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Slim-Hole Technology
(1994-1995)

DEA-67
Phase II

PROJECT TO DEVELOP AND EVALUATE COILED-TUBING AND SLIM-HOLE TECHNOLOGY

By

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1. Bits

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1. Bits

1.1 CHEVRON USA (DOME PDC BITS)

Chevron USA (Carter and Akins, 1992) developed and field-tested PDC bits and PDC underreamers with dome cutters in slim holes in the Permian Basin. They performed R&D and field testing to improve the economics of slim-hole deepening and underreaming. They saw increased ROPs and decreased costs in operations in holes ranging from 3¼ to 4¾ inches. These technologies show great promise for improving the economics of deepenings and recompletions in the Permian Basin.

Use of dome PDC technology (the diamond layer on the cutter has a dome-shaped profile) was based on previous studies that demonstrated improved heat dissipation and decreased torque generation with this type of cutter as compared to conventional PDC cutters. Additionally, dome cutters are more resistant to impact.

A typical wellbore configuration for Chevron's field work in the Permian Basin includes 5½-in. production casing and an open-hole completion (Figure 1-1). In many cases, wells had been deepened and completed with 4-in. flush-joint liners. More recently, operators have tended to underream before running liners.

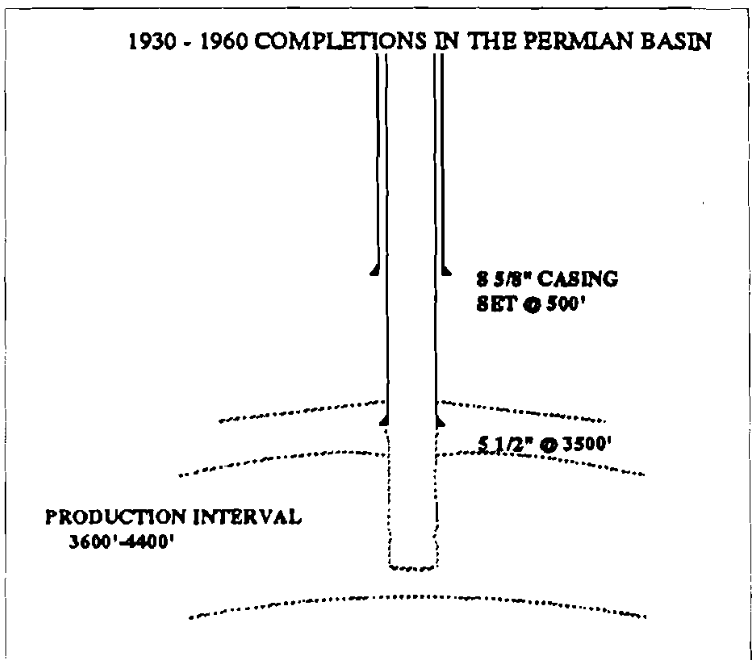

Figure 1-1. Permian Basin Completion (Carter and Akins, 1992)

Performing these recompletions had been difficult with roller-cone and conventional PDC-cutter technology. Roller-cone bearings have shown short lives for these slim-holes. In several field trials, open-bearing roller bits failed after 1-6 hr of rotation, often leaving cones in the hole. Conventional PDCs have performed with relatively low ROPs and have generally been uneconomical. In field trials, two sets of conventional cutters were worn out in less than 30 ft of hole.

Dome PDC bits were used in the Grayburg formation (Table 1-1) in Lea County, New Mexico. Economics were greatly improved with these bits, and ROP increased from about 30 to 50 ft/hr. These bits were also run in the Queen formation in Ward County, Texas. ROP almost tripled from 3 to 8 ft/hr. Costs per foot decreased by more than 70%.

TABLE 1-1. Mechanical Properties of Grayburg Formation (Carter and Akins, 1992)

SAMPLE DEPTH (Ft)	MINERALOGY DESCRIPTION	COMPRESSIVE STR. @ 800 PSI BHP(psi)	DYNAMIC POISSON'S RATIO	YOUNG'S MODULUS (10^6 psi)
3678	Dolo, Vuggy, Fr.	50,930	0.28	9.28
3762	Sand, Dolo, PPP	19,230	0.04	2.20
3986	Dolo, Sdy, PPP	40,270	0.25	7.72
4244	Dolo, PPP	30,450	0.31	1.99

Equipment used in these slim-hole operations included workover rigs with 450 hp and rated for 8000-ft working depths. Rig drive had a capacity of 70,000 lb and 2500 ft-lb at 100 rpm. Drill strings usually consisted of 2⅞-in. N-80 or J-55 8-rd tubing. These strings require less power than standard drill pipe and have been found to perform well in these operations due to reduced torque and WOB requirements. Drill collars (2⅞ in.) were used in 3¼-in. holes. Due to potential fishing problems with these collars, the use of motors was investigated to minimize torque in the drill string. Economics were not found to be favorable.

Basic power requirements of the dome PDC bits were 1.3-3 hp/in^2 at circulation rates of 80-150 gpm. Annular velocities ranged from 9000-20,000 ft/min. Neither heat checking nor hole cleaning were a problem at these rates.

One of the first dome PDC bits tested was a 4¼-in. bit with ⅜-in. cutters. A well was deepened 154 ft with 5000 lb WOB at 90 rpm. ROPs were 114% greater than the best results with roller-cone bits. Results with several bits in the Grayburg formation are summarized in Table 1-2.

TABLE 1-2. Bit Performance in Grayburg Formation (Carter and Akins, 1992)

TYPE BIT	INTERVAL (FT)	WOB (KIPS)	ROTARY (RPM)	ROP (FT/HR)
3¼ In. Dome PDC	601	4–5	80–90	60
3⅞ In. Balaset TSD	536	1–2	1200	10
4¼ In. Dome PDC	154	5	80–90	60
4¾ In. Dome PDC	727	5–15	120	20–40

Success with dome PDC bits led to the development of dome PDC underreamers. The first run with the new underreamer was at rates twice those typical for the area. Rebuilding was also efficient with these cutters. Performance is summarized in Table 1-3.

TABLE 1-3. Underreamer Performance in Grayburg Formation (Carter and Akins, 1992)

TYPE CUTTER	INTERVAL (FT)	WOB (KIPS)	ROTARY (RPM)	ROP (FT/HR)
Conv. PDC	30	0.5–1	1200	–
Mill Tooth: Open Brg. Sealed Brg.	150 754	2 2–4	60 60	10 11
TSD	1,461	2–3	80–120	4
Dome PDC (1st Gen.)	1,116	2	100–120	30

Underreaming costs were reduced by 56% on the first run. Other runs in additional wells confirmed the economic efficiency of these dome PDC systems (Figure 1-2).

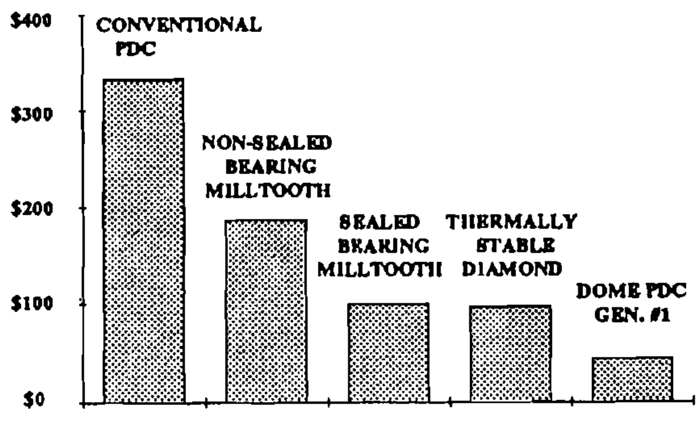

Figure 1-2. Underreamer Costs per Foot in Grayburg Formation (Carter and Akins, 1992)

Chevron expanded its successes with dome PDC cutters to West Texas fields, specifically the Queen formation in Ward County. As in New Mexico, dome PDCs performed much better than roller-cone bits (Table 1-4).

TABLE 1-4. Underreamer Performance in Queen Formation (Carter and Akins, 1992)

TYPE CUTTER	INTERVAL (FT)	WOB (KIPS)	ROTARY (RPM)	ROP (FT/HR)
Sealed Brg. Mill Tooth	146	3 - 5	70	3
Dome PDC (1st Gen.)	235	2 - 4	90 - 110	8
Dome PDC (2nd Gen.)	330	4 - 6	100 - 120	7.5

A second-generation dome PDC underreamer was developed with additional cutters for increased wear. ROP did not increase with this improvement; however, a longer tool life and more even wear reduced costs further (Figure 1-3).

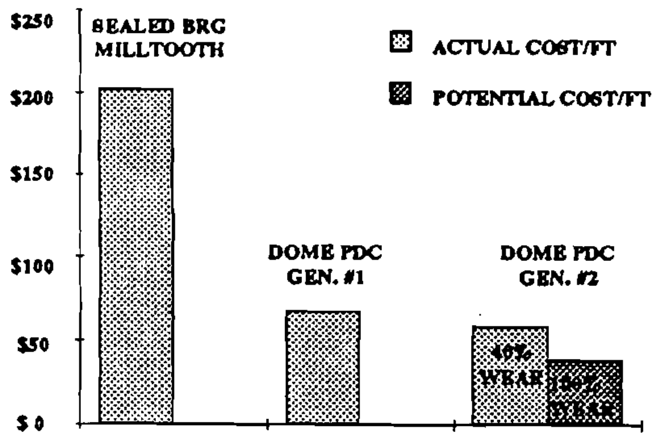

Figure 1-3. Underreamer Costs per Foot in Queen Formation (Carter and Akins, 1992)

Chevron USA was very positive about the potential of these new dome PDC cutters for economic slim-hole operations in the Permian basin. They concluded that these results suggest that this technology should be expanded into other hard-rock regions.

1.2 SHELL U.K. E&P (ANTIWHIRL PDC BITS)

Shell U.K. E&P, Shell Research B.V. and Baker Hughes INTEQ (Eide et al., 1993) discussed technological concerns for high-temperature high-pressure (HTHP) slim-hole wells in the North Sea. Conditions typical of these wells are undisturbed bottom-hole temperatures above 149°C (300°F) and pore-pressure gradients in excess of 0.8 psi/ft. They found that total cost savings of up to 15% were possible in HTHP wells with bottom hole sizes slimmed down to 5¾ or 4⅛ inches.

Bit selection criteria for North Sea slim HTHP wells include optimized ROPs and the generation of cuttings optimally sized for evaluation. In addition, no secondary metamorphic effects were desired.

Analysis of core samples resulted in Shell's selection of antiwhirl PDC bits (e.g., AR435 or 437) for use with their rètrofit slim-hole motor system. In zones with higher abrasion, a mixed-cutter bit (e.g., Z437 or Z435) was recommended.

Additional description of Shell's retrofit slim-hole system is presented in the Chapter *Motor Systems*.

1.3 REFERENCES

Carter, J.A. and Akins, M.E., 1992: "Dome PDC Technology Enhances Slim-Hole Drilling and Underreaming in the Permian Basin," SPE 24606, paper presented at the 67th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Washington, D.C., October 4-7.

Eide, Egil et al., 1993: "The Application of Slim-Hole Drilling Techniques to High-Pressure and High-Temperature Exploration Programs in the North Sea," SPE 26340, paper presented at the Offshore European Conference held in Aberdeen, Scotland, September 7-10.

2. Cementing

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2. Cementing

2.1 GAS RESEARCH INSTITUTE (SLIM-HOLE CEMENTING CHALLENGES)

The Gas Research Institute, BJ Services and Maurer Engineering (Brunsman et al., 1994A) summarized the results of a project to analyze the barriers hindering widespread application of slim-hole drilling and completion technology, with special regard for gas wells in the U.S. There appears to be significant opportunity for slim-hole technology in the U.S. gas industry. Typical wells require neither high-volume artificial lift equipment nor large production tubing to avoid restricting flow rates. The GRI study found that real and perceived limitations of slim-hole drilling exist, hindering the industry from enjoying the full benefits of the technology.

In Brunsman et al. (1994A), the project team presented an analysis of cementing issues and challenges in the slim-hole environment. Industry's opinions and perceptions with respect to cementing barriers are summarized in Figure 2-1.

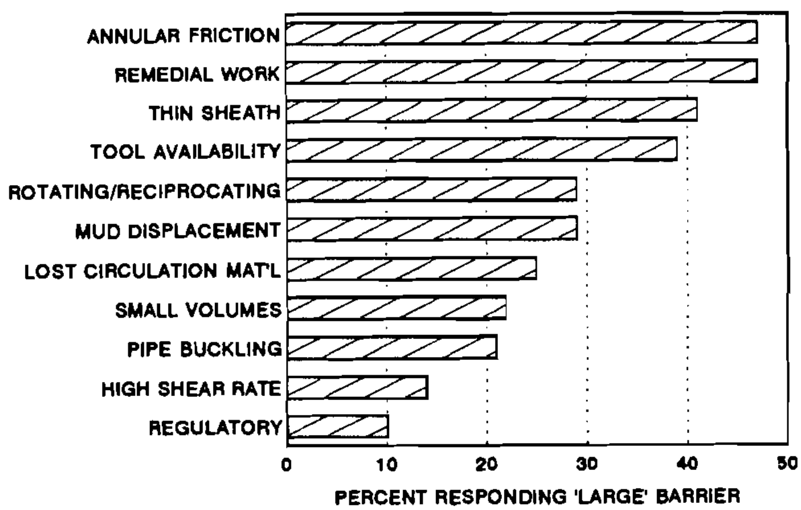

Figure 2-1. Barriers to Slim-Hole Cementing (Brunsman et al., 1994A)

For many wells, especially during earlier periods of high interest in slim holes, a hybrid approach has been used that includes cementing slim tubulars into a relatively large hole. These applications have not presented any unusual demands on cementing technology.

However, for a slim-hole/slim-casing application (Figure 2-2), cementing concerns are increased by the significantly reduced annular space. Careful attention is required with respect to the impacts of shear rates and mixing energy on the slurry, handling small cement volumes, thin cement sheaths, and mud displacement.

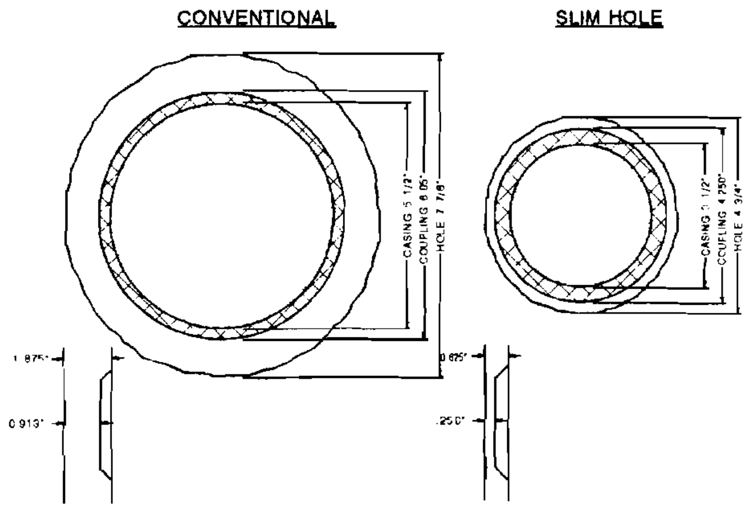

Figure 2-2. Geometry of Slim-Hole Annulus (Brunsman et al., 1994A)

The question may not yet have been settled with certainty regarding the effects of pumping cement slurry through a string of coiled tubing. Some researchers have shown that pumping through coiled tubing has little effect on thickening time. Others have found dramatic reductions in thickening time. (These issues are discussed in the companion volume *Coiled-Tubing Technology (1993-1994)* in the Chapter *Cementing*.) Pumping through coiled tubing exerts shear stresses exceeding that simulated by a consistometer. Property testing of the cement slurry must be carefully conducted for both primary and remedial cementing.

Smaller cement volumes are required in small-annulus geometries (Figure 2-3). This results in a need for greater consistency in cement density. Batch mixing is one beneficial approach for slim holes. Cement contamination must also be carefully minimized. Double wiper plugs or a flush-line valve in the displacement line can be used to combat contamination.

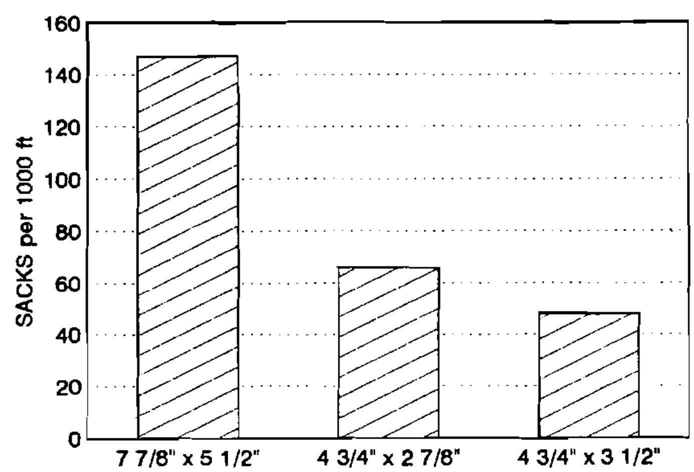

Figure 2-3. Cement Volumes for Slim-Hole Annuli (Brunsman et al., 1994A)

Mud displacement is both aided and hindered by a small annulus. Pump rates must be reduced to stay below fracture gradients at the formation. However, thinner annuli result in higher velocities for a given pump rate (Figure 2-4).

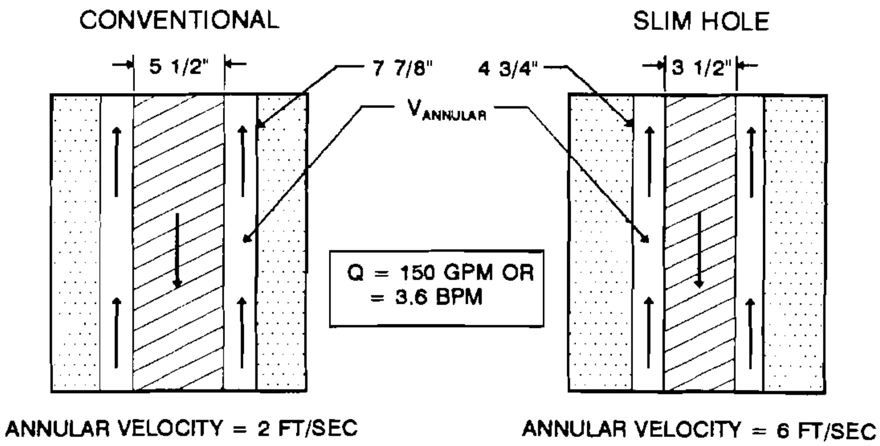

Figure 2-4. Cement Velocities in Slim-Hole Annuli (Brunsman et al., 1994A)

Suggested techniques to increase the efficiency of mud displacement include designing plastic viscosity, yield point and gel strength as low as possible; conditioning the mud and pumping several hole volumes before cementing begins; using dispersants and friction reducers; and designing spacer volume for 10 minutes contact time in turbulent flow.

The performance of thin cement sheaths is relatively untested. Stresses in thin sheaths are probably greater than in conventional. Brunsman et al. suggested that the use of latex additives, reinforcing agents or cements with moderate compressive strengths may counter this problem. Underreaming the productive interval is another option to avoid potential problems with thin sheaths.

Service companies have tools available for most cementing operations with sizes down to about 2 inches. Stage-cementing tools less than 4 in. are an exception. Availability of small cementing tools is much more likely to be an issue for the typical application.

Although research remains to be done in slim-hole cementing, reports from operators around the world suggest that consistent cementing in thin annuli is achievable. To maximize the potential for a successful slim-hole cementing job:

- Cement density should be kept as consistent as possible, e.g., through the use of batch mixers
- Underreaming of the productive internal might be considered
- Fluid loss in the slurry should be less than 1 cc (vertical wells) or zero (deviated wells)
- Centralizer placement should be optimized
- Careful design and thorough quality control are essential to achieve a competent sheath

Research and developments remaining in this area include a more complete understanding of the performance of thin cement sheaths, the utility of mud-to-cement technology in slim holes, and preferred methods of placement including rotation and reciprocation. Operators' and service companies' experiences with slim-hole cementing also need to be documented.

2.2 REFERENCES

Brunsman, Barry J., Mueller, Dan T., and Shook, R. Allen, 1994A: "Slimhole Wells Challenge Cementing Design, Execution," *Petroleum Engineer International*, October.

3. Completions

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3. Completions

3.1 COMPLETION DESIGN

3.1.1 Baker Oil Tools (Nippleless Completions)

Baker Oil Tools (Hopmann, 1993) described a nippleless completion system for use in slim-hole monobore completions. Activity in the development of slim-hole completions has increased significantly, with a progression similar to that of horizontal technology. Without the technology to economically manage the reservoir over the long term, slim-hole wells will not be viable.

Monobore completions have emerged to address problems with reservoir management. These completions allow unrestricted access to the reservoir and permit the operator to leave production tubing in the well for the life of the completion. This design has proven especially useful in areas where a high level of reservoir workover activity is required, such as the North Sea.

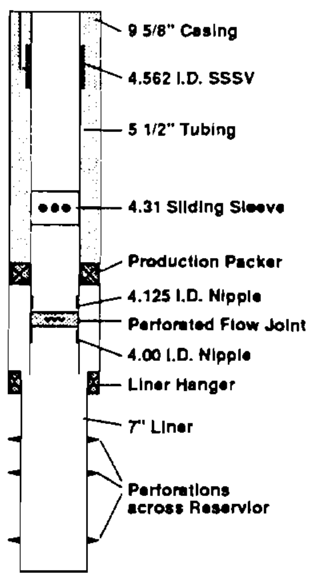

Figure 3-1. Conventional North Sea Completion (Hopmann, 1993)

Monobore completions were developed by UK operators in the 1980s for North Sea operations. A conventional North Sea completion (Figure 3-1) includes a 7-in. production liner and two different nipple sizes: 4⅛ and 4 inches. Working over these wells requires pulling production tubing from the well and milling out the packer to obtain access to the formation. Consequently, tool options are limited in these wells to through-tubing inflatables.

A typical monobore completion (Figure 3-2) has production tubing that is the same size (or larger) than the production liner. No permanent restrictions are installed that might limit access to the producing zone.

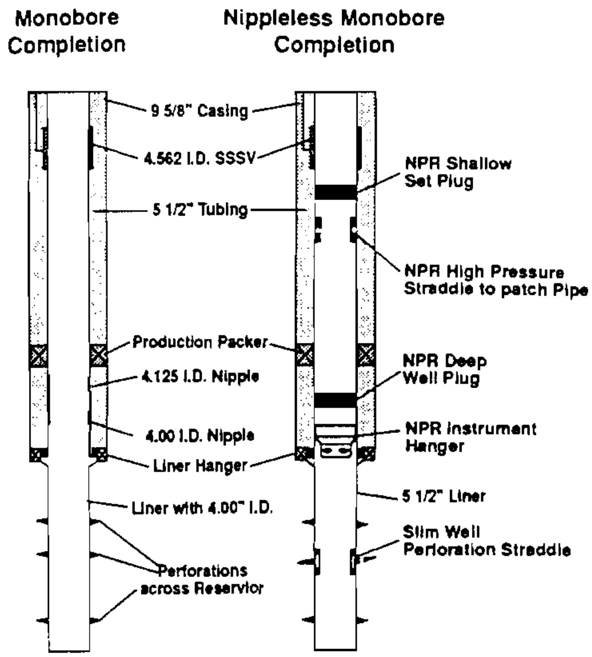

Figure 3-2. North Sea Monobore Completions (Hopmann, 1993)

Operators have found many advantages with the monobore completion, including:

- Workover operations can be conducted effectively without a rig
- Operations can be conducted on live wells, decreasing the chance for formation damage
- Initial completion hardware is simplified, with options for more advanced equipment to be installed later
- Workovers can be conducted on wireline, coiled tubing or by snubbing, without the need to shut down the platform, resulting in reduced costs
- Pressure losses are reduced by the smooth bore
- There is less susceptibility to scale and paraffin deposition, and if it occurs, milling is simplified
- Full-bore production logging tools can be used
- High-expansion mechanical tools are not needed for work in the liner

The primary disadvantage experienced with typical monobore completions is the nipple profiles that restrict access. To remedy these concerns, Baker Oil Tools has been developing an integrated nippleless completion system for monobore wells, which consists of three elements:

1. *Production bridge plug*. This is set on wireline and replaces the traditional lock and nipple.
2. *Retrievable slim-hole straddle system*. This can isolate producing or injection intervals of up to 300 ft in casing. Internal diameter of the straddle allows the passage of tools, inflatable through-tubing equipment, perforating guns, etc.
3. *Disappearing plug*. This assembly is run in as part of the tailpipe and allows the completion to be installed underbalanced. This plug is used for initial completion only.

With Baker's equipment, only one restriction remains in the system, that being the safety-valve profile. The nippleless completion system (see Figure 3-2) introduces challenges for performing operations that previously used nipple profiles, such as pressure testing the tubing, hanging instruments to measure pressures, or running chokes.

The centerpiece of the nippleless completion hardware is a nippleless production bridge plug. The bridge plug is designed to allow a large bore through its internal diameter. A comparison between the nippleless bridge plug and a conventional lock/nipple is shown in Table 3-1.

TABLE 3-1. Nippleless Production Bridge Plug (Hopmann, 1993)

FEATURES/BENEFITS	LOCK/NIPPLE	PRODUCTION BRIDGE PLUG
Pressure rating	15,000 psi or better	7500 psi max.
Damage to pipe	No	Slipmarks
Positive location	Via No-Go	Via survey or odometer
Low cost installation	Slickline	Most electric line, some slickline
Retrieve thru SCSSV w/o drag	Practical	Within limited time frame
Seal integrity	Seals on honed bore	Seals on pipe
Sets in scale	No	Yes, holds fluids okay Gas questionable

A design/implementation issue with the production bridge plug is the need to run and retrieve the plug through the SSSV. It is uncertain how long the plug can remain in the well and then retract sufficiently to pass through the safety valve. The plug's ability to effectively seal in the presence of scale is also under investigation.

A straddle system was developed for zone isolation without rig intervention. The packers used with this retrievable assembly are intended for use in the liner at a low pressure differential. Again, questions have not yet been answered about the long-term retrievability of the packers. Baker suggests that the system should be considered permanent after initial setting and early adjustments of the packers.

The disappearing plug is the third new piece of equipment for use with nippleless monobore completions. The plug is used to blank off tubing during completion operations so that these can be performed in underbalanced conditions. After equipment is in place, a pressure signal is used to actuate the plug, causing its destruction into small particles that can be produced from the well.

3.1.2 Eastern Kansas Oil & Gas Association (Failure Rates for SHC)

At a recent conference, the Eastern Kansas Oil & Gas Association (*American Oil & Gas Reporter* Staff, 1993) made several comments regarding the relative mechanical integrity of slim-hole completions (SHC) in Kansas fields. At the time of the conference, the U.S. Environmental Protection Agency was expected to propose new regulations for all newly drilled and converted injection wells. These regulations would require three levels of protection, including production tubing with packer, a long casing string, and surface casing.

The Eastern Kansas Oil & Gas Association stated that, if those requirements were enacted, slim-hole completions common in Kansas would be effectively eliminated. A typical Kansas slim-hole gas well includes 2⅞-in. casing cemented into about a 6-in. hole. Under current economic conditions and with the equipment that is available, it is cheaper to drill a medium-size hole and cement slim production tubing in place. Average TD of these wells is less than 1000 ft.

Support was provided for the Association's opposition to the proposed EPA ruling. The Kansas group examined data from 1000 randomly selected mechanical-integrity tests. They compared failure rates for slim-hole completions to wells with three layers of protection, as proposed by the EPA. Analysis of the well data showed that the failure rate for slim-hole completions was about half that of the larger conventional completions.

Opposition to the proposed ruling was building due to the increased interest in slim-hole completions across the industry. EPA procedures allow a rule to be withdrawn if it could be shown that oil and gas production would be impeded on a national scale, and that no environmental benefit could be proven for the rule.

3.1.3 Halliburton Energy Services (Monobore Completion Equipment)

Halliburton Energy Services (Robison, 1994) described several types of completion equipment designed to overcome limitations in slim-hole monobore completions. New servicing methods are being developed to allow operators to enjoy the full potential of these completion designs. Cost savings resulting from implementation of monobore designs are normally not enjoyed until later in the well's life. Justifying additional expenses up front for these completions can be difficult. Slim-hole cost savings, on the other hand, are realized in the drilling phase. This complementary aspect is one reason slim-hole drilling technology is being paired with monobore completions by more and more operators.

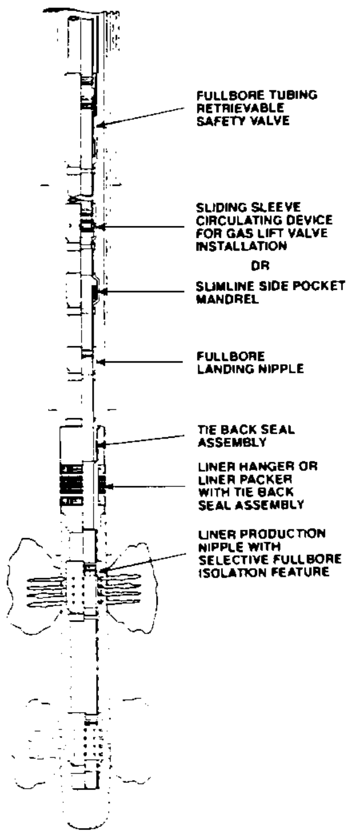

Figure 3-3. Slim-Hole Monobore Gas-Lift Completion (Robison, 1994)

Halliburton Energy Services has been developing completion equipment for slim-hole monobore wells. The reduced diametral clearance in these wells poses the need to rethink basic technology approaches, rather than simply downsize every conventional component. Several pieces of equipment that might be used in a monobore gas-lift completion are shown in Figure 3-3.

The conventional landing nipple/lock mandrel is replaced with an assembly that uses an expandable seal (Figure 3-4) instead of an interference-type seal. Consequently, the nipple does not pose a restriction to the ID.

Another approach is the use of nippleless locks. This assembly (Figure 3-5) uses slips, can be set anywhere in the tubing and is settable/retrievable with standard slickline.

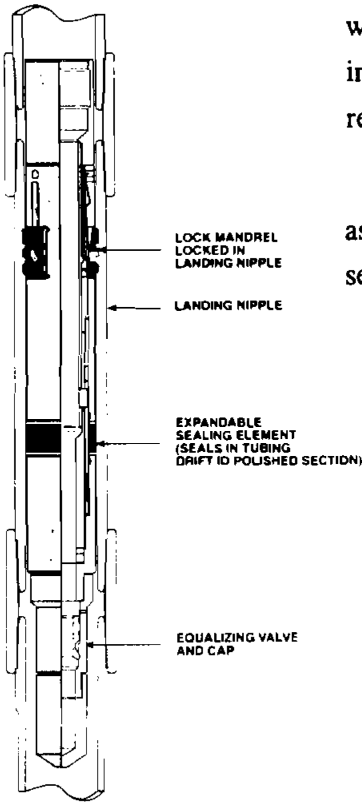

Figure 3-4. Landing Nipple/ Lock Mandrel (Robison, 1994)

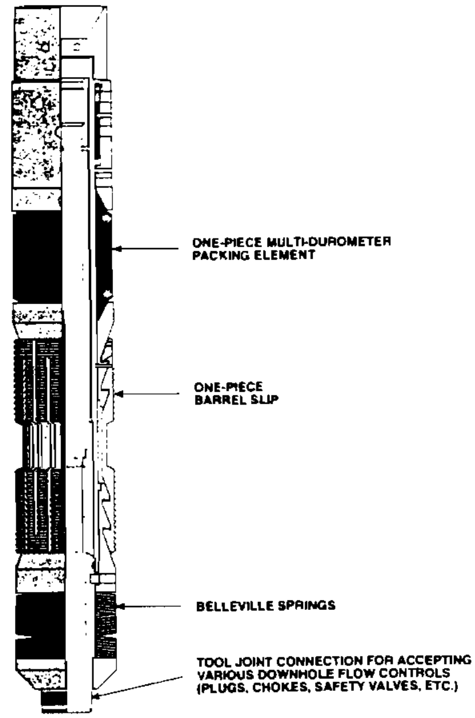

Figure 3-5. Nippleless Lock Mandrel (Robison, 1994)

A zone-isolation assembly (Figure 3-6) combines a locating nipple with a thin-wall section that accepts an expandable patch. There is insufficient room in these wellbores for conventional production-packer/sliding-sleeve assemblies or casing patches. The locating nipple in the monobore system serves as an anchor for placing the patch.

A typical tubing-retrievable SSSV (Figure 3-7) has its limiting restriction dictated by the size of the flow tube, not the nipple profile.

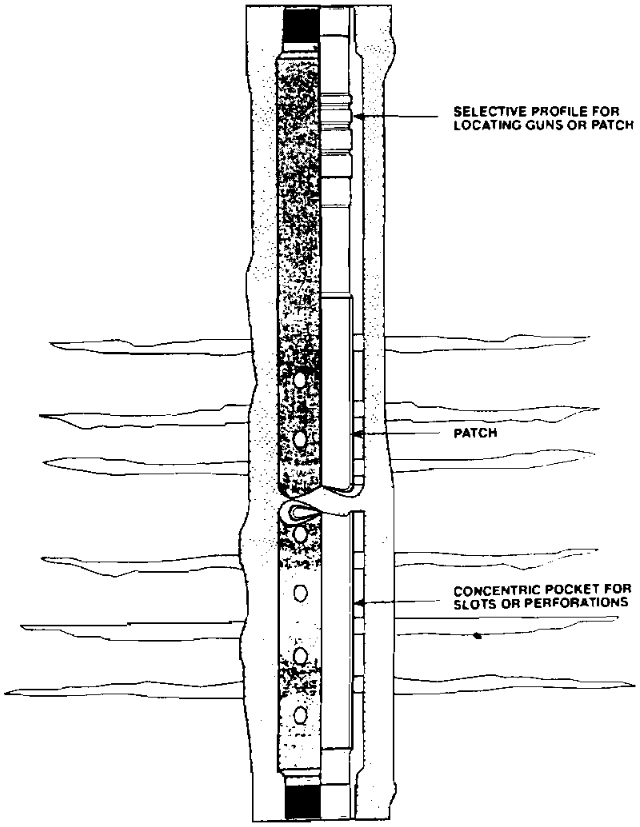

Figure 3-6. Monobore Zonal Isolation Patch (Robison, 1994)

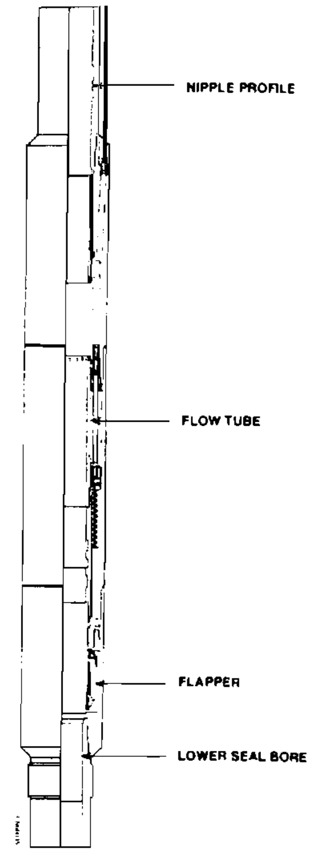

Figure 3-7. Tubing-Retrievable SSSV (Robison, 1994)

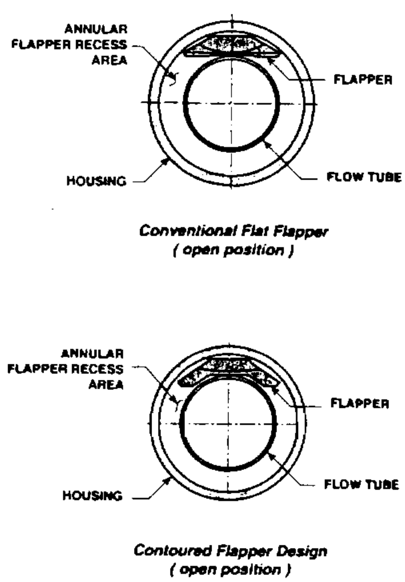

Figure 3-8. Contoured Flapper for Increased Flow Tube ID (Robison, 1994)

Halliburton's approach to increasing the diameter of the flow tube is a contoured flapper valve. This new flapper valve (Figure 3-8) provides additional clearance and permits the use of a larger internal diameter in the flow tube.

The use of nippleless assemblies requires that depth be measured accurately. Mechanical depth measurements for slickline operations have historically attained accuracies in the range of ±30 ft at 10,000 ft. A high-accuracy system (Figure 3-9) increases accuracy to the range of ±5 ft at 10,000 ft. This level of accuracy is comparable to wireline.

With new equipment and assemblies based on new design approaches, previous limitations for slim-hole monobore wells have been reduced.

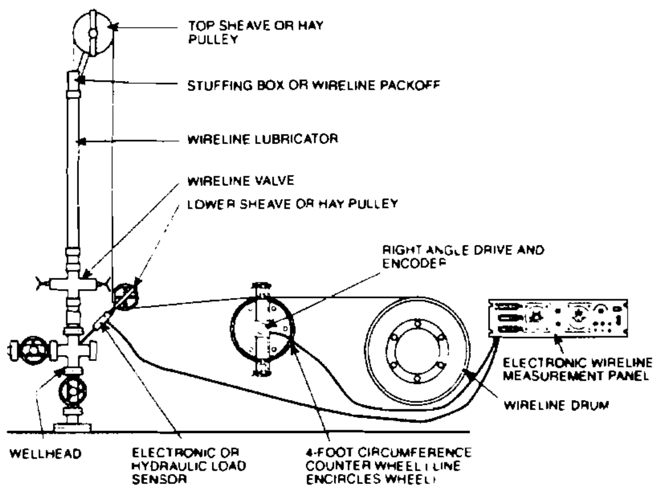

Figure 3-9. Accurate Depth Measurement for Nippleless Locks (Robison, 1994)

3.1.4 Shell Research (Monobore Completions)

Shell Research B.V. (Ross et al., 1992) invested significantly in the development of slim-hole technologies starting in the late 1980s. They saw slim holes as a necessary means to decrease costs in mature areas where unit costs must be reduced to continue increasing producible reserves. Initially, they set their goal as reducing viable wellbore diameters by at least one size. The original efforts were aimed primarily at disposable shallow exploration wells in low-temperature, low-pressure formations.

Before slim-hole drilling technology was improved, Shell saw little cost savings by reducing production casing to less than 7 inches. With the new potential of slim-hole drilling, it was necessary to adopt a new completion philosophy not based on the conventional tubing/packer/tailpipe design.

The monobore completion emerged from this design effort. The primary features of monobore are that the production liner is no larger than the production tubing, and that restrictions to full-wellbore access to the producing zone are absent. This basic design maximizes the potential for effective rigless well intervention.

In many cases, monobore completions contain landing profiles for flow-control devices contrary to the pure definition of monobore. The design goal is to minimize the size of these restrictions. Nippleless completions are another approach to solving this problem. These use flow-control assemblies that are set in the production string with slips.

Shell Research chose the 3½-in. slim monobore (Figure 3-10) as a base case for equipment and tool development. This size was chosen because:

- Production rates of 3000-5000 BOPD or gas rates of up to 50 MMscfd represent a large majority of wells, and 3½-in. tubing is normally suited for these conditions

- A 3½-in. liner is appropriate for use with the 4⅛- to 4¾-in. drilling technology also under development

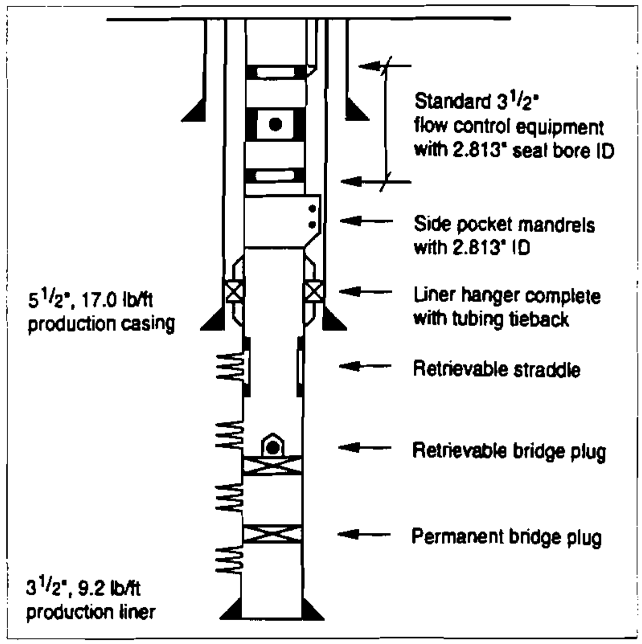

Figure 3-10. 3½-in. Monobore Completion (Ross et al., 1992)

Two standard casing schemes were developed. One includes a 5½-in. production casing and 3½-in. production liner. This design is intended for new wells and includes capacity for standard completion equipment, gas-lift mandrels, etc. in the production casing. The second casing design uses 5-in. production casing with 3½-in. liner set below. This design is directed toward cases where the wellbore is deepened out of 5-in. casing or liners, as is applicable in many areas.

As an integral part of their development of slim-hole technology, an investigation of the impact of slim production strings on production rates was conducted. Their calculations showed that production is often only minimally affected by wellbore diameter. In addition, slim-hole monobore completions offer advantages that serve to offset production impacts of slim holes. For example, Shell's slim-hole drilling system already incorporates most of the equipment needed to drill high-angle or horizontal laterals in the pay zone, so that incremental cost for devited drilling is minimal. Since drilling fluid requirements are reduced, a less damaging fluid can be economic, even though the cost per barrel is greater. Proportionally more can be spent on slim-hole completions than is economic for conventional holes, due to the significant cost savings for drilling. Additionally, the need to kill the well during completion or workovers is significantly less in the monobore.

The effect of bit diameter on wellbore productivity is illustrated in Figure 3-11. Parametric assumptions for these calculations include a drainage radius of 1475 ft, a skin of zero, and steady-state radial flow. These results suggest that the impact of reducing wellbore diameter from 8½ to 4¾ in. is similar to that of reducing diameter from 12¼ to 8½ inches.

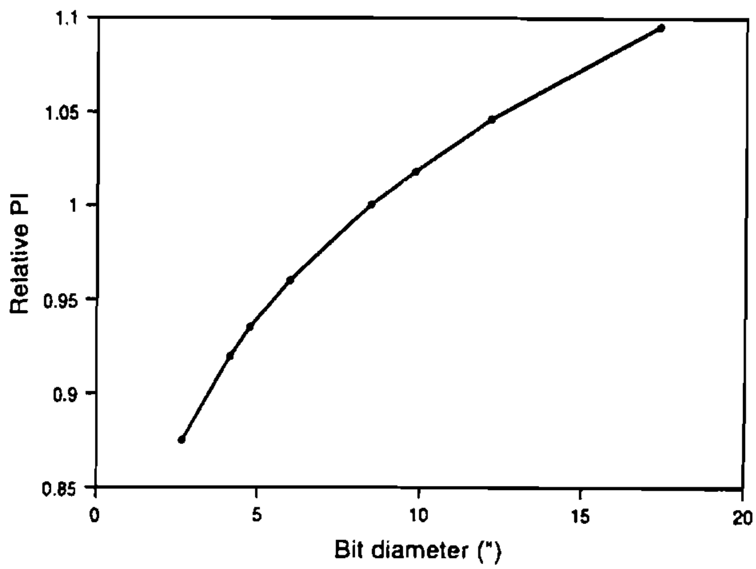

Figure 3-11. Well Productivity Relative to 8½-in. Bore (Ross et al., 1992)

The impact of skin on relative productivity was also investigated (Figure 3-12). The depth of invasion is assumed constant for these data at about 4 inches. The effect of skin on relative productivity is small if a high completion efficiency is achieved, that is, if the ratio of near-wellbore permability (ka) to reservoir permability (ke) is 1 of greater.

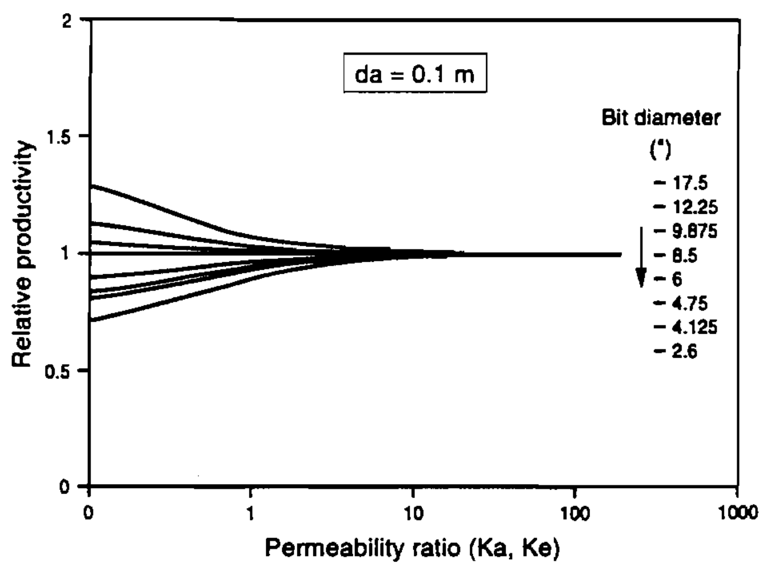

Figure 3-12. Well Productivity Relative to 8½-in. Bore with Skin Damage (Ross et al., 1992)

Shell Research's experience with the 3½-in. monobore completion includes two wells (as of late 1992). Experiences with these wells were encouraging and have led to the evaluation of additional applications for these technologies and designs.

3.2 CASE HISTORIES

3.2.1 ARCO British (Slimming of Horizontal Well Completion)

ARCO British Ltd. (Foster, 1993) described a horizontal well casing program that reduced the number of casing strings from five to four, resulting in savings of $570,000 per well. The well was drilled in the Pickerill gas field in the UK southern North Sea. The overall casing design is similar to other conventional directional wells in the field.

The design was slimmed by removing the 26-in. surface hole and 20-in. casing from the casing program (Figure 3-13). An 8½-in. hole was drilled through the reservoir, as is usual for this area. This large bore is needed to allow the use of LWD steering to find the best reservoir rock.

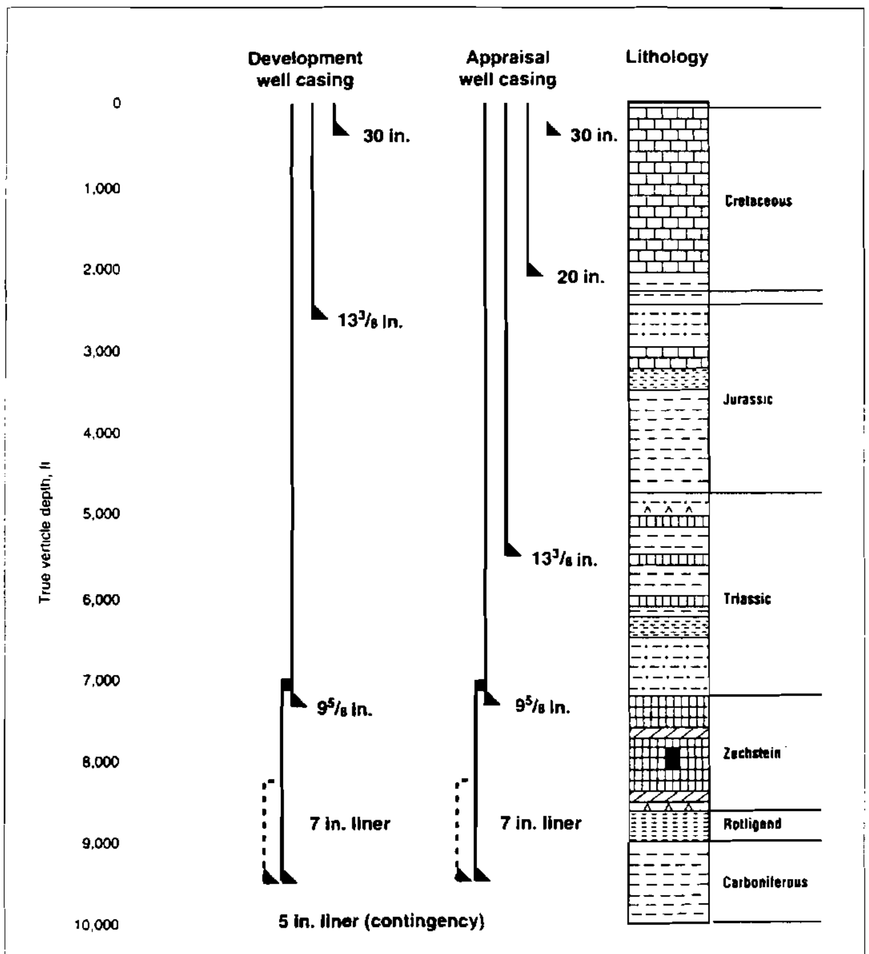

Figure 3-13. Pickerill Field Casing Programs (Foster, 1993)

ARCO stated that the problem with this slimmer casing program is that the contingency options are reduced. The most likely problem is encountering an overpressure in the Zechstein dolomite. The contingency plan is to set the 7-in. liner above the reservoir and finish the hole with a 6-in. hole and 5-in. liner.

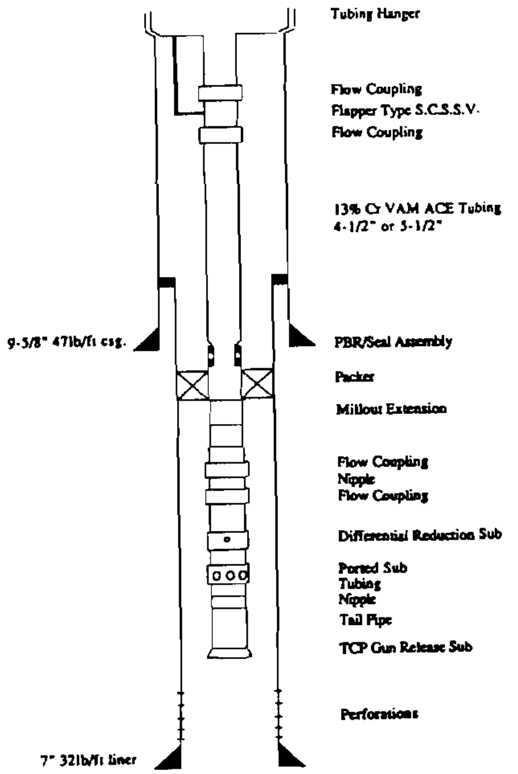

Figure 3-14. Pickerill Field Completion (Foster, 1993)

The completion (Figure 3-14) used components designed for long life, including chrome steel due to high levels of CO_2.

ARCO British's experience with this horizontal well illustrates that important cost savings can be achieved by slimming conventional designs and without compromising safety.

3.2.2 Gulf of Suez Petroleum (Slimmer Casing Offshore)

Gulf of Suez Petroleum Company (Ghazaly and Khalaf, 1993) adopted a slimmer casing program in an exploratory well in the northern Gulf of Suez. Compared to a well completed with the conventional number of casing strings, the slimmer well showed cost savings of 40-50%, amounting to $476,000. Operations also benefited from the smaller volume of oil-wet cuttings generated in the slim well, resulting in lower environmental impact.

A conventional well schematic (center of Figure 3-15) consists of 17½-in. surface hole, 12¼-in. intermediate hole and 8½-in. production hole. The production interval is about 2000 ft in length. Oil-base muds are used in the surface and production holes.

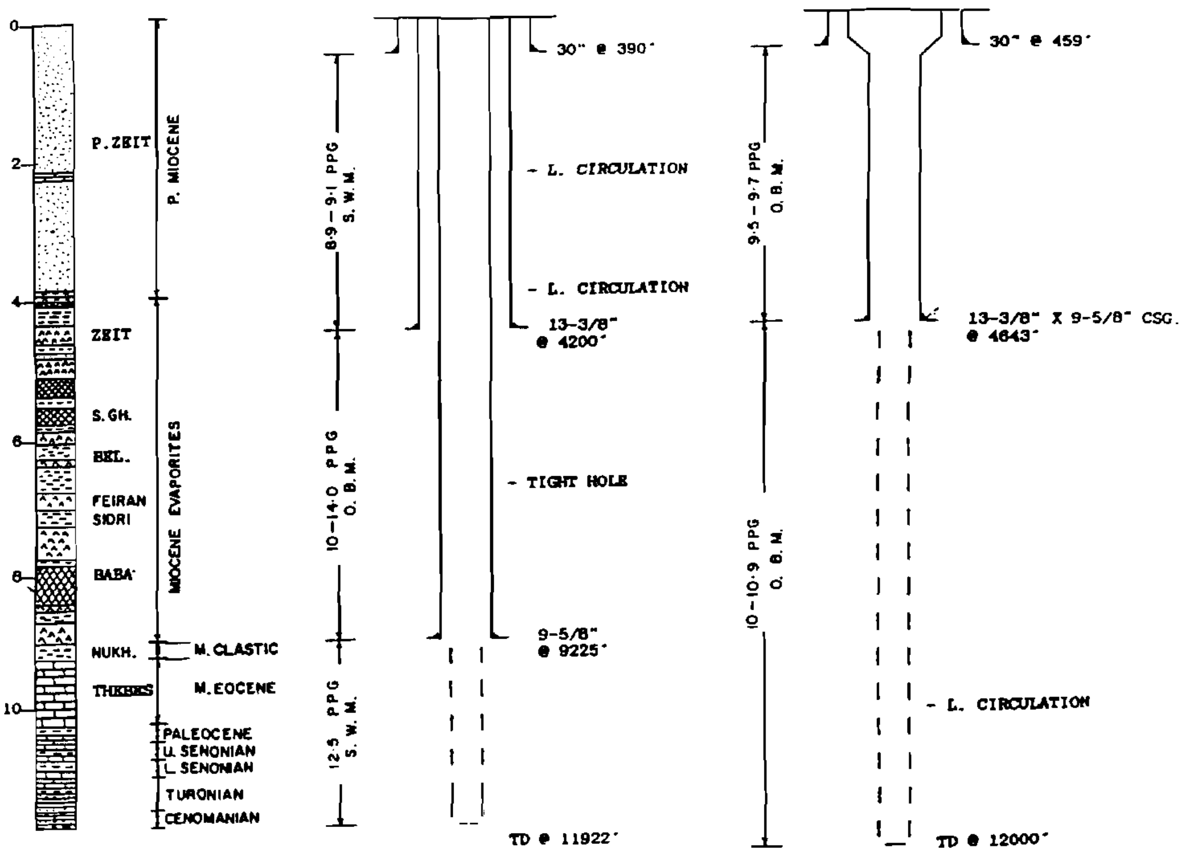

Figure 3-15. Conventional and Slim Well Schematics (Ghazaly and Khalaf, 1993)

A modified slim-hole casing program was adopted for well Tanka-3 (right side of Figure 3-15). The conventional 9⅝-in. casing string was eliminated, and a combination 13⅜- by 9⅝-in. string was run as the surface casing. The production hole was drilled out of the surface string with conventional diameter (8½ in.).

The principal risk associated with the slim program is the lack of contingency hole if an extra string of casing needs to be set in the 8½-in. hole before reaching TD. Gulf of Suez Petroleum Company stated that drilling a 6-in. contingency hole is difficult and very slow. They provided no details on the availability of various 6-in. bits.

Two trouble days were spent on a lost-circulation problem in the 8½-in. section of the slim hole. If conventional intermediate 9⅝-in. casing had been set, the mud weight would have been less and lost circulation probably would not have occurred. The problem was successfully remedied, and the overall cost savings more than offset the trouble.

Additional details of these operations are presented in the Chapter *Drilling Cost and Time.*

3.2.3 *Offshore/Oilman* Staff (Monobore Completions)

The industry's use of monobore completions around the world has increased so that over 200 wells have been completed under this design philosophy (*Offshore/Oilman* Staff, 1993). These wells include both slim and conventional large holes. Operators have found that investments for monobore completions are paid back many times over when workovers are frequently required.

Monobore completions were first used in the North Sea in the late 1980s. Several wells in the Gulf of Mexico and Southeast Asia have also been completed as monobores. Several advantages have accrued to these operators. These advantages were described previously in the first section of this chapter.

Statoil of Norway has recompleted many of the 108 wells in the Statfjord Field as 7-in. monobores (Figure 3-16). Corrosion and leaks have necessitated extensive workover operations in the field.

Statoil has cited several advantages (*Offshore/Oilman* Staff, 1993) to this particular application, including the ease of through-tubing perforation, the use of conventional large tools in through-tubing operations, and the ability to gravel pack through tubing.

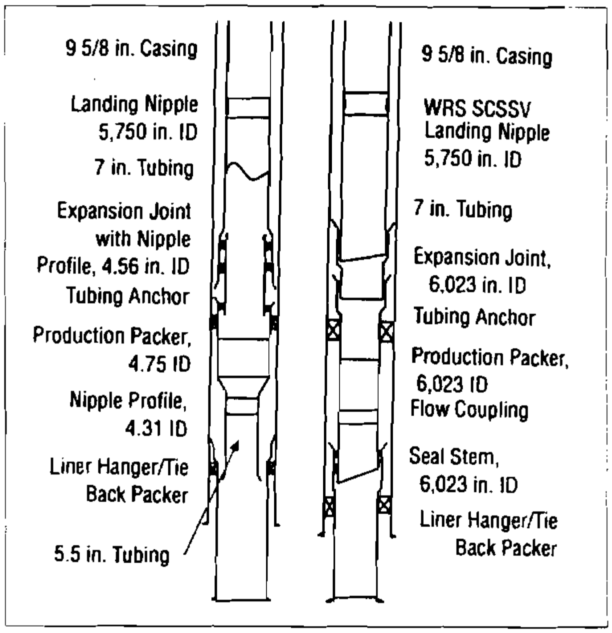

Figure 3-16. Original (left) and Monobore Recompletions in Statfjord Field (*Offshore/Oilman* Staff, 1993)

Mobil also reported success with monobores in the Arun Field offshore Indonesia. These completions may be the largest monobores yet (9⅝ in.). Special advantages cited by Mobil are that these completions eliminate gas turbulence, allow monitoring of tubing and production-casing annulus and liner lap, and allow tubing retrieval to the liner top in the event of corrosion.

3.2.4 OMV A.G. (Gravel Packs)

OMV A.G., an Austrian operator, has successfully gravel packed a number of slim-hole wells (Gollob, 1992). Previously, slim wells were abandoned after sand production began. OMV made several design modifications to the gravel-pack work string. Packs have been installed on several slim wells (Figure 3-17), most of which continue to produce without problems.

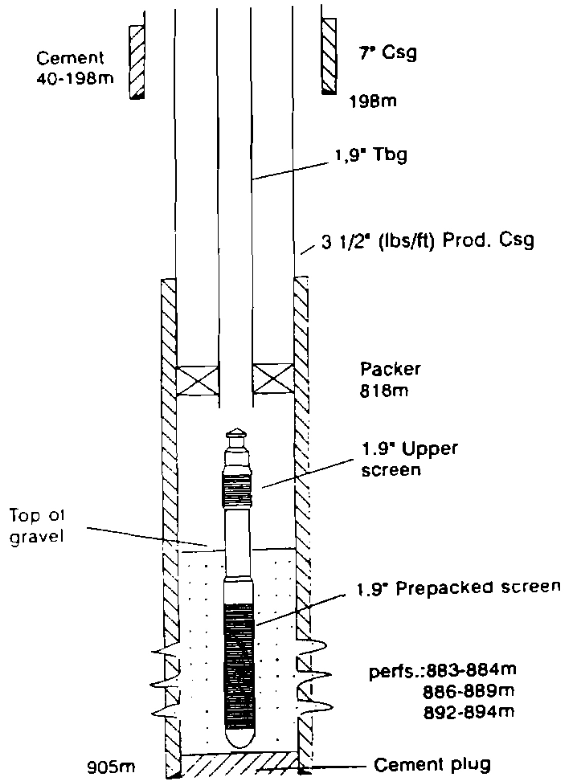

Figure 3-17. OMV Slim-Hole Gravel-Pack Completion (Gollob, 1992)

Their modified design also led to a reduction in pressure drop across the pack. OMV's work is presented in greater detail in the Chapter *Workovers*.

3.2.5 Union Pacific Resources (Dual Tubingless Completions)

Union Pacific Resources Company (UPRC) (Sackeyfio, 1993) described the use of dual tubingless completions to economically produce from low-pressure mature fields. Many domestic oil and gas fields were discovered in the 1930s and 40s and currently have pressures in the range of 150 to 2000 psi. New wells with conventional casing and production tubing are often not economically feasible.

UPRC completed a well in the Stratton Field near Corpus Christi, Texas, with a dual tubingless completion design. Reservoir pressures ranged from 100-1000 psi across the field. UPRC cemented two strings of 2⅞-in. jointed tubing in an 8¾-in. hole (TD of 7412 ft). This design (Figure 3-18) eliminated the cost of 5½-in. intermediate casing.

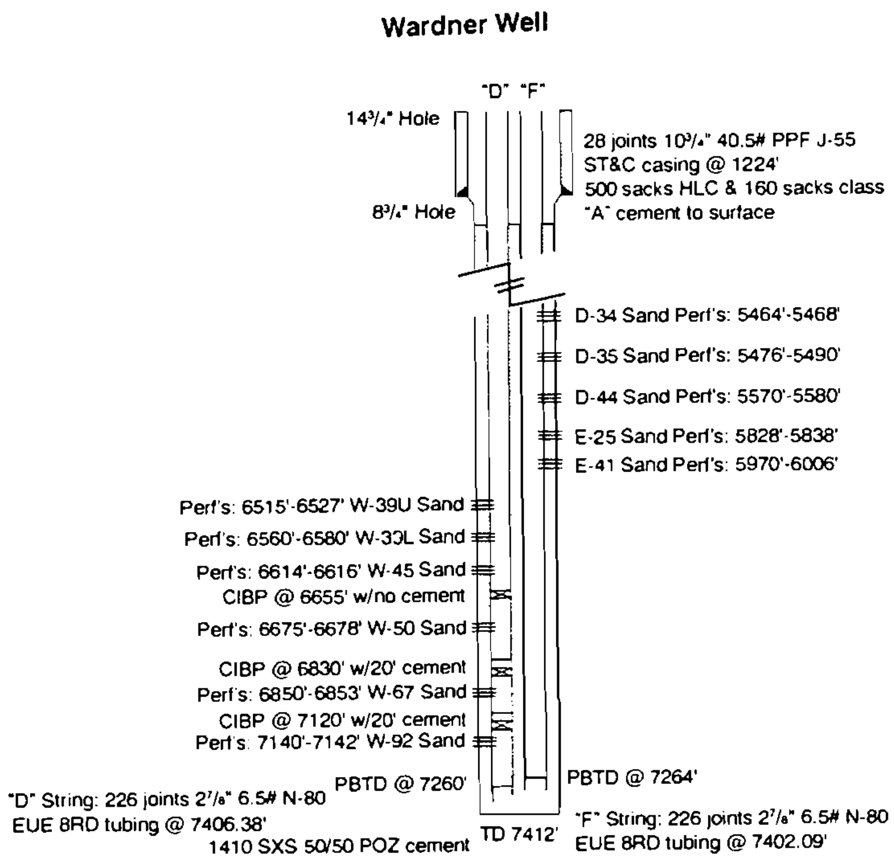

Figure 3-18. Dual Tubingless Completion in Stratton Field (Sackeyfio, 1993)

No production tubing is needed. Consequently, no packers or workover rig are needed to complete the well. A swab unit was used to complete the well at a day rate of $500/day compared to $1500/day for a workover rig. Drilling and completion costs for the well totaled $348,000.

The tubing strings were perforated at zero-degree phasing with a $2^1/_{16}$-in. hollow carrier gun with an electromagnetic orienter. These operations were performed on wireline.

The three lowest sands in the "D" string were not productive. Cast-iron bridge plugs and 20 ft of cement were set to isolate them (see Figure 3-18). The initial production from the "D" string was 110 Mscfd and from the "F" string was 371 Mscfd.

Economic modeling was performed based on an assumed abandonment production rate of 30 Mscfd and a decline rate of 10% per year. This well was expected to pay out in about two years and produce about 1.6 Bcf of gas during its life.

Workover options for this completion include the use of 1½-in. velocity strings, should fluid loading become a problem. The disadvantage of this completion noted by UPRC is that pumpjacks can't be used because of lack of availability of slim rods. Gas lifting is not a problem, however.

3.3 REFERENCES

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4. Coring Systems

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4. Coring Systems

4.1 AMOCO PRODUCTION COMPANY (AUTOMATED CORE EVALUATION)

Amoco Production Company (Spain et al., 1992) developed an automated core evaluation system for analyzing continuous slim-hole cores as part of their SHADS (Stratigraphic High-speed Automatic Drilling System) development project. Dealing with the large volumes of core generated and obtaining results in near real-time at the site are the principal benefits of this approach.

Amoco's core evaluation system is transported in eight 8 x 12-ft aluminum modules (Figure 4-1). Site set-up is accomplished by crane or forklift.

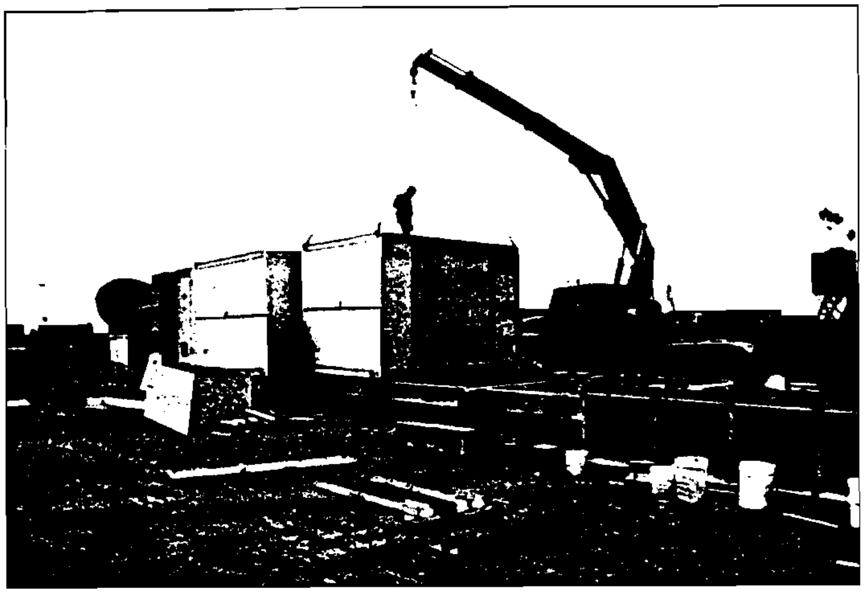


Figure 4-1. Amoco Core Evaluation Modules (Spain et al., 1992)

Cores are evaluated by inverse logging techniques, that is, moving the core past the logging instruments. Measurements made on the core (Figure 4-2) include gamma ray, magnetic susceptibility, ultraviolet fluorescence, nuclear magnetic resonance porosity, infrared mineralogy, and pyrolysis. Images of the core are recorded continuously by a video-disk recorder.

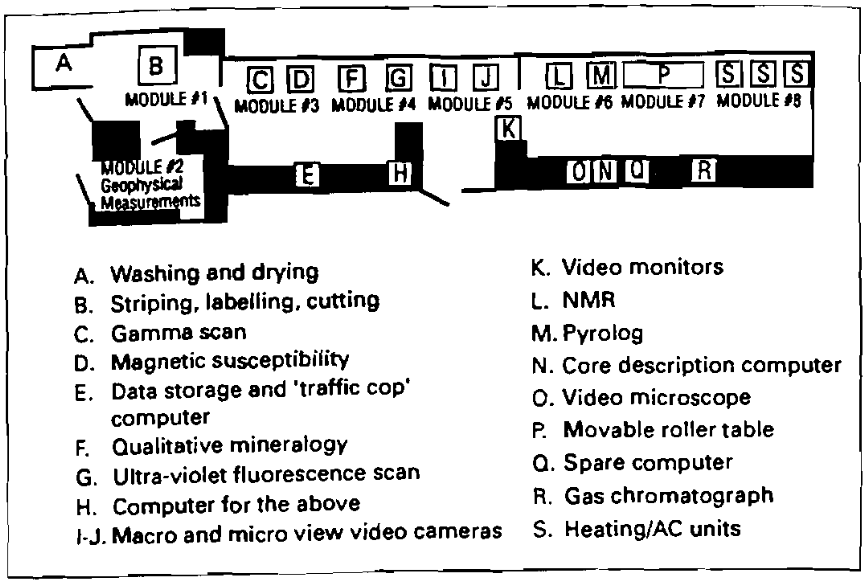


Figure 4-2. Amoco Core Evaluation System (Spain et al., 1992)

A core conveyor line continuous passes core through the evaluation modules. Four independent sections are driven by four controllers that control core speed and pass data to the central computer (Figure 4-3).

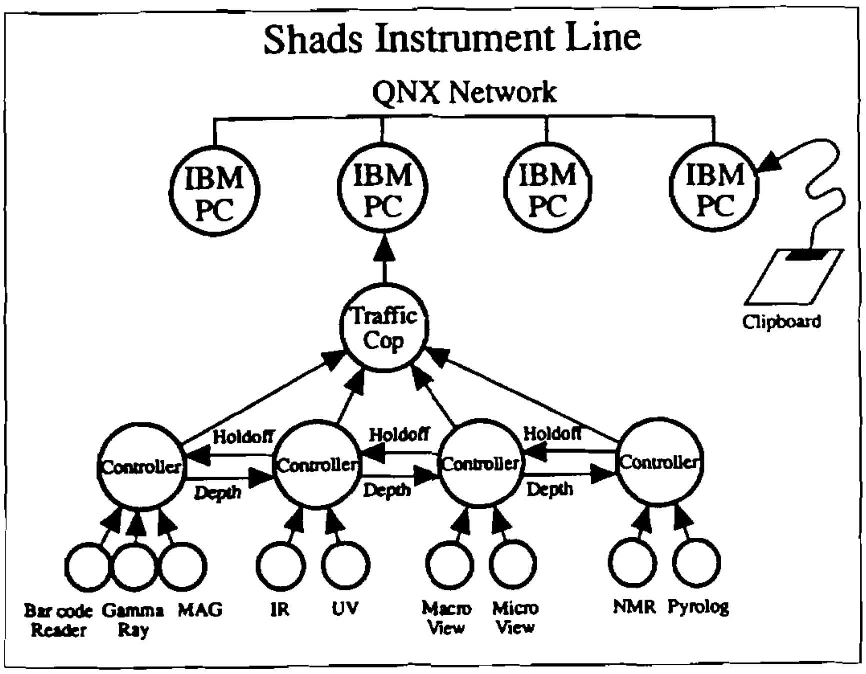


Figure 4-3. Core Evaluation Control System (Spain et al., 1992)

Gamma-ray measurements are useful for depth correlation and for determining stratigraphic profiles and shale content. A SHADS gamma-ray log is compared to a conventional downhole log in Figure 4-4.

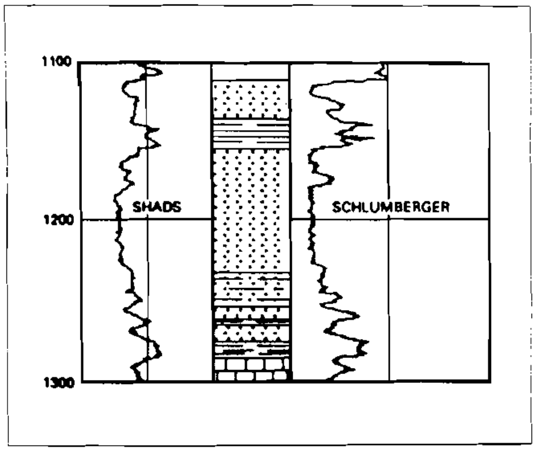


Figure 4-4. Gamma-Ray Comparison (Spain et al., 1992)

Magnetic susceptibility is measured at 3-in. intervals. These data are used to correlate with aeromagnetic surveys, taking advantage of the magnetic response of igneous rocks (Figure 4-5).

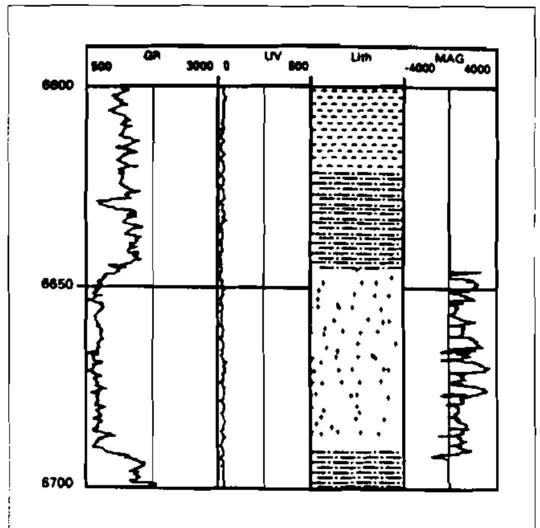


Figure 4-5. SHADS Magnetic Susceptibility Log (Spain et al., 1992)

Ultraviolet fluorescence is measured to detect and evaluate hydrocarbon shows in the core. An ultraviolet fluorescence log from an oil and gas bearing zone (Lower Skinner in Rogers County, Oklahoma) is shown in Figure 4-6.

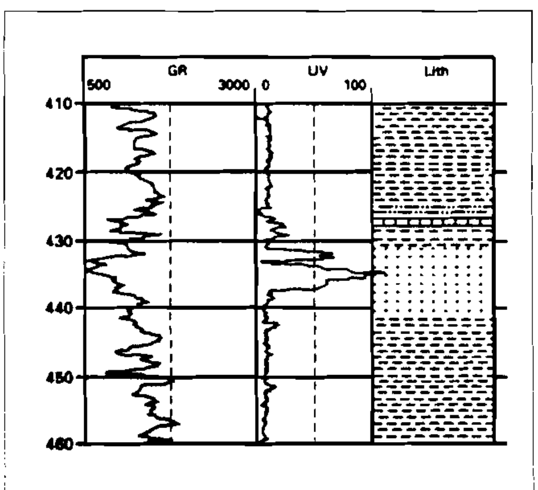


Figure 4-6. SHADS Ultraviolet Fluorescence Log (Spain et al., 1992)

The user's work station provides access to video images and other descriptive data. The equipment includes a computer, video-disk player, video monitor, and video copier. Conventional logs can be generated of all recorded data. An example of a lithology strip printout is shown in Figure 4-7.

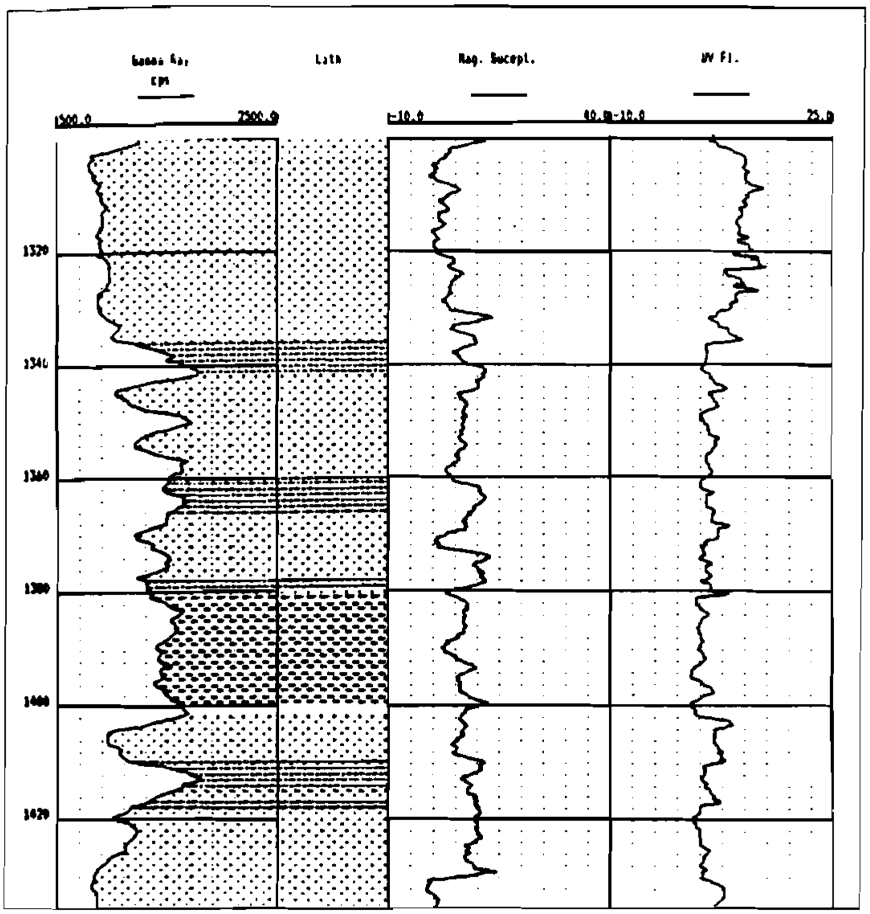


Figure 4-7. SHADS Lithology Log (Spain et al., 1992)

Additional capabilities Amoco plans to add to the system include the ability to obtain oriented cores and thermal conductivity measurements.

4.2 ASAMERA SOUTH SUMATRA LTD. (SUMATRAN CASE HISTORY)

Asamera South Sumatra Ltd. (Almendingen et al., 1992) drilled and cored five exploratory wells in remote locations in South Sumatra (Figure 4-8). Conventional drilling procedures were not feasible for this campaign due to the excessive time required to construct access roads and high overall estimated costs. A slim-hole mining approach based on helicopter transport was used to evaluate the subject acreage.

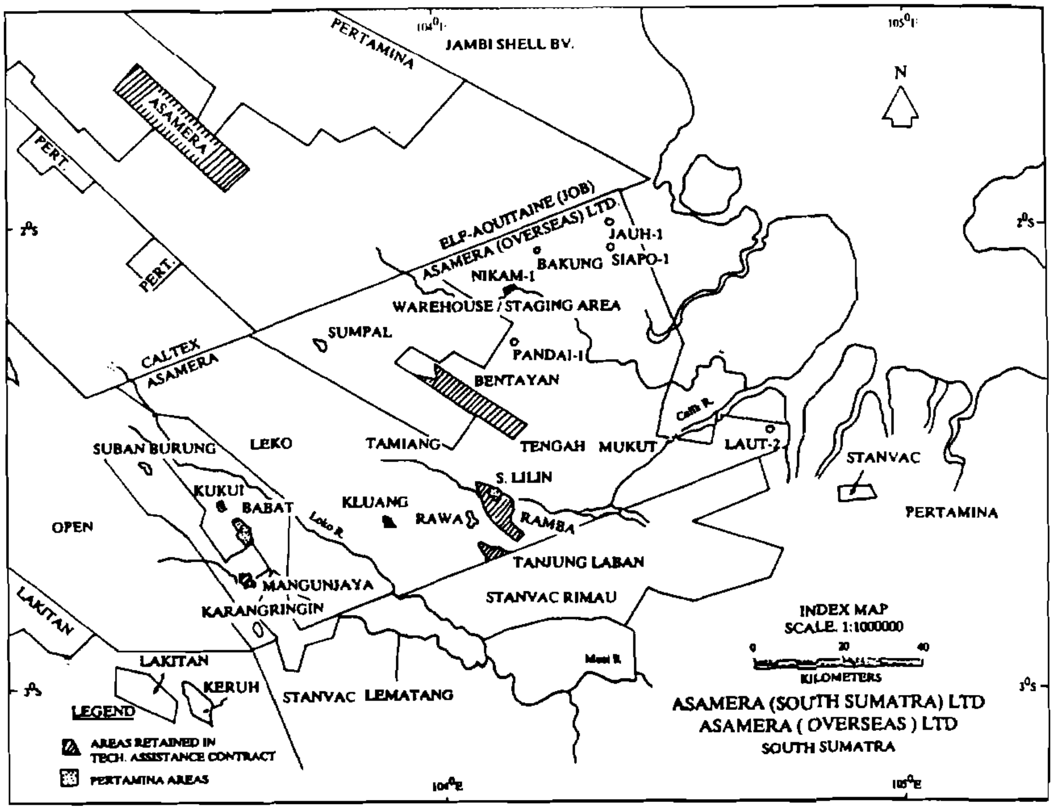


Figure 4-8. Slim Hole Locations in South Sumatra (Almendingen et al., 1992)

Major equipment included a Longyear HM 55 helirig and Bell 205 helicopter. No serious operational problems were encountered during the five-well project. One instance of differential pipe sticking was remedied by circulating a diesel pill and reducing mud weight. All wells were plugged and abandoned after formation evaluation.

Asamera found that slim-hole drilling offered considerable advantages for this program. The most important advantage was the elimination of the need to build access roads to the sites. Roads construction and site preparation for one typical well would have required up to 220 days. Roads were not needed for the slim helirig program.

The other important advantage of slim-hole drilling was cost savings (Table 4-1). Costs were about 37% less than with conventional road-based technology.

TABLE 4-1. Asamera Project Costs for Five Wells (Almendingen et al., 1992)

	ESTIMATED (THOUSANDS)		ACTUAL
	ASAMERA CONVENTIONAL DRILLING	SLIM-HOLE DRILLING P&A AFE	SLIM-HOLE DRILLING
Location & Access	7,874	3,007	2,460
Tangibles	215	178	85
Drilling	1,435	2,723	3,253
Completion	0	0	165
TOTAL COST	9,524	5,908	5,963

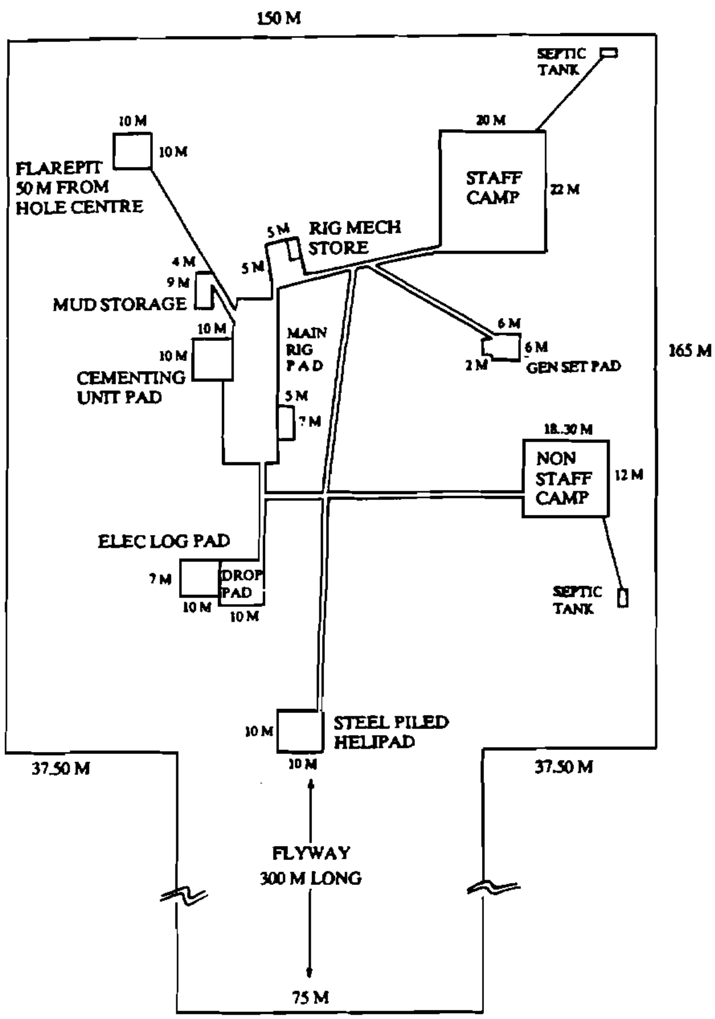


Figure 4-9. Location Layout in South Sumatra (Almendingen et al., 1992)

A typical location layout (Figure 4-9) was 150 x 165 m (492 x 541 ft) for rig and camp facilities. All equipment and materials were flown in. Eighty-three loads were required for the rig; another 60 loads were required for the fluids, tubulars, cement, and service company equipment. Only three days were required to rig down, move to the next site and rig up.

The first two slim-hole wells were shallow (about 250 m; 820 ft). Production casing of 2⅜-in. OD was cemented in the hole (Figure 4-10).

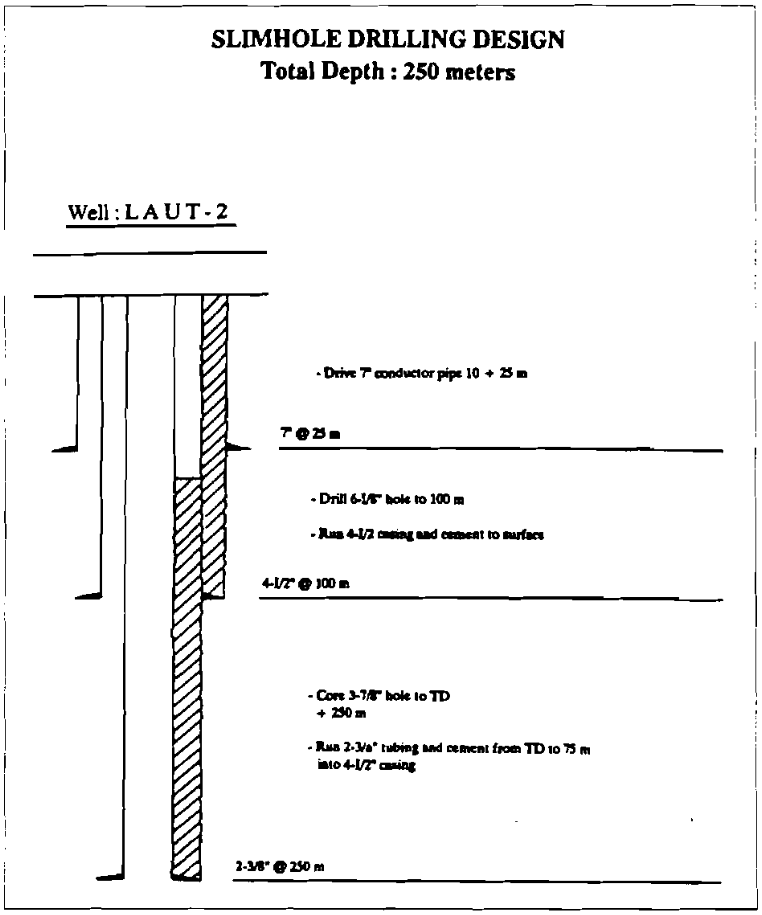


Figure 4-10. Slim-Hole Casing Program for Shallow Wells (Almendingen et al., 1992)

The final three wells were deeper (about 1080 m; 3543 ft) and required an additional string of casing (Figure 4-11).

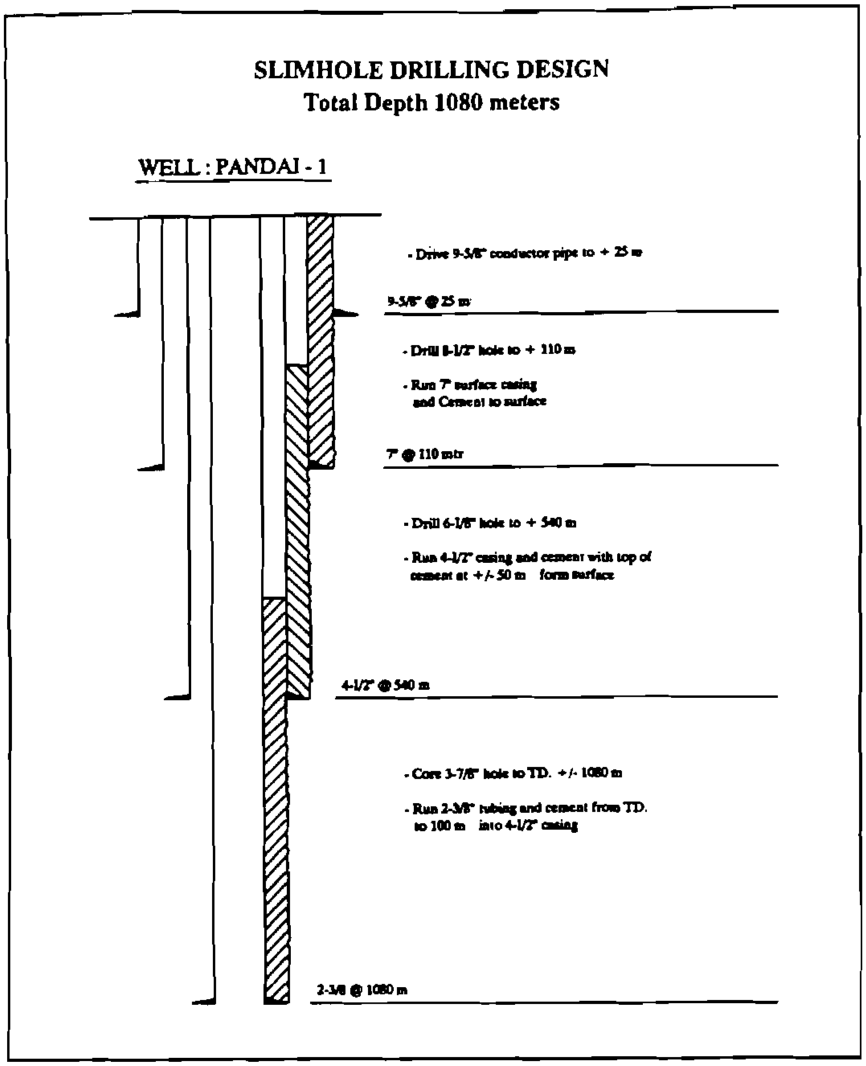


Figure 4-11. Slim-Hole Casing Program for Deeper Wells (Almendingen et al., 1992)

For all five wells, the 4½-in. casing strings were set at one-half of TD. Destructive drilling using CHD-101 drill rods was used to drill down to the 4½-in. set point. Continuous coring was used thereafter to TD. A summary of the complete drilling program for the final well is shown in Figure 4-12.

ASAMERA (OVERSEAS) LTD DRILLING PROGRAM SUMMARY	WELL NO : PANDAI-1 TYPE WELL : EXPLORATION T.D : 1080 M RIG NO : MINTEX SLIM HOLE	LAT : 002°15'04.10" S LONG. 104°11'01.15" E KBE : 21.0 M (EST.) GLE : 13.6 M (EST.)	X = 409 330.9 E Y = 9751 174.6 N

FORMATION	CASING	BITS	CEMENT	MUD PROGRAM	LOGGING PROGRAM
	DRIVE 9-5/8" CSG 25 M	NONE	NONE		
LOWER PALEMBANG	7" CSG AT 110 M	8-1/2"	PRE-FLUSH : 5 BBL MUD FLUSH CEMENT SLURRY 40 SX CLASS 'G' + 2% PF GEL + 2.0% CACL2 SLURRY DENSITY : 13.8 PPG SLURRY YIELD : 1.50 CF/SX MIX WATER : 8.22 gal/sx FRESH WATER TOP OF CEMENT : SURFACE EXCESS : CALIPER + 30%	PW/NATIVE CLAY WITH ADDITIONS OF BENTONITE AND CAUSTIC SODA IF REQUIRED FOR RHEOLOGY CONTROL MW : 8.5 - 9.2 PPG VISC : 30 - 45 SEC FL : N/C PH : 9.5	NO LOGS
	4-1/2" CSG AT 540 M	6-1/8"	PRE-FLUSH : 8 BBL MUD FLUSH CEMENT SLURRY 115 SX CLASS 'G' + 2% PH GEL + 1.5% CACL2 SLURRY DENSITY : 13.8 PPG SLURRY YIELD : 1.50 CF/SX MIX WATER : 8.22 gal/sx FRESH WATER TOP OF CEMENT : SURFACE EXCESS : CALIPER + 15%	FRESH WATER, GEL, POLYMER, CMC-LV, SPERSENE AND CAUSTIC SODA MW : 8.9 - 9.4 PPG VISC : 30 - 45 FL : 8 - 10 CC PH : 9.5	- IEL-SHS/SP/GR (GR TO SURFACE) - CNS-SHS/CDL-SHS/GR/CAL - SONIC-SHS/GR
TELISA MARKER 671 M BRF 892 M PENDOPO 923 M TAF 978 M BASEMENT 1050 M	2-3/8" CSG AT 1080 M	3-7/8"	PRE-FLUSH : 5 BBL MUD FLUSH CEMENT SLURRY 130 SX CLASS "G" + 20 GAL/10 BBL HALLAD-322L + 5 GAL/10 BBL CFR-3L SLURRY DENSITY : 15.8 PPG SLURRY YIELD : 1.15 CF/SX MIX WATER : 5 gal/sx FRESH WATER TOP OF CEMENT : ± 350 M FROM SURFACE EXCESS : CALIPER + 15%	POLYPLUS - K POLYPLUS AS PRIMARY VISCOSIFIER, POLYSAL TO CONTROL FLUID LOSS AND FILTER CAKE POLYPAC TO CONTROL FLUID LOSS AND VISCOSITY BRINE TYPE : KCL WITH ADDITIONS OF NACL FOR MUD WEIGHT CONTROL MW : 9.2 - 9.6 PPG VISC : 30 - 40 SEC FL : 6 - 8 ml PH : 9.0 KCL : 3% SOLIDS : "NO SOLIDS" DRILLING FLUID MAX. 2% (VDL)	- IEL-SHS/SP/GR - CNS-SHS/CDL-SHS/GR/CAL - SONIC-SHS/GR - VELOCITY SURVEY (SSL-SHS GEOPHONE)
TD 1080 M					

Figure 4-12. Drilling Program for Final Well (Almendingen et al., 1992)

A low-solids drilling fluid was used in the cored 3⅞-in. hole to minimize cake build-up inside the drill rod. KCl, NaCl and $CaCl_2$ were used to weight the fluid. Small amounts of bentonite were added to ensure a thin, tough filter cake.

Coring operations were performed with rotary speeds ranging from 300 to 450 rpm. Annular clearance between the drill rod and open hole was $^{3}/_{16}$ inches.

Location construction, drilling and evaluation of the five wells were completed in 27 weeks. Asamera was very pleased with the speed and low cost with which the project was conducted.

4.3 BP EXPLORATION (BP/STATOIL/EXLOG PARTNERSHIP)

BP Exploration Operating Company, Statoil A/S, and EXLOG (Murray et al., 1993) formed a strategic alliance to develop an integrated slim-hole coring and core-analysis system. A helicopter-transportable rig was developed, including an automatic kick-detection system. Continuous on-site core analysis was successfully implemented. All these concepts were evaluated in a series of field trials in a four-well exploration program.

BP identified slim-hole coring technology as an important component in its exploration strategy for the 1990s. A multidisciplined team (Figure 4-13) was formed within BP Exploration to promote slim-hole technology within BP's operations. Their review of the technology pointed to barriers, including core logging services and kick-detection technologies. Although early kick-detection models existed, none was available on the market that suited BP's needs.

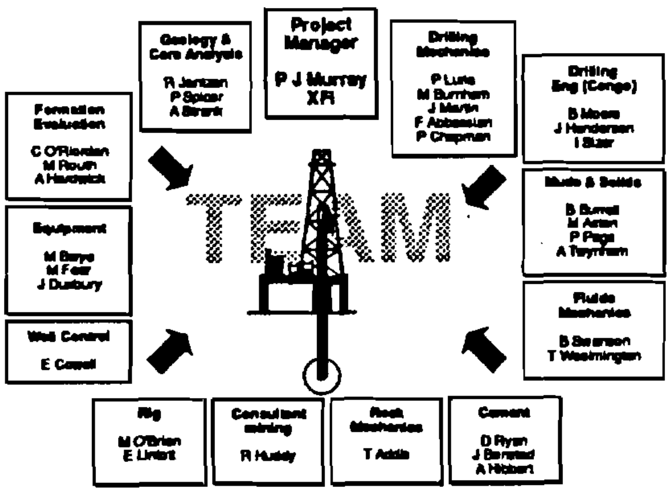


Figure 4-13. BP Slim-Hole Evaluation Team (Murray et al., 1993)

BP considered three options for overcoming existing slim-hole barriers:

1. Work with Amoco to adapt their SHADS technology for BP's use
2. Modify an existing large-hole kick-detection system already in use in the North Sea
3. Work in an alliance with service companies to develop the required technologies

BP chose to pursue the third option. In 1991, Statoil and BP joined to develop core logging capability. Soon thereafter, EXLOG and BP worked on modifying an existing BP fluids model to perform early kick detection in slim-hole wells. BP and Statoil contributed major funding and technical knowledge; Statoil contributed experience with automated miniparameter measurements; EXLOG contributed construction capability, onsite data management, well-site delivery, staff and service.

EXLOG investigated the potential for using an existing kick-detection model developed by Shell and Eastman Teleco (see the Chapter *Well Control*). However, the model was proprietary and not available for BP's use. Instead, EXLOG began with an existing BP Research wellbore fluids research model, upgrading it to work with slim holes.

The EKD (Early Kick Detection) system predicts return mud flow rate and compares it to measured return rate (Figure 4-14). Data required include mud properties, hole geometry, drill-string description, BHA description, flow rates, pressures and operational status (drilling, tripping, coring, etc.).

The sensor data flow is shown schematically in Figure 4-15.

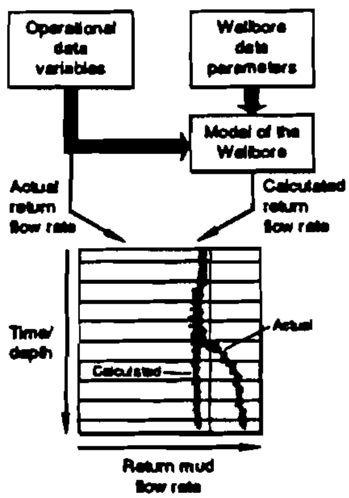


Figure 4-14. Schematic of EKD System (Murray et al., 1993)

The BP/ Statoil/EXLOG slim-hole system was first tested on a four-well program starting in early 1992. Early results were reviewed to guide techniques and procedures in later wells. A hybrid coring/drilling approach was used, with coring being initiated above the source interval.

A new type of core bit was used on the third well, resulting in improved ROPs that often exceeded ROPs expected for destructive drilling. Cores were retrieved and immediately transferred to the logging unit (Figure 4-14). The maximum throughput

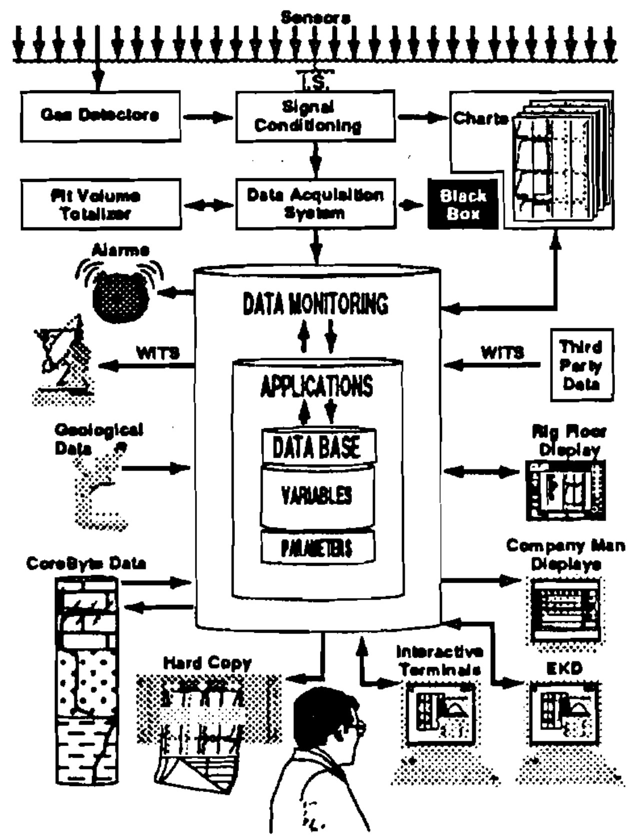


Figure 4-15. Well-Site Data Acquisition and Flow (Murray et al., 1993)

established for the core logging unit was about 216 m/day (700 ft/day). Net ROP in the hole was less than the core logging unit's capacity.

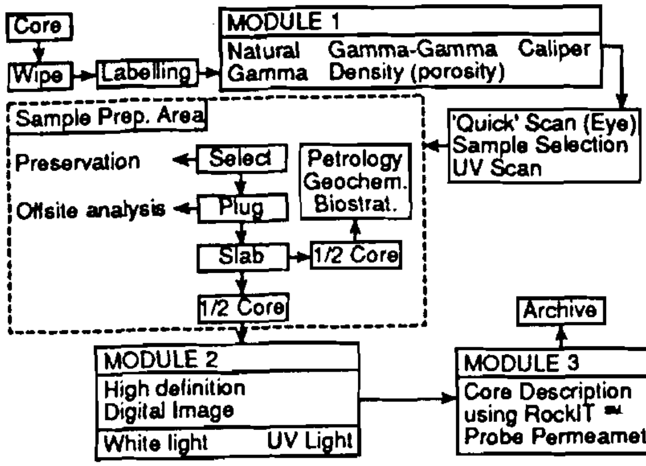


Figure 4-16. Core Data Analysis (Murray et al., 1993)

No kicks occurred during field operations in this campaign. Experience with fluid loss measurements showed that the desired system sensitivity of 1 bbl was attained. This high sensitivity allowed rapid response to fluid-loss episodes.

Overall cost savings were greater than 40%. The slim-hole alliance was found to be a successful, efficient approach. BP plans to continue pursuing this approach for exploration.

4.4 BP EXPLORATION VENEZUELA LTD. (DRILL-STRING VIBRATION)

BP Exploration Venezuela Ltd. (Murray et al., 1994) successfully analyzed and corrected severe vibration problems on a new slim-hole rig. These problems, which resulted in catastrophic failure of the drill string, appeared early in a ten-well exploration project in Western Venezuela for Maraven. After extensive redesign of the BHA, the project was continued with significantly improved performance.

A new hybrid coring system was developed by Nabors-Loffland and put to work in Venezuela in 1992. The technology is similar to mining coring systems, although with a variety of improvements for oilfield operations. The coring components are shown in Figure 4-17. Wireline retrievable core barrels speed the process, as with similar systems. Additional description of the rig is presented in Section 4.7.

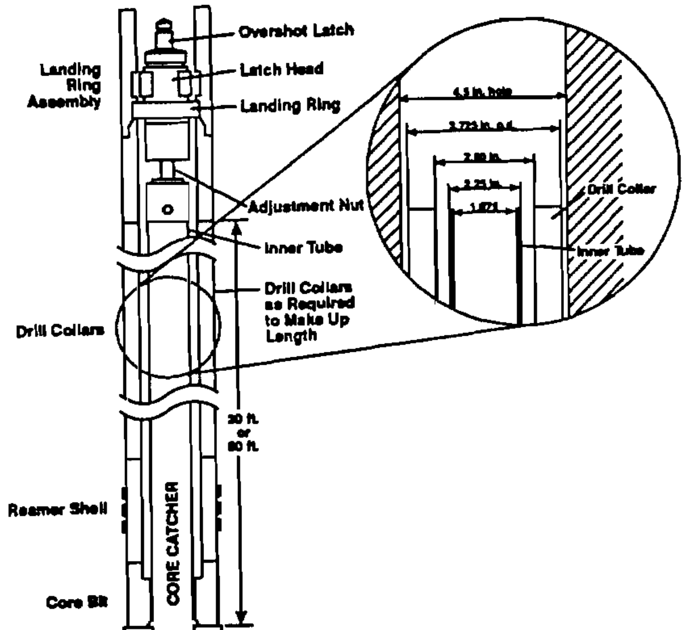


Figure 4-17. Coring Assembly for Nabors-Loffland Rig (Murray et al., 1994)

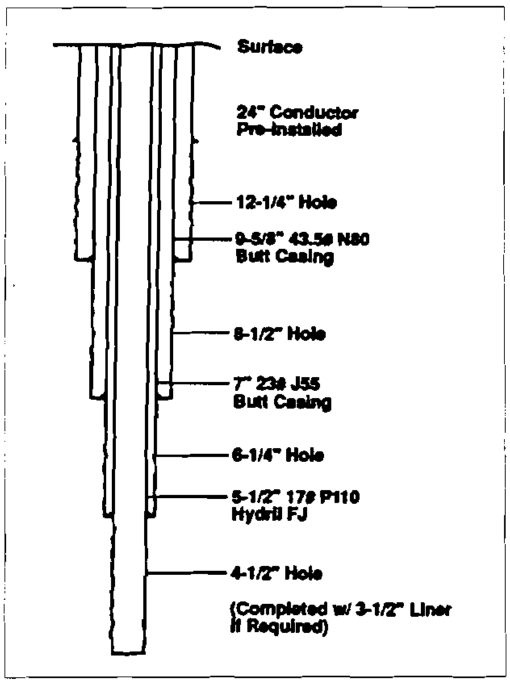


Figure 4-18. Typical Wellbore Schematic (Murray et al., 1994)

A typical wellbore schematic for the Venezuelan program is shown in Figure 4-18. In one well, slim-hole coring was initiated out of 5½-in. casing at 6000 ft. Core-bit diameter was 4½ inches. A special newly developed coring string was used (Table 4-2).

TABLE 4-2. Design of Coring String (Murray et al., 1994)

Hole Size	4.5"	114 mm
Core	1.75"	44.5 mm
D.C. OD	3.725"	94.6 mm
D.C. ID	2.600"	66.0 mm
D. Pipe OD (T/Joint)	3.725"	94.6 mm
D. Pipe OD (Body)	3.100"	78.7 mm
D. Pipe ID (T/Joint)	2.600"	66.0 mm
D. Pipe ID (Body)	2.700"	68.6 mm
Weight / ft. Pipe	9.55 lb/ft.	14.21 kg/m
Weight / ft. D.C.	18.98 lb/ft.	28.24 kg/m
Torque Operating	4141 ft. lb	
Make Up	5000 ft. lb	
Max	11500 ft. lb	
Pull Yield	206,250 lbf	
Max Tensile	237,187 lbf	

A series of BHAs were run into the well as 1) a vibration problem developed, 2) modified assemblies were run in to (unsuccessfully) combat the problem, and finally, 3) the problem was solved with a significantly modified BHA.

The first BHA (BHA 1 in Figure 4-19) had a core head and near-bit stabilizer. After drilling 238 ft, BHA 1 was pulled due to an increase in wellbore inclination. BHA 2 was run with stiffened components. Angle held for about 300 ft, then began to increase again. BHA 3 had no near-bit stabilizer, and was designed to allow the angle to drop. Over a run of 369 ft, inclination was brought from 14° down to 12°.

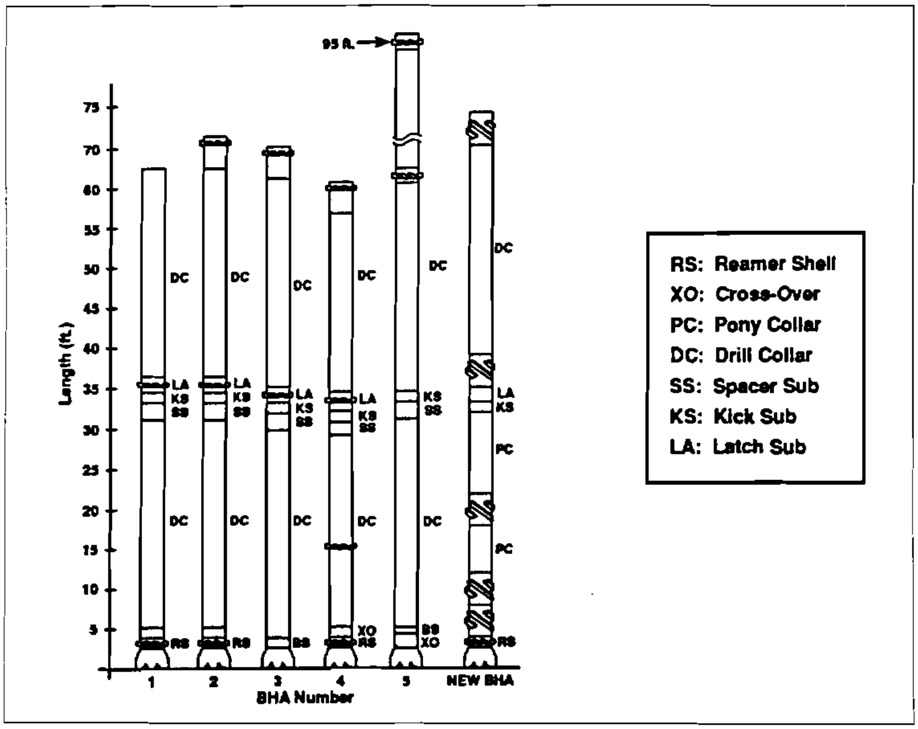


Figure 4-19. BHAs for Coring (Murray et al., 1994)

BHA 4 included additional stabilizers at the bit and at 15, 30 and 60 ft. Serious problems began to develop with BHA 4. It twisted off at the stabilizer at 30 ft. After BHA 4 was fished, BHA 5 was run with stabilizers at 60 and 90 ft. It too failed at the 30-ft position. Observations made on the rig floor during these runs included periods of extreme vibration of the drill string, broken connections at 30 ft above the bit, eccentric wear on tool joints, and excessive wear of the stabilizers.

After BHA 5 was removed, a caliper log was run of the cored section (Figure 4-20). The hole was shown to have several sections significantly out of gauge.

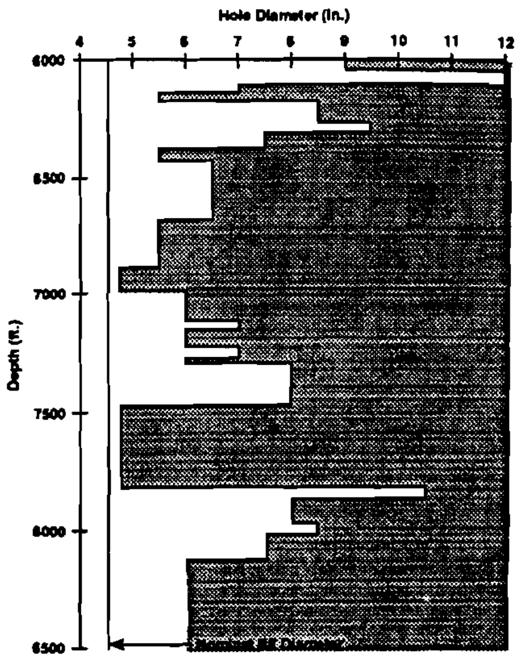


Figure 4-20. Caliper Log of Cored Hole
(Murray et al., 1994)

An extensive modeling study was conducted to determine the cause of these problems and to develop solutions. A vibration modal analysis (Figure 4-21) showed that the failures occurred about 30 ft behind the bit in a zone where lateral displacement of the assembly is at a maximum. High side forces across the stabilizers caused them to cut into the hole wall, contributing to the over-gauge hole. This combination of factors led to a bowed BHA in an enlarged hole and rapid fatigue.

BP's experience with drill-string design for a well in Africa was used to develop a new BHA for the Venezuelan wells ("New BHA" in Figure 4-19). Modeling runs showed the new BHA to be much stiffer, making first contact with the hole wall at 94 ft (Figure 4-22).

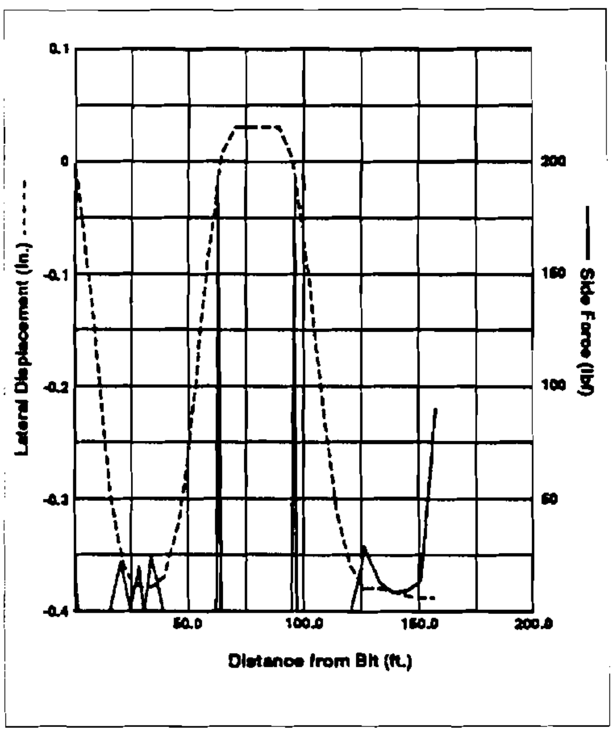


Figure 4-21. Vibration Modeling of BHA 5
(Murray et al., 1994)

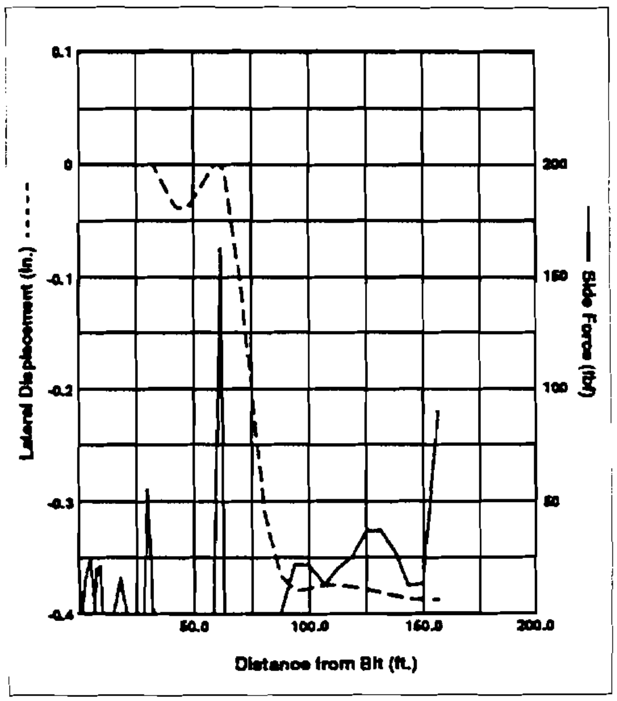


Figure 4-22. Vibration Modeling of New BHA
(Murray et al., 1994)

The rig was outfitted with vibration sensors so that the effects of the new BHA design could be proven. Several field tests were performed using nonrotating sensors. Results showed that the new BHA was not prone to catastrophic lateral resonances.

The project team also determined that analysis and interpretation of surface vibration data were very useful for ensuring that any potential resonant tendencies were not excited. Several phenomena were observed as they affected the vibration measured at surface. Core jamming impacted axial acceleration (Figure 4-23). Jamming would manifest as a drop in the peak at string rotational speed (250 rpm for this case) and an increase at twice rotational speed. The waterfall curves show that jamming was a persistent problem throughout the period these data were recorded.

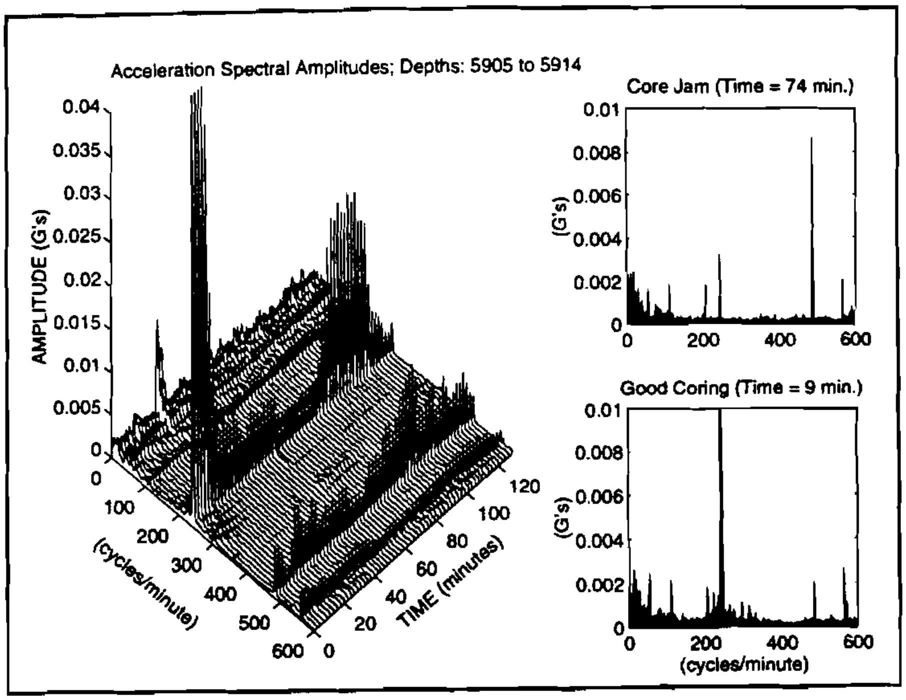


Figure 4-23. Acceleration Spectra for Core Jamming (Murray et al., 1994)

The data in Figure 4-24 correspond to bit bounce. The curve at the bottom is axial acceleration for 10 seconds of bounce. The spectrogram shows spikes in acceleration at multiples of ½(rpm).

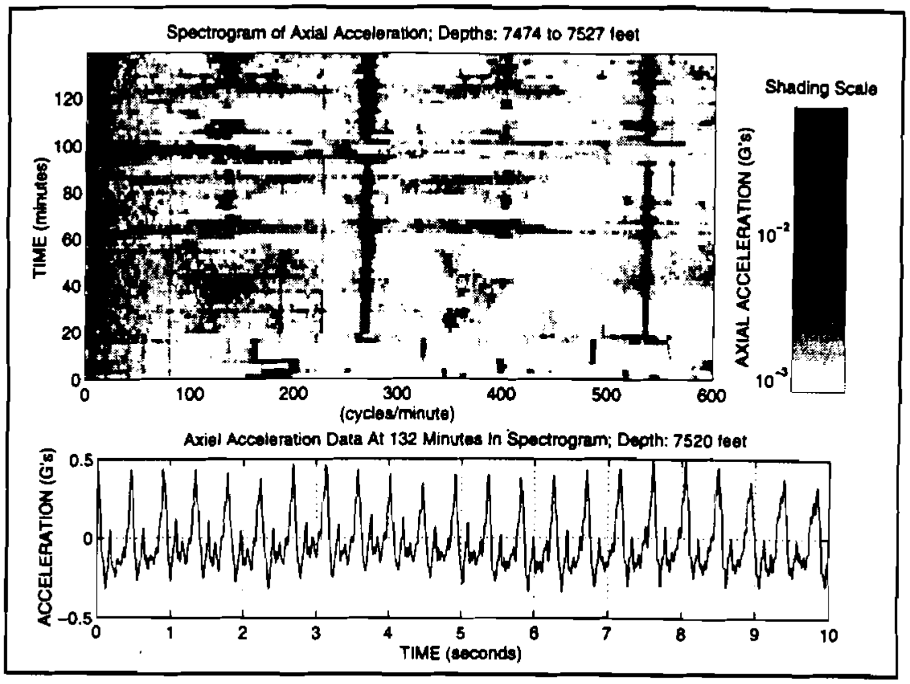


Figure 4-24. Acceleration Spectra for Bit Bounce (Murray et al., 1994)

Experiences by the project members showed the critical need to understand the limitations of slim-hole coring strings regarding WOB and rotary speed. The improved BHA was successfully run in additional wells, breaking world records for 4½-in. hole.

4.5 FORASOL/FORAMER (EUROSLIM PROJECT)

Forasol/Foramer and DB Stratabit (Dupuis and Fanuel, 1993) reported the development of a new slim-hole rotary rig for the Euroslim joint-industry project. A primary objective of the project was to design a rotary system that would drill slim holes at conventional penetration rates. Drilling small holes conventionally often resulted in significantly reduced ROPs. Devising a solution to this problem was considered as essential to obtain the promised benefits of slim-hole technology.

A new rig was designed based on rotary technology. Obtaining a continuous core was not an objective of the design. One drill string was designed for 8½- to 4¾-in. holes; another string was designed for 4- to 3-in. holes. Rotary speeds were set at a maximum of about 300 rpm to avoid major problems with centrifuging drilling fluid inside the drill string.

Tool joints were external upset and friction welded on a flush body. Low conicity of the threads (about 1°) is used to optimize the strength of the joint. Drill collars are flush both internally and externally, with strength similar to the drill pipe.

Drill-string tubulars were designed to permit wireline-retrievable coring operations. The outer barrels and couplings are designed for heavier duty than mining coring barrels, and have the same I.D. and O.D. as the drill collars.

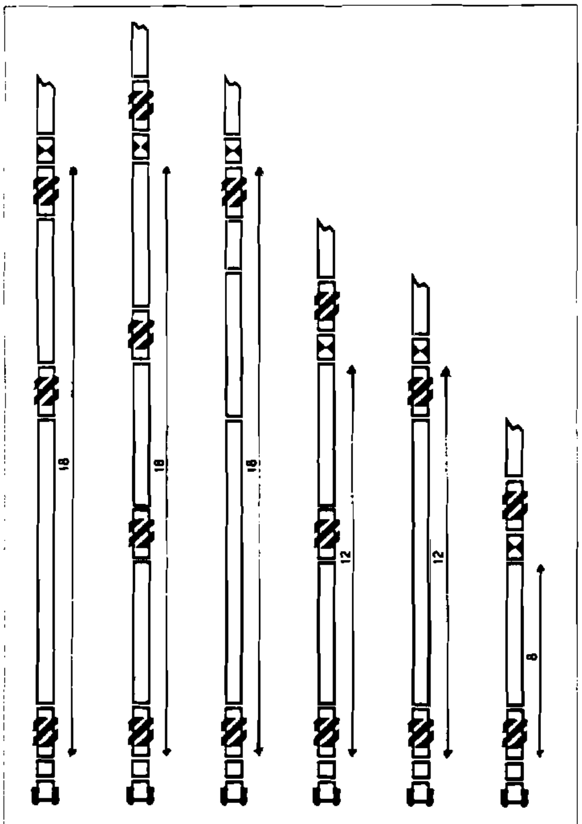


Figure 4-25. Core Barrel Assemblies for Euro-slim Rotary System (Dupuis and Fanuel, 1993)

Core-barrel design allows modular assembly (Figure 4-25) for core lengths of 6, 12 or 18 m (20, 40 or 60 ft). Stabilizers can be placed at any connection between core barrels, as required.

Special inner tubes were planned to be developed for use in unconsolidated formations.

Additional discussion of the Foraslim system is presented in the Chapter *Rotary Systems*.

4.6 MOBIL E&P TECHNICAL CENTER (BOLIVIAN CASE HISTORY)

Mobil E&P Technical Center and Longyear Oil & Gas Division (Shanks and Williams, 1993) described planning and coring operations for a test well and two slim-hole exploration wells. These operations were all completed successfully and many valuable lessons were learned regarding slim-hole rig and equipment design and operation.

Mobil began studying slim-hole drilling in earnest in 1990. A team was formed and discussions were held with many contractors. A test well was determined to be the best first step toward increased understanding of the technological requirements. Longyear provided the rig and crew for the test well at Mobil's research laboratories.

The Farmer's Branch No. 1 (Figure 4-26) was cored to a TD of 2509 ft. Open-hole hydraulics tests were conducted every 500 feet. Several comparative test logs were run in the

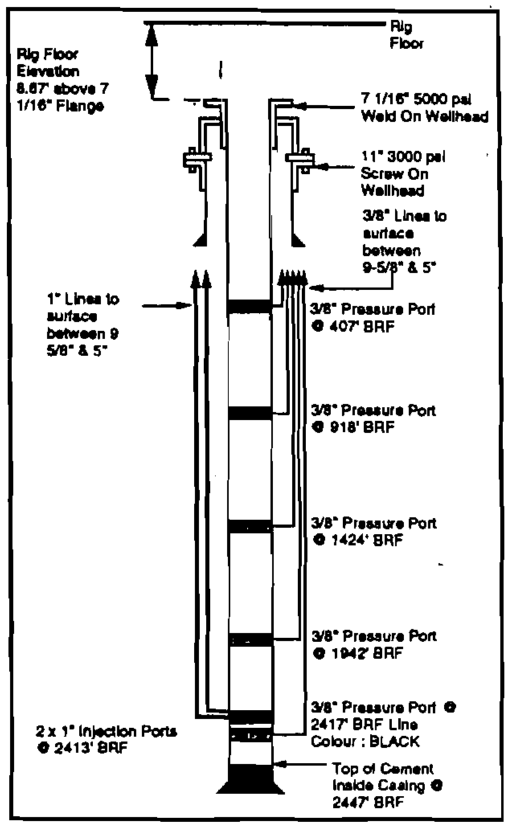


Figure 4-26 Farmer's Branch No. 1 Test Well (Shanks and Williams, 1993)

5½-in. hole. Next, the hole was underreamed to 8½-in. to make room for instrumented 5-in. casing, which included injection lines for simulating kicks and pressure taps at 500-ft intervals.

A number of cased-hole hydraulics, surge/swab, and well-control tests were conducted in the test well and in two exploration wells. Mobil's results are discussed in the Chapter *Hydraulics*. Information gained from the test well was added to models and used to plan the two remote exploration wells in Bolivia (Figure 4-27).

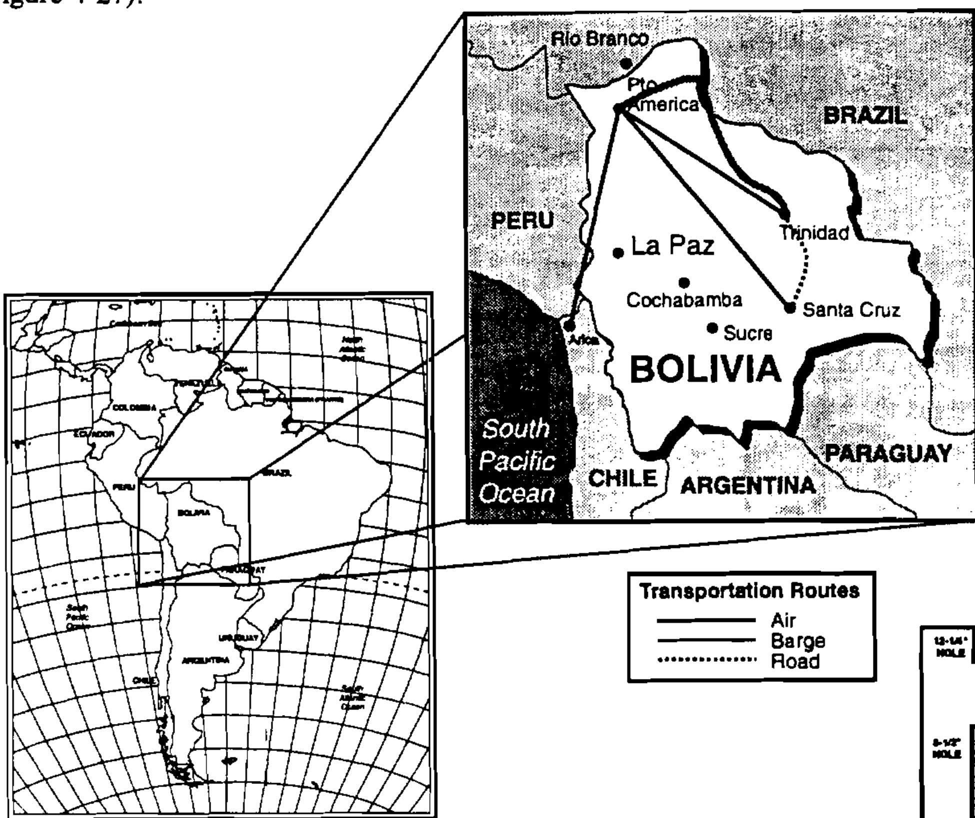


Figure 4-27. Location of Mobil Slim-Hole Project (Shanks and Williams, 1993)

The first well, the Pando-X1 (Figure 4-28), had a 12¼-in. surface hole, 8½- and 5½-in. intermediate holes, and $4^{1}/_{16}$-in. hole to TD. The 8½-in. hole was destructively drilled with CHD 134 drill rod. The 5½- and $4^{1}/_{16}$-in. sections were continuously cored.

Problems occurred after coring operations were initiated. The borehole had a 66-ft washout just below the 7-in. casing. The large annulus across this zone resulted in excessive vibration and high torque at higher rotary speeds. Several problems ensued, including multiple back-offs of the crossover sub on the power head, lost fish, and parting of the

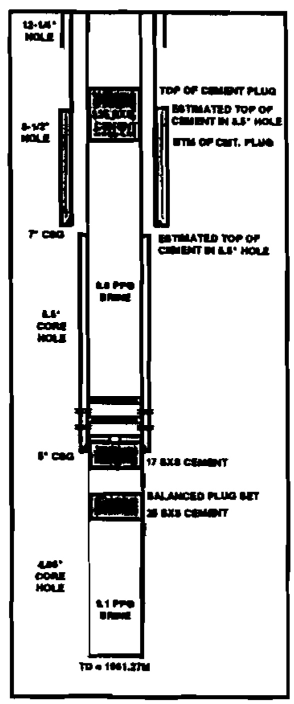


Figure 4-28. Pando-X1 Wellbore Schematic (Shanks and Williams, 1993)

coring assembly. Rotation had to be slowed considerably to keep torque within acceptable limits. Coring was conducted at 200-250 rpm versus 400-450 rpm in good hole.

Problems and slow rotation added several days to drilling operations (Figure 4-29).

The bottom-hole section was cored with CHD 101 drill rods to TD (6500 ft). Normal rotary speeds were possible due to the stability in the 5-in. casing. The hole remained near gauge for the lower sections (Figure 4-30).

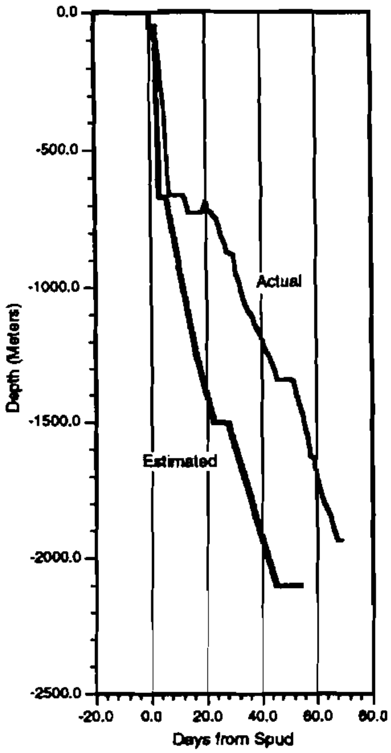


Figure 4-29. Pando-X1 Drilling Depth and Time (Shanks and Williams, 1993)

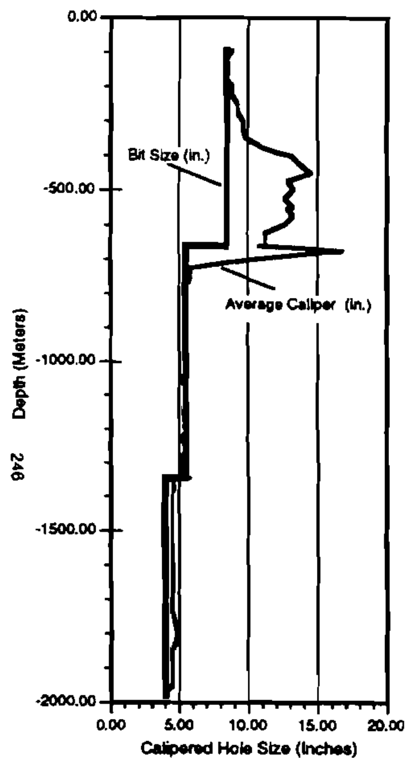


Figure 4-30. Pando-X1 Bit Size and Hole Gauge (Shanks and Williams, 1993)

After logging operations were complete, the bottom hole was plugged, two upper intervals were tested, and then the well temporarily plugged. The time distribution for operations at the site is shown in Figure 4-31.

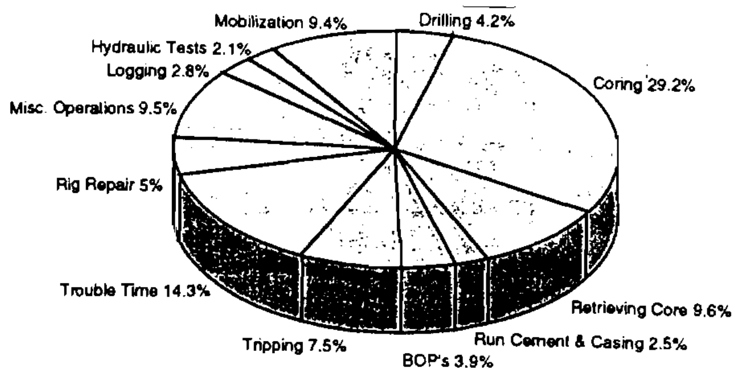


Figure 4-31. Pando-X1 Time Distribution (Shanks and Williams, 1993)

The second well, the Manuripi-X1 (Figure 4-32), was spudded with 8½-in. hole to 317 feet. A 6⅛-in. tricone bit was used for the next section, which was continued past the top of the limestone that was the zone with washout problems in the first well.

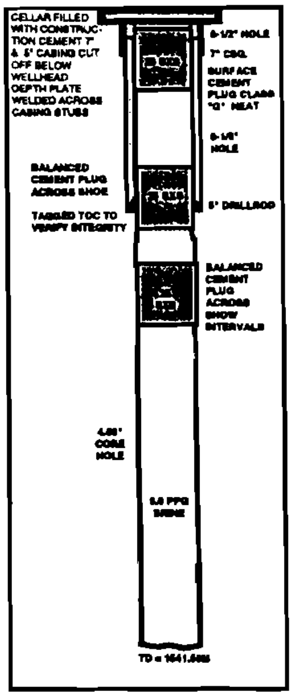


Figure 4-32. Manuripi-X1 Wellbore Schematic (Shanks and Williams, 1993)

Wellbore stability was maintained and coring operations were relatively trouble-free. Total trouble time was about 2% (Figure 4-33). ROP was much higher due to higher rotary speeds and lower torque.

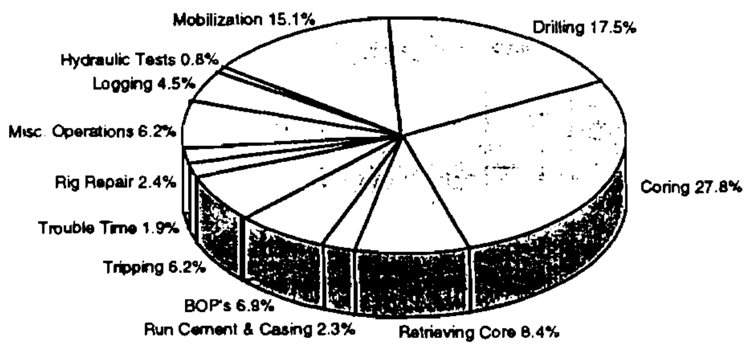


Figure 4-33. Manuripi-X1 Time Distribution (Shanks and Williams, 1993)

A well-control situation was successfully handled during drilling operations. The Exlog EKD system installed on the Longyear rig, combined with excellent crew response, resulted in quick reaction to the kick, with no more than ½ bbl of formation fluid taken before the well was shut in. The well was then circulated through the choke using conventional driller's method kill procedures.

After logging operations were completed, the well was abandoned. Time from spud to TD was 31 days for the Manuripi (Figure 4-34), compared to 56 to the same depth in the Pando well.

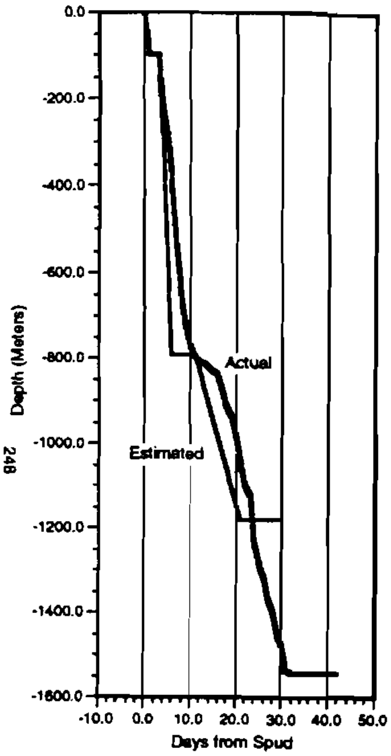


Figure 4-34. Manuripi-X1 Drill- ing Depth and Time (Shanks and Williams, 1993)

Mobil E&P Technical Center reached several conclusions about slim-hole coring operations and equipment. Among those presented by Shanks and Williams (1993) are:

- Small annuli lead to cost savings resulting from smaller, lighter tubulars, smaller equipment to run the tubulars and the ability to use drill rod as casing. The disadvantage for current operations is the lack of understanding of performance of drill-rod connections as casing.
- The Longyear power head would not accept a CHD 134 kelly. A crossover was required to tie in to a CHD 101 kelly. This lack of versatility was a prime cause of trouble in the first well.
- ROP appeared to be linearly related to rotary speed for these operations.
- ROP for slim-hole coring was comparable or better than conventional destructive operations in the same formations.
- Cementing in small annuli needs investigation to increase success. One possible approach is to displace the cement before casing is run.

Mobil also analyzed the design requirements for slim-hole drilling in ultradeep water (6000-11,000 ft). The surface and subsea equipment design (Figure 4-35) contains components similar to, though smaller than, other drilling systems for deep water. In addition, a sea-floor compensator has been added. This system should be capable of drilling to depths of 12,000+ ft.

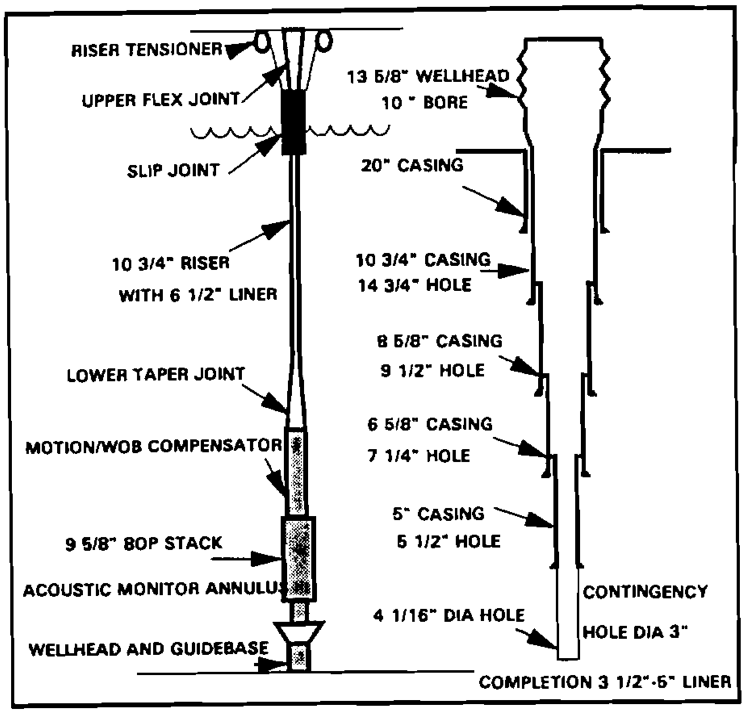


Figure 4-35. Drilling System for Deep Water (Shanks and Williams, 1993)

4.7 NABORS DRILLING INTERNATIONAL (SLIM-HOLE CORING RIGS)

Nabors Drilling International recently placed its second slim-hole drilling/coring rig into service on a three-well program for Corpoven in Venezuela (*Drilling Contractor* Staff, 1994). The newly outfitted Rig 170 was originally fabricated as part of Amoco's SHADS development.

Rig 170 has undergone significant modifications including a redesign of the mud system and an increase in capacity to 350,000 lb to allow use of standard 30-ft joints. Original design of the SHADS rig was for 20-ft mining joints. A parking position has been added for the top drive, which allows moving it off of the well for running casing. The newly decreased location size for the rig is about 200 ft^2.

Nabors' other rig, Rig 180, was built for Maraven's project (see also section 4.4 on BP Exploration Venezuela Ltd.). This rig made use of existing contractor's equipment, and includes conventional equipment for mud, diesel and water tanks. The rig can be reconfigured and is expected to be set up for helicopter transport in the future.

Both Rig 170 and 180 are capable of conventional drilling and slim-hole coring. The API opening on Rig 170 is 17½ in. and on Rig 180 is 27½ inches.

Rig 170's first well in the Corpoven project included 12¼-in. hole to 200 ft, 8½-in. hole to 3000 ft, 6¼-in. hole to 10,600 ft, and 4¾-in. coring to 12,400 ft.

Specially designed drill strings are used on both rigs (see Table 4-2). A 2¼-in. core barrel is run inside the drill string and retrieved by wireline. The tool joints are external upset, but with a lower profile than standard oil-field tubulars.

4.8 NABORS DRILLING INTERNATIONAL (SCR-BASED FEED CONTROL)

Nabors Drilling International and Tech Power Controls (Spoerker and Dhindsa, 1994) described the addition of an SCR-based (silicon-controlled rectifier) feed control system to Rig 180 to improve control of WOB during coring operations in Venezuela. This modification is part of a large-scale automization effort to improve efficiency and core recovery rates. WOB can be held to ±200 lb of the set point with the automated feed system. With SCR-based control, the rig operator can optimize ROP by matching bit performance to formation characteristics.

Slim-hole coring experience has proven that precise control of WOB and drill-string feed is essential to minimize vibration and protect the core. Rig 180 was originally equipped with a standard WOB-controlled operating mode by means of the drawworks motors. Nabors early experiences in Venezuela showed that a feed approach based on maintaining WOB was not ideal in the heterogeneous, laminated structures being cored.

Drill-string feed in response to a drop in WOB resulted in fluctuations and inconsistent movement due to inertia in the drawworks and string. The system oscillated around the set point because of the time lag between string feed and a change in WOB readout. This inconsistent string feed was suspected to contribute to core jamming.

As a result, the SCR control system was modified to control string feed rate instead of reacting to WOB. Real-time data are used to control the drawworks and top drive. Sensor inputs are shown in Figure 4-36.

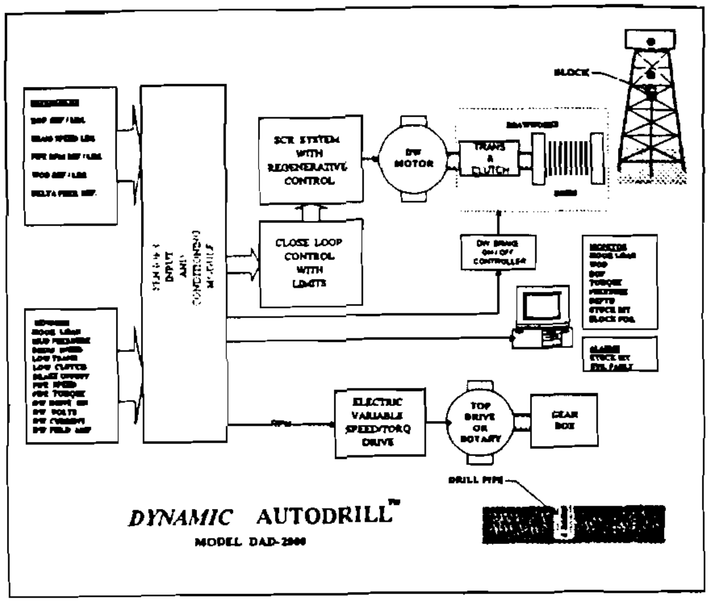


Figure 4-36. Schematic of Nabors' Dynamic Autodrill™ System
(Spoerker and Dhindsa, 1994)

Equipment requirements for the Dynamic Autodrill™ System include DC motors for driving the drawworks, low clutch and transmission on drawworks, and SCR-based drives for the drawworks and top drive. System hardware is controlled by PLCs (programmable logic controller) (Figure 4-37).

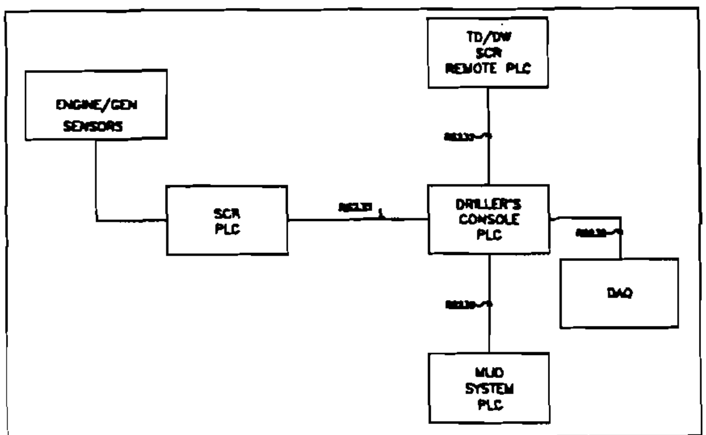


Figure 4-37. PLC Communication on Dynamic Autodrill™ System (Spoerker and Dhindsa, 1994)

Fine control of drilling parameters requires several sensors including a hook-load sensor with 0.01% accuracy, a block-position sensor with an accuracy of ±0.25 in., and an RPM sensor for the top drive. Drilling parameters are evaluated constantly and are adjustable (Figure 4-38) by analyzing WOB, ROP and rotational speed.

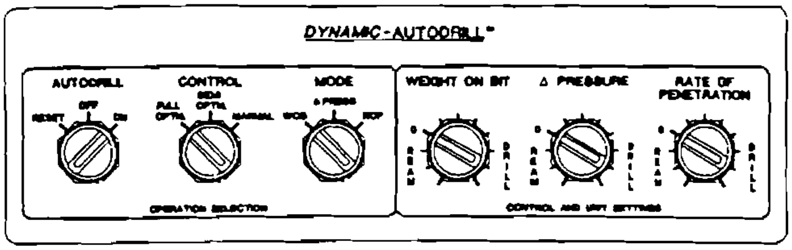


Figure 4-38. Controls on Driller's Console (Spoerker and Dhindsa, 1994)

The operation of the constant-feed system is based on preset feed rates and WOB limits. While drilling, the drawworks feeds off at the preset rate until the WOB limit is approached. Near the limit, feed is gradually decreased and comes to a smooth stop at the limit. Feed is smoothly started again when WOB drops. With experience, the driller should be able to adjust feed rate so that the system drills optimally just below the WOB limit.

In early tests with the constant-feed system, Nabors was concerned that a constantly fed drill string would cause either excessive or small WOBs. Results, however, showed excellent ROP and control. Formation drillability is readily interpreted from the ROP log (Figure 4-39).

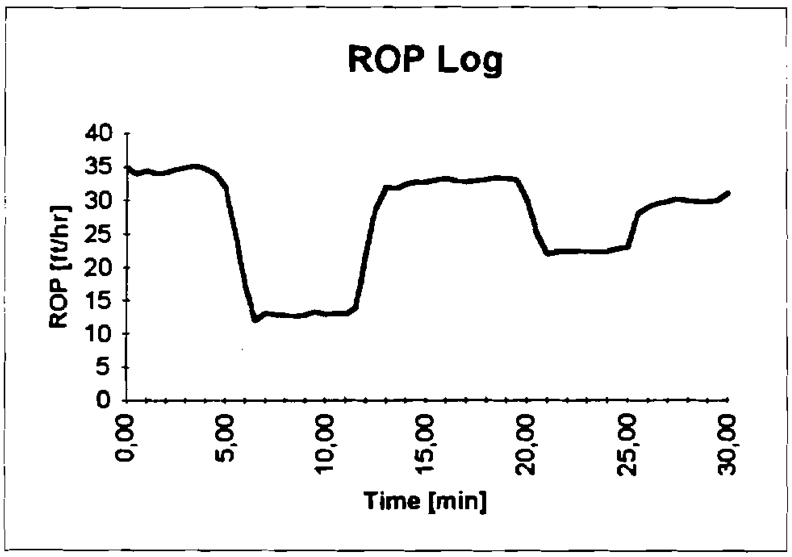


Figure 4-39. ROP Log with Dynamic Autodrill™ System (Spoerker and Dhindsa, 1994)

Nabors Drilling found that core recovery was greatly improved after the constant-feed system was implemented. Average core recovery increased from 84% up to 98% after the rig was modified (Table 4-3).

TABLE 4-3. Core Recovery with Dynamic Autodrill™ System
(Spoerker and Dhindsa, 1994)

Core #	Length Cored	Recvry. Rate	Comments
1	22	67 %	Fractured Shale
2	35	64 %	Fractured Shale
3	25	75 %	Fractured Shale
4	50	96 %	Fractured Shale
5	60	100 %	Shale/Limestone
6	60	90 %	Shale/Limestone
7	44	80 %	Shale/Limestone
8	60	98 %	Limestone
9	60	92 %	Limestone
10	60	83 %	Limestone
11	60	100 %	Limestone
12	60	65 %	Limestone/Sandstone
System Installation			
13	45	100 %	Sandstone/Siltstone
14	48	78 %	Sandstone/Siltstone
15	27	100 %	Sandstone/Siltstone
16	60	98 %	Sandstone/Siltstone
17	60	100 %	Sandstone/Siltstone
18	60	100 %	Shale/Siltstone/Quartz
19	60	100 %	Shale/Siltstone/Quartz
20	60	100 %	Shale/Siltstone/Quartz
21	41	95 %	Core Bit Dulled
22	60	100 %	Shale/Siltstone/Quartz
23	60	100 %	Sandstone/Siltstone
24	48	100 %	Sandstone/Siltstone

Nabors experiences showed that existing SCR technology can be superior to other automatic feed systems. Modifying the system is made simple through the use of programmable logic control. They recommend that this approach can optimize drilling operations in other coring and noncoring applications.

4.9 PARKER DRILLING (HYBRID CORING RIG)

Parker Drilling Company (Wagner, 1992) designed a hybrid coring rig to address many of the disadvantages of mining rigs. In its first field applications, Parker's rig cored to TD in hard rock formations in less than half the time required by conventional mining coring rigs.

The initial design of the hybrid rig was developed after a mining company asked Parker to design a system to core to almost 20,000 ft (6000 m). Over half of existing mining rigs are limited to 1000 ft (300 m) depth. Some mining rigs can core to 5000 ft (1500 m) and a few are rated to 10,000 ft (3000 m).

Original system requirements called for rotary drilling of the upper section(s) of the borehole. Bottom-hole diameter was specified as 4.8 in; minimum allowable core diameter was 1⅞ in. (Table 4-4).

Drill-string design had to include high strength for depth capability and allow rotation to 600 rpm without excessive fatigue.

TABLE 4-4. Hybrid Coring Rig Equipment Design (Wagner, 1992)

Drill Pipe	
Tool joint OD	104.78 mm (4.125 in.)
Tube OD	92.7 mm (3.650 in.)
Tool joint ID	69.85 mm (2.750 in.)
Weight per meter	19.30 kg/m (12.97 lb/ft)
Minimum tensile yield strength	723.975 kpa (105,000 psi)
Pull tested pipe to yield	213,646 kg (471,000 lb)
Wire Line Core Barrel	
Wireline system	104.78 x 47.63 mm (4.125 in. x 1.875 in.)
Outer barrel OD	104.78 mm (4.125 in.)
Inner barrel OD	63.5 mm (2.5 in.)
Length of barrel	9.14 m (30 ft)
Core Bit	
Type	Impregnated bit
Bit Size	121.92 mm (4.80 in.)
Core Size	47.63 mm (1.875 in.)
Kerf Size	37.15 mm (1.4625 in.)

Parker's hybrid system was designed with a top drive (Figure 4-40) rather than rotary table. This decision was based on the ability of a top drive to core 90 ft (27.4 m) without interruption. Field experience with rotary-table systems has shown that core has a tendency to break off after being restarted after the addition of another joint of drill pipe. Top-drive specifications included rotation up to 600 rpm, torque to 5200 ft-lb (7050 N-m), and static load capacity to design depth (6000 m).

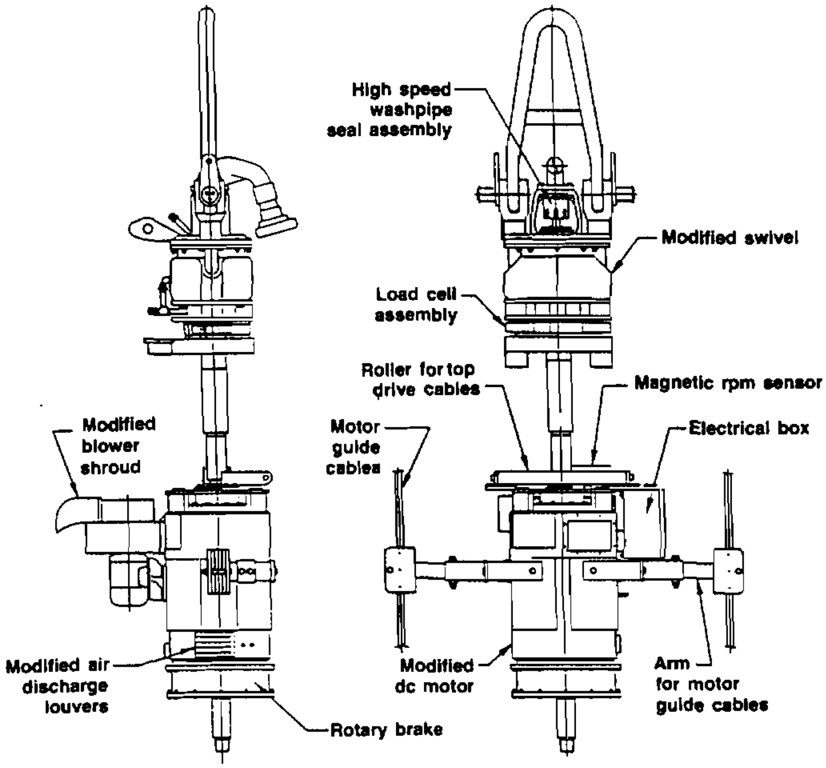


Figure 4-40. Hybrid Rig Top Drive (Wagner, 1992)

A cooling system was added to the swivel assembly to dissipate heat generated during high-speed rotation. A wave seal was incorporated into the washpipe assembly to counter problems resulting from high rotation rates and mud pressures.

Narrow-kerf coring bits, which perform optimally in hard-rock applications, are highly sensitive to overload. Parker designed an automatic drilling system (Figure 4-41) to monitor and control WOB through a hydraulic draw works. This design avoids large, abrupt increases in bit weight characteristic of manually controlled draw works. The controller is capable of maintaining WOB within 400 lb (181 kg) of the set point.

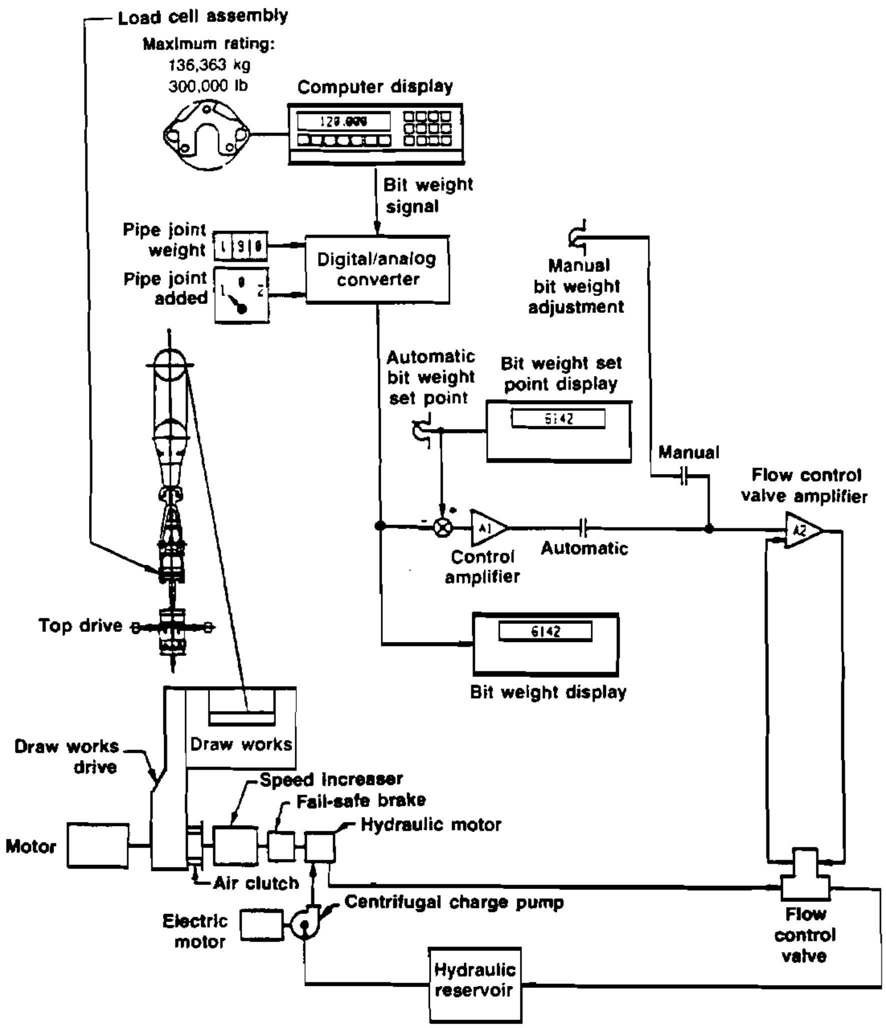


Figure 4-41. Parker Rig Automatic Drilling System (Wagner, 1992)

Wireline deployment speed is variable up to 440 ft/min (134 m/min). A large-diameter drum is used to minimize the number of layers of wireline and to reduce fatigue.

Results from the first three wells drilled and cored with the rig are summarized in Table 4-5. Rig 4 reached a TD of 12,730 ft (3880 m) in 187 days. An additional 1811 ft (552 m) were cored in six deflection holes. Core recovery averaged 95% to 98%.

TABLE 4-5. Field Results with Parker Hybrid Rig (Wagner, 1992)

METHOD OF DRILLING	BIT SIZE, MM	DEPTH, M	CASING SIZE, MM	
Petroleum tricone	311.15	100	244.48	
Petroleum tricone	215.90	2,800–3,450	127	
Wireline Coring	121.92	3,450–6,000	None	
RESULTS FROM THE FIRST THREE BOREHOLES				
	Petroleum Tricone Drilled			
	Rig 4	**Rig 3**	**Rig 7**	**TOTAL**
Total meters drilled	1,801	4,012	3,416	9,229
Rotating hr	1,210	2,848	1,349	5,408
Bits	40	62	26	128
Avg. meters/bit	45	64.7	131.4	72.1
Avg. penetration, m/hr	1.49	1.41	2.53	1.71
	Wireline Cored			
	Rig 4	**Rig 3**	**Rig 7**	**Total**
Total meters cored	2,079	1,059	499	3,638
Rotating hr	1,467	837	267	2,572
Bits	40	24	13	77
Avg. meters/bit	52.0	44.15	38.4	47.2
Avg. penetration, m/hr	1.42	1.27	1.87	1.41
*Total depth, m	3,880	5,071	3,915	
*Includes tricone and cored hole				

Initial holes with Rigs 3 and 7 were completed in 395 and 367 days, respectively. An estimated 1000+ days would be required for similar operations with conventional equipment.

4.10 SCIENCE APPLICATIONS INTERNATIONAL (CORE-ROD CONNECTIONS)

Science Applications International (Fehr and Bailey, 1994) investigated the relative service life of several slim-hole core-rod connection designs. As part of their work on the Yucca Mountain Characterization Project for the DOE, they needed to determine whether service life could be improved, and what parameters can be used to predict relative life of connections.

The Yucca Mountain Project is a scientific drilling project that uses air drilling to obtain continuous cores from surface to TD. The use of air decreases the hydraulic support of the drill pipe and results in increased vibration. A special dual-pipe design is used to assist in lifting cuttings to surface. This design results in conditions more severe than in typical mining operations, and has led to connection failures.

API Recommended Practice 7G is used to assist conventional drillers in the selection of connections for drill collars. The mining industry, on the other hand, does not offer an equivalent standardization scheme. Faced with a lack of standards, the slim-hole coring industry must depend on laboratory testing or field trials of specific connections.

The Yucca Mountain Project has used two different connections in the field: Case 1 and Case 2 in Table 4-6. Case 2 uses a straight walled tube slightly larger than Case 1.

TABLE 4-6. Comparison of Properties of Several Core-Rod Connections (Fehr and Bailey, 1994)

CONNECTION	SECTION MODULUS RATIO BOX TO PIN*	MOMENT OF INERTIA RATIO BOX TO PIN
CASE 1 MINING INDUSTRY MODERATE TORQUE 2-3 Threads/in. INTERNAL UPSET	1.23	1.357
CASE 2 MINING INDUSTRY MODERATE TORQUE 2-3 Treads/in. STRAIGHT WALL	2.377	2.750
CASE 3 HIGH TORQUE FLUSH JOINT BUTTRESS STYLE	1.015	1.082
CASE 4 LOW TORQUE Approx. 3.5 Threads/in. API EUE TUBING	1.308	1.446
CASE 5 MINING INDUSTRY LOW TORQUE	1.22	1.32

*Modified API BSR formula

The API recommended ratio of section moduli for connections less than 6 in. is between 2.25 and 2.75. Case 2 comes closer to this recommendation. However, it is unknown whether this recommendation has validity for slim-hole core rods or whether this ratio is related to intended service life. The tubular manufacturer suggested to Science Applications that the moment of inertia ratio might be a beneficial comparison.

Science Applications chose Case 2 connections in the absence of more definitive criteria for operations at Yucca Mountain.

Later, other connections were analyzed with respect to the same parameters. Case 4 had been used successfully by others and had shown a fatigue life exceeding 2 million cycles. The section modulus ratio for Case 4 was only slightly greater than standard Case 1. Case 5 was also obtained and tested. Fatigue life was greatly decreased (200,000 cycles), even though section modulus ratio was only slightly less.

Science Applications' analyses showed that the utility of API techniques for connection selection is not determined. More laboratory tests are required for the range of connection designs for slim-hole coring operations before any selection criteria can be developed.

4.11 SHELL E&P DE GUATEMALA (GUATEMALAN CASE HISTORY)

Shell E&P de Guatemala (Teurlai et al., 1994) drilled a 1600-m (5250-ft) slim-hole well near the eastern shore of Lake Izabal in Guatemala (Figure 4-42). The drilling area was in a region where environmental concerns are paramount. Significant energy and cost was spent in preparing the Environmental Impact Assessment, reducing potential environmental impact and preparing for any foreseeable contingency.

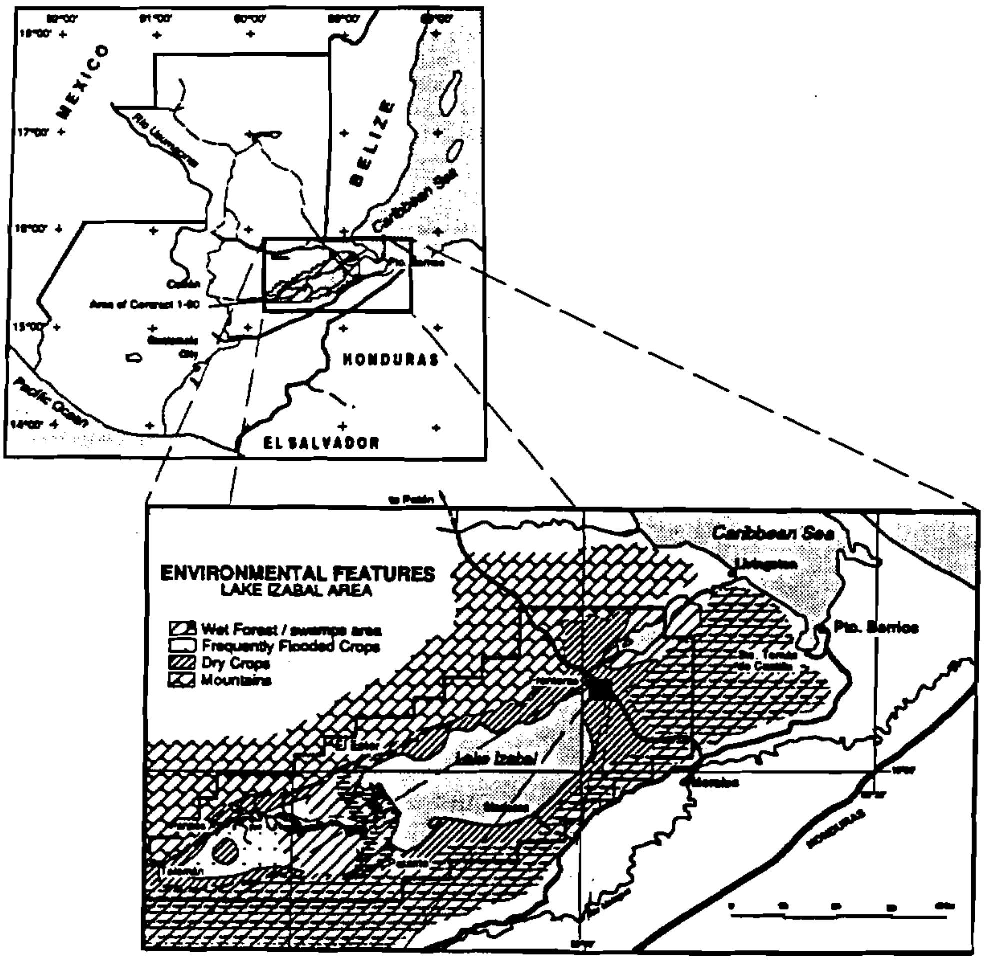


Figure 4-42. Well Site Near Lake Izabal (Teurlai et al., 1994)

The slim-hole well was drilled during the summer of 1993. Though originally proposed as an offshore well, the location was changed to onshore to reduce environmental concerns.

There was a myriad of agencies and organizations involved in environmental approval of the project (Figure 4-43). After the well was moved onshore, the Impact Assessment was approved in two months, regarded as close to a record for this type of situation.

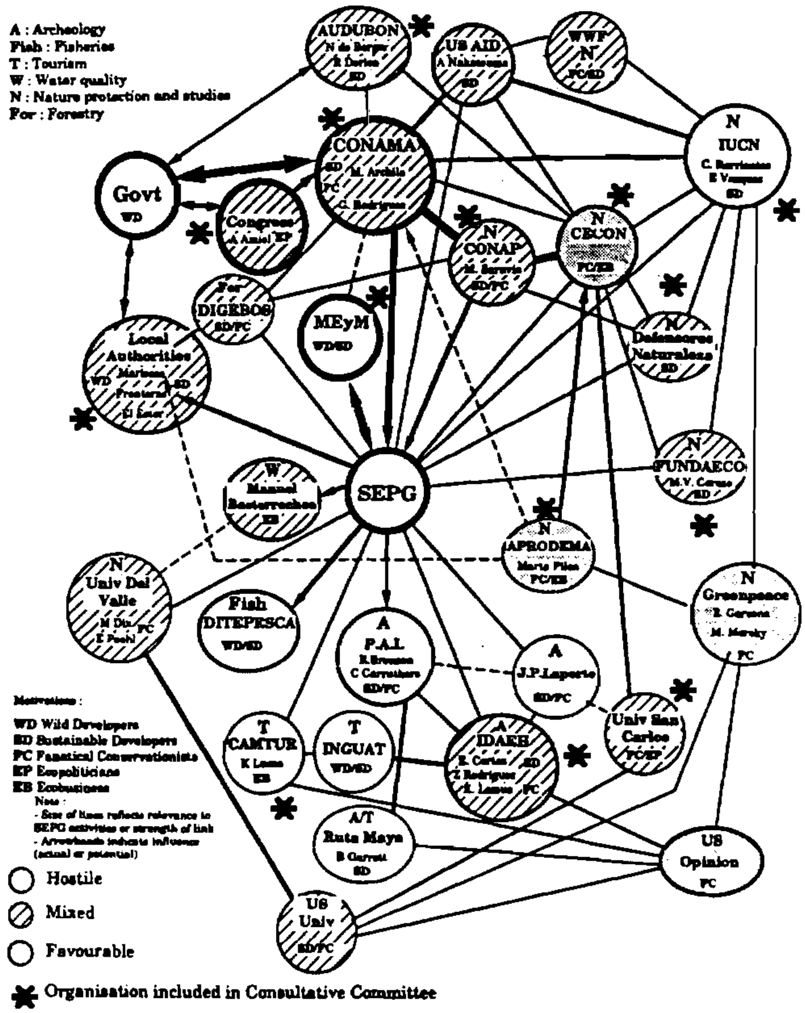


Figure 4-43. Parties Involved in Environmental Assessment of Project (Teurlai et al., 1994)

The very choice of slim-hole technology was a response to the significant resistance to the project anticipated by Shell. Slim-hole technology significantly reduced all aspects of the project, including location, rig, and materials (Table 4-7), and casing and cuttings (Figure 4-44).

TABLE 4-7. Comparison of Conventional and Slim-Hole Equipment (Teurlai et al., 1994)

CONVENTIONAL	vs	SLIM HOLE	Reduction Factor
772,000 Lbs.	Rated Hook Load	85,700 Lbs.	9.0
130 Ft.	Mast height	90 Ft.	1.4
1600 HP	Drawworks	300 HP	5.3
3200 HP	Mud pumps Power	400 HP	8
200 m^3	Mud tank capacity	40 m^3	5
9000 m^2	Location size	1500 m^2	6
8 1/2"	Hole size (TD)	4 1/4"	2
1000 T	Rig weight (total)	200 T	5

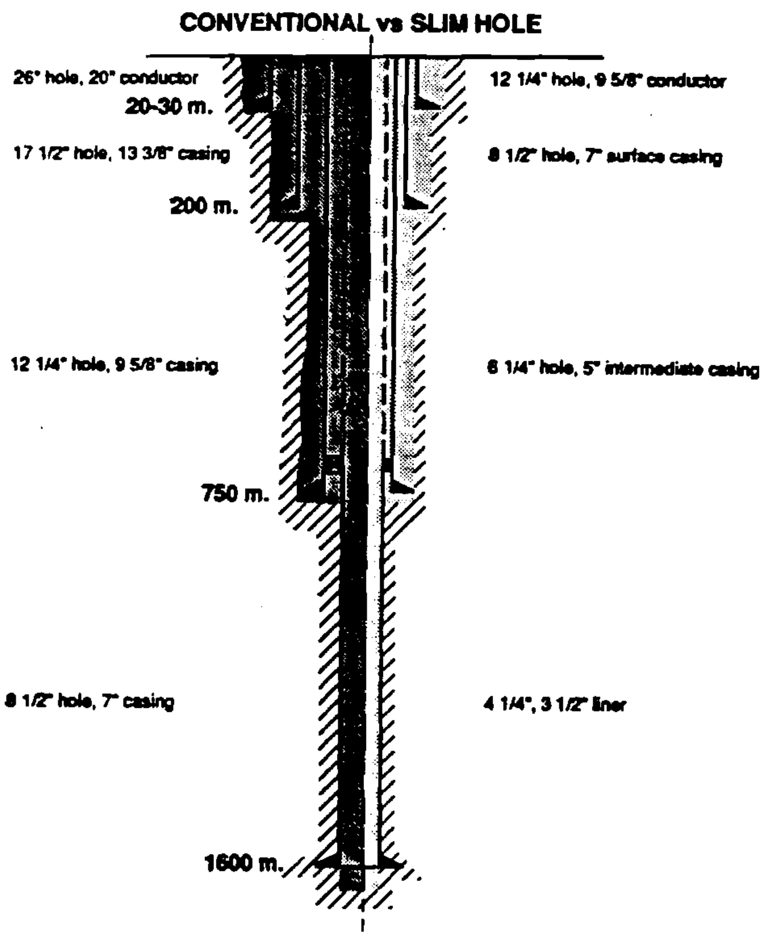


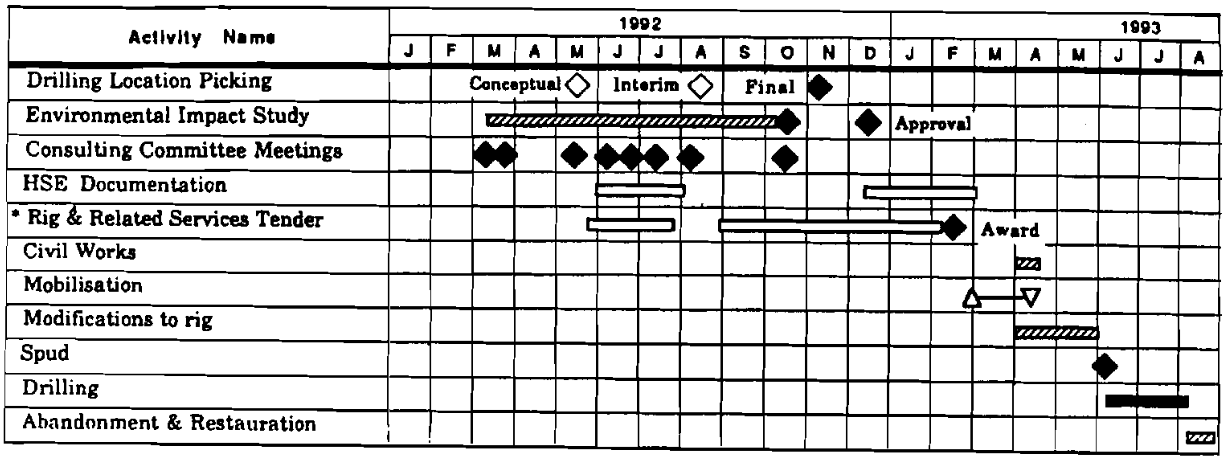
Figure 4-44. Comparison of Conventional and Slim-Hole Casing (Teurlai et al., 1994)

Longyear Company (Salt Lake City, Utah) was the prime drilling contractor. Related services (site preparation, cementing, mud facilities, mud logging, wireline logging, logistics) were included in the same contract. Additional stipulations of the contract included an HSE advisor at the site at all times, and an ambulance and driver. Bonuses to the contract were specified for achieving zero lost-time incidents during the contract and for successful recovery of the site 6 months after project completion.

The site area was 100 m (328 ft) square. Twenty-six truckloads were required to bring all equipment and materials to the site. "Environmentally friendly" mud additives were used.

At the conclusion of drilling and logging operations, the casing strings were cut below ground level and the area returned to natural conditions. All operations were completed in about 150 days (Table 4-8). No lost-time incidents were recorded.

TABLE 4-8. Schedule of Operations for Lake Izabal Well (Teurlai et al., 1994)



Project costs amounted to $3.6 million US. Shell stated that these costs compared favorably with costs for conventional wells in similar remote locations that did not include such stringent environmental requirements.

4.12 REFERENCES

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5. Drilling Cost and Time

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5. Drilling Cost and Time

5.1 ASAMERA SOUTH SUMATRA LTD. (SOUTH SUMATRA CORING)

Asamera South Sumatra Ltd. (Almendingen et al., 1992) drilled and cored five exploratory wells in remote locations in South Sumatra. Conventional drilling procedures were not feasible for this campaign due to excessive time to construct access roads and high overall costs. A slim-hole mining approach based on helicopter transport was used to evaluated the subject acreage.

Major equipment included a Longyear HM 55 helirig and Bell 205 helicopter. No serious operational problems were encountered during the five-well project. One instance of differential pipe sticking was remedied by circulating a diesel pill and reducing mud weight. All wells were plugged and abandoned after formation evaluation.

Asamera found that slim-hole drilling offered considerable advantages for this program. The most important advantage was the elimination of the need to build access roads to the sites. Building roads and a location for one typical well would have required up to 220 days for construction. Roads were not needed for the slim helirig program.

The other important advantage of slim-hole drilling was lower costs (Table 5-1). Costs were about 37% less than with conventional road-based technology.

TABLE 5-1. Asamera Project Costs for Five Wells (Almendingen et al., 1992)

	COSTS ($1000 U.S.)		
	CONVENTIONAL DRILLING	SLIM-HOLE P & A AFE	SLIM-HOLE ACTUAL
Location & Access	7,874	3,007	2,460
Tangibles	215	178	85
Drilling	1,435	2,723	3,253
Completion	0	0	165
TOTAL COST	9,524	5,908	5,963

A typical location layout was 492 x 541 ft for rig and camp facilities. All equipment and materials were flown in. Eighty-three loads were required for the rig. Another 60 loads were required for the fluids, tubulars, cement, and service company equipment. Only three days was required to rig down, move to the next site and rig up.

Location construction, drilling and evaluation of the five wells were completed in 27 weeks. Asemera was very pleased with the speed and low cost with which the project was conducted.

Additional details of this slim-hole coring project are presented in the Chapter *Coring Systems*.

5.2 CHEVRON USA (DOME PDC BITS)

Chevron USA (Carter and Akins, 1992) developed and field-tested dome PDC bits and PDC underreamers in slim holes in the Permian Basin. They performed R&D and field testing to improve the economics of slim-hole deepening and underreaming. They saw increased ROP and decreased costs in operations in holes ranging from 3¼ to 4¾ inches. These technologies show great promise for deepenings and recompletions in the Permian Basin.

Dome PDC bits were used in the Grayburg formation in Lea County, New Mexico. Economics were greatly improved with these bits, and ROP increased from about 30 to 50 ft/hr. Success with dome PDC bits led to the development of dome PDC underreamers. Underreaming costs were reduced by 56% on the first run. Other runs in additional wells confirmed the economic efficiency of these dome PDC systems (Figure 5-1).

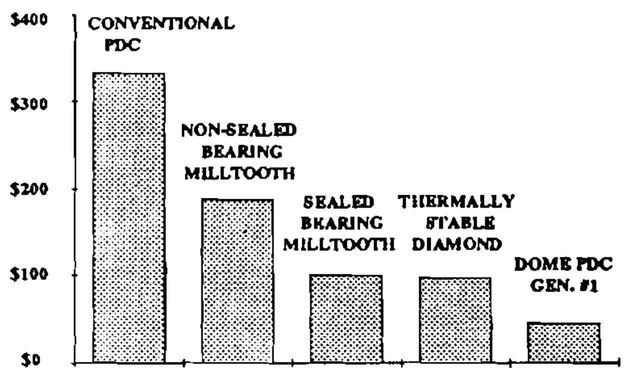

Figure 5-1. Underreamer Costs in Grayburg Formation (Carter and Akins, 1992)

Chevron expanded the successes with dome PDC cutters to West Texas fields. As in New Mexico, dome PDCs performed much better than roller bits. A second-generation dome PDC underreamer was developed with additional cutters for increased wear. ROP did not increase with this improvement; however, a longer life and more even wear reduced costs further (Figure 5-2).

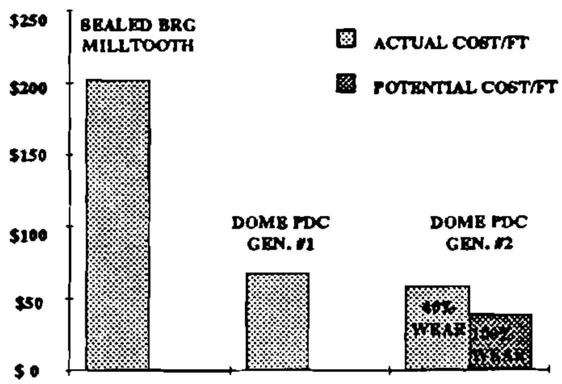

Figure 5-2. Underreamer Costs in Queen Formation (Carter and Akins, 1992)

Chevron USA was very positive about the potential of these new dome PDC cutters for economic slim-hole operations in the Permian basin. They concluded that these results suggest that this technology should be expanded into other hard-rock regions.

Additional details of Chevron's developments are presented in the Chapter *Bits*.

5.3 FORASOL/FORAMER (EUROSLIM PROJECT COSTS)

Forasol/Foramer and DB Stratabit (Dupuis and Fanuel, 1993) reported the design and development of a new slim-hole rig for the Euroslim joint-industry project. A primary objective of the project was to design a system that would drill slim holes at conventional penetration rates. Small holes drilled conventionally often resulted in significantly reduced ROPs. Devising a solution to this problem was considered as essential for obtaining the promised benefits of slim-hole technology.

A new rig was designed based on rotary technology. One high-strength drill string was designed for 8½- to 4¾-in. holes; another string was designed for 4- to 3-in. holes. These strings were designed to transmit enough torque to power PDC bits at conventional ROPs.

Cost savings with the Euroslim rig come from several areas:

- Site civil engineering (reduced from 6000 m^2 down to 1000 m^2)
- Access-road capacity requirements reduced from 45-ton loads to 10-ton loads
- Reduction in consumables
- Drilling contractor rate reduction due to fewer personnel and lower equipment capital expenses

Typical cost savings with the Euroslim system are shown in Table 5-2. These data are based on results to date. It is predicted that total cost savings of about 30% in developed areas and of 50% in remote areas would be expected with the system.

TABLE 5-2. Euroslim Cost Savings (Dupuis and Fanuel, 1993)

ITEM	URBAN AREA			REMOTE AREA		
	Reduction Slim/Conv.%)	Total Cost Conv. (%)	Reduction Contribution(%)	Reduction Slim/Conv.(%)	Total Cost Conv. (%)	Reduction Contribution (%)
Moving	60	15	9	60	25	15
Roads	-	-	-	-	-	-
Location	60	16	10	65	40	26
Rig & Services	15	49	7	15	15	2
Consumables	50	18	9	50	10	5
Logistics	40	2		40	10	4
		100	35		100	52

5.4 GULF OF SUEZ PETROLEUM (OFFSHORE SLIM-HOLE COSTS)

Gulf of Suez Petroleum Company (Ghazaly and Khalaf, 1993) adopted a slimmer casing program in an exploratory well in the northern Gulf of Suez. Compared to a well completed with the conventional number of casing strings, the slimmer well showed cost savings of 40-50%, amounting to $476,000. Operations also benefited from the smaller volume of oil-wet cuttings generated in the slim well, resulting in lower environmental impact.

A conventional well schematic (middle of Figure 5-3) consists of 17½-in. surface hole, 12¼-in. intermediate hole and 8½-in. production hole. The production interval is about 2000 ft in length. Oil-base muds are used in the surface and production holes.

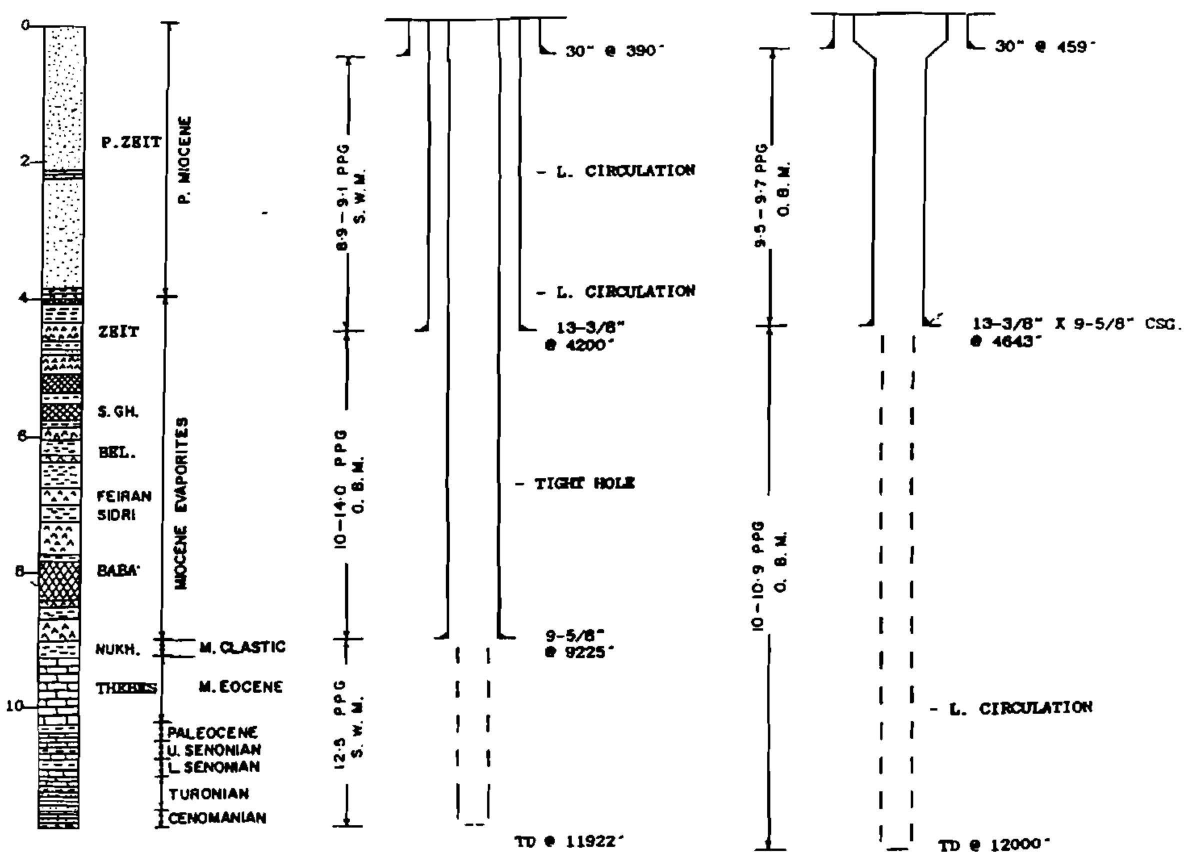

Figure 5-3. Conventional and Slim Well Schematics (Ghazaly and Khalaf, 1993)

A modified slim-hole casing program was adopted for well Tanka-3 (right side of Figure 5-3). The conventional 9⅝-in. casing string was eliminated, and a combination 13⅝- by 9⅝-in. string was run as the surface casing. The production hole was drilled out of the surface string with a conventional diameter bit (8½ in.).

The principal risk associated with this slim program, according to Gulf of Suez Petroleum Company, is the lack of contingency hole if an extra string of casing needs to be set in the 8½-in. hole before reaching

TD. Their experience suggested that drilling a 6-in. contingency hole is difficult and very slow. They provided no details on 6-in. bits.

Two trouble days were spent on a lost-circulation problem in the 8½-in. section of the slim hole. If conventional intermediate $9\frac{5}{8}$-in. casing had been set, the mud weight would have been less and lost circulation probably would not have occurred. The problem was successfully remedied in the slim hole, and the overall cost savings more than offset the trouble.

Conventional and slim-well costs are summarized in Table 5-3. Cost per foot is calculated for each section, both with and without bit costs included. Cost savings are slightly greater for the slim hole (Table 5-3B) without bit costs included due to the relatively high costs for additional 8½-in. bits.

TABLE 5-3. Conventional and Slim Well Costs (Ghazaly and Khalaf, 1993)

a. GS 196-3 (Conventional well)

Bit #	Bit Cost	Depth Out	Ftg.	Hours	$/ft w/o Bit Cost	$/ft with Bit Cost
Clean out cond.		400		0.0		
2	$ 16,151	4203	3803	63.5	$ 35.61	$ 39.85
3	$ 37,600	7650	3447	81.5	$ 51.73	$ 62.63
4	$ 0	9230	1580	40.5	$ 62.95	$ 62.95
6	$ 3,600	9823	593	33.5	$ 146.11	$ 152.19
7	$ 3,600	10211	388	33.5	$ 225.31	$ 234.59
8	$ 3,600	11000	789	51.5	$ 158.43	$ 162.99
9	$ 3,600	11421	421	36.5	$ 227.65	$ 236.20
10	$ 3,600	11922	501	49.0	$ 243.20	$ 250.39
GS 196-3 weighted average $/ft =					$ 80.71	$ 86.94

b. Tanka-3 (Reduced-Size hole)

Bit #	Bit Cost	Depth Out	Ftg.	Hours	$/ft w/o Bit Cost	$/ft with Bit Cost
Clean out cond.		482		0.0		
2	$ 43,355	3698	3216	52.0	$ 34.64	$ 48.12
3	$ 0	4655	957	31.5	$ 75.56	$ 75.56
4	$ 26,460	6426	1771	36.5	$ 48.48	$ 63.42
5	$ 24,500	6489	63	1.5	$ 253.62	$ 642.51
6	$ 0	8195	1706	49.0	$ 67.05	$ 67.05
7	$ 24,270	9950	1755	35.5	$ 51.79	$ 65.62
11	$ 0	12000	1880	46.0	$ 61.70	$ 61.70
Tanka-3 weighted average $/ft =					$ 53.47	$ 63.92
$/ft savings =					$ 27.230	$ 23.010
Based on a 12,000' well, $ savings =					$ 326,807	$ 276,137

A summary of project cost savings consists of:

- Time-Related Intangible Savings $276,000
- Fixed Intangible Savings $17,000
- Equipment Tangible Savings $183,000
- Total Savings $476,000

Most of the fixed intangible cost savings were due to savings in cement from eliminating one of the casing strings. Equipment cost savings resulted from significantly reduced casing requirements. Gulf of Suez Petroleum noted that relative cost savings would have been less if completions had been run in the 8½-in. sections, since the slim hole would have required much more liner than the conventional.

Drilling time is compared for the slim well (Tanka-3) and the conventional well (GS 196-3).

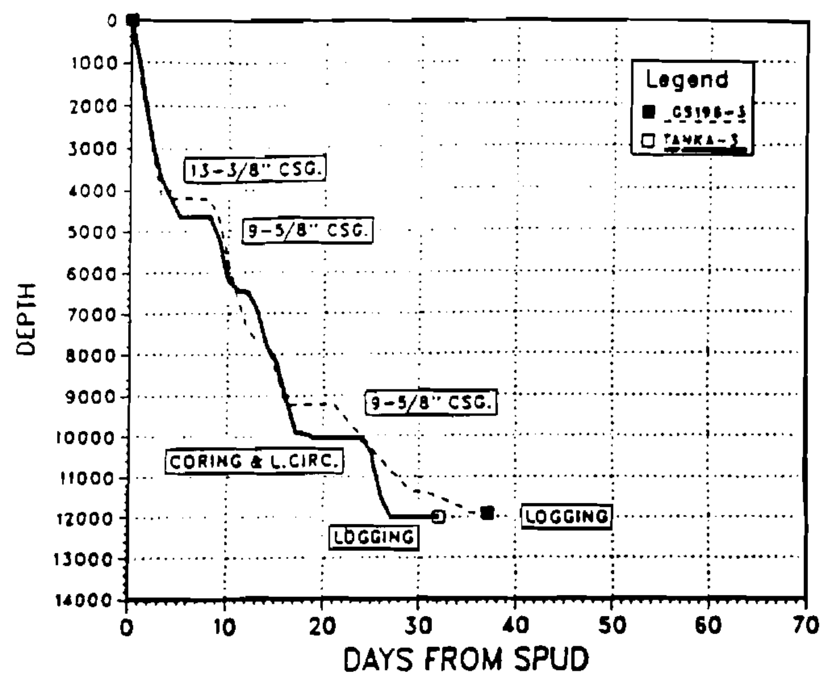

Figure 5-4. Conventional and Slim Well Drilling Time (Ghazaly and Khalaf, 1993)

Cumulative costs as a function of depth are shown in Figure 5-5. More logging costs were accrued in the slim well (Tanka-3) at TD. Logging costs were ignored in the cost analyses reported, as they were assumed to be unaffected by casing size.

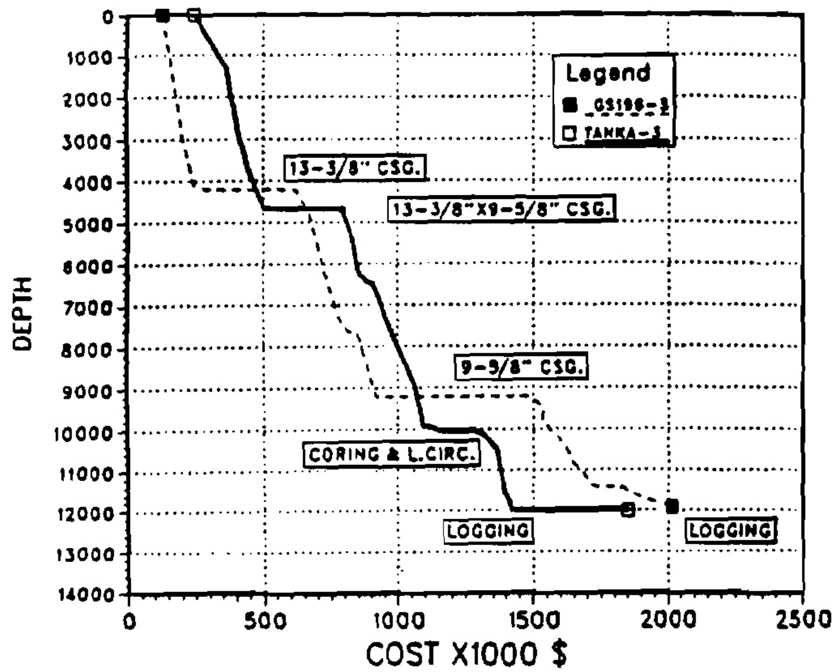

Figure 5-5. Conventional and Slim Well Drilling Costs (Ghazaly and Khalaf, 1993)

Gulf of Suez Petroleum reduced drilling costs by 40-50% by slimming their casing program. Savings resulted from reduced drilling fluid volumes, higher ROPs, better hole cleaning, less consumables, less material, and easier equipment mobilization.

5.5 ORYX ENERGY (HORIZONTAL SLIM-HOLE COSTS)

Oryx (Hall and Ramos, 1992) conducted a detailed cost analysis of slim-hole horizontal re-entry costs in the Austin Chalk. Costs of wells drilled in 1990 are summarized in Table 5-4. Total costs ranged from 60 to 109% of average conventional re-entry costs for 1990. The cost of a slim-hole lateral exceeded conventional costs for each of these wells. Oryx reports that these high costs associated with drilling the lateral were principally due to low ROP resulting from wiring problems with the steering tool.

TABLE 5-4. 1990 Oryx Slim-Hole Re-entry Costs (Hall and Ramos, 1992)

DAYS	DEPARTURE	LATERAL COST	TOTAL COST
44	1901	2.17	1.09
39	2316	1.83	1.12
25	2226	1.34	0.79
33	1419	1.68	0.63
18	1460	1.57	0.60
AVG 32	1864	1.72	0.85

1990 CONVENTIONAL COST = 1.00

Cost for eight wells re-entered during 1991 and 1992 are presented in Table 5-5. A dependable wet-connect steering tool system was developed between this and the previous 1990 campaign. This improvement increased slim-hole ROP by 55%.

TABLE 5-5. 1991 and 1992 Oryx Slim-Hole Re-entry Costs (Hall and Ramos, 1992)

DAYS	DEPARTURE	LATERAL COST	TOTAL COST
18	1458	3.88 (CT)	0.63
38	2018	3.31	0.74
24	2002	1.84	0.41
21	2692	1.46	0.43
20	2242	1.83	0.45
18	1927	2.36	0.50
14	1600	1.75	0.31
22	1900	2.60	0.54
AVG 22	1980	2.38	0.50

1991 CONVENTIONAL COST = 1.00

Total costs for slim-hole re-entries are less than in Oryx's earlier efforts. The data in Table 5-5 are based on 1991 conventional costs. As compared to 1990 conventional costs, 1991 conventional total cost was 21% less and lateral cost was 67% less. It is impressive that the slim-hole system became more competitive in 1992 despite these significant decreases in conventional costs.

Data are presented for one coiled-tubing re-entry (the first well in Table 5-5). Although lateral costs were much greater than conventional, overall re-entry costs with coiled tubing were 63% conventional.

Data for 1990 and 1991-92 are compared relative to 1990 conventional costs in Table 5-6. A significant reduction in costs was realized through ongoing technological improvements. A slim-hole re-entry in 1991 cost only 40% of a conventional job in 1990.

TABLE 5-6. Oryx Horizontal Slim-Hole Re-entry Costs (Hall and Ramos, 1992)

	1990	1991
Well Cost Index	0.85	0.40
Lateral Departure	1864	1980
Days	32	22
Lateral Cost/Ft	1.72	0.79
1990 Conventional Cost = 1.00		

New horizontal slim-hole wells also provided cost reductions for Oryx. Their first new slim hole (Table 5-7) had a cost of 85% of conventional 8½ in. Experiences with this first well led to modifications in the plan for the second slim hole. These included the use of a larger mud motor, a larger bit for increased clearance through the curve, and 2⅞-in. drill pipe in the vertical section to increase WOB. Total costs for the second well were 68% of conventional.

TABLE 5-7. Oryx New Horizontal Slim-Hole Costs (Hall and Ramos, 1992)

	HOLE SIZE	DEPTH/ DISPLACEMENT	LATERAL COST	TOTAL COST
CONVENTIONAL	8 1/2 in.	10,289'/3741'	1.00	1.00
REDUCED HOLE	6 1/8 in.	9698'/3257'	0.87	0.82
1st SLIM HOLE	4 1/2 in.	9568'/3110'	0.89	0.83
2nd SLIM HOLE	4 3/4 in.	9697'/3154'	0.73	0.68

Oryx's operations showed that slim-hole horizontal technology offers significant potential for cost savings for both re-entries and new wells (Table 5-8).

TABLE 5-8. Summary of Horizontal Slim-Hole Costs (Hall and Ramos, 1992)

	HOLE SIZE	DEPTH/ DISPLACEMENT	LATERAL COST	TOTAL COST
CONVENTIONAL	8 1/2 in.	10,289'/3741'	1.00	1.00
REDUCED HOLE	6 1/8 in.	9698'/3257'	0.87	0.82
SLIM-HOLE RE-ENTRY	3 7/8 in.	----/1980'	2.38	0.50
NEW SLIM HOLE	4 3/4 in.	9697'/3154'	0.73	0.68

Oryx concluded that "slim-hole 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 is waiting for the push to become an industry accepted practice.

Additional details of Oryx's operations and analyses are presented in the Chapter *Horizontal Drilling*.

5.6 SHELL RESEARCH (COSTS WITH SLIM-HOLE MOTOR SYSTEM)

Shell Research B.V., Shell Internationale Petroleum Maatschappij B.V., BEB Erdgas & Erdöl GmbH, and Eastman Teleco (Worrall et al., 1992) described the development of a retrofit slim-hole drilling system based on the use of a downhole motor. The essential elements of their system included diamond drag bits, mud motors, conventional drill pipe, shear-thinning muds, antivibration technology, and sensitive kick detection. Cost savings of up to 24% were shown in early efforts with their system.

Dry-hole costs for typical 4800-m (15,750-ft) 5⅞-in. and 4⅛-in. gas wells are compared in Figure 5-5. Slim-hole (4⅛-in.) costs are 76% those associated with the larger hole.

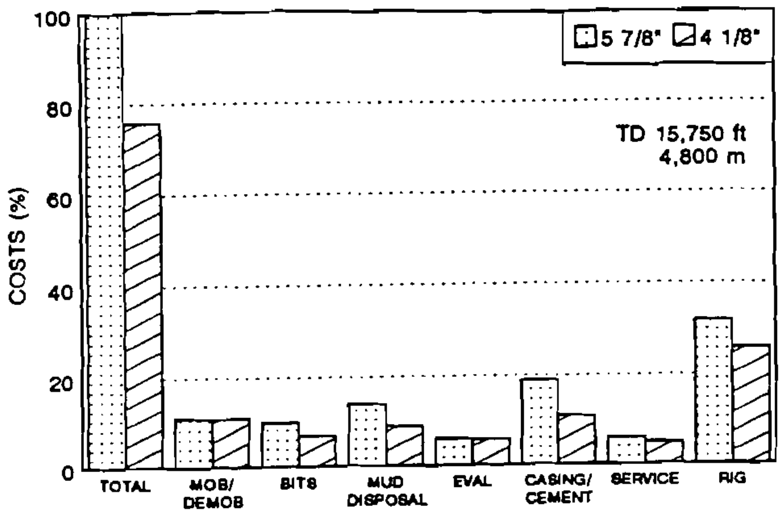

Figure 5-5. Shell/Eastman Teleco Well Costs (Worrall et al., 1992)

The largest relative cost reduction is in casing and cement: 19% of 5⅞-in. well costs versus 11% of 4⅛-in. well costs—a cost reduction of over 50%.

Shell found that improved ROP performance led to slim-hole cost savings ranging between 19 and 41% of conventional 5⅞-in. (Figure 5-6).

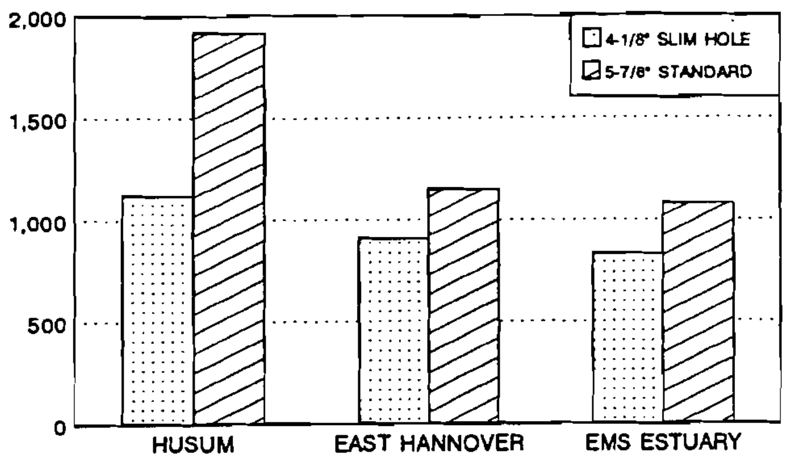

Figure 5-6. Shell's Cost Per Meter in Three Fields (Worrall et al., 1992)

Costs for 30 German wells, of which 13 are slim hole, are plotted at TD in Figure 5-7. These wells were drilled between 1987 and 1992; a 2.5% annual inflation correction is included in the data. Average conventional costs are indicated by the trend line in the figure. Eleven of the 13 slim wells fall below the conventional trend line.

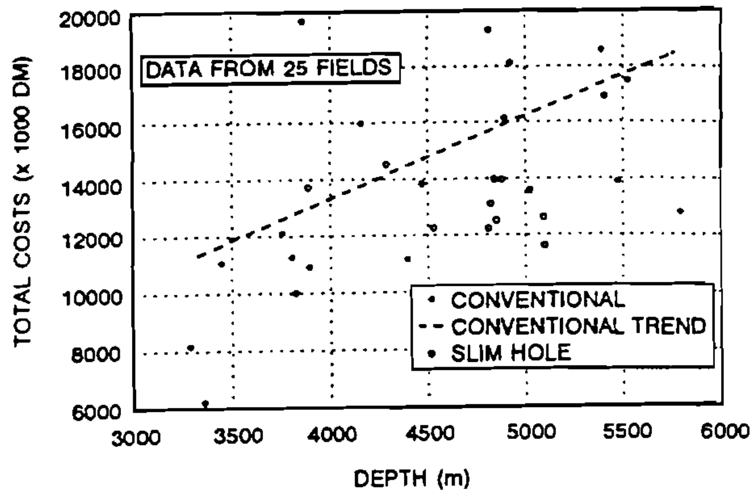

Figure 5-7. BEB's Conventional and Slim-Hole Costs (Worrall et al., 1992)

Shell's system has great potential for drilling operations on floating platforms. Smaller liners and casing programs allow the hook-load capacity to be reduced. Shell anticipated cost savings of £250,000–500,000 per well from these efficiencies.

Additional description of Shell's slim-hole drilling system is presented in the Chapter *Motor Systems*.

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6. Drilling Fluids

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6. Drilling Fluids

6.1 AMOCO PRODUCTION CO. (PIGMENT-GRADE BARITE)

Amoco Production Company (Randolph et al., 1992) investigated the benefits of pigment-grade barite for weighting slim-hole drilling fluids. They found that cationic brine muds can be weighted up to 14+ ppg with acceptable viscosity with this form of barite. Additionally, a centrifuge can be used to remove drill solids with only minimal loss of weighting material.

High-speed slim-hole coring operations cannot make use of conventional weighting materials, since these will be deposited inside the drill rod by cetrifugal forces and make retrieval of the core difficult or impossible. Previously, calcium chloride was the primary weighting agent used for SHADS operations (Amoco's pioneering slim-hole coring system). Maximum mud weight was 11.6 ppg. Calcium bromide was another option, although this was considered uneconomical and dangerous.

Conventional barite does have some potential use in coring operations. To decrease particle deposition within the drill pipe, rotation rates must be decreased if using conventional barite. Unfortunately, this approach results in lower ROPs.

Amoco experimented with pigment-grade barite as an alternative weighting material for slim-hole coring. This material is ground much finer than typical oilfield barite. Particle size of conventional barite is about 1-80 microns (μm) compared to pigment grade, which has a mean particle size of 0.18 microns and maximum size of 18 microns (Figure 6-1).

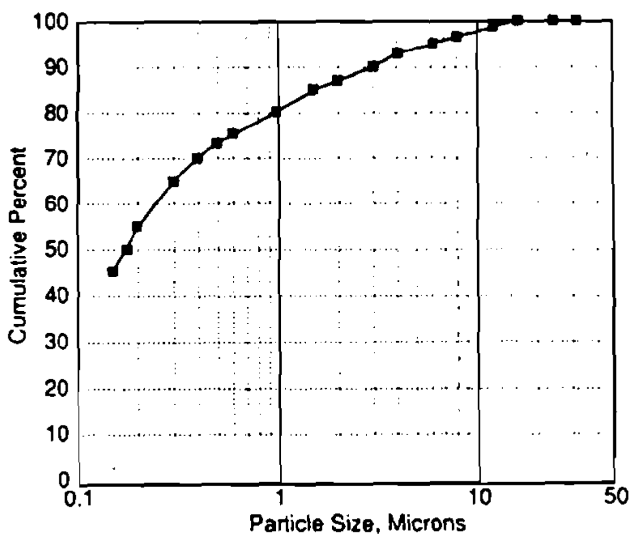

Figure 6-1. Particle Size of Pigment-Grade Barite (Randolph et al., 1992)

Amoco sought several qualities for a SHADS-compatible weighting fluid: it must not significantly increase the viscosity of the drilling fluid, it must disperse rapidly, it must allow removal of low-gravity solids, and it must not be centrifuged easily inside the drill pipe. Amoco's typical cationic brine drilling fluid contains 3-10% potassium chloride (shale inhibition), 4-10 lb/bbl cationic polymer (shale inhibition), 4-10 lb/bbl starch (fluid loss), and a polymer for viscosity.

A cationic brine fluid was weighted up to 14 ppg, while still maintaining acceptable viscosities (Figure 6-2).

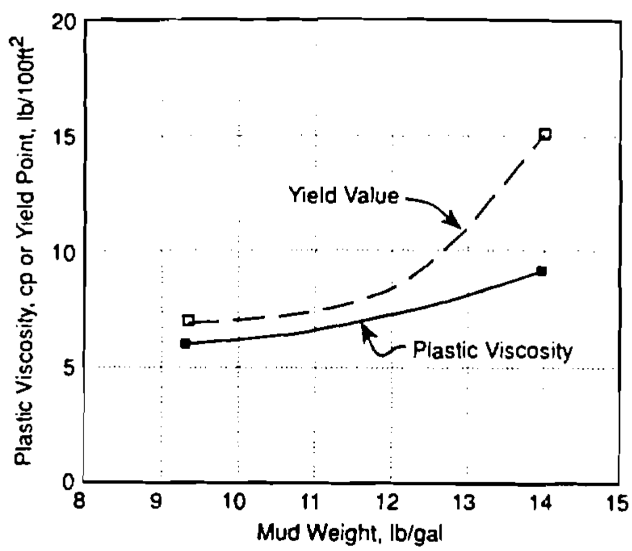

Figure 6-2. Viscosity of Weighted Cationic Brine (Randolph et al., 1992)

The impact of pigment-grade barite on viscosity was investigated for a range of viscosifier concentrations (Table 6-1). The results showed that fluid rheology can be adjusted by the addition of either additive.

TABLE 6-1. Rheology of Weighted Cationic Brine (Randolph et al., 1992)

Mud Weight (lb/gal)	Pigment-Grade Barite (lb/bbl)	Viscosifying Polymer (lb/bbl)	Plastic Viscosity (cps)	Yield Value (lb/100 ft²)
10.6	90	.5	5	3
11.5	158	.5	5	3
12.5	227	.5	5	2
13.3	303	.5	5	2
14.2	386	.5	6	4
10.5	90	1.0	7	9
11.5	158	1.0	8	8
12.2	227	1.0	8	8
13.2	303	1.0	9	7
14.2	386	1.0	9	7
10.4	90	1.5	8	15
11.4	158	1.5	10	15
12.4	227	1.5	12	14
13.2	303	1.5	14	12
14.2	386	1.5	16	17
10.4	90	2.0	11	22
11.5	158	2.0	13	25
12.2	227	2.0	15	24
13.2	303	2.0	16	24
14.1	386	2.0	19	24

Base Mud Formulation:

1	bbl	Water
39	lb/bbl	KCl
5	lb/bbl	Cationic Polymer
4	lb/bbl	Starch
20	lb/bbl	Drilled Solids

The effect of solids separation in a centrifuge or hydrocyclone on pigment-grade barite was considered. The particle size distributions for pigment-grade barite and a typical dispersive shale (Figure 6-3) show that it is possible to remove the majority of shale particles without removing much barite.

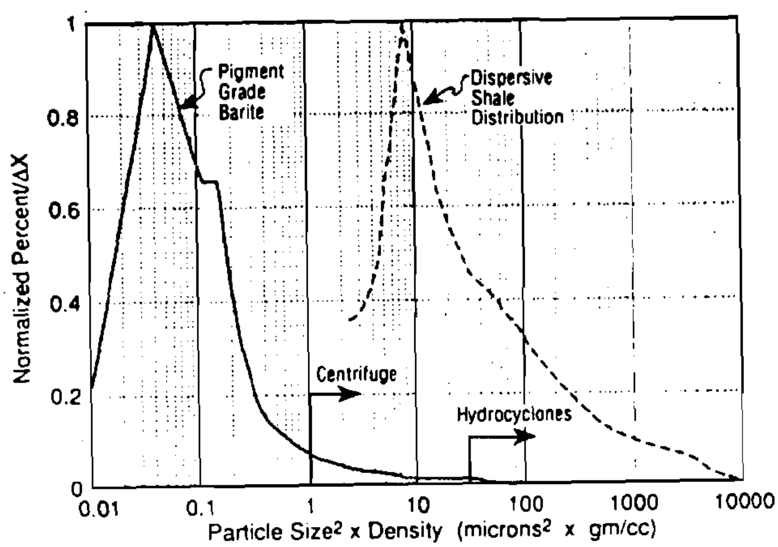

Figure 6-3. Particle Sizes for Shale and Barite (Randolph et al., 1992)

Tests were conducted to determine the rate of removal of pigment-grade barite by the centrifuge. Test apparatus are shown in Figure 6-4.

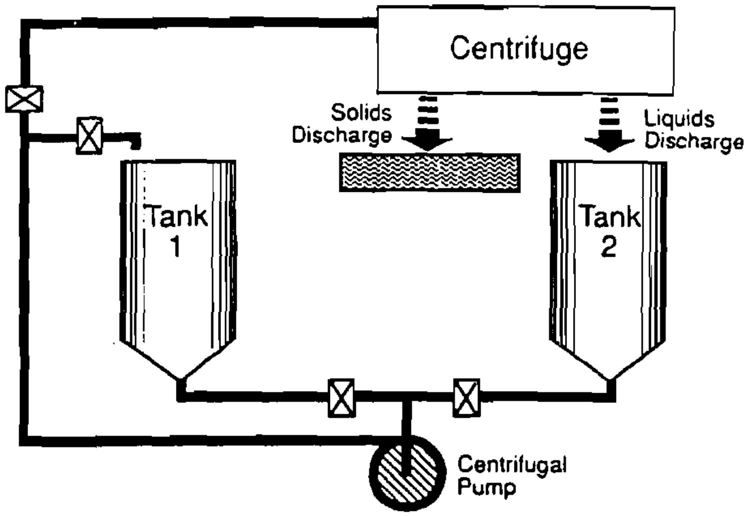

Figure 6-4. Test Set-up for Centrifuge (Randolph et al., 1992)

A 13 ppg slurry was circulated through the centrifuge. After circulation, the discharged solids were measured. The percentage of barite discharged decreased as the number of passes increased (Figure 6-5). After 12 passes, about 21% of the original quantity of barite was discharged for the 1647-rpm tests.

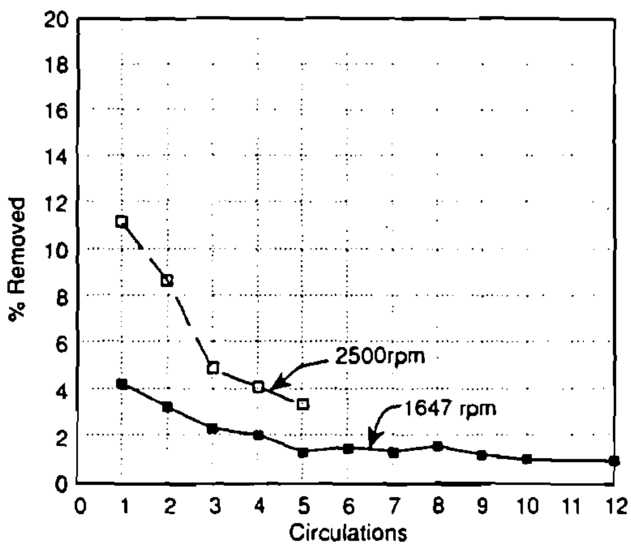

Figure 6-5. Barite Removed by Centrifuging (Randolph et al., 1992)

The effect of the loss of small quantities of barite on fluid weight was measured (Figure 6-6).

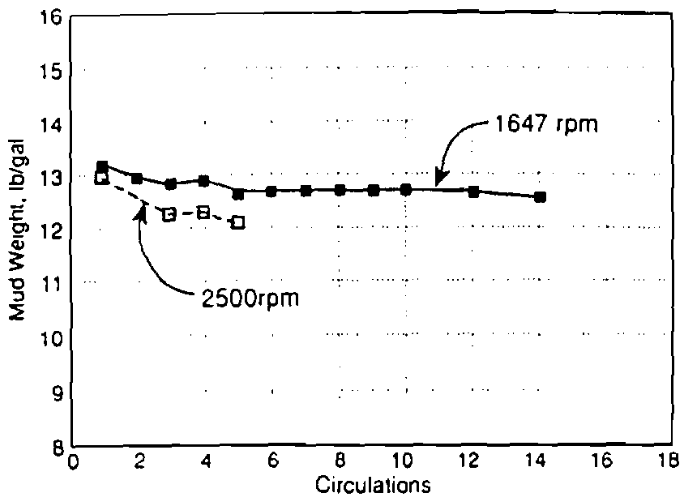

Figure 6-6. Fluid Weight and Barite Loss (Randolph et al., 1992)

A practical approach was developed to account for the loss of barite during field operations. The graph in Figure 6-7 can be used to estimate the weight of barite in the solids discharged from the centrifuge. For example, a discharge sample that weighs 16 ppg and is 54% solids consists of 10% barite by weight.

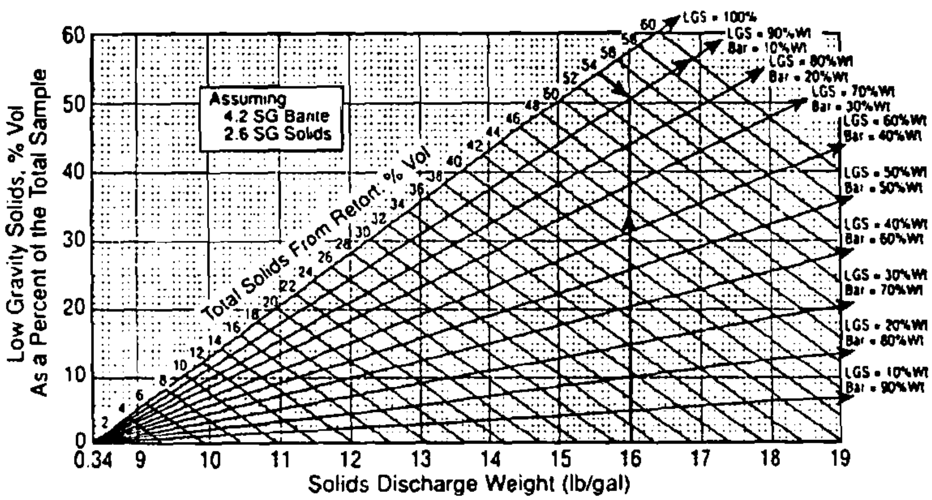

Figure 6-7. Method for Determining Percent Barite in Discharged Solids
(Randolph et al., 1992)

Amoco also conducted several tests in field wells to observe the performance of pigment-grade barite in coring and drilling operations. Flow rates, rotational speeds, and standpipe pressures were measured for tests with both CHD 76 (2.75-in. OD) and CHD 101 (3.7-in. OD) drill rods. Pressures with 14.8 ppg fluid are shown in Figures 6-8 (CHD 76) and Figure 6-9 (CHD 101).

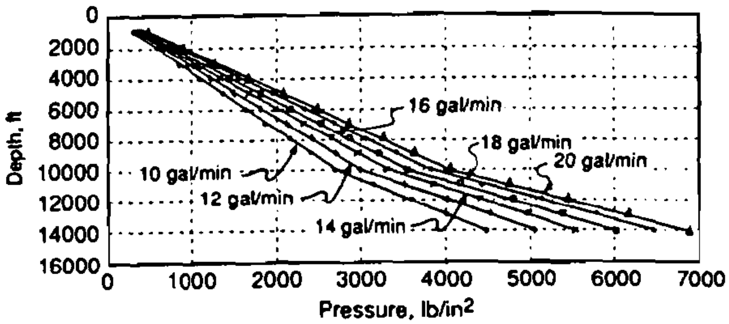

Figure 6-8. System Pressure Losses with CHD 76 Drill Rod (Randolph et al., 1992)

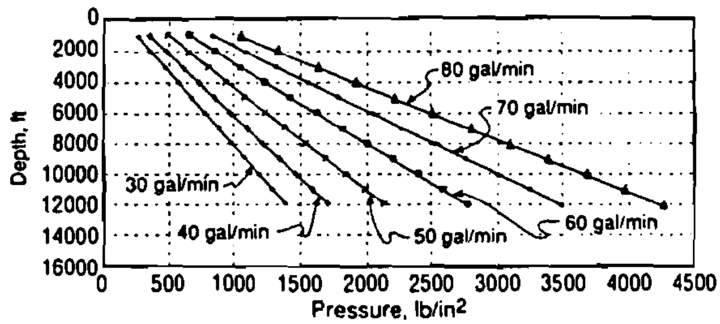

Figure 6-9. System Pressure Losses with CHD 101 Drill Rod (Randolph et al., 1992)

Amoco's investigations showed that useful drilling fluids can by formulated with pigment-grade barite as a weighting agent. Test results showed that coring could be conducted under the range of conditions described in Table 6-2.

TABLE 6-2. Conditions for Coring with Pigment-Grade Barite Fluids (Randolph et al., 1992)

Core Rods	Mud Weight (ppg)	PV (cp)	YP (lb/100 ft^2)	Starting Rotation (rpm)	Flow Rate (GPM)
CHD 76	15	17	23	0 - 600	0 - 25
CHD 101	15	15	11	0 - 550	0 - 60

6.2 ASAMERA SOUTH SUMATRA LTD. (SUMATRAN CASE HISTORY)

Asamera South Sumatra Ltd. (Almendingen et al., 1992) drilled/cored five exploratory wells in remote locations in South Sumatra. Conventional drilling procedures were not feasible for this campaign due to excessive time to construct access roads and high overall costs. A slim-hole mining approach via helicopter transport was used to evaluated the subject acreage.

Major equipment included a Longyear HM 55 helirig and Bell 205 helicopter. No serious operational problems were encountered during the five-well project. One instance of differential pipe sticking was remedied by spotting 5 gallons of diesel and reducing mud weight from 8.8 to 8.5 ppg. All wells were plugged and abandoned after formation evaluation.

For all five wells, a 4½-in. casing string was set at one-half of TD. TD was about 800 ft for two wells and 3500 ft for three wells (Figure 6-10).

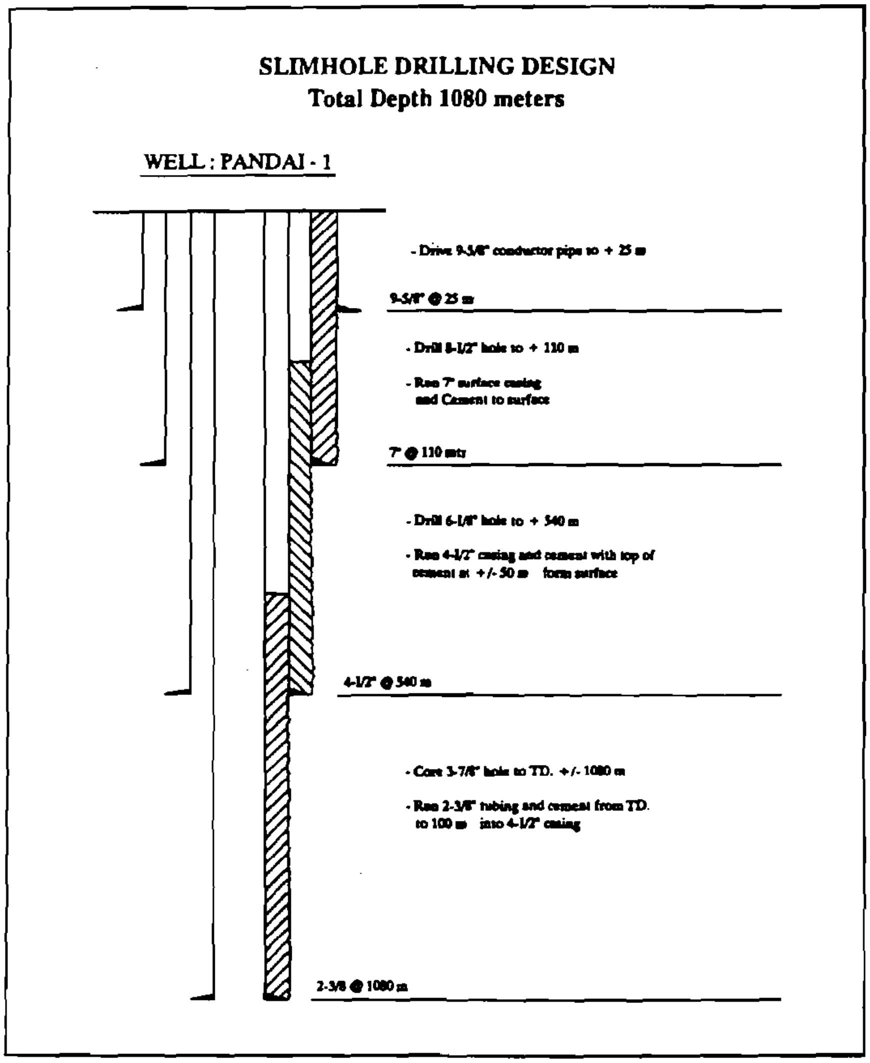

Figure 6-10. Slim-Hole Coring Well Schematic (Almendingen et al., 1992)

Destructive drilling using CHD-101 drill rods was used to drill down to the 4½-in. set point. Continuous coring was used thereafter to TD. A summary of the complete drilling program for the final well is shown in Figure 6-11.

ASAMERA (OVERSEAS) LTD DRILLING PROGRAM SUMMARY	WELL NO : PANDAI-1 TYPE WELL : EXPLORATION T.D : 1080 M RIG NO : MINTEX SLIM HOLE	LAT : 002°15'04.10" S LONG : 104°11'01.15" E KBE : 21.0 M (EST.) GLE : 15.6 M (EST.) X = 409 330.9 E Y = 9751 174.6 N

FORMATION	CASING	BITS	CEMENT	MUD PROGRAM	LOGGING PROGRAM
LOWER PALEMBANG	DRIVE 9-5/8" CSG 25 M	NONE	NONE	FW/NATIVE CLAY WITH ADDITIONS OF BENTONITE AND CAUSTIC SODA IF REQUIRED FOR RHEOLOGY CONTROL MW : 8.5 - 9.2 PPG VISC. : 30 - 45 SEC FL : N/C PH : 9.5	NO LOGS
	7" CSG AT 110 M	8-1/2"	PRE-FLUSH : 5 BBL MUD FLUSH CEMENT SLURRY 40 SX CLASS "G" + 2% PF GEL + 2.0% CACL2 SLURRY DENSITY : 13.8 PPG SLURRY YIELD : 1.59 CF/SX MIX WATER : 8.22 gal/sx FRESH WATER TOP OF CEMENT : SURFACE EXCESS : CALIPER + 30%		
	4-1/2" CSG AT 540 M	6-1/8"	PRE-FLUSH : 8 BBL MUD FLUSH CEMENT SLURRY 115 SX CLASS "G" + 2% PH GEL + 1.5% CACL2 SLURRY DENSITY : 13.8 PPG SLURRY YIELD : 1.59 CF/SX MIX WATER : 8.22 gal/sx FRESH WATER TOP OF CEMENT : SURFACE EXCESS : CALIPER + 15%	FRESH WATER, GEL, POLYMER, CMC-LV, SPERSENE AND CAUSTIC SODA MW : 8.9 - 9.4 PPG VISC. : 30 - 45 FL : 8 - 10 CC PH : 9.5	- IEL-SHS/SP/GR (OR TO SURFACE) - CNS-SHS/CDL-SHS/GR/CAL - SONIC-SHS/GR
TELISA MARKER 671 M BRF 892 M PENDOPO 923 M TAF 978 M BASEMENT 1050 M	2-3/8" CSG AT 1080 M	3-7/8"	PRE-FLUSH : 5 BBL MUD FLUSH CEMENT SLURRY 130 SX CLASS "G" + 20 GAL/10 BBL HALLAD-322L + 5 GAL/10 BBL CFR-3L SLURRY DENSITY : 15.8 PPG SLURRY YIELD : 1.15 CF/SX MIX WATER : 5 gal/sx FRESH WATER TOP OF CEMENT : ± 300 M FROM SURFACE EXCESS : CALIPER + 15%	POLYPLUS - K POLYPLUS AS PRIMARY VISCOSIFIER, POLYSAL TO CONTROL FLUID LOSS AND FILTER CAKE POLYPAC TO CONTROL FLUID LOSS AND VISCOSITY BRINE TYPE : KCL WITH ADDITIONS OF NACL FOR MUD WEIGHT CONTROL MW : 9.2 - 9.6 PPG VISC. : 20 - 40 SEC FL : 6 - 8 ml PH : 9.0 KCL : 3% SOLIDS : "NO SOLIDS" DRILLING FLUID MAX. 2% (VOL.)	- IEL-SHS/SP/GR - CNS-SHS/CDL-SHS/GR/CAL - SONIC-SHS/GR - VELOCITY SURVEY (SSL-SHS GEOPHONE)
TD : 1080 M					

Figure 6-11. Drilling Program for Final Well (Almendingen et al., 1992)

A low-solids drilling fluid was used in the cored 3⅞-in. hole to minimize cake build-up inside the drill rod. KCl, NaCl and $CaCl_2$ were used to weight the fluid. Small amounts of bentonite were added to ensure a thin, tough filter cake.

Coring operations were performed with a rotation speed in the range of 300-450 rpm. Annular clearance between drill rod and open hole was 0.1875 inches.

The shale shaker was not used for coring operations due to the small volume and size of the cuttings. The Polyplus-K mud would have flowed over the shaker and been wasted. A high-speed centrifuge was used to remove cuttings. Solids content was kept between 1-2%.

Mud weight ranged from 8.4 to 9.5 ppg for coring operations. PV was 3-14 and YP was 7-21. Partial losses (4-40 bbl/hr) on one well were overcome by adding 25 lb/bbl of Mad Seal and 25 lb/bbl of Kwikseal.

Additional details of this slim-hole coring program are presented in the Chapter *Coring Systems*.

6.3 ELF AQUITAINE (FORASLIM DRILLING SYSTEM)

Elf Aquitaine Production and Forasol S.A. (Sagot and Dupuis, 1994) described the design and operation of a purpose-built slim-hole rotary drilling rig. The Foraslim drilling system was constructed based on several cost-saving modifications. The number of personnel required at the site was reduced and operations were made more efficient.

The mud storage system was designed to allow detection of an influx as small as 80 l (21 gal). Mud tanks were designed with a tapered profile (Figure 6-12) to permit high resolution in the slim sections. The pit-level indicator has a minimum resolution of 5 mm (0.2 in.).

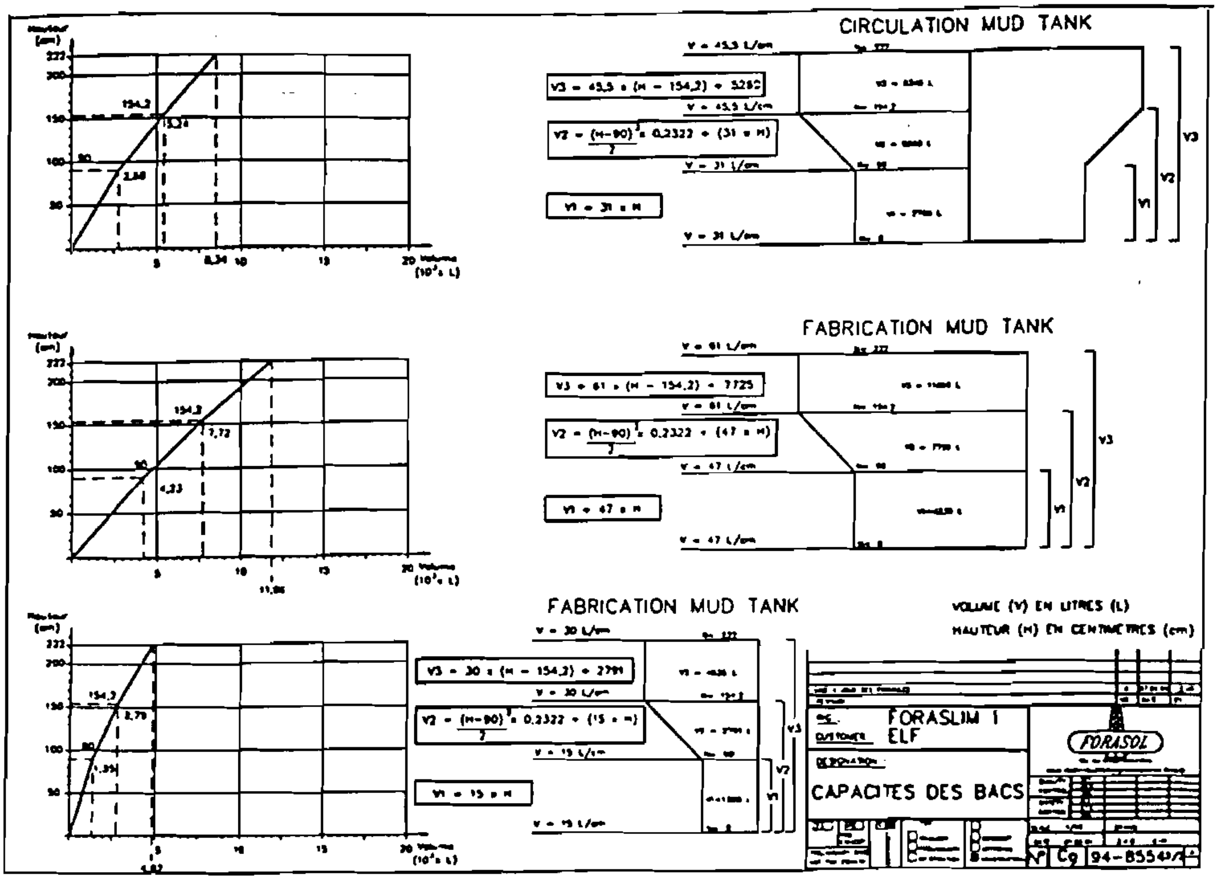

Figure 6-12. Foraslim Mud Tank Design (Sagot and Dupuis, 1994)

Circulating system design allows drilling without a waste pit, other than a 40 m^3 pit to collect drainage around the rig. Two centrifuges are used with a coagulation unit and a flocculation unit (Figure 6-13) for mud treatment. A linear-motion shale shaker is used.

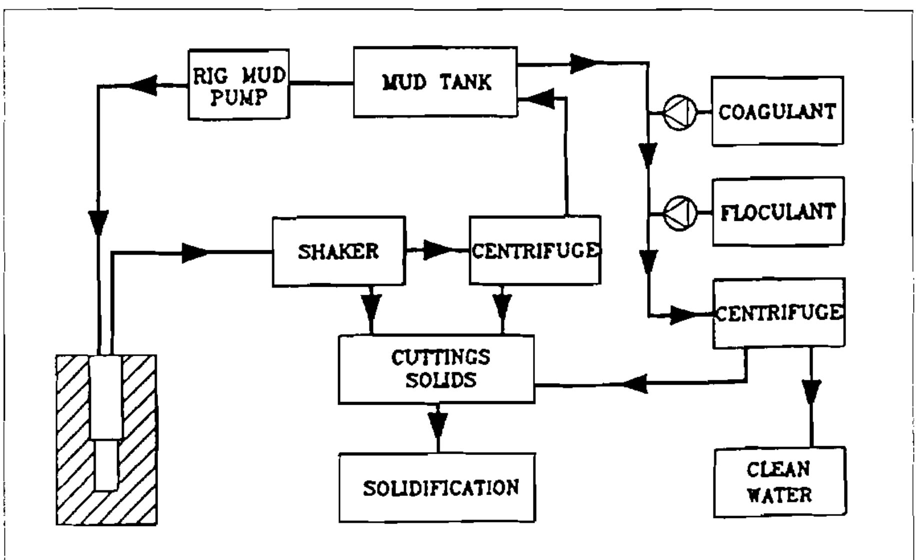

Figure 6-13. Foraslim Mud Treatment (Sagot and Dupuis, 1994)

The Foraslim rotary drilling system is described further in the Chapter *Rotary Systems*.

6.4 KONINKLIJKE/SHELL E&P (FORMATE BRINES)

Koninklijke and Shell E&P (Downs, 1992) worked together in the development of advanced drilling fluids for slim holes in harsh environments. They began developing a new group of high-density organic brine fluid systems that will minimize parasitic pressure losses while maintaining effective suspension properties. Among the advantages of formate brine systems are:

- They avoid the problems of solid weighting agents with respect to slim-hole coring and well control
- Pressure losses in deep slim holes are comparable with conventional systems
- They are non-hazardous fluids compatible with conventional equipment
- They are readily biodegradable
- Easy to maintain and can be run in closed-cycle/recycle systems

Industry's experience has demonstrated that traditional muds weighted with solids are not ideal for use in deep slim holes due to high frictional pressure losses. These pressure losses result in reduced hydraulic power available to drive the motor, reduced ROPs, high ECDs and high surge and swab pressures. Conventional muds may perform less effectively at high temperatures for hole cleaning, solids suspension and control of fluid loss.

New brine systems were developed to address these shortcomings. Shell experimented with sodium and potassium formates (Table 6-3). These are about the same density as sodium chloride, but have very high solubility, allowing densities up to 1.6 g/ml.

TABLE 6-3. Properties of Formate Brines (Downs, 1992)

Brine	Formate Concentration (% w/w)	Density @ 20°C (g/ml)	Viscosity @ 20°C (c St)	pH
Sodium formate	45	1.338	7.1	9.4
Potassium formate	76	1.598	10.9	10.6

Cesium formates have also been considered. All of these salts have been shown to be biodegradable and have low toxicity. An important benefit for using these cesium formates in drilling fluid is that they reduce the rate of hydrolytic and oxidative degradation of viscosifiers and fluid-loss additives at high temperatures.

Xanthan gum, a widely used viscosifier, can be maintained at higher temperatures in a formate brine. Very little thermal thinning is observed for xanthan in potassium-formate brine for temperatures up to 175°C (350°F) (Figure 6-14). However, thermal thinning is observed in sodium-formate brine.

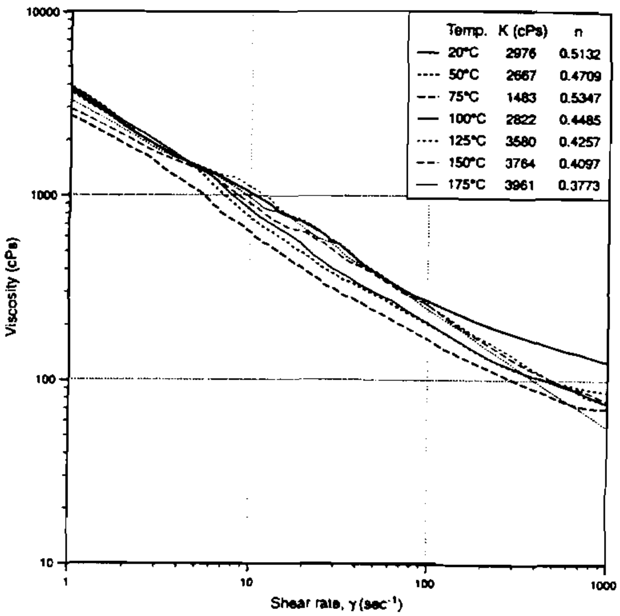

Figure 6-14. Rheology of Xanthan in Potassium Formate Brine (Downs, 1992)

Koninklijke and Shell E&P developed two new drilling fluids based on these formate brines. One fluid, SFX-1, is based on sodium-formate brine and maintains good properties up to 150°C (300°F) (Table 6-4).

TABLE 6-4. Properties of SFX-1 Sodium-Formate Drilling Fluid (Downs, 1992)

Parameter	Before hot rolling		After hot rolling 16 hours @ 150°C		After hot rolling 72 hours @ 150°C	
Temperature (°C)	25	50	25	50	25	50
Fann 600	87	50	77	45	64	39
300	55	33	48	29	39	25
200	41	26	35	23	30	19
100	27	18	23	16	20	13
6	5	4	7	5	6	4
3	5	4	5	4	4	3
PV (cP)	32	17	29	16	25	14
YP (lb/100 ft^2)	23	16	19	13	14	11
Gels 10"/10'	6/8	5/7	7/8	5/7	4/6	3/4
HT/HP fluid loss @ 150°C	21		20		24	

Another drilling fluid, PFX-1, was designed based on potassium-formate brine. This drilling fluid can be mixed to higher weights and also maintains good rheology up to 150°C (Table 6-5).

TABLE 6-5. Properties of PFX-1 Potassium-Formate Drilling Fluid (Downs, 1992)

Parameter	Before hot rolling		After hot rolling 16 hours @ 150°C		After hot rolling 72 hours @ 150°C	
Temperature (°C)	25	50	25	50	25	50
Fann 600	103	62	107	65	121	63
300	62	39	64	41	71	39
200	47	30	48	31	53	30
100	30	20	30	20	33	19
6	7	4	7	4	6	4
3	5	3	5	3	4	3
PV (cP)	41	23	43	24	50	24
YP (lb/100 ft²)	21	16	21	16	21	15
Gels 10"/10'	5/7	3/4	5/6	3/4	5/6	3/4
HP/HT @ 150°C	34		38		27	
API fl. loss	2.3		1.9		1.1	
pH	9.9		10.1		10.1	

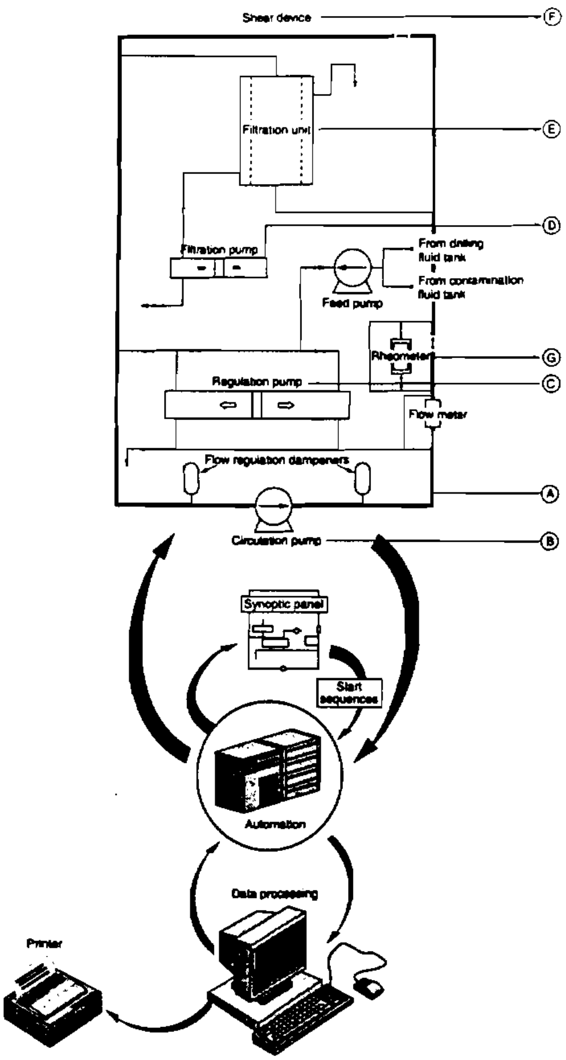

Figure 6-15. High-Temperature/High-Pressure Flow Loop (Downs, 1992)

These fluids were tested in the high-temperature/high-pressure flow loop (Figure 6-15) at the Institut Français du Pétrole. Bottom-hole conditions were simulated for harsh environments at temperatures up to 180°C (356°F), pressures to 500 bar (7250 psi), and shear rates to 10,000 sec^{-1}.

Flow-loop tests confirmed that the systems based on sodium-formate brine exhibit some thermal thinning at elevated temperatures (Figure 6-16).

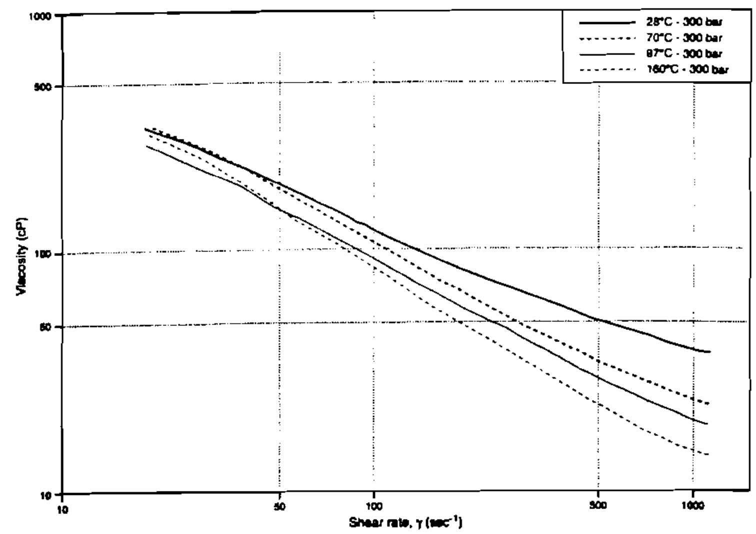

Figure 6-16. Rheology of SFX-1 Fluid in Flow Loop (Downs, 1992)

The effect of fluid aging was also investigated. Little effect was observed at 120°C (248°F) or 140°C (284°F). However, at 160°C (320°F) a progressive deterioration of rheology was observed (Figure 6-17).

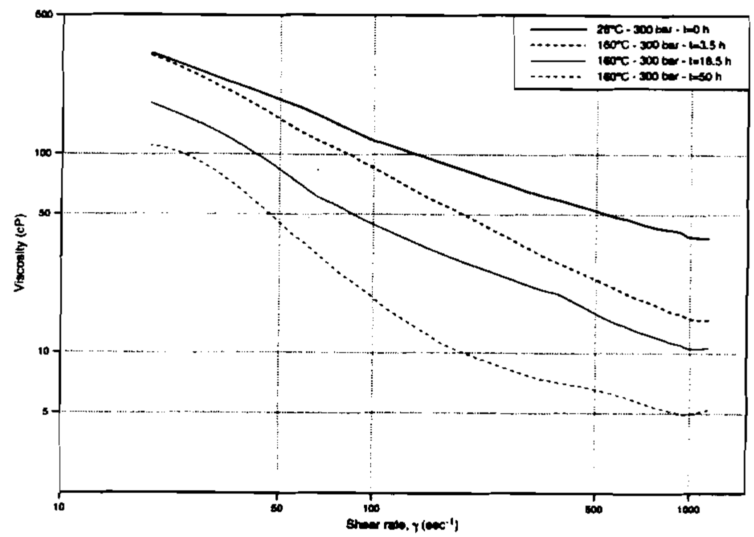

Figure 6-17. Rheology of SFX-1 Fluid at 160°C Over Time (Downs, 1992)

Koninklijke and Shell E&P planned to continue developing these drilling fluids. Field tests were also to be conducted in the near future.

6.5 REFERENCES

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7. Horizontal Drilling

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7. Horizontal Drilling

7.1 CHESAPEAKE OPERATING (RECORD SLIM HORIZONTAL WELL)

A world-record slim-hole re-entry was drilled in the Giddings Field in Fayette County, Texas by Chesapeake Operating Inc. and Ameritech Horizontal Drilling Services Inc. (*American Oil & Gas Reporter* Staff, 1992). The Gloria No. 1-H was re-entered through 5½-in. casing and extended horizontally with a 4½-in. hole for over 4100 ft. Savings of $300,000 to $400,000 were estimated for this well as compared to a new horizontal well drilled to the Austin Chalk.

The Gloria No. 1-H is relatively deep, with a TVD of 10,944 ft (3336 m). Drilling conditions were harsh: fluid temperatures in excess of 300°F and surface casing pressures as high as 3000 psi.

The re-entry window was initiated by setting a cast-iron bridge plug in the 5½-in. casing. A bottom-trip whipstock was oriented and a window was cut. Three mill runs were made to ensure a smooth window.

A thermally stable diamond bit was used to drill the lateral. Bit design included a short-gauge flat-bottom profile. A 3½-in. motor designed for hot environments was used. The motor's bearing system is sealed in oil (Figure 7-1). A 1⅜-in. steering tool was used in a wet-connect configuration. The connection point was oriented high in the hole to keep the probe cool.

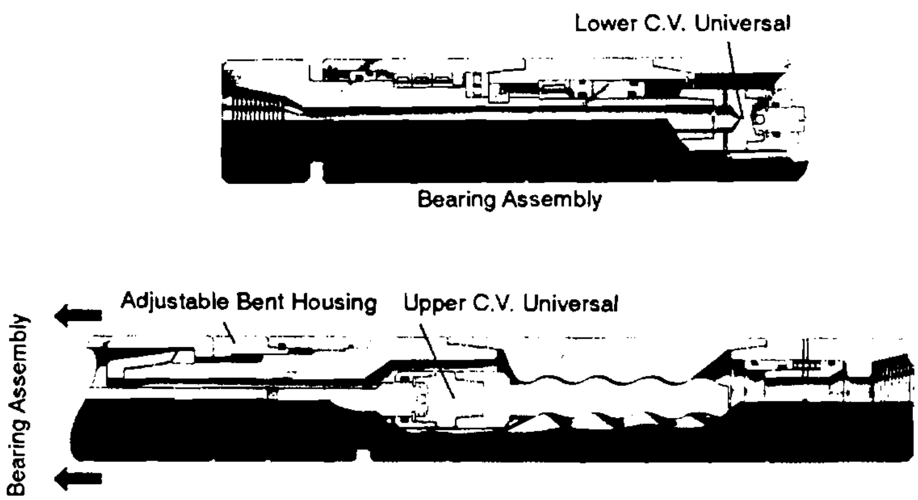

Figure 7-1. Slim Motor with Sealed-in-Oil Bearings (*American Oil & Gas Reporter* Staff, 1992)

The slim-hole drill string consisted of 2⅞-in. PH6 tubing with two stainless-steel 3½-in. drill collars.

Special training was given to the crew in blowout prevention in the slim hole. Kicks that occurred during drilling operations were circulated from the hole successfully.

The re-entry initially produced at 636 BOPD and 1.7 MMscfd of gas. Chesapeake was pleased with the results of this effort and acquired enough acreage in the field to allow re-entering 85 more vertical wells.

7.2 ORYX ENERGY (AUSTIN CHALK SLIM HOLES)

Oryx Energy Company (Hall and Ramos, 1992) investigated the use of slim-hole technology to lower costs for horizontal re-entries and new wells in the Pearsall Field in South Texas. Their approach was to compare the economics of both reduced-size holes (between 6 and 8 in.) and slim holes (less than 6 in.) to conventional holes (greater than 8 in.) (Table 7-1). They determined that the use of slim holes is technologically and economically viable for reducing costs. Their experience showed that the risks and assumed limitations of slim laterals on production capacity are not as significant as many assume.

TABLE 7-1. Comparison of Conventional, Reduced and Slim Horizontal Holes (Hall and Ramos, 1992)

	HOLE DESIGN		
ITEM	CONVENTIONAL	REDUCED	SLIM
Lateral Diameter	8½"	6⅛"	3⅞"
Build Rates (deg/100')	10–12	13–15	16–20+
Radius of Build (ft)	573–477	440–382	358–287
	CASING DESIGN		
Surface	13⅜"	10¾"	8⅝"
Intermediate	9⅝"	7"	4½"

In the past, limitations of downhole equipment have hindered the feasibility of drilling slim horizontal sections. Cost savings from smaller tubulars, rigs, etc. were more than offset by lower ROPs and directional control problems. Thus, many of the lessons learned and benefits with slim vertical wells were not readily transferred to horizontal operations.

Several practical considerations should be carefully weighed in the decision for (or against) slim horizontal wells. For example, re-entered wells in depleted reservoirs will often not produce at high enough rates to be rate-limited by smaller tubing. Additionally, a large population of wells in mature fields are completed with 4½-, 5- or 5½-in. casing. Slim horizontal re-entries may offer the only option for increasing reserves in these areas. One disadvantage is that achievable horizontal lengths may be less in slim holes. However, if a long lateral is not needed to achieve the desired allowable production rate, why should the operator spend extra to drill beyond the range of lengths where slim holes are competitive?

A major limitation in slim horizontal drilling operations is the difficulty transmitting weight to the bit. Larger drill strings provide significantly more weight, which in turn improves the ability to correct build angle. Steering difficulties caused by low WOB are a problem for both rotary operations (Figure 7-2) and slide drilling (Figure 7-3). Data in these figures were obtained using torque and drag models.

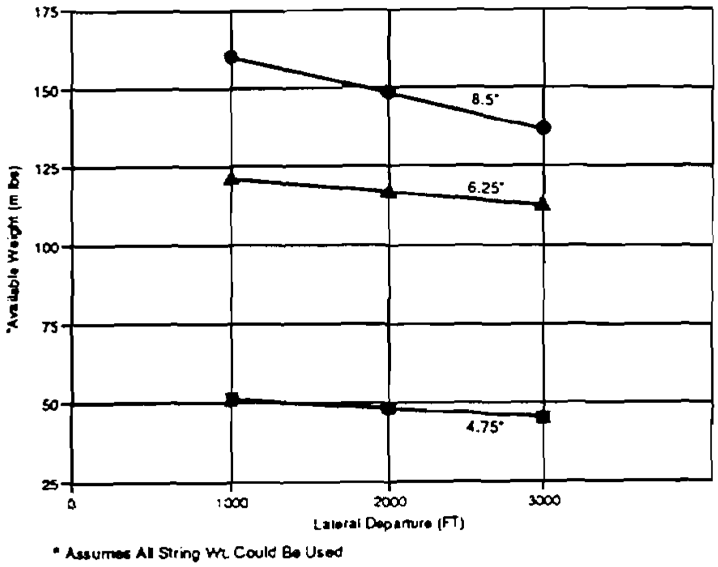

Figure 7-2. Lateral Length and WOB for Rotary Drilling (Hall and Ramos, 1992)

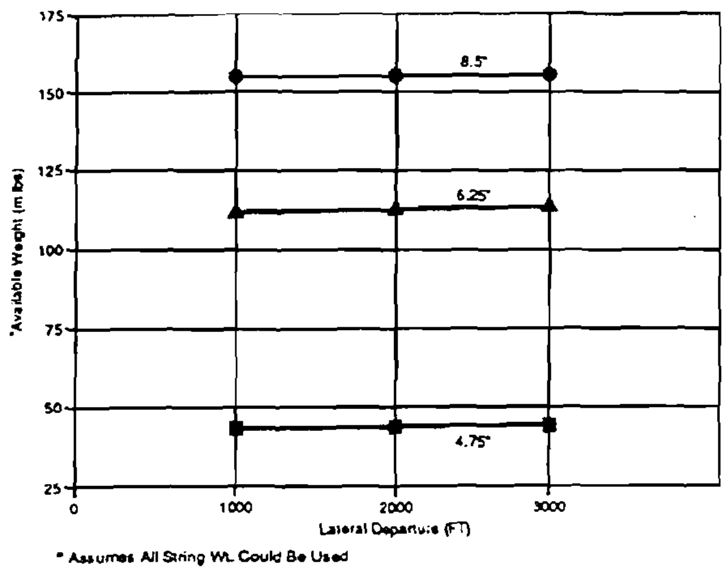

Figure 7-3. Lateral Length and WOB for Slide Drilling (Hall and Ramos, 1992)

The loss of WOB as the lateral length increases results in a maximum horizontal reach of about 2500 ft for slim holes versus over 4000 ft for larger conventional holes. Another limitation has been the availability of slim directional tools. MWD systems have not been available for smaller holes. Conventional tools have had to be used for determining hole orientation, resulting in a loss of efficiency.

Conventional rigs have been used in the Austin Chalk area for drilling slim holes. Advantages of this approach are that these rigs are readily available and familiar to operators and contractors. The disadvantage is the lower efficiency of paying for more rig than is required.

Workover or service rigs are another possibility. Their rental rates are cheaper; however, most are not fully equipped for drilling. Much auxiliary equipment has to be rented, and personnel may need to be trained, resulting in lost efficiency.

Coiled-tubing rigs are becoming more practical for these slim-hole drilling operations. The first coiled-tubing horizontal well was drilled by Oryx in this area. A chapter discussing coiled-tubing drilling technology is presented in the companion volume *Coiled-Tubing Technology (1993-1994)*.

Slim-hole hydraulics are controlled by mud-motor requirements in horizontal applications. Slim-hole motors generally have flow rates of 60-120 GPM. Pulsation damping is normally an important consideration with slim-hole tools. Triplex pumps are recommended.

Oryx, as part of their extensive campaign of horizontal drilling in the Austin Chalk, drilled several slim horizontal wells to evaluate the technologies involved. A typical new horizontal well in the Pearsall Field is shown in Figure 7-4; a typical re-entry in these projects is shown in Figure 7-5.

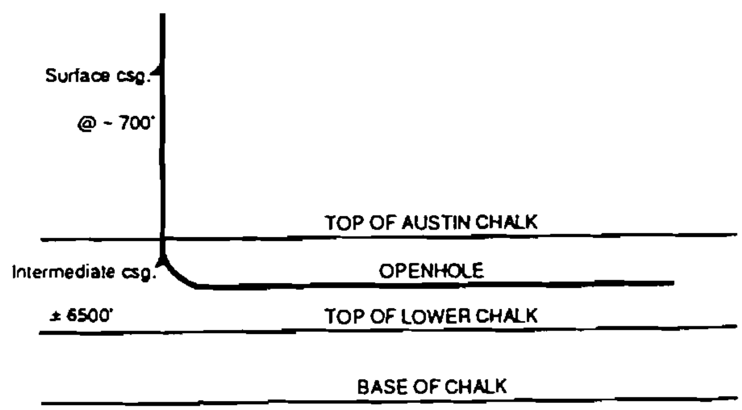

Figure 7-4. Typical Profile for New Horizontal Well in Pearsall Field (Hall and Ramos, 1992)

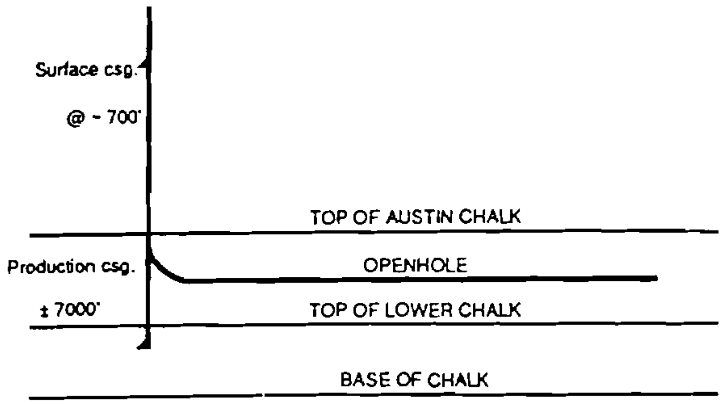

Figure 7-5. Typical Profile for Horizontal Re-entry in Pearsall Field (Hall and Ramos, 1992)

Oryx performed a series of slim-hole re-entries in 1990, drilling 4½-in. laterals out of 5½-in. casing. The first five re-entries were only slightly cheaper than a new conventional well. The primary problem in the slim-hole operations was the lack of a dependable steering tool. The following year an improved tool was developed. Slim-hole ROP and lateral reach increased, and costs and drilling days decreased. Table 7-2 summarizes the 1990 and 1991 slim-hole efforts.

TABLE 7-2. Success of Slim-Hole Re-entries in Pearsall Field (Hall and Ramos, 1992) 1990 Vs. 1991-1992*

ITEM	1990	1991
Total Well Cost Index*	0.85	0.40
Avg. Lateral Departure	1864	1980
Days	32	22
Lateral Cost/Ft Index	1.72	0.79
*Using 1990 Conventional Well Costs = 1.00		

Another development campaign was initiated to test the viability of new slim horizontal wells in more marginal areas of the field. The project plan included the use of a small drilling rig for performing all tasks prior to setting intermediate casing. Next, a workover rig was to be used to finish drilling and to complete the well. New slim MWD tools were available and would be used in place of the wireline steering tools.

The first slim (4½ in.) well had several problems principally with mud motors and directional equipment. Practical experience was gained and then applied to the second well. Costs for the second well were greatly improved: 20% less than the first slim well and 32% less than conventional (Table 7-3).

TABLE 7-3. Costs of New Slim-Hole Wells in Pearsall Field (Hall and Ramos, 1992)

	HOLE SIZE	DEPTH/ DISPLACEMENT	LATERAL COST	TOTAL COST
CONVENTIONAL	8 1/2 in.	10,289'/3741'	1.00	1.00
REDUCED HOLE	6 1/8 in.	9698'/3257'	0.87	0.82
1st SLIM HOLE	4 1/2 in.	9568'/3110'	0.89	0.83
2nd SLIM HOLE	4 3/4 in.	9697'/3154'	0.73	0.68

In summary, Oryx found that both slim new wells and re-entries were more economic than conventional new wells, after benefits from rapid learning curves and new tools were incorporated (Table 7-4). They also believe that the risks and perceived limitations of slim boreholes on production may not be as significant as often thought.

TABLE 7-4. Economics of Slim Horizontal Wells in Pearsall Field (Hall and Ramos, 1992)

	HOLE SIZE	DEPTH/ DISPLACEMENT	LATERAL COST	TOTAL COST
CONVENTIONAL	8 1/2 in.	10,289'/3741'	1.00	1.00
REDUCED HOLE	6 1/8 in.	9698'/3257'	0.87	0.82
SLIM-HOLE RE-ENTRY	3 7/8 in.	---/1980'	2.38	0.50
NEW SLIM HOLE	4 3/4 in.	9697'/3154'	0.73	0.68

Additional discussion of Oryx's economic results with slim horizontal drilling is presented in the Chapter *Drilling Cost and Time*.

7.3 SLIMDRIL INTERNATIONAL (RE-ENTRIES IN 4½-IN. CASING)

Horizontal re-entries have been performed routinely out of casing as small as 5½ inches. Several hundred 5½-in. re-entries have been performed in Austin Chalk fields. Technical benefits of re-entries over new wells include the availability of drilling records, well logs and seismic data on the old well. These data help the operator plan the optimum azimuth for the lateral.

Based on techniques used in these re-entries, several slim-hole re-entries through 4½-in. casing have been successfully performed (Pittard et al., 1992). In most cases in the Austin Chalk, smaller borehole sizes are not an overriding concern due to the predominance of open-hole completions.

Tubular strength issues become more critical with these slim re-entries. Smaller diameter drill strings must be treated with more care, particularly in milling operations where high torque is encountered. Lateral displacements are usually less with the smaller holes and reduced bit weights that can be attained.

Section milling (Figure 7-6) has been used for many 5½-in. re-entries. SlimDril recommends using a power swivel for section-milling 4½-in. casing to avoid generating excessive torque. After an approximately 60-ft section of casing is removed, the hole is usually underreamed 1 to 3 in. to remove the old cement sheath and provide a new surface for a clean bond.

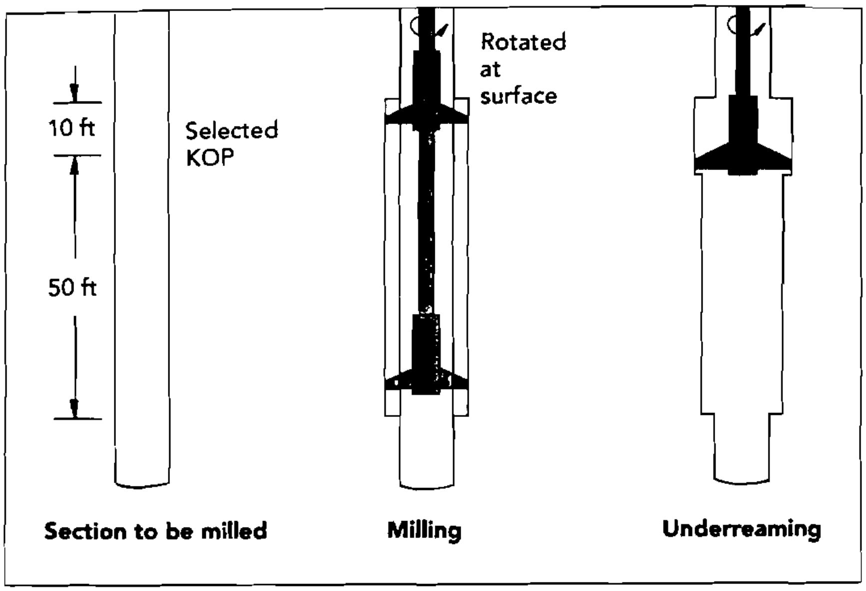

Figure 7-6. Section Milling for Slim Re-entry (Pittard et al., 1992)

Window milling has also been used successfully. This procedure can reduce the time required for sidetracking because less casing material is removed, no cement plug is required, and the sidetracking operation is performed while milling the window.

A typical BHA for a slim re-entry is shown in Figure 7-7. Assemblies for larger holes normally include centralizers. Slim assemblies can usually achieve the required build rates without centralizers.

Re-entries through 4½-in. casing can often be performed with a workover rig. A few modifications are required, including the addition of a power swivel and a mud circulation system with solids-removal equipment. The most common drill strings are 2⅜-in. tubing with CS-Hydril or PH-6 connections. The PH-6 connection has a higher torque rating, but this comes at the expense of a reduced ID.

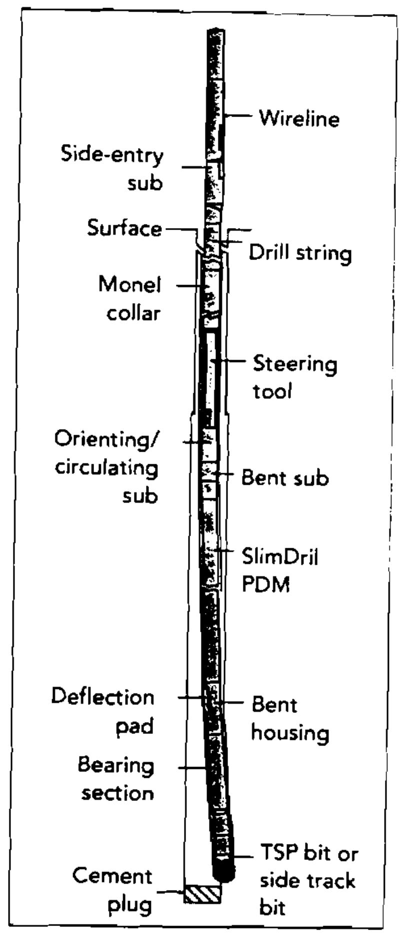

Figure 7-7. BHA for 4½-in. Slim Re-entry (Pittard et al., 1992)

In one of the first 4½-in. re-entries in the Austin Chalk, window milling was used successfully. However, the use of PH-6 connections prevented the passage of any available gyroscopes. Directional problems were experienced (Figure 7-8) while the steering tool was still in the existing casing. However, the lateral was eventually drilled as planned.

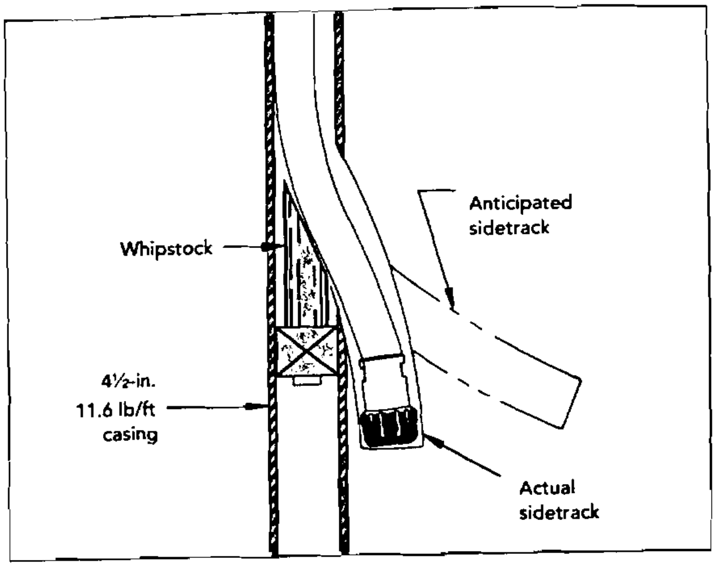

Figure 7-8. Directional Problems in 4½-in. Re-entry (Pittard et al., 1992)

In another well re-entered in Lee County, Texas, a modified workover rig was used to drill two laterals (Figure 7-9). A tapered drill string was used with 2⅞-in. pipe in the vertical section and 2⅜-in. in the curve and horizontal sections.

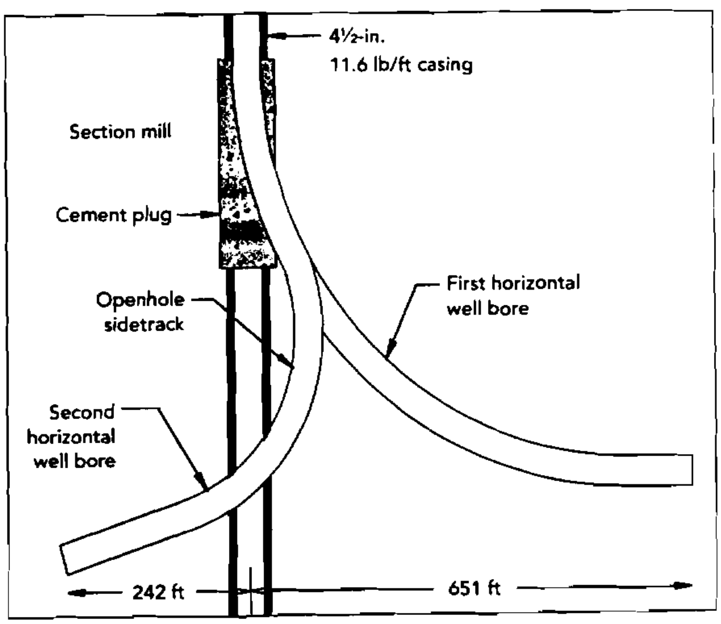

Figure 7-9. Dual Lateral 4½-in. Re-entry (Pittard et al., 1992)

The second lateral was kicked off by open-hole sidetracking. The BHA was repeatedly run across a short section of the first lateral to drill a trough in the wall. Time-drilling was used to start the second hole. The entire project was successfully completed in 9 days.

7.4 REFERENCES

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Pittard, Fred J., Weeks, Randall D. and Wasson, Michael R., 1992: "Slimhole Horizontal Re-Entries Provide Alternative to New Drills," *Petroleum Engineer International,* November.

8. Hydraulics

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8. Hydraulics

8.1 BP EXPLORATION (EKD SYSTEM)

BP Exploration and BP Research (Swanson et al., 1993) described the development of the Early Kick Detection (EKD) system based on real-time analysis of data obtained from a slim-hole rig during operations. The use of the EKD in conjunction with a slim-hole drilling operation has been shown to provide a basis for diagnosing abnormal drilling events, including gas kicks, mud losses and pipe washouts.

The special concerns for well control in slim holes are centered around the impact of a small annulus on hydraulics. Kicks must be identified that are considerably smaller than those identified by conventional technology. For example, conventional kick-detection sensitivity required for safe operations may range from a 10- to 25-bbl increase in pit volume. For many slim-hole applications, a detection threshold of 1 bbl is required.

Rotation of the drill string often has a significant impact on pressures (and flow rates) throughout the well. Kick events must be readily differentiated from normal background noise in the flow.

The hydraulics models in BP's EKD are modified to account for slim-hole pipe rotation and eccentricity. Model predictions for a 1000-m (3300-ft) well with 3.65-in. drill pipe in 4.8-in. hole (0.58-in. annulus) illustrate the impacts of flow rate and rotation (Figure 8-1). Note that at low flow rates, rotation has little effect.

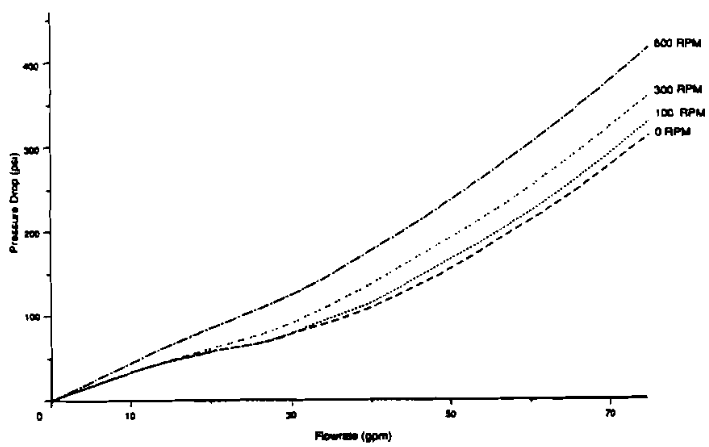

Figure 8-1. Predicted Impact of Rotation (Swanson et al., 1993)

BP Exploration's EKD model is described further in the Chapter *Well Control*.

8.2 DB STRATABIT/TOTAL (HYDRAULICS MODEL)

DB Stratabit and Total (Delwiche et al., 1992) developed a model of slim-hole hydraulics to predict pressure drop with rod rotation in coring applications. The small annulus and high drill-string rotation speeds typical of mining coring technology (Figure 8-2) make accurate hydraulics modeling critical from the aspects of wellbore stability and cuttings transport.

Parameters	*Oil-well drilling*	*Slimhole drilling*
Ø rod / Ø hole =	about 0,30	about 0,85 and more
annulus clearance	large (more than 50 mm)	slim (less than 20 mm)
rod rotation speed (rpm)	small (up to 150-200 rpm)	high (200 to 800 rpm)
losses inside rods	about 90% of total losses	about 10% of total losses
losses inside annulus	about 10% of total losses	about 90% of total losses
couette effect	weak	important
crescent effect	inexistant	important
mud rheological model	no need much precision	need of an accurate model

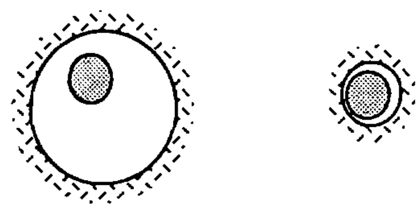

Figure 8-2. Comparison of Conventional and Coring Hydraulics (Delwiche et al., 1992)

Characteristics of the drilling fluid, circulation rates and annular dimensions must be chosen to provide several benefits:

- Cuttings removal, with annular velocity profiles as uniform as possible
- Wellbore stability, with small velocity gradients to minimize shear stresses and maintain annular pressures below fracture pressure
- Optimized bit performance, with sufficient flow rates to cool the bit and avoid clogging
- Optimized circulation rate for minimizing overall power requirements

Once formation type, drill-string design and bit diameter are known, a range of optimum flow rates can be designed for each particular mud. An example of this analysis is shown in Figure 8-3. The x-axis represents the percentage volume of cuttings in the mud.

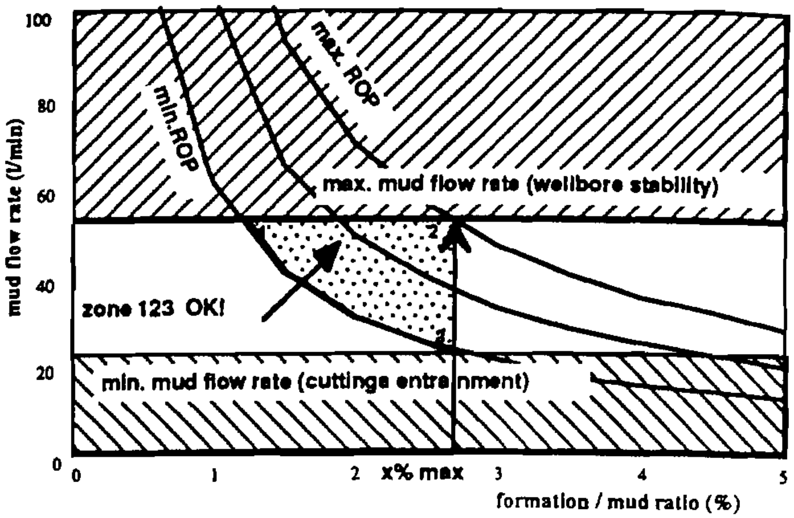

Figure 8-3. Analysis of Optimum Circulation Rate (Delwiche et al., 1992)

DB Stratabit and Total began with three principal rheological models: Newtonian, Bingham and Oswald (also referred to as power-law fluid) (Figure 8-4). A relatively wide zone of constant velocity is possible with both Bingham fluids (high YP) and Oswald fluids (low index).

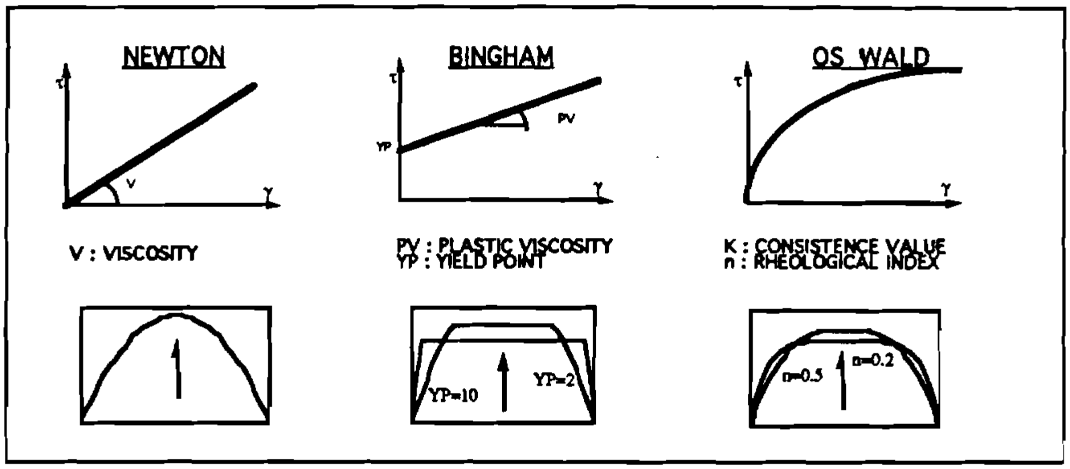

Figure 8-4. Velocity Profiles for Hydraulics Models (Delwiche et al., 1992)

They developed a new model (three-parameter model) that is more complex than either Bingham or Oswald. Many muds used in conventional and slim-hole applications resemble both Bingham and Oswald fluids. Measured shear rates are contrasted with model predictions in Figure 8-5.

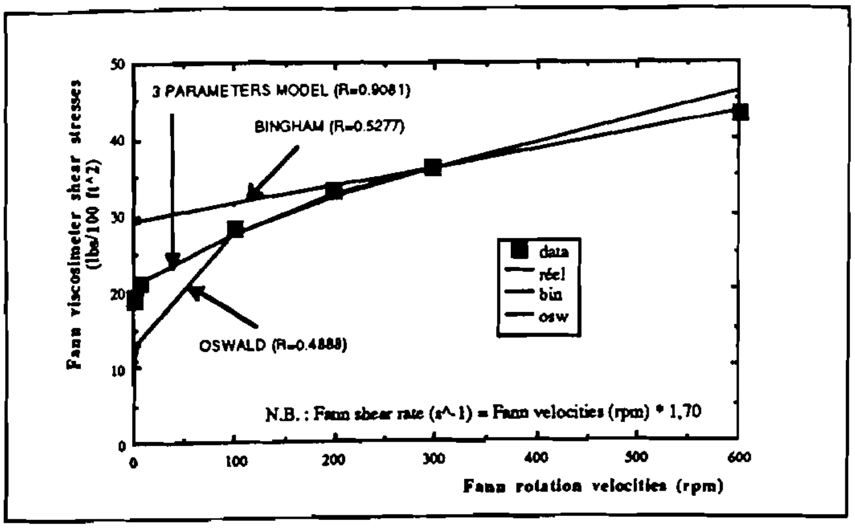

Figure 8-5. Slim-Hole Mud Data and Predictions (Delwiche et al., 1992)

The prediction of dynamic pressure in a slim-hole annulus is very sensitive to the choice of model. The smaller the annulus, the more difficult this calculation becomes. In a conventional drilling condition (5-in. drill pipe in 13⅜-in. casing), ECD predictions vary over a range of only about 1% for the flow rates shown (Figure 8-6).

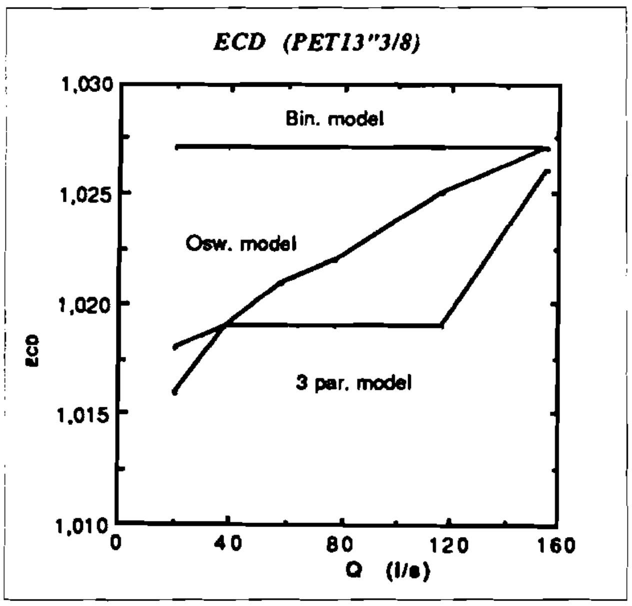

Figure 8-6. ECD Predictions in Conventional Hole (Delwiche et al., 1992)

By contrast, ECD predictions in a slim-hole coring application (3½-in. drill rod in 3⅞-in. casing) vary up to 25% between the three models (Figure 8-7).

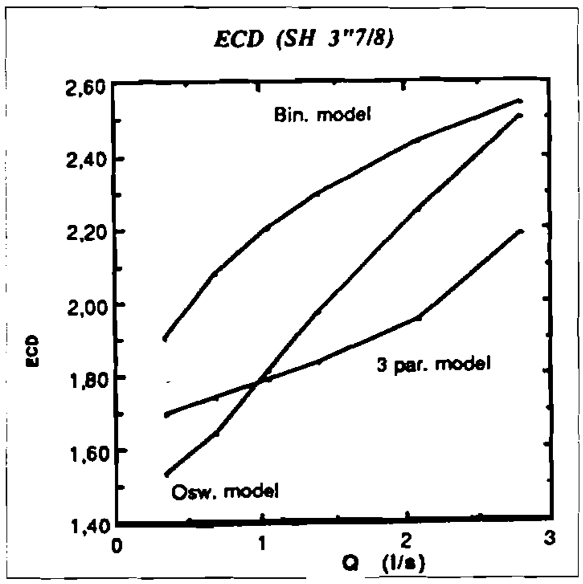

Figure 8-7. ECD Predictions in Slim Hole (Delwiche et al., 1992)

Rod rotation in slim-hole coring may induce the circulating fluid to follow a helical path up the annulus. This is termed the "Couette effect." A related effect is the "Pedalo effect," which results from transition of the annular flow from laminar to turbulent. As rotation speed is increased, the incremental fluid path length (ΔL) increases due to the Couette effect, then decreases due to Pedalo effect (Figure 8-8).

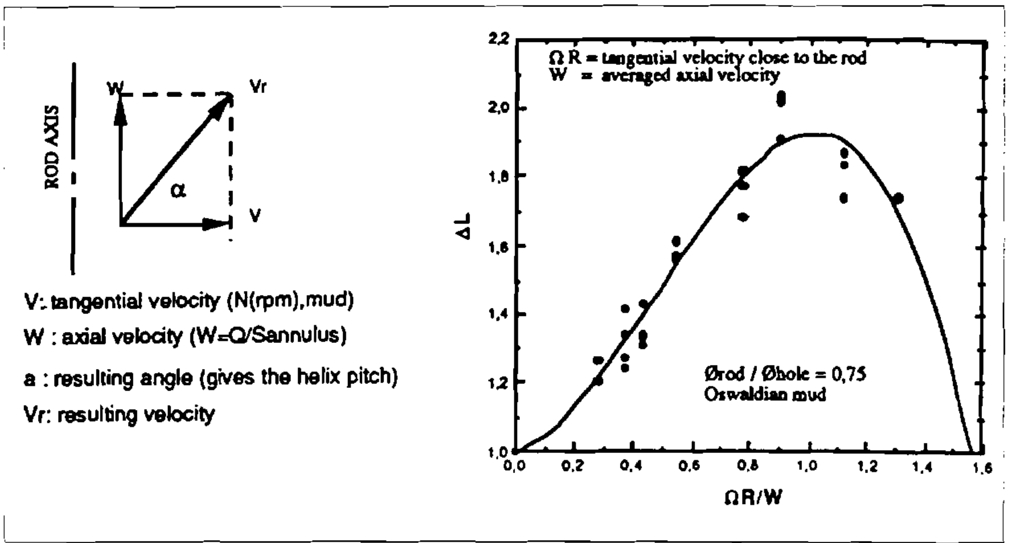

Figure 8-8. Couette and Pedalo Effects for Slim-Hole Mud (Delwiche et al., 1992)

The crescent effect is also an important concern in slim-hole hydraulics. Eccentricity of the slim-hole drill rods, which causes a crescent-shaped flow path, results in decreased annular pressure losses. The Ψ coefficient (ratio of eccentric loss to concentric loss) is plotted in Figure 8-9.

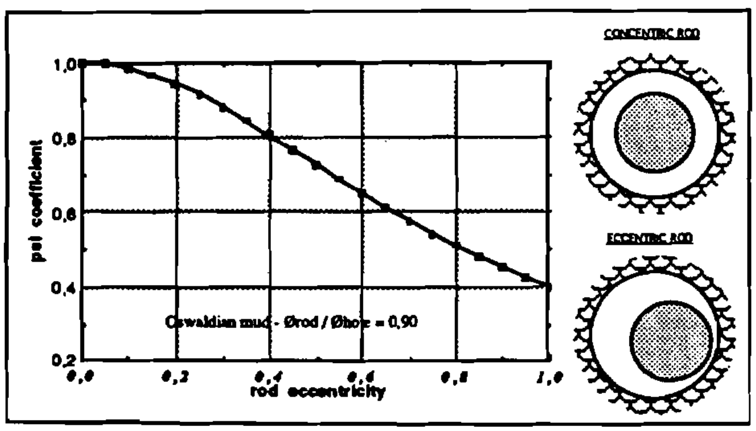

Figure 8-9. Effect of Eccentricity for Slim-Hole Mud (Delwiche et al., 1992)

DB Stratabit and Total performed a series of tests in field wells to analyze the accuracy of the various models for predicting slim-hole hydraulics. Measurements were made for a range of rotational speeds during coring operations in a well in Gabon. The tested well was cored starting about 1200 m (3937 ft) (Figure 8-10).

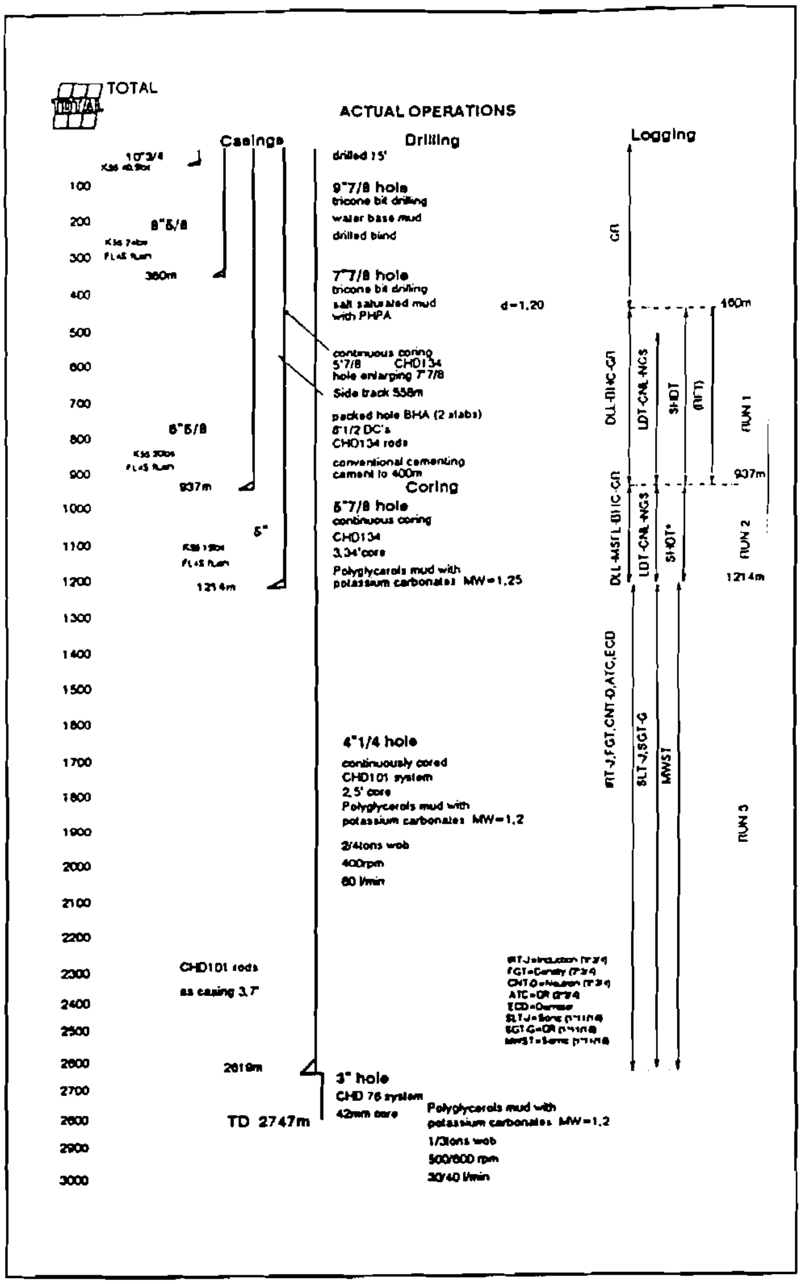

Figure 8-10. Drilling/Coring Operations in Gabon Well (Delwiche et al., 1992)

Polyglycerol muds with potassium carbonate were used for these operations. These fluids are almost perfect Oswald (power-law) fluids. Geometric and rheologic parameters are summarized for one test sequence in Figure 8-11.

Total : 425P2078

BHA

	5	127,0	Øe (mm)
		112,0	Øi (mm)
Shoe depth 1214m			
Open hole	4,25	108,0	Øe (mm)
Total depth	2078m		
Drill pipe	CHD101+	94,0	Øe (mm)
	312mH	83,0	Øi (mm)
		78,5	Øi upset (mm)

MUD

FANN 600	24	SG	1,2
FANN 300	14	T° /	
FANN 200	11		
FANN 100	7		
FANN 6	2	gel 0	1
FANN 3	1	gel 10	2
	pétrole	si	
AV	12	0,012	
osw			
n	0,777	0,777	
K	0,110	0,053	
bin			
YP	4	1,916	
PV	10	0,010	

Figure 8-11. Parameters for Field Test Series
(Delwiche et al., 1992)

Total pressure loss as a function of circulation rate is compared in Figure 8-12 for DB Stratabit theory (lines) and field measurements (points). The Couette effect is noted as higher pressure losses at higher rotation rates.

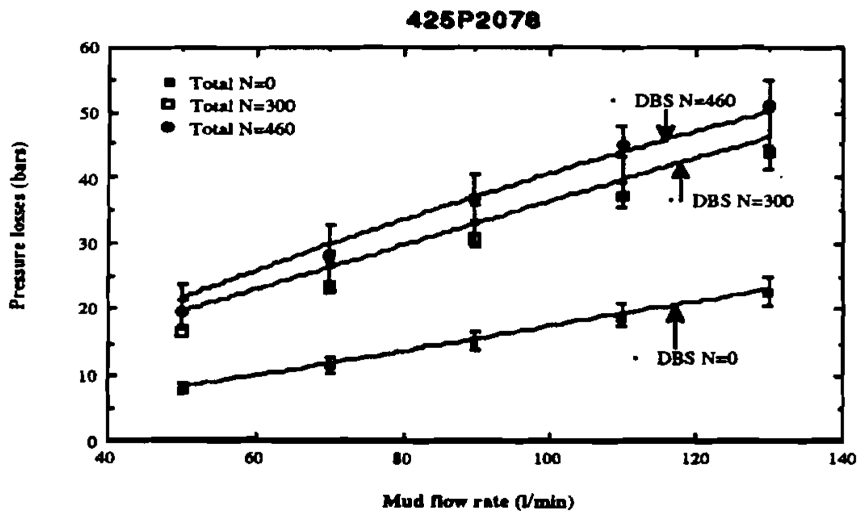

Figure 8-12. System Pressure Loss Versus Flow Rate (Delwiche et al., 1992)

The effect of drill-pipe rotation is highlighted in Figure 8-13. The ratio of pressure loss in the annulus with rotation to that without rotation is plotted for field data measured by Total and DBS. The Pedalo effect is not observed in these data, assumed to be due to the fact that the critical rotational velocity was not exceeded in these measurements.

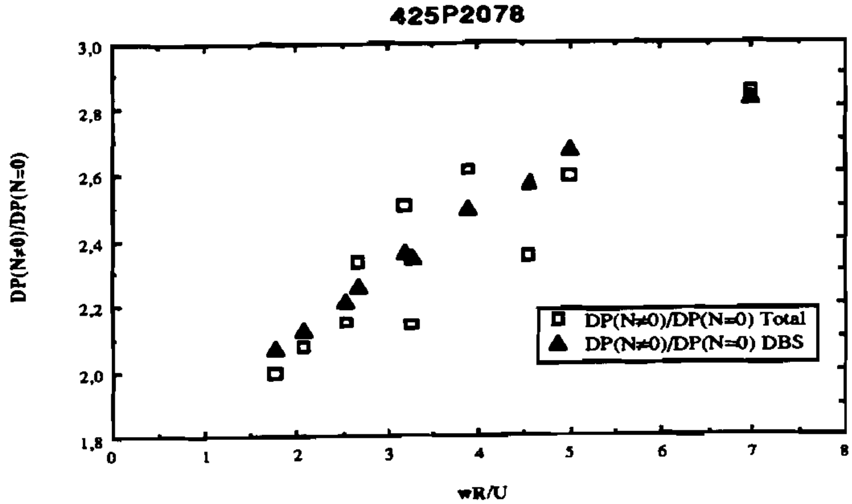

Figure 8-13. Comparison of Pressure Losses With and Without Rotation (Delwiche et al., 1992)

8.3 ELF AQUITAINE (HYDRAULICS FIELD TESTS)

Elf Aquitaine Production and Forasol S.A. (Sagot and Dupuis, 1994) drilled two ultraslim-hole wells in the Paris Basin. These wells, one 3-in. and one 3⅞-in. bottom section, were drilled to test the Foraslim rotary drilling system in performing destructive drilling, wireline coring, drill-stem testing, and logging. The field tests were successful and showed the system to be a cost-effective technique that provides the geologist with all data required for formation evaluation.

The primary objectives of the first well were to drill a long section of 4¾-in. hole with the SH 111 drill string (Table 8-1). Next, a 3-in. hole was to be drilled to TD with the SH 66 drill string.

TABLE 8-1. Properties of Foraslim Drill Strings (Sagot and Dupuis, 1994)

	SH111 System	SH66 System
Drill pipes		
Inner Diameter	74 mm (2,91")	48,1 mm (1,89")
Outer Diameter	89 mm (3,5 ")	57,1 mm (2,25 ")
Upset Diameter	105 mm (4,13 ")	66 mm (2,60 ")
Weight	15,6 daN/m (10,6 lbs/ft)	6,5 daN/m (4,5 lbs/ft)
Drill collars		
Inner Diameter	74 mm (2,91")	48,1 mm (1,89")
Outer Diameter	105 mm (4,13 ")	66 mm (2,60 ")
Weight	33,6 daN/m (22,9 lbs/ft)	12,8 daN/m (8,7 lbs/ft)
Mechanical properties		
Yield Point	139 T (310 000 lbs)	50 T (110 000 lbs)
Tensile Strength	152 T (340 000 lbs)	60 T (135 000 lbs)
Torsional Yield Point	4 300 mdaN (31 000 lbft)	600 mdaN (4 400 lbft)
Torsional Tensile Point	5 200 mdaN (38 000 lbft)	800 mdaN (5 900 lbft)
Core Diameter	74 mm (2,91")	36,4 mm (1 7/16")

The primary objective of the second well was to drill a long section of 3⅜-in. hole with the SH 66 drill string. Both new drill strings were based on oilfield mechanical standards.

Hydraulics and drilling fluid behavior were investigated during these operations. A new mud with PHPA was used in the slimmest sections. Higher mud weight and better control of rheology allowed operations to proceed without major problems on the second well.

With the Foraslim drill-string geometry, up to 60% of the system pressure losses occur in the annulus. Pressure losses were investigated at a range of flow rates and rotary speeds. Sensitivity to flow rate is shown in Figure 8-14. Although the annulus is relatively larger than that for mining coring systems, the Foraslim system is still more sensitive to flow rate than conventional systems.

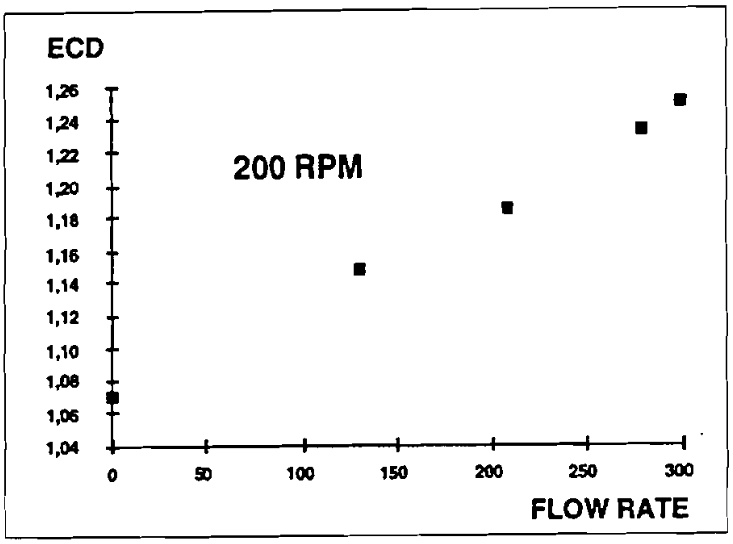

Figure 8-14. ECD at Various Flow Rates (Sagot and Dupuis, 1994)

The impact of drill-string rotation on pressure loss and ECD is less than with mining systems. For example, at 170 rpm the ECD increases by 0.03 specific gravity at a flow rate of 55 GPM (Figure 8-15).

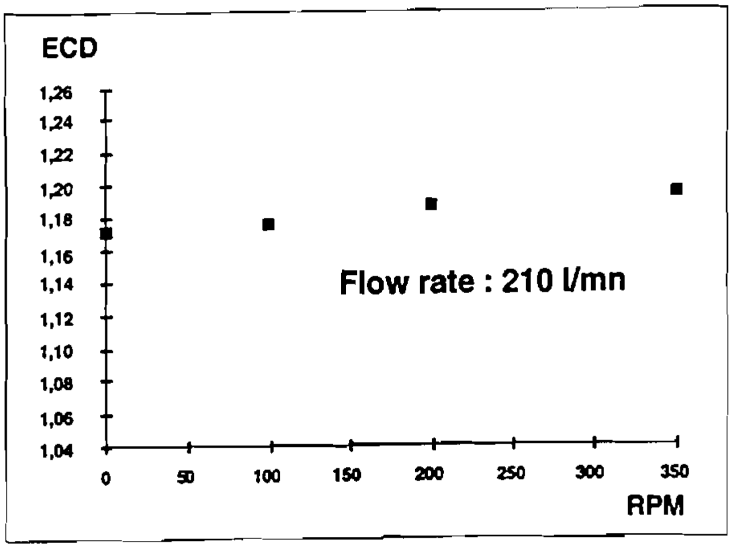

Figure 8-15. ECD at Various Rotary Speeds (Sagot and Dupuis, 1994)

Drill-string eccentricity was investigated as to its impact on fluid velocity. Results are shown for a constant flow rate of 250 l/min (66 GPM) in Table 8-2.

TABLE 8-2. Eccentricity and Annular Velocity (Sagot and Dupuis, 1994)

OFFSET (mm)	ECCENTRICITY (%)	VELOCITIES Min-Max (m/min)
0	0	100
2	20	53-140
5	50	12-173

Data from the same field tests are discussed from the service company's perspective in the next section. Drilling operations are described in the Chapter *Rotary Systems*.

8.4 GEOSERVICES SA (MONITORING ANNULAR PRESSURES)

Geoservices SA (Burban and Delahaye, 1994) developed a prototype slim-hole electromagnetic MWD tool to measure annular pressure losses during circulation and rotation. Given the lack of an accepted model for predicting annular pressures under conditions of vibration, high rotary speeds and eccentricity, downhole measurements were deemed the only source of accurate information during field operations. Another benefit was in monitoring swab (Figure 8-16) and surge pressures during tripping operations.

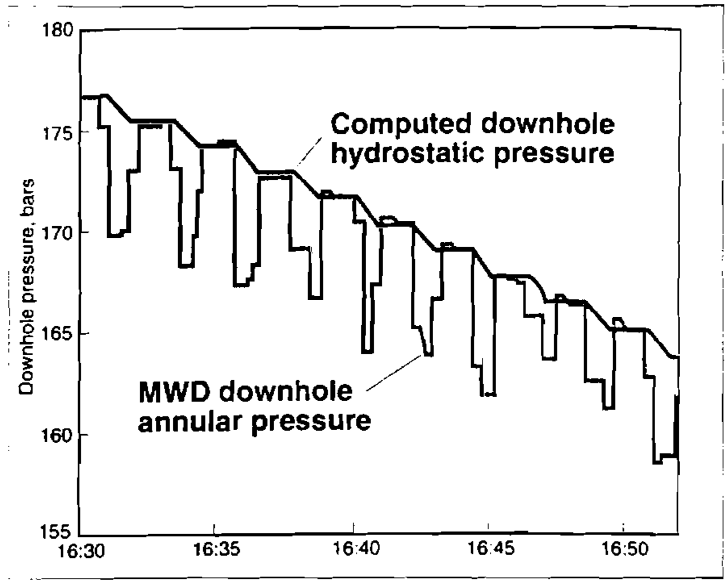

Figure 8-16. Predicted and Measured Annulus Pressures for POOH (Burban and Delahaye, 1994)

The Euroslim project developed a new slim-hole rotary drilling system, including a purpose-built rig and drill string. Hydraulics with the system are critical, though usually less severe than with mining coring systems. Additional discussion of the Euroslim system (now called Foraslim) is presented in the Chapter *Rotary Systems*.

Geoservices performed several tests to investigate the effects of flow rate, rotary speed and WOB. Significant pressure losses were observed for rotary speeds above 100 rpm.

Geoservices SA compared the magnitude of the Couette effect for several systems and hole sizes. The Couette effect is the tendency for the circulating fluid to be drawn into a helical trajectory by the rotating drill string. Their calculations (Table 8-3) show that the Couette shear rate is much more severe with the mining coring specifications.

TABLE 8-3. Couette Shear Rates for Drilling Systems (Burban and Delahaye, 1994)

Hole Type	Hole Dia. (In.)	Typical Rotary Speed (rpm)	Drill Pipe Nominal OD (In.)	Couette Shear Rate at Drill Pipe (sec^{-1})	Drill Collar Nominal OD (In.)	Couette Shear Rate at Drill Collar (sec^{-1})
Conventional	8.5	80	5	26	6	33
Reduced Hole	6	130	3.5	41	4.75	73
Euroslim	3.4	350	2.2	127	2.6	178
Mining	4.25	600	4	1,100	4	1,100

systems, by contrast, have nine times the shear rate of the Euroslim system. These data confirm that drill-string geometry has a major impact of slim-hole hydraulics.

A more detailed description of Geoservices SA's field experiences with the MWD pressure/temperature tool is presented in the Chapter *Logging*.

8.5 INSTITUT FRANÇAIS DU PÉTROLE/FORASOL (HYDRAULICS MODEL)

Institut Français du Pétrole and Forasol/Foramer (Cartalos and Dupuis, 1993) developed a model to predict the effect of drill-pipe eccentricity and rotation on annular pressure losses in slim-hole drilling. They found that, because some drill-pipe eccentricity is always present in real wells, annular pressure losses without rotation are always less than predictions that are based on concentric geometry. Rotation of the drill string leads to increased annular pressure losses due to induced transverse vibration. Additionally, their analyses showed that tool joints may have a significant impact on pressure losses.

Laboratory measurements and theoretical treatments reported in the literature have suggested that string rotation decreases annular pressure losses for a given flow rate. However, according to field observations, rotation causes increased pressure loss. To answer this contradiction, Cartalos and Dupuis set out to determine the effect of wellbore geometry and fluid rheology on pressure losses. Emphasis was placed on analyzing complex interactions between drill-string motion and flow structure.

Power-law fluids are useful for modeling slim-hole muds, which are typically low-solids polymer solutions. Power-law models assume that shear stress, τ, is related to shear rate, $\dot{\gamma}$, by $\tau = K\dot{\gamma}^n$. Institut Français du Pétrole and Forasol/Foramer performed several calculations of pressure loss assuming DBS SH111 drill pipes (Table 8-4) in open holes of various diameters.

TABLE 8-4. Drill-Pipe and Hole Geometry (Cartalos and Dupuis, 1993)

Drill Pipe SH111 of DBS	Outer Diameter	3.5 In. (89 mm)
	Inner Diameter	2.91 In. (74 mm)
	Total Length	33 ft (10 m)
	Tool Joint Outer Diameter	4.125 In. (105 mm)
	Tool Joint Total Length	28 in. (0.70 m)
Open Hole	Diameter (Planned)	4.375 In. (111 mm)
		4.750 In. (121 mm)
		4.875 In. (124 mm)

Calculated results suggest that annular pressure loss for a given flow rate increases linearly with K (power-law consistency index) and quasi-exponentially with n (power-law flow index) (Figure 8-17).

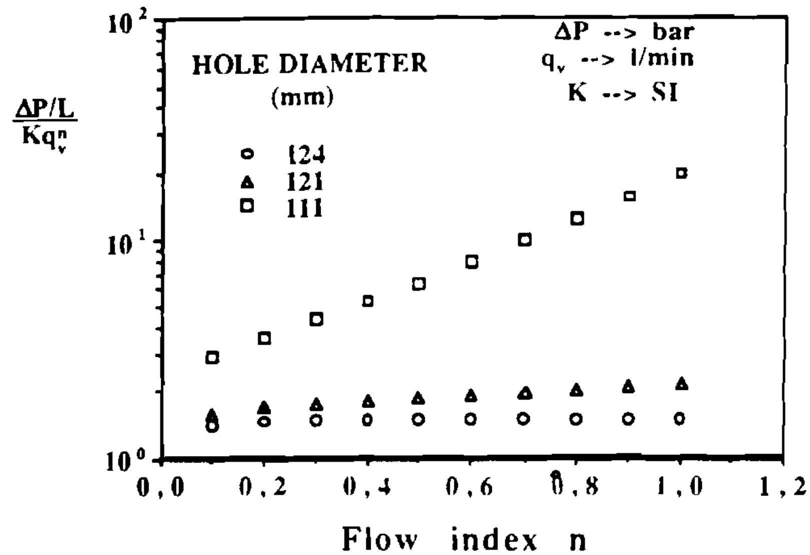

Figure 8-17. Relationship of K and n for Various Hole Sizes (Cartalos and Dupuis, 1993)

The contribution of pressure drops across the tool joints is significant, especially for small annuli (Figure 8-18). The effects increase linearly with n. The y-axis shows the ratio of pressure loss across the tool joints to total pressure loss in the annulus.

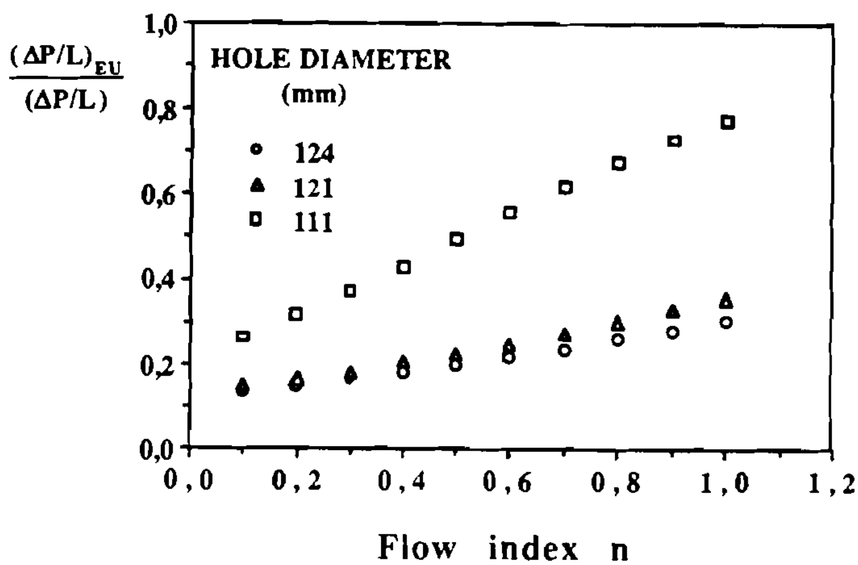

Figure 8-18. Pressure Losses Across Tool Joints (Cartalos and Dupuis, 1993)

The ratio of drill-string pressure loss ($(\Delta P/L)_c$) to annular pressure loss ($\Delta P/L$) is shown for several hole sizes in Figure 8-19. For a 124-mm hole (corresponds to a tool-joint annulus of 10 mm; 0.37 in.), pressure loss in the drill pipe ranges from about 40% to 20% of that in the annulus. For a 111-mm hole (tool-joint annulus of 3 mm; 0.12 in.), pressure loss in the drill pipe ranges from about 20% to 1% of that in the annulus.

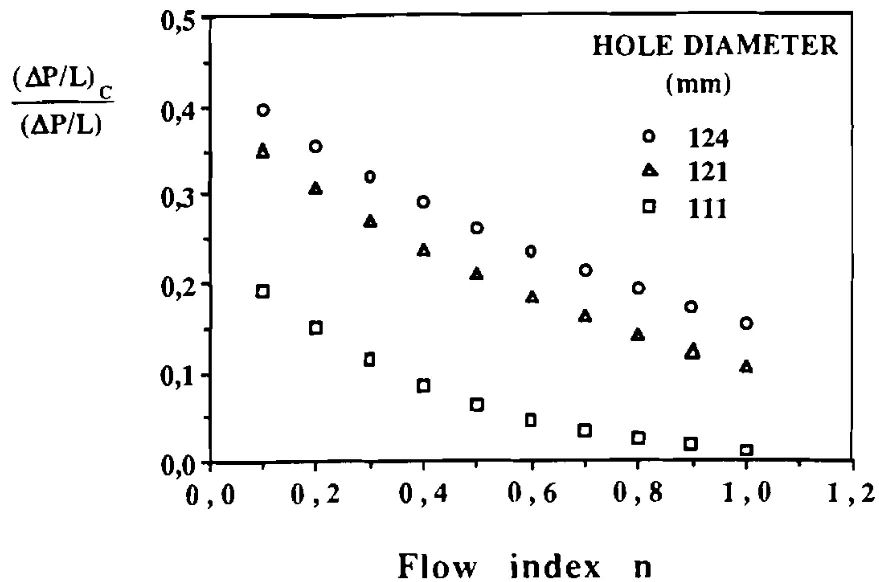

Figure 8-19. Comparison of Pressure Losses in Annulus and Drill String (Cartalos and Dupuis, 1993)

Cartalos and Dupuis determined that transverse, torsional and axial vibrations induce complicated flow patterns within the annulus during rotation. They developed a model to simulate transverse drill-string vibrations. Their "slot" approximation was based on the assumption that the annular space is small compared to drill-string radius and that the impact of curvature can be neglected. The annular space is treated as a slot of variable width.

Results are shown for the non-rotating case in Figure 8-20. Pressure losses in the annulus are reduced by about 50% at full eccentricity. Field observations verify that predictions based on concentric pipes are usually high, the difference being accounted for by the effect of eccentricity.

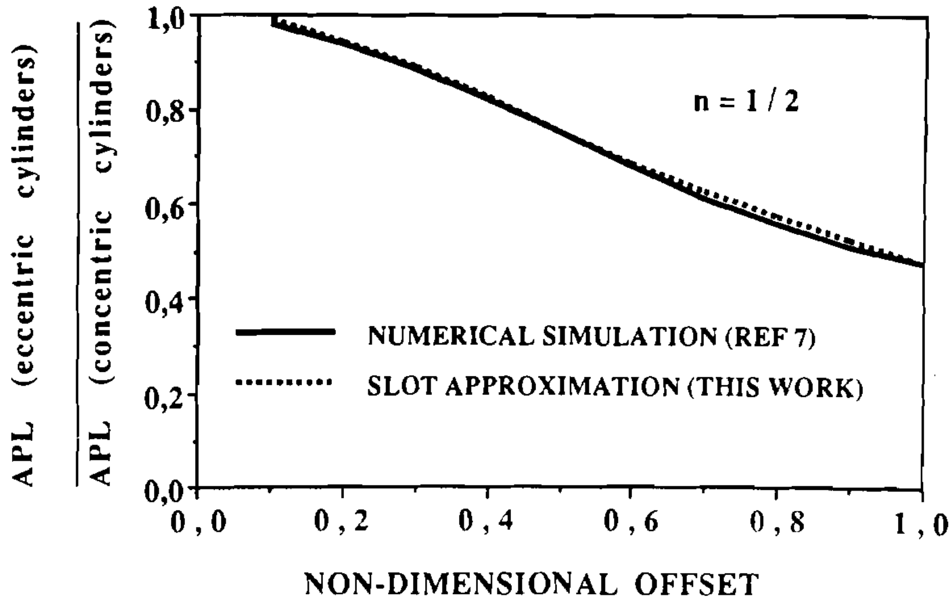

Figure 8-20. Pressure Losses for Eccentric Drill String (Cartalos and Dupuis, 1993)

To estimate the impact of rotation, a realistic profile of eccentricities over the depth of the well is used to calculate eccentricity at each given depth. Total annular pressure loss can be obtained by integrating these values from surface to total depth.

In summary, Cartalos and Dupuis state that the divergence between theory and field observation of pressure losses in rotating drill strings (theory says rotation lowers pressure drop; observation shows increased pressure drop with rotation) may be explained by the effects of vibration of the drill string induced by rotation. Their research of these phenomena is continuing.

8.6 LOS ALAMOS NATIONAL LABORATORY (HYDRAULICS IN ULTRASLIM HOLES)

Scientists from Los Alamos National Laboratory, in conjunction with Amoco and Texaco, proposed a feasibility study (DEA Proposal, 1994) of the use of ultraslim holes (1 in.) for placing monitoring instruments in or near petroleum reservoirs. Technologies potentially supported by this approach include 3-D seismic, VSP and microseismic mapping. The proposed concept may include the use of coiled tubing for drilling, completion and logging operations.

The project team studied various aspects of hydraulics in very slim boreholes. The most practical method of transmitting power to the bottom of the hole was assumed to be by means of hydraulic energy. A variety of calculations were performed of hydraulic power transmission through small tubing based on Von Mises design stress criteria and power-law circulating pressure losses.

Water was considered as a drilling fluid. Hydraulic power delivered down hole was calculated for an annular velocity of 150 ft/min for a range of slim hole sizes (Figure 8-21). Power falls off rapidly below about a 2-in. hole size. The optimum ratio of tubing size to hole size (D_o/D_h) is about 0.65, according to these results.

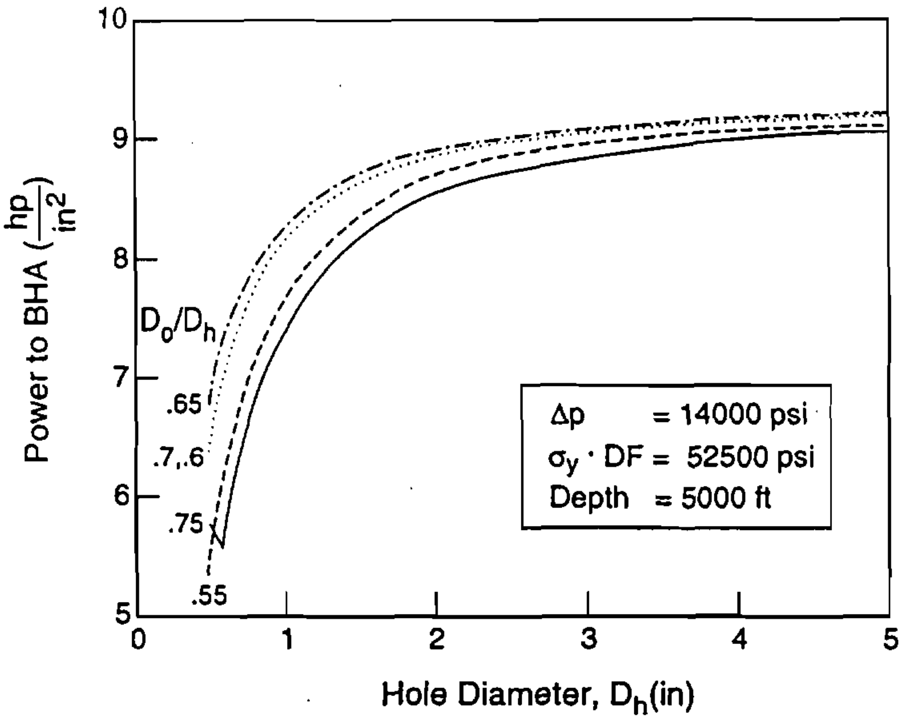

Figure 8-21. Hydraulic Power Available with Water for Different Tubing Sizes (DEA Proposal, 1994)

Hydraulic power for water at different pump pressures is plotted in Figure 8-22. As pressure increases, tubing thickness is also increased, as would be required. The ratio of tubing diameter to thickness (D_o/t) is shown.

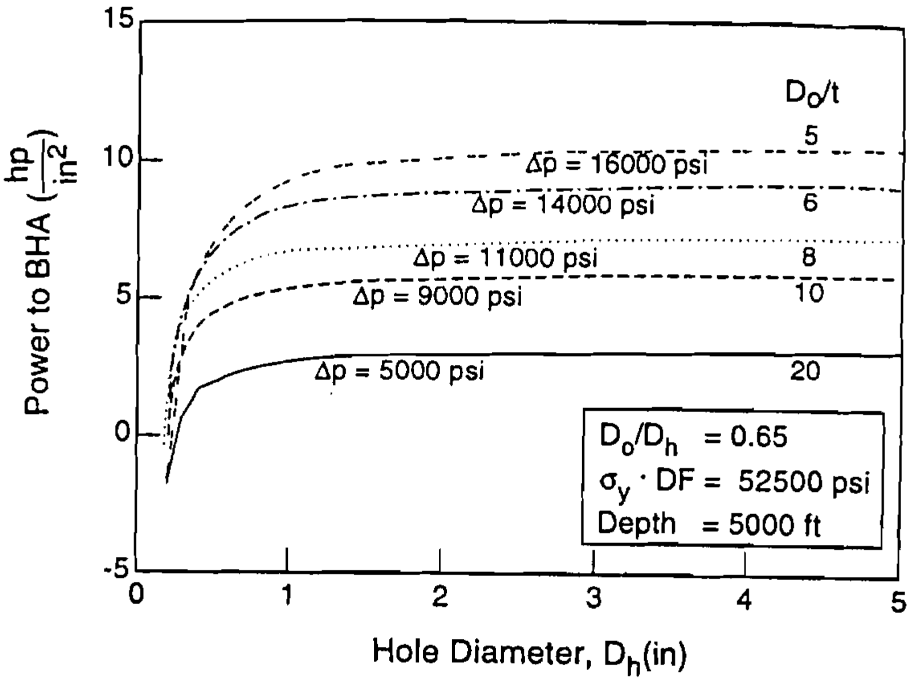

Figure 8-22. Hydraulic Power with Water for Different Pump Pressures (DEA Proposal, 1994)

A power-law fluid was also considered as the circulating fluid. The fluid is assumed as 9.1 ppg with K=0.15 and n=0.7. The optimum ratio of tubing to hole size is about 0.60 (Figure 8-23).

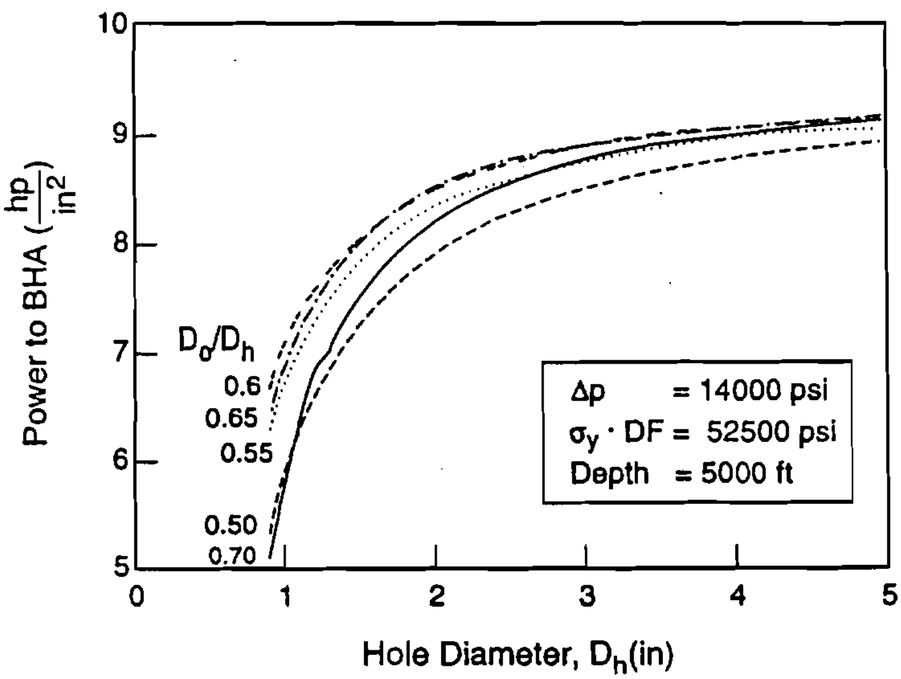

Figure 8-23. Hydraulic Power with Power-Law Fluid for Different Tubing Sizes (DEA Proposal, 1994)

Hydraulic power for this power-law fluid at different pump pressures is plotted in Figure 8-24.

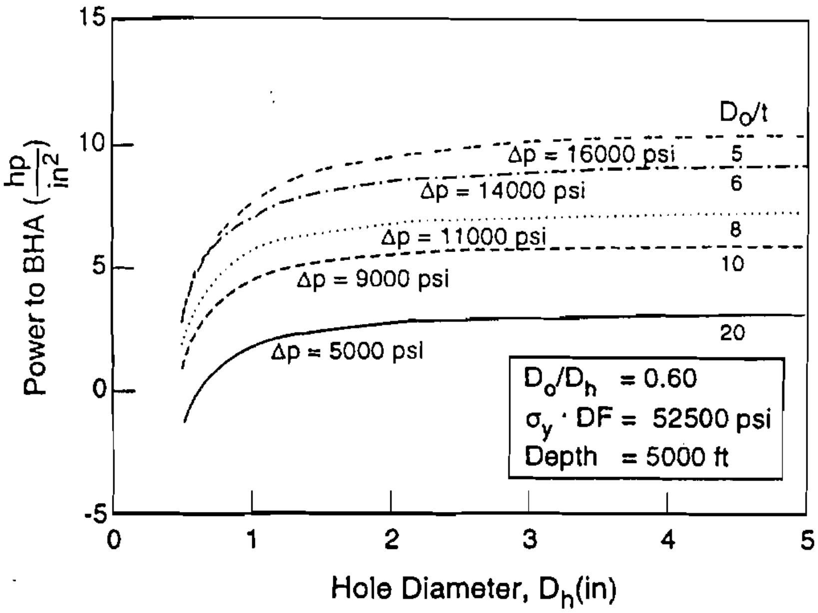

Figure 8-24. Hydraulic Power with Power-Law Fluid for Different Pump Pressures (DEA Proposal, 1994)

Calculations of energy requirements indicated that 5 hp/in^2 is sufficient to advance a water jet at 27 ft/hr, which corresponds to about 14,000-psi pump pressure with 9.1 ppg drilling fluid.

Preliminary cost savings estimates were also developed. The proposed 1-in. drilling system was compared to a conventional 10,000-ft land well with a P&A cost of $320,000. Costs would be reduced 66%, assuming an ROP during microdrilling of 27 ft/hr and a 24-hr bit life (Figure 8-25).

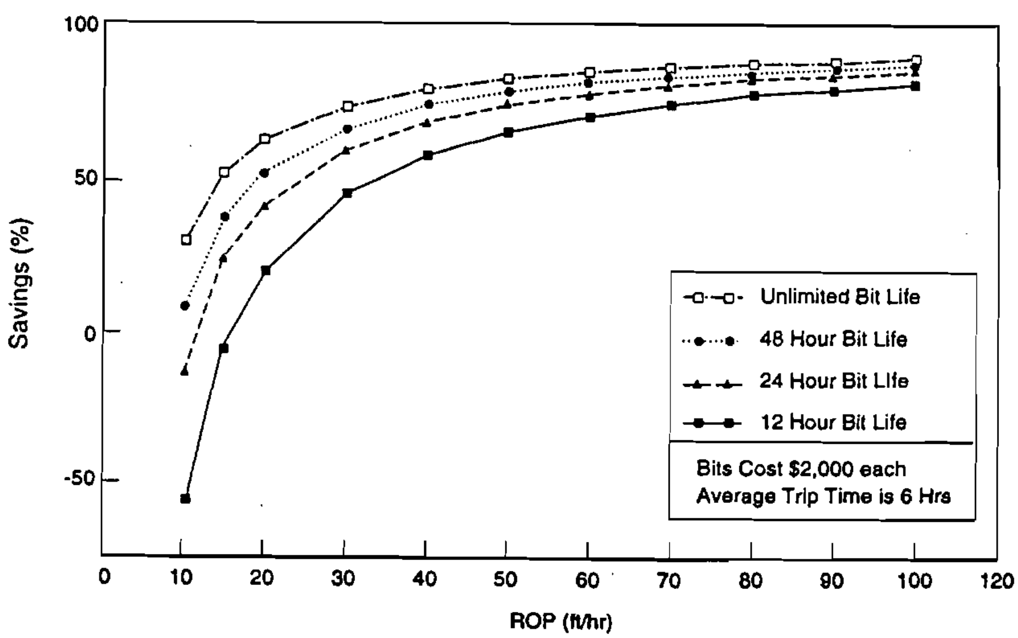

Figure 8-25. Cost Comparison of 1-in. Microsystem to Conventional (DEA Proposal, 1994)

After completion of Phase I feasibility studies, the project team intends to solicit partners for a completion of proof-of-concept testing and field tests of the ultraslim-hole system.

8.7 MOBIL E&P TECHNICAL CENTER/M-I DRILLING FLUIDS (HYDRAULICS MODEL)

Mobil E&P Technical Center and M-I Drilling Fluids (McCann et al., 1993) performed a series of measurements of pressure drops in slim-hole annuli. Data were recorded in a test well and with a customized laboratory flow loop. Tests were performed with water, glycerin solutions, viscosified clear brines, and several slim-hole drilling fluids. They found that annular pressure losses decrease with increasing pipe rotation when flow is laminar. For turbulent flow in the annulus, increasing rotation causes annular pressure loss to increase. Eccentricity causes pressure loss to decrease for both flow regimes.

Small variations in the width of the annulus, eccentricity of the drill pipe, and pipe rotational speed all affect pressure drops during fluid circulation. The contributions of these factors are usually negligible in conventional holes. In narrow annuli, typically with $D_{pipe}/D_{hole} \geq 0.8$, these factors can significantly impact pressure loss and complicate the task of calculating and controlling bottom-hole pressures.

Mobil E&P Technical Center sought to improve the ability to model slim-hole hydraulics. They performed tests both in the field and in the laboratory. Field tests, although useful, are hard to control precisely, and lack of agreement between measurements and predictions may be due to lack of control of test parameters, incorrect assumptions, or bad models.

Mobil's first slim-hole test well, the SHDT.1 (Table 8-4), was outfitted with pressure taps at regular intervals along its length. Hydraulics tests were conducted consisting of varying circulation rates and rotary speeds, and then recording corresponding annular pressures.

TABLE 8-4. Slim-Hole Test Well (McCann et al., 1993)

PARAMETER	SHDT.1	PANDO #1
Drill Rod	CHD 101	CHD 134
Drill Rod D_p (in)	3.701	5.000
Drill Rod Inside Diameter (in)	3.268	4.500
Inner Core Barrel D_p (in)	2.875	3.789
Outer Core Barrel D_h (in)	3.125	4.125
Core Barrel Length (ft)	18.3	18.3
Bit Total Flow Area (in^2)	---	8.788
Casing Nominal D_h (in)	4.408	6.276
Casing Shoe Depth (ft)	2505	2012
Open Hole Average D_h (in)	---	6.000

Pressure drops and circulation rates are compared at two depths in the test well for water and a 15-lb/bbl gel slurry in Figure 8-26. Annular gap is 0.35 in. for this configuration. The pipe was not rotated for this particular series of tests.

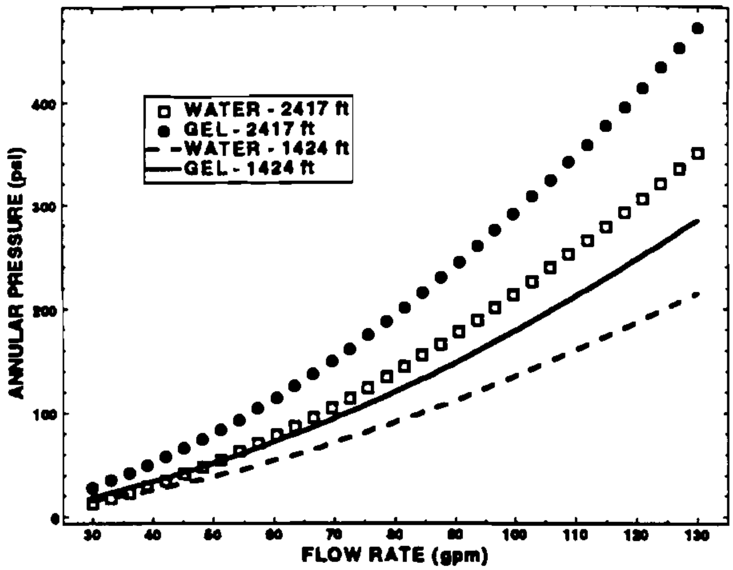

Figure 8-26. Mud Rheology and Flow Rate in Test Well (McCann et al., 1993)

Mud properties for these field tests are shown in Table 8-5.

TABLE 8-5. Muds Tested in Slim-Hole Test Well (McCann et al., 1993)

SLIMHOLE WELLS MUD PROPERTIES (Rotor = R, Bob B1, Spring F0.2)											
		Viscometer Dial Reading @ rpm =									MW
Well	Test	600	300	200	100	60	30	6	3	R	(ppg)
SHDT.1	Water	39	20	13.5	7	4.5	2.5	1	0.5	2	8.33
SHDT.1	Gel	127	69	47.5	25	16	9	2	1.5	2	8.34
Pando #1	3130 ft	300	152	90	86	60	36	10	6	2	9.1
Pando #1	1999 ft	164	95	68	40	26	15	5	3	1	9.1

Equivalent circulating density (ECD) in the test well was observed to increase significantly with pipe rotation (Figure 8-27). ECDs measured at 600 rpm are about 40% greater than those at 0 rpm. This type of response was also recorded by Amoco in the SHADS development, and led to the concept of dynamic kill for well-control operations.

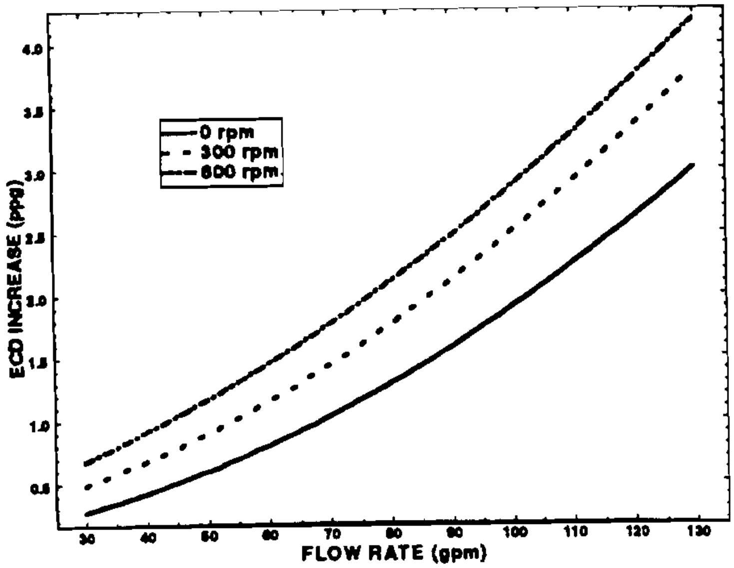

Figure 8-27. Pipe Rotation and ECD in Test Well (McCann et al., 1993)

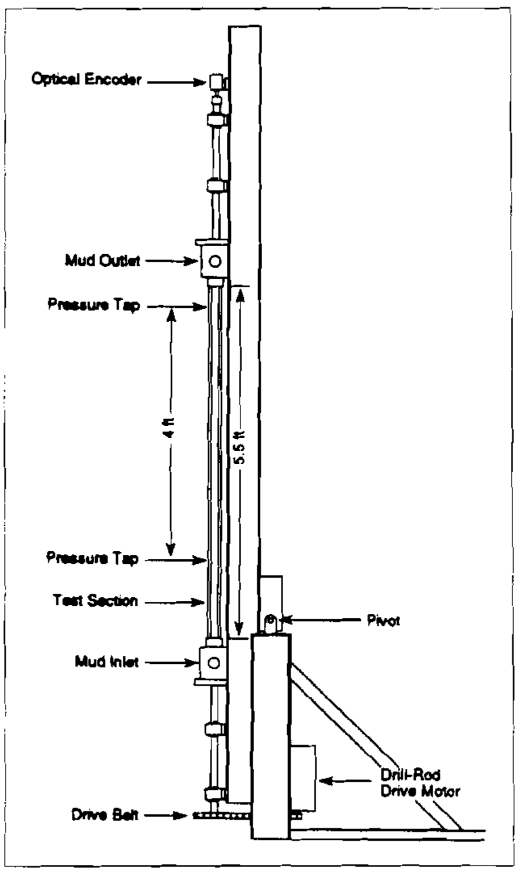

Figure 8-28. Mobil's Narrow-Annulus Test Fixture (McCann et al., 1993)

Determining flow regime in the annulus was of special concern during Mobil's efforts. Flow experiments were conducted in a custom narrow-annulus test fixture (Figure 8-28). Parameters investigated included pipe rotation, flow regime, fluid properties and eccentricity.

Fluids tested were designed to represent typical slim-hole drilling fluids. Fluid A, which consisted of 5 lb/bbl rev-dust in water, was representative of fluid present in the test well. Fluids B and C were NaCl brine and HEC, representing Mobil's Pando #1 well (see Table 8-4). Fluid D was CaCl brine with PHPA and PAC, patterned after Total's Gabon project. Test fluid properties are summarized in Table 8-6.

TABLE 8-6. Muds Tested in Test Fixture (McCann et al., 1993)

AVERAGE TEST FLUIDS PROPERTIES (Rotor R2, Bob B1, Spring F0.2)						
FLUID	A	B	C	D	Glycerin	Water
MW (ppg)	9.00	9.14	9.06	9.98	9.10	8.33
600 rpm	51	179	208	183	80	36
300 rpm	28	113	137	111	42	19
200 rpm	19	85	108	82	29	13
100 rpm	11	52	68	49	16	7
6 rpm	2	7	10	6	---	---
3 rpm	2	4	6	4	---	---
T (°F)	76.0	77.4	70.5	73.7	78.1	78.7

Annular gaps were varied during the experiments. A central core, representing the drill pipe, consisted of a 1¼-in. steel shaft that could be rotated. The casing was formed by interchangeable tubes with inner diameters of 1⅜, 1½ or 1¾ inches. Tests with water showed the effect of the width of the annulus (Figure 8-29). The shaft was not rotated for these tests. Pressure drop with water was four times greater and with fluid C was six times greater when the gap was decreased by 50%.

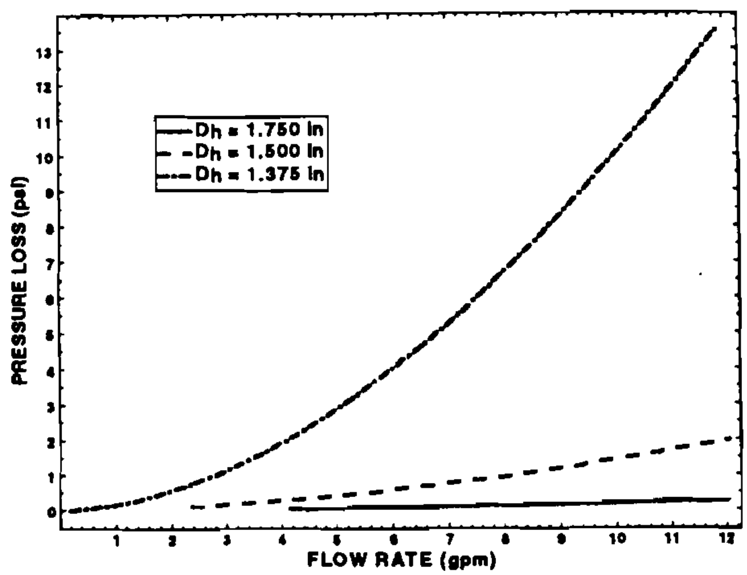

Figure 8-29. Effect of Annular Gap in Test Fixture (McCann et al., 1993)

The sensitivity to annulus size was analyzed further by plotting the calculated pressure drop for the nominal annulus width along with a ±1% variation. The results for Fluid C (Figure 8-30) are dramatic for the smallest nominal annulus width. This behavior can have an important impact on modeling under field conditions. For Mobil's test well, casing dimensions can vary +2.8% to -0.6% based on API tolerances. For the worst case, calculated pressure losses based on nominal dimensions may actually be 17% too high.

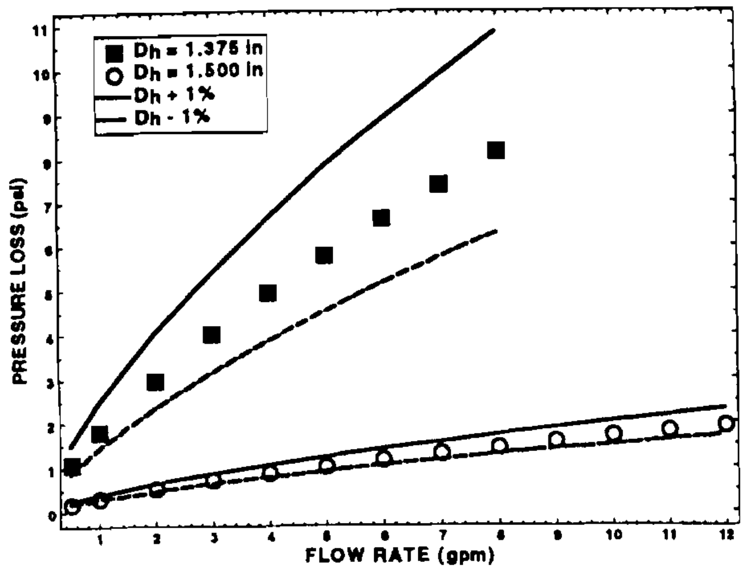

Figure 8-30. Sensitivity to 1% Change in Annular Gap (McCann et al., 1993)

The combined effects of flow regime and shaft speed can be seen in Figure 8-31. The traces corresponding to each annulus cross at about 3 GPM and then straighten out. Mobil states that this crossover represents the transition to turbulent flow.

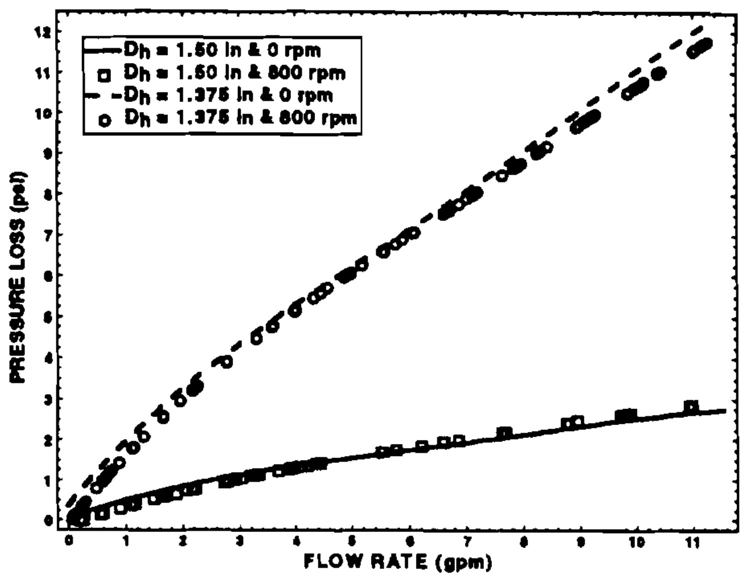

Figure 8-31. Effect of Annular Gap and Rotary Speed (McCann et al., 1993)

Eccentricity was clearly observed to reduce pressure drop by about 25%, both with and without rotation (Figure 8-32). These tests were conducted with glycerin fluid in the 1½-in. casing.

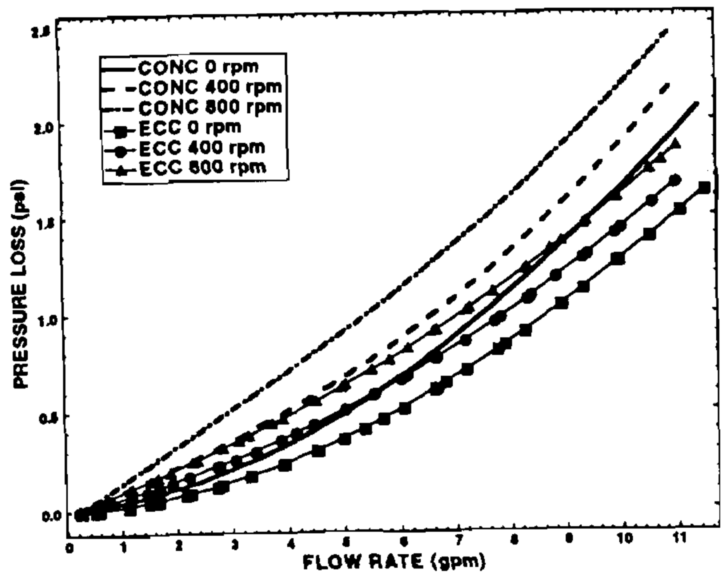

Figure 8-32. Effect of Eccentricity and Rotary Speed (McCann et al., 1993)

Theory predicts that pressure drop decreases as rotary speed is increased. This prediction is based on the assumption of laminar flow. Non-laminar flow is indicated when pressure increases along with rotary speed. Fluid B was tested at a range of flow rates and rotary speeds. The results (Figure 8-33) show that, at higher flow rates and higher speeds, pressure drop increased along with rotary speed. These tests were conducted with concentric 1½-in. casing.

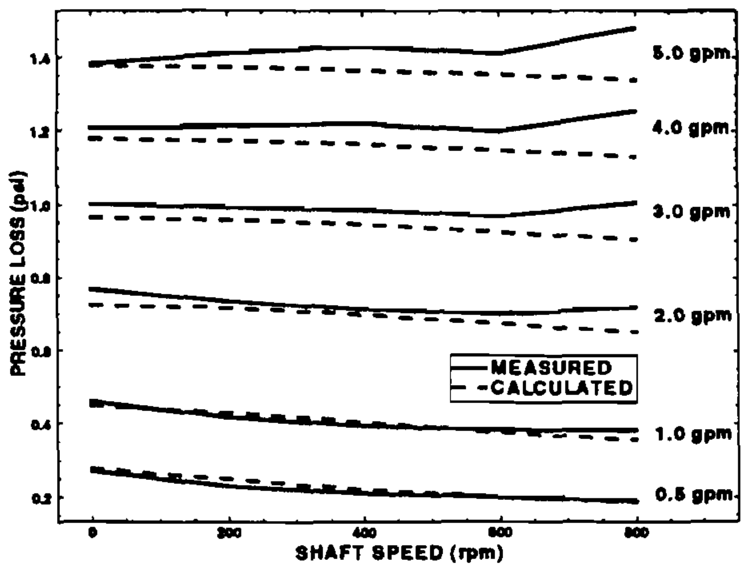

Figure 8-33. Effect of Flow Rate and Rotary Speed (McCann et al., 1993)

Turbulent flow in an eccentric annulus was modeled based on concentric theory with an adjusted Reynolds number. The modified theory accurately modeled turbulent flow in an eccentric annulus for water and for glycerin (Figure 8-34). These tests used 1½-in. casing and no rotation.

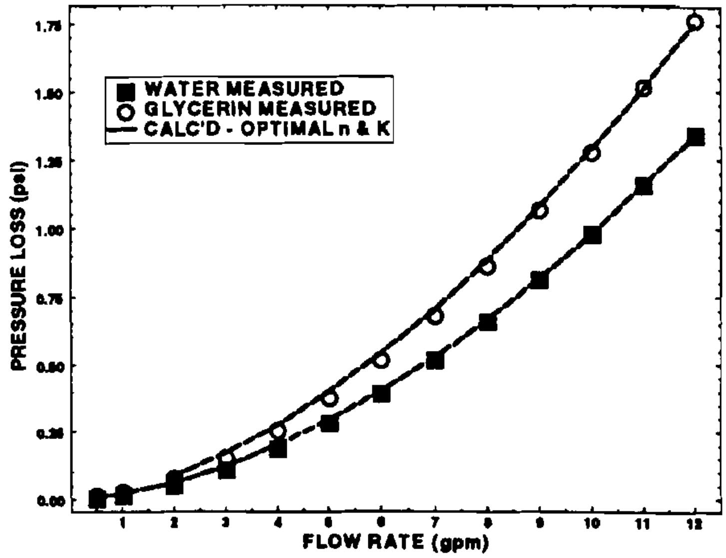

Figure 8-34. Turbulent Flow with Eccentricity (McCann et al., 1993)

Mobil E&P Technical Center and M-I Drilling Fluids concluded that hydraulics models accurately predict annular pressure loss for laminar flow in concentric annuli with rotation and in eccentric annuli without rotation. For turbulent flow of power-law fluids, measurements and theory agreed for concentric annuli without rotation. Measurements showed that, as pipe rotary speed is increased, pressure loss increases for turbulent flow and decreases for laminar flow.

Their results also showed conclusively that eccentricity of the tubing results in a significant decrease in pressure loss. Pressure loss is highly sensitive to width of the annular gap for narrow annuli.

8.8 UNIVERSIDADE ESTADUAL DE CAMPINAS/THE UNIVERSITY OF TEXAS (HYDRAULICS MODEL)

Universidade Estadual de Campinas and The University of Texas (Ribeiro et al., 1994) applied finite-element analysis to the problem of modeling hydraulics in narrow annuli. Their numerical model showed good agreement with published data for slim-hole annular flow with rotation and with eccentric casing.

Ribeiro et al. used a two-dimensional finite-element code with capacity for solving axisymmetric flow domains. They calculated flow profiles to compare with results from several authors. Significant use was made of data from McCann et al. (1993) (see preceding section). Pressure loss and rotary speed were calculated for McCann's test fixture. Agreement was generally good (Figure 8-35).

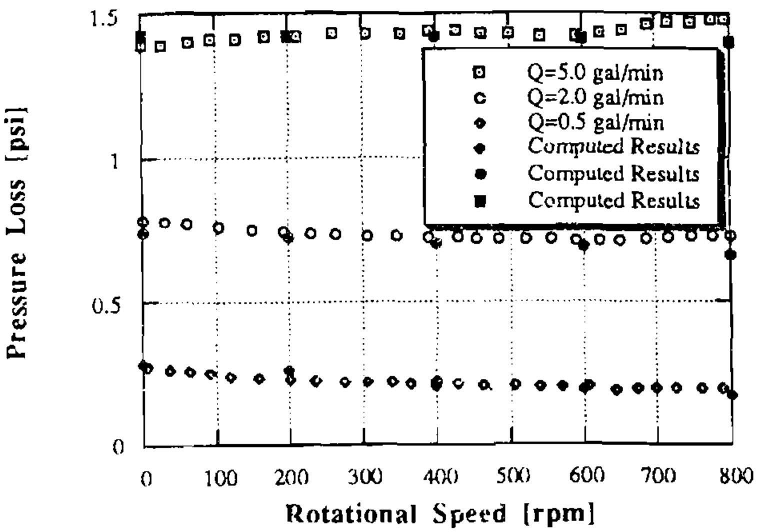

Figure 8-35. Finite-Element Predictions of Data by McCann et al. (1993) (Ribeiro et al., 1994)

Three-dimensional results for eccentric annuli were obtained using FIDAP, a general-purpose flow package. Agreement was sought with the data of Mitsuishi and Aoyagi (1973). They measured pressure loss with an aqueous solution of HEC across a test fixture. As before, finite-element analysis yielded good agreement (Figure 8-36).

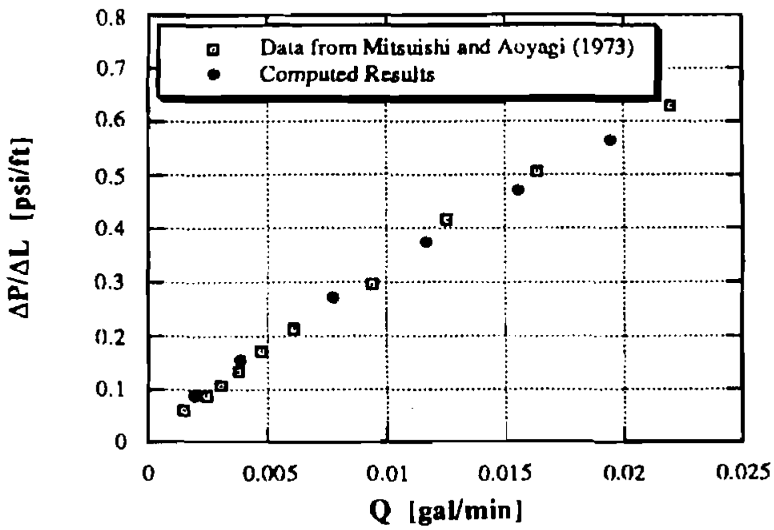

Figure 8-36. Finite-Element Predictions of Data by Mitsuishi and Aoyagi (1973) (Ribeiro et al., 1994)

Ribeiro calculated axial flow velocity contours for several eccentric flow cases. An example plot is shown in Figure 8-37 for an eccentricity of 0.75. The parameter shown in the figure is velocity divided by average velocity. A region of stagnant flow at the thinnest annulus is indicated by the data.

The vector plot for the same conditions is shown in Figure 8-38. The vector magnitude is defined by $(V_x^2 + V_y^2)^{1/2}/V_{tan}$.

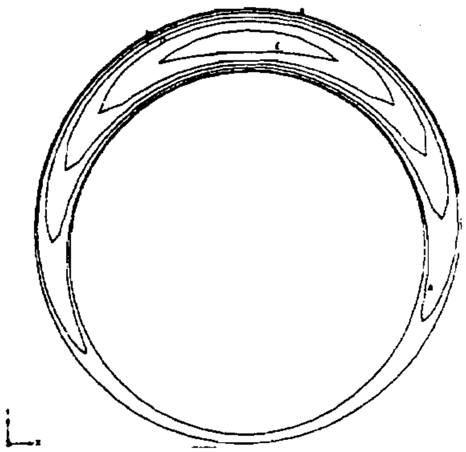

Figure 8-37. Dimensionless Axial Velocity for e=0.75 (Ribeiro et al., 1994)

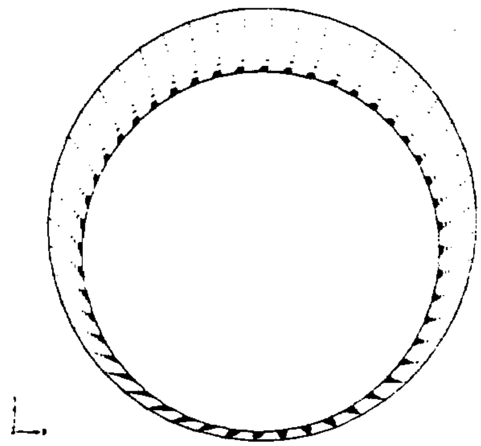

Figure 8-38. Dimensionless Flow Velocity for e=0.75 (Ribeiro et al., 1994)

Ribeiro et al. emphasized that these analyses were based on the assumptions of laminar flow and stationary system configuration. Field observations confirm that the position of the drill string is actually dynamic as a result of vibration. This is expected to induce turbulent flow patterns. They concluded that turbulent flow in rotary conditions should be studied in greater detail so that these efforts can be applied in the field.

8.9 REFERENCES

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9. Logging

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9. Logging

9.1 MWD/GUIDANCE

9.1.1 Geoservices SA (Monitoring Annular Pressure)

Geoservices SA (Burban and Delahaye, 1994) developed a prototype slim-hole electromagnetic MWD (Measurement While Drilling) tool to measure annular pressure losses during circulation and rotation. Given the lack of an accepted model for predicting annular pressures under conditions of vibration, high rotary speeds and drill-string eccentricity, downhole measurements were deemed the only source of accurate information during field operations. The new pressure monitoring tool was run successfully and gave new insight into slim-hole hydraulics.

The Euroslim project, with members Forasol SA, DB Stratabit, Geoservices SA and Institut Français du Pétrole, developed a new slim-hole rotary drilling system, including a purpose-built rig and drill string (Table 9-1). Additional discussion of the Euroslim drilling system is presented in the Chapter *Rotary Systems* and of Euroslim hydraulics is presented in the Chapter *Hydraulics*.

TABLE 9-1. Euroslim Drill String and Collars (Burban and Delahaye, 1994)

	Nominal Diameter	Pipe O.D.	Pipe I.D.	Tool Joint O.D.	Tool Joint I.D.
Drill Pipe, mm	SH 65	56	46	66	46
Drill Collars, mm	SH 65	65	46		
Drill Pipe, in.	2.56	2.2	1.8	2.6	1.8
Drill Collars, In.	2.56	2.56	1.8		
Hole diameter - 76 mm (3 in.) or 86 mm (3.4 in.)					

The Euroslim system was applied in the field during Elf's FAX (Forage Allégé d'Exploration) project. Two slim holes (Figure 9-1) were drilled to evaluate drilling, logging and well testing tools and techniques under field conditions.

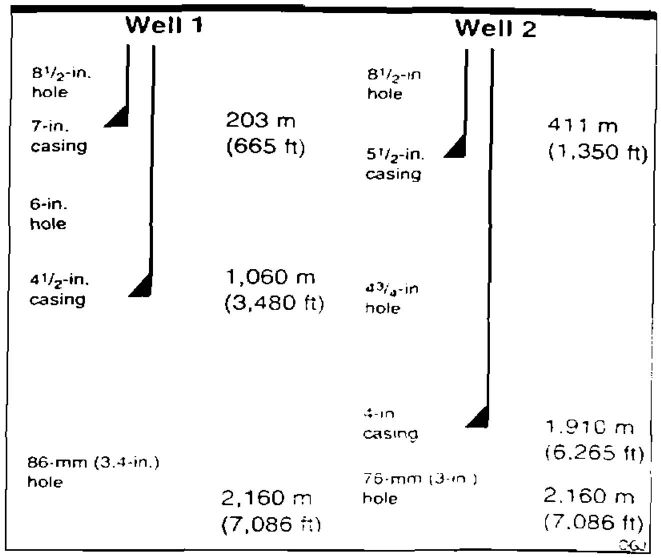


Figure 9-1. FAX Project Well Schematics (Burban and Delahaye, 1994)

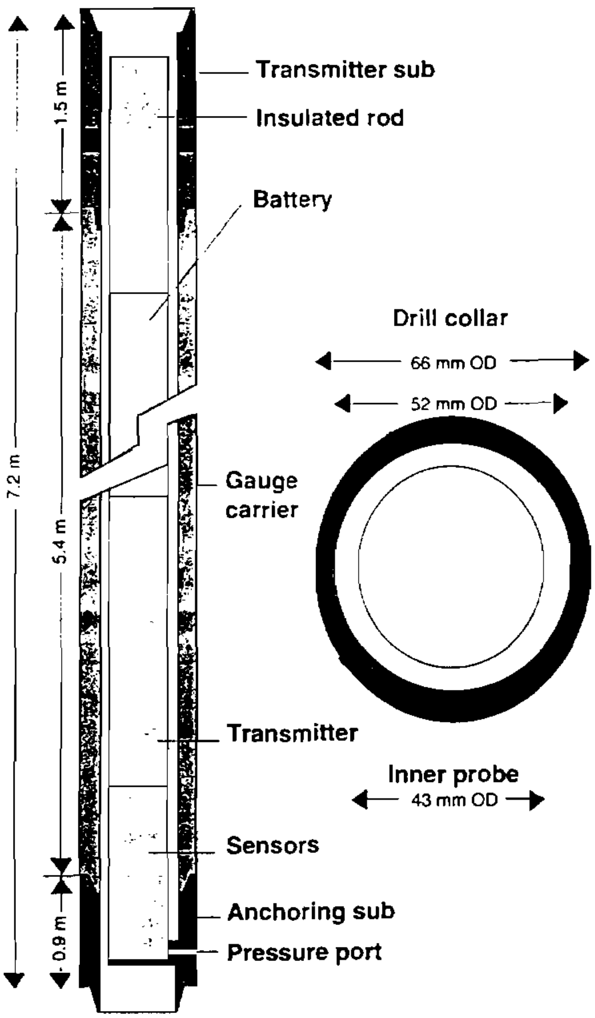


Figure 9-2. MWD Tool for Annulus Pressure/ Temperature (Burban and Delahaye, 1994)

These two slim wells (3.4- and 3-in. bottom hole) were drilled with real-time monitoring of annular pressure and temperature through the use of continuous electromagnetic wave transmission. Annular pressure is often a critical parameter in slim-hole applications. Pressure losses through the annulus are not negligible as they often are in conventional operations.

The annulus width used in the FAX field tests was as small as 5 mm (0.20 in.). Coupled with high rotary speeds and drill-string vibration, this narrow annulus width is the site of significant pressure losses that are difficult to model.

The first-generation slim MWD tool did not incorporate directional control or formation-evaluation capability, as these services were not required in the particular formation being tested. The tool included a $1^{11}/_{16}$-in. sensor probe inside a conventional 2.6-in. drill collar (Figure 9-2).

The tool sub was positioned 40 ft behind the bit. The system was run for about 200 hours, including 120 hours at rotary speeds above 350 rpm. No failures of the tool occurred during the field tests.

Data were transmitted to surface every 24 seconds; sensor measurements were scanned every 2 seconds. Temperature data were relayed as every ninth transmission. Geoservices SA's system uses geologic structures as the transmission medium. Mud circulation is therefore not required, and the system works in fluids, foam or air.

Project participants found that the slim-hole annular pressure tool provided very useful information. One unexpected benefit was seen during an episode where injection pressure increased from 430 to 760 psi (30 to 52 bars) in 10 minutes (Figure 9-3). Without downhole pressure readings, the most logical course of action would have been to pull the drill string to clean the well. However, the pressure data from the annulus showed downhole conditions to be stable. Based on downhole data, drilling was continued and the obstruction cleared after about 20 minutes.

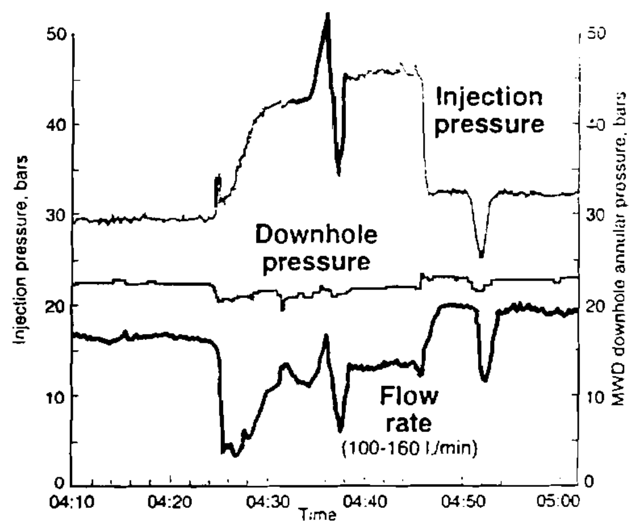


Figure 9-3. Annulus Pressure During Surge in Injection Pressure (Burban and Delahaye, 1994)

Geoservices performed several tests to investigate the effects of flow rate, rotary speed and WOB. Significant pressure losses were observed for rotary speeds above 100 rpm. Annulus pressure was monitored during a drill-string connection (Figure 9-4). When rotation was stopped, annulus pressure decreased 59 psi or 0.2 ppg ECD. Next, circulation was stopped. Annulus pressure decreased an additional 137 psi or 0.4 ppg ECD. These data were recorded in the 3.4-in. hole.

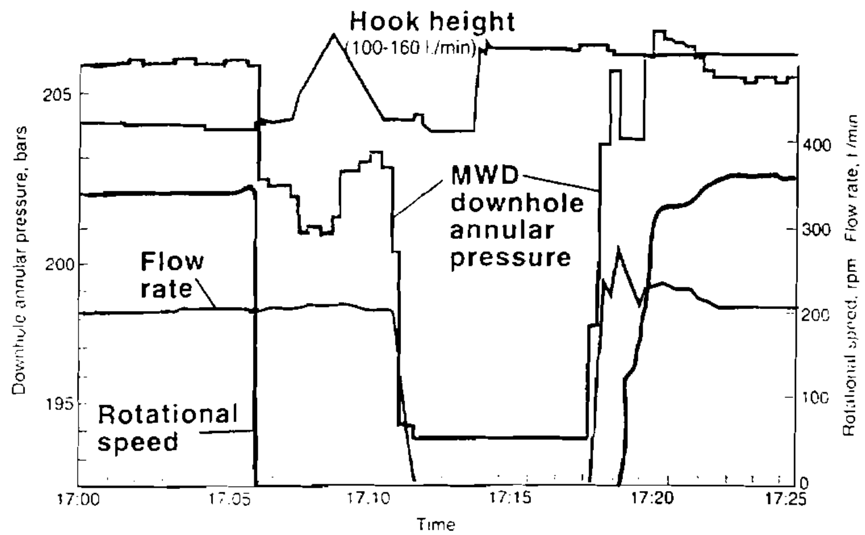


Figure 9-4. Annulus Pressure During Connection (Burban and Delahaye, 1994)

Annulus pressure during trips was also investigated. Swab pressures while tripping out are shown in Figure 9-5. The difference between predictions and measurements is significant. Annulus pressures drop about 90 psi (0.25 ppg ECD) while pulling pipe at an average speed of 0.8 ft/sec.

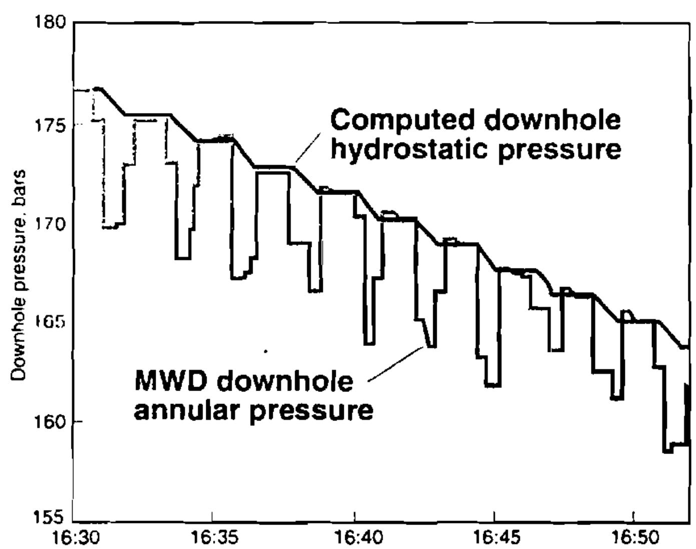


Figure 9-5. Annulus Pressures While Tripping Out (Burban and Delahaye, 1994)

Surge pressures while running in are shown in Figure 9-6. Before 4:00, pipe was run in at an average speed of 1.6 ft/sec. Annulus pressure increased about 44 psi (3 bars). After 4:00, the new crew ran in slower at about 1 ft/sec. Annulus pressure increased only 22 psi (1.5 bars) above hydrostatic.

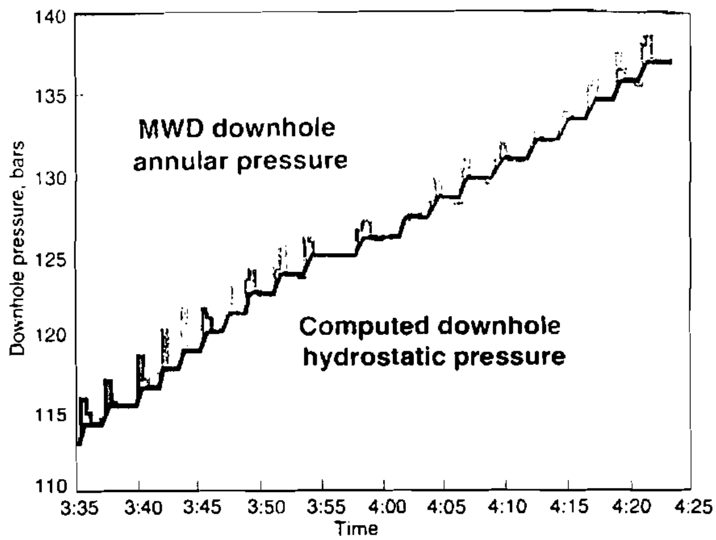


Figure 9-6. Annulus Pressures While Tripping In (Burban and Delahaye, 1994)

Geoservices and the other partners plan to add directional and gamma-ray sensors to this 2⅝-in. MWD tool.

9.1.2 Sperry-Sun Drilling Services (MWD Resistivity)

Sperry-Sun Drilling Services (Maranuk, 1994) developed a new multiple-depth resistivity MWD tool for use in slim holes as small as 5⅝ inches. The new slim tool was successfully built based on conventional electromagnetic-wave technology, and designed to incorporate the added features of self-contained gamma-ray sensor and vibration sensor. Over forty bit runs have been completed with the tool in fields around the world.

Until recently, MWD technology for holes less than conventional 8½ in. has been limited. Sperry-Sun developed the new SLIM PHASE 4™ tool based on the larger EWR-PHASE 4™ tool. Electromagnetic-wave tools can be run in any drilling fluid and allow relatively deep investigation depths. Primary specifications for the slim MWD tool include:

- High-pressure (18,000 psi)/high-temperature (150°C) operation
- Operation in all mud types
- Internal fluid flow from 150 to 350 gpm
- Maximum WOB: 25,000 lb
- Maximum rotary speed: 250 rpm
- Tool diameter 4¾ in.; antenna section must be 5⅛ in., but is limited to a length of 40 in.; hole size as small as 5⅞ in.
- Build rates of 14°/100 ft while rotating, 30°/100 ft for slide drilling

The slim MWD tool (Figure 9-7) includes an electromagnetic-wave resistivity sensor, a gamma-ray sensor, and a drill-string dynamics sensor. The tool can be run in record-only mode or in real-time mode by the addition of a directional sensor and pulser.

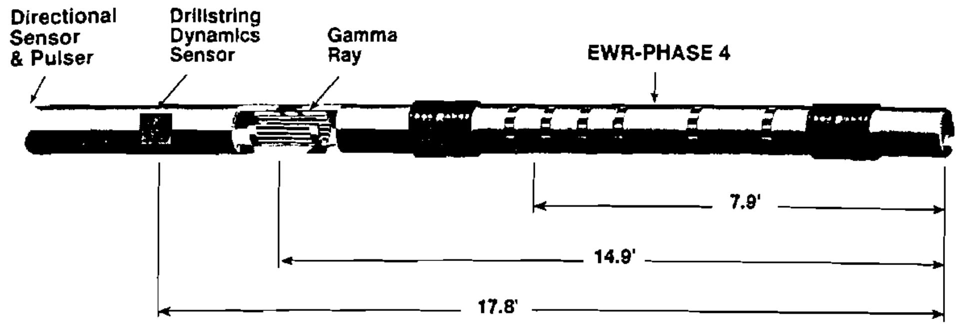


Figure 9-7. Sperry-Sun Slim MWD Tool (Maranuk, 1994)

The resistivity section (Figure 9-8) provides four transmitter/receiver spacings: extra-shallow (6 in./12 in.), shallow (12 in./18 in.), medium (24 in./30 in.) and deep (36 in./42 in.). Four phase-derived and four combined phase/amplitude measurements can be made.

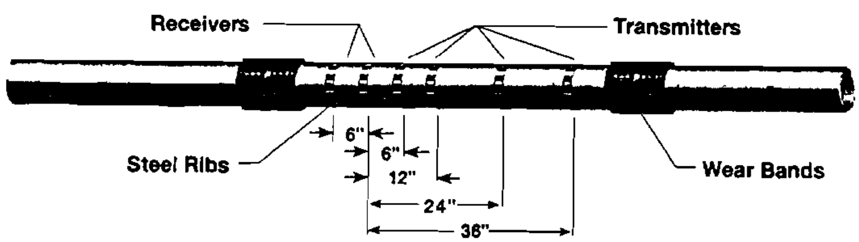


Figure 9-8. Slim MWD Resistivity Section (Maranuk, 1994)

Mud flow through the tool is off-center (Figure 9-9). Electronics boards are mounted opposite the flow area.

A summary of fourteen field operations that used the slim MWD tool is shown in Table 9-2. Borehole sizes have ranged from 5⅞ to 6¾ inches. Various drilling fluids have been used including water-base gels, oil-base polymers, and salt saturated fluids. Half of these jobs were horizontal wells. Only one failure of the MWD tool was recorded.

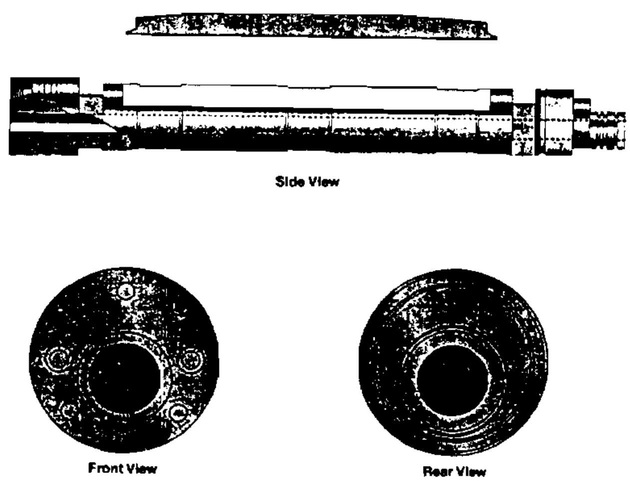


Figure 9-9. Mud Flow Through Slim MWD Tool (Maranuk, 1994)

TABLE 9-2. Jobs with Slim MWD Tool (Maranuk, 1994)

Job	Location	Bit Runs	Bit Size	Feet Logged	Hours Downhole	Maximum Deviation	Maximum Temperature	Total (ft) Depth	Service Type	% Delivered	Service Interrupt	Comments
#1	Onshore, TX	1	6.50	3,200	64	90.4	149	11,591	Rec	100	N	Horizontal
#2	Offshore, Gulf of Mexico	3	6.50	1,751	145	60.3	219	13,605	Rec	100	N	S-Shape
#3	Offshore, Norway	3	6.00	971	142	64.1	162	10,758	Rec	100	N	Directional
#4	Offshore, Norway	6	6.00	3,383	263	44.3	252	19,958	Rec	100	N	S-Shape
#5	Offshore, Gulf of Mexico	1	6.50						Rec		N	LIH
#6	North Slope, Alaska	2	6.00	1,190	94	93.3	178	13,545	Rec	100	N	Horizontal
#7	North Slope, Alaska	5	6.75	1,193	63	93.6	169	12,630	Rec	100	N	Horizontal
#8	North Slope, Alaska	2	6.00	1,101	63	87.2	190	12,381	Rec	100	N	Horizontal
#9	North Slope, Alaska	2	6.00	711	60	91.3	175	10,365	Rec	100	N	Horizontal
#10	Offshore, Gulf of Mexico	6	6.50	6,665	473	28.6	255	16,337	Rec	100	N	Directional
#11	Offshore, Aberdeen	2	6.00	1,198	156	93.5	192	12,800	R/T	70	Y	Horizontal
#12	Offshore, Gulf of Mexico	3	5.88	904	179	2.0	156	16,148	R/T	100	Y	S-Shape
#13	Offshore, Gulf of Mexico	4	6.00	1,084	110	33.0	217	12,911	Rec	100	N	Directional
#14	Offshore, Persian Gulf	1	6.13	3,325	78	90.0	201	13,674	R/T	99	Y	Horizontal
		41		26,676	1,889		193	13,593		98		

In one particular field operation, resistivity and gamma ray were obtained in a 6-in. hole in the North Sea. The tool was used while drilling an 800-ft section at a deviation of 60°. For this case, both wireline and MWD logging data were obtained for comparison. Wireline laterolog data (Figure 9-10, center track) were compared to electromagnetic-wave resistivity data (right track).

These data are overlain in Figure 9-11. The electromagnetic-wave data were found to exhibit better vertical resolution than the laterolog.

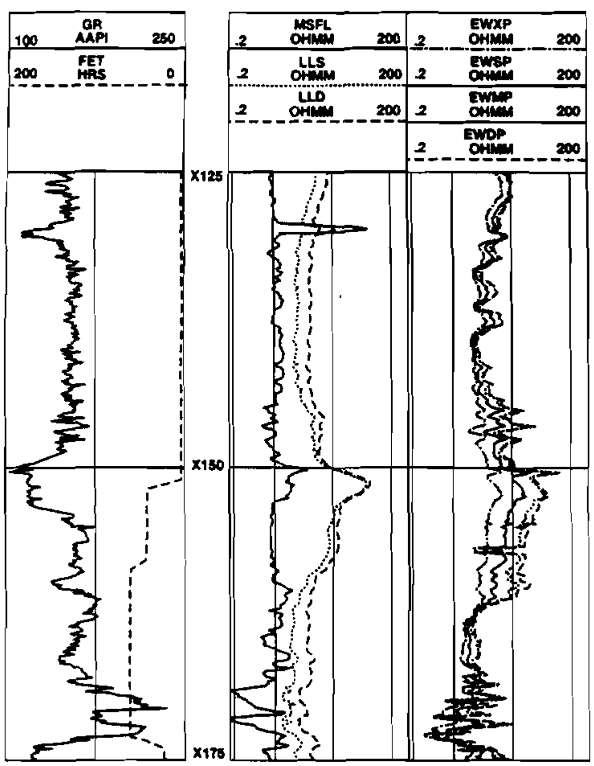


Figure 9-10. Laterolog and MWD Data from North Sea Well (Maranuk, 1994)

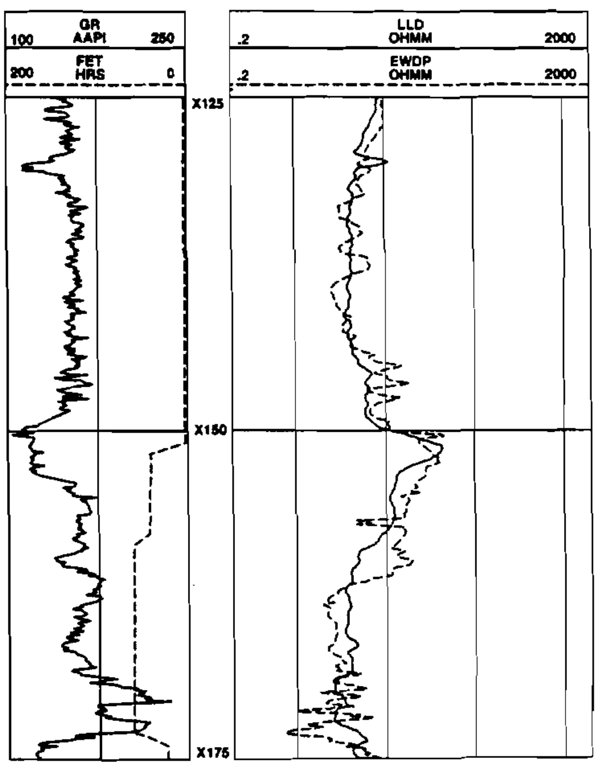


Figure 9-11. Comparison of Laterolog and MWD Data (Maranuk, 1994)

Sperry-Sun Drilling Services (*The Pulser* Staff, 1994) collected and published a summary of currently manufactured MWD tools. These data are shown in Table 9-3. Several manufacturers offer slim-hole tools for use with collars as small as 3½ inches.

TABLE 9-3. MWD Sensors by Collar Size (*The Pulser* Staff, 1994)

	ANADRILL										BAKER HUGHES INTEQ							COMPUTALOG				GEOLINK			GEOSERVICES			HALLIBURTON						QDT		SPERRY-SUN						
Sensor Type / Collar Size	6 3/4" MOTOR	3 1/16" PLUS	6 1/2"	6 3/4"	7"	7 3/4"	8"	8 1/4"	9"	9 1/2"	3 1/8" PLUS	4 1/8" PLUS	6 3/4"	7 3/4"	8 1/4"	9 1/2"		4 3/4" PLUS				3 1/2"	4 3/4" PLUS		3 1/2" PLUS			4 3/4" PLUS			6 3/4"	8"	9 1/2"	3 7/8" PLUS		6 1/2" MOTOR	8" MOTOR	3 3/8" PLUS	4 3/4"	6 3/4"	8"	9 1/2"
Directional	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x				x	x		x			x			x	x	x	x		x	x	x	x	x	x	x
Gamma Ray	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x		x				x	x		x			x			x	x	x	x				x	x	x	x	x
Electrode Resistivity	x			x	x		x		x				x	x	x	x																										
Propagation Resistivity			x	x		x	x	x		x			x	x	x	x															x	x	x						x	x	x	x
Multiple Spacing Resistivity																															x	x	x						x	x	x	
Bit Resistivity	x			x																											x	x	x									
Neutron Porosity			x	x			x						x	x	x																x	x								x	x	
Bulk Density			x	x			x						x		x																x	x								x	x	
Acoustic Porosity								x																																		
Ultrasonic Caliper				x				x																							x	x										
Vibration Detection			x	x	x	x	x	x	x	x			x	x	x	x																								x	x	x
Weight and Torque				x	x		x		x				x	x	x																											
Bending Moment													x	x	x																											
Pressure				x									x	x									x		x															x	x	x
Motor RPM	x																																									

9.1.4 Union Pacific Resources (Gamma-Ray MWD System)

Union Pacific Resources and Anadrill/ Schlumberger (Genrich et al., 1993) described the development and field use of a slim gamma-ray MWD system that can be retrieved with slickline. The system was developed for geosteering horizontal wells, with earliest applications in the Austin Chalk Trend in Texas. The MWD assembly can be run in drill collars with IDs as small as 2.19 in., and has been successfully run in 3½-in. OD collars.

The MWD gamma-ray system (Figure 9-12) can be run and retrieved on standard slickline (0.092 in.) with an overshot. The assembly fits in a standard API collar. Advantages of the design include minimal risk of losing the tool in the hole, reduced trouble time if the tool fails, reduced transportation costs, and versatility in that the same tool is used in holes ranging from 4¾-12¼ inches.

Positive mud-pulse telemetry is used to transmit data to the surface. In general, a 1-sec data rate is used. Transmitted data include inclination, azimuth, tool-face orientation, temperature, output from magnetometer and inclinometer, battery voltage, and gamma ray. Tool specifications include an operational range of -67 to 302°F and pressures to 20,000 psi.

The minimum drill-string ID to allow retrieving the tool is 2 inches. In field operations, the tool has been retrieved from a displacement of 3800 ft with coiled tubing and from a 2200-ft displacement with pumpdown cups and wireline.

Union Pacific Resources uses the MWD gamma-ray data for two purposes in drilling operations in the Austin Chalk. The MWD log is used to correlate depth with existing wireline logs. The system is also used for geo-steering the horizontal section. In one example scenario (Figure 9-13), formation dip angle can be determined by comparing data (wireline or MWD) from the pilot hole to MWD data from the same formations in the curve (point X and Y in the figure).

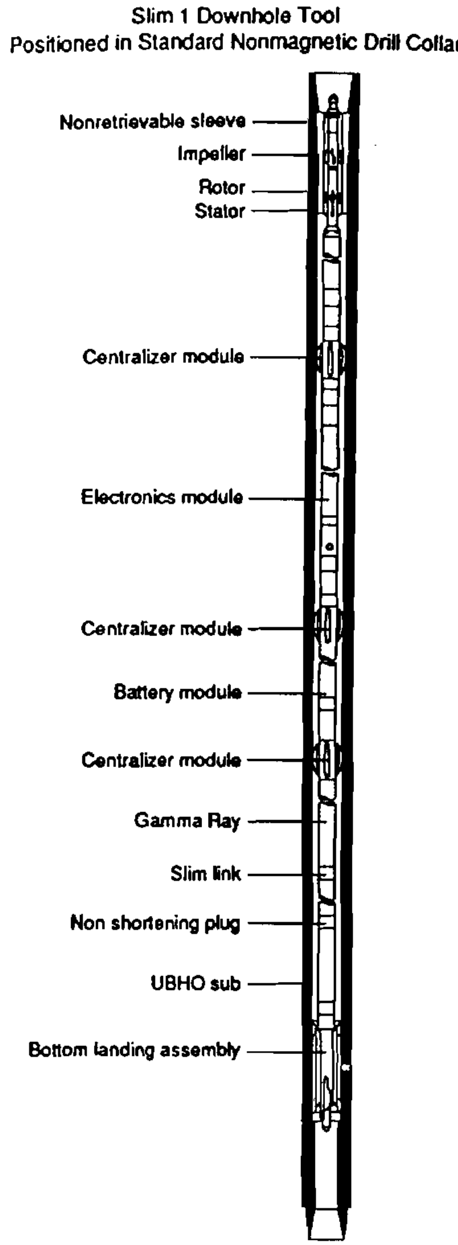


Figure 9-12. Slim Gamma-Ray MWD Tool (Genrich et al., 1993)

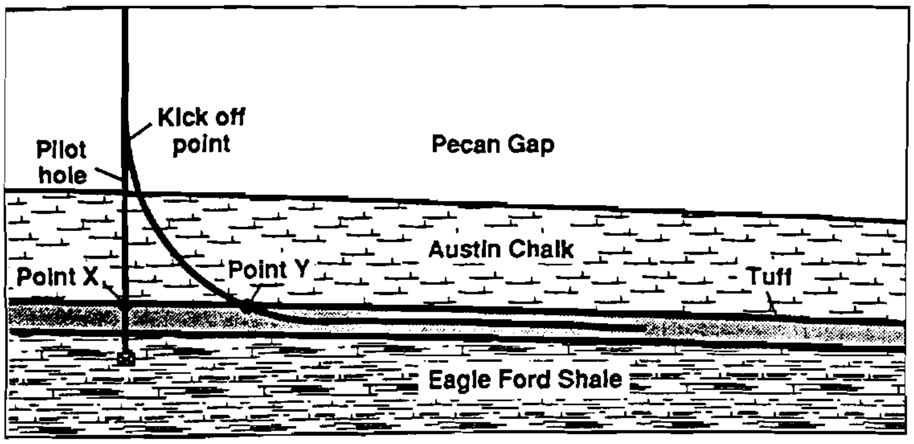
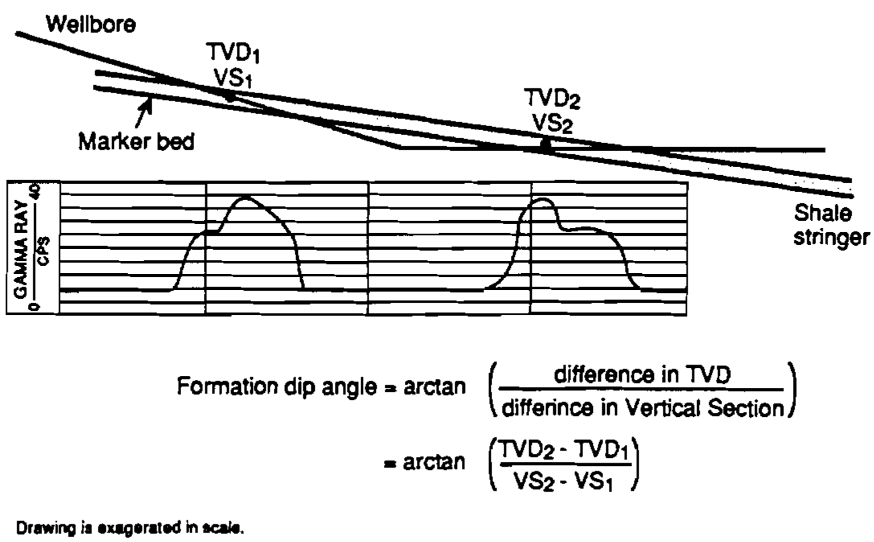


Figure 9-13. Determining Formation Dip Angle with Pilot Hole Data (Genrich et al., 1993)

If the wellbore crosses the same identifiable stringer twice, these markers can be used to determine formation dip angle (Figure 9-14).



$$\text{Formation dip angle} = \arctan\left(\frac{\text{difference in TVD}}{\text{differince in Vertical Section}}\right)$$

$$= \arctan\left(\frac{TVD_2 - TVD_1}{VS_2 - VS_1}\right)$$

Figure 9-14. Determining Formation Dip Angle by Marker Formations (Genrich et al., 1993)

An example log for formation dip determination based on passing through marker zones is shown in Figure 9-15. At point 1 in the figure, the detector passed through a shale bed. The tool exited the stringer at point A, then passed through a cleaner section of chalk as indicated by a drop in the count rate. Before point 2, the mirror image of the same sequence is visible, indicating the tool passed back through the same stringer.

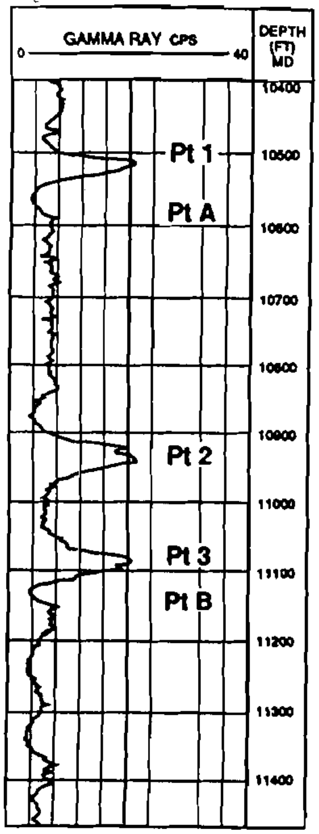


Figure 9-15. Log for Determining Formation Dip Angle by Marker Formations (Genrich et al., 1993)

A comparison of data from wireline gamma ray and MWD gamma ray (Figure 9-16) shows good agreement. The principal difference between the two systems is the response of the wireline system as it passes through connections.

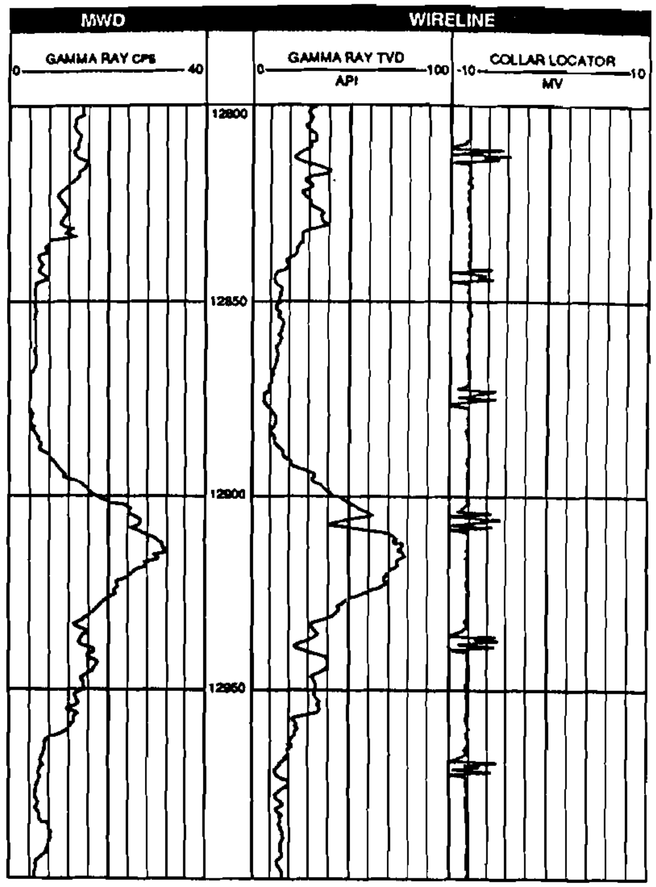


Figure 9-16. Comparison of MWD and Wireline Gamma Ray (Genrich et al., 1993)

The retrievable design of the tool saves the operator time and money. In high-angle wellbores, it is usually necessary to raise the string until the collars are almost vertical before the tool can be retrieved. Even then, time is saved with this system. Cost savings with the tool from less trouble time to replace failed tools are about $11,000 per well, based on typical data for an Austin Chalk project.

9.2 WIRELINE LOGGING

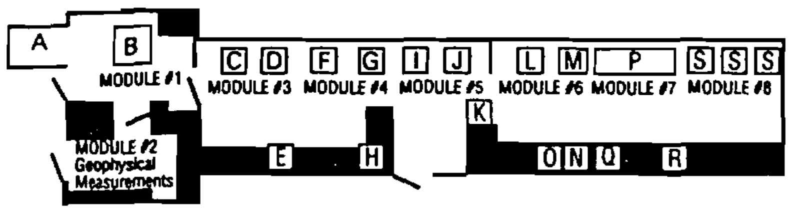
9.2.1 Amoco Production Company (Automated Core Logging)

Amoco Production Company (Spain et al., 1992) developed an automated core evaluation system for analyzing continuous slim-hole cores as part of their SHADS (Stratigraphic High-speed

Automatic Drilling System) development project. Efficiently dealing with the large volume of core generated and obtaining results in near real-time at the site are the principal benefits of this approach.

Amoco's core evaluation system is transported in eight 8 x 12-ft aluminum modules. Site set-up is accomplished by crane or forklift.

Cores are evaluated by inverse logging, that is, moving the core past the logging instruments. Measurements made on the core (Figure 9-17) include gamma ray, magnetic susceptibility, ultraviolet fluorescence, nuclear magnetic resonance porosity, infrared mineralogy, and pyrolysis. Images of the core are recorded continuously by a video disk recorder.



A. Washing and drying
B. Striping, labelling, cutting
C. Gamma scan
D. Magnetic susceptibility
E. Data storage and 'traffic cop' computer
F. Qualitative mineralogy
G. Ultra-violet fluorescence scan
H. Computer for the above
I-J. Macro and micro view video cameras
K. Video monitors
L. NMR
M. Pyrolog
N. Core description computer
O. Video microscope
P. Movable roller table
Q. Spare computer
R. Gas chromatograph
S. Heating/AC units

Figure 9-17. Amoco Core Evaluation System (Spain et al., 1992)

Additional details and several example logs from Amoco's system are presented in the Chapter *Coring Systems*.

9.2.2 Asamera South Sumatra Ltd. (Sumatran Case History)

Asamera South Sumatra Ltd. (Almendingen et al., 1992) drilled/cored five exploratory wells in remote locations in South Sumatra. Conventional drilling procedures were not feasible for this campaign due to excessive time to construct access roads as well as high overall costs. A slim-hole mining approach based on helicopter transport was used to evaluated the subject acreage.

Major equipment included a Longyear HM 55 helirig and Bell 205 helicopter. No serious operational problems were encountered during the five-well project. All wells were plugged and abandoned after formation evaluation.

For all five wells, the 4½-in. casing strings were set at one half of TD (Figure 9-18). Destructive drilling using CHD-101 drill rods was used to drill down to the 4½-in. set point. Continuous coring was used thereafter to TD.

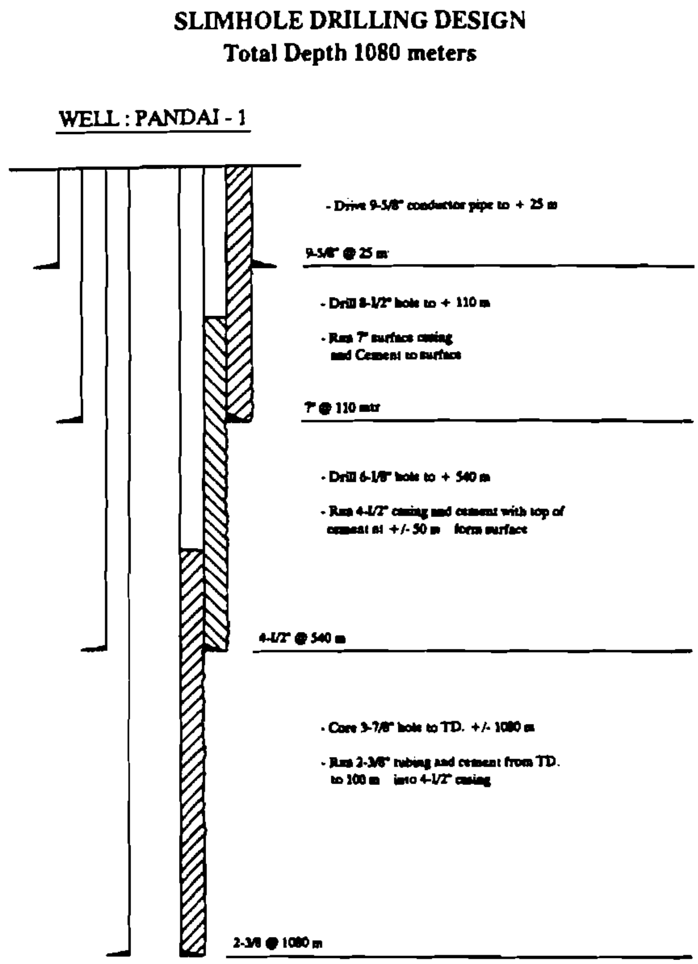


Figure 9-18. Slim-Hole Casing Program for South Sumatra Project (Almendingen et al., 1992)

Slim-hole logging suites were run in the 6⅛-in. (conventional) and 3⅞-in. (cored) sections of the hole. Suites included induction electric log with spontaneous potential, acoustic velocity log with gamma ray, neutron, and density with gamma ray. Multishot velocity surveys were also run.

A slim-hole laterolog system would have been preferred, but was not available to the project. Formation evaluation was done via porosity logs, oil shows in the core, and chromatograph readings from the mud stream.

Location construction, drilling and evaluation of the five wells were completed in 27 weeks. Asamera was very pleased with the speed and low cost with which the project was conducted.

Additional details on Asamera's slim-hole coring operations are presented in the Chapter *Coring Systems*.

9.2.3 BPB Wireline Services (Logging Slim Horizontal Wells)

BPB Wireline Services (Elkington, 1994) ran slim-hole logging tools in a horizontal sidetrack with a build rate of 34°/100 ft. Recently developed slim tools (2¼ in.) were successfully deployed on coiled tubing, producing conventional open-hole logs for formation evaluation.

Industry's experience has shown that it can be difficult to convey conventional logging tools into horizontal sections on coiled tubing, especially if the holes are slim, the wells are long-reach, or severe doglegs are present. Frictional forces often cause the coiled tubing to lock up before reaching TD. One operator (Van den Bosch, 1994) reported that conventional tools conveyed by coiled tubing failed to reach TD on three out of four wells. (See the Chapter *Logging* in *Coiled-Tubing Technology (1993-1994)*.)

BPB (British Plaster Board) has attacked this problem by reducing the size and weight of logging tools. A new generation of slim tools continues to be developed with a maximum OD of 2¼ in. and weights at least 80% less than their conventional counterparts. BPB began developing slim tools for the minerals industry in the 1960s. The first use of these tools in the oil field was during the 1980s. Two early applications emerged: slim vertical wells and logging through drill pipe.

BPB's general specifications for slim-hole tools include a maximum OD of 2¼ in., temperature rating of 255°F and pressure rating of 12,500 psi. Their product line includes:

- Array-induction resistivity
- Dual laterolog
- Dual density/gamma ray/caliper
- Dual neutron
- Multi-channel sonic
- Coiled-tubing tension/compression sub
- Repeat formation sampler

The slim repeat formation sampler is one of the newest tools. Size reduction has been obtained by abandoning the normal hydraulic generator used to set the tool, and replacing it with mud-column activation.

Nowsco used these tools in a horizontal sidetrack drilled on coiled tubing in 1994. Coiled tubing was 2⅜-in., which was slightly larger than the logging tools. Hole size was 4⅜ inches.

A primary consideration was whether the tools could be pushed through the short-radius curve (34°/100 ft). Design charts for slim 2¼-in. tools (Figure 9-19) and for more-conventional 3¾-in. tools (Figure 9-20) showed that the maximum tool length with slim tools was 4.6 m (15 ft), compared to tools (Figure 9-20) showed that the maximum tool length with slim tools was 4.6 m (15 ft), compared to 2.5 m (8 ft) with conventional tools. All logging subs were longer than 8 ft; consequently, slim tools were required.

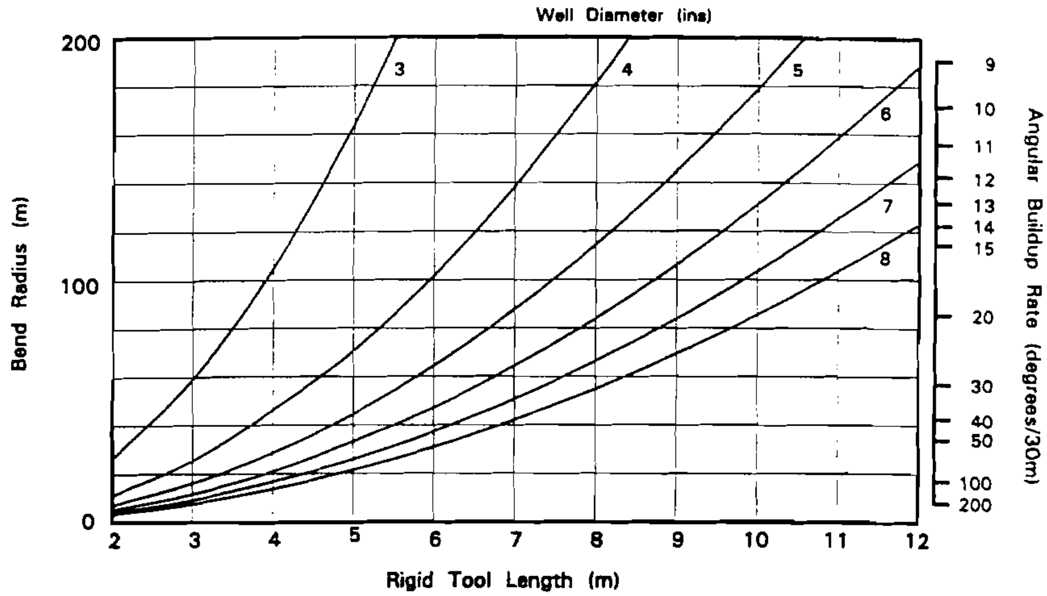


Figure 9-19. Rigid Length for 2¼-in. Logging Assembly (Elkington, 1994)

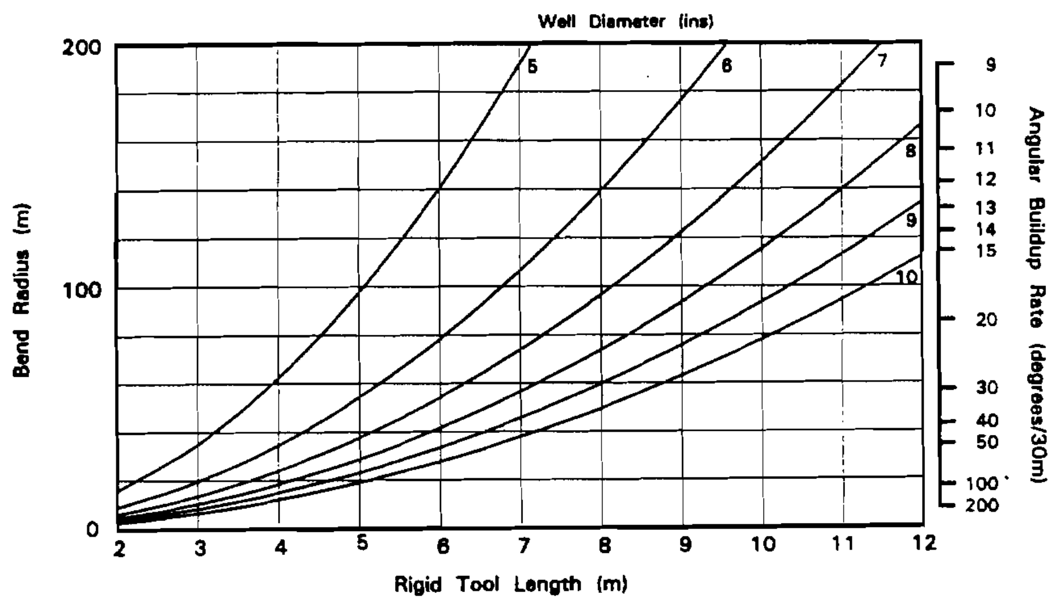


Figure 9-20. Rigid Length for 3¾-in. Logging Assembly (Elkington, 1994)

During operations in the well, a tension/compression sub was used to monitor downhole forces. Forces in the logging assembly never varied more than 20 lbs from the nominal force. This demonstrates that the slim tools behaved as extensions to the coiled-tubing string.

The dual-density, gamma-ray and caliper logs for this slim-hole horizontal sidetrack are shown in Figure 9-21. The frequent high-density streaks are calcareous lenses. According to the gamma-ray data, the wellbore entered shale below 1865 m. Data interpretation led to the conclusion that the reservoir was faulted out at this point.

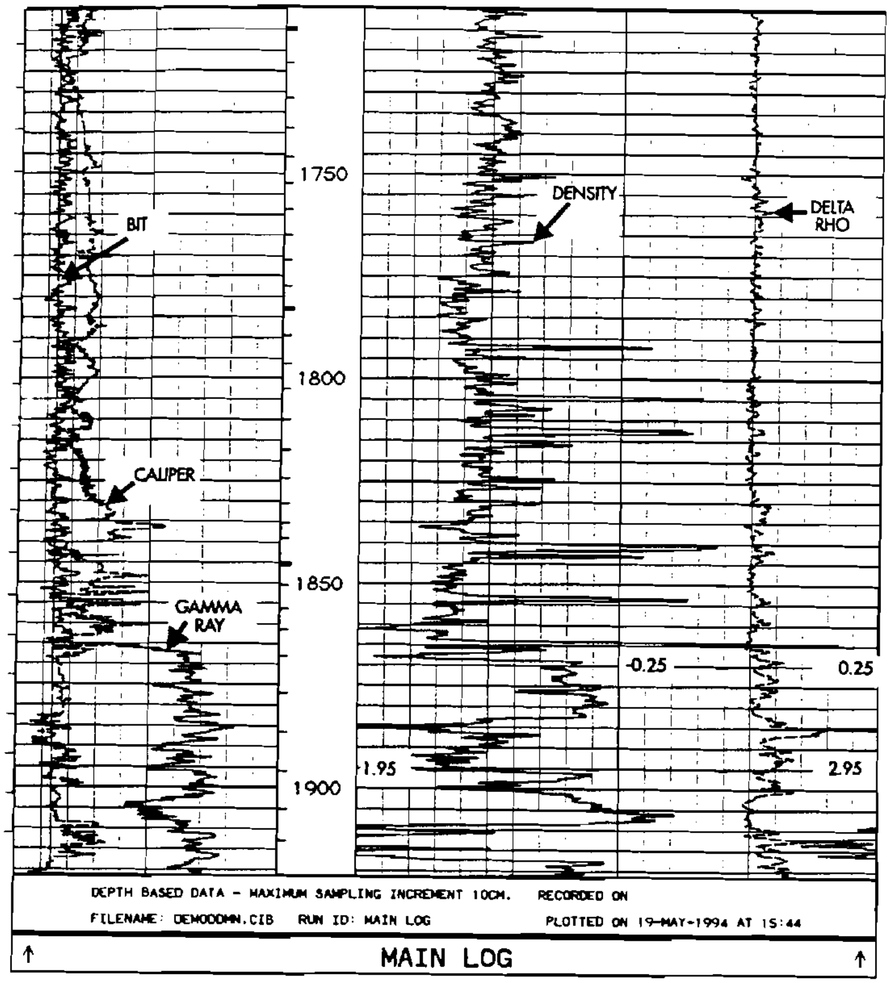


Figure 9-21. Dual-Density, Gamma-Ray and Caliper Logs in Slim Horizontal Sidetrack (Elkington, 1994)

There was evidence during run-in that the density tool was not always against the borehole wall. A comparison of the main and repeat induction logs (Figure 9-22) shows that the tool performed well despite any positioning problems.

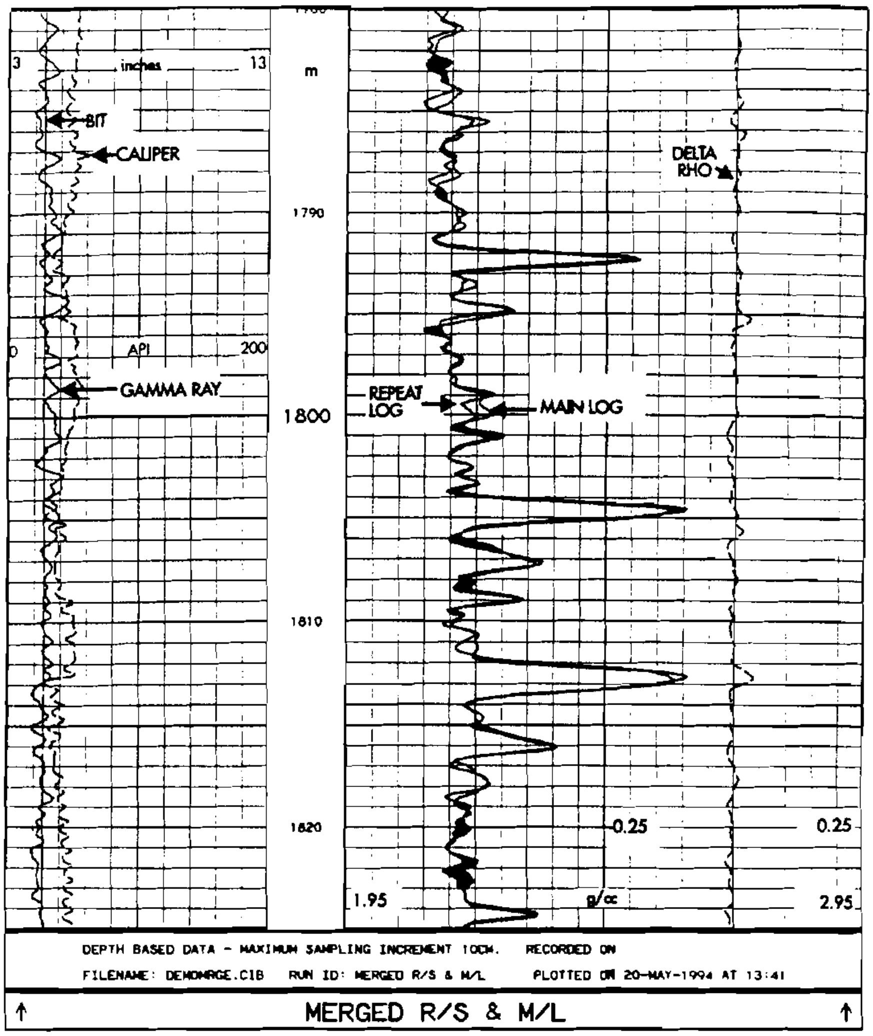


Figure 9-22. Main and Repeat Compensated Density in Slim Horizontal Sidetrack (Elkington, 1994)

9.2.4 BP Exploration (Automated Core Logging)

BP Exploration Operating Company, Statoil A/S, and EXLOG (Murray et al., 1993) formed a strategic alliance to develop an integrated slim-hole coring and core-analysis system. A helicopter-transportable rig was developed, including an automatic kick-detection system. Continuous on-site core analysis was successfully implemented. All these concepts were evaluated in a series of field trials in a four-well exploration program.

In 1991, Statoil and BP joined to develop core logging capability. Soon thereafter, EXLOG and BP worked on modifying an existing BP fluids model to perform early kick detection in slim-hole wells. BP and Statoil contributed major funding and technical knowledge; Statoil contributed experience with automated miniparameter measurements; EXLOG contributed construction capability, onsite data management, wellsite delivery, staff and service.

The BP/Statoil/EXLOG slim-hole system was first tested on a four-well program starting in early 1992. Early results were reviewed to provide recommended techniques and procedures for use in later wells. A hybrid coring/drilling approach was used, with coring being initiated above the source interval.

Cores were retrieved and immediately transferred to the logging unit (Figure 9-23). The maximum throughput established for the core logging unit was about 216 m/day (700 ft/day). Net ROP in the hole was less than the core logging unit's capacity.

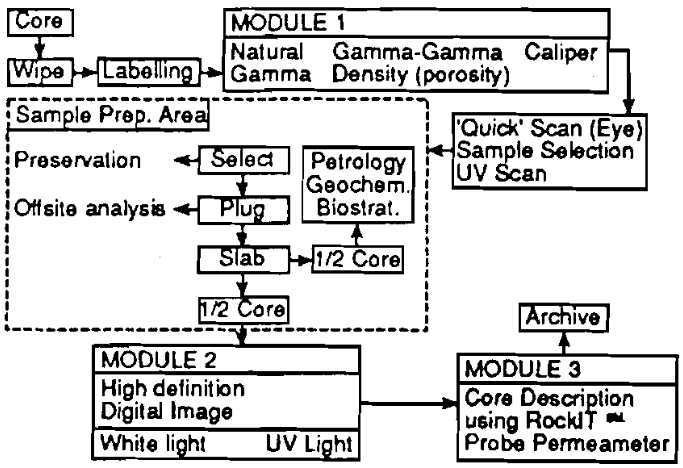


Figure 9-23. Core Data Analysis (Murray et al., 1993)

The BP/Statoil/EXLOG slim-hole system is described in the Chapter *Coring Systems*.

9.2.5 Halliburton Energy Services (Design of Slim Logging Tools)

Halliburton Energy Services, Maurer Engineering and Gas Research Institute (Boonen et al., 1995) summarized the results of a project designed to analyze the barriers hindering widespread application of slim-hole drilling and completion technology, with special emphasis on gas wells in the U.S. There appears to be significant opportunity for slim-hole technology in the U.S. gas industry since typical wells require neither high-volume artificial lift equipment nor large production tubing to avoid restricting flow rates. The study found that real and perceived limitations of slim-hole drilling for oil and gas exist, hindering the industry from enjoying the full benefits of the technology.

In Boonen et al. (1995), the project team presented an analysis of logging and perforating issues and challenges in slim-hole environments. Many services are available for both open- and cased-hole applications in slim holes (generally 4¾ in. or less). However, there are gaps remaining in tool availability.

Specific clearance requirements, including tool clearance, tool standoff, and wellbore curvature, dictate the minimum possible hole diameter (Figure 9-24). Many service companies consider that ¾ in. is the smallest possible clearance.

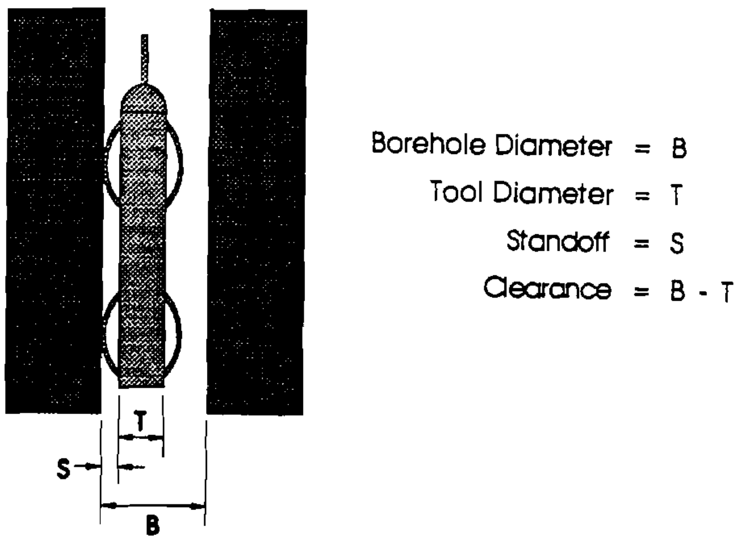


Figure 9-24. Logging Tool Clearance (Boonen et al., 1995)

Certain open-hole logging tools must be run in a specific orientation (Figure 9-25) for optimum performance. For example, gamma-ray tools are run free, sonic tools are centralized, and density tools are decentralized. Perforating guns usually require a specific standoff distance for achieving maximum potential penetration.

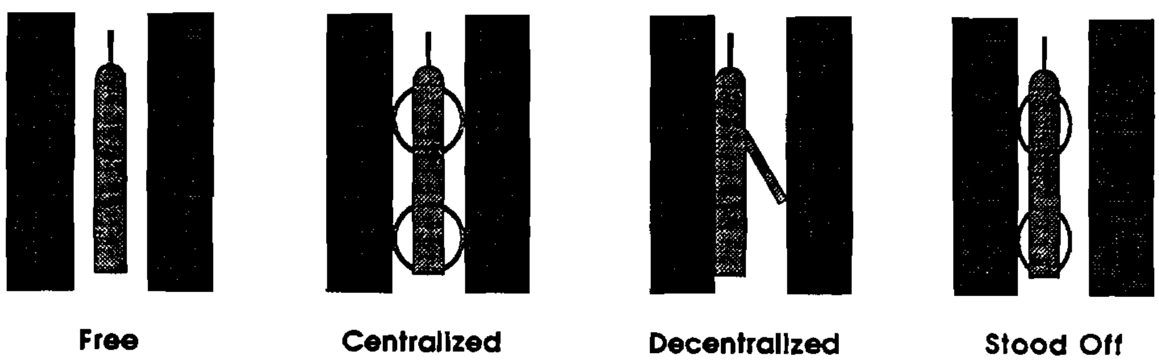


Figure 9-25. Logging Tool Orientation (Boonen et al., 1995)

A wellbore's radius of curvature can limit tool diameter, as well as total BHA length (Figure 9-26). Flex joints can be added to allow running longer logging assemblies.

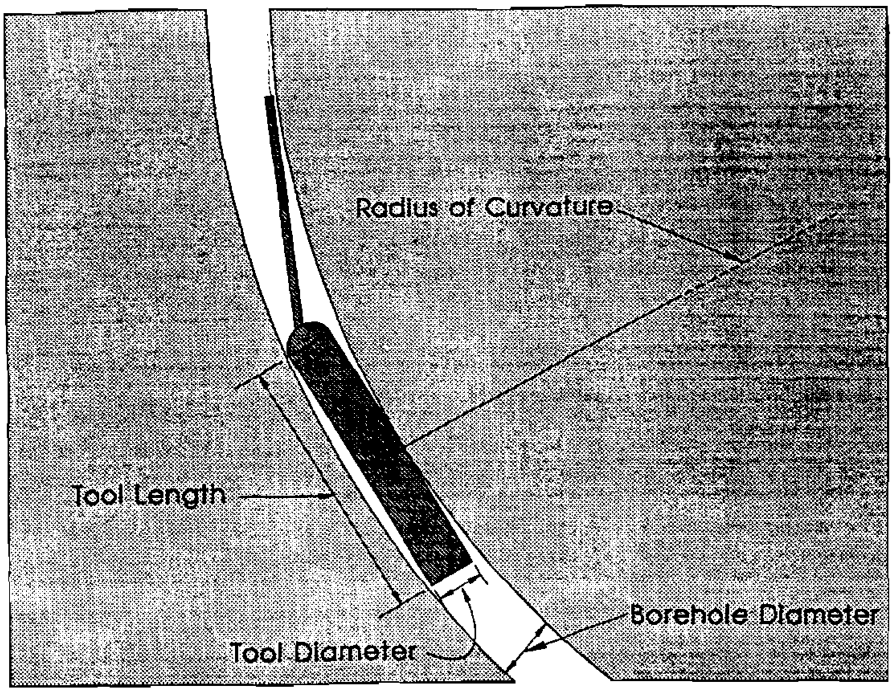


Figure 9-26. Wellbore Curvature and Tool Length (Boonen et al., 1995)

Boonen et al. also addressed MWD and LWD tools for slim holes. Currently available LWD tools are generally designed for use in 8½-in. holes. At least one company (Schlumberger Dowell) offers a slimmer gamma-ray tool for holes as small as 4¾ inches. Other LWD tools are being planned for reduced-diameter holes (5⅞ to 6¼ in.).

With regard to the difficulty of tool design and manufacture, large tools are easier and less expensive than slim tools. For example, slim induction and radioactive tools are much more challenging than conventional versions. Gamma-ray count rates from a slim sodium-iodide detector (1 by 8 in.) can be five times smaller than from a comparable 2- by 12-in. detector. Signal processing techniques become highly critical in slim tools.

Typical recommendations for minimum borehole diameter for a variety of open-hole wireline services are shown in Figure 9-27.

Boonen et al. listed several overall observations about the status of slim-hole logging technology. Among them are the following:

- Most full-size conventional tools can be used in holes as small as 4¾ inches. Formation evaluation can generally be performed in a 4¾-in. hole if hole quality is good and the interval is short.

- Triple-combo tools for slim holes are available from several companies, and provide responses matching conventional tools.

- R & D costs for slim-hole logging tools are considerable. Logging companies must carefully evaluate whether sufficient markets exist before pursuing specific developments.

- Higher development costs and lower tool availability will keep the rental costs of slim-hole logging tools higher than conventional.

- Industry's experiences have shown that fishing for slim-hole tools is not routine and requires special tools.

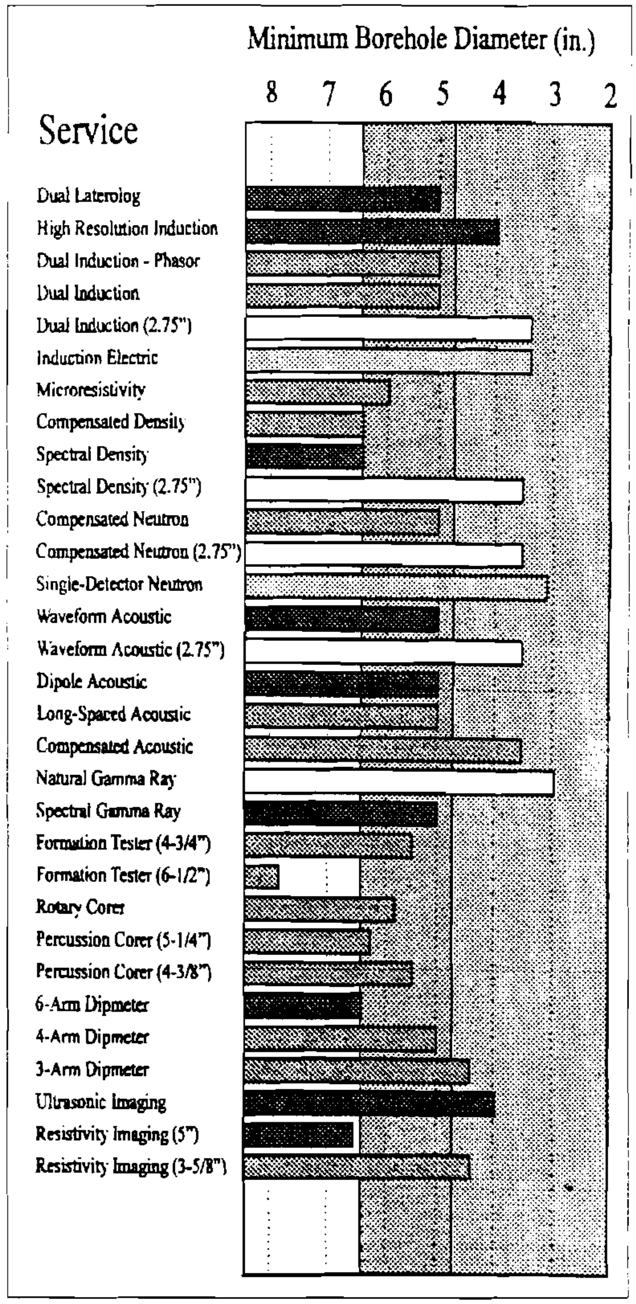


Figure 9-27. Minimum Wellbore Diameter for Wireline Tools (Boonen et al., 1995)

9.2.6 Mobil E&P Services (Field Comparison of Logging Tools)

Mobil Exploration and Producing Services compared the responses of slim-hole and conventional logging tools as part of their slim-hole development program (Schulze, 1992). Mobil questioned the assumption that conventional logging techniques and analyses could be used in slim-hole applications. They undertook a study to test that assumption.

In Mobil's study, conventional tools from one company (Company A) were compared to slim tools from Company A and another service company (Company B). The test well was originally drilled with a 5½-in. bit. After tests were conducted with all slim tools, the hole was reamed to 8½ inches. Conventional tools were tested in the larger hole along with a few slim tools.

The first series of measurements was of formation resistivity. According to Mobil's conclusions, neither of the slim-hole tools was acceptable for qualitative or quantitative identification of water saturations in permeable formations containing a mixture of water and hydrocarbons. They found that the depth of investigation is less for the slim tools.

An example log showing results of resistivity measurements (Figure 9-28) includes 1) conventional shallow laterolog (3⅜ in.), 2) conventional deep laterolog (3⅜ in.), 3) slim-hole deep laterolog (1½ in.), and 4) slim-hole deep induction resistivity (2¾ in.). The zone under investigation is permeable and filled with a mixture of fresh water and hydrocarbons.

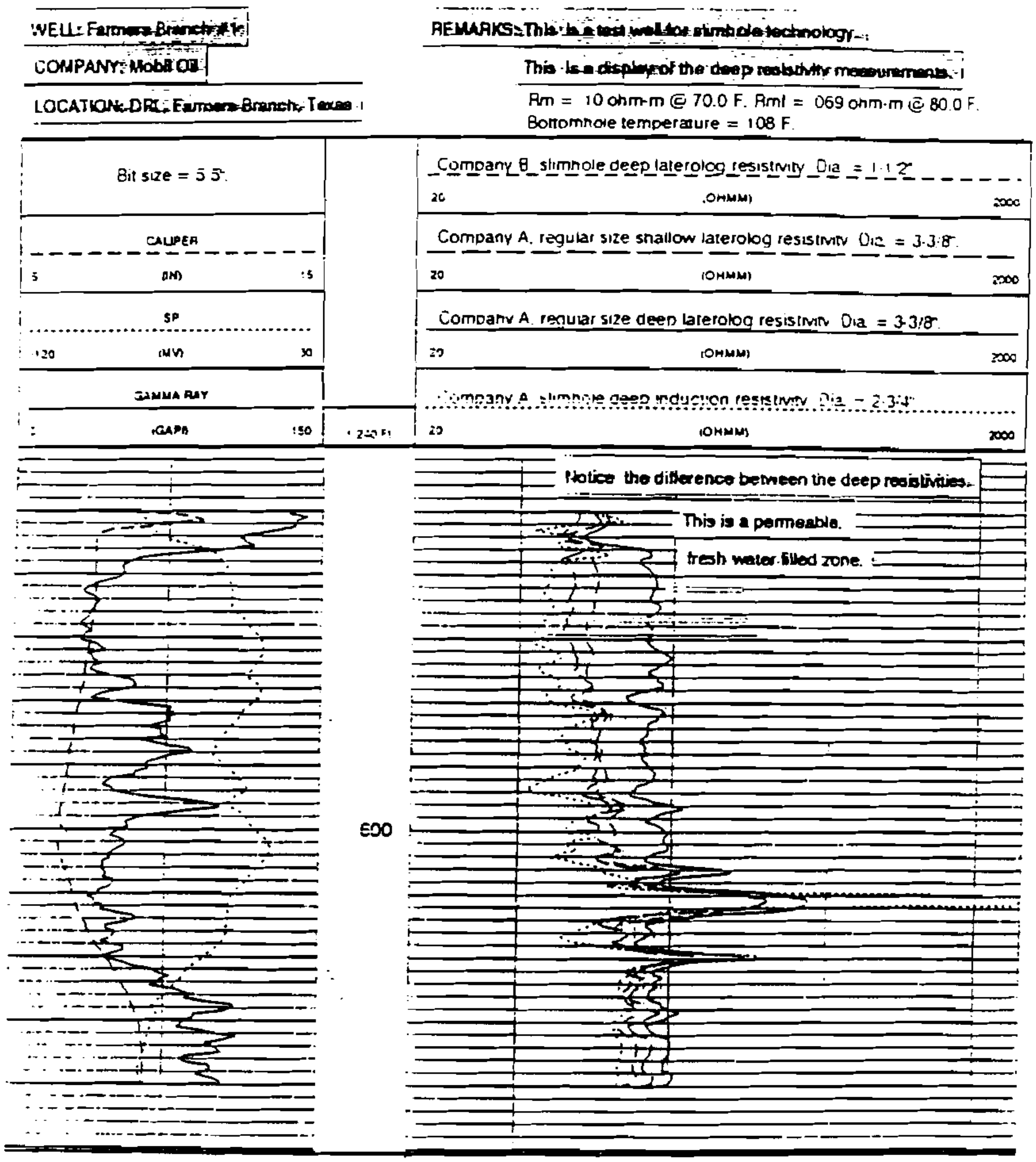


Figure 9-28. Mobil Slim-Hole/Conventional Resistivity Tool Comparison (Schulze, 1992)

The same four tools are compared in shale in Figure 9-29. The two slim-hole tools gave consistently lower measurements than the conventional tools.

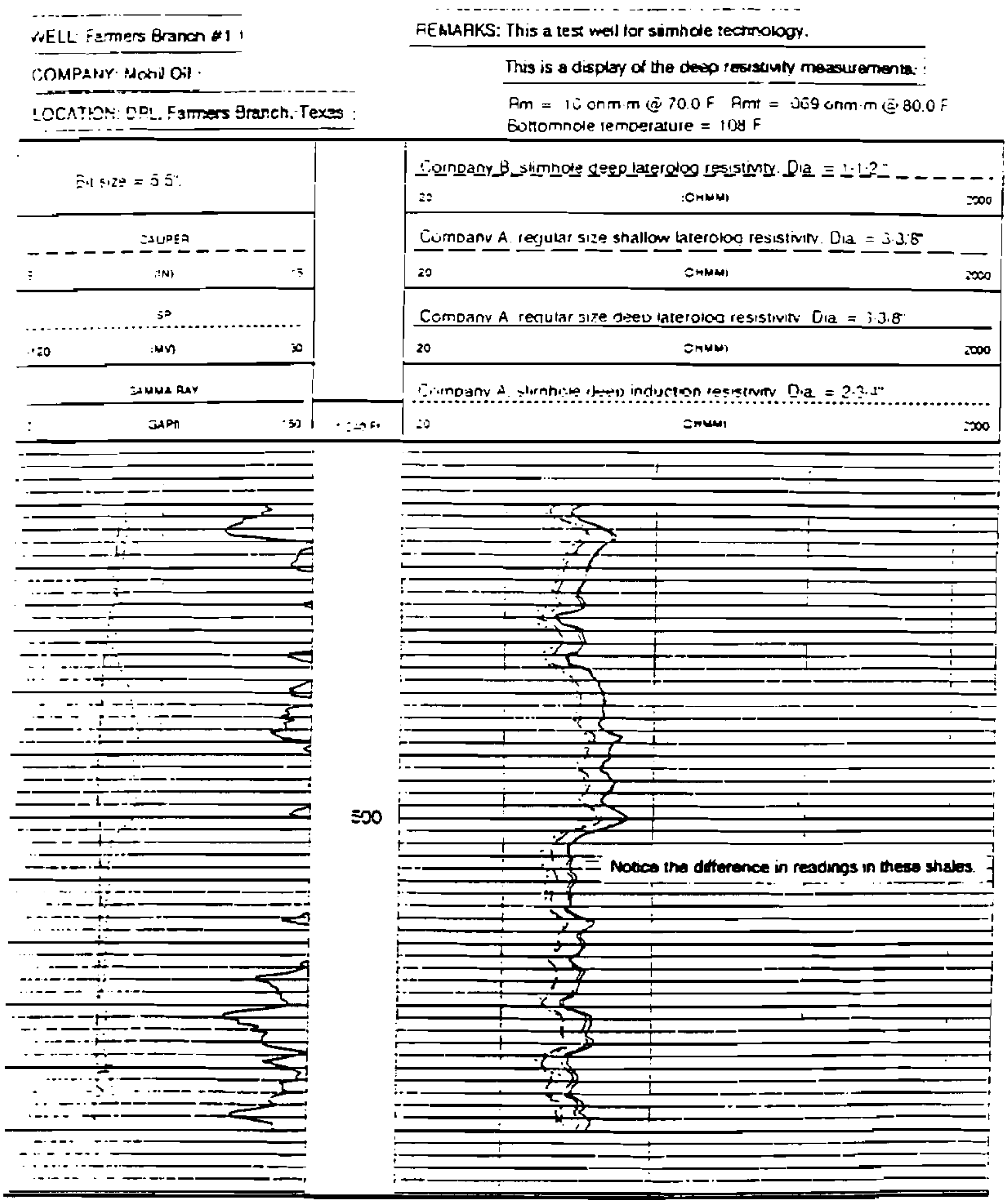


Figure 9-29. Mobil Slim-Hole/Conventional Resistivity Tool Comparison (Schulze, 1992)

Mobil concluded that the sensor spacings in the slim-hole resistivity tools were inadequate and that the slim tools do not measure as deeply as the conventional tools. After discussions with both manufacturers, Mobil analyzed data from slim-hole tools with spacing identical to standard tools and concluded that properly spaced slim-hole tools should give good results. Such tools are now available on the market.

Mobil tested density tools and found differences between conventional and slim tools (Figure 9-30). Their tests showed that the difference in tool readings increases as bulk density decreases.

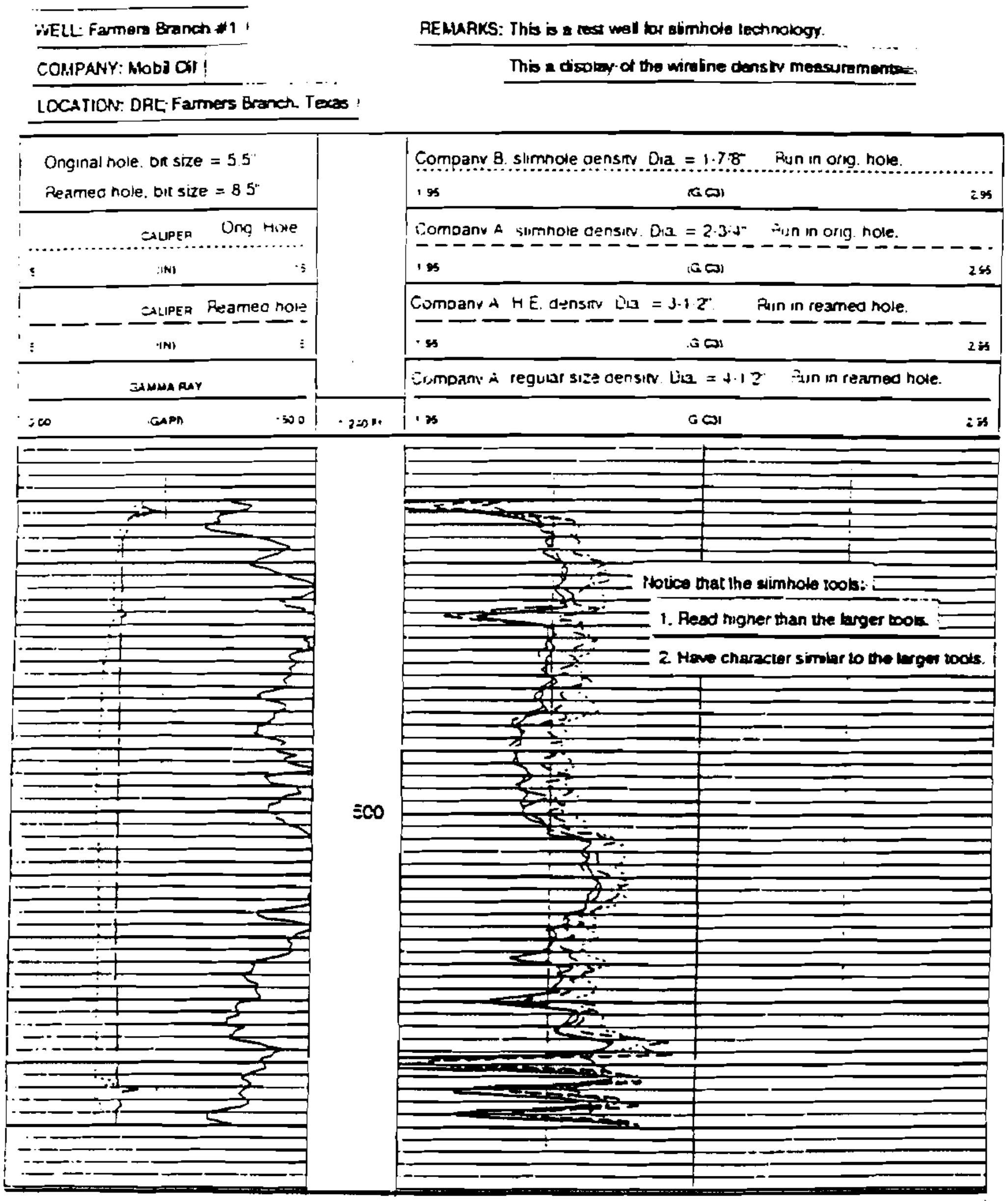


Figure 9-30. Mobil Slim-Hole/Conventional Density Tool Comparison (Schulze, 1992)

Slim-hole neutron tools were tested and yielded results differing from conventional. These differences were not unexpected, given that neutron tools usually vary in response from one tool to another and between manufacturers. In one zone of the test well, the two slim-hole tools gave higher readings than the conventional (Figure 9-31). In another zone, results were close for the three tools (Figure 9-32).

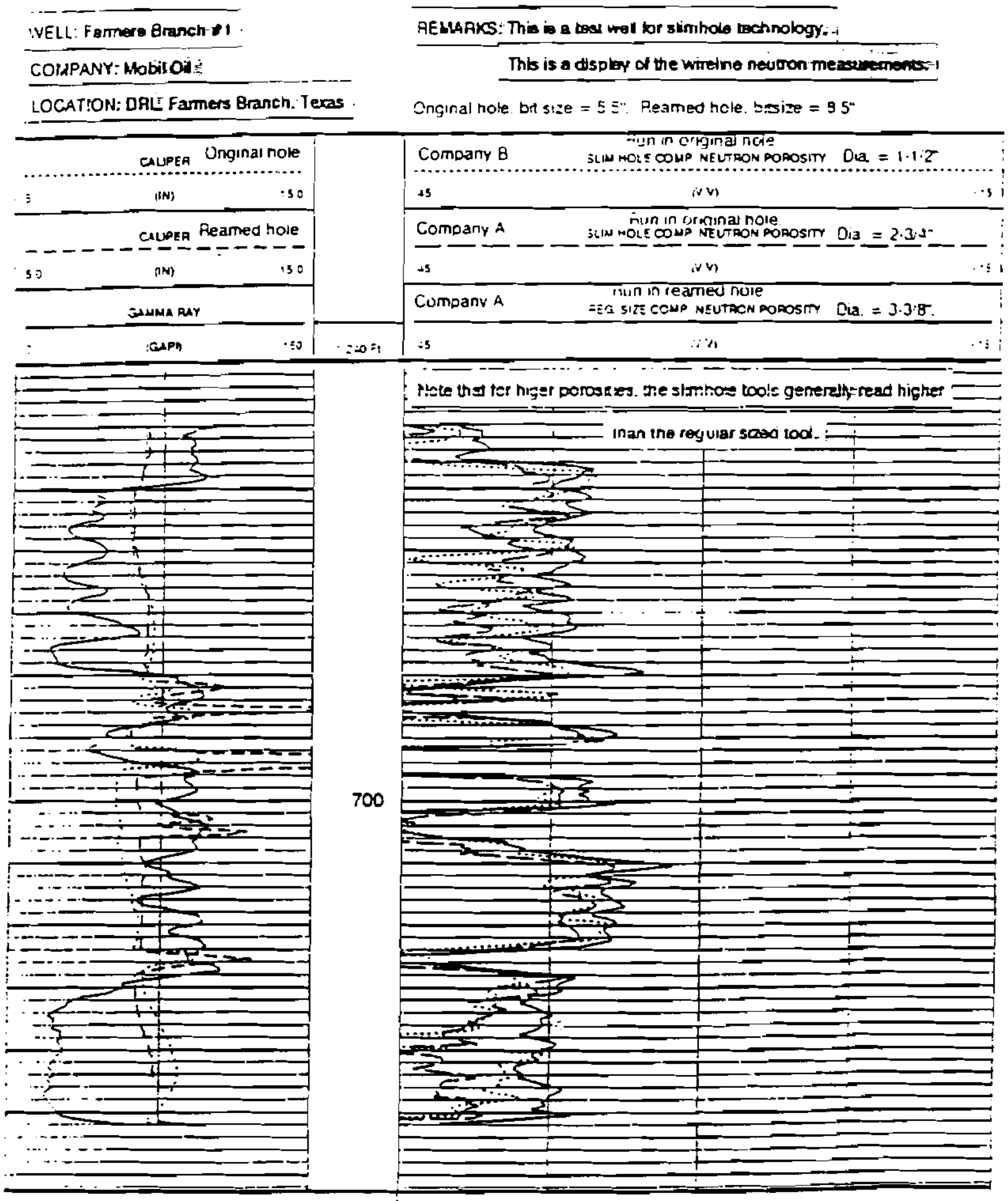


Figure 9-31. Mobil Slim-Hole/Conventional Neutron Tool Comparison (Schulze, 1992)

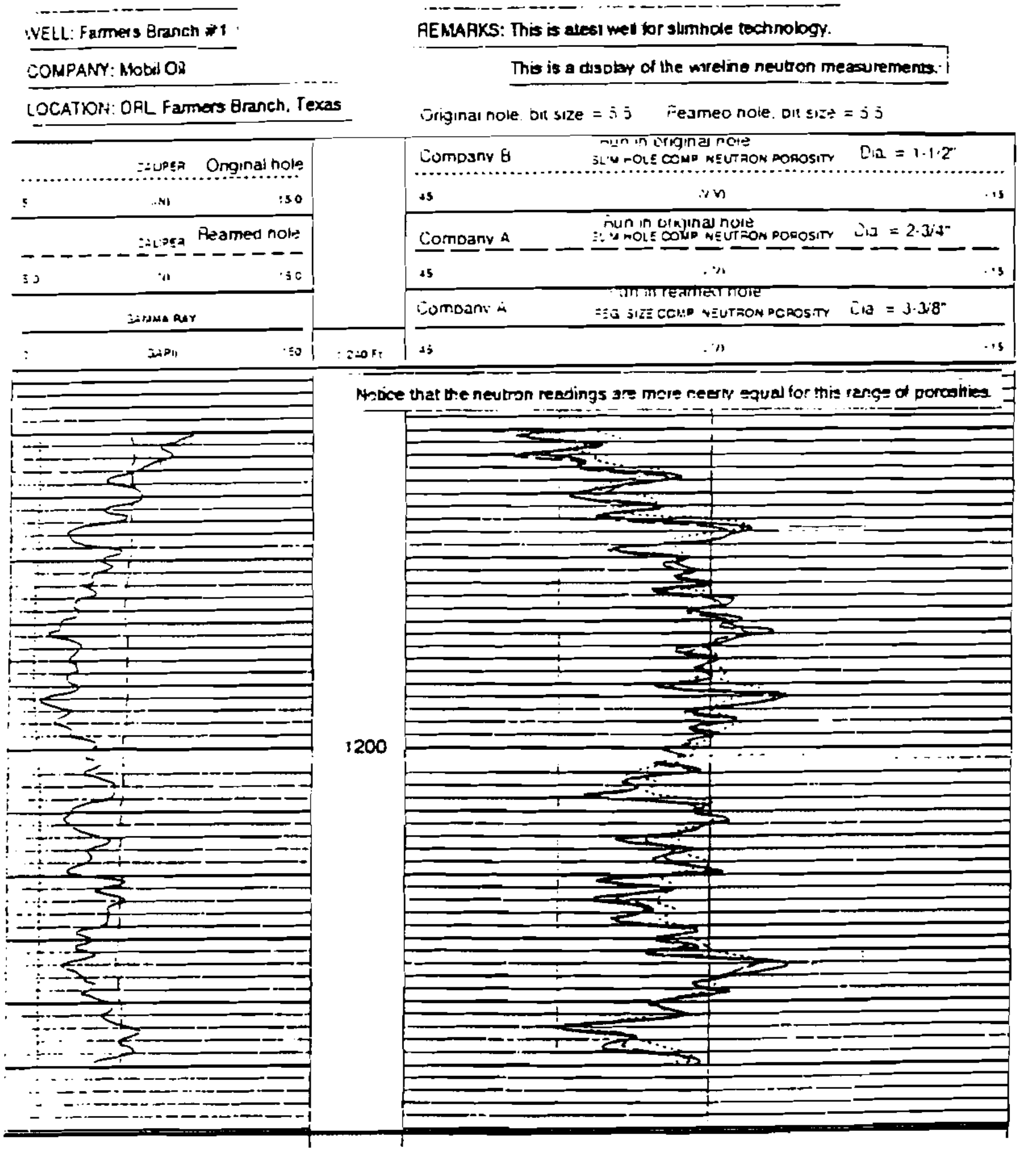


Figure 9-32. Mobil Slim-Hole/Conventional Neutron Tool Comparison (Schulze, 1992)

Mobil concluded the following as a result of their tests:

1. Differences were observed between the slim-hole and conventional size logging tools tested. Most of these problems can be reconciled by using improved slim tools and/or empirical transforms to correct slim-tool data.
2. Slim tools should be designed based on conventional depth of investigation, sensor spacing, tool response, etc.
3. Weaknesses in slim wireline logging data may require additional dependence and synergism with coring analysis and well testing.

Mobil's Farmer's Branch No. 1 test well and early field projects are described in detail in the Chapter *Coring Systems*.

9.3 PRODUCTION LOGGING

9.3.1 Baker Service Tools (Drill-Stem Testing)

Two types of tools are currently available for slim-hole formation testing (McKaughan, 1994). One design is a conventional on-bottom tool with a single compression packer. Minimum open-hole size for this tool is 4¾ in. A second type of formation test tool uses inflatable straddle packers to test specific zones. This tool can be used in holes from 2¾ to 4¾ in. in diameter (Baker Service Tool Specifications).

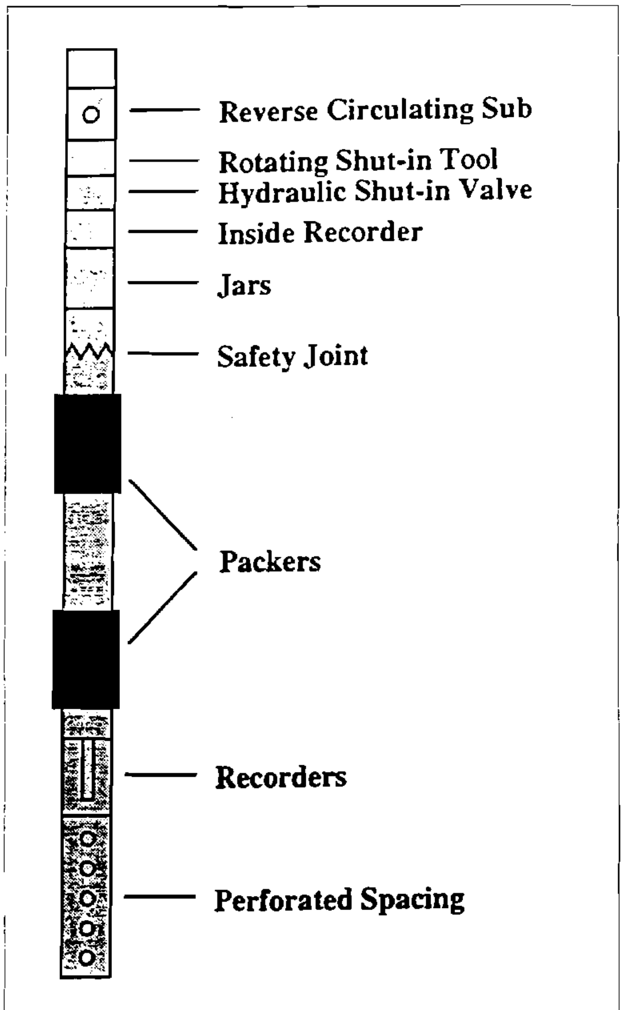


Figure 9-33. Slim-Hole On-Bottom DST Tool (McKaughan, 1994)

The conventional on-bottom drill-stem test (DST) tool can only be set for a single application per trip (Figure 9-33). A bull-plug anchor shoe is placed on the bottom of the well-bore. Perforated anchors act both as spacers and fluid test ports. Pressure and temperature recorders are placed in the recorder carrier below the packers.

Two compression packers above the recorder carrier sub are set with a differential pressure of 5500 psi. A safety joint allows the upper assembly to be removed should the lower assembly become stuck in the hole.

Hydraulic jars are often run above the safety joint and can be used to unseat the packers after the completion of formation testing. A second recorder carrier is used to convey instruments to record internal flow and shut-in pressures.

A hydraulic shut-in valve acts as a check valve to prevent fluid from entering the drill string during run-in. Straight pick-up of the string will cause the valve to close during or after testing operations. A rotating shut-in tool opens and closes the assembly when the drill string is rotated.

A reverse circulating sub at the top of the assembly can be activated by internal pressure or by dropping a bar from surface.

The drill pipe is usually dry when the DST tool is run down hole. A water cushion can be run inside the pipe if the differential pressure at the bottom of the well exceeds the rating of the packer elements. The packers are set with 20,000 to 25,000 lb of set-down load after reaching bottom (Figure 9-34). The hydraulic shut-in valve will open after 2-3 minutes, allowing formation fluids to enter the drill pipe.

A typical DST procedure includes 5-10 minutes preflow, 30-60 minutes shut-in, 1-4 hours flow, and 4-8 hours shut-in. After the test period, the drill pipe can be reverse circulated and the data retrieved and analyzed.

The inflatable straddle DST tool (Figure 9-35) can be reset downhole to test several zones on a single trip.

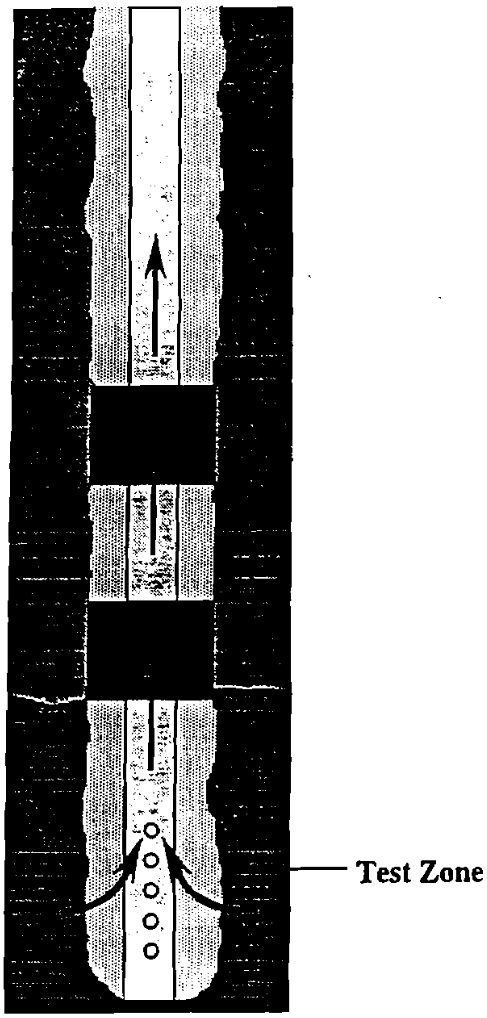


Figure 9-34. Slim-Hole On-Bottom DST Procedure (McKaughan, 1994)

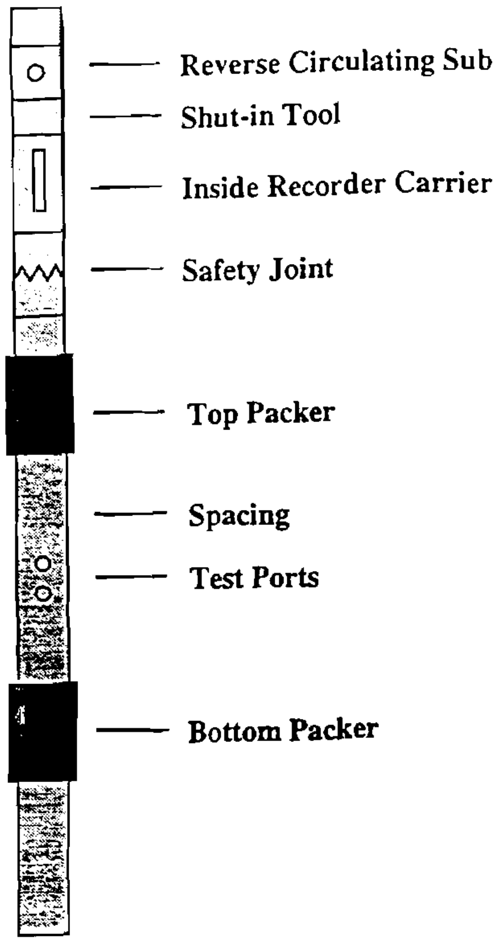


Figure 9-35. Slim-Hole Straddle DST Tool (McKaughan, 1994)

The tail pipe on the bottom of the assembly serves to protect the bottom packer mandrel, which moves as much as 17 in. up or down during the test. Between the packers are multiple test ports, which provide the required spacing according to zone thickness. Additional components of the inflatable straddle DST are similar to the conventional on-bottom system.

After the tool is placed across the formation of interest (Figure 9-36), the packers are activated by increasing pressure to 1500 psi above hydrostatic. Setting pressure should be maintained for 10-15 minutes to allow the packers to completely conform to the wellbore.

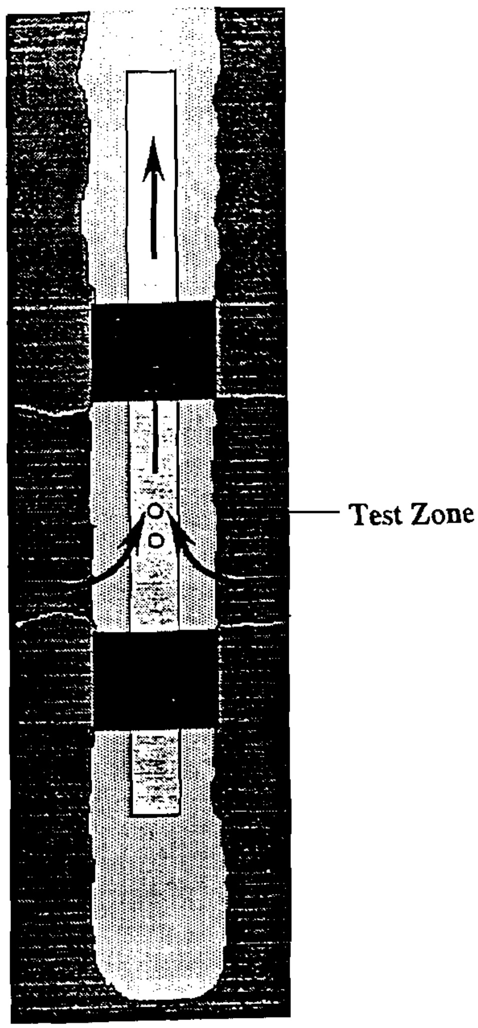


Figure 9-36. Slim-Hole Straddle DST Procedure (McKaughan, 1994)

After the string is rotated ¼ turn, it is lowered about 6 in. to equalize differential pressure. The DST is then conducted. The packers are deflated by pulling up on the string while holding some left-hand torque. The assembly can then be repositioned for additional testing, or retrieved.

Baker Service Tools states (McKaughan, 1994) that both designs of slim-hole DST tools have been used worldwide with great success.

9.3.2 Schlumberger (Slim Carbon/Oxygen Tool)

Schlumberger (Stoller et al., 1993) developed and tested a slim carbon/oxygen logging tool for monitoring reservoir water saturation. The $1^{11}/_{16}$-in. tool has been shown to be very versatile in several field applications. Through-tubing logging is possible and the tool can be run at much higher logging speeds than larger tools.

Schlumberger's Reservoir Saturation Tool (RST) is normally used in reservoirs undergoing water injection. Traditional pulsed-neutron capture tools do not perform well in the mixed and low-salinity water present in these formations. The RST tools used in the past have been limited by large tool size, slow logging speeds and sensitivity to fluids in the borehole. The use of large tools often requires that the production tubing be removed.

The new slim RST (Figure 9-37) addresses these shortcomings. The tool is run on coaxial or heptaxial wireline. Other production sondes can be run with the tool, including temperature, pressure or gradiomanometer.

Carbon and oxygen yields measured by the tool are used to calculate water saturation. The carbon/oxygen ratio is the parameter considered because this approach reduces the effects of variations in borehole size, casing size, porosity and other environmental conditions. The tool's response is shown in Figure 9-38, the so-called "fan chart."

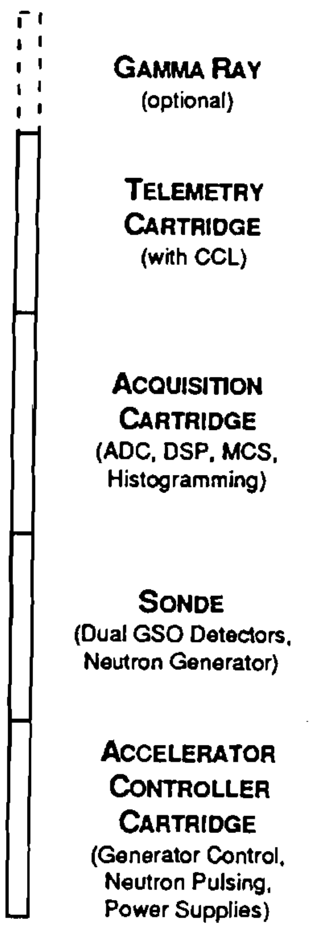


Figure 9-37. Slim Reservoir Saturation Tool (Stoller et al., 1993)

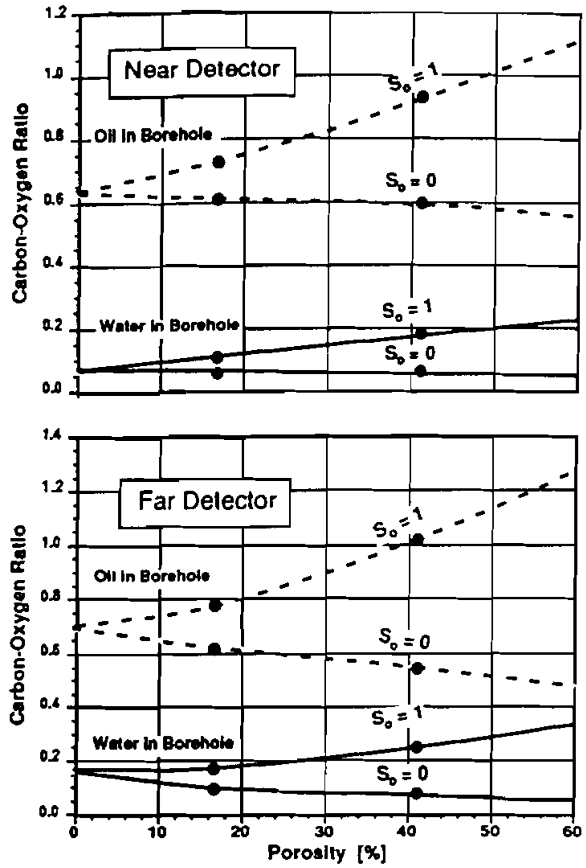


Figure 9-38. Fan Chart of Slim Reservoir Saturation Tool (Stoller et al., 1993)

Logging speeds are compared for the RST tool and GST (gamma-ray spectroscopy tool) in Table 9-4. The logging speed of the slim $1^{11}/_{16}$-in. RST is 1½ to 4 times faster than the older GST.

TABLE 9-4. Logging Speeds of Reservoir Saturation Tool (Stoller et al., 1993)

Lithology	Porosity (p.u.)	Logging Speed (ft/hr)		
		RST (shut in) 1 11/16-in.	RST (flowing) 2 1/2-in.	GST (shut in) 3 5/8-in.
Sand	16	30	8	18
Sand	33	250	110	160
Lime	16	30	10	11
Lime	41	250	70	60

The RST was successfully run in a 6½-in. well with 4½-in. casing in the Middle East. A plot of the near carbon/oxygen ratio versus the far carbon/oxygen ratio (Figure 9-39) showed that the borehole contained water.

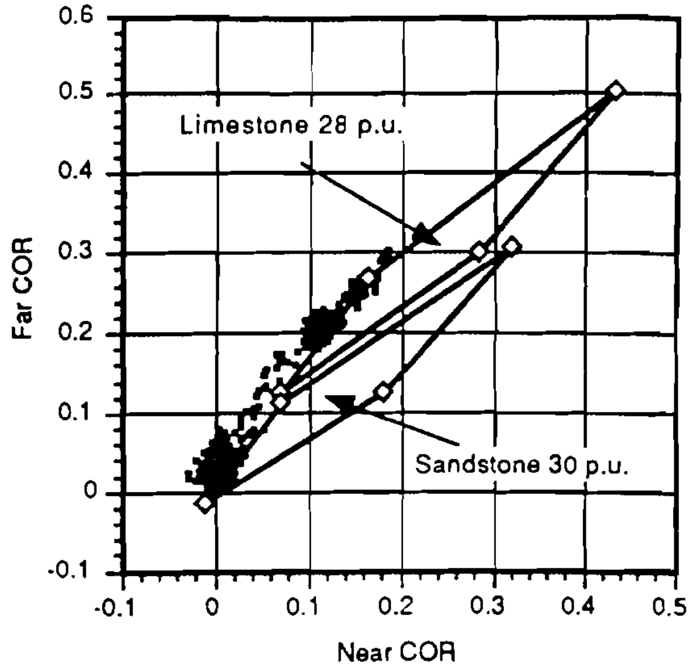


Figure 9-39. Near Vs. Far Carbon/Oxygen Ratios (Stoller et al., 1993)

The interval logged was limestone in the upper half and shaly sandstone in the lower half. Data, mostly from the limestone section, are shown in Figure 9-40. Partial depletion is indicated. These logs are well able to differentiate between limestone, sandstone and mixed lithologies.

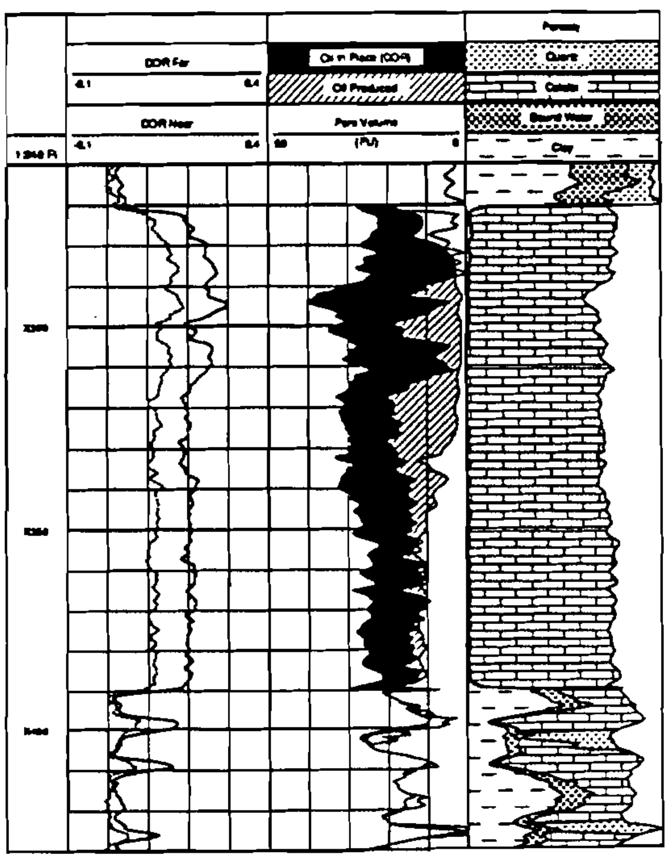


Figure 9-40. Formation and Fluid Analysis from RST Data (Stoller et al., 1993)

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10. Motor Systems

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10. Motor Systems

10.1 DRILL-PIPE SYSTEMS

10.1.1 Baker Hughes INTEQ (Slim-Hole Drilling System)

Baker Hughes INTEQ introduced their Slim-Hole Drilling technology based on conventional (non-coring) equipment and rigs (*World Oil* Staff, 1994). This technology was developed in conjunction with Shell and Eastman Teleco. The slim-hole BHA has been redesigned, resulting in improved drill-string integrity. Kick-detection has also been improved through advanced computer modeling. A number of wells have been successfully drilled with this system.

Baker's system incorporates improved PDC bits, high-strength drill-pipe connections, downhole motors, and a thruster for providing WOB. Low-solids drilling fluids are used to reduce torque and drag. Formate-base drilling fluids have been used as an alternative to solids-weighted fluids. One of the most important advantages of Baker's system is that conventional drilling practices are used. Crew training, safety standards and operating procedures are not substantially different from those for larger holes.

PDC bits are run at high speeds on motors to improve ROP in slim holes. A hydraulic thruster (Figure 10-1) is used to control WOB and isolate the BHA from torsional vibrations in the drill string. WOB is proportional to the pressure drop across the thruster, and is adjustable by changing circulation rates or bit nozzle area. Drill-pipe rotation is used to decrease drag, but is kept at a low rotary speed.

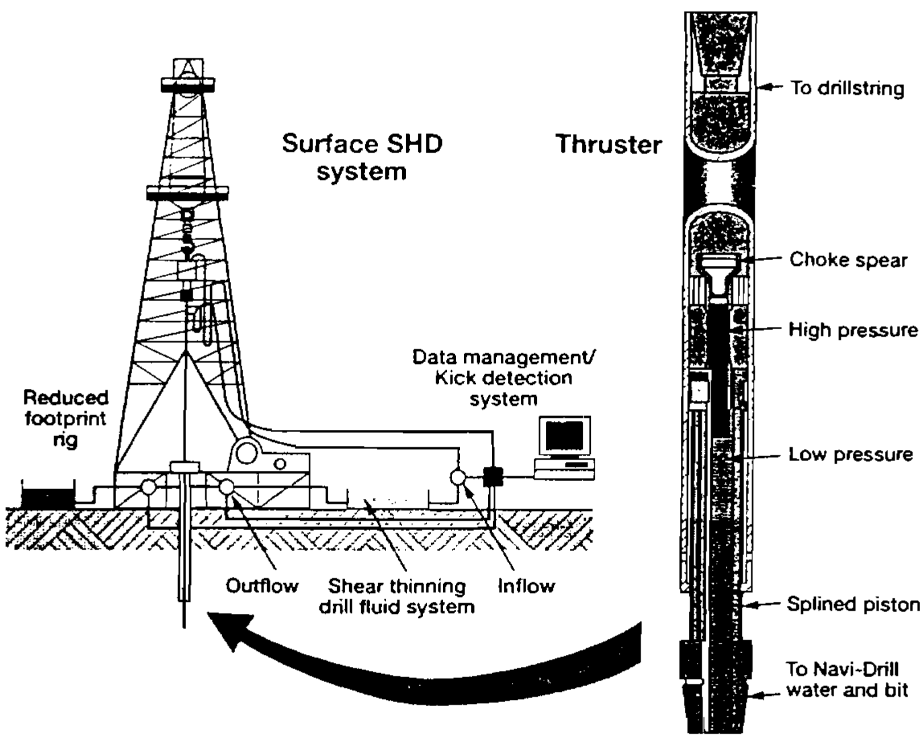

Figure 10-1. Thruster in Baker's Slim-Hole Drilling System (*World Oil* Staff, 1994)

Thruster and WOB performance is monitored by observing standpipe pressure with the bit at the bottom. The drill string is slacked off until the pressure drop equals that calculated for the required WOB.

A $4^{1}/_{16}$-in. overshot has been tested for fishing 3½- and 3¾-in. tools. Slim drilling jars (3½ and 4¾ in.) are also available. Downhole circulating subs, rupture-disk subs and safety subs have been designed for high-pressure wells.

ARCO used Baker's downhole motor system in a North Sea well being drilled from a jack-up rig. Unforeseen geologic conditions and pressures resulted in the need to set a 5-in. liner 1400 ft short of TD in this conventional well. Options considered included cementing and sidetracking, abandonment, or moving the well and drilling a new hole.

ARCO decided to drill a 4⅛-in. contingency hole using Baker's BHA. Over 1400 ft of formation were drilled at an average ROP of 5.8 ft/hr. Only three runs were required for the slim section. The hole was successfully drilled in gauge, and represents the first slim hole in the North Sea.

10.1.2 Shell Research B.V. (Slim-Hole Drilling System)

Shell Research B.V., Shell Internationale Petroleum Maatschappij B.V., BEB Erdgas & Erdöl GmbH, and Eastman Teleco (Worrall et al., 1992) described the development of a retrofit slim-hole drilling system based on the use of a downhole motor. The essential elements of their system included diamond drag bits, mud motors, conventional drill pipe, shear-thinning muds, antivibration technology, and sensitive kick detection. Cost savings of up to 24% were shown in early field projects with their system.

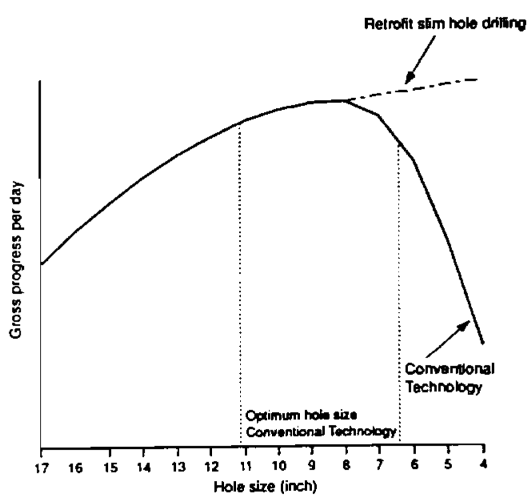

Figure 10-2. Hole Size and Drilling Progress (Worrall et al., 1992)

Shell began a study in 1987 to determine the most promising technologies for reducing drilling costs. Slim-hole technology was quickly determined to be among the most promising. Developments were needed to make the technology viable, however. Data showed that conventional technology was increasingly less efficient at hole sizes below 7⅞ in. (Figure 10-2).

Causes of low rates of penetration in slim holes included poor bit performance, poor drill-pipe performance, high ECDs, inappropriate muds, and a general lack of understanding of the drilling process. Shell set out to remedy this situation. The foundational criteria for the improved system stated that the new technology had to retrofit to existing rigs and use conventional practices, standard tubulars, wireline logging, etc. Additionally, overall ROPs had to be at least equivalent to conventional holes.

The family of Shell's slim BHA designs is summarized in Table 10-1. A typical retrofit slim-hole BHA is shown in Figure 10-3.

TABLE 10-1. Slim BHA Sizes (Worrall et al., 1992)

Host Liner (In.)	Hole Size (In.)	BHA Size (In.)
3½	2⅝	2⅜
4½	3⅞	3⅛
5	4⅛	3¾
5½	4¾	3¾
7	5⅞	4¾

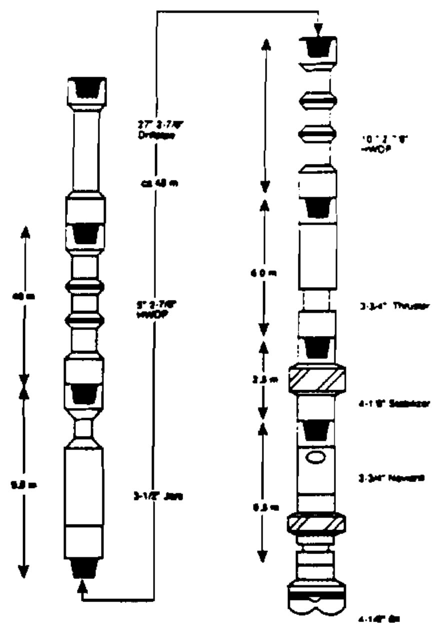

Figure 10-3. Retrofit Slim-Hole BHA (Eide et al., 1993)

Experience has shown that the use of drag bits is accompanied by significant vibration, which reduces ROP and bit life. Technologies to reduce vibration were pursued to increase efficiency and hole stability, and reduce drill-pipe fatigue. The antivibration system is comprised of three elements:

- *Soft-torque rotary table.* This serves to damp torsional vibrations of the drill string generated by stick/slip interactions between the hole and drilling assembly.
- *Downhole motor.* The motor functions as a partial isolator for torsional vibration between the bit and the rest of the string.
- *Thruster.* This hydraulically activated device decouples the motor and bit from the rest of the drill string, serving as an isolator for axial vibrations.

Conventional muds were used in early efforts with Shell's system. Experience showed that parasitic pressure losses need to be minimized to allow maximum power to the bit. Shear-thinning solids-free muds are optimum for these conditions. Shell found that deep 4⅛-in. holes in harsh environments are best drilled with low-solids heavy brine mud systems.

Significant effort was expended in the development of a sensitive kick-detection system. Shell's system compares flow in to flow out, while accounting for circulation dynamics. A disadvantage of the system is that the electromagnetic flow meter, which measures flow out, must be fully flooded for proper operation. This presents the potential for clogging.

Shell's well-control philosophy is "shut in and think." They evaluated dynamic well control, but decided not to pursue this approach because it calls for rapid and accurate decisions by the driller. Additional discussion of Shell's well-control systems and procedures is presented in the Chapter *Well Control*.

Shell found that most logging tools are available for slimmer holes (Table 10-2). Running tools in slim holes has been found to produce better log responses, due to smoother, less rugose wellbores as a benefit of antivibration technology. Improved core recovery is also observed.

TABLE 10-2. Availability of Logging Tools (Worrall et al., 1992)

COMPARISON OF SLIMHOLE (<4½") CAPABILITIES SCHLUMBERGER / WESTERN ATLAS / HALLIBURTON / BPB					
TOOL TYPE	WESTERN ATLAS	SCHLUM-BERGER	BPB	HLS	COMMENTS
CLASS	Combinable 350 °F 20k psi	Combinable 350 °F 20k psi	Non-comb. 212 °F 7.5k psi	Combinable 500 °F 25k psi	Temp. & pressure as specified left deviations below
Induction	2" IEL#)	----			#) deep induction only
	2.75" IEL	2.75" IRT-J	2.25" array ind. ^)	2.75" HDIL-A	^) early '93 260 °F/10k
Laterologs	----	2" DLT-X*)	1.88" RR2 $	----	*) superseded
	3.4" DLL/LL3	2.75" MDLT			$) dual focus. electric
Microlog	----	----	1.88" MG1 &)		&) microguard resist.
	3.63" MLL	2.75" SMRS @		2.75" SC only	@) early 1993
Density	3" CDL	2.75" FGT +)	1.88" DD3	2.75" HSDL-A	+) not compensated
	3.63" ZDL	3.5" HLDT			
Neutron	1.7" NEU +)	1.7" NDT +)	1.5" NN1		
	2.75" CN	2.75" CNT-D		2.75" HDSN-A	
Sonic	1.7" CBL +)	1.7" SLT-J *)	2" MS2		*) no full waveform
	2.75" BAL *)	2.75" SLT-S		2.75" HFWS ')	') full waveform
Spec. Gamma	----	----	3" SG3 ¢)	----	¢) 260 °F/10kpsi
Dipmeter	4" DIP	3.63" FMS-B#)	2" DV1 ¶)	----	¶) 3 arms
Micro-scan	----	3.63 FMS-B		----	#) 3.5" exopy removed
Sonic-scan	----	2.75" SBTT	3" BT1!)	3.64" CAST !)	!) 3.75 °F/20kpsi
Fluid sample pressures	----	3.375" SRFT •)	2.25" PT Ÿ)¢)	----	Ÿ) Proposed for '93
	4.3" FMT	3.63" RFT-N	3.5" RFS		•) early 1993
Rocksample	3" SWC	3.34" MCST ^)	2.25" Gun $)!)		$) prototype available
Pulsed neut	1.7" PDK-100	1.7" TDT-P	1.7" TDS &)	1.7" TMD @)	@) 350 °F/20kpsi
C/O tools	----	1.7" RST-A	----		^) selective sampling
	3.38" MSI	2.4" RST-B	----	----	&) 300 °F/15kpsi
Geophysical Tools	1.7" SEIS *)	2.5" MWST *)	2" SA-1 *)		*) one component
		2.75" BGFA §)			§) three component
Testing tool		3.2" MFL/PCT			▪ suitable for 3½" hole

This system has great potential for drilling operations on floating platforms. Smaller liners and casing programs allow the hook-load capacity to be reduced. Shell anticipated cost savings of £250,000-500,000 per well from these efficiencies.

Shell suggested that several elements of their slim-hole drilling system could be used with benefit in conventional shallow onshore operations. Technologies that could readily be transferred include improved 2⅞-in. drill pipe, soft-torque power swivel or rotary table, compact well heads, slim overshots, and monobore completion technology.

Cost savings have come primarily in two areas, that is, reduced size of casing in upper strings and greater ROP while drilling deeper slender holes. On an example 4800-m gas well, dry hole costs were reduced 24% (Figure 10-4).

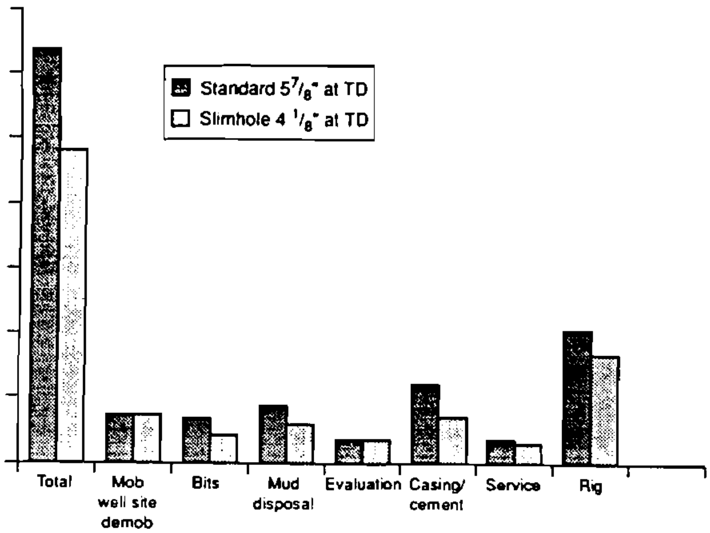

Figure 10-4. Slim-Hole Cost Savings (Worrall et al., 1992)

The system has been applied in vertical, deviated and horizontal wells from both land and jack-up rigs. ROP has improved as experience is increased. Fishing episodes are rare. Shell estimated that the dependability of the system saves about 1½-2 days of fishing per average well.

Shell's field experiences have shown that drilling efficiency no longer decreases in holes less than 7⅞ in. (Figure 10-5).

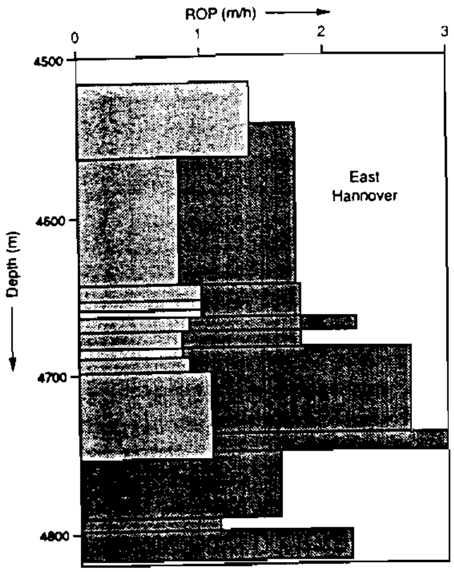

Figure 10-5. ROP of 4⅛-in. Slim Versus 5⅞-in. Conventional (Worrall et al., 1992)

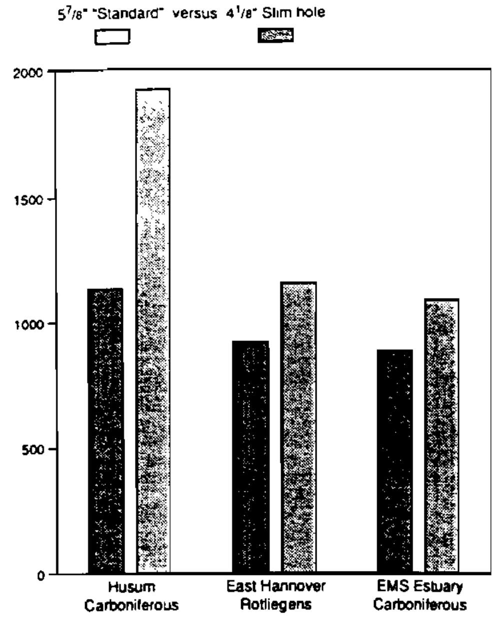

Figure 10-6. Cost per Meter of 4⅛-in. Slim Versus 5⅞-in. Conventional (Worrall et al., 1992)

Improvements in overall performance have decreased cost per meter based on operations in several fields (Figure 10-6).

10.1.3 Shell U.K. E&P (Drilling from Floating Rigs)

Shell U.K. E&P and Shell Internationale Petroleum Maatschappij B.V. (Eide and Colmer, 1993) discussed the issues and technologies required to introduce their slim-hole motor drilling system on floating rigs. Positive results in land and jack-up operations led Shell to consider applying this technology in other offshore wells. Special issues that were addressed include (Figure 10-7) improved heave compensation, kick detection during rig heave, and well evaluation and testing.

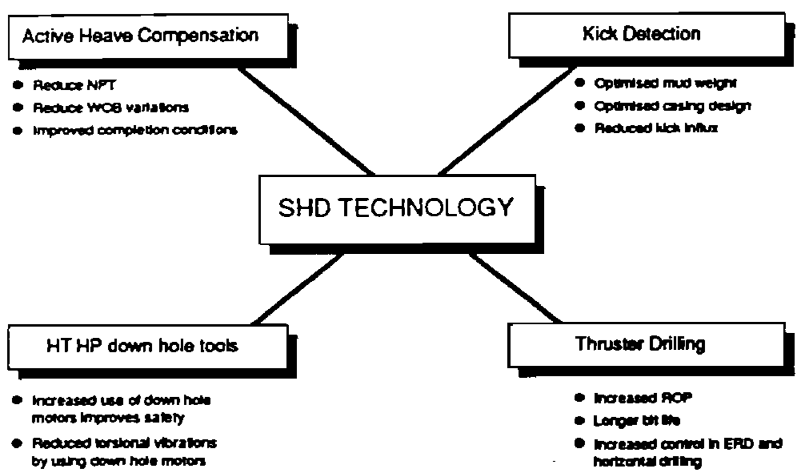

Figure 10-7. Technological Concerns for Floating Operations (Eide and Colmer, 1993)

Slim-hole techniques and designs were given serious consideration as a solution to reduce exploration and drilling costs in increasingly harsh environments. In many areas, the weight of casing strings for high-pressure deep targets is beginning to exceed capacities. The use of slimmer casing strings will allow high-pressure targets to remain within the capability of current rigs.

Shell U.K. E&P considers a 5¾-in. hole as slim for these applications (Figure 10-8). Contingency holes are 4⅛ in. for slim wells, compared to 5¾ in. for conventional.

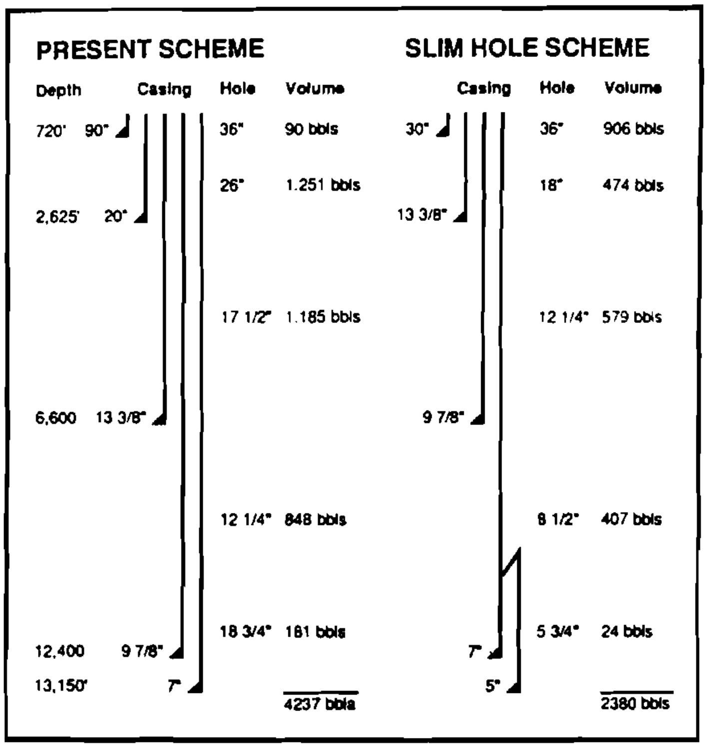

Figure 10-8. Shell E&P's Slim-Hole Design (Eide and Colmer, 1993)

Retrofit active heave-compensation systems are of significant interest to North Sea operators. These systems can extend weather windows, allow subsea equipment to be landed during larger heaves, and improve drill-string integrity. Several systems, including both traveling-block and crown-mounted compensators, have been installed. Fully active systems are considered impractical due to the large power requirements.

Semiactive systems (Figure 10-9) have been designed based on an active subsystem that is added to the conventional compensator. The pressure in the compensator unit is adjusted to account for the variations due to friction losses, seal friction, load variation and air-bank variation.

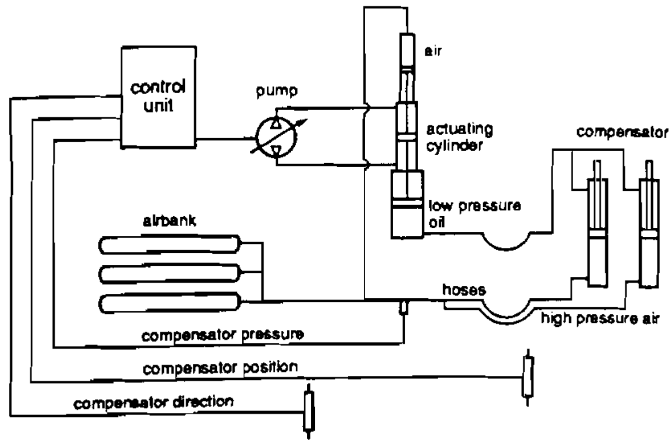

Figure 10-9. Semiactive Heave Compensator
(Eide and Colmer, 1993)

Required performance for heave-compensation systems in Shell's operations calls for a maximum 10-in. motion of the lower yoke during a 12-ft heave with a 12-sec period. Studies show that these requirements are attainable except for short (< 3000 ft) drill strings. The stiffness of shorter strings is too great for this compensator design.

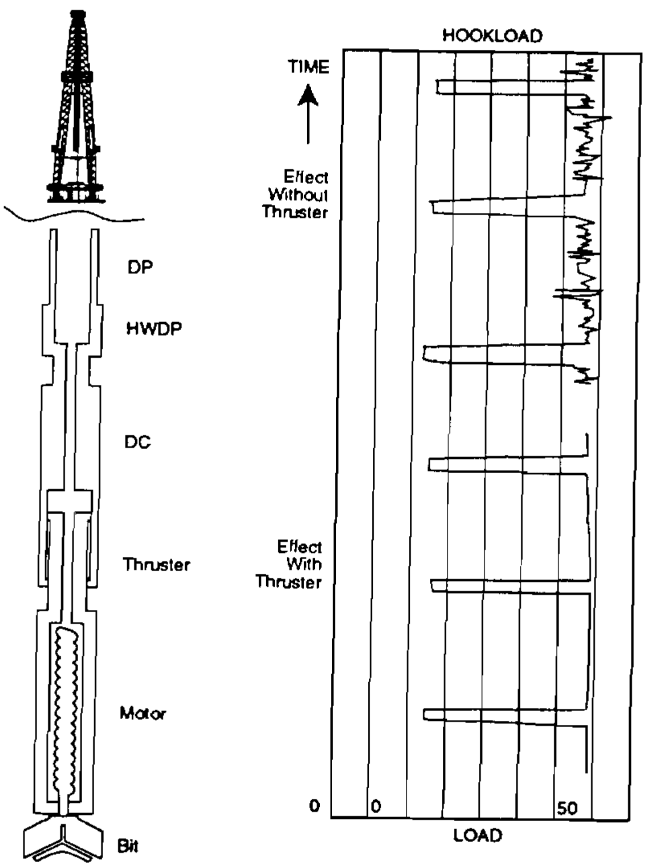

Figure 10-10. Thruster for WOB and Vibration Reduction (Eide and Colmer, 1993)

The use of a downhole thruster, while making heave compensation more complicated, improves ROP, bit life and hole quality. The thruster (Figure 10-10) is used in place of drill collars for generating WOB.

Shell also points out that active heave compensation can significantly improve drilling performance even in the absence of a thruster. For a 10,000-ft well, a reduction in heave of the drill string from 5 ft down to 10 in. results in an 83% decrease in variations of WOB.

Kick detection is also adversely impacted by rig heave due to surges in the mud caused by telescopic joint reciprocation. Other parameters can also cause differential flows in excess of alarm limits: flow-rate adjustments, turning pumps on/off, etc. A mud surge-compensation system (Figure 10-11) can be installed to allow use of a flow meter as part of the slim-hole kick-detection equipment.

Shell U.K. E&P, Shell Research B.V. and Baker Hughes INTEQ (Eide et al., 1993) discussed additional concerns for high-temperature high-pressure (HTHP) slim-hole wells in the North Sea. Conditions typical of these wells are undisturbed bottom-hole temperatures above 149°C (300°F) and pore-pressure gradients in excess of 0.8 psi/ft. They found that total cost savings of up to 15% were possible in HTHP wells with bottom-hole sizes of 5¾ or 4⅛ inches.

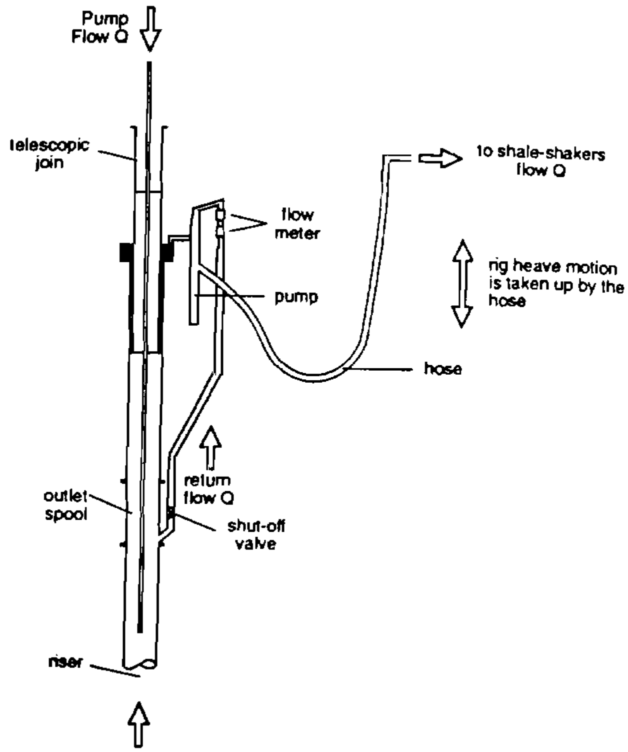

Figure 10-11. Mud Surge-Compensation System (Eide and Colmer, 1993)

Kick detection is critical on these HTHP wells. Shell's detection criteria (Table 10-3) are based on a kick volume that occupies 50 m (164 ft) of vertical wellbore. North Sea operators have found that an average of two well-control incidents will occur while drilling each HTHP well. Most kicks occur during trips; therefore, optimized bit life and ROP will reduce the number of trips and kicks.

TABLE 10-3. Kick-Detection Influx Criteria (Eide et al., 1993)

HOLE SIZE (in.)	BHA (in.)	DRILL PIPE (in.)	INFLUX VOLUME (litres)
5⅞	4¾	3½	564
4⅛	3¾	2⅞	222

The flow-out sensor (part of the kick-detection system) is positioned similarly to that of a land rig. The mud return line is routed from below the riser slip joint to a manifold tank above the moon pool. From there, a flexible hose passes mud to a buffer tank (Figure 10-12).

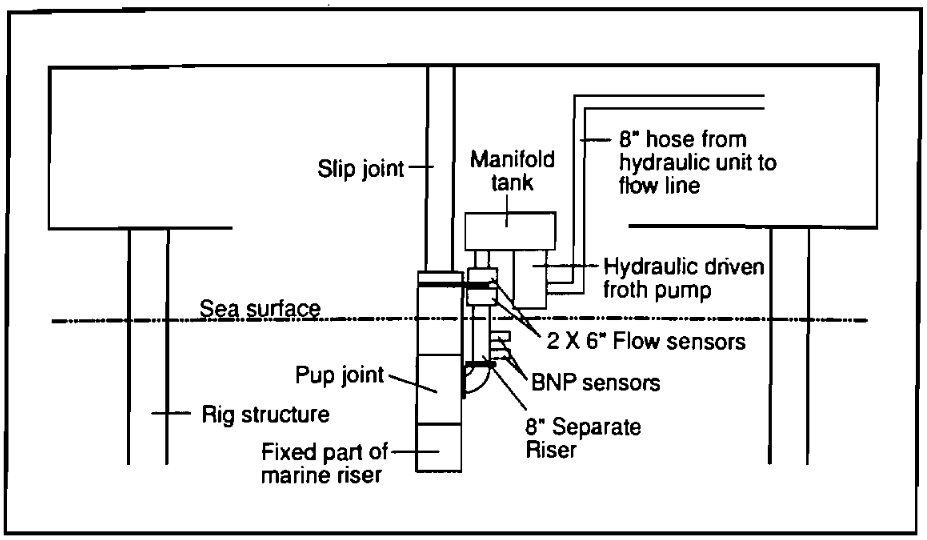

Figure 10-12. Return Flow System for Kick Detection (Eide et al., 1993)

Shell's slim-hole system was first used in a HTHP well late in 1992. The slim section was drilled at an average ROP of 20 ft/hr. ROPs 40-50% higher than offset wells were observed in some formations. Secondary metamorphism was not a concern for geologic interpretation. Cuttings quality with PDC bits was comparable to those generated with tricone bits.

Caliper logs showed that the slim holes were generally of excellent quality. The caliper from a 5¾-in. offset well drilled with rotary techniques (Figure 10-13) shows that the average diameter across this zone was near 8 inches. By contrast, a 6-in. hole drilled with the retrofit slim-hole system shows a greatly improved hole quality (Figure 10-14).

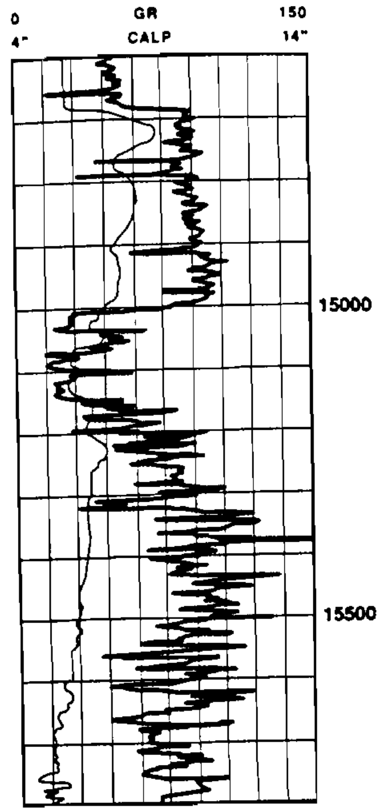

Figure 10-13. Caliper Log of 5¾-in. Rotary-Drilled Hole (Eide et al., 1993)

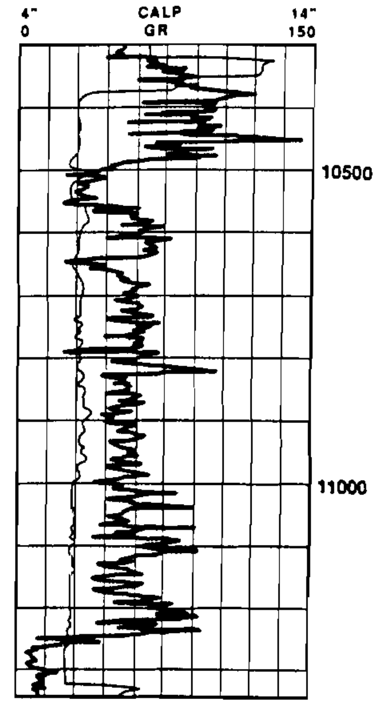

Figure 10-14. Caliper Log of 6-in. Hole Drilled with Retrofit System (Eide et al., 1993)

10.2 COILED-TUBING SYSTEMS

Drilling with coiled tubing has received considerable interest from the industry in recent years, probably more than any other area of coiled-tubing technological development. With the ability to be rapidly tripped under pressure, coiled tubing holds promise to provide a cost-saving alternative to conventional rotary drilling when applied under appropriate conditions.

Developments in coiled-tubing drilling technology are described in detail in Chapter 5 of the companion volume *Coiled-Tubing Technology (1993-1994)*. Summaries of a few of the most important developments as related to slim-hole applications are presented in this section.

10.2.1 History of Drilling with Continuous Strings

Drilling with a continuous string had been considered prior to the current boom. A drilling system based on a continuous drill string was developed by Roy H. Cullen Research in 1964 (Gronseth, 1993). The flexible drill string was constructed of multiple-wire tension members and had an O.D. of

$2^5/_8$ inches. The drill string was advanced and retracted by a hydraulic injector with gripper blocks. The system was used to drill a 4¾-in. test well through 1000 ft of granite near Marble Falls, Texas. Penetration rates of 5-10 ft/hr were reported.

Another system was developed by the Institut Français du Pétrole (IFP), which used 5-in. O.D., 2½- to 3-in. I.D. flexible drill strings containing several electrical conductors. Downhole electric motors or turbines were used to rotate the bit. Their injector was operated either electrically or hydraulically, and could be run in an "auto-driller" mode controlled by feedback from bit power consumption.

The IFP system could be used to drill holes from 6¾ to 12¼ in. to depths of 3300 ft (1000 m). By 1965, more than 20,000 ft (6000 m) of hole had been drilled with the system.

FlexTube Service Ltd. developed another system in the mid-1970s that used 2⅜-in. continuous tubing. They drilled shallow gas wells with the system in Alberta, Canada. Initial tubing strings were fabricated from butt-welded X-42 line pipe. They later developed the first aluminum coiled tubing in conjunction with Alcan Canada.

FlexTube's system used 4¾-in. drill collars, a positive-displacement motor, and conventional 6¼-in. bits. Penetration rates were comparable to those with conventional rigs.

Bottom-hole assemblies designed for drilling operations have also been run on conventional steel coiled tubing for some time. Most coiled-tubing drilling operations have been performed as part of workover applications, such as cement and scale removal, milling, and underreaming. More recently, coiled tubing has been used to drill vertical and horizontal re-entries and new wells. The industry has been watching these developments in coiled-tubing drilling with high interest.

Since 1991, over 200 wells have been drilled with coiled-tubing rigs and positive-displacement motors (Figure 10-15). Although there has been considerable activity and interest, coiled-tubing drilling technology is still immature, and the potential cost savings predicted for these operations have not yet been widely realized.

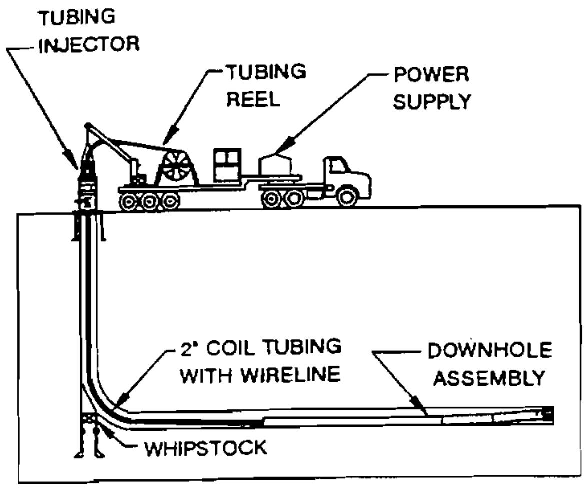

Figure 10-15. Open-Hole Drilling with Coiled Tubing (Ramos et al., 1992)

Halliburton, Cudd Pressure Control, NOWSCO, and Schlumberger Dowell have each organized specialty teams devoted to developing systems and techniques for coiled-tubing drilling. Field activity continues at a healthy pace.

Mud motors and various types of bits have historically been run on coiled tubing, including drilling open hole, drilling cement and scale, milling, and underreaming. Drilling with coiled tubing is obviously not a new concept; however, recent advances in both coiled-tubing and drilling technology have significantly increased the depth limitations and directional-control capabilities of these systems.

The driving force behind the development of coiled-tubing drilling is, not surprisingly, the need to reduce drilling costs. The economic advantages of slim-hole operations are shared by coiled-tubing drilling. Smaller rigs and surface locations result in less environmental impact and lower civil engineering costs. Lower mobilization costs and faster rig-up are also expected. Smaller scale operations lead to savings in mud, casing, and other consumables.

Fewer personnel and equipment should decrease day-rate costs. Unfortunately, the potential savings in equipment costs have generally not been realized as of yet. An important factor shifting the economic equation is that coiled-tubing rigs normally must compete against fully depreciated workover and drilling rigs, as well as steep discounts in slow conventional markets.

Coiled tubing has been used for several years to drill out scale and cement in cased wellbores. Recent applications have included both vertical and horizontal open-hole sections. The industry's attention has been focused on the cost-saving potential of drilling grassroots and re-entry wells with coiled tubing.

10.2.2 Berry Petroleum (McKittrick Field)

Berry Petroleum and Schlumberger Dowell (Love et al., 1994) drilled two shallow vertical wells with coiled tubing in the McKittrick Field in California. These wells are believed to be the first grass-roots wells drilled with coiled tubing. In addition, these wells were the first medium-diameter (6¼ in.) boreholes drilled using motors on coiled tubing.

A two-well project was designed to provide data on reservoir extent and evaluate the use of coiled tubing as a means of conveying drilling assemblies in this area. Completion operations were not included in original project plans. Secondary objectives of this project were to test coiled-tubing drilling in the context of slim (6¼ in.) vertical wells with conventional muds, and evaluate economic potential for coiled-tubing drilling for other applications. A hole size of 6¼ in. was chosen based on logging considerations (using conventional tools) and available motor/bit combinations.

The production horizon of interest was the Tulare tar zones, located at depths between 600–900 ft. Two wells, BY20 and BC4, were drilled in different edges of the reservoir.

A 4¾-in. medium speed motor was used for drilling operations (Figure 10-16). Rotational speed was 150-200 rpm at a flow rate of 150 gpm.

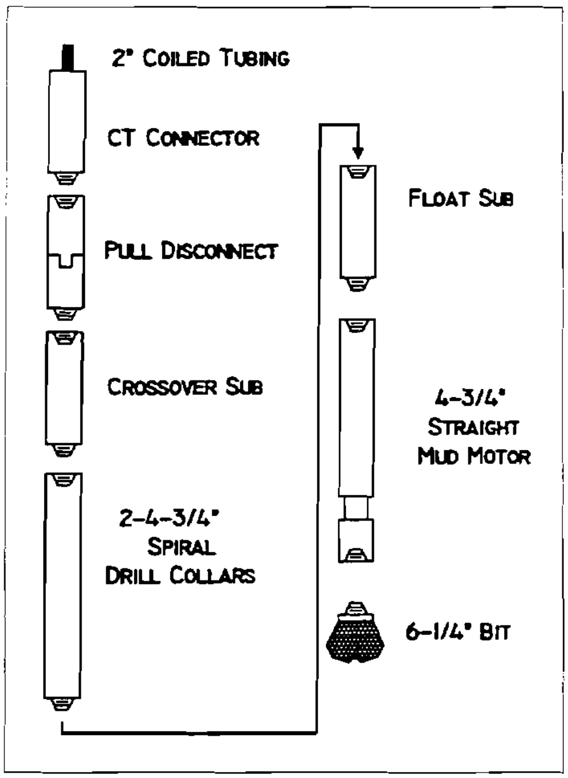

Figure 10-16. Drilling BHA
(Love et al., 1994)

A 3500-ft string of 2 x 0.156-in. coiled tubing was used for both wells. Drilling fluid was a cypan-based system. The location was about 90 ft on a side (Figure 10-17). Love et al. stated that reorganization would permit the location to be reduced to 90 x 70 ft, and that it need not be rectangular.

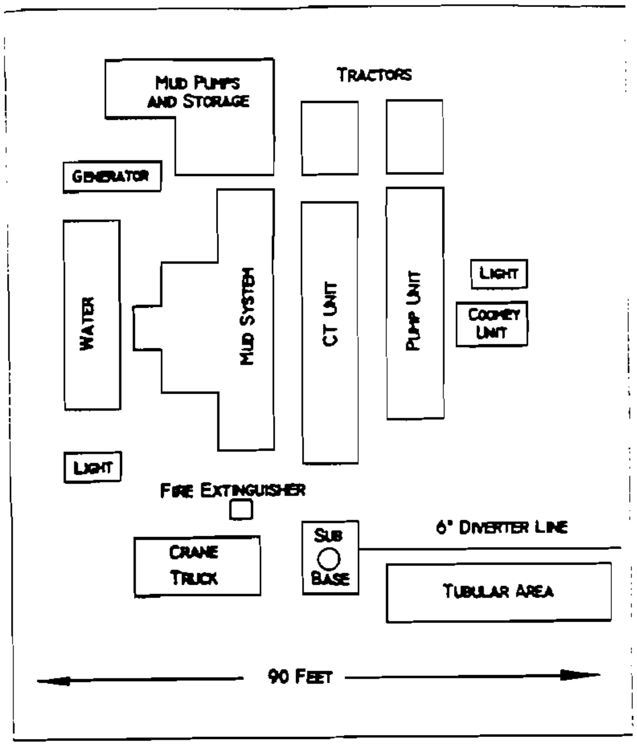

Figure 10-17. Surface Equipment Layout (Love et al., 1994)

The first well was spudded using two drill collars (Table 10-4). Deviation was checked at 259 ft MD. During this trip, a third drill collar was added to the BHA. Drilling continued successfully to TD at 1257 ft. Deviation along the wellbore was a maximum of 1¼°.

TABLE 10-4. Drilling Operations on Well BY20 (Love et al., 1994)

Hole Size	6¼"
CT Size	2" nominal, 0.156 wall
Drill Collars	3
Spudding Depth	78', Below conductor
Total Measured	1257'
Maximum Deviation	1¼°
Hole Length Drilled	1179'
Avg. Rate of Penetra-	32 ft/hr
Avg. Drilling Rate	51 ft/hr

Total drilling time was 35 hr, 10 hr of which were spent checking the survey with a conventional tool (Figure 10-18). Logging was performed successfully. A cement plug was placed on bottom.

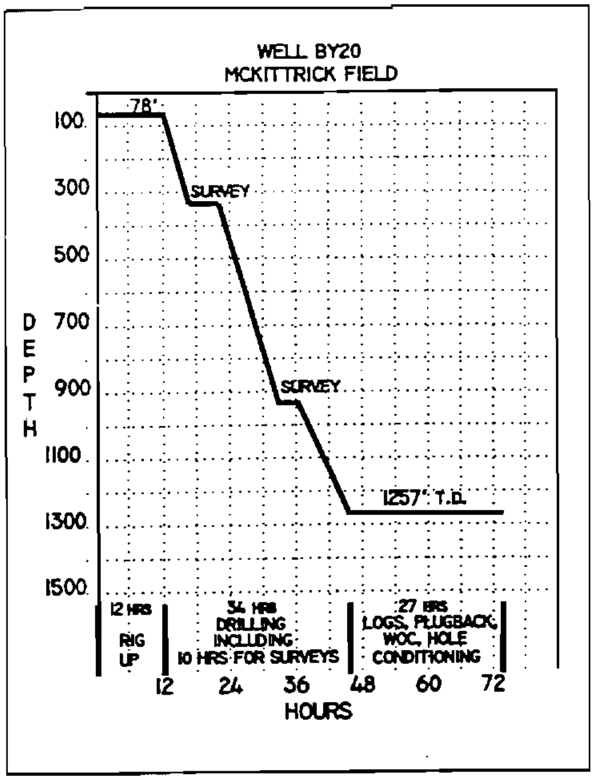

Figure 10-18. Time Summary for Well BY20 (Love et al., 1994)

A second well (BC4) was spudded from 80 ft with two drill collars (Table 10-5). Good penetration rates were achieved all the way to TD.

TABLE 10-5. Drilling Operations on Well BC4 (Love et al., 1994)

Hole Size	6¼"
CT Size	2" Nominal, 0.156 Wall Thickness
Drill Collars	2
Spudding Depth	78', Below Conductor
Total Measured Depth (TD)	1500'
Maximum Deviation	1°
Hole Length Drilled	1422'
Avg. Rate of Penetration	68 ft/hr*
Avg. Drilling Rate	70 ft/hr**

* includes all time, spud to TD
** 200'/hr 78-180'
100'/hr 180-860'
50'/hr 860-1500'

No intermediate directional surveys were taken on the second well due to the low deviation noted on the first well. Total drilling time was 21 hr (Figure 10-19). Dipmeter logs after drilling showed a maximum deviation of 1°.

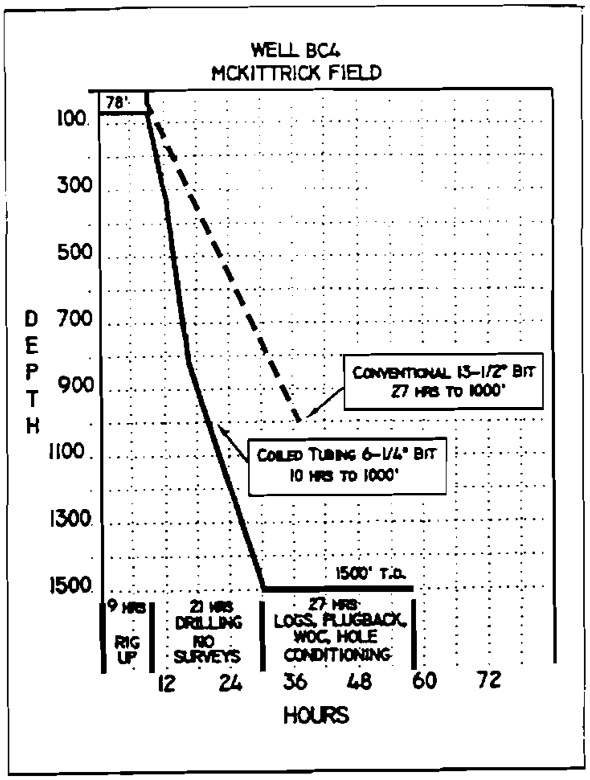

Figure 10-19. Time Summary for Well BC4 (Love et al., 1994)

Post-drilling analyses showed that drilling time for the second well was about 60% faster than for a conventional (larger diameter) well. Most of the time savings were attributed to faster ROP in the slimmer hole.

An additional benefit was a reduction in hole wash-out (Figure 10-20). Berry Petroleum believed that improved hole conditions were the result of continuous circulation with the coiled-tubing system, reduced pumping rates, and slimmer hole.

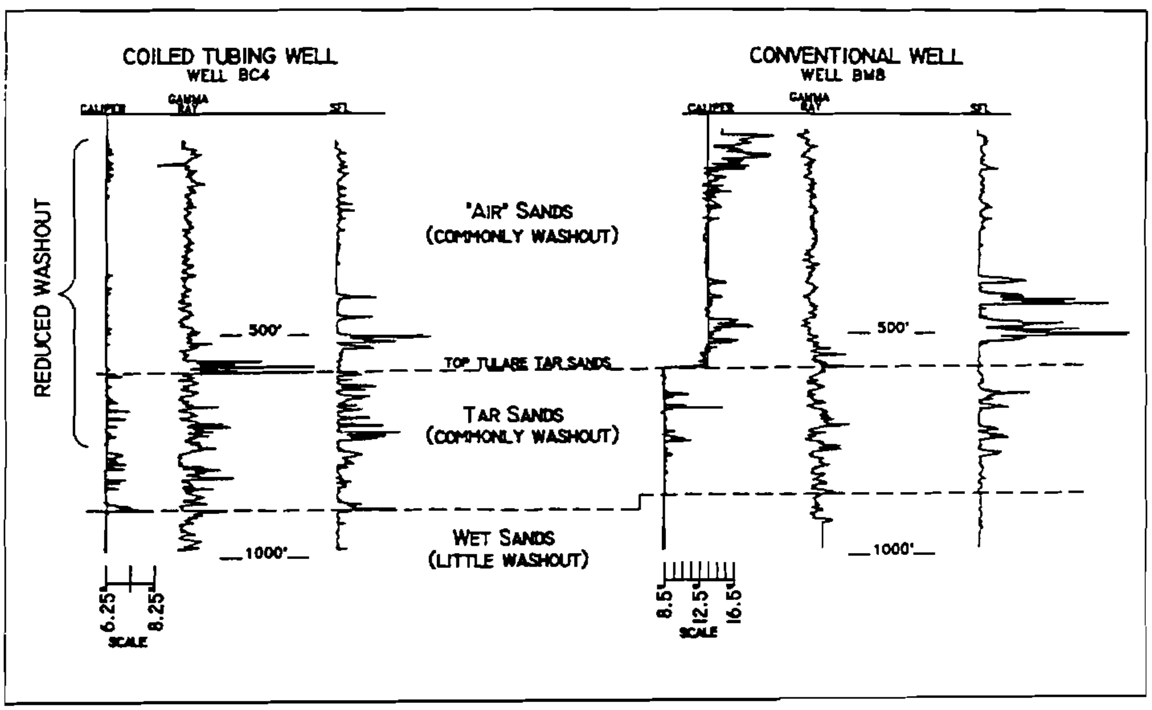

Figure 10-20. Coiled-Tubing and Conventional Hole Calipers (Love et al., 1994)

Fatigue life consumption of the string during these operations was moderate. For all operations on both wells, modeling indicated that a maximum of 18% of string life was used (Figure 10-21).

Berry Petroleum found that costs with coiled-tubing drilling were comparable or less than conventional rigs for this application. Costs would be even more favorable for deviated holes where conventional systems would also have to use motors.

10.2.3 Dresser Industries (Bit Selection)

A discussion of the parameters impacting drill-bit selection for coiled-tubing drilling was presented by Dresser Industries (King, 1994). It is emphasized that drill system components must be analyzed together, and that drill-bit design and compressive strength of the formation are both critical components.

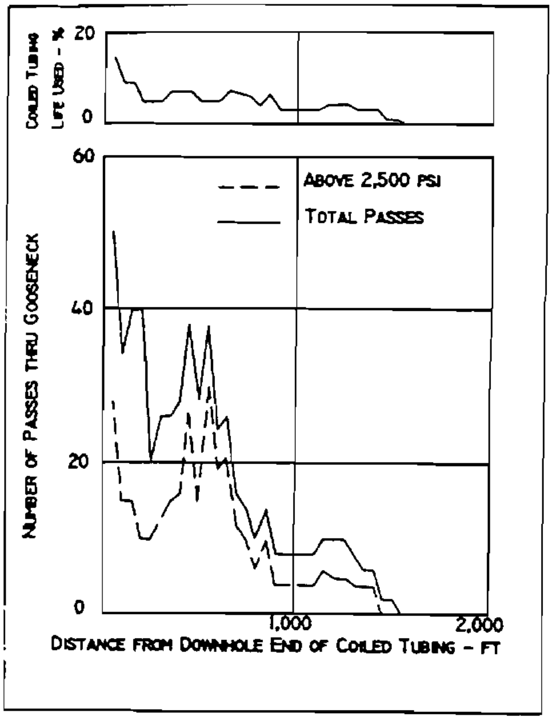

Figure 10-21. Coiled-Tubing Fatigue for Two-Well Project (Love et al., 1994)

Motor and bit selection are integrally related. The most common motors used on coiled tubing are high-speed, low-torque motors and medium-speed, medium-torque motors. Greater rotational speeds usually result in increased ROP. In general, roller-cone bits are run on medium-speed, medium-torque motors. Rotational capabilities of the bit should be matched to motor performance.

WOB (weight-on-bit) is generally less than optimal in coiled-tubing drilling, both vertical and directional. The use of drill collars is often limited due to tubing and surface handling constraints. They usually cannot be used in directional applications; WOB is provided by string weight and snubbing forces.

A relatively small proportion of system pressure drop occurs across the bit. Annular pressure drop, frictional pressure drop inside coiled tubing, and pressure drop across the BHA consume most of the available hydraulic energy.

A summary of coiled-tubing and bit sizes for several drilling jobs is presented in Table 10-6. The most common bit size has been 3⅞ in., with 2-in. coiled tubing the most common string.

TABLE 10-6. Bit and Coiled-Tubing Sizes* (King, 1994)

BIT DIAMETER, IN.	JOBS	COILED-TUBING DIAMETER, IN.	JOBS
3.750	6	1.500	6
3.875	15	1.750	4
4.125	2	2.000	25
4.500	1	2.375	3
4.750	9	TOTAL	38
6.125	1		
6.250	4		
TOTAL	38		

* Through late 1993

King (1994) designed three typical matched drilling systems for coiled tubing (Table 10-7). Systems are designed with 3⅞-, 4¾-, and 6¼-in. bits. King believes that both 2⅜-in. coiled tubing and 6¼-in. bits will see increased use in the future.

TABLE 10-7. Matched Coiled-Tubing Drilling Systems (King, 1994)

Coiled tubing diameter, in.	Bit diameter, in.	Motor OD, in.	Motor type	Flow rates, gpm	Rotational speed, rpm	Torque output, ft-lb	Differential pressure, psi
1.750	3.875	2.875	HSLT	20-70	225-800	20-160	100-700
			MSMT	30-70	60-375	40-280	100-600
2.000	4.750	3.500	HSLT	120-180	640-950	30-250	100-800
			MSMT	70-120	170-310	30-480	100-600
2.375	6.250	4.750	HSLT	150-250	325-550	50-440	100-800
			MSMT	150-400	175-475	50-1,100	100-700

Each of the bit types (Figure 10-22) should receive consideration. Bit type should not be chosen by default without proper analysis of economics and mechanics.

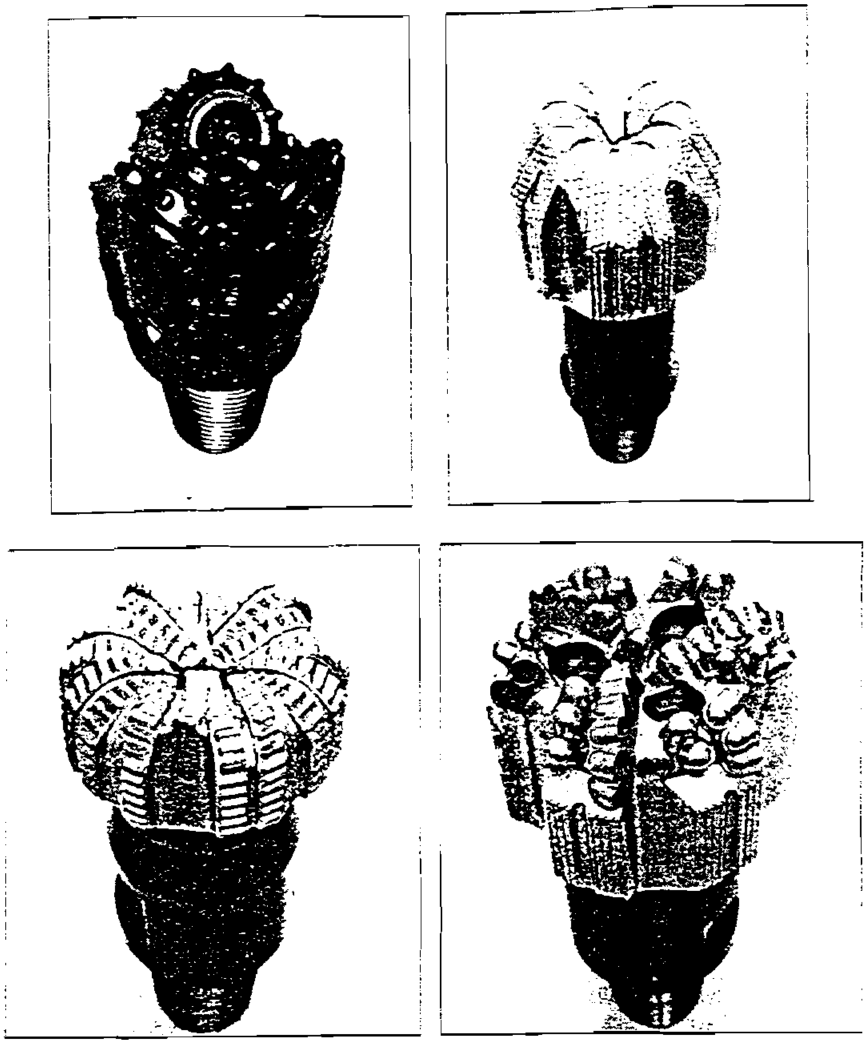

Figure 10-22. Bit Types: Roller Cone (upper left), Natural Diamond (upper right), TSP (lower left), and PDC (lower right) (King, 1994)

Roller-cone bits are available in diameters as small as 3⅞ in. with either sealed or nonsealed bearings (Table 10-8). Nonsealed bits are used for drilling out cement and for workovers. Sealed bits are used in drilling applications. Advantages of roller-cone bits in certain situations include almost no problems with stalling. However, these slim-hole bits lack the strength and capacity for lubrication available with larger bits.

TABLE 10-8. Slim-Hole Roller-Cone Bits (King, 1994)

IADC code			1 Standard roller bearing	2 Roller bearing air cooled	6 Sealed fiction bearing	7 Sealed friction bearing gauge protection
1	Steel tooth soft	1			▲	
		2	▲		■▲	
		3	■▲		■▲	
2	Steel tooth medium	1	▲		■	
		2	●■			
		3				
3	Steel tooth hard	1	■▲			
		2				
		3				
4	Insert very soft	2				
		3				
		4				■
5	Insert soft	1				■▲
		3				●■▲
		4				■
6	Insert medium	1				▲
		2				■▲
		3				■▲
7	Insert hard	3				▲
		4		▲		

● 3.875 in. ■ 4.750 in. ▲ 6.250 in.

The popularity of natural-diamond bits has lessened with the increased availability of TSP and PDC technology. Relatively low torque is generated with natural diamond bits due to less aggressive cutting action. Natural-diamond bits may be used to drill an angular tight sand or other applications where the life of other bits may be too limited.

TSP (thermally-stable polycrystalline) bits are long-lived but generally drill slower than comparable PDC or roller-cone bits. The torque consistency in TSP bits is helpful for overcoming difficulties with tool-face orientation and motor stalling. For some operators, TSP bits are the first choice because of life expectancy and torque consistency. However, if bit selection is based only on these considerations, potential benefits of higher ROP with other bits may never be enjoyed.

In many cases, PDC (polycrystalline diamond compact) bits are considered as too aggressive for coiled-tubing drilling, leading to erratic and excessive torque generation. However, recent developments to minimize axial and lateral vibrations have led to more consistent torque performance with these bits. With reduced vibrations and relatively consistent torque, improved PDC bits can be ideal for coiled-tubing applications.

Torque performance with WOB is compared for the four bit types in Figure 10-23.

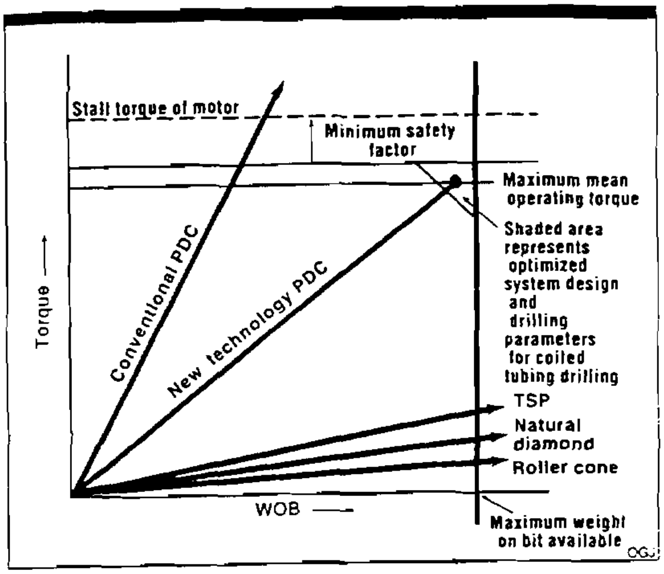

Figure 10-23. Torque and WOB for Bit Types (King, 1994)

Torque amplitudes are compared in Figure 10-24. Improved PDC bits have been shown to perform with significantly less torque cycling than conventional PDC bits.

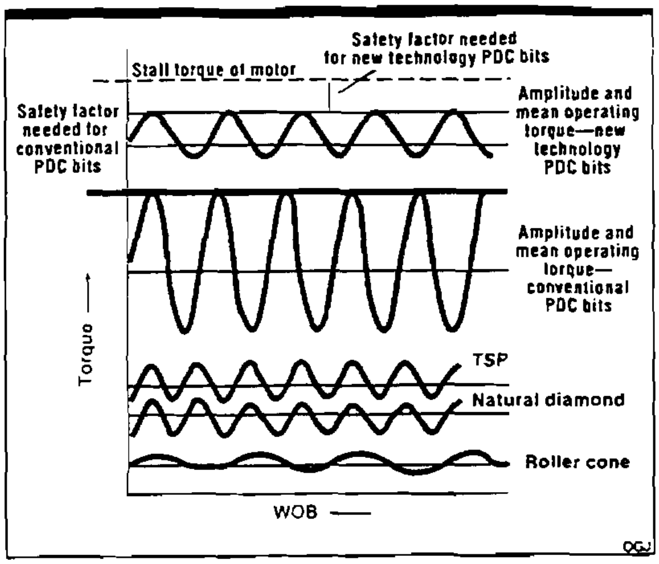

Figure 10-24. Torque Amplitude for Bit Types (King, 1994)

A comparison of general performance of bit types with respect to WOB, torque generation, torque cycling, and potential ROP for coiled-tubing drilling is shown in Table 10-9.

TABLE 10-9. Ranking of Bits for Coiled-Tubing Drilling (King, 1994)

AMOUNT OF WEIGHT REQUIRED TO DRILL (Ranked Highest to Lowest)
1. Roller cone
2. Natural diamond
3. TSP
4. New technology PDC
5. Conventional PDC
TORQUE GENERATION WHILE DRILLING (Ranked Most to Least)
1. Conventional PDC
2. New technology PDC
3. TSP
4. Natural diamond
5. Roller cone
HIGH-AMPLITUDE TORQUE VARIANCE WHILE DRILLING (Ranked Most to Least)
1. Conventional
2. New technology PDC
3. TSP
4. Natural diamond
5. Roller cone
ROP POTENTIAL AT HIGH ROTATIONAL SPEED WITHIN COILED TUBING DRILLING SYSTEM CONSTRAINTS (Ranked Highest to Lowest)
1. New technology PDC
2. Conventional PDC
3. Roller cone
4. TSP
5. Natural diamond

10.2.4 Drexel Oilfield Services (Hybrid Coiled-Tubing/Snubbing Rig)

Industry's experience with early coiled-tubing drilling applications demonstrated that a system was needed that could run both coiled and jointed pipe. In many cases, existing jointed production tubing needs to be pulled and run, or casing/liners need to be run after drilling is completed.

Drexel Oilfield Services (Newman and Doremus, 1994) considered several basic designs for hybrid coiled/jointed pipe operations. The first approach involved adding coiled-tubing subsystems to a conventional rig, including the control panel, injector, reel and accumulator. Power for coiled-tubing operations could be taken from the rig power.

Another approach to the design of a hybrid rig is to add a mast to a basic coiled-tubing rig. The mast would be used for pulling jointed pipe, and, if required, a top drive could be used to rotate jointed pipe.

The third approach is to add snubbing jacks to a basic coiled-tubing rig. If rotation were required, a rotary table could be added.

These three approaches are compared in Table 10-10.

TABLE 10-10. Coiled/Jointed Pipe Hybrid Systems (Newman and Doremus, 1994)

TYPE	ADVANTAGES	DISADVANTAGES
Rig + CTU Subsystems	◆ Fast running/pulling of jointed pipe ◆ Full rig capabilities	◆ Expensive –Cost of full rig + CTU ◆ Large amount of equipment ◆ Large location size ◆ Large crew size needed ◆ Cannot run jointed pipe underbalanced ◆ Transmits load only through substructure
CTU + Mast	◆ Fast running/pulling of jointed pipe	◆ Cannot run jointed pipe underbalanced ◆ Large crew size ◆ Transmits load only through substructure
CTU + Snubbing Jacks	◆ Can run jointed pipe underbalanced ◆ Small crew size ◆ Less equipment ◆ Small location ◆ Transmits load through either the substructure or the wellhead	◆ Slow running/pulling of jointed pipe

Drexel weighed the advantages/disadvantages of these three approaches and settled on the third: snubbing capability added to a coiled-tubing rig. The ability to run jointed tubing under pressure for underbalanced operations was an important factor favoring this design. Another important element was the ability to transmit axial loads through the wellhead, an important attribute for operations on some offshore platforms.

Drexel designed and manufactured a hybrid rig capable of running both continuous and jointed pipe (Figure 10-25). Some of the design features of the system are:

- Includes two snubbing jacks with 11-ft stroke capable of pulling 170,000 lb
- A trolley is used to move the injector on/off the well

- The jacks are used to lift the injector off the trolley and hold it while coiled tubing is run in. This design lessens fatigue life by allowing small pipe movements to be made by raising/lowering the injector, provided a telescoping lubricator is used.
- Height of the drilling floor adjusts between 14 to 18 ft above ground level
- Jointed pipe ranging from 2⅜ to 7⅝ in. can be run. A crane is used to handle pipe joints
- Operations can be switched between continuous and jointed pipe rapidly by moving the injector on or off the wellhead

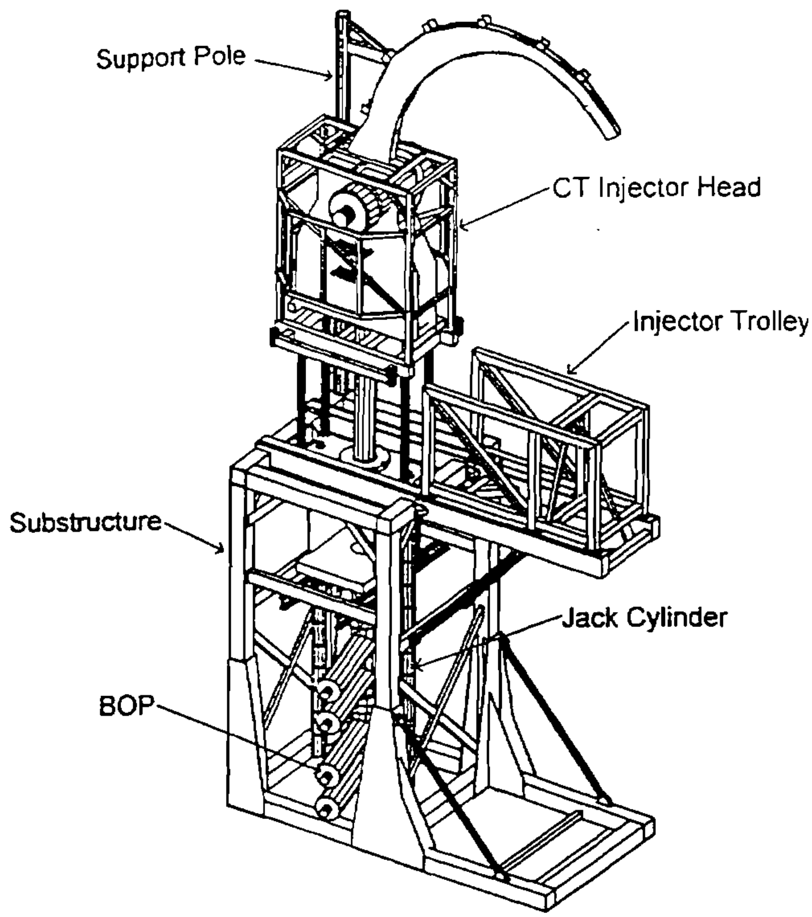

Figure 10-25. Drexel's Hybrid Coiled/Jointed-Pipe System (Newman and Doremus, 1994)

The first field use of the hybrid system was to drill a shallow gas well. After a water-well rig was used to drill the pilot hole and set surface casing, the hybrid rig drilled a 6½-in. hole to 2290 ft. Conventional casing (4½ in.) was run to complete the well. While lowering the casing, two bridges were encountered. The first bridge was pushed through by snubbing forces. The second bridge could not be overcome. A conventional rig was brought in to ream the hole and set the casing. Drexel believes that the job could have been completed with the hybrid rig if the casing could have been rotated.

10.2.5 Drilex Systems (Motor Selection)

Fothergill (1994) of Drilex Systems discussed the special concerns for running downhole motors on coiled tubing. Many difficulties that are experienced in the field can be avoided with appropriate design of the equipment and good operational practices.

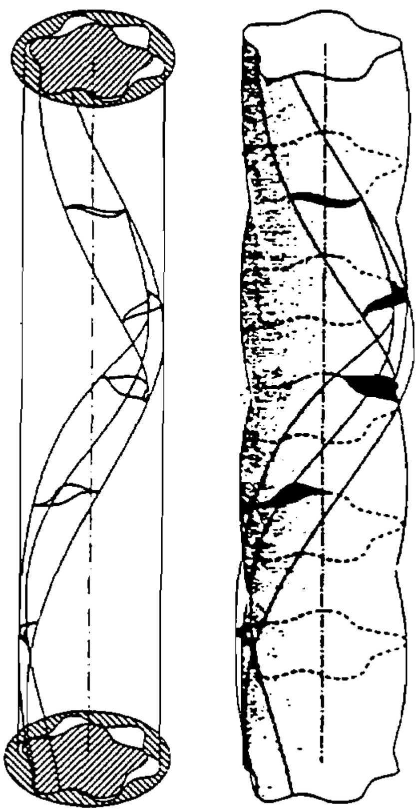

Figure 10-26. Fluid Path in Downhole Motor (Fothergill, 1994A)

Power to rotate cutting elements on coiled tubing is generated as fluid is pumped through a helical pathway (Figure 10-26) in the motor. Additional torque is generated by an increased number of stages.

The configuration of the rotor and stator (Figure 10-27) determines operating characteristics including flow rate, rotational speed, pressure drop and torque. Multilobe designs act as a gear reducer, providing high torque at reduced rotational speed.

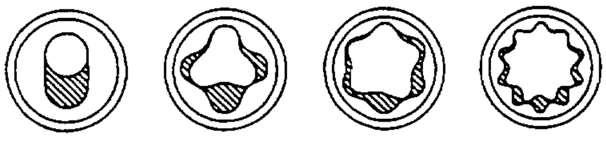

Figure 10-27. Rotor/Stator Configurations (Fothergill, 1994A)

Flow rate dictates motor rotational speed, unless weight is placed on the bit. Torque demand increases pressure drop through the motor. A typical torque/speed performance curve is shown in Figure 10-28.

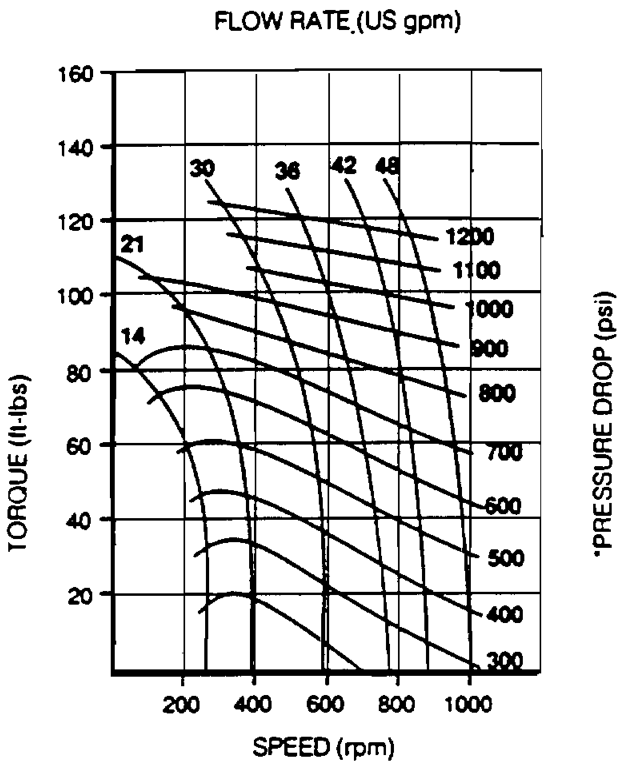

Figure 10-28. Motor Performance Curves (Fothergill, 1994A)

A typical bottom-hole assembly run above the motor is shown in Figure 10-29. Additional concern is warranted in the design of these components. Operators not familiar with coiled-tubing motor jobs often underestimate the effects of torque and vibration. Failures have occurred, most often in the hydraulic disconnect or tubing connector.

BHA components must be able to withstand the maximum reactive torque produced at stall. A common safety factor for tubing yield is that maximum motor stalling torque not exceed 40% of coiled-tubing yield.

Gel sweeps should be pumped periodically if annular velocities are restricted by BHA hydraulics. In addition, a conservative penetration rate should be adopted.

Drilex designed a selective flow sub (Figure 10-30) for coiled-tubing motor operations. The sub functions as a flow bypass tool that is closed at lower pressure differentials, and then opens to

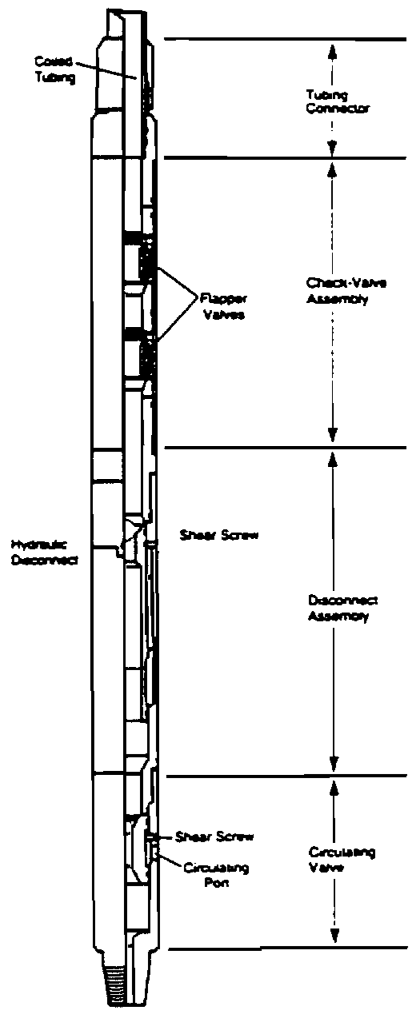

Figure 10-29. Typical Assembly for Running a Motor on Coiled Tubing (Fothergill, 1994A)

bypass flow at stall pressures. Excessive torques can thus be prevented. Bypass rates can be preset and changed in the field.

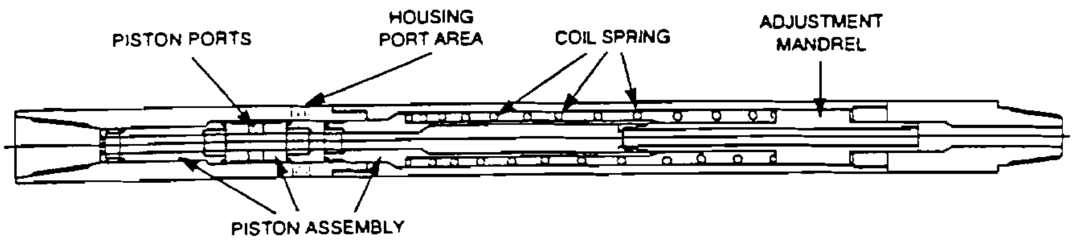

Figure 10-30. Selective Flow Sub (Fothergill, 1994B)

The prototype selective flow sub was 3⅛-in. for use with a 2⅞- or 3½-in. motor. In early tests the sub was configured to allow bypass of 42 gpm for maximum pump rate of 126 gpm. The operational window was designed as 100 psi between closed to full open.

Examples of uses of a selective flow sub are shown in Table 10-11. Various motors are listed in the left column; their model number refers to their diameter. Motor/coiled-tubing combinations that are within safety limits are marked with a check; impractical combinations are marked with an x. Matches that are possible with a selective flow sub show the necessary pressure limitation and the flow bypass area (TFA) required.

TABLE 10-11. Motor/Coiled-Tubing Combinations (Fothergill, 1994B)

Motor Size		Coiled Tubing Size							
		1.50"		1.75"		2.00"		2.38"	
	Wall Nom	.095	.156	.109	.156	.109	.203	.109	.203
D287	Max Pres Diff	500	700	✓	✓	✓	✓	✓	✓
	TFA	.155	.141						
D350	Max Pres Diff	500	883	✓	✓	✓	✓	✓	✓
	TFA	.136	.102						
D375	Max Pres Diff	412	600	612	864	874	1409	1265	✓
	TFA	.206	.169	.168	.141	.140	.110	.117	
DIR475	Max Pres Diff	x	x	x	x	346	576	514	869
	TFA					.371	.288	.305	.234
D475	Max Pres Diff	x	x	x	x	347	497	475	971
	TFA					x	.310	.317	.222

Fothergill (1994) listed a number of general operational guidelines for coiled tubing/motor procedures. Readers are referred to his papers for more details.

Motor stalls are detected by a significant increase in pressure (Figure 10-31). The tubing should be advanced at a rate to maintain a 300-400 psi differential above the pressure recorded during circulation while off bottom.

Common problems/mistakes during coiled-tubing motor operations include:

- Premature motor failure, caused by pump rates above specifications, high temperatures, poor solids control, excessive stalling or harsh chemicals
- Failure of hydraulic disconnect, caused by poor design or use of undersized disconnect
- Failure of tubing connector, caused by poor make-up or testing
- Tools stuck in hole, caused by not keeping the hole clean

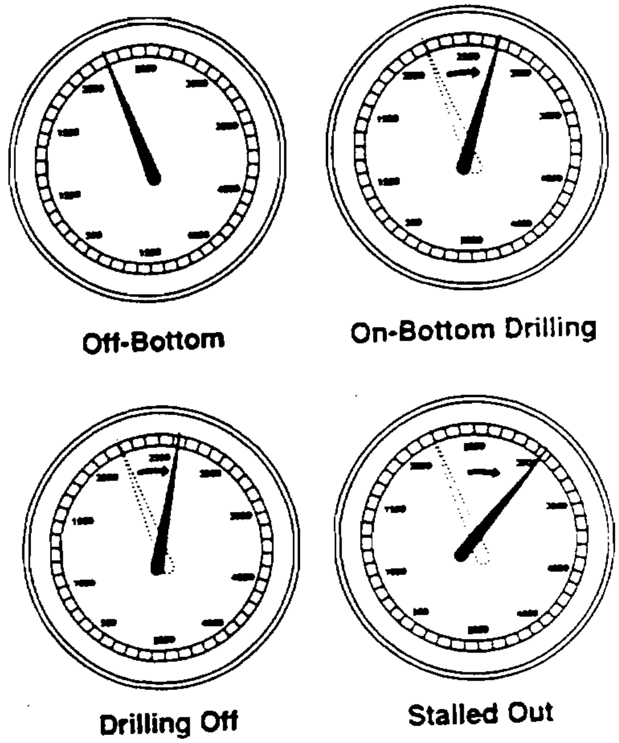

Figure 10-31. Pump Pressure for Motor Operations (Fothergill, 1994A)

10.2.6 Halliburton Energy Services (Applications of Coiled-Tubing Drilling)

Halliburton Energy Services (Rutland and Fowler, 1994) discussed the most economic applications for coiled-tubing drilling in the current market. They surmised that the technology is of economic advantage when some or all of certain factors are true:

- Surface conditions favor a small rig footprint
- Price of a conventional drilling rig is high
- Expected production gains (i.e., re-entry applications) do not justify shipping in a conventional rig
- Underbalanced drilling operations (Figure 10-32) are preferred

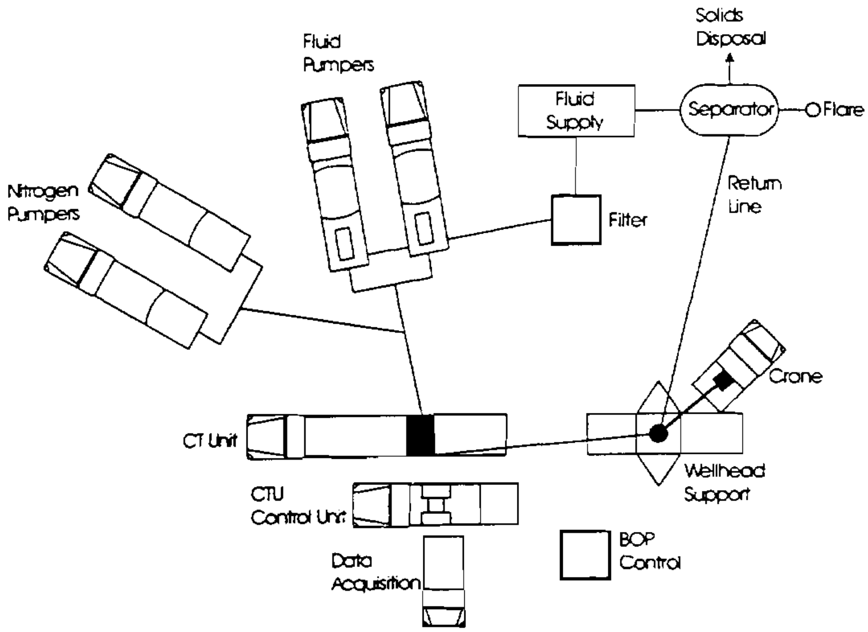

Figure 10-32. Surface Equipment for Coiled-Tubing Drilling with Nitrified Fluid (Rutland and Fowler, 1994)

Clearly, in the current market, there is no single answer for all drilling environments, and operators should compare costs for all systems. Costs vary widely. For example, a North Slope operator may reduce drilling costs by 50% by using coiled tubing. A Mid-Continent operator, however, would probably spend more money with a coiled-tubing rig than by using a fully-depreciated conventional rig.

Hole size, currently restricted to a maximum of about 6¼ in., is among the most important limitations. Horizontal penetration in horizontal applications may also be a limiting factor. Penetration limits are affected by casing and hole size, coiled-tubing size (Table 10-12), build radius, and fluids.

TABLE 10-12. Penetration Limits for Coiled-Tubing Drilling in Horizontal Holes (Rutland and Fowler, 1994)

	Maximum Horizontal Length (Ft)	
Casing x Hole (In.)	2-In. Tubing	2⅜-In. Tubing
4½ x 3⅞	2,700	4,600
5½ x 4½	1,000	2,600
7 x 4½	200	1,600

10.2.7 Nederlandse Aardolie Maatschappij (Evolution of Coiled-Tubing Drilling)

A long-lived dream of the drilling industry, the use of continuous tubing for drilling operations, is now feasible due to recent advances and developments in coiled-tubing technology. The earliest coiled-tubing drilling projects are summarized in Table 10-13. Almost all of these wells were drilled onshore where competing rig costs were low. Economics should be even more favorable offshore where reduced mobilization/demobilization costs are significant.

TABLE 10-13. Early Coiled-Tubing Drilling Projects (Simmons and Adam, 1993)

Date	Location	Operator	Wellbore	Deviation	CT Size, In.	Hole Size, In.
June 1991	Paris	Elf	Re-entry	Vertical	1.50	3.875
June 1991	Texas	Oryx	Re-entry	Horizontal	2.00	3.875
August 1991	Texas	Oryx	Re-entry	Horizontal	2.00	3.875
December 1991	Texas	Chevron	Re-entry	Horizontal	2.00	3.875
May 1992	Canada	Lasmo	New	Vertical	2.00	4.750
July 1992	Texas	Chevron	Re-entry	Horizontal	2.38	3.875
July 1992	Canada	Gulf	Re-entry	Horizontal	2.00	4.125
July 1992	Canada	Imperial	New	Vertical	2.00	4.750
July 1992	Texas	Arco	Re-entry	Horizontal	1.75	3.750
September 1992	Canada	Pan Canadian	Re-entry	Vertical	2.00	4.750
October 1992	Canada	Can. Hunter	Re-entry	Vertical	1.75	3.875
October 1992	Paris	Elf	New	Vertical	1.75	3.875
November 1992	Canada	Gulf	Re-entry	Vertical	2.00	4.750
November 1992	Austria	RAG	Re-entry	Vertical	2.00	6.125
December 1992	Alaska	Arco	Re-entry	Deviated	2.00	3.750
January 1993	Canada	Petro Canada	Re-entry	Vertical	2.00	3.875
February 1993	Holland	Shell-NAM	Re-entry	Horizontal	2.00	4.125
February 1993	North Sea	Phillips	Re-entry	Deviated	1.75	3.750
February 1993	Canada	Petro Canada	Re-entry	Horizontal	2.00	4.750
March 1993	Alaska	BP	Re-entry	Deviated	2.00	3.750*
April 1993	California	Berry	New	Vertical	2.00	6.250
April 1993	California	Berry	New	Vertical	2.00	6.250
May 1993	Alaska	Arco	Re-entry	Deviated	2.00	3.750
June 1993	Alaska	Arco	Re-entry	Deviated	2.00	3.750*
*Underreamed						

The first practical attempts at drilling with coiled tubing were made in the mid-1970s in Canada. No further attempts with the technology were recorded between 1976 and 1991. This lack of use of the technology underscores technical and economic hurdles encountered with early systems.

NAM (Simmons and Adam, 1993) listed important advantages and disadvantages of coiled-tubing drilling (Table 10-14). They emphasized that operators analyzing coiled-tubing drilling technology must consider the long-term benefits of this approach. Underbalanced drilling, a key benefit of coiled-tubing operations, impacts the economics of the well far into its production lifetime. The long-term economic benefits of underbalanced drilling have potential to outweigh most near-term technical disadvantages of coiled-tubing drilling.

TABLE 10-14. Coiled-Tubing Drilling Advantages/Disadvantages (Simmons and Adam, 1993)

ADVANTAGES	DISADVANTAGES
Underbalanced Drilling and Improved Well Control • Full pressure control possible throughout drilling operations • Underbalanced tripping, drilling, and completion reduces formation damage and permits faster penetration with reduced risk of differential sticking.	**Drill String Cannot Be Rotated** • Downhole motors required, even for vertical wells. • An orienting tool is required for steering. • Higher friction with the borehole wall.
Continuous Drill String • Allows continuous circulation while tripping. • Eliminates joint-related problems and allows faster tripping. • No pipe handling, which improves safety and reduces noise. • Reduced environmental impact. No spillage at joints. • Simplified automation, reduced manpower.	**Limited to Slim-Hole Applications** • Largest hole to date is 6¼ in., larger holes technically are feasible. • Small hole size limits the number of casing strings and liners that can be run.
Compact Unit and Equipment Configuration • Reduced drill site size and associated costs. • Reduced mobilization and demobilization costs.	**Wireline Inside the CT Drill String** • Fatigued or damaged sections of CT cannot be removed from the drill string.
Wireline Inside the CT Drill String • Allows high-speed telemetry for measurement and logging-while-drilling (MWD, LWD) • CT protects wireline and simplifies operations through simultaneous spooling of tubing and wireline. • Electrically operated directional control is possible.	**New Technique** • Currently in the learning curve.

Hybrid rigs designed to run both coiled and jointed tubing will speed the applications of coiled-tubing drilling. The added ability to run and cement casing after drilling operations is beneficial. In addition, having the option to pull existing production strings, work the well, and then recomplete with coiled or jointed tubing should result in cost savings.

The use of large-diameter coiled tubing for completions (Figure 10-33) has shown potential for decreasing overall future costs.

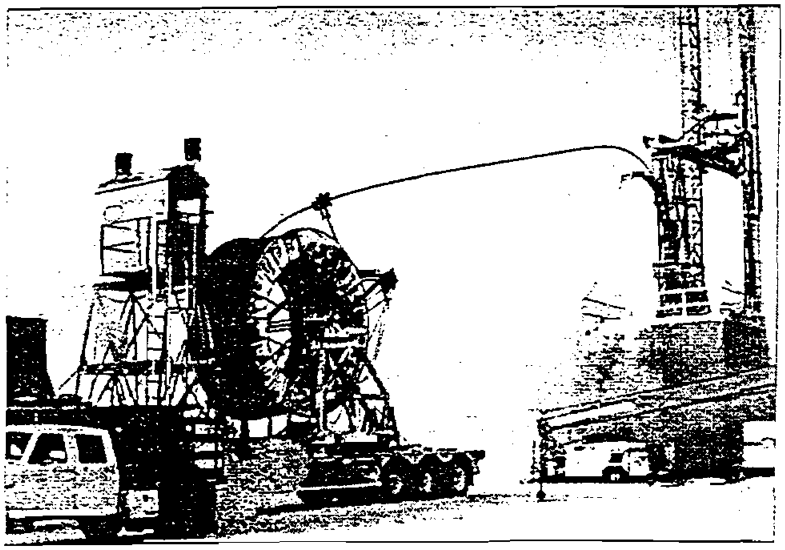

Figure 10-33. Running Large Coiled Completions (Simmons and Adam, 1993)

10.2.8 Petro Canada (Medicine Hat Re-entry)

Petro Canada (McMechan and Crombie, 1994) tested modified equipment and drilling techniques by deepening, completing and fracturing a vertical gas well with coiled tubing. The deepening of the well near Medicine Hat, Alberta was the first field operation in a larger project to evaluate balanced drilling of horizontal wells in sour reservoirs with coiled tubing. This first site was purposely chosen as a safer environment to test fluids handling systems, a new pressure sensor sub, and foam model accuracy.

The subject well (PEX WINCAN MEDHAT 10-9MR-17-3 W4M) was to be deepened from 448 m to 530 mMD (1470 ft to 1740 ft) with a 3⅞-in. hole. Drilling was to be conducted at balanced conditions with foam to avoid formation damage in the currently producing Milk River zone and the target Medicine Hat zone. Fluid modeling showed that foam rates of 33 gpm of water and 440 scfm of nitrogen would be required.

Drilling BHA components are listed in Table 10-15. Components were assembled to reflect the requirements for horizontal drilling in later phases. However, directional equipment (steering tool etc.) was not used.

TABLE 10-15. Coiled-Tubing Drilling BHA (McMechan and Crombie, 1994)

COMPONENT	O.D.(In.)	LENGTH (m)	TOTAL LENGTH (m)
Junk Mill	3⅞	0.46	0.46
Crossover Sub	3⅛	0.12	0.58
Motor	3⅛	3.80	4.38
Crossover Sub	3⅛	0.12	4.50
Thruster	2⅜	2.84	7.34
Crossover Sub	3⅛	0.24	7.58
Crossover Sub	3⅛	0.18	7.76
Drilling Release Tool	3⅛	1.77	9.53
Quick Latch, Pressure Sensor, Coil Connector	3⅛	1.97	11.50

The maintenance of balanced conditions with foam required accurate measurement of downhole pressures. A special sub was designed with two pressure sensors (Figure 10-34), one measuring pressure in the coiled tubing above the motor and one measuring pressure in the annulus. Pressure in the annulus ranged from about 245-320 psi during drilling operations.

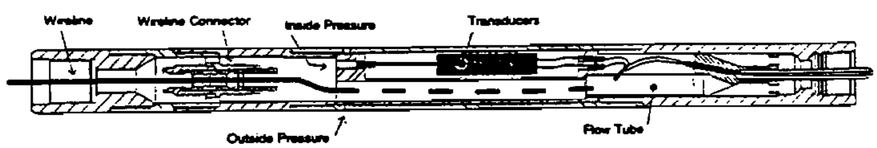

Figure 10-34. Pressure Sensor Sub (McMechan and Crombie, 1994)

Petro Canada and Nowsco wanted to obtain pressure data from drilling operations that could be compared with computer simulation data (Table 10-16) so that any appropriate empirical corrections could be determined and applied in later phases of the development.

TABLE 10-16. Predicted/Actual Drilling Pressures (McMechan and Crombie, 1994)

PRESSURE AT:	PREDICTED (MPa)	ACTUAL (MPa)
Rotating Joint	13	13.0–13.4
Gooseneck	7.5	N/A
Above motor	9.5	9.3–9.5
Annulus (surface)	0.49	0.40–0.45

Considerable design effort was directed toward a system to handle the foam (Figure 10-35). Calculated foam quality was 79% at bottom hole and 90% for returns at surface. Tests indicated that these foams could be broken down mechanically. However, in the field the system broke down only about 98% of the foam. A chemical breaker was used for the remainder.

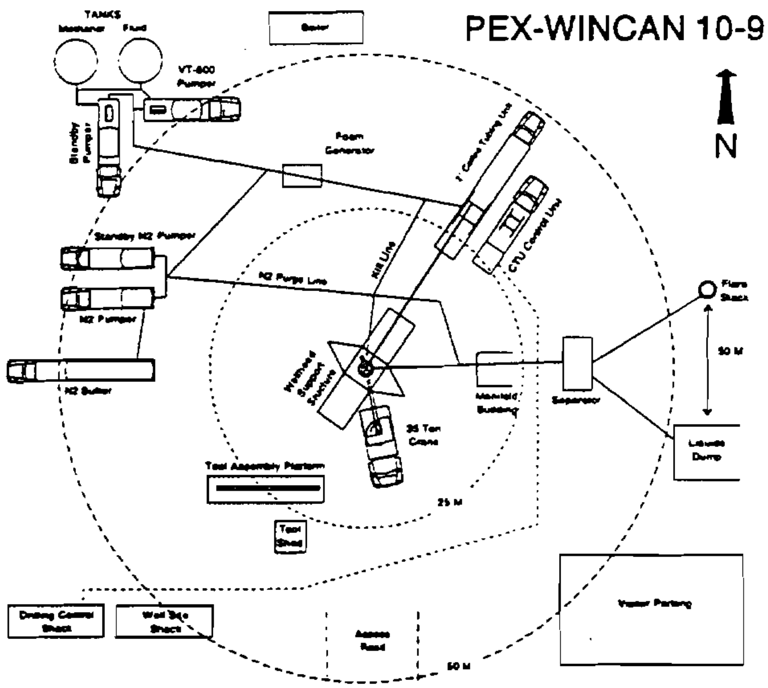

Figure 10-35. Surface Equipment with Foam Treatment (McMechan and Crombie, 1994)

Drilling operations progressed relatively smoothly. To drill out the shoe joint, a junk mill was substituted for the 3⅞-in. TSP bit run initially. The bit was reinstalled to drill the new hole. Drilling time was 9½ hr for 224 ft, for an average ROP of 27 ft/hr.

After drilling was complete, a string of 2⅞-in. coiled tubing was cemented in place as a production liner. After logging and perforating operations, a 55,000-lb frac job was pumped and the well put on production. The final wellbore status is shown in Figure 10-36.

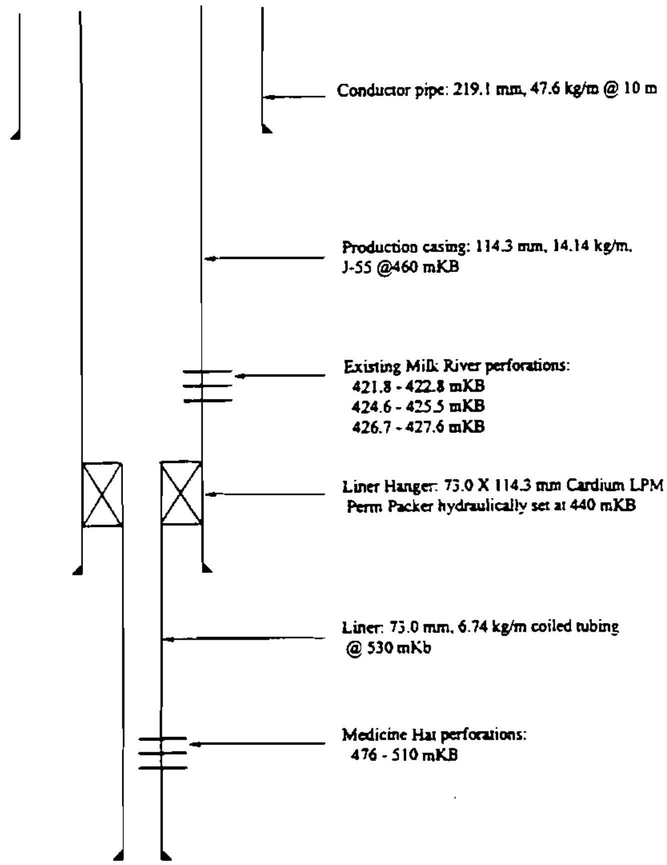

Figure 10-36. Final Completion of 10-9MR-17-3 W4M (McMechan and Crombie, 1994)

10.2.9 Schlumberger Dowell (Summary of Industry Experience)

Schlumberger Dowell has been involved in many of the developments of techniques and technologies, 1 related to coiled-tubing drilling. Several publications (for example, Newman 993; Doremus, 1994; Leising and Rike, 1994) summarize industry's efforts in modern coiled-tubing drilling. The most recent well counts are shown in Figure 10-37. For 1995, about 70 directional wells are predicted; the number of vertical jobs was not predicted, but is expected to continue to grow.

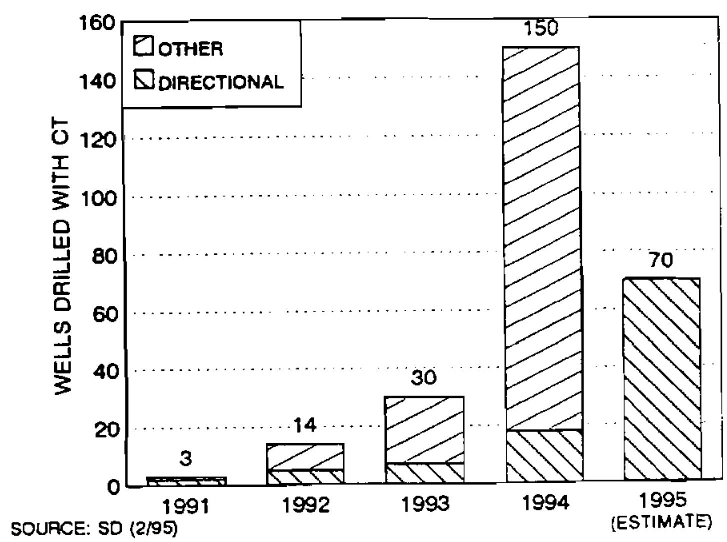

Figure 10-37. Job Counts for Coiled-Tubing Drilling (Gary, 1995)

Newman (1993), along with enumerating the advantages and disadvantages coiled-tubing drilling, presented a list of coiled-tubing drilling jobs as of February 1993 (Table 10-17). He noted that these attempts were not all successful.

TABLE 10-17. Coiled-Tubing Drilling Jobs as of 02/93 (Newman, 1993)

Date	Location	Client	New Re-entry	Vert. Dev.	CT Size	Hole Size
Jun 91	Paris	Elf	Re-entry	Vert.	1.50	3.875
Jun 91	Texas	Oryx	Re-entry	Devi.	2.00	3.875
Aug 91	Texas	Oryx	Re-entry	Devi.	2.00	3.875
Dec 91	Texas	Chevron	Re-entry	Devi.	2.00	3.875
May 92	Canada	Lasmo	New	Vert.	2.00	4.750
July 92	Texas	Oryx	Re-entry	Devi.	2.00	3.875
July 92	Canada	Gulf	Re-entry	Devi.	2.00	4.125
July 92	Canada	Imperial	New	Vert.	2.00	4.750
July 92	Texas	Arco	Re-entry	Devi.	1.75	3.750
Sept 92	Canada	Pan Can.	Re-entry	Vert.	2.00	4.750
Oct 92	Canada	Can. Hunt	Re-entry	Vert.	1.75	3.875
Oct 92	Paris	Elf	New	Vert.	1.75	3.875
Nov 92	Canada	Gulf	Re-entry	Devi.	2.00	4.750
Nov 92	Canada	Gulf	Re-entry	Vert.	2.00	4.750
Nov 92	Austria	RAG	Re-entry	Vert.	2.00	6.125
Dec 92	Alaska	Arco	Re-entry	Devi.	2.00	3.875
Feb 93	Holland	NAM	Re-entry	Devi.	2.00	3.875

Based on the data in Table 10-17, 2-in. coiled tubing is the most popular drill string and most holes are about 4 inches.

Schlumberger Dowell (Leising and Rike, 1994) discussed their own experience drilling wells with coiled tubing around the world. In addition, they presented data describing two of these wells in more detail. The number of coiled-tubing drilling jobs has increased significantly in recent years, with the annual percentage of vertical wells (versus deviated) increasing through 1993 (Figure 10-38).

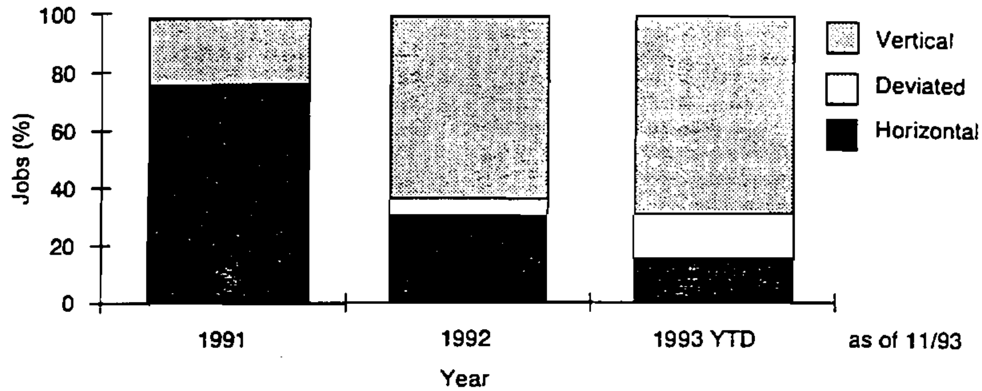

Figure 10-38. Orientation of Coiled-Tubing Wells (Leising and Rike, 1994)

A variety of operations have been proven during the jobs, including coring, setting whipstocks, cutting windows, MWD mud-pulse with gamma-ray, using new steering tools, running liners and hangers, using tricone and diamond bits, underbalanced drilling with artificial lift and lightweight fluids, air/mist drilling, drilling through 3½-in. tubing, and off-pad remote drilling.

Schlumberger Dowell's projects are summarized in Table 10-18. The footage drilled on a typical coiled-tubing drilling project was about 900 ft. The maximum is 4370 ft. WOB has ranged from 500-1000 lb per inch of bit diameter.

TABLE 10-18. Coiled-Tubing Wells by Schlumberger Dowell (Leising and Rike, 1994)

WELL #	DATE	LOCATION	CLIENT	TECH SUCCESS	DRILLED FT	COMMENTS	PROBLEMS
D-1	6-91	Paris	Elf	Yes	896	Cored	
D-2	7-92	Texas	Arco	No	382	Whipstock set/drilled, MWD	Software error
D-3	10-92	Canada	Can. Hunter	No	3	Gel diesel mud	Hard stringer below shoe
D-4	10-92	Paris	Elf	Partial	4370		Motors, differential sticking, bit balling, disconnects
D-5	2-93	Holland	Shell-NAM	Yes	1060	Liner, 11 times production increase	Orienting tool
D-6	4-93	California	Berry	Yes	1179	Washout 1/4 of Rotary	Bit balling
D-7	4-93	California	Berry	Yes	1422		
D-8A,B	6-93	Alaska	Arco	Yes	135	Underbalanced, TT[1]	Underreamer blade wear
D-9	8-93	Alaska	Arco	Yes	199	3½ times production increase	Weight transfer
D-10	9-93	Texas	Amoco	Yes	416	Air/mist	Motors
D-11	9-93	Texas	Amoco	Yes	467	Air/mist	CT scale
D-12	10-93	Texas	Amoco	Yes	424	Air/mist	Motor
D-13	10-93	California	Chevron	Yes	880		Mud handling
D-14	10-93	California	Chevron	Yes	872		
D-15	10-93	Venezuela	Lagoven	Yes	1000	Off pad drilling	
D-16	11-93	Venezuela	Lagoven	Yes	1000	Off pad drilling	
D-17	11-93	Venezuela	Lagoven	Yes	1005	Off pad drilling	
D-18	11-93	Venezuela	Lagoven	Yes	1000	Off pad drilling	Clay swelling/BHA LIH[2]
D-19	11-93	Venezuela	Lagoven	Yes	1000	Off pad drilling	
				TOTAL	17,710		

A problem with weight transfer is illustrated in Figure 10-39, which is a log from well D-4 (see Table 10-18). Although surface weight was increased over 2000 lb between 16:45 and 16:52, motor pressure did not increase significantly due to differential sticking. Logging was also a problem; tools could only pass the top third of the hole. Overall, well D-4 was listed as a partial success.

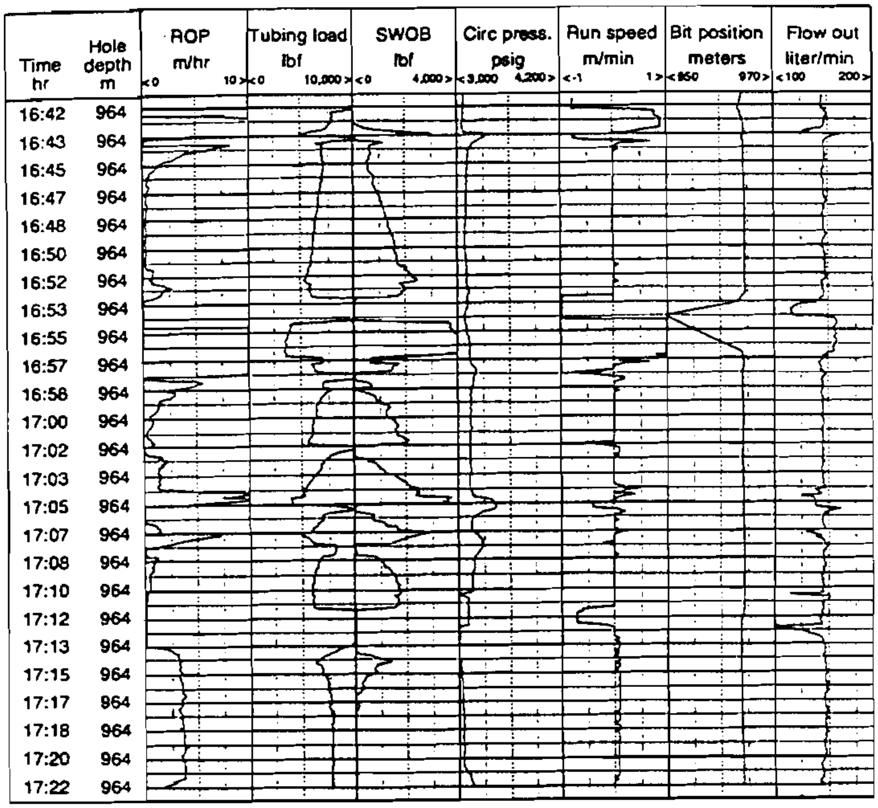

Figure 10-39. Drilling Log From Well D-4 (Leising and Rike, 1994)

Well D-9 was a horizontal well deepening operation. This Prudhoe Bay well was originally completed with a 4½-in. slotted liner and 4½ x 3½ production tubing (Figure 10-40). Formation damage during original drilling operations was suspected as the cause of the well's poor production (less than 300 BOPD).

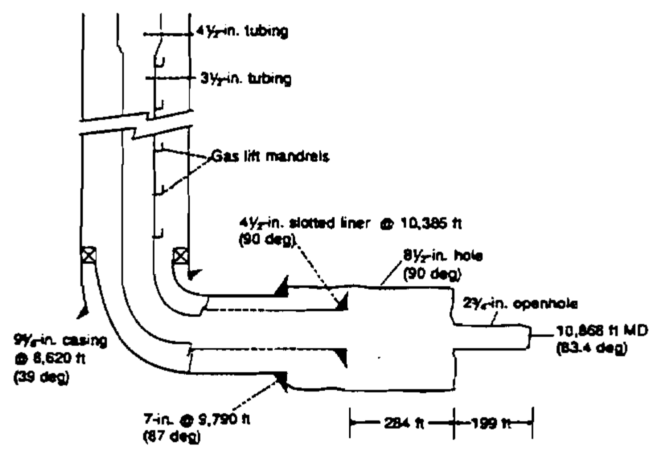

Figure 10-40. Well D-9 (Leising and Rike, 1994)

The deepening was performed underbalanced with gas lift. Wellhead equipment included a $7^{1}/_{16}$ BOP stack (Figure 10-41). Biozan drilling fluid (2.5 lb/bbl) was used for the operation. The drilling BHA consisted of a 2¾-in. bit, motor, drop-ball circulation sub, drop-ball disconnect, dual check valves, and weld-on connector.

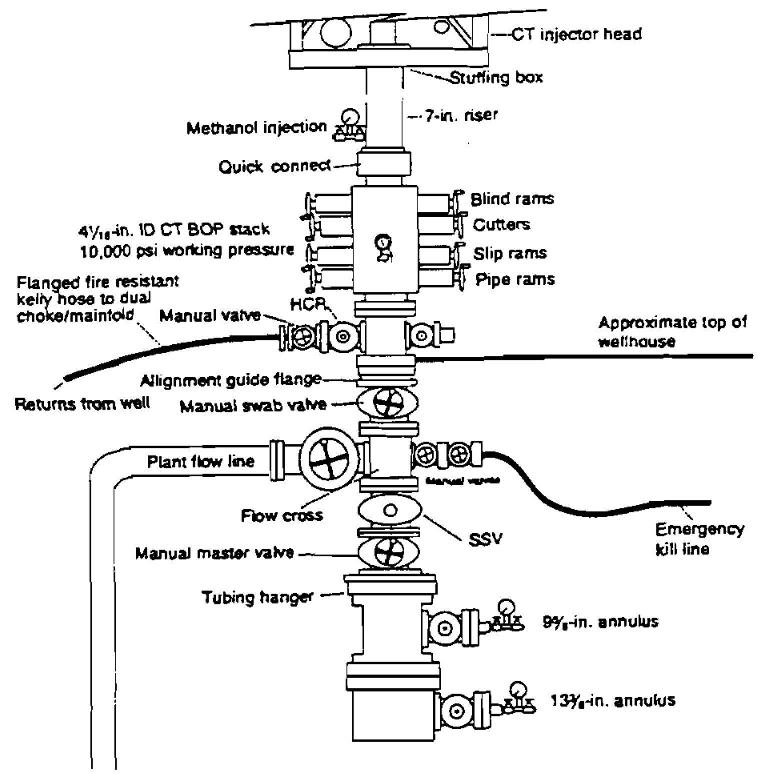

Figure 10-41. Wellhead Equipment for Well D-9 (Leising and Rike, 1994)

A two-phase separator was used along with collection tanks to store the usable fluid before returning it to the suction tanks. A layout of the surface equipment is shown in Figure 10-42.

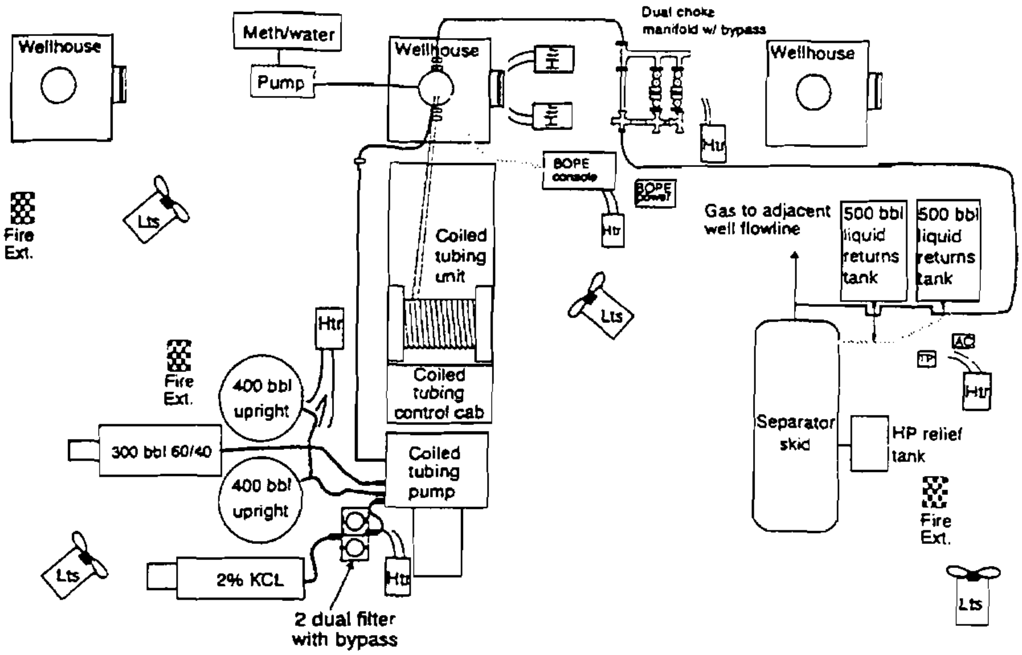

Figure 10-42. Surface Equipment for Well D-9 (Leising and Rike, 1994)

After a profile nipple was milled out, the BHA was run to the old TD and the hole lengthened 199 ft (Figure 10-43). A final survey showed that the new wellbore dropped angle along its length at a rate of about 3½°/100 ft. Guidance was not critical for this interval so no attempt was made to measure changes in inclination while drilling.

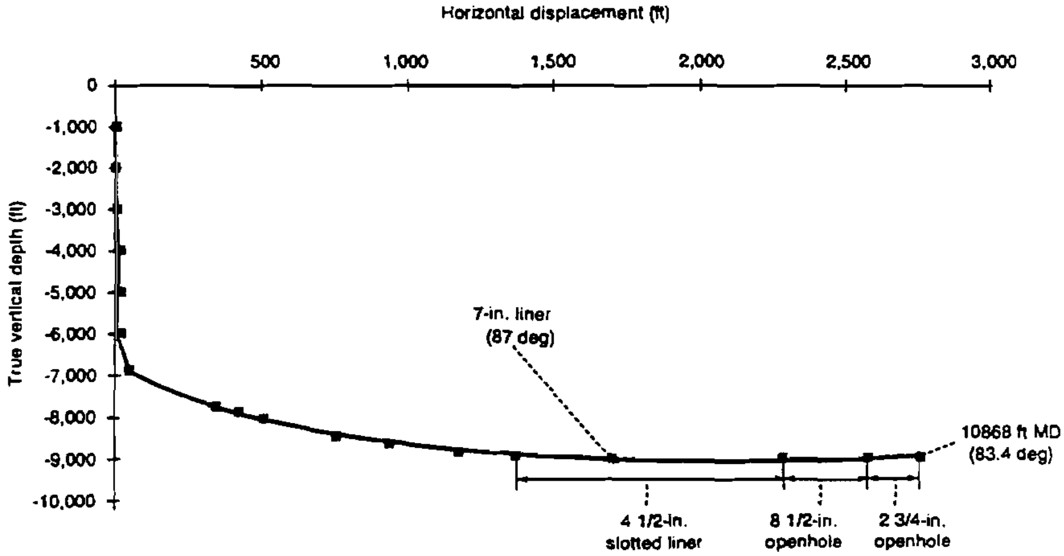

Figure 10-43. Final Survey for Well D-9 (Leising and Rike, 1994)

Problems with job design included difficulty achieving desired underbalanced conditions. The size of the annulus (2-in. coiled tubing in 3½-in. production tubing) resulted in high pressure losses in the annulus. Smaller coiled tubing (1¾ in.) was not considered feasible due to the large diameter of the original wellbore (8½ in.).

Unidentified fluid contamination and a large wellbore diameter led to stick/slip behavior of the coiled-tubing string, resulting in difficulty getting weight to the bit. ROP ranged from 6–18 ft/hr; the average was about 10 ft/hr.

Production from well D-9 was increased by a factor of 3½ by the coiled-tubing lengthening. The cost for this operation was about 75% less than if a conventional rig were used.

Doremus (1994) summarized Schlumberger Dowell's work with Lagoven in drilling top holes with coiled tubing in Lake Maracaibo, Venezuela. There was a risk in drilling these wells from gas-bearing sands at depths of 400-1000 ft. The conventional approach in this field was to place the diverter lines for piping away flowing gas on barges tied next to the platform. An effective coiled-tubing rig-up allowed most of the equipment and all of the personnel to be positioned over 100 ft from the platform (Figure 10-44). Consequently, diverter lines could be positioned normally on the platform.

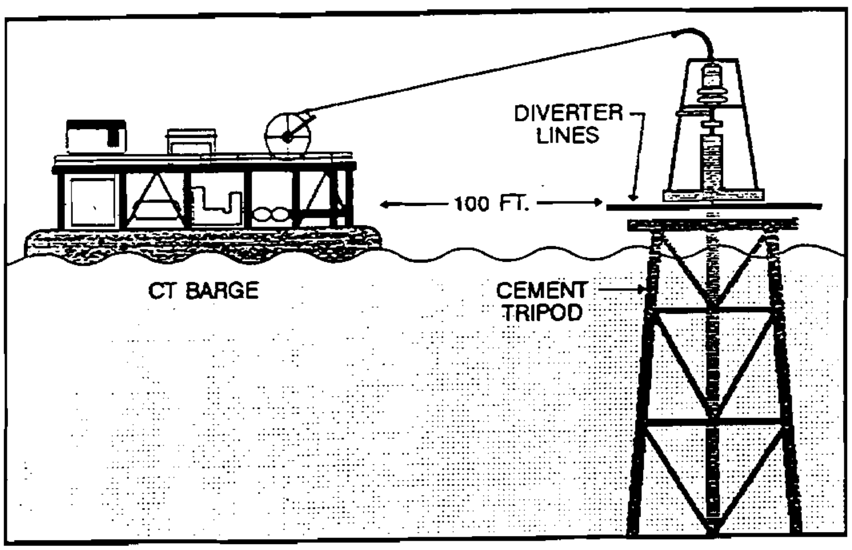

Figure 10-44. Lagoven Coiled-Tubing Rig-Up (*Offshore* Staff, 1994)

After the 24-in. conductor and cement tripod platform were installed, the BOP and injector were rigged up on the conductor. Pilot holes (3⅞ in.) were drilled on 1½-in. coiled tubing. A 5-in. flow conductor was used inside the 24-in. conductor to maximize ROP.

Coiled-tubing TD was about 1000 ft. Afterwards, a conventional system reamed out the pilot hole and completed the top hole to 3500 ft.

The coiled-tubing system proved very effective for this application. Four early pilot holes were drilled in 10 days. Cost savings were estimated at 70% for top-hole costs.

Doremus (1994) presented a summary of current coiled-tubing drilling capabilities for hole sizes and depths (Table 10-19). For through-tubing applications, the maximum diameter of production tubing that can be worked through is given. For other applications, the maximum hole diameter that can be drilled is presented. Obviously, these stated limits are contingent on site-specific conditions; however, these are given as a general indication of industry's capabilities.

TABLE 10-19. Current Coiled-Tubing Drilling Capability (Doremus, 1994)

Application	Max. Hole Size (in.)	Depth (ft)
Conventional Re-entry	3½-4¾	15,000
New Shallow Well	8½	6000
Through-Tubing Re-entry	**Min. Tubing Size (in.)**	
Vertical Deepening	3½	
Directional	4½	

10.2.10 Shell Research (Environmental Impact)

Shell Research (Faure et al., 1994) discussed the environmental impact of drilling operations, with special attention to the potential benefits of coiled-tubing drilling in this and related areas. Many established technical processes within the oil and gas industry around the globe have reached limits with respect to environmental impact, economic feasibility, or public acceptance in light of these concerns. Since coiled-tubing drilling represents a departure from established practice, this technology may be an excellent venue to rethink the drilling process while incorporating current concerns for health, safety and the environment.

Faure et al. cited the North Sea as an area with increased environment concerns. In that area, the offshore oil and gas industry is credited with about half of the hydrocarbon pollution each year (Figure 10-45).

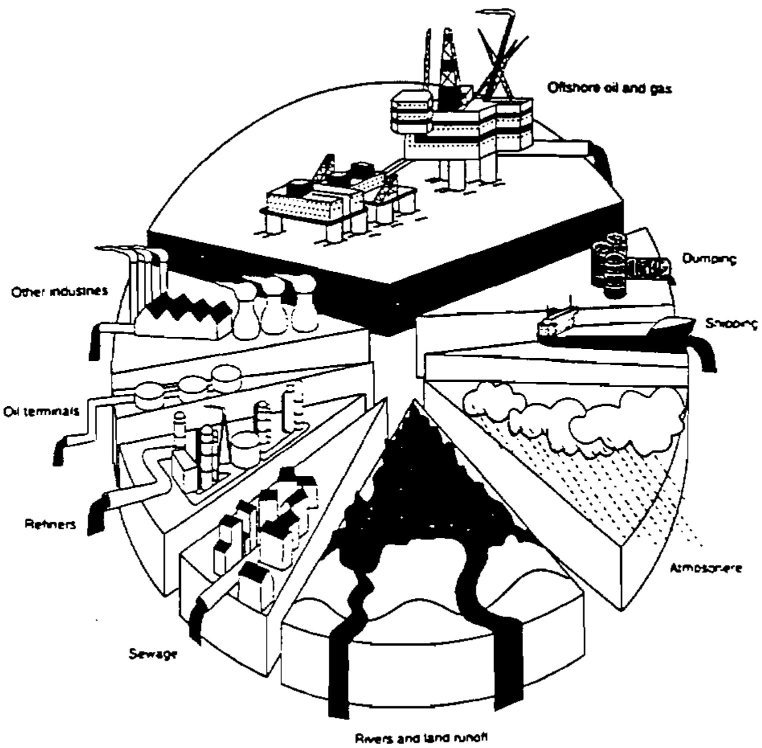

Figure 10-45. Sources of Hydrocarbon Pollution in the North Sea (Faure et al., 1994)

Environmental Control Technology (ECT) is being developed to counteract increasing limitations of traditional waste management. A primary objective of ECT is to use new approaches and techniques to avoid or minimize waste generation (Figure 10-46). Novel mud systems are being developed and applied to control offshore discharges. Slim-hole projects are also proving to yield impressive environmental benefits.

Environmental benefits from coiled-tubing drilling are complemented by other advantages including safe and efficient underbalanced operations.

A potential technique to minimize generated wastes is to use crude oil and nitrogen lift to create an underbalanced condition. After circulation, the crude oil is returned to the production facilities, eliminating environmental concerns and costs of drilling fluid disposal.

The ease with which high-rate real-time data can be relayed to surface in coiled-tubing operations could lead to greater automation of the drilling process than may be possible with jointed pipe. During drilling operations, there is no need for personnel to be stationed near the wellhead or reel. Exposure of rig personnel to dangerous conditions is greatly reduced.

Safety and costs are also positively affected by a reduction in personnel required to operate the rig. Typical crews consist of a drilling supervisor, coiled-tubing operator, and two helpers for a coiled-tubing drilling operation, compared to a driller, assistant driller, derrickman and three floor hands.

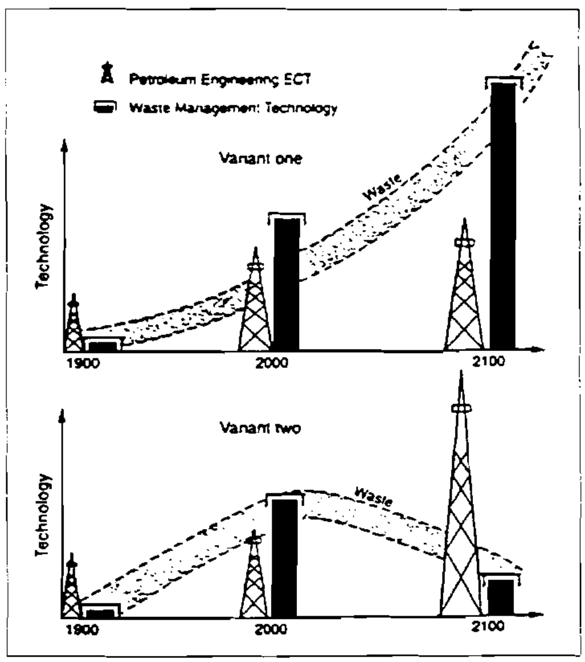

Figure 10-46. Using Control Technology to Reduce Environmental Impact (Faure et al., 1994)

Environmental impact on land is less with a coiled-tubing rig due to a greatly reduced footprint (Figure 10-47) compared to conventional rigs. A consequent benefit is that locations are more easily restored. In addition, mud spillage is much less likely with coiled tubing, and no hole is required for the kelly, both factors reducing the risk of contamination of the surface soil.

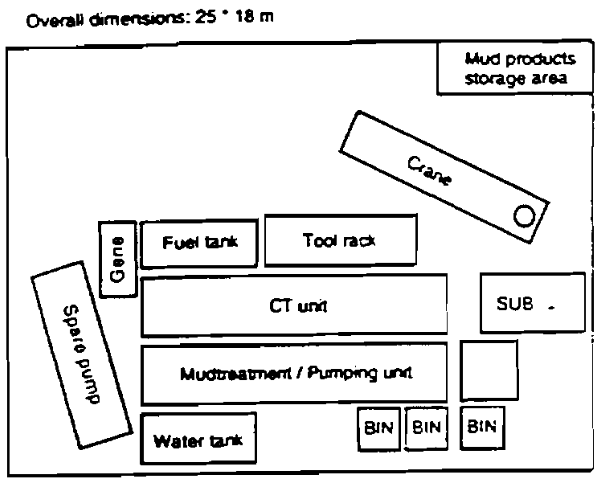

Figure 10-47. Footprint of Coiled-Tubing Drilling Operation (Faure et al., 1994)

Another benefit of special concern in many areas is the reduction in noise with coiled-tubing operations. Noise produced by a coiled-tubing rig and conventional rig is compared in Figure 10-48. Note that a reduction of 10 dB is reported for a radius of about 400 ft, which corresponds to a 90% reduction in acoustic energy.

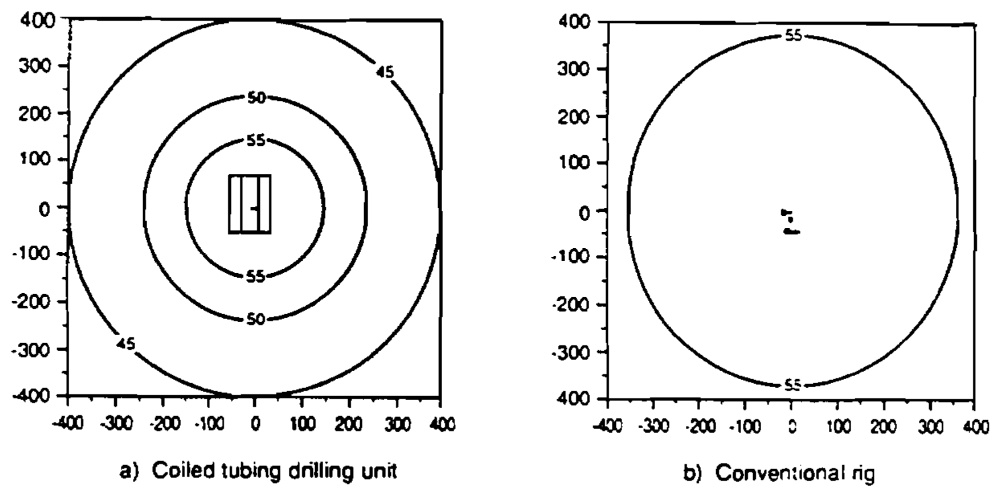

Figure 10-48. Noise Levels for Coiled-Tubing Drilling (Faure et al., 1994)

Other benefits for noise generation include a significant reduction in intermittent (and thus more annoying) noise from pipe bangs during making/breaking operations or squealing breaks. The smaller size of a coiled-tubing rig also makes the unit more amenable to noise enclosures or barriers if further noise reduction is required.

Waste reduction has received considerable attention as a response to the increasing costs associated with waste remediation and disposal. Coiled-tubing operations can take advantage of significant reductions in fluid and cuttings volumes through slim-hole design. Fluid volume reductions of about 70% are achievable (Figure 10-49). Waste transportation and environmental concerns are therefore less.

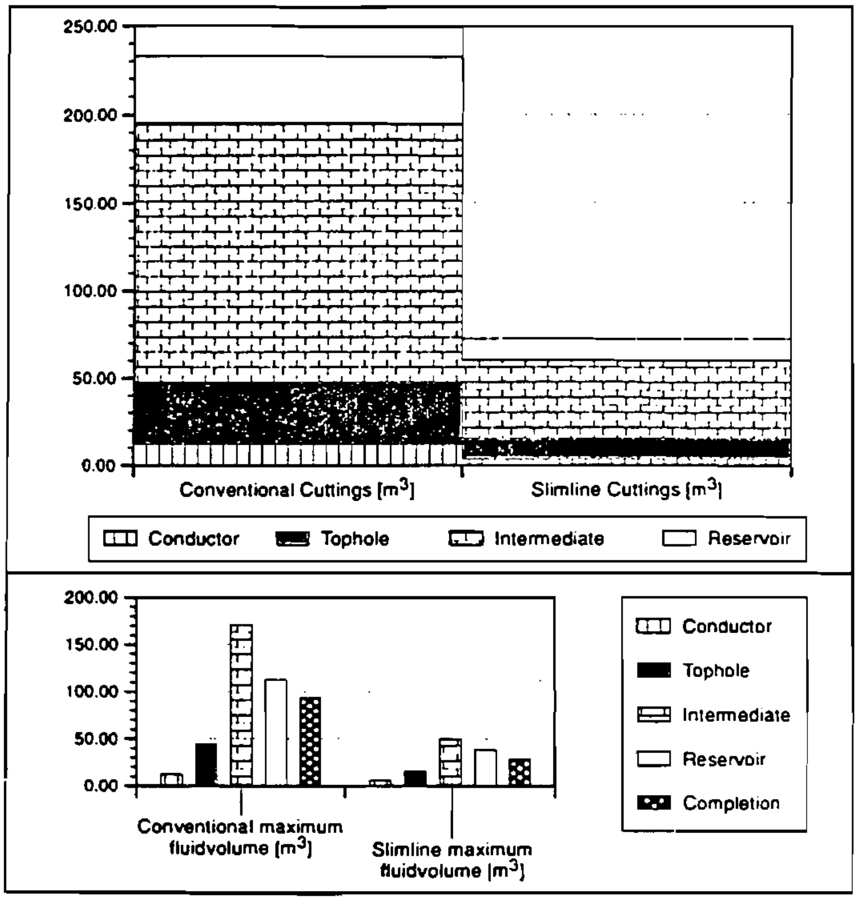

Figure 10-49. Cuttings and Mud Volumes with Slim Coiled-Tubing Drilling (Faure et al., 1994)

Another environmental benefit for coiled-tubing drilling is a reduction in fuel consumption and exhaust gas emission (Table 10-20).

TABLE 10-20. Rig Fuel Usage and Exhaust Emissions (Faure et al., 1994)

		Medium Workover Rig	Land Drilling Rig	CTD Unit
Diesel (m^3/month)		35	160	25
Gas emissions (kg/day)	CO_2	3293	15,055	2,122
	CO	3.7	16.8	2.5
	NOx	4.6	21	2.1
	HC	3.9	17.8	2.8
	HC (gas)	1.83	8.4	1.1
	SO_2	4.2	19.4	2.2

Early inefficiencies with coiled-tubing drilling were described by Faure et al. (1994). The inability for a conventional coiled-tubing rig to run casing has been among the prime deficiencies of these operations. The industry has begun moving along several avenues to address this need. Hybrid rigs with casing snubbing capability are currently in the field-testing phase.

Another avenue is the use of continuous composite casing systems that are hardened in place. Diameters up to 14 in. are possible. These casings are stored folded on a reel. Novel approaches such as composite casing may solve the problems in running conventional casing with a coiled-tubing rig and do so in an environmentally beneficial way.

10.2.11 Shell Western E&P (McKittrick Field)

Shell Western E&P used coiled tubing to drill 68 slim-hole injector wells in the McKittrick Field near Bakersfield, California (Figure 10-50). This project represents the largest coiled-tubing drilling program yet conducted. Costs were reduced significantly for this application. Background and results of this effort are described in detail in DEA-67 *Topical Report No. 1: Shell California Slim-Hole and Coiled-Tubing Drilling Operations*. A summary is presented in this section.

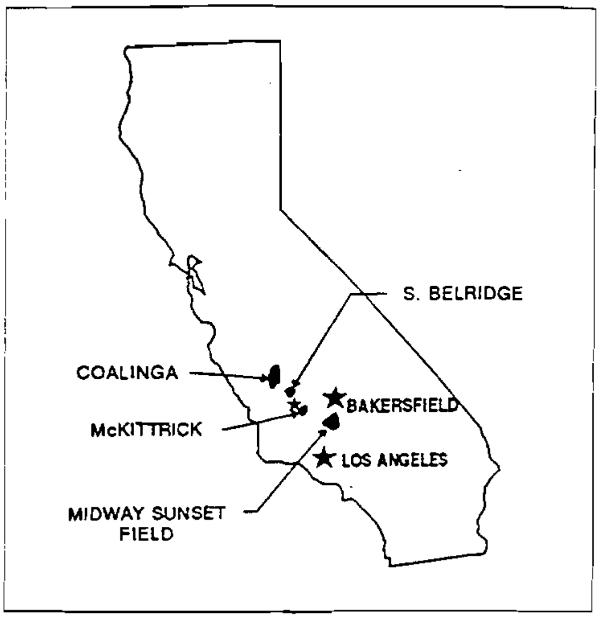

Figure 10-50. McKittrick Field

Shell drilled the slim-hole injection wells to improve thermal efficiency, production and economics of the McKittrick field. Steam is injected into these wells in the Tulare reservoir. Prior to project implementation, the field was shut in for several years due to poor economics. The redevelopment plan was to decrease well spacing by infill drilling 115 new injectors in thirty 5-acre inverted 9-spot patterns to increase thermal efficiency of the reservoir and increase production through existing or reworked conventional production wells.

The McKittrick field has a complex system of pumping equipment, steam distribution, production, and power lines that restrict the space available for conventional rotary drilling. Figure 10-51 shows the heavy congestion in the field.

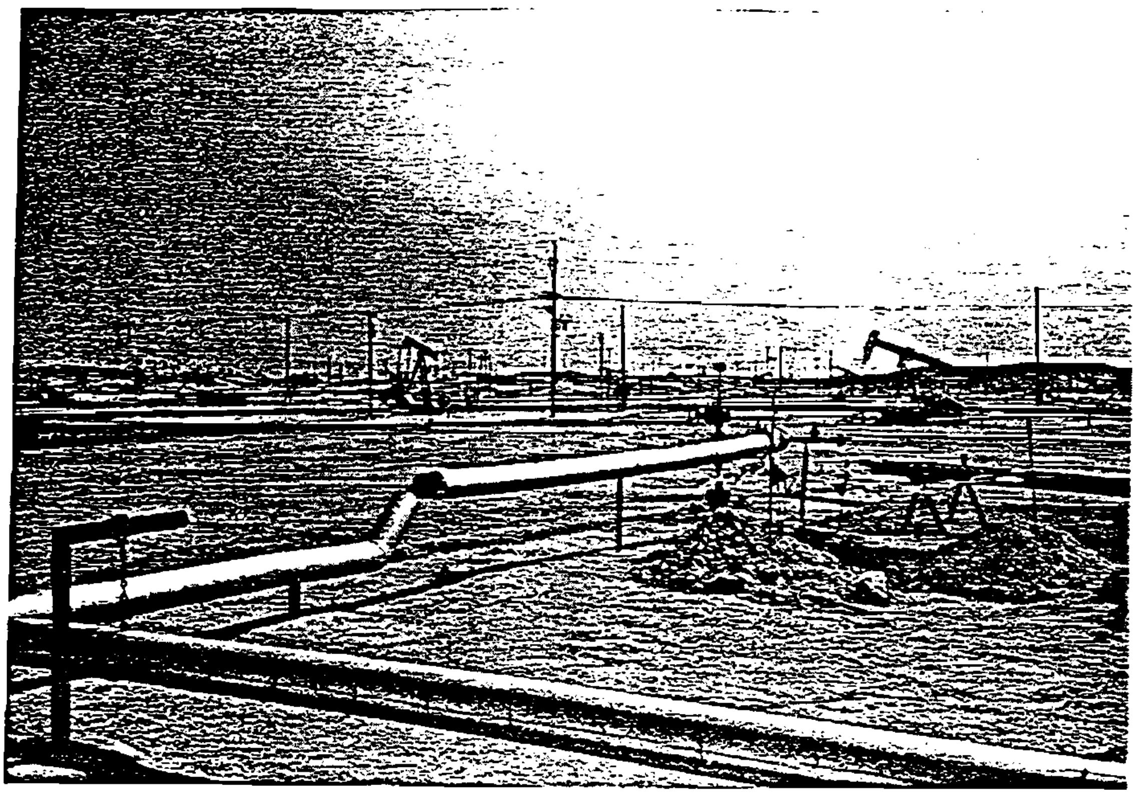
Figure 10-51. McKittrick Field Project Site

The slim-hole wells were drilled for primarily two reasons. First, by reducing hole and casing sizes, vertical slim-hole wells could be drilled and completed for approximately half the cost of conventional vertical wells. Secondly, coiled-tubing drilling allowed slim-hole infill wells to be drilled on the required precise patterns in this crowded field. These wells could not have been drilled with workover rigs because of their locations and would have required expensive directional drilling with conventional rigs.

Many of the new well locations were directly under existing power lines and very close to existing facilities. In addition, drilling conventional directional wells would have been relatively expensive since 68 wells had to be drilled.

Other benefits of using coiled-tubing drilling were:

1. Low mobilization and de-mobilization costs between wells.
2. Safer working environment (i.e., no couplings to make or break)
3. Decreased noise and emission levels.

A Halliburton coiled-tubing unit with 2-in. coiled tubing, 5-in. motor and 6⅛-in. bits was used to drill 68 injector wells. Mud and cement were pumped using a Halliburton 75TC4 cement pump truck. A portable trailer-mounted mud tank, shakers, mud mixer, centrifuge, and desanders were used. Shell supplied the mud tanks, bits, and the drilling mud. A typical wellbore schematic is shown in Figure 10-52.

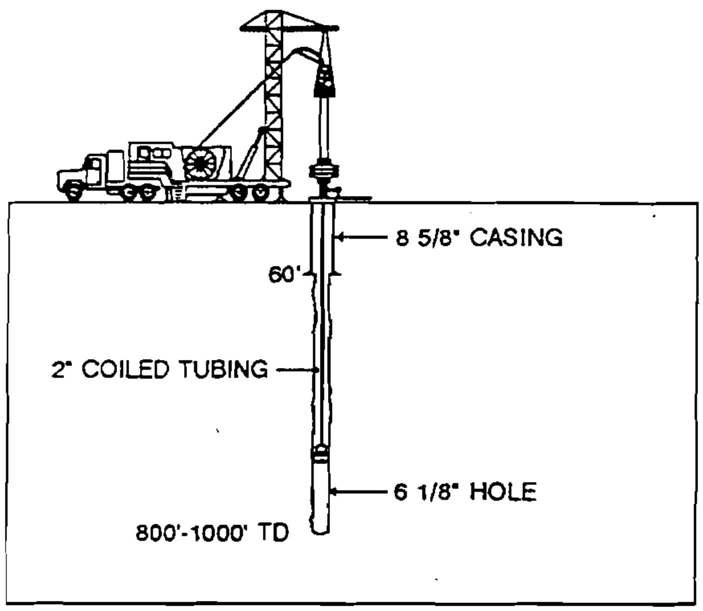

Figure 10-52. Shell Injector Well Schematic

After the wells were drilled, 2⅞-in. tubing was cemented to surface and perforated (Figure 10-53). Some wells will be acidized at a later date.

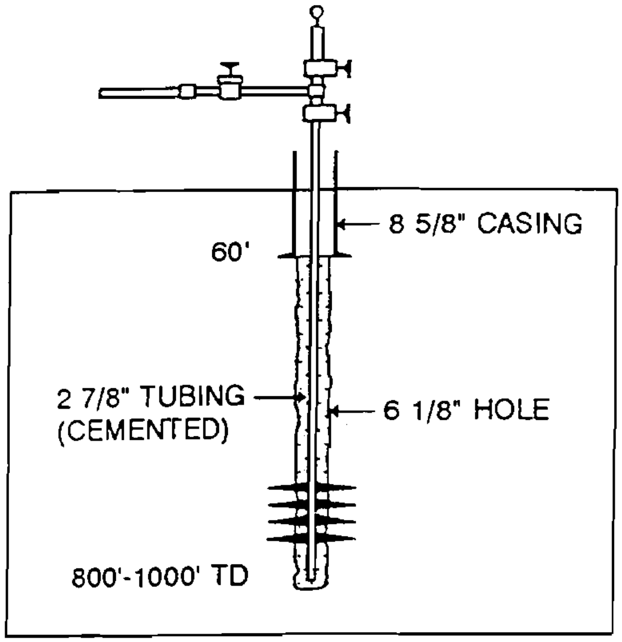

Figure 10-53. Shell Injector Completion

Prior to drilling operations, an 8 ft x 8 ft jacking framework floor was set by crane and a 6-in. diverter line and a 4-in. return line were installed (Figure 10-54). Power and backup tongs were installed on the working floor. A pump truck, coiled-tubing unit, and trailer-mounted mud system were rigged up on location and a small pit was dug next to the mud unit to handle cuttings and cement returns.

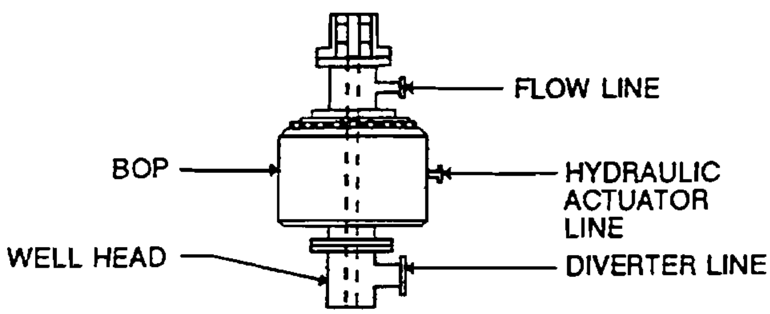

Figure 10-54. Wellhead Installation and Diverter Lines

An 8⅝-in. conductor was set at 60 ft to allow the BHA (6⅛-in. rock bit, 5-in. motor and 2-in. spiral drill collars) to be run before installing the injector. A fresh-water bentonite mud was used initially. Portable mud mixing facilities (Figure 10-55) were provided by Shell.

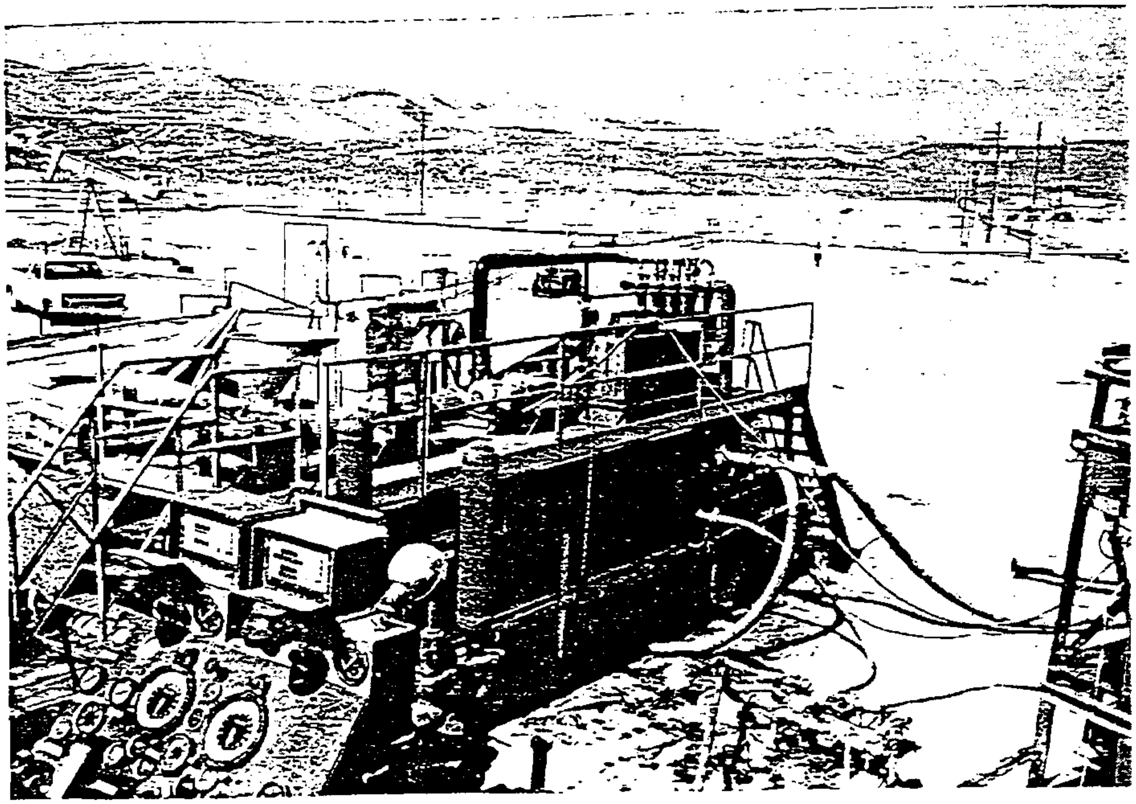

Figure 10-55. Portable Mud Tank

The workover and coiled tubing drilled slim-hole injectors took less time and cost to drill than conventional 8¾-in. injectors (Table 10-21). The workover and coiled-tubing rigs were used primarily due to surface constraints. The coiled-tubing rig proved to be ideal for drilling the shallow injectors due to the small location size and ease of mobilization.

TABLE 10-21. Shell Cost Comparison

	CONVENTIONAL OFFSET WELL	COILED TUBING WELL	WORKOVER RIG WELL
No. Of Wells	2(100)	68	45
Drill Pipe Size	3½ in.	–	2⅞ in.
Coiled-Tubing Size	–	2 in.	–
Hole Size	8¾ in.	6⅛	6⅛
Casing/Tubing Size	7(2⅞) in.	2⅞ in.	2⅞ in.
RDP	120 ft/hr	50–180 ft/hr	70–80 ft/hr
Days	7	1.25	4

There was a steep learning curve with coiled-tubing wells, with costs on initial wells being similar to conventional wells and then declining to 65% of the cost of conventional. Coiled-tubing drilling costs should continue to decline as more experience is gained and as better tools are developed.

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11. Overview

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11. Overview

11.1 BP EXPLORATION OPERATING CO. (BARRIERS TO SLIM HOLES)

BP Exploration Operating Co. Ltd. (Murray, 1994) outlined the barriers slim-hole drilling faces across the industry. Barriers are both technical and nontechnical, but many are much less challenging to overcome than is generally perceived. Slim-hole drilling has yielded proven cost savings ranging from 15 to 40% as well as significant savings in materials and logistics (Figure 11-1) in both frontier and mature areas. Most agree that the industry cannot afford to continue to drill conventional-size holes where slim-hole alternatives exist.

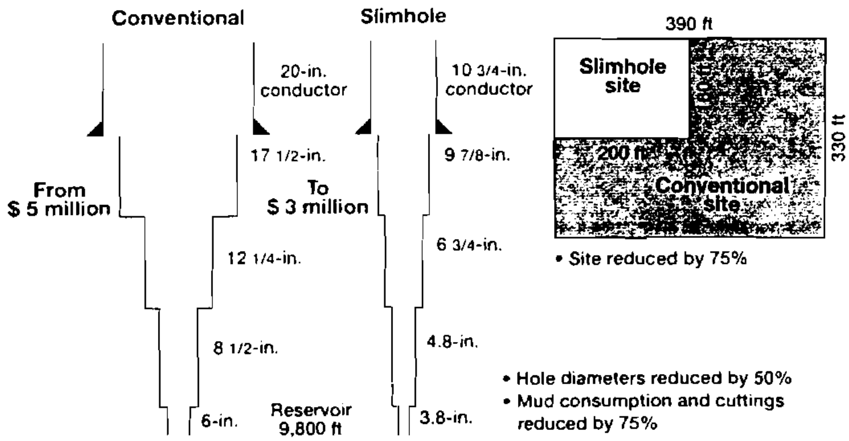

Figure 11-1. Slim-Hole Cost, Material and Logistics Savings (Murray, 1994)

The current interest in slim-hole techniques represents another peak in the approximately 10-year cycles of interest over the past few decades. The current revival differs from previous peaks of interest in that there is a much more concerted effort to develop new solutions to meet the challenges of the technology.

Murray (1994) contrasted the developments of two of the primary approaches to drilling slim holes: the modified mining systems (top-down), and the retrofit approach as typified by the Shell system (see Chapter *Motor Systems*). Operators have found that fine control of torque and WOB at high rotary speeds is one of the most critical keys to success. The retrofit system uses downhole motors and a thruster (Figure 11-2) to maintain WOB and minimize vibration.

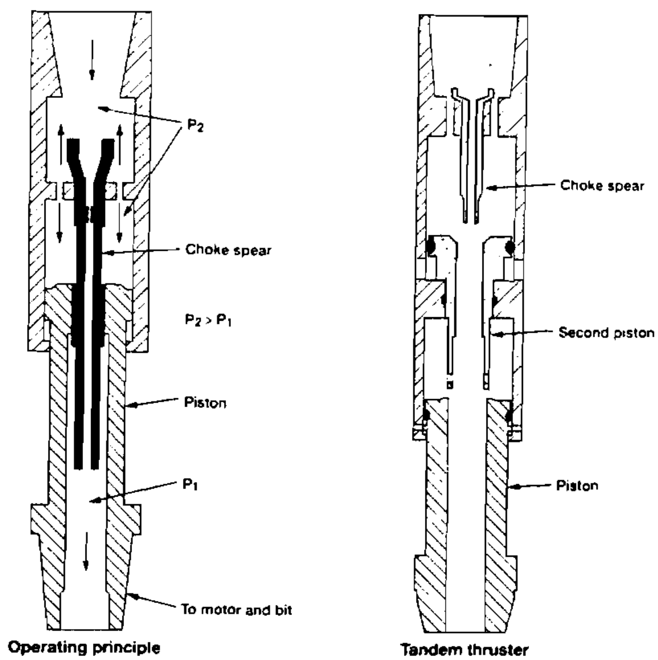

Figure 11-2. Thruster for Slim-Hole Retrofit System (Murray, 1994)

Top-down coring systems have been used for drilling slim holes for the mining industry for decades. These systems use high-speed rotation by a top drive with positive feed control (Figure 11-3). The oil industry has adapted this approach and increased depth capability to 14,000 ft. In many applications with these systems, continuous coring of the formations of interest is combined with destructive drilling of upper sections of the hole.

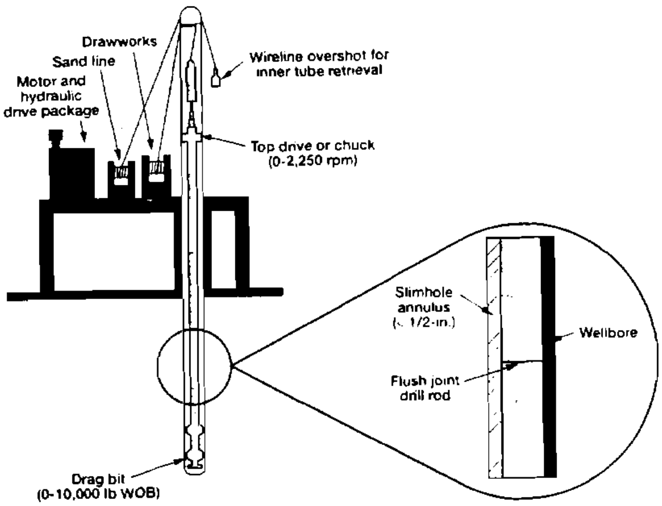

Figure 11-3. Top-Down Mining Coring System (Murray, 1994)

There are currently three principal types of applications for slim holes being pursued across the industry. First, exploration and appraisal drilling represents the most publicized uses of the technology. The benefits of slim holes have been particularly attractive in remote frontier areas. Second, many operators have downsized casing programs one or more sizes to achieve savings in consumables. The contingency hole, if required, falls under the range of slim-hole technology. As confidence increases in the ability to successfully drill and produce from these holes, their use will no doubt increase. Third, slim holes are often used for increasing production in developed fields via re-entries, extensions, deepenings and sidetracks. Coiled-tubing drilling is playing an important role in this area.

Several technical barriers hinder the use of slim-hole technology (Murray, 1994):

- *Contingency needs.* In many cases, adoption of a slim bottom hole means that no suitable contingency remains. This significance of this barrier can be analyzed by risk identification. Overall project savings may justify an occasional lost hole. Sidetracking is another suitable contingency option in many instances.
- *Depth limitations.* This represents an important concern for wildcats where the operator is reluctant to accept associated depth limits of slim-hole rigs. Ongoing developments suggests that 15,000 ft is attainable, but more work and experience are required.

- *Offshore applications*. Offshore use of slim holes is challenged by the need for fine WOB control. Development is ongoing, and use of top-down systems offshore will represent a major step forward.

- *Lost circulation*. There is concern in some applications about the ability to control lost circulation and elevated pore pressures with the solids-free drilling fluids required for many systems.

- *Mobile formations*. The potential for stuck pipe may be greater for small-annulus top-down designs. Some believe, however, that smaller holes are structurally stronger than conventional holes, although this has not been confirmed.

- *Logging*. All standard logs can be run in holes as small as 3¾ inches. However, tool availability can be a problem with more sophisticated tools.

- *Production/testing limits*. Many operators question whether slimmer tubulars will limit production. In many instances, these concerns are overstated. Perforating tools and techniques for small tubing are more serious questions.

- *Development drilling*. A slight reduction in production rate due to tubing size might prove to be significant over extended periods of production. Entire life cycles need to be considered.

Nontechnical barriers to the implementation of slim-hole technology also exist:

- *Cost savings*. The barrier of cost savings is centered in the fact that economic impacts may be unclear before the learning curve is developed. Experience in a given application helps define potential savings. Intangible savings (lighter materials, increased safety, less environmental impact) should also be factored in.

- *Casing stocks*. Availability and contingencies with casing stocks may prompt the purchase of large volumes of tubulars. Minimum quantities demanded by manufacturers may put slim designs at a disadvantage. Economic losses from switching to slim holes may be significant. Just-in-time delivery may solve this problem.

- *Rig availability*. Low rental rates of conventional rigs due to depressed markets combine with low availability of slim-hole rigs to create a barrier in many geographic areas.

- *Aversion to risk*. Risk aversion represents a significant cultural barrier within some companies. However, while there is increased risk with slim holes, the industry has advanced further down the learning curve than many realize.

- *Political barriers.* The primary political barrier for drilling slim holes is in countries with government-supported rig and service industries. Regulations demanding local crews may complicate the use of high-technology rigs and equipment.

Technical and nontechnical barriers to slim-hole implementation are summarized in Figure 11-4.

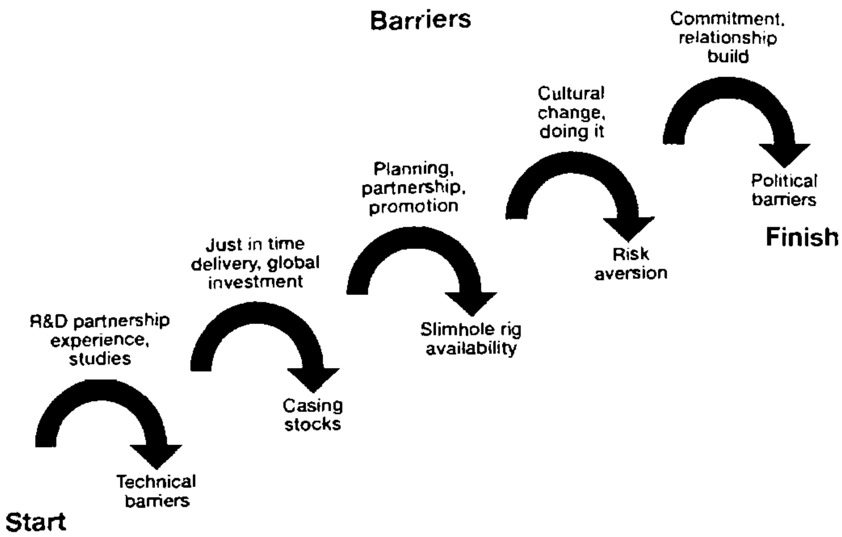

Figure 11-4. Slim-Hole Barriers and Solutions (Murray, 1994)

11.2 MAURER ENGINEERING (SLIM-HOLE DRILLING BARRIERS)

Maurer Engineering and the Gas Research Institute (Shook and Brunsman, 1994) summarized the results of a project to analyze the barriers hindering widespread application of slim-hole drilling and completion technology, with special regard for gas wells in the U.S. There appears to be significant opportunity for slim-hole technology in the U.S. gas industry since typical wells require neither high-volume artificial lift equipment nor large production tubing to avoid restricting flow rates. The GRI study found that real and perceived limitations of slim-hole drilling exist, hindering the industry from embracing the technology.

The ability to effectively drill holes less than 7⅞ in. is not universal within the U.S. gas industry. Operators along the Gulf Coast have drilled 6¼-in. holes for years. By contrast, Denver Basin operators have only just begun attempting to drill holes less than 7⅞ inches.

The slim-hole study found interesting trends in the usage of slim-hole completions (Figure 11-5). The peak usage of slim completions was in the 1960s. Slim refers to a casing size of 4 in. or less.

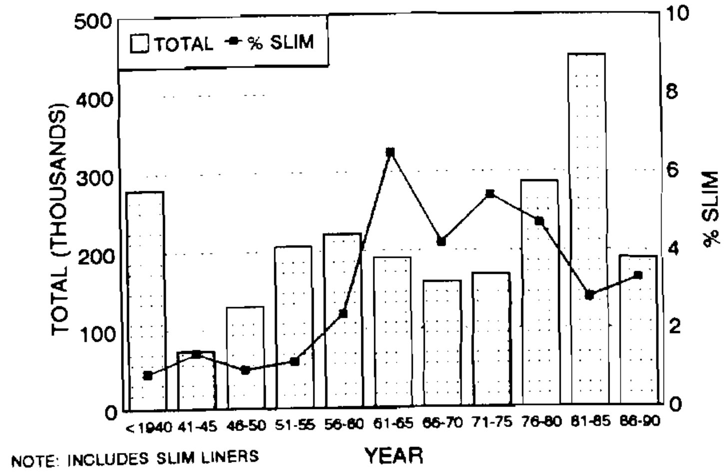

Figure 11-5. Slim Completions in U.S. (Shook and Brunsman, 1994)

Slim completions were differentiated from slim holes in the study. In many areas, operators have attempted to optimize their well designs by drilling larger holes (faster ROPs, wider availability of bits, etc.) and completing the wells with smaller casing (savings in casing costs). The relative percentage of slim completions of U.S. gas wells has increased significantly in recent years (Figure 11-6).

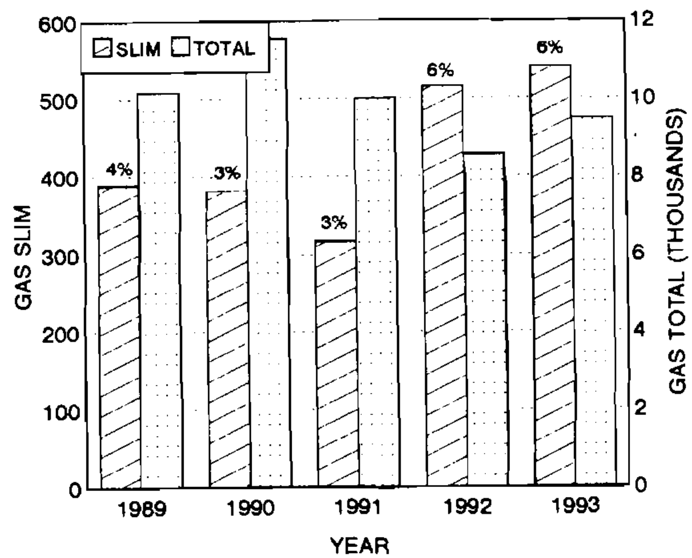

Figure 11-6. Recent Slim Gas Completions in U.S. (Shook and Brunsman, 1994)

Coring systems have been used effectively in remote locations outside the U.S., but are not expected to impact this industry significantly. Rotary and motor systems will be the avenues of slim-hole cost savings in U.S. fields. Barriers to the use of slim-hole drilling identified by a survey of U.S. operators are shown in Figure 11-7.

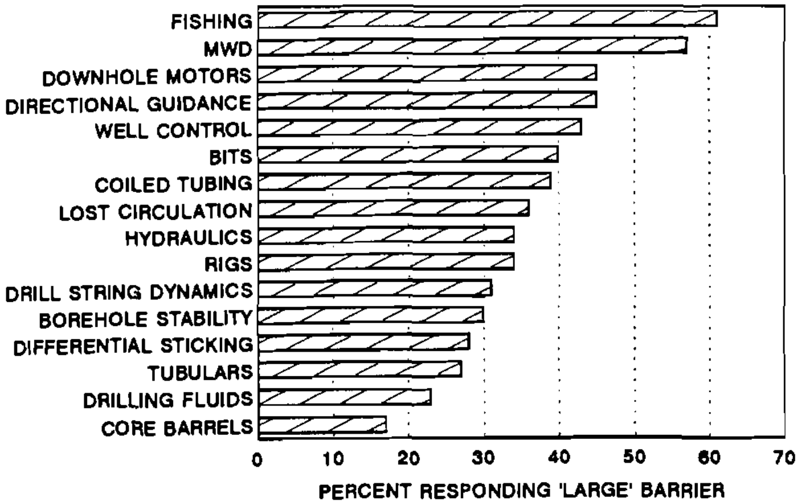

Figure 11-7. Barriers to Slim-Hole Drilling (Shook and Brunsman, 1994)

Fishing concerns was the barrier listed most often. Smaller drill-string components with thinner walls combine with smaller clearances to create increased difficulty for fishing attempts. Tight annuli may require the use of internal spear fishing tools (Figure 11-8), leading to increased tendency of splitting.

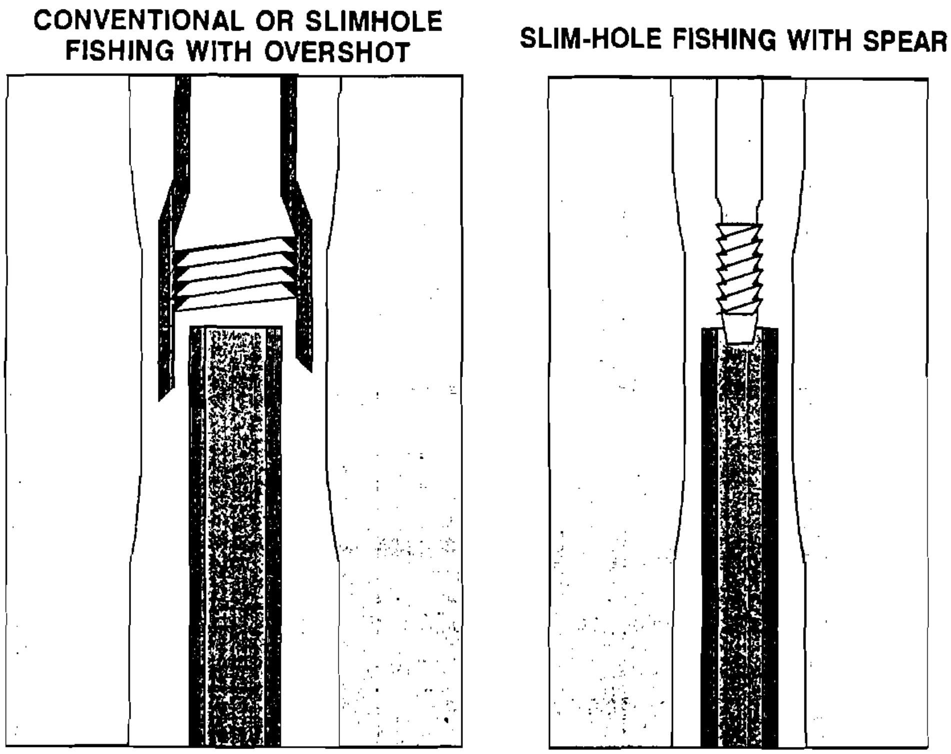

Figure 11-8. Slim-Hole Fishing (Shook and Brunsman, 1994)

One of the historic shortcomings of roller-cone bits, their poor performance in slim holes, has recently been reduced through the introduction of improved bearings in smaller bits. Fixed-bearing bits often perform well, but are limited in some applications by their narrow range of flexibility with respect to rock types and their limited performance history in smaller sizes.

Slimmer drill pipes are required in these holes. Weight and torque capacity diminish with smaller drill pipe (Table 11-1). High-strength materials and connections can be used to increase capacity; however, this approach erodes the accrued savings of using the technology.

TABLE 11-1. Properties of Grade E Drill Pipe (Shook and Brunsman, 1994)

O.D.(in.)	WT (lb/ft)	TENSILE YIELD (lb)	TORSIONAL YIELD (ft-lb)
4½	16.6	330,560	30,810
3½	13.3	271,570	18,550
2⅞	10.4	214,340	11,550
2⅜	6.6	138,220	6,250

Rotational forces can be reduced through the use of downhole motors. Fortunately, recent developments in seal and stator technology are reducing motor operating costs so that motors can compete with rotary drilling in many areas, e.g., the Denver Basin.

Annular clearances are a critical difference between slim holes and conventional systems. An important distinction should be made between coring and other slim-hole systems. Rotary or motor systems can have relative hole geometries much closer to conventional (Table 11-2).

TABLE 11-2. Annular Clearances (Shook and Brunsman, 1994)

WELL TYPE	HOLE SIZE (in.)	DRILL PIPE (in.)	RATIO	ANNULAR CLEARANCE (in.)
Conventional	7⅞	4½	0.57	1.69
Slim-Hole Drilling	4¾	2⅞	0.61	0.94
Continuous Coring	4 1/16	3.7	0.91	0.18

Drilling rig availability presents a significant barrier. Most conventional rigs have pipe-handling systems that are too large for slim drill pipe. Flow controls are often not precise enough for slim-hole operations and the pit-volume totalizer precision is too low. Using workover rigs requires renting a significant amount of additional equipment for continuous drilling operations. Once again, cost savings are consumed by this piecemeal approach.

The perceived need to avoid risk is one of the most significant overall barriers, according to the GRI study (Figure 11-9). Management attitude and workover problems (largely unquantified) are often used as a justification for continuing standard practices.

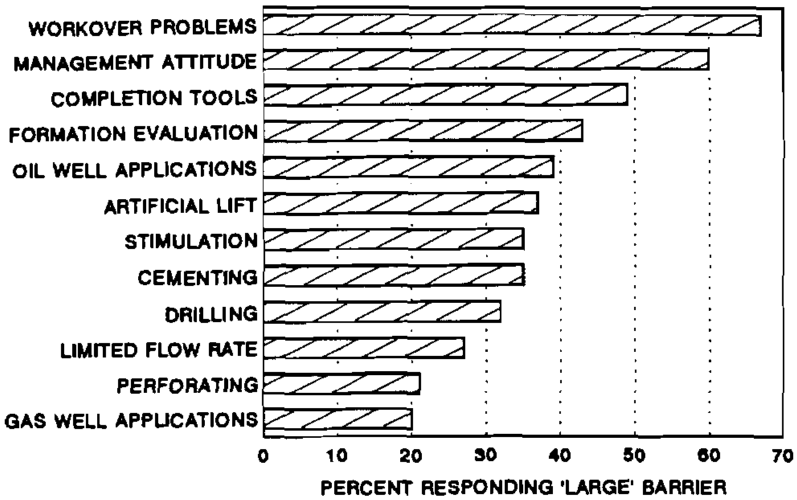

Figure 11-9. Overall Barriers to Slim-Hole Technology (Shook and Brunsman, 1994)

Maurer Engineering and the Gas Research Institute presented additional results of this industry survey. Detailed results for specific technical areas are presented in the Chapters *Cementing, Completions, Logging, Stimulation* and *Workovers*.

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12. Rotary Systems

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12. Rotary Systems

12.1 ELF AQUITAINE (FORASLIM RIG DESIGN)

Elf Aquitaine Production and Forasol S.A. (Sagot and Dupuis, 1994A) described the design and operation of a purpose-built slim-hole rig. The Foraslim drilling system (Figure 12-1) was a development of the Euroslim joint-industry project (members Forasol SA, DB Stratabit, Geoservices SA and Institut Français du Pétrole). Elf and other project members have performed field tests with the new rig (see next section). The new drilling system was constructed based on several cost-saving modifications. The number of personnel required at the site was reduced and operations were made more efficient.

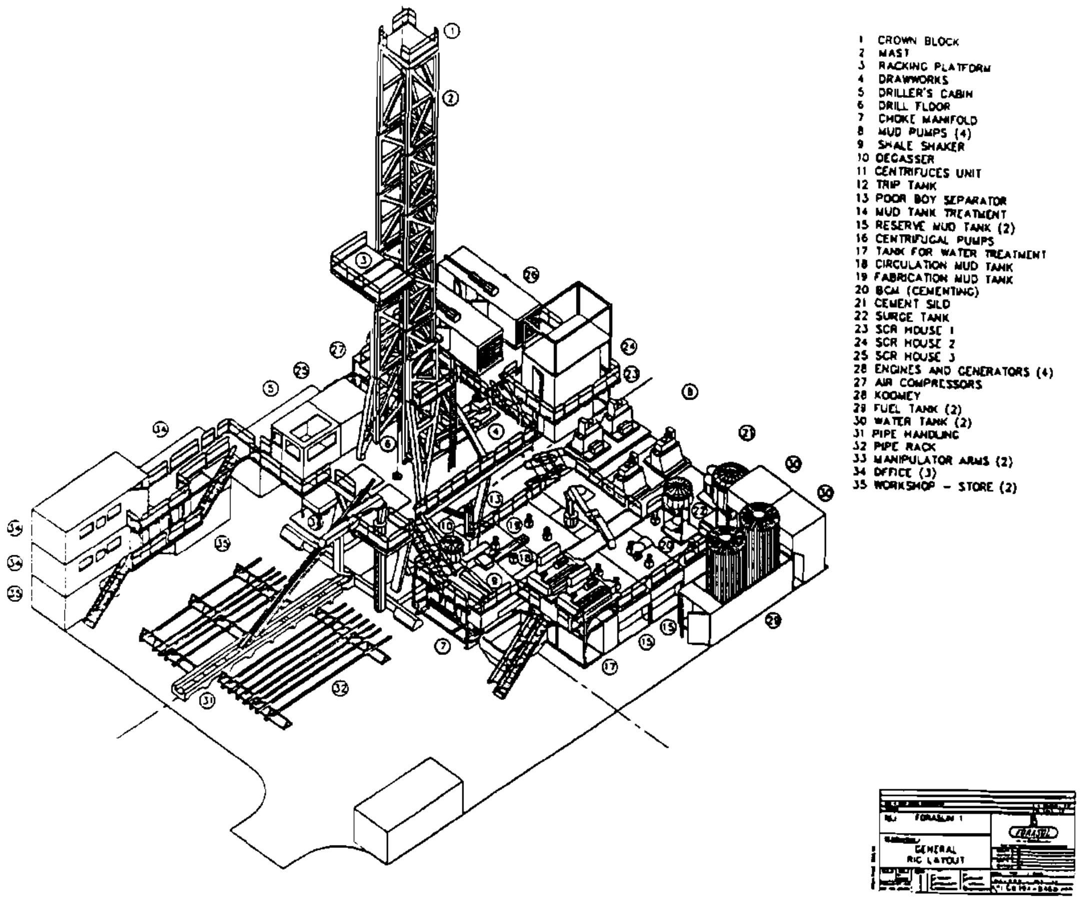


Figure 12-1. Foraslim Rotary Rig (Sagot and Dupuis, 1994A)

New slim-hole drill pipe (Table 12-1) was designed for rotary operations on the new rig. This was essential to meet project goals of economically drilling slim as well as larger holes with the system.

TABLE 12-1. Properties of Foraslim Drill String (Sagot and Dupuis, 1994B)

	SH111 System	SH66 System
Drill pipes		
Inner Diameter	74 mm (2,91")	48,1 mm (1,89")
Outer Diameter	89 mm (3,5 ")	57,1 mm (2,25 ")
Upset Diameter	105 mm (4,13 ")	66 mm (2,60 ")
Weight	15,6 daN/m (10,6 lbs/ft)	6,5 daN/m (4,5 lbs/ft)
Drill collars		
Inner Diameter	74 mm (2,91")	48,1 mm (1,89")
Outer Diameter	105 mm (4,13 ")	66 mm (2,60 ")
Weight	33,6 daN/m (22,9 lbs/ft)	12,8 daN/m (8,7 lbs/ft)
Mechanical properties		
Yield Point	139 T (310 000 lbs)	50 T (110 000 lbs)
Tensile Strength	152 T (340 000 lbs)	60 T (135 000 lbs)
Torsional Yield Point	4 300 mdaN (31 000 lbft)	600 mdaN (4 400 lbft)
Torsional Tensile Point	5 200 mdaN (38 000 lbft)	800 mdaN (5 900 lbft)
Core Diameter	74 mm (2,91")	36,4 mm (1 7/16")

A primary source of cost savings with this destructive drilling system results from the significant reduction in cuttings volumes with the slim bit program (Table 12-2).

TABLE 12-2. Reduction in Cuttings Volumes (Sagot and Dupuis, 1994A)

	Cuttings Volume (m^3)	
Drilling Phase	**Conventional**	**Foraslim**
0-1500 m	233	74
1500-2400 m	68	14
2400-3000 m	22	7
3000-3500 m	9	3
Total	333	97

Primary specifications for the new rotary rig included:

- Hoisting capacity of 100 tonnes (220,000 lbs)
- Rotary rates up to 600 rpm for slim-hole sections
- 600 HP drawworks
- Mud system capacity of 80 m^3 (500 bbl)
- Total installed power of 1200 HP

The drill pipe is rotated by an electric top drive. The required range of rotation is covered by using two gears, one for 0-270 rpm and one for 270-600 rpm.

For coring operations, an independent coring winch is provided with a depth capacity of 4000 m (13,100 ft). The Foraslim drill strings were designed to permit wireline-retrievable coring operations. The outer barrels and couplings are of heavier duty construction than mining coring barrels, and have the same ID and OD as the drill collars.

The mud storage system was designed to allow detection of an influx as small as 80 l (21 gal). Mud tanks were designed with a tapered profile (Figure 12-2) to permit high resolution in the slim hole sections. The pit-level indicator has a minimum resolution of 5 mm (0.2 in.).

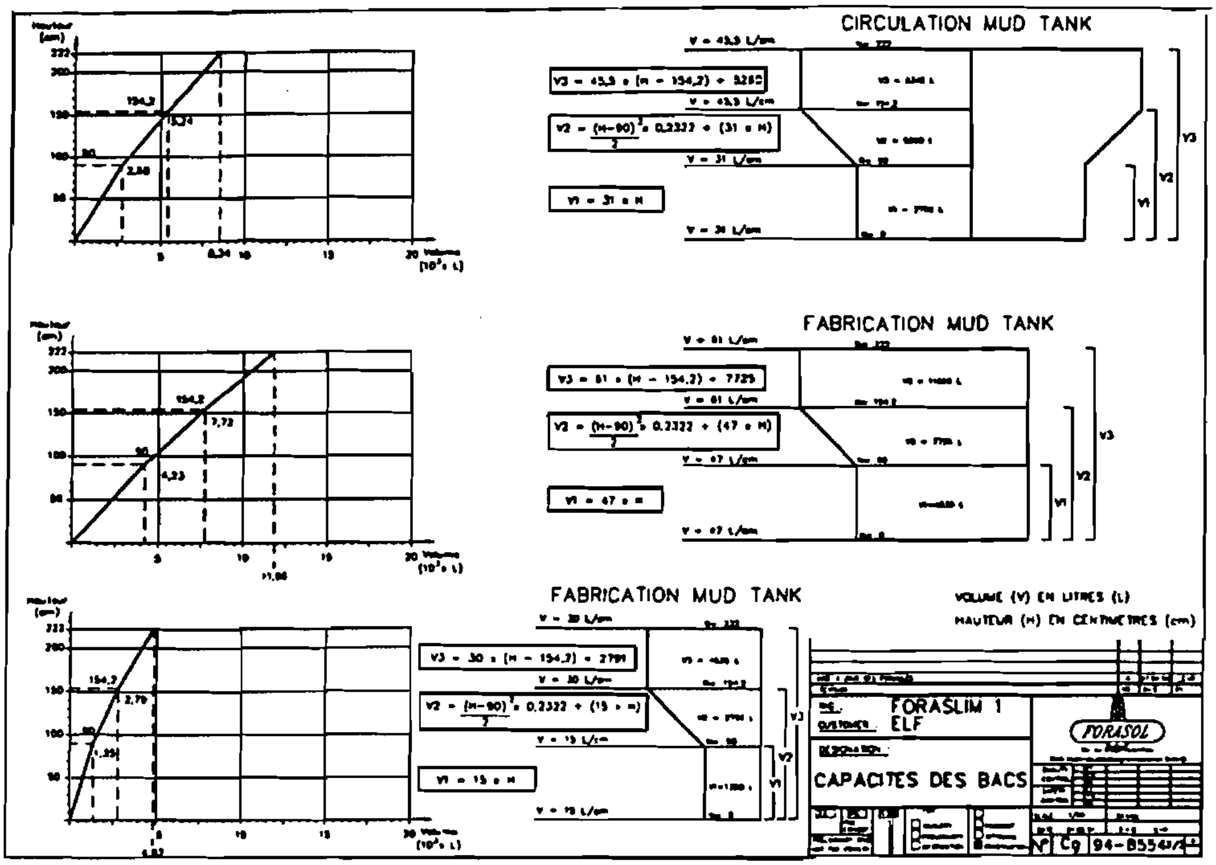


Figure 12-2. Foraslim Mud Tank Design (Sagot and Dupuis, 1994A)

The design of the circulating system allows drilling without a waste pit, other than a 40 m^3 pit to collect drainage around the rig. Two centrifuges are used with a coagulation unit and a flocculation unit (Figure 12-3).

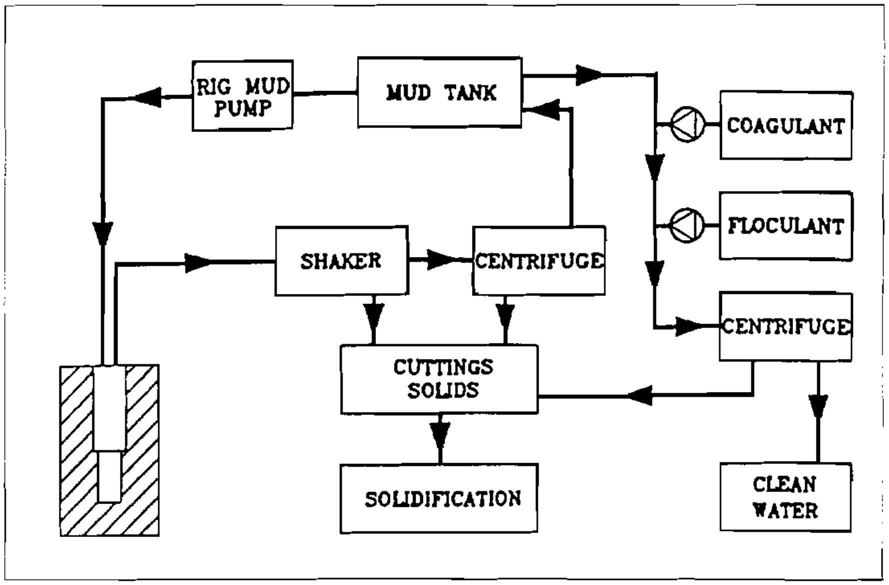


Figure 12-3. Foraslim Mud Treatment (Sagot and Dupuis, 1994A)

Electromagnetic flow meters are installed on the rig. Data signals are transmitted to several monitoring/control locations around the rig (Figure 12-4).

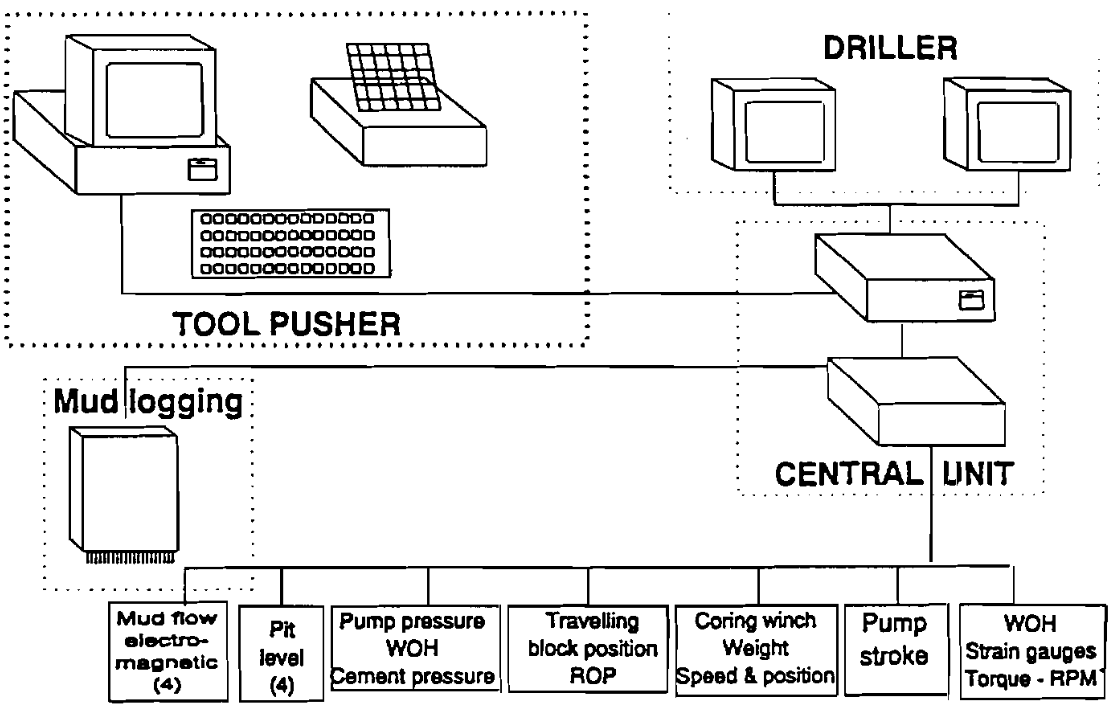


Figure 12-4. Foraslim Data Acquisition and Transmission (Sagot and Dupuis, 1994A)

An SCR system is used to precisely control the DC drive motors. SCR-based control was chosen over hydraulic control due to higher precision, accuracy and reliability. Reliability becomes an especially important concern in remote areas.

Rig erection is accomplished without requiring space to assemble the mast horizontally, as is conventionally required. Rig-up is accomplished at truck-bed height (Figure 12-5).

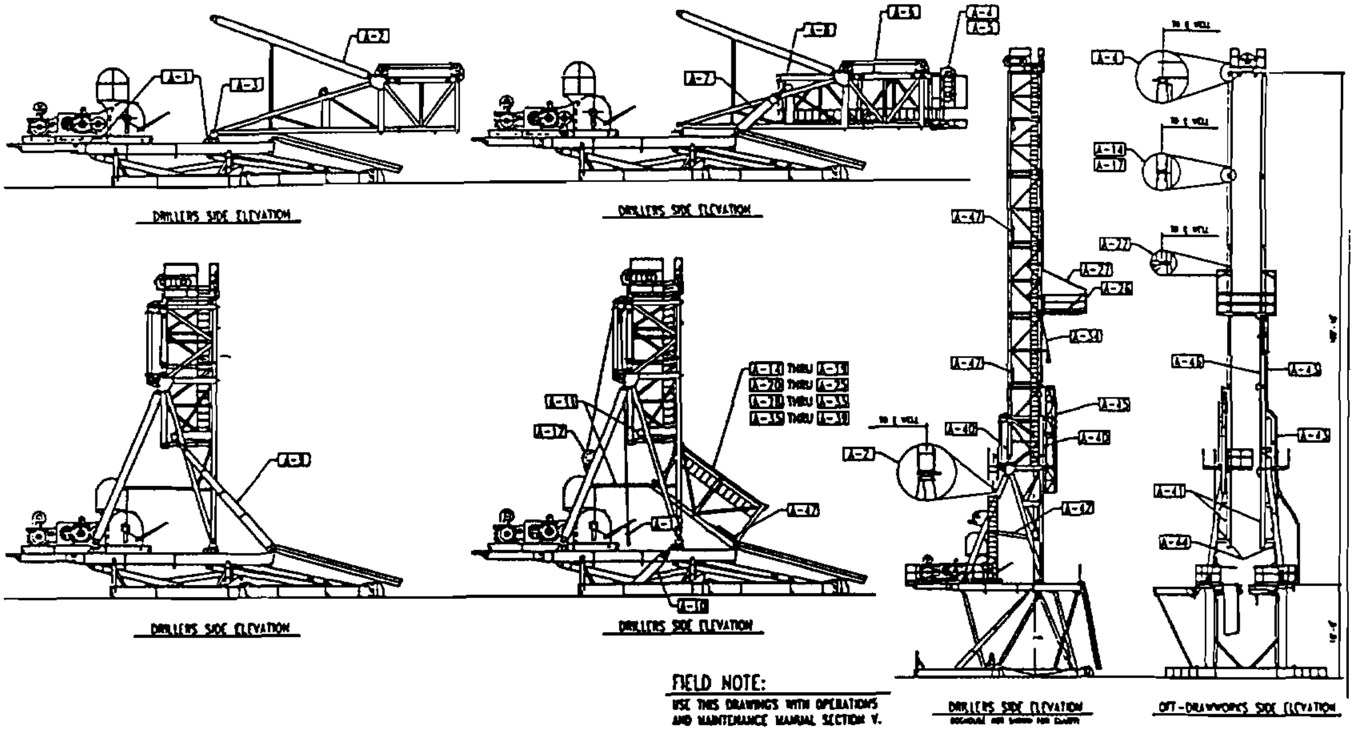


Figure 12-5. Rig Erection Sequence (Sagot and Dupuis, 1994A)

The rig layout has been optimized (Figure 12-1) to allow operation with fewer personnel. Robotic tools are used for automating pipe handling and increased safety. Only one floor hand is needed during drilling operations.

12.2 ELF AQUITAINE (PARIS BASIN FIELD TESTS)

Elf Aquitaine Production and Forasol S.A. (Sagot and Dupuis, 1994B) drilled two ultraslim-hole wells in the Paris Basin. These wells, one 3-in. and one 3⅜-in. bottom section, were drilled to test the Foraslim rotary slim-hole drilling system in performing destructive drilling, wireline coring, drill-stem testing, and logging. The Foraslim system was a development of Euroslim joint-industry project, which is discussed in greater detail in the previous section of this chapter. The field tests were successful and showed the system to be a cost-effective technique that provides the geologist with all data required for formation evaluation.

The design of this rotary system is based on the observation that destructive drilling is more efficient than coring. Additionally, in many instances, continuous core from surface to TD is not needed. Field tests with the new rig were designed to verify that a long section (>3000 ft) of ultraslim hole could be drilled.

The two wells were drilled into the same geologic profile, with surface locations about 50 m (164 ft) apart. No productive formations were in the area, although the geology was well known.

The primary objectives of the first well were to drill a long section of 4¾-in. hole with the SH 111 drill string (see Table 12-1), and then a 3-in. hole to TD with the SH 66 drill string. These special drill strings are central to the design and function of the Euroslim system.

The primary objective of the second well was to drill a long section of 3⅞-in. hole with the SH 66 drill string. Both new drill strings were based on oil-field standards. Improvements included the ability to wireline core as much as 50% of the hole diameter, high torque capacity, high fatigue resistance, and external-upset tool joints with a double shoulder and stress-relief groove.

On Elf's first well, the LTR1, the SH 111 drill string was used in the 4¾-in. section and run without stabilizers from 730 to 1910 m (2400 to 6270 ft). The system remained relatively stable due to the small annulus at the drill collars (4⅛-in. drill collar in 4¾-in. hole) and the high rotary speeds used (300-350 rpm).

A fishing incident occurred in the 3-in. bottom section. While tripping the drill string out, over 500 m of pipe were dropped in the hole. The pipe was successfully recovered by screwing back in to the string. Elf noted that the new threads facilitated this successful recovery.

Next, five cores were cut along a 25-m section. The inner core barrel was run in on wireline for cores 1-4. For core 5, the inner barrel was pumped down. Elf found the pump-down technique preferable.

The time/depth curve for the second well, the LTR2, is shown in Figure 12-6. This well was drilled faster than the first well. A problem occurred with junk in the hole (bit cones) in the 6-in. section. A magnet and recirculating basket were run; however, recovery was not successful. The hole was then successfully sidetracked with a flexible BHA, completed with casing and cemented.

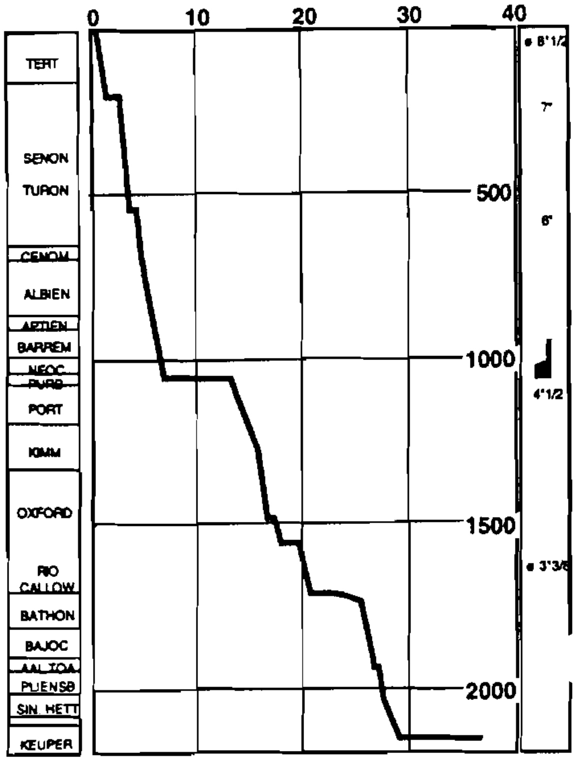


Figure 12-6. Time/Depth Curve for LTR2 (Sagot and Dupuis, 1994B)

A 3⅜-in. section was drilled from 1060 to 2160 m (3478 to 7087 ft). Bit performance was much better than on the first well. Elf believes that further optimization is possible. An electromagnetic MWD sub was run in this section to monitor annulus pressure. Details of the use of this tool are presented in the Chapter *Logging*.

Hydraulics and drilling fluid behavior were investigated during these operations. A new mud with PHPA was used in the slimmest sections. Higher mud weight and better control of rheology allowed operations to proceed without major problems on the second well.

With the Foraslim drill-string geometry, up to 60% of the system pressure losses occur in the annulus. Pressure losses were investigated at a range of flow rates and rotary speeds. Sensitivity to flow rate is shown in Figure 12-7.

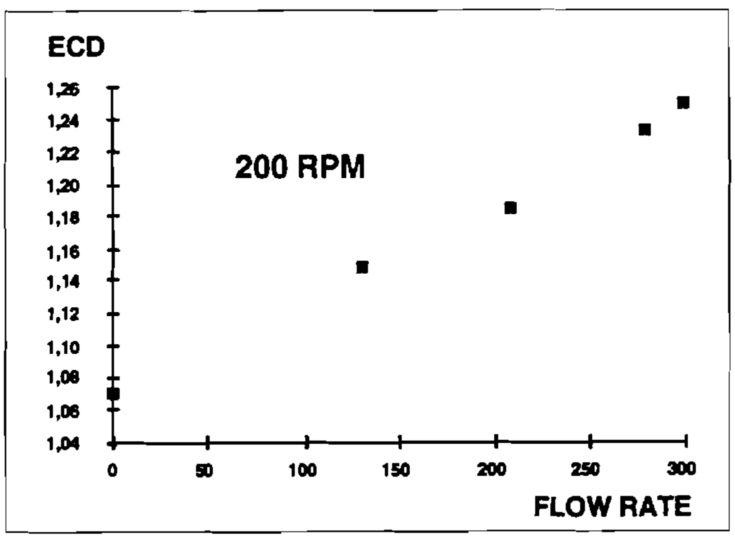


Figure 12-7. ECD at Various Flow Rates (Sagot and Dupuis, 1994B)

Well-control issues were investigated. The project team decided that the same relative kick-detection threshold used for conventional operations would be appropriate in Foraslim operations. A 1000-l (6.3 bbl) influx in 8½-in. conventional corresponds to about 162 l (1.0 bbl) in the 3⅜-in. ultraslim hole. This detection threshold was feasible. Foraslim kick detection is described in greater detail in the Chapter *Well Control*.

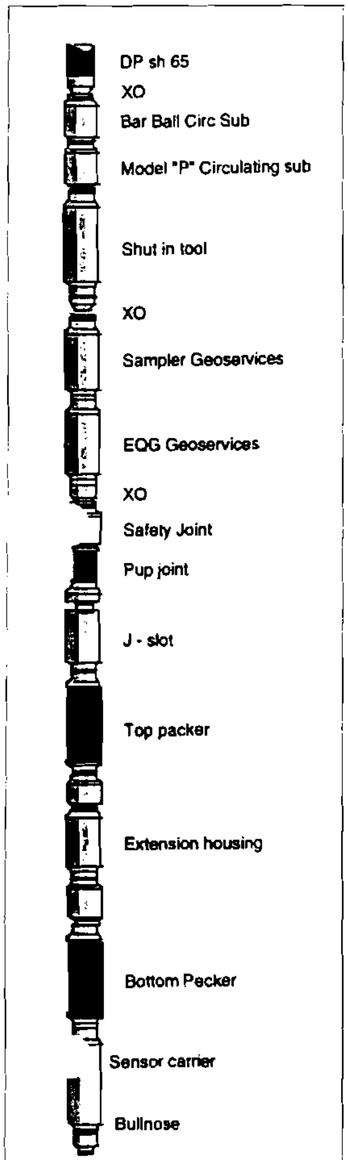


Figure 12-8. BHA for Drill-Stem Test (Sagot and Dupuis, 1994B)

A drill-stem test was performed with a straddle-packer assembly (Figure 12-8). Drilling fluid was reverse circulated through the drill string. A circulating valve and nitrogen were used. The drill-stem test was successful in the small hole and was completed without incident.

Drilling costs were reduced 15-20% for these Paris Basin wells. In the next planned project (three wells in Gabon), reduced road and logistics costs are expected to allow savings of 35-40%.

As a result of these field tests, Elf and Forasol concluded that no major barriers exist for ultraslim holes with small annuli. Slim-hole ROP was similar to conventional rates and, after continued optimization, may surpass conventional rates. They also concluded that a dedicated slim-hole rig is a necessity, along with specialized sensors, mud tanks and pumps.

12.3 FORASOL/FORAMER (EUROSLIM ROTARY SYSTEM)

Forasol/Foramer and DB Stratabit (Dupuis and Fanuel, 1993) reported some early results of the development of a new slim-hole rig for the Euroslim joint-industry project. A primary objective of the project was to design a system that would drill slim holes at conventional penetration rates. Small holes drilled with conventional equipment often resulted in significantly reduced ROPs. Devising a solution to this problem was considered as essential to obtain the full benefits of slim-hole technology.

Industry's experiences showed that drilling small holes was best suited to PDC bits, as a consequence of the short life of slim tricone bits. Euroslim's review of drill-string designs showed that no existing string had sufficient torque capacity to achieve conventional ROPs. The target depth capacity for the project was set at 3500 m (11,500 ft) for 4¾-in. hole.

Euroslim analyzed the use of motors for slim-hole drilling, paying special attention to the Shell/INTEQ system (see Chapter *Motor Systems*). Shell's system uses a mud motor along with a thruster to control WOB and to vibration-isolate the BHA from the drill string. Euroslim's economic analyses of this approach showed that the cost of maintaining the sophisticated BHA detracts from cost savings, and that a motor system is best suited for deeper applications.

A new rig was designed for Euroslim based on rotary technology. One drill string was designed for 8½- to 4¾-in. holes; another string was designed for 4- to 3-in. holes. These strings were designed to transmit enough torque to power PDC bits at conventional ROPs. Rotary speeds were originally limited to a maximum of about 300 rpm to avoid problems with centrifuging drilling fluid inside the drill string.

Bit power requirements (Figure 12-9) were based on a nominal value of 1.5 hp/cm^2 (9.6 hp/in^2).

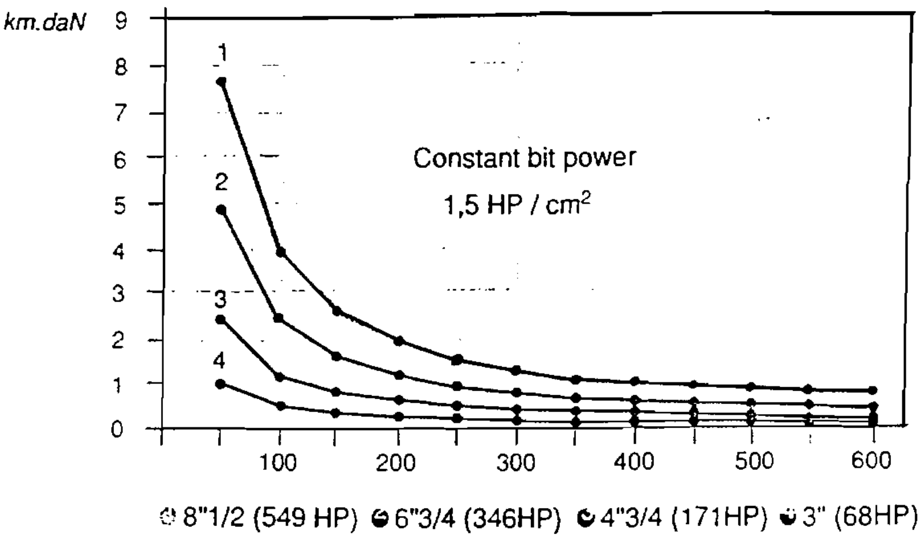


Figure 12-9. Torque and RPM for Drill Strings (Dupuis and Fanuel, 1993)

Tool joints were external upset and friction welded on a flush body (Figure 12-10). Low conicity of the threads (about 1°) is used to optimize the strength of the joint.

Euroslim drill collars are flush both internally and externally, with strength similar to the drill pipe. Core barrels are modular and of the same dimensions as the collars (see Chapter *Coring Systems*).

Maximum drilling depth depends on drill-string size (Figure 12-11). The SH 111 3½-in. drill string has a tension capacity of 110 tonnes (243 kips).

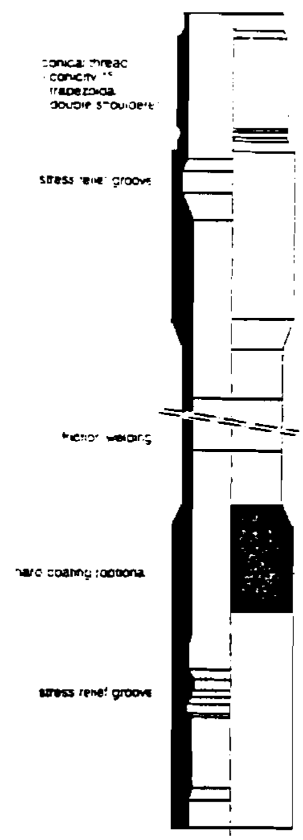


Figure 12-10. Euroslim Tool-Joint Design (Dupuis and Fanuel, 1993)

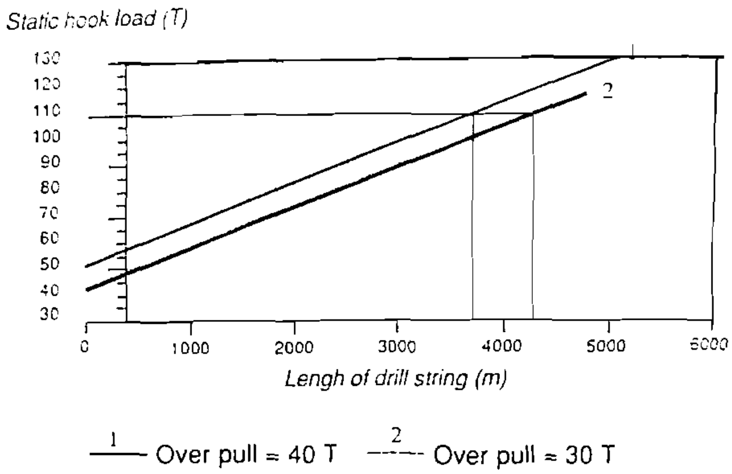


Figure 12-11. Depth Capacity of SH 111 Drill String (Dupuis and Fanuel, 1993)

Maximum casing depth for the Euroslim rig is shown in Figure 12-12. Depth rating of the rig can be increased if necessary through the use of lighter casing and drill pipe.

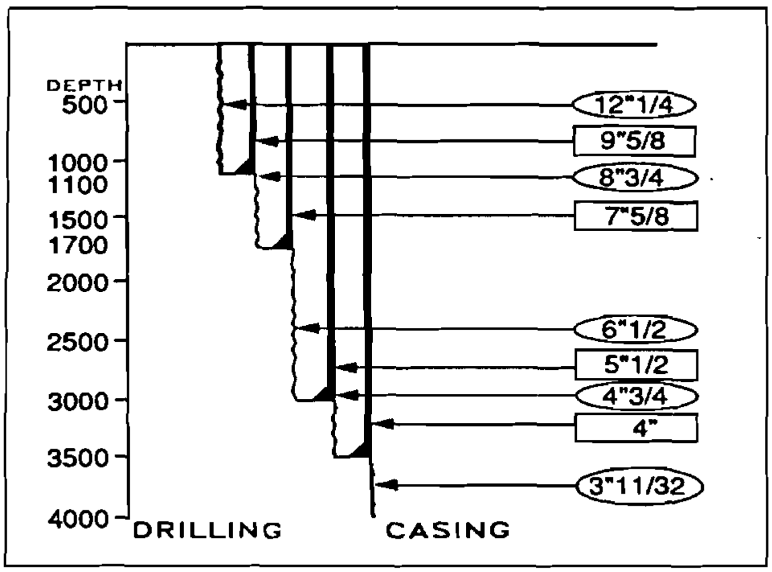


Figure 12-12. Maximum Casing Set Depth (Dupuis and Fanuel, 1993)

The circulating system is based on two 400-hp mud pumps, a high-efficiency shale shaker and centrifuges. Mud-tank volume varies according to the drilling program (Figure 12-12).

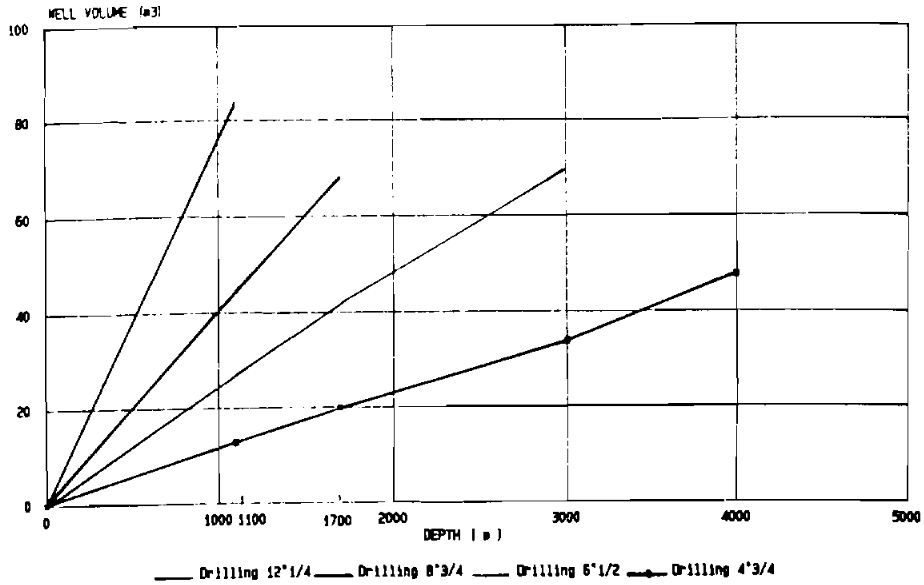


Figure 12-13. Mud-Tank Volumes (Dupuis and Fanuel, 1993)

As is true for all slim-hole drilling systems, the control of WOB is critical for maximizing ROP and bit life. The drawworks are designed to allow WOB control with an accuracy of 200-300 daN (450-675 lb).

Cost savings with the Euroslim rig come from several areas:

- Less civil engineering at drilling site (reduced from 6000 m^2 down to 1000 m^2)
- Capacity of access roads reduced from 45-ton loads to 10-ton loads
- Reduction in consumables
- Drilling contractor rate reduction due to fewer personnel and lower equipment capital expenses

Typical cost savings with the Euroslim system are shown in Table 12-3. These data are based on early results. It is predicted that total cost savings of about 30% in developed areas and of 50% in remote areas will be expected with the system.

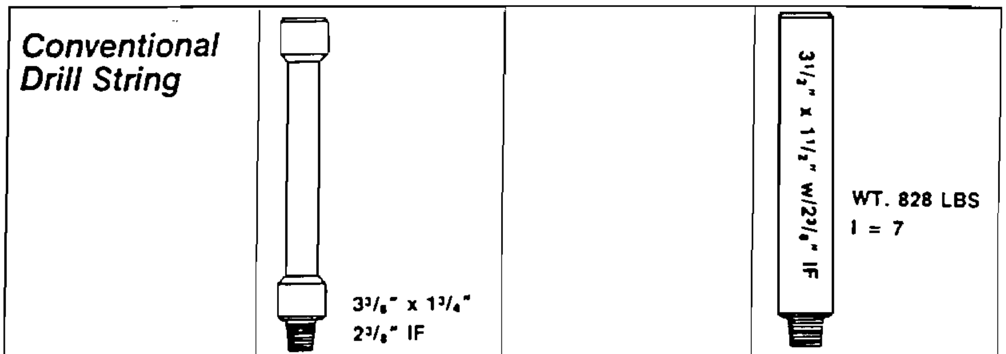
TABLE 12-3. Euroslim Cost Savings (Dupuis and Fanuel, 1993)

ITEM	URBAN AREA			REMOTE AREA		
	Reduction Slim/Conv.(%)	Total Cost Conv. (%)	Reduction Contribution(%)	Reduction Slim/Conv.(%)	Total Cost Conv. (%)	Reduction Contribution (%)
Moving	60	15	9	60	25	15
Roads	-	-	-	-	-	-
Location	60	16	10	65	40	26
Rig & Services	15	49	7	15	15	2
Consumables	50	18	9	50	10	5
Logistics	40	2		40	10	4
		100	35		100	52

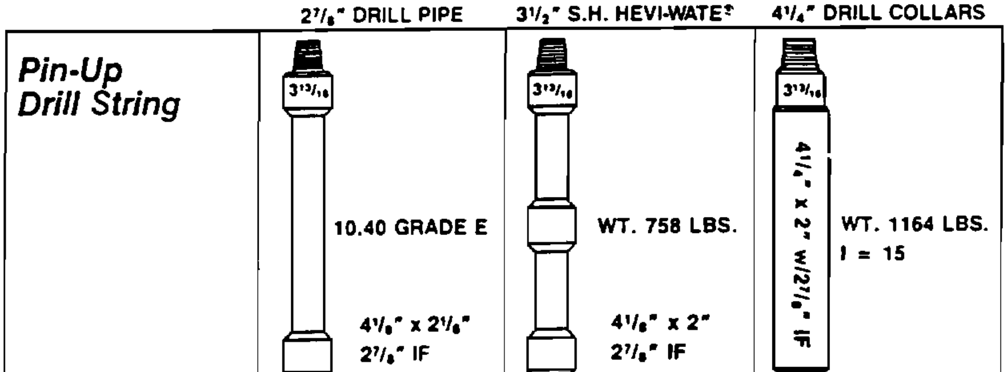
12.4 PINTEC DRILLING SERVICES (PIN-UP DRILL STRINGS)

PinTec Drilling Services (Dudman, 1994) described the advantages of pin-up drill strings for slim-hole rotary drilling applications. The use of pin-up drill-string components allows the use of tubulars one size larger than with box-up design. Stronger drill pipe and collars and improved hydraulics through larger IDs will, in most applications, result in faster penetration rates and fewer doglegs, keyseats and other problems. A principal advantage of pin-up strings is that, compared to a one-size-larger box-up pipe, pin-up pipe retains fishability without the need to cut a fishing neck and weaken the connection. Thus, larger, stronger pin-up components can be run without losing the ability to fish.

A comparison of two drill strings for drilling 4⅝- to 4¾-in. holes is shown in Figure 12-13. A pin-up 2⅞-in. drill-string connection has 60% more torsional strength and 43% more tensile capacity than a box-up 2⅜-in. connection.



Conventional Drill String	2 3/8" DRILL PIPE		3 1/2" DRILL COLLARS
BSR			2.42:1
Torsional Yield	6478 Ft-Lbs		8121 Ft-Lbs
Tensile Yield	313,681 Lbs		357,739 Lbs
Rec. Make-Up	3239 Ft-Lbs		4600 Ft-Lbs
Bore	1.815 In.		1.50 In.



Pin-Up Drill String	2 7/8" DRILL PIPE	3 1/2" S.H. HEVI-WATE	4 1/4" DRILL COLLARS
BSR		2.44:1	2.75:1
Torsional Yield	11,869 Ft-Lbs (+ 83%)	11,883 Ft-Lbs	11,883 Ft-Lbs (+ 46%)
Tensile Yield	447,130 lbs (+ 42%)	454,419 Lbs	454,419 Lbs (+ 27%)
Rec. Make-Up	5935 Ft-Lbs	6045 Ft-Lbs	6045 Ft-Lbs
Bore	2.151 In.	2.0 In.	2.0 In.

Figure 12-14. Strength of Box-Up and Pin-Up Drill Strings (Dudman, 1994)

Drill-string hydraulics for these two options are compared in Table 12-4. Greater flow rates and horsepower at the bit are available with the pin-up strings.

TABLE 12-4. Hydraulics of Box-Up and Pin-Up Drill Strings (Dudman, 1994)

Depth: 12,000 ft.	Mud Wt: 15.0 lb/gal.	Max. Rig: 3000 psi
Hole Size: $4^{7}/_{8}$ in.	Viscosity: 33 cp	

	CONVENTIONAL	PIN-UP	PIN-UP
1. B.H.A. BORE (psi)	$2^{3}/_{8}$" IF	$2^{7}/_{8}$" IF	$3^{1}/_{2}$" SH
Surface Equip. #4	2	3	5
Drill Pipe No. 1	2238	1859	825
Bit Throat Loss	10	21	33
TOTAL BORE HOLE PRESSURE	2250	1883	863
2. B.H.A. ANNULAR (psi)	$2^{3}/_{8}$" IF	$2^{7}/_{8}$" IF	$3^{1}/_{2}$" SH
Drill Pipe	634	912	1855
3. BIT PRESSURE	94	191	293
4. TOTAL ON BOTTOM DRILLING (psi)	2978	2986	3011
5. BIT PERFORMANCE			
Flow Rate (gpm)	73	104	129
HP/in²	0.2	0.7	1.2
6. DRILL STRING DATA	$2^{3}/_{8}$" IF	$2^{7}/_{8}$" IF	$3^{1}/_{2}$" SF
Torsional Yield (Tube/Tool Joint)	6250/6478 Ft/Lbs	11554/11869 Ft/Lbs	18551/11869 Ft/Lbs
Tensile Yield (Tube/Tool Joint)	138214/313681 Lbs	214344/447130 Lbs	271569/447130 Lbs
Bore (in.)	1.815	2.151	2.764
7. COMPARATIVE STRENGTHS (%)	$2^{3}/_{8}$" IF	$2^{7}/_{8}$" IF	$3^{1}/_{2}$" IF
Torsional Yield (Tube/Tool Joint)		+85/+83	+196/+83
Tensile Yield (Tube/Tool Joint)		+55/+43	+96/+43
8. WELL DATA	O.D. (in.)	I.D. (in.)	LG (ft.)
Casing	5.5	4.77	11000
Open Hole		4.75	1000

12.5 REFERENCES

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13. Stimulation

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13. Stimulation

13.1 GAS RESEARCH INSTITUTE (FRACTURING CONCERNS IN SLIM HOLES)

The Gas Research Institute, BJ Services and Maurer Engineering (Brunsman et al., 1994B) summarized the results of a project to analyze the barriers hindering widespread application of slim-hole drilling and completion technology, with special regard for gas wells in the U.S. There appears to be significant opportunity for slim-hole technology in the U.S. gas industry since typical wells require neither high-volume artificial-lift equipment nor large-diameter production tubing to avoid restricting flow rates. The GRI study found that real and perceived limitations of slim-hole drilling exist, hindering the industry from embracing the technology and reaping the full benefits.

In Brunsman et al. (1994B) the project team discussed special concerns for stimulating slim wells. Emphasis was placed on hydraulic fracturing operations. Fracturing operations in slim tubulars differ from conventional procedures in two important aspects: smaller tubulars cause increased pressure drops, and perforation options are reduced (Figure 13-1). The choice of perforating guns is restricted to smaller tools ($1^{11}/_{16}$ to 3⅛ in.) resulting in smaller perforation diameter, reduced penetration depth, and fewer options for phasing and shot density.

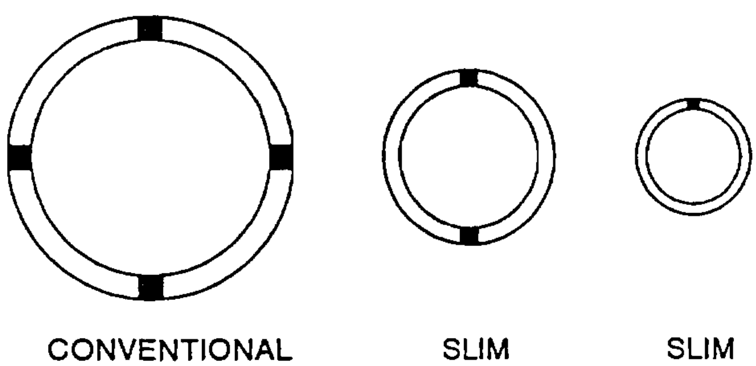

Figure 13-1. Reduced Perforation Options in Slim Casing (Brunsman et al., 1994B)

Frictional pressure drops during fracturing can be substantial in 2⅞-in. tubing. Data are shown in Figure 13-2 for several work fluids. Delayed cross-linked fluids have the lowest pressure drop, and are much improved as compared to nondelayed fluids.

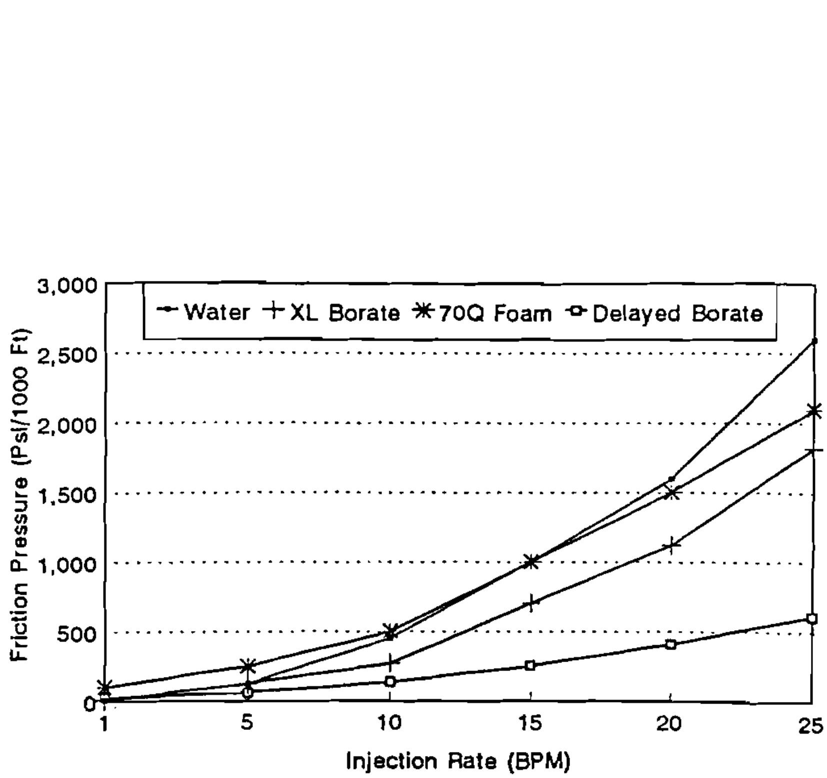

Figure 13-2. Pressure Drops with Frac Fluids in 2⅞-in. Tubing (Brunsman et al., 1994B)

Pressure drops with delayed borate fracturing fluid are shown in Figure 13-3 for several casing sizes. New technologies are needed to decrease friction and pumping requirements, especially for nitrogen and CO_2 fluids.

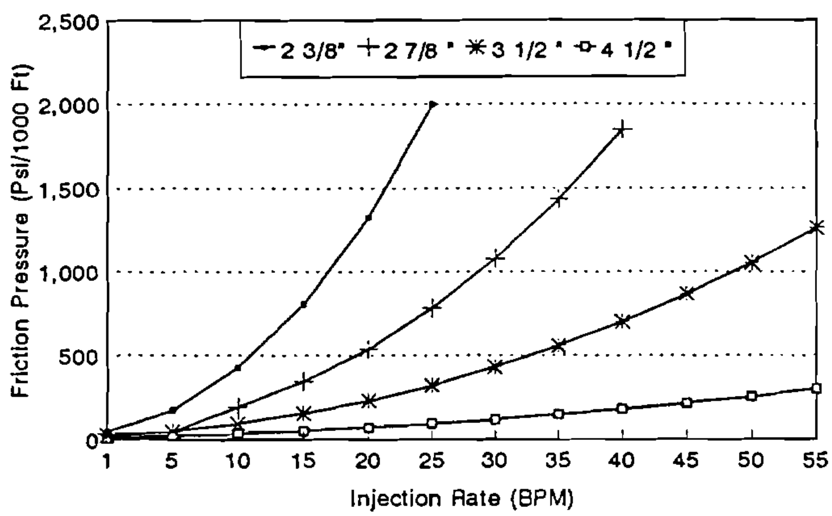

Figure 13-3. Pressure Drops with Delayed Borate Fluid (Brunsman et al., 1994B)

Perforation hole diameter has a significant impact on friction pressure (Figure 13-4). Slim perforation guns are typically designed to produce ¼- to ⅜-in. holes. Injection rates for slim-hole fracture jobs are normally limited so that the total friction losses can be maintained within acceptable ranges.

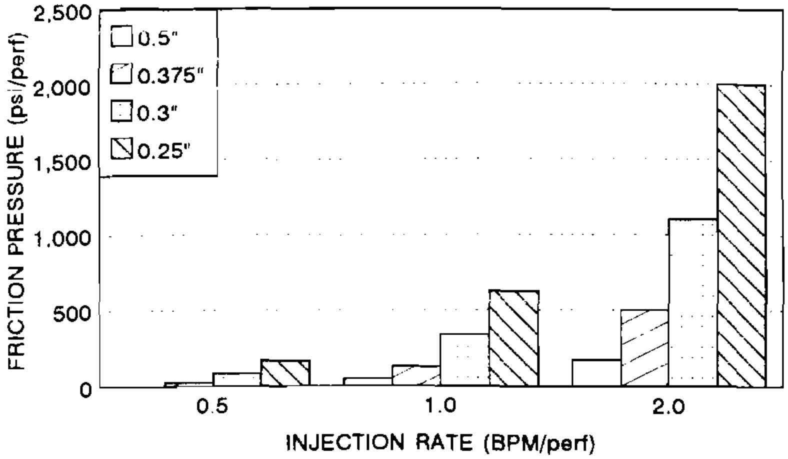

Figure 13-4. Pressure Drop per Perforation (Brunsman et al., 1994B)

Shear rates and stresses are increased due to smaller tubulars and perforations. Viscosity of a non-Newtonian fluid is a function of shear stress. Shear rates increase in smaller tubing (Figure 13-5). Delayed cross-linked fluids have greatly reduced concerns about shear degradation as compared to conventional fluids.

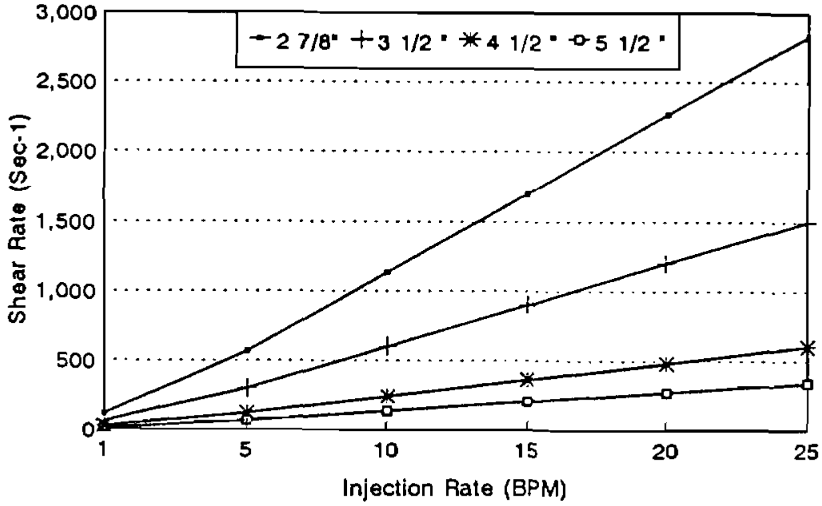

Figure 13-5. Shear Rates with Delayed Borate Fluid (Brunsman et al., 1994B)

Shear rates through small perforations increase rapidly as injection rates are increased (Figure 13-6). This effect is indicated by Brunsman et al. as the most critical concern with fracturing in slim completions. Fluid damage is expected through small perforations. Mature cross-linked fluids may be completely destroyed.

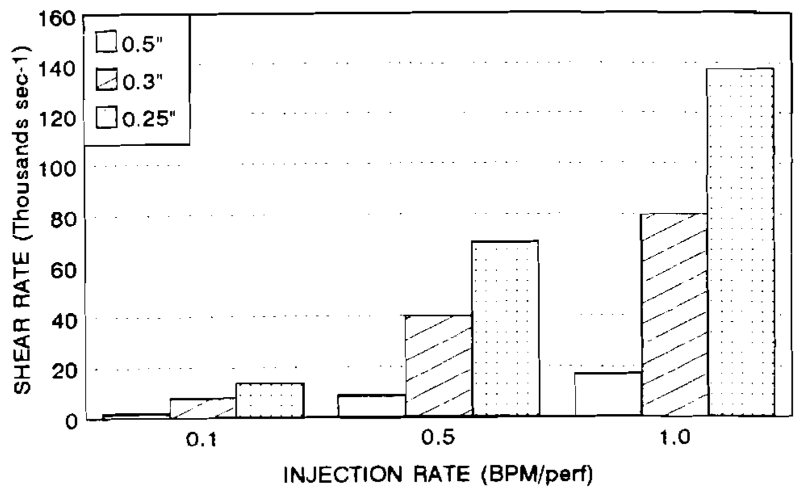

Figure 13-6. Shear Rates Through Perforations (Brunsman et al., 1994B)

Another issue of concern is proppant bridging the perforations. Proppant size is chosen based on several operational constraints. Guidelines for minimum ratios of perforation diameter to proppant diameter range from about 2 to 6, and are strongly impacted by proppant concentration (lb/gal). Table 13-1 shows that larger proppant meshes will approach this limit in smaller perforations.

TABLE 13-1. Perforation to Proppant Diameter Ratios (Brunsman et al., 1994B)

	Perforation Diameter (in.)			
Proppant Mesh	**0.50**	**0.38**	**0.30**	**0.25**
20/40	15	11	9	7
16/30	11	8	6	5
12/20	7	6	5	4

After their analyses, Brunsman et al. concluded that significant concerns exist for slim-hole fracturing design and implementation. Additional research needs to be conducted to speed the application of fracturing in slim holes. Perforation gun performance needs to be improved in smaller sizes. Proppant bridging needs to be investigated in slim holes, including deviated wellbores. Advanced diversion techniques are needed to address problems with ball sealers in small casing, as well as other concerns. Slim-hole fracturing technology transfer is also an important need of the industry.

13.2 REFERENCES

Brunsman, Barry J., Matson, Ron, and Shook, R. Allen, 1994B: "Slim Completions Offer Limited Stimulation Variances," *Petroleum Engineer International*, December.

14. Well Control

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14. Well Control

14.1 BP EXPLORATION (EKD SYSTEM)

BP Exploration and BP Research (Swanson et al., 1993) described the development of their Early Kick Detection (EKD) system based on analysis of data obtained in real time from a variety of sensors on the rig. The use of the EKD in conjunction with a slim-hole drilling operation has been shown to provide a basis for diagnosing abnormal drilling events, including gas kicks, mud losses and pipe washouts.

The special concerns for well control in slim holes are centered around the impacts of a small annulus. Kicks must be identified that are considerably smaller than those identified by conventional technology. For example, conventional kick-detection sensitivity required for safe operations may range from a 10- to 25-bbl increase in pit volume. For many slim-hole applications, a detection threshold as small as 1 bbl is required.

Rotation of the drill string often has a significant impact on pressures (and flow rates) throughout the well. Kick events must be differentiated from normal background noise in the flow. Another concern is connection gas and kelly cut, which will produce short-lived changes in flow out. These events must be differentiated from true kick events.

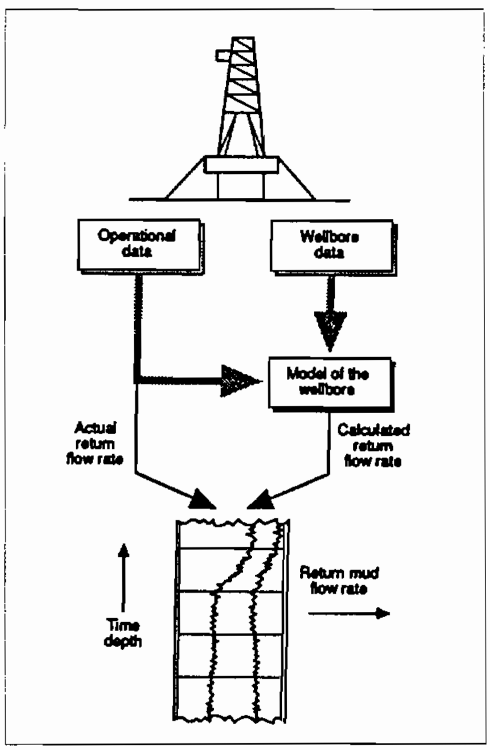


Figure 14-1. Operation of EKD System (Swanson et al., 1993)

An operational schematic of BP's EKD is shown in Figure 14-1. The basic strategy of the system is to compare events measured on the rig with results from a computer model driven by input data from the rig. Flow rates out of the well and standpipe pressures are the primary parameters used to identify a kick.

About 100 pieces of data from the rig are needed for the model. Critical sensors for kick detection include stroke counters on the mud pump(s), inflow for each pump, high and low standpipe pressure, casing pressure, bell-nipple pressure, flow out, mud density out, mud levels in each tank, depths, and drill-string velocity. About 30 subroutines are used in the well simulation.

The hydraulics models in the EKD are modified to account for pipe rotation and eccentricity. Model predictions for a 1000-m (3300-ft) well with 3.65-in. drill pipe in 4.8-in.

hole (0.58-in. annulus) illustrate the impacts of flow rate and rotation (Figure 14-2). Note that at low flow rates, increasing rotation has little effect.

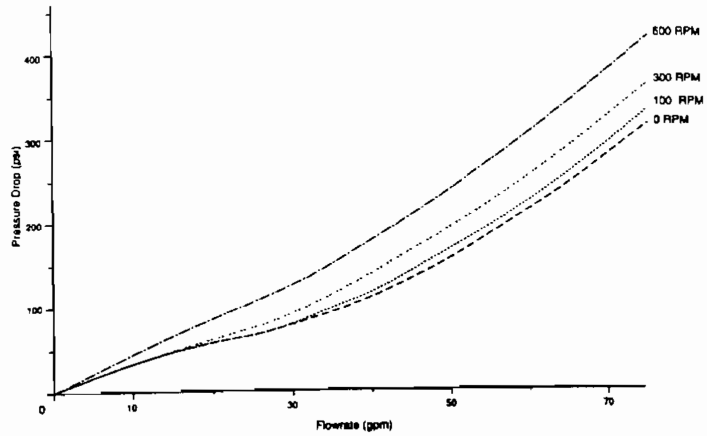


Figure 14-2. Predicted Impact of Pipe Rotation (Swanson et al., 1993)

The EKD system runs under the UNIX operating system and is interfaced with BP's DrillByte database (Figure 14-3).

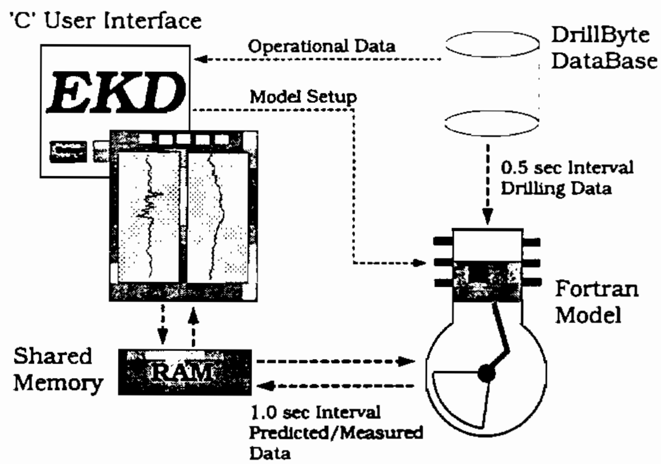


Figure 14-3. Schematic of EKD System (Swanson et al., 1993)

BP tested the EKD in a four-well project. Two events occurred during the project that showed the EKD to be an effective warning system. A small gas influx and a lost-circulation zone were both quickly detected and dealt with before they caused significant problems.

Monitoring the hole during connections is one of the important functions of the EKD. Bottom-hole ECD decreases when circulation is stopped, leading to an increased risk of kicks. Typical system response during a connection (Figure 14-4) shows small fluctuations in flow rate before and after the connection. These short-lived flow changes are not sufficient to trigger an alarm in the EKD system.

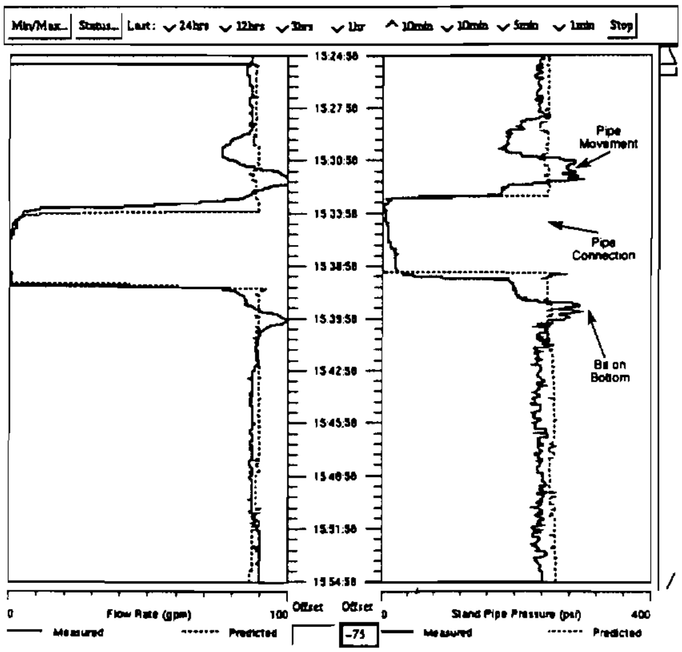


Figure 14-4. EKD Response During a Connection (Swanson et al., 1993)

A kick was simulated in a test well by injecting gas at TD. EKD response is shown in Figure 14-5. Gas injection was initiated at 15:38. A divergence between measured and predicted flow and standpipe pressure is soon evident. The difference between the model and actual events increases as the bubble rises. For this typical example, the driller could readily identify the kick within 1-2 minutes of its onset.

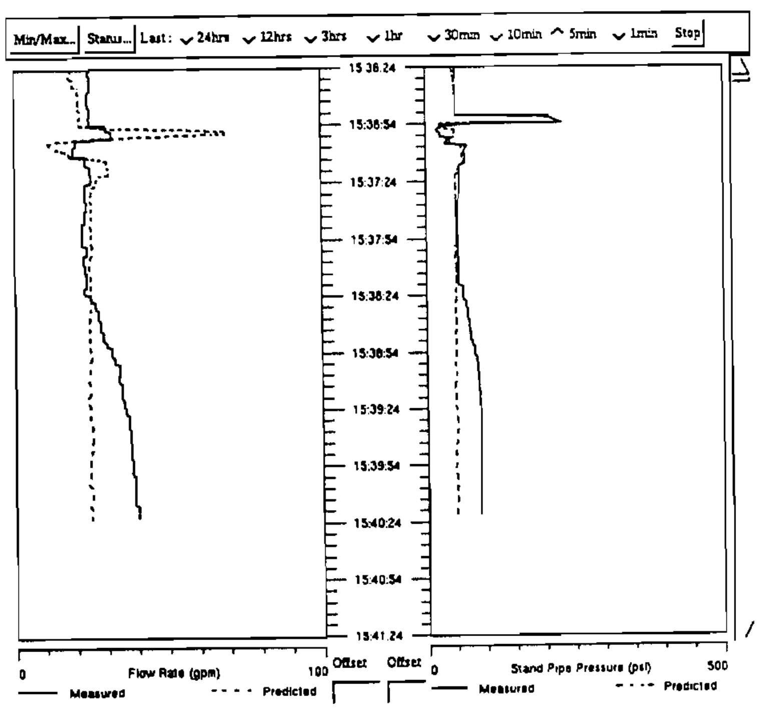


Figure 14-5. EKD Response During a Simulated Kick (Swanson et al., 1993)

BP found that the EKD system was useful for other drilling problems in addition to kick detection. The system predicts a number of parameters including pressure, flow rate, temperature, cuttings loading, mud density and mud viscosity. Comparison of these data can alert the operator to potential problems and assist in drilling and completion operations.

Other elements of BP's slim-hole system are described in the Chapter *Coring Systems*.

14.2 BP EXPLORATION OPERATING CO. (MODIFIED CONVENTIONAL WELL CONTROL)

BP Exploration Operating Company and EC Well Control (Prince and Cowell, 1993) presented the theoretical and practical concerns for well control in slim wells with small annuli. They analyzed the forces acting during a well-kill operation and developed modified well-control equations for slim holes.

The maintenance of safe standards of well control is perceived by many to be a major barrier to the widespread acceptance of slim-hole drilling technology. This problem has at least two facets:

1. Small annular capacity in a slim-hole well reduces kick tolerance and requires well-control systems to be capable of detecting kicks as small as 1 bbl or less.
2. Conventional well-control techniques are based on the assumption that annular pressure losses are a small fraction of total circulating pressure losses. Thus, a slight overbalance can be maintained at the formation under static conditions, and ECDs while circulating can be kept safely below fracture gradients. This assumption is often invalid in slim-hole wells due to high friction pressure losses in the annulus.

After a well is shut in after a kick, the formation pressure is balanced on the drill-pipe side by mud weight and shut-in drill-pipe pressure (SIDPP) (Figure 14-6). On the annulus side, pressure is balanced by the influx weight, mud weight and shut-in casing pressure (SICP). The SICP will usually exceed the SIDPP due to the loss of hydrostatic head on the annulus side.

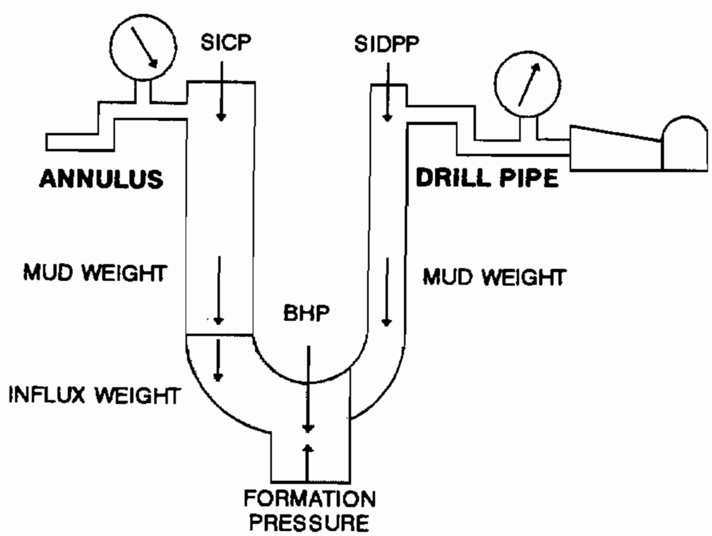


Figure 14-6. Shut-in Well Pressures After a Kick (Prince and Cowell, 1993)

The wellbore pressure balance changes when the kick is circulated out after shut-in (Figure 14-7). Frictional pressure loss in the drill pipe acts in the opposite direction to circulation pressure (P_c) and mud weight. In the annulus, pressure from frictional losses acts in the same direction as influx weight, mud weight and choke pressure.

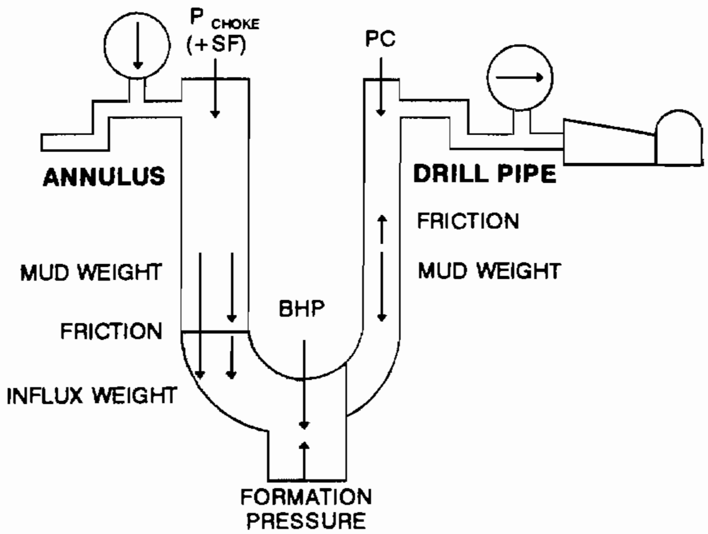


Figure 14-7. Circulating Pressures During Well-Control Operations (Prince and Cowell, 1993)

The effects of friction during circulation cause an increase in pressure drop on both the drill-pipe side and annulus side. The magnitude of frictional loss is usually greater on the annulus side due to restricted flow area. High pressure drops in the annulus, even at slow circulating rates, are the primary complication for slim-hole well control.

BP Exploration suggests that conventional well-control procedures can be employed if the additional annular pressure losses in the slim well will not cause a problem. If the additional pressure losses are not acceptable, modified slim-hole procedures must be followed. Therefore, slim-hole well-control systems and procedures are not necessarily required in all sections of a well, or in every geometrically similar well. A flow chart summarizing the choice of well-control philosophy is shown in Figure 14-8.

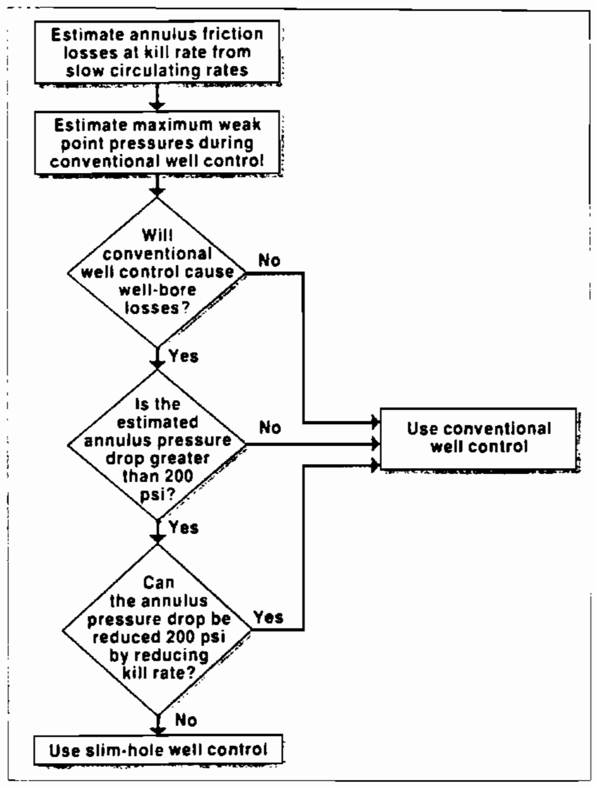


Figure 14-8. Well-Control Decision Tree for Slim Holes (Prince and Cowell, 1993)

Kicks are most likely to occur when the pumps are shut down, such as during connections. Detecting influxes during these periods can be more difficult due to changing pit levels and flow rates. Effective slim-hole kick-detection systems must be able to track well status during periods of pump shut-down.

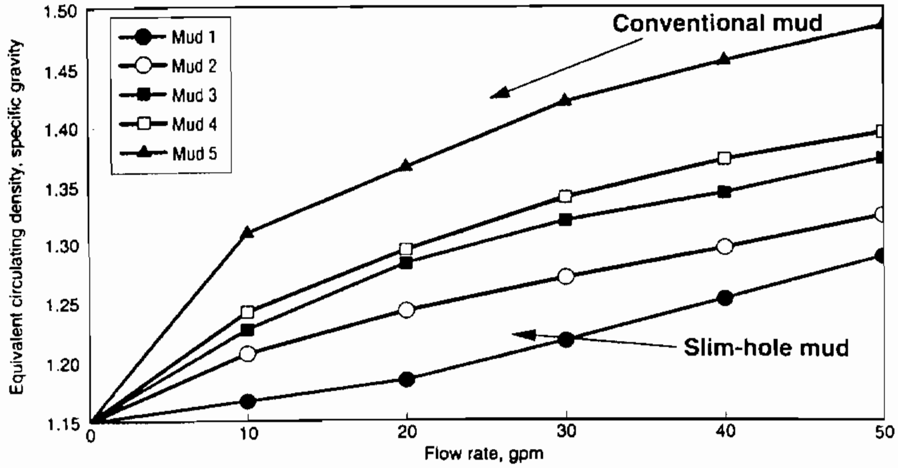
Normal anomalies in the flow out (Figure 14-9) must be analyzed to avoid false alarms. Variations in pump output can be caused by changes in efficiency due to problems with mud rheology or aeration. Flow out is increased slightly while pumping an overshot for core retrieval. Flow out can also be affected by variations in mud density between the drill pipe and annulus (U-tube effect).

Factor	Mud Flow In	Mud Flow Out	Mud Flow Delta	Comments
Reciprocation-down	0	+	-	Displacement
Reciprocation-up	0	-	-	Top up annulus
Rig movement	0	±	±	Floating rigs only
Mud gas expansion	0	+	+	In slim annuli
Pressure spikes	0	+	+	WOB loading
Pump speed	±	±	0	
Rig activity	+	+	0	Leaky hydraulic rigs
Sensor noise	±	±	±	
Rotation-increase	0	-	-	Dynamic ECD effect
Rotation-decrease	0	+	+	Dynamic ECD effect
Gains	**0**	**+**	**+**	
Losses	**0**	**-**	**-**	

Figure 14-9. Causes of Variations in Flow Out (Shields and Taylor, 1992)

Conventional paddle-type flow sensors are likely inadequate for slim holes due to inherent unreliability. Sensors with increased accuracy and sensitivity are preferred in slim holes and are commonly based on electromagnetic or impulse technology.

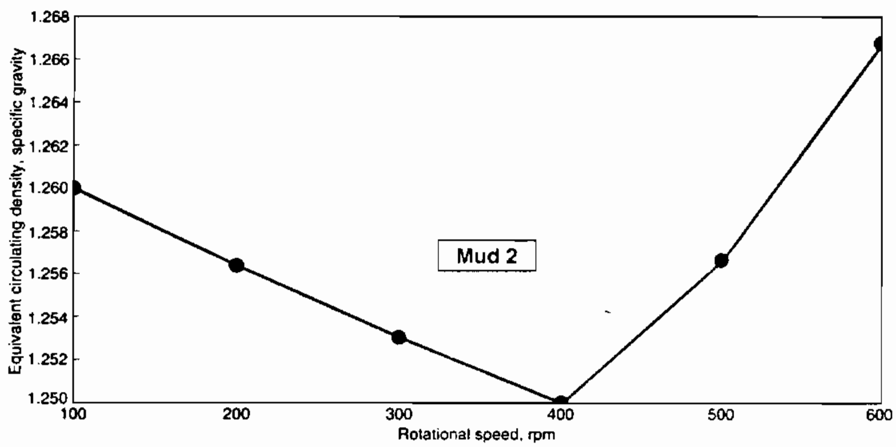
Mud rheology has a significant impact on the magnitude of pressure losses in the annulus. BP Exploration and others have developed slim-hole muds that reduce annular pressure losses (Figure 14-10). The data shown in the figure are based on a 10,000-ft, 3.8-in. well.



*Typical 10,000 ft, 3.8 in. well; 1.15 specific gravity muds

Figure 14-10. Annular Pressure Losses for Several Muds (Prince and Cowell, 1993)

Drill-pipe rotation also impacts annular pressure losses. In some muds, the transition from laminar to turbulent flow is marked by an increase in pressure loss (Figure 14-11).



*Typical 10,000 ft, 3.8 in. well; 1.15 specific gravity mud; 30 gpm flow rate

Figure 14-11. Annular Pressure Loss with Rotation (Prince and Cowell, 1993)

Calculation of ECDs while drilling and circulating is aided with a new worksheet (Figure 14-12). The effects of varying rotary speeds and kill rates can be computed.

Well No	Rig	Date	Time
TD (m)	TVD (m)	Shoe 10m	Shoe 10m
Csg Size (ins)	Shift (am/pm)		
Mud Wt (SG)	PV (lb/Hsq ft)	YP (cp)	Pump (gpm)

PUMP 1		NON ROTATING ANNULUS FRICTIONAL LOSSES					
SPM	GPM	SCR (1)	SCR (2)	DP (3)	Bit (3)	DS (5)	ANN (5)
		(TD)	(Surf)	(Calc)	(Calc)	Total	(Estim)
		psi	psi	psi	psi	psi	psi
						(2+3+4)	(1-5)

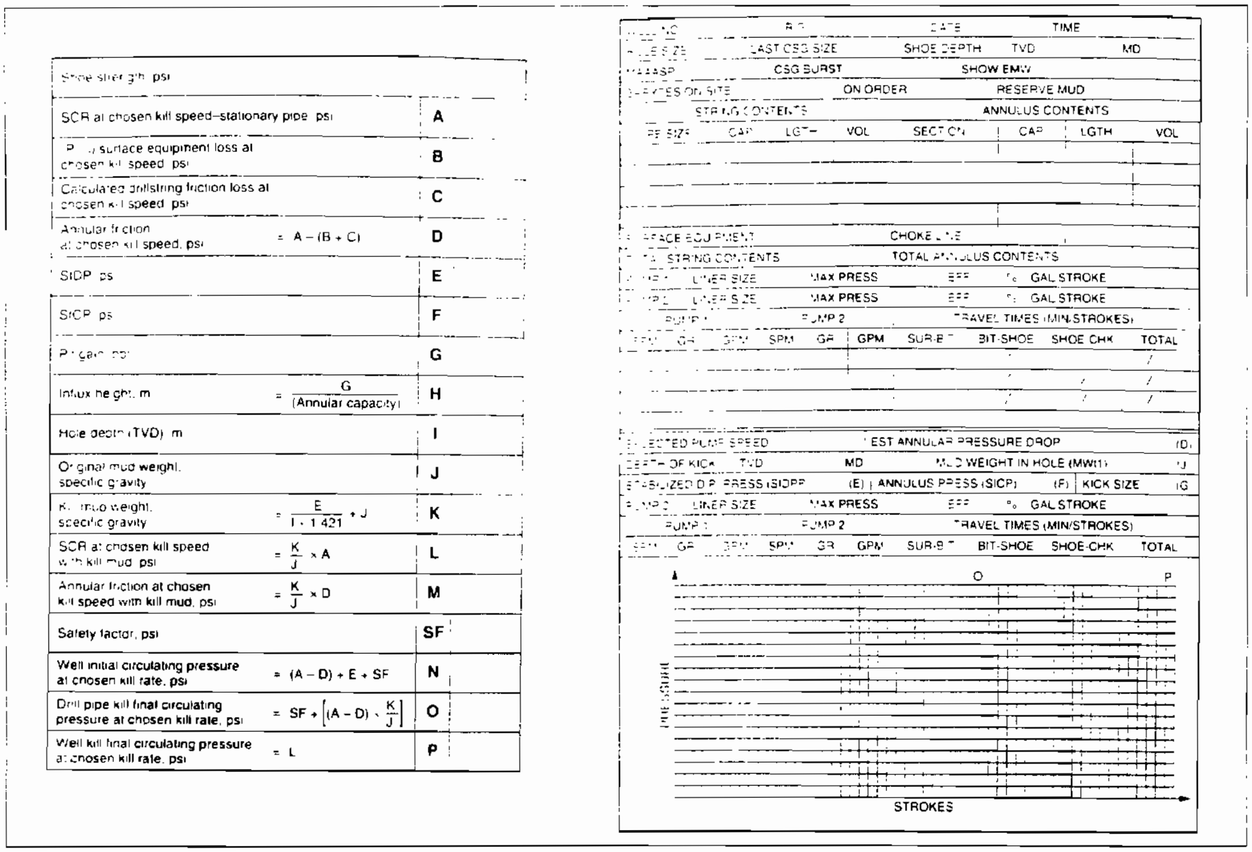
PUMP 2		NON ROTATING ANNULUS FRICTIONAL LOSSES					
SPM	GPM	SCR (1)	SCR (2)	DP (3)	Bit (3)	DS (5)	ANN (6)
		(TD)	(Surf)	(Calc)	(Calc)	Total	(Estim)
		psi	psi	psi	psi	psi	psi
						(2+3+4)	(1-5)

(TD-Rot)

CIRC RATE (gpm)				EMW - PIPE ROTATION
RPM	SCR (1)	SCR (7)	ANN (8)	
	(TD)	(TD-Rot)	(TD-Rot)	
	psi	psi	psi	SG
			(7-1)	(ANN (6) TVD) / 0.433) -MW)

Figure 14-12. Slim-Hole ECD Calculation Worksheet
(Prince and Cowell, 1993)

The kill sheet for slim-hole procedures (Figure 14-13) is similar to that for conventional operations. Circulating pressure is calculated differently, however.



Shoe strength psi		
SCR at chosen kill speed–stationary pipe psi		A
P... surface equipment loss at chosen kill speed psi		B
Calculated drillstring friction loss at chosen kill speed psi		C
Annular friction at chosen kill speed, psi	$= A - (B + C)$	D
SIDP psi		E
SICP psi		F
Pit gain psi		G
Influx height, m	$= \frac{G}{\text{(Annular capacity)}}$	H
Hole depth (TVD) m		I
Original mud weight, specific gravity		J
Kill mud weight, specific gravity	$= \frac{E}{I \cdot 1.421} + J$	K
SCR at chosen kill speed with kill mud psi	$= \frac{K}{J} \times A$	L
Annular friction at chosen kill speed with kill mud, psi	$= \frac{K}{J} \times D$	M
Safety factor, psi		SF
Well initial circulating pressure at chosen kill rate, psi	$= (A - D) + E + SF$	N
Drill pipe kill final circulating pressure at chosen kill rate, psi	$= SF + \left[(A - D) \times \frac{K}{J}\right]$	O
Well kill final circulating pressure at chosen kill rate, psi	$= L$	P

Figure 14-13. Slim-Hole Kill Worksheet (Prince and Cowell, 1993)

It is more difficult to predict the point when circulating pressure begins to rise (Figure 14-14). This condition indicates that the formation pressure is balanced by hydrostatic head and frictional pressure, and corresponds to the choke reaching the full open position.

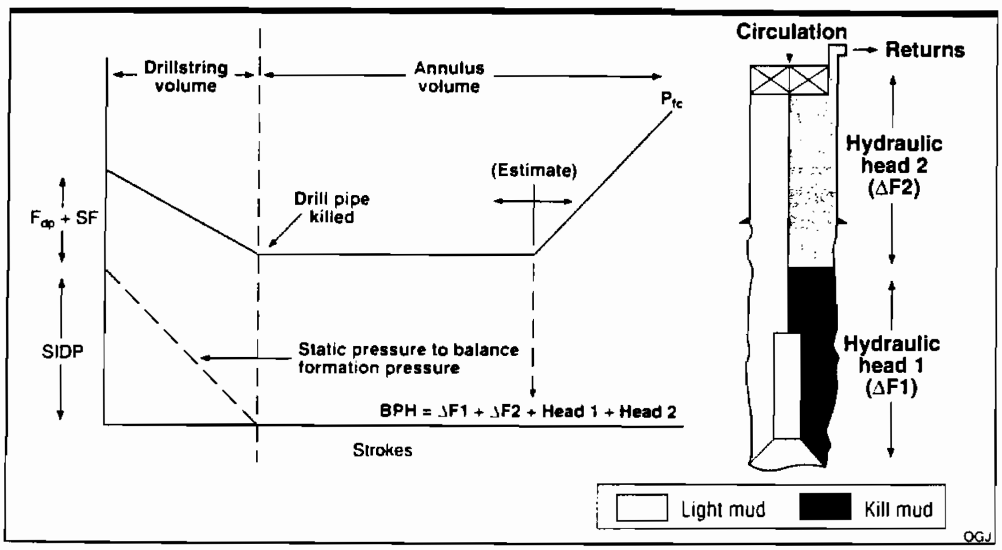


Figure 14-14. BHP While Circulating Kill Mud (Prince and Cowell, 1993)

BP Exploration concluded that conventional well-control procedures can be modified for slim-hole conditions. Modified procedures are necessary only if conventional procedures would present the risk of damage to the well due to high frictional pressure losses. They also suggest that modified conventional techniques are preferable to dynamic well-control procedures, which call for controlling the ECD by adjusting circulation rate and/or rotary speed, because modified conventional procedures allow more accurate control and easier implementation.

14.3 ELF AQUITAINE (PARIS BASIN CASE HISTORY)

Elf Aquitaine Production and Forasol S.A. (Sagot and Dupuis, 1994) drilled two ultraslim-hole wells in the Paris Basin. These wells, one 3-in. and one 3⅞-in. bottom section, were drilled to test the Foraslim rotary slim-hole drilling system in performing destructive drilling, wireline coring, drill-stem testing, and logging. The field tests were successful and showed the system to be a cost-effective technique that provides the geologist with all data required for formation evaluation.

Hydraulics and drilling-fluid behavior were investigated during these operations. A new mud with PHPA was used in the slimmest sections. Higher mud weights and better control of rheology allowed operations to proceed without major problems on the second well.

With the Foraslim rotary drill-string geometry, up to 60% of the system pressure losses occur in the annulus. Pressure losses were investigated at a range of flow rates and rotary speeds (Figure 14-15). Although the annulus is relatively larger than that for continuous coring systems, the Foraslim system is still more sensitive to flow rate than conventional systems.

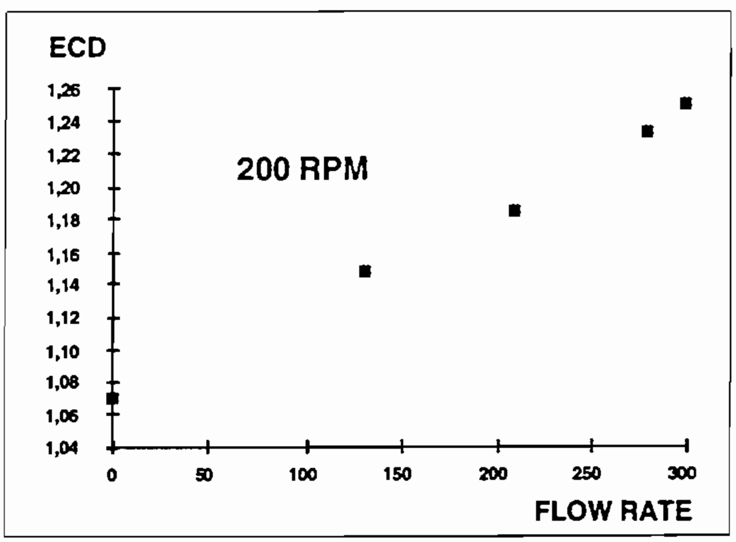


Figure 14-15. ECD at Various Flow Rates (Sagot and Dupuis, 1994)

Well-control issues were investigated. The project team decided that the same relative kick-detection threshold used for conventional operations would be appropriate in Foraslim operations. A 1000-l (6.3-bbl) influx in 8½-in. conventional corresponds to about 162 l (1.0 bbl) in the 3⅜-in. ultraslim hole (Figure 14-16). This desired detection threshold was deemed feasible.

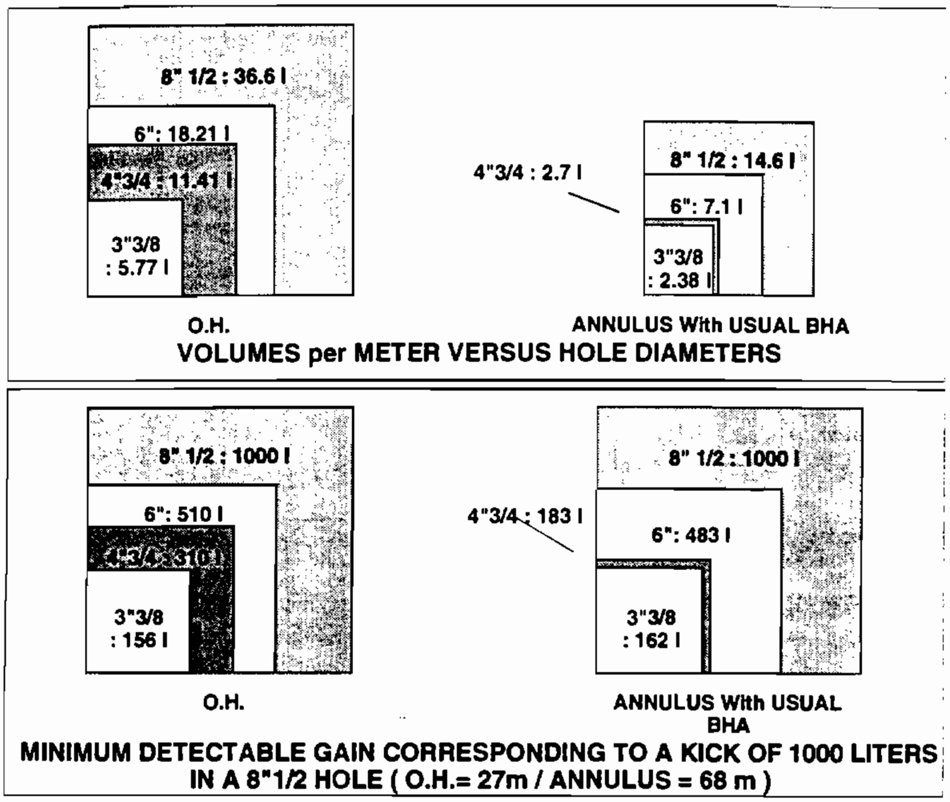


Figure 14-16. Minimum Detectable Kick Volumes (Sagot and Dupuis, 1994)

A time window of 15 minutes was used for kick-detection considerations. For the 3⅜-in. slim hole, a threshold influx rate of about 11 l/min (3 GPM) would correspond to 67 l/min (18 GPM) in a conventional geometry (Figure 14-17). Elf calculated that a change of 10 l/min in the flow rate would be detectable using special flow-in/flow-out sensors.

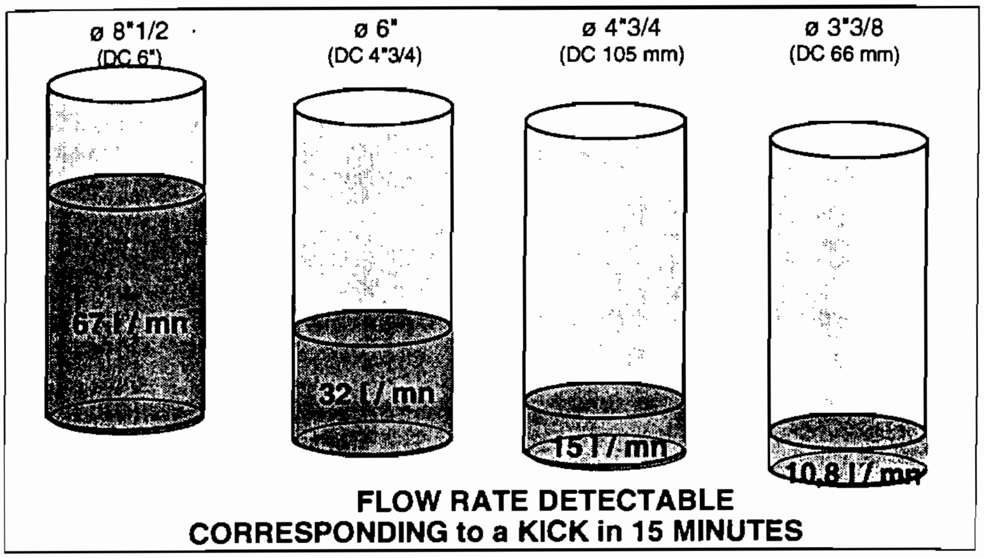


Figure 14-17. Threshold Kick Influx Rates (Sagot and Dupuis, 1994)

Pressure changes due to surge effects compared favorably with model predictions. Elf and Forasol were confident that well control can be maintained with this system safely and efficiently. Commercially available systems for slim holes were to be investigated for adaptation to this rotary system.

The Foraslim rotary slim-hole drilling system is described in the Chapter *Rotary Systems*.

14.4 SEDCO FOREX (RIG DESIGN FOR WELL CONTROL)

Sedco Forex and Schlumberger Dowell (Mehra et al., 1994) presented a review of concerns for well control in slim holes and highlighted the principal differences as compared to conventional geometries. They suggest holes less than 6 in. are usually critical well-control environments due to reduced annular clearances. The pressure drop through the annulus provides a small safety factor in conventional geometries, but complicates well-control technique in slim holes. Rig specification and crew training are especially impacted by well-control concerns for slim-hole operations.

The wellbore geometries considered in Mehra et al.'s analyses are shown in Figure 14-18. A 10-bbl kick would extend 370 ft in the 8⅜-in. hole and 1520 ft in the 4⅛-in. hole. If mud and influx density vary by 1.1 SG, a BHP reduction of 176 psi will occur in the conventional hole, compared to 725 psi in the slim hole.

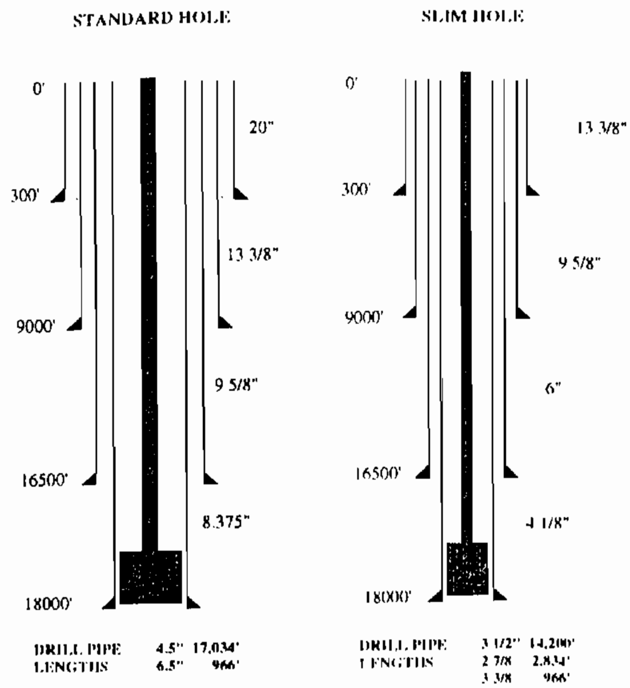


Figure 14-18. Comparison of Conventional and Slim Holes (Mehra et al., 1994)

Annular pressure loss is increased by pipe rotation due to the Couette effect (mud is drawn into helical circulation path). The impact of the Couette effect is most obvious when rotation is stopped. Pressure drop is reduced, which lowers ECD and increases the risk of an influx.

Due to these effects, flow regime is a more important consideration than for conventional holes. As fluid enters turbulent flow, a decrease in pressure drop is observed. For most fluids and geometries, the laminar/turbulent transition is difficult to predict. Turbulence causes an increase in shear stress close to the borehole wall, leading to increased erosion (Figure 14-19).

To minimise shear stress close the wall of the borehole in keeping small velocity gradient	
Turbulent flow	
• High velocity gradient	• Borehole wall erosion and caving
• High shear stress	• The rotating string could break (not surpported by the wall)
• High annular pressure Losses	
Laminar flow	
• Lower velocity gradient • Lower shear stress	
Recommendation : Laminar flow inside the annulus	

Figure 14-19. Effects of Flow Regime
(Mehra et al., 1994)

Surge and swab pressures increase significantly with trip speed in slim holes (Figure 14-20). Wells considered for these swab analyses were 11,811 ft TD with 10-ppg bingham muds.

The development of a kick after the initial influx of gas is usually slower in a slim-hole well. The influx rate is held back by annular pressure loss, to a degree. Later, the friction losses are overcome and the influx rate increases. Performing a flow check to determine whether a kick has occurred can lead to more rapid development of the kick since rotation and pumping are stopped.

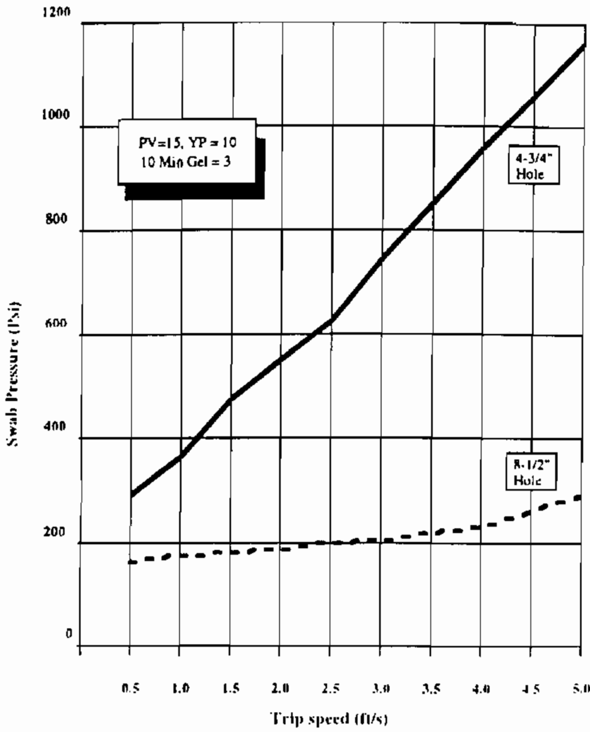


Figure 14-20. Swab Pressures for Slim Holes (Mehra et al., 1994)

Sedco Forex emphasized that the kick-detection technique chosen should be able to recognize a volume increase of 2 bbl or a differential flow of 25 GPM (Figure 14-21). Slow kicks will be more readily discerned by a gain in pit volume; fast kicks by a change in flow rate. Thus, it is important to monitor both differential flow and pit volume in a slim wellbore.

Accurate kick detection in slim holes requires the use of a greater number of sensors than normally employed in conventional operations. Several computer-based systems exist in the marketplace that integrate and compare real-time data with modified models.

Standard Well :	Detection at 10 bbl Time needed for Shut-in = 3 Min In 3 Min the influx reaches 30 bbl
Slim Hole :	From Geometry calculations, 30 bbl influx of standard well is equivalent to 6 bbl influx in slim holes If we need 3 min for shut-in then the kick detection in slim holes has to be at 1 bbl (Delta flow = 25 gpm If we need only 2 min for shut-in, then the kick detection criteria could be 2 bbl.
Detect a kick in slim hole while it is still small enough, so that casing shoe pressure is not jeopardised during well kill.	

Figure 14-21. Kick-Detection Criteria (Mehra et al., 1994)

Significant Annular Pressure Losses → Dynamic Kill

Dynamic Kill : Controlling of formation pressure using the friction loss in annulus when circulating.

Example :8000 ft	
ECD = 9.6 ppg	at 50GPM
ECD = 12.9 ppg	at 100 GPM
ECD = 16.1 ppg	at 100 GPM + Rotation

Control underbalanced formations by changing : Flow Rate or RPM or Mud Properties

Figure 14-22. Dynamic Kill for Slim Holes (Mehra et al., 1994)

Mehra et al. discussed the use of dynamic kill for controlling kicks in slim holes (Figure 14-22). This method involves using annular pressure losses to overcome formation pressure by increasing circulation rates. They suggest that dynamic kill is faster than other methods (driller's method or wait and weight method) and usually results in lower casing-shoe and surface pressures.

Dynamic kill is implemented by increasing pumping rate by a predetermined amount. Next, the drill string should by picked up, flow directed through the choke and the BOPs should be closed. Dynamic kill is more difficult to apply for large influxes due to the relatively large reduction in annular pressure loss after a large influx. Sedco Forex believes that dynamic kill is often the preferred method of well control in slim holes.

Crew training is a critical concern for safe well-control operations. Personnel must be familiar with dynamic kill, staged flow checks, modifications made to the driller's and wait and weight methods, the importance of early detection of influxes, and the need for rapid response to kicks.

14.5 SHELL RESEARCH B.V. (MOTOR DRILLING SYSTEM)

Shell Research B.V., Shell Internationale Petroleum Maatschappij B.V., BEB Erdgas & Erdöl GmbH, and Eastman Teleco (Worrall et al., 1992) described the development of a retrofit slim-hole drilling system based on the use of a downhole motor. The essential elements of their system include mud motors, diamond drag bits, conventional drill pipe, shear-thinning muds, antivibration technology, and sensitive kick detection. Cost savings of up to 24% were demonstrated in early efforts with Shell's system.

Significant effort was expended in the development of a sensitive kick-detection system. Shell's system models and compares flow in to flow out, accounting for circulation dynamics. A disadvantage of the instrumentation is that the electromagnetic flow meter must be fully flooded for proper operation. This presents the potential for clogging.

Shell's recommended well-control philosophy is "shut in and think." They evaluated dynamic well control, but decided not to pursue this approach because it calls for rapid and accurate decisions by the driller and was considered too dramatic a departure from conventional methods.

In offshore floating operations, kick detection is adversely impacted by rig heave as a result of surges in the mud caused by telescopic joint reciprocation. Other parameters can also cause differential flows in excess of alarm limits: flow-rate adjustments, turning pumps on/off, etc. A mud surge-compensation system (Figure 14-23) can be installed to allow use of a flow meter as part of the slim-hole kick-detection equipment.

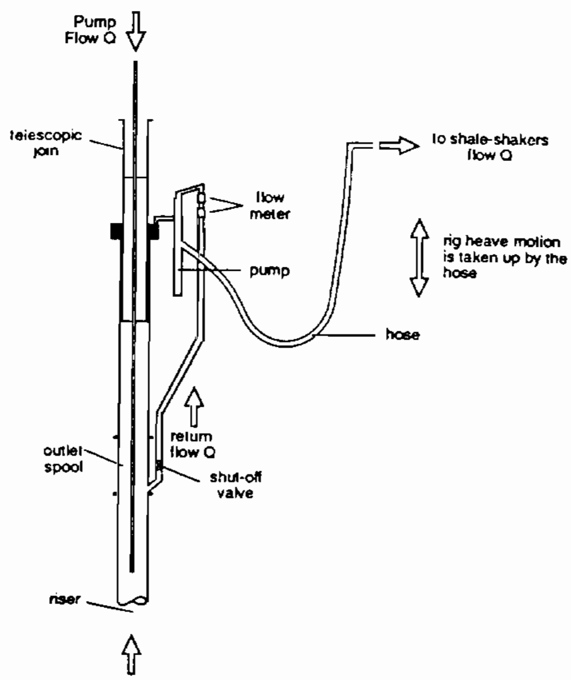


Figure 14-23. Mud Surge-Compensation System (Eide and Colmer, 1993)

14.6 SHELL U.K. E&P (WELL CONTROL IN HTHP WELLS)

Shell U.K. E&P, Shell Research B.V. and Baker Hughes INTEQ (Eide et al., 1993) discussed the special concerns for high-temperature high-pressure (HTHP) slim-hole wells in the North Sea. Conditions typical of these wells are undisturbed bottom-hole temperatures above 149°C (300°F) and pore-pressure gradients in excess of 0.8 psi/ft.

Kick detection is critical on these HTHP wells. Shell's detection criteria (Table 14-1) are based on a kick volume that occupies 50 m (164 ft) of vertical wellbore. North Sea operators have found that an average of two well-control incidents will occur while drilling each HTHP well. Most kicks occur during trips; therefore, optimized bit life and ROP will reduce the number of trips and kicks.

TABLE 14-1. Kick-Detection Influx Criteria (Eide et al., 1993)

HOLE SIZE (IN.)	BHA (IN.)	DRILL PIPE (IN.)	INFLUX VOLUME (LITERS)
5 7/8	4 3/4	3 1/2	564
4 1/8	3 3/4	2 7/8	222

The flow-out sensor, an integral part of the kick-detection system, is positioned similarly to that on a land rig. The mud return line is routed from below the riser slip joint to a manifold tank above the moon pool. From there, a flexible hose passes mud to a buffer tank (Figure 14-24).

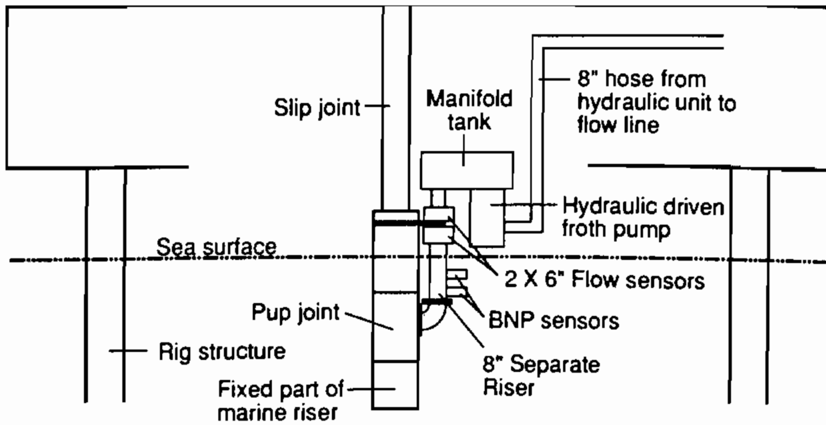


Figure 14-24. Return Flow System for Kick Detection (Eide et al., 1993)

14.7 REFERENCES

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15. Workovers

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15. Workovers

15.1 BAKER OIL TOOLS (SLIM-HOLE WORKOVER CHALLENGES)

An industry team consisting of Maurer Engineering, BJ Services, Baker Oil Tools and Halliburton Energy Services, and funded by the Gas Research Institute, analyzed the barriers hindering widespread application of slim-hole drilling, completion and workover technology. Special emphasis was given in the study to gas wells in the U.S. They concluded that there is significant opportunity for slim-hole technology in the U.S. gas industry. Typical wells require neither high-volume artificial lift equipment nor large production tubing to avoid restricting flow rates. The GRI study found that real and perceived limitations of slim-hole drilling exist, hindering the industry from enjoying the full benefits of the technology.

Overall results of the project are summarized in the Chapter *Overview*. In Hopmann (1995), the project team presented an analysis of completion and workover issues and challenges in the slim-hole environment.

The survey indicated that some of the largest *perceived* barriers relate to completion and workover options and flexibility. In contrast to these perceptions, the experiences of many operators have shown that workovers in slim applications are easier and less expensive than conventional. Areas that were indicated as requiring improved products for slim holes include gravel-pack technology, zone-isolation techniques, stronger tubulars, downhole monitoring capabilities, fishing techniques, and tool/equipment availability.

Many slim wells in U.S. gas fields were drilled with a hybrid approach that consists of cementing slim tubulars into a relatively large hole. In this way, difficulties common when drilling small holes (weaker bits and lower ROPs) are avoided, while retaining cost savings from smaller tubulars. The most common "slim" well in the U.S. is a 2⅞-in. tubingless completion set in a 7⅞-in. (or 6⅛-in.) hole.

Completion equipment for small holes has become much more readily available (Table 15-1). Production packers are available for 2⅞- through 5½-in. casing, and have functioned well even in hostile environments.

TABLE 15-1. Slim-Hole Completion/Workover Options (Hopmann, 1995)

Function	Standard size completion	Slimhole conventional	Slimhole coiled tubing*	Slimhole monobore	Slimhole tubingless
Temporary abandonment—lower zones	Use coiled tubing or E-line to set inflatable bridge plugs	Same as standard down to 2⅞ in.	Not practical without tubing retrieval	Retrievable plug set on E-line	Retrievable plug set on E-line
Temporary abandonment—intermediate or upper zones	Use coiled tubing to set inflatable straddle tool which limits ID or do cement squeeze with inflatable	Same as standard down to 2⅞ in.	Not practical without tubing retrieval	Mechanical straddle assembly or conventional block squeeze	Mechanical straddle assembly or conventional
Permanent abandonment—lower zones	Cement or inflatable down to 2⅞ in.	Same as standard	Not practical without tubing retrieval	Cast iron plug or cement	Cast iron plug or cement
Permanent abandonment—intermediate or upper zones	Cement squeeze with inflatable packer assembly	Same as standard down to 2⅞ in.	Not practical without tubing retrieval	Mechanical straddle or conventional block squeeze	Mechanical straddle or conventional block squeeze
Remedial and stimulation work	Mechanical tubing is pulled on inflatable thru tubing products	Same as standard down to 2⅞ in.	Conventional available down to 2⅞ in. after tubing retrieval	Conventional available down to 2⅞ in.	Conventional available down to 2⅞ in. after tubing retrieval
Recompletion	Conventional methods	Conventional methods	Pull coil, then conventional	Straddle assemblies and inflatable products	Straddle assemblies and inflatable products
Artificial lift	ESP, gas lift, rod pump and jet pump	Gas lift, rod pump and jet pump	ESP, gas lift	ESP, gas lift rod pump and jet pump	Rod pump

*Assumes coiled tubing completion has concentric accessories that restrict ID such as gas lift valves. If not, see conventional.

Workover and production applications requiring bridge plugs can be performed in casing and liners down to 2⅞ in. (Figure 15-1). Bridge-plug pressure ratings up to 7500 psi are available.

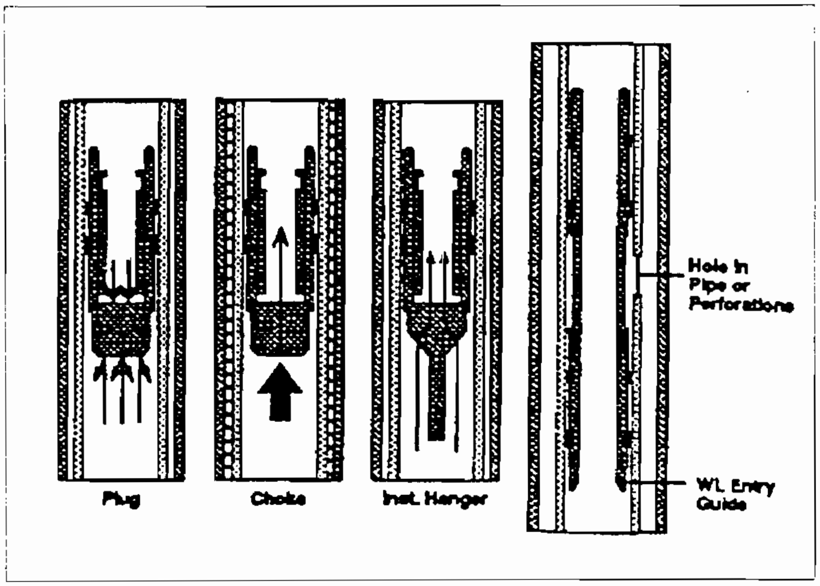

Figure 15-1. Production Bridge Plugs for Slim Casing (Hopmann, 1995)

Conventional gravel packs can be performed in casing as small as 3½ inches. Both squeeze and circulation methods for placing the pack are available. Prepacked screens can be run in on the production string. Chemical consolidation methods have also been used for short intervals (≈10 ft). Longer zones require a selective stimulation tool, which is not yet available for 3½-in. holes.

Monobore completions (Figure 15-2) have been effectively used in slim-hole settings where frequent workovers are required, such as for water/gas breakthrough or scale removal. The potential for low-cost workovers not requiring the use of a rig is maximized with this design. However, multiple-zone completions are not well suited to the monobore design. (See also the Chapter *Completions*.)

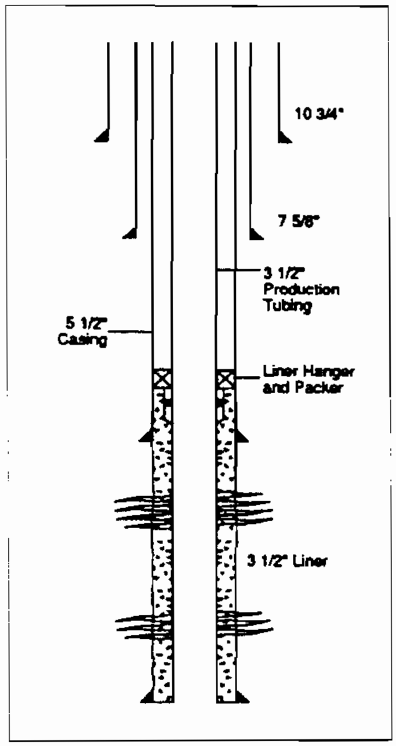

Figure 15-2. Monobore Completion Slim Hole (Hopmann, 1995)

The GRI project team also addressed fishing equipment and concerns for slim wells. Problems arise in the strength of fishing tools. Annular clearances are often less than in larger holes. Washover operations may be limited. Conventional fishing techniques, such as extended jarring, may not be feasible due to reduced tool strength. A description of fishing tools that are currently available is shown in Table 15-2.

TABLE 15-2. Slim-Hole Fishing Options (Hopmann, 1995)

HOLE SIZE	FISH SIZE	MAX. SIZE FOR CURRENT OVERSHOT	OPTIONAL FISHING TOOLS
4¾	3¾	4.625 x 3.875	Box tap, spear or taper tap
4½	3¾	4.375 x 3.500	Box tap, spear or taper tap
4⅛	3¾	4.0625 x 3.875 (Bull Dog)	Box tap, spear or taper tap
3⅞	3⅛	3.750 x 3.063	Box tap, spear or taper tap
2⅝	2⅜	2.313 x 2.000	Box tap, spear or taper tap

15.2 OMV A.G. (SLIM-HOLE GRAVEL PACKS)

OMV A.G. (Gollob, 1992) described development and field operations in gravel packing several slim-hole wells. These gravel/water packs were performed in an oil and gas province of the Vienna basin. Proper design modifications and careful job execution resulted in successful gravel packs inside slim casing. Slim holes are no longer at a disadvantage in unconsolidated formations in OMV's operations.

Over 4% of OMV's domestic producing wells have casing between 3½ to 4½ inches. The number of gravel packs has increased (Figure 15-3). As of 1992, about 5% of the gravel packs were in slim holes.

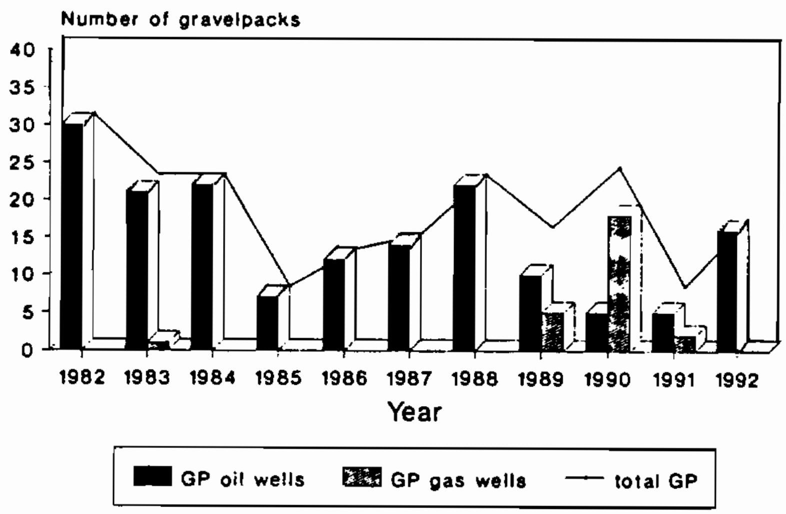

Figure 15-3. OMV Gravel-Pack Jobs (Gollob, 1992)

OMV described gravel-pack installation on one example slim-hole well. The subject well (M 84) had been gravel packed several times previously. Three packs were installed in the original 6-in. casing (Figure 15-4). The well was sidetracked for the second time in 1991 and completed with 4½-in. casing. The rod pump became stuck after two months of production. A gravel pack was planned for the well.

Design of blending and pumping equipment was considered as one of the most important concerns (Figure 15-5). A principal difference between this set-up and conventional lay-outs is that the gravel does not pass through the high-pressure pump. Consequently, gravel is crushed less than with other arrangements.

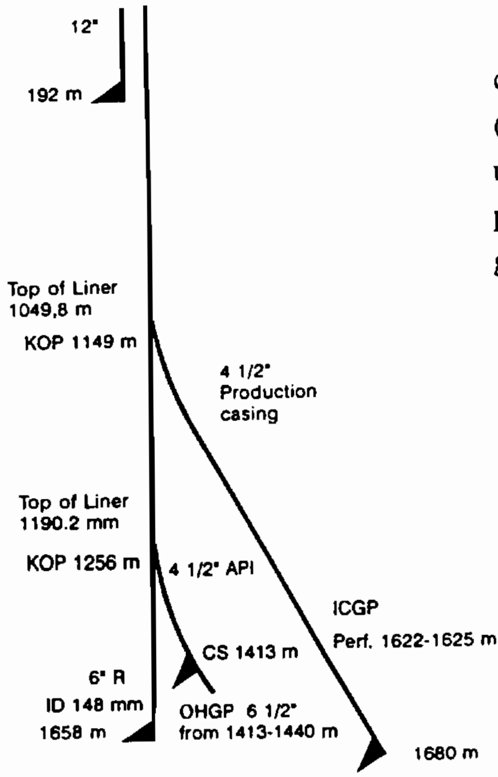

Figure 15-4. Well M 84 Schematic (Gollob, 1992)

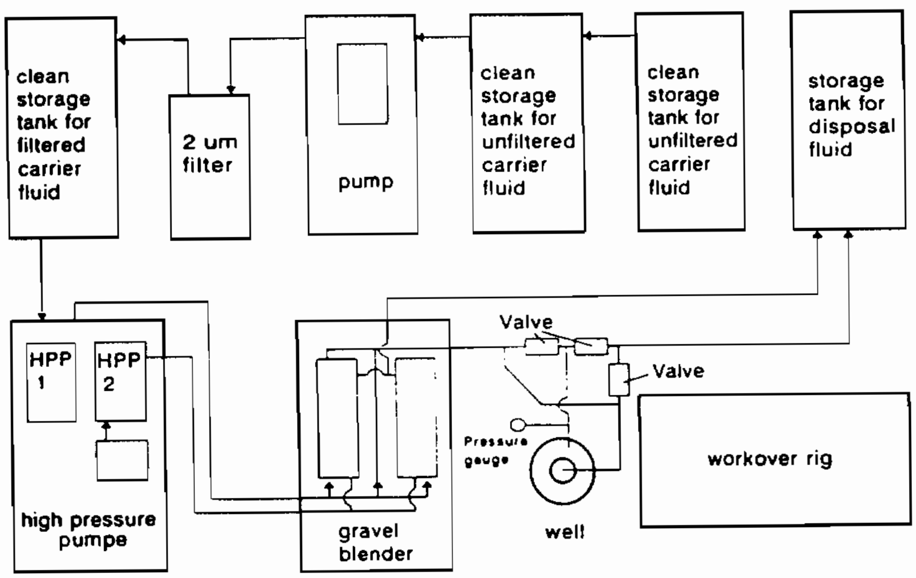

Figure 15-5. Surface Equipment for Slim-Hole Gravel Pack (Gollob, 1992)

The gravel-pack work string (Figure 15-6) was similar to conventional designs. However, the entire work string had to be redesigned for slim-hole operations. A crossover sub was designed with larger ports to minimize the risk of premature sand-out. The seal assembly was modified to prevent gravel migration. The wash-pipe diameter was chosen as 83% of screen base-pipe diameter.

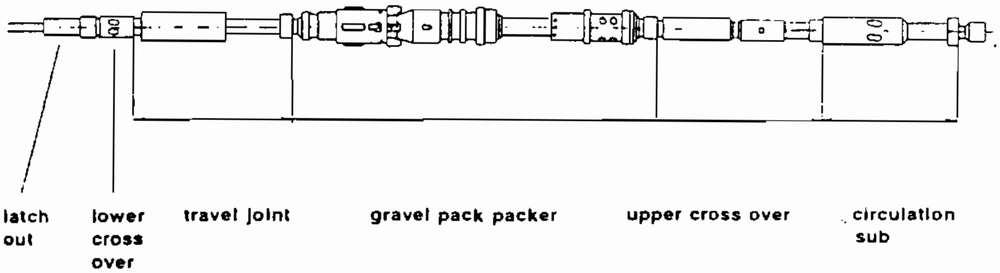

Figure 15-6. Gravel-Pack Work String (Gollob, 1992)

All of OMV's slim-hole gravel packs have been successfully completed with nonviscous carrier fluids. They determined that the pumping operation evolves from basically a constant-rate operation to a constant-pressure operation.

The gravel-pack design on well M 84 is shown in Figure 15-7.

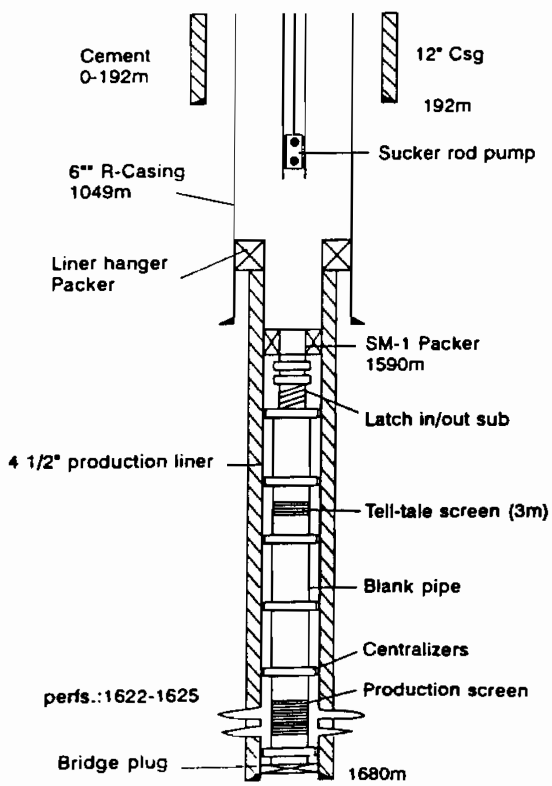

Figure 15-7. Gravel Pack in Well M 84
(Gollob, 1992)

Production before and after the gravel pack is summarized in Figure 15-8. About 3-4 months after installing the pack, GOR increased, indicating gas breakthrough from the overlying gas cap. Well production was restricted after that point to minimize gas production.

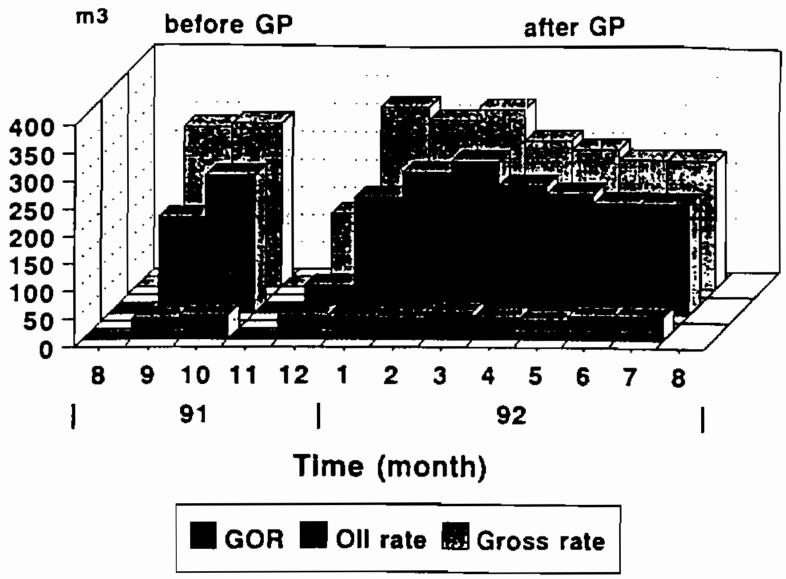

Figure 15-8. Production from Well M 84 (Gollob, 1992)

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Appendix A
Slim-Hole References

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