for enhanced risk management. And low-solids drilling fluids reduce torque and drag without compromising hole cleaning. In addition, conventional drilling practices are employed, so operating procedures, safety standards, and rig crew training do not differ substantially.

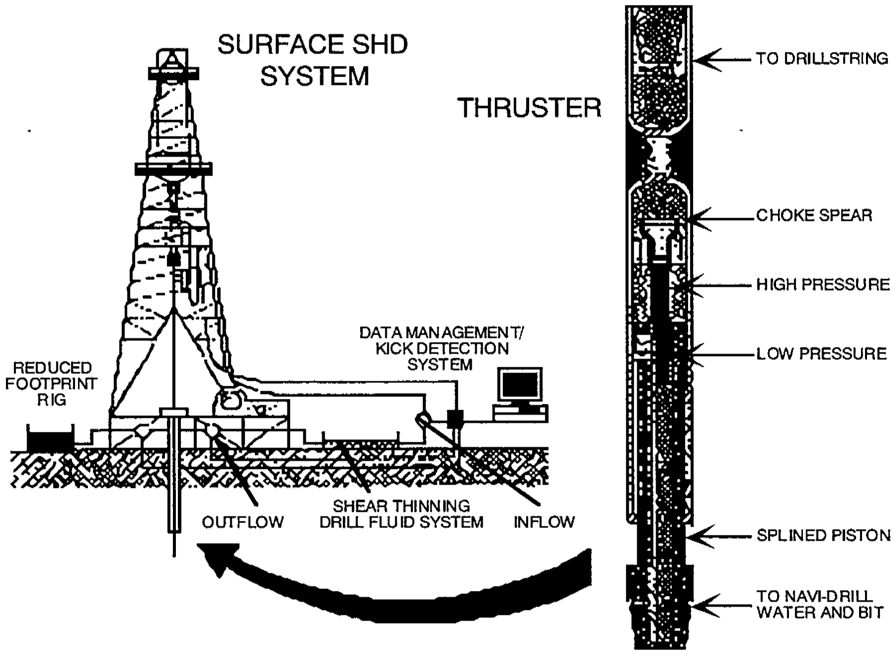


Figure 5–2 INTEQ's slimhole drilling system employs conventional oilfield equipment and drilling rigs.[54]

There are three choices of rigs, depending on the specific slimhole application desired for the Shell/Eastman's retrofit system. Conventional rigs, if sized accordingly, can be most economical in drilling new slimhole wells where the drilling parameters are well defined and location size is not limited. The use of conventional drilling rigs in drilling slimhole horizontal wellbores has several advantages, including that they are readily available and familiar to the industry. Hookload and pump capacities of most rigs are generally well within the hydraulic and workload requirements of drilling a slimhole. However if the rig's capabilities are too oversized, it can sometimes be detrimental. For example, the amount of rotary torque must be accurately controlled when drilling with small tubulars to avoid exceeding recommended makeup and failing the drillstring. The oversized conventional rigs can make it difficult to control the rotary torque. In reentry applications a conventional drilling rig may become uneconomic especially if preliminary remedial work is required prior to the actual drilling operation. Another additional disadvantage of using conventional rigs that are oversized is that the operator is paying for more rig than necessary. This would cause additional cost resulted from mobilization, location, and fuel consumption costs. Thus correct sizing of the rig to be used for smaller holes can be important from an economic standpoint as well as mechanical.

Workover or truck-trailer mounted service rigs are generally cheaper on a cost-per-hour basis and have substantially less mobilization costs. In the case of reentry, workover or service rigs may be beneficial if it is necessary for removing existing production equipment and for performing remedial work prior to the reentry. The cost of these rigs can be kept on an hourly basis with only essential equipment and personnel maintained until the initial remedial work is completed and the continuous drilling operation is ready. This allows the operators to suspend costs while waiting on cement, tools, etc., during remedial or preliminary well preparations. These rigs, however, are not equipped to maintain full drilling operation. They are primarily used for workover or well servicing and are set up to handle mostly tubing strings. Most do not have a rotary table, mud pump, mud tanks, and associated equipment that conventional drilling rigs. The operator using one of these rigs for drilling purposes must rent this auxiliary equipment and sometimes modify it for use. Well service crews must be trained to operate this unfamiliar equipment and sometimes some efficiency is lost. In addition, equipment capacity such as hookload for pulling on stuck pipe or running casing strings may be inadequate. As a result, safety may be compromised, especially when exposing workover equipment and personnel to unfamiliar drilling situations.

The third choice of rig in slimhole drilling is a coiled tubing system. These rigs are most beneficial in pressure situations or when underbalanced drilling is desired. However, they cannot be used for removing existing production equipment or performing extensive remedial work. The major components of a coiled tubing drilling system consist of truck-trailer mounted reel containing steel coiled tubing and a hydraulically operated injector head which grips and feeds the coiled tubing from the reel into the wellbore. Pumps for the circulatory system and other associated equipment are individually sized and arranged as required. These units are equipped to handle only the coil with which they are mounted and any other strings or tools that can be attached to the coil. Operating parameters are limited to those of the specific coiled tubing used. At present coil tubing strings and reel capacity are available up to 3½-inch (8.9 cm) OD. The lengths of coiled tubing strings is limited by both reel capacity and roadway load limitations. As the diameter of the string increased, so does the weight per feet, thus shortening the overall length that can be legally transported. Research presently being conducted to address this issue in the development of a coiled tubing string connector to enable the use of multiple strings. Inherent advantage of coiled tubing units over workover and conventional rigs is its well control aspects. As the injector feeds from the reel into the wellbore a positive seal on the tubing can be maintained with a BOP stack. In this manner the tubing can be tripped in or out of the hole under pressure. Additional advantages are reduced space requirements and increased mobility which enhances its use in offshore or remote area locations.

5.2 Modified Mining Drilling System

Another slimhole drilling system, often called continuous coring mining drilling, is adapted from mining drilling technique. The mining industry has been drilling slimhole's, for the past 50 years, and the main feature of this technique is as shown in Figure 5–3.[13] Most wells drilled by the mining industry are continuously cored. The rigs use high speed rotation and positive feed control with a top drive to maximize core recovery.

The mining industry generally uses surface-set diamond bits, or diamond impregnated bits, that generate only very fine cuttings. They use drill rods with high ID/OD ratios. The small annular clearance gives support so that the entire string can be run in compression.

Oil companies started to use mining technology for oil exploration in the early 1970s. A well was continuously cored to 11,600 ft using the slimhole coring system.[61] In 1979, three Australian oil companies (Western Mining, Poseidon Oil, and Australian Hydrocarbons) used slimhole, continuous coring rigs drilled a series of oil and gas exploration wells.[62] Between 1987 and 1989, Amoco Production Company using continuous coring mining technique drilled over 40,000 feet of continuous core in Oklahoma, Michigan, Kansas, Colorado, and Texas.[13] Continuous cores were obtained in 40-foot lengths using wireline-retrievable core barrels (as shown in Fig. 5–4). Core recovery averaged 98.3 % in

40,000 feet of formation in the above field wells. Adapted mining technique for oil and gas drilling, lightweight rigs with high-speed top drives have been developed.

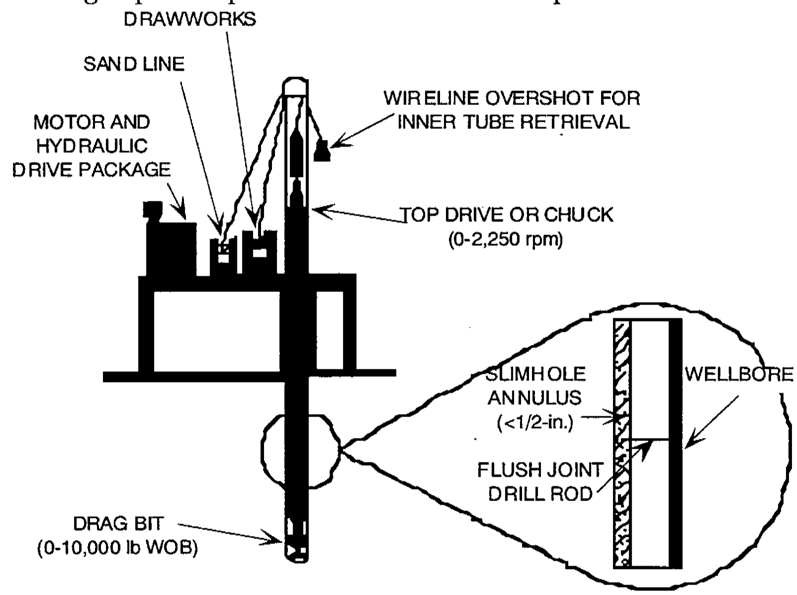


Figure 5–3 **Schematic of continuous coring mining drill system.[13]**

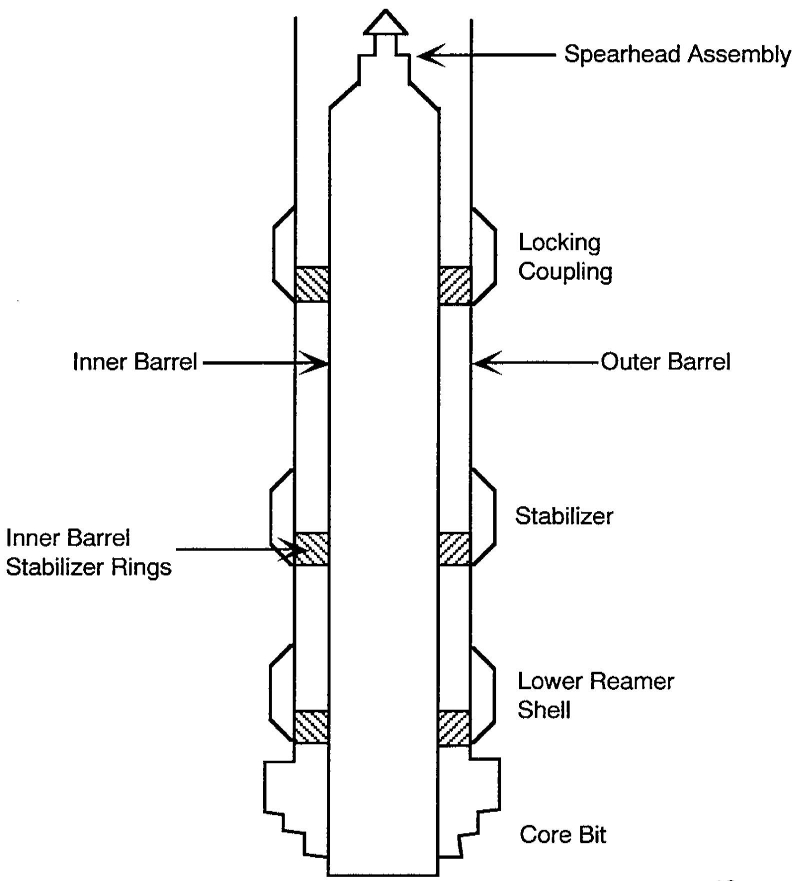


Figure 5–4 **Wireline retrievable coring assembly.[13]**

Muds containing solids cannot be used, since the high-rotary speeds can cause solids to cake out on the inside of the drillpipe, forming "mud rings." Mud viscosity is often increased to prevent vibration to the drillstring. Therefore, a special "no solid" water-based cationic polymer brine mud was used. The polymer brine drilling fluid performed well, with the average size of the holes being only one-half inch larger than the bit diameter. No problems with stuck pipe or mud rings were associated with this brine mud.

Amoco developed a model for hydraulics and a system for kick detection and proper kick control. Combined with high tubular performance, the modified mining drilling systems now have a capability to drill as deep as 14,000 feet.[51]

5.3 Coiled Tubing Drilling

Coiled tubing drilling has the potential to deliver cost-effective slimhole wells.[63-69] A coiled-tubing unit (CTU) is smaller than a slimhole rig and easier to mobilize. CTU requires less equipment and personnel. Its smaller site requirement allows decreased civil engineering costs, and the CTUs have a reduced environmental impact. Smaller surface site and lease requirements allow wells to be drilled in environmentallysensitive 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 avoids 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
- Drilling underbalanced
- Less equipment and personnel
- Smaller surface site
- Time and cost saving

In conventional drilling, there is always some drilling fluid spilling while making each connection. The use of a continuous string eliminates the drill string connections, which resulting minimum drilling fluid spill. The continuous drillingstring also significantly improves safety for rig crews because of reduced interaction between human and equipment. In addition, coiled tubing permits drilling and tripping continuously while circulating drilling fluid. This will reduce 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 surface while drilling and tripping to shutoff the pressure in the annulus. Underbalanced drilling can reduce reservoir damage from invading mud particles, which can improve production rates. In addition, lower mud weights can improve penetration rates. Tracy et al. reported that penetration rates of 100 feet per hour and initial production rates 300% higher than anticipated have been realized when underbalanced conditions were achieved.[64]

Coiled tubing drilling was identified by Elf Aquitaine as a technology with the potential to reduce drilling costs.[47,65,70] Two trial exploration wells have been drilled south of Paris using coiled tubing. The purpose of this test was to determine the feasibility of using coiled-tubing drilling units instead of conventional rotary rigs to drill slimhole wildcats. A conventional drilling rig was used to drill a surface hole and set 4½-inch casing at about 1,000 feet (300 m). A 3⅞-inch hole was then drilled vertically from 1,000 feet (300 m) to 5,167 feet (1,575 m) using a 1¾-inch coiled tubing. Penetration rates were achieved in the softer formations that were comparable to those achieved with conventional drilling, but drilling of shales was relatively slow.[47] The test resulted a significant cost savings. Elf reported that factors contributing to cost reduction are drilling smaller diameter holes, avoiding intermediate casing string, using PDC (polycrystalline diamond compact) drill bits, and reducing the size of the drilling pad. The installation of a small coiled-tubing unit in rural areas is quick and requires little preparation of the drill pad and access road. Elf Aquitaine cited that coiled tubing is an efficient drilling tool inside the casing strings of completed wells to drill out cement, which is harder than soft formations.[65] With coiled tubing, drilling and tripping are continuous processes that eliminate the need to make connections.

Shell International and NAM (Nederlandse Aardolie Maatschappij B.V.) recognized coiled tubing drilling as a technique that had the potential to reduce the drilling costs and to meet environmental objectives.[47] Shell and NAM drilled a horizontal sidetracking well, Berkel-five, in the Netherlands by coiled tubing.[71] Berkel-5 was sidetracked at 4,524 feet (1,379 m) measured depth in 4⅛-inch hole with a 2-inch coiled tubing. Total depth was reached at 5,577 feet (1,700 m), having obtained a maximum inclination of 96.7° .[47] Good penetration rates were achieved (16 ft/hr or 5 m/hr in the shale, 33 ft/hr or 10 m/hr in the sand). Combined with the reduced trip times, the method is considered to be competitive with conventional techniques with regard to the time required for a complete drilling operation.[47]

Dowell coiled tubing services for slimhole wells has recently developed a computer-aided design and evaluation software to help optimize both the drilling program and the completion configuration, taking into account requirements for future coiled tubing workover operations.[72] The new coiled tubing drilling program provides safe and efficient underbalanced drilling and conventional slimhole reentry, at reduced costs, without the need for mobilizing a rig. Dowell claimed that completion hardware can be inserted into a coiled tubing string and spooled up at the yard, then unspooled at the wellsite to complete a well quickly and efficiently. Dowell also stated that they developed a through-tubing sand control treatment program. The treatment program includes gravel packing and resin consolidation. Dowell now are conducted routinely in both cased and open holes using coiled tubing. Newly developed downhole tools permit tubing-convened perforating and re-perforating operations prior to gravel packing.[72]

Recently a slimhole horizontal well in Alaska was drilled by coiled tubing and resulted a significant increase in oil production.[73] The well was drilled to a depth of 8,900 ft using a conventional rig, then extended horizontally by coiled tubing drilling. The bottomhole assembly (BHA) used to drill the horizontal drainhole included a 3¾-inch bit, a 2⅞-inch steerable motor, a Slim1 MWD system with gamma ray capability mounted in 3⅟₁₆-inch nonmagnetic collars, and an orientation tool for steering.[73] Real-time data supplied by the Slim1 MWD system enabled the driller to closely follow the planned trajectory. Formation damage was minimized by drilling underbalanced. As a result, production from the well was 3,800 BOPD, 2,600 BOPD more than the 1,200 BOPD the operator estimated would have been produced if the horizontal drainhole had been conventionally drilled and completed.[73]

Cudd Pressure Control and Sperry-Sun are planning to implement existing MWD technology into coiled tubing drilling.[74] Cudd Pressure Control and Sperry-Sun stated that a well should be drilled with the new system in less time. They also are redesigning downhole orienting tools to be more powerful (up to six times the current torque output) and versatile. These advancements, along with the emergence of slimhole logging will expedite the use of coiled tubing drilling in the near future.

5.4 Drilling Bits (TSD and PDC Bits)

The rapidly advancing of bit technology utilizing polycrystalline diamond composite (PDC) and thermally stable synthetic diamond (TSD) has enabled bit manufactures to develop and produce drilling bits for slimhole drilling, which have produced outstanding performances and improved the penetration rate.[76-82]

In slimhole drilling, fixed-cutter bits are generally preferred because they can withstand high rotational speeds up to 1,000 rpm compared to a maximum of 200 rpm in conventional drilling.[75] Hence, they permit higher power to be transmitted. The use of the fixed-cutter PDC and TSD bits has given a long life with a high rate of penetration (ROP) at a low weight on bit (WOB). Penetration rates of three times and a bit life of six times comparing to that of small diameter conventional roller cone bits have been reported.[83]

During the drilling, the rate of penetration (ROP) usually decreases with depth. Penetration rates using conventional rock bits are affected by tooth and bearing wear, whereas PDC bits are minimally affected. A study by Gault et al. to evaluate PDC usage in Miocene sections of the Gulf of Mexico reported more than $1.4 million savings based on 22 bit runs (Table 5–1).[87] Typical savings, as compared to conventional mill tooth rock bits, ranged from $30,000–$90,000 per run (Table 5–2). The longest continuous run was 5,685 feet (6,665 feet–12,350 feet) at an average penetration rate of 90 ft/hr.[87]

Table 5–1 PDC Bit Performance in the Gulf of Mexico[87]

Comparison of ROP between PDC and Rock bits			
Well	Total Footage	Average ROP ft/hr PDC	Average ROP ft/hr ROCK
EC 236 #1	3400	82	35
EC236 #1 ST	2950	50	35
GA 303 #2	2680	39	25
GI 78 #2	5963	60	50
MU A-22 #1	4068	36	15
MU A-65 A-2	1100	6	8
SS 97 #2	532	12	7
SS 129 #1	6993	90	40
SS 198 I-11	3955	55	40
ST 22 E-3	2200	90	35
ST 196 A-7	8400	95	25
VR 245 #8	1300	25	7
	43,541		

Table 5–2 Cost Savings

TYPE BIT	RUNS	FEETAGE	SAVINGS
Large Diameter PDC Cutter PDCs	12	27,100	$1,105,800
Fishtail PDC	10	16,100	$ 317,800
TOTAL	22	43,200	$1,423,600

PDC bits were broken down into three general classes:

- Conventional PDC: Bits made with ½-inch cutters found on familiar diamond bit profiles.
- Fishtail PDC: Bits made with ½-inch cutters on historic fishtail drag bit profile.
- Large Cutter PDC: Bits made with large PDC cutters with a nozzle for each cutter. The cutters are 1-inch,. 1½-inch, or 2-inch diameter.

In a hard rock environment, to operate with a diameter less than 4¾-inch requires special consideration. Bearing structures in this range are often nonsealed roller bearings that exhibit short lives under the rigorous drilling conditions of the hard rock. Diamond and other fixed cutting structures were slow and not economical for the hard rock environments. To overcome the above problems, a relatively new design in the PDC technology, the Dome Polycrystalline Diamond Compact, is developed. The Dome PDC has a radius of curvature across the diamond table rather than being flat.

The Dome PDC cutter was used in slimhole operations (3¼-inch to 4¾-inch diameters) in the Permian Basin by Chevron USA.[82] The new cutter has been tested and applied in dolomitic formations where conventional PDCs have failed in the past. For example, the Dome PDC has been applied in the Queen Formation of Ward County, Texas. The Queen Formation has a history of being a tougher drilling environment. The cost per feet was decreased by more than 70% due to the longevity and increased ROPs by using Dome PDC.[82]

The use of Dome PDC bits has also proven successful in the 3500–4500 feet Grayburg/San Andres Formation of Lea County, New Mexico (Table 5–3). The increased ROP's and dependability of the fixed cutter in this area offer an economic advantage over roller cone technology. The Dome PDC bits have proven a fast economical way to deepen through 4-inch and 5-inch liners. Using the dome PDC in New Mexico has shown savings in excess of 70% over roller cone tools. These savings are reflected by an increase of penetration rates from 10 to over 30 ft/hr.[82]

Table 5–3 Diamond Product Bit Performance in New Mexico Grayburg interval (3,600 –4,200 feet) in Lea County, New Mexico[82]

Type bit	Interval (ft)	WOB (k lbs)	Rotary (RPM)	ROP (ft/hr)
3¼" Dome PDC	601	4–5	80–90	60
3⅞" Balaset TSD	536	1–2	1,200	10
4¼" Dome PDC	154	5	80–90	60
4¾" Dome PDC	727	5–15	120	20–40

The success of the Dome PDC cutter in a dolomite environment is inspirational to the application of PDCs in general. The ⅜-inch diameter Dome PDC has also been used on bits for underreamers. The introduction of the Dome PDC cutter has tripled underreaming rates in New Mexico to 30 ft/hr and also added a certain amount of dependability and longevity (Table 5–4). The increased longevity decreased cost from about $200/per feet to about $54/per feet (as shown in Fig. 5–5). This has reduced underreaming cost in this area by 73% over the alternative roller cone cutters.[82]

Table 5–4 Underreamer Performance in New Mexico Grayburg Interval (3,600 ft–4,200 ft) in Lea County, New Mexico.

Type cutter	Interval (ft)	WOB (k lbs)	Rotary (rpm)	ROP (ft/hr)
Conv. PDC	30	0.5–1	1,200	-----
Mill Tooth:				
Open Brg.	150	2	60	10
Sealed Brg.	754	2–4	60	11
TSD	1,461	2–3	80–120	4
Dome PDC	1,116	2	100–120	30

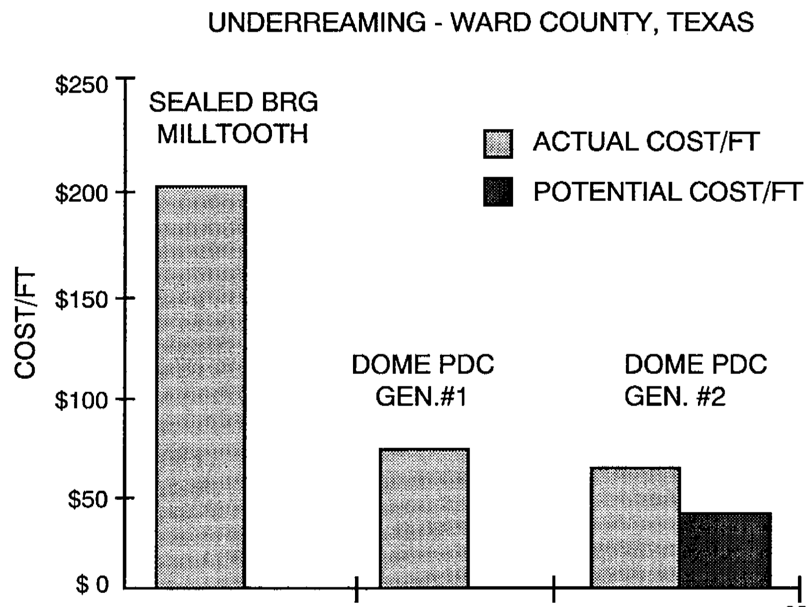


Figure 5–5 Underreamer cost per feet comparisons for Texas.[82]

TSD bits have proved to be an excellent alternative for slimhole drilling.[88] Unlike diamond compacts, TSD cutters are not bound to carbide backing posts. TSD bits are better than PDC or roller cone bits for hard rock drilling because of their thermal stability. The TSD bits are thermally stable in temperatures reaching 1,200°C, as opposed to PDC bits, which are stable only to 750°C. As a result, the use of optimized TSD bits on high-power drilling motors can greatly reduce drilling time for harsh-environment wells, such as deep gas wells. TSD bits typically can drill harder, more abrasive formations, while PDC bits usually can be used with success only in soft, soft to medium-hard, and medium-hard, nonabrasive formations. TSD bits tend to drill well with low weight on bit, high rotary speeds, and good hydraulics. They also perform well with downhole mud motors. TSD will have long bit life because of the self-sharpening cutters and no movable parts to fail. Their prices are in the same range as PDC bits but higher than natural diamond and roller cone bits.[88] TSD bits can operate at a power level five to ten times greater than that typically delivered by conventional rotary drilling. These bits can drill three to six times faster than rotary drilling.[89]

5.5 Hydraulic Thrusters

Drillstring vibrations are often a serious problem for slimhole drilling. Drillstring vibrations mainly occur due to bit/formation interaction and drillstring/borehole interactions. In order to reduce drillstring torsional vibrations, hydraulic thrusters, important tools in slimhole and high-angle drilling for antivibration, have been developed.[90]

The thrusters are designed to maintain accurate control of WOB. Positioned directly above the motor, they generate constant WOB without drill collars and mechanically reduce axial drillstring movement from the bit for smoother drilling. The thruster is a piston that maintains a force when drilling fluid is circulated through the tool. The thruster uses drillpipe circulating pressure, acting on a floating piston, to provide preset bottomhole force, as shown in Figure 5–6.[51] When the thruster is used, WOB is proportional to pressure drop across the thruster and can be adjusted by changes in flow rate, bit flow area, and type of motor used.

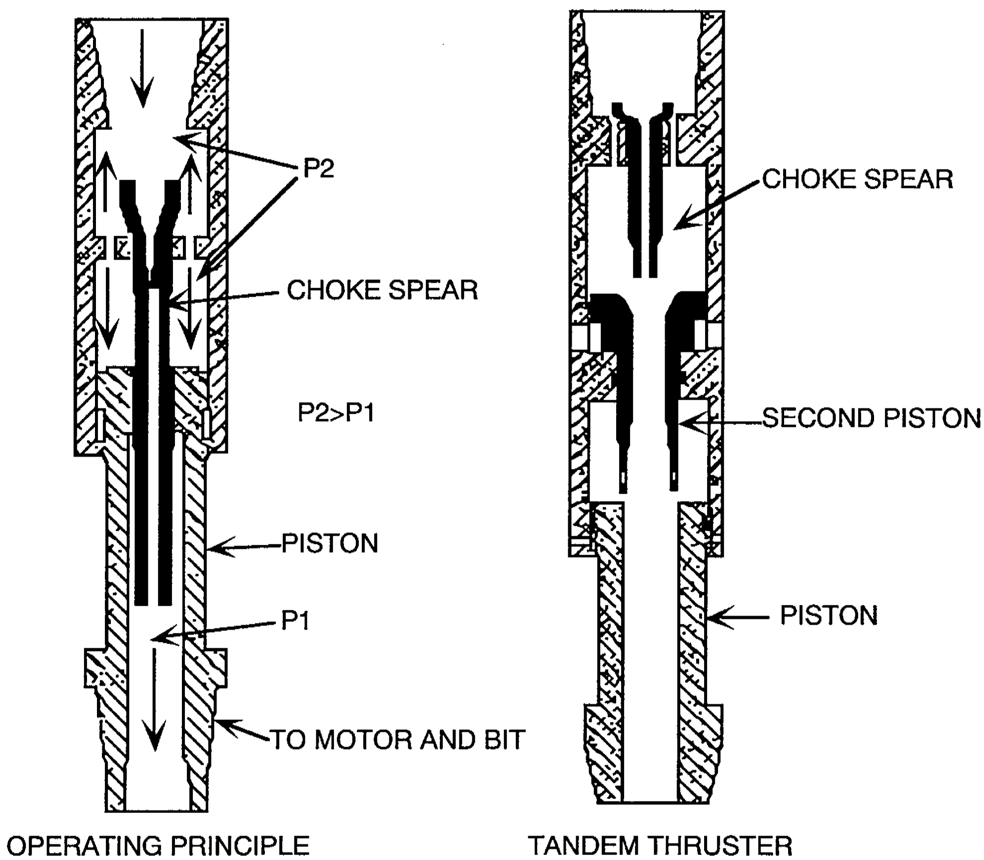


Figure 5–6 Eastman Teloco thruster used in slimhole.[51]

Using thruster can reduce axial vibration. By diminishing axial vibration the hydraulic thruster reduces the overall vibration level and furthermore avoids the possibility of dynamically bucking the string. Combining the downhole motor with a thruster helps limit torsional vibration in the drillstring. Drillpipe rotation is kept to the minimum necessary to overcome drag, so bit life is improved This reduces wear and improves drilling bit performance.

Drilling performance data with thruster drilling by Shell Exploration Company. shown encouraging results particularly in smaller hole sizes (4⅛ inch to 6 inch).[91] Shell reported that improvements have been achieved in ROP of up to 35% and longer bit life has been recorded. In deeper wells the reduced number of round trips due to longer bit life can be equivalent to one operating day or even more.

5.6 Early Kick Detection

Early kick detection has been identified as being of primary importance in slimhole drilling.[21,44,49,91,92] In a conventional drilling, primary kick detection is a gain in the mud pit volume. The sensitivity of this kick detection method depends on the type of pit volume totaling equipment and the size of the mud tanks. However, slimhole rigs cannot rely on pit gains for kick detection. In slimhole drilling, small annular volumes result in small allowable kick volumes. In order to minimize the influx volume, a kick should be shut in as soon as possible and should be confirmed not by a flow check but by observing the pressure buildup under the closed BOP. Thereafter the kick may be circulated out conventionally.

Recently, several slimhole well kill methods have been developed. All these methods are depend upon dynamic techniques. The advantage of the dynamic well control method is faster to employ and minimizes casing shoe pressure.[49] With this technique, the first action taken after detecting a kick is to increase the circulation rate to increase the annular pressure drop and the bottomhole pressure.

In the late 1980s, Amoco developed a slimhole well control system by using a dynamic kill procedure instead of wait and weight or driller methods.[49] In Amoco's slimhole well control system, electromagnetic flowmeters were used in-line with the mud pump suction and the flowline from the well. The flow-in and flow-out readings were plotted along with pit volumes. By superimposing the flow-in and flow-out plots in real time, influxes (and losses) are indicated immediately.

In addition, Amoco also developed an Expert System for use on their slimhole rig as shown in Figure 5–7.[49] The Expert System can incorporate the knowledge of the planning engineer and the expertise of rig personnel into a rule-based program. The system provide continuous monitoring of well control parameters and allow rig site personnel to concentrate on the drilling operations.

Field tests of Amoco's slimhole well control system confirmed that the system did provide accurate and reliable service.[49] The pressure correlations proved to be accurate and were not only used for well control assessment but also to determine the affect on pump pressure when changes in mud rheology were anticipated.

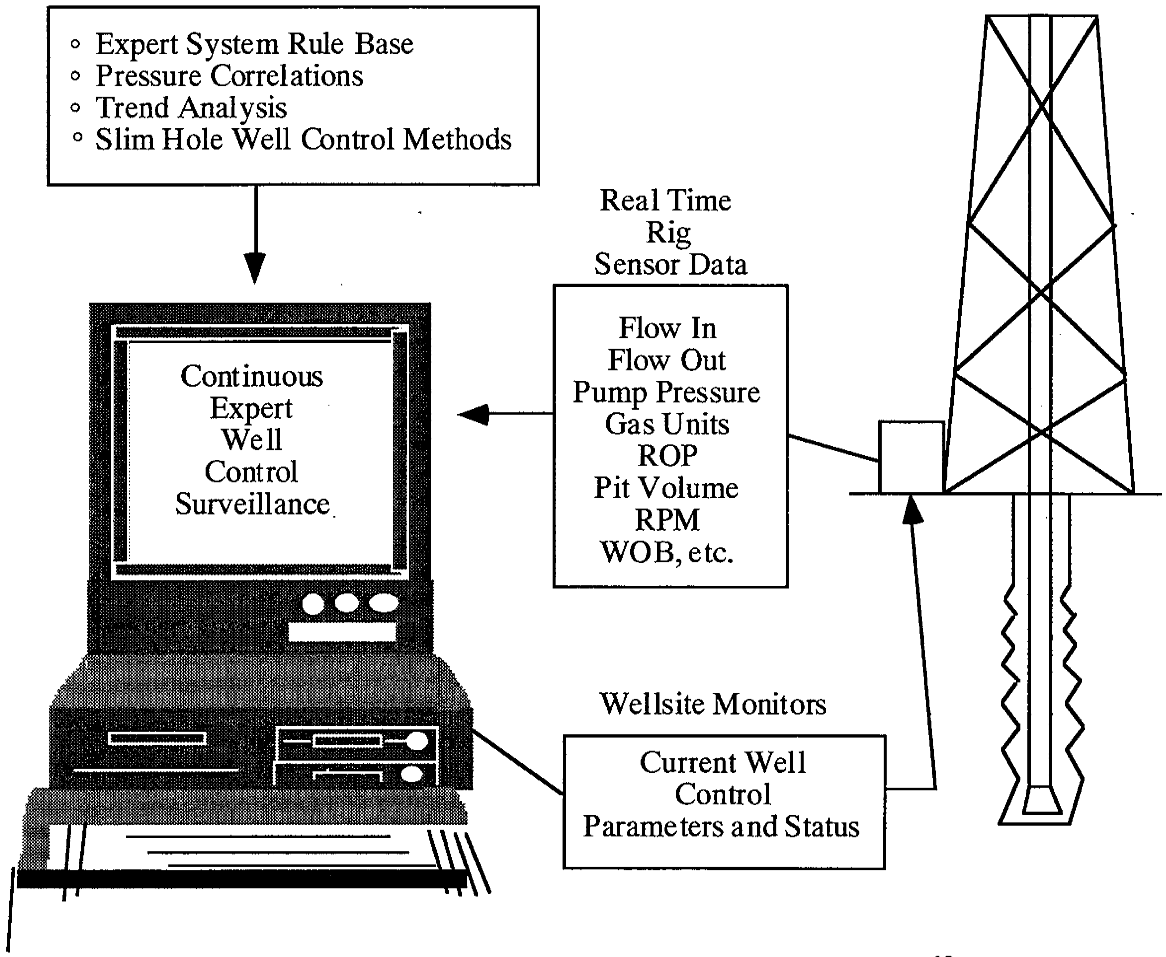


Figure 5–7 Amoco expert slimhole well control system.[49]

Recently, BP Exploration Operating Company. developed an early kick detection system for slimholes to detect and confirm the presence of an influx rapidly.[21,92] The early kick detection system is based on real time analysis of drilling data obtained directly from a comprehensive mud logging system on the rig. The analysis technique compares predictions of mud flow out and standpipe pressure from a dynamic wellbore model with corresponding measured values form the rig. Any difference between actuality and ideally will indicate an abnormal event. Kick detection is based on deviations between measured data and the idealized model predictions.

In the BP's early kick detection system, two parameters are used to identify a kick and confirm its presence; these are flow out of the well and standpipe pressure.[21] Flow out of the well is predicted by the dynamic wellbore model from an input flowrate fed directly from the rig. Standpipe pressure is calculated by the dynamic model from the input flowrate. Standpipe pressure was chosen to provide a secondary indicator of the influx and hence confirmation of the kick. The dynamic wellbore model used in early kick detection is connected to the slimhole rig via an interface in the form of a comprehensive mud logging database as shown in Figure 5–8.

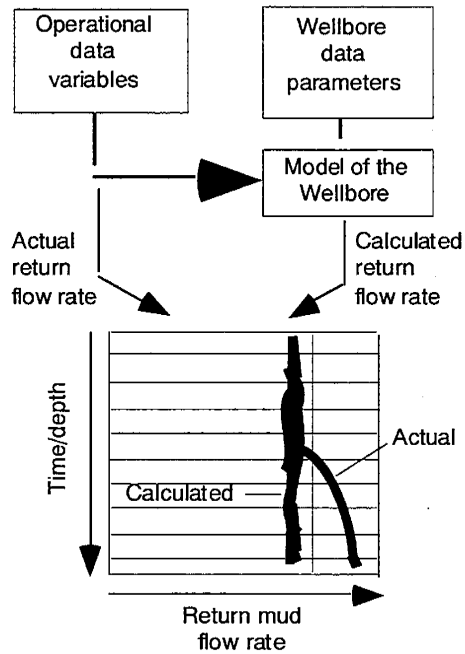


Figure 5–8 BP's EKD Model.[21]

Shell and Eastman Teleco developed a slimhole kick detection system similar to BP's system, which is based on measurement of mud flow-in and flow-out of the well, corrected for system dynamics using a computer.[44] However, Shell's system is a continuously measuring system with capabilities of detecting kicks while drilling, making connections, reaming, tripping, running liners, and wireline logging. The system is used in addition to other kick indicators such as the drilling break. An influx of 50 liters was successfully detected while drilling inside 7-inch liner at a depth of 12,500 feet.[44] In another situation of using the kick detection system, a complex sequence of increasingly pressured formations rising from 0.69 psi/ft to 0.83 psi/ft was successfully drilled with a $5\frac{7}{8}$-inch hole where a series of small kicks was progressively detected and dealt with.[44] A disadvantage of the system is that the electromagnetic flowmeter in the flowline has to be operated fully flooded causing potential clogging with clay-balls. However, these are rarely found when drilling deeper than 4,500 feet.[44]

Recently Shell modified their kick detection system for applications of offshore slimhole drilling. The objective of the modification is to make the system robust and simple enough that the operation and maintenance can be resolved by the rig crew with a display to the driller.[91] The modified system has shown encouraging results in identifying losses or influx to the wellbore.[91]

A new acoustic kick detection system has been developed by Shell.[91] The device calculates the velocity of sound in the mud by measuring the time it takes off the noise of the mud pump to travel down the drillstring and back up the annulus. Gas influx is detected by decrease in the calculated sound velocity in the mud column. Shell tested another system using the MWD pulse. However, both systems are limited to gas influx and do not provide information when pumping stops. As a consequence these two systems can be considered as backup kick detection slimhole drilling where gas kicks are the greatest safety risk.

5.7 Advanced Slimhole Tools

One of the limiting factors of slimhole applications has been a lack of available downhole tools. However, because the demand for slimhole downhole tools is growing rapidly as operators and producers expand slimhole drilling from exploration wells to production wells and horizontal sidetracks, the development of advanced guidance tools, MWD tools, logging tools, perforating tools, and testing tools for slimhole can now allow operators to perform tasks such as directional drilling, formation evaluation, well testing, and well completion.

5.7.1 Slimhole Logging Tools

Special logging tools have been developed to overcome problems for slimhole wells. Table 5–5 lists the wireline logging tools that can be run in slimhole wells.[45]

Table 5–5 Slimhole Wireline Logging Tool Diameters (Randolph et al. 1991)

	Tool Diameter (inches)		Hole Size	(inches)	
		5.857	4.375	4.125	3.40
Dual	3.375	2.50	1.00		
Laterolog	2.750	3.12	1.62	1.38	0.65
Gamma Ray	3.375	2.50	1.00		
	2.750	3.12	1.62	1.38	0.65
	1.688	4.18	2.68	2.44	1.71
Induction	3.375	2.50	1.00		
	2.750	3.12	1.62	1.38	0.65
Density	3.50	2.38	0.86[2]		
	2.750	3.12	1.62	1.38	0.65
Neutron	3.375	2.50	1.00	0.75	
	2.750	3.12	1.62	1.38	0.65
	1.688	4.18	2.68	2.44	1.71
Sonic	2.750	3.12	1.62	1.38	0.65
	1.688	4.18	2.68	2.44	
Dielectric	4.750	1.12			
Formation Microscanner	3.625	2.25	0.75[2]		
Borehole Seismics	1.688	4.18	2.68	2.44	1.71

1. Clearance is difference between hole size and tool diameter.
2. Has been run successfully in 4.125-inch holes.

Schlumberger Oilfield Services recently has developed slimhole logging tools that can give measurements whose quality is similar to or better than the quality of the measurements made with standard tools.[93] These slimhole logging tools include resistivity measurement, nuclear measurement and acoustic measurement slimhole logging tools.

Resistivity measurement tools include the Dual Laterolog Tool (MDLT*), Slimhole Microresistivity Sonde (SRMS*), and Induction Resistivity Tool (IRT*). All of these resistivity measurement tools have 2¾-inch OD. The MDLT tool provides deep and shallow laterolog curves, the

SRMS sonde measures microresistivity, and the IRT tool gives an induction resistivity curve, a 16-inch short-normal curve, and a spontaneous potential (SP).[93]

Slimhole nuclear measurement tools include the Formation Gamma-Gamma Tool (FGT*), Hostile Litho-Density* Tool (HLDT*) and Reservoir Saturation Tool (RST*) shown in Figure 5–9. The FGT and HLDT tools measure compensated bulk density, density correction, and caliper. The 1 11/16- and 2 1/2-inch RST tools, which have electronic neutron generators rather than radioactive sources, are used for formation evaluation through tubing or casing.[93]

Figure 5–9 Slimhole RST reservoir saturation logging tool (after Schlumberger, OGJ, July 25, 1994).

Slimhole tools for acoustic measurement include the Sonic Logging Tool (SLT*) and two geophone arrays. They are the Through-Tubing Well Seismic Tool (TWST*) and the Borehole Geophone Fixture, Anchorable (BGFA*).[93] The 2 1/2-inch SLT tool is a depth-derived, borehole-compensated sonde with 3-, 5- and 7-foot spacings. It provides an interval transit time curve, an amplitude curve and waveform recording. The 1 11/16-inch TWST tool has eight single-axis geophones. It can be run with the well under pressure, without removing the tubing, through the wellhead pressure-control equipment. The 2-inch BGFA tool uses a three-axis geophone with a lightweight sonde. Its measurements are particularly useful for filling in critical gaps in the 3D seismic coverage of a producing field.[93]

A recently introduced slimhole sampling tool by Schlumberger Oilfield Services, the 3 3/8-inch Chronological Sample Taker gun (CST*), recovers rock samples in 4 1/8-inch holes. It can take 25 rock samples per tool, each sample 1 1/8 inch long with a 7/8-inches diameter.[93]

Sperry-Sun Drilling Services is developing a 4 3/4-inch slimhole version of the multiple depth-of-investigation resistivity sensor.[74] The resistivity/gamma ray tool has four independent transmitter-receiver spacings and is believed to be the first electromagnetic wave propagation resistivity device available for 6 1/4- to 5 7/8-inch hole sizes.

5.7.2 Slimhole Testing Tools

Schlumberger Oilfield Services has also developed slimhole testing tools including formation pressure measurement, formation fluid sampling and drillstem test.[93] The new Slimhole Repeat Formation Tester (SRFT*) as shown in Figure 5–10, a 3 3/8-inch OD tool, is used for wireline formation testing in 4 1/8- to 8-inch wells. In a single trip, the SRFT tool can make as many formation pressure measurements as desired and collect 2 3/8-gallon formation fluid samples.

Newly introduced by Schlumberger Oilfield Services, the 2 1/2-inch Mechanical Slimhole Testing System (MSTS) as shown in Figure 5–11 is used for drill-stem tests in 3- to 4 1/2-inch openhole or cased wells.[93] Inflate straddle packers allow testing of multiple zones in a single trip. A sleeve-type valve controls flow and shut-in. Since the MSTS system is operated entirely by vertical (axial) motion of the test string, it can be run on coiled tubing as well as regular tubing or drillpipe. The test string can be equipped with PVT samplers and pressure sensors.

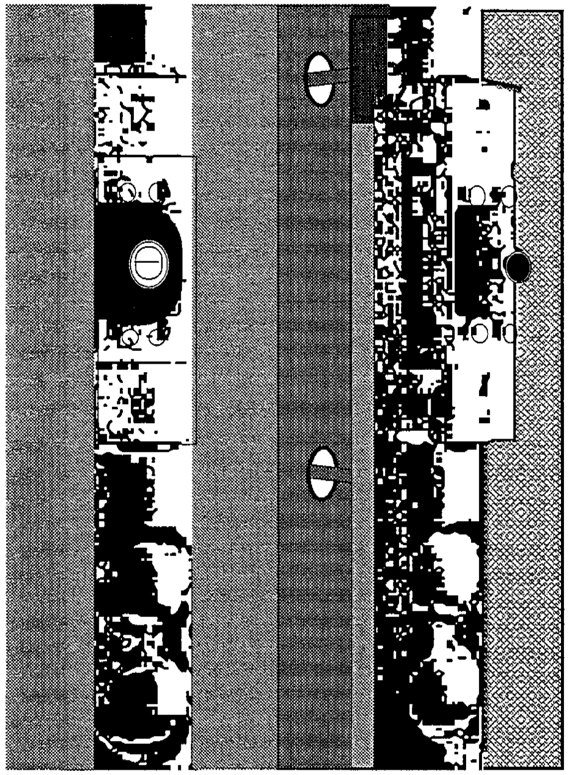


Figure 5–10 SRFT slimhole formation testing tool (after Schlumberger, OGJ, July 25, 1993).

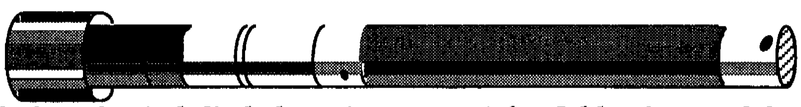


Figure 5–11 MSTS mechanical slimhole testing system (after Schlumberger, OGJ, July 25, 1994).

Drillstem test strings with a 3⅛-inch OD are available for larger cased and open holes.[93] These strings can be tailored to match test needs with multiple-operating downhole shut-in valves, reversing valves, retrievable packers, and recorders.

5.7.3 Slimhole Perforating and Cased Hole Logging Tools

The new, 1½-inch OD, High Shot Density gun system (HSD*), developed by Schlumberger Oilfield Services, perforates at six shots per feet with 60° phasing.[93] Penetration is 15 inches, with 0.32-inch entrance holes. This perforating system has a 25,000-psi pressure rating and can be run on wireline, standard tubing, or coiled tubing. It will pass through restrictions as small as 2¾-inch

Wireline & Testing also has many other perforating systems suitable for slimhole completions. They include the 2⅞-inch HSD gun system, 1 11/16- and 2⅛-inch HyperDome* and Enerjet* guns and the 1 11/16-inch Pivot Gun system (as shown in Fig. 5–12).[93]

Figure 5–12 Pivot gun system (after Schlumberger, OGJ, July 25, 1994).

Slimhole production services include corrosion monitoring with the Tubing Geometry Sonde (FTGT*) and production logging with the Combinable Production Logging Tool (CPLT*).[93] The FTGT sonde provides 16 radii, or 8 diameters, with analysis of maximum and minimum radius, while the CPLT tool makes fluid density, velocity, temperature and pressure measurements, plus tracer ejector measurements.

5.7.4 Directional Drilling Steering Tools

The ongoing developments associated with directional drilling tools make the directional drilling steering system a viable technique for drilling horizontal and extended reach wells.[94-96] A directional drilling steering system is comprised of steerable motor, MWD and stabilization. The system is designed to control bit trajectory without the need for tripping in both directional and straight hole application. To steer the bit, the system has two modes: orienting and rotating. In orienting mode the drillstring is not rotated while the bit is turned by a downhole motor.

Bottomhole Assembly for Steering. The bottomhole assembly is designed to impart a sideload on the bit through either offset stabilizers or bend in the bottomhole assembly. Sideloading causes the bit to deviate the well-path. In rotary mode the drillstring is rotated in addition to bit rotation by a motor. There are three different steerable bottomhole assembly systems available in the oil industry.[94]

- Offset stabilizer on motor.
- Adjustable bent sub above motor.
- Motor housing with one or two bends.

The majority of steerable systems used are with bend housing positive displacement motor and stabilization on the motor (as shown in Fig. 5–13).[94] Positive displacement motor is a high-torque motor, and it can cover a wide range of controlled speeds, from fast rotary to turbine speeds. The typical bent housing angles are between 0.5° and 1.25°. The bends provide for build rates ranging from approximately 1.5° to 5.0° per 100 feet depending upon hole angle, WOB and formation tendencies.

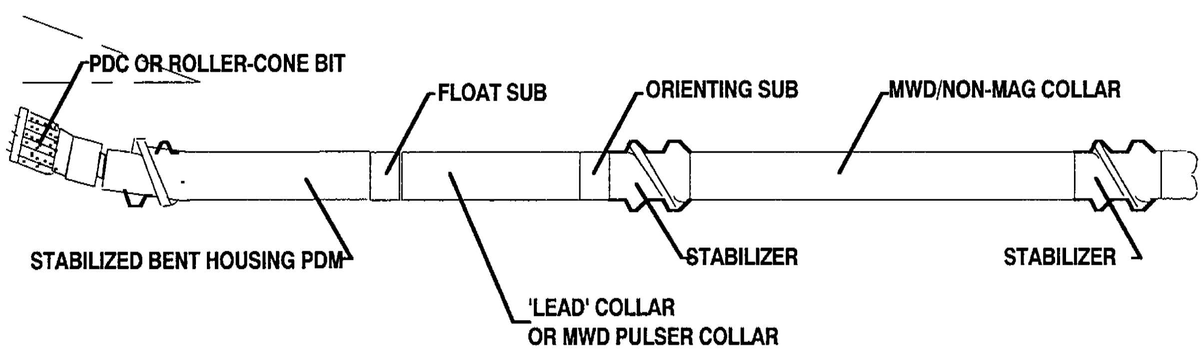


Figure 5–13 Steerable drilling system.[94]

Anadrill Schlumberger and Shell U.K. E&P recently developed an instrumented steerable downhole motor (Fig. 46) to improve the results of geosteering.[96] The tool is a conventional positive displacement steerable motor with a near-bit sensor sub inserted between the power section and the bearing housing. The sub contains the sensors, electronics, power supply, and electromagnetic telemetry system. The near-bit sensor sub contains annular chambers positioned around the rotating driveshaft in which are packaged the sensors, electronics, power supply, and electromagnetic telemetry system. The instrumented steerable motor makes a combination of drilling and formation evaluation measurements: inclination, motor rpm, temperature, gamma ray, and two resistivity measurements.

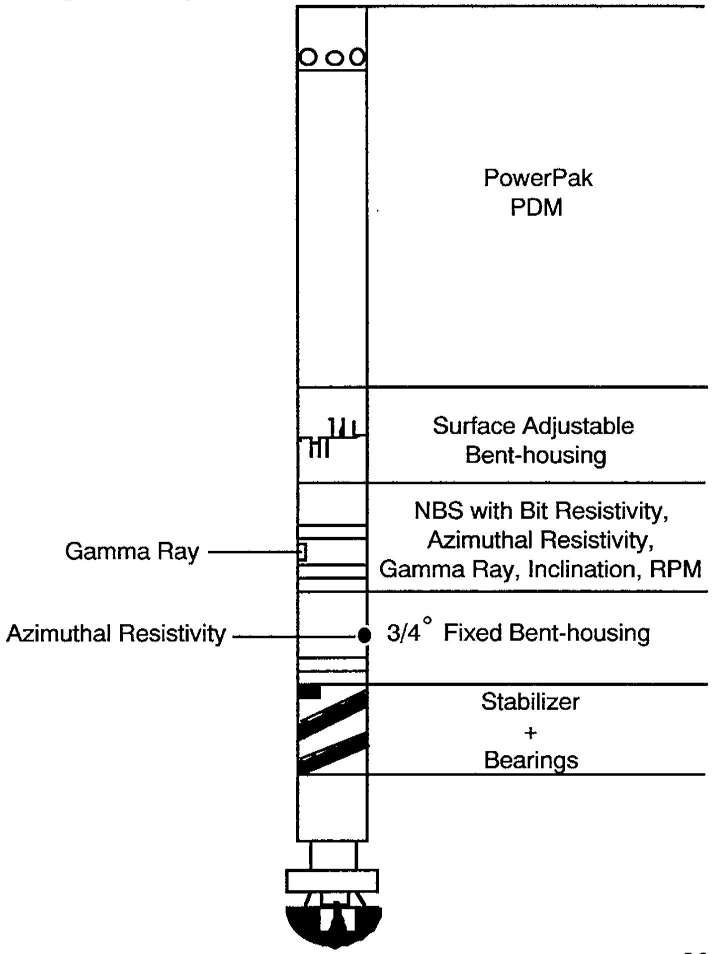


Figure 5–14 **Instrumented steerable downhole motor.**[96]

The instrumented motor is fitted with a double bent housing system. A fixed bent housing is positioned immediately above the bearing section of the motor. A second rig floor-adjustable bent housing is positioned between the sensor sub and power section of the motor. This combination of fixed and adjustable bend system is designed to give the motor various build up rates to a maximum in excess of 15°/100 feet.[96]

Bell reported that Cambridge Radiation Technology has been conducted a research to develop a closed-loop directional drilling tool called Automated Guidance System (AGS).[74] The AGS will provide continuous directional control, which should permit an increase in drilling range.

The AGS will be a self-contained unit placed between the near-bit stabilizer and the drillstring stabilizer.[74] An on-board computer will provide accurate control of inclination and azimuth. It will be designed to sense small deviations in the wellbore course and make small corrections, ensuring a straight hole when drilling a tangent section. When changing course, the AGS is designed to produce a smooth curve with a maximum dogleg of 2.2° per 100 feet.[74] The control system will steer the bit through a target course preprogrammed at the surface and can alter the course without tripping. The most important benefit is expected to be a substantial improvement in the horizontal displacement of extended-reach wells. Bell said that the first AGS device is expected to be tested with British Petroleum by the end of 1994 or early 1995.

Slimhole Measurement-While-Drilling (MWD) Tools. The MWD system is currently used to provide accurate and reliable information on the formation being drilled and the behavior of the drillstring.[97-98] The MWD directional data determines how the borehole direction should be changed to achieve the desired objectives of the well. In horizontal or directional drilling, it cannot be adequately controlled without the MWD for monitoring both the well trajectory and the geological environment. In addition to directional control, the information can be used for formation evaluation and abnormal pressure detection. The recent increase in the number of downhole logging measurements, and the development of geosteering techniques, have resulted in a great improvement of MWD tools.

Union Pacific Resources and Anadrill/Schlumberger recently developed a fully retrievable slimhole gamma ray MWD system to minimize the risk of drilling.[98] The system can be run in drill collars with internal diameters as small as 2.19 inches, and has been run in collars with 3½-inch ODs. It has also been run in coiled tubing drilling operations.

The fully retrievable slimhole gamma ray MWD system has following advantages:[98]

- Minimum lost-in-hole liability
- Reduced rig down time in the event of MWD failure
- Reduction in cost of transporting equipment to the rig site (everything fits into a pickup truck)
- Lower overall cost for a system
- The same MWD tool can be used from 4¾-inch to 12¼-inch hole sizes, and in coiled tubing applications.

Slimhole gamma ray MWD system has been used to pinpoint zones of interest and calculate formation dip angles in the Austin Chalk.[98] A typical target zone in the Chalk is bounded by the Eagleford shale below, and a 5-foot Tuff bed above with 30 feet of true vertical depth (TVD) between these two marker beds, it is also required to stay within a 10-foot window inside of this zone. An error of 1° in the calculated formation dip angle translates into an error of 17.5 feet of TVD over 1,000 feet of section, and as formations do not dip at a fixed rate and contain faults, it becomes very easy for a horizontal well to wander out of the target formation. By using gamma ray MWD system in the build section of the well, formation dip angle can be corrected for target depth correction.

Union Pacific reported a significant time savings in the event of a tool failure by using retrievable slimhole gamma ray MWD system, for example, if an MWD tool fails in a well at 40° inclination, at 10,000 ft measured depth.[98] A collar-mounted tool requires a round trip, which cost 11½ hours of rig time, assuming 1,000 ft/hr round trip time and 1½ hours at surface to swap out tools. A retrievable tool requires about 2 hours of rig time to get back to drilling, with none of the associated tripping problems, and so represents a substantial cost savings.

Recently, Anadrill developed new MWD system, called Slim1* MWD, to guide the bit to target.[73] The Slim1 MWD system transmits information to the surface in real time using positive mud pulse telemetry. Data from the downhole directional sensors and the gamma ray detector are processed electronically downhole and put into a binary format for transmission to the surface. These data include borehole inclination, azimuth, tool face orientation, downhole temperature magnetometer and inclinometer outputs, battery voltage and gamma ray words. Anadrill cited that real-time MWD data are particularly useful in horizontal drilling. They allow correlation with existing logs to adjust the build rate, geosteering to stay in the pay zone, wellsite calculation of formation dip angle and detection of faults while drilling.[73]

Sperry-Sun recently is developing a triaxial MWD vibration sensor for monitoring downhole shocks to the BHA and diagnosing downhole drillstring dynamics.[74] Triaxial accelerometers measure lateral, torsional, and longitudinal vibration, which can be used to determine conditions such as bit whirl, slip-stick, and bit bounce. Corrective actions then can be taken to improve drilling efficiency and bit life while decreasing BHA mechanical failures. Several successful runs in the North Sea have been reported.[74]

Halliburton recently conducted research in the area of MWD algorithms to improve MWD survey accuracy and quality control. The development of algorithms such as the Magnetic Azimuth Correction (MAC) allows elimination of some nonmagnetic components from the drillstring, previously a prerequisite for quality magnetic measurements.[74]

Halliburton reported that some corrections produced by the Halliburton MWD algorithms remain stable under circumstances where other proprietary algorithms used in the industry are inadequate.[74] Projects now are underway to develop such algorithms into programs. Several field applications are being arranged to test the new programs.

Until now, there were three types of MWD transmitting systems: positive pulse, siren, and negative pulse. These three systems are all depend on the pressure modulator, which is easily worn out and has limited capacity to transmit the readings.

To overcome the above mentioned problems, Geoservices SA in France recently developed a new E.M. MWD system which uses electromagnetic waves to transmit the signals.[99] The electromagnetic transmission, which entered the market about five years age, overcomes its primary depth limitation and matches drillers requirements: high reliability, no drilling constrains. It does not have the disadvantages inherent in mud pulse technologies and, progressively, the propagation distance (its primary default) is being overcome.

The new E.M. MWD tool is composed of two parts: (1) the upper part, called the emitter sub is approximately 11.5 feet (3.5 meters) long, and (2) the lower part is the supporting drill collar or tool carrier. The lower part is about 19.7 feet (6 meters) long and designed for supporting the active part of the MWD (which is called the shuttle) which acts as an antenna. The shuttle contains the electronics and sensors.

6.0 RECOMMENDATIONS

6.1 The Future of Slimhole

In both frontier and mature oil provinces, slimhole wells have proven savings of 15% to 40%. In the current economic climate, slimhole horizontal wells will continue to play a larger role in exploration and development of reserves. However, slimhole technology is at roughly the same technological position as horizontal and extended reach drilling was five years ago. It has been proven to be feasible and economical, but it is waiting for the push to become an industry accepted practice.

Development of slimhole drilling is clearly cost driven. However, the environmental impact of the oil industry activities is playing an increasing role. The oil industry is facing the challenge to reduce discharge of cuttings from oil base mud to zero before the end of 1996. It is considered important to look beyond oil discharge and even to be a few steps ahead of the requirements. The possible legislation associated with all drilling waste is probably in the near future. Slimhole drilling is contributing towards this target.

At the present time, slimhole drilling cannot offer consistent results, especially for drilling the lateral intervals. The reason is that the slimhole drilling is still in its early development stage. The reliability and experience with the new generations of downhole equipment are still limited.

Slimhole vertical drilling is seeing a great push, especially in remote areas. The service companies now can offer a slimhole real time resistivity data from its standard MWD measurement. However, the services only are limited to certain size. More sophisticated slimhole MWD or LWD tools are needed, especially in exploratory horizontal wells. There is great room to improve drillstrings, mud motors and bottomhole assemblies. Such improvements will result the dramatic improvement in the costs.

The elimination of excess tortuosity is critical in to extend the lateral distance for slimhole horizontal drilling. Tortuosity occurs when a BHA drifts away from the planned profile and must be adjusted to keep the well on course. Current directional drilling technology using steerable motors produces numerous discrete deviations in the wellbore course. Such deviations severely limit the range in many drilling situations. Therefore, there is a need to develop downhole guidance systems that have the potential to minimize excess curvature.

As mentioned above there are approximately 500,000 wells in the United States, with a large number of wells with 4-inch to 5-inch casing in mature areas, slim reentries and sidetracks may be the only solution. Slimhole drilling offers cheap incremental production, and it may be one of the best solution to effectively develop new reserves. The slimhole wells may offer opportunities to access bypassed oil and gas, giving cheap production.

Slimhole drilling has seldom been tried in areas traditionally considered as risky, such as high-pressure deep drilling. The challenges faced to introduce slimhole drilling safely into high pressure deep drilling are kick detection. However, for high-pressure deep drilling where casing string weights are becoming the limiting factor, slimhole drilling is considered an attractive solution to keep the wells within the capacity of the current rigs. Coiled tubing drilling could offer the potential of drilling safely under pressure. This would open new areas for slimhole technology.

6.2 Slimhole Early Kick Detection

One of the major barriers to the application of slimhole drilling technology to oilfield operations is kick detection.[100-103] 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 must 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 should be active during drilling connecting operations and capable of differentiating a kick from the additional noise introduced by drilling operations.

The annular volume of slimhole geometries severely limits 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 a well control situation. The greater the height of the influx, the more serious the well control problem.

To determine the annular volume the following equation can be used.

$$V = \frac{d_o^2 - d_i^2}{1029.4}$$

Using the equation on the 8,000 feet example well, the annular volume between conventional 8½-inch (21.6 cm) hole and 4½-inch (11.4 cm) drillstring is 50 bbl/1,000 ft. Whereas the slimhole annular volume between 4⅜-inch (11.1 cm) hole and 3.7-inch (9.4 cm) drill string is only 5.3 bbl/1,000 ft.

Let us examine the consequence of one barrel gas kick in a conventional well and a slimhole well. In an annulus between conventional 8½-inch (21.6 cm) hole and 4½-inch (11.4 cm) drillstring, a one barrel influx will occupy a length of 19.8 ft (6 m) while the same volume in the annulus between 4⅜-inch (11.1 cm) hole and 3.7-inch (9.4 cm) drill string will occupy about 190 ft (58 m) at the bottomhole conditions. For a 10.8 ppg (1200 kg/m^3) mud in this hole geometry this increase represents an additional 95 psi (655 kPa) at surface on shut in.

However, as the gas expands when circulated out of the hole, the influxes of gas stretch out much more in the slimholes than in larger diameter conventional wells, thus having a larger effect in wellbore pressure. Let us consider 8,000-foot conventional and slimholes as shown in Figure 6–1.

If the gas is circulated to the position of 1,500 feet where a casing shoe is located, one barrel gas in a conventional hole would only occupy 105 feet. (32 m) in the annulus and reduce the hydrostatic pressure by about 59 psi (406 kPa) for a 10.8 ppg mud. The one barrel in the slimhole annulus, however, would occupy 1,017 ft (310 m) and reduce the hydrostatic pressure by about 570 psi (3,935 kPa). The casing pressure must increase to maintain a constant bottomhole pressure as shown in Figure 6–2.

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 it is common to base kick detection on a pit volume increase of between 10 and 25 barrels (1.59 and 3.97 m^3).[105] This detection limit for slimholes would have potentially hazardous consequences. Therefore the kick detection system should be very sensitive to kick volume. A detection limit of a 1 barrel (0.159 m^3) influx would be considered as appropriate kick detection for a slimhole.[104]

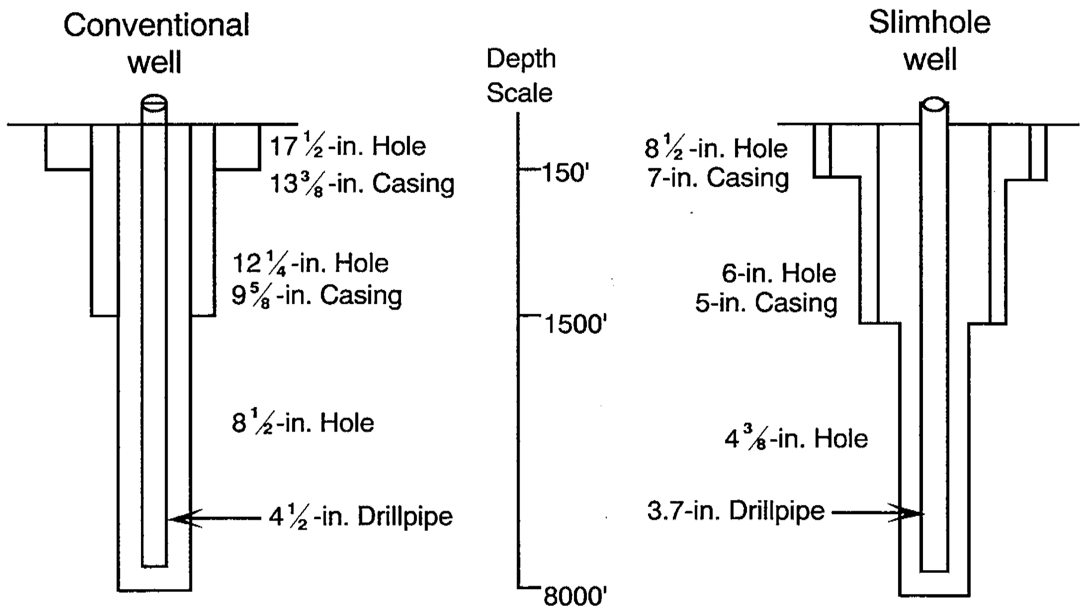


Figure 6–1 Wellbore diagram of example conventional and slimhole wells.

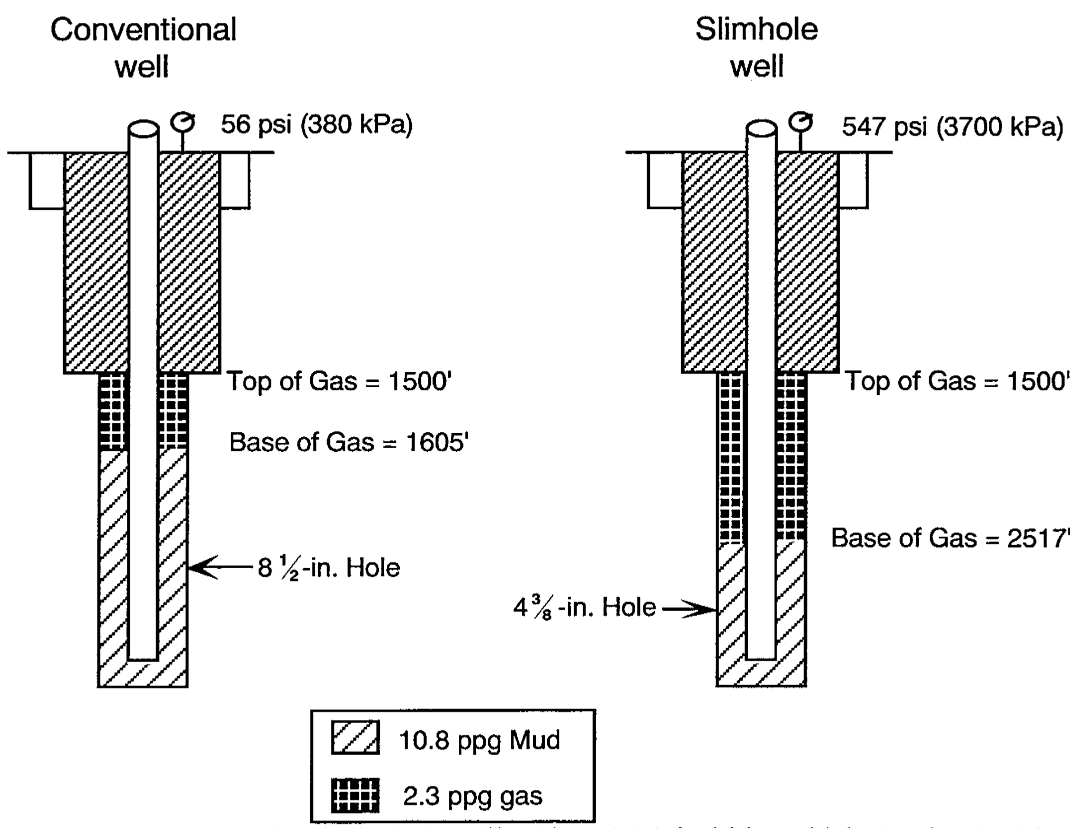


Figure 6–2 Conventional and slimhole well with an initial 2 bbl gas kick circulated with drillers method to a position of maximum using shoe pressure.

The system pressure losses is the key to slimhole well control. Slimhole drilling differs from conventional drilling in the distribution of circulating pressures. The circulating pressure is dominated by the annular pressure drop in slimhole drilling. A result calculated by Bode et al. indicates that 90% of pressure losses takes place in the slimhole wellbore annulus compared to conventional drilling where 90% of the pressure losses takes place in the drill pipe and bit nozzles.[49] 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 6–1 and Figure 6–3.

Table 6–1 Slimhole annular pressure losses (Bode et al. 1989).

Flow Rate GPM	Pump Pressure PSI	Calculated APL PSI	ECD 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

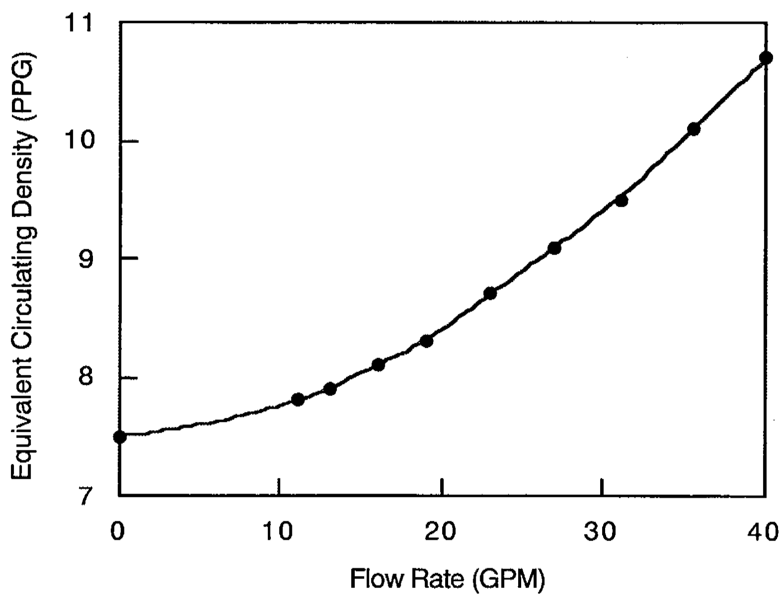


Figure 6–3 Example annular pressure loss test.[49]

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, 4⅜-inch hole and a 4¾-inch hole at 50 gpm on the sample 8,000 feet slimhole well is 269 psi or 0.65 ppg equivalent.[48] Due to the sensitivity of annular pressure loss to hole size, a divert method of well control is recommended for slimhole drilling.

The annular pressure drops are also very sensitive to the rotation speed of the drill pipe. Authors have demonstrated the dramatic increase in annular pressures caused by drill pipe rotation at high speed.[18,49,104-107] The annular pressure losses induced by drillstring rotation were measured on a test well by Amoco.[49] The test results (shown in Figure 6–4) 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 affect rotation has on annular pressure loss, the 8,000 feet slimhole well in Figure 6–1 has an annular pressure loss of 485 psi or 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 1,065 psi or 11.1 ppg equivalent.[49] A kick detection system therefore, should be capable of differentiating a kick from the additional noise introduced by drillpipe rotation.

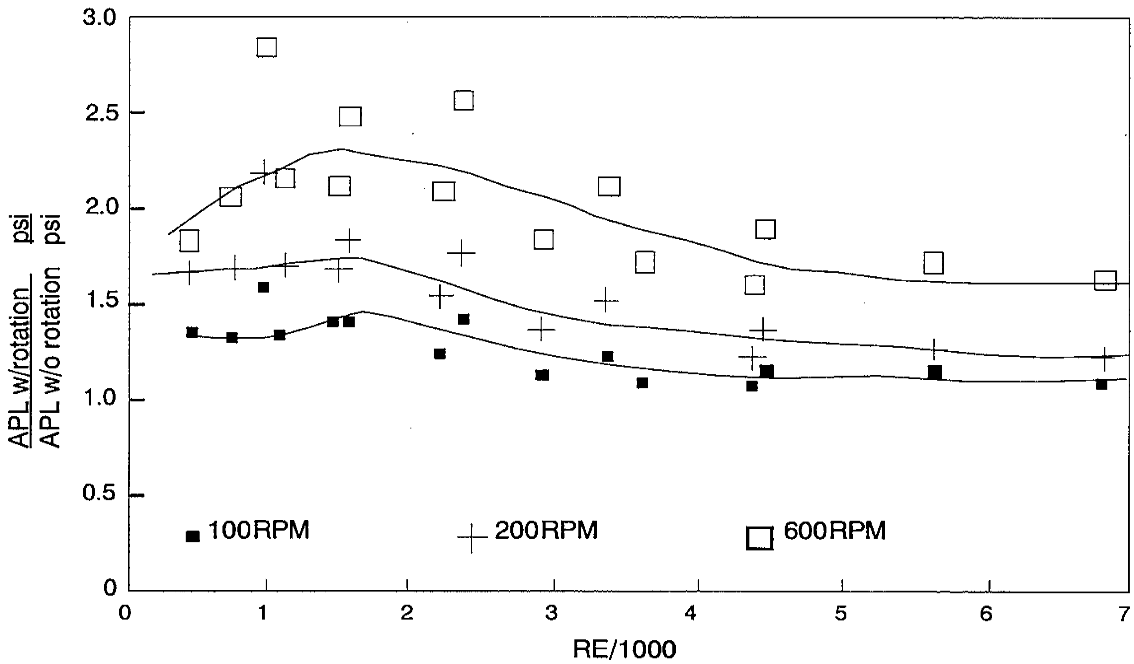


Figure 6–4 **Ratio of annular pressure loss with rotation to annular pressure loss without rotation vs. Reynolds Number.**

Dynamic kill is the controlling of formation pressure using the friction loss in the annulus when circulating. Typical equivalent circulating densities while circulating with 50 gpm at 8,000 ft as an example of slimhole would be approximately 9.6 ppg. An 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 gpm will increase the equivalent circulating densities to 16.1 ppg.[49] Thus by changing the flow rate, rotation rate or mud properties an underbalanced formation can often be controlled. However, dynamic kill 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 influx volume, the more difficult is the kill 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 cause pipe connecting operation 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 are ceased which will result a large reduction in 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 should be active during drilling connecting operations.

The small annulus and relatively low flow rates used in slimhole drilling also introduce a source of noise not normally considered a problem in conventional drilling. In slimholes, air entrained in the drillpipe during a connection will produce appreciable changes in flow as they appear at the flowline. A slimhole kick detection system should be able to differ a real influx from this artificial influx as well.

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

6.3 Slimhole Drilling With Coiled Tubing

The coiled tubing drilling is a viable technique for drilling development and exploration slimhole wells at shallow to medium depths. Field experiments have proven the technical feasibility of coiled tubing drilling for both new wells and reentry applications. In addition to benefits of environment protection and personnel safety, coiled tubing drilling appears as a promising technology for reducing drilling costs and increasing well productivity. The challenge is now for the industry to develop this technology in a viable alternative to conventional drilling techniques.

For drilling new wells, the coiled tubing unit could not run casing. Normally, the top-hole section may not be drilled with the coiled tubing because 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 which is able to carry out all the phases of a well operation without conventional rig intervention.

Recently, larger sizes coiled tubing up to 3½-inch has been developed. It becomes theoretically possible to drill hole sizes of up to 9⅞-in.[47] However, this will require new 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. Therefore, there is a need to develop new techniques to connect or assemble small reels to bigger drum on site for drilling operations. With the connecting techniques, coiled tubing can be transported on relatively small reels. In addition, new technique for the development of composite coiled tubing should provide further improvement of the continuous drillstem system.

The recent experience in coiled tubing reentry drilling indicated that the coiled tubing drilling technology is required for further research and development. Again, a conventional work over rig was required to supplement the deficiencies of the coiled tubing system with regards tubing or casing handling. Other restrictions were related to horizontal drilling with a continuous flexible string. When using coiled tubing, pipe buckling is another major problem. Buckling can lead to lock-up, which limits achievable WOB and horizontal displacement but also complicates WOB control and monitoring. The limitations of coiled tubing with regards to buckling must be addressed to realize the full potential of coiled tubing drilling operations.

Another disadvantage of coiled tubing is tubing fatigue. The low cycle fatigue is induced by plastic deformation of the coiled tubing through the surface equipment. It can become quite significant in lateral drilling applications where the tube can be cycled several times at the same spot to work through a tight spot or during repeated trips to modify bottomhole assembly configuration, especially in short-radius horizontal wells. Low cycle fatigue problems can be solved with better materials or alternative surface equipment design. The development of specific bottomhole assemblies can solve part of this problem. The bottomhole assemblies should incorporate thrusting devices which are able to generate WOB and motion in horizontal holes, independently from compressive load on the coiled tubing. They should also have orienting tools that can be either rotated continuously or locked in a preferred direction.

Formation impairment can be prevented by underbalanced drilling, which in turn eliminates the requirement for acid stimulation that are often used to treat the damaged zone. This minimizes handling of dangerous materials and reduces toxic waste streams and safety hazards. Safety is increased during underbalanced drilling since pressure is contained and drilling can be performed in controlled conditions. However, the results from underbalanced drilling are not consistent. Adequate procedures and equipment need to be developed for performing underbalanced operations. Finally complementary completion technology should be developed with coiled tubing drilling abilities to drill multiple drainholes in the reservoir.

6.4 Top drive Drilling Systems

The top-drive drilling systems were introduced to the oil industry in the early 1980s. Since then, the systems have become the predominant way of drilling offshore wells. Approximately 60% to 70% of all offshore wells are currently drilled with top-drive drilling systems.[109] Unlike the conventional way of rotating the drillstring with a Kelly and rotary table, the top-drive drilling systems drives the drillstring from the top, up in the derrick, by means of hydraulic or electrical motors.

The top-drive drilling system has several advantages over conventional kelly drilling. The first benefit is 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-foot stands. In directional or horizontal drilling, this ability drastically reduces the trip time as well as the risk of getting stuck in the hole. As a result, it 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 and circulation provided within seconds at any position in the derrick.

The top-drive drilling systems were designed for installation on offshore units. They were permanent installation in a 160 feet derrick and powered with the vessels or platform power generation system. Such a system was therefore not applicable on a land rig with a small and short mast which has to be rigged up and down for each well.

Recently, a portable top-drive drilling system has been developed for onshore drilling.[109] The basic model is equipped with two hydraulic drivers, giving a continuos drilling torque of 31,400 ft-lb at 200 rpm. The high speed model for slimholes has a continuous speed 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 for application of top drive drilling systems to the land drilling. The systems are too expensive and costly to install. For example, it takes about 8 to 12 hours to install a portable top-drive drilling system.[109] In addition, the derrick or mast needs to be modified to install the system.

To meet the challenges posed by today's market, oil and gas companies are demanding greater drilling efficiency and higher performance. The top drive drilling systems provide oil industry with the potential to meet such challenges, especially for extended reach and horizontal drilling. If the above barriers can be solved or eased, it is likely that top drive drilling system will be the industrial standard on land rigs in the near future as it is in offshore drilling.

7.0 SUMMARY

Slimhole drilling provides tremendous opportunities to significantly reduce overall drilling costs for exploration and development of oil fields. Major part of the capital cost of exploration and development of oil fields relates to the cost of drilling wells. Slimhole technology has the capability to reduce these costs significantly. As a result, many currently uneconomic prospects could be profitably explored and developed by using slimhole drilling techniques.

Based on the literature review, the following conclusions can be drawn:

1. Slimhole drilling is a technologically and economically viable method of reducing drilling costs for exploration and development of oil fields. Cost reduction of 40% to 60% (or more in some cases) for exploration/appraisal wells and 25% to 40% (or more in some cases) for production/injection wells is possible. The savings are achieved by the use of smaller drilling rigs and/or workover rigs, smaller surface drilling sites, reduced casing sizes, reduced cutting volumes, less mud cement, reduced fuel costs, reduce disposal costs and other costs associated with hole size.

2. Slimhole drilling can minimize the effect of drilling operation on the environment and improve working conditions. The reduced environmental impact and improved working conditions can be achieved from reduced waste generation, scaled-down equipment, reduced air pollution because of less power required, reduced noise, and reduced overall impact and the risk of incidents linked to equipment transportation.

3. Slimhole drilling technology can be used for exploration in remote areas, low-cost development wells including infill drilling for bypass oil and thin oil rims, reentering existing wells including deepening and sidetracking drill, and newly drilled horizontal and multilateral drainhole wells.

4. Early kick detection have been identified as being of primary importance in slimhole drilling. The application of real time dynamic early kick detection system has been shown to provide a basis for diagnosis of abnormal drilling events such as mud losses and kicks during normal drilling operations.

5. Slimhole drilling with coiled tubing is a promising technology for reducing drilling costs and improving exploration and production potential under current economic conditions. The main benefits it offers is enhanced ability to achieve effective underbalanced drilling without compromising safety. The priority should be given to the development of a stand-alone coiled tubing system which should be able to perform drilling or reentry operations without external assistance.

6. New developments of slimhole technology are required to meet the challenges of the offshore environment, underbalanced operations, and short-radius multiple drainholes. Investment in these directions are well worthwhile, in view of the opportunities that slimhole drilling offers for enhancement of drilling & production process.

7. Efforts to surmount present technical constraints in slimhole drilling are well worthwhile in view of the opportunities that slimhole drilling offers. Operators, service companies,

manufacturers and authorities need to jointly define adequate procedures and equipment to capitalize upon the advantages of slimhole drilling. Top priority should be given to the development of the slimhole reentry technique, slimhole early kick detection, and slimhole drilling with coiled tubing, as well as tools and equipment especially for directional control tools.

8. Tools and equipment for completing slimhole wells as down to $3\frac{1}{2}$-inch hole size are currently available. Improved bottomhole assemblies will improve penetration rate and reduce potential for drillstring failure. Further development of tools and equipment will have a positive impact on the applications of slimhole drilling.

9. Slimhole drilling has limitations especially in equipment reliability, reduced penetration rate, and difficulties to control a kick-out. In addition, limited productivity of slimhole also limits its application in many areas. Therefore, the decision to drill a slimhole well must consider the longterm effects as well as the shortterm cost savings. The impact of smaller hole size on longterm production and operations costs must be weighted against the initial savings of drilling a slimhole well.

In summary, slimhole technology offers great opportunity for cost reduction and waste minimization. Slimhole drilling, however, is still a ongoing development technology. It requires effective communications and involvement from all areas, including operators, service companies, manufactures and authorities to overcome the limitations of slimhole drilling. The technology is waiting for the push to become an industry accepted practice.

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