Slim-Hole Technology
(1995-1998)

DEA-67
Phase II

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

By

MAURER ENGINEERING INC.
2916 West T.C. Jester Boulevard
Houston, TX 77018-7098

Telephone: (713) 683-8227 Facsimile: (713) 683-6418
Internet: http://www.maureng.com
E-Mail: mei@maureng.com

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1. Artificial Lift

1.1 PANCANADIAN PETROLEUM AND BMW PUMP (SLIM-HOLE PC PUMP)

PanCanadian Petroleum Limited and BMW Pump Inc. (Chachula and Anderson, 1995) described the development and field testing of a slim-hole high-volume progressive-cavity (PC) pump for lifting viscous oil (12° API) with a high sand content. Testing showed that increased efficiency would be attainable at lower rotary speeds in slanted (35-45°) slim holes. Savings in drilling and completion by using slim holes in their operations amounted to 18% for a typical 16-well pad.

The slim PC pump was developed for use in the Frog Lake field in northeast Alberta. The productive horizon is capable of prolific production of high-viscosity oil with water and sand cut. Previous experience showed that conventional artificial lift would not be economically successful. A typical pad layout is shown in Figure 1-1.

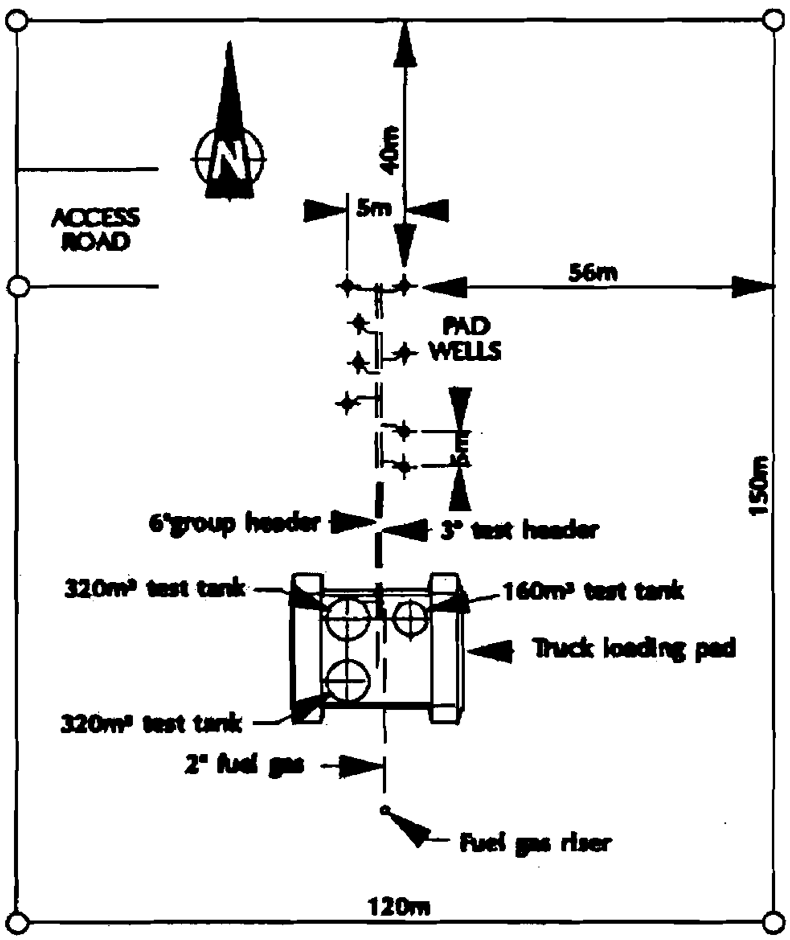

Figure 1-1. Typical Pad Layout at Frog Lake Field (Chachula and Anderson, 1995)

Progressive-cavity pumps are similar to Moineau motors in basic design. They produce a steady flow that is proportional to rotary speed and pressure differential across the pump. A standard pump design was modified for this application (Figure 1-2), including cutting down the outer diameter of the stator section to 3.80 inches. Heavy-wall pipe for the pump body was required for elastomer injection but not for pump operation. The trimmed system could then be deployed in slimmer holes.

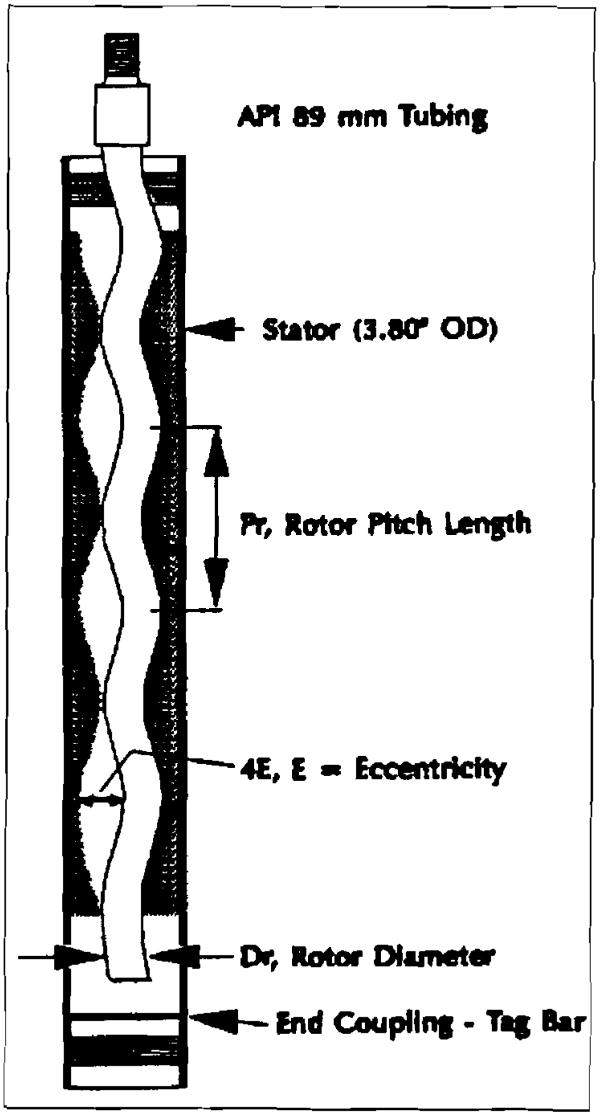

Figure 1-2. Slim Progressive-Cavity Pump (Chachula and Anderson, 1995)

Modifications to the standard pump for slim applications are summarized in Table 1-1. Bench tests of pump performance were very successful (Figure 1-3).

TABLE 1-1. Modifications for Slim PC Pump (Chachula and Anderson, 1995)

	SERIES 83-600 STANDARD PUMP	SERIES 83-600 SLIM PC PUMP
STATOR OD	4.500 inches	3.800 inches
STATOR LENGTH	289 inches	289 inches
ROTOR OD	Major diameter = 2.265 Minor diameter = 1.720	Major diameter = 2.252 Minor diameter = 1.716
DISPLACEMENT	83 m^3/day/100 rpm	83 m^3/day/100 rpm
NET LIFT	600 meters of water	600 meters of water
TEST TORQUE	516 ft-lbs at 100 psi/stage	498 ft-lbs at 100 psi/stage
EFFICIENCY	72% at 100 psi/stage	78% at 100 psi/stage
STAGES	9	9
ROTOR	Double Plated Chrome	Double Plated Chrome
STATOR	High Nitrile	High Nitrile

The operator had seen a high failure rate for downhole pumps (Figure 1-4) caused by large volumes of sand produced in the initial stages of production.

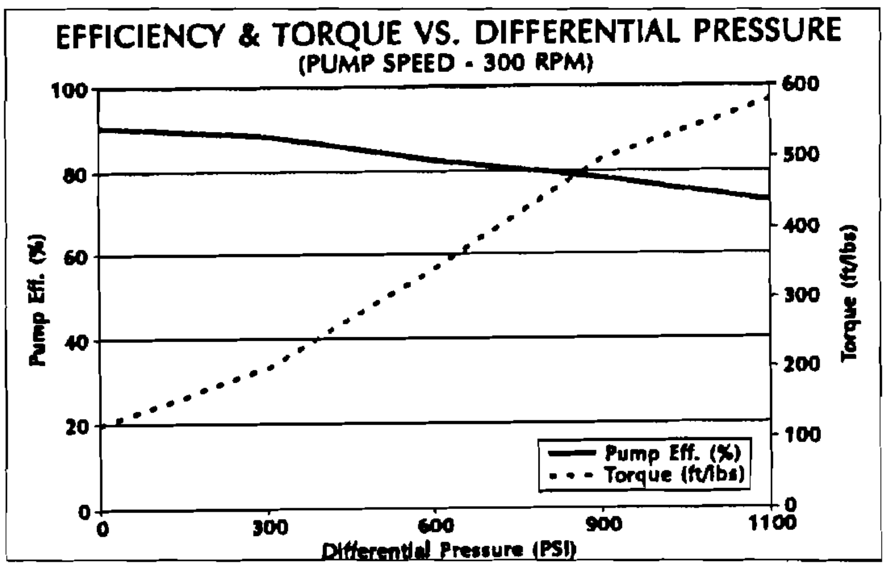

Figure 1-3. Efficiency and Torque of Slim PC Pump (Chachula and Anderson, 1995)

Two slant wells at Frog Lake were chosen for prototype development of the slim-hole PC pump. Through these tests PanCanadian hoped to gain sufficient confidence to proceed with further applications of these pumps in slim wells. The downhole equipment for a typical slim completion is shown in Figure 1-5.

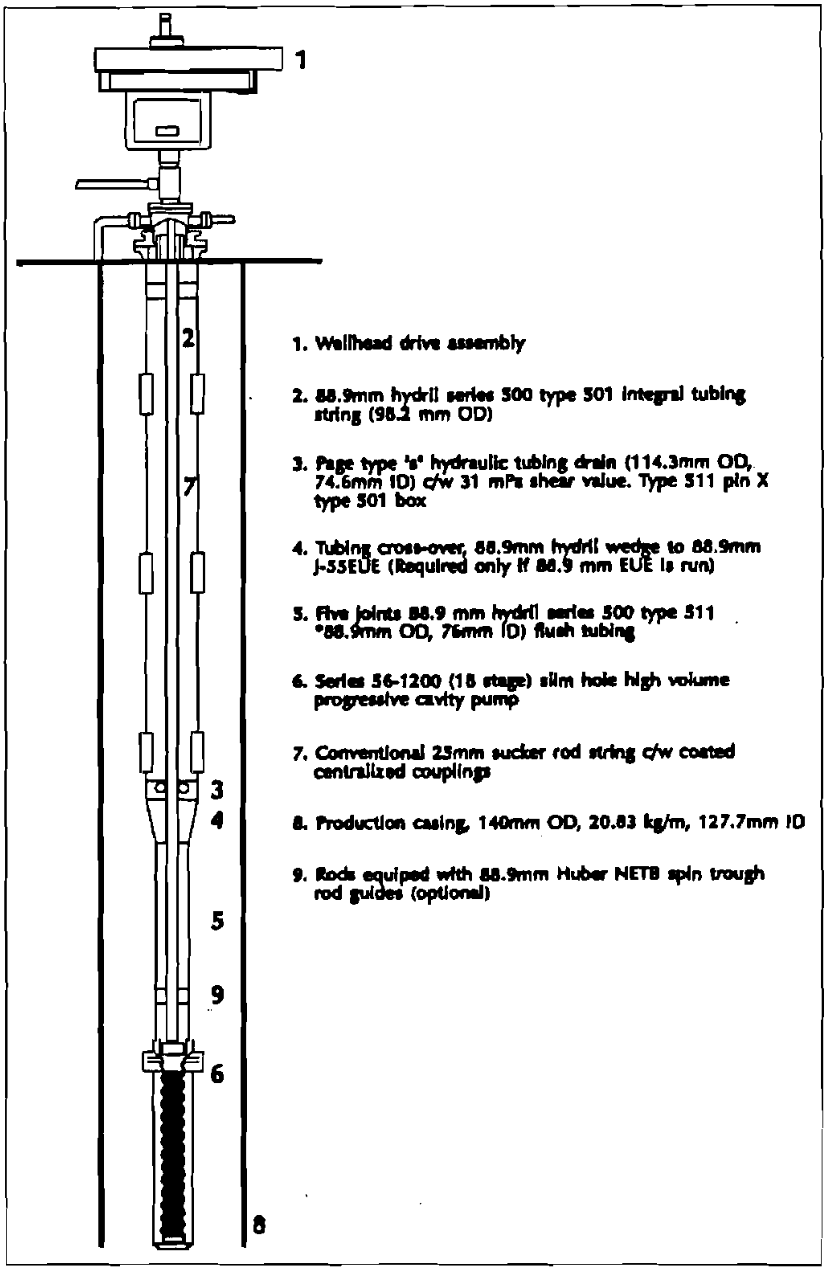

Figure 1-5. Downhole Equipment for Slim PC Pump (Chachula and Anderson, 1995)

Results with the slim PC pumps were successful. Pump efficiencies increased significantly (to 85-95%) across the entire pump life. The low rate of sand-ins in the prototypes prompted the operator to proceed with additional installations inside 140-mm (5½-in.) casing. Sixteen wells were next drilled at inclinations ranging between 12 and 45°. Overall cost savings with respect to the conventional 178-mm (7-in.) completion averaged 18% (Table 1-2).

TABLE 1-2. Slim-Hole Cost Savings (Chachula and Anderson, 1995)

DETAILS	178 MM CASING	140 MM CASING	COST SAVING
Surface Hole			
Surface Hole Size mm:	311	311	
Surface Casing Size:	244.5	219.1	
Weight kg/m:	53.57	35.72	
ID mm:	225	205.66	
Grade:	H-40	J-55	
Connection:	ST&C	ST&C	
$/m:	55.05	38.03	
Hole Depth m:	100	26	
Casing Cost $:	5500	1000	4500
Surface t:	8	3	
Cement			
Surface Cement Cost $:	3500	2100	1400
Main Hole			
Main Hole Size mm:	222	200	
Production Csg Size mm:	177.8	139.7	
Weight kg/m:	29.8	20.8	
Grade:	J-55	J-55	
Connection:	ST&C	ST&C	
$/m:	31.68	21.09	
Hole Depth m:	675	675	
Casing Costs $:	21400	14200	7200
Main Hole t:	17	20	
Cement			
@ $520/t			
Prod'n Cement Cost $:	8800	10400	
			(1600)
Other Savings:			
Rig @ 12 hrs less:(@12M$/day)			6000
Mud, water, etc. @10% less			2000
Bits are a wash:			
222 mm tooth bit = $2125			
200 mm tooth bit = $1980			

TOTAL SAVINGS $19500/WELL

(18% Cost Reduction)

1.2 REFERENCES

Chachula, R.C. and D. G. Anderson, 1995: "Slim-Hole, High-Volume, PC Pump Development for 150 mm Cased Well Applications," SPE 30270, presented at the International Heavy Oil Symposium, Calgary, Alberta, Canada, June 19-21.

2. Bits

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2. Bits

2.1 CHEVRON, DIAMOND PRODUCTS AND DELMAR DIRECTIONAL (SLIM BICENTER BIT)

Chevron USA Production Company, Diamond Products International Inc. and Delmar Directional Systems (Sketchler et al., 1995) described the design and field testing of a slim bicenter bit for decreasing costs associated with re-entries through 7-in. casing. Bicenter technology allowed fewer bit runs and eliminated the risks associated with using underreamers in slim-hole high-angle wells. Overall re-entry costs were reduced about 45% as compared to offset wells.

Chevron found significant potential for slim-hole re-entries in the Gulf of Mexico. Sections drilled out of 7-in. casing typically range from 5⅞ to 6⅛ inches, allowing running 5-in. casing in the horizontal section. Problems have arisen when trying to fish 3½-in. assemblies through 5-in. casing. It has been found to be expedient to underream the intermediate hole to accommodate a 5½-in. casing string. Slim underreamers used for this application have been successful; however, mechanical failures and high costs are associated with their use.

Bicenter bit (Figure 2-1) technology was investigated as a means to reduce risks and costs of underreaming operations. Typical problems with bicenter bits (short life, undergauge hole, poor directional performance) were decreased through better design of cutters and changing the direction of the imbalance forces.

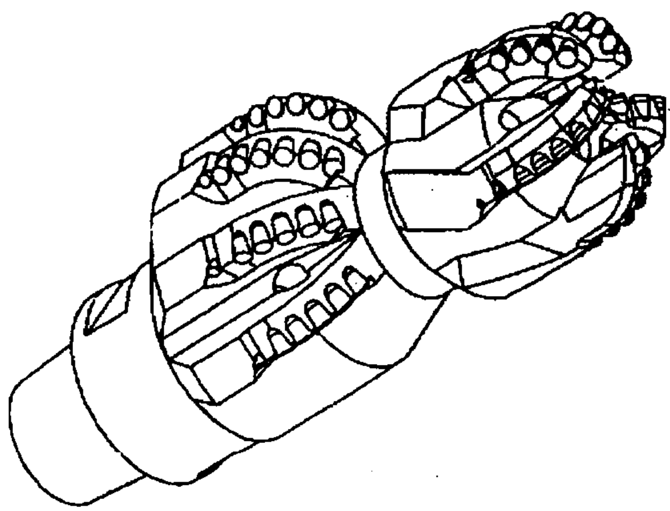

Figure 2-1. Bicenter Bit (Sketchler et al., 1995)

Shaped cutters and reverse bullets (Figure 2-2) have been successfully used to stabilize bits in a variety of designs. Both of these elements are primarily designed for stabilization (not cutting) by limiting penetration of the primary cutters. The benefits of stabilization include reduced cutter breakage, reduced torque and improved directional characteristics.

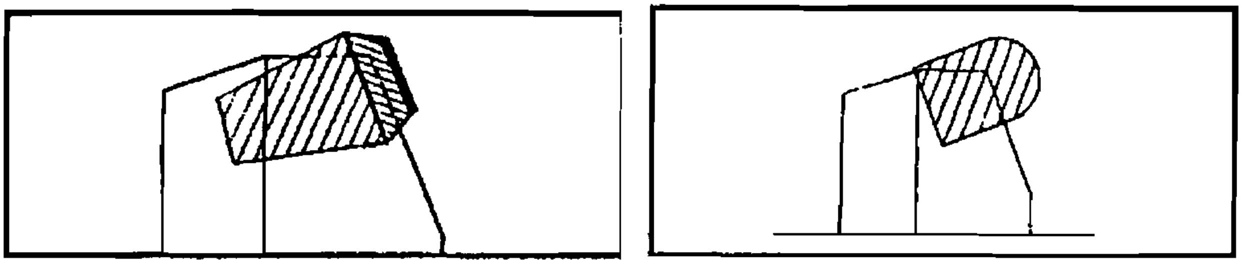

Figure 2-2. Shaped Cutter (left) and Reverse Bullet (right) (Sketchler et al., 1995)

Directional characteristics of a moderately aggressive PDC bit without stabilizing elements are illustrated in Figure 2-3.

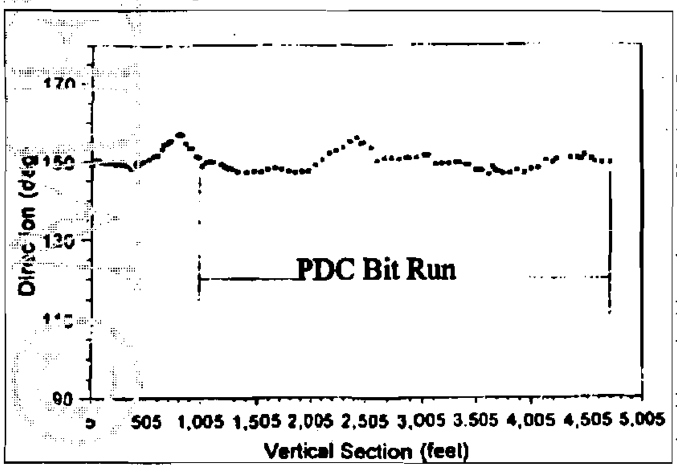

Figure 2-3. Standard PDC Directional Performance (Sketchler et al., 1995)

Bit performance improves after shaped cutters and reverse bullets are added (Figure 2-4). ROP was also increased with the new bits as a side benefit of improved performance.

These improvements in PDC-bit technology were applied to bicenter bits. Additional modifications included placing a small stabilizer between the pilot bit and reamer section, and increasing the imbalance of the pilot bit so that it will (partially) counterbalance the reamer imbalance force and reduce vibration loads.

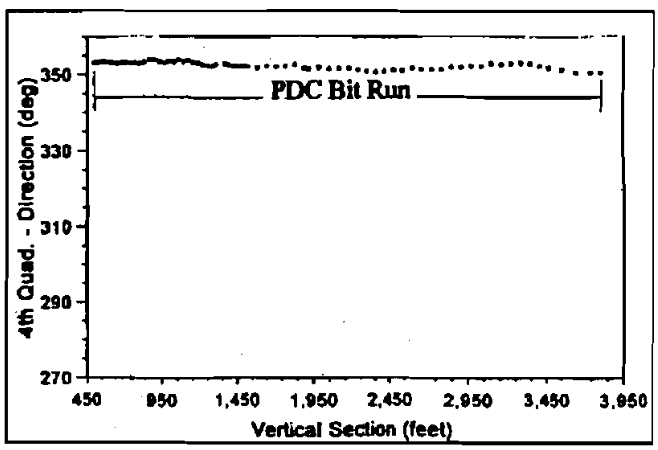

Figure 2-4. Directional Performance with Shaped Cutters and Reverse Bullets (Sketchler et al., 1995)

An improved 6 x 7-in. bicenter bit was used for a well in the Bay Marchand area in the Gulf of Mexico. The plan called for sidetracking out of 7-in. casing, holding angle in a 7° tangent section, and then building to horizontal at 6°/100 feet. Liner (5½ in.) would be run into the hole.

The new bicenter bit performed very well without severe or erratic vibration. No excess wear of any component was observed. Build rates with the steerable assemblies (Table 2-1) were comparable with those attained with conventional assemblies.

TABLE 2-1. BHAs with Improved Bicenter Bit (Sketchler et al., 1995)

BHA #1	BHA #2	BHA #3	BHA #4	BHA #5	BHA #6
6 X 7 Bicenter	6 X 7 Bicenter	6 X 7 Bicenter	6 X 7 Bicenter	6 X 7 Bicenter	6 X 7 Bicenter
1¼ Degree Tandem Motor	1¼ Degree Tandem Motor	2 Degree Tandem Motor	2¼ Degree Tandem Motor	1¾ Degree Tandem Motor	2¼ Degree Tandem Motor
Double Pin Sub	Double Pin Sub	Double Pin Sub	Double Pin Sub	Double Pin Sub	Double Pin Sub
5¾" Stabilizer	5¾" Stabilizer	Float Sub	Float Sub	5¾" Stabilizer	Float Sub
Float Sub	Float Sub	10' Non-Magnetic Flex	10' Non-Magnetic Flex	Float Sub	10' Non-Magnetic Flex
Orienting Sub	10' Non-Magnetic Flex	Joints	Joints	10' Non-Magnetic Flex	Joints
2-Non Magnetic Flex	Joints	MWD Collar	MWD Collar	Joints	MWD Collar
Joints	MWD Collar	Double Pin Sub	Double Pin Sub	MWD Collar	Double Pin Sub
6⅛" Stabilizer	30' Non Magnetic Flex	Resistivity Collar	Resistivity Collar	30' Non Magnetic Flex	Resistivity Collar
3 - 4¾" Drill Collar	Joints	30' Non Magnetic Flex	30' Non Magnetic Flex	Joints	30' Non Magnetic Flex
33 -3½" Heavy Wt.	6⅛" Stabilizer	Joints	Joints	6⅛" Stabilizer	Joints
Drill Pipe	3 - 4¾" Drill Collar	24 -3½" Heavy Wt	24 -3½" Heavy Wt.	33 -3½" Heavy Wt.	24 -3½" Heavy Wt.
Jars	33 -3½" Heavy Wt	Drill Pipe	Drill Pipe	Drill Pipe	Drill Pipe
8 - 3½"Heavy Wt.	Drill Pipe	Jars	Jars	Jars	Jars
Drill Pipe	Jars	41 - 3½"Heavy Wt.	41 - 3½"Heavy Wt.	8 - 3½"Heavy Wt.	41 - 3½"Heavy Wt.
	8 - 3½"Heavy Wt.	Drill Pipe	Drill Pipe	Drill Pipe	Drill Pipe
	Drill Pipe				

Significant cost savings were enjoyed with this project. With the previous conventional approach, a minimum of three rock bits (two trips each), a PDC bit run and at least two underreamer runs would have been required. The bicenter bit can be used to complete the job in only two runs. This allows an overall savings of $225,000 (45% of total costs) as compared to offset wells in the area.

2.2 HUGHES CHRISTENSEN AND AMOCO (SLIM COATED TSP BIT)

Based on significantly increased interest in improved bits for slim holes, Hughes Christensen (and other manufacturers) have introduced newly engineering lines of small-diameter bits (3⅞ to 6¾ in.) with advanced roller-cone and PDC technologies. Previous generations of slim bits have had a history of problems in the field (weak bearings in slim roller-cone bits; and high torque fluctuations, cutter fracturing, and rapid gauge wear in slim PDC bits). A range of improvements have been incorporated into both bit types to address the market demands. Reports from the field have shown significant increases in ROP and durability, and reductions in drilling costs.

Hughes Christensen and Amoco Corporation (Felderhoff et al., 1995) collaborated in the development of an improved TSP bit for drilling a 4¾-in. section in the Prentice Field in West Texas. The best design drilled 28% faster and lasted 4 times longer than bits used previously. Total costs were reduced 19% per well with the improved slim bit.

The use of fixed-cutter bits in this area has begun only relatively recently. Improvements in diamond-bit design have resulted in the use of these bits in drilling environments once reserved for roller-cone bits. Tests had shown that TSP bits provided the lowest cost per foot in this West Texas area. Amoco decided to optimize bit design further with a controlled experimental program. Parameters for the testing program are summarized in Table 2-2.

TABLE 2-2. Drilling Equipment for Slim TSP Tests (Felderhoff et al., 1995)

Rig:	Workover
Pump:	Triplex
Flow Rate:	160 gpm
Standpipe Pressure:	1,700 - 2,200 psi
Hydraulic HP/in^2:	1.69 HHP/in^2
Total Flow Area:	0.25 in^2 (later changed to 18/32 = .2485)
Weight on Bit:	6000 - 12,000 pounds
Bit Speed:	600 (MACH II) - 900 (MACH III) (combined motor and power swivel)
Circulating Fluid:	Freshwater (8.4 ppg 28 vis) (changed out a midpoint of interval to reduce solids)

New diamond-cutter coating technology was also investigated. These coatings have been found to improve cleaning, among other benefits. A three-layer metal coating ensures solid bonding of the cutter to the bit and prevents the TSP from cracking during manufacturing.

A series of tests was conducted to increase performance. The shape of the TSP was changed to hexagonal to increase impact resistance. Back-rake angles were adjusted to increase durability. A variable TFA nozzle system was also added. TSP bit #4 (Table 2-3) drilled 1440 ft in four wells with an average ROP of almost 53 ft/hr.

TABLE 2-3. Performance of Slim Coated TSP Bits (Felderhoff et al., 1995)

Bit Type	No. Wells	Avg. Feet/Well	Avg. Hours	Avg. ROP	Avg. $/Foot
S725 (old H#1)	2	478	18.6	34.7	12.66
S #1 (3bits)	18	325	8.4	38.7	13.60
S725 (H#2)	7	425.7	9.1	46.8	10.88
S725 (H#3A)	7	412.9	7.9	52.3	12.34
S725 (H#3B)	5	332.8	7.2	46.2	12.20
S725 (H#4)	4	860	6.8	52.9	10.94
Calculations based on $300/hours rig and motor cost					Savings: $2.61/foot
Total footage drilled (bits 2, 3A, 3B and 4): 894 feet					Total Savings: $23,422

The use of coated TSP cutters was found to increase the average drilled feet per bit by 985 ft. Overall drilling costs were reduced $2.61/ft ($23,422 per well).

2.3 HYCALOG (BIT SELECTION)

Hycalog (Feiner, 1995) summarized major concerns for bit selection with respect to slim-hole operations on drill pipe and coiled tubing. PDC, TSP, natural diamond, and roller-cone bits are all used in slim-hole drilling. Technical constraints at smaller diameters have lead to design modifications and adjustments to operating practices.

Lithological description is key in the initial steps of bit selection. After this type of data is analyzed, other constraints guide bit selection. Due to larger proportions of hydraulic horsepower being consumed by frictional pressure losses, less power is generally available to drive the bit, with correspondingly smaller ratios of $HHP/inch^2$. Torque may also need to be carefully limited due to relative weaknesses in drill-string elements.

Identifying the best bit type is the next step. Natural- and synthetic-diamond bits, roller cone, and combination bits have each proven the best choice in particular situations. Basic advantages of these bit types are compared in Table 2-4.

TABLE 2-4. Features of Slim Bits (Feiner, 1995)

Small Diameter Bits	Advantages	Disadvantages
Roller cone bits	Lowest torque requirements. Can drill most formation types. Can drill out shoes. Adjustable hydraulics.	Moving parts can fail. High weight on bit. Limited sizes available. Long lead times for new sizes.
Natural diamond	Low torque. Can be manufactured to any size quickly. Drill harder, more abrasive formations. Long life.	Fixed total flow area. Can easily ball in soft formations. Slow ROP. High weight on bit.
TSP	Normally faster ROPs than natural diamonds. Require less WOB than natural diamonds. Can be manufactured to any size quickly. Lower torque response than PDC bits.	Shorter drilling life than natural diamonds. May have shorter life due to inadequate cooling. Fixed total flow area. Has balling potential.
Combination ND and TSP	More impact resistant than natural diamonds. Can drill a greater variety of formations than natural diamonds or TSP bits alone. Can be manufactured to any size.	Slower ROPs than PDC bits. Fixed total flow area. Has balling potential.
PDC	Can produce high ROPs. Needs least weight for drilling. Adjustable hydraulics. Design flexibility. Shorter manufacturing time.	Highest torque. Limited drill out capabilities of float equipment.

Slim PDC bits require the least WOB and can typically drill faster and longer than other bit types. Their design parameters are also quite flexible. Reliability of slim PDC bits is also good. Disadvantages of PDCs for slim applications include the highest torque generated of any bit type.

Natural-diamond bits generate low torque. These bits have been used in build sections drilled on coiled tubing as a conservative approach to maintain directional control. However, if hydraulics change following a trip, diamond bits cannot be reconfigured at the rig.

TSP (thermally stable) bits allow a compromise between PDC and natural diamonds. ROP with TSP bits is faster than with natural diamonds, and less torque is generated than with PDC bits. As another approach to decrease limitations, combination TSP/natural-diamond bits have been successfully used in slim holes (Figure 2-5).

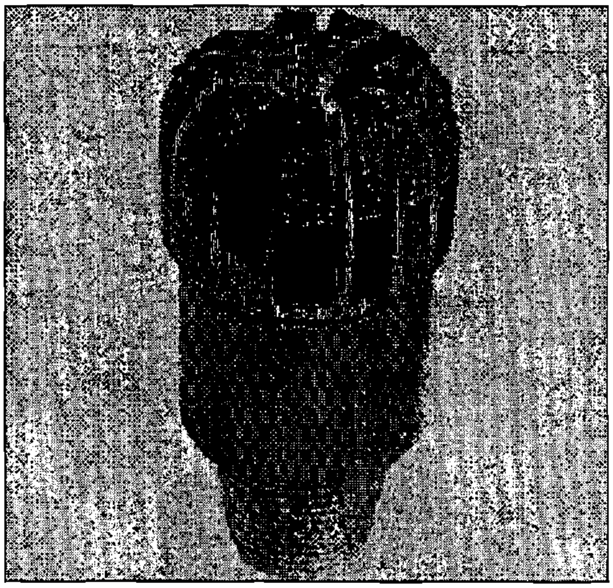

Figure 2-5. Combination TSP/Natural-Diamond Slim Bit (Feiner, 1995)

In one application in the Austin Chalk, the formation was first identified as able to be drilled with a PDC bit. A 4¾-in. lateral section was drilled with a PDC bit with 8-mm cutters. The bit drilled 4584 ft at over 25 ft/hr, amounting to a world-record run.

2.4 MARATHON AND HUGHES CHRISTENSEN (PERMIAN EXPERIENCE)

Marathon Oil Company and Hughes Christensen Company (Tank et al., 1996) summarized developments in bits, motors, and techniques that have reduced costs in the Permian Basin. Slim roller-cone bits have played an important role in the slim-hole horizontal drilling applications. Several wells have been drilled with 3⅞-in. roller-cone bits on new 3⅛-in. PDMs. New equipment and optimized procedures have reduced per-foot costs by over 50%, increased total penetration per bit, and increased wellbore displacement.

In previous operations with marginal development in the Permian Basin, slim-hole designs were used in horizontal re-entries. Reduced ROPs were seen with earlier systems, and the cost advantages of a slim hole were often offset by longer drilling times. However, with new optimized systems, ROPs were nearly doubled.

In the Yates Field Unit, short-radius profiles were often used due to the thin target zone. Lateral lengths attained an average length of 190 ft in early efforts. With optimized bits and motors, the laterals now achieve an average length of 780 ft.

A standard truck-mounted workover rig is used to drill these slim-hole re-entries. Equipment includes a triplex pump, power swivel, and 2⅞-in. drill string. IADC 537 and 547 roller-cone bits have been found to be best suited to this geology. Diamond bits have been used and have demonstrated less success than roller cone. One exception is a coated TSP bit (see section 2.3).

Bearing speed in the roller-cone bit decreases with hole size (Figure 2-6).

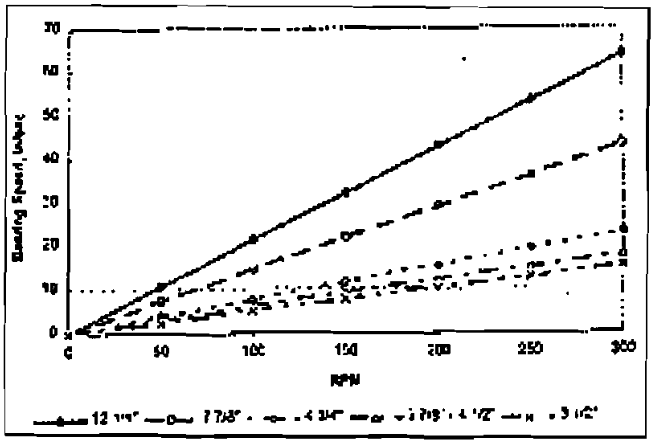

Figure 2-6. Roller-Cone Bearing Speed (Tank et al., 1996)

Ball-lock cone retention systems (Figure 2-7) have been found to be especially beneficial in slim-hole roller-cone bits, providing better retention and higher rpm capacity. Most bits used in the Permian projects incorporate these elements.

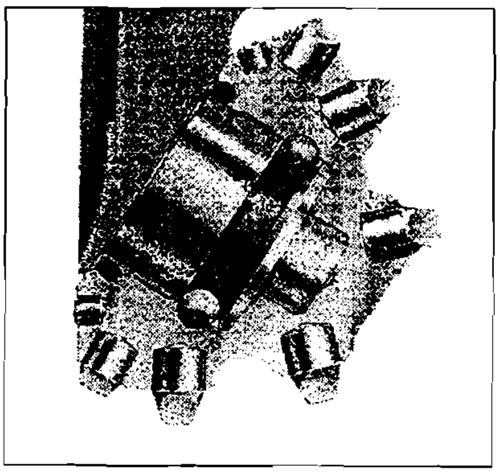

Figure 2-7. Ball-Lock Bearing Retention (Tank et al., 1996)

A typical bit (Figure 2-8) is as short as possible to enhance directional capability.

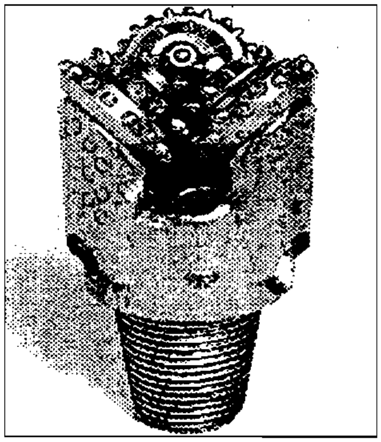

Figure 2-8. Short-Body 4¾-in. Bit (Tank et al., 1996)

Motor designs have been improved by lengthening the housing of the build section (Figure 2-9). This modification proved to enhance the positional stability of the BHA.

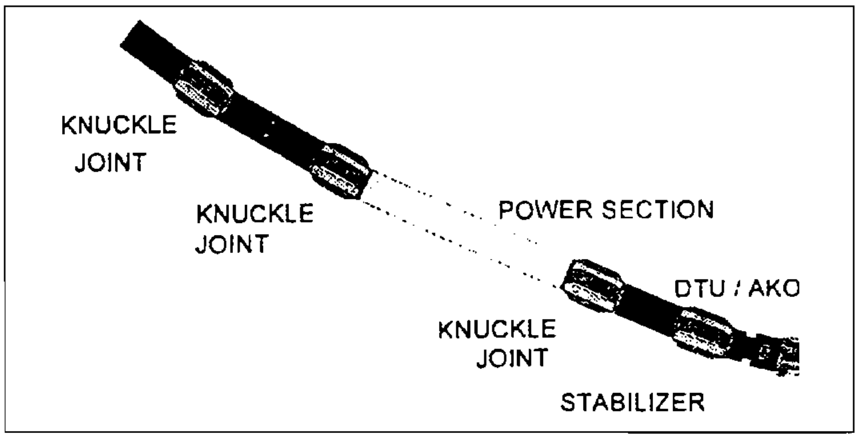

Figure 2-9. Typical PDM in Permian Basin (Tank et al., 1996)

Slim-hole motor specifications are summarized in Table 2-5. Improvements in the motor have been shown to increase average ROP from about 30 ft/hr to 60 ft/hr.

TABLE 2-5. Slim PDM Specifications (Tank et al., 1996)

Specifications for Typical Motor Used in the Yates Field Unit							
Motor Size	Bit Size	Design Radius	GPM	RPM	Temp Limit	Diff. Pressure	Max Oper. Torque
3⅛"	3⅞" - 4⅛"	60' - 100'	90 - 120	182 - 365	260F		400 ft lbs
3¾"	4½" - 4¾"	40' - 100'	150 - 185	210 - 370	260F	683 psi	679 ft lbs

Drilling performance has also been improved by using a thinner drilling fluid. Operators have reduced the concentration of biopolymer, resulting in increased turbulence downhole and improved cuttings removal.

The use of intermediate-radius profiles has allowed greatly increased lateral reach. Average displacement has increased from 488 ft to 1300 ft. Marathon saved over $100,000 on each of three intermediate-radius horizontal slim-hole re-entries. These new profiles have reduced the number of correction runs needed. Longer runs have been enjoyed, along with faster ROPs and less formation damage.

2.5 REED TOOL COMPANY (NEW SLIM BITS)

Reed Tool Company (Neal, 1996) described the development process for an improved 4¾-in. insert bit for slim-hole horizontal re-entries. A special concurrent engineering approach reduced development time for the new bit by about 25%. An improved cone retention design resulted in increased performance in several field applications. A savings of 40% compared to previous horizontal wells was reported for one operation in New Mexico. This represented a cost reduction of $52/ft.

The primary improvement in the design of the new 4¾-in. bit was the use of a two-piece threaded ring retention mechanism to attach the cone on the journal (Figure 2-10). Ball bearings, the most common means to retain cones, have been found to be less effective in slim bits.

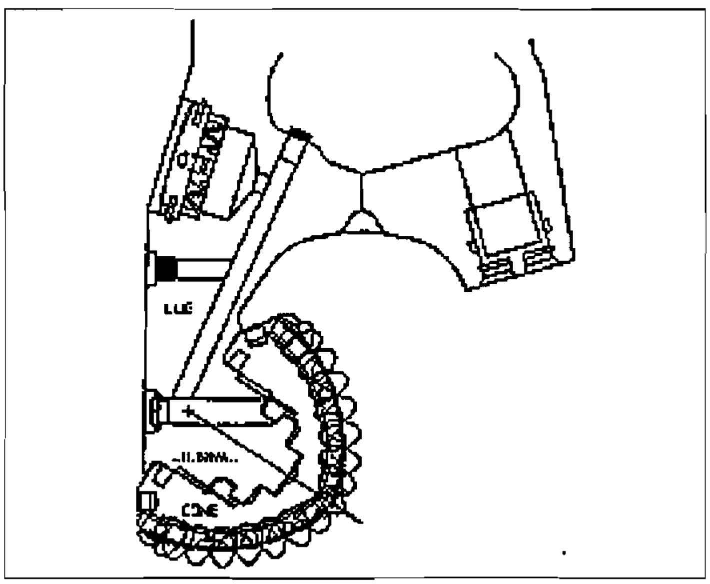

Figure 2-10. Cone Retention for Slim Bit (Neal, 1996)

Several field tests were performed with the bit in Canada, New Mexico and North Dakota. Data from offset wells were analyzed in detail for performance comparison. Overall results showed that bits run in build sections drilled an average of 295 ft in 25 hr at 10,000 lb WOB and 180 rpm. No bearing failures were reported. Bits run in the lateral drilled an average of 580 ft in 30 hr at 12,000 lb WOB and 320 rpm. Fourteen percent bearing failures were reported. Bits run in vertical sections drilled an average of 419 ft in 36 hr at 16,000 lb WOB and 50 rpm. No bearing failures were reported.

Footage drilled per bit is compared for several field trials in Figure 2-11. Drilling hours are compared in Figure 2-12.

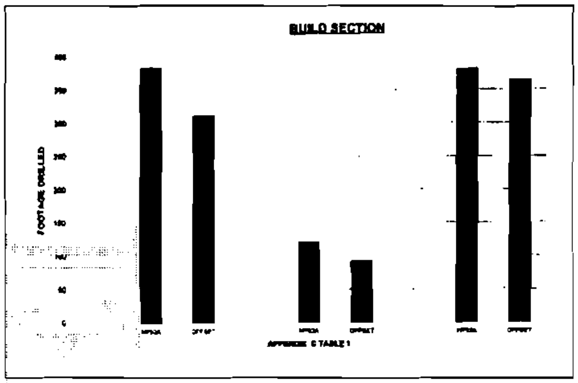

Figure 2-11. Footage Drilled for New 4¾-in. Insert Bit (Neal, 1996)

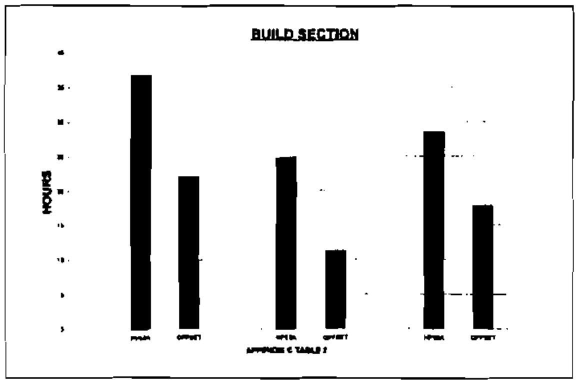

Figure 2-12. Hours Drilled for New 4¾-in. Insert Bit (Neal, 1996)

2.6 UNION PACIFIC RESOURCES AND ROCK BIT INT. (SINGLE-CONE BIT)

Union Pacific Resources and Rock Bit International (Flatern, 1995) performed preliminary testing of a single-cone bit (Figure 2-13) for slim-hole drilling applications. The 4¾-in. bit was patterned after the Russian Zeublin bit. Good bit design allowed bearing surface durability to be equivalent to that of a 9⅞-in. tricone bit.

Figure 2-13. 4¾-in. Single-Cone Bit (Flatern, 1995)

Results from three bit runs demonstrated that the bit has low cone seal rpm, extended life, and a greater response to changes in rotary speed than to WOB, allowing easier discernment of bit failure in the hole. No additional deviation tendencies were observed.

ROP with the single-cone bit compared well with a conventional 7⅞-in. bit at 90 to 100 ft/hr. These original tests were conducted with N-80 tubing as the drill string and air as the drilling fluid. Several operators plan to run the new bit with standard drill strings and muds.

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3. Cementing

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3. Cementing

3.1 BJ SERVICES INDONESIA (LIQUID CEMENT PREMIX)

BJ Services Indonesia (Anderson et al., 1996) described the use of a liquid cement premix (LCP) to maintain accurate density control in restrictive applications including slim holes. LCP is a storable cement slurry with set-retarding and conditioning agents that can be stored in liquid form indefinitely (several days to more than six months), and made to set when required. Slurry density is 16 ppg in stored form and can be diluted to the required density on site. This new system was applied successfully in a slim-hole geothermal evaluation project in Indonesia.

Slim-hole techniques were employed to reduce the environmental impact of an appraisal project of a geothermal resource on the island of Java. A significantly reduced site size was possible (Figure 3-1).

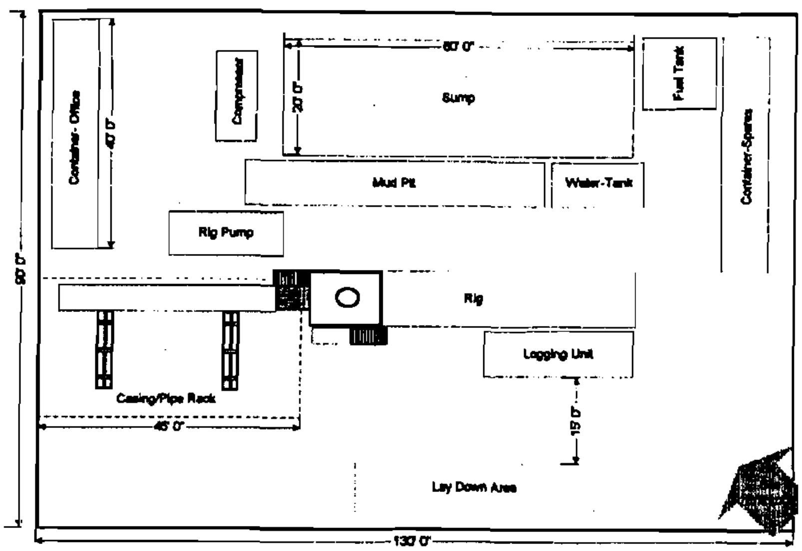

Figure 3-1. Indonesia Slim-Hole Site (Anderson et al., 1996)

The LCP is activated at the rig site by the addition of an activator. The cement then behaves as a conventional slurry with excellent setting behavior (Figure 3-2).

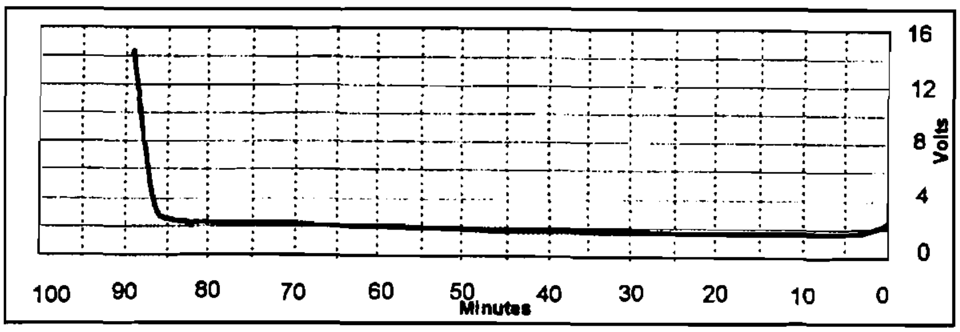

Figure 3-2. Thickening Time of LCP (Anderson et al., 1996)

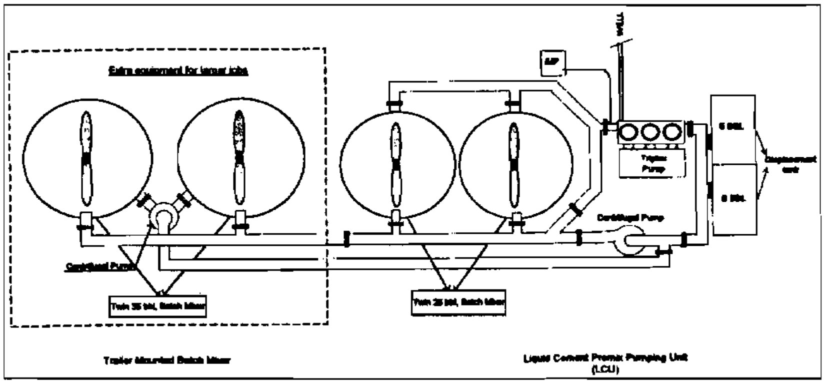

Figure 3-3. Mixing Equipment for LCP (Anderson et al., 1996)

Wellbore temperatures as high as 450°F can be treated. Thickening time can be adjusted between 1 to 24 hours. LCP is compatible with conventional cementing additives.

Trailer-mounted batch mixers (Figure 3-3) are used when operations require different densities for lead and tail slurries.

Over twenty jobs completed with the LCP are summarized in Table 3-1. Many more jobs are being planned by operators in the area.

TABLE 3-1. LCP Jobs (Anderson et al., 1996)

JOB NUMBER	DATE	RIG	OPERATION	DEPTH feet	BHCT deg F	DENSITY ppg	ACTIVATOR A-1	A-3	VOLUME bbls
001	29/03/96	Rig # 2	9-5/8" Casing	126	80	16.00	0.10	0.55	20.0
002	04/04/96	Rig # 2	Lost Circulation Plug#1	617	100	14.00	0.45	0.80	7.5
003	04/04/96	Rig # 2	Lost Circulation Plug#2	617	100	14.00	0.45	0.80	7.5
004	05/04/96	Rig # 2	7" Casing	617	100	13.50	0.25	0.55	25.0
005	05/04/96	Rig # 2	7" Back-fill	617	100	13.50	0.25	0.55	25.0
006	05/04/96	Rig # 2	7" Top Job	126	80	16.00	0.20	0.55	10.0
007	13/04/96	Rig # 1	Lost Circulation Plug#1	22	80	14.00	0.30	0.80	10.0
008	13/04/96	Rig # 1	Lost Circulation Plug#2	22	80	14.00	0.30	0.80	10.0
009	15/04/96	Rig # 1	9-5/8" Casing	108	80	16.00	0.10	0.55	40.0
010	22/04/96	Rig # 1	Lost Circulation Plug#1	260	80	14.50	0.55	0.80	10.0
011	26/04/96	Rig # 1	7" Casing (lead)	1000	110	13.50	0.40	0.15	35.0
			7" Casing (tail)	1000	110	16.00	0.40	0.15	10.0
012	26/04/96	Rig # 1	7" Top Job	1000	80	16.00	0.10	0.55	10.0
013	29/04/96	Rig # 2	4-1/2" Casing (lead)	1827	120	13.50	0.40	0.15	20.0
			4-1/2" Casing (tail)	1827	120	16.00	0.05	0.20	10.0
014	30/04/96	Rig # 2	4-1/2" Back-fill	1827	120	13.50	0.40	0.15	30.0
015	30/04/96	Rig # 2	4-1/2" Top Job	1827	80	16.00	0.10	0.55	10.0
016	08/05/96	Rig # 1	4-1/2" Casing (lead)	1975	135	13.50	0.40	0.20	35.0
			4-1/2" Casing (tail)	1975	135	16.00	0.05	0.10	10.0
017	08/05/96	Rig # 1	4-1/2" Back-fill	1975	135	16.00	0.05	0.55	20.0
018	08/05/96	Rig # 1	4-1/2" Top Job	1975	80	16.00	0.10	0.55	10.0
019	25/05/96	Rig # 2	Cement Plug	4175	185	16.00	0.00	0.15	4.0
020	26/05/96	Rig # 2	Cement Squeeze	1720	90	14.90	0.35	0.55	4.0
021	26/05/96	Rig # 2	Cement Squeeze	1720	90	14.90	0.35	0.55	5.0
							Total:		378.0

Note: Activator concentrations specified in gallons per barrel of Liquid Cement

BJ Services Indonesia emphasized that storage life of LCP must be tested at rigsite ambient temperatures (not necessarily room temperature). Thickening times should also be checked before LCP is pumped into the well.

LCPs are of obvious benefit for slim-hole operations for which site size is limited. BJ Services believes that these products are also a realistic alternative for conventional operations by making use of larger storage tanks.

3.2 SCHLUMBERGER DOWELL (ANADARKO EXPERIENCE)

Schlumberger Dowell (Waters and Wray, 1995) described cementing developments and experience in cementing narrow slim-hole annuli in the Anadarko Basin. They found that a more dispersed cement is required to reduce friction pressure losses. At the same time, acceptable fluid-loss control and solids suspension must be maintained. A rapid and predictable transition from fluid to set cement is very advantageous. Mud removal is also critical in a slim annulus. It may be possible to attain turbulent flow to aid in removal of drilling mud during cementing operations. Development, laboratory testing and field operations were successfully conducted with improved spacer and cement formulations and field procedures.

A common casing program in the Anadarko Basin (West Oklahoma and Texas panhandle) includes 5½-in. intermediate casing with a 3½-in. liner or 2⅞-in. production casing run below into the Red Fork formation inside a 4¾-in. hole. Achieving an effective seal in the narrow annulus of the production zone was studied in detail.

Standard cement slurries in this area included Class H cement, silica sand and/or flour, a retarder, a dispersant and a cellulose fluid-loss additive. Inadequate performance of this system in the narrow annuli was attributed to poor mud removal and nonoptimum slurry properties. Transition periods with cellulose were found to be about 49 minutes. This long transition period may allow excessive invasion of reservoir fluid into the slurry during set-up.

A new slurry was developed specifically for these slim-hole applications. Basic objectives included:

- Reduced slurry viscosity without sedimentation problems
- Reduced transition period from fluid to set cement
- Effective placement techniques based on turbulent flow or optimized laminar flow
- Low fluid loss and free water

Computer modeling was used to estimate flow rates required (and attainable) for the spacer and slurry. An appropriately designed spacer can achieve turbulent flow at pump rates of 3 BPM and above outside the 3½-in. liner.

Friction pressure must be monitored at higher pump rates. Pumping pressure is compared to pore and frac pressures in Figure 3-4. These data represent a 3½-in. liner in 4¾-in. open hole, spacer under turbulent flow and a pump rate of 3.5 bpm. Only a limited range of flow rates can attain turbulence while remaining below frac pressure.

If the hole is over gauge due to washout, injection rates required for turbulence most likely cannot be attained. Careful attention should then be given to optimizing laminar flow techniques.

Waters and Wray discussed steps to ensure effective removal of drilling mud when laminar conditions must be used. These include:

- Density of displacing fluid should be at least 10% greater than displaced mud
- Friction pressure of the displacing fluid should be at least 20% greater than displaced mud
- Flow rates on the narrow side of an eccentric annulus must be sufficient to overcome the yield point of the mud
- Fluid velocity on the wide side of an eccentric annulus must not be significantly greater than on the narrow side so that channeling is minimized

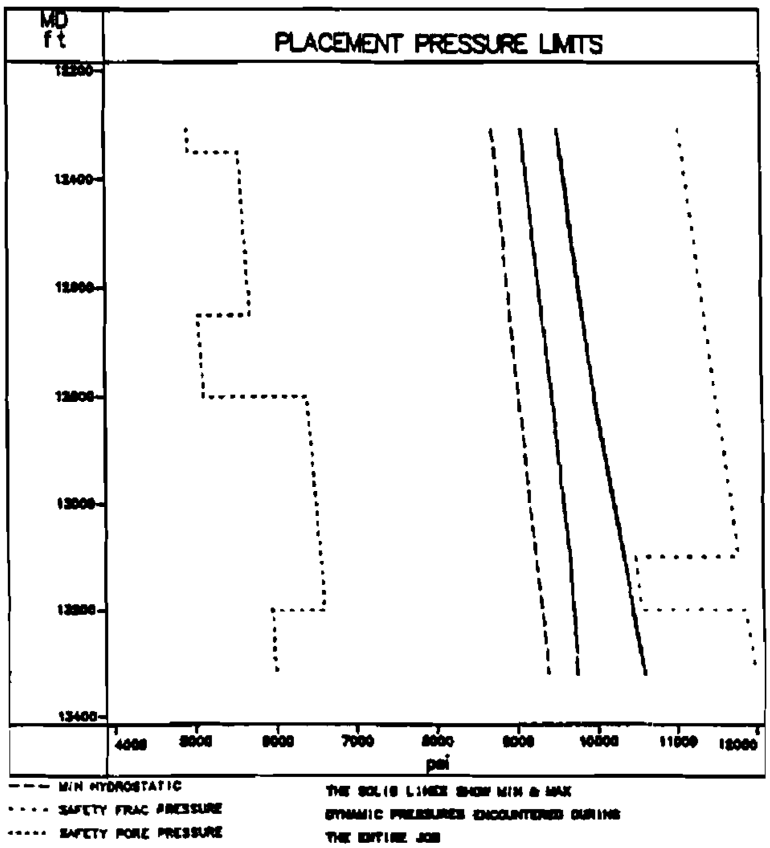

Figure 3-4. Cement Pump Pressures and Frac Gradient (Waters and Wray, 1995)

Maximum and minimum pump rates for meeting these criteria can be estimated. Rates for spacer and slurry for 3½-in. liner in 4¾-in. hole are summarized in Table 3-2. Rates of 1 to 6 BPM are appropriate for a centered liner. However, maximum practical rates are limited by formation frac pressure.

TABLE 3-2. Pump Rates for Effective Laminar Flow of Spacer (Waters and Wray, 1995)

Displacing Fluid: Drilling Mud Displacing Fluid: Laminar Flow Spacer				
		Open Hole Size		
Standoff %		4.50" bpm	4.75" bpm	5.0" bpm
100%	Min. Rate	1.0	1.0	1.0
	Max. Rate	3.0	5.0	6.0
95%	Min. Rate	1.0	1.0	1.0
	Max. Rate	3.0	5.0	6.0
85%	Min. Rate	1.0	1.0	1.0
	Max. Rate	3.0	4.0	6.0
75%	Min. Rate	1.0	1.0	1.0
	Max. Rate	2.0	3.0	5.0

Displacing Fluid: Laminar Flow Spacer Displacing Fluid: Cement Slurry				
		Open Hole Size		
Standoff %		4.50" bpm	4.75" bpm	5.0" bpm
100%	Min. Rate	1.0	1.0	1.0
	Max. Rate	6.5	7.5	8.4
95%	Min. Rate	1.0	1.0	1.0
	Max. Rate	7.1	8.0	9.0
85%	Min. Rate	1.0	1.0	1.0
	Max. Rate	8.6	9.5	10.7
75%	Min. Rate	1.0	1.0	1.0
	Max. Rate	10.7	11.8	13.2

Schlumberger Dowell found that the required fluid-loss properties using conventional cellulose additives are difficult to attain without significantly increasing viscosity. A copolymer fluid-loss additive was investigated for these applications. Viscosity increases with copolymer were found to be relatively small.

Slurry thickening time was another important property. To reduce the time available for gas cutting, a thickening time of 1 hr after placement was considered maximum. In many cases, this requirement dictates that retarder not be used.

Turbulent flow was also desired for slurry placement. Minimum pumping rates are compared in Table 3-3 for the 3½-in. liner and 2⅞-in. casing options. Limitations in the flow rates for mud removal preclude obtaining turbulent flow with the slurry.

TABLE 3-3. Pump Rates for Turbulent Slurry Placement (Waters and Wray, 1995)

Liner Outer Diameter: 3½"				
		Open Hole Size		
Field Name	Standoff %	4.50" bpm	4.75" bpm	5.0" bpm
Class H	100%	7.00	7.34	7.83
Cement	95%	7.50	7.96	8.46
Plus	85%	9.03	9.55	10.10
Copolymer	75%	11.22	11.81	12.44

Casing Outer Diameter: 2⅞"				
		Open Hole Size		
Fluid Name	Standoff %	4.50" bpm	4.75" bpm	5.0" bpm
Class H	100%	6.93	7.45	8.02
Cement	95%	7.49	8.03	8.61
Plus	85%	8.91	9.54	10.16
Copolymer	75%	10.95	11.63	12.35

Several cementing jobs have been performed with the optimized system. One well had a 3½-in. liner cemented from 12,900 to 12,500 ft. The turbulent spacer and modified cement slurry were used. Thickening time for the cement is shown in Figure 3-5. The transition time was only 20 min and total thickening time was just over 3 hours. An excellent hydraulic seal was obtained over the entire interval.

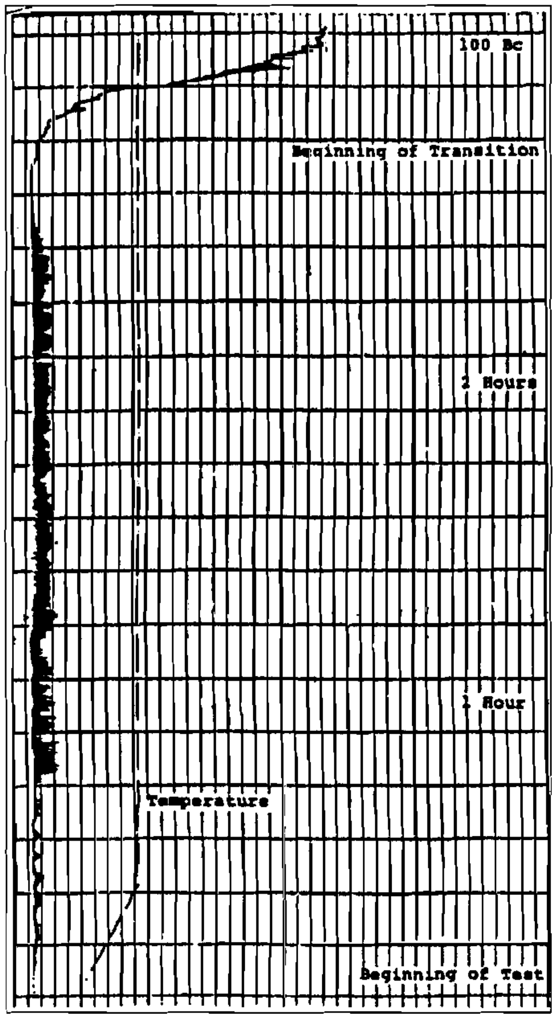

Figure 3-5. Thickening Time for Field Slurry (Waters and Wray, 1995)

Based on slim-hole cementing experience in the Anadarko Basin, Schlumberger Dowell recommended that small-annulus wells be carefully modeled prior to cementing, that spacers be pumped in turbulent flow if possible, that cement slurries be pumped using effective laminar placement techniques (since turbulent flow probably cannot be attained), that minimum fluid-loss values be used, that thickening time after placement be minimized, and that transition times from fluid to set cement be short as possible.

3.3 SHELL RESEARCH AND HALLIBURTON ENERGY SERVICES (MUD DISPLACEMENT)

Shell Research Rijswijk and Halliburton Energy Services (van Vliet et al., 1995) performed a theoretical and experimental study of cementing efficiencies in a slim-hole annulus using conventional and special drilling fluids. They analyzed cement displacement for cementing a 3½-in. liner in a 4⅛-in. hole. Both computer simulations and experimental results were compared. Harsh environmental conditions were assumed: a HPHT well with a minimal window between pore and frac pressures. Their results showed that a conventional solids-laden water-base drilling fluid cannot be fully displaced by the slurry. However, a potassium-formate brine drilling fluid can be displaced at almost 100% efficiency. They concluded that drilling fluids with low, flat gel strength that produce a thin, tough filter cake are greatly preferred from the aspect of improved cementing efficiency in slim holes.

A paramount concern in slim-hole cementing operations is excessive frictional pressure loss when pumping fluids at high rates in the narrow annulus (Figure 3-6). Rule-of-thumb recommendations suggest a displacement velocity of at least 80 m/min (260 ft/min). It is challenging to achieve efficient displacement of the drilling fluid while remaining below frac pressures in a slim annulus.

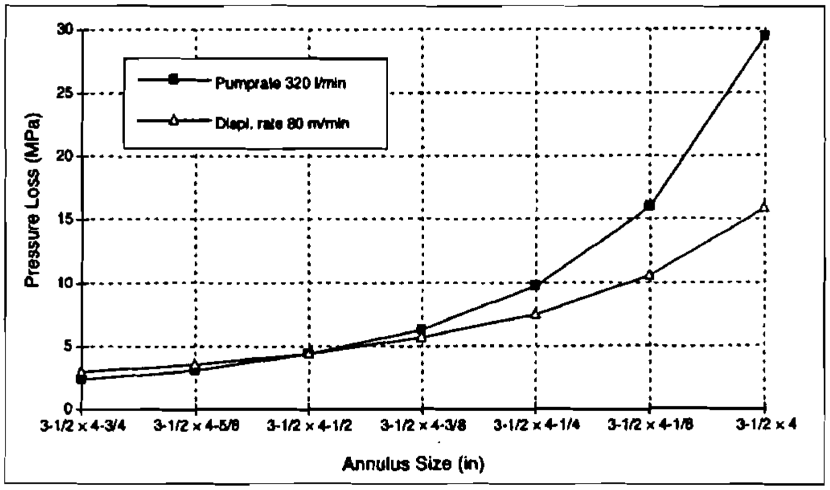

Figure 3-6. Pressure Losses in Slim Annuli (van Vliet et al., 1995)

Computer simulations were performed using a modified Bingham plastic model that did not include the effects of eccentricity or rotation. Two basic drilling fluids were modeled: 1) conventional water-base fluid weighted with barite and 2) caesium formate brine-base fluid with xanthan polymer. A weighted spacer (SG = 2.34) was required. Spacer volumes corresponded to either 300 or 1000 m height in the annulus. Slurry density was also high (SG = 2.37).

Results of the simulations indicated that an 80 m/min annular velocity could not be achieved in the 3½ by 4⅛-in. annulus of the HPHT well tested.

Experiments were conducted in a test apparatus consisting of a 4.6-m length of artificial sandstone (Figure 3-7). The inner pipe was rotated at 20 rpm during pumping.

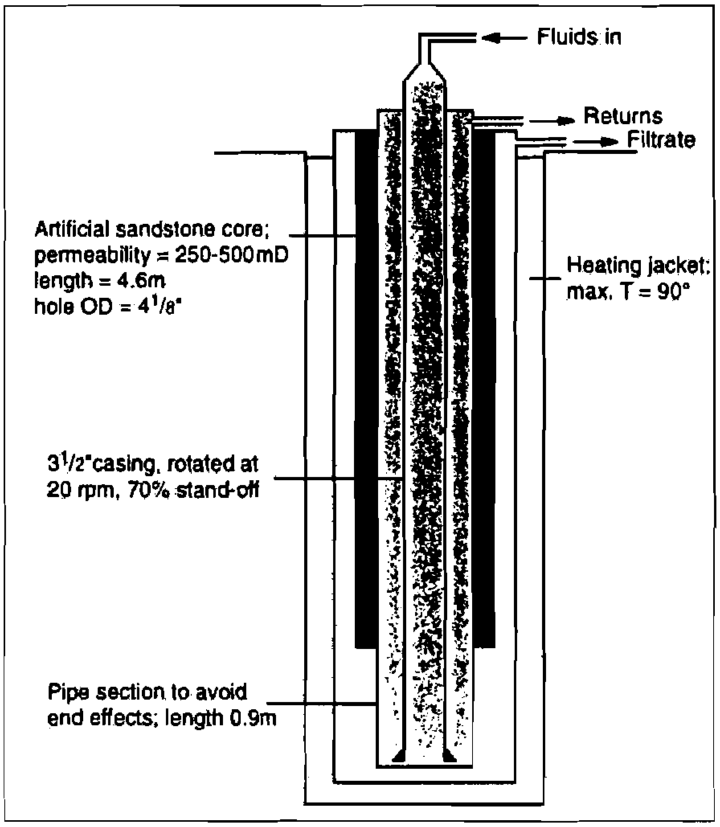

Figure 3-7. Experimental Apparatus for Cementing Tests (van Vliet et al., 1995)

Two HPHT drilling fluids were tested (Table 3-4). The brine-base fluid is part of Shell Research's overall slim-hole development project underway for the past few years.

TABLE 3-4. Fluid Properties (van Vliet et al., 1995)

Fluid	T (°C)	PV - YP (cP - lbs/100 ft²)	10"/10' gels (lbs/100 ft²)	API mud fluid loss	
				Volume (ml/30 min)	Cake thickness (mm)
Conventional drilling fluid	80	43 - 38	50/115	8	3
Heavy brine based drilling fluid	80	43 - 27	5/7	4	0.5
Dual spacer	27	81 -26	4/17	--	--
Cement slurry	27	43 - 12	10/37	--	--

The maximum displacement efficiency of the drilling fluid by the cement ranged only from 65-80% with conventional muds (Table 3-5). A mud channel was observed in all cases. Increasing the contact time of the spacer (test 4) or slurry (test 5) did not improve displacement.

TABLE 3-5. Experimental Results (van Vliet et al., 1995)

Test	Average pipe stand-off (%)	Fluids	Annular velocity (m/min)	Contact time (min)	Pressure to break circulation (kPa)	Mud displacement efficiency (%)	Remarks
1	6	Conventional mud Spacer Cement	100 80 50	80 4 12	620	79	Base case
2	17	Conventional mud Spacer Cement	100 80 50	80 4 12	410	65	Base case
3	8	Conventional mud Chem. wash Spacer Cement	100 80 80 50	80 4 4 12	480	78	Attempt to remove mud with chemical wash
4	13	Conventional mud Spacer Cement	100 80 50	80 12 12	550	66	Cement volume doubled
5	13	Conventional mud Spacer cement	100 80 50	80 4 24	550	66	Cement volume doubled
6	12	Brine-based mud Spacer Cement	100 80 50	80 4 12	100	95	Base case with PFX-2 mud
7	9	Brine-based mud Spacer Cement	100 80 50	80 4 12	70	93	No pipe rotation
8	7	Brine-based mud Spacer Cement	50 50 50	160 6.5 12	70	95	Lower annular velocity of mud and spacer

Remarks: 1) Tests were preceded by 8 hr mud circulation stage.
2) Pipe was rotated at 20 RPM, except in tests 7 and 8.
3) Test temperature was 90°C.

Results with the brine-base muds were excellent (close to 100% displacement). Fluid properties that were found to be important were not primary rheology (PV, YP). It was determined that it is important to use a drilling fluid with low, flat gels that form a thin, tough filter cake.

Example graphs comparing contact times for the experiments are shown in Figure 3-8.

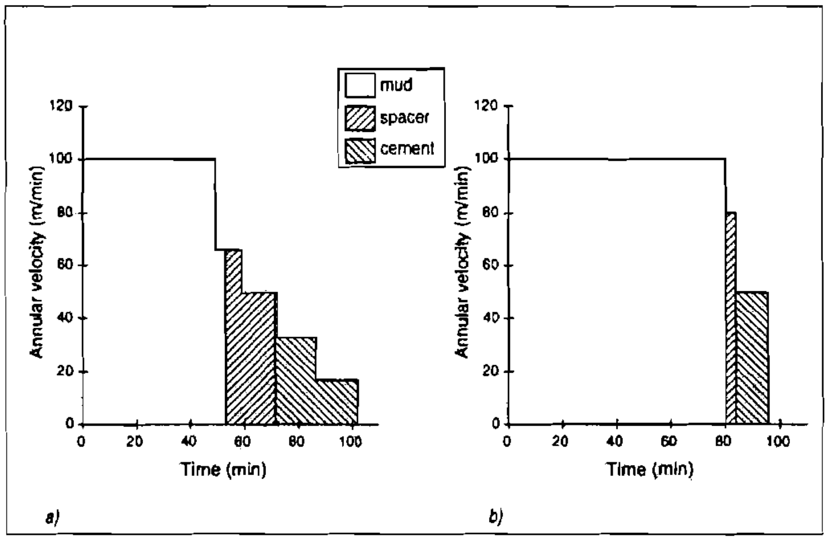

Figure 3-8. Annular Velocities During Cementing with Conventional Fluid: a) Simulation b) Experiment (van Vliet et al., 1995)

Shell Research Rijswijk and Halliburton Energy Services concluded that, for cementing slim-hole wells, it is very important to use a drilling fluid that has a low, flat gel strength and forms a thin, tough filter cake. Brine-based fluids are representative of these types of fluids.

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4. Completions

4.1 ARCO ALASKA (KUPARUK COMPLETIONS)

ARCO Alaska (Pearson et al., 1996) achieved significant cost reductions by combining slim-hole drilling and completion technology with increased efficiency in planning and procurement of consumables. A goal was set for the Kuparuk River Field (Figure 4-1) for reducing well costs by 30%. Reduced-diameter injectors and monobore producers were designed for the field. Early results with the revised designs and operations showed that the potential exists for exceeding 30% cost reductions as the equipment and procedures are finely optimized.

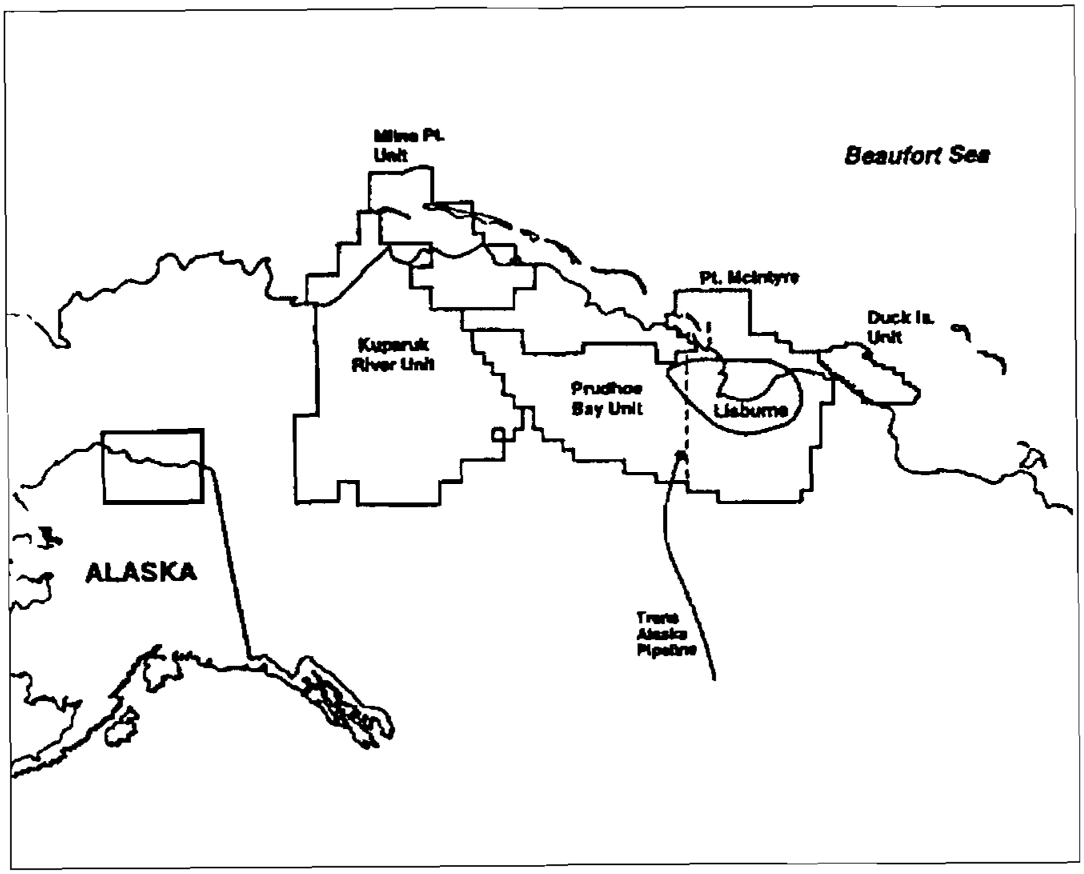

Figure 4-1. Kuparuk River Field (Pearson et al., 1996)

Development wells in the Kuparuk River Field have generally used a standard drilling and completion program which consists of 16-in. conductor, 9⅝-in. surface casing, and 7-in. production string (Figure 4-2). A 5-in. liner is run when overpressured zones are encountered or lost circulation occurs. Completions are either single zone or selective for two productive sands.

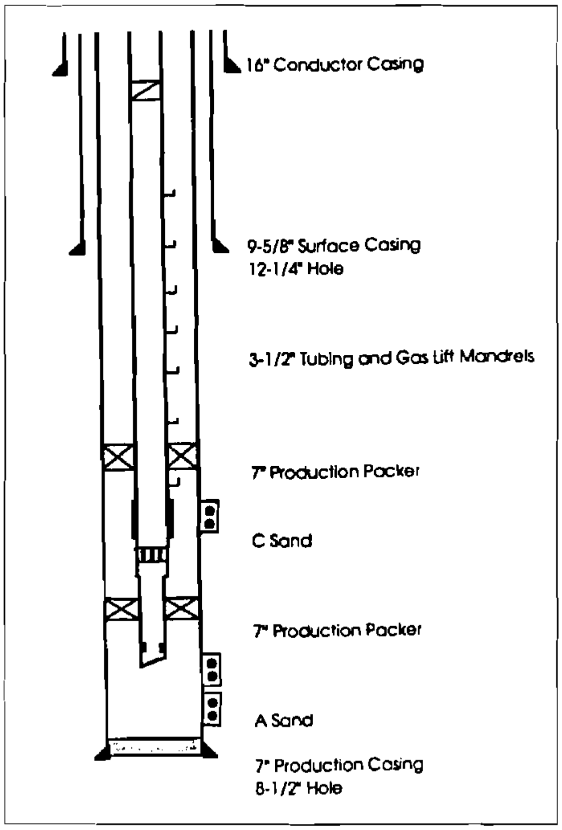

Figure 4-2. Conventional Selective Completion (Pearson et al., 1996)

Historic costs in the field are compared in Figure 4-3. Expected costs for future wells were determined to be too high because most future wells would be infill wells. With significantly lower reserves associated with each well, costs needed to be reduced to maintain economic viability.

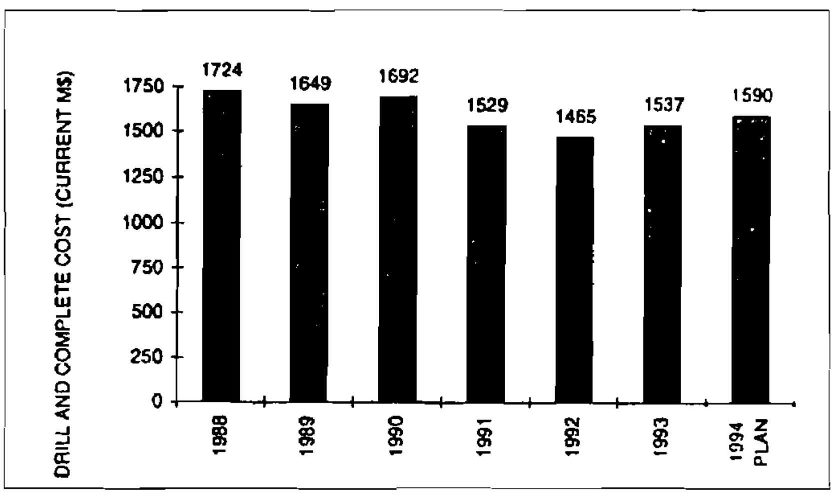

Figure 4-3. Drilling Costs at Kuparuk River (Pearson et al., 1996)

A goal of 30% cost reduction was set (i.e., starting in 1994). No single cost category was foreseen for achieving the entire reduction. Small-scale reductions were implemented in several areas. These included: 1) long-term alliances with contractors and suppliers (7% savings), 2) optimized well drilling plan that eliminated cement isolation of upper annulus, eliminated SSSVs, reduced gyro runs and reduced open- and cased-hole logs (4% savings), 3) reduced number of selective completions (2% savings) and 4) field management procedures to reduce reservoir pressure around an infill well prior to initiating drilling operations (4% savings).

Beyond these steps (a 17% cost reduction), slim-hole drilling was the remaining potential technology for savings. ARCO determined that 3½-in. production tubing was required for the expected flow rates. The downsized drilling program included a 9⅞-in. surface hole and 6¾-in. production hole.

A significant aspect for achieving the targeted cost reductions was the requirement that drilling efficiency not decrease in smaller hole sizes. If it was found to be reduced, additional days on site could quickly offset any savings from smaller equipment and pipe.

Three slim-hole completion designs were developed, two for producers and one for injectors. Injectors were to be tubingless monobore wells with 4½-in. casing cemented in 6½-in. hole.

Producers were designed with tapered production casing. A 3½-in. monobore completion results in a 5½ by 3½-in. tapered design (Figure 4-4).

In some areas of the field, a long string is required for pressure isolation prior to penetrating the target zone. For these cases (Figure 4-5), a 4¾-in. hole is drilled out of casing with coiled tubing or a conventional rig.

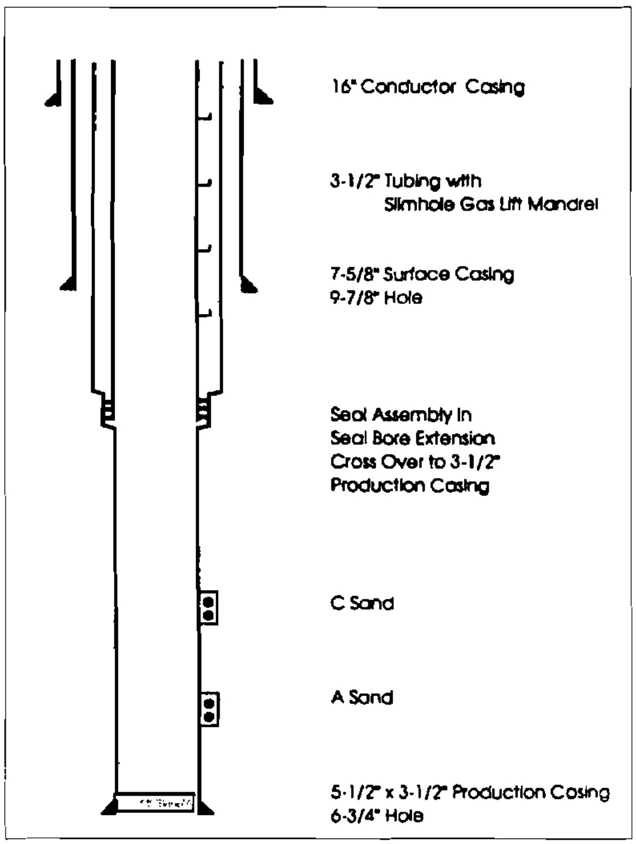

Figure 4-4. Slim Monoboro Completion (Pearson et al., 1996)

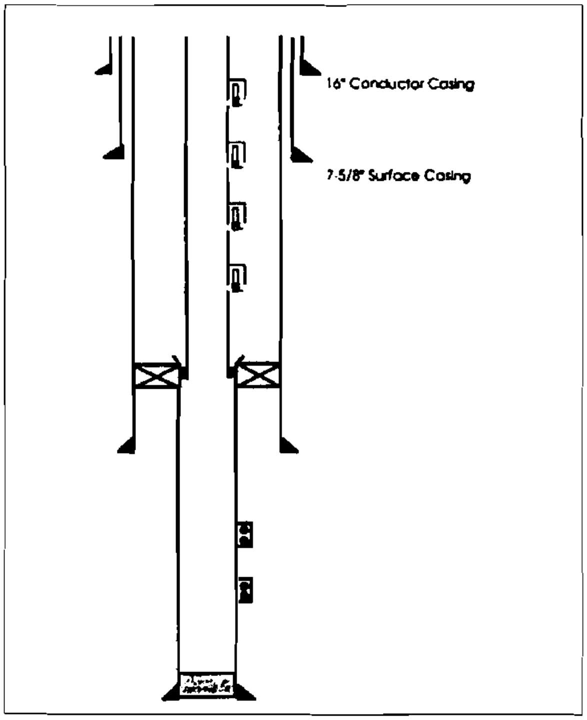

Figure 4-5. Slim Completion with Pressure Isolation (Pearson et al., 1996)

Cost savings with these slim-hole completions were estimated at 8% of total cost for monobore producers and 13% for injectors. Gains were analyzed after several slimmed completions had been run in the field after implementing all areas for cost savings (Figure 4-6). The average cost for these wells was 26% below the base cost. Operations had proven that the drilling and casing programs were feasible and that comparable drilling efficiencies could be achieved in reduced size holes.

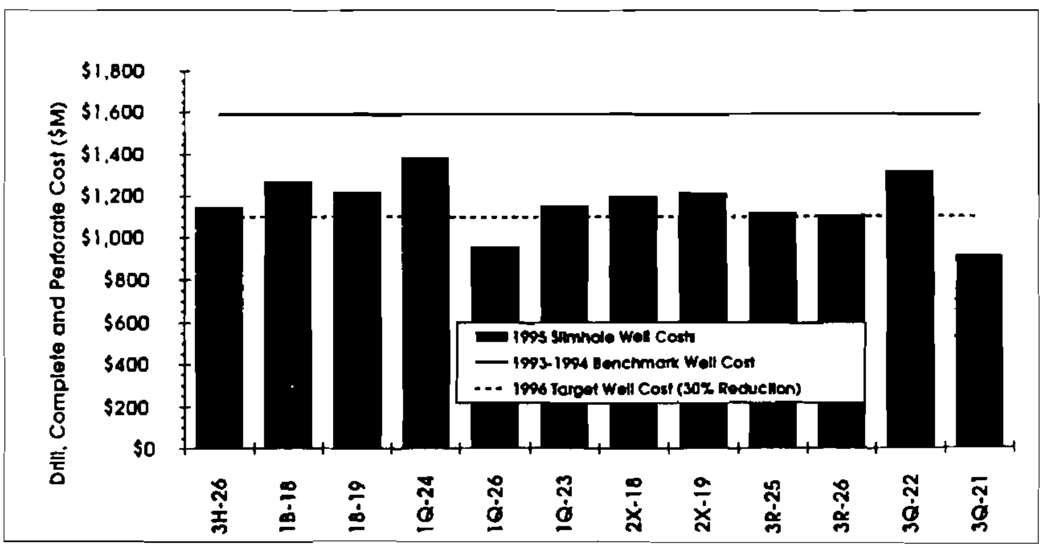

Figure 4-6. Slim Well Costs (Pearson et al., 1996)

Average drilling times were 0.4 days longer than conventional offset wells (Figure 4-7). However, further optimization was possible in hydraulics and downhole tools. Reaching and exceeding the cost reduction goal for the project was anticipated by ARCO.

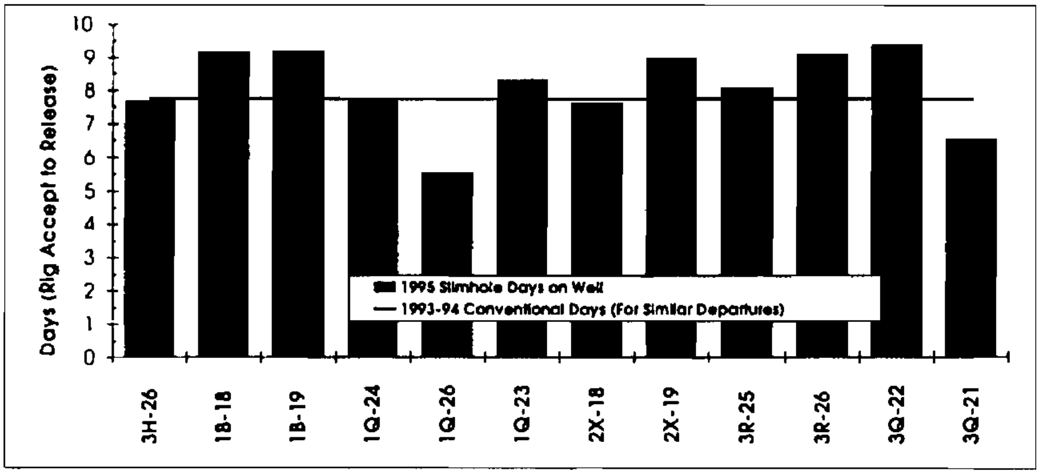

Figure 4-7. Slim Well Rig Time (Pearson et al., 1996)

Other areas in which optimization was expected include improved design to combat erosion of the 9⅞-in. bits, improved hydraulics for different motors and turbodrills, identifying more applications for tubingless monobore producers, extending lateral departure limits for slim-hole assemblies, and careful evaluation of other advanced technologies and concepts for the field (horizontal wells, multilaterals, open-hole completions, underbalanced drilling etc.).

4.2 BP (SAVINGS WITH SMALLER COMPLETIONS)

BP (*Downhole Talk* Staff, 1995) reported time and cost savings breakdowns for operations at Wytch Farm in the North Sea. They compared the 17½-in. section in a Stage 3 ERD well to the 12¼-in. equivalent section in a horizontal producer. Section lengths were similar for these wells. The 12¼-in. hole was drilled and completed 40% faster than the 17½ in. and at a cost savings of 36%.

Time savings are compared in Table 4-1. The largest contribution (25%) to the time savings is the faster ROP in the smaller hole.

TABLE 4-1. Time Savings for 12¼-in. Section (*Downhole Talk* Staff, 1995)

SECTION TIMINGS		
Operation	**% Improvement of M4 over M5**	**Improvement as a % of M5 trouble free time**
M/U BHA	25%	3%
Tripping	56%	3%
Circulating	48%	4%
Drilling	44%	25%
Pulling BHA	15%	1%
Ream	100%	1%
Flow Check	33%	0%
Rig Up	40%	1%
Rig Down	100%	1%
Run Casing	23%	2%
Total Trouble Free	**40%**	**40%**

Cost savings for the smaller section were also substantial, amounting to 36% overall (Table 4-2). The largest component of the cost savings was rig costs (11% less). Several other areas provided significant cost reductions.

TABLE 4-2. Cost Savings for 12¼-in. Section (*Downhole Talk* Staff, 1995)

SECTION COSTS		
Category	**%Improvement of M4 over M%**	**Improvement as a % of M5 Total Cost**
Casing	27%	6%
Casing Accessories	100%	1%
Rig	42%	11%
Bits	-51%	-2%
Mud	50%	6%
Cement	69%	8%
Fuel, Power, Water	79%	2%
Directional	20%	2%
Geological	50%	0%
Environmental	19%	2%
Total	**36%**	**36%**

4.3 CHEVRON USA (SLIM-COMPLETION INJECTORS)

Chevron U.S.A. Inc. (Dennis et al., 1995) successfully used slim-completion technology in an expansion of a steam-injection project at the Midway Sunset field in California. Slim injectors were used to reduce capital investment. Three slim completions (6¼-in. bit and 2⅞-in. casing) could be drilled for the cost of each conventional injector, i.e., about $40,000 for a slim well versus $120,000 for conventional. Costs were reduced in rig costs, cementing, packers and tubulars. The additional injectors allowed with the slim-hole development plan provided improved profile control and management of the steam flood. Total production has increased since the flood was implemented.

A conventional design for this steam-flood expansion would have consisted of ten injection wells (seven dual-string completions) and three temperature/observation wells. The slim-hole option allowed 38 injectors and 10 temperature/observation wells for the same costs.

Cost advantages with the slim option were obvious. However, some technical issues needed to be addressed before proceeding. Casing failure from thermal stress was considered and determined to be an insignificant problem. Pilot slim wells showed no mechanical failures from thermal stresses.

Chevron considered whether heat losses would be excessive in the slim tubingless completions as compared to the conventional design, which included production tubing. An analysis of heat losses showed that, over time, additional losses in the slim completions were not significant (Figure 4-8).

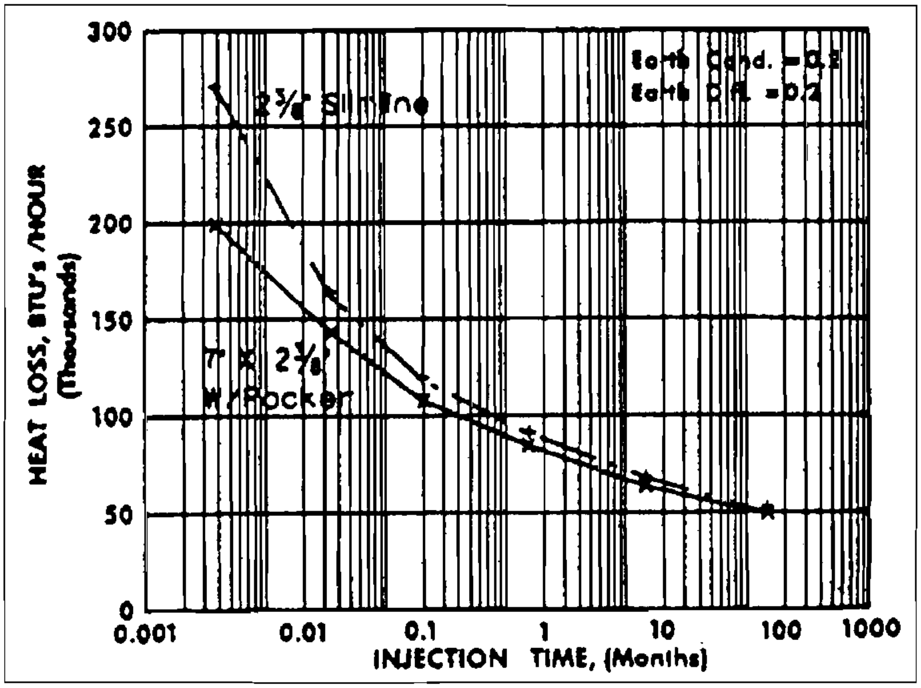

Figure 4-8. Heat Losses for Injector Options (Dennis et al., 1995)

Frictional pressure losses in the steam injectors were also compared. Modeling suggested that pressure drops would be less than 30 psi at the highest anticipated steam injection rate. Variation in steam quality was also analyzed with respect to pressure drop (Figure 4-9). These effects were also found to be insignificant for the slim option.

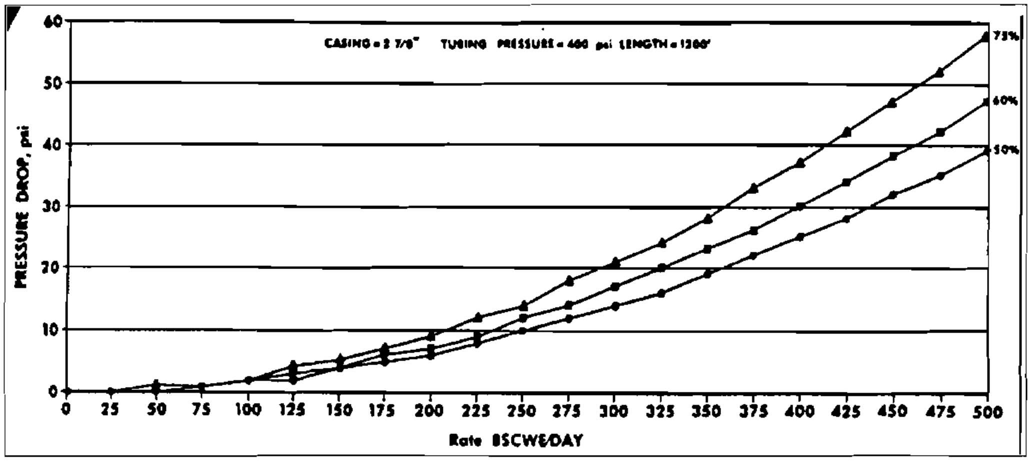

Figure 4-9. Steam Quality and Pressure Drop (Dennis et al., 1995)

A standard rotary rig was used to drill the slim-hole injectors. Average TD was about 1500 feet. Drilling the hole and cementing casing were completed in 1½ days. Conductor (8⅝-in. casing) was set to 80 ft; the production string was 2⅞-in., 6.5-lb J-55 tubing with ≤10% wall loss.

The slim injectors were completed with only minimal problems. Casing was perforated with a $1^{11}/_{16}$-in. wireline gun and 0.33-in. holes. Some perforations had to be broken down using acid which was spotted with coiled tubing or bullheaded.

The only operational problem with the slim completions was some sanding. Sanding occurred when injection was halted due to facility disruptions. Sand was successfully foamed out using coiled tubing.

4.4 HALLIBURTON ENERGY SERVICES (SLIM-HOLE SSSV)

Halliburton Energy Services (Vinzant and Smith, 1995) described the design and development of improved subsurface safety valves (SSSVs) for slim-hole applications. These assemblies have been required to support the stringent requirements of slim-hole monobore completion designs.

A typical flapper valve (Figure 4-10) places relatively severe constraints on the flow-tube ID. In most instances, the flapper closure design has been the limiting factor for determining the OD of tubing-retrievable flapper valves.

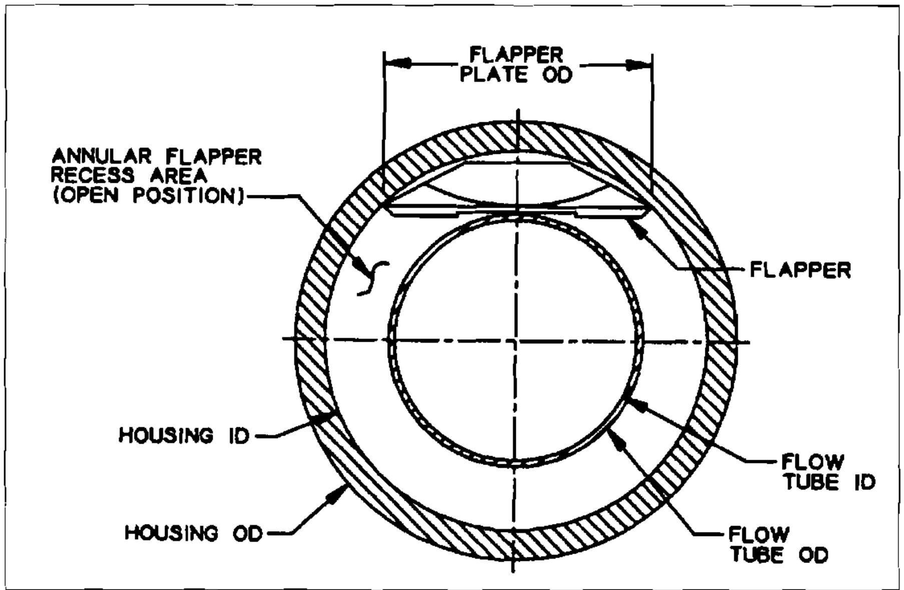

Figure 4-10. Conventional SSSV with Flat Flapper
(Vinzant and Smith, 1995)

Flapper-valve designs have become relatively popular (as compared to ball valves etc.) due to the need to minimize costs through simpler designs, reliability issues, and recent innovations in flapper design with better OD/ID ratios, especially with reference to curved flappers (Figure 4-11).

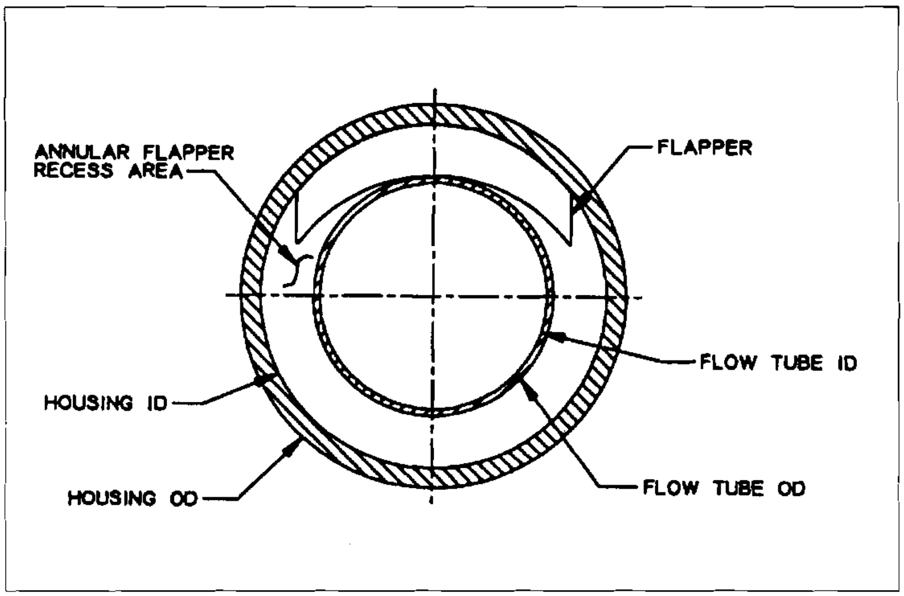

Figure 4-11. Curved Flapper Valve (Vinzant and Smith, 1995)

Halliburton Energy Services had sought to optimize the design of the flapper and its seat to maximize OD/ID ratio, sealing ability, reliability, etc. The angle of the seat was varied from 45 to 90° (Figure 4-12).

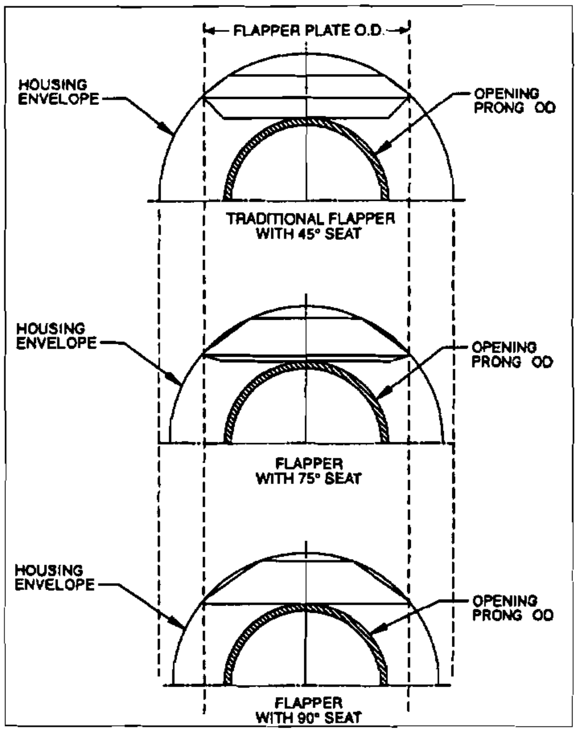

Figure 4-12. Flat Flapper Seat Designs (Vinzant and Smith, 1995)

Modifications in 90° seat designs led to curved flapper technology. As an example of the benefits of this approach, Halliburton stated that a reduction in OD of 1½ in. was attained for the 7-in. tubing-retrievable assembly. The sealing surface is formed along the curved intersection of two perpendicular cylinders (Figure 4-13).

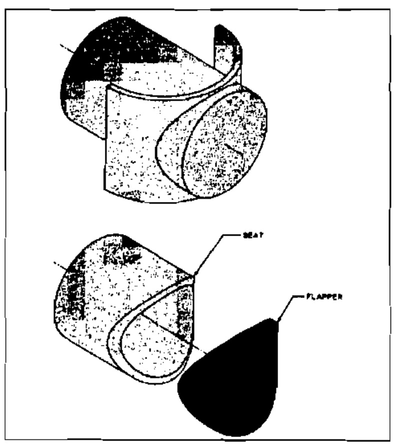

Figure 4-13. Curved Flapper Seat (Vinzant and Smith, 1995)

An additional improvement in flapper design is the use of metal-to-metal (i.e., sphere-to-sphere) contact for the seal surface, rather than a resilient element. Tests of the final design (Figure 4-14) showed that requirements for both low- and high-pressure sealing were met (200 to 15,000 psi).

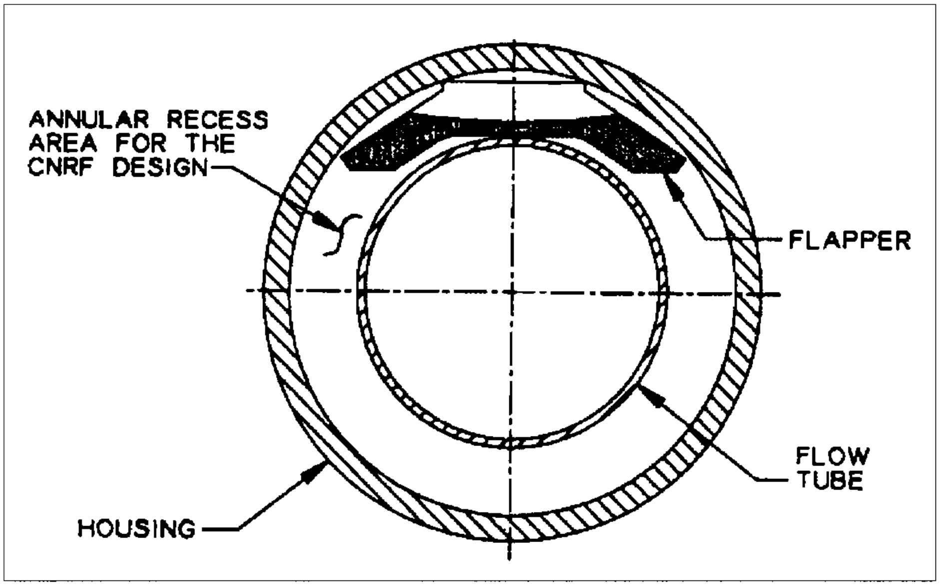

Figure 4-14. Contoured Nonresilient Flapper Valve
(Vinzant and Smith, 1995)

4.5 SHELL CANADA, BAKER AND IMPORT TOOL (THIN LINERS)

Shell Canada Limited, Baker Oil Tools and Import Tool Corporation Limited (Sutherland et al., 1996) carefully analyzed and successfully employed a thin-walled liner for pressure isolation prior to deepening a well in the Waterton field. Savings of $3-4 million per well are possible in deep re-entry applications by avoiding the need to drill a new well from surface. Thin-walled, close-tolerance 5½-in. liner equipment was placed in 7-in. casing and allowed drilling a long and deviated 4¾-in. hole with a tapered drill string.

The Waterton 14 well was drilled in 1964 to a depth of over 12,000 ft (Figure 4-15). Completion included perforated 7-in. casing and an open-hole zone. Recent production averaged over 4 MMscfd with 18% H_2S. The objective of the modern re-entry was to seal off depleted bottom zones and drill to deeper formations at virgin pressure.

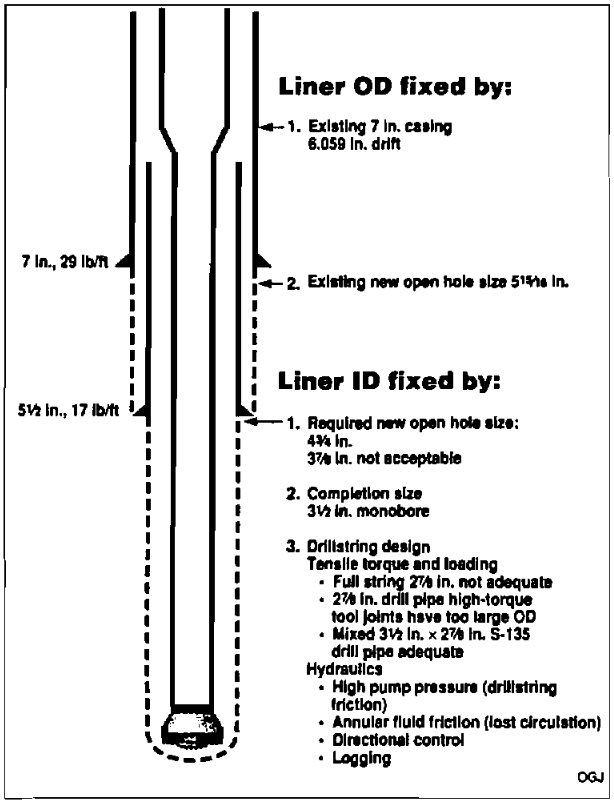

Figure 4-15. Liner Requirements for Deepening
(Sutherland et al., 1996)

The Waterton field is in a wilderness area with high environmental sensitivity. There were significant environmental issues which strongly favored a re-entry over a new well.

The drilling plan called for deepening the well from 12,054 to 18,241 ft followed by logging and some coring. Operations were designed to maintain the viability of the existing completion if the new section were plugged back.

The cost for a new well was estimated as $8-10 million. Drilling, evaluation and completion of the re-entry was estimated to cost $2.85 million, along with $1 million for well preparation and production testing.

Shell determined that it was necessary to set a drilling liner at the current TD to avoid lost circulation problems during drilling. A service rig would be used to snub in and cement the liner prior to rigging up the drilling rig.

A 4¾-in. hole was chosen because a 2⅞ by 3½-in. drill string was essential to achieve planned TD of over 18,000 ft, logging tool operations would be restricted in a smaller hole (i.e., 3½ in.), as well as concerns with high pump pressures, stiff BHAs, and deviation control.

Normally, a 4½ or 5-in. liner would have been run in 7-in. casing. However, only a 5½-in liner would allow the required hole to be drilled. Special liner equipment and running procedures were required due to the very small clearances (Figure 4-16).

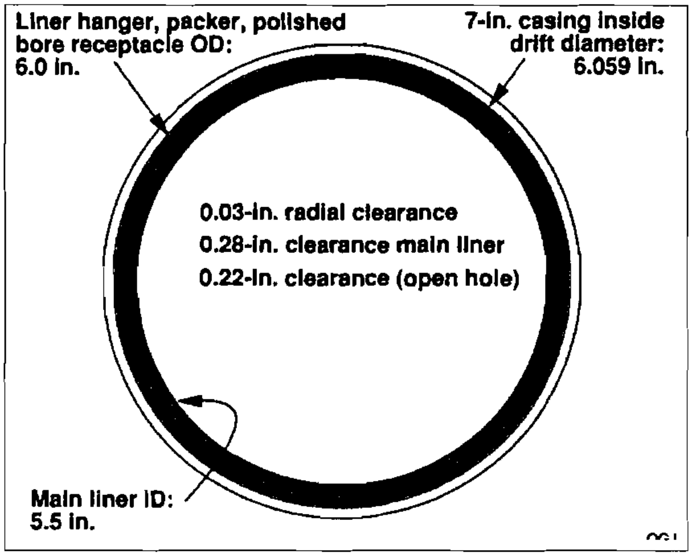

Figure 4-16. Liner Clearances (Sutherland et al., 1996)

Shell determined that a single-stage cementing operation would have a low probability of success because no liner packers could support a full column of hydrostatic pressure at that depth (Figure 4-17).

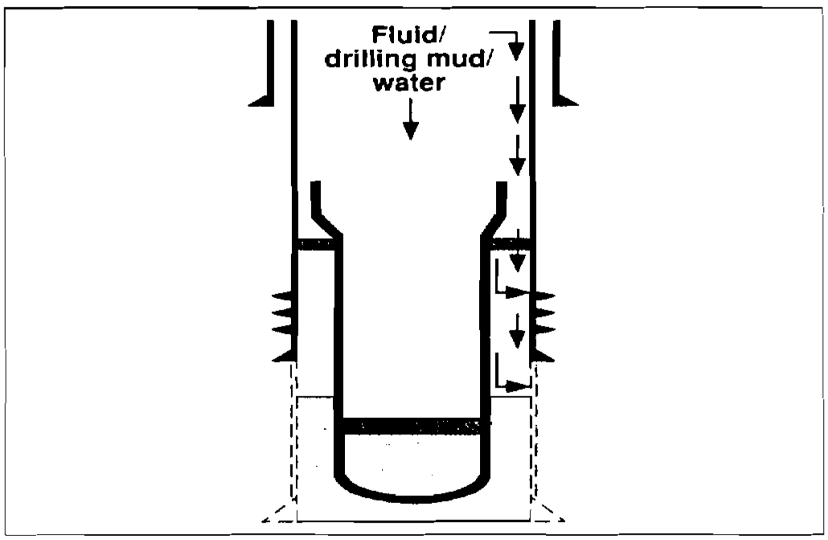

Figure 4-17. Packer as Primary Isolation (Sutherland et al., 1996)

The approach adopted was to first cement the bottom of the liner, run a second stub liner with a tieback seal assembly, and cement and sting it into the primary liner (Figure 4-18). With this approach, the seals only needed to be able to support the weight of the cement balanced plug used to cement the stub liner.

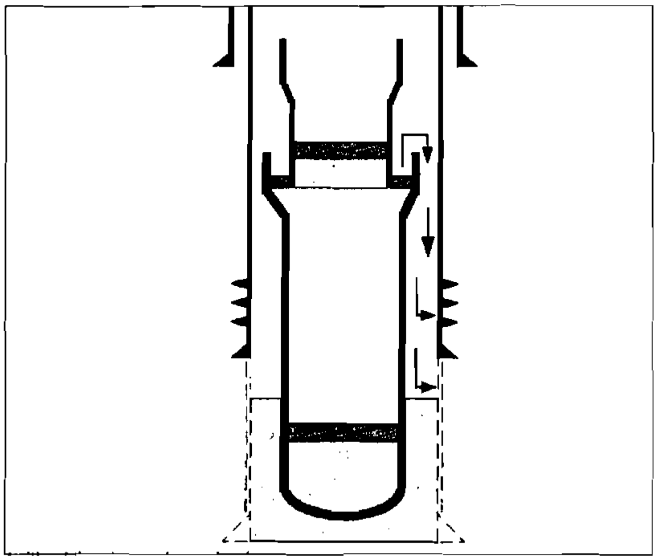

Figure 4-18. Stub Liner Cement Loss (Sutherland et al., 1996)

A new design mechanical-set liner hanger (Figure 4-19) was used that allowed hanger setting by rotation alone. This greatly increased the probability of a successful set if the liner should become stuck, i.e., upward motion is not required to release the hanger.

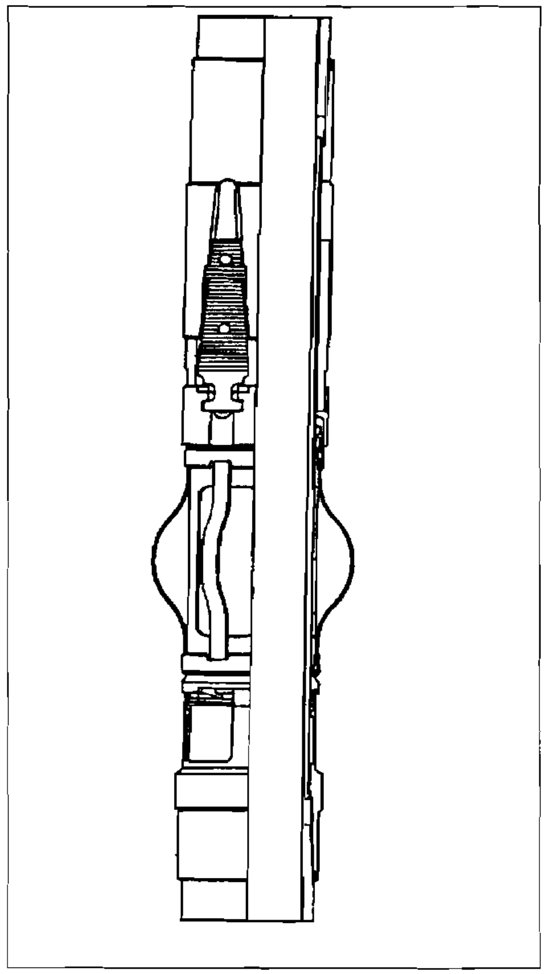

Figure 4-19. New Liner Hanger (Sutherland et al., 1996)

The liner assembly was run successfully and served to isolate the current productive intervals (Figure 4-20). The Waterton 14 was then deepened to the target depth of 18,000 ft.

The liner assembly was run successfully and served to isolate the current productive intervals (Figure 4-20). The Waterton 14 was then deepened to the target depth of 18,000 ft.

All design criteria were met with the special liners and assemblies. Burst capacity was attained inside 7-in. casing while allowing a 4¾-in. hole to be drilled. Shell is convinced that this well could not have been deepened to this great depth if the hole had been restricted to 3⅞ inches.

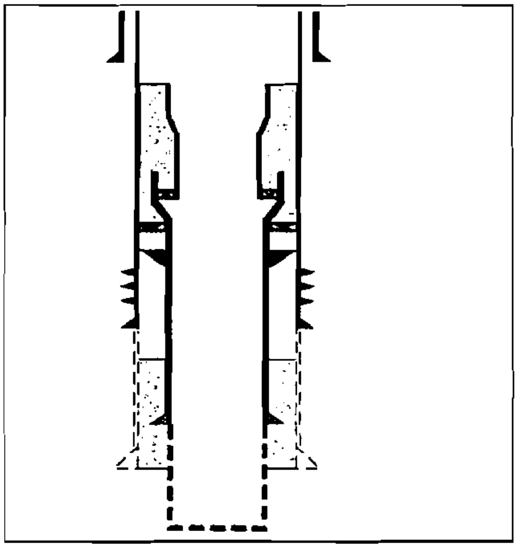

Figure 4-20. Completed Liner Assembly (Sutherland et al., 1996)

4.6 TEXACO (DUAL TUBINGLESS COMPLETIONS)

Texaco Exploration and Production (Holub, 1996) reported the results of using dual slim completions to reduce costs and increase safety in a high-pressure formation in an environmentally sensitive area. The marginally feasible development in the mature North Milton Field included three completions at 10,500 ft and two at 12,500 ft. Drill-site selection and environmental safety were critical in the area (near Houston). Costs were cut by planning a tubingless approach, which required only three wells be drilled for the five completions.

One string of the dual completion was run to the deeper zone and another to the 10,500 ft zone (Figure 4-21).

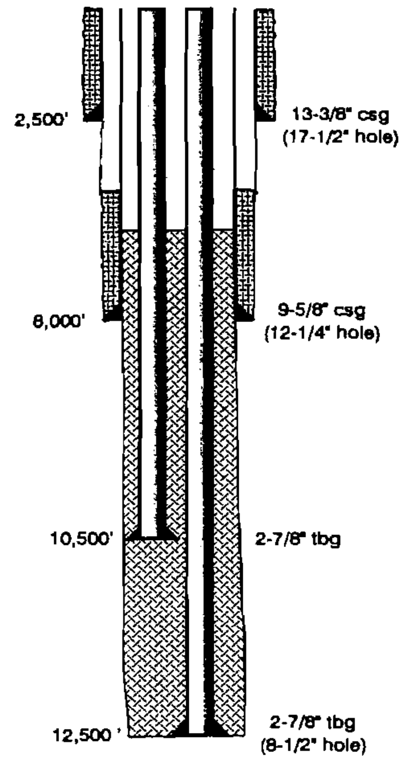

Figure 4-21. Dual Tubingless
Completion Design (Holub, 1996)

The costs saved for the two dual-completion wells amounted to about 40% of that estimated to drilled four wells for the four completions.

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5. Coring Systems

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5. Coring Systems

5.1 BAKER HUGHES INTEQ, NORSK HYDRO AND NOWSCO (EXPLORATION CONCEPT)

Baker Hughes INTEQ, Norsk Hydro and Nowsco UK (Ehret et al., 1995) described results of field trials of elements and procedures which would be required as part of a fit-for-purpose slim-hole floating vessel. The first step in this investigation was to determine whether high-quality cores and electric logs could be obtained using slim-hole technology on a floating vessel, and to drill/core with coiled tubing from a floating vessel. Cores were taken both with coiled tubing and with drill pipe. Although several problems were encountered, the technological feasibility of this approach for exploration applications was demonstrated.

An integrated slim-hole exploration system (including subsea BOPs, risers and small floating vessels) showed significant promise as an economically attractive system for exploration in deep water and/or remote locations. Rising costs in the North Sea have led to serious consideration of alternate exploration paradigms.

A test site was selected off Norway in over 400 ft of water. A semisubmersible rig would be used to drill to 5570 with drill pipe and set 7-in. casing. Coiled tubing and drill pipe would be used to drill and core with 4⅛-in. BHAs.

Additional equipment required for the offshore operation included an extra 5⅛-in. pipe ram between the standard triple BOP and 4-in. stuffing box. A drill-string lifting frame (Figure 5-1) was also devised. This connects the rig heave-compensation system to the injector. The frame had to be extended for planned operations.

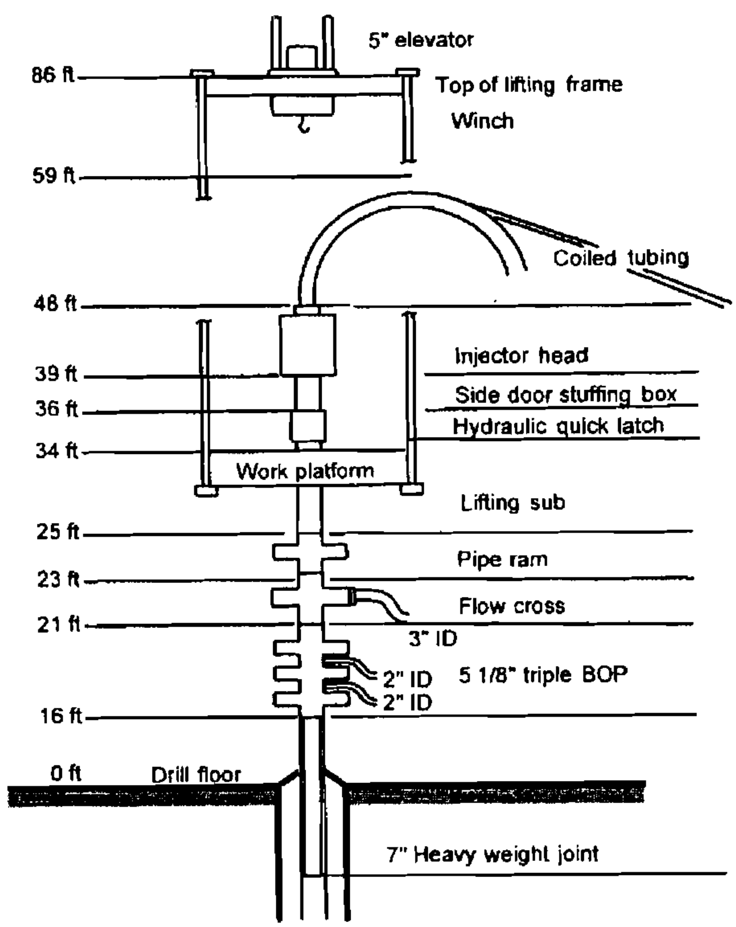

Figure 5-1. Drill-String Lifting Frame for CT Operations (Ehret et al., 1995)

Subsea well control was accomplished with a standard 18¾-in. 15,000-psi BOP. A 7-in. riser was run inside the existing (21-in.) riser for coiled-tubing operations. The smaller riser would increase annular velocities and decrease the tendency of buckling.

Coiled-tubing fatigue was a concern with respect to rig heave. Continuous small-scale pay-out and reel-in of the tubing might dramatically shorten fatigue life. This potential was addressed by reducing the operational pressure of the hydraulic motor on the tubing reel. This decreased tension on the reel and introduced slack (about 9 ft) into the tubing wraps.

Two-inch coiled tubing was selected for the operation based on fatigue and pressure loss estimates. Pressure-loss modeling was inconclusive based on the ether-based drilling fluid. A full-scale test was performed for pumping fluid through the spool. Results suggested that the fluid should be maintained at a temperature of about 50°C (122°F). A jetting assembly was added to the circulating system for pumping and shearing the fluid to increase its temperature.

Pressure losses within the coiled tubing dictated that maximum flow rates be maintained at about 80 gpm. This was much less than the 185-gpm allowable flow rate for the 3¾-in. mud motor. The motor was tested at a range of flow rates (Figure 5-2). Results showed that the motor could deliver 1000 ft-lb at 80 gpm and 1050 psi. This was determined to be sufficient for this operation.

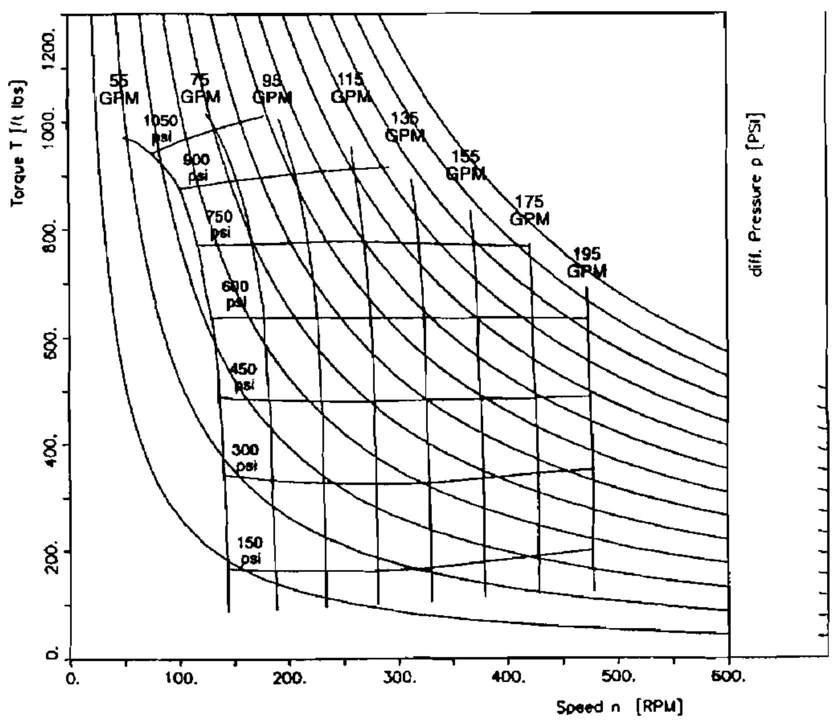

Figure 5-2. Motor Performance Tests (Ehret et al., 1995)

A 3½-in. core barrel was selected (delivers a 1¾-in. core). Aluminum was chosen for the inner tubes for its reduced friction and ease of handling on the rig floor. Three different core bits were used, including ballaset and PDC bits.

The coiled-tubing coring BHA is shown in Figure 5-3. Drill pipe and drill collars were placed above the BHA to add weight, reduce stress on the coiled tubing, and keep the disconnect sub inside casing.

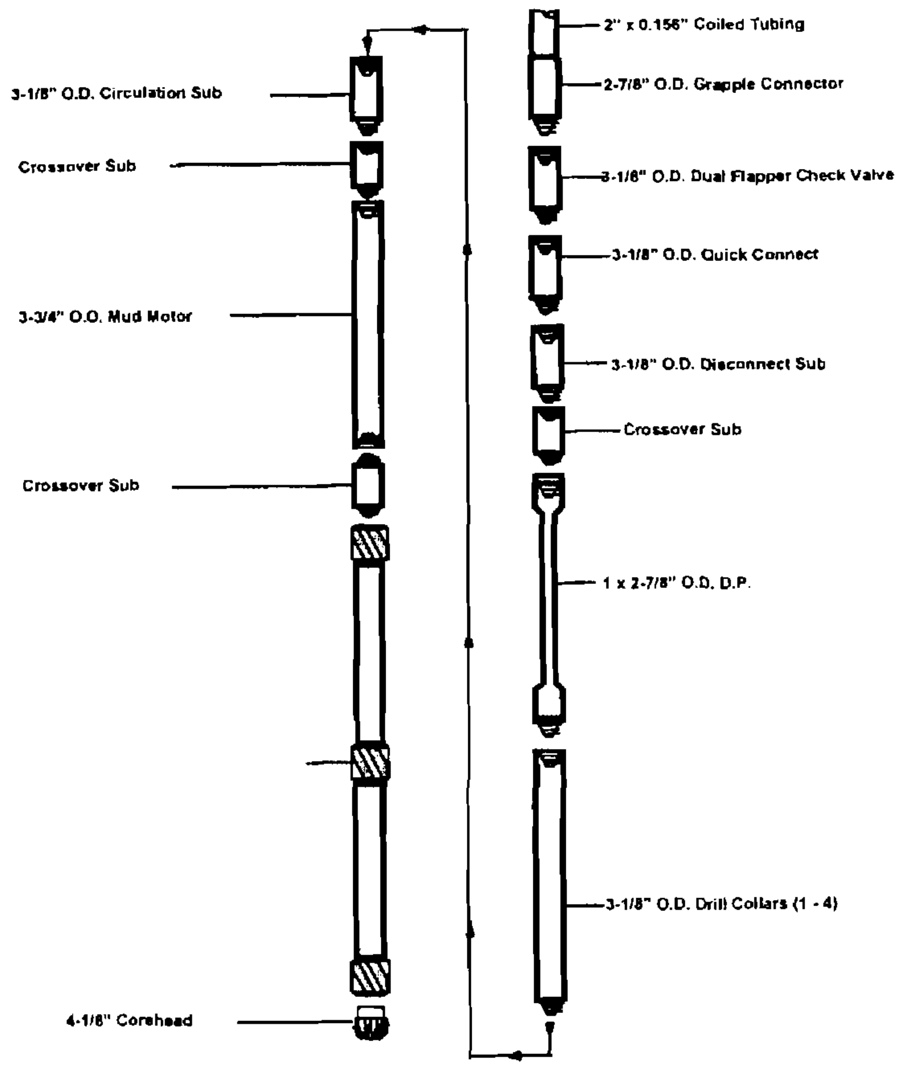

Figure 5-3. BHA for Coring on CT (Ehret et al., 1995)

After the 7-in. casing shoe was drilled out at 5525 ft, two coring runs were made on drill pipe to establish an operational reference for coiled-tubing runs. Several coring runs were completed (Table 5-1). Recovery was generally low due to junk, fissile shales, unconsolidated sands, core jamming, washing of the core, and plugged nozzles. Recovery efficiency did not increase until the final runs, where the improvement can be largely attributed to increasing hardness of the formations.

TABLE 5-1. Coring Performance (Ehret et al., 1995)

Core No	DP/ CT	From - To (ft)	Recovery	Avg ROP (ft/hr)	Flow (gpm)	WOB (lbf)	Pressure (psi)	Comments
1	DP	5545-5574	8.9%	5.2	80	1100-2200	1450-1550	Junk found in barrel
2	DP	5574-5584	33%	8.9	80	1100-2200	1390-1670	Jammed off core, motor stalling
3	CT	5584-5614	0.4%	16.4	58	7000-8000	2090-2450	Found Steel junk on Top of Core
4	CT	5643-5670	23%	20.2	60	3000-8000	2750-2840	Barrel jammed
5	CT	5670-5683	8%	15.6	60	4000	2600	Steel junk. Corehead damaged
6	DP	5732-5747	75.5%	30.8	60	2000	1300-1550	Good run
7	DP	5747-5775	54%	45.4	66	1100	1390-1600	Washed down from csg shoe
8	DP	5775-5804	0%	14.8	87	900-2000	1410-1570	3 plugged nozzles
9	DP	5804-5834	35%	19.7	66	0-2000	1420-1580	Wash down assembly
10	DP	5834-5863	44.4%	21.1	66	0-2000	1450-1550	Wash down assembly
11	DP	5863-5893	81.7%	29.5	66	0-2000	1277-1520	Good run
12	DP	5893-5922	93.3%	15.5	66	0-2000	1277-1490	Good run

Project members found that core quality was generally high even though recovery efficiency was low. Lower flow rates (about 66 gpm) provided the best recoveries. The average coring rate was 15 ft/hr compared to an average drilling rate of 40 ft/hr. Performance of the mud motor was better than expected.

The project team believed that the effectiveness of the coiled-tubing operations would be greatly improved by a built-for-purpose heave-compensation system.

5.2 FORASOL (FORASLIM RIG)

Forasol introduced a new slim-hole rotary rig for drilling and coring named Foraslim (Sagot and Dupuis, 1997). Footprint of the drill site is only 26 by 32 m (85 by 105 ft) (Figure 2-3). Depth range is to 3500 m (11,500 ft) in ultraslim holes (3⅜ in.) or 3000 m (9850 ft) in slim hole (4¾ in.). The rig has been used successful in several campaigns including the Paris Basin and Gabon.

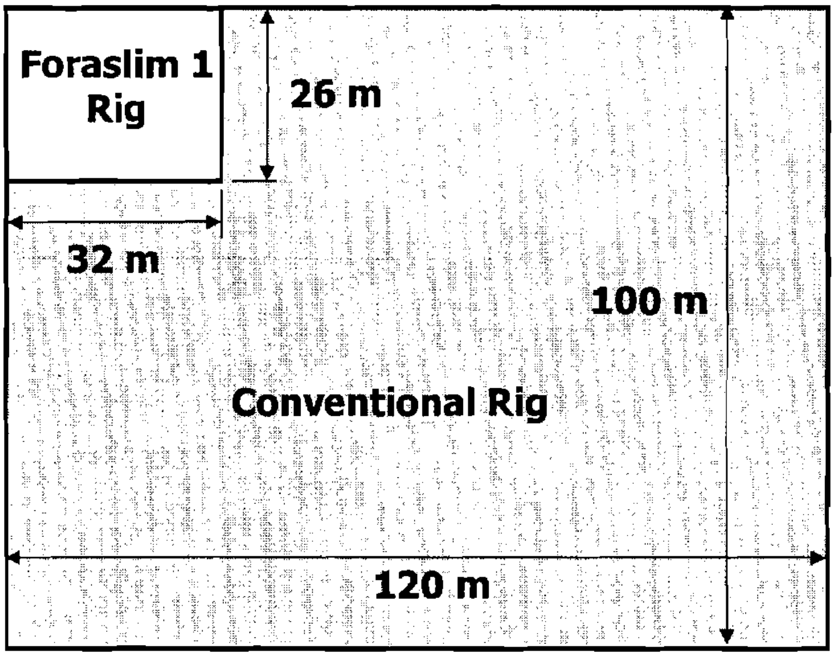

Figure 5-4. Footprint for Foraslim Rig (Sagot and Dupuis, 1997)

Several important technical issues were addressed in the four-well Gabon project, where cost savings of 33% were achieved. These included: 1) kick-detection and control are adequate, with two kicks taken and readily controlled, 2) good results were achieved with wireline-retrievable cores through the drill string, 3) performance of slim PDC bits was greatly improved, 4) a suite of 2¼-in. logging tools has been developed and provided high-quality logs, although highly sophisticated logs (e.g., bottomhole imaging) are not available or foreseen in the slim versions, and 5) DSTs can be successfully completed in 4¾-in. holes.

5.3 FUGRO-McCLELLAND MARINE GEOSCIENCES (CORING SYSTEM)

Fugro-McClelland Marine Geosciences (Chatagnier and Head, 1995) described modified tool joints to be used in slim-hole coring operations in U.S. Patent #5,425,428. Their invention addresses well-control concerns when running in or retrieving core barrels through the drill string. Grooves or other fluid passages are placed in the tool joints to allow fluid to bypass the core assembly.

Surge and swab pressures while tripping a core barrel can be a significant concern for formation fracturing or well control in slim-hole operations with small clearances. This invention reduces these pressures as the core barrel is tripped across a tool joint. In a conventional tool joint (Figure 5-1, left), reduced cross section causes significant increases in hydraulic pressure as the core barrel passes. A modified drill string with a larger tool-joint ID and a fluid passage across the tool joint is shown in Figure 5-5 (right).

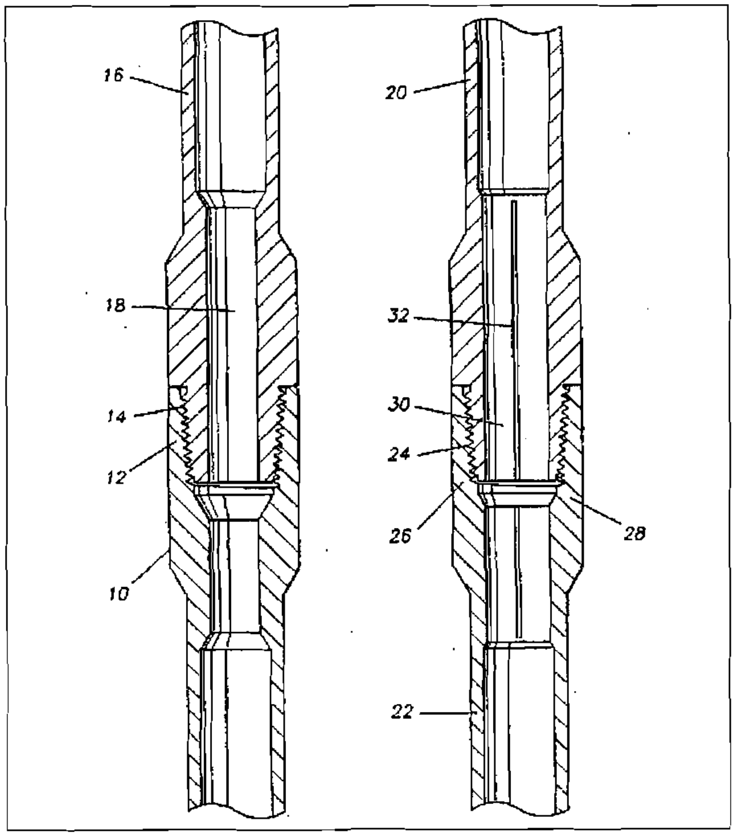

Figure 5-5. Conventional (left) and Improved (right) Tool Joints for Slim-Hole Coring (Chatagnier and Head, 1995)

The inventors state that the special fluid passage across the tool joint can consist of a groove (no. 32 in the figure) or multiple grooves milled into the inner wall of the drill pipe. Another option mentioned is a fluid port drilled or formed in the tool joint to allow fluid flow out of the pipe.

5.4 JOURNAL OF PETROLEUM ENGINEERING (PROSPECTS FOR SLIM HOLES)

A discussion of prospects within the oil field for slim-hole technology was presented in *JPT* (*JPT* Staff, 1995). Comments from several proponents and players in the modern slim-hole coring market were summarized. In general, the future for several companies' purpose-built rigs and slim-hole projects (that is, remote coring operations) was not bright, based on the current activity levels.

Several rig manufacturers have made offerings to the slim-hole coring market. Longyear Company (out of Salt Lake City) closed its slim-hole division in 1995. The 100-year old company entered the slim-hole market in 1984 and participated in several remote coring projects over the intervening years. Longyear, which was involved early with Amoco and the SHADS development of the late 1980s, departed from the slim-hole coring market due to 20% utilization rates for their three purpose-built rigs. Amoco's current emphasis is on the use of smaller oil-field rigs to address slim-hole issues.

Nabors Drilling bought the SHADS rig, modified it into Rig 170 (Figure 5-6), and built a second purpose-built rig for a remote campaign in Venezuela (see the next section). They drilled nine wells with the rigs. Although there was significant interest in these rigs from most of the majors during the Venezuelan campaign, no new contracts were forthcoming.

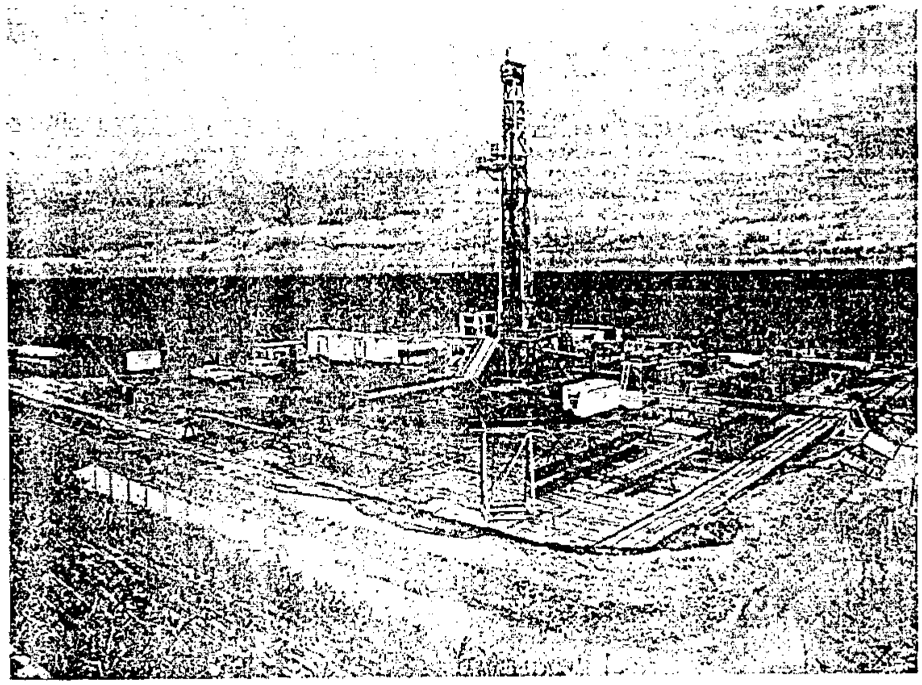

Figure 5-6. Nabors Slim-Hole Rig (*JPT* Staff, 1995)

Parker also offered a slim-hole rig based on a modified conventional rig with a slim-hole top-drive assembly. Parker's oil-field coring business has also been characterized as on-again, off-again, despite their success in the field.

Reasons for slim-hole drilling/coring technology not being embraced by the industry include the lack of interest in many companies in extensive coring. Some project leaders believe that all necessary information to appraise a well is available from electric logs.

Contingency limitations are high on the list of objections to slim holes. Slim-hole advocates counter that the costs to support a contingency habit are too high. For example, if 5% of wells need to make use of the contingency, and the slim-hole option is 30% cheaper than conventional, overall economics do not support the use of this type of insurance.

Changing E&P strategies among the majors are also playing a role. Many have significantly decreased the number of remote wildcats, adding more established acreage to their portfolios. The appeal of deep-water plays near infrastructure has caused some to direct their exploration capital toward offshore areas rather than to the jungle.

An abundant supply of conventional land rigs at depressed day rates also hinders slim-hole usage. Low-cost purpose-built slim (non-coring) rigs are being developed to address market issues. Among them is the Kenting Drilling Services Ltd. rig, which was built from standard components at a 20% savings over conventional rigs.

5.5 MARAVEN, INTEVEP, CORPOVEN AND NABORS (VENEZUELAN EXPLORATION PROJECT)

Maraven S.A. and Intevep S.A. (Cambar et al., 1995) and Nabors Drilling International Limited, Maraven S.A. and Corpoven S.A. (Spoerker et al., 1995) described the planning, implementation, problems encountered and successes enjoyed during a multiwell, multiyear slim-hole exploration project in Venezuela. Two purpose-built slim-hole rigs were used to meet specific project requirements, which included high environmental sensitivity, full helicopter transportability, zero discharge drilling, and drilling depths to greater than 13,000 ft. Over the project phase consisting of seven wells, overall times and costs were close to estimates, 14,000 ft of core were recovered, almost all problems encountered were solved through analysis and innovation, environmental restrictions were met, and overall costs were about 20% less than conventional operations.

Long-term strategic goals of Venezuela's oil and gas industry were under review and refinement near the end of the 1980s. One significant project under consideration was the use of slim-hole technology for remote exploration using a customized rig and continuous coring through the prospective intervals at significant depths (Figure 5-7). A rig was designed, constructed and put into operation in 1993.

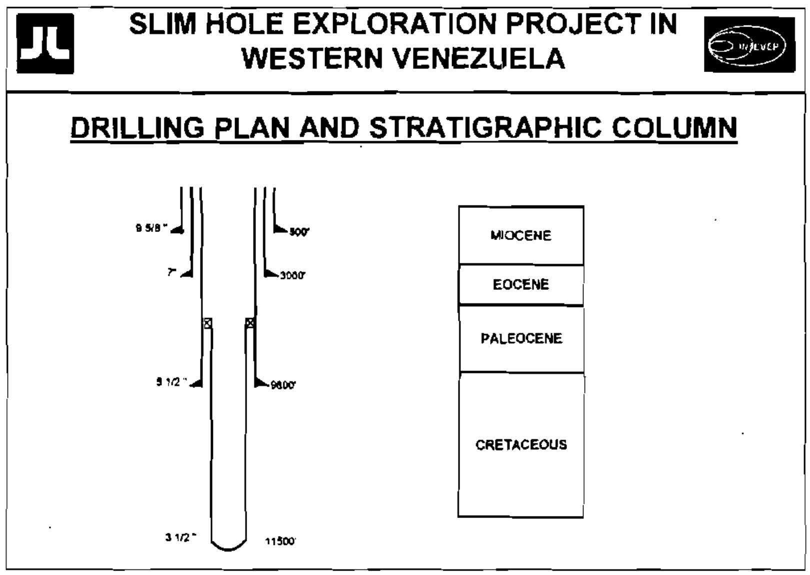

Figure 5-7. Typical Drilling Plan for Venezuelan Wells (Cambar et al., 1995)

Early in the project, significant problems were experienced with drill string failures. It was determined that standard (mining industry) CHD core rod is not strong enough for the depths involved in this campaign. A new drill string and BHA system was developed. Mechanical properties of oil-field slim coring strings are compared in Table 5-2.

TABLE 5-2. Comparison of Slim Drill Strings (Spoerker et al., 1995)

	Weight [lbm/ft]	Pipe Body OD [in]	Tool Joint OD [in)	Body Tensile Yield [ft-lbf]	TJ Torsional Yield [ft-lbf]	Pressure Loss [psi/1000ft]**	Self Support Length [ft]
API 3.5"/NC38	13.3	3,500	4,750	271,600	18100	230	20,400
API 2.875"/NC31	10.4	2,875	4,125	214,300	11800	745	20,600
NSH3.7"/*	9.5	3,250	3,725	334,600	18000	250	35,200
RSA6K/*	12,7	3,675	4,125	432,200	27500	150	34,000
CHD101/*	8,7	3,700	3,700	164,900	10300	100	19,000
DBS SH111/*	10,6	3,500	4,125	306,000	31100	175	26,900

*special slimhole string connection. **calculated for 9 ppg mud, PV=10cP, YP= 10 lbg/100ft^2, q=100GPM

Despite significant difficulties, the first well was completed for production at a depth of near 10,000 ft, and 2000 ft of borehole were cored with an 86% recovery.

Maraven and the other participants redoubled their planning and organizational efforts as operations began on the second well. This second effort produced a record drilling time of 63 days for the 11,000-ft well. A world-record core bit run (971 ft of 4½-in. hole cored in 164 hr) was also achieved.

The third and fourth wells saw the first application of PDC core heads. About half the 9000-ft depth was cored (with various bits). Improvements continued to be made in operations and procedures. A severe vibration problem was overcome by an extensive investigation into BHA design. A continuous drill-string feed system was also developed to avoid sudden surges in WOB experienced at depth with standard systems.

The fifth well saw a rise in the learning curve (Figure 5-8) due to a variety of problems. This was attributed to the team members adopting a basic routine that proved to be unsatisfactory for the new location. TD was reached only after 120 days, and the well was abandoned at 9900 ft with a 60-ft fish in the hole.

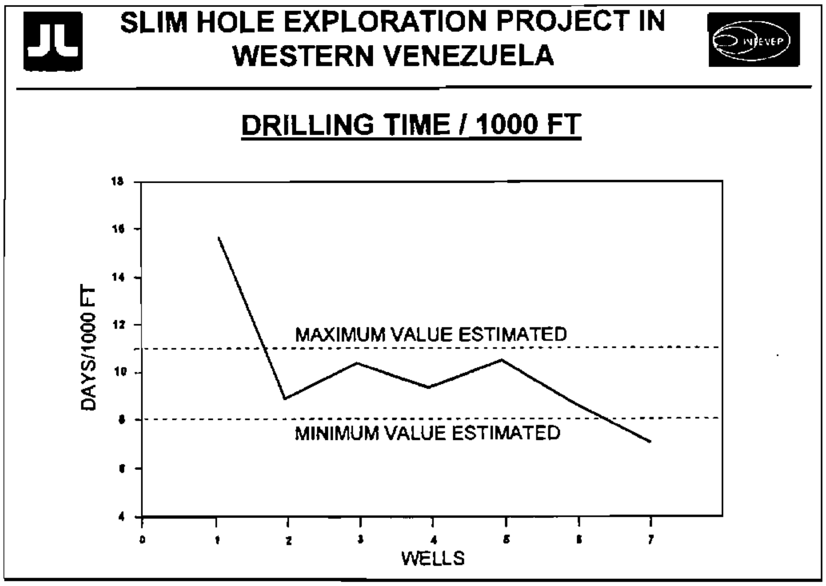

Figure 5-8. Drilling Time for Venezuelan Wildcats (Cambar et al., 1995)

The sixth well was launched with renewed care in planning and communication of team members. This effort was much more successful. An unsuccessful fishing effort at 7000 ft was overcome by a sidetrack. Core recovery efficiency suffered in this well (Figure 5-9), although was considered sufficient for the purposes of this well.

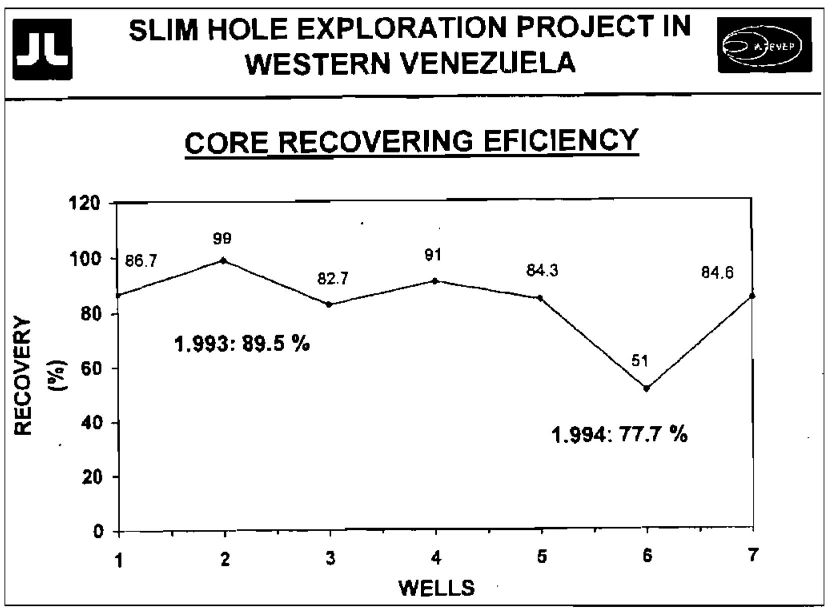

Figure 5-9. Core Recovery for Venezuelan Wildcats (Cambar et al., 1995)

Costs per 1000 ft are compared in Figure 5-10. The project team estimated that slim-hole savings were about 20 to 30% as compared to conventional equipment.

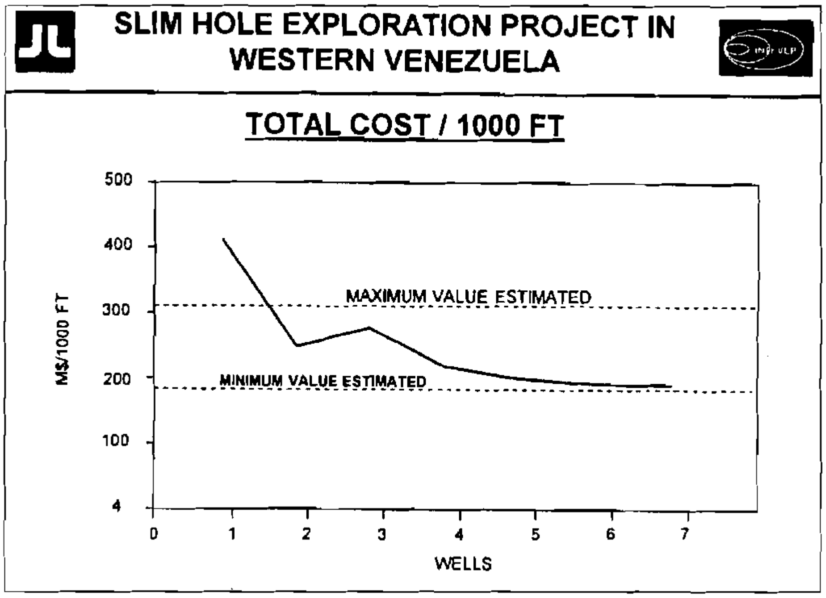

Figure 5-10. Cost/1000 ft for Venezuelan Wildcats (Cambar et al., 1995)

A variety of problems were addressed during the project. When differential sticking occurred, the string normally unstuck after lubricants were spotted and soaked for 20-36 hours.

The participants found that fishing in a slim wellbore was less problematic than commonly feared. Several fishing incidents (including parted drill collars) were resolved using spear or taper tap tools to grab the inside of the fish.

The combination of standard rotary drilling for surface and intermediate hole, and continuous high-speed coring for the target interval proved to be a viable drilling concept. They found that purpose-built slim-hole drilling rigs can out-perform conventional equipment when the entire project cost is considered.

5.6 MOBIL E&P (SLIM-HOLE OFFSHORE DRILLING SYSTEMS)

Mobil Exploration and Producing (Shanks, 1995) considered the design of slim-hole drilling and coring systems for offshore applications. They suggest that technologies exist or can be developed for harsh environments (deep wells, HTHP wells and difficult geologies). Slim-hole technology can save money offshore, but its strengths and weaknesses must be recognized. Offshore costs for floating operations are dominated by vessel day rates. Intangibles account for 80-85% of total costs. The most practical approach to reducing costs is therefore to reduce drilling time. Additional cost reductions can be achieved by reducing casing size for all strings.

Mining industry coring technology was first applied offshore in the coring vessel Bucentaur. No active motion compensation is used to control WOB. The Ocean Drilling Program vessel, SEDCO/BP 471 is another pioneer in this area. Special techniques and equipment have been developed and cores have been taken in waters as deep as 5900 ft.

The most critical technology for adapting mining systems for offshore operations is the need to provide adequate heave compensation from floating vessels. One of the most critical aspects of slim-hole coring operations is the need to maintain consistent WOB. Motion compensators on most offshore rigs are not sufficiently precise. Typical operating ranges are within 3000 to 6000 lb at a WOB of 40,000 lb. Slim-hole requirements may be close to 2000 lb WOB with a precision of 500 lb. Development of effective heave-compensation systems for slim holes has met with some success and continues at present.

Mobil's approach to slim-hole heave compensation is the use of a support device on the seafloor to remove fluctuations from the drill string (Figure 5-11). These components are controlled from the surface. The string is rotated from the surface, or alternatively, downhole motors are used.

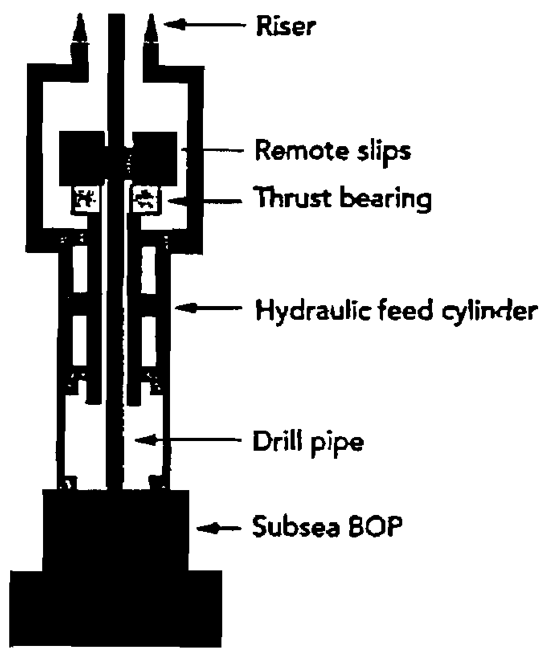

Figure 5-11. Seafloor Drilling Assembly
(Shanks, 1995)

Remotely actuated slips anchor the drill pipe at the seafloor assembly. With this system, only the drilled depth affects string tension.

Mobil, as part of continuing exploration into deeper waters, considered the cost to develop a rig capable of conventional operations in 10,000 ft water depths. A new semisubmersible with dynamic positioning would cost more than $250 million. An upgrade of an existing vessel might cost about $100 million. Rig costs may be reduced significantly using slim-hole designs. Standard components may be used along with the seafloor compensator (Figure 5-12). Given the greatly reduced weight of the riser etc., existing drilling vessels may be used with relatively minor modifications.

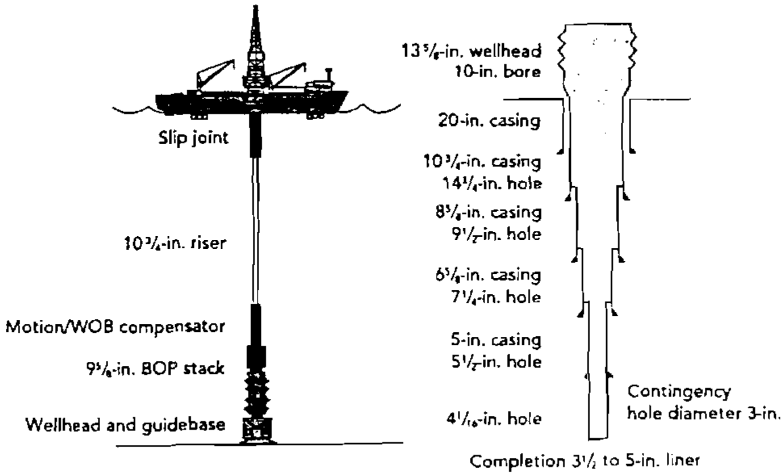

Figure 5-12. Slim-Hole Deep-Water System (Shanks, 1995)

Well-control considerations would be important challenges in these offshore applications. Kick detection is normally complicated with floating vessels because rig heave causes variations in the return flow. In slim holes with tight annular clearances, special methods would be required for accurate measurement of differential flow (Figure 5-13).

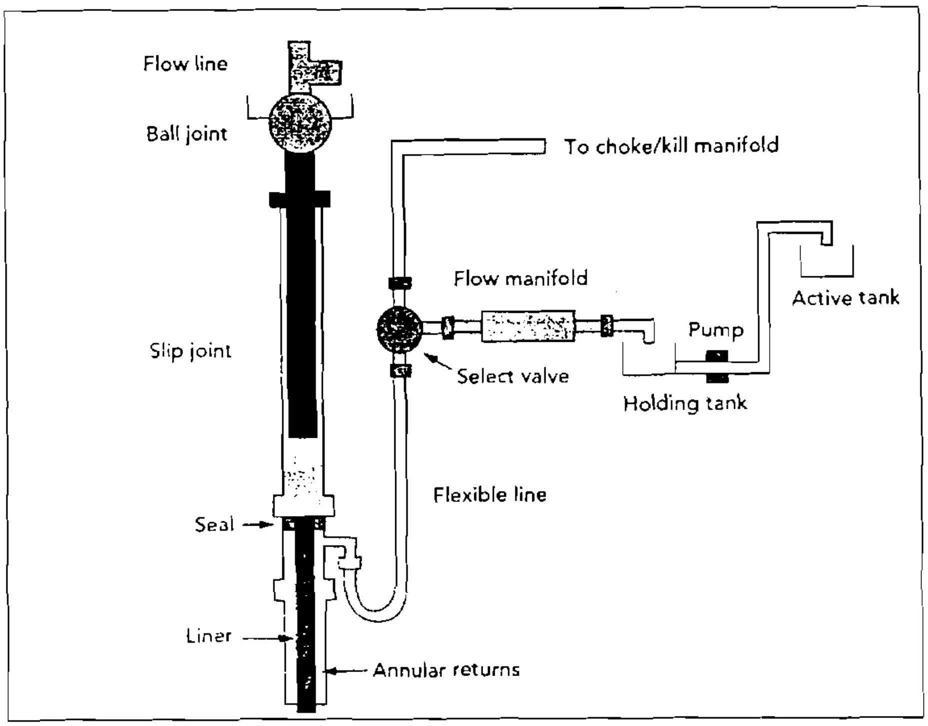

Figure 5-13. Offshore Differential Flow Measurements (Shanks, 1995)

New techniques may also be required for circulating out a kick. It may not be practical to use standard choke and kill lines because of substantial weight relative to the riser. Other options exist including composite choke and kill lines, reverse circulation up the drill pipe, a seafloor choke system, or very low pump rates through slim choke and kill lines.

5.7 SHELL ROMANIA, FORASOL AND SECURITY DBS (ROMANIAN PROJECT)

Shell Romania BV, Forasol Romania, Forasol Foramer and Security DBS (Groenevelt et al., 1997) summarized the operations of a three-well slim-hole project in Transylvania, Romania. The Foraslim 1 rig, designed for depths to 3500 m (11,500 ft), was used both for destructive drilling and wireline-retrievable continuous coring. The new rig is designed for remote onshore operations for low environmental impact, high drilling efficiency, high safety at the wellsite, and complete geologic evaluation.

The camp site was 2000 m^2 and the rig site 2500 m^2. These areas did not represent the minimum site sizes for operation with the Foraslim-1. Winterizing the operation required an increase in space.

Four primary service contracts were managed by the lead contractor Forasol. These included 1) cementing and pumping services, 2) mud engineering, 3) borehole surveying and directional drilling, and 4) mud logging with kick detection.

The critical 4¾-in. section was to be drilled with a wide choice of bits designs including tricone, PDC, TSP and natural diamond. Field results showed that performance of newly designed slim bits with low WOB was as good as conventional. Optimization of bit design continued throughout the three-well campaign.

Time and depth curves are shown for the three wells in Figures 5-14, 5-15 and 5-16.

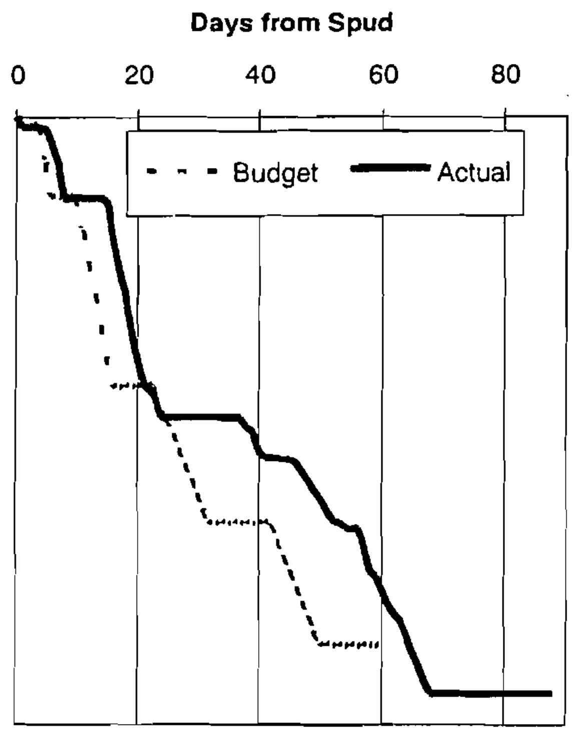

Figure 5-14. Drilling Time for First Well (Groenevelt et al., 1997)

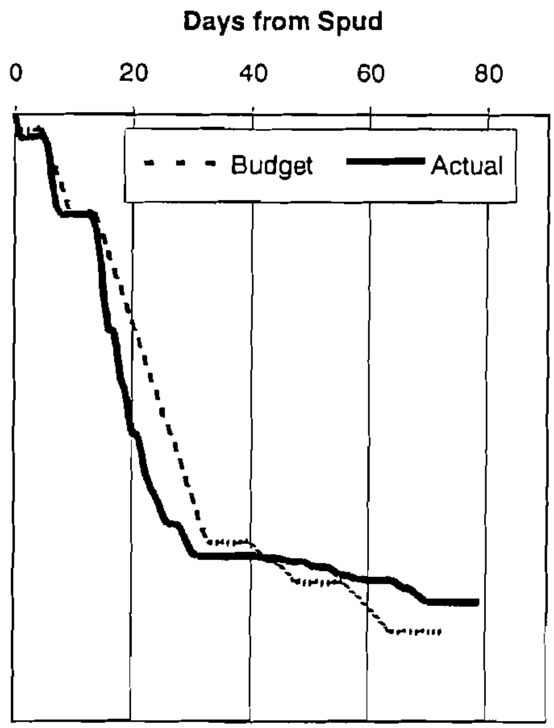

Figure 5-15. Drilling Time for Second Well (Groenevelt et al., 1997)

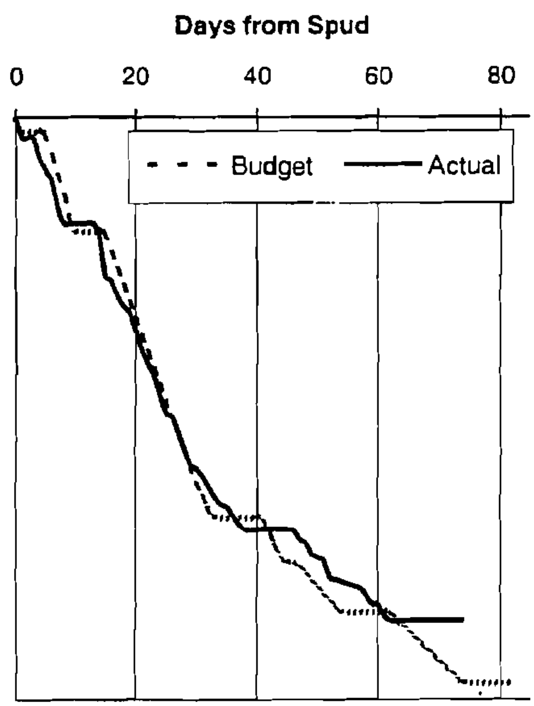

Figure 5-16. Drilling Time for Third Well (Groenevelt et al., 1997)

The 4-in. liners were not required since the slim hole sections were stable.

Several 2-in. cores were taken in the 4¾-in. section. A new design of wireline core barrel was developed by Security DBS. A hydraulic hold-down was used to connect the inner tube to the outer tube instead of latches. The operator concluded that coring operations were very effective. Success is summarized in Table 5-3.

TABLE 5-3. Core Recovery (Groenevelt et al., 1997)

Well No.	Core Length (m)	Recovery (%)	9-m Core Cut (hr)	9-m Core Recover (hr)
1	43	93	2.3	4.2
2	167	88	5	2.5
3	24	96	6.6	3

Project participants found that coring ROP was similar to that for drilling. Consequently, economics for coring were similar to those for drilling.

A complete range of logging tools were run in the 4¾-in. sections. Several tools were available for running in the 3⅜-in. contingency hole (Table 5-4), had that become necessary.

Table 5-4. 3⅜-in. Logging Tools (Groenevelt et al., 1997)

Tool Description	Maximum O.D. (inches)
Dual Focused Resistivity	2¾
Induction	2¾
Array Sonic	2¾
Natural gamma ray	2¾
Compensated Density	2¾
Borehole Compensated Neutron	2¾
Borehole Compensated Sonic	2¾
High resolution dipmeter	2¾
3-D seismic acquisition	2
Cable head tension	2¾

The quality of the logs was very high. All hole sections were in good condition. Cuttings quality was also good with both tricone and diamond bits.

Overall savings for the project were estimated as 20% less than conventional. Cost increases were recorded for wireline logging and well testing, primarily due to the need for nonstandard equipment for these operations. Total cost savings amounted to $1.2 million for the campaign.

The operators concluded that these wells were drilled almost problem free and within time and cost budgets. They cautioned that problem time for contingencies would probably be greater than in larger holes (should problems occur in a similar operation). Junk in the hole was found to be a more critical concern in the slim holes.

Side-wall core samples in 4¾-in. hole were generally of poor quality and highly fractured. Reservoir characteristics were hard to discern from the samples. Basic lithology could be interpreted, however.

They also concluded that among the best applications for slim holes are development drilling projects of multiple wells where the drilling plan is relatively optimized so that the potential for drilling problems is minimized, where marginal cost savings per well will amount to a significant amount for the entire program, and where a reduction in environmental impact is desirable.

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6. Drilling Cost and Time

6.1 ARCO ALASKA (KUPARUK SLIM-HOLE PROGRAM)

ARCO Alaska (Pearson et al., 1996) achieved significant cost reductions by combining slim-hole drilling and completion technology with increased efficiency in planning and procurement of consumables. A goal was set for the Kuparuk River Field (Figure 6-1) for reducing well costs by 30%. Slimmed injectors and monobore producers were designed for the field. Early results with the revised operations and efficient procurement showed that the potential exists for exceeding 30% as the equipment and procedures are fine-tuned and optimized.

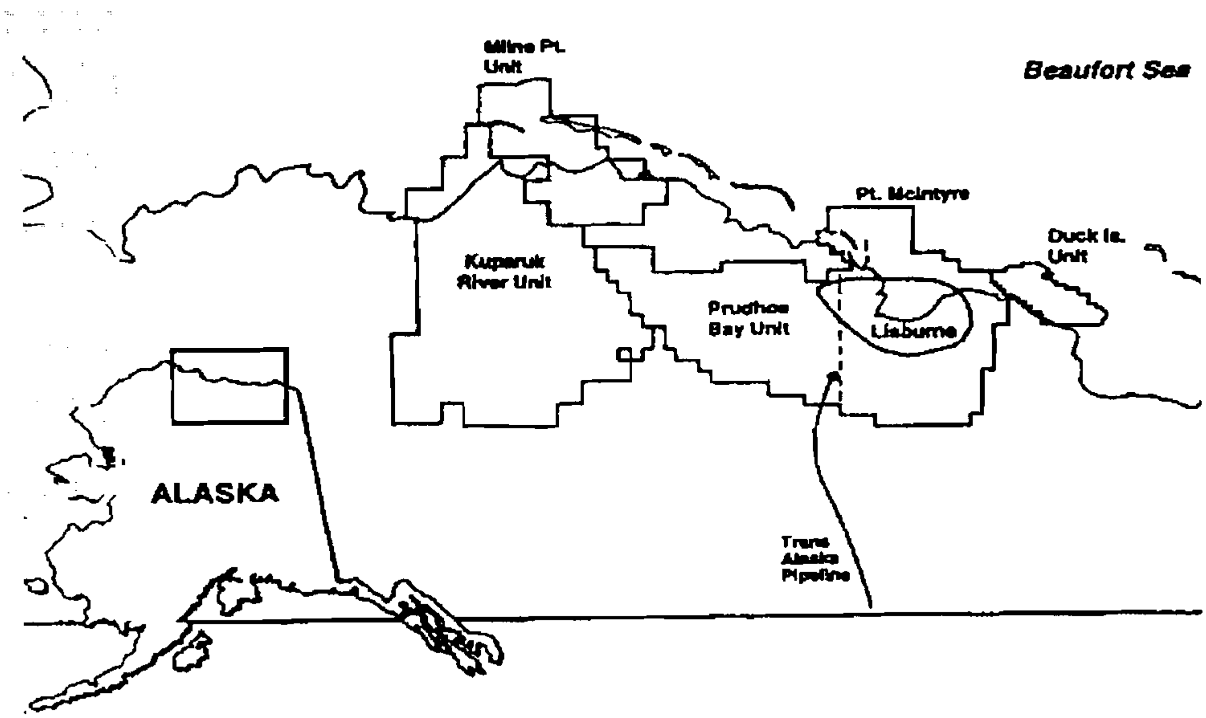


Figure 6-1. Kuparuk River Field (Pearson et al., 1996)

Historic costs in the field are compared in Figure 6-2. Expected costs for future wells were determined to be too high because most of the 436 additional wells anticipated would be infill wells. Because significantly lower reserves were associated with each well, costs needed to be reduced to maintain economic viability.

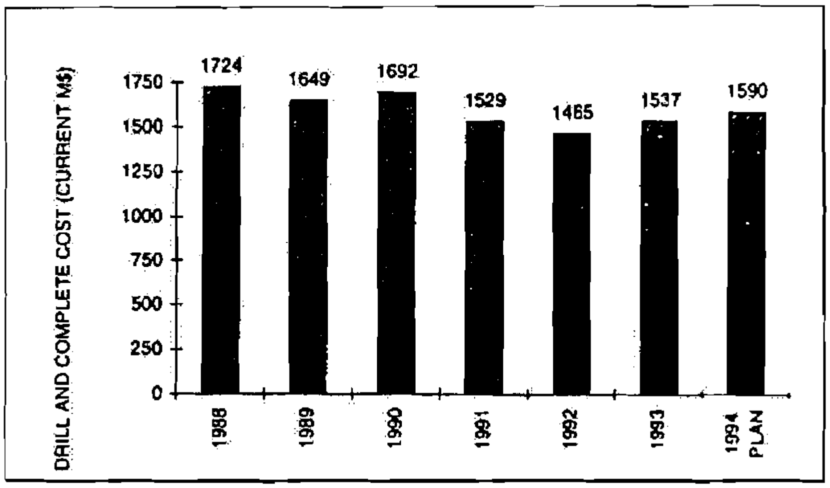


Figure 6-2. Drilling Costs at Kuparuk River (Pearson et al., 1996)

A goal of 30% cost reduction was set for future wells (i.e., starting in 1994). No single area was foreseen as having the potential to achieve the entire reduction. Small-scale reductions were implemented in several areas. These included: 1) long-term alliances with contractors and suppliers (7% savings), 2) optimized well drilling plan, which eliminated cement isolation of upper annulus, eliminated SSSVs, reduced gyro runs and open- and cased-hole logs (4% savings), 3) reduced number of selective completions (2% savings) and 4) reducing reservoir pressure around an infill well prior to initiating drilling operations (4% savings).

Beyond these steps (17% cost reduction), slim-hole drilling was the remaining potential technology. ARCO determined that 3½-in. production tubing was required for the expected flow rates. The downsized casing program included a 9⅞-in. surface hole and 6¾-in. production hole.

Cost savings with three slim-hole completions were estimated at 8% of total cost for monobore producers and 13% for injectors. Gains were analyzed after several slimmed completions had been run in the field (Figure 6-3). The average cost for these wells was 26% below the base cost. Operations had proven that the drilling and casing programs were feasible and that comparable drilling efficiencies could be achieved in reduced size holes.

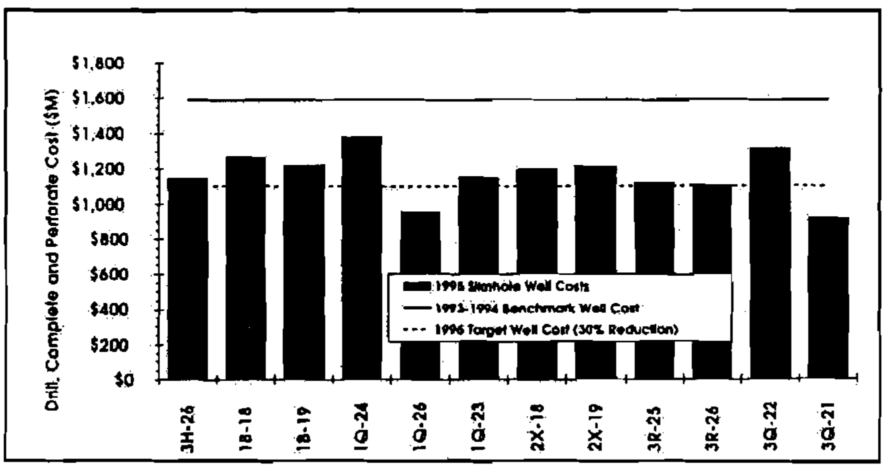


Figure 6-3. Slim Well Costs (Pearson et al., 1996)

Average drilling times were 0.4 days longer than conventional offset wells (Figure 6-4). Further optimization was possible in hydraulics and downhole tools. ARCO anticipated that the cost reduction goal for the project could be reached and exceeded.

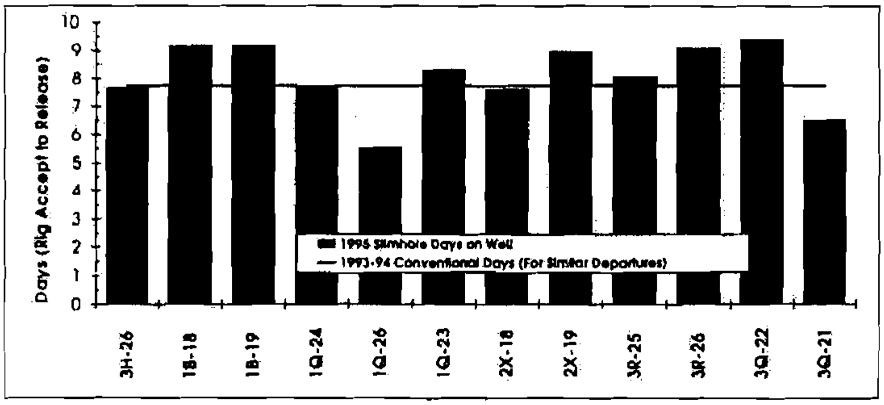


Figure 6-4. Slim Well Rig Time (Pearson et al., 1996)

Other areas in which optimization was expected include improved design to combat erosion of the $9\frac{7}{8}$-in. bits, improved hydraulics for different motors and turbodrills, identifying more applications for tubingless monobore producers, extending lateral departure limits for slim-hole assemblies, and careful evaluation of other advanced technologies and concepts for the field (horizontal wells, multilaterals, open-hole completions, underbalanced drilling etc.).

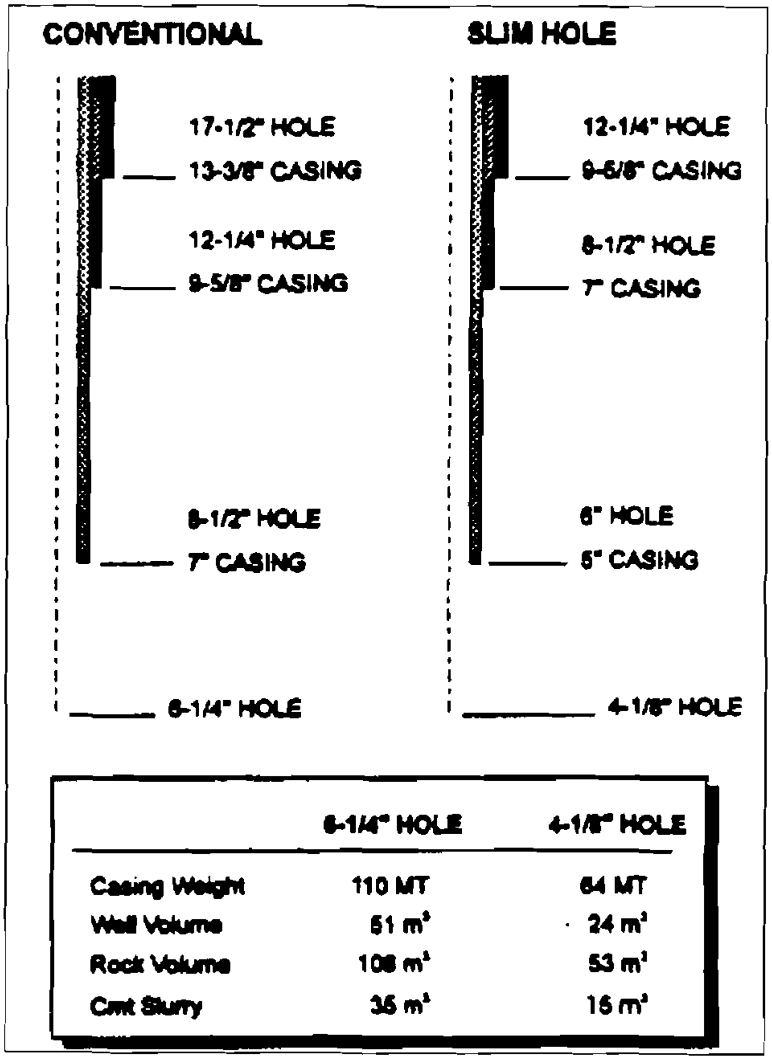
Additional details are presented in *Completions.*

6.2 BAKER HUGHES INTEQ, DEUTAG AND BPB WIRELINE (DRILLING PACKAGE)

Baker Hughes INTEQ, Deutag and BPB Wireline Services (McNicoll et al., 1995) described the planning, equipment and field operations for drilling a slim-hole exploration well in Madagascar. The hole size was $4\frac{1}{8}$ in. at TD. A small modified workover hoist was used. An overall cost savings of 40% was realized compared to a nearby offset conventional well ($6\frac{1}{4}$ in. at TD). A 45% reduction in cuttings volume and 40% less mud decreased the environmental impact of the project.

Shell Madagascar had previously drilled an exploratory well in the area, and wanted to achieve cost savings on the second project. Shell's slim-hole system developments were used, most significantly the motor/thruster assembly and PDC bits. The KDS kick-detection system was used, which compares actual returns to model predictions of the circulating system operating in real time.

The slim-hole design included $9\frac{5}{8}$-in. conductor and a $4\frac{1}{8}$-in. final hole (Figure 6-5). Drilling was completed in 36 days to a TD of 2223 m (7293 ft); abandonment was completed in three days. The conventional offset required 53 days for drilling and 11 days for abandonment. TD was slightly greater than the slim hole: 2508 m (8228 ft).



	6-1/4" HOLE	4-1/8" HOLE
Casing Weight	110 MT	64 MT
Well Volume	51 m^3	24 m^3
Rock Volume	108 m^3	53 m^3
Cmt Slurry	36 m^3	16 m^3

Figure 6-5. Conventional/Slim-Hole Casing Program (McNicoll et al., 1995)

Drilling mud was a shear-thinning low-solids KCl polymer. Mud weight ranged up to 1.12 SG. Calculated ECD in the final hole size was as great as 1.3 SG (10.8 ppg).

After drilling was completed, five logging runs were made to TD without incident. The well was then plugged and abandoned. Logs included Laterolog, multichannel compensated sonic, dual-density/gamma-ray/caliper, dual neutron, and seismic reference sonde.

The project schedule is summarized in Figure 6-6.

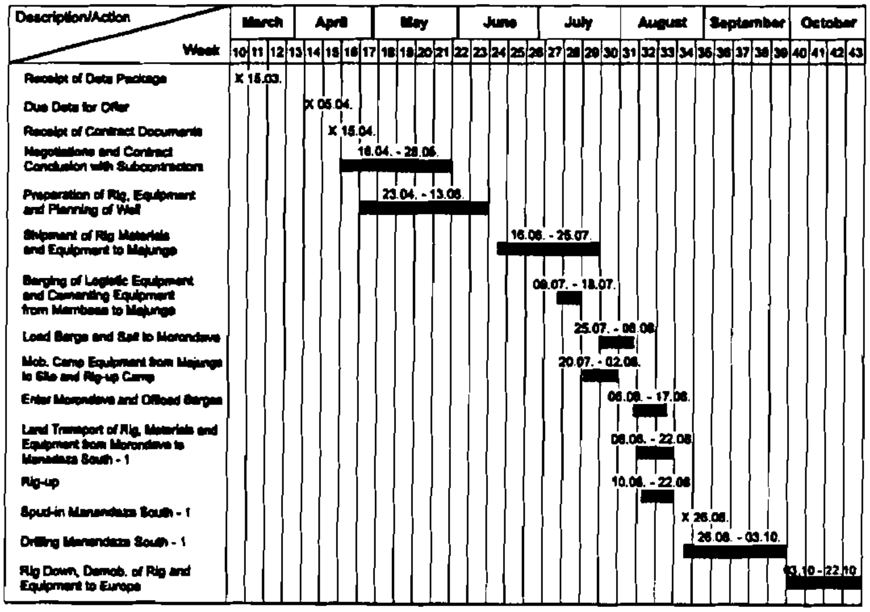


Figure 6-6. Slim-Hole Project Schedule (McNicoll et al., 1995)

Cost savings were substantial. The offset conventional well was drilled to a greater depth. Its costs were normalized to the same depth as the slim hole for a more valid comparison. Total costs were reduced about 40% (Table 6-1).

TABLE 6-1. Conventional versus Slim-Hole Costs (McNicoll et al., 1995)

	Manandaza 1 Conventional (Normalized)	Manandaza South Slimhole	% Savings
Hole Size at TD	6¼"	4⅛"	
Depth	2,200 m	2,200 m	
Days on Well	38	38	
Meters per Day	58	58	
Costs ($Million)			
Ex Mob/Civil	2.97	1.75	41
Ex Mob	6.83	2.68	61
Total Well Costs	11.4	7.0	39
Unit Costs			
Depth Dependent $/Meter	376	88	77
Time Dependent $000/day	46.7	39.7	15
One-off Costs $ Million	8.8	5.3	40

The project team concluded that light workover rigs can be successfully used for slim-hole drilling. ROPs can also be maintained comparable to conventional operations. Technology to limit drill-string vibration can provide a smooth and stable borehole.

Additional details describing this drilling operation are presented in *Motor Systems*.

6.3 BAKER HUGHES INTEQ AND NAM (DOWNHOLE THRUSTERS)

Baker Hughes INTEQ and Nederlandse Aardolie Mij. B.V. (Reich et al., 1995) described the design, usage and performance of downhole thrusters for motor drilling operations. These elements decouple the lower section of the BHA from the drill string and provide a constant, controllable WOB for smoother, more predictable drilling. Thrusters have been run on more than 120 jobs, increasing ROPs, bit life, and steerability. They have been employed in hole sizes ranging from 3⅞ to 12¼ inches on fixed and floating rigs.

Vibration in the drill string can reduce ROP, cause twist-offs, lead to early failure of motors and MWDs, and reduce borehole stability and tool-joint life. These problems can be especially significant in slim holes due to the weaker drill string. In directional drilling, longitudinal vibration can make it difficult to maintain WOB. In many cases, slower drilling tricone bits are preferred because they are less sensitive to changes in WOB.

Baker Hughes INTEQ developed a thruster to address these problems. Early trials with the thruster proved that system optimization was not easily achieved. Theory was developed and incorporated into design software for use with this system.

The thruster has been run in several wells in Canada for 4¾-in. horizontal sections. Based on data from 50 bit runs (about 40% of which included a thruster), ROP was increased by 12% with a thruster.

The standard thruster design with spear is shown in Figure 6-7. It was found that the WOB adjustment range is relatively limited within a single design. Additional designs were developed to increase/decrease potential WOB. Additional details are presented in *Motor Systems*.

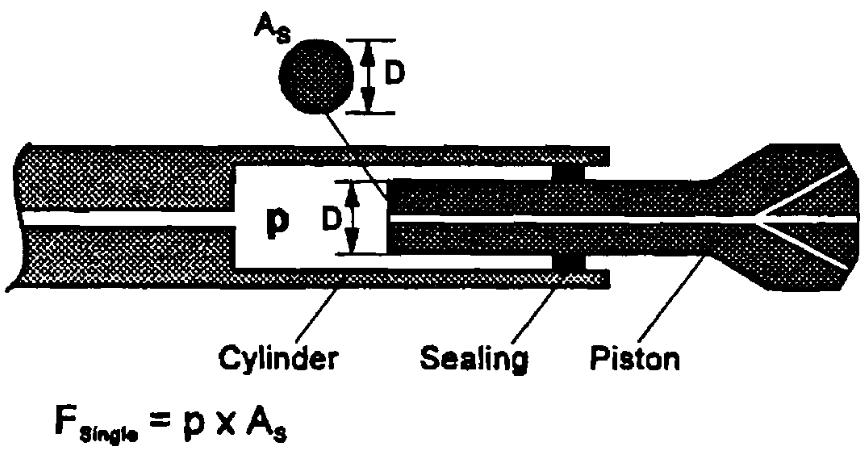


Figure 6-7. Standard Thruster Design (Reich et al., 1995)

6.4 BP (SAVINGS WITH SMALLER HOLES)

BP (*Downhole Talk* Staff, 1995) reported time and cost savings breakdowns for operations at Wytch Farm in the North Sea. They compared the 17½-in. section of a Stage 3 ERD well to the equivalent 12¼-in. section in a horizontal producer. Section lengths were similar for these wells. The 12¼-in. hole was drilled and completed 40% faster and at a cost savings of 36%.

Time savings are compared in Table 6-2. The largest contribution (25%) to the time savings is the faster ROP in the smaller hole.

TABLE 6-2. Time Savings for 12¼-in. Section (*Downhole Talk* Staff, 1995)

SECTION TIMINGS		
Operations	**%Improvement of M4 over M5**	**Improvement as a % of M5 trouble free time**
M/U BHA	25%	3%
Tripping	56%	3%
Circulating	48%	4%
Drilling	44%	25%
Pulling BHA	15%	1%
Ream	100%	1%
Flow Check	33%	0%
Rig Up	40%	1%
Rig Down	100%	1%
Run Casing	23%	2%
Total Trouble Free	**40%**	**40%**

Cost savings for the smaller section were also substantial, amounting to 36% overall (Table 6-3). The largest component of the cost savings was rig costs (11% less). Several other areas provided significant cost reductions.

TABLE 6-3. Cost Savings for 12¼-in. Section (*Downhole Talk* Staff, 1995)

SECTION COSTS		
Category	**%Improvement of M4 over M%**	**Improvement as a % of M5 Total Cost**
Casing	27%	6%
Casing Accessories	100%	1%
Rig	42%	11%
Bits	-51%	-2%
Mud	50%	6%
Cement	69%	8%
Fuel, Power, Water	79%	2%
Directional	20%	2%
Geological	50%	0%
Environmental	19%	2%
TOTAL	36%	36%

6.5 BP ALASKA (HORIZONTAL SIDETRACK)

BP Alaska reported (*Downhole Talk* Staff, 1995) successful operations drilling a 4¾-in. sidetrack (P-12a) at Prudhoe Bay. Almost 1000 ft of 4¾-in. hole were drilled before TD was declared due to geologic constraints. A 3½-in. mud motor was used. Operations were very similar to those used for 6- or 6¾-in. laterals. The hole was completed with a 3½-in. slotted liner.

BP Alaska reported that instantaneous ROPs were greater than those observed in larger holes. In one interval, ROPs of 250 ft/hr were observed, as compared to 100 to 120 ft/hr in a 6-in. hole.

6.6 CHEVRON USA (SLIM-COMPLETION INJECTORS)

Chevron U.S.A. Inc. (Dennis et al., 1995) successfully used slim-completion technology in an expansion of a steam-injection project at the Midway Sunset field in California. Slim injectors were used to reduce capital investment. Three slim completions (6¼-in. bit and 2⅞-in. casing) could be drilled for the cost of each conventional injector, i.e., about $40,000 for each slim hole versus $120,000 per conventional well. Costs were reduced in rig costs, cementing, packers and tubulars. The additional injectors allowed under the slim-hole development plan provided improved profile control and management of the steam flood. Production has increased since the flood was implemented.

A conventional design for the steam-flood expansion would have consisted of ten injection wells (seven with dual-string completions) and three temperature/observation wells. The slim-hole option allowed thirty-eight injectors and ten temperature/observation wells for the same costs.

A standard rotary rig was used to drill the slim-hole injectors. Average TD was about 1500 feet. Drilling and cementing casing were completed in 1½ days. Conductor (8⅝-in. casing) was set to 80 ft; the production string was 2⅞-in., 6.5-lb J-55 tubing with ≤10% wall loss.

Additional information is presented in *Completions*.

6.7 FORASOL AND ELF AQUITAINE PRODUCTION

Forasol and Elf Aquitaine Production (Dupuis and Sagot, 1995) described an approach to further reduce drilling costs with the purpose-built slim-hole rig Foraslim. By integrating various services into the rig design, service costs can be saved by making use of integrated equipment and the drilling crew.

The principal components of drilling costs are shown in Figure 6-8. Services and operator costs are not highly impacted by slim-hole versus conventional technology.

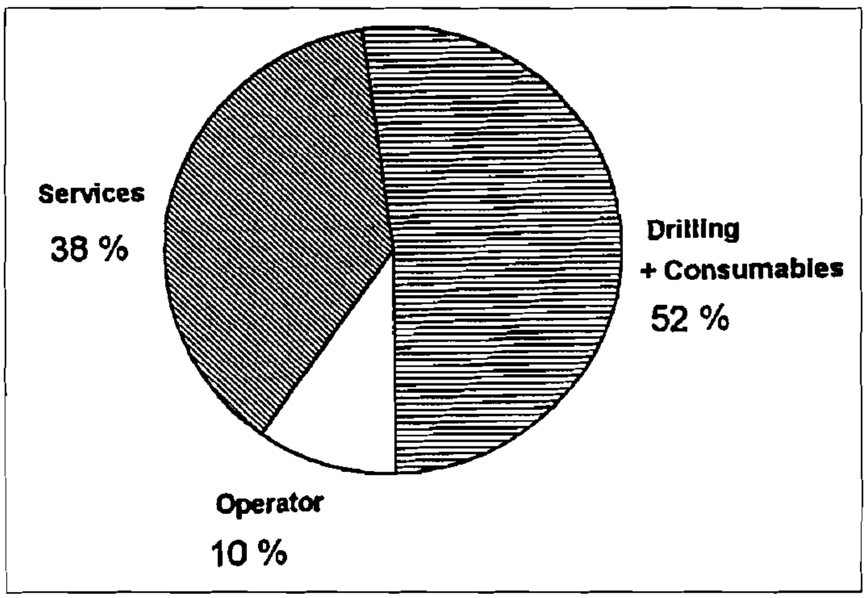


Figure 6-8. Typical Distribution of Drilling Costs (Dupuis and Sagot, 1995)

Primary cost savings in drilling and consumables are achieved through reductions in site size, mobilization costs, civil engineering, and consumables (Table 6-4). Field experience has shown that drilling times are similar for slim and conventional holes.

TABLE 6-4. Volume Reductions in Slim Holes (Dupuis and Sagot, 1995)

	Conventional Well		Slim Hole Well	
	Hole Diameter	Drilled Volume	Hole Diameter	Drilled Volume
Drilling phase 0 to 1500 m	17½"	233 m3	9⅞"	74 m3
Drilling phase 1500 to 2400 m	12¼"	68 m3	6¾"	21 m3
Drilling phase 2400 to 3000 m	8½"	22 m3	4¾"	7 m3
Drilling phase 3000 to 3500 m	6"	9 m3	3⅜"	3 m3
TOTAL		332 m3		105 m3

Forasol and Elf considered how to reduce costs for services. The approach they adopted is to integrate several items into the slim rig design not normally present. Services that could be affected by integration included instrumentation, cementing, mud management and waste treatment.

Advanced sensors were included in the rig for the driller, tool pusher, company man and mud logger. The drilling contractor becomes responsible for data acquisition, and duplication of instrumentation is avoided. A special mud logging unit was built and placed next to the company man office.

As a result of the greatly reduced volumes of cement required for slim-hole operations, cement slurry is prepared in two batch tanks and pumped by the rig pumps. Cost savings are accrued since a dedicated cementing unit is not needed.

Slim-hole operations produce a greatly reduced volume of cuttings and mud. Mud management was made more efficient by minimizing waste volumes using an efficient shale shaker and two high-speed centrifuges. Only high-concentration solids and clear water are disposed.

These newly integrated services impact the day rate of the rig and amount to about 10% of the total rig cost. In addition, another crew member is needed to act as fluid engineer. Overall cost reductions with this integrated approach are substantial (Figure 6-9). Further improvements in procedures and productivity are expected.

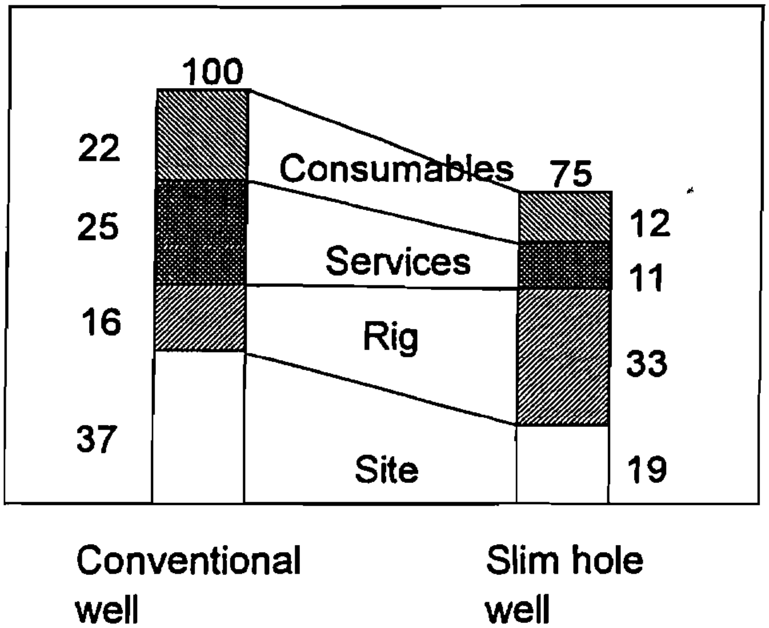


Figure 6-9. Cost Savings with Slim-Hole Integrated Services (Dupuis and Sagot, 1995)

6.8 HOLDITCH & ASSOCIATES (SLIM-COMPLETION ECONOMICS)

Holditch & Associates (Robinson and Syfan, 1995) performed a study sponsored by the Gas Research Institute of the economics of slim completions in the Wilcox formation in South Texas. Normalized costs are reduced by 10-15% (about $170,000 per well) by using slim tubulars to complete the well. Average reserves per slim well were less than those for conventional completions; however, this observation was attributed to the operators' tendency to use the slim option when thinner pay was expected or encountered.

The study was based on 23 slim and 21 conventional completions (Figure 6-10) in Webb and Zapata counties (Texas).

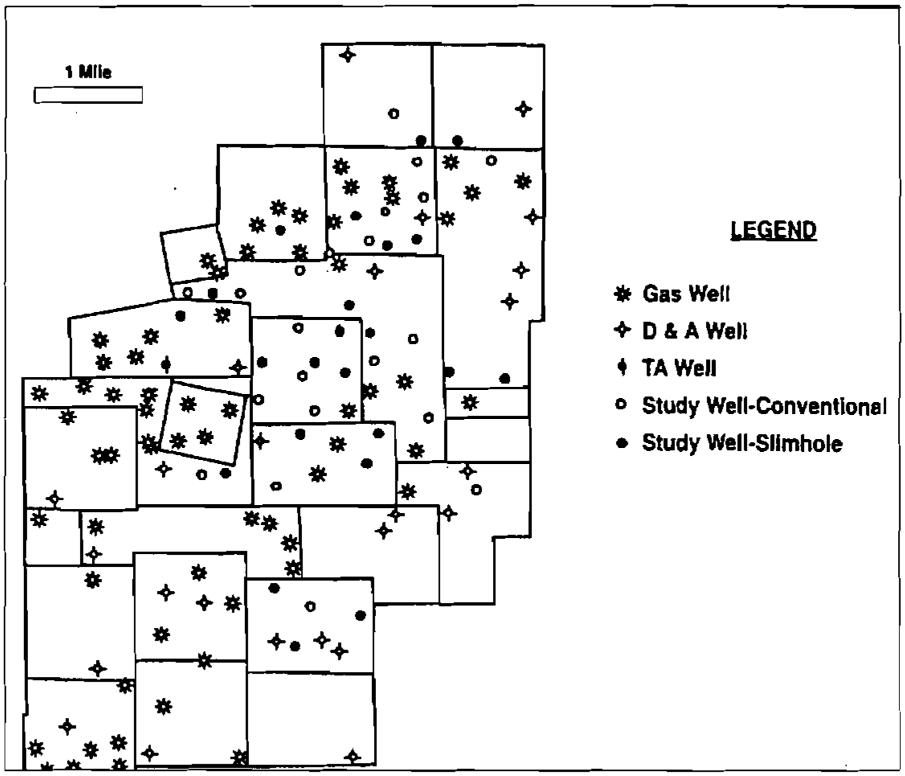


Figure 6-10. Slim-Completion Study Wells (Robinson and Syfan, 1995)

Average costs for drilling, completion and operation of the slim and conventional completions are compared in Table 6-5.

TABLE 6-5. Wilcox Slim Completion Costs (Robinson and Syfan, 1995)

	Conventional	Slimhole	Difference
Casing Size (inches)	4½ - 7	2⅞ - 3½	—
Drilling Cost ($M)	485	471	14
Completion Cost ($M)	542	385	157
Workover Cost ($M)	—	2	(2)
Operating Expenses ($M)	1.6/mo	1.6/mo	0
Total Difference ($M)			169

A reserves analysis indicated that the average slim-hole reserves (0.93 Bcf) were less than that for an average conventional well (1.35 Bcf). The primary reason for this difference was not wellbore geometry, but rather, a variation in average pay thickness (28 versus 45 ft). To provide a more accurate basis for comparison, reserves were normalized. For identical reserves, a slim completion significantly improves rate of return and pay-out time (Table 6-6).

TABLE 6-6. Slim-Hole Economics (Robinson and Syfan, 1995)

	Conventional	Slimhole
Reserves (MMSCF)*	1,148	1,148
Net Revenue ($M)*	1,572	1,572
Cost + Operating Expense ($M)	1,176	1,007
Net Profit ($M)	396	565
10% Discounted Profit ($M)	205	372
Payout (years)	2.3	1.6
ROR (%)	24	40

**Figures are identical due to normalization to equal drainage volumes.*

Surveyed operators reported that general operating expenses for slim-hole and conventional wells are essentially equal. Recompletion costs for slim wells are less (about $30,000) because operations can be performed without a workover rig. Typical workover costs are higher for the slim wells, however.

Hydraulic fracture treatments are slightly smaller for the population of slim completions. However, data analysis showed that treatment size was a function of operator preference, rather than limitations imposed by tubing size.

Slim completions are no longer considered novel in the area, with most operators considering the application routine. No special problems are associated with these wells.

6.9 GUPCO AND AMOCO EGYPT (SLIM-HOLE MARGINAL FIELD DEVELOPMENT)

Gulf of Suez Petroleum Company and Amoco Egypt Oil Company (Hassan et al., 1995) successfully applied a slim casing program to drill and complete wells in a marginal field not economically exploitable with conventional designs. Overall drilling costs for the first three wells were reduced about 20%. Drilling risks, while increased slightly under the slim-hole option, are considered manageable. Slimmer casing was one of several innovations applied to this project. Slots were added to an existing platform rather than setting a new platform. Gas-lift requirements were supplemented by onshore compression through existing pipelines.

GUPCO considered the applications of slimmer (reduced) casing in the October Nezzazat Field. A conventional completion included 7-in. casing across the productive interval (Figure 6-11). A build-and-hold directional plan is used for an average total cost of $3.2 million.

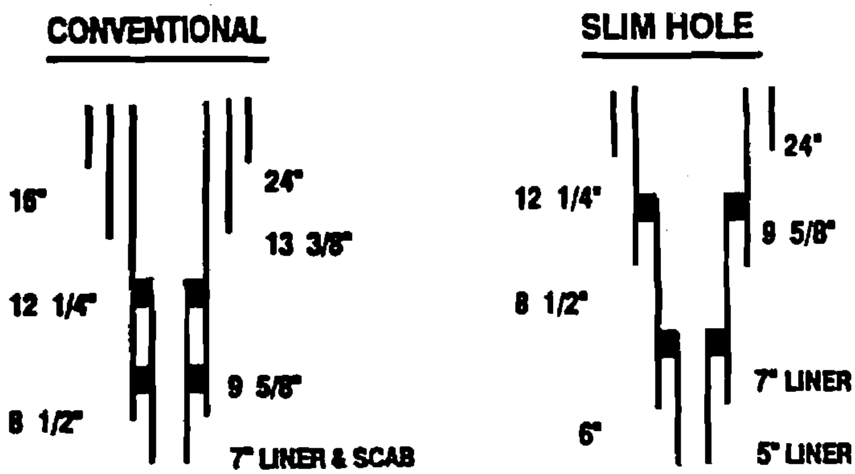


Figure 6-11. GUPCO Conventional and Slim Wells (Hassan et al., 1995)

The slim completion reduced each casing string by one size. This modification was easy to implement with commonly stocked equipment and tangibles. One slim well (Figure 6-12) was completed to 12,200 ft TD for a cost of $2.3 million.

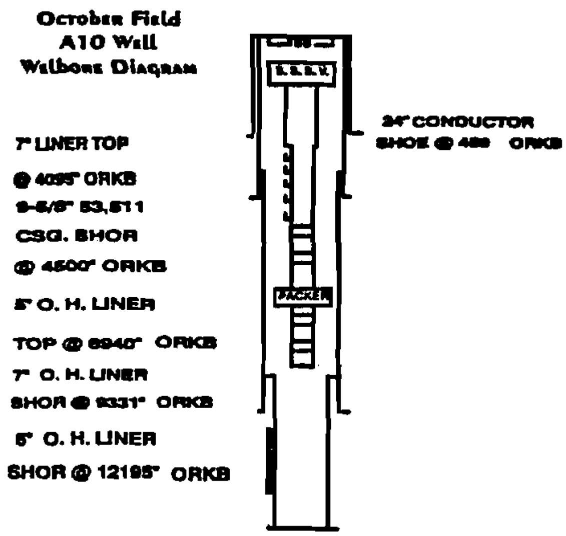


Figure 6-12. Slim-Hole Completion (Hassan et al., 1995)

Most cost savings can be attributed to lower casing costs. However, some time and money was saved by increased penetration rates in the slimmer hole. Overall drilling rates are compared in Figure 6-13.

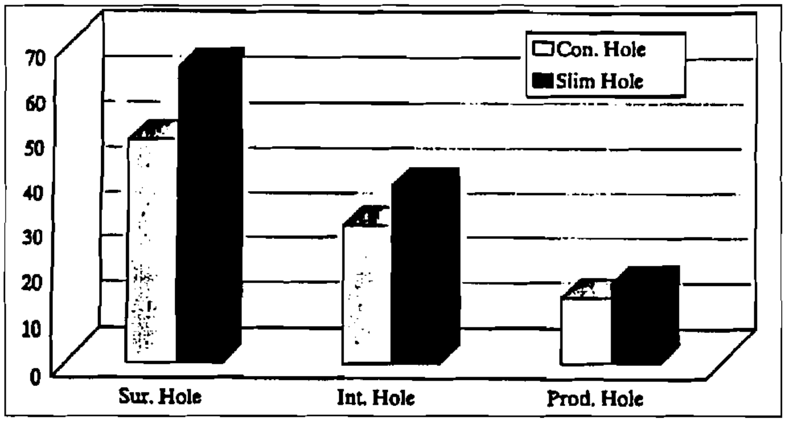


Figure 6-13. ROP Comparison (Hassan et al., 1995)

Cuttings disposal was another important concern. Costs were reduced in the slim wells due primarily to reduced cuttings volumes (Figure 6-14). GUPCO also noted that hole cleaning was generally better in the slim holes.

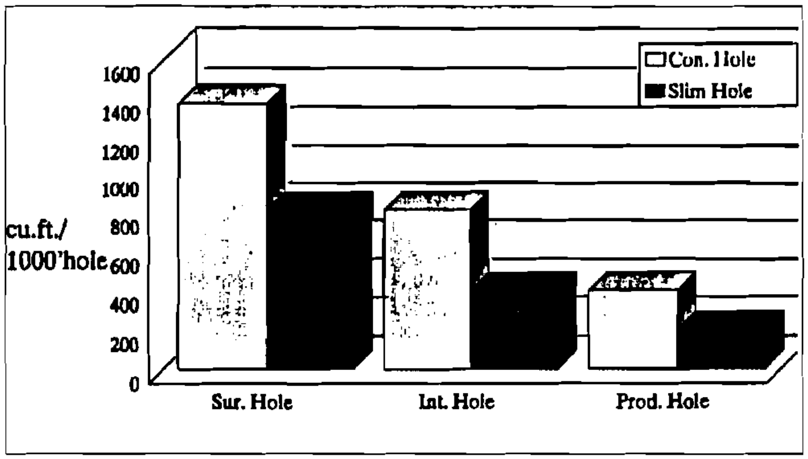


Figure 6-14. Savings in Cuttings Volume (Hassan et al., 1995)

The disadvantages of the slim option were also described. They include mechanical risk with weaker drill strings, loss of casing contingencies, limits to sidetracking options, and smaller completion across the productive interval. GUPCO stated that the fishability of completion equipment inside the 5-in. liner was limited.

Another innovation that made development of this marginal field economic was the creation of additional slots in existing platforms. One platform, originally designed for nine slots, can be expanded to fourteen (Figure 6-15). New slots can be installed in a few weeks for about $200,000 each. This approach is much cheaper than construction of a new platform.

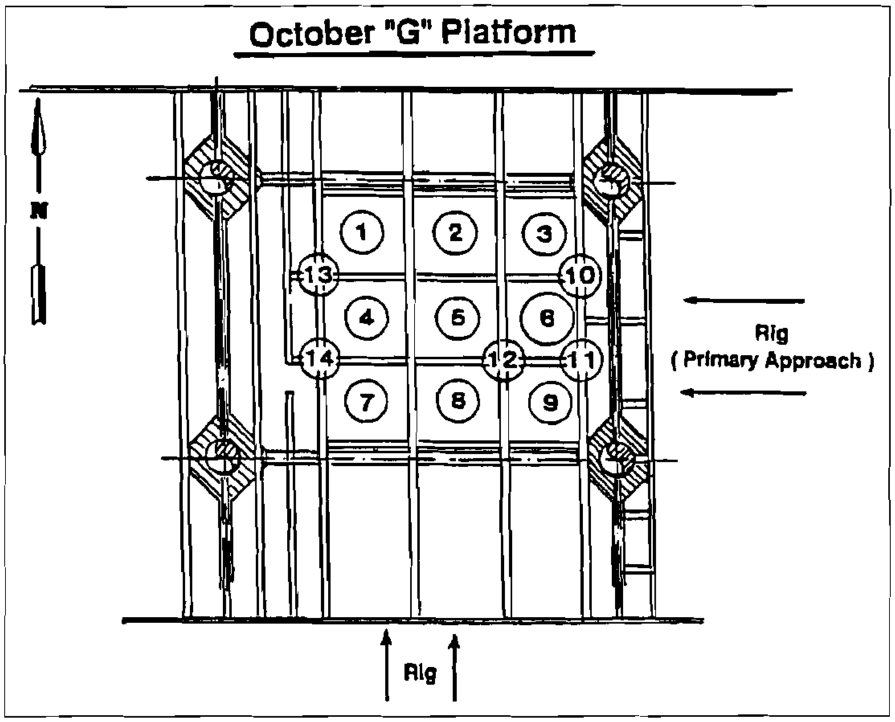


Figure 6-15. Additional Slots for Slim Wells (Hassan et al., 1995)

6.10 HUGHES CHRISTENSEN AND AMOCO CORP (SLIM COATED TSP BIT)

Hughes Christensen and Amoco Corporation (Felderhoff et al., 1995) collaborated in the development of an improved TSP bit for drilling a 4¾-in. section in the Prentice Field in West Texas. The best design drilled 28% faster and lasted 4 times longer than bits used previously. Total costs were reduced 19% per well with the improved slim bit.

The use of fixed-cutter bits in this area has only begun relatively recently. Improvements in diamond-bit design have resulted in the use of these bits in drilling environments once reserved for roller-cone bits. Tests had shown that TSP bits provide the lowest cost per foot in this West Texas area.

Amoco decided to optimize bit design further with a controlled experimental program. Parameters for the testing program are summarized in Table 6-7.

TABLE 6-7. Drilling Equipment for Slim TSP Tests (Felderhoff et al., 1995)

Test Equipment & Fluid Data	
Rig:	Workover
Pump:	Triplex
Flow Rate:	160 gpm
Standpipe Pressure:	1,700 - 2,200 psi
Hydraulic HP/in^2:	1.69 HHP/in^2
Total Flow Area:	0.25 in^2 Later changed to 18/32 = .2485
Weight on Bit:	6000 - 12,000 pounds
Bit Speed:	600 (MACH II) - 900 (MACH III) combined motor and power swivel
Circulating Fluid:	Freshwater (8.4 ppg. 28 vis) changed out at midpoint of interval to reduce solids)

The use of coated TSP cutters was found to increase the average drilled feet per bit by 985 feet. Overall drilling costs were reduced $2.61/ft ($23,422 per well).

Additional information on this optimization project is presented in *Bits*.

6.11 HUSKY OIL OPERATIONS AND INTEQ (RE-ENTRIES AT RAINBOW LAKE)

Husky Oil Operations and Baker Hughes INTEQ (Hollies and Szutiak, 1997) reported the successful application of slim-hole drilling techniques to revive several declining pools in the Rainbow Lake Field. Drilling problems for these re-entries, which include an overlying gas cap, sour uphole zones in the build section, and lost circulatino and differential sticking in the horizontal section. In the slim-hole approach (Figure 6-16), intermediate liner (4½ in.) is now being run into the curve. The lateral is then drilled with a reliable 3⅞-in. slim-hole system. Husky has found that completions in these wells are no more expensive than the conventional single-size version, and that production rates are similar for conventional and slim-hole. Overall costs with the slim-hole dual-size section are 10-15% less than conventional.

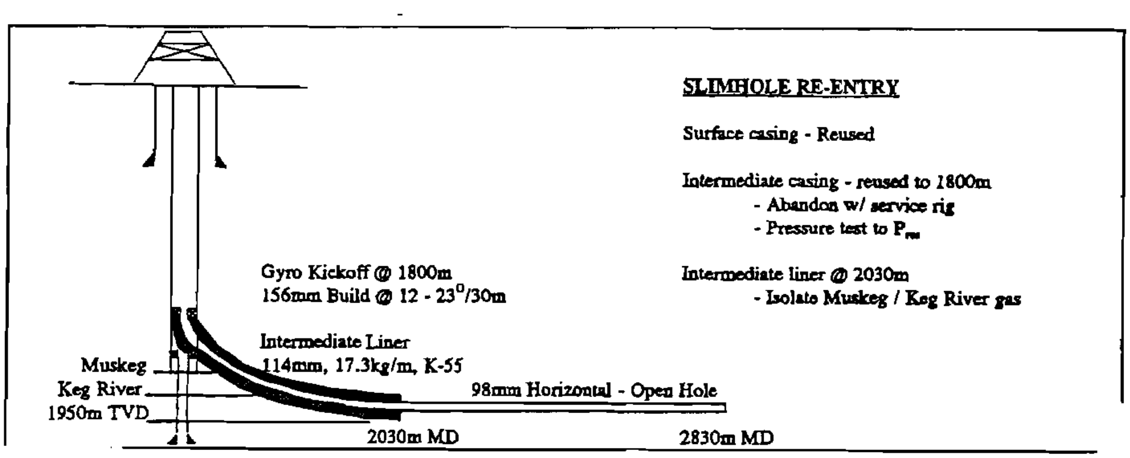


Figure 6-16. Typical Slim-Hole Re-entry at Rainbow Lake (Hollies and Szutiak, 1997)

Productive time and costs were compared for new horizontal wells, conventional re-entries, and the slim-hole dual hole. Slim hole re-entries were the most efficient in time and cost (Figure 6-17).

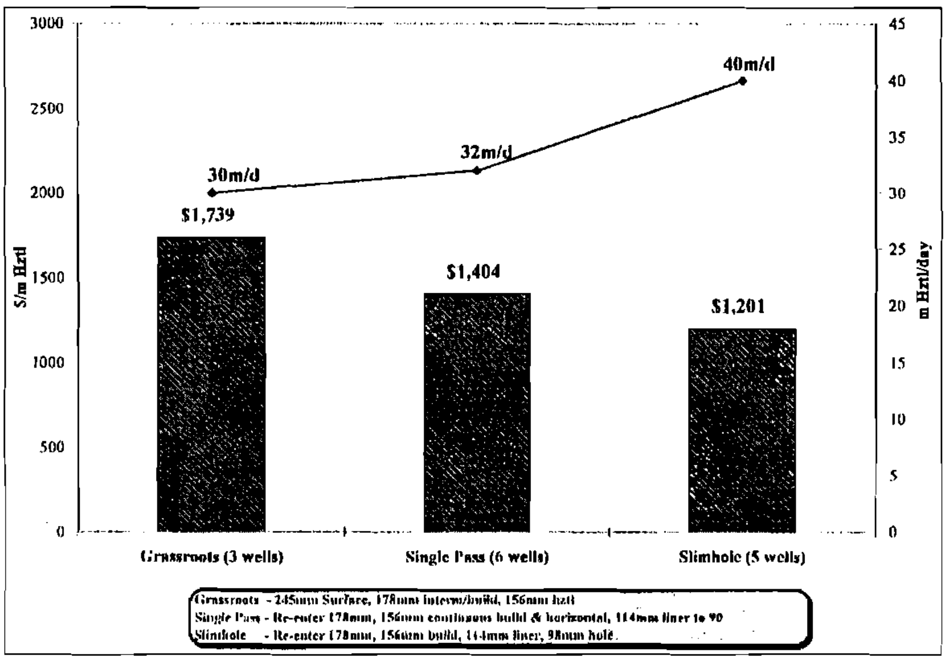


Figure 6-17. Time and Cost for Rainbow Lake Wells (Hollies and Szutiak, 1997)

The learning curve with the slim-hole completion showed a dramatic reduction in costs with time (Figure 6-18). In addition, the length of the lateral has increased significantly.

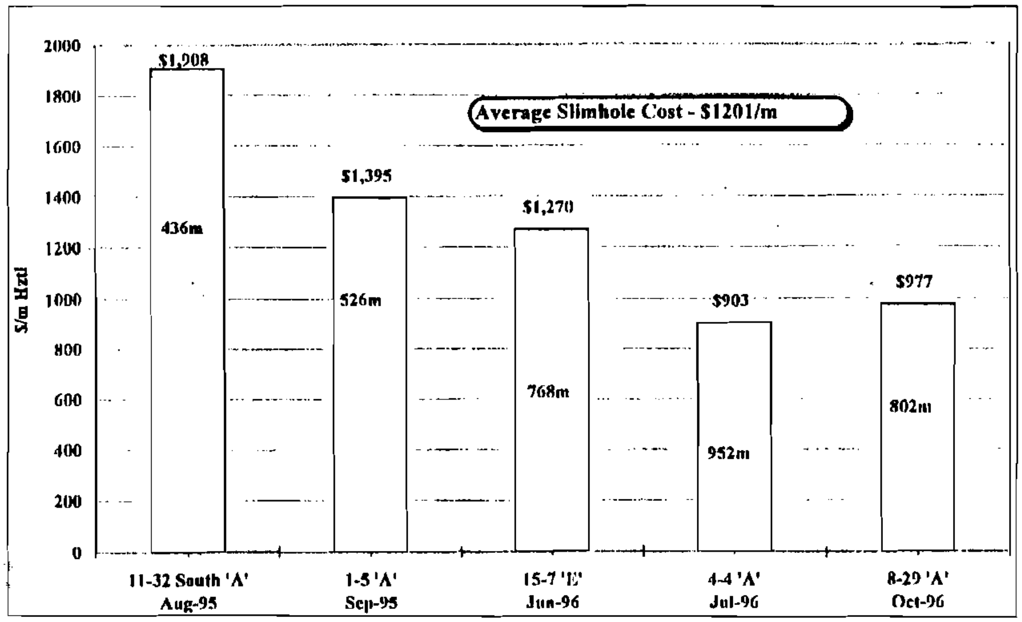


Figure 6-18. Slim-Hole System Performance (Hollies and Szutiak, 1997)

Well cost per meter of horizontal hole has improved $203/m, a 28% improvement as compared to a new grassroots horizontal well (Figure 6-19). Slim-hole performance has also been consistent as the techniques have been improved. The slim-hole re-entries can be completed on an average of 17 days.

Date	Well Name	Days	Hztl Section (m)	Drilling Cost ($,000)	Completion Cost ($,000)	Total Cost ($,000)
1) 156mm Grassroots Horizontal						
Jan-94	10-18-109-7W6	29	597	1292	90	1382
Aug-96	12-2-107-8W6	25	1039	1450	143	1593
Dec-96	12-18-110-7W6	21	582	1115	285	1400
	Average	25	739	1,286	173	1,458
2) 156mm Single Pass Horizontal Re-entry						
Feb-94	10-17-110-9W6	12	305	680	191	871
Jun-94	1-32/8-32-109-8W6	29	1682	1200	280	1480
Aug-94	4-9/5-9-109-8W6	35	458	1625	235	1860
Sep-94	3-5-108-9W6	22	1041	950	130	1080
Oct-94	2-11-107-9W6	18	588	811	170	981
Nov-94	13-29-108-8W6	19	300	875	570	1445
	Average	23	729	1,024	263	1,286
3) 98mm Slimhole Horizontal Re-entry						
Aug-95	02/11-32-107-9W6	17	436	832	160	992
Sep-95	1-5-110-8W6	17	526	734	372	1106
Jun-96	15-7-109-8W6	19	768	975	190	1165
Jul-96	4-4-110-8W6	18	952	860	287	1147
Oct-96	8-29-109-8W6	16	798	780	280	1060
	Average	17	696	836	258	1,094

Figure 6-19. Slim-Hole Costs at Rainbow Lake (Hollies and Szutiak, 1997)

6.12 MARATHON AND HUGHES CHRISTENSEN (PERMIAN BASIN COSTS)

Marathon Oil Company and Hughes Christensen Company (Tank et al., 1996) summarized developments in bits, motors, and techniques that have reduced costs in the Permian Basin. Slim roller-cone bits have played an important role in the slim-hole horizontal drilling applications. Several wells have been drilled with 3⅞-in. roller-cone bits on new 3⅛-in. PDMs. New equipment and optimized procedures have reduced per-foot costs by over 50%, increased total penetration per bit, and increased wellbore displacement.

In previous operations with marginal development in the Permian Basin, slim-hole designs were used in horizontal re-entries. Reduced ROPs were seen with earlier systems, and the cost advantages of a slim hole were often offset by longer drilling times. However, with new optimized systems, ROPs were nearly doubled.

In the Yates Field Unit, short-radius profiles were often used due to the thin target zone. Lateral lengths attained an average length of 190 ft in early efforts. With optimized bits and motors, the laterals now achieve an average length of 780 ft.

Slim-hole motor specifications are summarized in Table 6-8. Improvements in motors have been shown to increase average ROP from about 30 ft/hr to 60 ft/hr.

TABLE 6-8. Slim PDM Specifications (Tank et al., 1996)

Specifications for Typical Motor Used in the Yates Field Unit							
Motor Size	Bit Size	Design Radius	GPM	RPM	Temp Limit	Diff. Pressure	Max Oper. Torque
3⅛"	3⅞" - 4⅛"	60' - 100'	90 - 120	182 - 365	260F		400 ft lbs
3¾"	4½" - 4¾"	40' - 100'	150 - 185	210 - 370	260F	683 psi	679 ft lbs

Drilling performance has also been improved by using a thinner drilling fluid. Operators have reduced the concentration of biopolymer, resulting in increased turbulence downhole and improved cuttings removal.

The use of intermediate-radius profiles has allowed greatly increased lateral reach. Average displacement has increased from 488 ft to 1300 ft. Marathon saved over $100,000 on each of three intermediate-radius horizontal slim-hole re-entries. These new profiles have reduced the number of correction runs needed. Longer runs have been enjoyed, along with faster ROPs and less formation damage.

Additional information is presented in *Bits*.

6.13 MARAVEN, INTEVEP, CORPOVEN AND NABORS (VENEZUELAN EXPLORATION PROJECT)

Maraven S.A. and Intevep S.A. (Cambar et al., 1995) and Nabors Drilling International Limited, Maraven S.A. and Corpoven S.A. (Spoerker et al., 1995) described the planning, implementation, problems encountered and successes enjoyed during a multiwell, multiyear slim-hole exploration project in Venezuela. Two purpose-built slim-hole rigs were used to meet specific project requirements, which included high environmental sensitivity, full helicopter transportability, zero discharge drilling, and drilling depths to greater than 13,000 ft. Over the project phase consisting of seven wells, overall times and costs were close to estimates, 14,000 ft of core were recovered, almost all problems encountered were solved through analysis and innovation, environmental restrictions were met, and overall costs were about 20% less than conventional operations.

The learning curve showed significant ongoing improvements in time on location (Figure 6-20). The most successful efforts were accompanied by careful planning and communication. The fifth well showed a backward step in efficiency, due primarily to a relaxation in planning efforts and the adoption of a "routine" attitude.

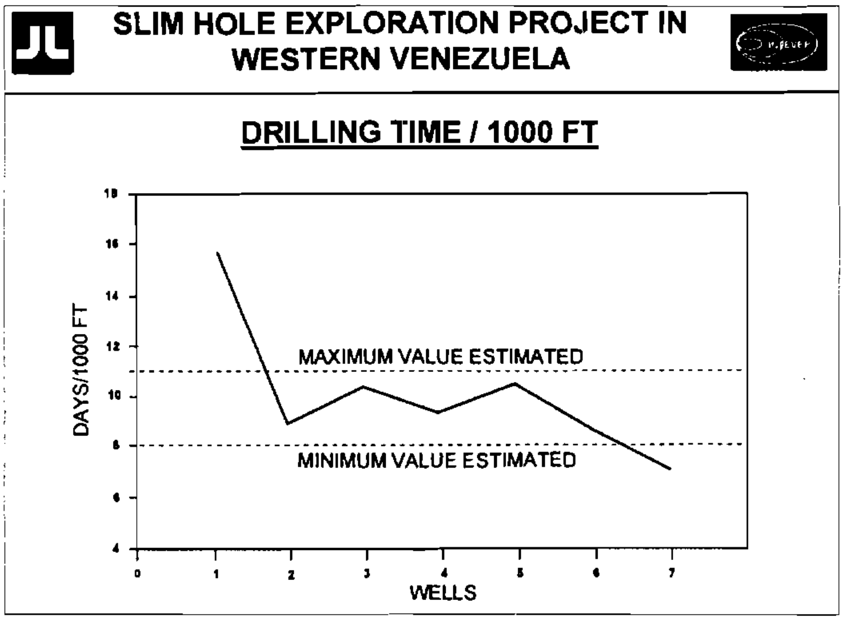


Figure 6-20. Drilling Time for Venezuelan Wildcats (Cambar et al., 1995)

Costs per 1000 ft are compared in Figure 6-21. The project team estimated that slim-hole savings were about 20 to 30% as compared to conventional equipment.

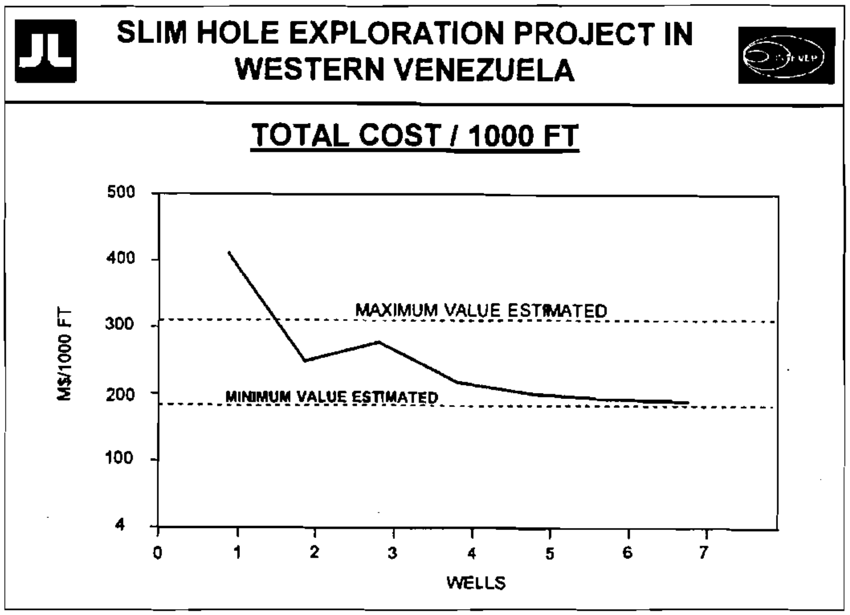


Figure 6-21. Cost/1000 ft for Venezuelan Wildcats (Cambar et al., 1995)

The combination of standard rotary drilling for surface and intermediate hole, and continuous high-speed coring for the target interval proved to be a viable drilling concept. They found that purpose-built slim-hole drilling rigs can out-perform conventional equipment when the entire project cost is considered.

Additional details describing this project are presented in *Coring Systems*.

6.14 MINING UNIVERSITY OF LEOBEN AND RDS (SLIM-HOLE OVERVIEW)

The Mining University of Leoben and RDS (Millheim et al., 1995) presented a summary of the history and status of slim-hole technology for oil-patch drilling. They believe that the technology is highly under utilized and that 70-80% of all wells drilled could be drilled with some type of slim-hole system. They considered the factors and dynamics that drive the acceptance and development of new technologies (such as slim hole) within the industry and within individual companies. A summary of the major operations and cost savings is shown in Table 6-9 (i.e., those that have been published).

TABLE 6-9. Slim-Hole Projects (Millheim et al., 1995)							
		Remarks	Location	Rig	Depth	Diameter	Savings
(a)	Amoco	drilled 40000 ft of continuous core in the US during 1987-89, explains the concept of SHADS	Upper Peninsulas, Michigan Western Kansas Southern Colorado West Texas	mining type SH rig	2206 m 1815 m 624,951 m 2931 m	6 in. 4¾ in. and 3 $^{1}/_{16}$ holes	n.a.
(b)	Texaco	continuous coring project overall core recovery 99.4%	Parena basin, Paraguay	Longyear PM 603	2987m	3$^{1}/_{32}$ in hole CHD 76 rod	$3.6 Million total costs, including core analysis (25% savings)
(c)	Shell, BBB, Bastman Teleco	drilled 46 wells destructively used "a lot in and think" method of well control	5 countries 15 wells in Germany with BBB	'Retrofit' rigs with soft tourque' rotary table or top drive, mud motor thruster	3838 - 5382 m in Germany	5⅞ in, 6⅛ in holes initially 4⅛ in as confidence growed	drilling costs per meter reduced by 19 - 41% for 4⅛ in wells, total well costs versus depth below trend of conventional well
(d)	Oryx	slimhole technology for horizontal wells and re-entries, destructive drilling, compared slim, reduced and large holes	Pearsall Field, South Texas	re-entries: 1990: workover rig 1991: coiled tubing new slim holes: small conventional rig for vertical, workover rig for horizontal sections	re-entries: av. 603 m new slimholes: 2955m vertical 961 m lateral	re-entry: 3⅞ in. new slimhole: 4¾ in.	A) total cost index B) lateral cost/ft index re-entries savings: 1990: a)0.85 b) 1.72 1991: a)0.50 b) 0.79 new slimhole savings: a) 0.68 b) 0.73
(e)	Asmera	5 wells drilled in remote-swamp area, continuous coring applied	South Sumatra	Longyear HM55 SH heli rig	>1186m	3⅞ in hole and 2⅞ in production casing	$9.52 Million Estimated for 5 conventional wells, $5.94 Million were actual SH costs (40% savings mainly due to lower costs for location construction
(f)	Total	2 wells were drilled in tropical rain forest, continous cored 59% of the total ength drilled	Gabon	Longyear PM 603	2747m and 418m	3 in and 5⅞ in holes	$12.8 Million for 2 wells, 15% savings estimated if conventional well would have no problems
(g)	BP, Exlog, Statoil	slimhole drilling venture was formed, continuous coring applied	Congo	helitransportable SH Rig, n.a.	700 - 2500m	n.a.	40% savings
(h)	BP	4 wells drilled, continuous coring and destructive drilling	Kayes "B", Congo	Parker hybird SH Rig	1132- 2086m	4.8 in hole	40% savings
(i)	Mobil, Oxy	2 wells were continous cored	Pando, Mantripi, Bolivia	Longyear PM 603	1981m 1542m	4$^{1}/_{16}$ in coring assembly	20 - 25% savings
(j)	Amoco	continuous coring and destructive drilling	Creston Nose, Wyoming	Rig No 170	3816m	3$^{1}/_{16}$ in coring assembly	$500,000 (41% savings)
(K)	Union Oil Comp, California	destructive drilled steam injection well	Bakersfield, California	workover rig	n.a.	2⅞ in tubing 6⅛ in hole	50% savings
(l)	Shell, Baker, Hughes Inteq	"Retrofit" SH offshore project, drilled high pressure wells	Offshore North Sea		>3000m	5⅞ and 4⅛ in holes	10 - 15% savings per well
(m)	Forasol/Foramer, Diamant Boart Stratabit	Introduction of Euroslim Project		purpose-built SH rig (15, 1994)	project goals: 4000m	project goals: 3 - 3$^{11}/_{32}$ in wells	30% in non-remote areas 50% in very remote areas (16, 1993)
(n)	Elf Aquitaine, Forasol	2 "ultraslim" holes were drilled destructive drilling and continous coring applied	Paris Basin, France	fitted for purpose slimhole rig (21, 1994)	2157m and 2160m	3 in hole and 3⅜ in hoe	n.a.

The modern revival of slim-hole technology was driven by at least two major factors: flat oil prices and the need to improve exploration results. Within the last several years, the center of activity in the slim-hole industry has shifted away from the continuous-coring applications and systems that characterized early efforts in the modern revival. The question of "why drill a slim hole?" should currently be addressed in the context of reducing overall project costs (on a macro scale). When overall project costs are lower than those costs using a conventional project approach, slim holes should be used.

Millheim et al. mentioned the outside forces of environmental pressure and profit accountability. Slim-hole technology is able to address increasing environmental pressures and concerns. The drive to reduce costs may also serve to overcome established levels of risk aversion within an organization and result in greater slim-hole usage than would normally occur.

Additional information is presented in *Overview*.

6.15 NORSK HYDRO, NORSKE SHELL AND MERCUR SUBSEA (SLIM-HOLE DRILLING FROM LIGHT VESSEL)

Norsk Hydro Production, A/S Norske Shell, and Mercur Subsea Products (Carstens et al., 1996) described the design of a slim-hole drilling vessel to be used for reducing costs at 5000-ft water depths. The vessel is dynamically positioned and fully heave compensated for tripping and drilling. A high-pressure riser is used, eliminating the need for kill and choke lines. They analyzed the market for such a vessel and determined that the greatest potential is for subsea well intervention and exploration drilling in deep water.

System costs and operating expenses are estimated in Table 6-10.

TABLE 6-10. Costs of Slim-Hole Drilling System (Carstens et al., 1996)

System Cost and Time-Dependent Operational Cost	
Dynamically positioned NMD class 3 vessel	
Heave-compensated rig.	
9" bore 10000 PSI riser	
Rated for 5000 ft water depth and 16000 ft drilling depth.	
Delta-Shaped Mono-Hull Vessel (Ramform)	
Total investment cost	:70 mill US$
Total daily cost*	:90,000 US$
Mini Semi-Submersible	
Total investment cost	:100 mill US $
Total daily cost*	:120,000 US $

Norsk Hydro performed a time analysis comparing slim-hole light-vessel costs with conventional. They assumed that slim-hole drilling is slower than conventional drilling. They then calculated the time factor that would result in break-even costs with the slim-hole approach. These data (Table 6-11) suggest that a mono-hull light vessel could require 2.3 times more days on location and still break even.

TABLE 6-11. Drilling Time for Break-Even Costs (Carstens et al., 1996)

Break Even Cost Factors for 5000 ft. Water Depth	
Time-dependent daily costs in Norwegian waters:	
Conventional operation	:210,000 US$
Light mono-hull	:90,000 US$
Mini semi-sub	
Time consumption factor on a well that gives equal cost:	
Light mono-hull	:210,000/90,000 = 2.3
Mini semi-sub	:210,000/120,000 = 1.7

The project team concluded that slim-hole drilling from a dynamically positioned light vessel is a feasible option for offshore operations to depths of 5000 ft. A significant reduction in costs is possible. Primary savings are in the use of a high-pressure riser and full heave compensation.

Additional information is presented in *Rotary Systems.*

6.16 OMV AG AND OIL & GAS TEK INT. (SLIM-HOLE PRODUCTIVITY)

OMV AG and Oil & Gas Tek International Limited (Kroell and Spoerker, 1996) provided a review and analysis of slim-hole production and hydraulics issues. They believe that the drilling industry has conclusively demonstrated that slim-hole technology can be used to reach objectives and is usually technically and economically feasible. They discussed completion and production aspects and the impact of slim wellbore diameters. For most cases, constraints on production are minimum, although more planning for completions, artificial lift, etc. will likely be required.

They also state that "only low- to medium-permeability reservoirs should be completed with slim holes." Economic advantages of smaller wells and equipment have to be compared to overall costs with a life-cycle analysis (Figure 6-22). Production constraints may offset the advantages of initial cost savings.

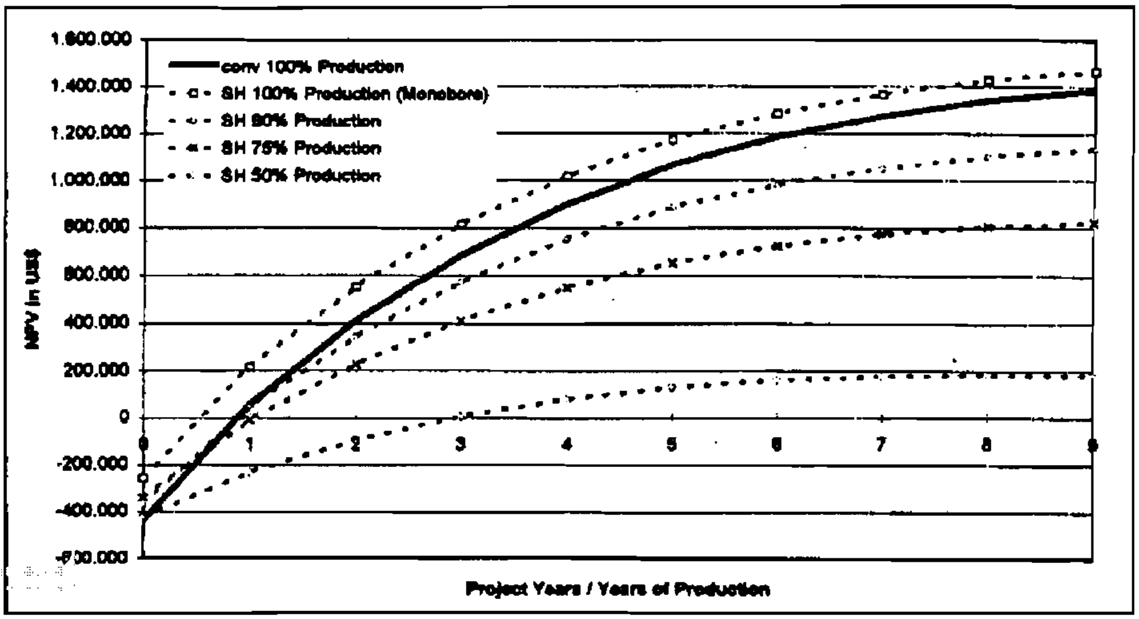


Figure 6-22. Life-Cycle Economics and Well Diameter (Kroell and Spoerker, 1996)

Additional discussion is presented in *Hydraulics*.

6.17 PANCANADIAN PETROLEUM AND BMW PUMP (SLIM-HOLE PC PUMP)

PanCanadian Petroleum Limited and BMW Pump Inc. (Chachula and Anderson, 1995) described the development and field testing of a slim-hole high-volume progressive-cavity pump for lifting viscous oil (12° API) with a high sand content. Testing showed that increased efficiency would be attainable at lower rotary speeds in slanted (35-45°) slim holes. Savings in drilling and completion by using slim holes amounted to 18% for a typical 16-well pad.

Two slant wells at Frog Lake were chosen for prototype development of a slim-hole progressive-cavity pump. Through these tests PanCanadian hoped to gain sufficient confidence to proceed with further applications of these pumps in slim wells. The downhole equipment for a typical slim completion is shown in Figure 6-23.

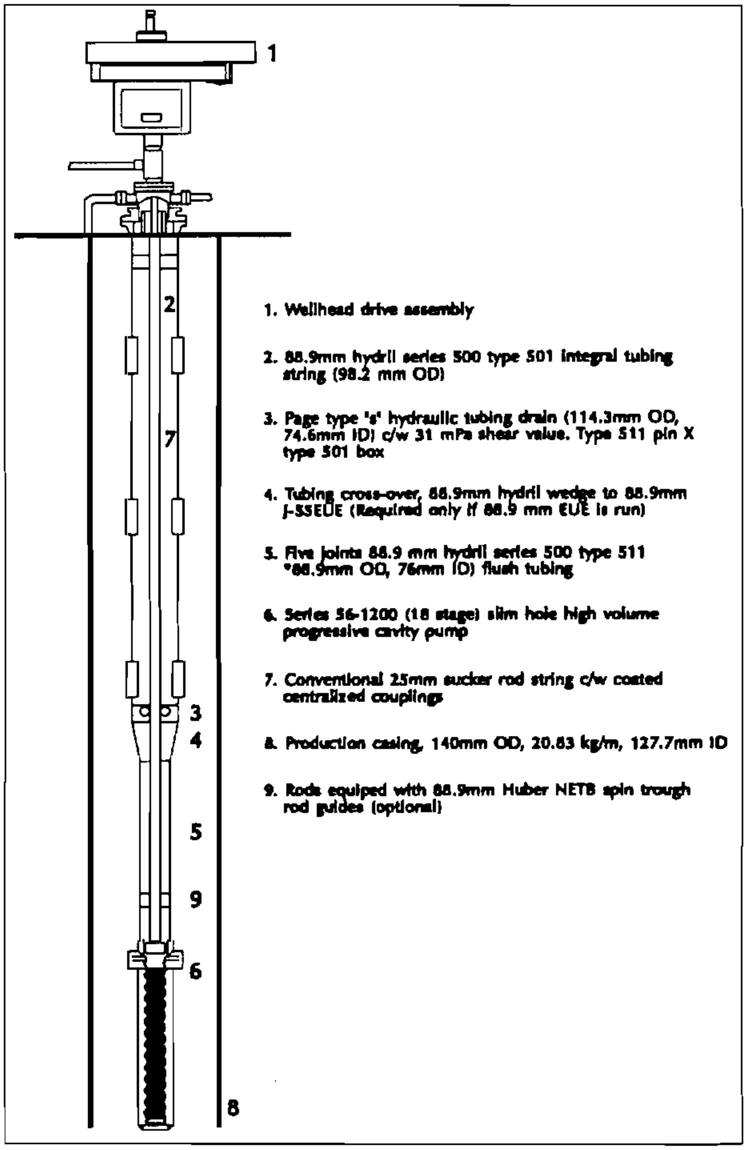


Figure 6-23. Downhole Equipment for Slim PC Pump (Chachula and Anderson, 1995)

Results with the slim progressive-cavity pumps were successful. Pump efficiencies increased significantly (to 85-95%) across the entire pump life. The low rate of sand-ins in the prototypes prompted the operator to proceed with additional installations inside 140-mm (5½-in.) casing. Sixteen wells were next drilled at inclinations ranging between 12 and 45°. Overall cost savings with respect to the conventional 178-mm (7-in.) completion averaged 18% (Table 6-12).

TABLE 6-12. Slim-Hole Cost Savings (Chachula and Anderson, 1995)

DETAILS	178 MM CASING	140 MM CASING	COST SAVING
Surface Hole			
Surface Hole Size mm:	311	311	
Surface Casing Size:	244.5	219.1	
Weight kg/m:	53.67	35.72	
ID mm:	225	205.66	
Grade:	H-40	J-55	
Connection	ST&C	ST&C	
$/m:	55.06	38.03	
Hole Depth m:	100	26	
Casing Costs $:	5600	1000	4600
Cement			
Surface t:	6	3	
Excess %100			
Surface Cement Cost $:	3500	2100	1400
Main Hole			
Main Hole Size mm:	222	200	
Production Csg Size mm:	177.8	139.7	
Weight kg/m:	29.8	20.8	
Grade:	J-55	J-55	
Connection:	ST&C	ST&C	
$/m:	31.68	21.09	
Hole Depth m:	675	675	
Casing Costs $:	21400	14200	7200
Cement			
Main Hole t:	17	20	
Excess% 30			
At $/t: 520			
Prod'n Cement Cost $:	8800	10400	(1600)
Other Savings:			
Rig @ 12 hrs less: (@ 12M$/day)			6000
Mud, water, etc. @ 10% less			2000
Bits are a wash:			
222 mm tooth bit = $2125			
200 mm tooth bit = $1980			

Additional details on this development are presented in *Artificial Lift*.

6.18 SHELL ROMANIA, FORASOL AND SECURITY DBS (ROMANIAN PROJECT)

Shell Romania BV, Forasol Romania, Forasol Foramer and Security DBS (Groenevelt et al., 1997) summarized the operations of a three-well slim-hole project in Transylvania, Romania. The Foraslim 1 rig, designed for depths to 3500 m (11,500 ft), was used both for destructive drilling and wireline-retrievable continuous coring. The new rig is designed for remote onshore operations for low environmental impact, high drilling efficiency, high safety at the wellsite, and complete geologic evaluation.

The camp site was 2000 m^2 and the rig site 2500 m^2. These areas did not represent the minimum site sizes for operation with the Foraslim-1. Winterizing the operation required an increase in space.

Four primary service contracts were managed by the lead contractor Forasol. These included 1) cementing and pumping services, 2) mud engineering, 3) borehole surveying and directional drilling, and 4) mud logging with kick detection.

The critical 4¾-in. section was to be drilled with a wide choice of bits designs including tricone, PDC, TSP and natural diamond. Field results showed that performance of newly designed slim bits with low WOB was as good as conventional. Optimization of bit design continued throughout the three-well campaign.

Time and depth curves are shown for the three wells in Figures 6-24, 25 and 26.

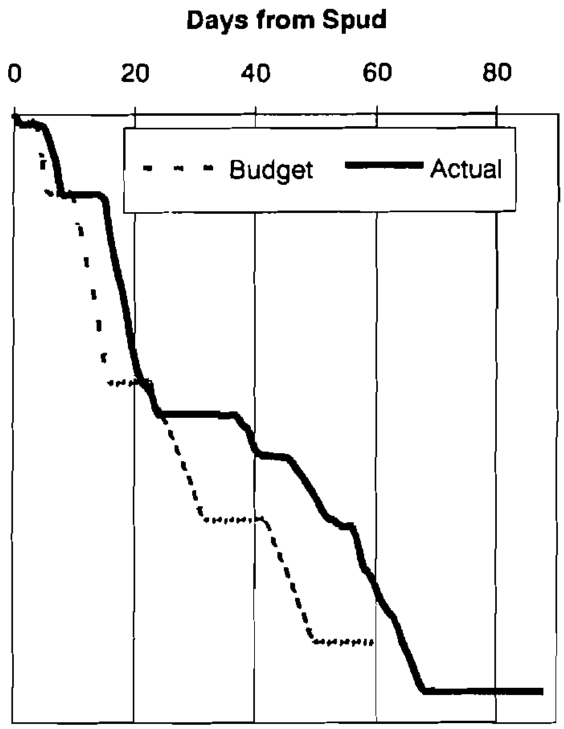


Figure 6-24. Drilling Time for First Well (Groenevelt et al., 1997)

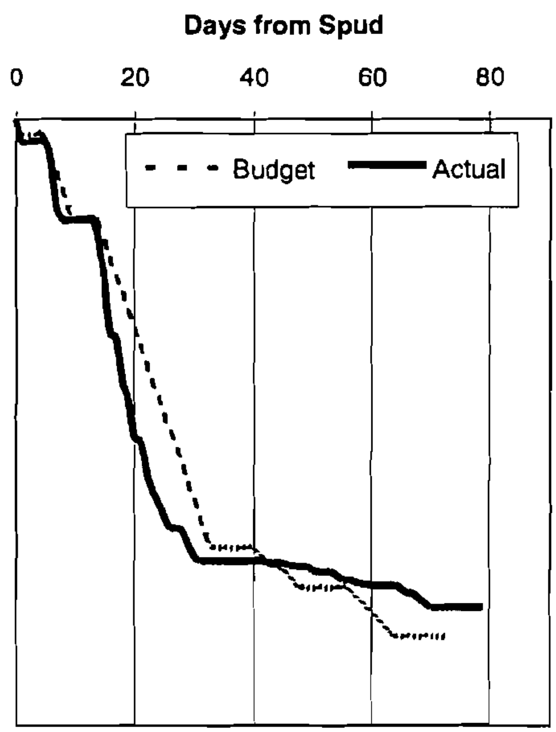


Figure 6-25. Drilling Time for Second Well (Groenevelt et al., 1997)

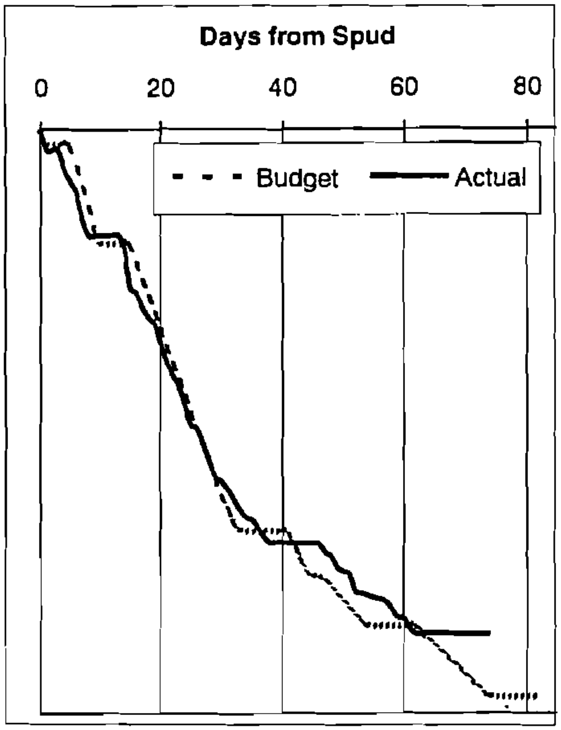


Figure 6-26. Drilling Time for Third Well (Groenevelt et al., 1997)

The 4-in. liners were not required since the slim hole sections were stable.

Several 2-in. cores were taken in the 4¾-in. section. A new design of wireline core barrel was developed by Security DBS. A hydraulic hold-down was used to connect the inner tube to the outer tube instead of latches. The operator concluded that coring operations were very effective. Success is summarized in Table 6-13.

TABLE 6-13. Core Recovery (Groenevelt et al., 1997)

Well No.	Core Length (m)	Recovery (%)	9-m core cut (hr)	9-m core recover (hr)
1	43	93	2.3	4.2
2	167	88	5	2.5
3	24	96	6.6	3

Project participants found that coring ROP was similar to that for drilling. Consequently, economics for coring were similar to those for drilling.

A complete range of logging tools were run in the 4¾-in. sections. Several tools were available for running in the 3⅜-in. contingency hole (Table 6-14), had that become necessary.

Table 6-14. 3⅜-in. Logging Tools (Groenevelt et al., 1997)

Tool Description	Maximum O.D. (inches)
Dual Focused Resistivity	2¾
Induction	2¾
Array sonic	2¾
Natural gamma ray	2¾
Compensated Density	2¾
Borehole Compensated Neutron	2¾
Borehole Compensated Sonic	2¾
High resolution dipmeter	2¾
3-D seismic acquisition	2
Cable head tension	2¾

The quality of the logs was very high. All hole sections were in good condition. Cuttings quality was also good with both tricone and diamond bits.

Overall savings for the project were estimated as 20% less than conventional. Cost increases were recorded for wireline logging and well testing, primarily due to the need for nonstandard equipment for these operations. Total cost savings amounted to $1.2 million for the campaign.

The operators concluded that these wells were drilled almost problem free and within time and cost budgets. They cautioned that problem time for contingencies would probably be greater than in larger holes (should problems occur in a similar operation). Junk in the hole was found to be a more critical concern in the slim holes.

Side-wall core samples in 4¾-in. hole were generally of poor quality and highly fractured. Reservoir characteristics were hard to discern from the samples. Basic lithology could be interpreted, however.

They also concluded that among the best applications for slim holes are development drilling projects of multiple wells where the drilling plan is relatively optimized so that the potential for drilling problems is minimized, where marginal cost savings per well will amount to a significant amount for the entire program, and where a reduction in environmental impact is desirable.

6.19 UNOCAL THAILAND (SLIM HOLES IN THE GULF OF THAILAND)

Well-publicized exploration operations in remote areas have shown large savings with slim-hole technology; however, operators involved in development drilling in more established areas also continue to report significant cost savings. An impressive example is reported by Unocal Thailand in the Gulf of

Thailand (Callahan and Schut, 1997) (Figure 6-27). Cost reductions due to optimizing conventional operations had become flat by the early 1990s. After 1994, the standard offshore well design was completely overhauled and replaced by a slim-hole design with a monobore completion. By 1997, wells were completed in 6 days for $750,000 (a 42% savings compared to 1994), with times and costs continuing to decrease. These slim-hole developments have transformed the future of operations in this area and allowed continued economic development of the gas resources.

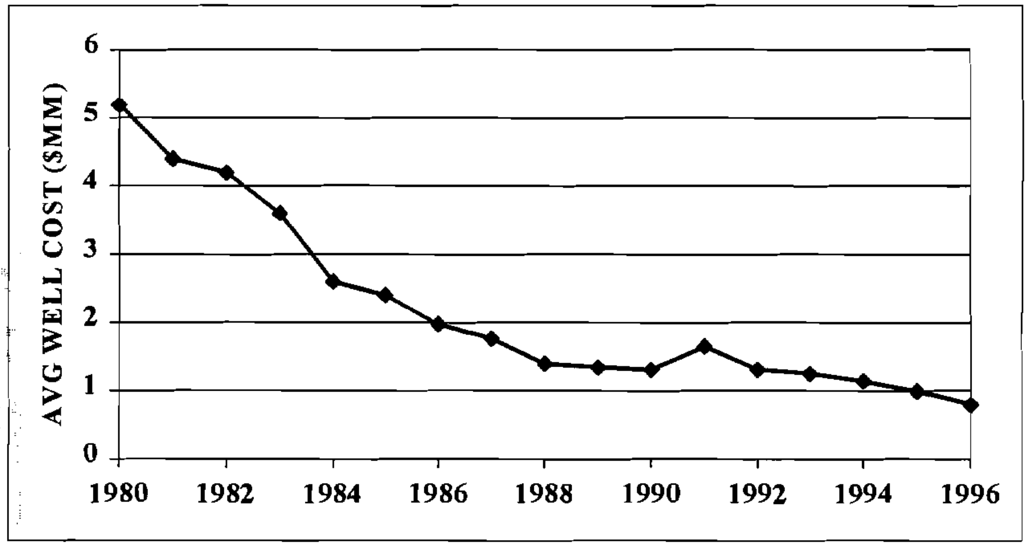


Figure 6-27. Drilling Cost in Gulf of Thailand with Slim-Hole Technology (Callahan and Schut, 1997)

Drilling time has also been reduced dramatically over the same period (Figure 6-28), with a significant reduction since the slim-hole monobore design was implemented in 1994.

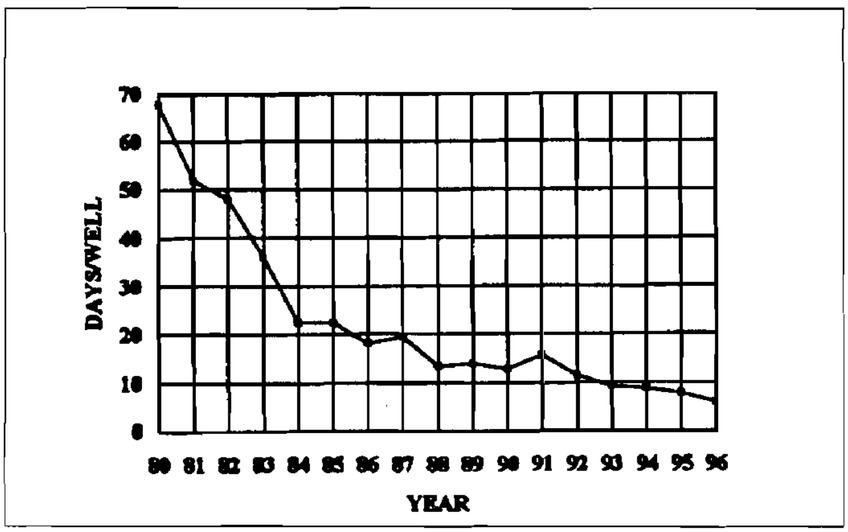


Figure 6-28. Drilling Time with Improved Conventional and Slim-Hole Technology (Callahan and Schut, 1997)

Unocal has found that drilling performance (Figure 6-29) is improved in the slimmer wells in every consideration. Running, tripping and pipe handling are all faster. ROP has increased through every geologic section. A reduction in material requirements has reduced supply boat shipments by 25%.

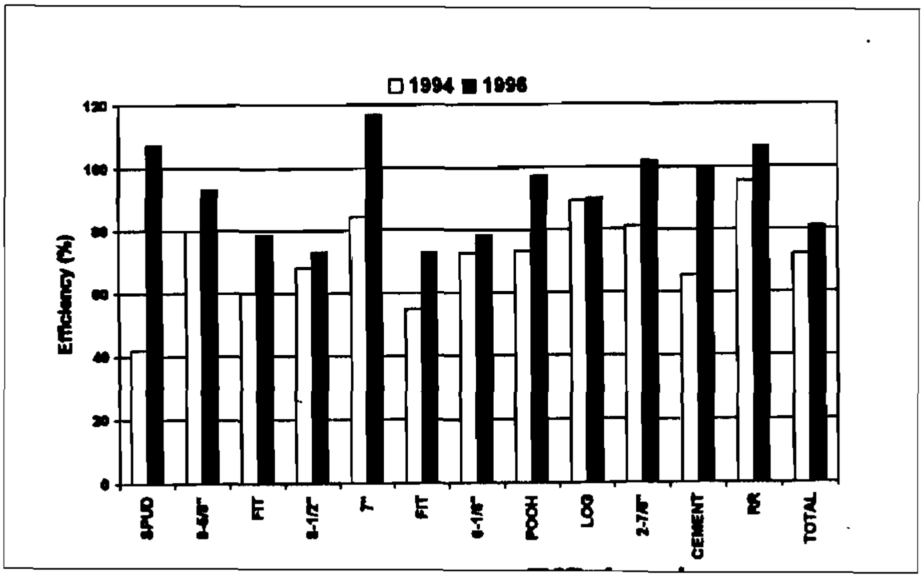


Figure 6-29. Drilling Efficiency for Conventional (1994) and Slim Hole (1996) (Callahan and Schut, 1997)

Unocal adopted a slimmer size hole of 6⅛-in. hole (Figure 6-30) for the initial foray into slim-hole technology. They were more comfortable that bits, motors, MWD, stabilizers, high-strength drill pipe, and logging tools were readily available for that size and could be applied using the same techniques and skills.

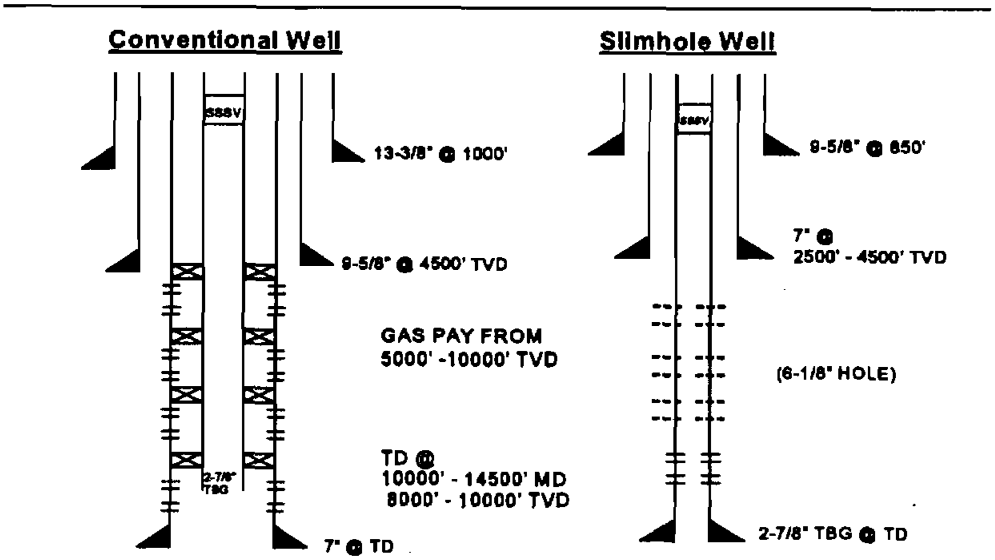


Figure 6-30. Hole Size Programs for Gulf of Thailand (Callahan and Schut, 1997)

They are continuing the evaluation of a slim design including a 4¾-in. hole at the target. Results of studies suggest that an additional $50,000 can be saved as compared to the current reduced-hole design. Full-suite logging tools for high-temperature environments was mentioned as a current limitation for applying the slim design.

6.20 UPRC (AUSTIN CHALK RE-ENTRIES)

Union Pacific Resources Company reports continuing cost savings averaging 30% for drilling horizontal slim-hole laterals out of existing wells (Strunk, 1997). The alternative is to drill a new well from the surface. A large number of vertical wells in the Austin Chalk were completed with 5½-in. casing. UPRC re-enters these wells and drills a medium-radius lateral with a 4¾-in. bit. The approach has proven very successful; they have more than 20 rigs drilling horizontal wells in the area.

They also reported that drilling efficiency in slim holes is not yet as high as in larger 6½ to 8½-in. holes, although it is improving.

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7. Drilling Fluids

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7. Drilling Fluids

7.1 FORBRICO (FORMATE FLUIDS)

Forbrico (Hallman, 1996) described successful field applications using formate drilling fluids. In one case, Mobil Oil Germany drilled a slim-hole gas well in the Walsrode Field using a 12.9-ppg potassium formate fluid in the producing horizon with excellent results. Fluid maintenance costs were reduced 75% compared to offset wells, ROPs were increased by 50% and circulating pressures lowered by 30%. Friction coefficients were low and filtercakes were very thin and tough.

Previous wells had been drilled using KCl/gel/carbonate fluids. Mobil was interested in formate drilling fluids due to their low solids content and stability of the polymer at elevated temperatures (325°F BHT). They hoped to increase ROP due to improve hydraulics and hole cleaning.

The potassium-formate fluid was found to be superior to fluids used previously. In addition to improved drilling performance, fluid properties remained stable at the elevated temperatures downhole.

7.2 RF - ROGALAND RESEARCH (DRILL-STRING ROTATIONAL EFFECTS)

RF - Rogaland Research (Hansen and Sterri, 1995) presented the results of experimental and analytical analyses of frictional pressure losses for various drilling fluids in slim annuli. They observed that frictional pressure losses increase as rotary rate increases with low-viscosity fluids. They attributed this phenomenon to the onset of centrifugal instability. Frictional pressure losses were observed to decrease with increasing rotary speeds for high-viscosity shear-thinning fluids.

Hansen and Sterri reviewed previous work investigating the hydraulics behavior of drilling fluids in narrow annuli between drill pipe (or core rod) and the hole. Some studies reported that rotation of the drill string increased frictional pressure loss. An important exception to this observation was Walker et al. in the SHADS development, where it was observed that friction pressure decreased with rotation. Hansen and Sterri surmised that this difference was due to the shear-thinning viscous nature of the SHADS drilling fluid.

RF - Rogaland investigated axial flow of non-Newtonian fluids with centrifugal instabilities. Their experimental apparatus (Figure 7-1) included a 4-m annular flow loop, a 1.25-in. drill string and a 1.57-in. casing. The diameter ratio r1/r2 was 0.8 and is compatible with most slim-hole geometries. Rotary speeds up to 700 rpm were used. Flow rates ranged up to 240 l/min (63 gpm).

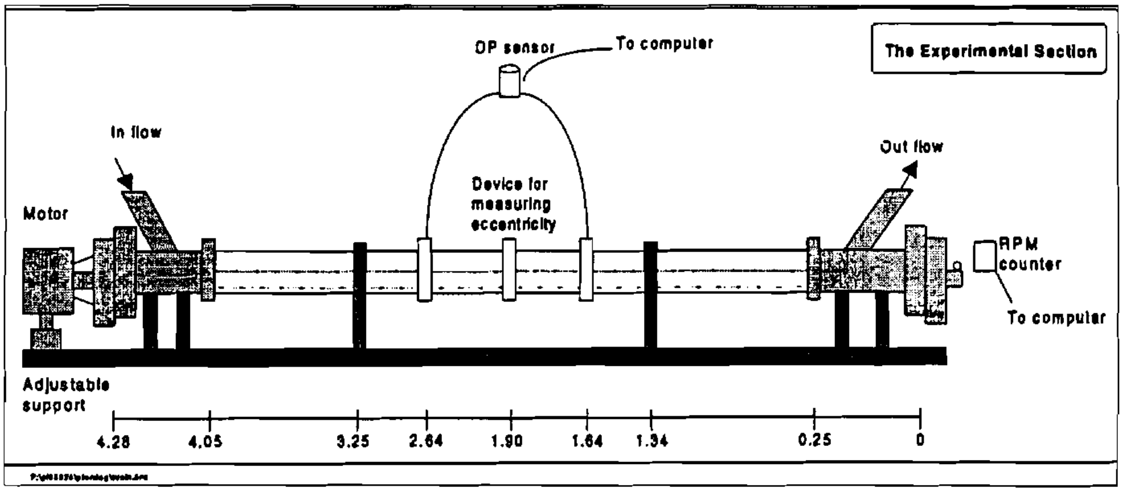

Figure 7-1. Flow Loop Apparatus (Hansen and Sterri, 1995)

Fluids used in the experiments were various blends of water and CMC. Power-law models were used based on the constants listed in Table 7-1. Fluid F1 was designed to represent a high viscosity fluid and to maintain laminar conditions at all times. Fluid F2 could achieve both laminar and turbulent flow under the range of experimental parameters. Fluid F3 (water) was used to achieve turbulent conditions at all flow rates and rotary speeds.

TABLE 7-1. Rheology of Experimental Fluids (Hansen and Sterri, 1995)

Fluid	k [Pa-s^n]	n
F1	4.112	0.43
F2	0.066	0.77
F3 (tap water)	0.001	1.0

Pressure drops for fluid F1 were measured at a range of flow rates and rotary speeds (Figure 7-2). These data were obtained with a drill-string eccentricity of 50%. Reduced frictional pressure is evident, especially for the highest rotary speed (595 rpm). The largest magnitude of pressure reduction is about 20% (for 595 rpm versus 0 rpm).

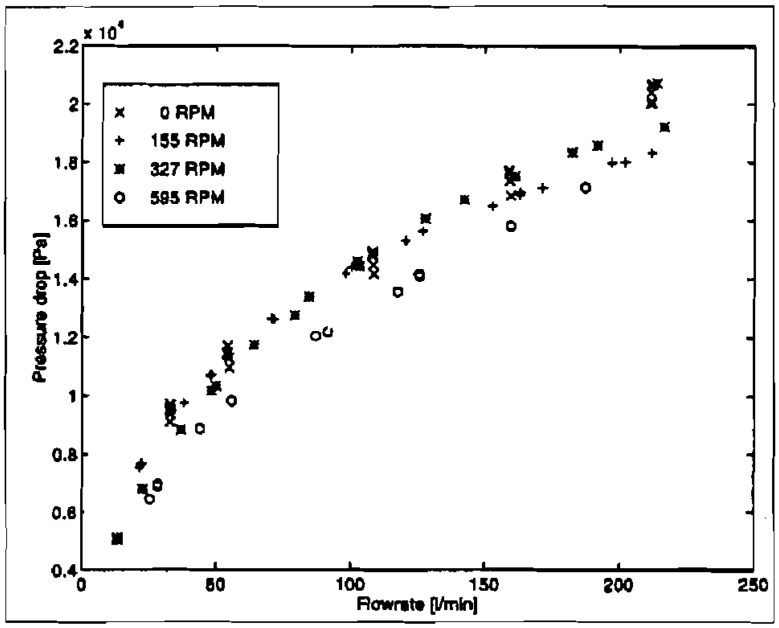

Figure 7-2. Flow Rate and Rotary Speed for F1 (Hansen and Sterri, 1995)

Pressure drops with and without rotation are compared for fluid F2 for the case of 40% eccentricity in Figure 7-3. The y-axis variable, R_{rot}, is the ratio of pressure loss with rotation to that without rotation. Pressure losses for this fluid increase steadily with increasing rotary speeds. For rotary speeds less than about 400 rpm, the magnitude of the flow rate was not observed to be significant.

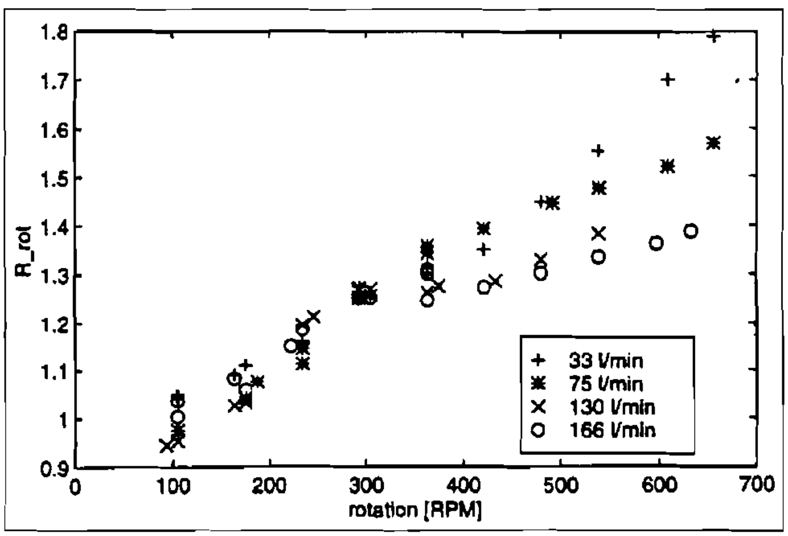

Figure 7-3. R_{rot} for F2 with 40% Eccentricity (Hansen and Sterri, 1995)

Flow rate does has a discernible effect for this case when eccentricity is reduced to 10% (Figure 7-4). However, as in Figure 7-3, flow rates greater than 33 l/min produce similar impacts on pressure loss for rotary speed less than about 400 rpm.

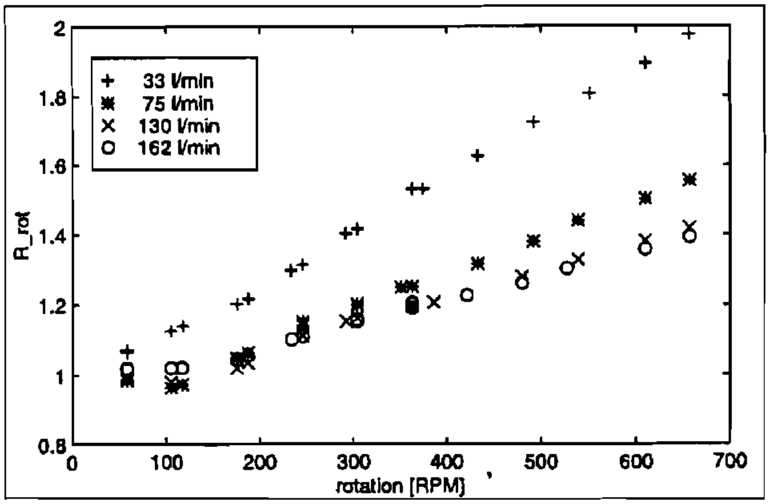

Figure 7-4. R_{rot} for F2 with 10% Eccentricity (Hansen and Sterri, 1995)

RF - Rogaland concluded that rotation can cause friction pressure loss to increase or decrease, and is a function of Reynolds and Taylor numbers. The results are summarized as follows:

- For Reynolds and Taylor numbers less than critical values, friction pressure loss decreases with rotation
- For Reynolds less than critical and Taylor greater than critical, friction pressure loss increases with rotation
- For Reynolds and Taylor numbers greater than critical, friction pressure loss increases with rotation

When friction pressure loss increases with rotation, the magnitude of increase is affected by flow rate, with the greatest effect observed at low Reynolds numbers.

Additional details of RF - Rogaland's experiments are presented in *Hydraulics*.

7.3 SHELL RESEARCH AND HALLIBURTON ENERGY SERVICES (MUD DISPLACEMENT)

Shell Research Rijswijk and Halliburton Energy Services (van Vliet et al., 1995) performed a theoretical and experimental study of cementing efficiencies in a slim-hole annulus using conventional and special drilling fluids. They analyzed cement displacement for cementing a 3½-in. liner in a 4⅛-in. hole. Both computer simulations and experimental results were compared. Harsh environmental conditions were assumed: an HPHT well with a minimal window between pore and frac pressures. Their results showed that a conventional solids-laden water-base drilling fluid cannot be fully displaced by the slurry. However, a potassium-formate brine drilling fluid can be displaced at almost 100% efficiency. They concluded that drilling fluids with low, flat gel strength that produce a thin, tough filter cake are greatly preferred from the aspect of improved cementing efficiency in slim holes.

A paramount concern in slim-hole cementing operations is excessive frictional pressure loss when pumping fluids at high rates in the narrow annulus (Figure 7-5). Rule-of-thumb recommendations suggest a displacement velocity of at least 80 m/min (260 ft/min). It is challenging to achieve efficient displacement of the drilling fluid while remaining below frac pressures in a slim annulus.

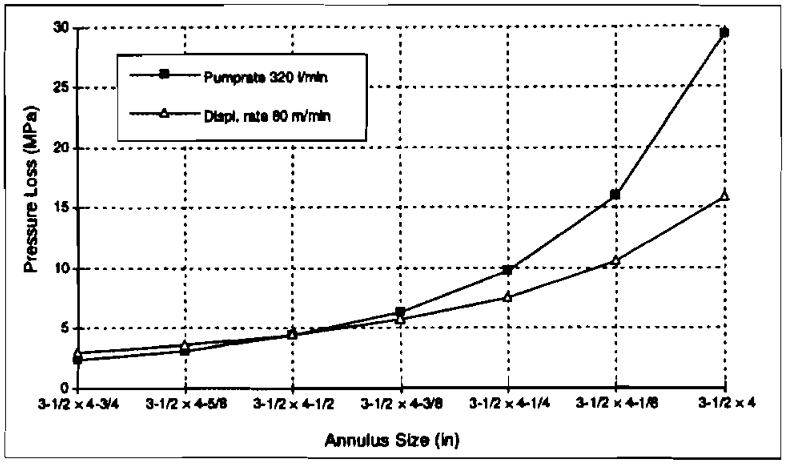

Figure 7-5. Pressure Losses in Slim Annuli (van Vliet et al., 1995)

Computer simulations were performed using a modified Bingham plastic model that did not include the effects of eccentricity or rotation. Two basic drilling fluids were modeled: 1) conventional water-base fluid weighted with barite and 2) caesium formate brine-base fluid with xanthan polymer. A weighted spacer (SG = 2.34) was required. Spacer volumes corresponded to either 300 or 1000 m height in the annulus. Slurry density was also high (SG = 2.37).

Results of the simulations indicated that an 80 m/min annular velocity could not be achieved in the 3½ by 4⅛-in. annulus of the HPHT well tested.

Two HPHT drilling fluids were tested (Table 7-2). The brine-base fluid is part of Shell Research's overall slim-hole development project underway for the past few years.

TABLE 7-2. Fluid Properties (van Vliet et al., 1995)

Fluid	T (°C)	PV - YP (cP - lbs/100 ft²)	10"/10' gels (lbs/100 ft²)	API mud fluid loss	
				Volume (ml/30 min)	Cake thickness (mm)
Conventional drilling fluid	80	43 - 38	50/115	8	3
Heavy brine based drilling fluid	80	43 - 27	5/7	4	0.5
Dual spacer	27	81 -26	4/17	--	--
Cement slurry	27	43 - 12	10/37	--	--

The maximum displacement efficiency of the drilling fluid by the cement ranged only from 65-80% with conventional muds (Table 7-3). A mud channel was observed in all cases. Increasing the contact time of the spacer (test 4) or slurry (test 5) did not improve displacement.

TABLE 7-3. Experimental Results (van Vliet et al., 1995)

Test	Average pipe stand-off (%)	Fluids	Annular velocity (m/min)	Contact time (min)	Pressure to break circulation (kPa)	Mud displacement efficiency (%)	Remarks
1	6	Conventional mud Spacer Cement	100 80 50	80 4 12	620	79	Base case
2	17	Conventional mud Spacer Cement	100 80 50	80 4 12	410	65	Base case
3	8	Conventional mud Chem. wash Spacer Cement	100 80 80 50	80 4 4 12	480	78	Attempt to remove mud with chemical wash
4	13	Conventional mud Spacer Cement	100 80 50	80 12 12	550	66	Cement volume doubled
5	13	Conventional mud Spacer cement	100 80 50	80 4 24	550	66	Cement volume doubled
6	12	Brine-based mud Spacer Cement	100 80 50	80 4 12	100	95	Base case with PFX-2 mud
7	9	Brine-based mud Spacer Cement	100 80 50	80 4 12	70	93	No pipe rotation
8	7	Brine-based mud Spacer Cement	50 50 50	160 6.5 12	70	95	Lower annular velocity of mud and spacer

Remarks: 1) Tests were preceded by 8 hr mud circulation stage.
2) Pipe was rotated att 20 RPM, except in tests 7 and 8.
3) Test temperature was 90°C.

Results with the brine-base muds were excellent (close to 100% displacement). Fluid properties that were found to be important were not primary rheology (PV, YP). It was determined that it is important to use a drilling fluid with low, flat gels that form a thin, tough filter cake.

Shell Research Rijswijk and Halliburton Energy Services concluded that, for cementing slim-hole wells, it is very important to use a drilling fluid that has a low, flat gel strength and forms a thin, tough filter cake. Brine-based fluids are representative of these types of fluids.

Additional data are presented in *Cementing*.

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8. Horizontal Drilling

8.1 BLUE RIDGE DIRECTIONAL SERVICES (MIDWAY FIELD RE-ENTRIES)

Blue Ridge Directional Services (Harry, 1997) reported on the successes of medium-short radius re-entry drilling in the Midway Field in Arkansas. The third attempt at horizontal drilling (the first two were only marginally successful) in the field was conducted in 1997 with increased success. Medium-short radius curves are being drilled. In a neighboring field, one well may be a record length for horizontal length (over 2400 ft) in the 4½-in. re-entry (Figure 8-1).

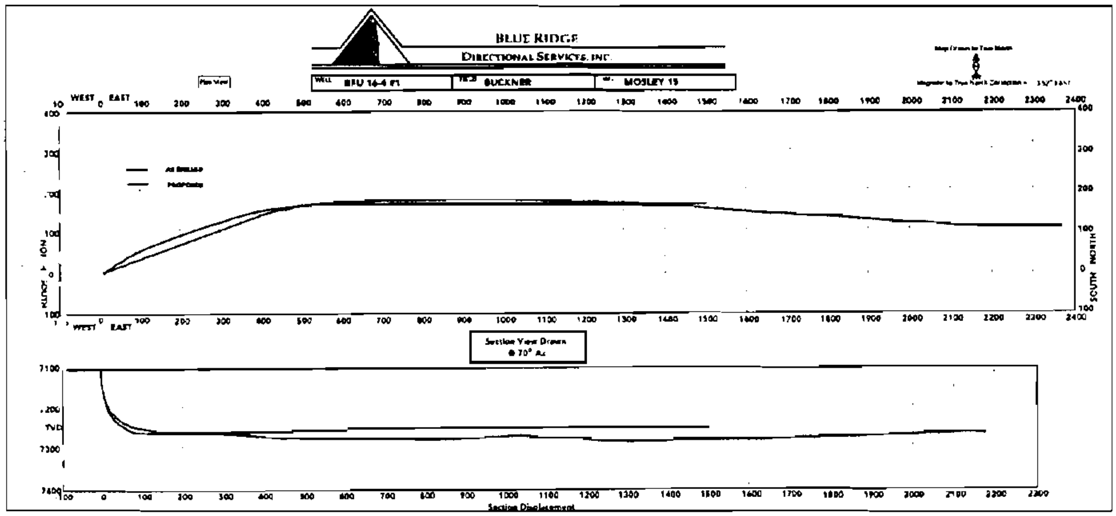


Figure 8-1. Directional Survey of BFU 16-4 Re-entry (Harry, 1997)

The successful equipment included a 3¾-in. motor with 4° or 3.5° single bends. These are used to drill the hole at a build rate of 45-70°/100 ft out of 5½-in. casing. A variety of PDC bits have been used, with each completing several laterals before being retired.

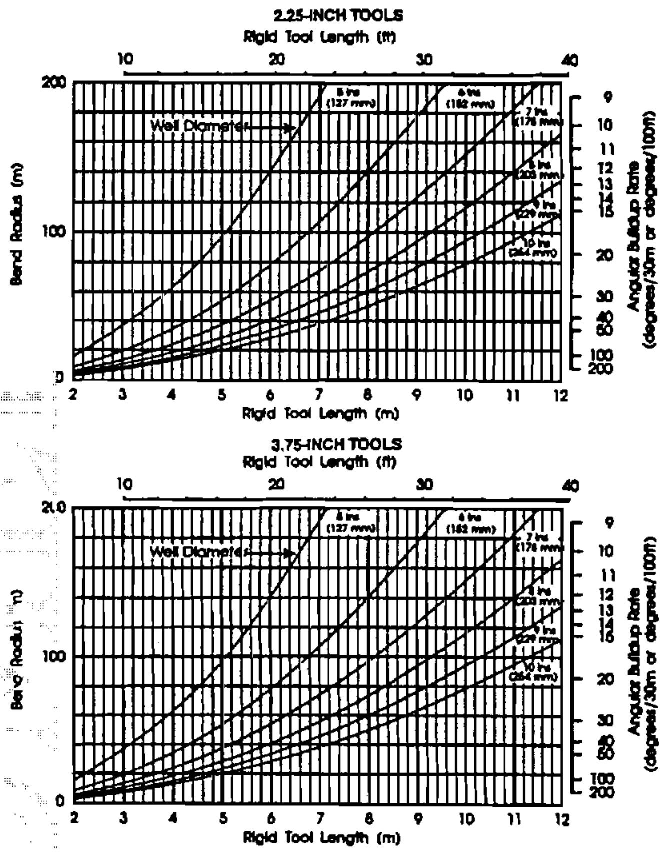
8.2 BP ALASKA (HORIZONTAL SIDETRACK)

BP Alaska reported (*Downhole Talk* Staff, 1995) successful operations drilling a 4¾-in. sidetrack (P-12a) at Prudhoe Bay. Almost 1000 ft of 4¾-in. hole were drilled before drilling was stopped due to geologic constraints. A 3½-in. mud motor was used. Operations were very similar to those used for 6- or 6¾-in. laterals. The hole was completed with a 3½-in. slotted liner.

BP Alaska reported that instantaneous ROPs were greater than those observed in larger holes. In one interval, ROPs of 250 ft/hr were observed, as compared to 100 to 120 ft/hr in a 6-in. hole.

8.3 BPB WIRELINE SERVICES (CT-CONVEYED SLIM LOGGING TOOLS)

BPB Wireline Services (Houpe, 1996) summarized the benefits and availability of slim logging tools suited for use in horizontal wellbores. Coiled-tubing conveyance has been proven as superior to jointed-pipe methods. Lateral penetration limits resulting from buckling have been extended through various methods including larger CT and temporarily hanging small tubing or casing to the lowest vertical section of the well. A reduced diameter in the vertical section effectively reduces friction and extends horizontal penetration.



Note: For a given tool diameter, maximum build tool length (L) that will traverse a well of diameter (d) and bed radius (R) is given by: L=2[(R+d)2-(R+t)2]1/2. Angular build rate (degrees/30 meters)=1718/R.

Figure 8-2. Maximum Tool Length Through a Curve (Houpe, 1996)

Negotiating the curve with the logging string can be a significant obstacle/limitation for logging horizontal wells. The rigid tool length for 2¼-in. tools is plotted in the upper graph in Figure 8-2. The lower graph is for conventional 3¾-tools. A slim short logging tool string is preferred in most cases. Swivels, knuckles and cranks are also used to minimize effective string length.

BPB Wireline provided example logs from a job in Germany to illustrate the benefits of logging in horizontal holes, even when significant offset vertical well data are available. In one case, a re-entry was drilled on coiled tubing and logged with the same rig. Coil size was 2⅜ inches. The logging tools were slightly smaller than the tubing, resulting in an ideal situation with respect to buckling and lateral penetration.

The dual-density/gamma-ray/caliper trace from a slim horizontal sidetrack revealed several tight lens. These barriers were blamed for previously observed pressure variations across the field. Significant hydrocarbon deposits were revealed in the shaly sand analysis. The well-defined permeability barriers and faults were revealed in greater detail than expected.

Additional details are presented in *Logging*.

8.4 BP ALASKA (THROUGH-TUBING ROTARY-DRILLED LATERAL)

BP Alaska (*Downhole Talk* Staff, 1996) described an innovative drilling operation based on through-tubing rotary drilling of a horizontal sidetrack. A 3¾-in. lateral was drilled to a length of 1478 ft and a 2⅞-in. liner run and cemented. The sidetrack of Prudhoe Bay C-23 was completed at a cost of $1.3 million, about 33% less than a conventional re-entry with tubing removal. The lateral was placed on production at over 4000 BOPD (35% above projections).

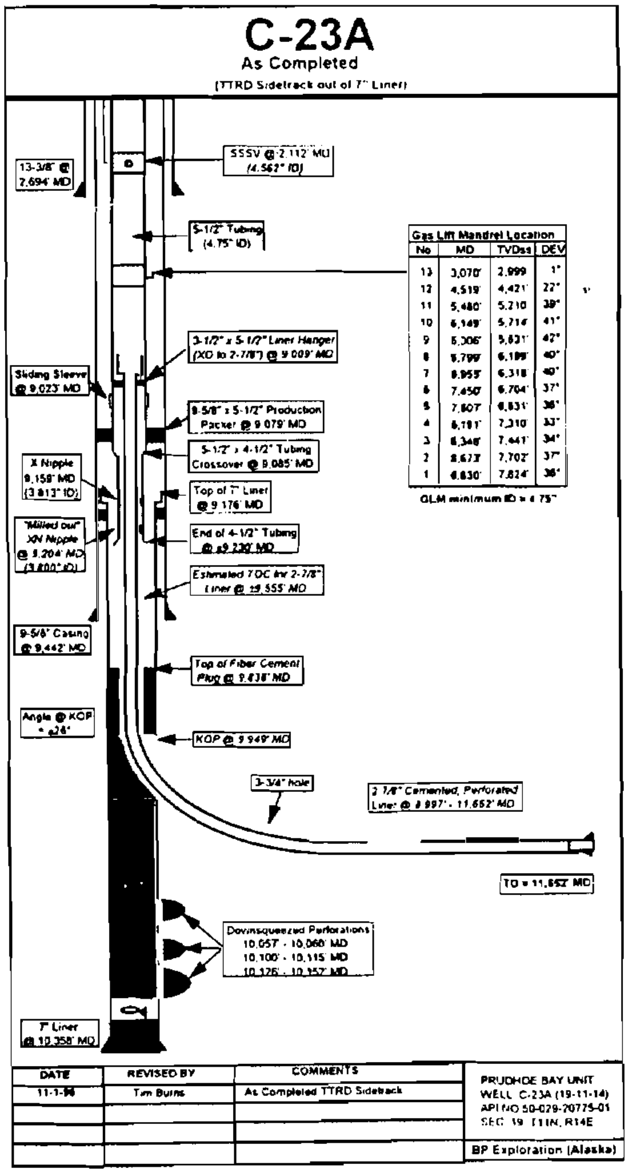


Figure 8-3. C-23 Completion (*Downhole Talk* Staff, 1996)

The original production interval was abandoned by placing a fiber-cement plug across the perforations with coiled tubing. The milling assembly was run through the 4½-in. production tubing tailpipe and a window milled in the 7-in. production liner. After milling, a directional assembly was used to drill the curve at a planned rate of 30°/100 ft. A lateral drilling assembly was then used for drilling the lateral out to 1478 ft.

A 2⅞-in. production liner (flush joint) was successfully run to TD and cemented in place. The same $1^{11}/_{16}$-in. work string was used to run perforating guns in the liner.

The complete wellbore schematic is shown in Figure 8-3.

Important accomplishments and lessons learned in this project include the following: 1) through-tubing rotary drilling is a technically and economically successful procedure, 2) well control in the small annulus requires special attention, 3) torque and drag were lowered with lubricants, 4) build rates up to 50°/100 ft are attainable with current technology, 5) only minimal casing wear was measured in the existing completion, and 6) through-tubing rotary drilling is economically competitive with coiled-tubing drilling.

8.5 MARATHON AND HUGHES CHRISTENSEN (PERMIAN RE-ENTRIES)

Marathon Oil Company and Hughes Christensen Company (Tank et al., 1996) summarized developments in bits, motors, and techniques that have reduced costs in the Permian Basin. Slim roller-cone bits have played an important role in the slim-hole horizontal drilling applications. Several wells have been drilled with 3⅞-in. roller-cone bits on new 3⅛-in. PDMs. New equipment and optimized procedures have reduced per-foot costs by over 50%, increased total penetration per bit, and increased wellbore displacement.

In previous operations with marginal development in the Permian Basin, slim-hole designs were used in horizontal re-entries. Reduced ROPs were seen with earlier systems, and the cost advantages of a slim hole were often offset by longer drilling times. However, with new optimized systems, ROPs were nearly doubled.

In the Yates Field Unit, short-radius profiles were often used due to the thin target zone. Lateral lengths attained an average length of 190 ft in early efforts. With optimized bits and motors, the laterals now achieve an average length of 780 ft.

A standard truck-mounted workover rig is used to drill these slim-hole re-entries. Equipment includes a triplex pump, power swivel, and 2⅞-in. drill string. IADC 537 and 547 roller-cone bits have been found to be best suited to this geology. Diamond bits have been used and have demonstrated less success than roller cone. One exception is a coated TSP bit.

A typical bit (Figure 8-4) is as short as possible to enhance directional capability.

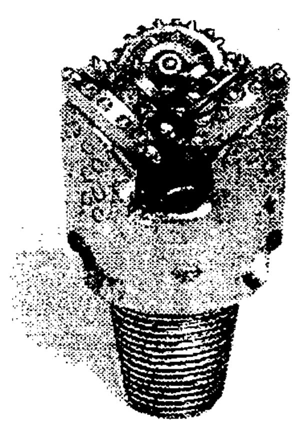


Figure 8-4. Short-Body 4¾-in. Bit (Tank et al., 1996)

Motor designs have been improved by lengthening the housing of the build section (Figure 8-5). This modification proved to enhance the positional stability of the BHA.

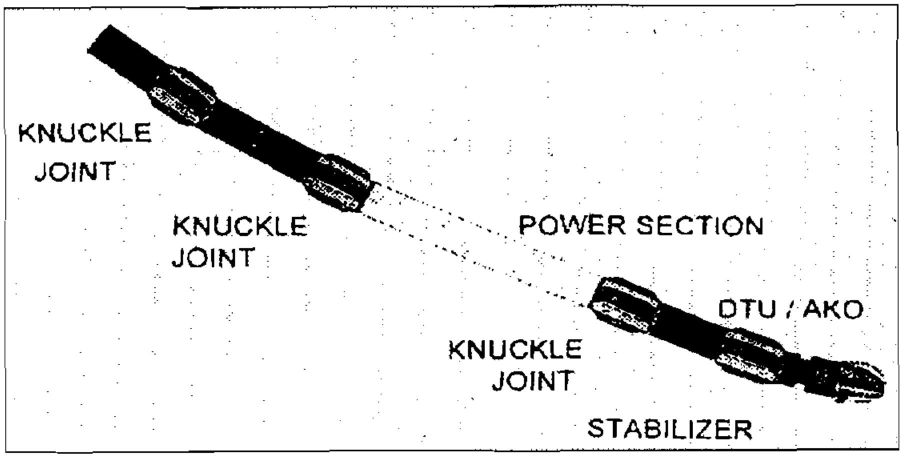


Figure 8-5. Typical PDM in Permian Basin (Tank et al., 1996)

Drilling performance has also been improved by using a thinner drilling fluid. Operators have reduced the concentration of biopolymer, resulting in increased turbulence downhole and improved cuttings removal.

The use of intermediate-radius profiles has allowed greatly increased lateral reach. Average displacement has increased from 488 ft to 1300 ft. Marathon saved over $100,000 on each of three intermediate-radius horizontal slim-hole re-entries. These new profiles have reduced the number of correction runs needed. Longer runs have been enjoyed, along with faster ROPs and less formation damage.

Additional information is presented in *Bits*.

8.6 PETROLEUM ENGINEER INTERNATIONAL (SLIM MWD TOOLS)

Petroleum Engineer International (Perdue, 1996) surveyed the logging service industry and provided a summary of developments in slim-hole MWD tools. Tools are available that fit into drill collars as small as 3⅛ inches. The availability of smaller tools has extended their application into new areas such as high risk for stuck pipe, high temperatures, low-budget wells and remote locations. The cost of drilling horizontal wells has been significantly reduced through integrated MWD systems.

Slim-hole activity has increased in the Gulf of Mexico in recent years. The first slim horizontal well was drilled there with a 3¾-in. directional/gamma-ray tool in 1993. Over 80 sidetracks have since been performed in the area.

Re-entries of old wells is the fastest growing segment of the slim-hole MWD market. Many of these involve drilling 6-in. horizontal laterals out of 7-in. casing. MWD has also proven to be an ideal tool for rapid evaluation of slim wildcats.

New capabilities are continually being added to slim MWD systems. Drilling Measurements Inc. provides a wireline steering system (probe OD of 1 in.) that measures directional data, gamma ray, temperature and vibration, and incorporates a wet-connect system that permits drilling rotation. This type of system is widely used in the Austin Chalk and for underbalanced and aerated-fluid applications.

Halliburton Energy Services, Schlumberger Anadrill, Baker Hughes INTEQ and Sperry-Sun all report significant interest in their slim MWD systems and capabilities.

8.7 REED TOOL COMPANY (NEW SLIM BITS)

Reed Tool Company (Neal, 1996) described the development process for an improved 4¾-in. insert bit for slim-hole horizontal re-entries. A special concurrent engineering approach reduced development time for the new bit by about 25%. An improved cone retention design resulted in increased performance in several field applications. A savings of 40% compared to previous horizontal wells was reported for one operation in New Mexico. This represented a cost reduction of $52/ft.

The primary improvement in the design of the new 4¾-in. bit was the use of a two-piece threaded ring retention mechanism to attach the cone on the journal (Figure 8-6). Ball bearings, the most common means to retain cones, have been found to be less effective in slim bits.

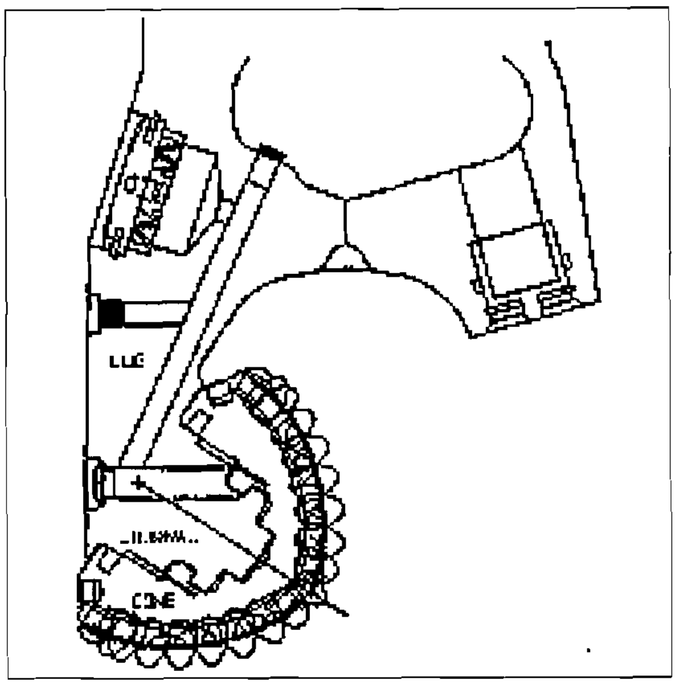


Figure 8-6. Cone Retention for Slim Bit (Neal, 1996)

Several field tests were performed with the bit in Canada, New Mexico and North Dakota. Data from offset wells were analyzed in detail for performance comparison. Overall results showed that bits run in build sections drilled an average of 295 ft in 25 hr at 10,000 lb WOB and 180 rpm. No bearing failures were reported. Bits run in the lateral drilled an average of 580 ft in 30 hr at 12,000 lb WOB and 320 rpm. Fourteen percent bearing failures were reported. Bits run in vertical sections drilled an average of 419 ft in 36 hr at 16,000 lb WOB and 50 rpm. No bearing failures were reported.

Footage drilled per bit is compared for several field trials in Figure 8-7. Drilling hours are compared in Figure 8-8.

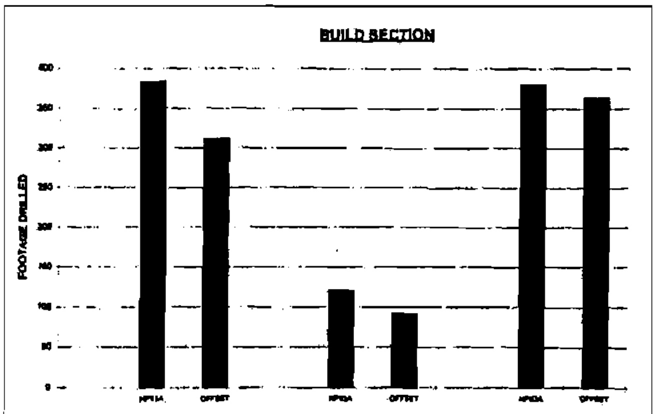


Figure 8-7. Footage Drilled for New 4¾-in. Insert Bit (Neal, 1996)

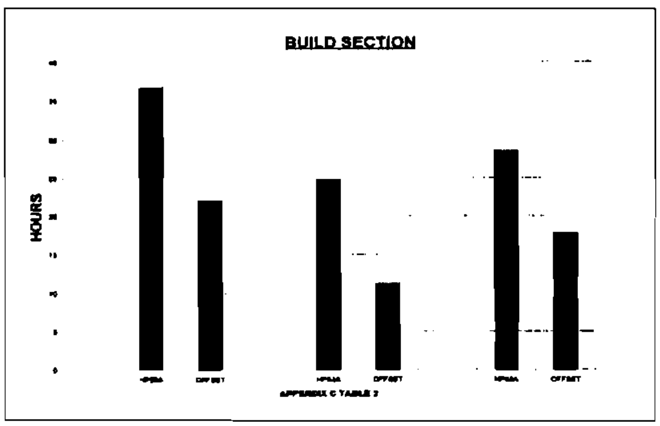


Figure 8-8. Hours Drilled for New 4¾-in. Insert Bit (Neal, 1996)

8.8 PANHANDLE EASTERN AND SLIMDRIL (HORIZONTAL STORAGE WELL)

Panhandle Eastern Pipe Line Company and SlimDril International (Gredell and Benson, 1995) described planning and successful drilling/completion of a slim horizontal into the Howell gas storage field in Livingston County, Michigan. A new well with a 2000-ft lateral was placed under the city of Howell. Costs, while higher than normal due to the stringent requirements for drilling in an urban setting, were considerably reduced by slim-hole technology. A slim well design was selected to minimize rig requirements and conserve space. The horizontal well produced at rates about four times greater than a nearby offset vertical well.

About one-third of the storage field lies under the city. Cycling of stored gas in this section of the reservoir was limited by a lack of wells (Figure 8-9). This problem was confirmed by shut-in pressure data from wells in this section. Objectives of the project included increasing the volume of working gas that can be cycled from the field, and increasing the deliverability (production rate) during late-season drawdown.

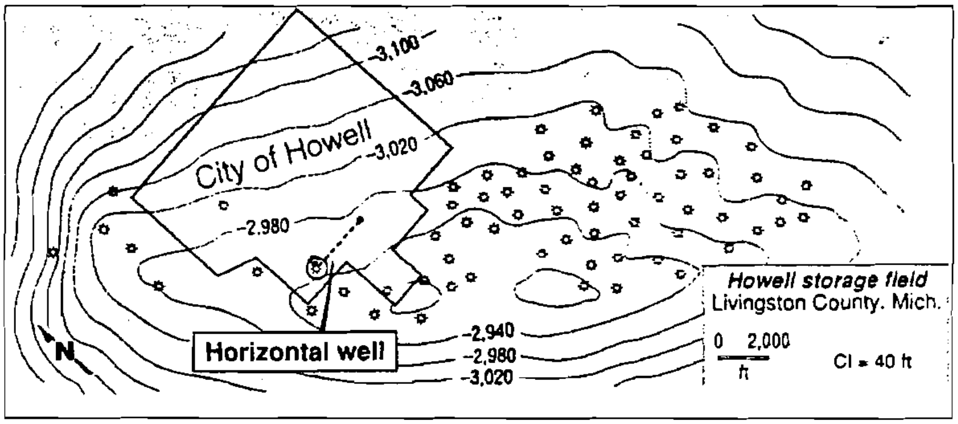


Figure 8-9. Howell Field Storage Wells (Gredell and Benson, 1995)

Several technical and operational issues were addressed during planning, including modeling performance of a horizontal well, special environmental/safety concerns for an urban setting, protecting the integrity of the storage zone, and geosteering the lateral within a thin reservoir. The average depth of the reservoir is 3900 ft. Permeability in the targeted section is about 50 md and porosity 10%. Reservoir modeling for the proposed horizontal well suggested that interference effects would be minimum, especially for laterals as long as about 2000 ft (Figure 8-10).

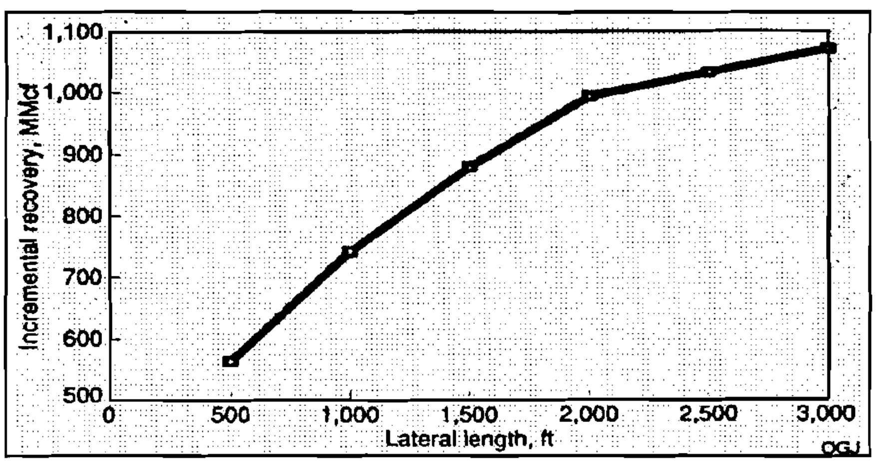


Figure 8-10. Modeled Well Production (Gredell and Benson, 1995)

A medium-radius curve was selected (9.6°/100 ft) to ensure that casing could be successfully run to the beginning of the lateral (Figure 8-11). The 4¾-in. lateral was completed open hole based on reservoir competence.

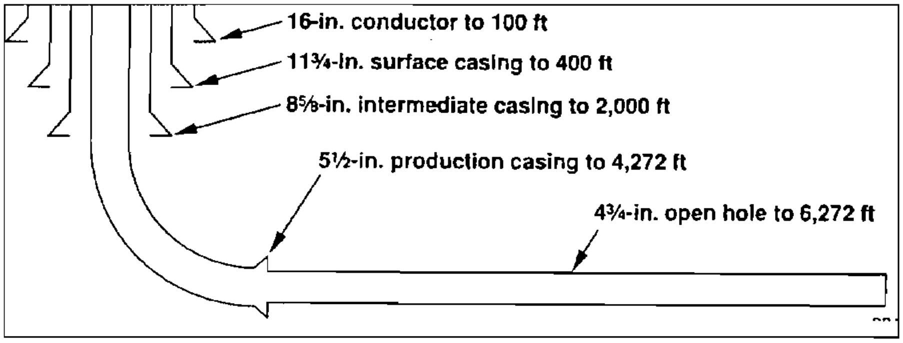


Figure 8-11. Casing Program (Gredell and Benson, 1995)

A clear brine fluid was used for drilling the lateral to minimize formation damage. Low solids were maintained to minimize damage, torque and drag. High-viscosity sweeps were periodically run to clean the hole. The BHA (Figure 8-12) included a 4¾-in. PDC bit, a 3⅜-in. motor and two Monel drill collars.

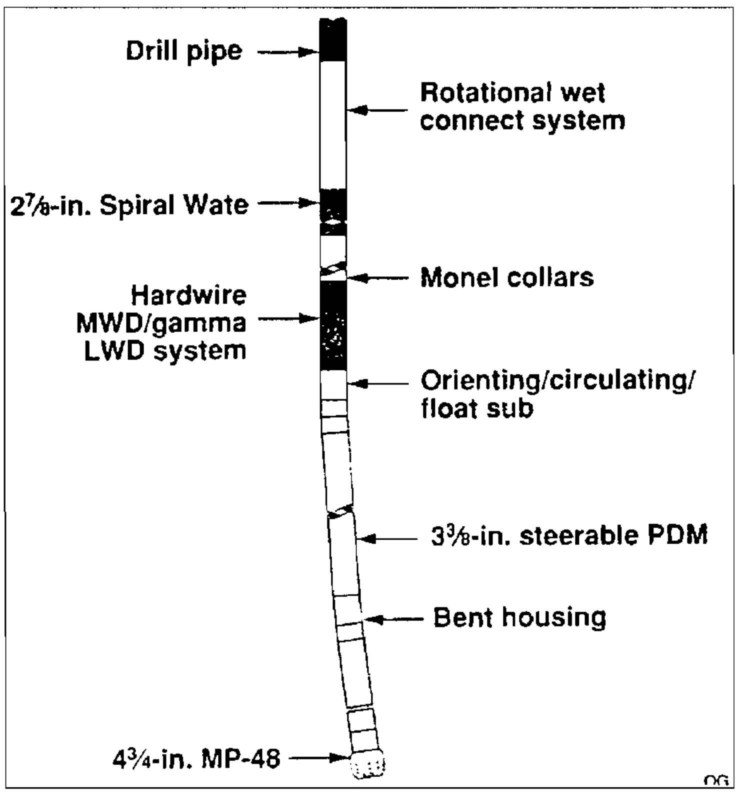


Figure 8-12. Drilling BHA (Gredell and Benson, 1995)

The first section of the lateral was drilled at very high ROPs (over 60 ft/hr). During a connection, a kick occurred and unloaded most of the annular volume. The relatively small annulus was believed to be a key factor in the effects of the kick. After that point, ROP was limited to 20-30 ft/hr to control the gas influx into the annulus.

After drilling was completed, a CT rig was used to unload the well with nitrogen. A small acid wash was also performed. The well stabilized quickly.

After the well was tied into the field pipeline, stable flow rates of up to 100 MMscfd were recorded. This represents about four times the productive capacity of a vertical well.

8.9 SCHLUMBERGER ANADRILL (MULTIARRAY RESISTIVITY MWD TOOL)

Schlumberger Anadrill (Bonner et al., 1995) described a new 4¾-in. mixed borehole-compensated 2-MHz array resistivity tool used for resistivity MWD in slim holes from 5¾ to 6¾ inches. The tool can be used in real time to steer the well within the reservoir and help maintain the well path within the pay zone. It combines the benefits of multispacing probes for formation evaluation with the advantages of borehole compensation.

The tool is 21 ft in length (Figure 8-13). The maximum build rate allowed is 15°/100 ft during rotation and 30°/100 ft during slide drilling.

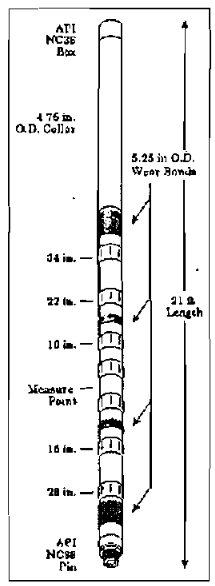


Figure 8-13. Slim Multiarray Resistivity Tool (Bonner et al., 1995)

The tool is useful for identifying low-permeability zones, discriminating between hydrocarbon and wet intervals. Borehole effects are only minimal in 6-in. holes. The resistivity and gamma-ray measurements can be used for real-time formation evaluation in slim holes (minimum 5¾ in.).

8.10 SCHLUMBERGER ANADRILL (SLIM MWD/LWD TOOL)

Anadrill recently introduced a new tool that combines MWD and LWD in a slim BHA. The tool is built into 4¾-in. drill collars and is recommended for use in 5⅞- to 6¾-in. holes (Kunkel, 1998). Build rates up to 30°/100 ft while sliding and 15°/100 ft while rotating are achievable. The system proved its ability to access "sweet spots" in the reservoir using azimuthal density geosteering in an early field application. Well paths for the new tool (6-in. borehole) and one drilled previously and steered by resistivity (8½-in. borehole) are compared in Figure 8-14.

The sensitivity of the new slim tool kept the bit in the lower high-porosity zone for almost the entire length. Productivity indices were 2.4 for the first well versus 8.2 for the new lateral.

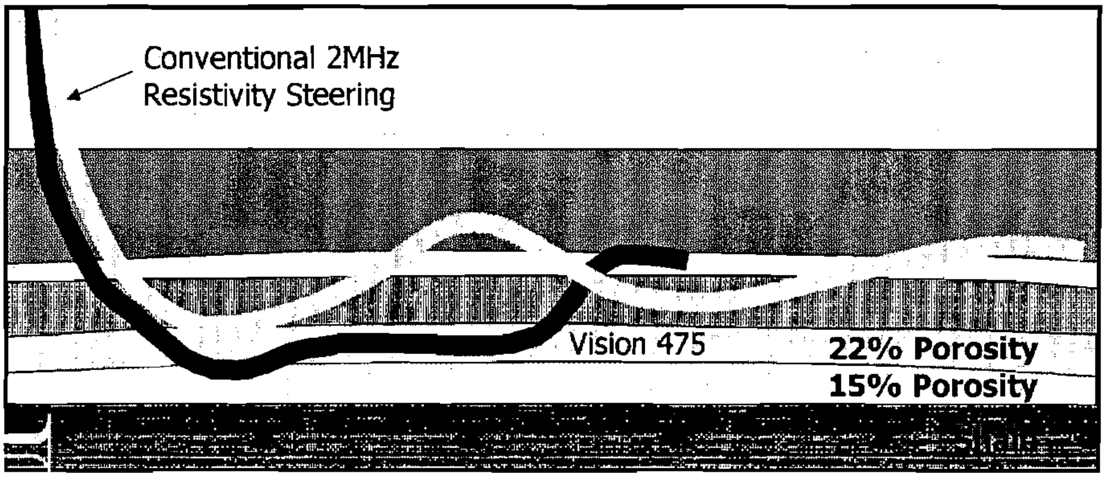


Figure 8-14. Well Drilled with Slim Geosteering Tool (Kunkel, 1998)

8.11 TEXAS A&M UNIVERSITY (WELL CONTROL IN HORIZONTAL WELLS)

Texas A&M University (Choe and Juvkam-Wold, 1996) presented an analysis of well-control procedures based on their simplified two-phase model that analyzes kick and pressure responses in directional/horizontal slim holes and wells drilled with coiled tubing. They compared theoretical kill sheets to conventionally devised procedures. Conventional kill sheets overestimated kill pumping pressures. For directional/horizontal wells with high build rates, choke pressure is predicted to change quickly without much kick expansion due to TVD change as the kick migrates through the curve. Their study results suggested that a theoretically based kill sheet should be used for kill procedures in slim directional/horizontal wells, along with a small safety overpressure.

Choe and Juvkam-Wold's model is based on unsteady two-phase flow, one-dimensional flow along the wellbore, water-base mud, negligible gas solubility, incompressible mud, known mud temperature with depth, and that the kick enters the well at current TD. Eight parameters are used to describe the system: pressure, temperature, and gas and liquid fractions, densities and velocities.

In conventional operations, frictional pressure losses at low kill rates are normally minor. However, frictional pressure losses are often critical for slim holes, for coiled-tubing drilling, and in choke/kill lines for offshore wells.

Specifications for the slim-hole well analyzed in the well-control study are shown in Table 8-1.

TABLE 8-1. Well Specifications for Well-Control Study (Choe and Juvkam-Wold, 1996)

Initial kick volume, bbls	2.0
Mud density, ppg	12.0
Plastic viscosity, cp	10.0
Yield point, lbf/100 ft^2	15.0
Bit nozzle diameter, 1/32 in.	3 x 10
Well true vertical depth, ft	10,000
Depth of casing seat, ft	6,000
Inner diameter of last casing, in.	5.0
Open hole diameter, in.	4.25
OD & ID of drill pipe, in.	2.875 x 2.441*
Pump capacity, bbls/stroke	0.17
Pump rate while drilling, gpm	143.
Kill mud pump rate, gpm	50.
Gas specific gravity (air = 1.0)	0.65
Surface temperature, °F	70.0
Mud temperature gradient, °F/100 ft	1.6
Formation permeability, md	5.0
Final hold length, ft	2,000**
Depth of kick-off point, ft	6,000**
Build-up rate, deg./100 ft	1.433**

*also used for coiled tubing OD and ID

**for horizontal wells

Choke pressures for a well with a 2000-ft horizontal section are shown in Figure 8-15 based on both the engineer's and driller's methods. No hydrostatic pressure reduction occurs in the annulus while the 2-bbl kick remains in the horizontal section. Therefore, the SICP and SIDPP are equal (520 psi) until the influx begins to rise. The reduction in choke pressure due to the kill mud (engineer's method) is not large because the effect of gas expansion near the surface dominates.

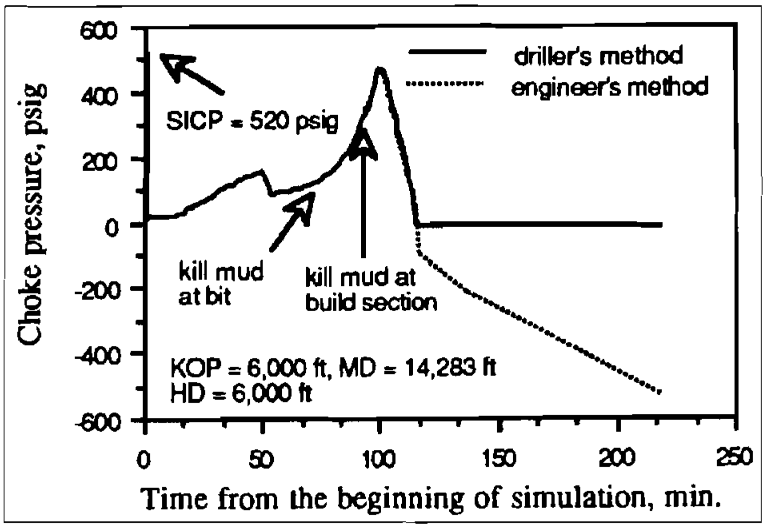


Figure 8-15. Choke Pressures in Horizontal Well (Choe and Juvkam-Wold, 1996)

Kill sheets based on model predictions and conventional field procedures were compared. Kill sheets map the choke pressure required to maintain constant bottom-hole pressure. In the field, detailed hydrostatic and frictional pressure data are not readily available. Kill sheets are often constructed by calculating initial and final circulating pressures and assuming a linear path between them.

A comparison of modeled and field kill sheets for a vertical slim-hole well is shown in Figure 8-16. The conventional kill sheet maintains bottom-hole pressure above formation pressure by an amount equal to annular pressure losses. This overpressure may be too large in slim annuli, leading to fracturing, lost circulation etc.

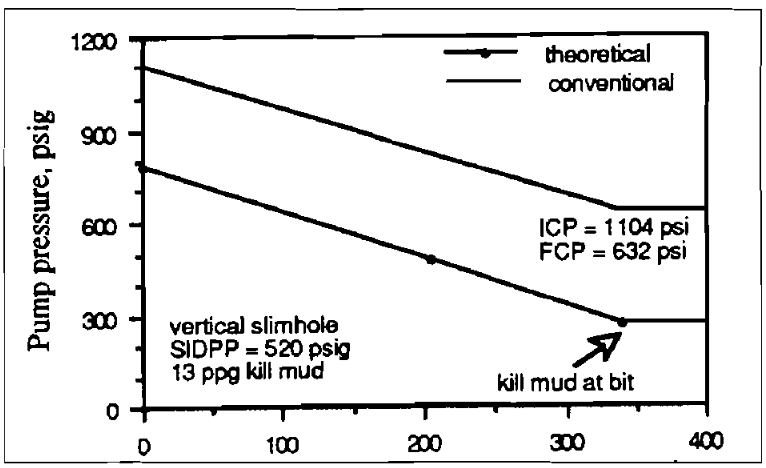


Figure 8-16. Kill Sheets for Vertical Slim Hole (Choe and Juvkam-Wold, 1996)

Kill sheets for a slim horizontal well with a 4000-ft lateral are compared in Figure 8-17. Pump pressure is minimum when the kill mud first arrives at the lateral TVD. With the conventional sheet, bottomhole pressure may be too high, resulting in failure of the casing shoe.

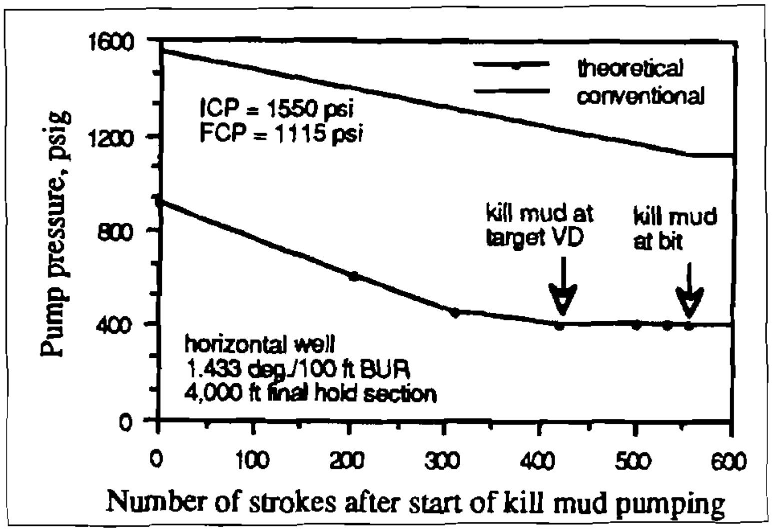


Figure 8-17. Kill Sheets for Horizontal Slim Hole (Choe and Juvkam-Wold, 1996)

The same 4000-ft horizontal well was assumed for another case, this time drilled with coiled tubing (Figure 8-18). Pressure is constant until kill mud fills the entire spool on the rig (4000 ft assumed). For higher kill rates, pump pressure will increase due to frictional pressure drop in the spool.

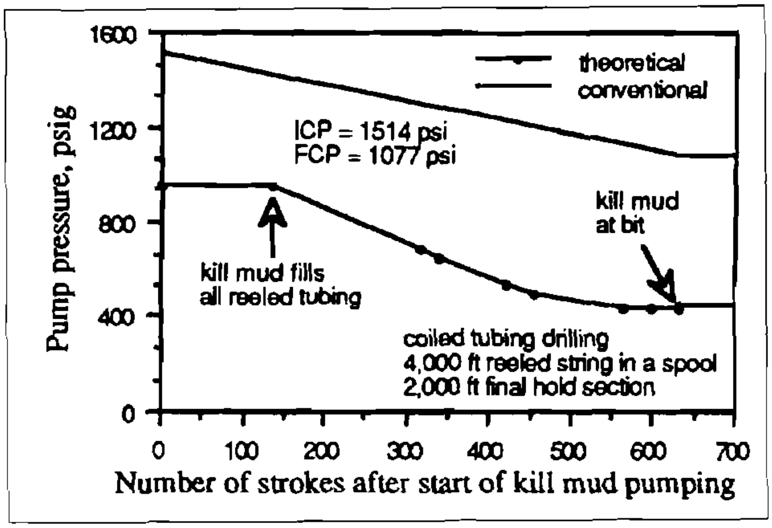


Figure 8-18. Kill Sheets for Horizontal Slim Hole Drilled with CT (Choe and Juvkam-Wold, 1996)

8.12 UPRC (AUSTIN CHALK RE-ENTRIES)

Union Pacific Resources Company reports continuing cost savings averaging 30% for drilling horizontal slim-hole laterals out of existing wells (Strunk, 1997). The alternative is to drill a new well from the surface. A large number of vertical wells in the Austin Chalk were completed with 5½-in. casing. UPRC re-enters these wells and drills a medium-radius lateral with a 4¾-in. bit. The approach has proven very successful; they have more than 20 rigs drilling horizontal wells in the area.

They also reported that drilling efficiency in slim holes is not yet as high as in larger 6½ to 8½-in. holes, although it is improving.

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9. Hydraulics

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9. Hydraulics

9.1 FORASOL, ELF, TOTAL, IFP, AND GEOSERVICES (RESPONSE TO KICKS)

Forasol, Elf Acquitaine Production, Total, Institut Français du Pétrole and Geoservices (Dupuis et al., 1995) reported the results of experiments to validate a kick-control method and a pressure-loss model for use with slim-hole applications. They determined that the impact of rotation on pressure losses is keyed to the Taylor and Reynolds numbers. For Re < 1000, pressure losses in the annulus increase with rotation. For Re > 1000, the impact of rotation is greatly reduced. Experimental results of well-control events showed that it is best to not perform a flow check after a kick has been detected, but rather to quickly close the BOP.

The principal objectives of the hydraulics experiments were to chart the increase in pressure loss with flow rate and rotation in a simulated field condition and to validate predictions of IFP's model in each flow regime. Well-control simulations were designed to evaluate the capabilities of surface detection equipment, sensor response under various drilling scenarios, and procedural options for treating a gas kick in a slim hole.

Reduced annular clearances in many slim-hole applications have been shown to significantly impact ECDs and the development of kicks. The project team conducted experiments in a pilot well that was outfitted with pressure sensors at several depths (Figure 9-1). TD was over 900 m (2950 ft). A 3⅜-in. bit was rotated on 2⅝-in. mining drill pipe (flush joint). The corresponding annular clearance was 8.5 mm (0.34 in.); annular volume was 2.2 l/m (0.42 bbl/100 ft).

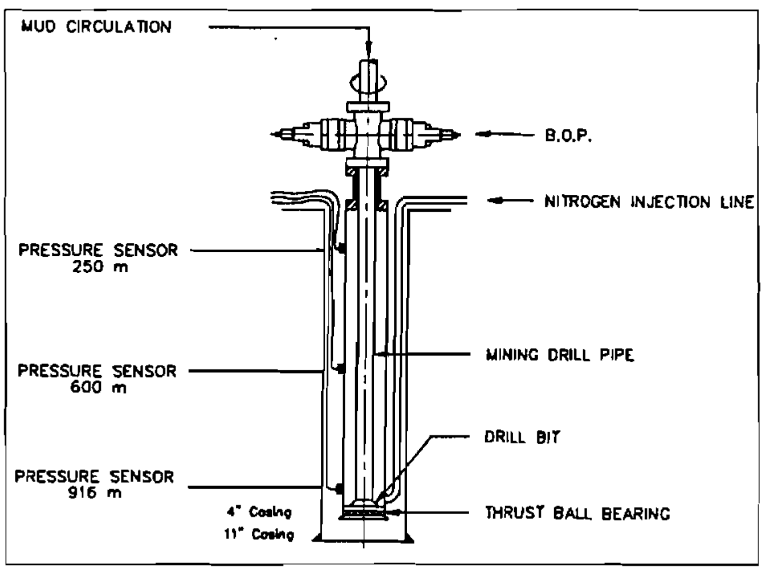

Figure 9-1. Well-Control Test Well (Dupuis et al., 1995)

Drilling fluids were designed for these tests based on requirements typical of slim-hole applications. Power-law fluids consisting of water-base mud with xanthan were investigated over a wide range of shear rates. Viscosity was relatively low to allow investigations in both laminar and turbulent flow regimes. Drilling fluid composition is summarized in Table 9-1.

TABLE 9-1. Fluids Used in Experiments (Dupuis et al., 1995)

	Fluid 1	Fluid 2
XCD concentration (g/l)	1.0	2.5
Specific mass (Kg/m^3)	999.5	999.8
Zero shear rate viscosity (Pa-s)	0.205	4.58
Consistency index -K (Pa-s^n)	0.112	0.720
Flow behavior index n	0.48	0.30

The variation of pressure along the wellbore was recorded as flow rates were varied. Typical results without rotation are shown in Figure 9-2. Fully established flow was observed for these data (based on fluid 1).

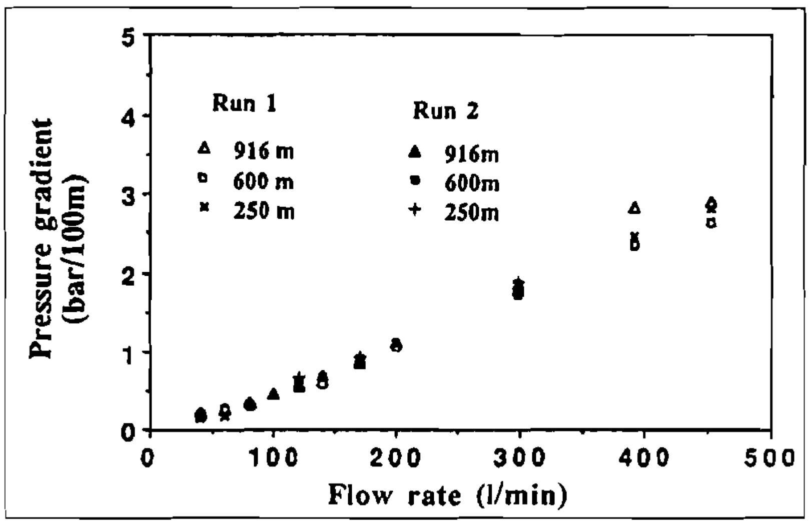

Figure 9-2. Pressure Gradient and Flow Rate (Dupuis et al., 1995)

The distribution of pressure drops along the circulation path (without rotation) is charted in Figure 9-3. Pressure drop in the annulus is greater than pressure drop in the drill string by an order of magnitude. Losses in the surface equipment and drill string were modeled, and compare very favorably with measured stand-pipe pressure (SPP).

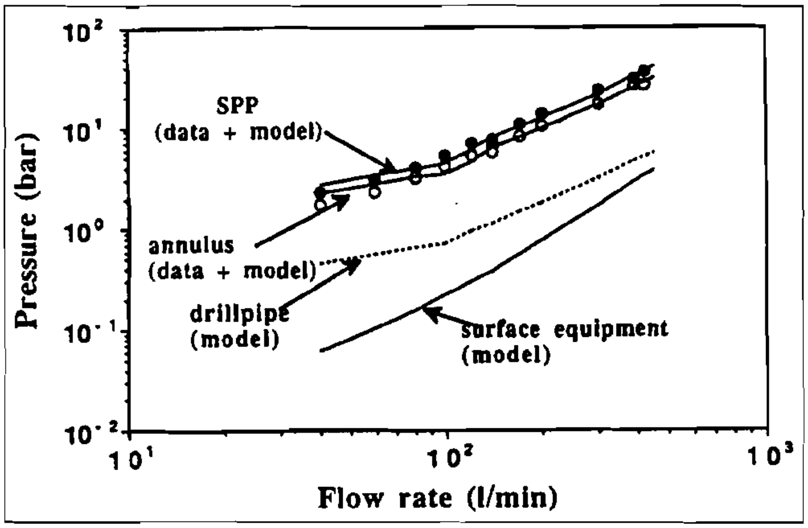

Figure 9-3. Distribution of Pressure Losses (Dupuis et al., 1995)

The impact of rotation on pressure losses for a range of flow rates is compared in Figure 9-4. Flow was laminar for Reynolds numbers up to 1020; a significant increase in pressure loss with rotation was observed for these laminar cases. At higher Reynolds numbers, there is much less relative increase with rotation.

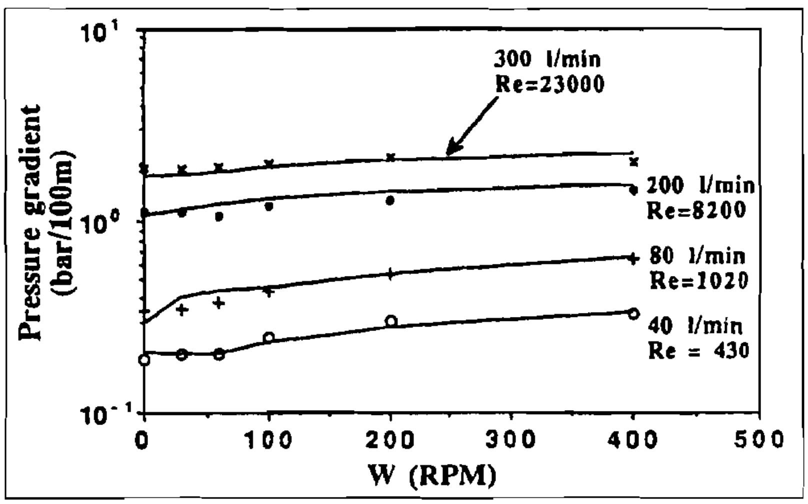

Figure 9-4. Impact of Rotation on Annular Pressure Loss (Dupuis et al., 1995)

Kick-control procedures and methods were investigated by simulating gas kicks in the instrumented test well. A mass flow meter (Figure 9-5) was used to inject nitrogen at a constant rate to the bottom of the well. Kicks were simulated while drilling and when circulation is stopped. Continuous injection in an open well and gas migration in a closed well were also investigated.

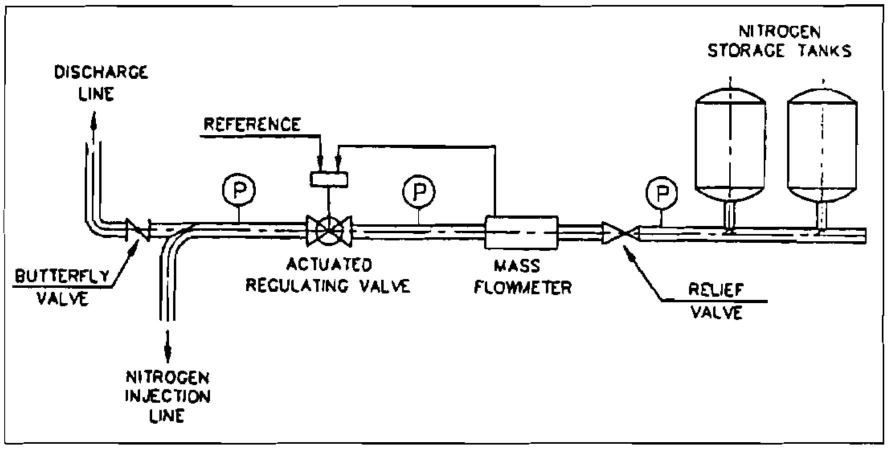

Figure 9-5. Flow Regulation for Kick Simulation (Dupuis et al., 1995)

Flow variables for a simulated kick while drilling are plotted in Figure 9-6. Differential pressure for the kick was 1 bar (15 psi). Flow out increases exponentially until drilling (rotation) is stopped. This is due to the cumulative gas volume in the well and volume expansion as gas approaches the surface. There is a time delay between kick responses in flow out versus pit level. This demonstrates the need for accurate flow measurement to allow rapid detection of kicks.

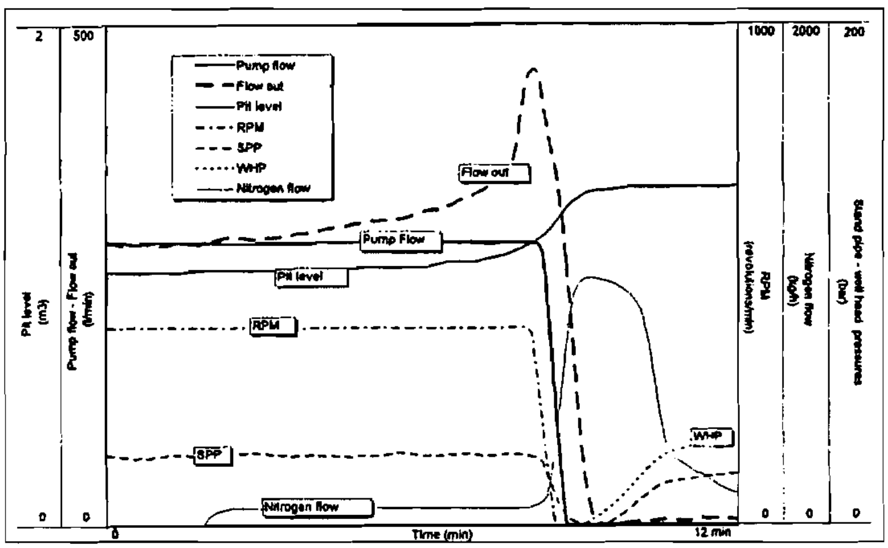

Figure 9-6. Simulated Kick While Drilling (Dupuis et al., 1995)

If, in response to a kick, rotation and circulation are stopped, the pressure differential between the annulus and formation will be increased, leading to increased gas influx (Table 9-2). Consequently, performing a traditional flow check can be counterproductive to controlling a kick.

TABLE 9-2. Kick Influx After Stopping Circulation (Dupuis et al., 1995)

	Case 1		Case 2	
	400 rpm 300 l/min	0 rpm 0 l/min	0 rpm 0 l/min	0 rpm 0 l/min
Differential pressure Reservoir/bottom hole	7 bar	31 bar	1 bar	23 bar
Gas influx flow rate	45 l/min	179 l/min	8 l/min	134 l/min

Kick problems during a drill-pipe connection were simulated by stopping circulation and rotation for 2.5 min and then resuming. Influx pressure was set at 7 bar (100 psi) over hydrostatic pressure. The kick is not discernible (Figure 9-7) by monitoring differential flow until about 2 min after rotation and circulation are stopped. Kick flow was also calculated based on a divergence in predicted flow versus measured flow. The kick can be observed almost immediately using special kick-modeling software and an accurate flow meter.

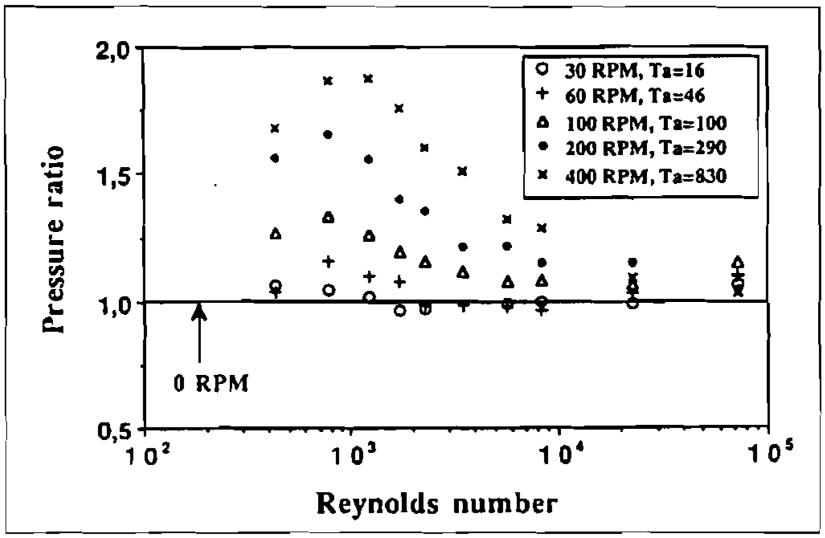

Figure 9-7. Simulated Kick While Making a Connection (Dupuis et al., 1995)

Gas migration during drilling was also investigated. For one test, nitrogen was injected at a flow rate of 210 l/min (1.3 BPM) at the bottom of the fluid-filled well without circulation or rotation. Gas first reaches the surface after about 4.5 min (Figure 9-8). Injection was then stopped and hole pressures allowed to stabilize.

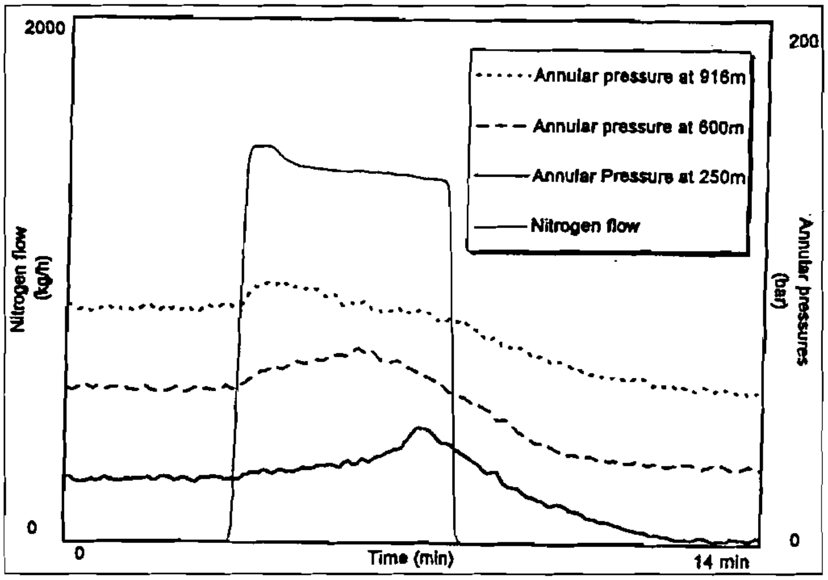

Figure 9-8. Gas Migration During Kick (Dupuis et al., 1995)

After gas had migrated out of the hole, wellbore pressures had been decreased by 30 bar, representing a loss of 305 m (1000 ft) of hydrostatic head.

9.2 HALLIBURTON ENERGY SERVICES (RESERVOIR PERFORMANCE)

Halliburton Energy Services (Azari et al., 1995 and Azari and Soliman, 1997) performed analyses of slim-hole hydraulics with respect to production, stimulation, conformance, perforation, and reservoir testing. Among the conclusions they reached are the following:

- Careful planning is required for successful slim-hole drill-stem testing. Good results are achievable with current tools.
- The most significant limitation for slim-hole completion technology is additional frictional pressure losses through slim tubulars. This can occasionally limit operational design, such as in hydraulic fracturing.
- Pressure loss through smaller perforations is usually not significant. An exception is again the case of high-rate hydraulic fracturing.
- Slim completions can be of benefit for well testing by minimizing wellbore storage.
- Slim wellbores and tubulars have little impact on calculated maximum production rates to avoid coning/cresting and times for water/gas breakthrough. The movement of phase boundaries is not affected by changes in wellbore radius.

Halliburton Energy Services commissioned Resource Marketing to survey slim-hole trends around the world. Of about 776 surveyed slim holes drilled in 1992, half were undertaken due to favorable economics. Ninety percent of the operations were mechanically successful; 60% were economically successful. Of unsuccessful applications, the most-often cited reason was formation problems (not production string limits).

Halliburton Energy Services found that a selection of tools for drill-stem testing is available with ODs of 3⅝, 3, and 1¾ inches. Smaller tubing for running these tools results in lower tensile strength, torque and weight at depth for operating tools, controlling well fluids, or retrieving stuck tools. Smaller flow passages also require excellent solids control and minimizing the production of solids or sand.

Azari et al. also stated that, in slim holes, cased-hole testing is generally preferred over open-hole testing because of reduced solids and debris (and consequent sticking problems) in open hole. Tools that are actuated by annulus pressure are also preferred for superior operational ease and reliability.

A series of wellbore simulations was performed to gauge the impact of reduced diameter. A single-phase r-θ-z simulator was used. Reservoir properties assumed for the analyses are summarized in Table 9-3.

TABLE 9-3. Reservoir Properties (Azari et al., 1995)

p_i, psia	4900	Depth, ft	10,000
T, °F	200	Well comp., V/MM/psi	20
r_e, ft	2000	c_f, V/MM/psi	3.5
ϕ_{hc}, %	10	$k_v = k_h$, md	1
p_{bp}, psia	2500	h, ft	20
Radial grid blocks	198		

Production performance for 4-in. and 10-in. vertical wellbores is compared in Figure 9-9. The difference in production is small and decreases throughout the production life. The difference in cumulative recovered reserves is also relatively small.

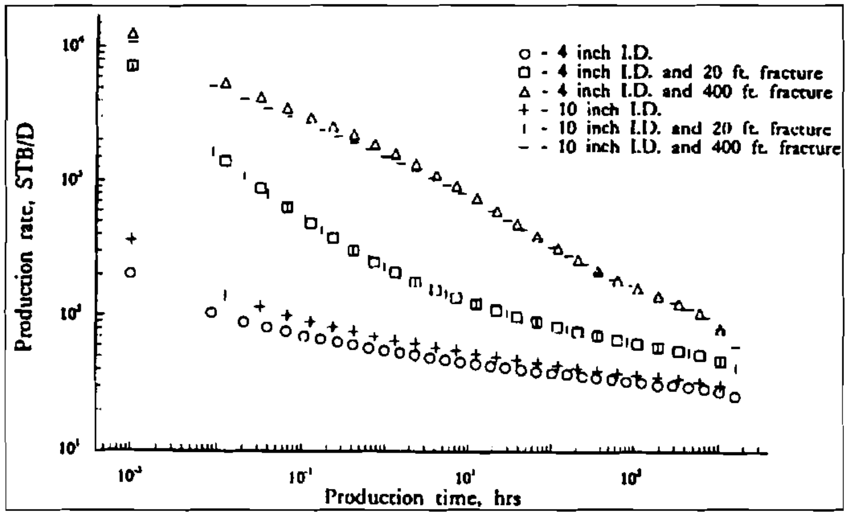

Figure 9-9. Vertical Wellbore Diameter and Production (Azari et al., 1995)

The impact of hydraulic fracturing on these wellbores was considered next. The upper sets of curves in Figure 9-9 shows that production performance of fractured 4- and 10-in. wellbores is only negligibly different.

The impact of these considerations with respect to horizontal wells was analyzed. Production curves for 4- and 10-in. horizontal wells are compared in Figure 9-10. Production differences are most pronounced at very early production times and converge after a few hundred hours of production. Hydraulic fractures cause the production differences in different sizes of wellbore to become smaller still.

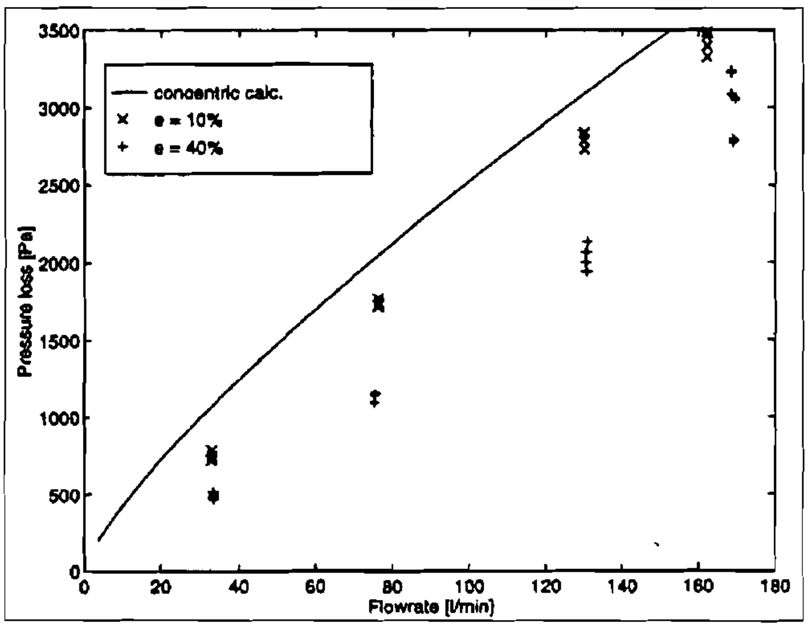

Figure 9-10. Horizontal Wellbore Diameter and Production (Azari et al., 1995)

Nodal performance of slim wells was compared. Basic reservoir properties for the analysis are shown in Table 9-4. Hagedorn and Brown's correlation was used.

TABLE 9-4. Reservoir Properties for Nodal Analysis (Azari et al., 1995)

k_e, md	10	p_{bp}, psia	2173
h, ft	20	p_{wh}, psia	100
T, °F	200	r_e, ft	5000
γ_o, °API	35.0	Pipe roughness	0.007
GOR, Mscf/STB	350		

Inflow/outflow curves are shown in Figure 9-11 for wellbores ranging from 1½- to 4-in. ID. Each outflow curve can have zero, one or two points of intersection with the inflow curve. These results suggest that, at low flow rates and saturated conditions, small tubing is more efficient. Slug flow may occur in small tubing, whereas bubble flow is more likely in larger tubing.

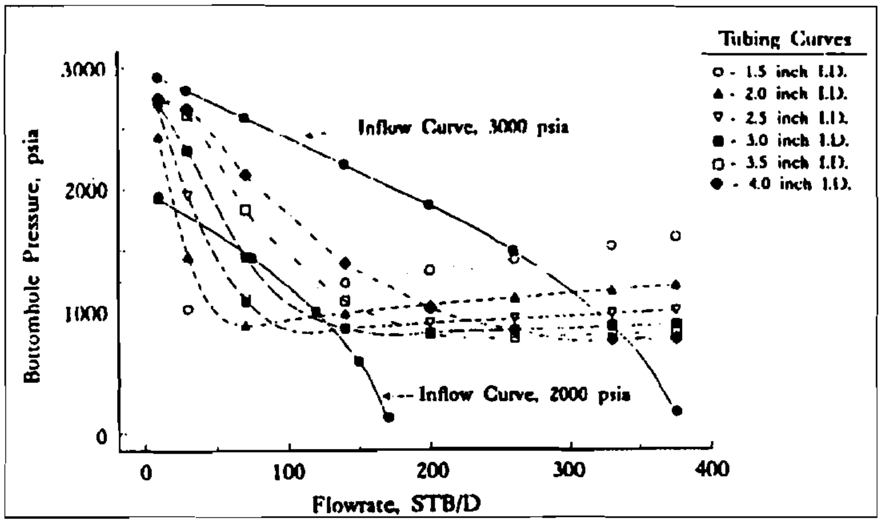

Figure 9-11. Inflow/Outflow Performance Curves (Azari et al., 1995)

The impact of tubing size was also investigated for lifting water or condensate to prevent loading problems in gas wells. Results are shown in Figure 9-12 for a gas well with a flowing pressure of 1000 psi, temperature of 70°F and deviation factor of 1.0. Minimum gas rates for keeping the well unloaded increase with tubing size.

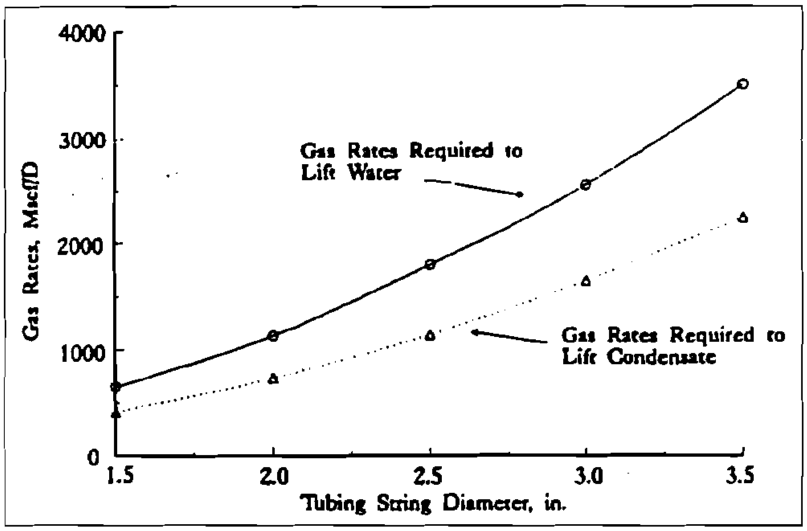

Figure 9-12. Minimum Gas Rates to Lift Fluid (Azari et al., 1995)

Pressure losses increase with flow rate, depth, and decreasing tubing diameter. Fluids used in fracturing operations in slim holes must be carefully designed to reduce friction losses through additives etc. Higher pressures should be planned for surface equipment and pump specifications.

The effect of tubing diameter on long-term production behavior of a well was also investigated. Of special interest was whether coning or cresting are influenced by tubing size. The first analysis was of a two-phase oil/water environment. Parameters are summarized in Table 9-5.

TABLE 9-5. Oil/Water Coning Parameters (Azari et al., 1995)

k_h, md	1500	Top of perfs, ft	12,118
kv, md	1500	Bottom of perfs, ft	12,123
ρ_o, gm/cc	0.62	Top of oil zone, ft	12,118
ρ_w,gm/cc	1.1	Oil column, ft	16
B_o, bbl/STB	1.4	r_e, ft	1000
μ_o, cp	0.3		

Results show that only small changes are predicted for a 4-in. versus a 10-in. wellbore (Table 9-6). Maximum allowable rates, pressure drops at the interface, and stable coning height remain nearly the same. Similar results were obtained for the case of three-phase coning, that is, neither gas nor water movement were significantly impacted by changes in well diameter.

TABLE 9-6. Wellbore Diameter and Coning (Azari et al., 1995)

k_h, md	1500	Top of perfs, ft	12,118
kv, md	1500	Bottom of perfs, ft	12,123
ρ_o, gm/cc	0.62	Top of oil zone, ft	12,118
ρ_w,gm/cc	1.1	Oil column, ft	16
B_o, bbl/STB	1.4	r_e, ft	1000
μ_o, cp	0.3		

9.3 INSTITUT FRANÇAIS DU PÉTROLE, FORASOL AND ELF (HYDRAULICS MODEL)

The Institut Français du Pétrole, Forasol, and Elf Aquitaine Production (Cartalos et al., 1996) developed a hydraulics model for slim-hole geometries. Developed under the Euroslim project, the model was devised to predict flow behavior in the restrictive flow channels between slim drill pipe and casing. Their model accounts for eccentricity of the drill pipe and effects of rotation. Close agreement was obtained with results from three field wells.

The slim-hole hydraulics model was devised as a simulator for field operations. The development involved three steps: 1) develop theory and mathematics based on realistic assumptions of rheology and geometry, 2) validate model predictions with laboratory and field test data, and 3) compare model predictions to normal field operations.

It has been widely reported that pressure losses are influenced by eccentricity of the drill pipe. Losses in a fully eccentric annulus may be as much as 60% less than in the concentric case. The project team considered two idealized cases for eccentricity (Figure 9-13). The variable ΔL represents the distance between contact points with the borehole.

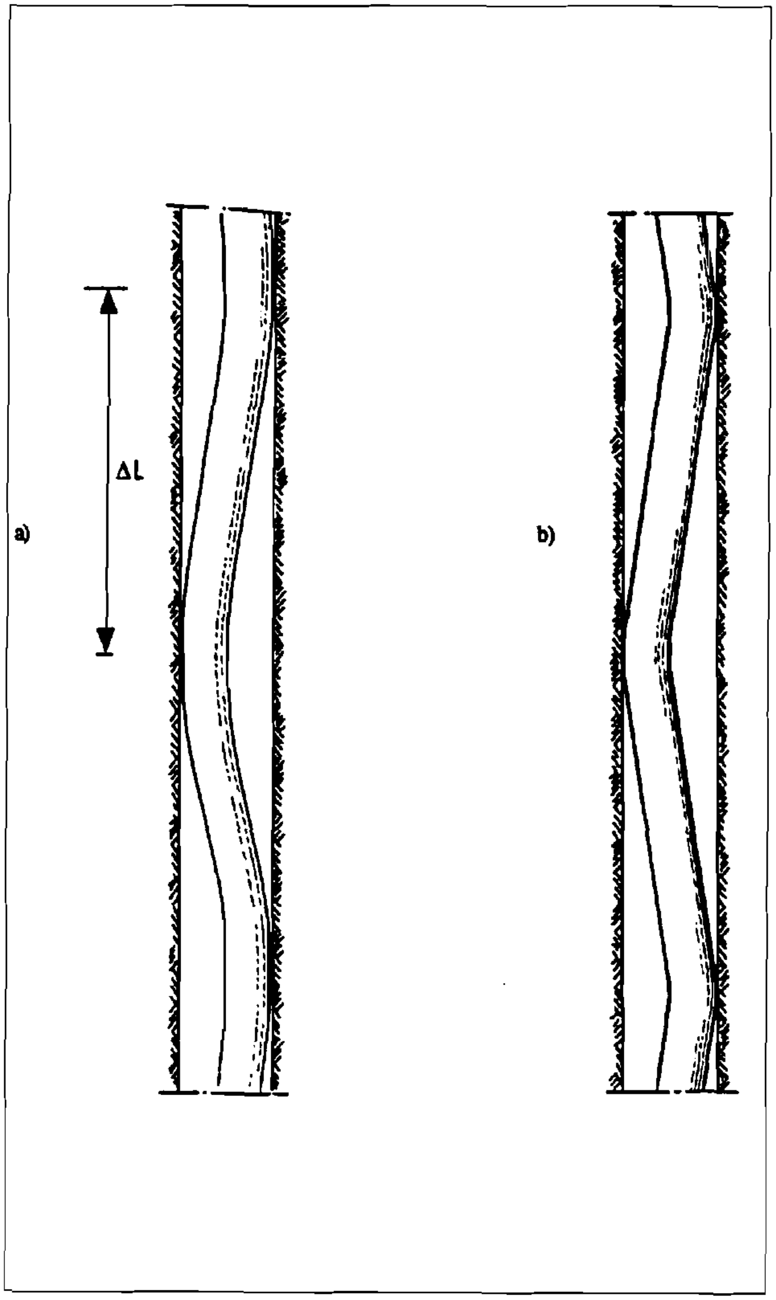

Figure 9-13. Drill-String Eccentricity Cases (Cartalos et al., 1996)

A pressure-loss model was derived to accommodate various functions e(x). The project team found that, for geometries applicable to oil wells, results are relatively insensitive to the exact function selected.

Results are shown in Figure 9-14 for a Newtonian fluid and eccentricity of 0.8. Predictions and experimental data are in good agreement. It is seen that pressure losses are lower in eccentric annuli in both laminar and turbulent flow, but may be greater in transitional regimes.

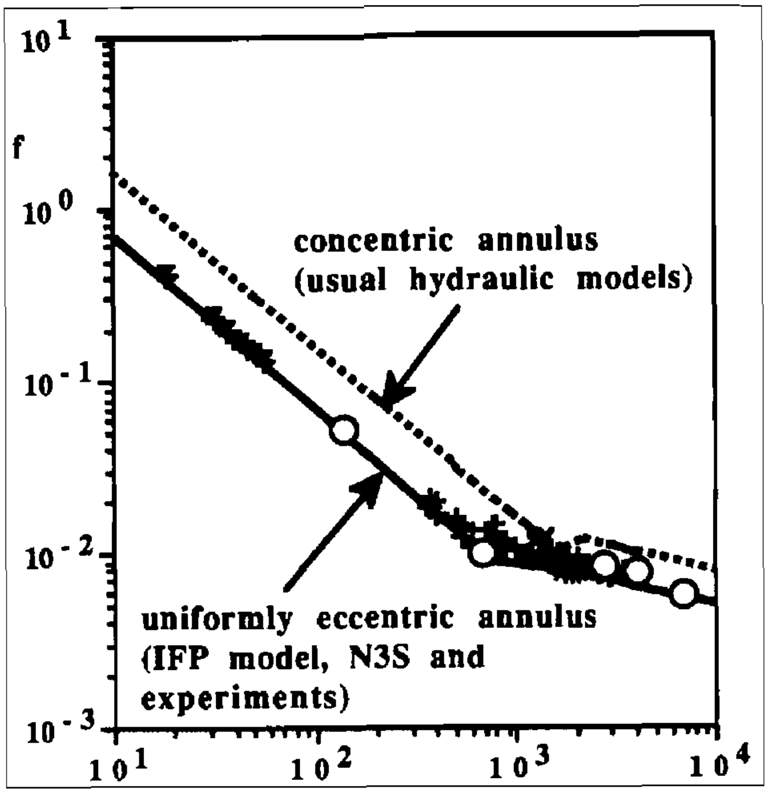

Figure 9-14. Friction Factor and Reynolds Number (Cartalos et al., 1996)

The effect of rotation was observed to vary with Reynolds and Taylor numbers. For drilling applications, the Taylor number is usually above the critical value. For this case, pressure losses increase with rotation. However, at very high Reynolds numbers, pressure loss is almost independent of rotation.

Data from field tests are compared to model predictions in Figure 9-15. These data are without rotation. Excellent agreement is seen. Changes in slope of the results represent changes in flow regime (from laminar to transition, then from transition to turbulent). The first well (pilot 1) had an annular gap of 22 mm (0.87 in.); pilot 2 had a gap of 9 mm (0.35 in.).

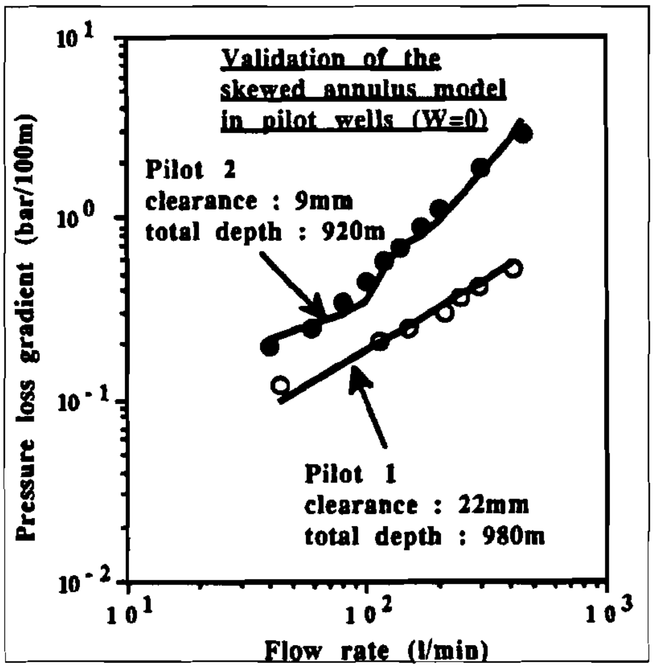

Figure 9-15. Comparison of Field Tests and Model (Cartalos et al., 1996)

Three commercial wells were drilled under the Euroslim project, two in the Paris basin and one in Gabon. Geometries of these wells (including two sections of the Gabon well "Ozima") are summarized in Table 9-7.

TABLE 9-7. Euroslim Slim Holes (Cartalos et al., 1996)

	LXE	CVP	OZIMA	OZIMA
Wellbore				
Casing size OD/ID (in)	4.5 / 4.05	5.5 / 4.9	5.5 / 5.0	4 / 3.6
Casing length (m)	920	719	1410	2400
Open hole size (in)	3⅝	4¾	4¾	3⅝
Drillstring				
Drill pipe OD (in)	2.25	3.5	3.5	2.25
Drill pipe ID (in)	1.89	2.91	2.91	1.89
Tool joint OD (in)	2.60	4.13	4.13	2.60
Tool joint length (m)	0.6	0.7	0.7	0.6
Drill collar OD (in)	2.6	4.13	4.13	2.6
Drill collar ID (in)	1.89	2.91	2.91	1.89
BHA length (m)	290-360	250-280	185-240	270-364

Water-base fluids (with bentonite and lubricant) were used in all slim sections. Stand-pipe pressure, flow rate and rotary speed were recorded during drilling operation. Recorded and predicted stand-pipe pressures are compared in Figure 9-16. The error was less than 5% for almost all observations.

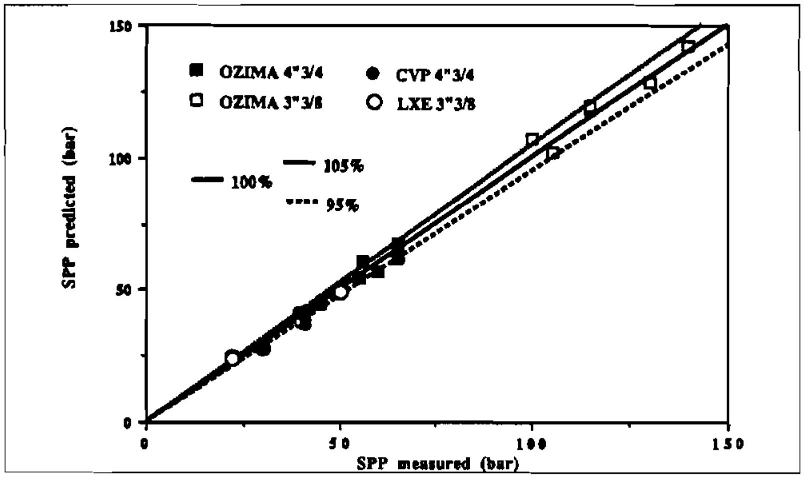

Figure 9-16. Measured and Predicted Stand-Pipe Pressures (Cartalos et al., 1996)

The majority of the annular pressure loss occurs in the open hole section. More than two-thirds of the losses occur at the drill collars, due to the highly restricted annular clearance.

Velocity profiles were analyzed with respect to eccentricity, rheology, etc. to study the overall impact on hole cleaning. Results for an eccentricity of 0.6 are compared in Figure 9-17. The velocity ratio is constant in both the laminar and turbulent flow regimes as Reynolds number is increased. While the position of the laminar plateau is sensitive to the value of n of these fluids, the position of the turbulent plateau is not greatly affected by n.

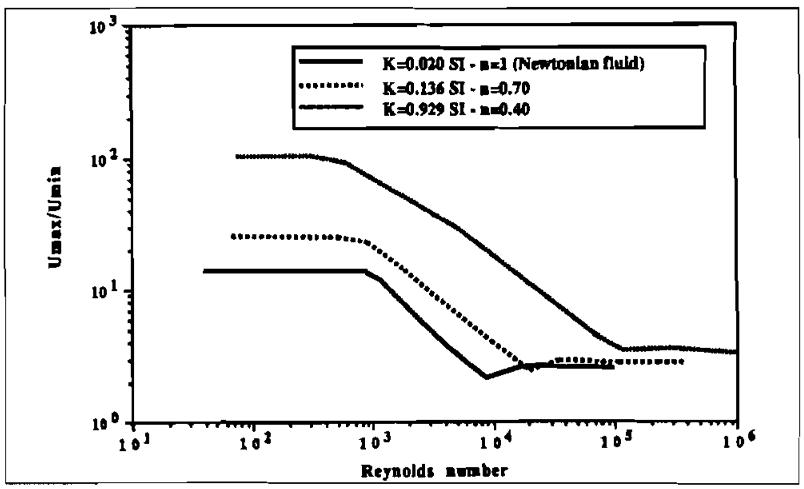

Figure 9-17. Velocity Profile and Reynolds Number (Cartalos et al., 1996)

These results confirm that turbulent flow is preferred for improved cuttings transport in an eccentric hole.

9.4 MINING UNIVERSITY OF LEOBEN AND OIL&GAS TEK (HYDRAULICS REVIEW)

The Mining University of Leoben and Oil&Gas Tek International (Thonhauser et al., 1995) critically analyzed the effectiveness of slim-hole hydraulics models. They compared field results from five deep slim holes to various approaches for modeling hydraulics. It was determined that, in many cases, various phenomena impact hydraulics behavior and are not accounted for in existing simulators. They concluded that current models can only approximate hydraulics in slim wells, and additional improvements are required.

As part of an effort to assess the accuracy of slim-hole hydraulics models, data were obtained from a drilling contractor representing field operations for five slim-hole wells as deep as 11,000 ft. Typical wellbore data are listed in Table 9-8. Two software packages were tested using data from over 2400 drilling hours. One package was developed for slim-hole applications and accounts for rotation and eccentricity of the drill pipe. The second package was designed for conventional pressure-loss calculations.

TABLE 9-8. Wellbore Data for Test Cases (Thonhauser et al., 1995)

Wellbore	
Casing Size, in.	5½, 12#, P 110
Open Hole Size, in.	4½
Drillstring	
Pipe Inner Diameter, in.	2.700
Pipe Outer Diameter, in.	3.250
Tool Joint Inner Diameter, in.	2.600
Tool Joint Outer Diameter, in.	3.725
Tool Joint Length (Pin, Box), in.	12/18
DC Inner Diameter, in.	2.600
DC Outer Diameter, in.	3.750
BHA-Length, ft	650
Core Barrel Inner Diameter, in.	2.250
Core Bare Outer Diameter, in.	2.600
Hydraulic Diameter, in.	0.957

The diameter ratio was about 0.66 for the cased hole and about 0.83 for the open hole (an annular gap of about 0.38 in. in the 4½-in. open hole). All hole sections that were analyzed were continuously cored with mining-type core bits and wireline-retrievable equipment. Electromagnetic flow meters were used to measure flow in and out. Flow rates ranged between 40-70 gpm, resulting in laminar flow predicted for most cases.

Eight types of field data were chosen for detailed analysis. These included pump pressure, mud flow in, mud flow out, rotary speed, rotary torque, hookload, weight on bit, and hole depth.

Several simulations were conducted to compare the results of software predictions to the measured pressure losses. In one case (Figure 9-18), predictions based on the slim-hole software (HYDKCK) are relatively accurate. It was observed that it is necessary to account for eccentricity and rotation. The conventional model varied from measurements by as much as 75%.

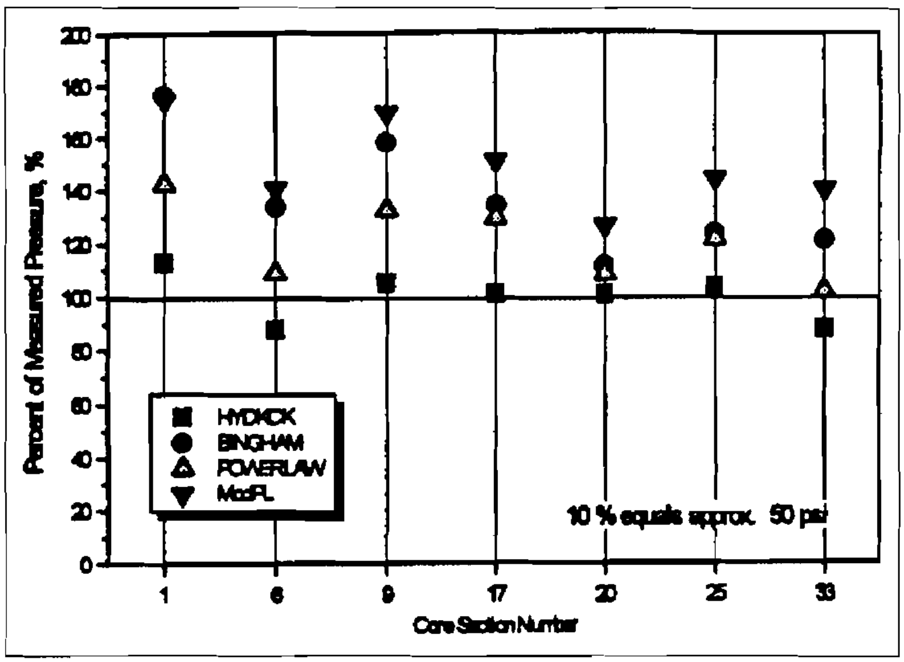

Figure 9-18. Measured and Calculated Pressure Loss (Well A) (Thonhauser et al., 1995)

Modeling predictions were less successful on other wells. In well B (Figure 9-19), mud rheology was changed near the last section. Geology was also much more varied across these intervals. These results suggested strongly that other parameters not accounted for in these calculations had an important impact on hydraulics behavior.

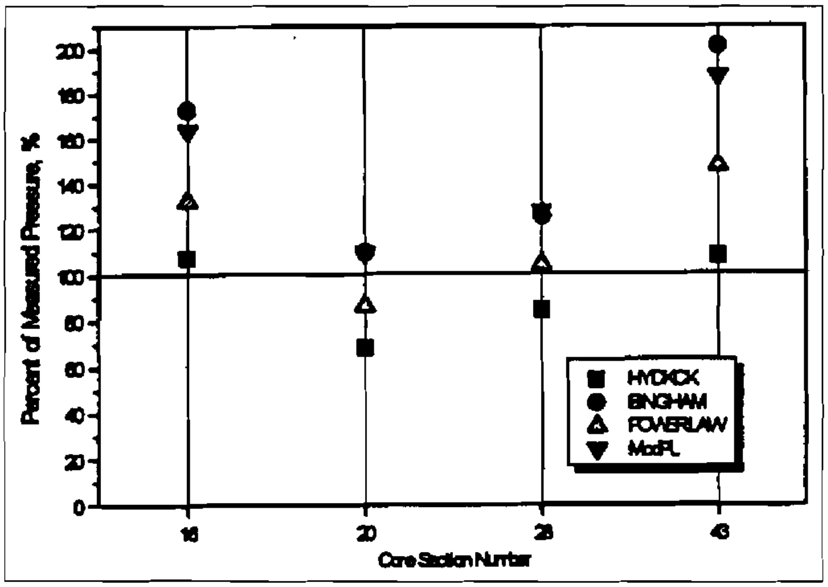

Figure 9-19. Measured and Calculated Pressure Loss (Well B) (Thonhauser et al., 1995)

Thonhauser et al. divided potentially influencing parameters into two categories: macroscopic factors (these drive the general trends in pressure loss) and microscopic factors (these affect pressure loss in a margin around the general pressure trend). In one case, a rapid change in pressure of 20% could not be predicted by changes in obvious parameters such as flow rate or rotary speed. This pressure drop (Figure 9-20) was analyzed with respect to a variety of other parameters to attempt to predict its occurrence.

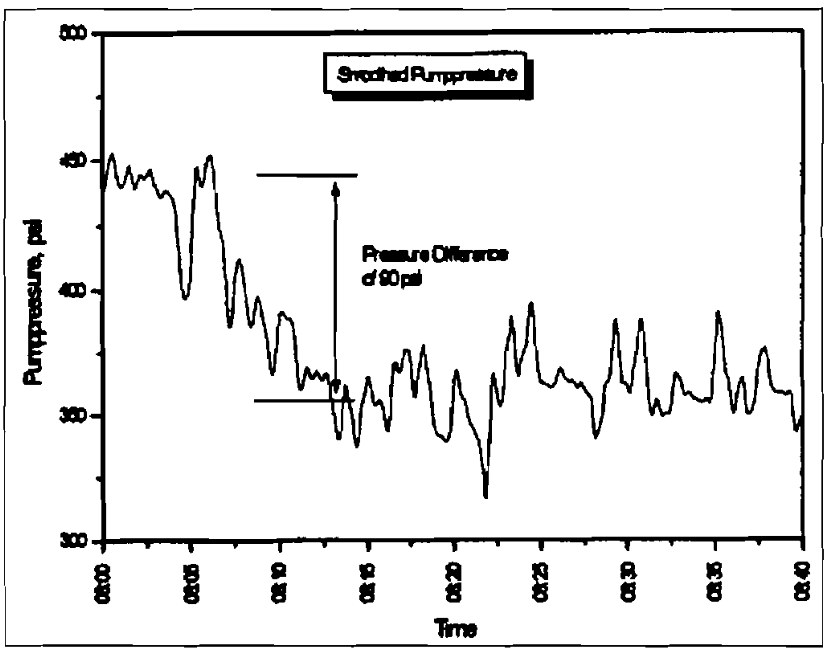

Figure 9-20. Example Unexplained Pressure Drop (Thonhauser et al., 1995)

Factors such as wellbore diameter can have significant impact. Since hole diameter is related to pressure loss by the fifth power, swelling and overgauge holes may significantly impact pressure loss (Figure 9-21). Hole gauge is affected by drilling parameters, BHA condition, drilling fluid performance, and operating time in the open hole.

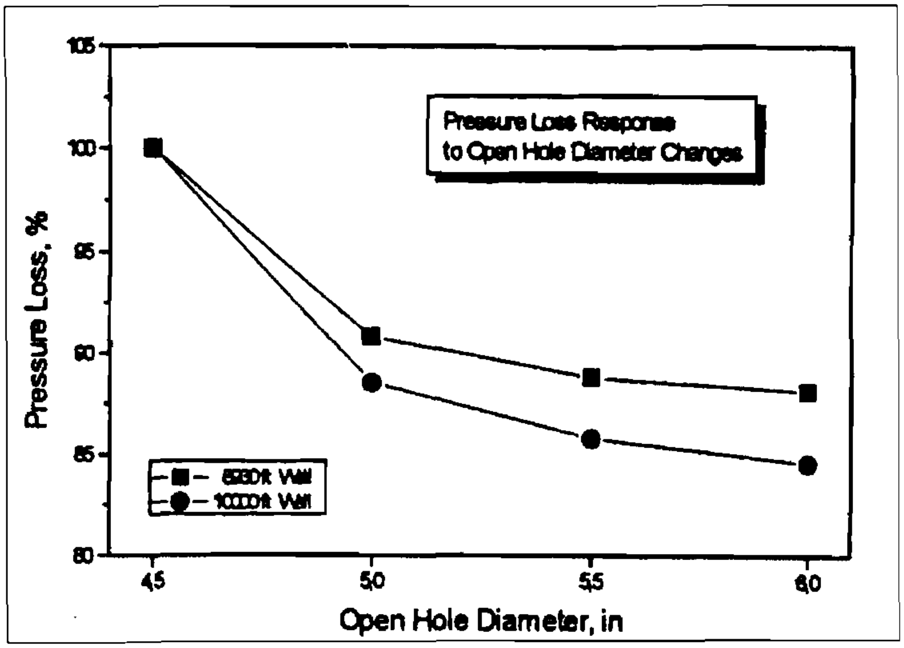

Figure 9-21. Effect of Hole Gauge on Pressure (Thonhauser et al., 1995)

Macroscopic and microscopic influences are summarized in Table 9-9. Operational influences (WOB, torque, and ROP) were found to be better represented as indicators of changes in the systems rather than as direct influences. These are indicators from which the learning curve can be improved.

TABLE 9-9. Factors Affecting Pressure Losses in Slim Holes (Thonhauser et al., 1995)

	Macroscopic-Influence	Microscopic-Influence
Flow Rate		
Mud Flow-In Losses & Gains	++ +	+
Fluid Properties		
Rheology	++	+
Geometry		
Drillpipe	++	
Annulus		
—Casing Diameter	++	
—Open Hole Diameter	++	+
Eccentricity	++	
Pipe Rotational Speed	+	
Core Barrel	+	+
Bit	+	+
Operational Influences		
Weight on Bit		+
Topdrive Torque		+
Penetration Rate		+
Geology		
Lithology		+

++Influence of major importance
+Influence of minor importance

9.5 OMV AG AND OIL & GAS TEK (SLIM-HOLE PRODUCTIVITY)

OMV AG and Oil & Gas Tek International Limited (Kroell and Spoerker, 1996) provided a review and analysis of slim-hole production and hydraulics issues. They believe that the drilling industry has conclusively demonstrated that slim-hole technology can be used to reach objectives and is usually technically and economically feasible. They discussed completion and production aspects and the impact of slim wellbore diameter. For most cases, constraints on production are minimum, although more planning for completions, artificial lift, etc. will likely be required.

They also state that "only low- to medium-permeability reservoirs should be completed with slim holes." Economic advantages of smaller wells and equipment have to be compared to overall costs with a life-cycle analysis (Figure 9-22). Production constraints may offset the advantages of initial cost savings.

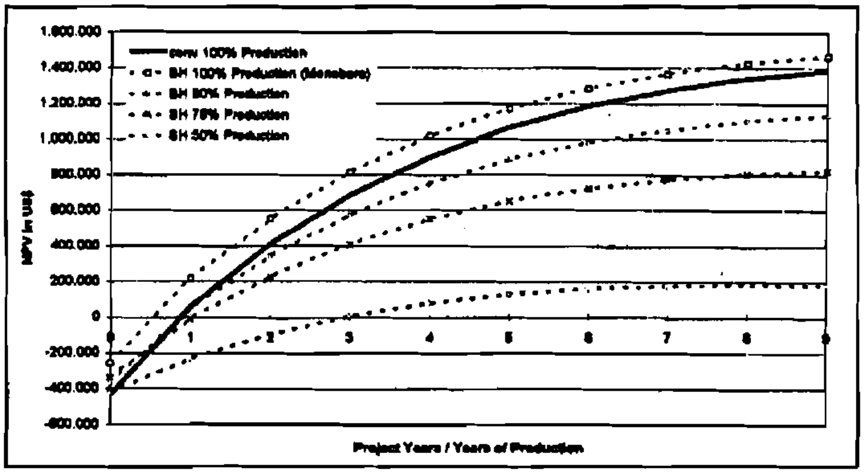

Figure 9-22. Life-Cycle Economics and Well Diameter (Kroell and Spoerker, 1996)

Formation damage in slim wells is generally thought to be a much greater problem than for conventional wellbores. ROP is also commonly assumed to be less in slim holes. Analysis shows that, if similar mud systems are used for slim-hole drilling, formation damage potential is equivalent to (or less than) that in larger holes (Figure 9-23).

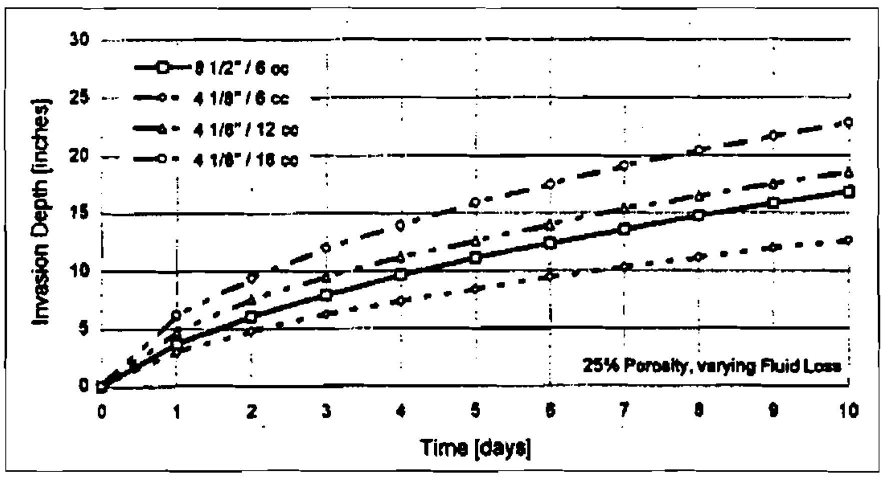

Figure 9-23. Formation Damage Potential (Kroell and Spoerker, 1996)

Production constraints of slimmer wells are also of great concern across the industry. Differences in production potential are significantly greater at high PIs (Figure 9-24). A conventional completion ("convl" in the figure) includes 7-in. casing and 3½-in. production tubing. One slim-hole option incorporating 3½-in. monobore design (monol) is expected to yield no production penalty. The most aggressive slim-hole design (sliml) was based on 3½-in. casing and 2⅜-in. production tubing. The design slim2 incorporated 5-in. casing and 2⅜ x 2⅞ tapered tubing. These results indicate that high-productivity reservoirs may not be appropriate applications for slim completions.

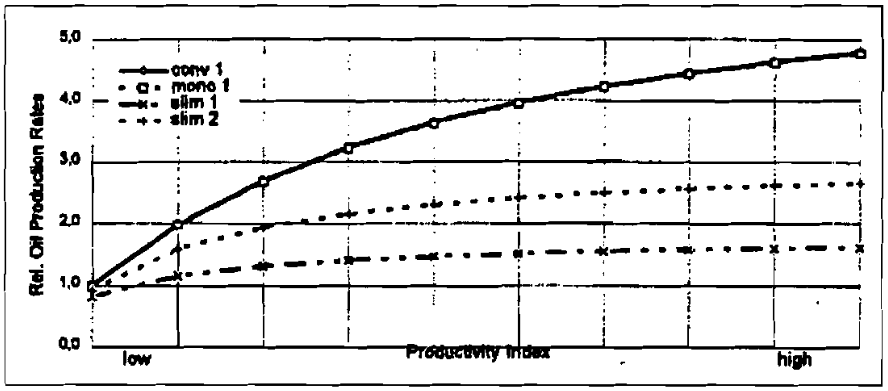

Figure 9-24. Productivity Index and Diameter (Kroell and Spoerker, 1996)

Gas wells for which artificial lift is not required are often ideal candidates for slim completions. Workover restrictions may be significant in artificial-lift applications.

9.6 RF - ROGALAND RESEARCH (ROTATIONAL EFFECTS)

RF - Rogaland Research (Hansen and Sterri, 1995) presented the results of experimental and analytical analyses of frictional pressure losses in slim annuli. They observed that frictional pressure losses increase as rotary rate increases with low-viscosity fluids. They attributed this phenomenon to the onset of centrifugal instability. Frictional pressure losses were observed to decrease with increasing rotary speeds for high-viscosity shear-thinning fluids.

Hansen and Sterri reviewed previous work investigating the hydraulics behavior of drilling fluids in narrow annuli between drill pipe (or core rod) and the hole. Some studies reported that rotation of the drill string increased frictional pressure loss. An important exception to this observation was Walker et al. in the SHADS development, where it was observed that friction pressure decreased with rotation. Hansen and Sterri surmised that this difference was due to the shear-thinning viscous nature of the SHADS drilling fluid.

A case for the impact of centrifugal instability had been presented by McCann et al. (1995), who found that frictional pressure loss increases with pipe rotation for power-law fluids in turbulent flow, and decreases with rotation for fluids in laminar flow. Centrifugal instabilities between the drill string and casing are suppressed in laminar flow.

To further understand this behavior, RF - Rogaland investigated axial flow of non-Newtonian fluids with centrifugal instabilities. Their experimental apparatus (Figure 9-25) included a 4-m annular flow loop, a 1.25-in. drill string and a 1.57-in. casing. The diameter ratio r1/r2 was 0.8 and is compatible with most slim-hole geometry. Rotary speeds up to 700 rpm were used. Flow rates ranged up to 240 l/min (63 gpm).

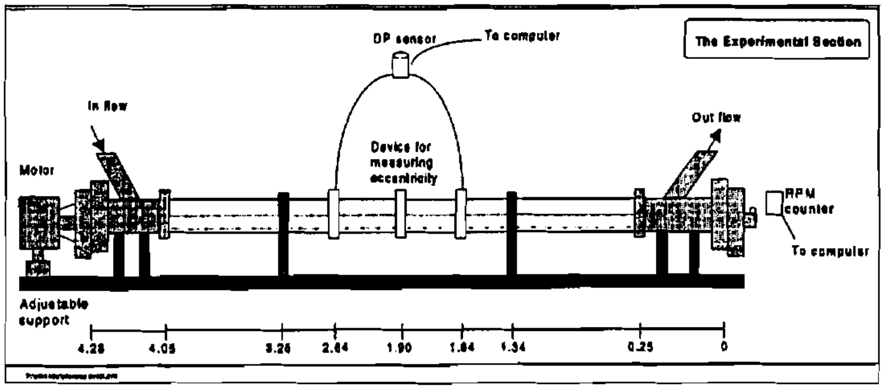

Figure 9-25. Flow Loop Apparatus (Hansen and Sterri, 1995)

Fluids used in the experiments were various blends of water and CMC. Power-law models were used based on the constants listed in Table 9-10. Fluid F1 was designed to represent a high viscosity fluid and to maintain laminar conditions at all times. Fluid F2 could achieve both laminar and turbulent flow under the range of experimental parameters. Fluid F3 (water) was used to achieve turbulent conditions at all flow rates and rotary speeds.

TABLE 9-10. Rheology of Experimental Fluids (Hansen and Sterri, 1995)

Fluid	k [Pas^n].	n
F1	4.112	0.43
F2	0.066	0.77
F3 (tap water)	0.001	1.0

Pressure drops for fluid F1 were measured at a range of flow rates and rotary speeds (Figure 9-26). These data were obtained with a drill-string eccentricity of 50%. Reduced frictional pressure is evident, especially for the highest rotary speed (595 rpm). The largest magnitude of pressure reduction is about 20% (for 595 rpm versus 0 rpm).

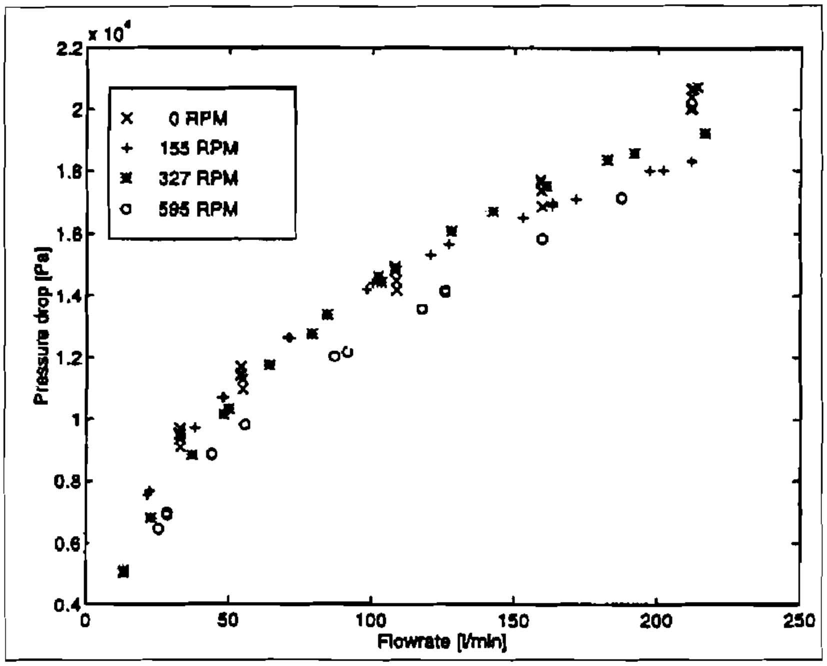

Figure 9-26. Flow Rate and Rotary Speed for F1 (Hansen and Sterri, 1995)

The effects of flow rate and eccentricity are compared for fluid F2 in Figure 9-27. Eccentricity was observed to decrease frictional pressure drop. The difference in pressure drop between 10% and 40% eccentricity is nearly proportional to flow rate. Both eccentric cases are lower than the pressure losses with a concentric annulus (0% eccentric).

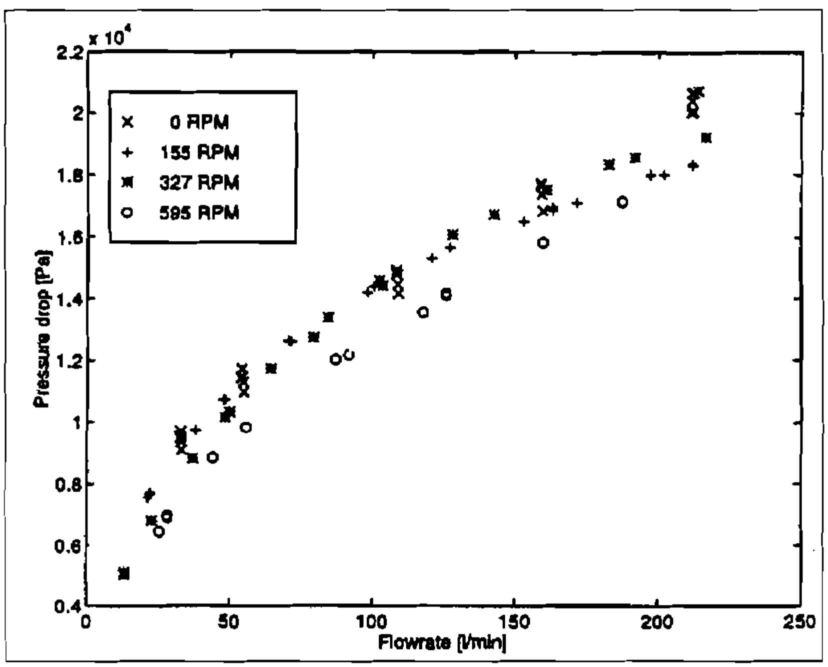

Figure 9-27. Flow Rate and Eccentricity for F2 (Hansen and Sterri, 1995)

Pressure drops with and without rotation are compared for fluid F2 for the case of 40% eccentricity in Figure 9-28. The y-axis variable, R_{rot}, is the ratio of pressure loss with rotation to that without rotation. Pressure losses for this fluid increase steadily with increasing rotary speeds. For rotary speed less than about 400 rpm, the magnitude of the flow rate was not observed to be significant.

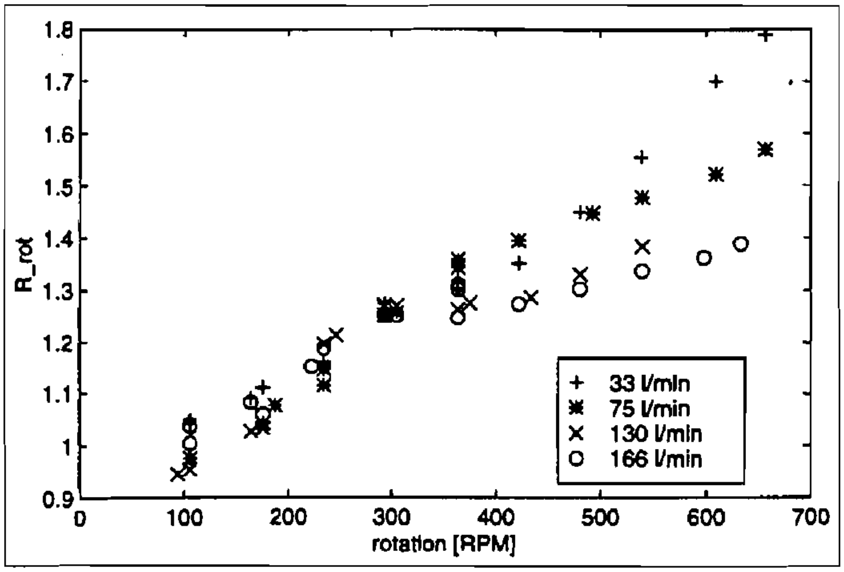

Figure 9-28. R_{rot} for F2 with 40% Eccentricity (Hansen and Sterri, 1995)

Flow rate does has a discernible effect for this case when eccentricity is reduced to 10% (Figure 9-29). However, as in Figure 9-28, flow rates greater than 33 l/min produce similar impacts on pressure loss for rotary speed less than about 400 rpm.

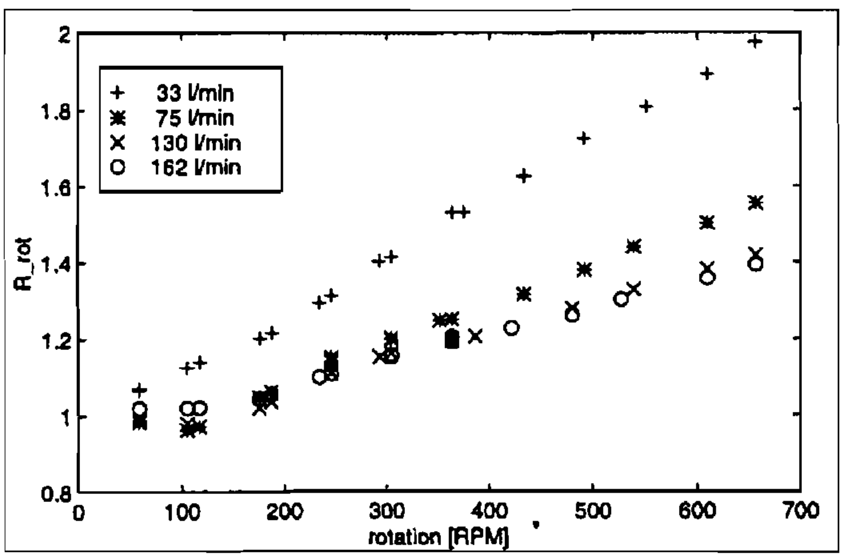

Figure 9-29. R_{rot} for F2 with 10% Eccentricity (Hansen and Sterri, 1995)

RF - Rogaland concluded that rotation can cause friction pressure loss to increase or decrease, and is a function of Reynolds and Taylor numbers. The results are summarized as follows:

- For Reynolds and Taylor numbers less than critical values, friction pressure loss decreases with rotation
- For Reynolds less than critical and Taylor greater than critical, friction pressure loss increases with rotation
- For Reynolds and Taylor numbers greater than critical, friction pressure loss increases with rotation

When friction pressure loss increases with rotation, the magnitude of increase is affected by flow rate, with the greatest effect observed at low Reynolds numbers.

9.7 RF-ROGALAND, AGIP AND ELF AQUITAINE (TESTS OF KICK-DETECTION SYSTEMS)

RF-Rogaland Research, Agip SPA and Elf Aquitaine Production (Steine et al., 1996) performed a series of well-control experiments in an inclined onshore research well in Stavanger. Tests included gas kicks, annular pressure loss measurements and surge/swab effects. Three different commercial kick-detection systems and one flow meter were tested. They found that the impact of drill-pipe rotation on ECD is significant and may increase frictional pressure losses as much as 30%. Surge/swab pressures over 100 bar (1450 psi) were also observed during the tests.

A 5-in. casing was run inside the test well to provide a slim-hole geometry. The drill string consisted of 758 m of 3.7-in. CHD 101 drill rod and 1178 m of 3.65-in. drill string with 4⅛-in. upsets. The surface equipment was heavily instrumented (Figure 9-30). Flow in was measured with a 4-in. electromagnetic flow sensor. Return flow was measured by a 6-in. meter.

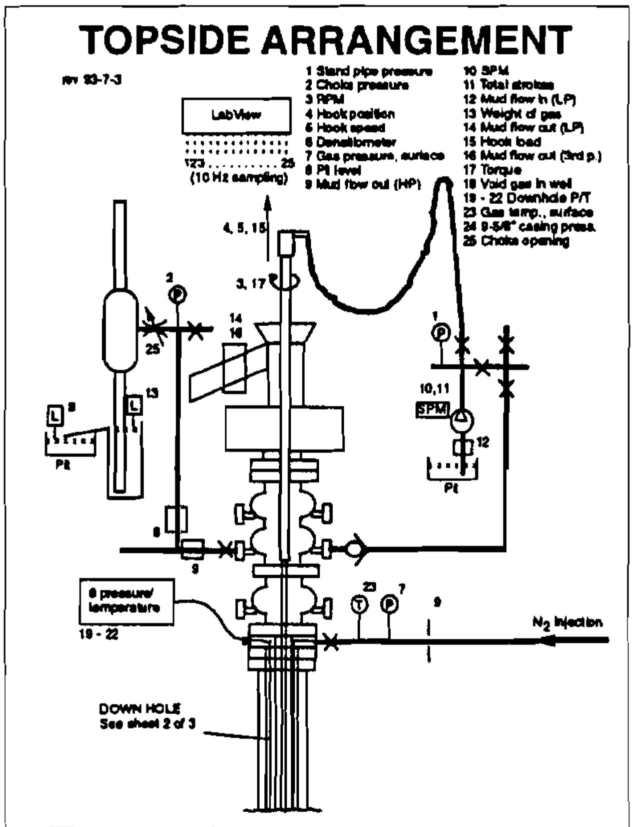

Figure 9-30. Sensors on Test Well (Steine et al., 1996)

The project team investigated the effects of drill-string rotation on pressure losses in the small annulus. Rotary speed was cycled between 200, 350 and 500 rpm at increasing flow rates (Figure 9-31).

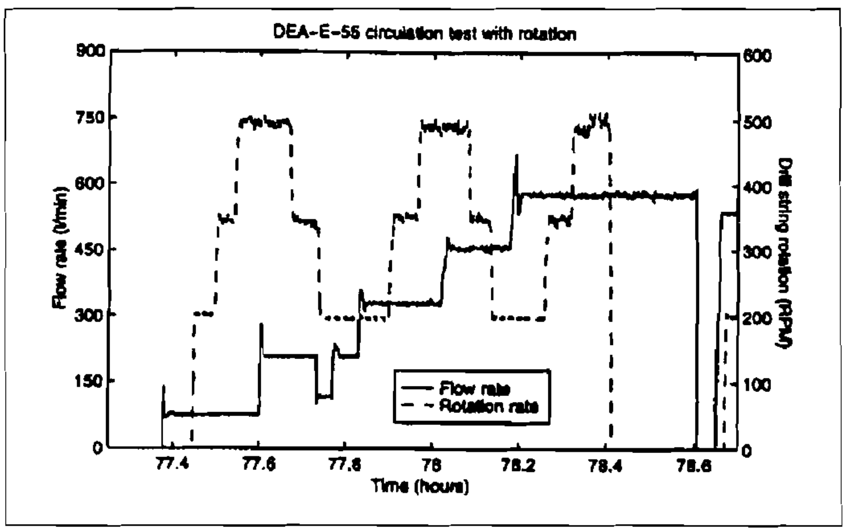

Figure 9-31. Rotation and Circulation Test (Steine et al., 1996)

Significant surge/swab effects were observed. Downhole pressure data show (Figure 9-32) pressures in excess of 100 bars can occur at faster tripping speeds.

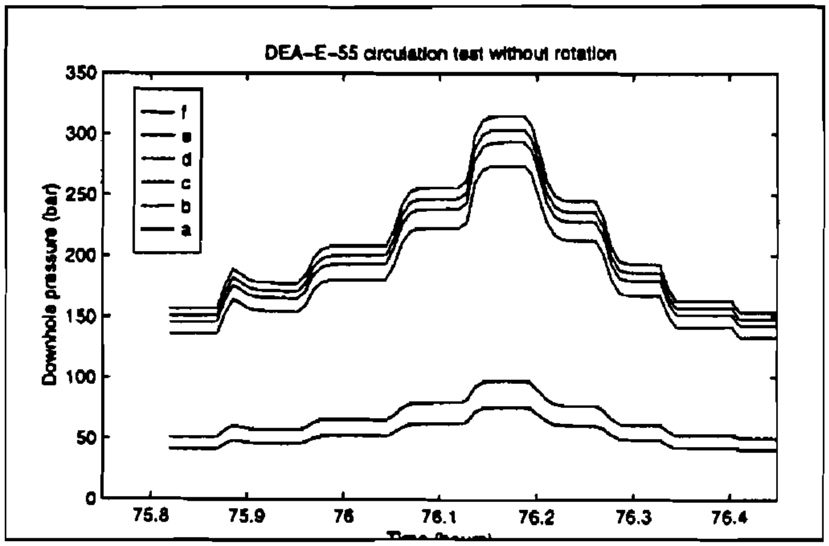

Figure 9-32. Downhole Surge/Swab Pressures (Steine et al., 1996)

More data from these tests are presented in *Well Control*.

9.8 SCHLUMBERGER DOWELL (ANADARKO CEMENTING)

Schlumberger Dowell (Waters and Wray, 1995) described developments and experience in cementing narrow slim-hole annuli in the Anadarko Basin. They found that a more dispersed cement is required to reduce friction pressure losses. At the same time, acceptable fluid-loss control and solids suspension must be maintained. A rapid and predictable transition from fluid to set cement is very advantageous. Mud removal is also critical in a slim annulus. It may be possible to attain turbulent flow of the spacer to aid in removal of drilling mud during cementing operations. Development, laboratory testing and field operations were successfully conducted with improved spacer and cement formulations and field procedures.

A common casing program in the Anadarko Basin (West Oklahoma and Texas panhandle) includes 5½-in. intermediate casing with a 3½-in. liner or 2⅞-in. production casing run below into the Red Fork formation inside a 4¾-in. hole. Achieving an effective seal in the narrow annulus of the production zone was studied in detail.

A new slurry was developed specifically for these slim-hole applications. Basic objectives included:

- Reduced slurry viscosity without sedimentation problems
- Reduced transition period from fluid to set cement

- Effective placement techniques based on turbulent flow or optimized laminar flow
- Low fluid loss and free water

Computer modeling was used to estimate flow rates required (and attainable) for the spacer and slurry. An appropriately designed spacer can achieve turbulent flow at pump rates of 3 BPM and above outside the 3½-in. liner. Friction pressure must be monitored at high pump rates. Pumping pressure is compared to pore and frac pressures in Figure 9-33. These data represent a 3½-in. liner in 4¾-in. open hole, spacer under turbulent flow and a pump rate of 3.5 bpm. Only a limited range of flow rates can attain turbulence while remaining below frac pressure.

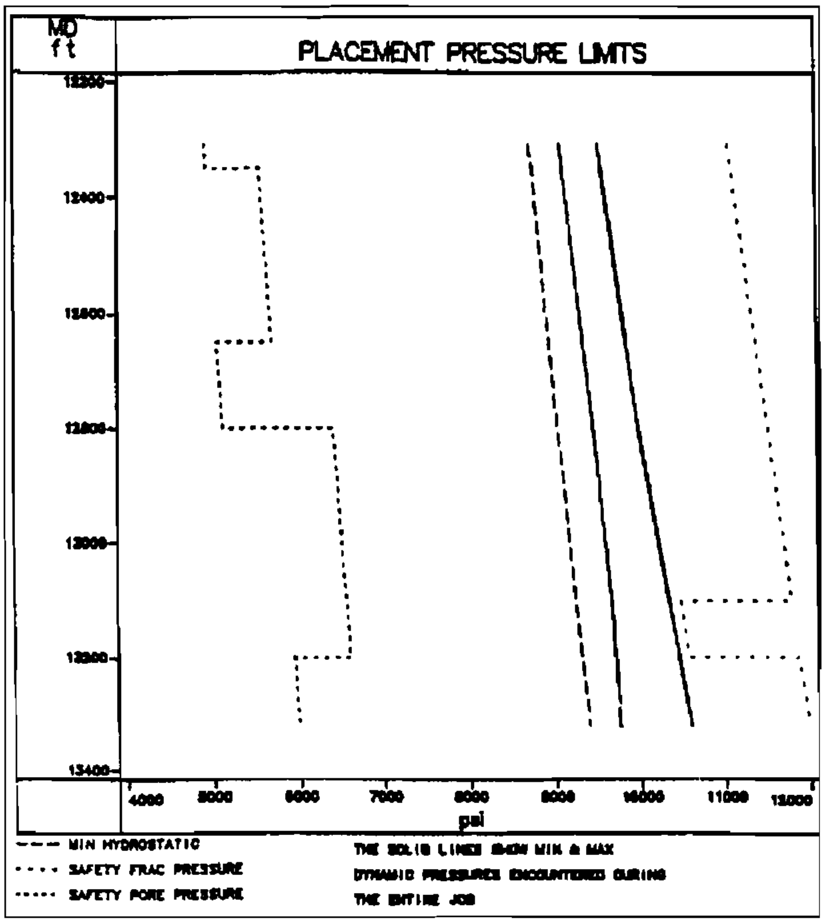

Figure 9-33. Cement Pump Pressures and Frac Gradient (Waters and Wray, 1995)

Schlumberger Dowell found that the required fluid-loss properties using conventional cellulose additives are difficult to attain without significantly increasing viscosity. A copolymer fluid-loss additive was investigated for these applications. Viscosity increases with copolymer were found to be relatively small.

Turbulent flow was also desired for the slurry placement. Minimum pumping rates are compared in Table 9-11 for the 3½-in. liner and 2⅞-in. casing options. Limitations in allowable flow rates for mud removal preclude obtaining turbulent flow with the slurry.

TABLE 9-11. Pump Rates for Turbulent Slurry Placement (Waters and Wray, 1995)

Liner Outer Diameter: 3 1/2"				
		Open Hole Size		
Fluid Name	Standoff %	4.50" bpm	4.75" bpm	5.0" bpm
Class H	100%	7.00	7.34	7.83
Cement	95%	7.50	7.96	8.46
Plus	85%	9.03	9.55	10.10
Copolymer	75%	11.22	11.81	12.44
Casing Outer Diameter: 2 7/8"				
		Open Hole Size		
Fluid Name	Standoff %	4.50" bpm	4.75" bpm	5.0" bpm
Class H	100%	6.93	7.45	8.02
Cement	95%	7.49	8.03	8.61
Plus	85%	8.91	9.54	10.16
Copolymer	75%	10.95	11.63	12.35

Several cementing jobs have been performed with the optimized system. One well had a 3½-in. liner cemented from 12,900 to 12,500 ft. The turbulent spacer and modified cement slurry were used. Thickening time for the cement is shown in Figure 9-34. The transition time was only 20 min and total thickening time was just over 3 hours. An excellent hydraulic seal was obtained over the entire interval.

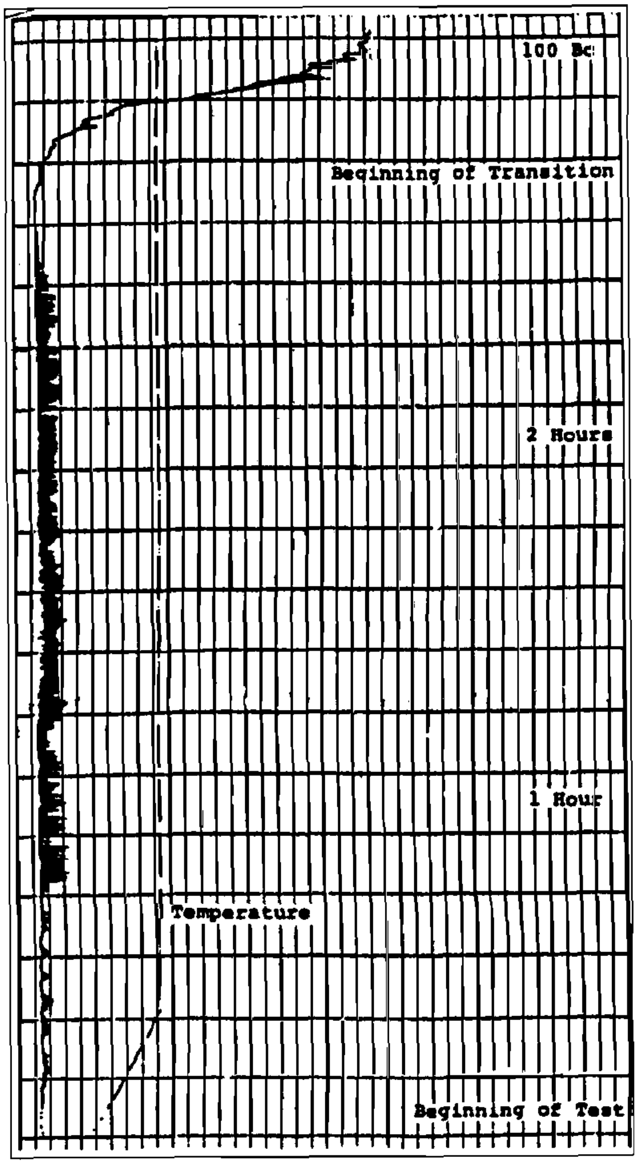

Figure 9-34. Thickening Time for Field Slurry (Waters and Wray, 1995)

Based on slim-hole cementing experience in the Anadarko Basin, Schlumberger Dowell recommended that narrow-annulus wells be carefully modeled prior to cementing, that spacers be pumped in turbulent flow if possible, that cement slurries be pumped using effective laminar placement techniques (since turbulent flow is not likely attainable), that minimum fluid-loss values be used, that thickening time after placement be minimized, and that transition times from fluid to set cement be short as possible.

Additional information is presented in *Cementing*.

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10. Logging

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10. Logging

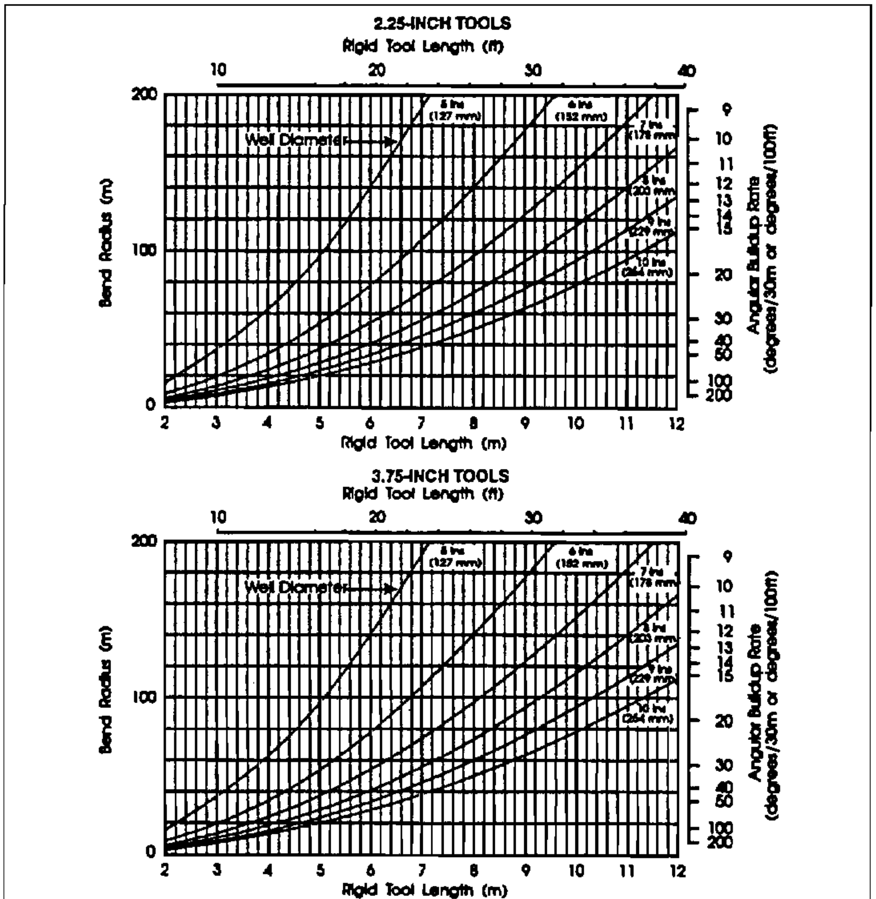
10.1 BPB WIRELINE SERVICES (CT-CONVEYED SLIM LOGGING TOOLS)

BPB Wireline Services (Houpe, 1996) summarized the benefits and availability of slim logging tools suited for use in horizontal wellbores. Coiled-tubing conveyance has been proven as generally superior to jointed-pipe methods. Lateral penetration limits resulting from buckling have been extended with larger CT and through various procedural methods including temporarily hanging small tubing or casing to the lowest vertical section of the well. A reduced diameter in the vertical section effectively reduces friction and can greatly extend horizontal penetration.

BPB Wireline Services' slim-hole logging tool line is based on the following general specifications: 2¼-in. OD, 255°F maximum temperature, and 12,500 psi rating. Oil-field slim tools include:

RESISTIVITY:	Array Induction Sonde Dual Laterolog Sonde
NUCLEAR:	Dual Density/GR/Caliper Dual-Neutron Sonde
ACOUSTIC:	Multichannel Sonic
AUXILIARY:	CT Adaptor Tension/Compression Sub Slim Repeat Formation Tester Four-Arm Dipmeter

Negotiating the curve with the logging string can be a significant obstacle/limitation for logging horizontal wells. The rigid tool length for 2¼-in. tools is plotted in the upper graph in Figure 10-1. The lower graph is for conventional 3¾-in. tools. A slim short logging tool string is preferred in most cases. Swivels, knuckles and cranks are also used to minimize effective string length.



Note: For a given tool diameter, maximum build tool length (L) that will traverse a well of diameter (d) and bed radius (R) is given by: L=2[(R+d)2-(R+t)2]1/2. Angular build rate (degrees/30 meters)=1718/R.

Figure 10-1. Maximum Tool Length Through a Curve (Houpe, 1996)

BPB Wireline provided example logs from a job in Germany to illustrate the benefits of logging in horizontal holes, even when significant offset vertical well data are available. In one case, a re-entry was drilled on coiled tubing and logged with the same rig. Coil size was 2⅜ inches. The logging tools were slightly smaller than the tubing, resulting in an ideal situation with respect to buckling and lateral penetration.

Dual-density/gamma-ray/caliper traces from a slim horizontal sidetrack are shown in Figure 10-2. Several tight lens were found between 1792 and 1865 m. These barriers were blamed for previously observed pressure variations across the field.

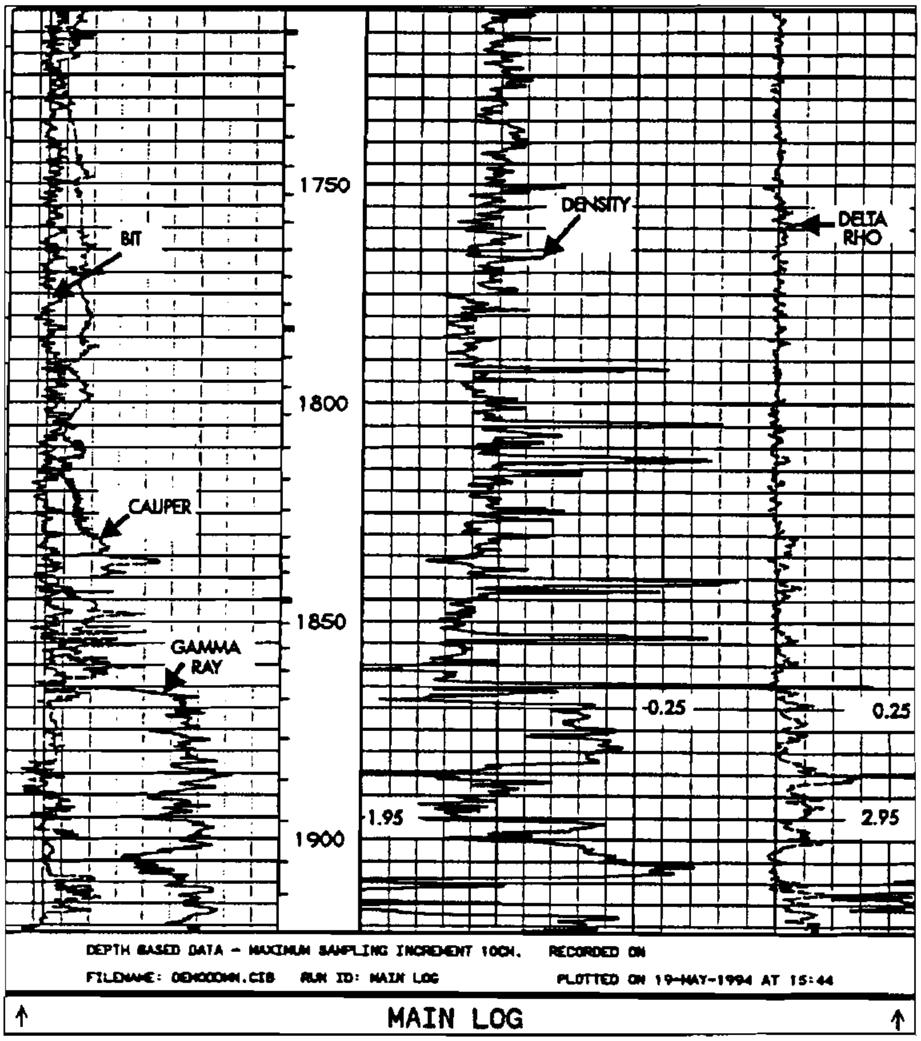


Figure 10-2. Log from Horizontal Sidetrack (Houpe, 1996)

Significant hydrocarbon deposits were revealed in the shaly sand analysis (Figure 10-3). The well-defined permeability barriers and faults were revealed in greater detail than expected.

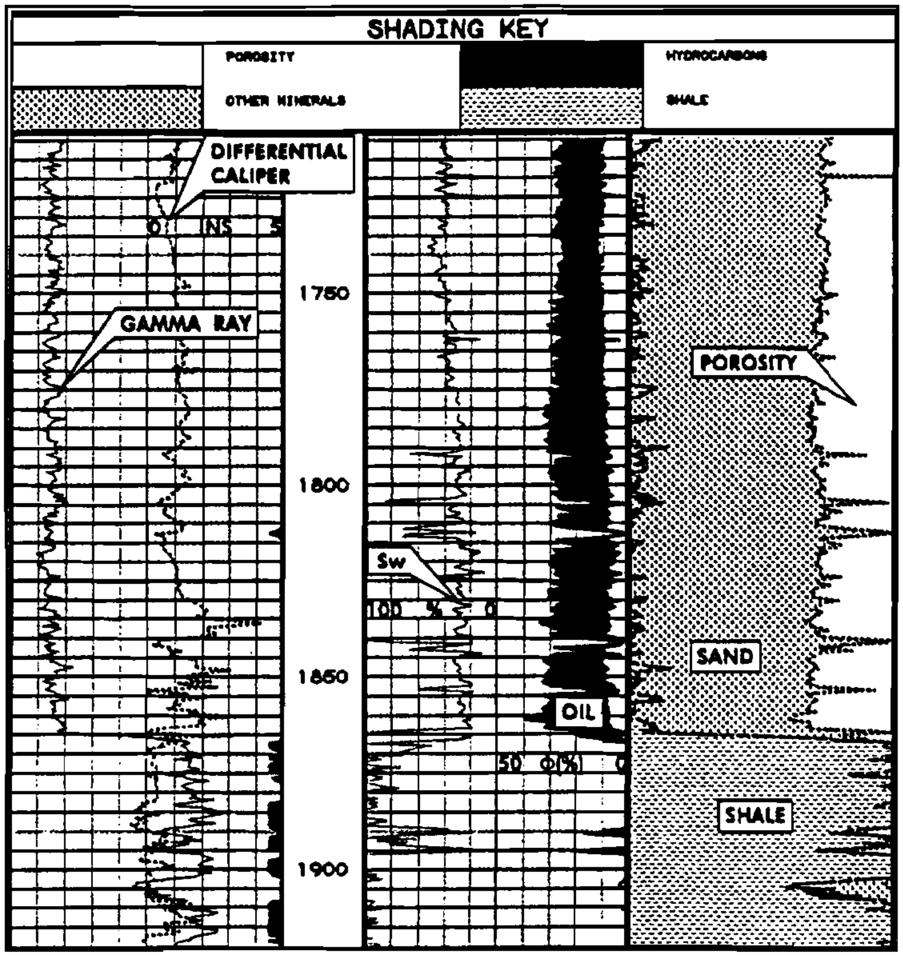


Figure 10-3. Lithology Log from Sidetrack (Houpe, 1996)

10.2 HALLIBURTON ENERGY SERVICES (SLIM RESISTIVITY FOR LWD)

Halliburton Energy Services (Heysse, 1995) described the design and performance of the recently developed Slim Compensated Wave Resistivity tool. This tool provides four resistivity measurements for formation evaluation in all mud types in holes as small as 5⅞ inches. The tool was designed and optimized for deep formation evaluation, invasion detection, and improved accuracy at higher resistivities. Tool length and flexibility allow operations in curved sections as great as 19°/100 ft while rotating and 36°/100 ft while sliding.

Tool configuration is illustrated in Figure 10-4. Nominal diameter is 4¾ in.; 5-in. wear bands surround the transmitters and receivers.

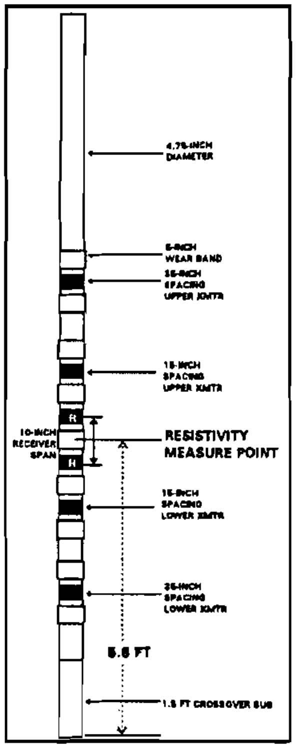


Figure 10-4. Slim Compensated Wave Resistivity Tool (Heysse, 1995)

Circulating temperatures up to 150°C are allowable. A summary of mechanical and operational specifications of the Slim Compensated Wave Resistivity tool is presented in Table 10-1. In addition to real-time relay of data via mud pulse, the tool contains enough internal memory for 200 hours of high-resolution logging.

TABLE 10-1. SCWR Tool Specifications (Heysse, 1995)

Nominal OD	4.75 in.
Smallest Internal Diameter	1.50 in.
Length	30.63 ft
Weight	1,150 lbm
Equivalent Stiffness	4.33 in. OD
	2.0 in. ID
Average Moment of Inertia	16.42 in^4
Tool Joints - Field	NC38 box/pin
Shop	NC31, NC38
Make-up Torque - Shop NC38	9,800 ft-lbf
Bending Strength Ratio	2.33
Make-up Torque - Shop NC31	5,800 ft-lbf
Bending Strength Ratio	2.65
Make-up Torque - Field NC38	10,400 ft-lbf
Bending Strength Ratio	1.88
Maximum Tensional Load	389,500 lbf
Maximum RPM	250 RPM
Maximum Torque	6,100 ft-lbf
Maximum Bend Angle and	(see Fig. 3)
Compression Load	(see Fig. 3)
Maximum Temperature	302 F
Maximum Pressure	20,000 psi
Flow Rates	125 to 275 gal/min
Pressure Drop @ 125 gpm	21 psi
@ 200 gpm	62 psi
@ 275 gpm	103 psi
Mud Sand Content	maximum 1%

Vertical resolution of the SCWR is greater than most wireline induction tools. Log responses have shown that the tool is capable of detecting formations less than 1 ft thick.

Halliburton Energy Services presented example logs with the SCWR from a Gulf of Mexico well. Productive formations in the area ranged from about 10 to 100 ft thick. The first wellbore was drilled at a 40° deviation. Logging results (Figure 10-5) were obtained in real time for resistivity, gamma ray, and directional data. (Resistivity data in the figure were retrieved from tool memory.)

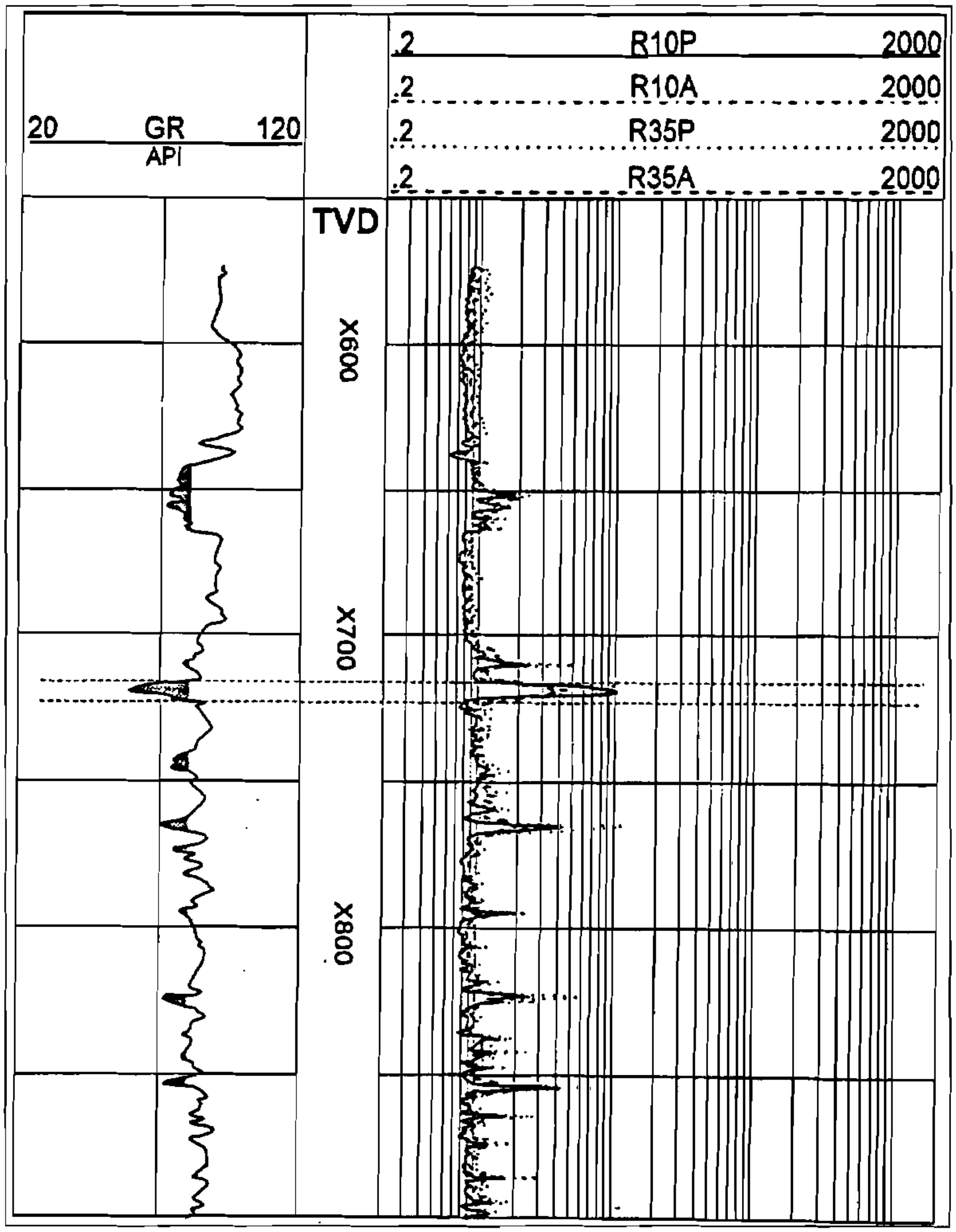


Figure 10-5. Log in 40° Deviated Well (Heysse, 1995)

The target sand is apparent on the gamma ray and resistivity at X715 ft. It was soon determined that the productive interval was only 6 ft thick. Based on this information, the operator chose to sidetrack the well and penetrate the formation several hundred feet away. The second leg entered the formation at a deviation of 50° through a sand layer about 13 ft thick. A more productive and economic well was the result.

10.3 PETROLEUM ENGINEER INTERNATIONAL (SLIM MWD TOOLS)

Petroleum Engineer International (Perdue, 1996) surveyed the logging service industry and provided a summary of developments in slim-hole MWD tools. Tools are available that fit into drill collars as small as 3⅛ inches. The availability of smaller tools has extended their application into new areas such as high risk for stuck pipe, high temperatures, low-budget wells and remote locations. The cost of drilling horizontal wells has been significantly reduced through integrated MWD systems.

Slim-hole activity has increased in the Gulf of Mexico in recent years. The first slim horizontal well was drilled there with a 3¾-in. directional/gamma-ray tool in 1993. Over 80 sidetracks have since been performed in the area.

Re-entries of old wells is the fastest growing segment of the slim-hole MWD market. Many of these involve drilling 6-in. horizontal laterals out of 7-in. casing. MWD has also proven to be an ideal tool for rapid evaluation of slim wildcats.

New capabilities are continually being added to slim MWD systems. Drilling Measurements Inc. provides a wireline steering system (probe OD of 1 in.) that measures directional data, gamma ray, temperature and vibration, and incorporates a wet-connect system that permits drilling rotation. This type of system is widely used in the Austin Chalk and for underbalanced and aerated-fluid applications.

Halliburton Energy Services, Schlumberger Anadrill, Baker Hughes INTEQ and Sperry-Sun all report significant interest in their slim MWD systems and capabilities.

10.4 SCHLUMBERGER ANADRILL (MULTIARRAY RESISTIVITY TOOL)

Schlumberger Anadrill (Bonner et al., 1995) described a new 4¾-in. mixed borehole-compensated 2-MHz array resistivity tool used for resistivity MWD in slim holes from 5¾ to 6¾ inches. The tool can be used in real time to steer the well within the reservoir and help maintain the well path within the pay zone. It combines the benefits of multispacing probes for formation evaluation with the advantages of borehole compensation.

The tool is 21 ft in length (Figure 10-6). The maximum build rate allowed is 15°/100 ft during rotation and 30°/100 ft during slide drilling.

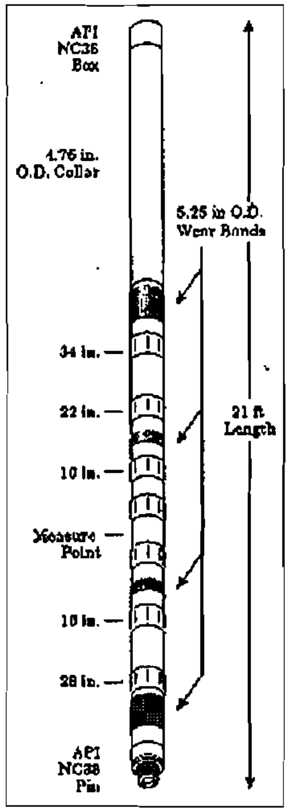


Figure 10-6. Slim Multiarray Resistivity Tool (Bonner et al., 1995)

10.5 SCHLUMBERGER WIRELINE (SLIM DENSITY TOOL)

The tool is useful for identifying low-permeability zones and discriminating between hydrocarbon and wet intervals. Borehole effects are only minimal in 6-in. holes. The resistivity and gamma-ray measurements can be used for real-time formation evaluation in slim holes (minimum 5¾ in.).

Schlumberger Wireline and Testing (Stoller et al., 1997) reported the development of an improved 2½-in. three-detector density log for slim-hole and re-entry drilling. They report that the new tool overcomes many limitations of older tools and measures bulk density and photoelectric factor with the same precision and reliability as larger logging tools. The compact tool (Figure 10-7) has increased reliability and improved wellsite efficiency.

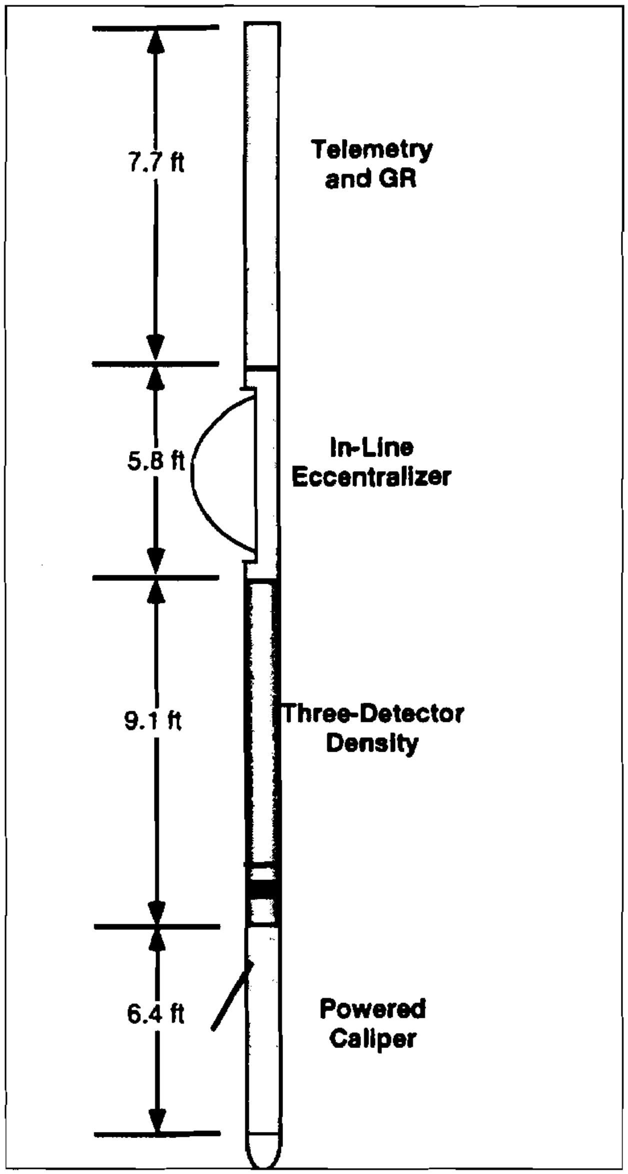


Figure 10-7. Slim 2½-in. Density Logging Tool (Stoller et al., 1997)

The density tool is part of a slim quad-combo (gamma ray, neutron, density, monopole sonic and array induction). These tools are designed for slim holes as small as 3½ inches, and high doglegs (up to 60°/100 ft in 4⅛-in. hole).

An example log from a 4¾-in. hole is shown in Figure 10-8. The interval consisted of dolomite. The slim tool (SLDT in the figure) compares well with the larger tool (LDT).

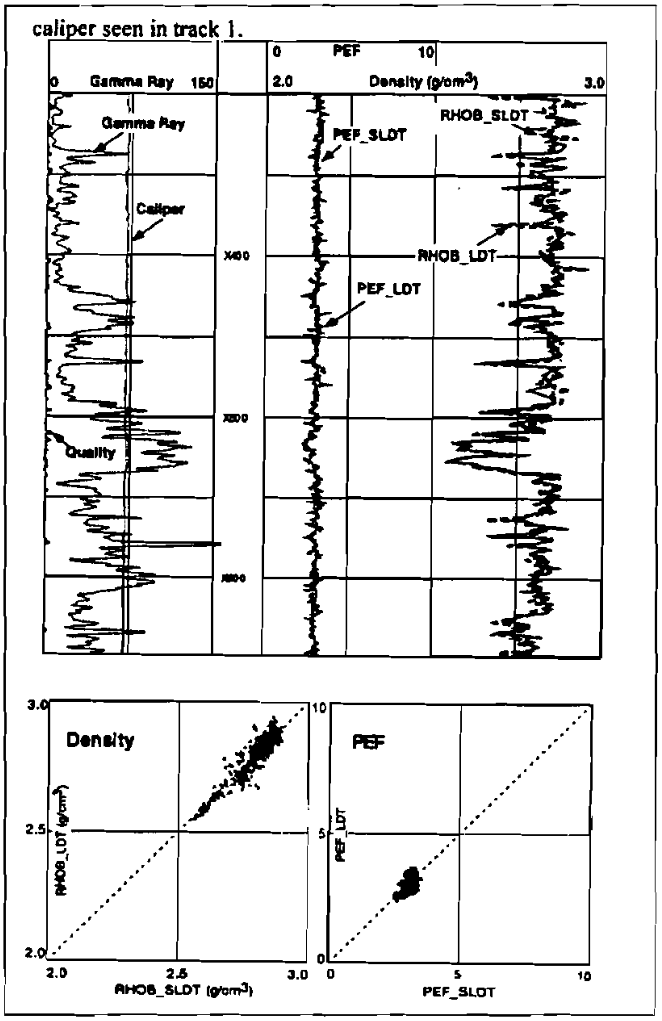


Figure 10-8. Comparison Log for Slim 2½-in. Density Log (Stoller et al., 1997)

10.6 SCHLUMBERGER ANADRILL (SLIM MWD/LWD TOOL)

Anadrill recently introduced a new tool that combines MWD and LWD in a slim BHA. The tool is built into 4¾-in. drill collars and is recommended for use in 5⅞- to 6¾-in. holes (Kunkel, 1998). Build rates up to 30°/100 ft while sliding and 15°/100 ft while rotating are achievable. The system proved its ability to access "sweet spots" in the reservoir using azimuthal density geosteering in an early field application. Well paths for the new tool (6-in. borehole) and one drilled previously and steered by resistivity (8½-in. borehole) are compared in Figure 10-9.

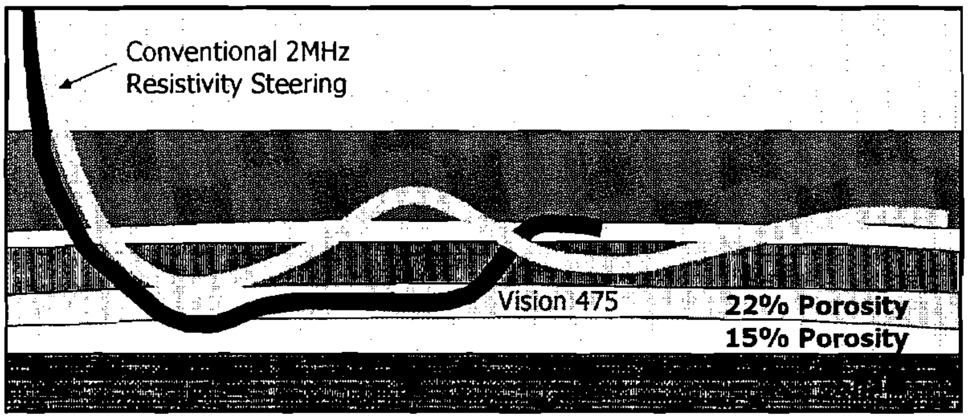


Figure 10-9. Well Drilled with Slim Geosteering Tool (Kunkel, 1998)

The sensitivity of the new slim tool kept the bit in the lower high-porosity zone for almost the entire length. Productivity indices were 2.4 for the first well versus 8.2 for the new lateral.

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11. Motor Systems

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11. Motor Systems

11.1 BAKER HUGHES INTEQ (COPERNICUS RIG)

Baker Hughes INTEQ (Burge, 1996) designed a new drilling rig (Figure 11-1) that combines capabilities to drill with coiled tubing as well as with jointed pipe. This project, called Copernicus, was undertaken in response to industry's need for fit-for-purpose slim-hole rigs and hybrid coiled-tubing rigs that can handle jointed tubulars. The economics of the system are significantly improved through the use of multitasking crew function and the integration of downhole and surface operations by means of a single process control cabin.

Figure 11-1. Copernicus Rig (Burge, 1996)

Overall capabilities to be fulfilled with the new rig include pulling production tubing and preparing the well, drilling directional wells, running casing and liners, and drilling underbalanced.

Operational modules include conventional open fluid tanks and solids-control equipment, closed-loop fluid handling for underbalanced drilling, full coiled-tubing operations, and tubing handling systems. A typical site layout (Figure 11-2) encompasses an area of about 625 m^2 (6727 ft^2).

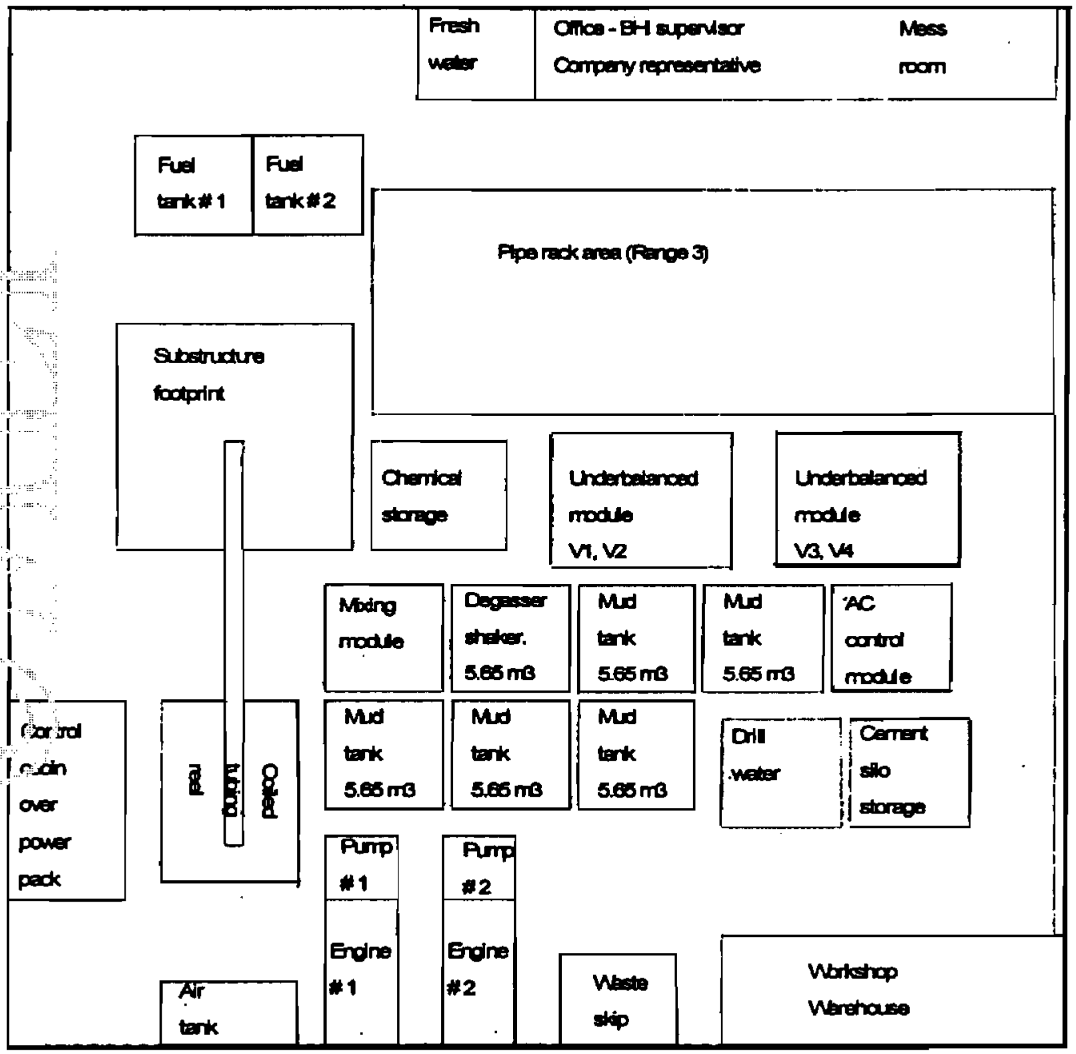


Figure 11-2. Site Layout (Onshore) (Burge, 1996)

Critical features of the rig include the use of a modified coiled-tubing injector that can handle coiled tubing, drill pipe and casing. A lubricator is not required for deploying BHAs into live wells.

Hole sizes and rig capabilities are summarized in Table 11-1.

TABLE 11-1. Drilling Capabilities of Rig (Burge, 1996)

	CTD (Horizontal, through tubing)	Slim-hole exploration
Hole size	3½" to 5⅞"	3⅞" to 9⅞"
Depth	To 15,000' (4,500 m)	11,500' (3,500 m)
Temperature	max. 125 °C	max. 125 °C
Pressure Wellhead Differential	5,000- 10,000 psi (340 - 680 bar) 5,000 - 10,000 psi (340 - 680 bar)	10,000 psi (680 bar) 10,000 psi (680 bar)
Sour service	Yes	Yes
Build up rate	45°/100' (45°/30 m)	
Max. host casing size	9⅝" dependent on depth	Not applicable

A modified coiled-tubing injector can handle casing and drill pipe (Table 11-2).

TABLE 11-2. Capabilities of Injector (Burge, 1996)

Maximum load	100,000 lbs.
Maximum operating load	80,000 lbs.
Coiled tubing sizes	2" to 3½"
Drilled pipe sizes	2⅜" to 3½" (externally flush)
Casing sizes	2⅞" to 7⅝"

Burge presents a detailed description of rig function, capacities and capabilities in his paper.

11.2 BAKER HUGHES INTEQ, DEUTAG AND BPB WIRELINE (DRILLING PACKAGE)

Baker Hughes INTEQ, Deutag and BPB Wireline Services (McNicoll et al., 1995) described planning, equipment and field operations for drilling a slim-hole exploration well in Madagascar. The hole size was 4⅛ in. at TD. A small modified workover hoist was used. An overall cost savings of 40% was realized compared to a nearby offset conventional well (6¼ in. at TD). A 45% reduction in cuttings volume and 40% less mud decreased the environmental impact of the project.

Shell Madagascar had previously drilled an exploratory well in the area, and wanted to achieve cost savings on the second project. Shell's slim-hole system developments were used, most significantly the motor/thruster assembly and PDC bits. The KDS kick-detection system was used, which compares actual returns to modeled predictions of the circulating system operating in real time.

Drilling operations were designed based on Shell's "Drilling in the 90s" initiative, whereby the lead contractor (Deutag, the drilling contractor) assumed responsibility for daily operations with only minimal involvement of the operator. Operator/contractor relationships for this approach are summarized in Figure 11-3.

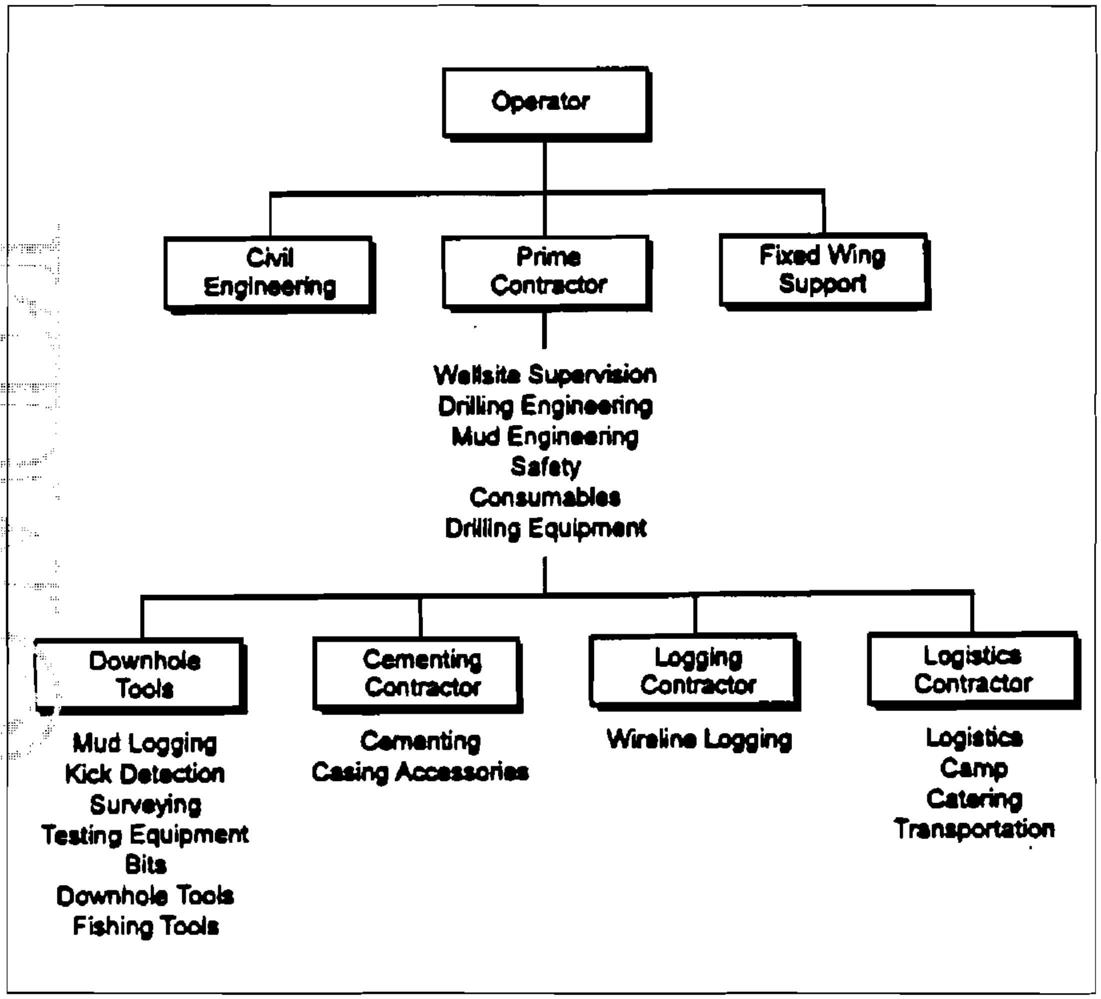
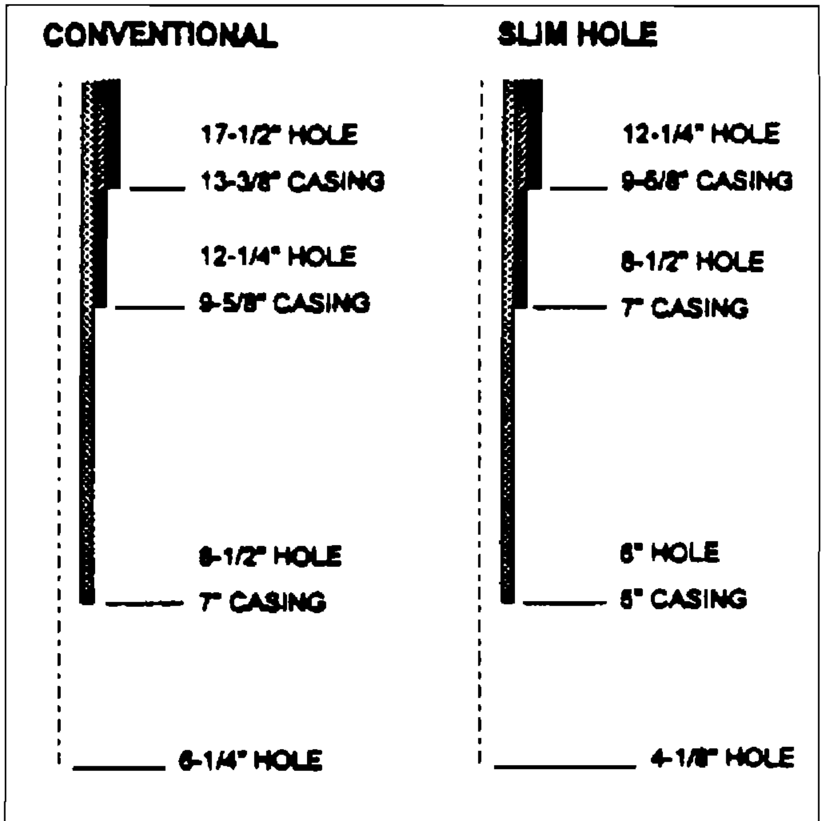


Figure 11-3. Contractor Relationships (McNicoll et al., 1995)

The slim-hole design included 9⅝-in. conductor and a 4⅛-in. final hole (Figure 11-4). Drilling was completed in 36 days to a TD of 2223 m (7293 ft); abandonment was completed in three days. The conventional offset required 53 days for drilling and 11 days for abandonment. TD was slightly greater than the slim hole: 2508 m (8228 ft).



	6-1/4" HOLE	4-1/8" HOLE
Casing Weight	110 MT	64 MT
Well Volume	51 m³	24 m³
Rock Volume	108 m³	53 m³
Cmt Slurry	35 m³	15 m³

Figure 11-4. Conventional/Slim-Hole Casing Program (McNicoll et al., 1995)

The drilling rig for the slim hole consisted of a modified light workover rig with a 69-tonne hookload. Key specifications for the rig are summarized in Table 11-3.

TABLE 11-3. Rig Specifications (McNicoll et al., 1995)

Item	National 80B	Cabot 200	Slim/Normal
	Standard Rig	Slim Rig	Ratio
Mast Height	43 m	29.3 m	67.7%
Hookload	272 MT	68.9 MT	25.3%
Drawworks	1000 HP	200 HP	20%
Substructure			
Height	6.7m	4.34 m	64.7%
Setback Cap	158.7 MT	65 MT	40.9%
RT	698.5 mm	374.7 mm	53.6%
Pumps	2 x CE F 1000	1 x Nat 7-P-50	41.9%
		1 x CE F350	
Tanks	118.5 m^3 vol.	63 m^3	53.1%
	Shale Shaker	Shale Shaker	
	Desandeer	Desilter	
	Desilter		
BOP	13 ⅝" 5,000 psi	11" 3,000 psi	
	1 x annular	1 x annular	
	3 x Ram	2 x Ram	
Drillstring	4,000 m of 4½	2,000 m of 3½	
	3,000 m of 3½	2,500 m of 2⅞	
	24 x 8¼ DC	18 x 6¾ DC	
	30 x 6¼ DC	20 x 4¾ DC	
	20 x 4¾ DC	12 x 3½ DC	
Depth Range	4,250 m w/4½	2,500 m w/2⅞	58%

The site layout is shown in Figure 11-5. Eighty-seven truck loads at a maximum of 12 tons each were required for mobilization. The conventional campaign required 220 truck loads.

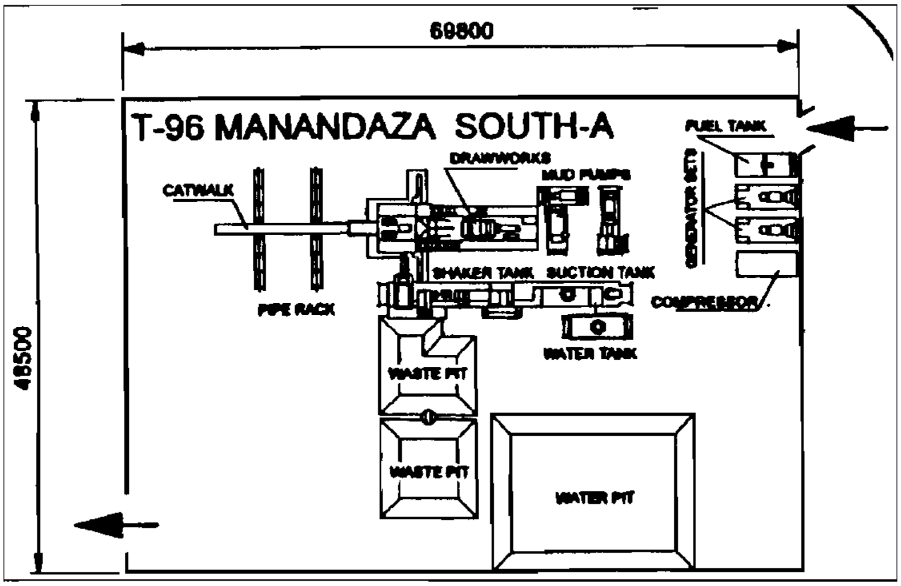


Figure 11-5. Location Layout for Slim Hole (McNicoll et al., 1995)

A primary feature of this slim-hole drilling system (based on Shell Research's developments) is the use of a downhole motor and thruster for increased drilling efficiency through consistent speed and torque without damaging drill-string vibrations. Efficiency increases because, as the motor and bit get smaller, specific power to the bit increases (Figure 11-6). Penetration rates with the motor/thruster system compared very favorably with ROPs on the conventional well. Time-dependent costs were readily controlled.

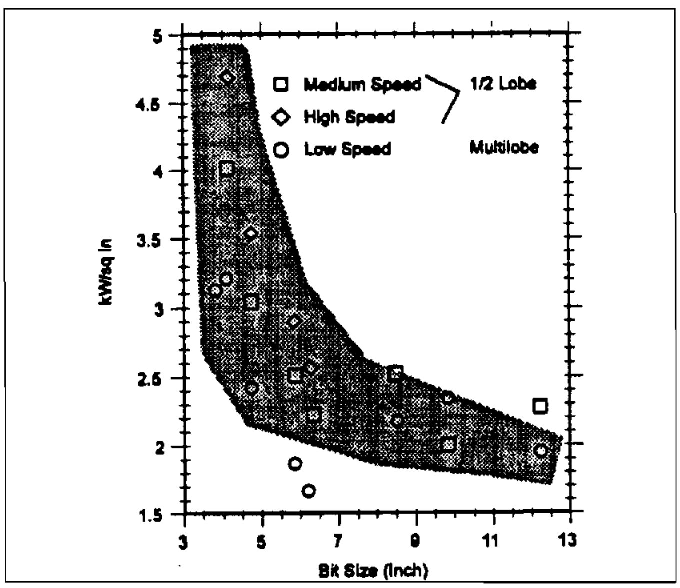


Figure 11-6. Hole Size and Power to the Bit (McNicoll et al., 1995)

The 4⅛-in. section was drilled with two PDC bits on two BHAs, one with the thruster and one without.

One of the primary functions of the downhole thruster (Figure 11-7) is to decouple the drill string and BHA to reduce the impact of drill-string vibration. Another important function is to provide consistent WOB. The contractor found that matching the thruster to the particular drilling assembly is complex and was initially a trial and error process. Based on field experience, software was written to optimize the BHA system for each application.

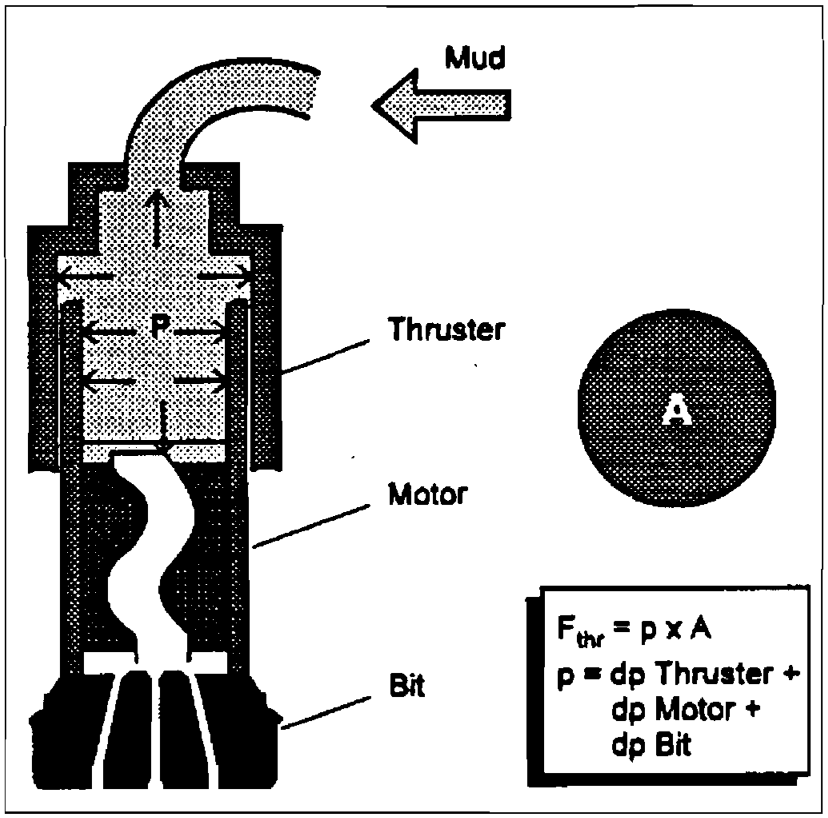


Figure 11-7. Downhole Thruster (McNicoll et al., 1995)

Reduced drill-string vibration provides several benefits including fewer twist-offs, and smoother and more stable boreholes. A caliper log through the 4⅛-in. section showed that gauge was maintained within 0.1 inch (Figure 11-8). No twist-offs occurred during operations.

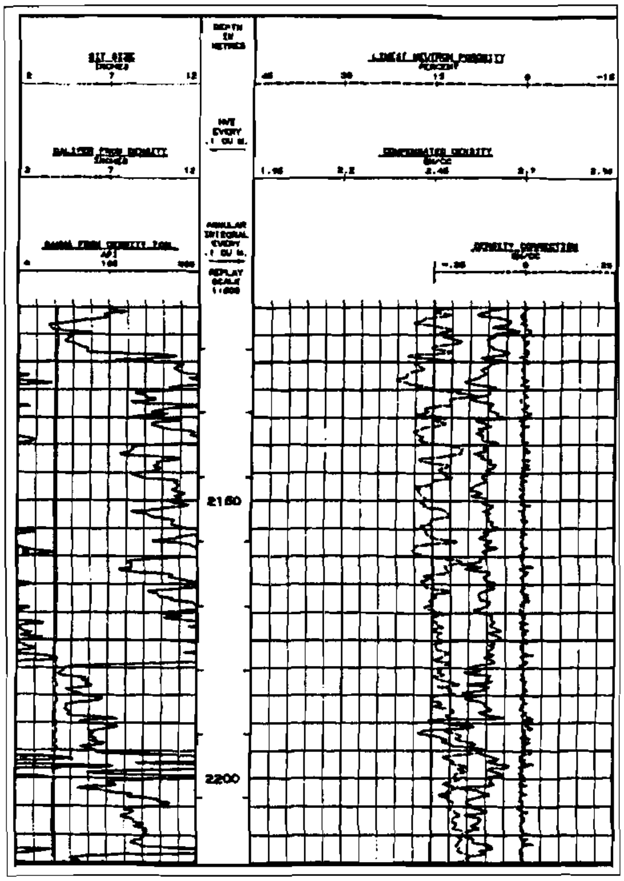


Figure 11-8. Caliper Log in 4⅛-in. Hole (McNicoll et al., 1995)

The kick-detection system utilizes several sensors around the rig and three magnetic-induction flow meters (suction line, flow line, and trip tank). Computer programs monitor rig activity and predict expected flow behavior. Any significant departure greater than a preset limit triggers alarms to warn the driller to take action. Fluid losses occurred in the final hole section. Losses of 30 l/min were detected by the kick-detection system.

Drilling mud was a shear-thinning low-solids KCl polymer. Mud weight ranged up to 1.12 SG. Calculated ECD in the final hole size was as great as 1.3 SG (10.8 ppg).

After drilling was completed, five logging runs were made to TD without incident. The well was then plugged and abandoned. Logs included Laterolog, multichannel compensated sonic, dual-density/gamma-ray/caliper, dual neutron, and seismic reference sonde.

The project schedule is summarized in Figure 11-9.

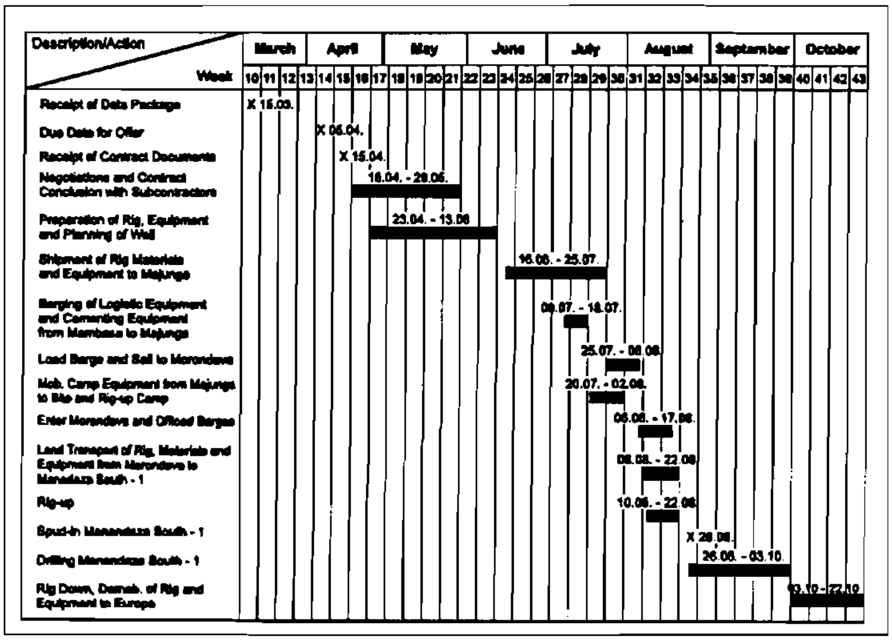


Figure 11-9. Slim-Hole Project Schedule (McNicoll et al., 1995)

Cost savings were substantial. The offset conventional well was drilled to a greater depth. Its costs were normalized to the same depth as the slim hole for a more valid comparison. Total costs were reduced about 40% (Table 11-4).

TABLE 11-4. Conventional versus Slim-Hole Costs (McNicoll et al., 1995)

	Manandaza 1 Conventional (Normalized)	Manandaza South Slimhole	% Savings
Hole Size at TD	6 ¼"	4⅛"	
Depth	2,200 m	2,200 m	
Days on Well	38	38	
Meters per Day	58	58	
Costs ($Million)			
Ex Mob/Civil	2.97	1.75	41
Ex Mob	6.83	2.68	61
Total Well Costs	11.4	7.0	39
Unit Costs			
Depth Dependent $/Meter	376	88	77
Time Dependent $000/day	46.7	39.7	15
One-off Costs $ Million	8.8	5.3	40

The project team concluded that light workover rigs can be successfully used for slim-hole drilling. ROPs can also be maintained comparable to conventional operations. Technology to limit drill-string vibration can provide a smooth and stable borehole.

11.3 BAKER HUGHES INTEQ AND NAM (DOWNHOLE THRUSTERS)

Baker Hughes INTEQ and Nederlandse Aardolie Mij. B.V. (Reich et al., 1995) described the design, usage and performance of downhole thrusters for motor drilling operations. These elements decouple the lower section of the BHA from the drill string and provide a constant, controllable WOB for smoother, more predictable drilling. Thrusters have been run on more than 120 jobs, increasing ROPs, bit life, and steerability. They have been employed in hole sizes ranging from 3⅞ to 12¼ inches on fixed and floating rigs.

Vibration in the drill string can reduce ROP, cause twist-offs, lead to early failure of motors and MWDs, and reduce borehole stability and tool-joint life. These problems can be especially significant in slim holes due to the weaker drill string. In directional drilling, longitudinal vibration can make it difficult to maintain WOB. In many cases, slower-drilling tricone bits are preferred because they are less sensitive to changes in WOB.

Baker Hughes INTEQ developed a thruster to address these problems. Early trials with the thruster proved that system optimization was not easily achieved. Theory was developed and incorporated into design software for use with this system.

In one well offshore Brunei, a heavy and abrasive oil-base mud (20 ppg) was required. BHAs with and without the thruster were run in the 4½-in. section. The standard BHA (3¾-in. motor) was used for a 184-m interval. The thruster was incorporated for the next 201 m. ROP was improved with the thruster (Figure 11-10).

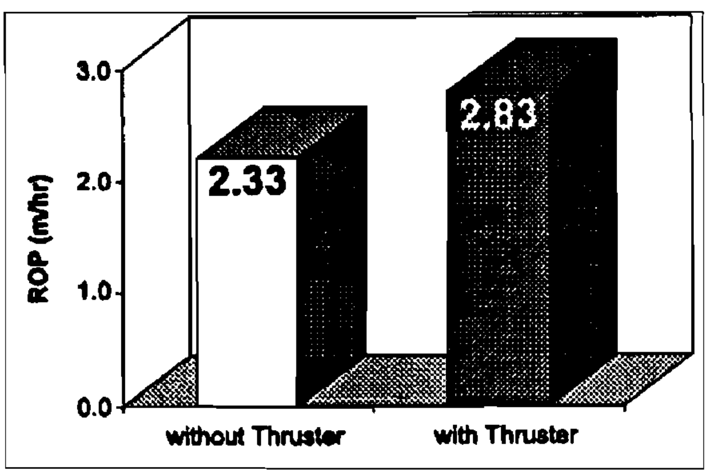


Figure 11-10. ROP with Thruster (Reich et al., 1995)

Surface torque was also much more consistent with the thruster (Figure 11-11). WOB was relatively unchanged between the two runs. The improvement in ROP was attributed to decreased axial vibrations resulting in improved contact between the bit and formation.

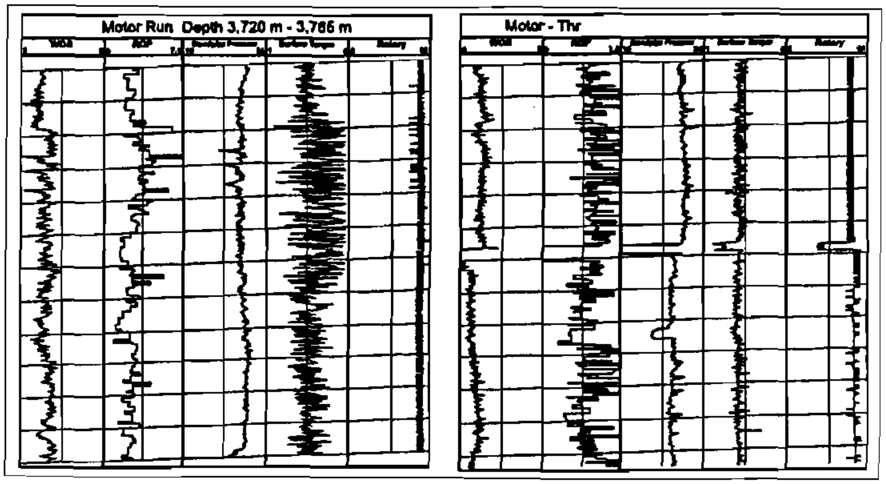


Figure 11-11. Performance with Thruster (Reich et al., 1995)

The thruster has been run in several wells in Canada for 4¾-in. horizontal sections. Based on data from 50 bit runs (about 40% of which included a thruster), ROP was increased by 12% with a thruster.

The pressure drop that controls WOB with the thruster includes all pressure drops below the thruster, i.e., Δp between the thruster and the annulus. Control of WOB is enhanced and controlled with a choke spear (Figure 11-12) through which part of the mud flow is bypassed.

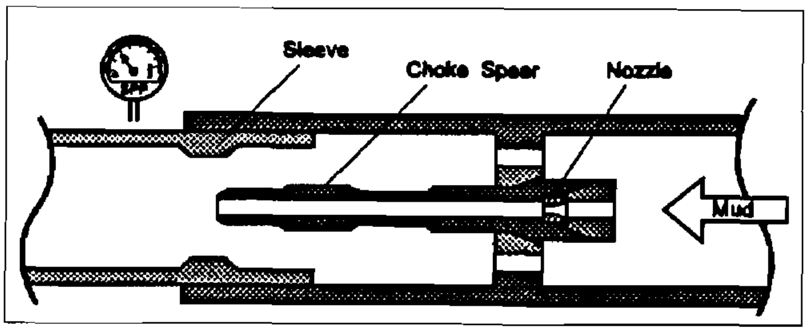


Figure 11-12. Standard Thruster Configuration (Reich et al., 1995)

Nozzles within the choke spear (Figure 11-13) can be replaced on the rig floor to create higher/lower pressure drops for fine tuning the system for specific operational requirements.

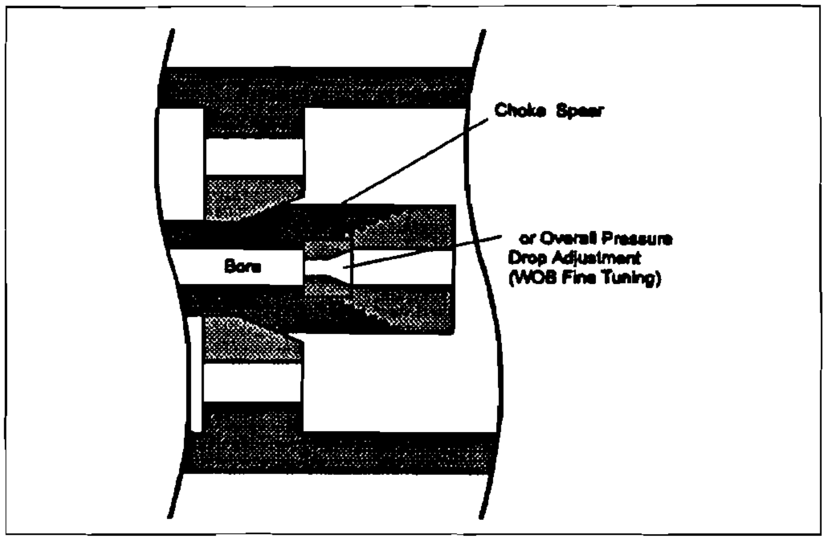


Figure 11-13. Thruster Choke Spear Nozzle (Reich et al., 1995)

Since the response of all components below the thruster impacts the effective WOB, a mathematical model is required to optimize performance. One variable that may be relatively difficult to quantify is bit aggressiveness. This quantity relates torque on bit to WOB. Typical values are: 0.03 to 0.05 for roller-cone bits and 0.1 to 0.3 for diamond bits. Mud motor performance is accounted for by using a simplified model to relate torque to differential pressure. The resulting system of equations is solved by iteration. A typical calculation of operation point is shown in Figure 11-14.

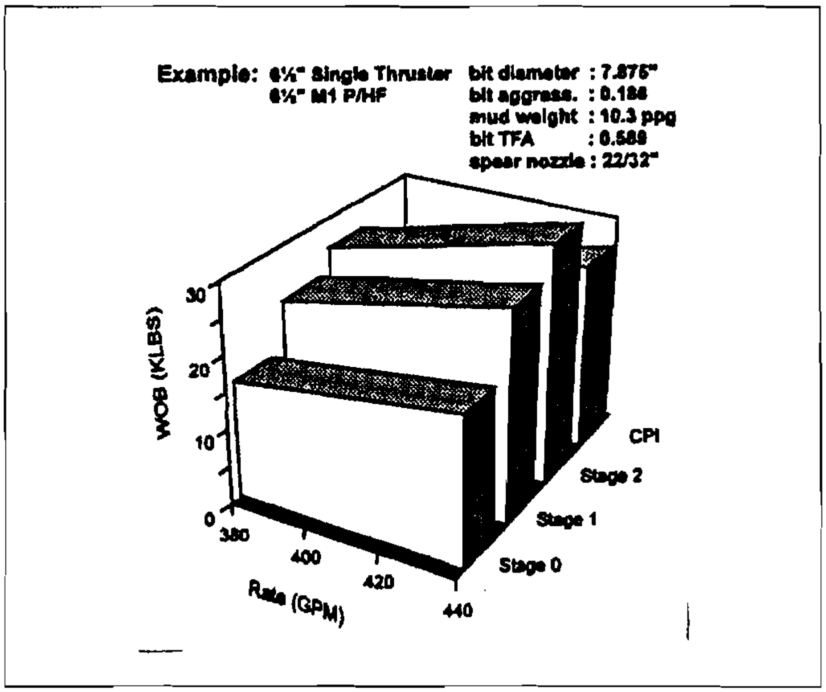


Figure 11-14. Thruster Optimization Calculation (Reich et al., 1995)

The standard thruster design with spear is shown in Figure 11-15. It was found that the WOB adjustment range is relatively limited within a single design. Additional designs were developed to increase/decrease potential WOB.

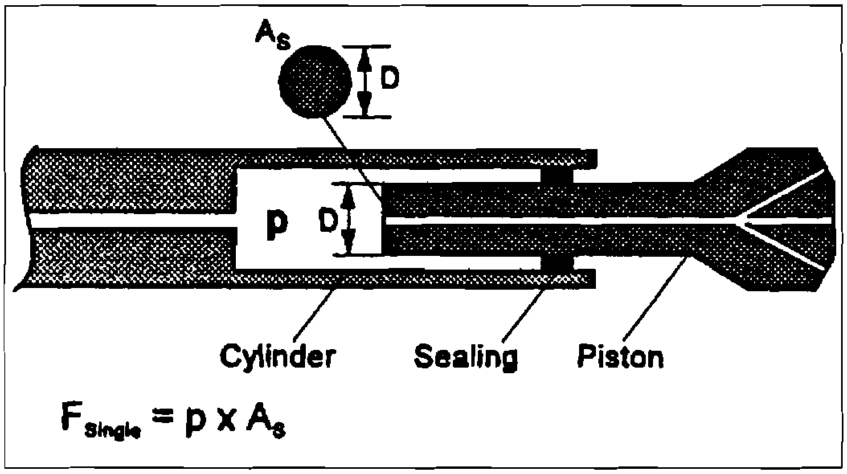


Figure 11-15. Standard Thruster Design (Reich et al., 1995)

A low-WOB system was designed by decreasing the seal area (Figure 11-16). This modification reduces down thrust by about 50%.

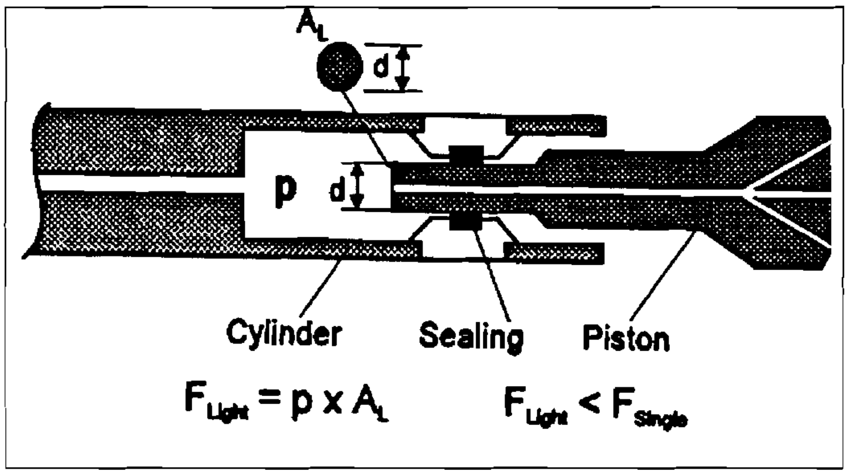


Figure 11-16. Light Thruster Design (Reich et al., 1995)

A high-WOB system was designed by adding a second actuation piston (Figure 11-17). The upper piston is activated by the pressure differential between the annulus and inside of the thruster (there are mud ports for pressure communication with the annulus). This modification increases down thrust by about 50%.

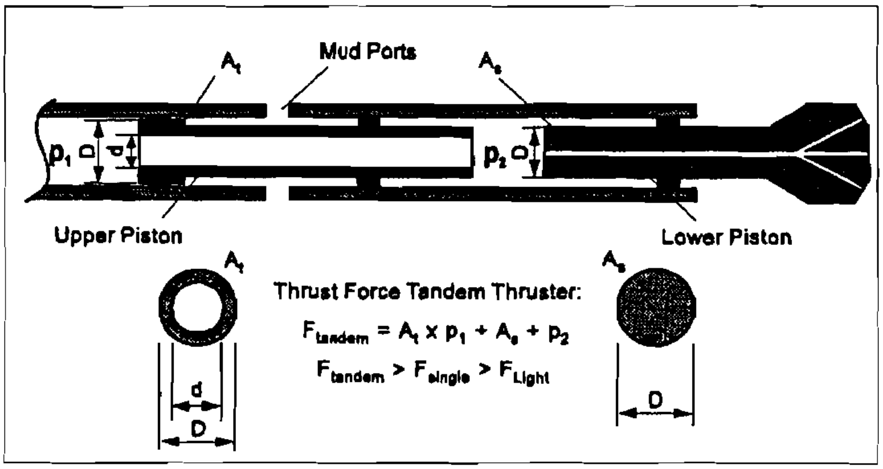


Figure 11-17. Tandem Thruster Design (Reich et al., 1995)

11.4 BAKER HUGHES INTEQ, NORSK HYDRO AND NOWSCO (SLIM-HOLE DRILLING PACKAGE)

Baker Hughes INTEQ, Norsk Hydro and Nowsco UK (Ehret et al., 1995) described results of field trials of elements and procedures which would be required as part of a fit-for-purpose slim-hole floating vessel. The first step in this investigation was to determine whether high-quality cores and electric logs could be obtained using slim-hole technology on a floating vessel, and to drill/core with coiled tubing from a floating vessel. Cores were taken with coiled tubing and with drill pipe. Although several problems were encountered, the technological feasibility of this approach for exploration was demonstrated.

An integrated slim-hole exploration system (including subsea BOPs, risers and small floating vessels) showed significant promise as an economically attractive system for exploration in deep water and/or remote locations. Rising costs in the North Sea have led to serious consideration of alternate exploration paradigms.

A test site was selected off Norway in over 400 ft of water. A semisubmersible rig would be used to drill to 5570 ft with drill pipe and set 7-in. casing. Coiled tubing and drill pipe would be used to drill and core with 4⅛-in. BHAs.

Additional equipment required for the offshore operation included an extra 5⅛-in. pipe ram between the standard triple BOP and 4-in. stuffing box. A drill-string lifting frame (Figure 11-18) was also devised. This connects the rig heave-compensation system to the injector. The frame had to be extended for planned operations.

Subsea well control was maintained with a standard 18¾-in., 15,000-psi BOP. A 7-in. riser was run inside the existing (21-in.) riser for coiled-tubing operations. The smaller riser increased annular velocities and decreased the tendency for buckling.

Coiled-tubing fatigue was a concern with respect to rig heave. Continuous small-scale pay-out and reel-in of the tubing might dramatically shorten fatigue life. This potential was addressed by reducing the operational pressure of the hydraulic motor on the tubing reel. This decreased tension on the reel and introduced slack (about 9 ft) into the tubing wraps.

Two-inch coiled tubing was selected for the operation based on fatigue and pressure loss estimates. Pressure-loss modeling was inconclusive based on the ether-based drilling fluid. A full-scale test was performed for pumping fluid through the spool. Results suggested that the fluid should be maintained at a temperature of about 50°C (122°F). A jetting assembly was added to the circulating system for pumping and shearing the fluid to increase its temperature.

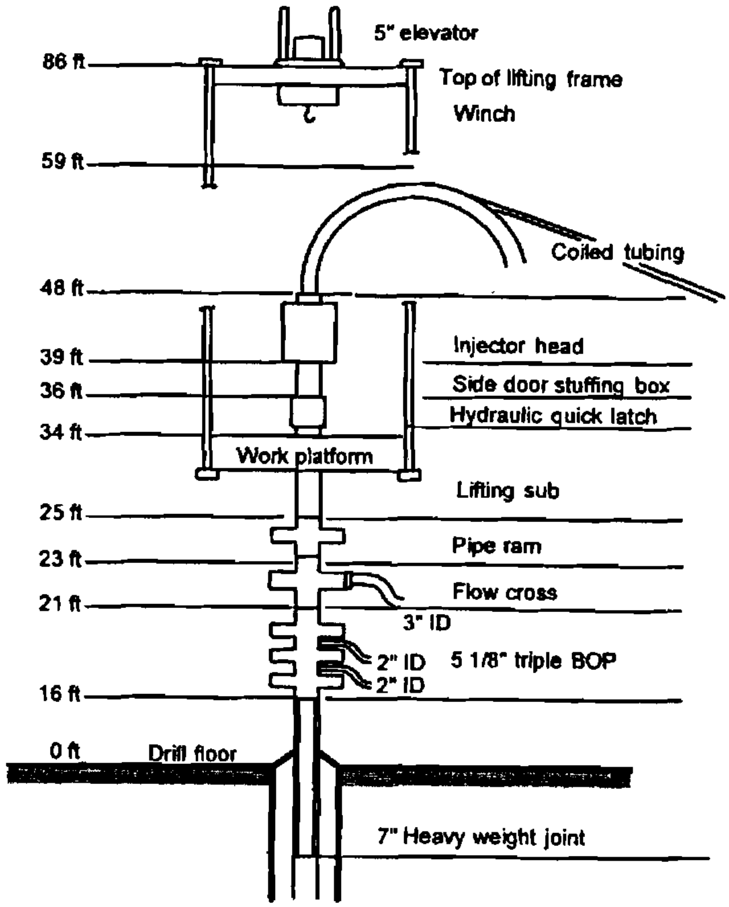


Figure 11-18. Drill-String Lifting Frame for CT Operations (Ehret et al., 1995)

Pressure losses within the coiled tubing dictated that maximum flow rates be maintained at about 80 gpm. This was much less than the 185-gpm allowable flow rate for the 3¾-in. mud motor. The motor was tested at a range of flow rates (Figure 11-19). Results showed that the motor could deliver 1000 ft-lb at 80 gpm and 1050 psi. This was determined to be sufficient for this operation.

A 3½-in. core barrel was selected (delivers a 1¾-in. core). Aluminum was chosen for the inner tubes for its reduced friction and ease of handling on the rig floor. Three different core bits were used, including ballaset and PDC bits.

After the 7-in. casing shoe was drilled out at 5525 ft, two coring runs were made on drill pipe to establish an operational reference for coiled-tubing runs. Several coring runs were completed (Table 11-4). Recovery was generally low due to junk, fissile shales, unconsolidated sands, core jamming, washing of the core, and plugged nozzles. Recovery efficiency did not increase until the final runs, where the improvement was largely attributed to increasing hardness of the formations.

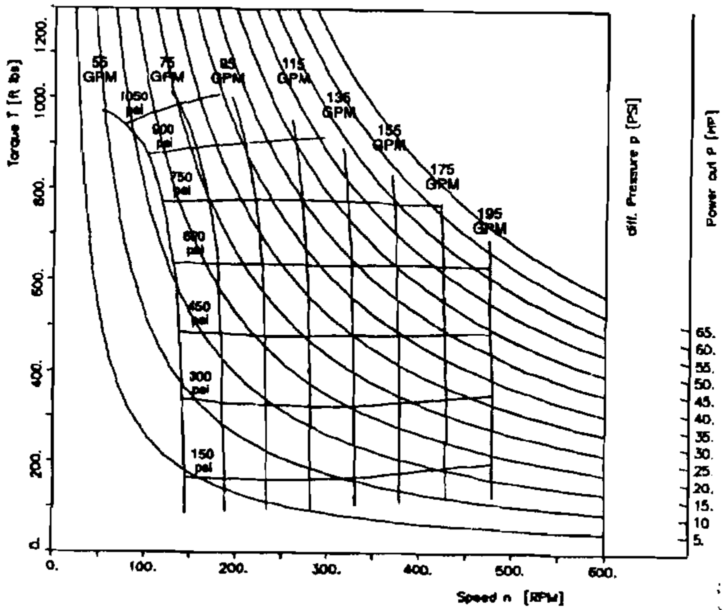


Figure 11-19. Motor Performance Tests (Ehret et al., 1995)

TABLE 11-4. Coring Performance (Ehret et al., 1995)

Core No	DP/ CT	From - To (ft)	Recovery	Avg ROP (ft/hr)	Flow (gpm)	WOB (lbf)	Pressure (psi)	Comments
1	DP	5545-5574	8.9%	5.2	80	1100-2200	1450-1550	Junk found in barrel
2	DP	5574-5584	33%	8.9	80	1100-2200	1390-1670	Jammed off core, motor stalling
3	CT	5584-5614	0.4%	16.4	58	7000-8000	2090-2450	Found Steel junk on Top of Core
4	CT	5643-5670	23%	20.2	60	3000-8000	2750-2840	Barrel jammed
5	CT	5670-5683	8%	15.6	60	4000	2600	Steel junk. Corehead damaged
6	DP	5732-5747	75.5%	30.8	60	2000	1300-1550	Good run
7	DP	5747-5775	54%	45.4	66	1100	1390-1600	Washed down from csg shoe
8	DP	5775-5804	0%	14.8	87	900-2000	1410-1570	3 plugged nozzles
9	DP	5804-5834	35%	19.7	66	0-2000	1420-1580	Wash down assembly
10	DP	5834-5863	44.4%	21.1	66	0-2000	1450-1550	Wash down assembly
11	DP	5863-5893	81.7%	29.5	66	0-2000	1277-1520	Good run
12	DP	5893-5922	93.3%	15.5	66	0-2000	1277-1490	Good run

Project members found that core quality was generally high even though recovery efficiency was low. Lower flow rates (about 66 gpm) provided the best recoveries. The average coring rate was 15 ft/hr compared to an average drilling rate of 40 ft/hr. Performance of the mud motor was better than expected.

Baker Hughes INTEQ, Norsk Hydro and Nowsco UK found that the effectiveness of the coiled-tubing operations could be greatly improved by a built-for-purpose heave-compensation system.

11.5 BPX COLOMBIA AND BAKER HUGHES INTEQ (COLUMBIAN WELLS)

BPX Colombia reported (*Downhole Talk* Staff, 1995) successful slim-hole operations in Columbia in which a Baker Hughes INTEQ thruster (see section 11.2) was used in a deep 3¾-in. hole. A slim-hole contingency option was used to continue a well below the 6-in. shoe. BPX found that the motor/thruster system helped minimize surface manipulation of the drill string, thereby avoiding the common problems with string failures at the depths being drilled (14,000-17,000 ft).

On the Cupiagua C-4 well, a major fault was encountered in 6-in. hole after drilling 2245 ft. BPX decided to set 4½-in. liner and continue drilling with a 3¾-in. BHA including a thruster. An additional 784 ft of hole were drilled without serious problems. A basic suite of logs was run in the slim hole.

11.6 MARATHON AND HUGHES CHRISTENSEN (PERMIAN OPERATIONS)

Marathon Oil Company and Hughes Christensen Company (Tank et al., 1996) summarized developments in bits, motors, and drilling procedures that have reduced costs in the Permian Basin. Slim roller-cone bits have played an important role in slim-hole horizontal drilling applications. Several wells have been drilled with 3⅞-in. roller-cone bits on new 3⅛-in. PDMs. New equipment and optimized procedures have reduced per-foot costs by over 50%, increased total penetration per bit, and increased wellbore displacement.

In previous operations with marginal development in the Permian Basin, slim-hole designs were used in horizontal re-entries. Reduced ROPs were seen with earlier systems, and the cost advantages of a slim hole were often offset by longer drilling times. However, with new optimized systems, ROPs were nearly doubled.

A typical bit (Figure 11-20) is as short as possible to enhance directional capability.

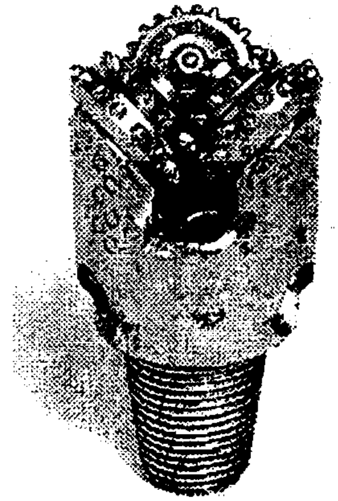


Figure 11-20. Short-Body 4¾- in. Bit
(Tank et al., 1996)

Motor designs have been improved by lengthening the housing of the build section (Figure 11-21). This modification proved to enhance the positional stability of the BHA.

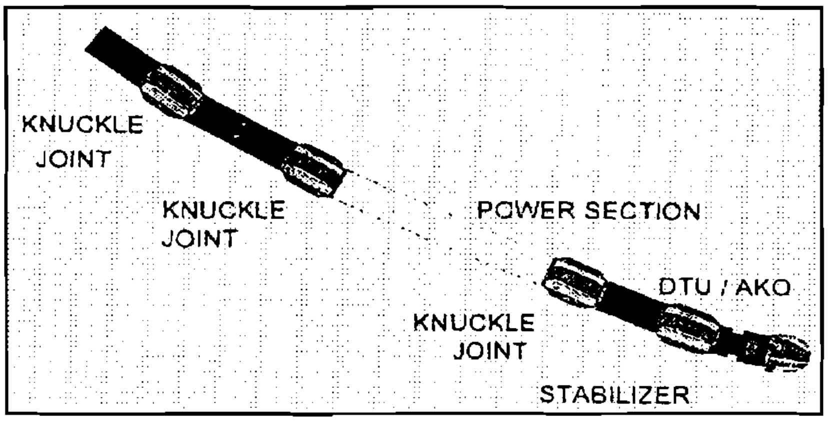


Figure 11-21. Typical PDM in Permian Basin (Tank et al., 1996)

Slim-hole motor specifications are summarized in Table 11-5. Improvements in the motor have been shown to increase average ROP from about 30 ft/hr to 60 ft/hr.

TABLE 11-5. Slim PDM Specifications (Tank et al., 1996)

Specifications for Typical Motor Used in the Yates Field Unit							
Motor Size	Bit Size	Design Radius	GPM	RPM	Temp Limit	Diff. Pressure	Max Oper. Torque
3⅛"	3⅞ - 4⅛"	60' - 100'	90 - 120	182 - 365	260F		400 ft lbs
3¾"	4½" - 4¾"	40' - 100'	150 - 185	210 - 370	260F	683 psi	679 ft lbs

Drilling performance has also been improved by using a thinner drilling fluid. Operators have reduced the concentration of biopolymer, resulting in increased turbulence downhole and improved cuttings removal.

The use of intermediate-radius profiles has allowed greatly increased lateral reach. Average displacement has increased from 488 ft to 1300 ft. Marathon saved over $100,000 on each of three intermediate-radius horizontal slim-hole re-entries. These new profiles have reduced the number of correction runs needed. Longer runs have been enjoyed, along with faster ROPs and less formation damage.

Additional information is presented in *Bits*.

11.7 NORSK HYDRO, NORSKE SHELL AND MERCUR SUBSEA (SLIM-HOLE DRILLING FROM LIGHT VESSEL)

Norsk Hydro Production, A/S Norske Shell, and Mercur Subsea Products (Carstens et al., 1996) described the design of a slim-hole drilling vessel to be used for reducing costs at 5000-ft water depths. The vessel is dynamically positioned and fully heave-compensated for tripping and drilling. A high-pressure riser is used, eliminating the need for kill and choke lines. They analyzed the market for such a vessel and determined that the greatest potential is for subsea well intervention and exploration drilling in deep water.

The size of rigs for deep-water operations is strongly impacted by the need for storing long and heavy strings with buoyancy material. A reduction in riser weight would allow a large reduction in rig size. However, slim-hole floating vessels have generally showed low efficiency due to the lack of adequate heave compensation, which does not allow fine control of WOB.

Norsk Hydro previously drilled a 4⅛-in. section in similar conditions. Based on these experiences, a slim-hole well design was developed (Figure 11-22).

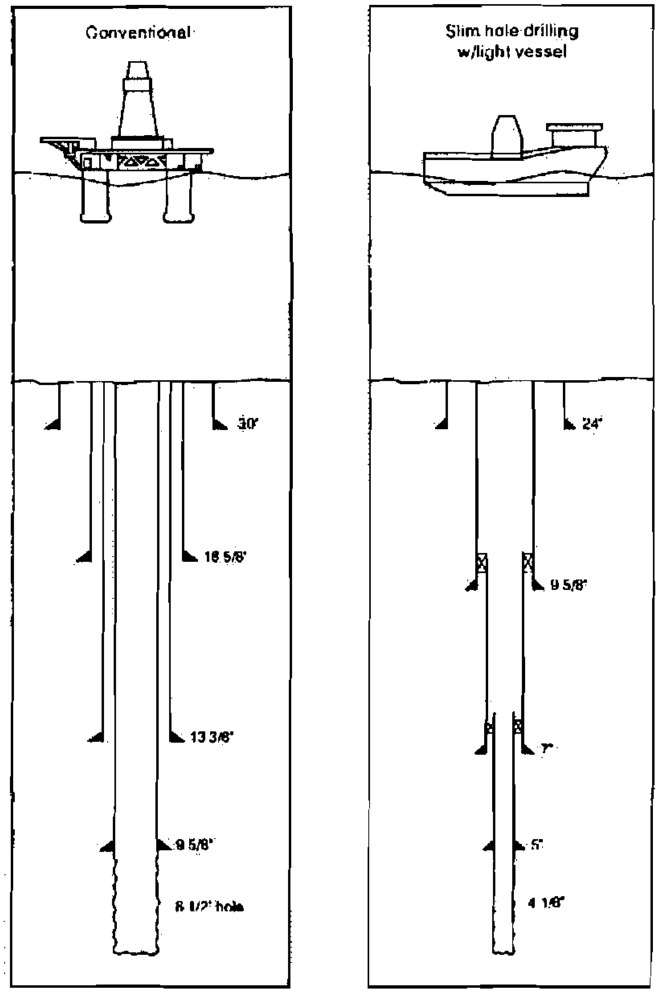


Figure 11-22. Slim-Hole Design for Light Vessel (Carstens et al., 1996)

Using a high-pressure riser allows kick control to occur from the surface. Kill and choke lines are not used, and the riser weight is only about 17% of a standard 21-in. system.

A subsea BOP is provided (Figure 11-23) but used only if the riser disconnects in an emergency drive-off situation. The subsea BOP is fitted with rams for drill pipe and coiled tubing. A fail-safe subsea multiplex control prevents well control from being lost. A weak link is fitted above the subsea BOP.

Since the vessel remains in position, the telescopic joint is not required. A swivel is used instead.

A ⅜-scale model was built to analyze rig operations and efficiency of pipe handling. Two pipe-handler arms were found to be able to deliver made-up pipe as fast as it could be run.

System costs and operating expenses are estimated in Table 11-6.

TABLE 11-6. Costs of Slim-Hole Drilling System (Carstens et al., 1996)

System Cost and Time-Dependent Operational Cost	
Dynamically positioned NMD class 3 vessel.	
Heave-compensated rig.	
9" bore 10000 PSI riser.	
Rated for 5000 ft water depth and 16000 ft drilling depth.	
Delta-Shaped Mono-Hull Vessel (Ramform)	
Total Investment Cost	:70 mill US $
Total Daily Cost*	:90 000 US $
Mini Semi-Submersible	
Total Investment Cost	:100 mill US $
Total Daily Cost*	:120 000 US $

*Daily cost includes third party services, logistics and overhead for operation in 5000 ft. water depth in Norwegian waters.

Norsk Hydro performed a time analysis comparing slim-hole light-vessel costs with conventional. They assumed that slim-hole drilling is slower than conventional drilling. They then calculated the time factor for break-even costs for the slim-hole approach. These data (Table 11-7) suggest that a mono-hull light vessel could require 2.3 times more days on location and still break even.

TABLE 11-7. Drilling Time for Break-Even Costs (Carstens et al., 1996)

Break Even Cost Factors for 5000 ft. Water Depth	
Time-Dependent Daily Costs in Norwegian Waters:	
Conventional Operation	:210 000 US $
Light Mono-Hull	:90 000 US $
Mini Semi-Sub	:120 000 US $
Time consumption factor on a well that gives equal cost:	
Light Mono-Hull	:210 000/90 000 = 2.3
Mini Semi-Sub	:210 000/120 000 = 1.7

The project team concluded that slim-hole drilling from a dynamically positioned light vessel is a feasible option for offshore operations to depths of 5000 ft. A significant reduction in costs is possible. Primary savings are in the use of a high-pressure riser and full heave compensation.

11.8 UNIVERSITY OF TULSA (SLIM MOTOR DESIGN)

The University of Tulsa and the University of Alabama (Sanchez et al., 1996) presented a study on the torque and flow-rate requirements for slim-hole motor drilling, including PDMs, turbines and electric motors. They addressed the potential minimum diameter for slim motors while still satisfying drilling power requirements. Modeling results demonstrated that currently available motors are capable of producing more torque than is required for drilling horizontal sections.

Sanchez et al. considered torque, horsepower and required flow rate for selecting motors for short-radius re-entries. The basic wellbore schematic considered is shown in Figure 11-24.

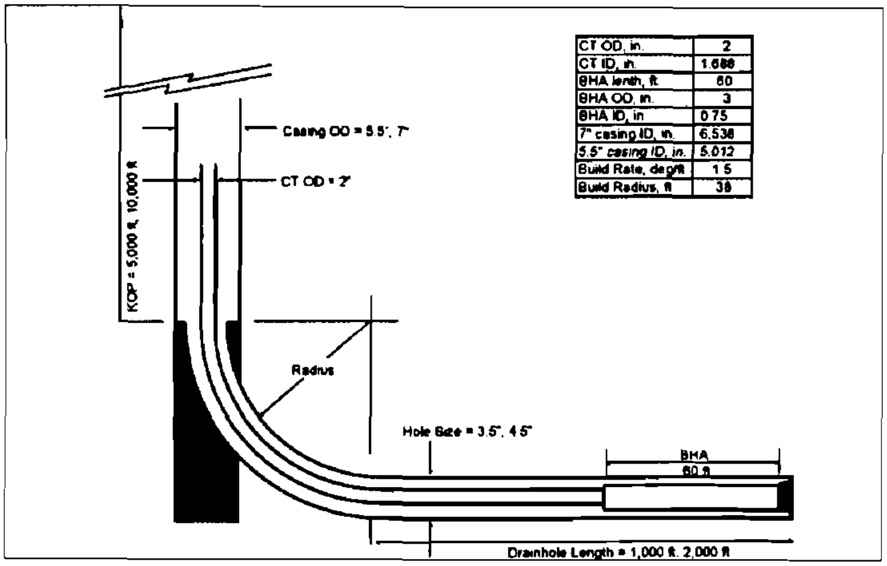


Figure 11-24. Re-entry for Modeling Studies (Sanchez et al., 1996)

Other geometric and parametric data are summarized in Table 11-8.

TABLE 11-8. BHA and Hole Description (Sanchez et al., 1996)

Friction coefficient = 0.1	C1 = 1.9
Bit diameter (in) = 4.5	C2 = 8.1
Hole diameter (in) = 4.5	ROP (ft/hr) = 30
BHA OD (in) = 3	N (rpm) = 500
BHA ID (in) = 0.75	Formation const. = 1E-05
BHA Volume/1ft (ft^3) = 0.046	BHA Weight (lbs/ft) = 22.14
BHA Density (lbs/ft^3) = 481	Clearance (ft) = 0.0625
Moment of inertia (ft^4) = 0.0001	
E (Young's) (lbs/ft^2) = 4.3E+09	Parabolic distribution of Fs

Results suggested that fluid flow rates of 500-1000 scfm are required for drilling these re-entries. For muds, the critical velocity ranges between 90 and 120 ft/min in vertical wells, with a safety factor of 2 to 4 required in horizontal wells. Flow rates to meet these criteria are shown in Table 11-9. About 160 gpm are needed to clean the horizontal annulus, which is not sufficient to clean the larger vertical section. Almost 220 gpm are required.

TABLE 11-9. Mud Flow Rates for Hole Cleaning (Sanchez et al., 1996)

Vertical Section						
Hole OD (in) =	7	7	7	5	5	5
String OD (in) =	2	2	2	2	2	2
Annular area (in^2) =	35	35	35	16	16	16
Assumed Vmin (fpm) =	90	105	120	90	105	120
Flow rate (GPM) =	165	193	220	77	90	103
Horizontal Section						
Hole OD (in) =	5	5	5	4	4	4
String OD (in) =	2	2	2	2	2	2
Annular area (in^2) =	13	13	13	6	6	6
Assumed Vmin (fpm) =	180	120	240	180	210	240
Flow rate (GPM) =	119	139	159	61	71	81
BHA						
Hole OD (in) =	5	5	5	4	4	4
String OD (in) =	3	3	3	3	3	3
Annular area (in^2) =	9	9	9	3	3	3
Assumed Vmin (fpm) =	180	210	240	180	210	240
Flow rate (GPM) =	83	96	110	24	28	32

Several parametric studies were conducted for turbine design in slim-hole applications. The relationship between turbine speed and required rotor radius (Figure 11-25) shows that a 150-stage motor running at 150 rpm requires a rotor radius of less than 1 inch. Even smaller motors could be designed with higher flow rates or more stages.

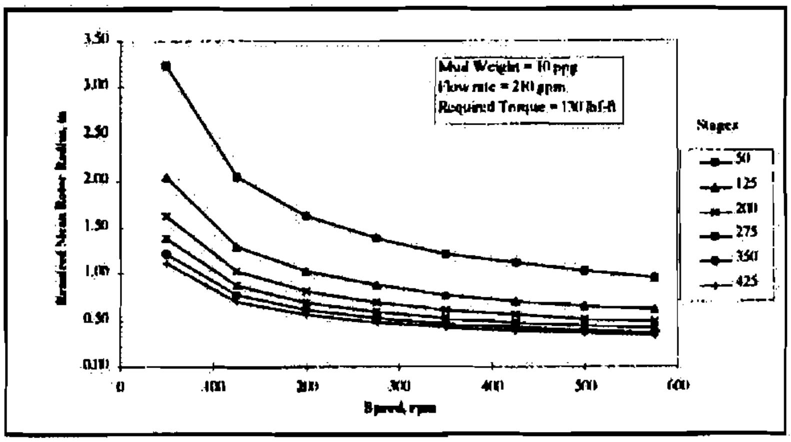


Figure 11-25. Turbine Speed and Rotor Radius (Sanchez et al., 1996)

The constraints of short-radius drilling dictate that the lowest possible number of stages be used so that the assembly can pass through the curve. Sanchez et al.'s analyses suggested that a slim turbine motor could have between 50 and 300 stages and could be run at speeds ranging from 200 to 500 rpm.

PDM design would probably focus on a 1:2 lobe configuration to maximize rotary speed for the assumed low WOB for slim-hole drilling, particularly with coiled tubing. The relationship between shaft diameter and speed is shown in Figure 11-26.

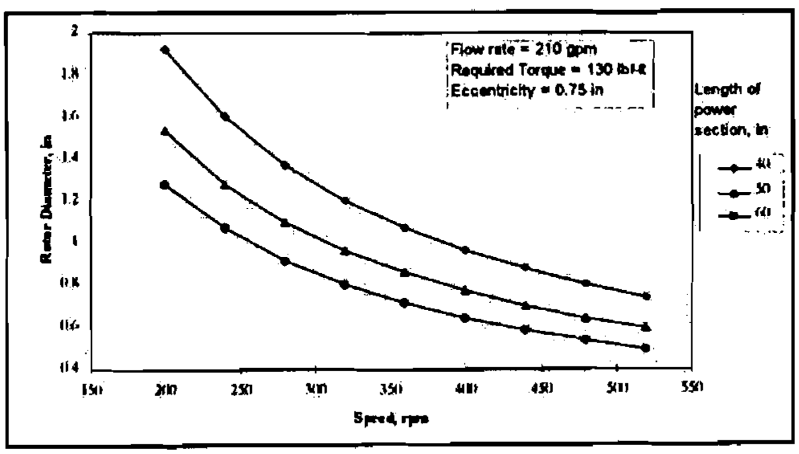


Figure 11-26. PDM Speed and Rotor Diameter (Sanchez et al., 1996)

The results of a recent study on the feasibility of electric motors for coiled-tubing drilling (conducted by CTES and sponsored by GRI) suggested that electric motors as small as 4¾ in. are feasible, running at 1200 to 3600 rpm. A gear box would probably be needed to lower bit rpm. Power output can be as great as 80 HP and torque as high as 160 ft-lb.

11.9 REFERENCES

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12. Overview

12.1 GAS RESEARCH INSTITUTE

The Gas Research Institute (Weiss, 1995) summarized its basic research plans for promoting slim-hole technology to the gas (and oil) industry. Gas wells and slim-hole techniques have been found to be an effective combination. Artificial lift represents the most significant drawback, although fortunately, it is not required in most cases.

GRI funded a study to identify barriers to slim-hole technology. (That study was conducted by Maurer Engineering; a copy of the final report was presented to DEA-67 Participants as an addendum to *Slim-Hole Technology (1994-1995)*.) The basic level of technology development was found to be generally adequate. Primary hindrances are concern about risks and cost of the learning curve.

Most operators reaping slim-hole benefits in drilling gas wells are actually drilling conventional holes and completing them with slim casing/tubing. The reasons for avoiding slim drilling include bit availability, concerns about mud motor performance, and drill-string limitations/considerations. Marginal anticipated flow rates drive the use of slim completions to save money.

Among the next steps in GRI's plan is the funding of slim-hole drilling and completion projects and the dissemination of the results through technology transfer. OGCI will play a major role in this phase of the process.

12.2 JOURNAL OF PETROLEUM ENGINEERING (PROSPECTS FOR SLIM HOLES)

A discussion of prospects for slim-hole technology within the oil field was presented in *JPT* (*JPT* Staff, 1995). Comments from several proponents and players in the modern slim-hole drilling/coring market were summarized. In general, the future for several companies' purpose-built rigs and slim-hole projects (that is, remote coring operations) was not bright, based on the current activity levels.

Several rig manufacturers have made offerings to the slim-hole coring market. Longyear Company (out of Salt Lake City) closed its slim-hole division in 1995. The 100-year old company (primarily mining technology) entered the slim-hole oil-field market in 1984 and participated in several remote coring projects over the years. Longyear, which was involved early with Amoco and the SHADS development of the late 1980s, departed from the slim-hole coring market due to 20% utilization rates for their three purpose-built rigs. For example, Amoco's current emphasis is on the use of smaller oil-field rigs to address slim-hole issues.

Nabors Drilling bought the SHADS rig, modified it into Rig 170, and built a second purpose-built rig for a remote campaign in Venezuela (Figure 12-1). They drilled nine wells with the rigs. (More details

Nabors Drilling bought the SHADS rig, modified it into Rig 170, and built a second purpose-built rig for a remote campaign in Venezuela (Figure 12-1). They drilled nine wells with the rigs. (More details on this campaign are presented in *Coring Systems*.) Although there was significant interest in these rigs from most of the majors during the Venezuelan campaign, no new contracts were forthcoming.

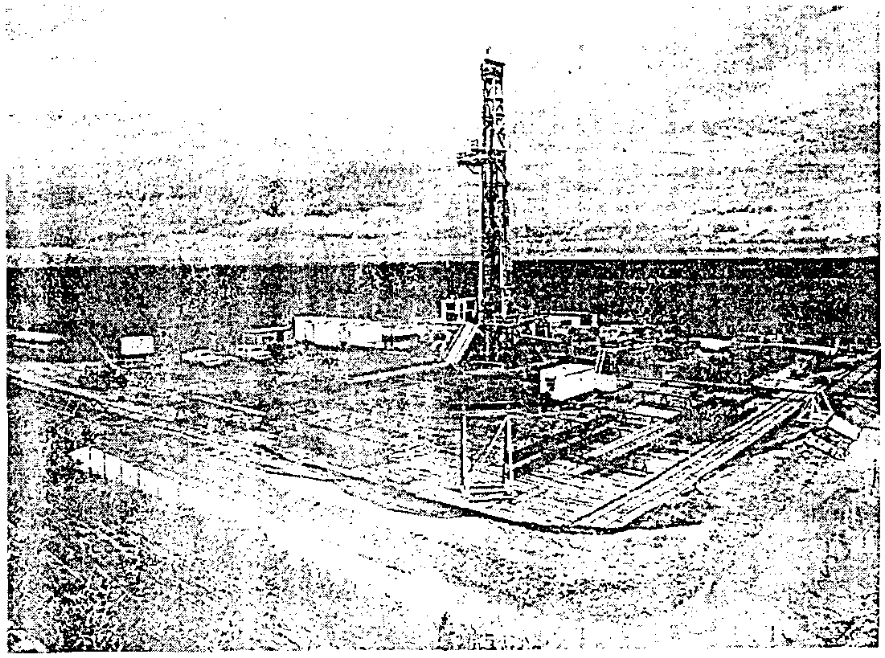

Figure 12-1. Nabors Slim-Hole Rig (*JPT* Staff, 1995)

Parker also offered a slim-hole rig based on a modified conventional rig with a slim-hole top-drive assembly. Parker's oil-field coring business has also been characterized as on-again, off-again, despite their successes in the field.

Reasons for slim-hole drilling/coring technology not being embraced by the industry include the lack of interest in many companies in extensive coring. Some project leaders believe that all necessary information to appraise a well is available from electric logs.

Contingency limitations are high on the list of objections to slim holes. Slim-hole advocates counter that the costs to support a contingency habit are too high. For example, if 5% of wells need to make use of the contingency, and the slim-hole option is 30% cheaper than conventional, overall economics usually do not support the use of this type of insurance.

Changing E&P strategies among the majors are also playing a role. Many have significantly decreased the number of remote wildcats, adding more established acreage to their portfolios. The appeal of deep-water plays near infrastructure has caused some to direct their exploration capital toward offshore areas rather than to the jungle.

An abundant supply of conventional land rigs at depressed day rates also hinders slim-hole usage. Lower cost purpose-built slim (non-coring) rigs are being developed to address these market issues. Among them is the Kenting Drilling Services Ltd. rig (Figure 12-2), which was built from standard components at a 20% savings over conventional rigs.

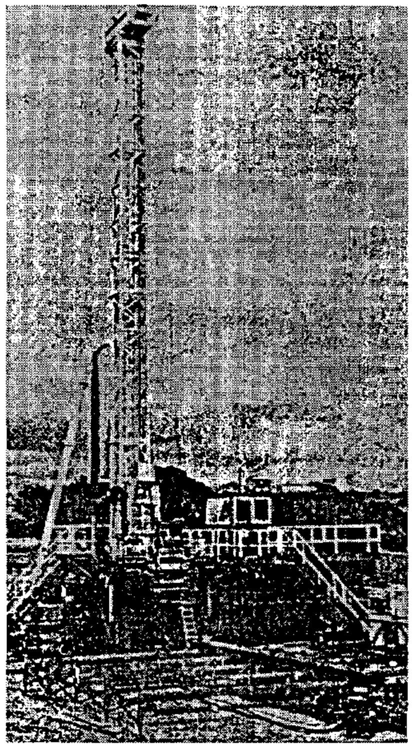

Figure 12-2. Kenting's Slim-Hole Rig (*JPT* Staff, 1995)

12.3 MINING UNIVERSITY OF LEOBEN AND RDS (SLIM-HOLE OVERVIEW)

The Mining University of Leoben and RDS (Millheim et al., 1995) presented a summary of the history and status of slim-hole technology for oil-patch drilling. They believe that the technology is highly under utilized and that 70-80% of all wells drilled could be drilled with some type of slim-hole system. They considered the factors and dynamics that drive the acceptance and development of new technologies (such as slim hole) within the industry and within individual companies. A summary of the major (published) operations and cost savings is shown in Table 12-1.

TABLE 12-1. Slim-Hole Projects (Millheim et al., 1995)							
	Companies	**Remarks**	**Location**	**Rig**	**Depth**	**Diameter**	**Savings**
(a)	Amoco	drilled 40000 ft of continuous core in the US during 1987-89, explains the concept of SHADS	Upper Peninsulae, Michigan Western Kansas Southern Colorado West Texas	mining type SH rig	2206 m 1815 m 624,951 m 2931 m	6 in. 4¾ in. and $3^{1}/_{16}$ holes	n.a.
(b)	Texaco	continuous coring project overall core recovery 99.4%	Parana basin, Paraguay	Longyear PM 603	2987m	$3^{1}/_{32}$ in hole CHD 76 rod	$3.6 Million total costs, including core analysis (25% savings)
(c)	Shell, BBB, Bastman Teleco	drilled 46 wells destructively used "a lot in and think" method of well control	5 countries 15 wells in Germany with BBB	'Retrofit' rigs with soft tourque' rotary table or top drive, mud motor thruster	3838 - 5382 m in Germany	5⅞ in, 8½ in holes initially 4⅛ in as confidence growed	drilling costs per meter reduced by 19 - 41% for 4⅛ in wells, total well costs versus depth below trend of conventional well
(d)	Oryx	slimhole technology for horizontal wells and re-entries, destructive drilling, compared slim, reduced and large holes	Pearsall Field, South Texas	re-entries: 1990: workover rig 1991: coiled tubing new slim holes: small conventional rig for vertical, workover rig for horizontal sections	re-entries: av. 603 m new slimholes: 2955m vertical 961 m lateral	re-entry: 3⅞ in. new slimhole: 4¾ in.	A) total cost index B) lateral cost/ft index re-entries savings: 1990: a)0.85 b) 1.72 1991: a)0.50 b) 0.79 new slimhole savings: a) 0.66 b) 0.73
(e)	Asemera	5 wells drilled in remote-swamp area, continuous coring applied	South Sumatra	Longyear HM55 SH heli rig	>1186m	3⅞ in hole and 2⅜ in production casing	$9.52 Million Estimated for 5 conventional wells, $5.94 Million were actual SH costs (40% savings mainly due to lower costs for location construction
(f)	Total	2 wells were drilled in tropical rain forest, continuos cored 59% of the total ength drilled	Gabon	Longyear PM 603	2747m and 418m	3 in and 5⅞ in holes	$12.8 Million for 2 wells, 15% savings estimated if conventional well would have no problems
(g)	BP, Exlog, Statoil	slimhole drilling venture was formed, continuous coring applied	Congo	helitransportable SH Rig, n.a.	700 - 2500m	n.a.	40% savings
(h)	BP	4 wells drilled, continuous coring and destructive drilling	Kayes "B", Congo	Parker hybird SH Rig	1132- 2086m	4.8 in hole	40% savings
(i)	Mobil, Oxy	2 wells were continous cored	Pando, Mantripi, Bolivia	Longyear PM 603	1981m 1542m	$4^{1}/_{16}$ in coring assembly	20 - 25% savings
(j)	Amoco	continuous coring and destructive drilling	Creston Nose, Wyoming	Rig No 170	3816m	$3^{1}/_{16}$ in coring assembly	$500,000 (41% savings)
(K)	Union Oil Comp, California	destructive drilled steam injection well	Bakersfield, California	workover rig	n.a.	2⅜ in tubing 6⅛ in hole	50% savings
(l)	Shell, Baker, Hughes Inteq	"Retrofit" SH offshore project, drilled high pressure wells	Offshore North Sea		>3000m	5⅞ and 4⅛ in holes	10 - 15% savings per well
(m)	Forasol/Foramer Diamant Boart Stratabit	Introduction of Euroslim Project		purpose-built SH rig (15, 1994)	project goals: 4000m	project goals: 3 - $3^{11}/_{32}$ in wells	30% in non-remote areas 50% in very remote areas (16, 1993)
(n)	Elf Aquitaine, Forasol	2 "ultraslim" holes were drilled destructive drilling and continous coring applied	Paris Basin, France	fitted for purpose slimhole rig (21, 1994)	2157m and 2160m	3 in hole and 3⅞ in hoe	n.a.

The modern revival of slim-hole technology was driven by at least two major factors: flat oil prices and the need to improve exploration results. Within the last several years, the center of the slim-hole industry has shifted away from the continuous-coring applications and systems that characterized the early efforts in the modern revival. The question of "why drill a slim hole?" should currently be addressed in the context of reducing overall project costs (on a macro scale). When overall project costs are lower than those costs using a conventional project approach, slim holes should be used.

The state-of-the-art options for slim-hole technologies include three major categories:

13. Continuous coring using a mining-type, purpose-built or conventional rig (see *Coring Systems*)

14. Destructive drilling using a mining-type, purpose-built or conventional rig (see *Rotary Systems*)

15. Destructive drilling using a mud motor on coiled tubing or with a rig (see *Motor Systems*)

The perception of risk within a given company is strongly influenced by which of the following applies: 1) slim-hole technology has never previously been considered as an option, 2) slim-hole technology has been considered as an option although not yet used, or 3) slim-hole technology has been previously used. The first group probably assumes that many "common-sense" risks (appropriate or not) apply to slim-hole drilling. The second group assumes a lower level of risk than the first group, although still likely too high. The third group begins to understand that technical and safety risks are no greater than with conventional drilling.

Millheim et al. provided a summary of the approximate risk levels for various slim-hole drilling operations (Table 12-2). These comparisons are based on 1=lowest risk to 5=highest risk.

TABLE 12-2. Slim-Hole Risk Factors (Millheim et al., 1995)			
	Conventional System	Slimhole Systems	With More Research and Development
Drill Rig Design	1	2-3	1-2
Well Control	2-4	2-3	1-2
Logging	1-2	2-3	1-2
Cementing	2-4	3-4	2-4
Solids Control	1-3	1-2	-
Drilling Fluids	2-4	3-4	2-4
Drill Pipe	1	3-4	2-4
Mud Motors	1-2	1-2	-
Directional Drilling	1-2	1-2	-
Lost Circulation	1-3	2-4	1-3
Well Testing	2-5	2-4	1-3
Wellbore Stability	2-4	2-4	1-3
Completion	1	3-4	1-2
Fishing Operation	3-5	2-4	1-3

Average Risk Factor based on Conventional Drilling Practices: 1 lowest, 5 highest

Technological areas in which Millheim et al. suggest the need for research and development include the following:

- Drill-string dynamics and vibration are not yet well understood
- Hydraulics algorithms are needed for predicting pressure profiles as related to pump rates, rotation, annular clearance and mud properties
- Fatigue life of slim drill string is not well understood
- Work is needed to determine why slim-hole ROP is not faster than conventional, and how to address this potential

Other areas (cementing, small mud motors, lost circulation, well testing and fishing) are considered to be no more difficult than in conventional holes.

To develop additional understanding of the processes of risk assumption and analyses, Millheim et al. borrowed theory from systems technology and developed representative causal loops for slim-hole risk. A basic reinforcing positive feedback loop (Figure 12-3) shows how new technologies such as slim holes are directly driven by cost benefits. As more slim holes are drilled, more cost benefits are quantified, more proponents for the technology arise, and the need for more equipment and processes is met by the industry. Consequently, more holes are drilled, etc. The result of this type of group behavior is an exponential growth curve.

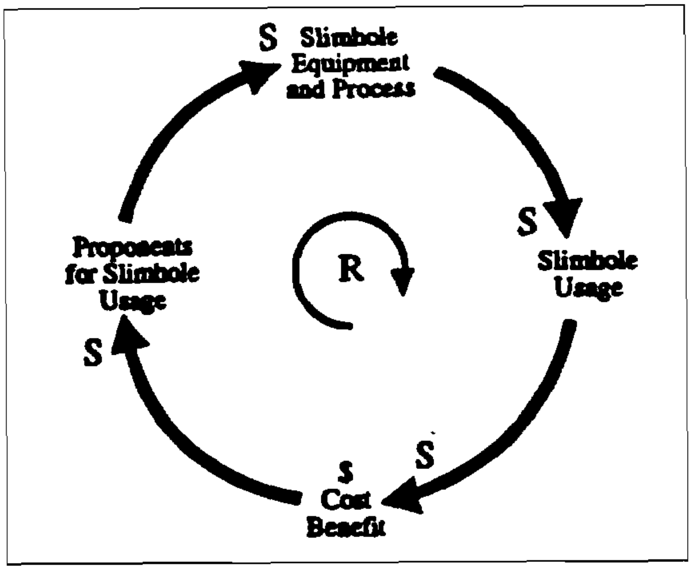

Figure 12-3. Reinforcing Positive Feedback Loop for Slim Holes (Millheim et al., 1995)

The adoption of slim-hole technology is, of course, not explained by the feedback loop alone. A balancing loop indicates the impact of risk assessment and perception among the users (Figure 12-4).

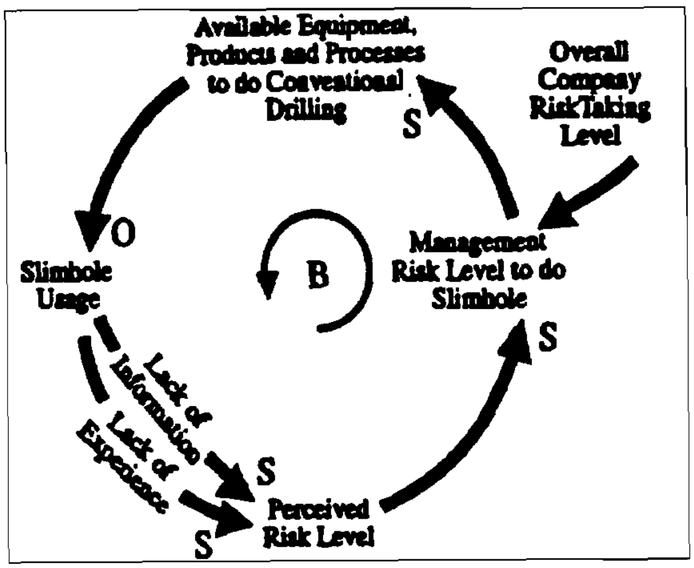

Figure 12-4. Balancing Loop for Slim-Hole Risk (Millheim et al., 1995)

A more accurate picture of the growth of the use in slim-hole technology across the industry and in an individual company is seen by combining these two curves (Figure 12-5). Exponential growth of slim-hole technology from the left loop is tempered by risk management in the right loop. Of note is the input of the conventional contractor to the risk assessment loop. This input generally strengthens management's risk aversion and increases the level of comfort with conventional approaches. Understandably, contractors are not normally inclined to invest in R&D of new systems unless forced to do so.

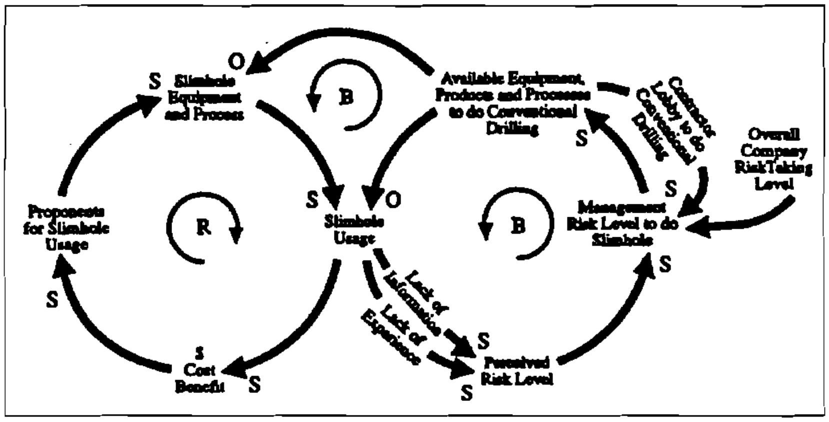

Figure 12-5. Causal Loops for Growth in Slim-Hole Technology (Millheim et al., 1995)

Other factors arising from outside of the realm of slim-hole technology may influence (speed) its growth. Millheim et al. mentioned the outside forces of environmental pressure and profit accountability. Slim-hole technology is able to address increasing environmental pressures and concerns. The drive to reduce costs may also serve to overcome established levels of risk aversion within an organization and result in greater slim-hole usage than would normally occur.

Millheim et al. also listed factors that will increase the usage of slim-hole technology in the future:

- Continued pressures to reduce costs
- Engineers' acceptance of simpler well completions
- More re-entries out of old wells
- Continued environmental pressures
- Greater use of continuous coring
- Retirement of old rigs and equipment
- Entrance of new contractors into the market

- More publications describing successful projects
- Flat oil prices
- New slim-hole completion and production equipment and capabilities

Several factors may slow the growth of slim-hole technology:

- Higher oil prices
- Relaxation of environmental pressures
- Safety regulations structured to favor larger wellbores
- A lack of experienced engineers
- A lack of required equipment and products

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13. Rotary Systems

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13. Rotary Systems

13.1 AGIP AND SAIPEM (INNOVATIVE SLIM-HOLE RIG)

AGIP SpA and SAIPEM SpA (Schenato et al., 1995) developed and tested concepts for the design of an innovative rig for slim-hole operations in marginal gas fields on and offshore. AGIP sought ways to develop several candidate fields that are not economic with conventional technology. The new rig design was directed toward reducing dimensions and volumes, have high mobility, require fewer personnel, as well as other innovations. Targeted cost reductions of 30-40% were sought. Other objectives were fast mob/demob, reduced loads, fewer personnel, and increased operational flexibility. Concepts were tested and verified using a converted water-well rig to drill a series of three wells.

A large number of gas fields have not been exploited due to relatively small reserves (a few hundred million m^3) and low production rates (20,000-70,000 m^3/day; 700-2500 Mscfd). Depths range from 1300 to 2500 m (4270 to 8200 ft). AGIP carefully considered the use of modern slim-hole rigs for this application. Their evaluation concluded that these would not be economical because the planned operations were not remote. The proposed efforts would only be viable if operating times and day rates were reduced over conventional.

The approach taken to address this need was to confirm basic concepts for a smaller, more economic rig by modifying an existing rig and field testing the system. The concept rig was a totally hydraulic system used for water wells and soil foundation work. The existing rig was patch-worked together with other elements with minimal investment. Field tests were used to evaluate the economic impact and verify the basic approach and concepts.

To minimize initial investment, only 6-in. final holes (conventional for that area) were used. Two vertical wells and one deviated well were drilled (Figure 13-1), all of which were successful.

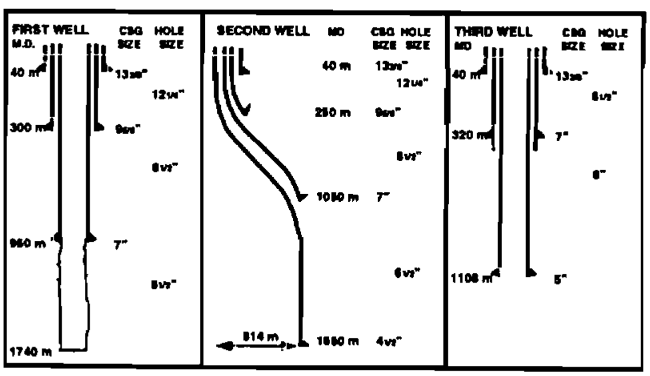

Figure 13-1. Wells Drilled with Prototype Rig (Schenato et al., 1995)

Based on the results of the field trials, a new rig was designed (Figure 13-2). Primary features include total hydraulic drive, hydraulic hoisting equipment (no traveling/crown blocks), weight capacity of 136,000 kg (150 tons), and a vertical pipe-racking system with a jib crane. The hydraulic system allows better control of equipment and easier measurement of drilling parameters (bit position, torque, etc.).

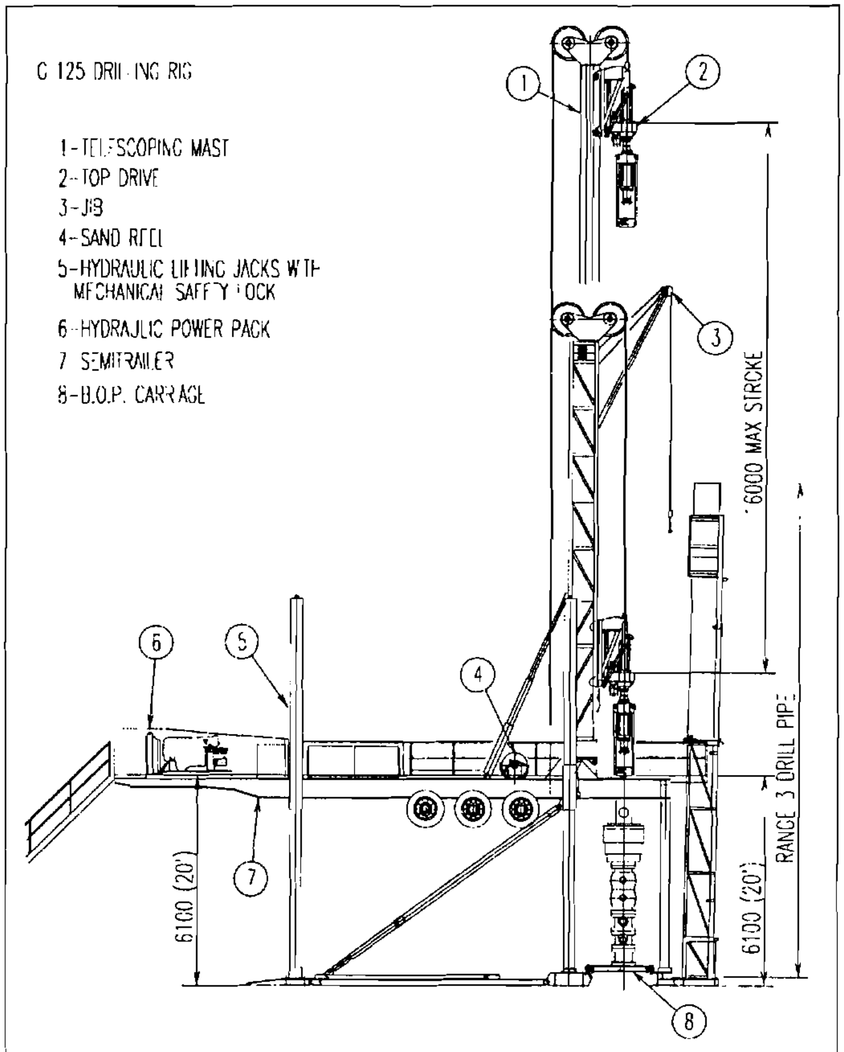

Figure 13-2. Design of New Drilling Rig (Schenato et al., 1995)

The compact rig is mounted on a three-axle semitrailer (Figure 13-3). The top drive is powered by four motors, producing a torque of 3600 kg-m at 60 rpm. Rotary speeds up to 200 rpm are possible. Automatic drilling with either a constant WOB or ROP is available.

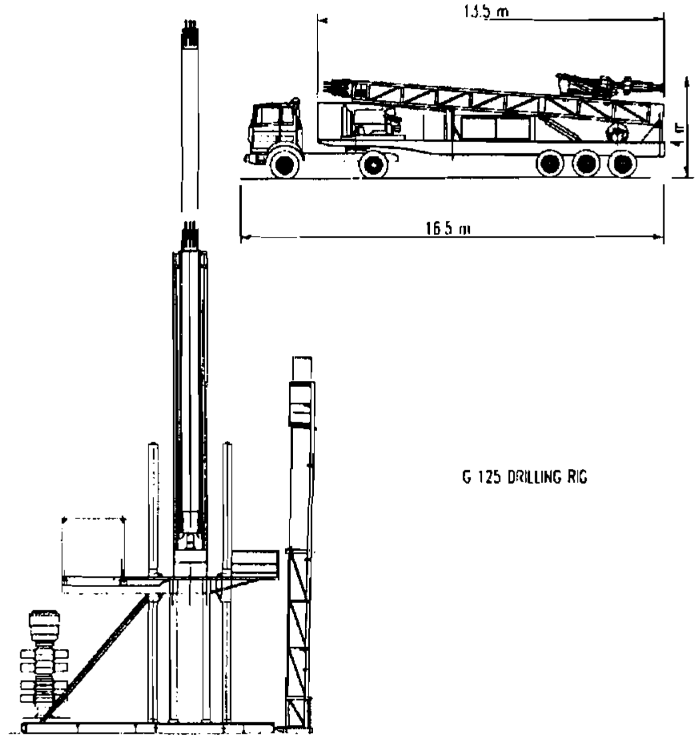

Figure 13-3. Rig Trailer and Side View (Schenato et al., 1995)

Twenty land loads are required to move the system, compared to thirty-five for conventional equipment. Moving and rig-up only requires less than five days, compared to eight for standard systems.

Important lessons learned during the three field tests were incorporated into the final rig design. The field results were generally very positive. On the third well, TD was reached two days less than expected (Figure 13-4).

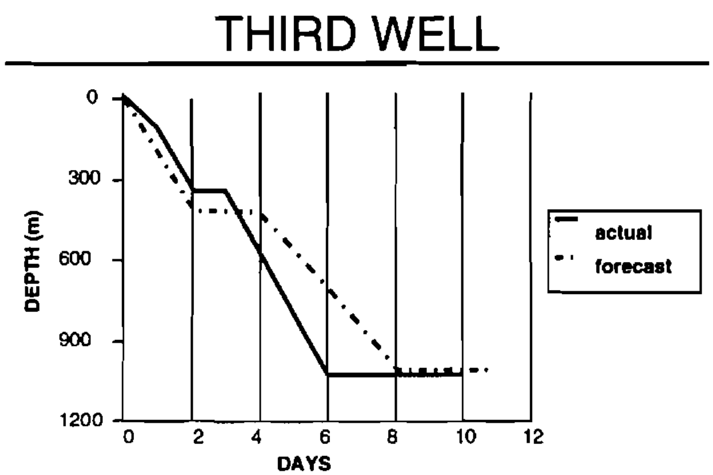

Figure 13-4. Time/Depth Curve for Third Field Trial (Schenato et al., 1995)

AGIP and SAIPEM found the trial results to be very satisfactory for demonstrating the cost competitiveness of the new approach. After the new rig was constructed, other wells are to be drilled. They believe that personnel were well trained on the trials and can efficiently use the new system. They also plan to drill slim holes using monobore and coiled-tubing completions.

13.2 BP ALASKA (THROUGH-TUBING ROTARY DRILLING)

BP Alaska (*Downhole Talk* Staff, 1996) described an innovative drilling operation based on through-tubing rotary drilling of a horizontal sidetrack. A 3¾-in. lateral was drilled to a length of 1478 ft and a 2⅞-in. liner run and cemented. The sidetrack of Prudhoe Bay C-23 was completed at a cost of $1.3 million, about 33% less than a conventional re-entry that includes tubing removal. The lateral was placed on production at over 4000 BOPD (35% above projections).

The original production interval was abandoned by placing a fiber-cement plug across the perforations with coiled tubing. The milling assembly was run through the 4½-in. production tubing tailpipe and a window milled in the 7-in. production liner. After milling, a directional assembly was used to drill the curve at a planned rate of 30°/100 ft. A lateral drilling assembly was then used for drilling the lateral out to 1478 ft.

A 2⅞-in. production liner (flush joint) was successfully run to TD and cemented in place. The same $1^{11}/_{16}$-in. work string was used to run perforating guns in the liner.

The complete wellbore schematic is shown in Figure 13-5.

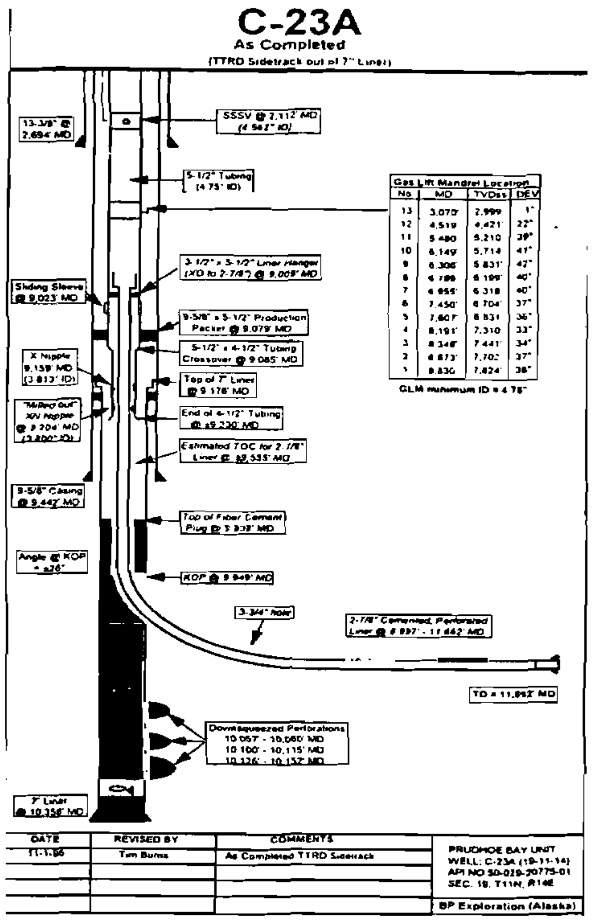

Figure 13-5. C-23 Completion (*Downhole Talk* Staff, 1996)

Important accomplishments and lessons learned in this project include the following: 1) through-tubing rotary drilling is a technically and economically successful procedure, 2) well control in the small annulus requires special attention, 3) torque and drag were lowered with lubricants, 4) build rates up to 50°/100 ft are attainable with current technology, 5) only minimal casing wear was measured in the existing completion, and 6) through-tubing rotary drilling is economically competitive with coiled-tubing drilling.

13.3 FORASOL AND CARREL (REMOTE-CONTROL DRAWWORKS)

Forasol and Carrel (Dupuis et al., 1995) described a new remote-control system installed in the Foraslim slim-hole rig. Two principal design criteria were to design a cabin for the driller that provides good visibility and comfort, and to allow fine adjustment of the drilling parameters such as WOB and ROP. They developed and implemented a remote-control drawworks to satisfy these criteria.

The Foraslim rig was developed to economically address the needs of slim-hole rotary operations based on a smaller purpose-built rig and a newly developed drill string. The rig power is 600/750 HP and depth rating is 11,500 ft. Forasol determined that the driller's cabin should be located away from the drawworks to provide the most satisfactory ergonomics.

A remote-control drawworks system was developed (Figure 13-6) that allows control of pick-up and slack-off speeds via a single joy stick, and without modifying any of the mechanical components of the conventional drawworks. The system includes a single reference controller (the joy stick), several sensors to measure drill-string movement and position, data control and processing by a programmable logic controller, and digital power drives to control the DC motors and brake.

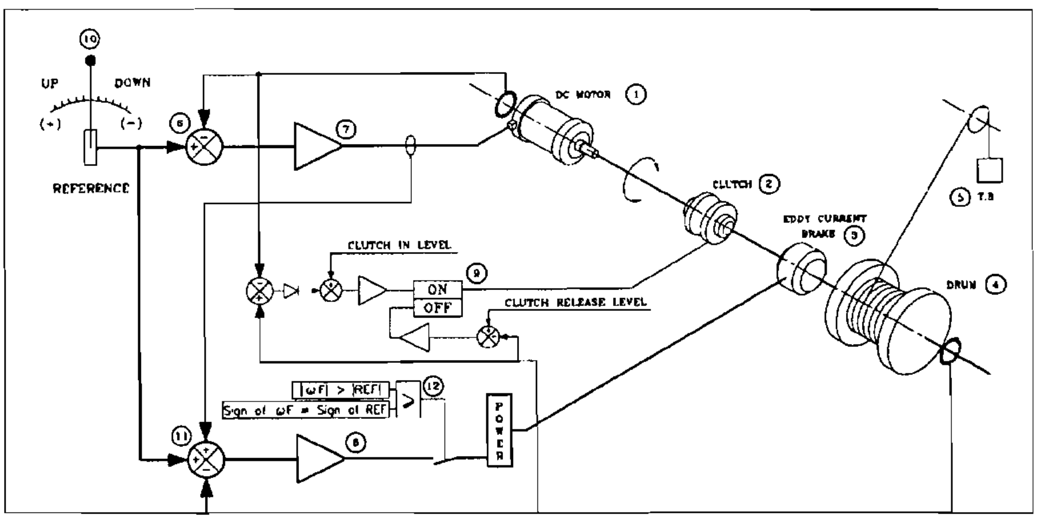

Figure 13-6. Electrical Schematic of Remote-Control Drawworks (Dupuis et al., 1995)

Forasol believes they achieved a major improvement in drawworks control with the new system. The new control system performed well on the first five field trials on the Foraslim rig. Tripping performance (Figure 13-7) was similar to that obtained with conventional controls. This type of system can be adapted to any conventional land rig or offshore unit without major modifications.

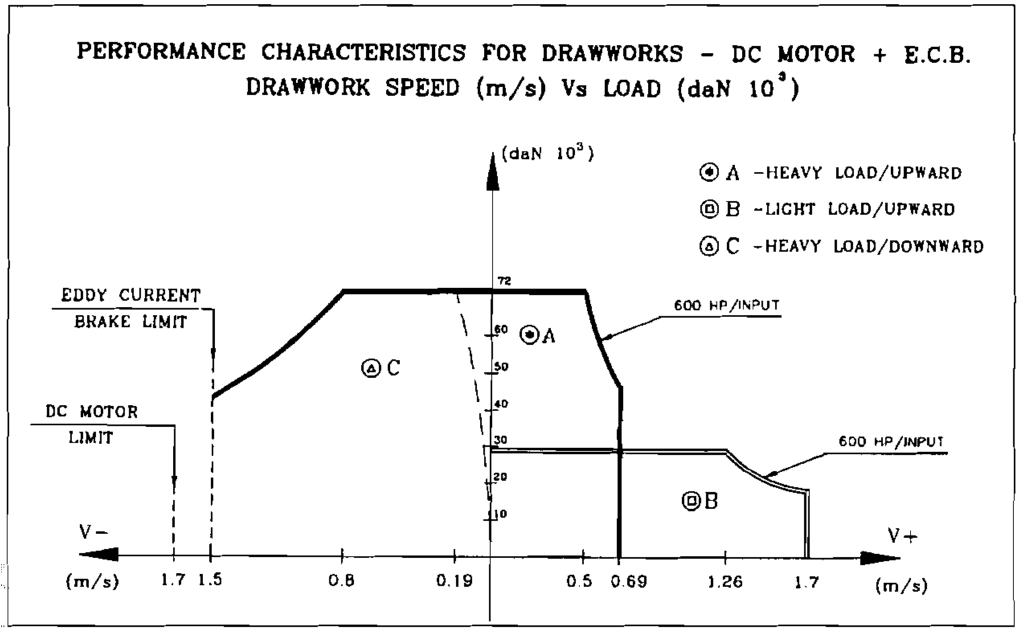

Figure 13-7. Drawworks Performance Characteristics (Dupuis et al., 1995)

13.4 FORASOL AND ELF AQUITAINE PRODUCTION (INTEGRATING SERVICES)

Forasol and Elf Aquitaine Production (Dupuis and Sagot, 1995) described an approach to further lower drilling costs with the purpose-built slim-hole rig Foraslim. By integrating various services into the rig design, service costs can be saved by making use of integrated equipment and the drilling crew.

The principal components of drilling costs are shown in Figure 13-8. Services and operator costs are not highly impacted by slim-hole versus conventional technology.

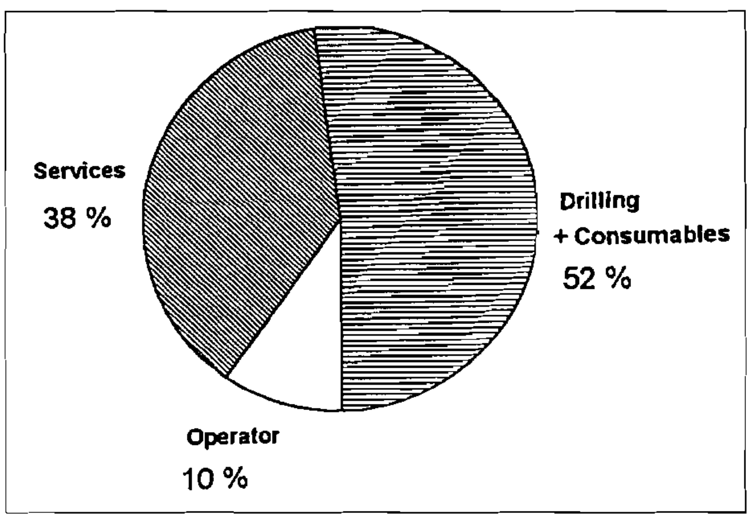

Figure 13-8. Typical Distribution of Drilling Costs (Dupuis and Sagot, 1995)

Primary cost savings in drilling and consumables are achieved through reductions in site size, mobilization costs, civil engineering, and consumables (Table 13-1). Field experience has shown that drilling times are similar for slim and conventional holes.

TABLE 13-1. Volume Reductions in Slim Holes (Dupuis and Sagot, 1995)

	Conventional Well		Slim Hole Well	
	Hole Diameter	Drilled Volume	Hole Diameter	Drilled Volume
Drilling phase 0 to 1500 m	17½"	233 m3	9⅞"	74 m3
Drilling phase 1500 to 2400 m	12¼"	68 m3	6¾"	21 m3
Drilling phase 2400 to 3000 m	8½"	22 m3	4¾"	7 m3
Drilling phase 3000 to 3500 m	6"	9 m3	3⅜"	3 m3
TOTAL		332 m3		105 m3

Forasol and Elf considered how to reduce costs for services. The approach they adopted is to integrate several items into the slim rig design not normally present. Services that could be affected by integration included instrumentation, cementing, mud management and waste treatment.

Advanced sensors were included in the rig for the driller, tool pusher, company man and mud logger. The drilling contractor becomes responsible for data acquisition, and duplication of instrumentation is avoided. A special mud logging unit was built and placed next to the company man's office.

As a result of the greatly reduced volumes of cement required for slim-hole operations, cement slurry is prepared in two batch tanks and pumped by the rig pumps. Cost savings are accrued since a dedicated cementing unit is not needed.

Slim-hole operations produce a greatly reduced volume of cuttings and mud. Mud management was made more efficient by minimizing waste volumes using an efficient shale shaker and two high-speed centrifuges. Only high-concentration solids and clear water are disposed.

These newly integrated services impact the day rate of the rig and amount to about 10% of the total rig cost. In addition, an extra crew member is needed to act as fluid engineer. Overall cost reductions with this integrated approach are substantial (Figure 13-9). Further improvements in procedures and productivity are expected.

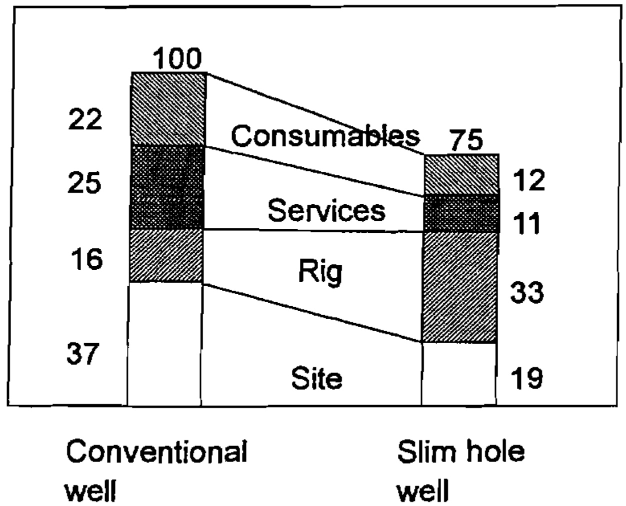

Figure 13-9. Cost Savings with Slim-Hole Integrated Services (Dupuis and Sagot, 1995)

13.5 FORASOL (FORASLIM RIG)

Forasol introduced a new slim-hole rotary rig for drilling and coring named Foraslim (Sagot and Dupuis, 1997). Footprint of the drill site is only 26 by 32 m (85 by 105 ft) (Figure 13-10). Depth range is to 3500 m (11,500 ft) in ultraslim holes (3⅜ in.) or 3000 m (9850 ft) in slim hole (4¾ in.). The rig has been used successful in several campaigns including the Paris Basin and Gabon.

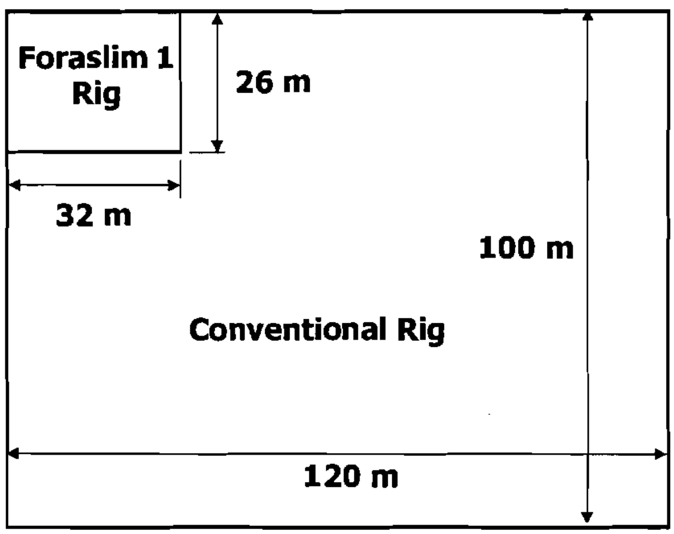

Figure 13-10. Footprint of Foraslim Rig (Sagot and Dupuis, 1997)

Several important technical issues were addressed in the four-well Gabon project, where cost savings of 33% were achieved. These included: 1) kick-detection and control are adequate, with two kicks taken and readily controlled, 2) good results were achieved with wireline-retrievable cores through the drill string, 3) performance of slim PDC bits was greatly improved, 4) a suite of 2¼-in. logging tools has been developed and provided high-quality logs, although highly sophisticated logs (e.g., bottomhole imaging) are not available or foreseen in the slim versions, 5) DST can be successfully completed in 4¾-in. holes.

13.6 FORASOL-FORAMER (SLIM-HOLE DRILLING OFFSHORE)

Forasol-Foramer (Duhen et al., 1997) described considerations and designs for applying slim-hole techniques in the deep offshore environment. There is a critical need to adapt slim-hole drilling to offshore exploration and development for significant size and cost reductions (Figure 13-11) in deep water to 2000 meters and beyond. Major challenges offshore include adapting to floating support, solving heave-compensation problems, accurate control of WOB and designing a riser.

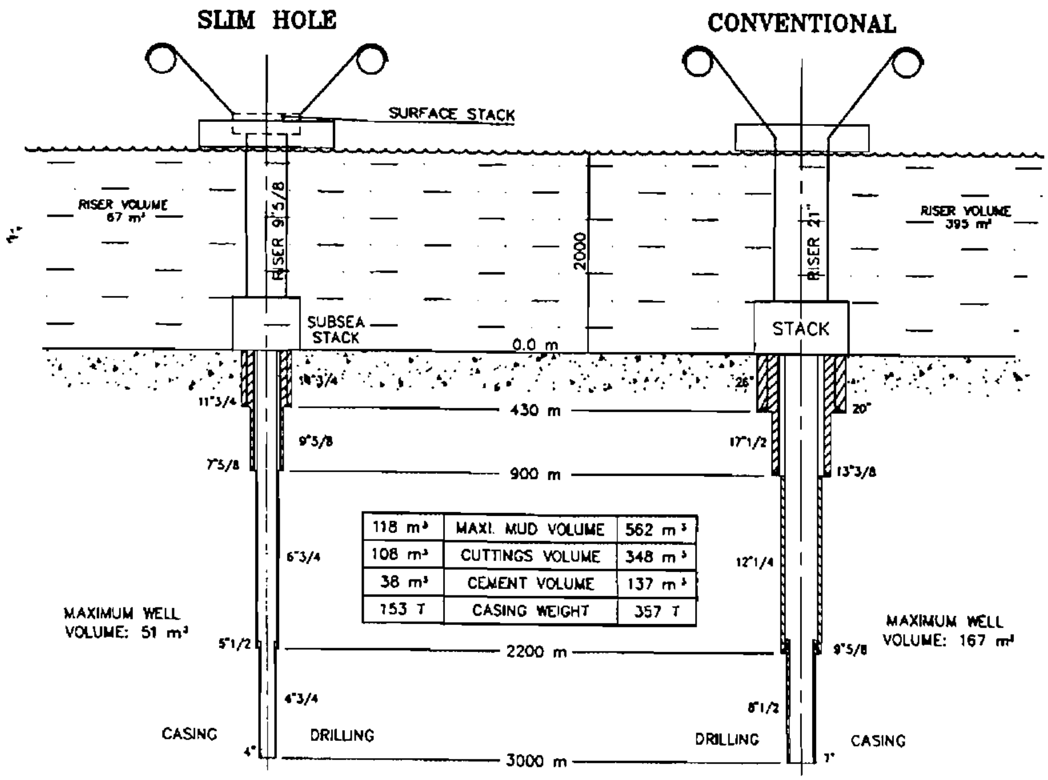

Figure 13-11. Offshore Completion Designs (Duhen et al., 1997)

Duhen et al. considered the potential of applying a variety of vessel designs for deep offshore drilling applications. One semisubmersible design, the Amethyst, is a four-column catamaran originally designed for workover operations (Figure 13-12). One of these units is operating offhsore Brazil. This vessel could be readily upgraded for drilling operations.

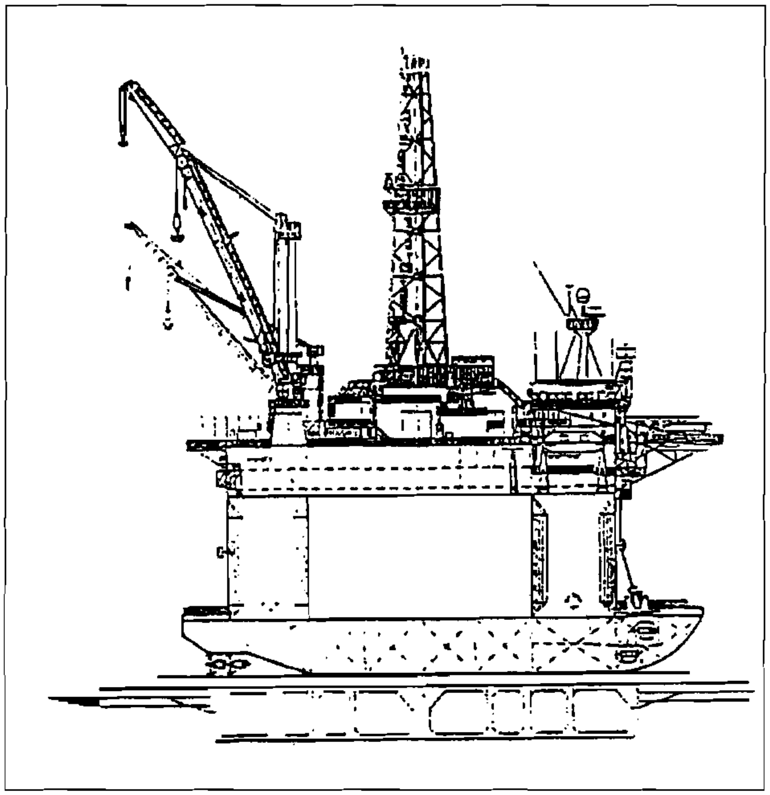

Figure 13-12. Amethyst Drilling Vessel (Duhen et al., 1997)

A monohull called "Ulstein" was specially design for slim-hole drilling and subsea well intervention. The design allows operation in wave heights of up to 4.5 meters.

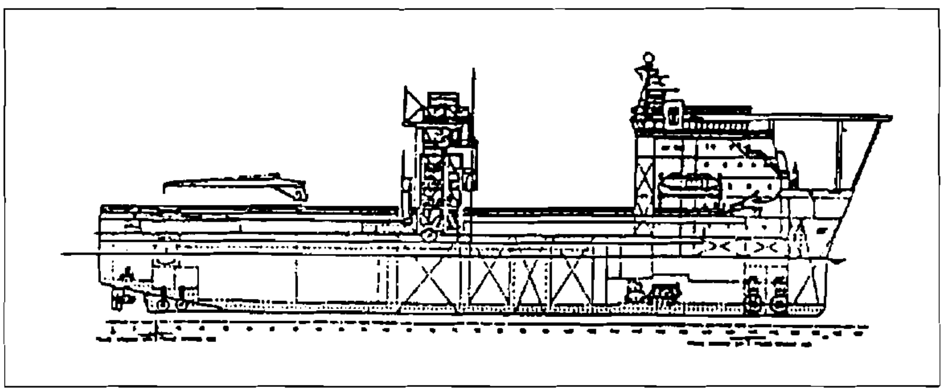

Figure 13-13. Ulstein Slim-Hole Drilling Vessel (Duhen et al., 1997)

Heave compensation is a critical concern for slim-hole drilling offshore. By one estimate, a fluctuation in WOB of up to 10% might be acceptable. Based on typical bit weights for 4¾-in. hole, this amounts to a WOB precision requirement of 400 kg (880 lb). Active heave compensation is required. One design developed by Maritime Hydraulics replaces the conventional drawworks by two hydraulic cylinders for hoisting (Figure 13-14). Active heave compensation is thereby incorporated directly into the system.

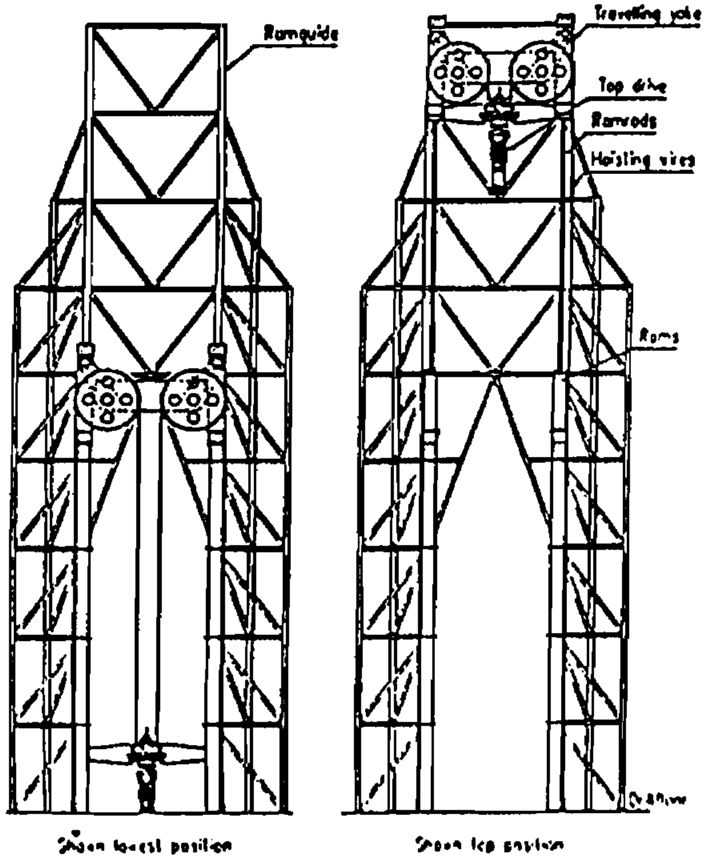

Figure 13-14. Drillworks Incorporating Heave Compensation for Slim Holes (Duhen et al., 1997)

13.7 INSTITUT FRANÇAIS DU PÉTROLE, FORASOL AND ELF (HYDRAULICS MODEL)

The Institut Français du Pétrole, Forasol, and Elf Aquitaine Production (Cartalos et al., 1996) developed a hydraulics model for slim-hole geometries. Developed under the Euroslim project, the model was devised to predict flow behavior in the restrictive flow channels between slim drill pipe and casing. Their model accounts for eccentricity of the drill pipe and effects of rotation. Close agreement was obtained with results from three field wells.

The slim-hole hydraulics model was devised as a simulator for field operations. The development involved three steps: 1) develop theory and mathematics based on realistic assumptions of rheology and geometry, 2) validate model predictions with laboratory and field test data, and 3) compare model predictions to normal field operations.

A pressure-loss model was derived to accommodate various functions e(x) describing drill-string eccentricity along the wellbore. The project team found that, for geometries applicable to oil wells, results are relatively insensitive to the exact function selected.

Results are shown in Figure 13-15 for a Newtonian fluid and eccentricity of 0.8. Predictions and experimental data are in good agreement. It is seen that pressure losses are lower in eccentric annuli in both laminar and turbulent flow, but may be greater in transitional regimes.

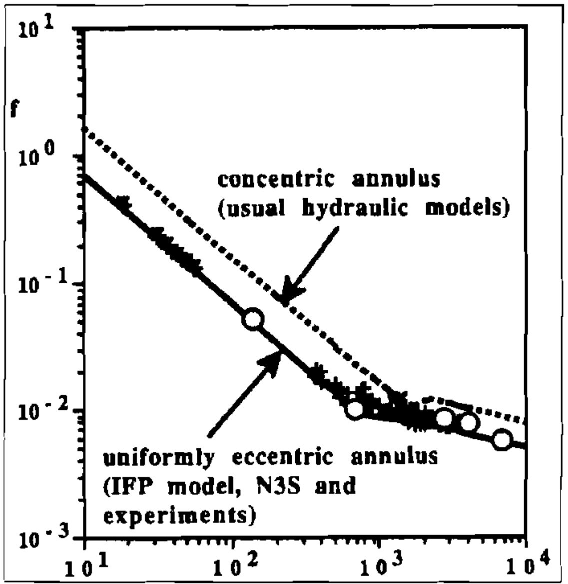

Figure 13-15. Friction Factor and Reynolds Number (Cartalos et al., 1996)

Three commercial wells were drilled under the Euroslim project, two in the Paris basin and one in Gabon. Geometries of these wells (including two sections of the Gabon well "Ozima") are summarized in Table 13-2.

TABLE 13-2. Euroslim Slim Holes (Cartalos et al., 1996)

	LXE	CVP	OZIMA	OZIMA
Wellbore				
Casing size OD/ID (in)	4.5/4.05	5.5/4.9	5.5/5.0	4/3.6
Casing length (m)	920	719	1410	2400
Open hole size (in)	3"3/8	4"3/4	4"3/4	3"3/8
Drillstring				
Drill pipe OD (in)	2.25	3.5	3.5	2.25
Drill pipe ID (in)	1.89	2.91	2.91	1.89

Tool joint OD (in)	2.60	4.13	4.13	2.60
Tool joint length (m)	0.6	0.7	0.7	0.6
Drill collar OD (in)	2.6	4.13	4.13	2.6
Drill collar ID (in)	1.89	2.91	2.91	1.89
BHA length (m)	290-360	250-280	185-240	270-364

Water-base fluids (with bentonite and lubricant) were used in all slim sections. Stand-pipe pressure, flow rate and rotary speed were recorded during drilling. Recorded and predicted stand-pipe pressures are compared in Figure 13-16. The error was less than 5% for almost all observations.

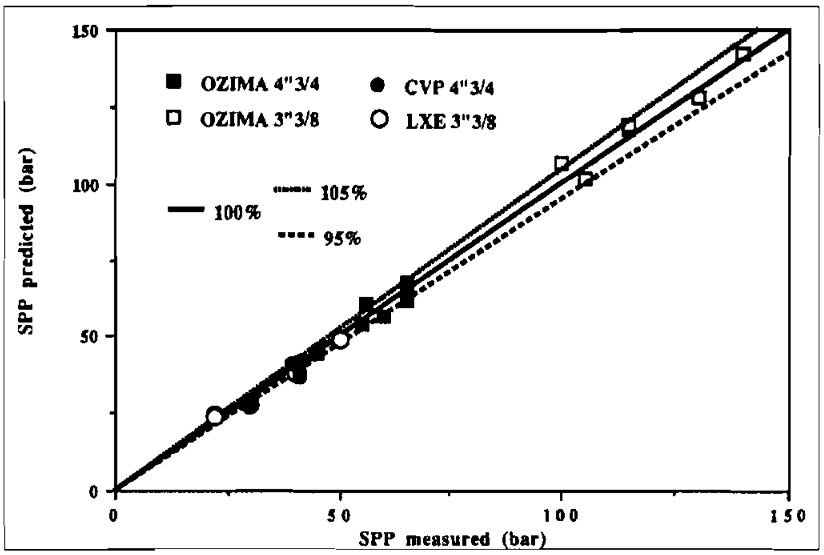

Figure 13-16. Measured and Predicted Stand-Pipe Pressures (Cartalos et al., 1996)

The majority of the annular pressure loss occurs in the open-hole section. More than two-thirds of the losses occur at the drill collars, due to the highly restricted annular clearance.

Results confirmed that turbulent flow is preferred for improved cuttings transport in an eccentric hole.

Additional details of these analyses are presented in *Hydraulics*.

13.8 KENTING DRILLING SERVICES (SLIM-HOLE RIG)

Kenting Drilling Services (Beswick and Hills, 1995) described a new purpose-built slim-hole rig for vertical and slant wells (Figure 13-17). Their system is designed to minimize drilling costs and is a blend of oil-field and mining technologies. The rig is based on simple, proven concepts and makes use of available standard components. The estimated rig cost is only about 20% of an equivalent conventional rig, and less than half the cost of other purpose-built slim-hole rigs. Consequently, using this system compares favorably with the cost of a used and refurbished standard rig.

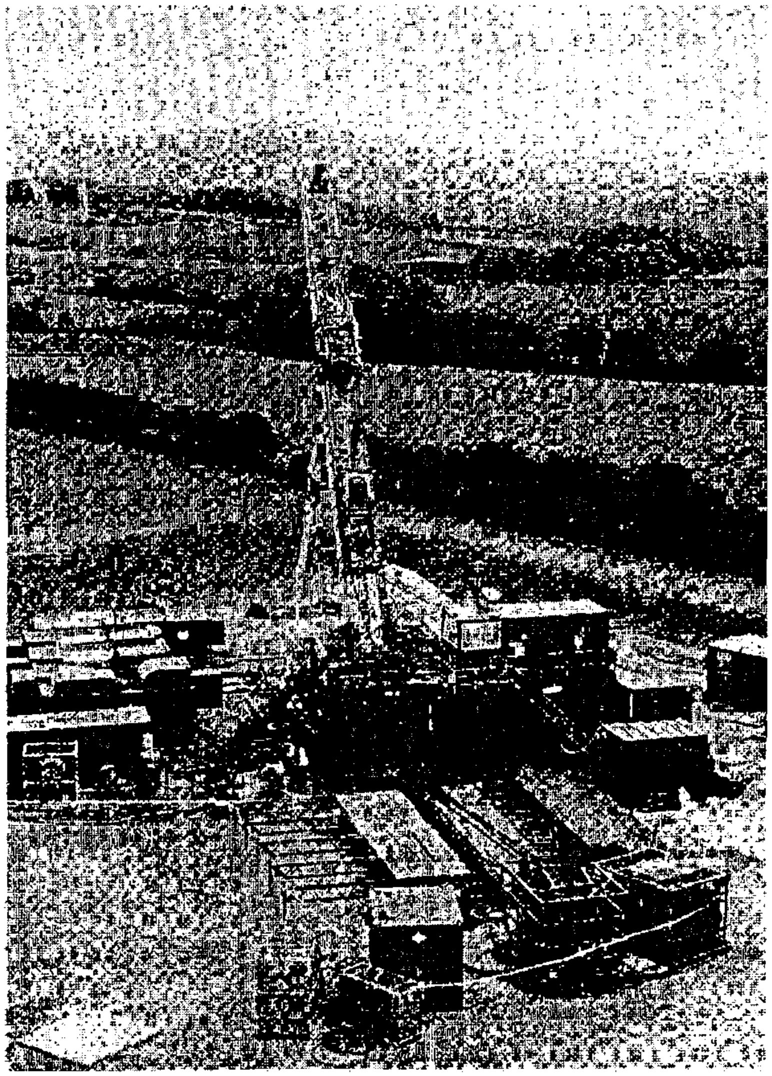

Figure 13-17. Kenting Slim-Hole Rig (Beswick and Hills, 1995)

The development of the slim-hole rig market has been negatively impacted by the over capacity of conventional rigs offered at fire-sale rates. This situation has hindered the development of smaller innovative rigs and associated equipment and systems. Kenting Drilling Services had an opportunity to design and construct a low-cost rig for slim applications. The rig was designed to demonstrate that a low-cost system could satisfy the requirements for frontier drilling.

Their new rig is capable of running up to 17½-in. bits and 6¼-in. continuous coring. Depth rating is to 3500 m (11,500 ft). Rig capacities are summarized in Table 13-3. The power system is completely hydraulic. A mechanized pipe-handling system includes a hydraulic clamp in the top drive and an elevating and extending catwalk with hydraulic power breaker.

TABLE 13-3. Features of Low-Cost Rotary Rig (Beswick and Hills, 1995)

Depth rating	3500 m (slim hole)
Overall height	26 m
Footprint	40 m x 20 m (800 m^2)
Mast	Singles lattice open box
Hydraulic power system	385 hp
Hook load	100 ton (200 000 lb)
Traveling equipment	100 ton, 8-lines
Drawworks winch	6-speed hydraulic with 1 in (EIPS) drilling line with hydraulic braking and emergency band brake
Pulldown winch	Single speed hydraulic with 1 in (EIPS) line
Wireline winch	Hydraulic variable speed for wireline coring
Substructure	220 000 lb rating, 4.0 m high (3.6 m clear) hydraulic self elevating with BOP lifting and positioning system
Top drive	Hydraulic 400 rpm 22 500 Nm (16 500 ft lb) with hydraulic tilt and swing, floating shaft and integral hydraulic power clamp
Standpipe pressure	5000 lb/in^2
Primary mechanized handling	Hydraulic elevating and extending catwalk, top drive clamp, power slips, power breaker
Secondary handling system	Hydraulic floor mounted crane, bushing for standard inserts, 7⅝-in. hydraulic power tong, tugger winch and forklift with hydraulic pipe clamps
Maximum casing size	13⅜-in. Range 3
Mud pumps	165 hp triplex (two to four) with independent diesel engines
Mud system	320 bbl 7-compartment with associated solids control equipment, degasser and pumps
Generator system	210 kW main unit with 50 kW standby unit
Instrumentation	Rig instrumentation package, computerised rig instrumentation system, kinetic energy monitoring system with multi-function autodriller
Noise attenuation	80 dB(A) at 1 m
Buildings	Drillers station, Rig Manager, crew welfare, workshop, stores
Load packaging	6 m ISO container or equivalent including mast

A comprehensive computerized rig instrumentation system with a local computer network and an automatic driller through the hydraulic drawworks are included (Figure 13-18).

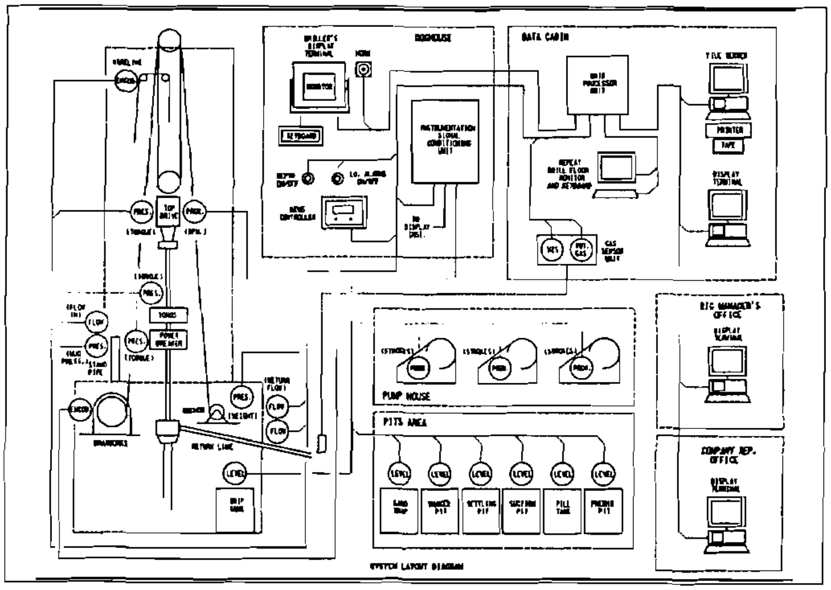

Figure 13-18. Rig Instrumentation System (Beswick and Hills, 1995)

Cementing equipment is not included in the rig design. Standard services are assumed adequate. Drill string was also not designed; existing strings including conventional and exotic coring strings are to be used.

Making the rig helicopter transportable, though desirable, was not undertaken at this stage due to added costs and complexity. Instead, the entire system is modular and can be fit into standard 6-m shipping containers.

The top drive is capable of operating at a wide range of torques at speeds up to 400 rpm (Figure 13-19).

A typical site layout (Figure 13-20) requires a footprint of about 40 by 20 m (130 by 65 ft).

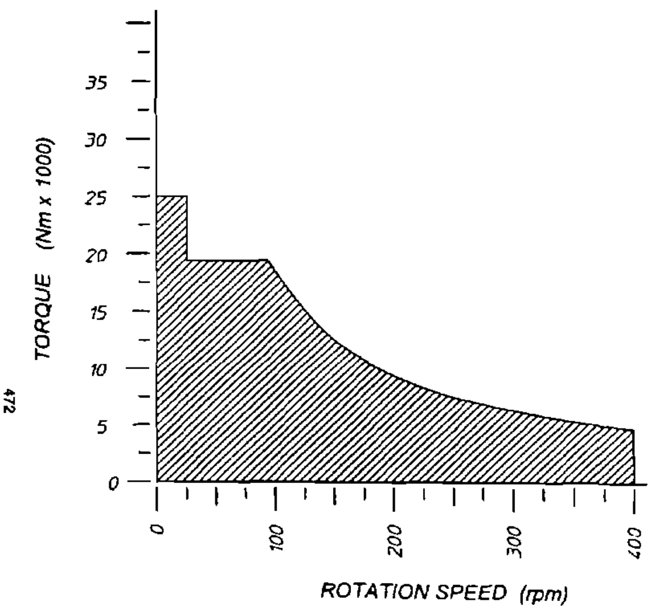

Figure 13-19. Rotary Speed and Torque (Beswick and Hills, 1995)

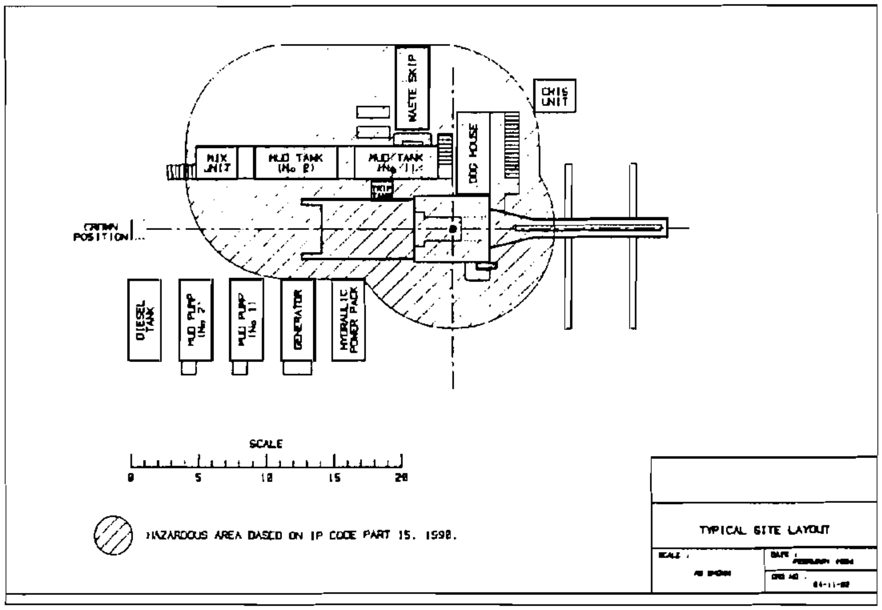

Figure 13-20. Typical Site Layout (Beswick and Hills, 1995)

Kenting's new rig has been used to drill two slant holes to about 1000 m and on two workovers. Holes have been drilled (up to 12¼ in.) using the top drive or downhole motors. Early experience with the system has shown it to be effective over a wide range of applications.

13.9 KUWAIT OIL COMPANY (SLIM-HOLE EXPERIENCE)

Kuwait Oil Company (Al-Khayyat and Al-Azmi, 1997) summarized their experience drilling 4½-in. slim holes in difficult drilling conditions. Slim holes have only been adopted as contingencies up to the present. They described case histories of slim sections at depths to 20,700 ft with mud weights to 19.3 ppg. Both rotary and motor drilling systems have been used.

In one well (Figure 13-21), a shallower-than-planned string of casing required that the final section be drilled with rotary equipment and a toothed bit. The interval was from 19,300 to 20,774 ft MD. Maximum mud weight was over 19 ppg. Mud cost was over $280/ft.

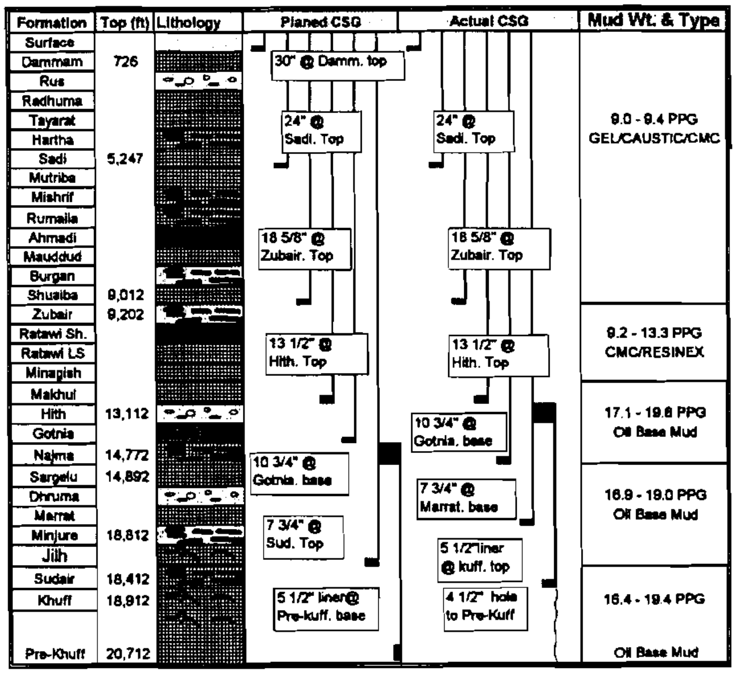

Figure 13-21. Casing Summary for Well EXW-1 (Al-Khayyat and Al-Azmi, 1997)

Based on experiences in several wells, Kuwait Oil Company found that high mud weights and temperature restrict the use of motors in these slim sections. Combination drill strings have been needed to allow as much clearance as possible for fluid circulation. Given that contingencies will be expected to be required in the future, KOC continues to investigate ways to improve performance and efficiency in these slim holes.

13.10 NORSK HYDRO, NORSKE SHELL AND MERCUR SUBSEA (SLIM-HOLE DRILLING FROM LIGHT VESSEL)

Norsk Hydro Production, A/S Norske Shell, and Mercur Subsea Products (Carstens et al., 1996) described the design of a slim-hole drilling vessel to be used for reducing costs at 5000-ft water depths. The vessel is dynamically positioned and fully heave compensated for tripping and drilling. A high-pressure riser is used, eliminating the need for kill and choke lines. They analyzed the market for such a vessel and determined that the greatest potential is for subsea well intervention and exploration drilling in deep water.

The size of rigs for deep-water operations is strongly impacted by the need for storing long and heavy strings with buoyancy material. A reduction in riser weight would allow a large reduction in rig size. However, slim-hole floating vessels have generally showed low efficiency due to the lack of adequate heave compensation, which does not allow fine control of WOB.

Norsk Hydro previously drilled a 4⅛-in. section in similar conditions. Based on these experiences, a slim-hole well design was developed (Figure 13-22).

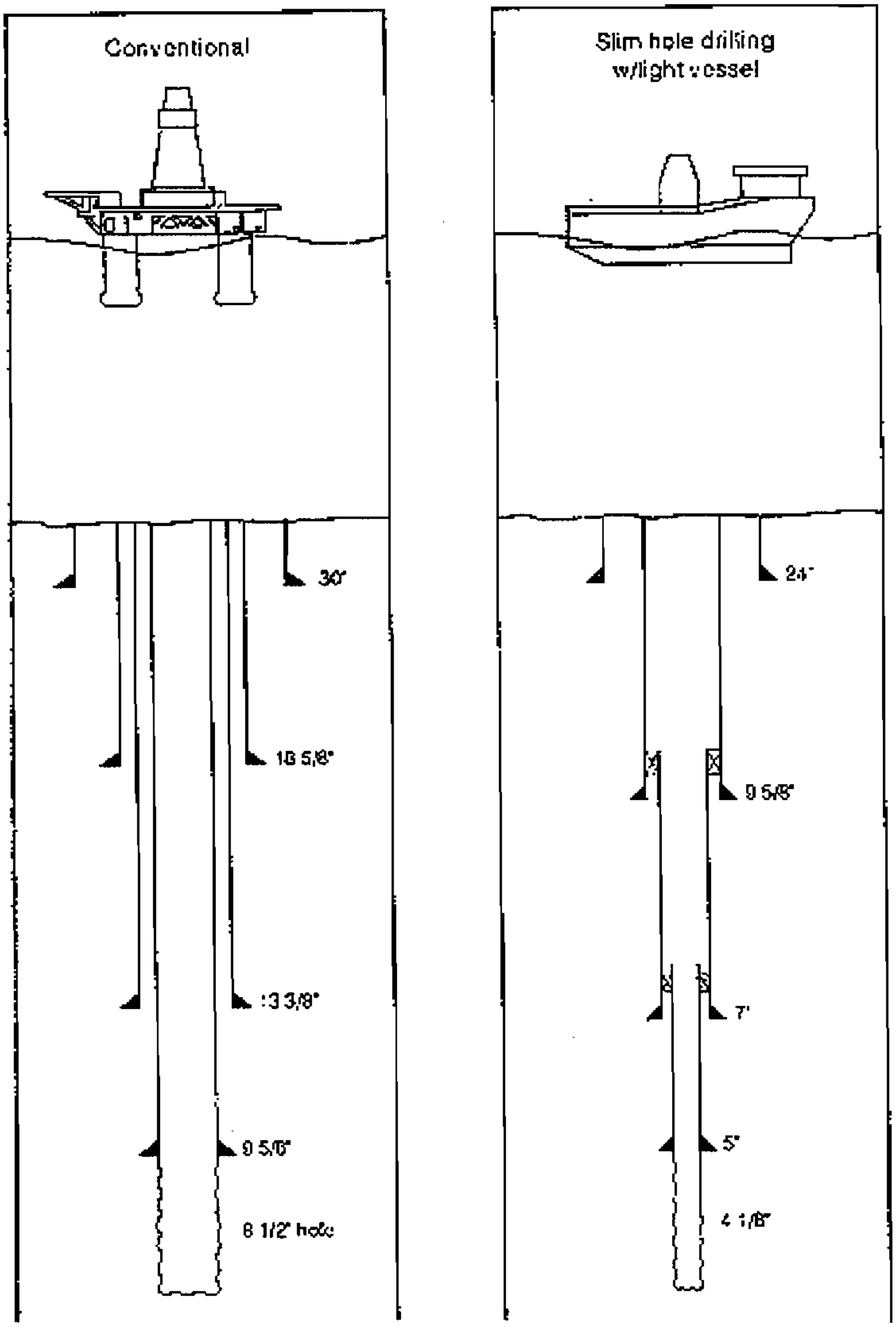

Figure 13-22. Slim-Hole Design for Light Vessel (Carstens et al., 1996)

Using a high-pressure riser allows kick control to occur from the surface. Kill and choke lines are not used, and the riser weight is only about 17% of a standard 21-in. system.

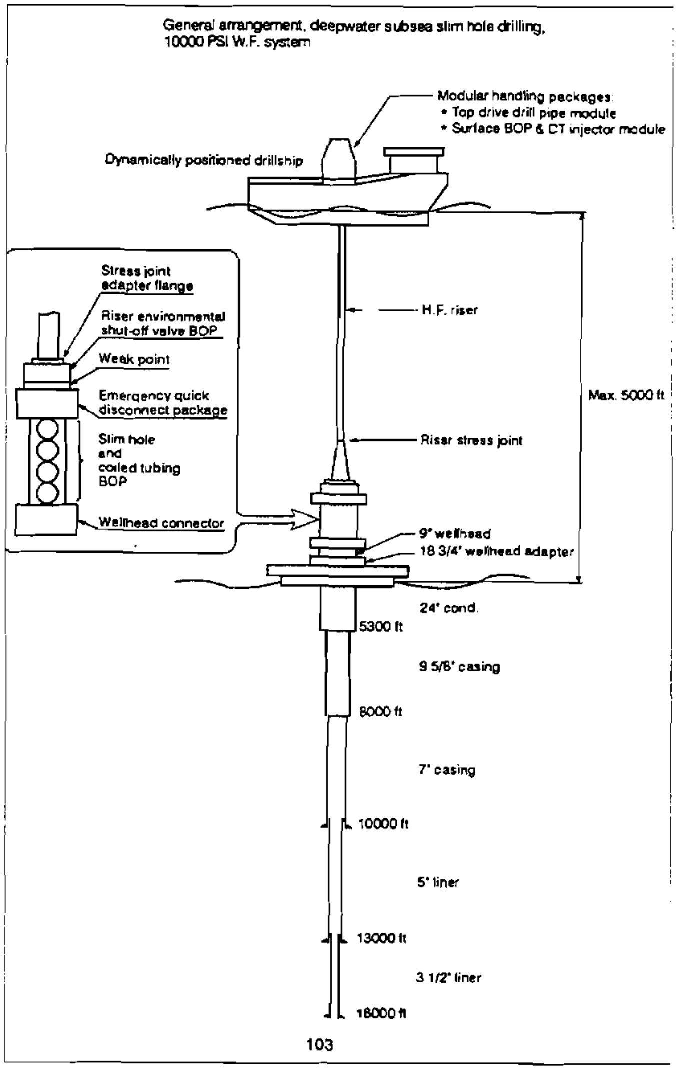

Figure 13-23. Slim-Hole Dynamically-Positioned Drilling System (Carstens et al., 1996)

A subsea BOP is provided (Figure 13-23) but used only if the riser disconnects in an emergency drive-off situation. The subsea BOP is fitted with rams for drill pipe and coiled tubing. A fail-safe subsea multiplex control prevents well control from being lost. A weak link is fitted above the subsea BOP. Since the vessel remains in position, the telescopic joint is not required. A swivel is used instead.

A ⅜-scale model was built to analyze rig operations and efficiency of pipe handling. Two pipe-handler arms were found to be able to deliver made-up pipe as fast as it could be run.

System costs and operating expenses are estimated in Table 13-4.

TABLE 13-4. Costs of Slim-Hole Drilling System (Carstens et al., 1996)

System Cost and Time-Dependent Operational Cost	
Dynamically positioned NMD class 3 vessel	
Heave-compensated rig.	
9" bore 10000 PSI riser	
Rated for 5000 ft water depth and 16000 ft drilling depth.	
Delta-Shaped Mono-Hull Vessel (Ramform)	
Total investment cost	:70 mill US$
Total daily cost	:90,000 US$
Mini Semi-Submersible	
Total investment cost	:100 mill US $
Total daily cost	:120,000 US $

Norsk Hydro performed a time analysis comparing slim-hole light-vessel costs with conventional. They assumed that slim-hole drilling is slower than conventional drilling. They then calculated the time factor for break-even costs for the slim-hole approach. These data (Table 13-5) suggest that a mono-hull light vessel could require 2.3 times more days on location and still break even.

TABLE 13-5. Drilling Time for Break-Even Costs (Carstens et al., 1996)

Break Even Cost Factors for 5000 ft. Water Depth	
Time-dependent daily costs in Norwegian waters:	
Conventional operation	:210,000 US$
Light mono-hull	:90,000 US$
Mini semi-sub	:120,000 US$
Time consumption factor on a well that gives equal cost:	
Light mono-hull	:210,000/90,000 = 2.3
Mini semi-sub	:210,000/120,000 = 1.7

The project team concluded that slim-hole drilling from a dynamically positioned light vessel is a feasible option for offshore operations to depths of 5000 ft. A significant reduction in costs is possible. Primary savings are in the use of a high-pressure riser and full heave compensation.

13.11 SHELL CANADA, ENTERRA CANADA AND GRANT TFW (HIGH-STRENGTH SLIM TOOL JOINT)

Shell Canada Limited, Enterra Canada Limited and Grant TFW (Weich et al., 1995) described the design process of a new high-torque tool joint for slim-hole applications. The new tool joint, the 2⅜-in. HTSLH90, has significantly greater torsional capacity than conventional API joints. A double-shoulder design increases torsion strength for slim-hole usage and provides additional allowance for wear not available with API connections. The new joint is well matched with high-strength drill pipe (2⅞- or 3½-in. S-135) and can meet the API recommendation that the joint be at least 80% as strong as the pipe in torsion. This joint has been used in various applications where API tool joints have insufficient strength, small OD and large ID are required for hydraulics and fishability, and wear of conventional tool joints leads to early derating of the pipe.

A conventional-style thread form and primary make-up shoulder seals and preloads the threads, just as in a conventional joint. A second shoulder at the pin makes up with a shoulder in the box, providing an additional stop that resists over torquing the joint.

Shell Canada had need for high-strength slim-hole drill pipe for use in several 3⅞-in. re-entries in the House Mountain area. A typical drilling plan is shown in Figure 13-24. A limiting specification was that a 1.975-in. drill string ID was required for running the gyro tool.

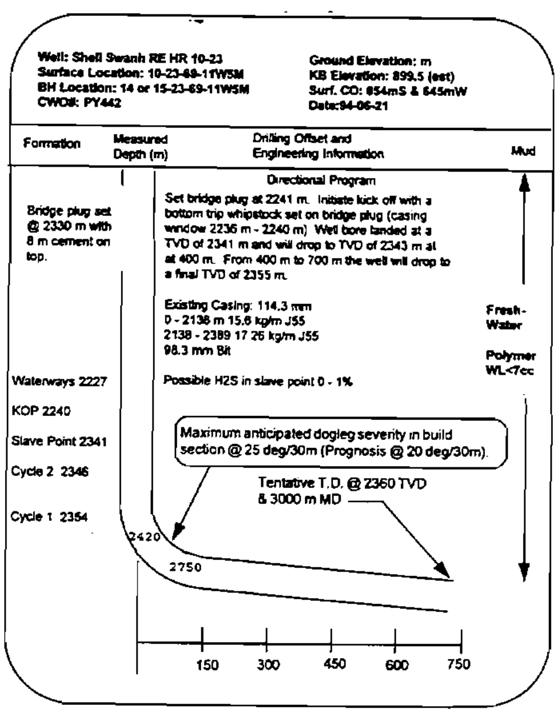

Figure 13-24. Drilling Plan for 3⅞-in. Re-entries (Weich et al., 1995)

Existing standard and other tool joints were investigated to determine whether the dimensional and strength requirements could be met. Performance data are summarized in Table 13-6.

TABLE 13-6. 2⅞-in. Drill Pipe with Conventional Joints (Weich et al., 1995)

Pipe		Torque N-m			Tensile Strength kN		
2⅞ 10.40 x -95	New	19,842			1,207.7		
2⅞ 10.40 x -95	Prem	15,212			938.3		
Tool Joints			**% of Pipe (New)**	**% of Pipe (Prem)**		**% of Pipe (New)**	**% of Pipe (Prem)**
79.38 mm x 50.17 mm (3⅛" X 1.975") NC23		2,476	12%	16%	421.6	35%	45%
79.38 mm x 50.17 mm (3⅛" X 1.975") 2⅞ PAC		3,232	16%	21%	522.5	43%	56%
79.38 mm x 50.17 mm (3⅛" X 1.975") 2⅜ WO		5,650	28%	37%	912.1	76%	97%
79.38 mm x 50.17 mm (3⅛" X 1.975") 2⅜ OH		6,398	32%	42%	959.1	79%	102%
79.38 mm x 50.17 mm (3⅛" X 1.975") 2⅜ SLH90		7,224	36%	47%	943.2	78%	101%

No effective matches for the 2⅞-in. drill pipe were found. Torsional strength of these tool joints was significantly less than the pipe.

A double-shouldered "HI TORQUE" joint manufactured by Grant TFW (Figure 13-25) was considered and found to be a closer match to the pipe strength. However, this joint could not be manufactured with the required ID.

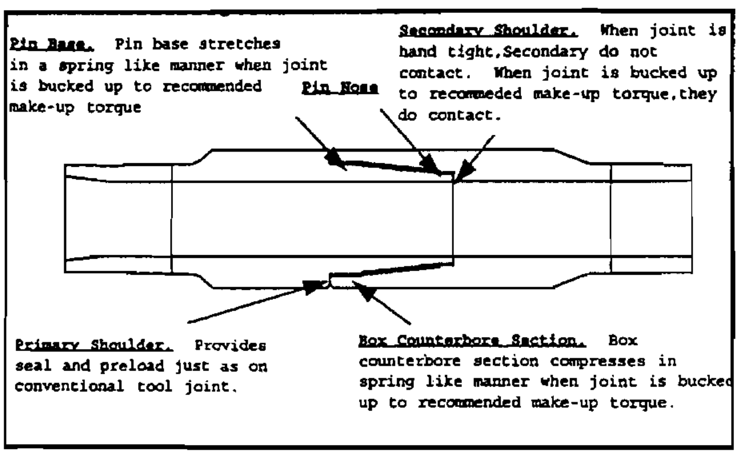

Figure 13-25. Features of HI TORQUE Connector (Weich et al., 1995)

No connector designs were available that met the required specifications. Consequently, a new connector was designed to meet Shell Canada's needs. The SLH90 was used as the basis for the new design. A high-torque connector, the HTSLH90, was based on the double-shoulder design, thereby creating more stored energy in the connector and greater torque capacity. Basic dimensions are summarized in Figure 13-26.

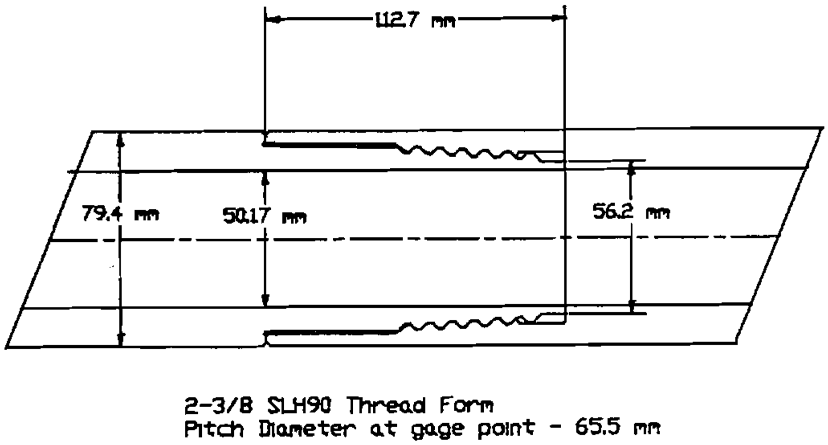

Figure 13-26. Dimensions of 2⅜-in. SLH90 (Weich et al., 1995)

Mechanical testing showed that the new connection began to yield at 9087 N-m (6700 ft-lb). The failure mode is most likely to be parting of the pin or thread shear. In either case, the connection is likely to be fishable without any milling required.

Shell Canada used slim drill pipe with the new high-torque connection for drilling four re-entries. The drill pipe performed satisfactorily in all cases.

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14. Well Control

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14. Well Control

14.1 FORASOL, ELF, TOTAL, IFP, AND GEOSERVICES (KICK-CONTROL METHOD)

Forasol, Elf Acquitaine Production, Total, Institut Français du Pétrole and Geoservices (Dupuis et al., 1995) reported the results of experiments to validate kick-control methods and a pressure-loss model for use with slim-hole applications. They determined that the impact of rotation on pressure losses is influenced by the Taylor and Reynolds numbers. For Re < 1000, pressure losses in the annulus generally increase with rotation. For Re > 1000, the impact of rotation is greatly reduced. The experimental results of well-control events showed that it is best to not perform a flow check after a kick has been detected, but rather to quickly close the BOP.

The principal objectives of the hydraulics experiments were to chart the increase in pressure loss with flow rate and rotation in simulated field conditions and to validate predictions of IFP's model in each flow regime. Well-control simulations were designed to evaluate the capabilities of surface detection equipment, sensor response under various drilling scenarios, and procedural options for treating a gas kick in a slim hole.

Reduced annular clearances in many slim-hole applications have been shown to significantly impact ECDs and the development of kicks. The project team conducted experiments in a pilot well that was outfitted with pressure sensors at several depths (Figure 14-1). TD was over 900 m (2950 ft). A 3⅜-in. bit was rotated on 2⅝-in. mining drill pipe (with flush joints). The corresponding annular clearance was 8.5 mm (0.34 in.); annular volume was 2.2 l/m (0.42 bbl/100 ft).

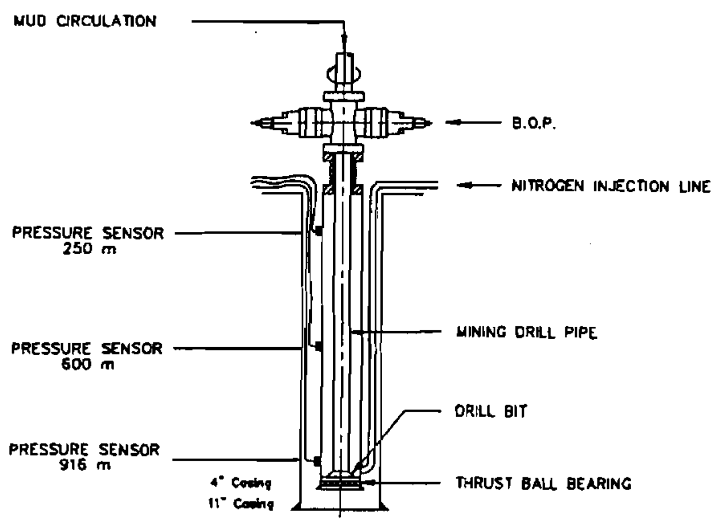

Figure 14-1. Well-Control Test Well (Dupuis et al., 1995)

Drilling fluids were designed for these tests based on requirements typical of slim-hole applications. Power-law fluids consisting of water-base mud with xanthan were investigated over a wide range of shear rates. Viscosity was relatively low to allow investigations in both laminar and turbulent flow regimes. Drilling fluid composition is summarized in Table 14-1.

TABLE 14-1. Fluids Used in Experiments (Dupuis et al., 1995)

	Fluid 1	Fluid 2
XCD concentration (g/l)	1.0	2.5
Specific mass (Kg/m^3)	999.5	999.8
Zero shear rate viscosity (Pa-s)	0.205	4.58
Consistency index -K (Pa-s^n)	0.112	0.720
Flow behavior index n	0.48	0.30

The variation of pressure along the wellbore was recorded as flow rates were varied. Typical results without rotation are shown in Figure 14-2. Fully established flow was observed for these data (based on fluid 1).

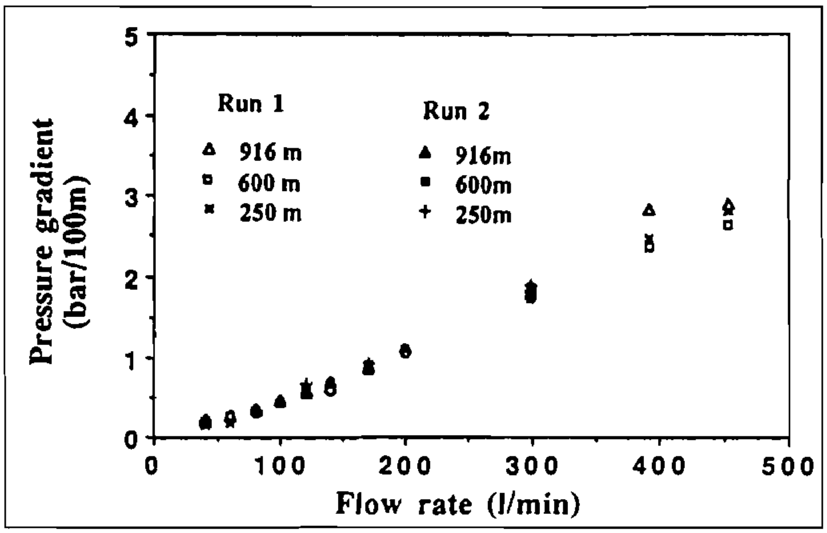

Figure 14-2. Pressure Gradient and Flow Rate (Dupuis et al., 1995)

The distribution of pressure drops along the circulation path (without rotation) are compared in Figure 14-3. Pressure drop in the annulus is greater than pressure drop in the drill string by an order of magnitude. Losses in the surface equipment and drill string were modeled, and compare very favorably with measured stand-pipe pressure (SPP).

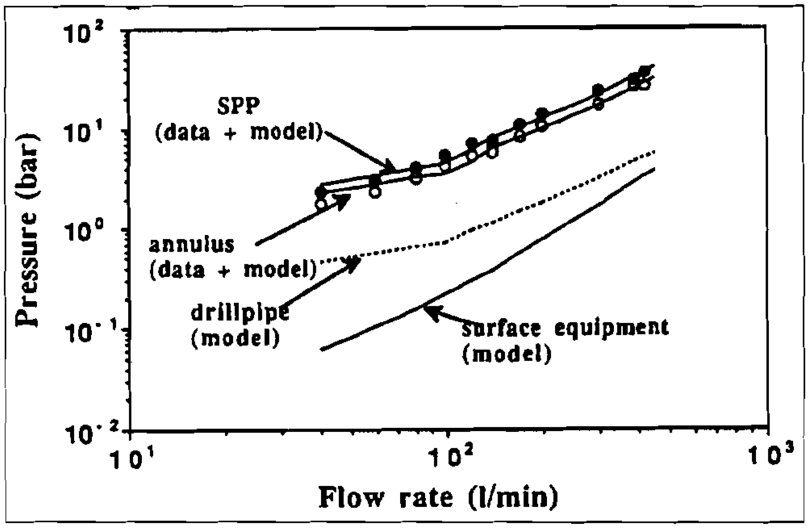

Figure 14-3. Distribution of Pressure Losses (Dupuis et al., 1995)

The impact of rotation on pressure losses for a range of flow rates is compared in Figure 14-4. Flow was laminar for Reynolds numbers up to 1020; a significant increase in pressure loss with rotation was observed for these laminar cases. At higher Reynolds numbers, there is much less relative increase with rotation.

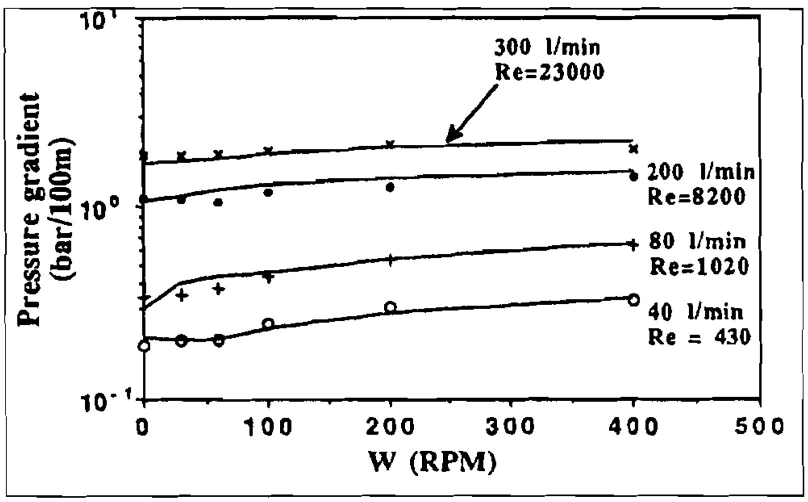

Figure 14-4. Impact of Rotation on Annular Pressure Loss (Dupuis et al., 1995)

Kick-control procedures and methods were investigated by simulating gas kicks in the instrumented test well. A mass flow meter (Figure 14-5) was used to inject nitrogen at a constant rate to the bottom of the well. Kicks were simulated while drilling and when circulation is stopped. Continuous injection in an open well and gas migration in a closed well were also investigated.

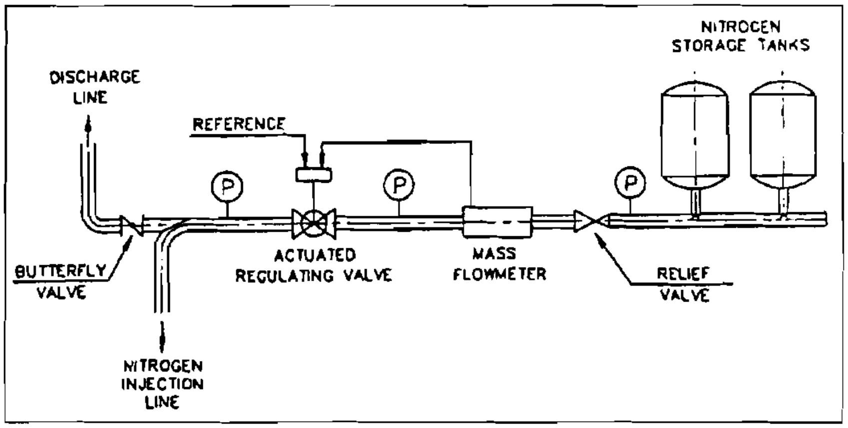

Figure 14-5. Flow Regulation for Kick Simulation (Dupuis et al., 1995)

Flow variables for a simulated kick while drilling are plotted in Figure 14-6. Differential pressure for the kick was 1 bar (15 psi). Flow out increases exponentially until drilling (rotation) is stopped. This is due to the cumulative gas volume in the well and volume expansion as gas approaches the surface. There is a time delay between kick responses in flow out versus pit level. This demonstrates the need for accurate flow measurement to allow rapid detection of kicks.

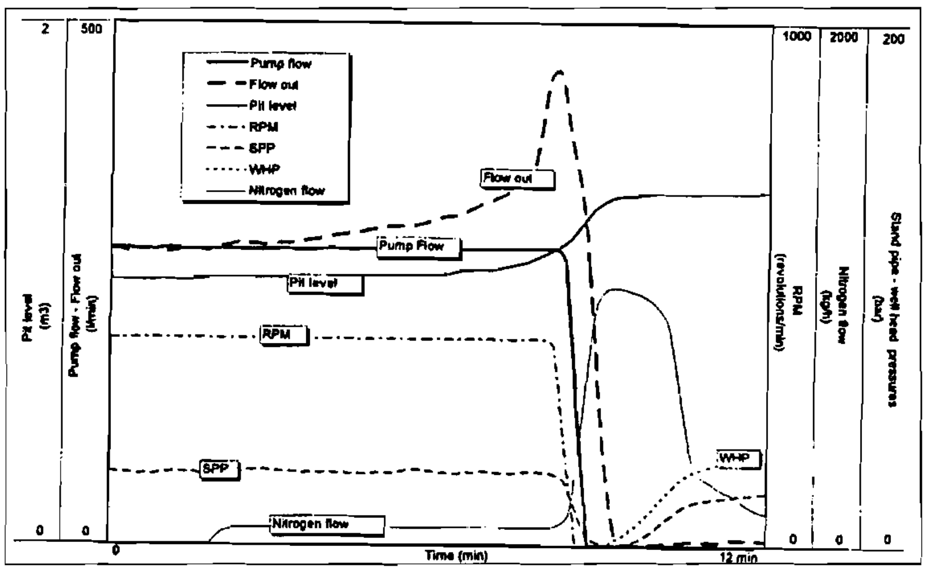

Figure 14-6. Simulated Kick While Drilling (Dupuis et al., 1995)

If rotation and circulation are stopped in response to a kick, the pressure differential between the annulus and formation will be increased, leading to increased gas influx (Table 14-2). Consequently, performing a traditional flow check can be counterproductive to controlling a kick.

TABLE 14-2. **Kick Influx After Stopping Circulation (Dupuis et al., 1995)**

	Case 1		Case 2	
	400 rpm 300 l/min	0 rpm 0 (l/min)	0 rpm 0 (l/min)	0 rpm 0 (l/min)
Differential pressure Reservoir/bottom hole	7 bar	31 bar	1 bar	23 bar
Gas influx flow rate	45 l/min	179 l/min	8 l/min	134 l/min

Kick problems during a drill-pipe connection were simulated by stopping circulation and rotation for 2.5 min and then resuming. Influx pressure was set at 7 bar (100 psi) over hydrostatic pressure. The kick is not discernible (Figure 14-7) by monitoring differential flow until about 2 min after rotation and circulation are stopped. Kick flow was also calculated based on a divergence in predicted flow versus measured flow. The kick can be observed almost immediately using special kick-modeling software and an accurate flow meter.

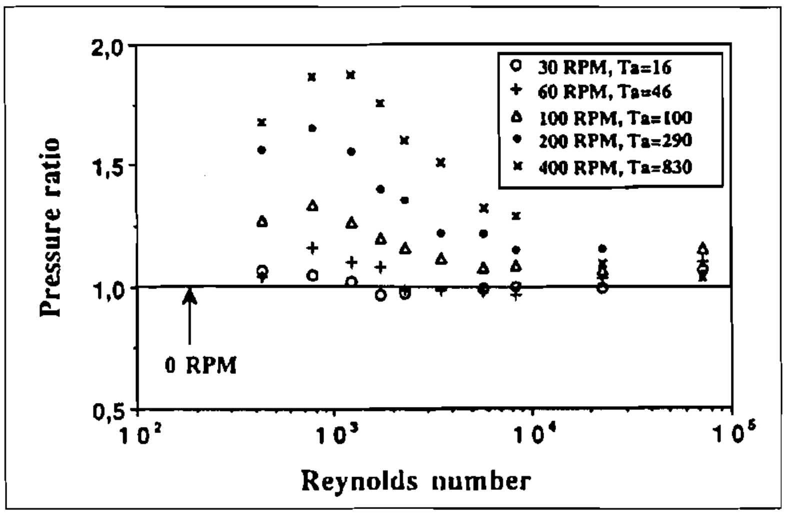

Figure 14-7. Simulated Kick While Making a Connection (Dupuis et al., 1995)

Gas migration during drilling was also investigated. For one test, nitrogen was injected at a flow rate of 210 l/min (1.3 BPM) at the bottom of the fluid-filled well without circulation or rotation. Gas first reaches the surface after about 4.5 min (Figure 14-8). Injection was then stopped and hole pressures allowed to stabilize.

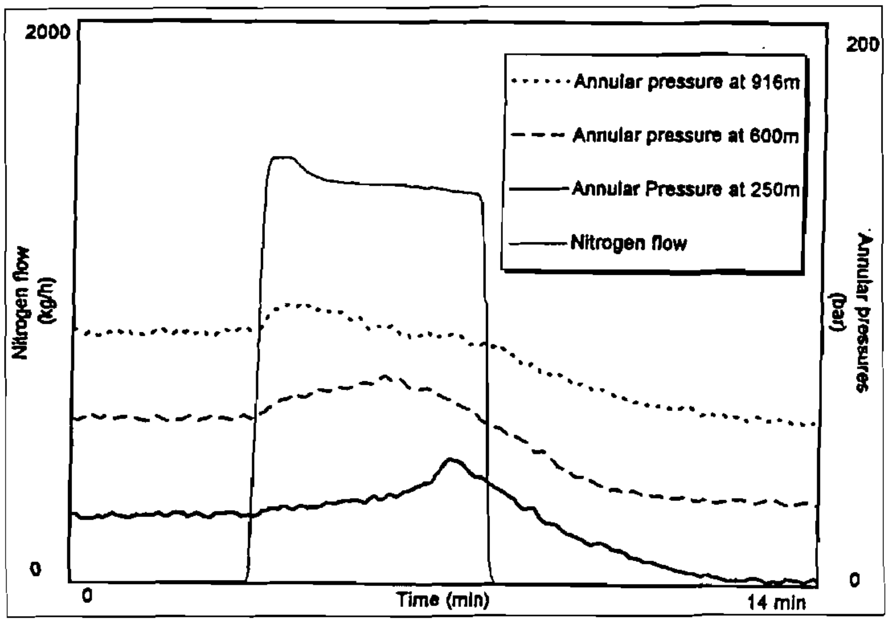

Figure 14-8. Gas Migration During Kick (Dupuis et al., 1995)

After gas had migrated out of the hole, wellbore pressures had been decreased by 30 bar, representing a loss of 305 m (1000 ft) of hydrostatic head.

14.2 FUGRO-McCLELLAND MARINE GEOSCIENCES (TOOL JOINTS FOR CORING)

Fugro-McClelland Marine Geosciences (Chatagnier and Head, 1995) described modified tool joints in U.S. Patent #5,425,428 to be used in slim-hole coring operations. Their invention addresses well-control concerns when running in or retrieving core barrels through the drill string. Grooves or other fluid passages are placed in the tool joints to allow fluid to bypass the core assembly.

Surge and swab pressures while tripping a core barrel can be a significant concern for formation fracturing or well control in slim-hole operations with small clearances. This invention reduces these pressures as the core barrel is tripped across a tool joint. In a conventional tool joint (Figure 14-9, left), reduced cross section causes significant increases in hydraulic pressure as the core barrel passes. A modified drill string with a larger tool-joint ID and a fluid passage across the tool joint is shown in Figure 14-9 (right).

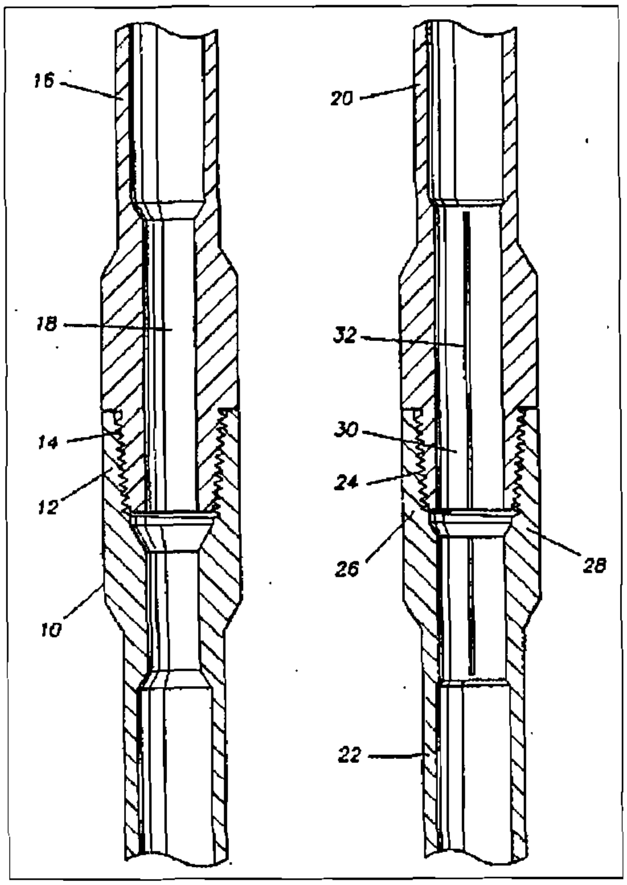

Figure 14-9. Conventional (left) and Improved (right) Tool Joints (Chatagnier and Head, 1995)

The inventors state that the special fluid passage across the tool joint can consist of a groove (no. 32 in the figure) or multiple grooves milled into the inner wall of the drill pipe. Another option mentioned is a fluid port drilled or formed in the tool joint to allow fluid flow out of the pipe.

14.3 MD TOTCO, BP EXPLORATION AND SHELL (FIELD TESTS OF EKD)

M/D Totco, BP Exploration, Shell KSEPL and NAM (Swanson et al., 1995) presented results of tests of the Early Kick Detection (EKD) system for slim-hole applications. The model was tested in a full-scale test well in which kicks could be simulated. Test results showed that dynamic modeling combined with smart alarms (for avoiding false alarms) could successfully differentiate kicks from normal drilling activities. Kicks could generally been detected at volumes of less than 42 gal.

The EKD system (Figure 14-10) is based on comparing predictions of flow out and stand-pipe pressure with real-time data. Measurements and predictions are compared using statistical process-control techniques and antifalsing logic to avoid false alarms. A variety of normal drilling operations can alter

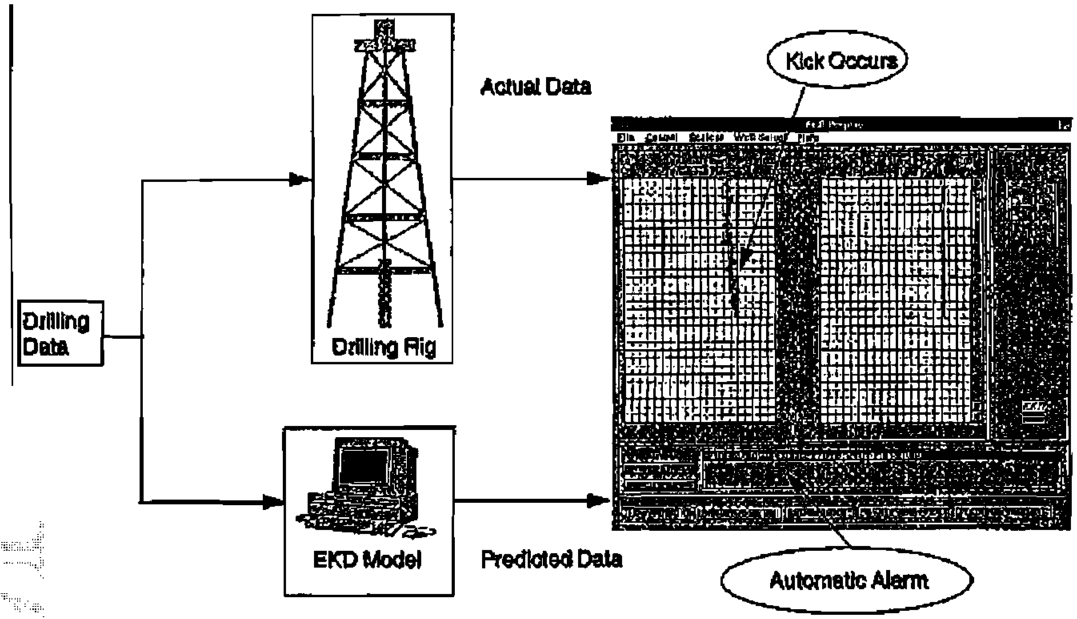

Figure 14-10. Schematic of EKD System (Swanson et al., 1995)

It is expected that model predictions and measured values will not necessarily match on a moment-to-moment basis. However, the trends should agree. EKD uses the Hinkley method for comparing statistically significant trends.

Input data required in real time at the rig site include flow in (an electromagnetic or ultrasonic flow meter), flow out (an electromagnetic meter or a J-meter), standpipe pressure, block position, hook load, rotary speed (impacts pressure losses in small annuli), hole depth, mud temperature, and mud density.

Tests were conducted with the system in a partially abandoned gas well in the Netherlands (Figure 14-11). A 2⅞-in. drill string is run inside 5½-in. casing. Tests used clear brine and viscosified brine. Primary test objectives were to discriminate between normal drilling events and kicks, and to detect kicks with different flow profiles.

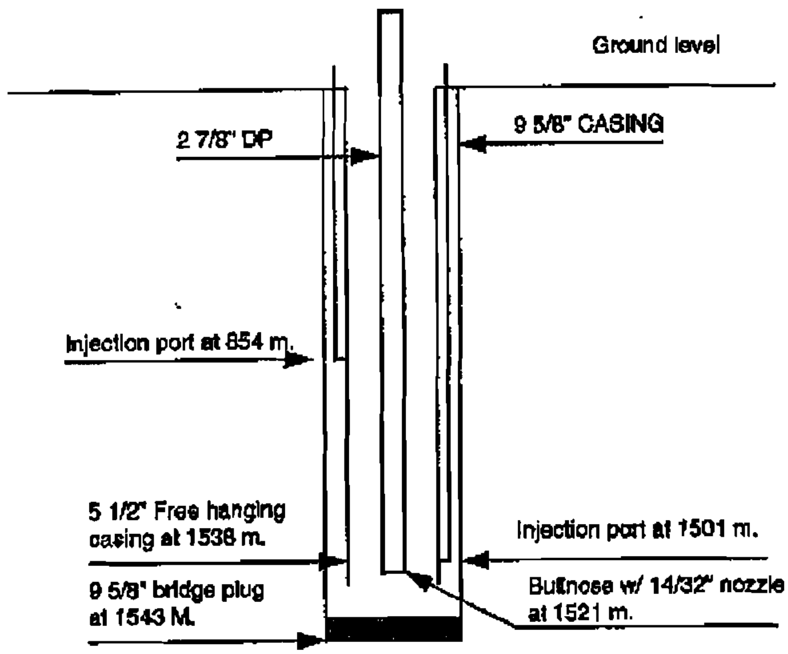

Figure 14-11. Test Well for EKD Tests (Swanson et al., 1995)

Nine kicks were simulated for normal drilling operations (Table 14-3). Kicks were not detected in two tests. In these cases, the flow-in meter failed. All four types of kick profiles were detected.

TABLE 14-3. Results of Simulated Kicks (Swanson et al., 1995)

Kick Profile	EKD Sensitivity	Detection Volume (gal)	Success (Y/N)
Medium	9.5	13.3	Y
Medium	9.7	32.0	Y
Slow	9.5	Test terminated early	N
Slow	9.5	23.3	Y
Medium	9.5	24.7	Y
Fast	9.5	27.0	Y
Very Slow	9.7	17.2	Y
Slow	9.7	19.4	Y
Fast	9.7	Test terminated early	N

A typical flow-out response is shown in Figure 14-12.

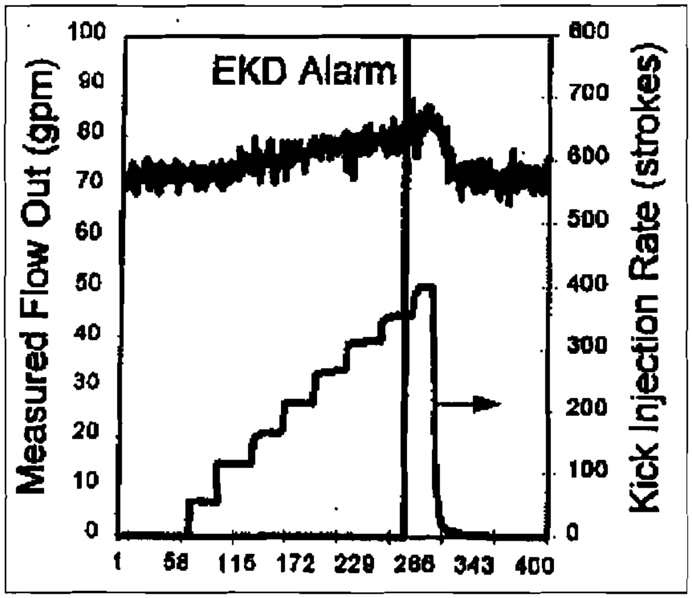

Figure 14-12. Typical Kick Simulation (Swanson et al., 1995)

Eleven kicks were simulated during pipe reciprocation procedures. These tests proved to be the most difficult conditions with respect to generating false alarms. The system detected only six of the kicks. Setting the EKD sensitivity to the correct range was found to be critical for these tests.

Tests were also devised to determine the ability of the EKD to avoid false alarms. Normal drilling activities were simulated with the system sensitivity at various settings. No false alarms were detected (Table 14-4).

TABLE 14-4. Results of False Alarm Tests (Swanson et al., 1995)

Activity	EKD Sensitivity	Detection Volume (gal)	Success (Y/N)
Connection	9.2	No Detection	Y
Connection	9.5	No Detection	Y
Connection	9.7	No Detection	Y
Connection	9.5	No Detection	Y
Connection	9.7	No Detection	Y
Pump change/ pipe movement	9.7	No Detection	Y

The system was also able to discriminate between normal events and kicks. In one case, a kick was detected that occurred after a pipe connection (Figure 14-13).

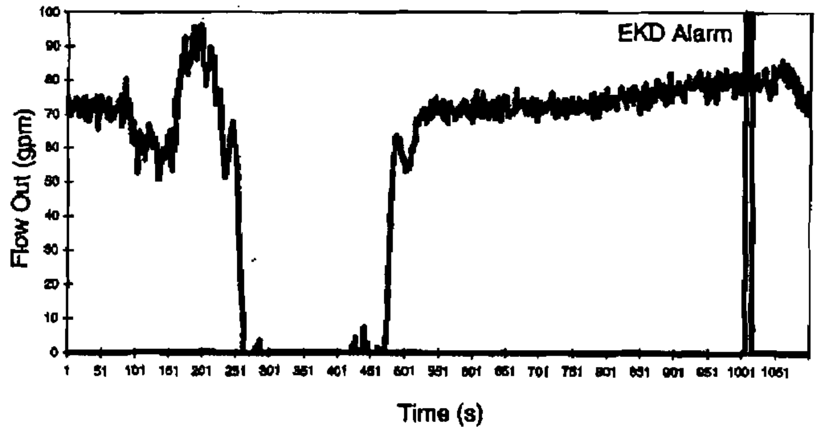

Figure 14-13. Simulated Kick After Connection (Swanson et al., 1995)

14.4 MOBIL E&P (SLIM-HOLE OFFSHORE DRILLING SYSTEMS)

Mobil Exploration and Producing (Shanks, 1995) considered the design of slim-hole drilling and coring systems for offshore applications. They suggest that technologies exist or can be developed for harsh environments (deep wells, HTHP wells and difficult geologies). Slim-hole technology can save money offshore, but its strengths and weaknesses must be recognized. Offshore costs for floating operations are dominated by vessel day rates. Intangibles account for 80-85% of total costs. The most practical approach to reducing costs is therefore to reduce drilling time. Additional cost reductions can be achieved by reducing casing for all strings.

The most critical technology for adapting mining systems for offshore operations is the need to provide adequate heave compensation from floating vessels. One of the most critical aspects of slim-hole coring operations is the need to maintain consistent WOB. Motion compensators on most offshore rigs are not sufficiently precise. Typical operating ranges are within 3000 to 6000 lb at a WOB of 40,000 lb. Slim-hole requirements may be close to 2000 lb WOB with a precision of 500 lb. Development of effective heave-compensation systems for slim holes has met with some success and continues at present.

Well-control considerations would be important challenges in these offshore applications. Kick detection is normally complicated with floating vessels because rig heave causes variations in the return flow. In slim holes with tight annular clearances, special methods would be required for accurate measurement of differential flow (Figure 14-14).

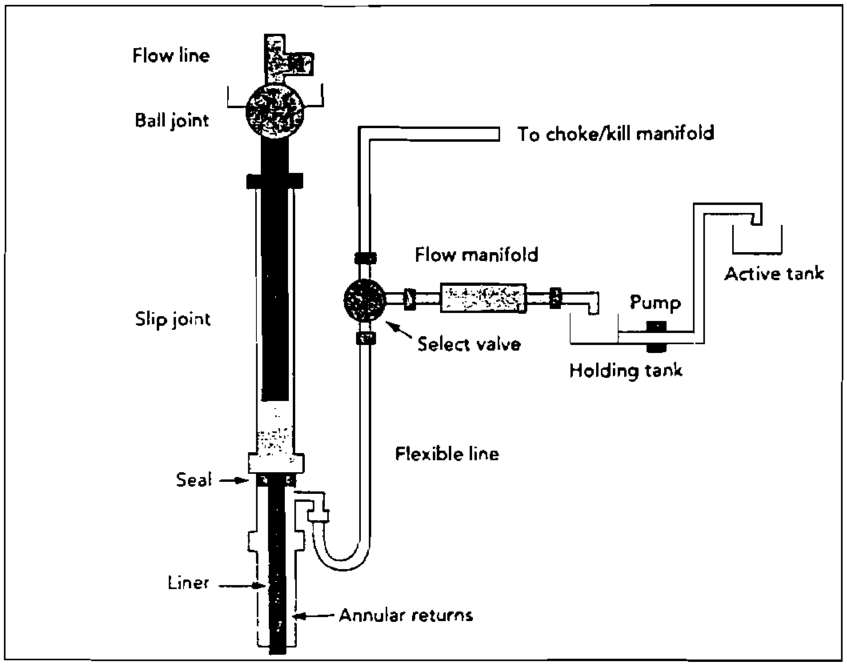

Figure 14-14. Offshore Differential Flow Measurements (Shanks, 1995)

New techniques may also be required for circulating out a kick. It may not be practical to use standard choke and kill lines because of substantial weight relative to the riser. Other options exist including composite choke and kill lines, reverse circulation up the drill pipe, a seafloor choke system, or very low pump rates through slim choke and kill lines.

Additional discussion is presented in *Coring Systems*.

14.5 PANHANDLE EASTERN AND SLIMDRIL (HORIZONTAL STORAGE WELL)

Panhandle Eastern Pipe Line Company and SlimDril International (Gredell and Benson, 1995) described planning and successfully drilling/completing a slim horizontal into the Howell gas storage field in Livingston County, Michigan. A new well with a 2000-ft lateral was placed under the city of Howell. Costs, while higher than normal due to the stringent requirements for drilling in an urban setting, were considerably reduced by slim-hole technology. A slim well design was selected to minimize rig requirements and conserve space. The horizontal well produced at rates about 4 times greater than a nearby offset vertical well.

About one-third of the storage field lies under the city. Cycling of stored gas in this section of the reservoir was limited by a lack of wells (Figure 14-15). This problem was confirmed by shut-in pressure data from wells in this section. Objectives of the project included increasing the volume of working gas that can be cycled from the field, and increasing the deliverability (production rate) during late-season drawdown.

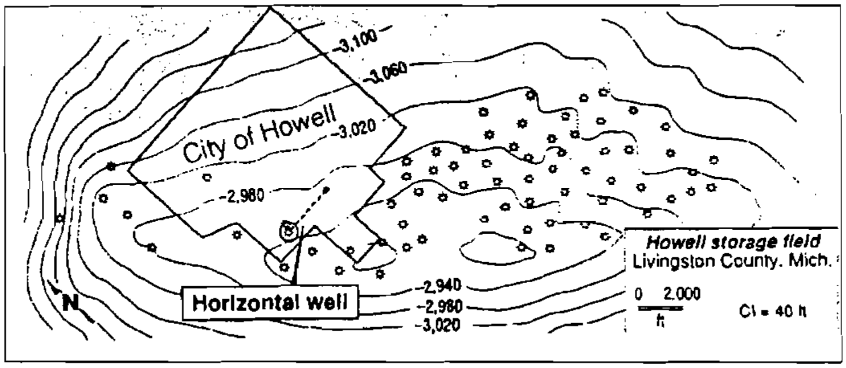

Figure 14-15. Howell Field Storage Wells (Gredell and Benson, 1995)

A clear brine fluid was used for drilling the lateral to minimize formation damage. Low solids were maintained to minimize damage, torque and drag. High-viscosity sweeps were periodically run to clean the hole. The BHA (Figure 14-16) included a 4¾-in. PDC bit, a 3⅜-in. motor and two Monel drill collars.

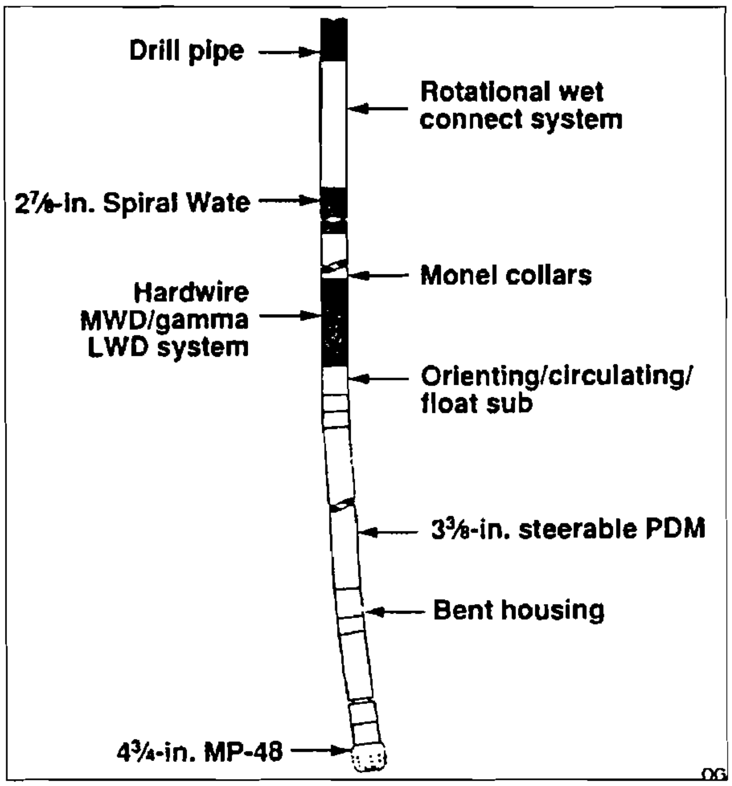

Figure 14-16. Drilling BHA (Gredell and Benson, 1995)

The first section of the lateral was drilled at very high ROPs (over 60 ft/hr). During a connection, a kick occurred and unloaded most of the annular volume. The relatively small annulus was believed to be a key factor in the impact of the kick. Drilling was resumed after the well was killed and the mud weight stabilized. After that point, ROP was limited to 20-30 ft/hr to control the gas influx into the annulus.

After the well was tied into the field pipeline, stable flow rates of up to 100 MMscfd were recorded. This represents about four times the productive capacity of a vertical well.

Additional information is presented in *Horizontal Drilling*.

14.6 RF-ROGALAND, AGIP AND ELF AQUITAINE (TESTS OF KICK-DETECTION SYSTEMS)

RF-Rogaland Research, Agip SPA and Elf Aquitaine Production (Steine et al., 1996) performed a series of well-control experiments in an inclined onshore research well in Stavanger (Figure 14-17). Tests included gas kicks, annular pressure loss measurements and surge/swab effects. Three different commercial kick-detection systems and one flow meter were tested. They found that flow checks are recommended for slim holes, that gas kicks develop very quickly, that critical parameters should be monitored very carefully, and that the impact of drill-pipe rotation on ECD is significant and may increase frictional pressure losses as much as 30%. Surge/swab pressures over 100 bar (1450 psi) were also observed during the tests.

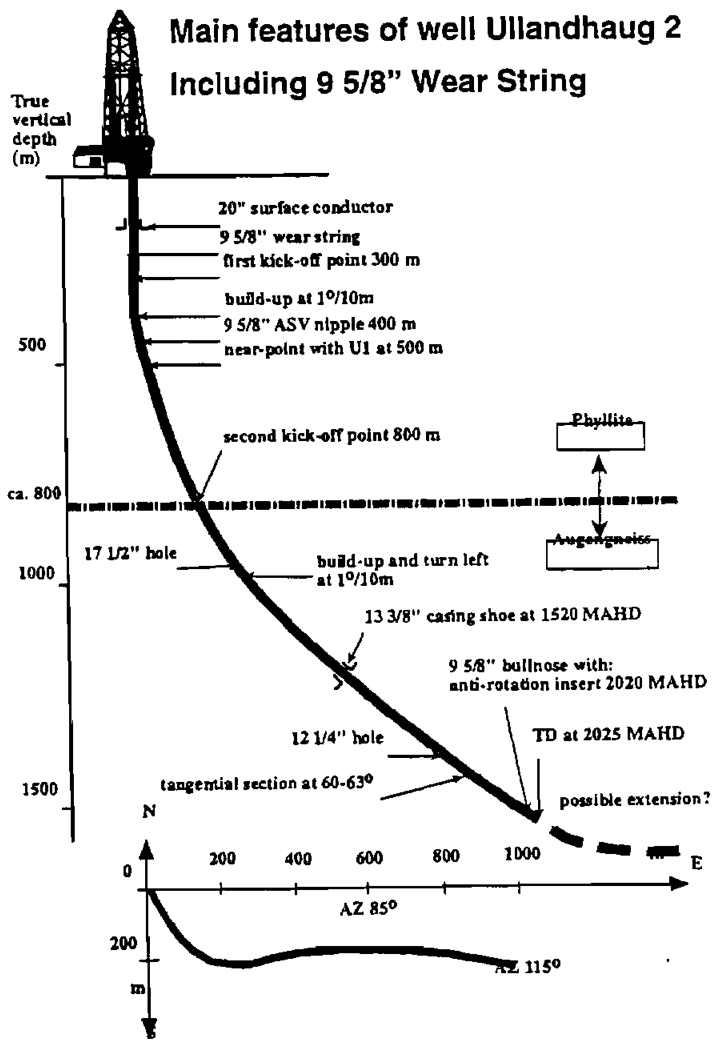

Figure 14-17. Ullandhaug 2 Test Well (Steine et al., 1996)

A 5-in. casing was run inside the test well to provide a slim-hole geometry. The drill string consisted of 758 m (2487 ft) of 3.7-in. CHD 101 drill rod and 1178 m (3865 ft) of 3.65-in. drill string with 4⅛-in. upsets. The surface equipment was heavily instrumented (Figure 14-18). Flow in was measured with a 4-in. electromagnetic flow sensor. Return flow was measured by a 6-in. meter.

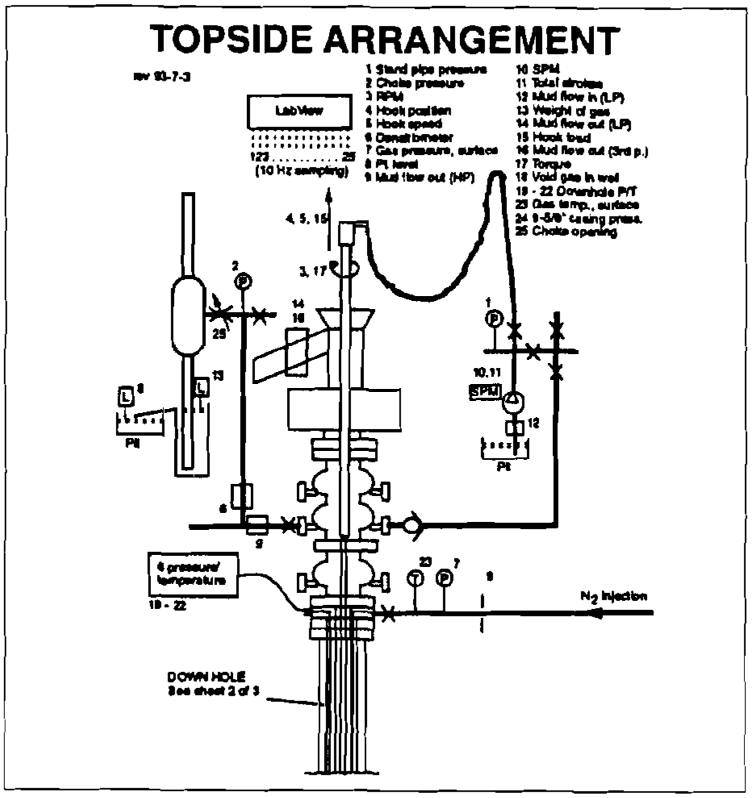

Figure 14-18. Sensors on Test Well (Steine et al., 1996)

The three systems tested included the Smedvig Gas Kick Detection system (an acoustic system), the DrillByte KickDetect, and the Baker Hughes INTEQ KDS system. During the kick simulation tests, the J-meter was very sensitive as long as it was maintained properly, the KDS system performed well, and the KickDetect gave good results (although less reliably than KDS). The Smedvig system gave an early alarm, but only when free gas was present in the annulus.

Flow rates are compared for one of the gas kicks in Figure 14-19.

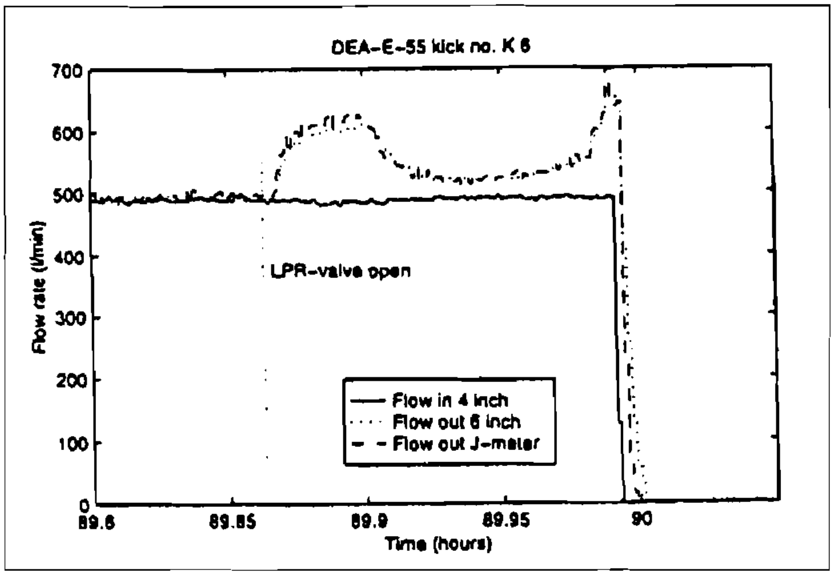

Figure 14-19. Flow Rates for Gas Kick (Steine et al., 1996)

Output data from INTEQ's KDS system for the same kick are shown in Figure 14-20.

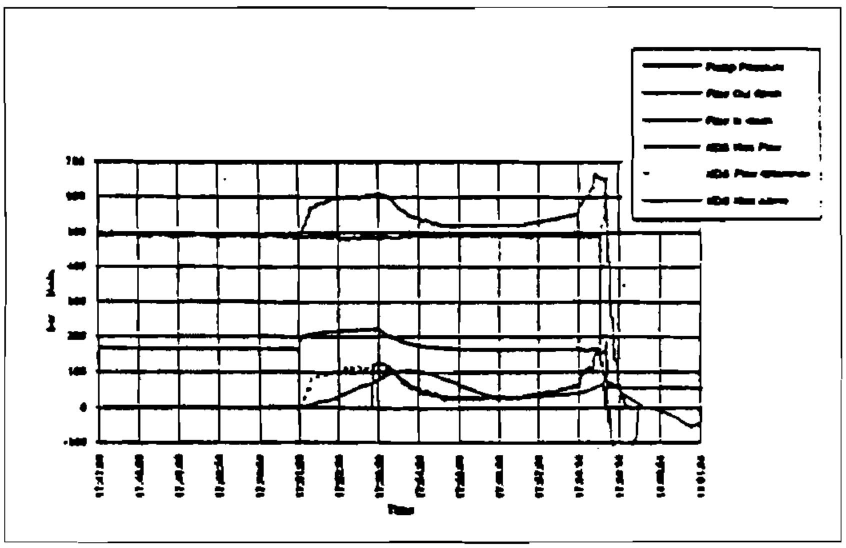

Figure 14-20. Data from KDS System (Steine et al., 1996)

Output data from the Petreco J-meter for the same kick are shown in Figure 14-21.

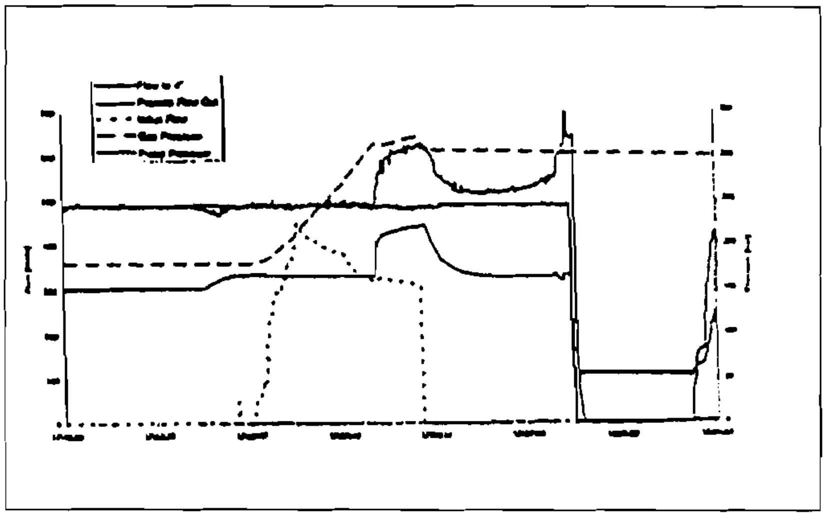

Figure 14-21. Data from Petreco J-Meter (Steine et al., 1996)

Data recorded by the downhole pressure gauges for the same kick are shown in Figure 14-22.

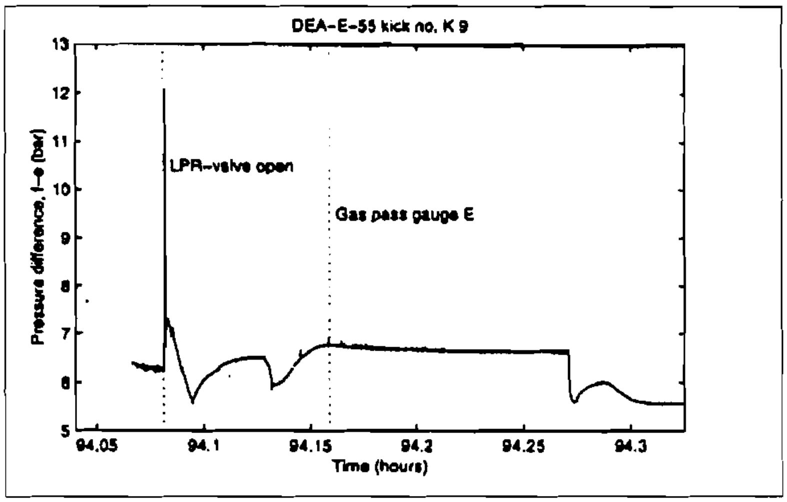

Figure 14-22. Downhole Pressure During Gas Kick (Steine et al., 1996)

The project team also investigated the effects of drill-string rotation on pressure losses in the small annulus. Rotary speed was cycled between 200, 350 and 500 rpm at increasing flow rates (Figure 14-23).

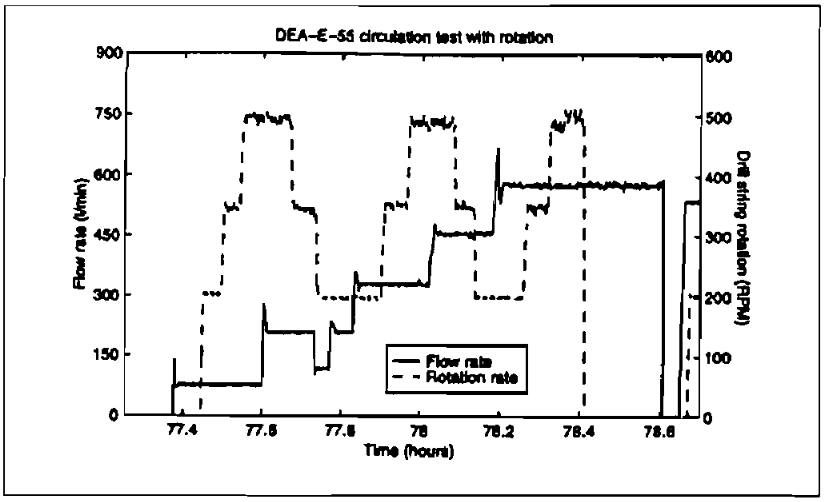

Figure 14-23. Rotation and Circulation Test (Steine et al., 1996)

Significant surge/swab effects were observed. Downhole pressure data show pressures in excess of 100 bars can occur at faster tripping speeds (Figure 14-24).

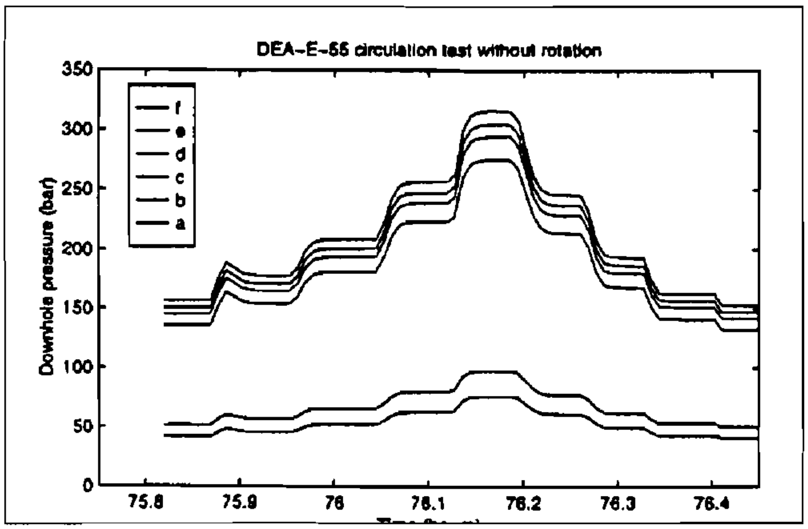

Figure 14-24. Downhole Surge/Swab Pressures (Steine et al., 1996)

14.7 TEXAS A&M UNIVERSITY (WELL-CONTROL MODEL)

Texas A&M University (Choe and Juvkam-Wold, 1996) presented an analysis of well-control procedures based on their simplified two-phase model that analyzes kick and pressure responses in directional/horizontal slim holes and wells drilled with coiled tubing. They compared theoretical kill sheets to conventionally devised procedures. Conventional kill sheets overestimated kill pumping pressures. For directional/horizontal wells with high build rates, choke pressure is predicted to change quickly without much kick expansion due to changes in TVD as the kick migrates through the curve. Their study results suggested that a theoretically based kill sheet should be used for kill procedures in slim directional/horizontal wells, along with a small safety overpressure.

Choe and Juvkam-Wold's model is based on unsteady two-phase flow, one-dimensional flow along the wellbore, water-base mud, negligible gas solubility, incompressible mud, known mud temperature with depth, and the kick enters the well at current TD. Eight parameters are used to describe the system: pressure, temperature, and gas and liquid fractions, densities and velocities.

In conventional operations, frictional pressure losses at low kill rates are normally minor. However, frictional pressure losses are often critical for slim holes, for coiled-tubing drilling, and in choke/kill lines for offshore wells.

Specifications for the slim-hole well analyzed in the well-control study are shown in Table 14-5.

TABLE 14-5. Well Specifications for Well-Control Study (Choe and Juvkam-Wold, 1996)

Initial kick volume, bbls	2.0
Mud density, ppg	12.0
Plastic viscosity, cp	10.0
Yield point, lbf/100 ft^2	15.0
Bit nozzle diameter, 1/32 in.	3 x 10
Well true vertical depth, ft	10,000
Depth of casing seat, ft	6,000
Inner diameter of last casing, in.	5.0
Open hole diameter, in.	4.25
OD & ID of drill pipe, in.	2.875 x 2.441*
Pump capacity, bbls/stroke	0.17
Pump rate while drilling,gpm	143.
Kill mud pump rate, gpm	5.0
Kick intensity, ppg	1.0
Gas specific gravity (air = 1.0)	0.65
Surface temperature, °F	70.0
Mud temperature gradient, °F/100 ft	1.6
Formation permeability, md	5.0
Final hold length, ft	2,000**
Depth of kick-off point, ft	6,000**
Build-up rate, deg./100 ft	1.443**

*also used for coiled tubing OD and ID

**for horizontal wells

Choke pressures for a well with a 2000-ft horizontal section are shown in Figure 14-25 based on both the engineer's and driller's methods. No hydrostatic pressure reduction occurs in the annulus while the 2-bbl kick remains in the horizontal section. Therefore, the SICP and SIDPP are equal (520 psi) until the influx begins to rise. The reduction in choke pressure due to the kill mud (engineer's method) is not large because the effect of gas expansion near the surface dominates.

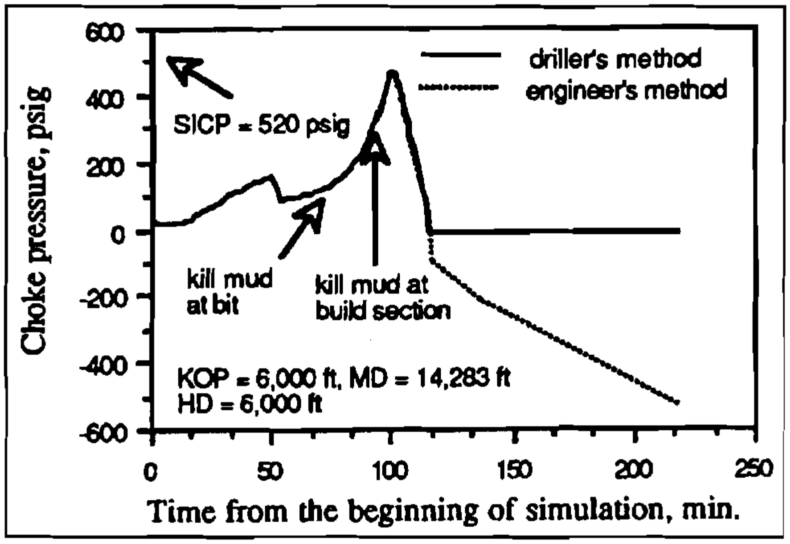

Figure 14-25. Choke Pressures in Horizontal Well (Choe and Juvkam-Wold, 1996)

Kill sheets based on model predictions and conventional field procedures were compared. Kill sheets map the choke pressure required to maintain constant bottom-hole pressure. In the field, detailed hydrostatic and frictional pressure data are not readily available. Kill sheets are often constructed by calculating initial and final circulating pressures and assuming a linear path between them.

A comparison of modeled and field kill sheets for a vertical slim-hole well is shown in Figure 14-26. The conventional kill sheet maintains bottom-hole pressure above formation pressure by an amount equal to annular pressure losses. This overpressure may be too large in slim annuli, leading to fracturing, lost circulation etc.

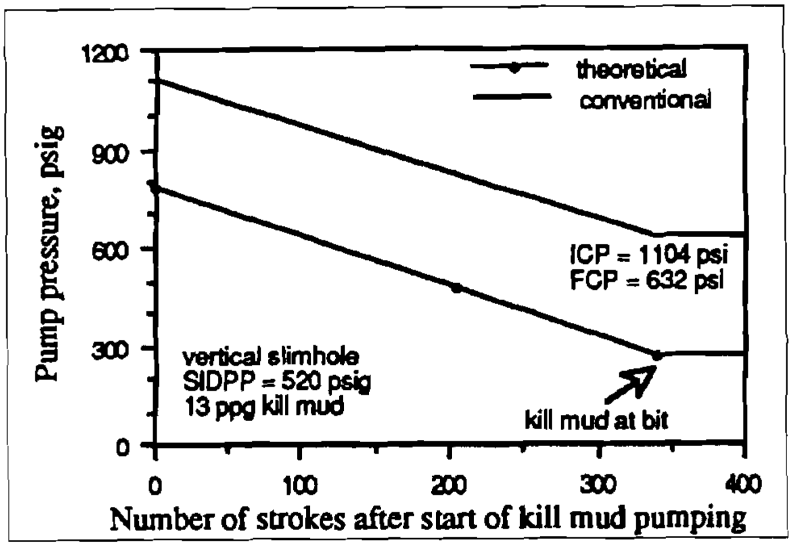

Figure 14-26. Kill Sheets for Vertical Slim Hole (Choe and Juvkam-Wold, 1996)

Kill sheets for a slim horizontal well with a 4000-ft lateral are compared in Figure 14-27. Pump pressure is minimum when the kill mud first arrives at the lateral TVD. With the conventional sheet, bottomhole pressure may be too high, resulting in failure of the casing shoe.

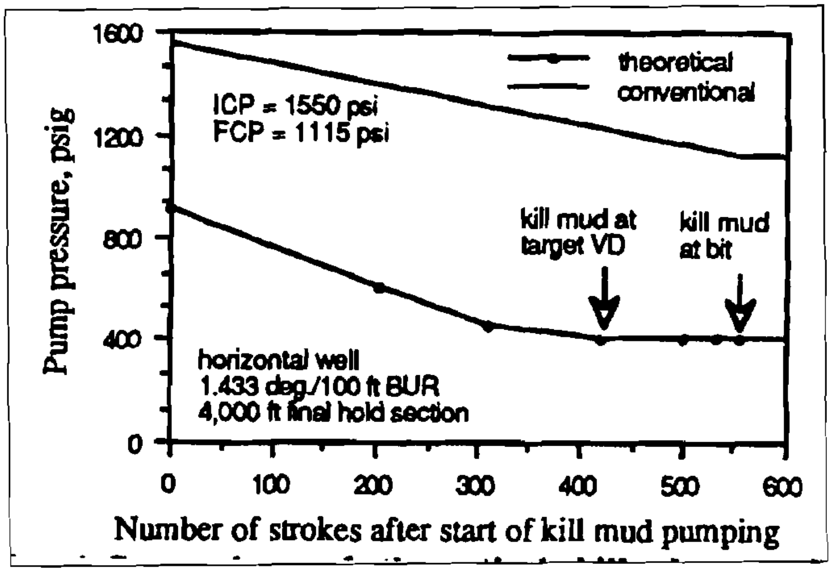

Figure 14-27. Kill Sheets for Horizontal Slim Hole (Choe and Juvkam-Wold, 1996)

The same 4000-ft horizontal well was assumed for another case, this time drilled with coiled tubing (Figure 14-28). Pressure is constant until kill mud fills the entire spool on the rig (4000 ft assumed). For higher kill rates, pump pressure will increase due to frictional pressure drop in the spool.

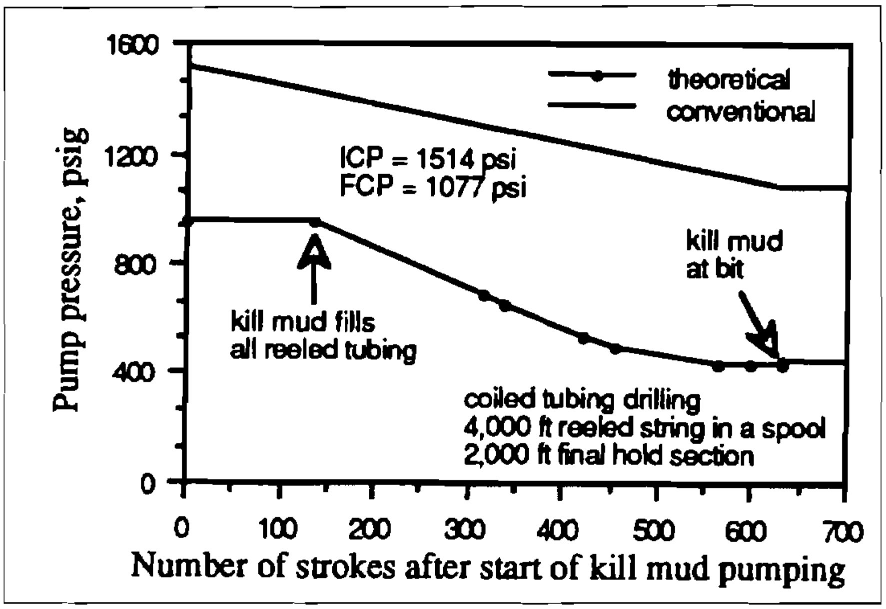

Figure 14-28. Kill Sheets for Horizontal Slim Hole Drilled with CT (Choe and Juvkam-Wold, 1996).

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Appendix A
Slim-Hole References

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