GRI-95/0182

Slim-Hole Drilling and Completion Barriers

FINAL REPORT

(July 1993 - April 1995)

Prepared By:

R. Allen Shook
James A. Dech
William C. Maurer, Ph.D.
Maurer Engineering Inc.

Ron P. Matson
Dan T. Mueller
BJ Services Company, U.S.A.

Mark Hopmann
Baker Oil Tools

Paul Boonen, Ph.D.
Halliburton Energy Services

Scott R. Reeves
Advanced Resources International

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GRI Technology Manager
John Hansen

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16. Abstract (limit: 200 Words)

The objective of this project was to identify the barriers to greater use of slim-hole techniques for reducing the cost to drill and complete U.S. gas wells.

An industry team consisting of Maurer Engineering Inc., BJ Services, Baker Oil Tools, Halliburton Energy Services, and Advanced Resources International analyzed technical issues in drilling, cementing, logging, perforating, stimulation, and completion and workover tools. U.S. slim completion activity was analyzed and a case study of an active slim completion area, the Denver-Julesberg Basin, was performed. A comprehensive questionnaire was distributed and results analyzed to determine perceived slim-hole barriers.

There have been many projects developing technology and information for slim-hole drilling and completion, but little of this has been integrated and utilized for onshore U.S. drilling. Slim completions are being used on an increasing basis for U.S. gas wells but are not typically placed in slim holes. The greatest perceived barriers to the use of slim-hole techniques are related to concerns over the ability to repair (workover) wells and a low appetite for lengthy learning curves associated with a slim-hole approach. Other large perceived barriers include the ability to obtain necessary log data and limitations imposed by increased stimulation friction pressure.

An integrated field testing program in relevant U.S. gas plays is needed to demonstrate the true potential of modern slim-hole technology and drive the most appropriate individual technology developments for U.S. gas drilling.

17. Document Analysis a. Description

Slim Hole, Drilling, Slim Completion, Drilling Costs, Completion Costs

b. Identifiers/Open-Ended Terms

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Research Summary

Title:	Slim-Hole Drilling and Completion Barriers
Contractor:	Maurer Engineering Inc. 2916 West T.C. Jester Houston, TX 77018-7098
GRI Contract No.	5093-222-2603
Principal Investigator:	W.C. Maurer, Ph.D.
Report Period:	July 1993 — May 1995
Objective:	To identify and evaluate the barriers to greater use of slim-hole drilling and completion techniques for reducing the cost of drilling and completing U.S. gas wells.
Technical Perspective:	Increasingly marginal natural gas plays and shorter than initially-modeled hydraulic fractures have renewed a need for technologies that can substantially reduce drilling and completion cost beyond only incremental steps. Slim-hole drilling and completion techniques have the potential to provide methods of reducing well costs in many categories such as tubulars, rig costs, transportation, location, mud, and cement. In addition, adverse environmental impact can be minimized. Many U.S. gas wells appear to be ideal candidates for slim-hole techniques because of relatively low producing volumes and infrequent need for high-volume artificial lift. Despite this potential, vertical slim-hole drilling and completions are not widely used in the U.S.
Technical Approach:	For this project, *a slim completion* is defined as a well with final production casing size of 4 in. or less, regardless of hole size. *Slim-hole drilling* is generally defined as a final hole size of less than 6 in., while acknowledging that in many areas any size below 7⅞ in. can be considered slim. An industry team consisting of Maurer Engineering Inc., BJ Services, Baker Oil Tools, Halliburton Energy Services, and Advanced Resources International investigated technical issues and barriers related to slim-hole techniques in the areas of drilling, logging, cementing, perforating, stimulation, and completion and workover tools. Producer and service company interviews and literature reviews were used as additional sources of information. An analysis of U.S. slim-completion activity and trends was performed by obtaining a customized database from Petroleum Information Corp. A comprehensive questionnaire was constructed and distributed to a targeted sample for analysis of industry perceptions regarding slim-hole barriers. A case study of a very active basin where slim completions are regularly utilized, the Denver-Julesberg Basin, was performed. An independent market assessment previously performed for a group of service

companies was obtained. A 59-participant Drilling Engineering Association-sponsored project studying slim-hole and coiled-tubing technology was joined for information exchange.

All of these analyses and information sources were integrated and used to identify current state-of-the-art systems, identify technology needs, and recommend courses of action for reducing the barriers to greater use of slim-hole techniques.

Results: The greatest *perceived* barriers to slim-hole techniques relate to a continued concern about the ability to workover wells, an apparent low appetite for potentially lengthy learning curves associated with adopting slim-hole drilling techniques, logging limitations, and stimulation friction pressure. However, there have been many industry projects by multiple producer and service company groups developing advanced technology and information for slim-hole techniques over the past ten years. This includes the areas of hydraulics, kick detection/well control, bits, drill strings, downhole motors, and rig design. Little of this technology and information has been integrated and used for U.S. onshore gas well drilling. The use of *slim completions* for U.S. gas wells has increased from 3% to 6% of total onshore U.S. gas wells from 1989 to 1993 with increases occurring in Colorado, Texas, and Oklahoma. Most of these slim completions are not placed in slim holes, but do require substantial hydraulic fracture treatments. The most important action that can be taken near-term to accelerate the usage of slim completions and slim-hole drilling is implementation of cooperative slim-hole field test programs with U.S. gas producers that will integrate the latest technology, experience, and knowledge. This will establish the true slim-hole state-of-the-art and ultimate potential of this technology for U.S. gas well drilling. In addition, this will drive the most appropriate individual technology developments for domestic onshore drilling.

Project Implications: Slim-hole drilling and completion techniques offer substantial potential for decreasing well costs. Making this potential a reality for U.S. gas producers will require an integrated effort of technology testing in relevant settings, transferring the latest information and data, and developing advanced individual technologies. Because of its great potential, GRI has committed to a slim-hole RD&D program and will use the results of this project to plan and implement such a program. In addition, the comprehensive report should provide a useful slim-hole technology resource for U.S. gas producers and service companies.

GRI Project Manager
John T. Hansen
Technology Manager, Drilling & Completion Group

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Executive Summary

A study was performed to identify barriers to greater use of slim-hole techniques to reduce the cost of drilling and completing U.S. gas wells. The study was conducted by an industry team consisting of Maurer Engineering, BJ Services, Baker Oil Tools, Halliburton Energy Services, and Advanced Resources International. Specific tasks included U.S. activity assessment and analysis of technical issues in the areas of drilling, cementing, logging and perforating, stimulation, and completion, workover and fishing tools. Barrier surveys were distributed and analyzed, a case study of the Denver-Julesberg basin was performed, and a slim-hole savings impact model was constructed.

A *slim completion* is defined as a well with final production casing size of 4 in. or less. *Slim-hole drilling* is more contingent on location but is analyzed in this study generally with regard to hole sizes of less than 6 inches.

ACTIVITY

Figure 1 shows how slim completion activity in U.S. gas wells has increased from 3 to 6% of U.S. gas completions since 1991.

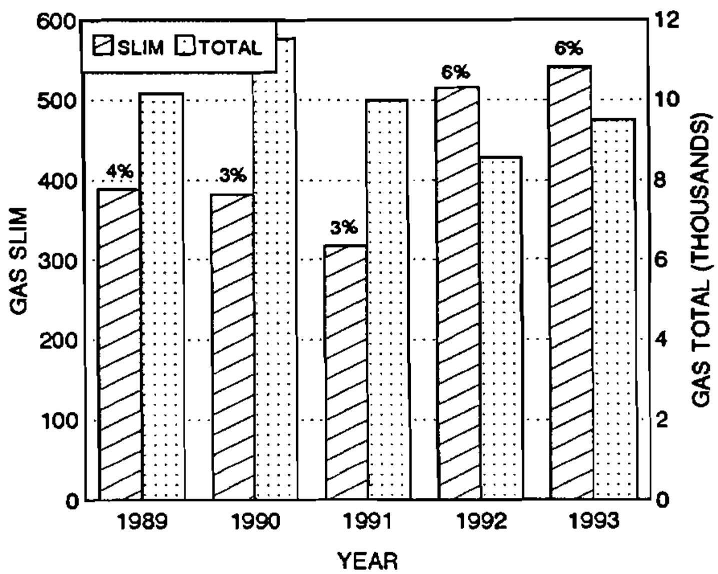

Figure 1. Recent U.S. Slim Gas Completion Activity

The largest increase occurred in Colorado, but activity has also increased in Texas and Oklahoma. Most of these slim completions are 2⅞-in. tubingless completions placed in conventional size holes (Figure 2). The use of 3½-in. casing is also increasing, especially in the D-J Basin, Colorado.

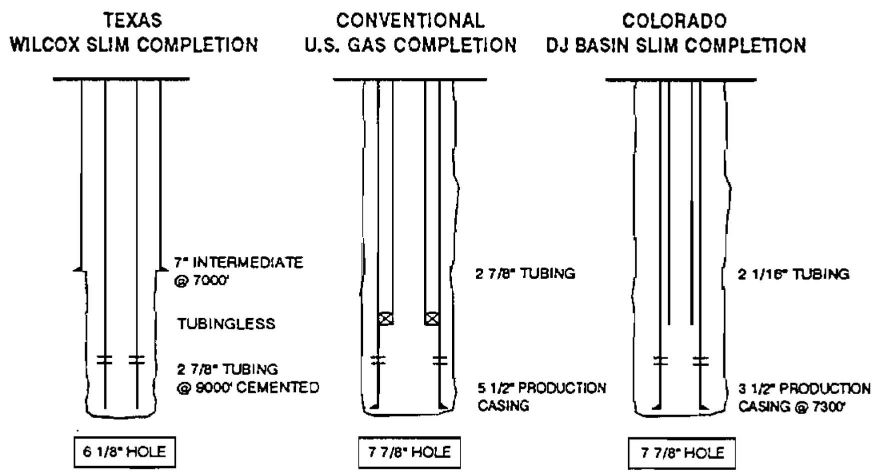

Figure 2. U.S Conventional and Slim Completions

DRILLING

Barriers to effective slim-hole drilling include reduced performance and life of small diameter bits and downhole motors, weaker drill strings, small annuli effects (hydraulics, kick detection, well control, and fishing), lack of dedicated rigs, and very limited experience. Figure 2 shows how bit options are reduced for small diameter drilling.

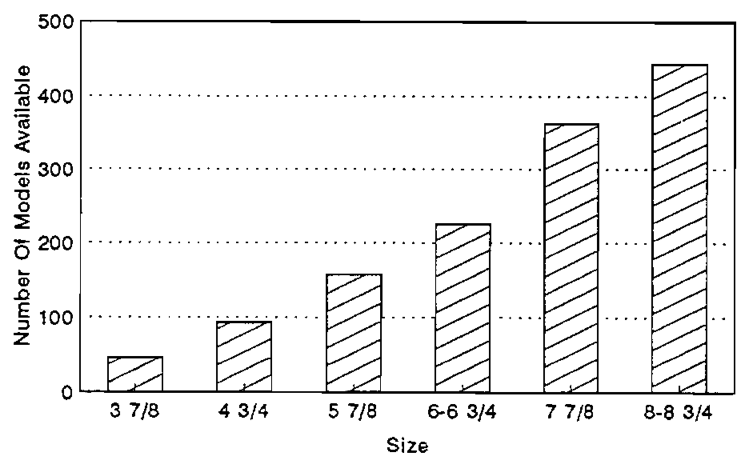

Figure 3. Bit Options

Several projects over the past five to ten years by multiple groups have substantially advanced technology for, and the understanding of, drilling slim holes. Very little of this technology has been integrated and used for vertical U.S. gas well drilling. Coiled-tubing drilling is a rapidly growing niche with near-term beneficial application primarily for horizontal re-entries, vertical deepenings, shallow new wells with severe surface location restrictions, and especially underbalanced drilling.

LOGGING

Most commonly requested logging tools, such as the triple-combo, are now available in slim-hole configurations. Notable exceptions include imaging tools and dipmeters. Slim-hole formation testers are also now available. Slim-hole logging tools are typically packaged in hostile-environment equipment and are usually more costly with availability more limited. Standard 3⅝-in. tools can be run in 4¾-in. holes if the hole is in good condition and the logging interval is not lengthy. Independent studies comparing conventional and slim-hole log data would be beneficial.

CEMENTING

Aggressive cementing in small annuli is similar to many liner applications (Figure 4). More rigorous slurry and job design, execution, and quality control is needed. A study of the long-term competency of thin cement sheaths is needed.

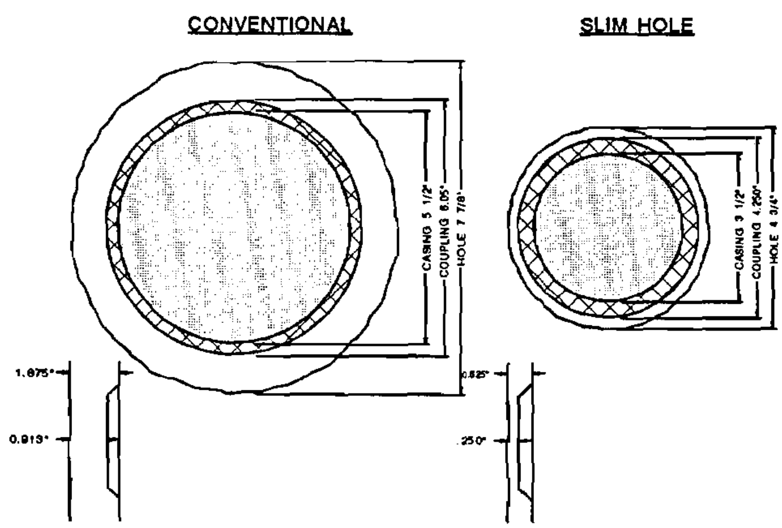

Figure 4. Wellbore Geometries

STIMULATION

The largest concern with hydraulic fracturing in small diameter completions is increased friction and shear and uncertain performance through smaller and shorter perforations. Figure 5 shows how hole diameter and tunnel length are reduced with use of the smaller perforating equipment to which slim completions are restricted.

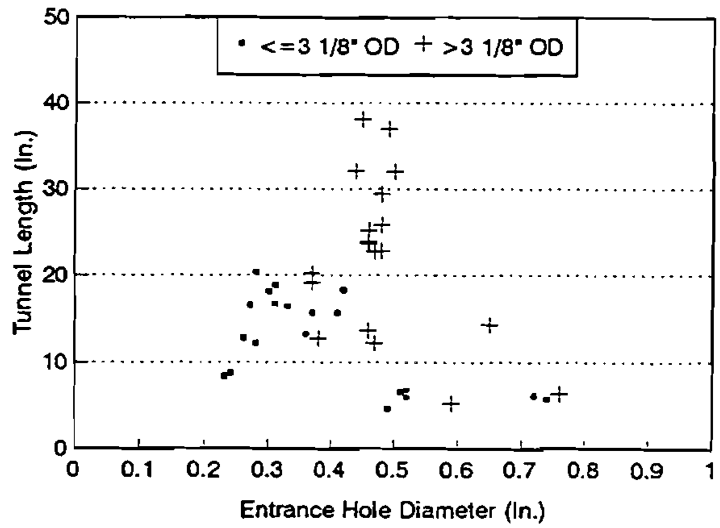

Figure 5. Typical Perforation Diameters and Tunnel Lengths

COMPLETION, WORKOVER, AND FISHING TOOLS

Through-tubing and coiled-tubing developments have increased small diameter tool options available for many gas well requirements. As with logging tools, availability may be more limited and systemization and refinement are needed. Improvements needed include increased strengths with minimized diameters, improved fishing tools and techniques, and more sand control options. The use of 3½-in. casing greatly increases flexibility over, for example, the use of 2⅞ inch.

PERCEIVED BARRIERS

Analysis of barrier survey responses indicate that concerns with workover limitations and completion tools are among the greatest perceived barriers to use of slim techniques (Figure 6). In addition, a very low appetite for lengthy learning curves and/or uncertain outcomes associated with slim-hole techniques is evidenced by *Management Attitude* being the second highest-ranked barrier by respondents. Also important is that respondents perceive barriers to gas well applications to be considerably lower than to oil well applications.

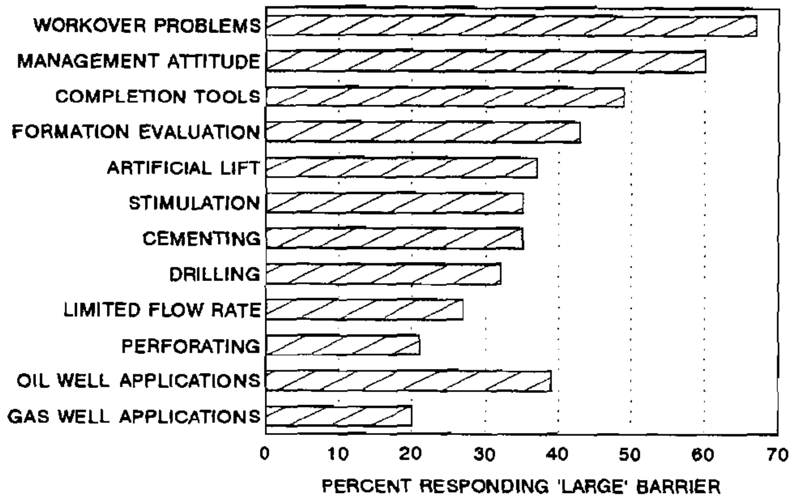

Figure 6. Responses To Barrier Survey – Overall Areas

Highly ranked individual items include fishing tools, logging tools, stimulation friction pressure and proppant transport, downhole motors, well control, MWD, coiled tubing (drilling), service company experience (formation evaluation), and mechanical packers.

CONCLUSION AND RECOMMENDATIONS

Comparison of perceived barriers to the analyses conducted in the overall project indicates actual barriers may be less than perceived in many areas, including workover and completion tools, stimulation, and logging tools. In general, a lack of integration of new technology and information and a low U.S. experience base are hindering the greater use of slim-hole techniques for gas well drilling and completions. An R&D program structured around the following components would be of great benefit to the U.S. gas industry.

Slim-Hole Field Testing/Demonstration Program

Testing and demonstration is needed of state-of-the-art slim-hole drilling and completion technology in multiple wells in multiple basins with multiple operators. This will define the true potential of the technology, as well as drive appropriate individual technology development, begin to establish consistent standards, and allay potential regulatory agency and land/mineral owner concerns.

Analysis and Transfer Of Current and Future U.S. Slim Activity

Detailed analysis should be performed of current and future U.S. slim-hole drilling and completion activity, including tools and techniques, production and workover histories, life-cycle costs, and database development. An independent slim-hole focal point is needed to integrate this information specifically for the needs of the U.S. gas industry.

Development Of Slim-Hole Drilling And Completion Manual

Specifically for U.S. gas well drilling, this manual should be a logical *end-product* of a comprehensive field test program. This is analogous to the coalbed methane manuals developed by GRI near the end of the research efforts in the Black Warrior Basin and San Juan Basin.

Individual Technology Development

The project has identified many drilling and completion technologies that need to be improved, tested, or developed in various areas. This activity should be pursued with continuous interaction with the field test program to ensure the most relevant developments for U.S. gas drilling. Some of the most important include small diameter bits and motors (important for conventional rig and coiled-tubing drilling), better drilling hydraulics models, improved fishing tools and techniques, improved small-diameter perforating equipment performance, better understanding of small diameter and short tunnel length perforation effects on fracturing (in specific applications), and advanced completion and workover tools and options.

POTENTIAL IMPACT

A savings model was constructed to compare the impacts of various assumptions regarding slim completion escalation, slim-hole drilling escalation, and cost savings specific to each. Conservative assumptions of about 15% overall well cost savings on initial well costs for an 8-10,000 ft. well (baseline drilling and completion cost of $774,000), 10.5% of U.S. gas wells using slim completions (currently about 7%), and 1.1% of U.S. gas wells using slim-hole drilling (currently about .5%), results in *incremental present value* savings of almost $100 million from 1995 to 2010. Figure 7 shows the range of results for all cases modeled.

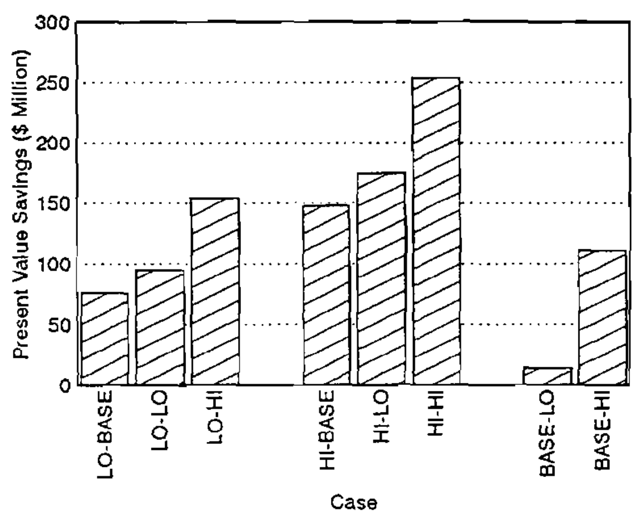

Figure 7. Potential Slim-Hole Impact On U.S. Gas Industry

1. Introduction

The National Petroleum Council's (NPC) 1992 study and GRI's 1994 projections of natural gas supply and demand indicate the growing demand for natural gas can only be met at competitive market prices if supply technology improvements continue at the current rapid pace (Figure 8). GRI has successfully focused research on advanced technology for formation evaluation, completion, and stimulation technologies since about 1983. One important conclusion from this research is that hydraulic fractures are not as long as early modeling theory predicted, resulting in a large gas resource that can only be recovered by drilling a greater number of development wells.

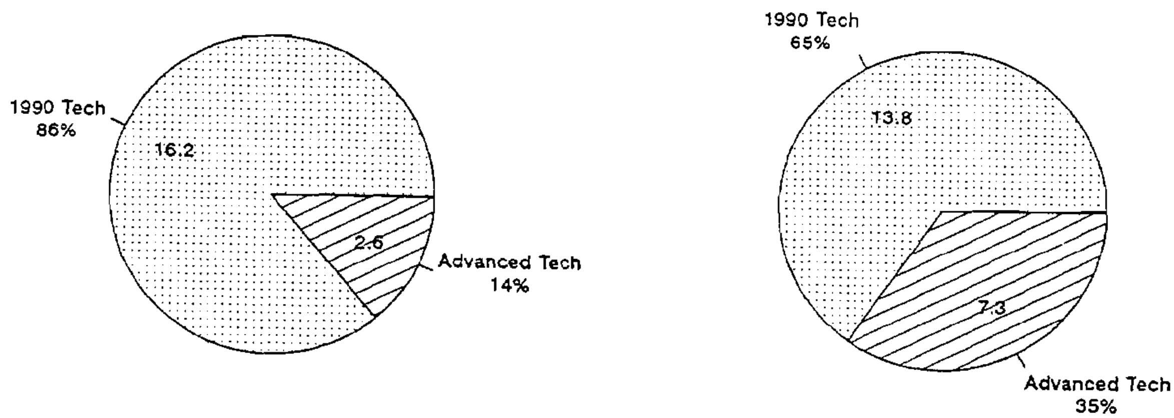

Figure 8. Current and Advanced Technology Share of U.S. Gas Production, Tcf
(Year 2000 — Left, Year 2010 — Right) (Woods, 1994)

In addition, a large portion of the remaining U.S. gas resource is in formations that are only marginally economic to explore and develop. An example is the Greater Green River Basin with an estimated 3,500 trillion cubic feet of in-place gas (USGS estimate) and about 90 Tcf estimated by the NPC as recoverable. This is a geologically complex basin with production controlled primarily by an unpredictable natural fracture system.

The most direct way to favorably affect the economics of marginal or higher-risk natural gas drilling projects is to reduce the direct cost of drilling and completing the wells. The use of *slim-hole* techniques offers potential cost reductions in a variety of categories including tubulars, rig rate and time, location, transportation, mud, cement, and even environmental. Analysis of a recent GRI study on well costs indicates that slim-hole techniques can attack cost categories accounting for 50 to 70% of total well cost. In gas formations not requiring expensive hydraulic fracturing, the percentage of costs affected can be much higher.

A *slim completion*, regardless of hole size, can provide significant savings in production casing and tubing costs. *Slim-hole drilling* offers additional savings as the smaller holes reduce mud volumes and pump requirements. Reduced hook-loads can reduce rig size requirements and resulting rig, transportation, and location costs. Smaller annular volumes reduce the cement volume and cost. Reduced cuttings volume and location size can reduce surface damages and environmental compliance costs. Figure 9 shows some example potential physical reductions associated with slim-hole drilling under simplifying assumptions.

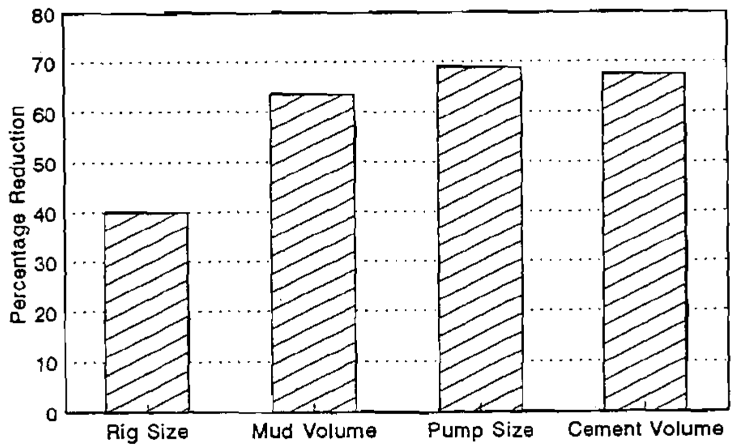

Figure 9. Slim-Hole Physical Reductions (7⅞ in. to 4¾ in.)

There have been many projects conducted by producers and service companies over the past five to ten years developing slim-hole technology and information. Many wells have been drilled and completed using these techniques with documented savings routinely in the 30 to 50% range. However, most of these projects have been outside of the U.S.,usually in more remote locations.

U.S. gas wells appear to be ideal candidates for use of slim techniques due to marginal economics, relatively low production, and infrequent need for high-volume artificial lift. Despite the potential, the use of these techniques has been relatively rare. Determining why this is the case and identifying the barriers to greater beneficial use of slim-hole drilling and completion are the primary goals of this project.

1.1 OBJECTIVE

The objective of this project is to identify and assess the barriers to greater use of slim-hole techniques to reduce the cost of drilling and completing U.S. gas wells.

1.2 METHODOLOGY

To accomplish the objective, the following general tasks were undertaken:

1. ***Analysis of U.S. Slim Completion Activity (Chapter 2)***

   A customized database was compiled using Petroleum Information Corp. data to identify areas and trends of U.S. slim completion activity and operators.

2. ***Technology Analysis (Chapters 3-7)***

   A team of experts analyzed technology areas of drilling, logging and perforating, cementing, stimulation and completion/workover/fishing tools to identify relevant slim-hole issues and technology needs. Data and information sources for this analysis included workshops, literature reviews, and interviews. In addition, the *DEA-67 Slim-Hole and Coiled-Tubing Technology Project* was joined and the technical resources available within that project utilized.

4. ***Case Study (Chapter 8)***

   A case study of an active slim completion basin, the Denver-Julesberg basin in northeast Colorado, was undertaken to assist the analysis of current slim-hole methods and barriers and evaluate the potential impact of future slim-hole drilling in a specific basin.

3. ***Barrier Surveys (Chapter 9)***

   A comprehensive slim-hole barrier survey was compiled and distributed to a targeted, knowledgeable sample. The responses were analyzed to determine statistics on industry opinion and perceptions regarding slim-hole technology barriers, limitations, and needs. A previous market assessment performed by Resource Marketing International was also obtained.

5. ***Potential Industry Savings (Chapter 10)***

   An analysis was conducted and an impact model constructed to provide a baseline and methodology for estimating the savings impact of using slim-hole techniques for drilling and/or completing U.S. gas wells.

6. ***Technology Transfer Activities***

   To assist in the transfer of the information and results of the study to the industry, technology transfer efforts included the preparation and distribution of a GRI Technical Summary brochure entitled *Slim-Hole Options For The U.S. Natural Gas Producer* and a five-article series that was published in *Petroleum Engineer International* from September 1994 to February 1995.

1.3 PROJECT TEAM

The project was conducted by the following team:

Company	Primary Responsibility
Maurer Engineering Inc.	Activity, Surveys, DEA-67, Drilling, Integration, Analysis, Reports, Technology Transfer
BJ Services Company, U.S.A.	Stimulation, Cementing

Company (Cont'd.)	Primary Responsibility (Cont'd.)
Halliburton Energy Services	Logging, Perforating
Baker Oil Tools	Completion, Workover, and Fishing Tools
Advanced Resources International	D-J Basin Case Study

1.4 DEFINITION

For this project, a *slim completion* is defined as a well with 4 in. or less final production casing. *Slim-hole drilling* is more contingent on location but is generally defined as hole sizes of less than 6 inches.

1.5 REFERENCES

Robinson, B.M., Saunders, B.F., and Vonciff, G.W.: "Evaluation of Drilling and Completion Costs in Various Tight Gas Sands," S.A. Holditch & Associates, Gas Research Institute Topical Report, (January-December 1993).

Woods, Thomas J.: "The Long-Term Trends in U.S. Gas Supply and Prices: 1994 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010," Gas Research Insights, (May 1994).

2. Slim-Completion Activity

2.1 INTRODUCTION

Data on historical slim-completion activity in the U.S. were obtained from Dwights Energydata, Inc. and Petroleum Information Corp. (PI). These data were obtained to satisfy two primary objectives:

1) Determine slim-hole activity and trends
2) Identify operators for barrier survey distribution and interviews

Customized databases were compiled for wells with production (smallest) casing of 4 in. or less. Hole size is infrequently populated in Dwights and PI data, requiring communication with operators to determine hole sizes. The data was analyzed relative to a variety of parameters including location, casing size, well type (oil, gas, injector), operator, depth, and time. The analysis of this data will be presented as follows:

- Historical Activity
- Recent Overall Activity
- Recent Gas Activity
- Major State Activity

2.2 HISTORICAL ACTIVITY

To obtain a historical perspective of slim-completion activity, five-year well counts and casing size only were tabulated based on criteria of 4-in. and less production casing. No detail well information was obtained for this historical analysis. This data provided only the number of wells with various casing sizes over five-year intervals starting with 1940. Pre-1940 wells were included as one data point. In addition, the total U.S. completion counts were also obtained in order to evaluate slim-completion activity relative to overall activity.

As shown in Figures 10 and 11, slim-completion activity peaked in the early 1960s in absolute number and relative percentage with an average of about 2500 slim completions over the five-year interval, which was about 6% of the total U.S. completions. The slim-completion percentage remained at 4 to 5% of the total through the late 1970s. While the number of slim completions surged back to the 2500 per year level in the late 1970s and early 1980s, the percentage dropped in the early 1980s to around 3 percent. The percentage has remained in the 3 to 4% range since that time. The dominant casing size has been 2⅞ in. with no other apparent trends.

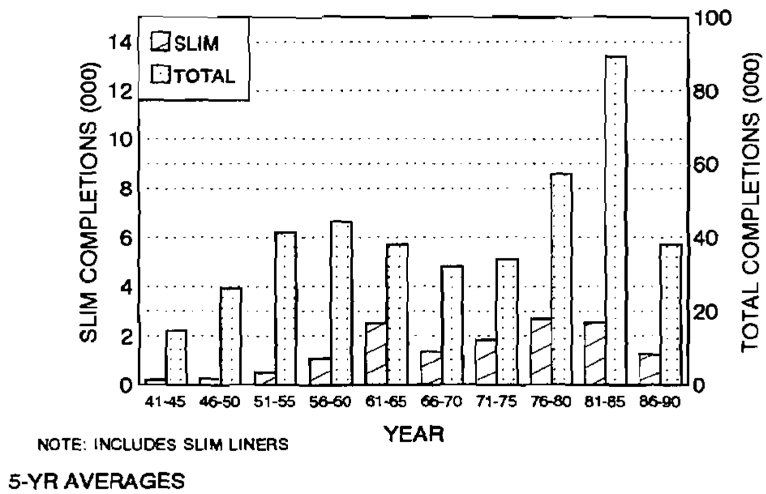

Figure 10. Historical Slim-Completion Activity

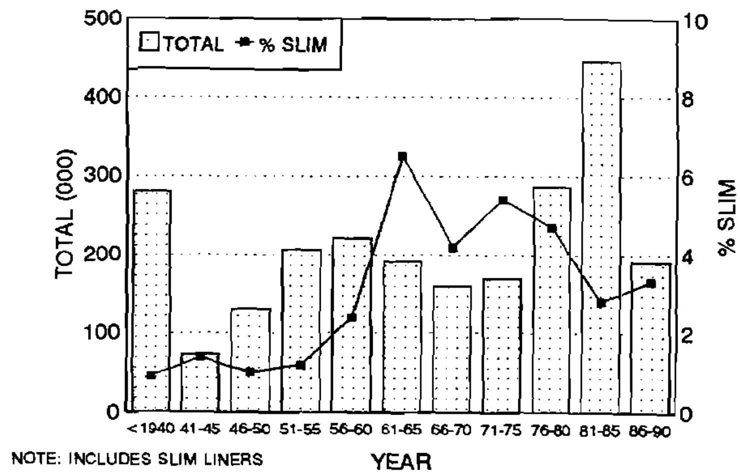

Figure 11. Historical Slim-Completion Activity

An interesting corollary to this historical slim-completion analysis is the number of publications discussing slim holes or slim completions. Figure 12 plots this approximate count and reveals the increased interest in slim holes and slim completions in the late 1950s and early 1960s, as well as greatly increased recent interest. Also of note is that the early articles addressed primarily U.S. applications while most of the recent articles address primarily technology being developed and used in international exploration projects.

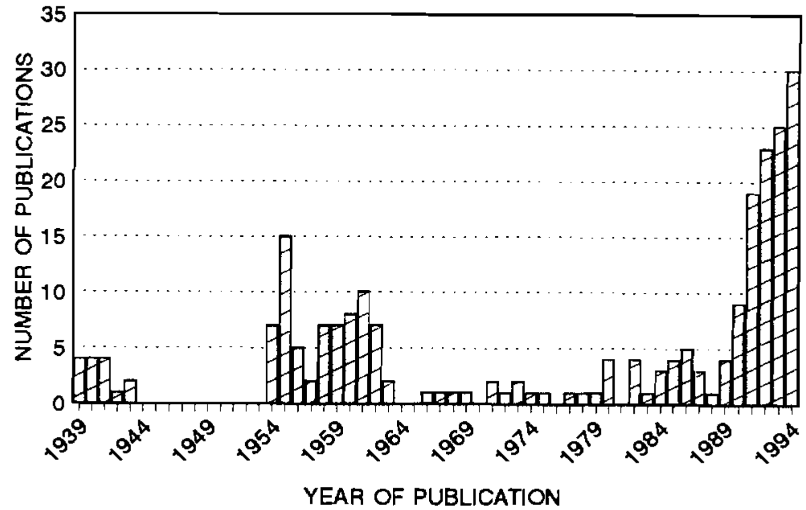

Figure 12. Slim-Hole Publications

2.3 RECENT OVERALL ACTIVITY

For a more detailed analysis, slim-completion data were obtained from PI for the most recent five years (1989-1993) which provided information on state, county, operator, total depth, casing sizes and depths, tubing size, well number, year completed, and well type for slim completions. This data allowed analysis of recent activity and trends as well as identifying specific operators and locations for follow-up interviews.

2.3.1 General Information

Figures 13, 14, 15, and 16 show summary information on the recent slim-completion activity data. As shown, over the 1989-1993 time period:

- Most slim completions (91%) are in Texas, Colorado, Oklahoma, and Kansas
- Most slim completions are gas (45%)
- Most slim completions are less than 10,000-ft deep
- Most slim completions (89%) use 2⅞-in. production casing with no tubing installed

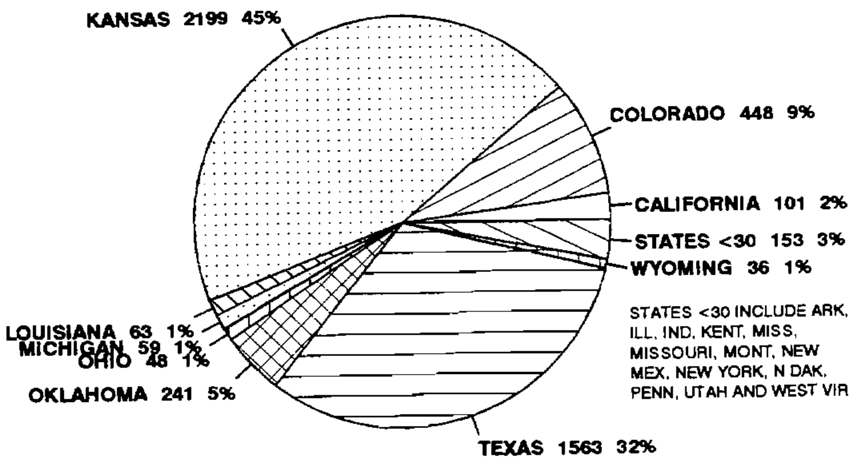

Figure 13. Slim Completions By State (1989-1993)

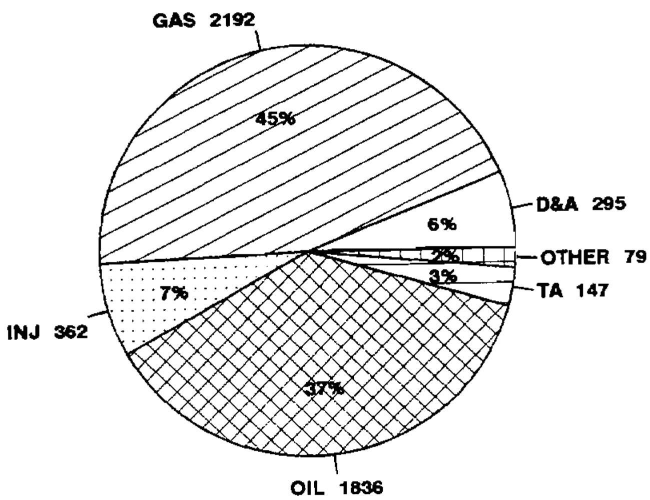

Figure 14. Slim Completions By Type (1989-1993)

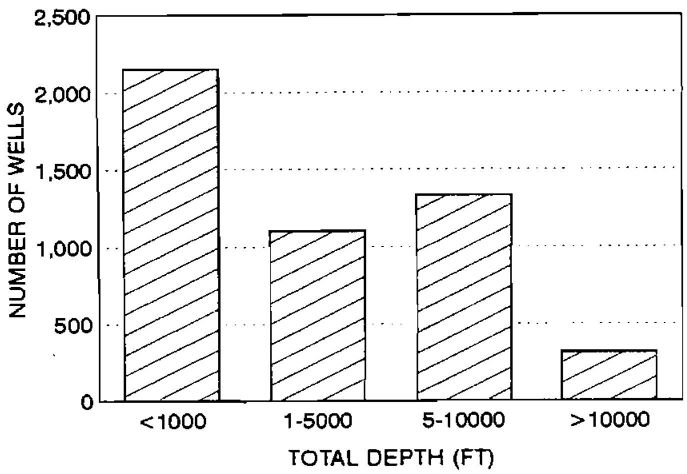

Figure 15. Slim-Completion Depths (1989-1993)

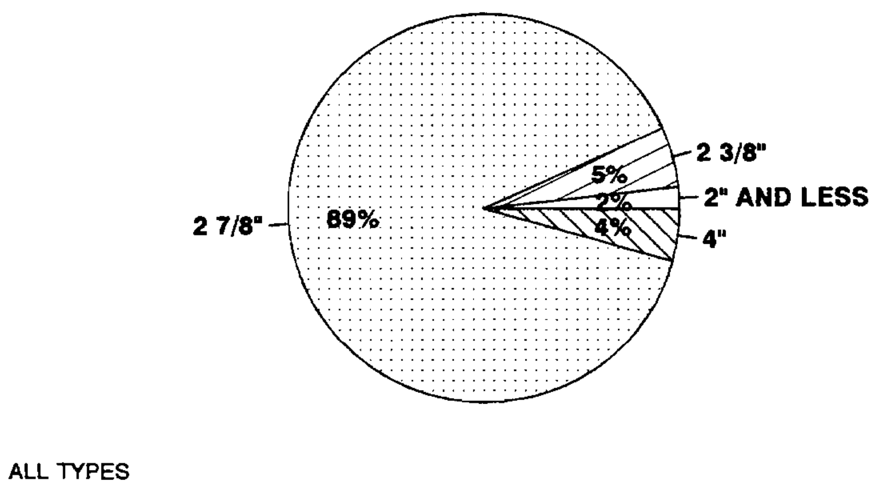

Figure 16. Slim-Completion Casing (1989-1993)

2.3.2 <u>Overall Trends</u>

Figures 17 through 21 shows various slim-completion data plotted versus year for the 1989-1993 time period. These indicate the following trends:

- The number of overall slim completions slightly decreased from 1990 to 1993
- The number of slim gas completions is increasing
- The percentage of gas completions that are slim is increasing
- The number of slim oil completions is decreasing
- The percentage of oil completions that are slim is decreasing
- The number of slim injection wells is increasing dramatically
- There is no discernible trend in slim-completion casing size, 2⅞ in. remains preferred
- The greatest number of slim completions are in Kansas, but the number has decreased over 50% in the last two years
- The second largest number of slim completions are in Texas, the number in 1993 is equivalent to 1989 and 1990 levels after a two-year decrease.
- Slim completions in Oklahoma are essentially flat
- Slim completions in Colorado increased over 100% from 1991 to 1992

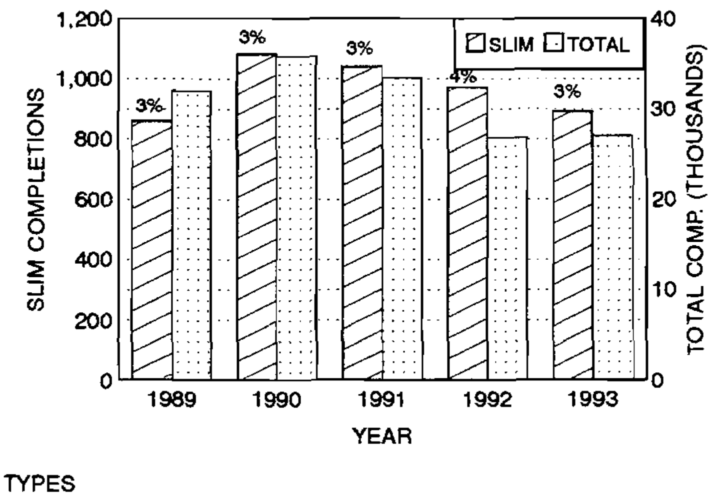

Figure 17. U.S. Slim and Total Completions

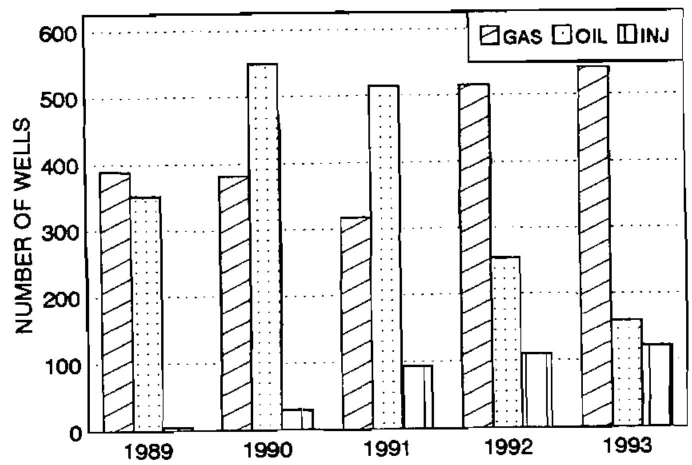

Figure 18. Slim-Completion Type Trends

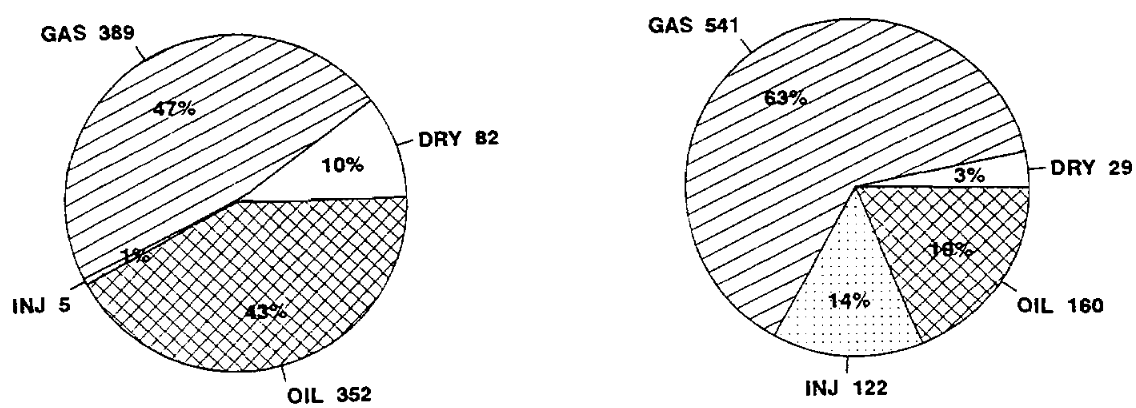

Figure 19. Changes in Slim-Completion Type
(1989 — Left; 1993 — Right)

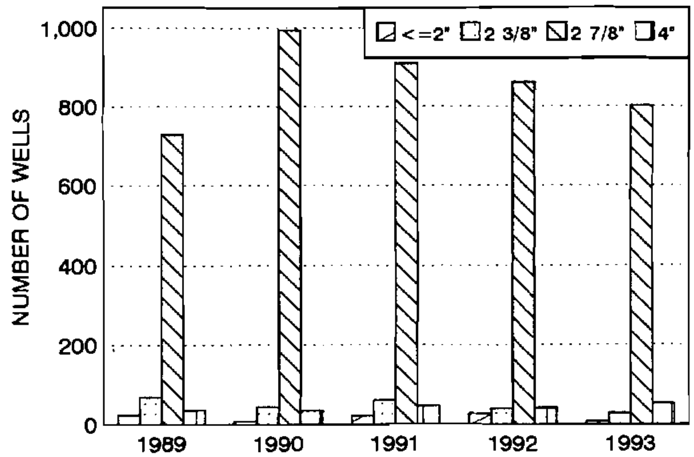

Figure 20. Slim-Completion Casing Trend

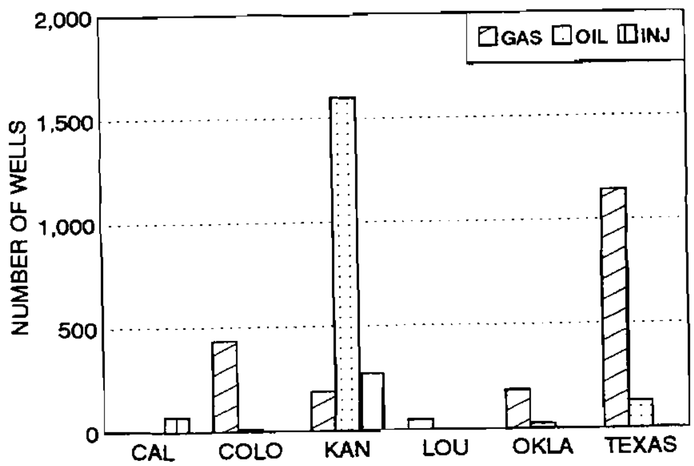

Figure 21. Slim-Completion Type By State (1989-1993)

The most important conclusion from this recent overall activity data is that the number and percentage of slim completions that are gas is increasing while the number and percentage for oil wells has decreased rather dramatically over the past five years. While the five-year total data indicates gas wells were 47% of the total slim completions, in 1993 the percentage was about 63% of the total (Figure 19).

2.4 RECENT GAS ACTIVITY

Figure 22 shows the number and percentage of gas wells using slim completions over the most recent five-year period. As shown, the number increased from slightly over 300 in 1991 to over 500 in 1993. This increased the percentage from about 3% to about 6% of all gas wells. Figure 23 shows the majority (94%) of the gas slim completions are in Texas, Colorado, Kansas, and Oklahoma. Texas overwhelmingly leads with 55% (1143) of the slim-gas completions, over double the number of second place Colorado (434).

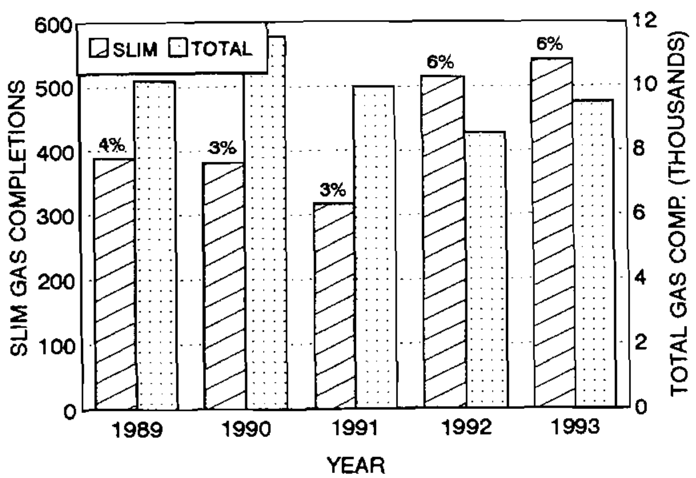

Figure 22. U.S. Slim and Total Gas Completions

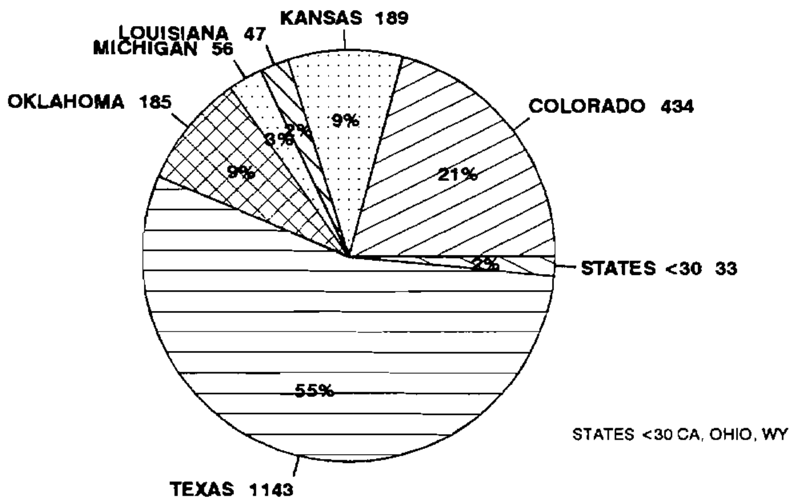

Figure 23. Slim-Gas Completions By State

Figure 24 identifies the five-year trend for slim-gas completions for the four major states and Louisiana, presented on the same scale. This reveals increasing numbers of slim-gas completions from 1991 to 1993 for Texas, Oklahoma, and Colorado while Kansas experienced a considerable decrease. The key states of Texas, Colorado, and Oklahoma will be further discussed in the next section.

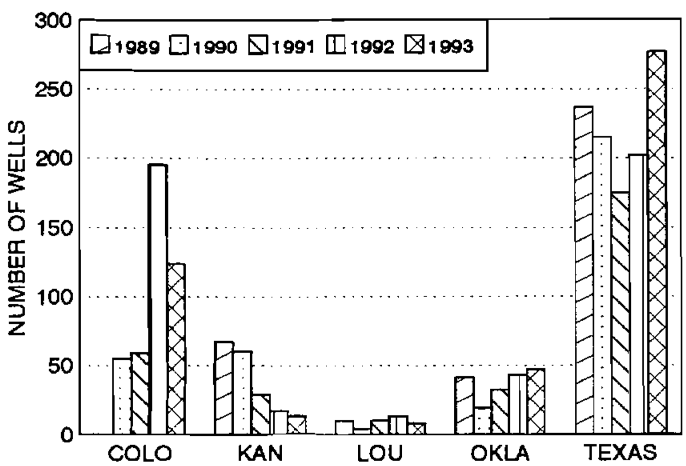

Figure 24. State Trends — Slim Gas Completions

2.5 MAJOR STATE ACTIVITY

The greatest number of slim-gas completions are in Texas with about 275 in 1993. Colorado is second with about 195 in 1992 and 124 in 1993. While Kansas was third for the five year total, the number declined dramatically after 1990 and Oklahoma had the third highest number in 1992 and 1993 with the total approaching 50.

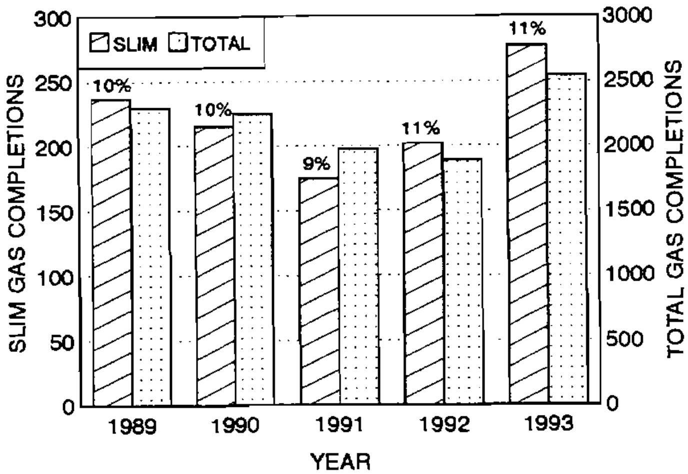

Figure 25. Texas Slim and Total Gas Completions

2.5.1 Texas

The largest number of gas well slim completions is in the state of Texas. Figure 25 shows the number of slim-gas completions and total gas completions in Texas for 1989-1993. After a decrease from 1989 to 1991 from 237 to 175 and dropping from 10 to 9% of the total, slim completions in Texas have increased to over 275 and to 11% of the total. Table 1 shows the slim completions by major counties and operators. As shown, Webb and Zapata counties had the greatest number of slim completions from 1989 to 1993. Enron and UPRC were the operators with the greatest number of slim completions in Texas over this time period. Texas activity can generally be broken down into two regions: South Texas and East Texas. These regions will be discussed individually.

TABLE 1. Texas Counties and Operators (1989-1993)

Counties	Wells	Percent	Operators	Wells	Percent
Webb	301	26	Enron	222	19
Zapata	163	14	UPRC	98	9
Goliad	76	7	Trans America	79	7
Victoria	67	6	Pennzoil	61	5
Nueces	49	4	Conoco	46	4
Hidalgo	47	4	88 JV	31	3
Jackson	42	4	Mobil	29	3
Panola	42	4	Chevron	27	2
Wharton	39	3	Westhall	26	2
Duval	34	3	Exxon	25	2
Other	283	25	Other	499	44
Total	1143	100.0	Total	1143	100.0

TABLE 2. Oklahoma Counties and Operators (1989-1993)

Counties	Wells	Percent	Operators	Wells	Percent
Haskell	40	22	Sonat	41	22
Roger Mills	33	18	Bear	35	19
Custer	26	14	Wild Fire	16	9
Osage	16	9	Apache	13	7
Kay	8	4	Ganer Mark	6	3
Other	62	33	Other	74	40
Total	185	100.0	Total	185	100.0

2.5.1.1 South Texas

Interviews with operators indicate the slim completions shown for the counties of Webb and Zapata are mostly in the prolific and areally extensive Wilcox formation. Slim completions are used in Wilcox wells that are projected to have short lives of one to five years with no recompletion potential. In these areas, generally 7-in. intermediate casing is set from about 6000 to 8000 ft and 6⅛- to 6½-in. hole is drilled to TDs ranging from 1000 to 3000 ft deeper than the intermediate casing point. Thus, TDs range from about 7000 to 10,000 ft. 2⅞-in. tubing is then run for casing and cemented. The wells are treated with substantial hydraulic fracture treatments.

Operators were queried about drilling smaller, or slim, holes for the 2⅞-in. casing string, such as 4¾ inch. The responses were generally consistent, describing concerns about penetration rates, bit life, and rig equipment.

2.5.1.2 East Texas

Slim tubingless completions (2⅞-in.) are being utilized in East Texas Travis Peak wells by certain operators where marginal economics dictate cost savings wherever possible. Once again, these wells are not drilled with slim holes (4¾ in. or smaller), but rather with 7⅞-in. bits. Operators indicate this is due primarily to the extreme hardness of Travis Peak drilling and the inability of bits smaller than 7⅞ in. to perform in this environment. Some pilot testing has been done with smaller bits but with no success.

2.5.2 Colorado

Figure 26 plots the Colorado slim and total completion activity. The number of slim completions has increased from none in 1989 to 195 in 1992, second only to Texas, with a slight fall-off to 124 in 1993. This was 17% of the total Colorado gas completions in 1992 and 8% in 1993. There were delays in posting of well reporting information by the regulatory agency and it is believed the number of 1993 completions in the PI database (at the time obtained) may be understated. All Colorado slim-completion wells identified in the database are in Weld County. Weld County is the heart of the Denver-Julesberg Basin which is the subject of a case study covered elsewhere in this report. These wells are targeting primarily the Niobrara and Codell reservoirs at around 7500 ft. The wells listed in the database are all 2⅞-in. tubingless, but it is known many of the operators are now using 3½-in. casing with 2¹⁄₁₆-in. tubing installed as the preferred completion. Once again, the exclusion of these type completions in the database indicates an underreporting problem at the time the data was acquired. Intermediate casing (8⅝ in.) is set from 300 to 600 ft and the remainder of the well is drilled with 7⅞-in. PDC bits operated on mud motors. These wells are drilled very fast with ROPs approaching 100 ft per hour. Rigs are moved about every five or six days. Attempts are being made by one operator to reduce hole size from 6⅛ to 6¼ in. which allows the use of smaller, truck-mounted rigs. ROPs at first were not as high as the 7⅞-in. hole size but after several wells and optimization of drilling parameters, ROPs are again approaching the 7⅞ in. performance. It should be noted that drilling down to the Codell and Niobrora is considered to be very "easy drilling," primarily shale, that is highly conducive to effective PDC drilling. At least one operator expressed the desire of ultimately reducing hole sizes to 4¾ in. using coiled-tubing drilling with 2⅞-in. casing and 1¼-in. tubing. Coiled-tubing drilling is attractive in the D-J due to the high cash-crop agricultural land on which the operators are forced to drill. Surface damage expense can be high and surface owner relations can be strained. Any technology which would allow substantial reduction of surface location size will be economically and environmentally attractive.

The wells are fracture treated down the 2⅞- or 3½-in. casing.

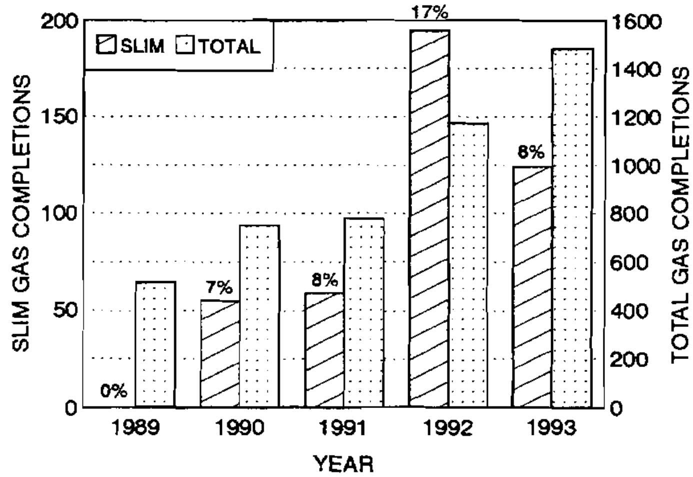

Figure 26. Colorado Slim and Total Gas Completions

2.5.3 Oklahoma

Figure 27 shows Oklahoma slim and total gas completions over the five-year period. After declining from 41 to under 20 from 1989 to 1990, slim completions have increased back to about 47 in 1993, which is about 5% of the total gas completions. Table 2 shows the major slim- completion operators and counties. Most of the slim-completion gas wells in Oklahoma with significant depths (greater than 1000 ft) are found in the Anadarko Basin. These wells are typically targeting the Red Fork formation. Unlike Texas and Colorado, several operators are utilizing slim-hole drilling in this arena by setting 5½-in. intermediate casing at about 11–12,000 ft and drilling out with 4¾-in. natural-diamond bits (operated on mud motor) to TD at about 13–14,000 ft (1000–1500 ft of true slim-hole drilling). This requires picking up 2⅞-in. drill pipe. The resulting cost per foot is higher for the slim-hole section of the well due to lower penetration rates and additional costs of a motor and rental drill pipe. However, cost reductions from the downsized intermediate and production casing strings results in considerable net savings to the operator. The wells are fracture treated down the 2⅞-in. casing with 50 to 100,000 gal of fluid, 80 to 150,000 lb of sand, at rates of 15 to 20 BPM and treating pressures of 6000 to 10,000 psi. Some operators also use 3½-in. liners cemented in the 4¾-in. hole with 2⅞-in. production tubing run on a packer in the 5½-in. intermediate casing.

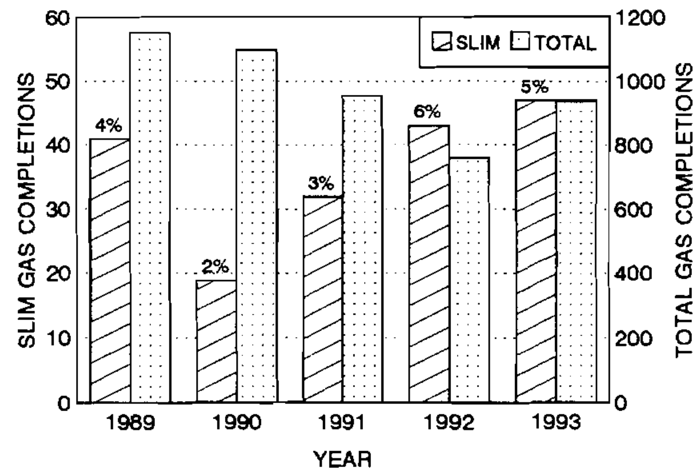

Figure 27. Oklahoma Slim and Total Gas Completions

2.5.4 Wyoming

Several operators began using 3½-in. casing in the Wamsutter area of the Greater Green River Basin in 1994 (Brett and Gregoli, 1995). These wells are approximately 10,000 ft Mesaverde completions that require substantial hydraulic fracture treatments. Once again, conventional 7⅞-in. holes were initially used for these slim completions, but operators have now started drilling 6¼-in. holes for some of these smaller diameter completions. These 1994 wells are not reflected in the 1989-1993 database obtained from PI and are therefore not included on any of the activity figures.

2.6 ACTIVITY SUMMARY

The most important findings from the activity analysis include the following:

- Slim completions for gas wells have increased since 1991, both in number and percentage of total gas completions.
- Most of the increase occurred in the Colorado D-J Basin, but increases also were seen in Texas and Oklahoma.
- Most slim gas completions are 2⅞-in. tubingless completions placed in conventional size holes.
- The use of 3½-in. casing with 2¹⁄₁₆-in. tubing is becoming the preferred slim completion in the D-J Basin. 3½-in. casing is also now being used in the Greater Green River Basin.
- True 4¾-in. vertical slim-hole drilling is occurring in the Oklahoma Anadarko Basin.

Figures 28 and 29 present wellbore diagrams of the most common conventional and slim gas completions in the U.S.

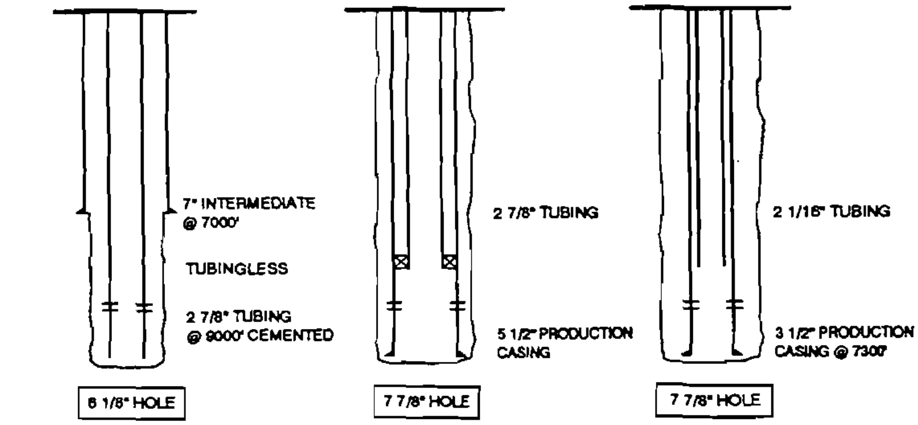

Figure 28. Conventional and Slim Colorado and Texas Completions

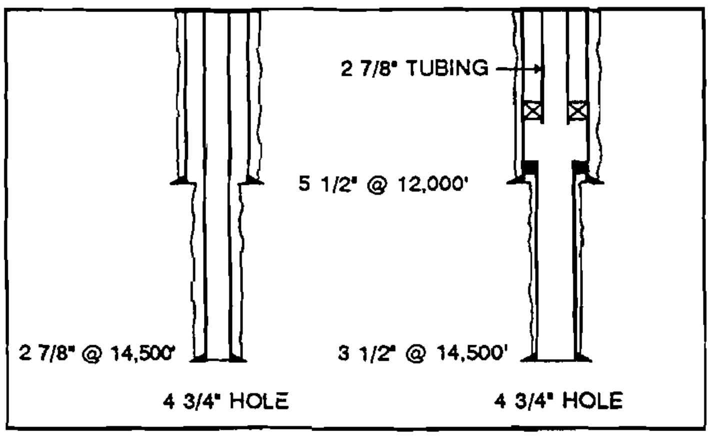

Figure 29. Slim-Hole Drilling and Completions in the Anadarko Basin

2.7 REFERENCES

Brett, J.F. and Gregoli, M.K. "Successful Drilling Practices Study - Greater Green River Basin," Gas Research Institute Final Report, GRI-95/0132.1, (March, 1995).

3. Slim-Hole Drilling

3.1 INTRODUCTION

The definition of slim-hole drilling is very contingent on the application, location, and operator experience. The extremely wide range of well designs (depth, casing sizes, liner requirements, hole problems, etc.) makes it difficult to assign one unique size above which is always conventional and below which is always "slim hole." However, there are two fairly accepted bounding conditions.

A 7⅞-in. hole is the most common final hole size and is usually cost-effective in most applications. That is, it can be drilled at least as efficiently as larger, alternative sizes. A 4¾-in. hole size is not common in open-hole vertical drilling and is almost universally accepted as a slim-hole condition in all applications. Between these two boundaries is an area of uncertainty that is very contingent on location, application, and experience. Common bit sizes in this range include 5⅞ in., and those in the 6- to 6¾-in. range (6, 6⅛, 6½, 6¾). Table 3 displays how drilling with 4¾-in. and 5⅞-in. is infrequently used in the domestic U.S. with less than 1% of the total domestic footage drilled with less than 6-in. bits (Hughes Christensen data only).

TABLE 3. U.S. Bit Footages (Hughes Christensen)
Final Hole Sizes

Bit Size	1994 (Thousand ft.)	1994 %*
4¾	193	0.4
≤ 4¾	246	0.5
5⅞	17	0.04
< 6	266	0.5
6–6¾	4754	10
7⅞	34,287	70
8–8⅞	8893	18
	48,656	
* % of "Final" sizes only		

Evidence of this slim-hole definition is found in two areas of slim completion activity. As discussed in Section 2.5, operators in the D-J Basin drill 7⅞-in. holes for 2⅞-in. and 3½-in. completions. In South Texas, 2⅞-in. slim completions are placed in 6⅛-in. holes drilled out of a 7-in. intermediate liner (Figure 30).

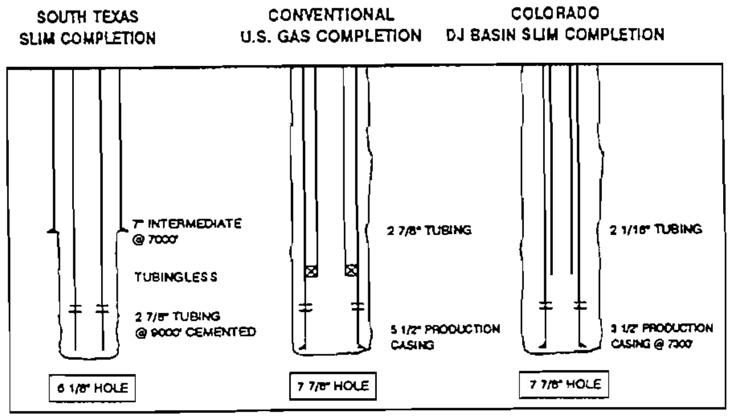

Figure 30. U.S. Slim and Conventional Completions

Both of these hole sizes are considerably larger than is necessary to place 2⅞-in. pipe. A 4¾-in. hole, for example, would be adequate.

The primary reason for a slim completion is dramatic savings in casing and tubing costs. But, as has been discussed, there is additional significant savings potential in drilling smaller holes. Mud volumes are reduced and reductions in hook load and pump requirements can significantly reduce rig requirements. Reductions in rig size reduces location size and costs, and transportation and logistics costs. Reductions in location size and cuttings volumes can reduce surface damages, disposal, and environmental compliance costs, and can beneficially influence landowner relations. Smaller annular volumes dramatically reduce cement volumes and costs. The smaller final hole size allows the use of smaller surface and, if necessary, intermediate casing strings. Figure 31 graphs *potential* percentage reductions in physical parameters associated with slim-hole drilling.

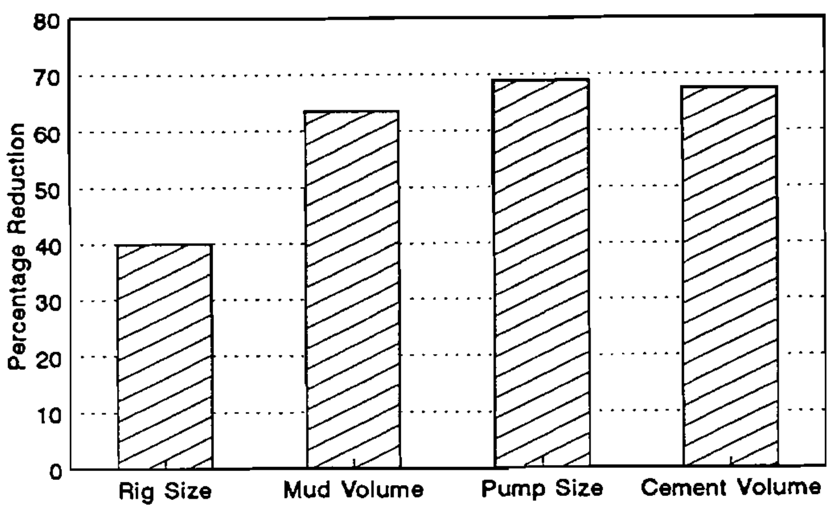

Figure 31. Slim-Hole Physical Reductions (7⅞- to 4¾-in.)

Given these *potential* savings but current low usage, this section of the report addresses the issues surrounding cost-effectively drilling a slim hole in lieu of a conventional size hole. The barriers to achieving these savings are obviously perceived to be large. Otherwise, at a minimum, those U.S. producers already using slim completions would be drilling smaller holes for their reduced casing sizes. The increased savings from such an integrated slim-hole approach would undoubtedly increase the number of applications where slim completions would become the preferred economic option.

Despite the contingent area of the slim-hole definition discussed above (primarily the 6-in. sizes), the technical barrier discussions that follow are most applicable for true slim-hole drilling conditions of 4¾ in. and smaller. It is in this range where technology limitations, and potential savings, are the greatest. Even though savings can likely be gained in some categories by dropping from, for example, 7⅞ to 6¼ in. (and obtaining comparable performance will likely require a learning curve), the greatest potential for significant cost reductions and industry impact will come from reducing the barriers associated with more aggressive slim-hole sizes.

Recent industry efforts addressing slim-hole drilling have been generally directed around four systems: conventional surface rotary techniques, continuous coring techniques, motor techniques, and coiled-tubing drilling. Details of the conventional, coring, and motor techniques are discussed within the various technical barrier topics and again in Section 3.10. Coiled-tubing drilling is discussed in a separate section (3.11).

A cursory description of these techniques is presented below to provide background for the subsequent barrier discussions.

3.1.1 Conventional Rotary

Slim-hole drilling with conventional surface rotary techniques simply means using normal rotary rig drilling equipment and practices.

3.1.2 Continuous Coring

Slim-hole drilling with continuous coring techniques implies using technology adapted from the mining industry to continuously core significant slim-hole intervals. These systems use mining rods or specially developed drill strings rotated from the surface with a top drive at extremely high speeds. Annular clearances are maintained very small in order to provide stability to the drill string. The core barrels are retrieved to the surface via wireline which negates the need to trip, significantly increasing effective drilling time (Figure 32). Hydraulic controls provide very accurate WOB control. Rig sizes are typically considerably smaller than conventional. Provisions must be made to handle large volumes of core at the surface.

3.2 BITS - CONVENTIONAL

3.2.1 General

The first limitation usually considered in slim-hole drilling evaluation is the performance and life of small-diameter bits. A drill bit must deliver energy to the formation to fail the rock and remove cuttings as efficiently as possible to maximize penetration rate. There are two main bit types used in conventional rotary drilling operations; fixed-cutter bits and rolling cutter, or roller cone bits.

3.2.2 Roller Cone Bits

The three-cone roller cone bit is by far the most common bit type currently used in rotary drilling. Roller cone bits employ all of the basic mechanisms of rock removal (crushing, erosion, wedging, scraping, twisting) with the dominant mechanism dependent on the formation and specific bit design. However, crushing is usually the main mechanism with roller cone bits. A relatively high weight-on-bit (WOB) is required to achieve high rates of penetration (ROP).

A wide variety of bit designs are available with roller cone bits. Design variables, each with an impact on performance, include overall bit diameter, cone offset, bit tooth length, bit tooth spacing, tooth shape (conical, chisel, scoop, wedge, flat, etc.), tooth positioning, bearing size, bearing type, and cutters. The two primary types of cutters are milled tooth and tungsten carbide insert. Tungsten carbide insert bits are typically used for harder formations. Tungsten carbide hardfacing can also be applied to mill tooth bits for drilling in harder formations. Bearing types include (in order of complexity and expense) non-sealed roller bearings, sealed bearings, and journal bearings.

3.2.3 Fixed-Cutter Bits

Fixed-cutter bits consist of fixed cutter blades that are integral with the body of the bit and rotate as a unit with the drill string. Since there are no independent moving parts, there are no bearings associated with these bits. The three types of fixed-cutter bits used today include polycrystalline diamond compact (PDC), natural diamond, and thermally stable polycrystalline (TSP) diamond bits.

3.2.3.1 Diamond Bits

The face, or crown, of diamond bits consists of diamonds set in a tungsten carbide matrix. These bits cut by indenting, plowing, and grinding the formation. Fluid is pumped through fluid courses in the bit matrix and directed over the face of the bit. These bits are most effective in very hard and abrasive formations. They have limited depths of cut and typically low rates of penetration, but are the most effective in certain formations.

Design variables for diamond bits include crown profile, taper length, curvature, size of diamonds, number of diamonds, as well as bit diameter.

3.2.3.2 PDC Bits

PDC bits were introduced to the industry in the 1970s and are continuing to evolve rapidly. PDC bits consist of a sintered polycrystalline diamond drill blank as a bit cutter element. This is a polycrystalline diamond layer about $^1/_{64}$-in. thick bonded to a tungsten carbide substrate in a high-pressure, high-temperature process. The substrate is either a stud that is mounted into the steel bit body or a cylinder mounted directly in a tungsten carbide body matrix.

PDC bits drill by a shearing action and can achieve higher rates of penetrations at lower WOB in certain formations. This shearing action is most effective in relatively plastic sedimentary rocks such as shale, limestone, and weak sandstones, requiring less energy and providing more effective cleaning. This shearing action, however, can result in increased vibrations, primarily highly erratic torque, in the drill string, a critical problem with slim-hole drilling.

PDC bit design variables, in addition to bit diameter, include crown profile, taper, cutter size, cutter shape, number of cutters, and cutter orientation (expressed in terms of back rake, side rake, and cutter exposure).

With these large number of variables, PDC bits are very sensitive to changes in lithology and optimum parameters are very formation dependent. Drilling into very hard streaks can result in rapid cutter failure. This makes bit selection much more difficult with PDC bits than with roller cone bits. Experience in an area greatly enhances successful drilling with PDC bits. Hydraulic energy provided by jets or water courses is even more critical with PDC bits for cooling and hole cleaning.

3.2.3.3 TSP Cutter Bits

Thermally-stable diamond product cutters consist of small man-made diamonds bonded together at a high temperature and pressure in large disks. These are then cut into smaller pieces for use in drill bits and other tools. One reason PDC cutters fail at high temperature is due to the cobalt binder holding the diamonds together having a higher coefficient of thermal expansion than that of the diamond matrix. TSP cutters have the cobalt leached out of the diamond matrix, increasing the high-temperature capabilities.

3.2.4 Recent Bit Technology Advances

Recent improvements in bearings, seals, and materials (such as new tungsten carbide hardmetal), and computer-aided design are all facilitating vast improvements in bit performance. For example, Figure 35 shows performance cost parameters for 7⅞-in. roller cone mill-tooth bit performance over the 1984 to 1993 ten-year period. This is an interesting example since 7⅞-in. is one of the bounding sizes for the definition of conventional drilling and is the final hole size for a large number of U.S. gas wells. Better bearings and improved seals have allowed the use of higher WOB and rotary speeds, delivering more energy to the bit while also increasing the bit life.

Improvements in diamond technology, such as the ability to apply diamond to curved surfaces, anti-whirl technology, impact arrestors, and larger cutters are also expanding the use of PDC bits into harder and more variable formations.

Three-dimensional computer design software and computer controlled manufacturing processes allow the rapid re-design and optimization of bits within an area. Therefore, subtle changes in bit design can result in rapid improvements in performance in the first few wells of a drilling program.

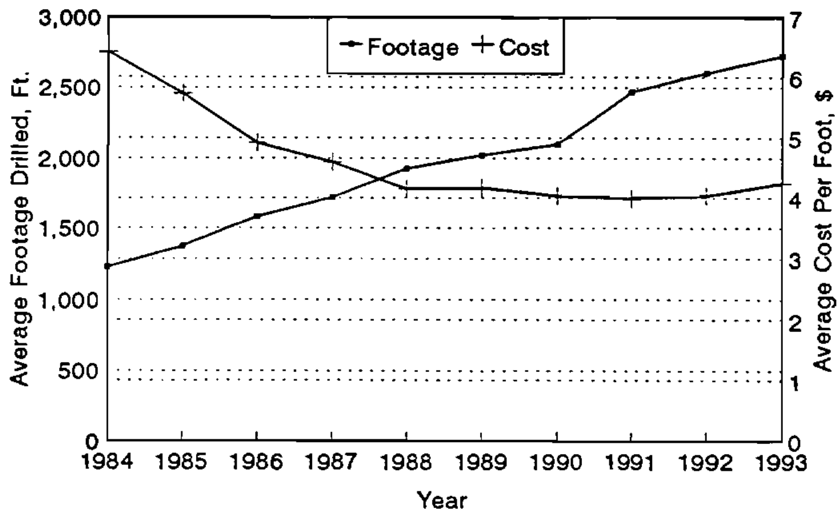

Figure 35. Improvements in 7⅞-in. Bit Performance (PEI Staff, 1993)

3.3 BITS - SLIM HOLE

The penetration rate and bit life achieved during a drilling operation is dependent on a variety of factors including formation characteristics, drilling fluid properties, bottom-hole assembly, bit type, bit weight, rotary speed, bit tooth or cutter wear, hydraulics, and bit size. Sophisticated drilling models have been developed which relate a very large number of variables. However, one simple formula useful for a slim-hole discussion is as follows:

$$\text{Energy at the Bit} = \frac{\text{Rotary Speed} \cdot \text{WOB}}{\text{Bit Diameter}}$$

This points out the fact that as bit size is reduced, *theoretically*, energy at the bit and penetration rate is increased *at comparable bit weights and rotary speeds*. However, as bit size is reduced, the area available for bearings, teeth or cutters, and other design options is also reduced. The weight and rotary speed limits (relative to bit size) are therefore typically less than for larger bits. Or alternatively, if the same relative weight is carried on the smaller bit, the bit life is lessened, increasing overall bit costs and trip time.

As further illustration, in roller cone bits, bearing area tends to be proportional to the square of the diameter while the WOB for a constant ROP is directly proportional to bit diameter *(all else being equal).* If this is converted to a ratio of the smaller bit size to the larger bit size, it can be seen that the available bearing area decreases much faster than the required WOB. For example, when comparing 7⅞ in. to 4¾ in.: WOB ratio is 0.6, while the bearing area ratio is only 0.36 (Figure 36).

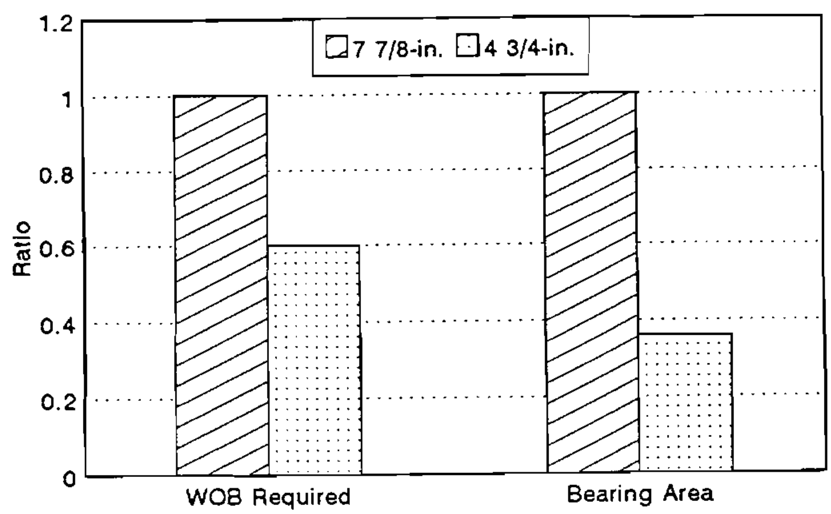

Figure 36. Bearing and Weight-on-Bit Ratios (4¾- to 7⅞-in)

This limitation of reduced bearing area is the primary reason for the use of fixed-cutter bits as a viable alternative in slim-hole drilling. Since fixed-cutter bits contain no bearings, this limitation in smaller sizes is removed from consideration. Unfortunately, fixed-cutter bits are not a perfect substitute for roller cone bits. Natural diamond bits are effective in only the very hardest formations. PDC bits perform best in soft, firm, and medium-hard, nonabrasive formations that are not "gummy" and PDC bit optimization takes greater trial-and-error experience to optimize performance. Rapid cutter abrasion and breakage become a problem in hard abrasive formations such as hard sandstone streaks. Vibration tendencies are greater due to the shearing action which is very harmful to the smaller, weaker, more flexible drill strings. Use of PDC bits requires more careful matching to the formation being drilled and other drilling parameters. Areas where drillability and abrasiveness change very quickly can be very detrimental to their performance. Roller cone bits are more forgiving in their performance characteristics, and are cheaper, such that total destruction of a bit due to encountering an unanticipated hard streak is not as costly.

PDC bits do not require as much WOB as roller cone bits, but generally perform better with less vibration at higher speeds and require more precise control of WOB. These bits tend to "bounce" more and set up conditions conducive to high impact loads and cutter breakage.

It is difficult to put a definitive size at which bit limitations reach the critical point, due to the number and variability of drilling conditions found. This is why it is best to look at current practices of operators and drilling contractors which point out that bits less than 7⅞ in. are not common in some areas despite use of slim completions, while 6⅛ in. is used with slim completions in other areas. Therefore, between 4¾ in., a definite slim-hole size, and 7⅞ in., a definite conventional size, there is a "gray area" regarding effective drilling. In terms of common bit sizes, this covers 5⅞-, 6⅛-, 6¼-, 6½-, 6⅞-, 7½-, and 7⅜-in. bits. Bit designers indicate that only a small incremental reduction in diameter (for example, 6¼- to 6⅛-in.) can dramatically alter design parameters, options, and resulting performance.

3.3.1 Availability

Figure 37 shows the number of different bit models from major manufacturers for various sizes and types (roller cone - RC; PDC; natural diamond - ND). Although custom bit design is routinely done, this listing gives an indication of the current limited availability of, and demand for, small diameter bits.

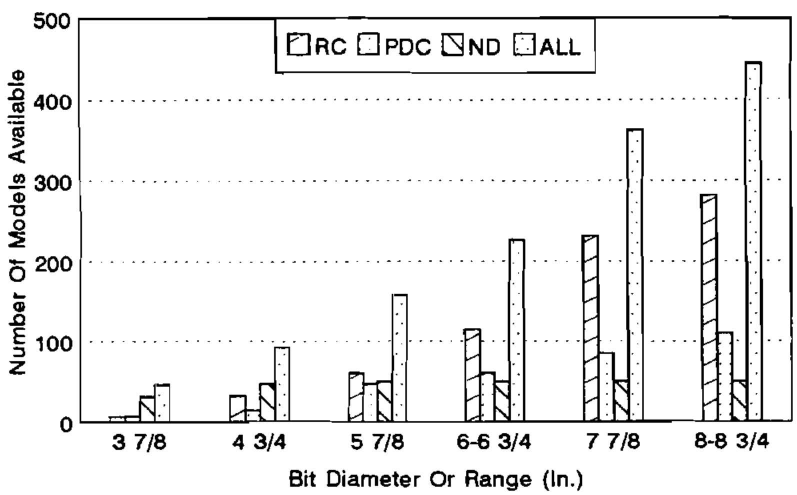

Figure 37. Bit Options - All Types (*World Oil*, 1994)

3.3.2 Literature Review

It is interesting to review selected literature beginning in the 1950s when there was a surge of slim-hole drilling and quite a few articles written on the subject of slim-hole drilling and small diameter completions. This review is restricted to pertinent articles discussing isolated comparisons between bit sizes, or improvements in smaller bit performance, using conventional rotary or motor techniques. Also included are excerpts from more recent publications for comparison.

Early Literature

- McGhee, 1954

  "...in hard rock country...a small bit may not be able to carry enough weight to permit a satisfactory rate of penetration."

  "Fortunately, the 7⅞-in. bit is large enough to carry bearings that will stand up to long runs at high weights. Reducing the hole size to 6¾ in. and carrying proportionately less weight should get the same drilling rate, but bit runs would be sharply decreased. Round-trip and total bit cost would probably go up."

  "Bit manufacturers cannot, of course, say that there is an exact critical size below which a bit is too small to carry the optimum bearing. However they will admit that their design problem is simplified in sizes larger than 6⅜ in."

This article also reports that 5⅝-in. holes were drilled with air to more than 3600 ft and still demonstrated very good results when compared to conventional holes drilled with mud. Two bits averaged 1103 ft and 24.7 ft per hour each compared to a 237 ft per bit and 16.6 ft per hour average for 13 conventional size (unknown) mud drilled wells.

- Valint, 1955

  Socony-Vacuum Oil Company of Canada, Ltd. drilled ten slim-hole wells to test the concept. They drilled 4¾-in., 5⅝-in., and 6⅞-in. holes to depths of 4500 ft and compared the performance to conventional 9-in. holes. These tests were in soft formations with roller cone jet bits. Their conclusions state that the slim holes "...almost without exception, proved to be more costly than drilling a conventional nine-inch hole." and the 9-in. hole was drilled "...at a penetration rate almost 100% higher than the time required to complete the slim hole."

- McGhee, 1955

  "Gulf Coast operators are defining a slim hole as one drilled with 6⅛-in. to 6⅞-in. bits."

  "Only two major producers on the Gulf Coast are drilling slim holes on a regular basis."

  "Contractors who have drilled slim holes on the Gulf Coast report no particular trouble in drilling...Drilling rate may be slightly slower and bit life shorter."

- McLaughlin, 1955

In this paper study, the author compares estimated performance for conventional 9-in. holes with 6⅞- and 5⅝-in. slim holes and concludes that theoretical bit performance should decrease and costs increase, but that "many contractors are reporting excellent comparative results in slim-hole sizes, with the effect that slim-hole bit costs are actually reduced rather than increased."

- Arnold, 1955

The operator drilled 34 wells with 4¾-in. (27) and 6⅛ in. (7) holes to average depths around 6000 ft to the Wilcox in Louisiana and Mississippi. Comparison was made to 7⅞ in. to 9 in. conventional size holes and conclusions drawn including "... the penetration rates, drilling time, and bit cost of the slim holes compare favorably with the conventional hole sizes..." "...the 6⅛-in. hole does not show any marked advantage over the 4¾-in. hole in penetration rates, the 50 per cent reduction in the number of rock bits used and the resultant saving in trip time tend to favor the 6⅛-in. hole."

- Huber, 1956

"Recently, important improvements have been made in drilling tools and techniques for these small holes. Bearings in 5⅝ in. and slightly larger rock bit sizes have been improved...drilling rates for these holes being comparable to larger holes."

- Scott and Earl, 1961

This article summarizes the early work in slim-hole drilling, which was considered at the time to include 6⅞ in. and smaller in all applications. Scott concludes, based on an AAODC operator survey (targeting those doing slim-hole work) and operator interviews, that after years of experimenting with 4¾- to 7⅞-in. holes, 6¾ in. appeared to be the most favorable, although 80% favored the range including 6⅛ to 6¾ inches.

Recent Literature

- Hays, 1986

"Most operators and drilling contractors consider a 7⅞-in. hole the minimum diameter for drilling most wells of intermediate depth."

- Worrall, 1992

This paper reports on the development and progress of Shell's slim-hole system using PDC bits, mud motors, and other advancements with hole sizes down to 4⅛ in.: "Prior to this (1987) progress per day decreased with sizes below 7⅞ in..."

"Analysis of well data in three fields shows that, due to improved performance, the drilling cost per meter of 4⅛-in. hole drilled with the Slim-Hole Drilling System is between 19% and 41% lower than that of conventional 5⅞ in. drilling confirming that drilling progress no longer decreases with hole size below 7⅞ inches."

- Carter and Akins, 1992

  In this study of using smaller than 4¾-in. bits for deepening existing wells in the Permian Basin, the authors make several interesting statements:

  "The problems associated with slim-hole drilling in the Permian Basin are predominantly in the holes smaller than 4¾ inches. Generally roller cone bits in sizes 4¾ in. and greater can be obtained with various cutting structures as well as bearing surfaces. This usually provides an adequate means of drilling and deepening in the areas represented here...the data represented here targets the drilling of smaller diameter holes (3¼ to 4¼ in.)."

  "The lack of a more durable sealed journal bearing has resulted in short bit runs which often leave junk in the hole."

  The authors relate their successful experience of using dome (curved surface) PDC cutters in the smaller bit sizes and state that the dome PDC "...has proven to be an economic alternative for deepening and underreaming in areas of the Permian Basin." The dome PDC cutters performed better than roller cone or other diamond bit products.

- Dupuis and Fanuel, 1993

  This paper outlines the joint EUROSLIM project that developed and tested an integrated slim-hole drilling system.

  "Small diameter drilling has proven to be most suited to the application of monobloc (fixed-cutter) drilling bits due to the extremely limited life of small tricone bits." The paper is addressing sizes of 4¾ in. and smaller.

3.3.3 Bit Conclusions

The last 40 years have seen significant advancements in bit technology in large <u>and</u> small sizes. Interestingly, these advancements have resulted, essentially, in maintenance of the status-quo. That is, a hole size of 7⅞ in. is still perceived to be the cut-off for conventional and cost-effective drilling in many areas. Advancements <u>have</u> resulted in the use of 6⅛- to 6¾-in. holes to be essentially as effective as 7⅞-in. drilling, and considered conventional practice in some areas of the U.S., especially where less than 5½-in. casing is used. One exception is the D-J Basin, where small 2⅞-in. completions are used but 7⅞ in. is still the preferred hole size by most operators and drilling contractors.

There is further evidence that modern 4¾-in. bits are better than smaller bits (3⅞ in.). An example of using 4¾-in. diameter bits in new wells is in the Anadarko Basin where some operators are drilling out of 5½-in. intermediate casing. Even so, the overall tubular costs reduction is the driver and one operator states that the drilling cost per foot is still appreciably higher with the 4¾-in. bits.

Several bit manufacturers have focused recent development on smaller diameter bits and recent introductions of 3⅞-in. roller cone bits with improved sealed journal bearings may narrow the gap between 4¾- and 3⅞-in. bits.

Improvements in PDC technology in larger sizes are coming fast with more widespread application, especially with motors. These improvements need to be transferred to the smaller sizes. Some believe that modern PDC bits may actually suffer very little reduction in performance in smaller diameters (DEA, 1994).

The development and demonstration of improved bit technology in slim-hole sizes is a critical path item for slim-hole drilling. Although other savings may offset reductions in penetration rates, or increased numbers of bits and trips required, full benefits and widespread application will only occur when slim-hole bit performance is equitable with larger sizes. Unfortunately, bit technology is driven by very specific demands and conditions. This is further complicated by the fact that bit optimization varies considerably from formation to formation and area to area, and thus requires multi-well programs. In addition, other drilling variables play important roles in ROP and bit life and optimization of those parameters must be done concurrently with bit development. Even with development of new sizes and styles of large and small-diameter fixed cutter and roller-cone bits, there is a limited history of bit runs, making performance prediction difficult. Therefore, extensive integrated slim-hole test programs are needed to drive rapid improvements in small bit and bit-motor optimization technology for various areas and drilling environments, as well as provide analogies and case histories for all operators considering slim techniques.

3.4 DRILL STRING

3.4.1 General

In most conventional U.S. vertical drilling operations, power is transmitted from the surface rotary table, top drive, or power swivel/power sub to the bit through the drill string. Technically, the drill string's three basic functions include:

1) Transmit and support axial loads

2) Transmit and support torsional loads

3) Transmit hydraulics

The drill string includes drill pipe, heavy wall drill pipe, drill collars, stabilizers, shock subs, jars, crossovers, and bits. Drill pipe is specified by its outer diameter, weight per foot, steel grade and range length. Drill collars are thick-walled, heavy steel tubulars used to provide weight to the bit, minimize buckling tendencies, provide rigidity, and provide a pendulum to maintain a vertical well.

As bit size is reduced, the size of the drill pipe used is reduced to maintain adequate annular clearance for fishability and hydraulics. Commonly used combinations of bit size and drill pipe size are shown in Table 4. The use of 2⅞-in. tubing with tool joints or premium connections is also commonly used in the smaller hole sizes for deepenings and horizontal re-entries. Since hole sizes below 6 in. are not common, the use of 2⅞-in. drill string (drill pipe or tubing) is also not common in new well applications, especially on drilling rigs. Most drilling contractors do not own or provide the smaller drill string as normal rig equipment. The use of 3½ in. is more common than 2⅞ in., but 4 in. and larger is by far the most common drill pipe.

TABLE 4. Common Bit and Drill-Pipe Combinations

Bit/Hole Size (in.)	Drill Pipe Size (in.)
8-8¾	4½
7⅞	4 - 4½
6-6¾	3½
4¾-5⅞	2⅞
3⅞	2⅜

3.4.2 Slim-Hole Issues

As drill pipe size is reduced, the amount of steel available to provide strength is reduced. The key specifications of maximum tensile and torsional limits are therefore lessened with size. Figure 38 shows how pipe and tool joint tensile yield is reduced with size. Smaller drill pipe is also much more flexible.

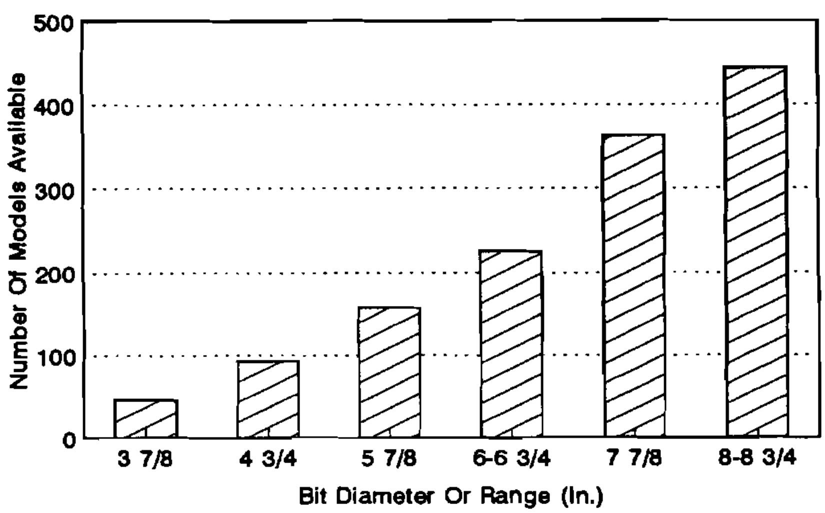

Figure 38. Typical Drill Pipe Tensile Yields

Typical torsional yields are shown in Figure 39.

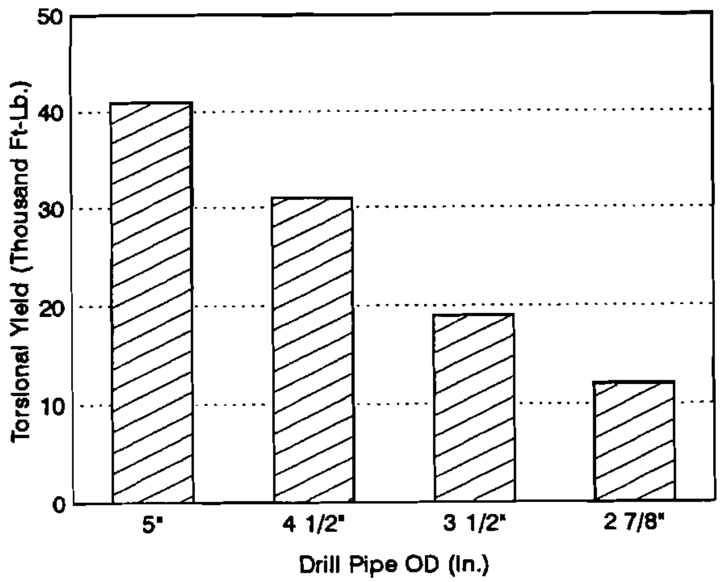

Figure 39. Typical Drill Pipe Torsional Yields

Drill-string weight is reduced as well, meaning tensile loading limits remain proportional except in fishing or stuck pipe conditions. Dynamic tensile stresses and torsional stresses are the parameter that become much more critical with slim-hole drilling.

Smaller tool joints are inherently weaker and thus more prone to belling and twist-off and are more sensitive to hole and casing wear.

Thinner-wall pipe is more susceptible to corrosion due to the greater relative percentage of wall thickness a given corrosion pit will occupy. This increases the pipe's susceptibility to corrosive environments.

Because there is less mass and strength due to the reduced dimensions, higher strength steel is often used. This further affects wear, fatigue life, H_2S and other corrosion resistance, and fishing tool selection.

Vibration due to the interactions between the drill string and the hole is a problem with rotary drilling in all sizes. The problem is magnified with slim-hole drilling due to the reduced loading limits of the smaller drill-string components, and greater susceptibility to borehole wear. Conventional rigs and drill pipe have the strength and durability necessary to overcome most vibration problems and continue towards TD, even if inefficiently. Slim-hole drill pipe has a much higher probability of suffering catastrophic failure at much lower levels of vibration.

Three different modes of vibration are axial, torsional, and lateral or bending (Figure 39). Axial loading (longitudinal) arises primarily from interactions between the bit and the formation, sometimes leading to bit bounce. When a bit instantaneously sticks in the rock, torque can build up until released when the bit breaks loose. The pipe then momentarily spins at a much higher rate. This stick-slip phenomena creates torsional vibrations and loading on the drill string. Lateral vibrations can occur due to bit whirl, friction, out-of-balance mass, and motor reaction forces. Lateral vibrations also occur when the drill string rotates/rolls around the ID of the wellbore due to weight imbalances (bent pipe, etc.) or lateral string excitations and thus does not rotate around a fixed axis. This "whipping" typically occurs at the top of the drill collars and can result in extra fatigue life lost and failure of the pipe directly above the DCs.

Vibrations with PDC bits, all else equal, tend to be greater. Thus, drilling with smaller PDC bits, while beneficial because of no bearings, requires even greater attention to rotary speed, WOB, and other drilling parameters to minimize vibrations. Generally PDC bits favor higher rotary speeds for maximum ROP and minimum vibration.

Another problem related to slim-hole drilling with ramifications for drill-string failures is dogleg severity and hole deviation (Section 3.4.4). Lighter and more flexible bottom-hole assemblies and reduced mud pump rates set up conditions more susceptible to doglegs and hole deviation. These cause greater fatigue accumulation in drill strings and increased failure incidence rate. Fatigue is the major cause of drill pipe failures and occurs primarily when drill pipe is rotated in a dogleg causing cyclical axial bending stresses on the pipe wall as shown in Figure 40. Additional stresses occur in the drill pipe body adjacent to the tool joints where incremental bending takes place to make up for the bending that does not occur in the stiffer tool joints. Figure 41 shows an example of how fatigue life of drill pipe expended in doglegs increases rapidly as dogleg severity increases. This example assumes 1000 ft of pipe below the dogleg, 100 rpm, 10 ft/hr drilling rate, and a 3° dogleg for 5-in. drill pipe and a 5° dogleg with 3½-in. drill pipe.

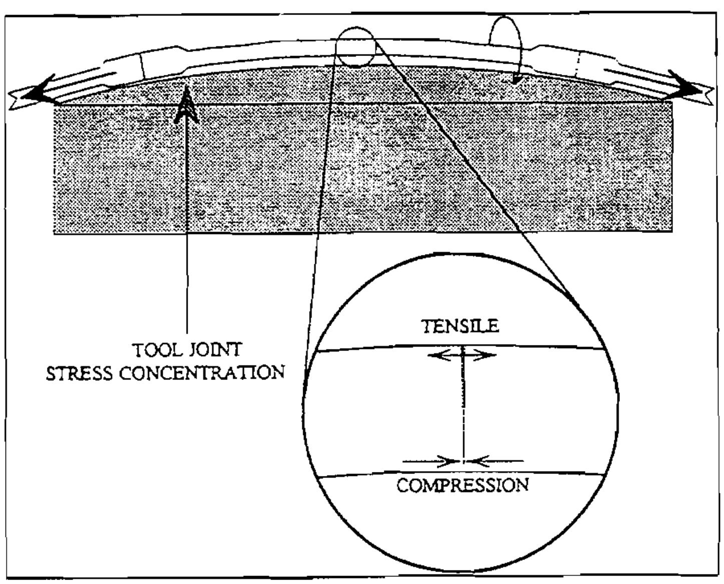

Figure 40. Cyclical Bending Stresses on Drill Pipe

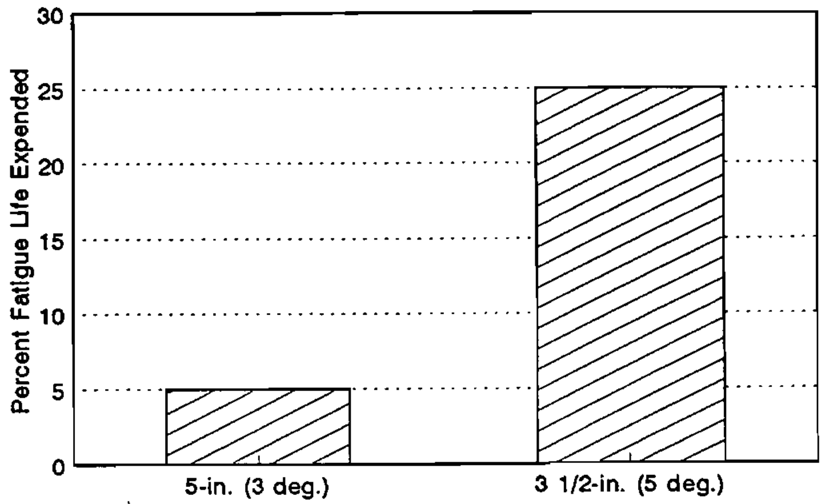

Figure 41. Percent Fatigue Life Expended in a 30-ft Interval

Most drilling rigs are equipped with handling tools designed for larger drill-string components. Crews are also more familiar with the larger pipe and tools. The thinner walls on smaller drill-string components increase the risk of damage from handling tools, such as tongs and slips. A $^1/_{16}$- in. cut in a ¾-in. wall pipe is 8.3% of the wall thickness, but is 16.6% of ⅜-in. wall pipe. Slip crushing of the drill pipe is more likely if excessive weight is supported by thinner wall pipe.

Rig modifications for racking of smaller drill pipe are also recommended due to the increased flexibility.

The lower yield strength of the smaller pipe and drill-string components result in lower overpull limits for attempting to free small drill strings from stuck situations. Fishing is discussed in more detail in Section 3.9 and Section 7.4.

3.4.3 Hole Deviation and Doglegs

Bits with smaller, weaker bearings and smaller, lighter, weaker, and more flexible drill string and bottom-hole assemblies create difficulties in maintaining a straight hole with minimal doglegs. Reduced hydraulics capability through the smaller pipe, annulus, and motor (if used) also can contribute to doglegs. Deviation, or stabilization, is normally controlled by decreasing bit weight, increasing the weight provided by drill collars, and the use of stabilizers. However, stabilizer use in slim holes is complicated by increased torsional stresses due to concentrated stabilizer/wall contact.

Smaller drill string and drill collars are lighter and more flexible, resulting in the need to provide more power (relatively) to the bit through increased WOB. However, increased WOB results in greater hole deviation tendencies. A desire to maintain a vertical hole means WOB must be cut back, resulting in reduced ROP. It is easy to see how these conflicting objectives can lead to greater incidence of hole deviation and dogleg problems in slim-hole drilling. As stated earlier, hole deviation and doglegs are major contributors to fatigue build-up in drill strings of all sizes. Therefore, the cost of maintaining the drill string increases with greater hole deviation and dogleg frequency and severity.

Of course, hole deviation, or crooked hole problems are more severe in some areas, typically in harder rock country.

The use of larger, heavier, and stiffer than normal drill pipe and connections (40 to 60% stronger torsionally) run pin-up with a fishing neck below the pin has been shown to be advantageous in small hole situations (Figure 42).

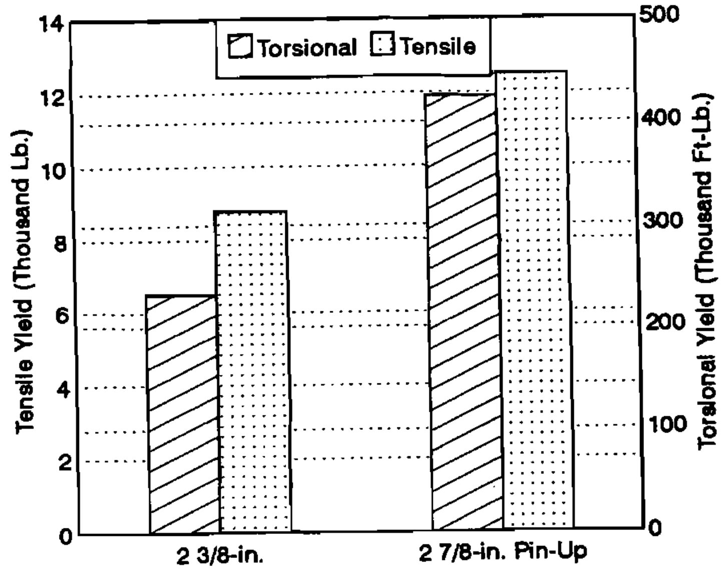

Figure 42. Slim-Hole Pin-Up Drill Strings (Dudman, 1994)

3.4.4 Literature Review

Information is presented below from selected literature where the specific problems related to slim-hole drill-string limitations and problems are mentioned.

- Wilson, 1954

"...the driller on the slim-hole rig must learn early that he cannot apply the degree of torque that normally would be done in big rig drilling. He must remember that he is turning a drag bit and cannot rotate too fast as a point will be reached where the bit jumps and skips on bottom. He has much more power available, in relation to his small size string of pipe, than he would have on a large rig. Therefore, he must cultivate a 'feel' for the smaller sizes of pipe and related equipment in order to avoid twist-offs in the hole."

- MacDonald, 1956

"The larger diameter and stiffer drill pipe will transmit unmistakable evidence to the surface of a hanging bit and permit appropriate clutch disengagement. The more flexible small pipe will merely wind up..."

- Worrall, 1992

Shell's slim-hole system relies generally on standard drill pipe with downhole motors, soft-torque rotary table, and downhole thruster to reduce vibrations which lead to drill-string failure. They have developed new threads for improved torsional strength of the tool joints in 2⅞- and 3½-in. drill pipe.

- Dupuis and Fanuel, 1993

Forasol/Foramer and Elf Aquitaine developed a slim-hole system based on conventional rotary techniques. As testimony to the importance of tubulars in slim-hole drilling, the drill string is considered the heart of this system and Elf has stated they "...would not have participated on the project...if these tubulars had not existed." (*Drilling Contractor*, July 1994).

The tubulars are approximately 3.5- and 2.2-in. OD and use high quality steel, tool joints friction welded on a flush body, and high-torque threads. Special drill collars and stabilizers have also been developed for this system, now being tested in Europe.

3.5 DOWNHOLE MOTORS

The two barrier topics discussed thus far, bits and drill strings, point to the potential benefits of the use of downhole positive displacement mud motors. Motors can be used to address the limitations of inherently weaker drill-string components, bit limitations, and susceptibility to severe hole deviation problems. In conventional rotary drilling, smaller bits and weaker drill strings limit the rotary speed and weight on bit that can be applied when the entire drill string must handle the torque and other stresses from the bit through the rotary table. In other words, rate of penetration is less and/or mechanical failure incidence rate is greater than would be expected using more conventional bits and drill strings.

Downhole positive displacement motors (PDM) (Figure 43) are positioned directly above the bit and convert energy from the drilling fluid (usually mud) to rotary power for the bit using the Moineau principle. The circulated fluid passing through the motor and around the spiral shaped rotor inside a rubber elastomer stator causes the rotor to turn. Fluid continues to pass from motor chamber to chamber. This rotation is then transferred to the bit through a universal joint and rotating sub allowing the motor and the rest of the drill string to remain stationary. Thrust and radial bearings are used to absorb the axial and normal loads generated during the drilling operation. The standpipe pressure is a direct indication of WOB and can be closely controlled. Therefore, the use of PDMs isolates the torsional loadings at the bit from the rest of the drill string, allowing for greater rotary speed and WOB flexibility.

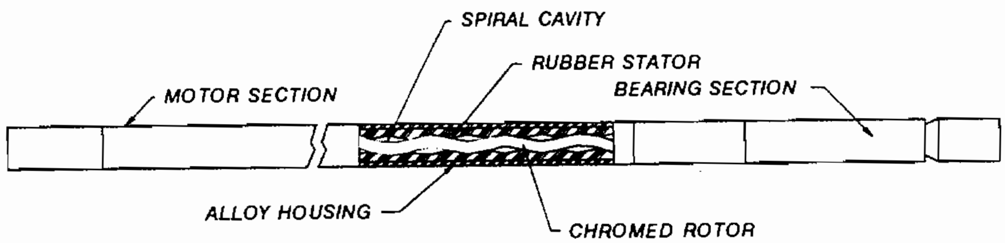

Figure 43. Downhole Positive Displacement Motor

PDMs have been used since the late 1960s primarily as a directional drilling tool. However, their use, and the technology related to PDMs, has accelerated greatly with horizontal drilling applications since the mid to late 1980s.

Most commercial motors have been high-speed/low-torque designs. More recently, medium-speed/medium-torque and low-speed/high-torque motors have become more common. The thrust bearings and seals, drive coupling, and stator are the primary limitations on motor life. Historically, the incremental cost of running a downhole motor has been such that it was not cost effective in vertical wells (of conventional size) despite the potential benefits such as increased ROP available with higher downhole rotary speeds, minimized drill-string fatigue, and minimized hole problems.

Producers or drilling contractors typically rent PDMs and are therefore dependent on the service company for recommendations and quality control. Recent technology developments in the areas of sealing systems, rotor and stator material and geometries, and higher-power, tandem motors are escalating the use of PDMs in a much wider variety of applications, including vertical gas well drilling in the United States. Of critical importance is the proper matching of bit and motor types with the formation to be drilled.

Adding the cost of a downhole motor to a drilling system in a typical U.S. vertical, onshore gas well is not trivial. Significantly enhanced drilling performance is required to make it cost beneficial to do so, even in larger sizes. As stated, technology is improving in larger motor sizes making this a reality in a widening number of applications. These technology enhancements need to be made in smaller motor sizes in order to allow slim-hole drilling to become beneficial for a greater number of operators. These improvements need to be made both in performance and operating life and cost. A typical challenge: increasing the number of lobes in a motor stator (to lower speed and increase torque) tends to decrease its operating life because of the higher torque on the small universal joint and drive train components.

The benefits of PDMs and the widening applications of PDC fixed-cutter bit technology drove Baker Hughes INTEQ, in conjunction with Shell, to build their slim-hole system around downhole motors and PDC bits. Despite the reduction in torque carrying requirements of the drill pipe by using a downhole PDM, this system also utilizes additional novel anti-vibration technology to damp the vibrations even further. This includes a soft-torque rotary table system and downhole thruster. To take advantage of the benefits of downhole motors and PDC bits requires precise control of WOB and minimization of bit bounce (axial vibrations), which is the function of the downhole thruster in the INTEQ system (Figure 44). The thruster is more necessary at lower speeds and higher torques than at higher speeds and lower torques. The need for thrusters with medium depth, vertical drilling (common to most U.S. gas wells) is unclear. A good brake, automatic driller, and crew awareness, training, and experience are probably the most critical elements. Sophisticated and costly devices such as a thruster may not be necessary. Field testing in U.S. gas drilling could ascertain the benefit-to-cost of such a device.

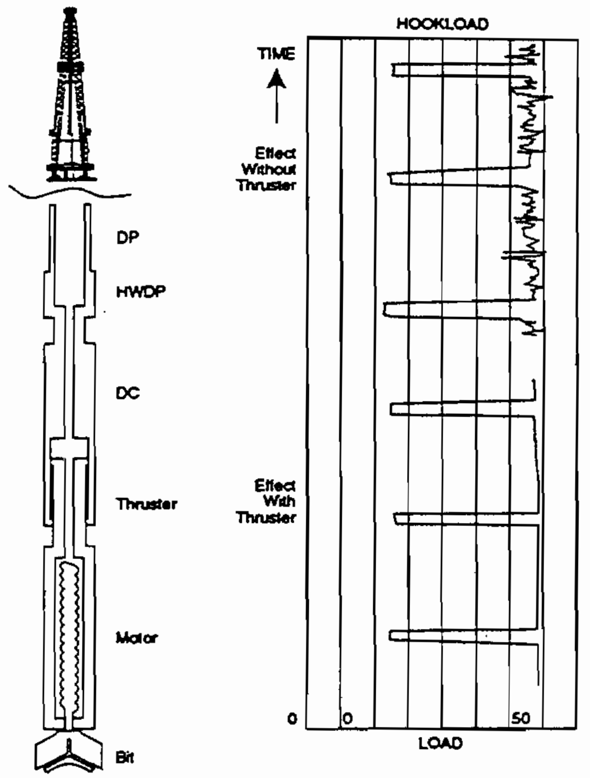

Figure 44. Downhole Thruster (Eide and Colmer, 1993)

Recent GRI research has shown that ROP can be substantially increased by increasing the power output of small diameter motors by running them at significantly higher speeds (Figure 45). Increasing the length of the motors also increases the torque and power. Developing more power at the motor with lower bit weight reduces the problems related to small-motor flexibility such as directional control and motor damage. However, motor life is limited by universal joint failures, bearing life, seal life, and stator erosion and delamination problems, all of which are complicated by smaller diameters. Improved higher-power, long-life motors are a critical need for cost-effective slim-hole drilling. High temperature and oil-based mud-tolerant small diameter motors have also been mentioned as a need for use in some South Texas gas reservoirs (DEA, 1994).

Achieving adequate or desired annular velocity for optimum hole cleaning and maximum ROP can be limited by flow rate limitations of the motor. Incorporation of adjustable annular bypass valves or a hollow-shafted rotor with nozzle are possible solutions.

Lost circulation material (LCM) handling is a problem for all motors, but is typically worse in small motors. Bypass valves at the top of the motor are now used to divert LCM away from the motor, but drilling must be stopped while this valve is open. A hollow-shafted rotor may be a solution.

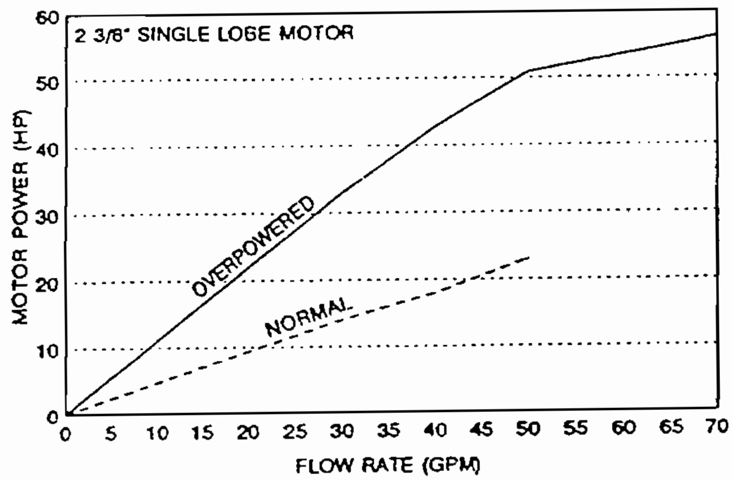

Figure 45. Laboratory Performance of Slim-Hole Bits and Motors (Cohen et al., 1995)

Because of the complex, interrelated aspects of motor drilling with bit selection, drilling fluids, hydraulics, and formation characteristics, the expansion of the technology into more onshore U.S. areas with smaller sizes will require considerable field testing and experimentation to stimulate and escalate technology development and facilitate technology transfer.

Evidence of the cost-effective viability of motor drilling is found in several areas where drilling contractors and operators have recently begun using motors in vertical medium-depth wells. *After adequate experience* in an area, they have found that, despite the added cost of the motor, the drilling performance and increased drill-pipe life is very beneficial. The Greater Green River Basin is one such area. Gaining this multi-well experience with smaller motors is very important to making slim-hole drilling and completions a viable near-term cost reduction method for U.S. gas producers.

3.6 HYDRAULICS, KICK DETECTION/WELL CONTROL, AND DRILLING FLUIDS

3.6.1 General

The main functions of the drilling fluid are to carry cuttings from beneath the bit to the surface, provide hydrostatic pressure to prevent formation fluids from flowing into the well, and to keep the hole open and competent for subsequent drilling until casing is run. Optimization of the rates and pressures of the drilling fluid throughout the system is generally referred to as hydraulics. Drilling slim holes means the use of smaller drill-pipe, bits, and reduced annular clearances, which affect many interrelated issues revolving around drilling fluids and the circulating pressures developed.

The coring method of slim-hole drilling with its extremely narrow clearance and very high rotational speed is the extreme condition and, due to the numerous projects using this method for international exploration, has received the greatest hydraulics, kick detection/well control and fluids attention by companies researching and implementing projects. In contrast, the numerous articles published in the 1950s and 1960s discussing conventional slim-hole drilling seldom mentioned hydraulics and never mentioned kick detection/well control as a problem or barrier to drilling slim holes with standard methods.

3.6.2 Hydraulics

In performing its function, the drilling fluid is pumped from the mud pump through the surface lines, standpipe hose, kelly, down the drill string and bottom-hole assembly and back up the annulus and through the surface mud treating system (Figure 46). Hydraulics optimization entails the careful analysis of the fluid properties and pipe, bit, and hole geometries in order to optimize the end results of the interrelated drilling fluid functions: maximizing rate of penetration while maintaining control of the well, a competent, in-gauge borehole, and minimizing formation damage.

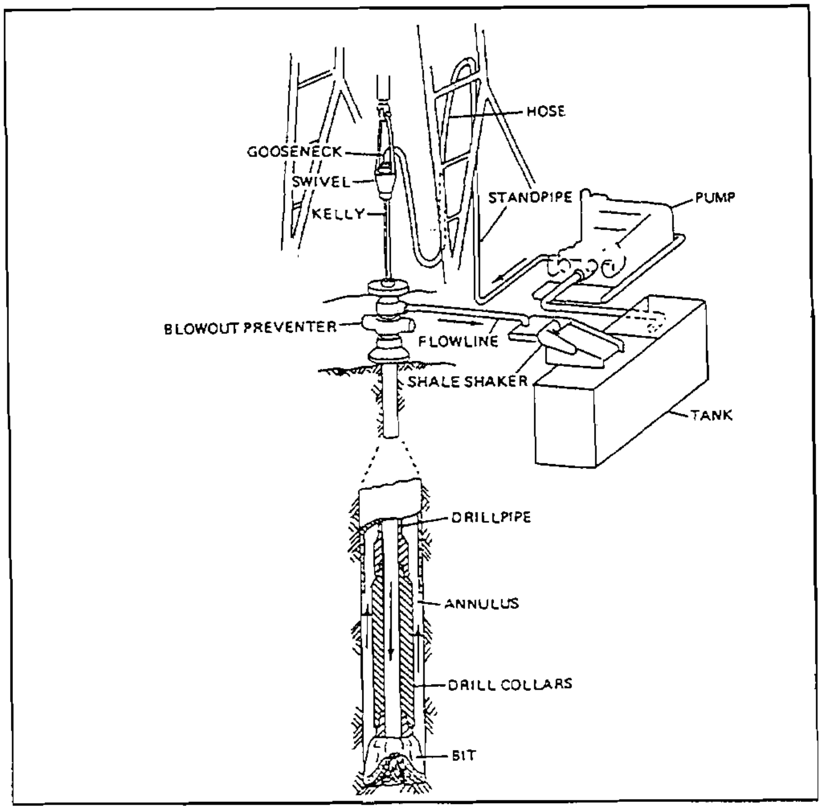

Figure 46. Typical Mud System (Hughes, 1979)

A smaller drill string, narrow annulus, and higher rotating speeds typically create added sensitivities to the key hydraulics variables. Table 5 compares typical pipe and annulus geometries. Considerations that result from the slim geometries include:

1. Higher internal friction pressure due to smaller drilling tubulars
2. Higher annular friction pressure due to smaller annulus
3. Higher Equivalent Circulating Density (ECD) due to increased annular friction
4. Greater ECD sensitivity to flow rate changes due to increased annular friction
5. Higher and more sensitive ECD increases the susceptibility to lost circulation, kicks, borehole stability, and differential sticking
6. The effect of rotary speed on annular friction and ECD is greater
7. The effect of eccentric drill pipe on annular friction is greater
8. Greater surge and swab pressures
9. Higher rotary speeds can cause drill solids and weighting materials to plate out inside of the drill pipe
10. Increased hole cleaning and annular velocity sensitivities

TABLE 5. Typical Drill Pipe/Hole Geometries

Well Type	Hole Size, in.	Drill Pipe, in.	Ratio	Annular Clearance
Conventional	7.8750	4.500	0.57	1.69
Slim-Hole Drilling	4.7500	2.875	0.61	0.94
Continuous Coring	4.375	3.700	0.85	0.34

3.6.3 Friction Pressure and ECDs

Because of these heightened sensitivities, accurate hydraulics computer models should be used to predict pressure losses and optimize drilling fluid selection and overall hydraulics. For illustration, example cases were prepared and run using the DEA-67 hydraulics model, HYDMOD, for the conditions shown in Table 6. These cases represent a conventional-size drilling configuration and three different slim-hole configurations. The three slim-hole cases include slim-hole drilling using standard equipment and two different slim-hole coring geometries.

TABLE 6. Hydraulics Examples

	Conventional Drilling	Slim-Hole Drilling	Slim-Hole Coring (1)	Slim-Hole Coring (2)
Depth (ft)	10,000	10,000	10,000	10,000
Md. Weight (ppg)	10.0	10.0	10.0	10.0
Md. PV (cp)	16.0	16.0	16.0	16.0
Md. YP (lb/100 ft^2)	10.0	10.0	10.0	10.0
Bit Size (in.)	7⅞	4¾	4½	4½
Drill Pipe OD (in.)	4.5	2.875	3.7	3.1
Drill Pipe ID (in.)	3.25	2.125	3.0	2.7
Drill Collar OD (in.)	6.50	3.125	—	3.725
Drill Collar ID (in.)	2.813	1.500	—	3.100
Drill Collar Length (ft)	600	600	—	60
Flow Rate (GPM)	300	100	50	75
Nozzles	3x13	3x10	3x7	3x9

Flow rate and nozzle parameters were chosen to achieve approximately comparable annular velocities and pressure drops (percentage) at the bit rather than a rigorous optimization procedure for each case. Figures 47 and 48 graph the assumed flow rates and resulting annular velocities.

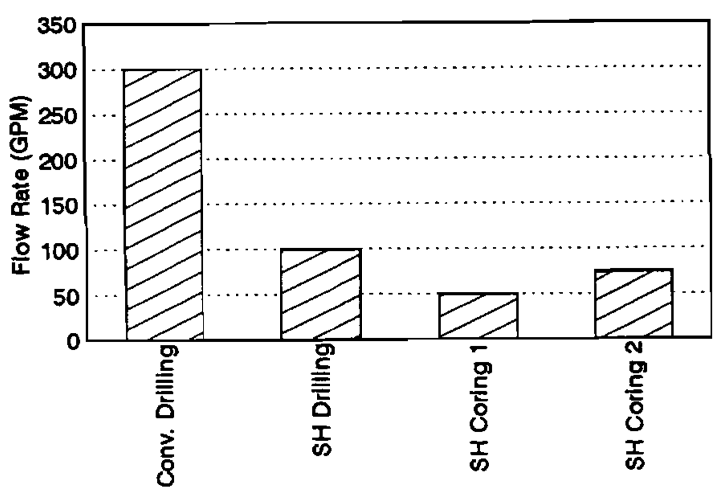

Figure 47. Example Well Flow Rates

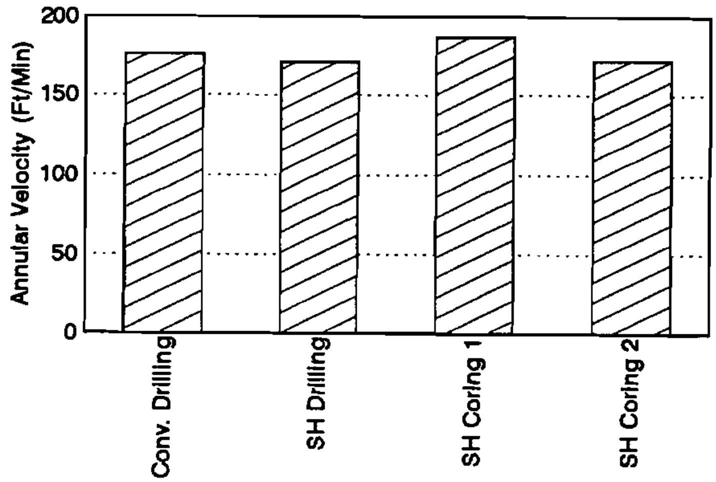

Figure 48. Example Annular Velocities

Figures 49, 50, and 51 show how pressure drops and ECDs vary with the different conditions.

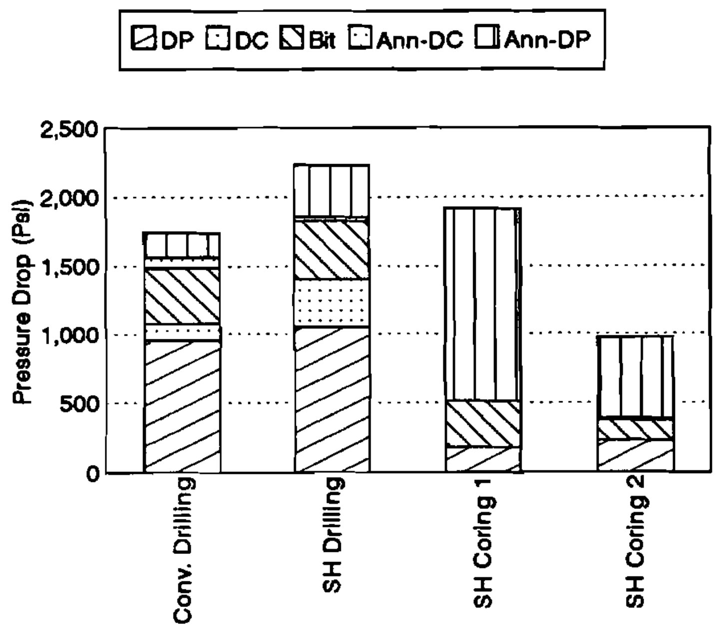

Figure 49. Example Pressure Drops

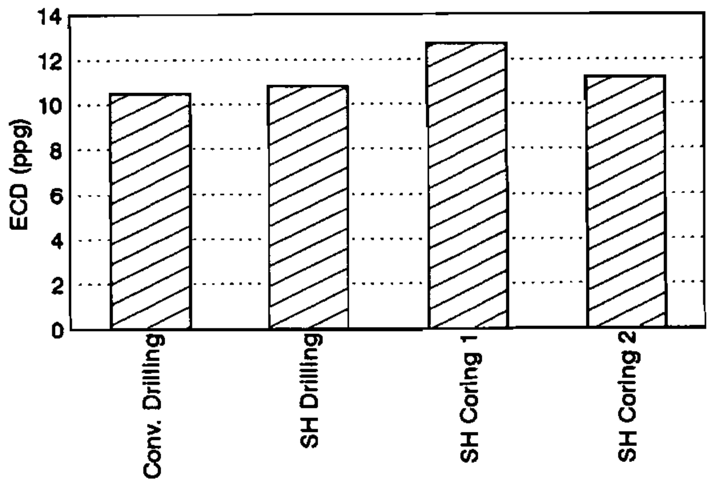

Figure 50. Example ECDs

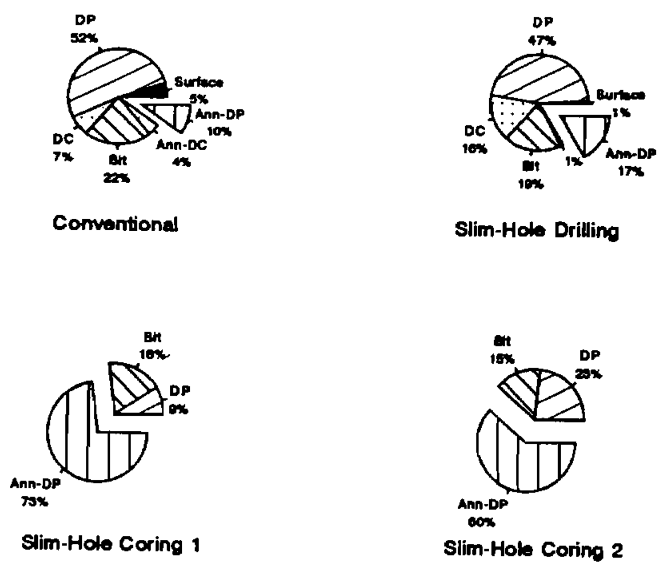

Figure 51. Example Pressure Drops (Percent)

These examples illustrate the fact that the <u>relative</u> pressure drops with slim-hole drilling with conventional equipment and geometries are comparable to the conventional case, while the coring cases exhibit very different results. That is, most of the pressure drop for the coring case is in the annulus, whereas most of the pressure drop is in the pipe for the conventional and slim-hole drilling cases. This is very important since conventional well control techniques rely on annulus friction pressure being a small percentage of the total system losses. Pressure drops are greater and flow rates reduced in all the slim-hole cases, but to a much greater extent with the coring geometries than with conventional rotary or motor geometries. Also, ECDs are much closer to conventional levels with the slim-hole drilling than with coring. These examples illustrate that the sensitivities and variances with conventional, and hence the associated barriers to effective slim-hole drilling, are not as great using rotary and motor slim-hole techniques as with continuous coring techniques. However, greater awareness and explicit consideration of hydraulics issues are still necessary for maximizing the cost-effectiveness and success of slim-hole drilling, especially in deeper, higher-temperature and higher-pressure applications.

Higher annular friction and ECD, with the extreme case being continuous coring, means that the bottom-hole pressure exerted on formations being balanced with the drilling fluid is much more sensitive to drilling parameters such as mud flow rate changes. Therefore, since drilling rate is often optimized by fine-tuning mud weight to a near-balance condition, there is a heightened probability of unknowingly increasing bottom-hole pressure to the point that drilling fluid is lost to a formation (lost circulation). This can lead to reduction of hydrostatic pressure such that the same or another formation becomes underbalanced and a kick occurs. The circulating bottom-hole pressure <u>could</u> be sufficiently high (due to annular friction) to fracture a formation and lose circulation while the hydrostatic (non-circulating) bottom-hole pressure is sufficiently low as to allow formation fluids to enter the wellbore. Or, the formation could be balanced while circulating, but underbalanced while flow is stopped for connections or tripping.

Although this is a major concern, it has been addressed by substantial research efforts by multiple companies, and many exploration wells have been successfully drilled in this manner with very few problems. It cannot be overemphasized that the key to this past success has been enhanced understanding of the problem, accurate modeling of hydraulics, crew training and experience, overall awareness, and advanced kick detection systems. Special coring drill strings, such as that modeled in the coring Case 2, also have helped to reduce the ECD effects by using greater clearances.

Figure 52, based on the example cases, illustrates how hydraulic power requirements are reduced substantially with slim-hole drilling conditions.

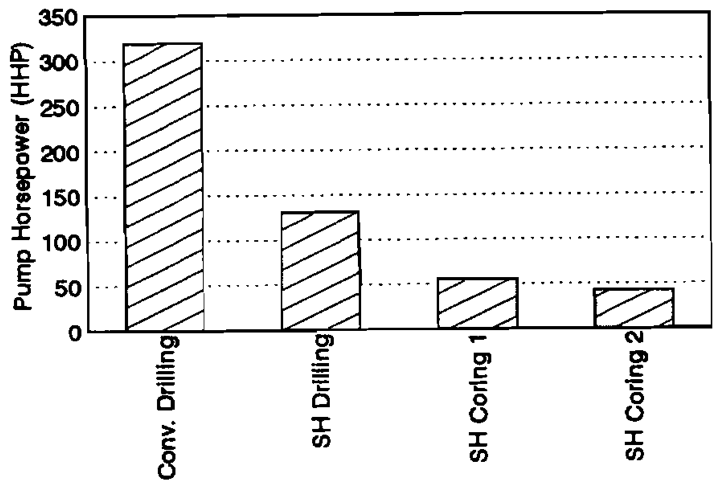

Figure 52. Example Hydraulic Power Requirements

3.6.4 Rotary Speed Effects

Work by multiple research groups has also shown that the extremely high-speed rotation used with coring methods can result in an increase in annular friction pressure that must also be considered in slim-hole drilling. Most hydraulics models are based on conventional hole and drill pipe sizes where the effect is immaterial. Drill-string rotation in extremely small clearances affects the trajectory of the mud and cuttings. By a viscous coupling effect called the "Couette effect," the rotating drill string forces the mud to be in rotation. The annular mud flow then becomes helical, skewing the velocity profile and causing an increase in the effective length of the return mud path and cutting travel. This in turn affects annular pressure drop as well as reducing the cutting carrying force (Figure 53). Turbulent flow has been shown to increase annular friction while laminar flow actually decreases annular friction. Several research groups, including Amoco, Total, and BP, have studied this effect during the development of their slim-hole programs. Their findings are discussed under Section 3.7.

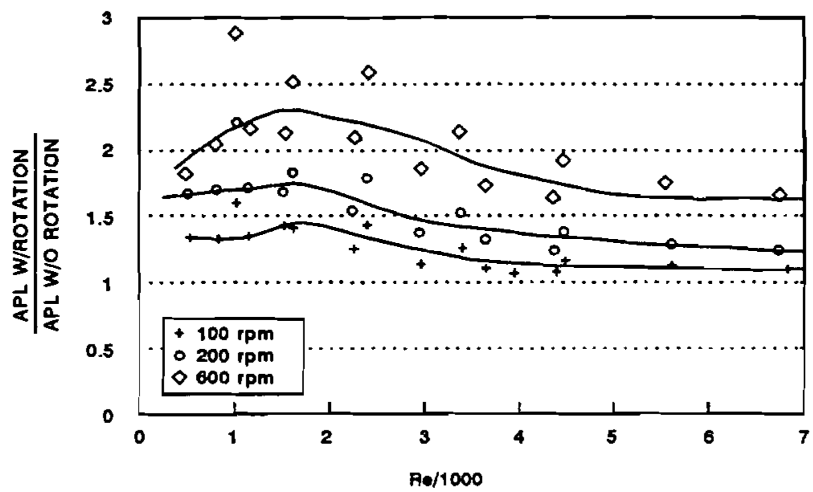

Figure 53. Circulating Pressure Loss with Rotation (Bode, 1989)

3.6.5 <u>Eccentric Drill Pipe</u>

Pipe eccentricity also has been shown to have an increasing effect on annular pressure losses as pipe/hole clearance is reduced. In general, annular pressure drop reduces with increased eccentricity in the absence of rotation (Figure 54).

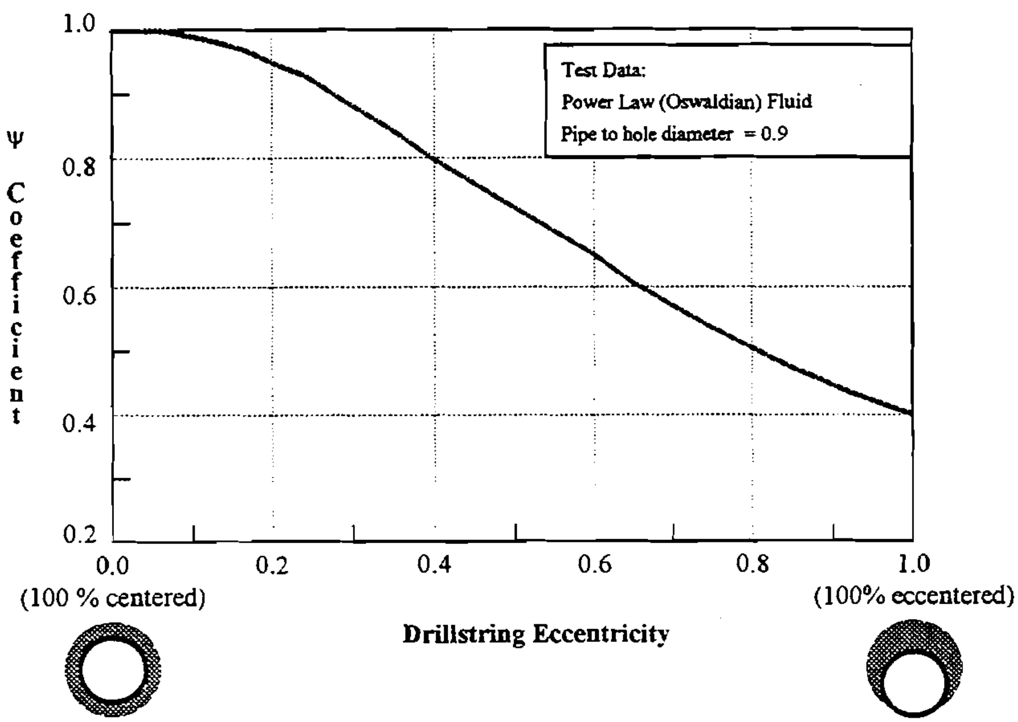

Figure 54. Influence of Drill-String Eccentricity (Delwiche et al., 1992)

3.6.6 Surges and Swabbing

The pressure at a given point in a well increases when running drill pipe into the hole (surging) and decreases when pulling pipe (swabbing) due to the piston-cylinder action of the pipe and borehole. Swabbing is recognized as a leading cause of kick development. These effects increase rapidly with reduced clearance as shown in Figure 55. Therefore tripping speeds should be closely analyzed with state-of-the-art hydraulics models when drilling slim holes.

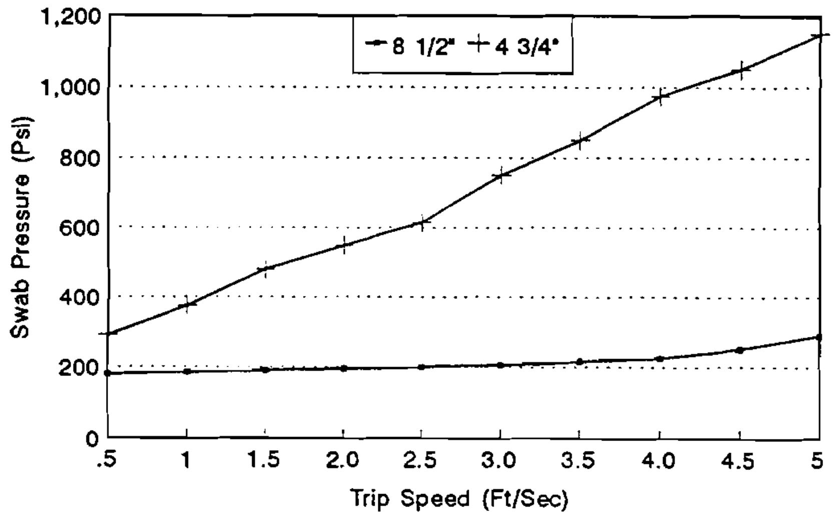

Figure 55. Swab Pressure During Tripping (Mehra and Damak, 1994)

3.6.7 Hole Cleaning and Annular Velocity

The small annular area in a slim hole increases the susceptibility to cuttings build-up in the annulus. Theoretically, hole cleaning should not be a problem because the reduced annular cross-section lowers the flow rate needed to achieve the required annular velocity for adequate cuttings removal. However, other factors become more important and may dominate. Mud flow rate and annular flow regime (laminar or turbulent) is much more critical in slim-hole configurations than conventional. Obtaining the sufficiently high annular velocities for cuttings removal should not be a problem with the smaller annular area, but it must also remain below a critical shear stress level on the borehole wall to avoid hole erosion and instability problems. Shear rate and shear stress in slim-hole conditions, all else equal, will be greater. Turbulent flow regimes maintain a uniform velocity profile across the annulus, beneficial to cuttings removal, but contribute to higher annular friction and borehole shear stresses. Laminar flow regimes become more dependent on mud rheology for adequate velocity profiles. Once again, state-of-the-art computer models need to be used to study overall hydraulics and mud rheology effects.

The use of downhole motors, especially small diameter motors, also complicates hole cleaning considerations. The flow rate requirements or limitations of the motor may result in lower than desired annular velocity. Hollow-shaft motor rotors and adjustable bypasses located above the motors could be used to increase the flow rate to improve hole cleaning.

3.6.8 Borehole Stability

The subject of borehole stability is presented here, even though it is not strictly a hydraulics issue per se. Theoretical borehole stability equations are dimensionless, meaning the stress around boreholes in homogenous formations is independent of hole diameter. In fact, there is anecdotal evidence from logging companies that smaller holes tend to be more "rifle barrel"-like, meaning more in-gauge and competent than larger sizes. However, because of the reduced annular clearance, any stability problem (such as shale sloughing) is more prone to result in stuck pipe, etc.

Mechanical and hydraulic factors affecting hole stability in slim holes include:

1. Increased ECD and ECD sensitivity to rate changes, hole conditions, etc. provides greater susceptibility to overpressuring of formations.
2. More flexible drill string and resulting vibrations and pipe-whipping resulting in greater hole erosion.
3. Greater shear rates and stresses exerted by the drilling fluid on borehole walls.

Of course, all "conventional" borehole stability concerns and precautions are just as applicable in slim-hole drilling as in conventional size hole drilling. Proper mud chemistry to avoid adverse reactions with shale is no different. The end result of borehole instability is simply more problematic in slim holes because of the reduced annular area and increased fishing difficulties.

3.6.9 Differential Sticking

Differential sticking occurs when a portion of the drill string is held against the mud cake due to the hydrostatic pressure in the wellbore exceeding the pore pressure of the adjacent formation. As with borehole stability, the primary concern with differential sticking in slim-hole drilling is the weaker pipe and reduced annular clearance in which to work on the problem after it occurs. However, there are also some factors which may increase the possibility of differential sticking in slim-hole drilling.

The differential sticking force (F) is represented by the following equation:

$$F = \Delta P \cdot A \cdot f$$

A is the effective contact area and f is the coefficient of friction between the pipe and mud cake. Factors related to slim-hole drilling which *may have a tendency* to increase this sticking force include higher than necessary wellbore pressure (possible due to sensitive ECDs), thick mud cakes causing a greater effective contact area, and larger relative pipe diameters causing a greater effective contact area. The use of externally flush drill-string components in slim-hole drilling to maximize annular area will also have a tendency to increase the effective contact area as does the pipe used in coiled-tubing drilling and continuous coring. All of these factors need to be considered along with mud rheology and design in order to minimize the chances of having a sticking problem. Minimizing continuous contact area is typically accomplished by designing drill-string components with spirals (such as spiral drill collars), heavy wall drill pipe with upsets, or by adding clamp-on stabilizers.

3.6.10 Lost Circulation

Lost circulation occurs when whole mud, as opposed to just the filtrate, is lost to the formation due to excessive bottom-hole pressures or pre-existing voids. Lost circulation material is used to control whole mud losses to the formation. Types of LCM include granular, fibrous, and flake or lamellar materials. Lost circulation is typically controlled and cured by treating the entire system with LCM or spotting viscous pills with LCM material across lost circulation zones. As discussed with kick detection and hydraulics, LCM bridging tendencies in the small annular area in slim-hole drilling will be greater. This can create excessive ECDs which can lead to increased sensitivity to lost circulation from high filtrate loss, jetting fluid into the formation, or even fracturing. Increased susceptibility to cuttings build-up in the annulus due to insufficient hole cleaning and solids control can also lead to this condition.

Once lost circulation occurs, the use of LCM can be more problematic in slim-hole drilling due to potential plugging of smaller flow areas in bits, motors, and MWD tools (if in use). Using conventional LCM mixing and pumping procedures in slim holes could cause unexpected cuttings build-up problems as the LCM plugs act as a viscous sweep. Some downhole tools with severe restrictions may necessitate the use of a circulation sub that can be cycled open and closed. This is a common practice for conventional wells, but improvements may be necessary in slim-hole tools that will allow for more cycling. LCM, like cuttings, will also have a higher susceptibility to bridging in the annulus, compounding the problem. Once again, these conditions and sensitivities are of most concern in the extremely narrow annulus of a slim-hole coring system.

Laboratory testing to determine proper LCM type, mixture, concentration, size, and distribution for various downhole slim-hole tools may be beneficial to operators implementing slim-hole programs.

3.6.11 Kick Detection and Well Control

Inherently related to all hydraulics issues is the detection of unwanted formation fluid into the wellbore (kick detection) and the subsequent manner in which this fluid is circulated out and further fluid is prevented from entering the well (well control).

The basic and major variance with slim-hole kick detection is this: the smaller annular space means a given volume of gas kick will occupy a greater height. This greater height of lighter fluid will result in a greater reduction of hydrostatic pressure on the kicking formation. For example, a two barrel kick occupies 49 ft in a conventional 7⅞-in. hole with 4½-in. drill pipe. In a 4¾-in. hole with 2⅞-in. drill pipe, the same two barrel kick occupies 144 ft (ignoring differing BHA sizes and washouts). In a continuously cored annulus (4.0625-in. hole, 3.7-in. drill rods), the height of the kick increases to 732 ft (Figure 56). This further illustrates the large difference between coring and conventional slim-hole drilling. Without shut-in, a greater influx rate then results, compounding the well control problem.

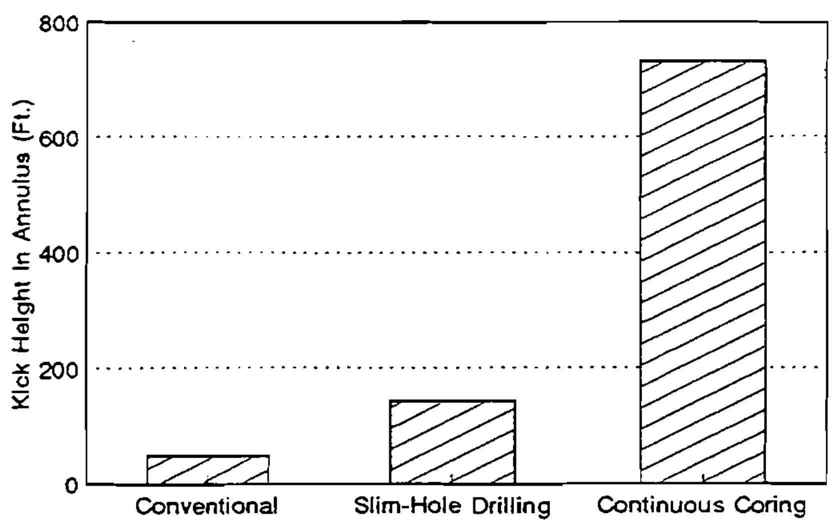

Figure 56. Two-Barrel Kick Heights in Conventional and Slim-Hole Annuli

Another way to consider the above problem is that it takes a smaller volume kick in a slim hole to result in the same detrimental effect. A 10-bbl kick in a conventional well is equivalent to a 3.4-bbl kick in a slim-hole drilled well and .7-bbl kick in a continuously cored slim-hole well.

The key for kick detection in slim-hole drilling is early detection of very low kick volumes, essentially less than 1 barrel. This requires more, and more accurate, monitoring points and devices. Sophisticated kick detection and well control equipment and procedures have been investigated and developed by several producers and service companies. These are covered in Section 3.7.

Conventional well control techniques call for quick shut-in and then monitoring of drill pipe and annulus pressures while slowly circulating the kick out and increasing mud weight to prevent further kick influx. These conventional techniques depend on the annulus friction pressure being a very small percentage of the total system pressure losses, such that slow circulation does not effect the ECD to a great degree. With the extremely small annulus of the continuous coring technique, the annular pressure drops can be 90% of the total system, greatly increasing the complexity of the well control problem. Because of this, dynamic well kill has been suggested and studied as an alternative in certain situations. This method calls for using the greater ECD effect to overcome the flowing formation pressure by quickly increasing the pump rate. However, this is a very sensitive and not very proven method of well control. Modified procedures for more conventional "Driller" or "Wait and Weight" methods have become the more common approach. This is also covered in Section 3.7.

3.6.12 <u>Drilling Fluid Implications</u>

All of the above hydraulics issues are obviously inherently related to drilling fluid property and rheology. Once again, the extreme case of slim-hole coring is where most of these issues become the most critical. However, all of the issues discussed should also be considered with slim-hole rotary and motor drilling as well, especially in areas where drilling even conventional sizes presents difficult hydraulic trade-offs.

Ideally, a slim-hole drilling fluid for the more extreme geometries (smaller annuli) would have very closely controlled properties, with the following characteristics:

1. Lower viscosities to reduce friction pressure in pipe and annulus.
2. Low fluid loss with a thin but tough filter cake.
3. Low solids content to reduce plating out tendencies at high rotational speeds, enhance cuttings removal, and increase the penetration rate.
4. Inhibited to minimize wellbore instability problems.

Advantageously, the reduced mud volume requirements of slim holes reduce initial cost, and offset the cost and difficulties of maintaining well-conditioned, higher quality, perhaps sophisticated mud systems, if such fluids are deemed necessary under extreme conditions.

New muds have been developed by operators and service companies for these extreme requirements. One concern is that the different rheological and physical properties of these muds cannot be adequately measured and analyzed with current field techniques.

3.6.13 Downhole Motor Fluid Issues

Drilling with downhole motors adds additional concerns to slim-hole fluid issues:

1. Abrasive drilling muds (such as the use of iron oxide weighting materials) can cause severe erosion and wear problems in small diameter motors.
2. Brine muds can cause rotor chrome coatings to flake off.
3. Oil-based mud properties (such as aniline point) must be carefully chosen and monitored to avoid stator rubber swelling.

3.6.14 Lightweight Fluids

Lightweight drilling fluids (air, foam, mist) have been used for many years to prevent lost circulation and reduce formation damage in depleted or low pressure reservoirs. Lightweight fluids can also be used to significantly increase rate of penetration in certain areas. Some stated limitations of air or lightweight drilling for even conventional applications include borehole erosion, hole cleaning, corrosion, formation water handling, compression costs, surface handling of foam, reduced bit life, and reduced motor life (if applicable). The area of most concern for conventional and slim holes is the lack of adequate hydraulics models to accurately model drilling conditions with lightweight fluids. As previously covered, this becomes extremely important in slim-hole conditions. For example, annular friction and ECDs are greater and pipe rotation plays a greater role.

Since the use of downhole motors will likely be more common with slim-hole drilling, improvements in slim-hole motors will also need to address performance and life limitations associated with air and lightweight fluid drilling. Reduced motor life is a problem due to inadequate cooling and subsequent overheating of the rubber motor stator. Motor torque and power output are reduced with lightweight fluids due to lower pressure drops across the motor.

3.7 MAJOR PROJECT REVIEWS

Considerable work has been done recently by several companies on drilling fluids, hydraulics, and kick detection/well control, primarily for the extreme conditions of continuous coring slim-hole drilling, or deeper, high-pressure/high-temperature applications for conventional or motor drilling. These will be reviewed briefly in this section.

3.7.1 Amoco

As part of their Stratigraphic High-Speed Advanced Drilling System (SHADS) development program, Amoco performed extensive studies on hydraulics, fluids, and kick detection and well control under the conditions of continuous coring.

As part of this investigation, a full scale slim-hole well was drilled and instrumented for well control research. Five-in. casing with a 4⅜-in. ID (approximating the common SHADS hole size) was equipped with eight ¼- in. transmission lines ported to the casing ID through special pup joints (Figure 57). These were used to monitor pressures along the wellbore during various simulations. Lines were also used to inject nitrogen near the bottom of the well to simulate kick conditions. Their findings included the following:

1. The small annular volumes in slim holes require kick detection systems capable of detecting kicks smaller than 1 barrel.
2. Reliance on conventional detection methods such as mud pit volume gain is not adequate. Quantitative electromagnetic flow meters on the mud pump suction and flowline with graphical rig floor display are necessary.
3. Annular pressure losses with coring geometries are 90% of the system versus 10% with conventional well drilling.
4. Dynamic well kill is a viable method of well control with excessive annular pressures.
5. Swab pressures while removing the core barrel can be compensated for by circulating down the drill string via a lubricator.
6. Training of rig personnel in slim-hole well control is necessary.

As a result of this work and subsequent field tests, Amoco developed kick detection and well control equipment, procedures, manuals, and training guidelines for slim-hole coring applications, and successfully drilled many wells without well control problems.

Initially, Amoco developed a fluid for the extremely narrow annuli of slim-hole coring directed towards the primary objectives of being essentially solids-free and as inhibitive as possible toward reactive shales. This fluid is a water-based cationic polymer brine mud called CBF. Laboratory and field testing proved this fluid was compatible with their SHADS system with properties easily controllable and shale reactivity acceptable.

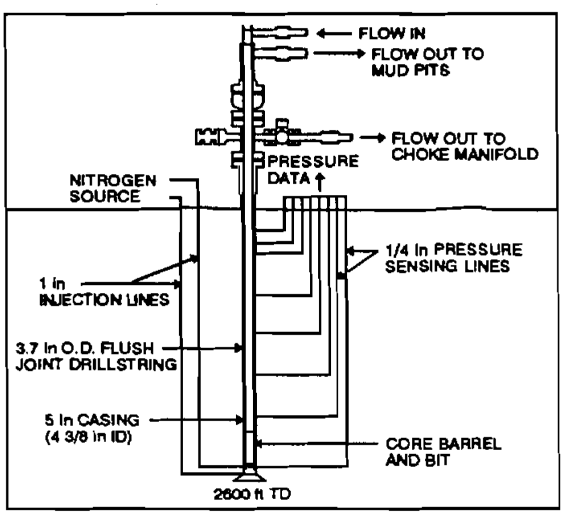

Figure 57. Amoco Test Well for Kick Detection/Well Control Experiments (Bode et al., 1989)

Later in their SHADS program, Amoco addressed various problems while conducting slim-hole testing with Elf in unconsolidated, soft-rock, tertiary sediments along the Gulf Coast. In these wells, a more conventional gel/water mud was used (8.6 ppg, PV 10, YP 15, 10-1 ml/30 min). Lost circulation was a considerable problem in this drilling environment. From these tests, Amoco and Elf concluded:

1. The higher viscosity of the gel/water mud did not create operational problems such as hole enlargement or excessive pump pressure.
2. Higher cuttings load in the slim hole did not hamper operations, but may have contributed to lost circulation at higher penetration rates.
3. Solids build-up did not occur under moderate rates of penetration with the solids control system (shale shaker, two centrifuges, closed system) working very well.
4. Low viscosity, low solids content muds created difficulties with maintaining circulation. The best fluid for avoiding lost circulation was higher viscosity, higher solids content with controlled fluid loss.
5. Calcium carbonate and starch were successfully used for fluid loss control.
6. The most important factor for wellbore stability was maintenance of the annular flow regime in laminar flow by increasing mud viscosity, decreasing pump rate, and increasing annular cross-sectional area when possible.

Amoco and Elf investigated and tested the use of a finer-grind of barite, called pigment-grade, to allow for increasing the weight of the CBF to over 14 lb/gal. This material was found suitable for the SHADS system with no wireline core retrieval or hydraulics problems occurring due to solids centrifuging. A centrifuge operating at a reduced speed discarded the drill solids without discarding unacceptable amounts of the fine-grind barite used for weighting.

3.7.2 Shell

Shell began investigating slim-hole technology in 1987. Their developments ultimately centered around using downhole motors with conventional rigs.

Shell developed an early kick detection system with Eastman Teleco, now part of Baker Hughes INTEQ. This system utilizes mud flow-in and flow-out sensors corrected for system dynamics by accurate computer modeling using a mass damper algorithm to model the dynamics of the mud in the hole. The model takes into account the normal disruptions in flow rates that occur due to changes in mud pump rate or drill-string movement. The system then compares actual out-flow to predicted out-flow. Alarms for kicks or lost circulation are then programmed. Shell states that the system has proven itself in wells with slim-hole sections, including high-temperature, high-pressure applications. This system is now available on a stand-alone basis from Baker Hughes INTEQ as part of their Slim-Hole Drilling Service (SHD).

Shell's experience has shown that all muds can be used, but that pressure losses need to be minimized to maximize hydraulic power available for the mud motor and bit. They concluded that the optimum mud is shear-thinning and solids-free with minimal viscosity in the drill string to minimize friction losses, but with adequate viscosity in the annulus for hole cleaning. For deeper, higher temperature, higher pressure slim-hole wells, Shell also concluded that smaller pipe and annulus again necessitated a low- or no-solids fluid to minimize frictional losses, maximize hydraulic power available to the motor, minimize ECD contrasts, minimize swab and surge pressures, and remain stable over a large temperature range. Shell developed and tested, in conjunction with Baker Hughes INTEQ, solid-free brines using organic sodium and potassium formate salts. These fluids are available up to 1.6 SG with temperature stability to 200°C and excellent shear-thinning characteristics.

3.7.3 Euroslim/Foraslim

Several European partners investigated slim-hole technology and ultimately developed a system based on conventional rotary techniques while retaining the ability to wireline-core zones of interest. As part of this project, theoretical calculations and laboratory testing was done to test the effects of drill-string rotation and eccentricity on pressure losses, as discussed earlier. This work confirmed the importance of including these factors in more complex hydraulic models for use with slim-hole drilling conditions, especially for very aggressive geometries such as found in continuous coring. They also confirmed the necessity of low solids and fine weighting materials and accurate control and modeling of mud rheology in slim-hole drilling.

Kick detection in their system is accomplished by very accurate flow-in and flow-out sensors with pit levels measured very accurately. They also developed a special kick detection program which includes the ECD effects in very small hole sizes.

3.7.4 Total

Total conducted a continuous coring slim-hole drilling investigation project and studied friction pressures, mud systems, and well control procedures. Their laboratory and theoretical analysis again found the importance of rotation and eccentricity in small annuli configurations and the heighted importance of accurately knowing mud properties. Additionally, they discovered that Binghamian fluids with high yield points cause unacceptable friction pressure. Oswaldian muds with lower yield points were more suitable for aggressive slim-hole conditions.

In their field testing in Gabon, Total used a water-based mud with potassium carbonate and insoluble glycol for the continuously cored slim-hole sections. This choice was based on the need for low solids, low viscosity, low friction, and environmental concerns. The mud performed as designed, but was considered costly. The special mud required a variable speed, efficient centrifuge.

For kick detection, Total relied successfully on the more accurate pit volume readings available with the slim-hole rig used. However, they also acknowledged the additional need for reliable and accurate flow-in and flow-out meters and software for continuous analysis of all drilling parameters for additional kick detection capabilities in coring configurations.

3.7.5 British Petroleum

BP has done extensive recent work investigating slim-hole coring technology as a means of reducing exploration costs. Much of their published work centered around development of a kick detection system (in conjunction with Exlog, now part of Baker Hughes INTEQ). The BP/Exlog Early Kick Detection System (EKD) is shown in Figure 58. Its performance is based on analysis of drilling data obtained in real time from sensors on the rig. Mud flow out and standpipe pressure are calculated based on a dynamic wellbore model and compared to measured values on the rig. Kicks are detected based on variations between measured and idealized model predictions. This system was used by BP on a four-well slim-hole program in Africa and demonstrated its effectiveness with the early detection of a small gas influx and the rapid detection of a mud loss zone.

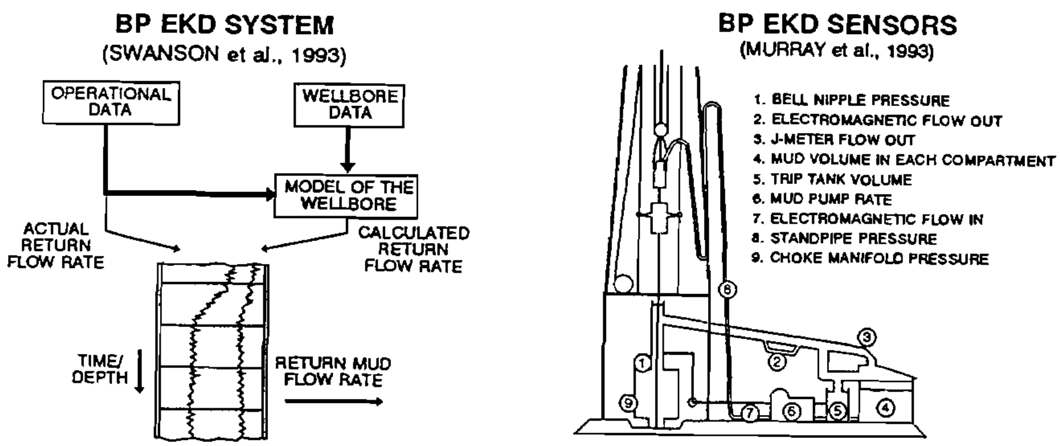

Figure 58. Early Kick Detection System (Swanson et al., 1993; Murray et al., 1993)

BP also recognized the sensitivities inherent in slim-hole well control and focused research toward developing slim-hole well control techniques. BP desired to stay away from untried and unproved dynamic well control procedures and instead developed a "modified conventional approach." Their system is based on more accurate estimation of drill string and annular friction pressure through frequent rheological testing and accurate modeling. To maintain the proper level of bottom-hole pressure during well control operations, the BP methodology calls for adjusting choke pressure upon initiating or ceasing circulation by the calculated annular friction loss, plus a safety factor.

BP's system also stresses the importance of deciding if a modified well control approach is even necessary. Modified well control is only necessary if the annular friction losses are critical, and need not be necessary on all geometrically similar wells, or in all sections of a given well. The BP kick detection system is now available from Martin Decker. The Exlog EKD system is available as part of the INTEQ DrillByte service, not as a stand-alone system.

3.7.6 Mobil

Mobil undertook an extensive study in 1991 to investigate and test slim-hole technology prior to drilling two slim-hole wells in Bolivia. This study also focused on slim-hole coring technology. Mobil drilled a test well at its Research Lab in Texas to study various aspects of slim-hole drilling. Part of this effort included a series of hydraulics, surge and swab, and well control simulation tests using an instrumented casing string. These tests provided the necessary information for development of generic slim-hole well control procedures, hydraulics modeling, and operations procedures and recommendations. The hydraulics model developed successfully predicted water performance in the test wells but was not as successful at predicting the non-Newtonian fluid used in the actual wells.

A well control situation was successfully handled during the drilling of one of the Bolivian wells. The Exlog EKD in use on the Longyear rig, combined with crew training, resulted in quick reaction to the kick with no more than .5 bbl of kick volume taken before shut-in.

Other pertinent fluids and hydraulics issues addressed and studied by Mobil during this project include hole stability and differential sticking. No hole trouble was encountered and almost gauge holes were drilled in very unconsolidated sands. No differential sticking was encountered despite almost 1.0 ppg overbalanced drilling, high ECDs, and long periods of stationary drill string on bottom. This was attributed to the low-solids brine used as the drilling fluid in these wells.

3.7.7 Anadrill

Anadrill's KickAlert system analyzes the mud pumps' pulses and detects changes in the mud's acoustic impedance to identify gas influx into the well. The pulse travels down the drill string, through the BHA, and up the annulus to surface sensors. Changes in the return time can indicate the influx of gas into the wellbore. Influxes less than 1 bbl have been detected in the lab and in field operations. Other companies either have or are working on similar concepts.

3.7.8 Conclusions

Maximizing the probability of successfully drilling a slim-hole well cost-effectively involves optimizing all of the variables associated with these issues. As has been stated several times, the most severe slim-hole case is with the geometries commonly associated with coring systems. State-of-the-art hydraulics modeling and analysis is necessary for proper planning and implementation of a slim-hole project. Early kick detection systems and modified well control procedures may be necessary. Due to the considerable work already done by major operators and service companies, most of this technology and information is available to the U.S. producer. Most importantly, accurate software models, education, training, awareness, *experience,* and field testing assistance are the biggest needs related to hydraulics, fluids, and kick detection/well control in slim-hole drilling.

3.8 RIG EQUIPMENT

This section focuses on conventional rotary and motor drilling only. The special rig considerations for using continuous coring for the slim-hole sections of a well are covered under the descriptions of that technique in Section 3.10.

3.8.1 General

Many slim-hole drilling barriers relate directly to technology, tools, and equipment that are generally provided by the drilling contractor, either in daywork, footage, or turnkey contracts. Rigs are depth-rated based on conventional hole and casing sizes and on common hook loads needed for those depths. Unfortunately, few drilling rigs are outfitted specially for slim-hole drilling and few rig crews, drillers, and supervisors are experienced at drilling smaller holes.

Rotary rigs generally have components falling under six categories: the power system, hoisting system, fluid-circulating system, rotary system, well control system, and the well monitoring system. These will be generally described and the slim-hole implications discussed.

3.8.2 Rotary System

The rotary system consists of the equipment used to rotate the bit including the swivel, the kelley, rotary drive, rotary table, drill pipe, and drill collars. A power swivel or top drive unit may be used below the swivel instead of the kelly, kelly bushings, rotary drive and rotary table for purposes of turning the drill pipe.

Drilling slimmer than conventional holes means generally the use of 3½- or 2⅞-in. drill pipe. The problems associated with the lower torque and tensile limits of the smaller pipe are discussed under Section 3.4 and are not repeated here. Most rig contractors provide 4- to 5-in. drill pipe in their normal contracts. Therefore, the cost, availability, and contracting details (such as who pays for damages) of the smaller drill pipe and required ancillary handling and fishing tools become questions under the contracting of the rig and equipment.

Conventional rotary tables are typically too massive and too powerful for slim-hole drilling operations. Only gross torque limits can be set with mechanical rotary tables. Even if a sufficiently low torque limit can be set, the sheer mass and resulting momentum of conventional rotary tables make over-torquing of the weaker pipe more likely.

The use of a top drive or power swivel typically provides for a greater range of rotary speed and torque combinations. Top drives and power swivels are hydraulically coupled to the power source, thus allowing torque limits to be more accurately set. Torsional shock loads are reduced because 1) the mass and momentum of the rotating components are significantly lower than with a rotary table, and 2) hydraulic fluid is somewhat compressible. Using a top drive or power swivel entails analyzing the derrick torsional strength since the reactive torque is transferred to the derrick instead of to the substructure. Derrick height and rig floor lay-out must also be analyzed for crown clearance and making connections. The speed and torque combinations and torque reduction aspects of using top drives or power swivels are important in slim-hole drilling. Making these techniques cost-effective from an ROP standpoint and a drill-string fatigue standpoint requires experience. Contracting and cost details when employing non-standard components must be dealt with by operators and rig contractors.

New sizes of bushings and slips are usually needed for slim-hole drilling. Conventional slips rely upon the weight of the drill pipe to engage the dies to grip and passively hold the pipe. The lower weight of smaller drill strings may necessitate the use of an active die engagement process in the slip assembly (Figure 59).

The advantages of using a downhole motor in slim-hole drilling have been previously discussed. The use of a motor affects the specifications required for the rotary system in slim-hole rigs since most rotation will be provided downhole by the motor.

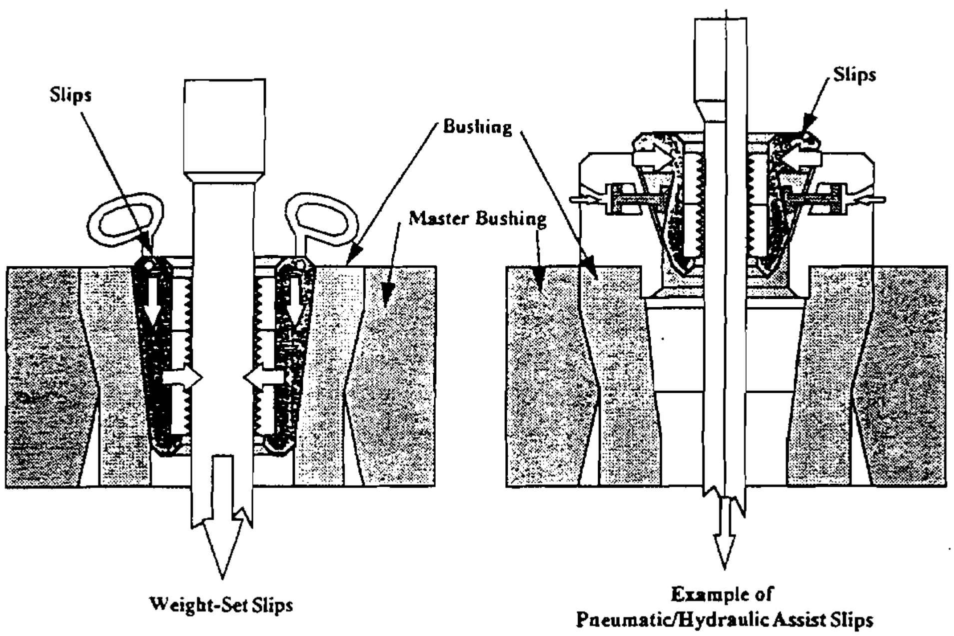

Figure 59. Slip Types - Weight Set vs. Assist Type

3.8.3 Hoisting System

The hoisting system provides the mechanism for raising and lowering the downhole assemblies into and out of the hole. The main components are the derrick, the substructure, the block and tackle, and the drawworks.

The function of the derrick is to provide the vertical height required to raise sections of pipe from or lower them into the hole. Most medium-depth and greater larger drilling rigs have derricks with sufficient height for pulling three joints of pipe. Shallower depth capacity rigs that may be modified for slim-hole drilling deeper wells may have derrick heights that restrict stands to only two joints, or doubles. This will slow tripping speed and reduce overall ROP if many trips are required. Another main concern for derricks with slim-hole drilling is associated with the increased flexibility of the smaller pipe. This makes standing back or racking the tubulars much more dangerous and susceptible to wind loading and pipe failure. Existing derricks might need to be modified by adding one or more intermediate racking boards or by providing pipe hanging capability to the main racking board as shown in Figure 60.

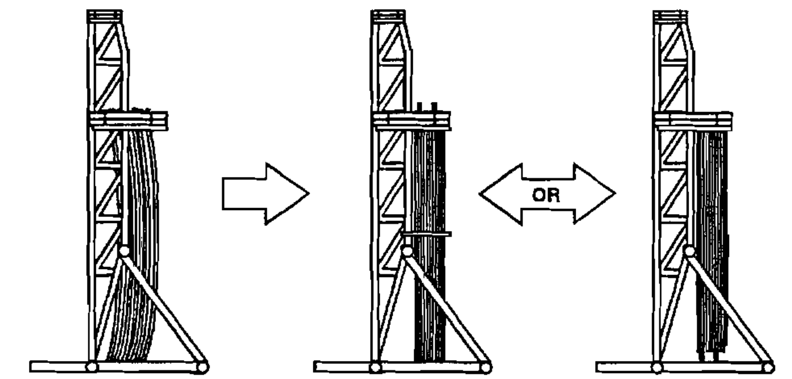

Figure 60. Pipe Racking Consideration

The drawworks provide the hoisting and braking power required to raise or lower the downhole drilling assembly. The principal components include the drum, the brakes, the transmission, and the catheads. One of the primary concerns with slim-hole drilling is the ability to feed off weight uniformly and accurately control weight on bit. It is desired to feed the drill pipe off in very small increments such that the bit weight is increased only a few hundred pounds. Since this is a very small percentage of the weight of the suspended load, which includes the traveling block, drill pipe, and bottom-hole assembly, this requires a very well-maintained and accurate brake. Hydraulic feed mechanisms developed for continuous coring rigs, or other state-of-the-art automatic drilling devices, could be very valuable on conventional drilling rigs to effectuate more optimum slim-hole drilling. The use of downhole thrusters, such as those developed by INTEQ, should be tested in vertical onshore U.S. slim-hole gas wells.

The block and tackle assembly comprises the crown block, the traveling block, and the drilling line. The function is to provide a mechanical advantage for easier handling of larger loads.

The reduced weight requirements with slim-hole drilling means smaller blocks can, and should, be used. The size of drilling line and the number of lines run can also be reduced.

The substructure supports the derrick and derrick load and the weight of the other large pieces of equipment, such as the drawworks. Substructures are commonly rated according to the maximum pipe weight that can be set back in the derrick, the maximum pipe weight that can be suspended in the rotary table, and the corner loading capacity. Obviously, with smaller pipe requirements, substructure loadings and requirements are smaller with slim-hole drilling. However, smaller drilling rigs and workover rigs may not have sufficient substructure height to accommodate the necessary BOP stack for drilling to greater depths and pressures. Rig modifications such as the use of a "pony" substructure may be necessary in certain situations.

3.8.4 Circulation System

The fluid circulation system consists of mud pumps, mud tanks, mud mixing equipment, and solids control equipment.

Mud pump volumetric requirements change significantly with hole size, even within an individual well. For example, while drilling a conventional hole, the pump requirement for the surface hole may be 800 GPM but only 200 GPM for the production hole. Slim-hole wells may require a reduction in range requirements down to 50 to 250 GPM. A continuously cored well may require a range from 10 to 150 GPM. However, the pressure requirements are relatively greater in slim holes due to the increased friction in the pipe and annulus. Mud pumps and rig piping on more conventional rigs are not usually designed to handle the range of rates and pressures seen with more aggressive slim-hole conditions. In addition, higher annular friction pressure and resulting ECD sensitivity requires greater circulation rate accuracy and control than is normally available on conventional rigs drilling conventional size holes. For conventional drilling, a tolerance of 15 GPM may be acceptable, but control down to 1 GPM may be needed in very aggressive slim-hole conditions.

Some drilling contractors have converted acidizing, fracturing, or cementing pump units for use as mud pumps because of their wider pressure range, higher pressure limits, and more accurate rate control. SCR controlled mud pumps are also used because of their good variable speed controls. Direct mechanical drive, clutch-controlled pumps are generally not acceptable because of their limited operating speeds which are controlled by preset gear ratios and number of gears. Drilling rigs with mud pumps compounded to the rotary table or drawworks should be avoided for slim-hole drilling.

Triplex pumps with properly sized and properly charged pulsation dampers are preferable for smoothing the pulsations and damaging vibrations.

Mud pits and tanks typically used on conventional drilling operations are too large. The reduced mud volume requirements with smaller holes allows the use of smaller or fewer steel tanks.

As discussed in the well control section, pit level monitoring is extremely critical with slim holes, especially slim-hole coring, due to the need for early kick detection. Pit volume totalizers on most rigs are set to trip at volume changes of 5 to 10 barrels while a sensitivity of 1 bbl or less may be needed. Smaller, more accurate trip tanks are necessary to measure mud gains or losses during trips.

Conventional solids control equipment includes shale shakers, hydrocyclones, and centrifuges. This equipment must be in adequate condition to properly treat the specific mud system. Additionally, the equipment may have to be modified or replaced in order to obtain adequate operation at lower circulation rates. Continuous coring slim-hole drilling requires special attention be paid to the solids control equipment, with the use of centrifuges more important.

3.8.5 Power System

The majority of the rig power is consumed by the hoisting and circulation systems. Generally, these two systems are not used simultaneously so the same engines can perform both functions. Modern rigs are powered by internal combustion diesel engines and are either diesel-electric or direct drive. Since the hoisting and circulation systems power needs are lessened with slim-hole drilling, the power requirements likewise are lessened. Ideally, this will be to the extent that a smaller rig can be used. However, other factors such as the need for accurate and smooth control over power transfer to various systems becomes even more important in slim-hole drilling.

3.8.6 Well Monitoring System

The rig monitoring system includes devices that record or display parameters such as depth, hook load, rotary speed, rotary torque, pump strokes, pump pressure, mud density, mud temperature, mud salinity, gas content of mud, and pit level. Accurate knowledge of all of these parameters is necessary for the driller to achieve safe and cost-effective slim-hole drilling. Slim-hole drilling requires more sensitive weight-on-bit and rotary speed control for maximum rate of penetration and minimal vibrations, equipment failure, and hole deviation. Motor drilling requires a very accurate standpipe pressure gauge to monitor and control motor torque. Monitor displays of all parameters at the driller's console (with graphical options) are recommended.

3.8.7 Well Control System

The well control system prevents the uncontrolled flow of formation fluids from the wellbore. This typically includes kick detection equipment, blowout prevention equipment, and choke equipment. Kick detection is normally achieved by use of pit volume totalizers, mud flow meters, and alarms. Small trip tanks are usually used for more accurate monitoring of hole fill-up volumes while tripping pipe. Blowout prevention equipment includes annular preventers, pipe rams, blind rams, shear rams, internal BOPs, and the high-pressure fluid accumulator. The choke equipment includes an adjustable choke and high-pressure circulating system used for well control operations.

For slim-hole drilling, smaller than conventional BOP equipment will likely be needed. However, when using standard equipment installed on conventional rigs, smaller ID pipe rams and elastomer elements can be used for smaller drill strings, and adapter flanges can be used to nipple up to smaller wellheads. The heavier BOP stacks should have external support (chains, struts, bracing, guy wires) to prevent buckling or bending the casing below the wellhead and weld area.

The choke and manifold equipment may have to be modified to accommodate the smaller BOP stacks. Sizing and positioning must be reviewed. Standard accumulators should be sufficient for slim-hole drilling applications.

More accurate and additional flow and pit level sensors are necessary to ensure adequate kick detection in the slim annular condition. Sophisticated software may be necessary in more aggressive conditions. New influx detection systems as previously described show promise in conventional size wellbores and should be unaffected by reduced hole sizes.

3.8.8 Literature Review

A review of miscellaneous pertinent articles dealing with specific rig and rig equipment issues not previously covered is presented below. Although the early literature is very dated, this is when much of the experimental slim-hole drilling in the U.S. occurred and the number of recent publications dealing with more conventional slim-hole drilling rigs is very limited. The information is still pertinent to a very large degree.

- Wilson, 1954

  Tapco Drilling used a special purpose rig to drill "ultra-slim" 2⅞-in. and 2¾-in. holes with 1¼-in. drill pipe to depths of 2200 ft. The rig was designed to drill to 4000 ft. The rig used a weight indicator calibrated in hundred of pounds instead of thousands in order to provide the sensitivity required for the small pipe. A torque converter allowed the driller an infinite number of hoisting speeds for the drawworks. Reduced height blowout preventers were necessary for the lower floor level. Tubing elevators instead of slips were used. The mast height allowed the pulling of single joints of pipe only. However, modified travelling blocks and a pair of guides were used to increase the pipe handling speed.

- Stormont, 1955

  Gene Reid Drilling in California designed a highly-mobile rig specifically for slim-hole drilling. The rig was rated to drill slim holes (undefined) to about 7500 ft using 2⅞-in. drill tubing. The rotary table, drive, cathead shaft, and sand reel were mounted on a 40-ft semi-trailer. A second trailer held the power pump and diesel, a generator set, and fuel tank. The power was supplied by a 300 HP prime mover. The mast was 93 ft tall and telescoping. It was equipped with double in-line crown blocks so two sets of traveling blocks could be used, one for the drill pipe and one for the kelley and swivel.

- McGhee, 1955

  A quote from this article is still very applicable today:

  "Many Gulf Coast operators would like to try slim-hole drilling—at least experimentally. But they find that contractors are not geared to drill a small diameter hole economically. The operators need the incentive of a cheaper footage bid to drill a slim hole, but most contractors are in no position to bid cheaper on it. If a contractor has to use the same rig as on a regular-size hole, his costs on a slim hole would be as much or more than on a conventional hole. Not enough slim holes are being drilled to make it profitable for the average contractor to tie his money up in a slim-hole rig that might be idle much of the time."

- Arnold, 1955

  Woolf and Magee Company put together three rigs designed for slim-hole drilling in Texas and Louisiana. These rigs drilled 4¾- to 6⅛-in. holes to 8000 ft using 2⅞-in. drill pipe. The rigs were highly portable with 94 ft masts, substructures of 5 to 8 ft, 60 ton swivel, and 100 ton hook and traveling block. The rig and pipe could be moved in eight loads.

- MacDonald, 1956

  This article assesses the potential for slim-hole drilling and associated problems: "The need for special rig design and the advisability of considering, in that design, hole size to be drilled is apparent. The draw works engine, if adequate to hoisting power demands, is more than adequate for pump power demands for a 5⅝-in. hole, and four times too big for pump service in a 4¾-in. hole. The most important fact is that the power available from the drawworks must be kept out of the rotary table. The usual conventional hole, shallow rig seldom is equipped with an individual rotary table drive, and while this is satisfactory when 4½- or 3½-in. OD drill pipe is used, it could be disastrous when 2⅞-in. OD tubing is used."

- Scott and Earl, 1961

  "Portability, in addition to matching the horsepower and hydraulic requirements, is important in slim-hole rig design....An independently powered rotary table, therefore, is desirable to avoid application of excess torque. In this case, a diesel-electric installation could compete economically with a straight mechanical drill split rig because one motor would drive both the drawworks and pump. Electric power would provide an ideal rotary table drive and would insure the degree of sensitivity required when tubing is used as drill pipe."

- Hall and Ramos, 1992

This article addressed drilling slim-hole horizontal wellbores, but the comments regarding rigs and rig equipment are equally valid for vertical drilling:

"Hookload and pump capacities of most rigs are generally well within the hydraulic and workload requirements of drilling a slim hole. The rig's capabilities can sometimes be detrimental if too oversized, an example of this would be the amount of rotary torque that can be applied to smaller tubulars. The amount of rotary torque must be accurately controlled when drilling with small tubulars. Workover or truck-trailer mounted service rigs are generally cheaper on a cost-per-hour basis and have substantially less mobilization costs. These rigs, however, are not equipped to maintain a full drilling operation. Most do not have a rotary table, mud tanks, pumps and associated equipment. Well service crews must be trained to operate this unfamiliar equipment."

3.8.9 Rig Equipment Summary and Conclusions

Ideally, all of the physical benefits of drilling a slim hole will accrue to the point that a smaller and more mobile rig can be used, reducing transportation, location, and daily costs. However, most drilling rigs are generally set up for drilling larger hole sizes and crews are not experienced with smaller pipe and downhole equipment. Larger conventional workover rigs are highly mobile and have potential for drilling small size holes to considerable depth. But these rigs are not usually equipped with rotaries, mud systems, BOPs, and other standard drilling equipment. Land-based workover rigs usually do not work 24 hours. Workover rig crews are not familiar with open hole drilling and the concurrent muds, hydraulics issues, and kick detection and well control procedures.

Operators attempting to implement an initial slim-hole drilling project must analyze, determine, and specify to the drilling contractor what special equipment he wants included in his drilling contract. Or the operator can procure the equipment apart from the drilling contract. Either way, these add-ons will result in additional cost to the operator, quickly eroding any potential savings from rig size reductions, or simply increasing the cost of the equivalent rig and eroding savings being obtained in other categories. Certainly, as the operator and contractor become experienced in the drilling of slim holes, the cost of obtaining unusual items will go down and the efficiency of the entire rig and its crew will increase. However, recognizing, quantifying, and justifying the costs associated with the learning curve are difficult for a drilling engineer without slim-hole experience.

There are very few rigs and crews available to the U.S. producer that are specifically designed for, or experienced with, the subtleties of slim-hole drilling. This puts greater burden on the operator to design, coordinate, and assemble the rig and rig components necessary to effectively drill a slim hole. There are incremental costs associated with this effort alone, especially when considering the continued down-sizing of many U.S. producers. The drilling engineering staff may not have the time to adequately design and procure the rig modifications necessary. This is a significant barrier in two ways: 1) because of the extra effort and uncertain outcome, the decision may be to not implement a slim-hole test project, or 2) if the project is initiated, the outcome may be less than the potential due to inadequate time and effort available to be spent on optimizing the rig and equipment necessary to safely and effectively drill a slim hole. The resulting poor outcome may not be representative of the true state of, or potential of, existing technology. For this reason, the lack of dedicated slim-hole rigs and experienced crews is considered a major barrier to slim-hole drilling in the U.S. A co-funded field test project could greatly assist the industry in applying the technology and escalating the learning curve more quickly. This would necessarily include assistance with specifying and procuring the rig equipment necessary to provide the greatest chance of evaluating true slim-hole drilling potential in the U.S.

3.9 FISHING

The term fishing applies to all operations concerned with the retrieving of equipment or other objects from the hole. Differential sticking of the pipe, pipe or BHA failure (twist-offs, etc. due to fatigue, corrosion, etc.), insufficient cuttings removal, wellbore instability (due to shale sloughing, etc.), foreign objects (dropped tools, etc.), doglegs and key seating, and bit and drill collar balling are all common causes of fishing jobs.

The slim-hole fishing issue is two-fold: 1) there are several factors that tend to increase the probability of downhole conditions leading to a fishing job (weak pipe, differential sticking, high ECDs and lost circulation, deviation problems leading to doglegs), and 2) once the trouble occurs, the narrower pipe/hole annulus, pipe properties, and fishing tool properties make it more difficult to retrieve the fish.

The inherent properties of smaller drill strings make fishing more difficult. They have thinner walls, lower tensile and torsional strength, and are more flexible. Resistance to collapse, burst, splitting, necking-down, twisting, and buckling is reduced. Higher strength steel is more difficult for the grapples and dies in fishing tools to grab, since the hardness differential is reduced.

Common operator practice is to run the largest drill-string components that can be fished with overshots. Overshot tools are preferred by most operators since they are stronger and allow higher loads to be pulled on the stuck pipe in attempts to free it. These tools are cylindrical, bowl-shaped tools which telescope over the fish with an internal slip arrangement grasping the outside of the fish.

Washover pipe is commonly used in conjunction with overshots to remove cuttings or formation material from around the fish or to mill off pipe upsets that may be helping to stick the fish.

Spear-type fishing tools go inside of the drill pipe and are typically weaker than overshots. Care must be taken to prevent splitting the fish because the gripping action of the spear is radially outward, in the direction the pipe is the weakest. If splitting occurs, the top of the fish can become wedged in the hole.

Inside and outside cutters are used to cut the fish in sections prior to retrieving. Junk baskets and magnets are run to recover smaller items in the hole. Various types of mills are used to mill up pipe and junk in the hole. Various jars are used to provide a hammer-type effect on the fish to intensify the pulling or pushing load on the fish in attempts to unstick.

In general, fishing options are reduced with slim-hole drilling. Internal fishing may be the only recourse in certain situations (Figure 61). Proper planning and design of the drill string and bottom-hole assembly will maximize the probability of successful fishing should a problem occur. Fishing tools and techniques for slim-hole conditions will expand as the need develops. Certainly, the fear of greater probabilities of a lost hole is a large barrier to more widespread use of slim-hole drilling. As slim-hole field projects and tests are conducted, documentation of how fishing is planned for and success (and failure) case histories will greatly assist operators in evaluating their options. More information on fishing tools is available in Section 7.4.

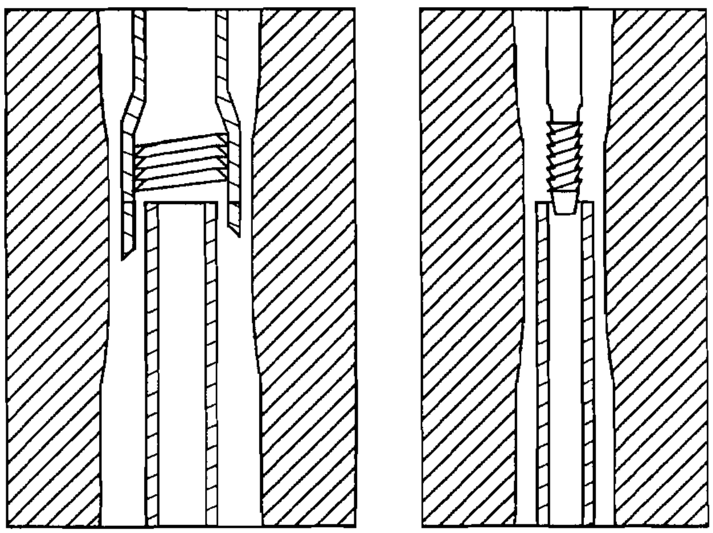

Figure 61. Fishing Methods
(Overshot - Left; Spear - Right)

3.10 SLIM-HOLE DRILLING STATE-OF-THE-ART

There are new slim-hole "state-of-the-art" component technologies, understanding, and products for almost all aspects of the drilling process. Indeed, a considerable number of new tools and services are being developed and marketed for slim-hole applications. However, effective slim-hole drilling is possible only when a systems approach is undertaken and technologies are integrated. A review of individual products will not be covered here, but rather a brief discussion of the several slim-hole systems that have been put together that can be considered representative of "state-of-the-art" in slim-hole drilling technology. These are not necessarily currently being used in the U.S., but the technology is important to review for pointing out technology sources for transfer into and within the U.S. gas drilling industry.

3.10.1 Rotary

Probably the current state-of-the-art in the industry for non-motor slim-hole drilling with more conventional rotary technology and techniques is the comprehensive system designed and built by a joint effort of Elf Aquitaine, DBS, Forasol, and IFP. This system uses a specially built rig, drill string and bottom-hole assemblies, and a comprehensive hydraulics model, for optimizing drilling performance in hole sizes from 8½ to 3 inches. The design strategy was to avoid extremely narrow annuli and questionable overall performance of continuous coring, and not resort to the use of downhole motors because of the burdensome incremental cost for shallower drilling conditions. Therefore, the system includes newly designed drill strings and bottom-hole assemblies designed for transmitting the necessary power to PDC bits at moderate rotational speed (300 rpm). The drill string and bottom-hole assemblies were designed to maintain the ability to wireline core the zone of interest. However, the designs were based on standard oil-field drill pipe, instead of weaker mining equipment.

The heart of the system is considered the newly designed and manufactured drill strings, one for drilling 8½- to 4¾-in. holes, the other for drilling less than 4¾-in. holes. The specifications for these two strings are shown in Table 7, with comparisons made to standard 3½- and 2⅞-in. drill pipe. The drill pipe has a high torque and high fatigue resistant body, and the tool joints are external upset with conical threads with a double shoulder and a stress relief groove. The ID is maintained sufficient to wireline core with a core diameter half that of the hole diameter.

TABLE 7. Foraslim Slim-Hole Drill Pipe Specifications (Sagot and Dupuis, 1994)

Pipe	ID (in.)	OD (in.)	Weight (lb/ft)	Tensile Yield (lbs)	Torsional Yield (ft-lb)
SH 111	2.91	3.5	10.6	310,000	38,000
SH 66	1.89	2.25	4.5	110,000	4,400
Standard 3½"	2.99	3.50	9.5	194,270	14,150
Standard 2⅞"	2.44	2.875	6.85	135,900	8,080
Standard 2⅜"	1.81	2.375	4.85	97,820	4,760

The drill collars were designed to maximize weight without losing the ability to wireline core and without increasing the OD such that pressure losses are unacceptable. The collars are one-piece and flush internally and externally. The dimensions and mechanical performance are comparable to the drill pipe.

The drill-string components are made with high-quality steels type G 105 and SAE 4145 H.

Testing with the drill string and other technologies developed during the EUROSLIM project validated that slim-hole drilling performance could be comparable to conventional size hole drilling, but that an integrated technological approach was needed and a dedicated slim-hole rig is an absolute necessity due to the specialized sensors and special mud tanks and pumps. The rheology and hydraulics models used were calibrated and it was determined that the smaller annuli can be safely drilled with as long as pressures are properly modeled and additional kick detection monitoring, training, and awareness are implemented.

The slim-hole rig designed and built by Forasol for $7.5 million includes a 100-ft mast, 600-HP drawworks, 550-HP top drive, and 500 barrel mud system. The rig can drill 7⅝-in. hole to 4900 ft, 5½-in. hole to 6600 ft, 4-in. hole to 9800 ft, and 3⅞-in. hole to 11,500 ft. The mast is rated to about 240,000 lb static hook load capacity with racking of two joints of range II drill pipe.

A top drive is used to achieve more efficiency than a rotary table and greater ability to avoid sticking in the small annulus since the top drive allows rotation while tripping. The 550-HP engines provide adequate power to drill larger top hole sections and the higher rotation speeds necessary in the slim-hole sections.

The mud system is zero-discharge, meaning it recirculates all fluid and does not require an earthen mud reserve pit. High efficiency shale shakers and a centrifuge are used to keep solids low to avoid centrifuging effects inside the drill pipe at the higher rotational speeds.

To achieve the sensitive WOB control necessary in slim-hole drilling, the rig uses electric motors that pull and brake in both directions of rotation (four quadrants mode) and hydraulic controls.

Total rig weight with tubulars is 470 tons. The rig can be broken down into 5500 lb packages for helicopter transport, or can be shipped in 10-ton, 20-ft long containers (except the pipe).

The rig has been tested in the Paris Basin and in Gabon with cost savings of 15 to 40%, primarily due to sharp decreases in location and road expenses. A 5000 ft, 4¾-in. well was drilled in a pristine location in France and used a location of only 90 ft x 100 ft for the equipment. A crew of four is needed rather than the standard five-man crew.

The rig design, experience, and research efforts of this project can be very valuable to U.S. producers and service companies investigating and implementing slim-hole projects. All of the components of the special built rig may not be necessary to effectively drill slim holes in "bread-and-butter" U.S. locations, but the technology behind it and lessons learned are very important since the techniques are much closer to conventional than the coring approach.

3.10.2 Continuous Coring Systems

The continuous coring approach has been adapted to the oil and gas industry from the mining industry. The newest hybrid rigs generally allow for effective destructive drilling in conventional hole sizes down to about 6¼ in., but will use state-of-the-art high-speed continuous coring for the smaller hole sizes, typically 4¾ in. and smaller. Nabors-Loffland and Parker Drilling Company are two drilling contractors offering state-of-the-art hybrid rigs for destructive drilling/continuous coring options.

Slim-hole continuous coring is a standard mining industry technique for mineral deposit evaluation. There is a large sub-industry not related to the oil and gas sector that supports this hole making technology. Oil and gas companies have experimented with mining rig continuous coring techniques for exploration drilling off and on since the 1950s. However, the effort picked up momentum in the 1980s and early 1990s with companies such as Western Mining, Conoco, Texaco, Total, BP, Mobil, and Amoco all undertaking projects.

Amoco, with its SHADS project in the late 1980s and early 1990s, was probably the most widely published effort.

Amoco conducted extensive laboratory and field research to fully investigate slim-hole coring as a viable tool for oil and gas exploration. Most of these efforts are discussed in the various individual barrier sections. Amoco, and the other companies, initiated these projects due to 1) potential savings available from drilling smaller holes with considerably smaller rigs, especially beneficial in exploration locations, and 2) the large amount of core, and higher percentage of core recovery, that becomes available to the explorationists evaluating the prospect.

There are significant differences between the normal mining rig application and oil and gas applications, primarily depths and the type of rocks drilled. Mining exploration is usually shallower than 6000 ft and carried out in hard, competent rocks. Oil and gas exploration to 15,000 ft is not uncommon, and drilling is done in sedimentary rocks.

The differences between mining drilling and oil field destructive drilling techniques and equipment include the following:

1. Mining rigs use top drive or chucking device and can snub as well as pull.
2. Mining rigs are usually hydraulically powered.
3. Cores are removed by wireline retrieval of inner core barrels without tripping the entire drill string.
4. Mining drill rod joints are 1.75- to 5-in. OD, 20-ft long, externally flush, and internally upset. They can be left in the hole and used as casing.

5. Annular clearances in the wellbore is usually only ¼ to ½ in. to support and stabilize the small drill string during the high speed rotation.
6. Rotational speeds are very high, usually, 300-600 rpm.
7. WOB is obtained by the surface unit rather than with drill collars.
8. Circulation rates are lower.
9. ECD can increase 1-3 lb/gal due to high annular friction.
10. Very low solids content must be maintained to avoid centrifuging inside the drill string and resulting mud ring and inability to wireline retrieve the core barrel.
11. Drag-type diamond core bits are almost exclusively used.
12. Wellbore deviation is strictly controlled to protect the weak tubulars by close control of WOB, rotational speed, core barrel stabilization, and the extremely narrow annulus.
13. Overall rig size is usually much smaller, reducing transportation and location costs.

The advantage of the mining wireline retrievable coring systems is in the ability to maintain high ROPs while coring and still provide high quality cores and high percentage core recovery, when compared to conventional oil-field coring techniques. The major reason for this is the ability to retrieve the core without tripping the pipe. A wireline overshot is lowered into the well to pull the inner core barrel, and then a second inner barrel is allowed to free fall to bottom. The significantly reduced rig size translates into considerable location savings when drilling in remote exploration areas.

The problems associated with attempting to drill oil and gas plays with continuous coring mining rigs mainly revolve around drill strings and hydraulics. The extremely narrow annulus maximizes the hydraulics, fluids, and well control problems discussed in Section 3.6. The thin wall pipe does not allow for sufficient WOB to be applied and bottom-hole assemblies for weight and hole deviation control are not used. Vibrations due to washouts in sedimentary rocks can be fatal to these drill strings.

The recent efforts by the companies investigating the potential of slim-hole continuous coring have studied many of the barriers of adapting this technology to the oil and gas environment. Many have made minor and major alterations to mining rigs for use in specific projects. Two systems that have been developed as a result of some of these efforts can be considered representative of the state-of-the-art in slim-hole continuous coring for oil and gas exploration. These represent the optimized approach of performing more conventional drilling operations in the upper, more conventional hole sizes while continuously coring only the lower true slim-hole sections.

3.10.2.1 Nabors

Nabors International's two slim-hole rigs, 170 and 180, are representative of the state-of-the-art in mining techniques applied to oil and gas slim-hole drilling. These rigs began

2. Extremely limited experience base within U.S. producer companies with this vastly different technology.
3. Considerable research efforts needed within each individual company to gain knowledge and expertise of the unique drilling system.
4. Significant near-term U.S. cost reductions with slim holes can be achieved only if the existing U.S. rig fleet is able to be utilized.

3.10.3 Motor Systems

The use of downhole positive displacement motors is becoming very commonplace for slim-hole horizontal re-entry wells, and vertical deepenings, out of existing 4½-, 5½-, and 7-in. casings. The technology and performance of these drilling systems have advanced such that the savings from avoiding a new top-down well is substantial. In some cases, performance is comparable to the larger sizes that would be normally drilled in a new well. As with slim-hole vertical wells, the use of smaller workover rigs is possible for the re-entry work due to the smaller pipe, lower mud volume and circulation rate requirements. These systems include small high-speed downhole motors designed specifically for use in horizontal wells that contain bent housings and deflection pads. Bent subs are also used above the motor for high build rates. The high-speed motors are important in horizontal wells where bit weight is limited due to pipe drag and small pipe. The system typically uses PDC, TSD, or natural diamond bits that perform well at the high speeds (Figure 63).

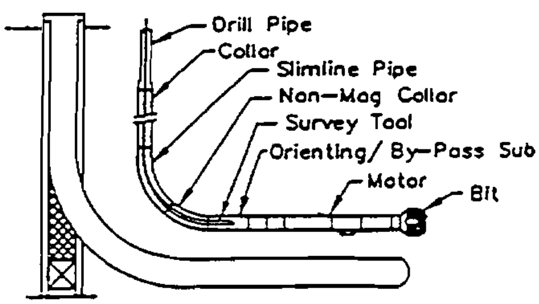

Figure 63. Horizonatal Slim-Hole Drilling Bottom-Hole Assembly (Pittard and Fultz, 1990)

Shell has developed, in conjunction with Baker Hughes INTEQ, a downhole motor system designed to effectively drill slim holes in lengthy vertical sections. This system includes the use of downhole positive displacement mud motors, fixed-cutter bits, conventional geometry drill pipe, shear thinning muds, anti-vibration technology, and sensitive kick detection devices.

The drill pipe used is conventional 3½ in. and 2⅞ in. with new high-torque tool joints. A downhole thruster was developed to decouple the mud motor and bit from axial vibrations and assist with avoiding erratic weight-on-bit that can damage small downhole equipment. A soft-torque rotary table is used to further dampen stick-slip vibrations. Novel low solids brine drilling fluids have been developed as well for higher temperature and pressure applications.

The kick detection system was discussed in Section 3.7.2.

This system is now available as a package from Baker Hughes and is marketed as the INTEQ Slim-Hole Drilling System (SHD). It is understood that the system has not been used in an onshore U.S. well.

3.11 COILED-TUBING DRILLING

3.11.1 Introduction

Drilling with coiled tubing (Figure 64) has received considerable interest from the industry in recent years, probably more than any other area of coiled-tubing application development. With the ability to be rapidly tripped under pressure, coiled tubing holds promise to provide a beneficial alternative to conventional rotary drilling when applied under appropriate conditions, primarily re-entry and underbalanced work. Figure 65 shows the recent increase in open-hole coiled-tubing drilling jobs.

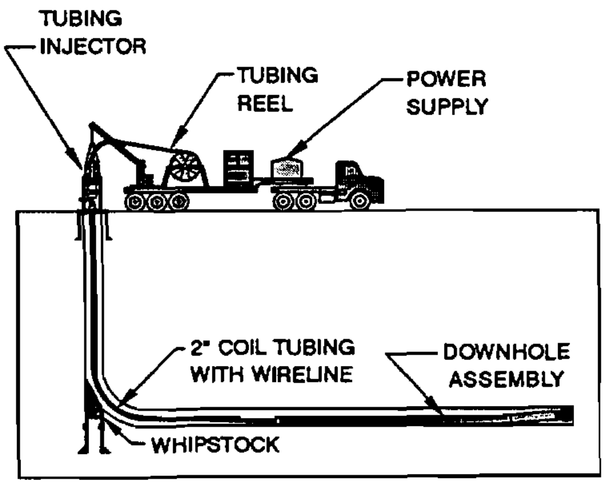

Figure 64. Open-Hole Drilling with Coiled Tubing (Ramos et al., 1992)

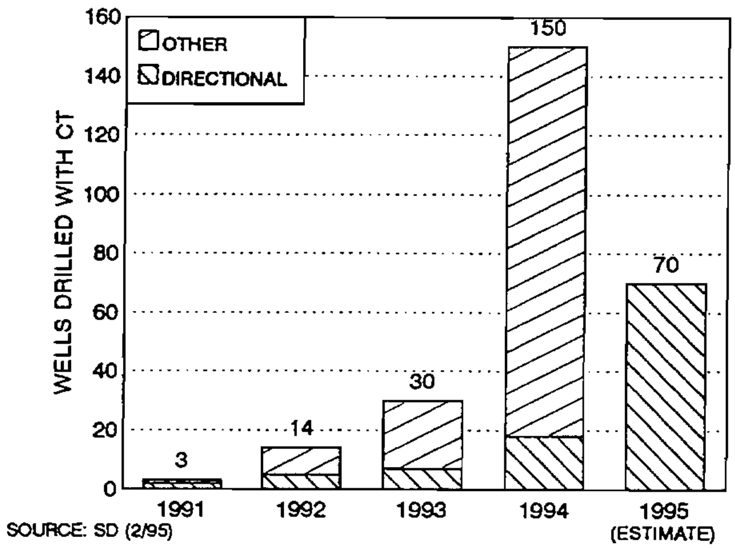

Figure 65. Job Counts for Coiled-Tubing Drilling (Gary, 1995)

Drilling with a continuous string had been considered prior to the current boom. A drilling system based on a continuous drill string was developed by Roy H. Cullen Research in 1964 (Gronseth, 1993). The flexible drill string was constructed of multiple-wire tension members and had an OD of 2⅝ in. The drill string was advanced and retracted by a hydraulic injector with gripper blocks. The system was used to drill a 4¾-in. test well through 1000 ft of granite near Marble Falls, Texas. Penetration rates of 5-10 ft/hr were reported.

Another system was developed by the Institut Français du Pétrole (IFP), which used 5-in. OD, 2½- to 3-in. ID flexible drill strings containing several electrical conductors. Downhole electric motors or turbines were used to rotate the bit. Their injector was operated either electrically or hydraulically, and could be run in an "auto-driller" mode controlled by on feedback from bit power consumption.

The IFP system could be used to drill holes from 6¾ to 12¼ in. to depths of 3300 ft (1000 m). By 1965, more than 20,000 ft (6000 m) of hole had been drilled with the system.

FlexTube Service Ltd. developed another system in the mid-1970s that used 2⅜-in. continuous tubing. They drilled shallow gas wells with the system in Alberta, Canada. Initial tubing strings were fabricated from butt-welded X-42 line pipe. They later developed the first aluminum coiled tubing in conjunction with Alcan Canada.

FlexTube's system used 4¾-in. drill collars, a positive-displacement motor, and conventional 6¼-in. bits. Penetration rates were comparable to those with conventional rigs.

Bottom-hole assemblies designed for drilling operations have been run on conventional steel coiled tubing for some time. Most coiled-tubing drilling operations have been performed as part of workover applications, such as cement and scale removal, milling, and underreaming. Drilling with coiled tubing is therefore not a new concept; however, recent advances in both coiled-tubing and drilling technology have significantly increased the depth limitations and directional control capabilities of these systems.

Camco, Cudd Pressure Control, Halliburton, Nowsco, Schlumberger Dowell, and Transocean Petroleum Technology have each organized specialty teams devoted to developing systems and techniques for coiled-tubing drilling. The recent increase in activity has been in open-hole drilling of vertical and horizontal re-entries and shallow new wells with severe surface location restrictions. Since 1991, almost 200 wells have used coiled tubing for open-hole drilling. Table 11 (page 89) lists some of these jobs.

The driving force behind the development of coiled-tubing drilling is the ability to substantially reduce drilling costs in certain niche applications and the production enhancement potential offered by underbalanced drilling. Many economic advantages of slim-hole operations are shared by coiled-tubing drilling. Smaller rigs and surface locations result in less environmental impact and lower location and transportation costs. Small diameter operations lead to savings in mud, cement, and casing costs.

An important economic factor for new well drilling is that more expensive coiled-tubing rigs must be evaluated against fully depreciated and discounted conventional drilling rigs. This is why coiled-tubing drilling must offer advantages other than just size reduction-such as safer, more effective underbalanced drilling—in order to be a viable alternative for new well drilling. Additionally, strong technical limitations limit its applicability for most new gas well needs.

3.11.2 Benefits and Limitations

In the following paragraphs, the principal advantages and disadvantages of coiled-tubing drilling are summarized. More detailed discussion appears in the sections that follow.

Benefits

Costs can be reduced with coiled-tubing operations. Many of the cost savings attainable with coiled-tubing drilling arise from the extremely small size of the rig (relative to conventional), the inherent automation of coiled-tubing rigs, and other savings enjoyed in slim-hole operations. Costs other than drilling time, such as mobilization, site size and preparation, and expendables, often account for more than 50% of conventional costs.

Coiled-tubing drilling operations have smaller surface requirements than most conventional rigs due to a smaller footprint (usually less than 50% conventional) for the coiled-tubing system (Figure 66). Costs in several categories can be significantly reduced with coiled-tubing slim-hole systems.

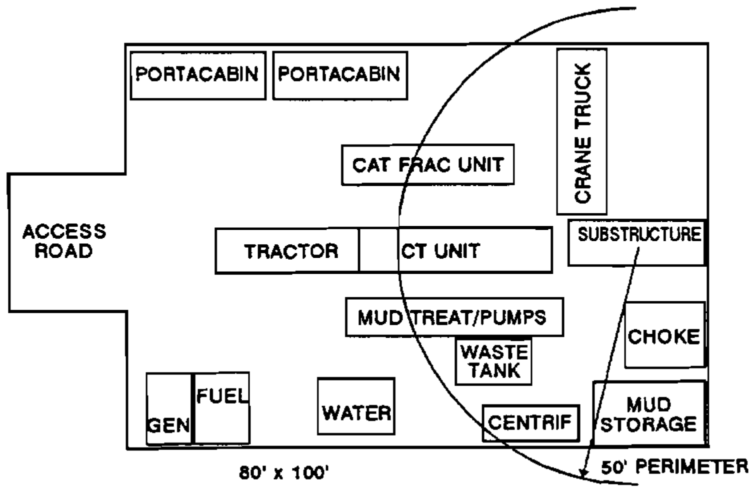

Figure 66. Coiled-Tubing Drilling Land Rig Layout (Schlumberger Dowell, 1994)

Drill-string trip time is reduced. Continuous tubing eliminates the need for drill-string connections, thus reducing trip times and increasing safety. Many rig-floor accidents and stuck-pipe incidents occur when conventional drilling is stopped to make a connection.

Underbalanced drilling is practical with coiled tubing. The design of coiled-tubing pressure-control equipment and systems allows the tubing to be run safely in and out of live wells. Drilling can be performed in underbalanced conditions, which minimizes formation damage, minimizes differential sticking tendencies, and possibly increases rate of penetration. Reducing formation damage can lead to increased well productivity and eliminate the need for stimulation or damage removal treatments during completion operations.

Coiled tubing allows continuous circulation. A fluid swivel joint installed on the axle of the tubing reel allows circulation through coiled tubing while tripping. This design simplifies well-control techniques and helps maintain good hole conditions. Continuous circulation also allows continuous drilling, facilitating the use of foam as a low-weight drilling fluid when appropriate.

Coiled tubing is readily adapted for wireline telemetry. Wireline is routinely installed inside coiled tubing. High-speed continuous telemetry is practical with coiled tubing for MWD (measurement-while-drilling) and FEMWD (formation evaluation MWD). The same wireline can also be used for steering-tool data and orientation-tool control. Hydraulic lines can also be installed to provide a greater power source downhole than with electric cable. Combinations of electric/hydraulic power and control of the BHA are designed into new coiled-tubing drilling BHAs.

Limitations

Coiled tubing cannot be rotated. Downhole motors, an expensive component, are required when drilling with coiled tubing. Consequently, slide drilling is the only mode of operation, which results in increased friction losses and reduced WOB. Separate BHAs must be run for straight hole sections and for angle building sections. Basic BHAs are shown in Figure 67.

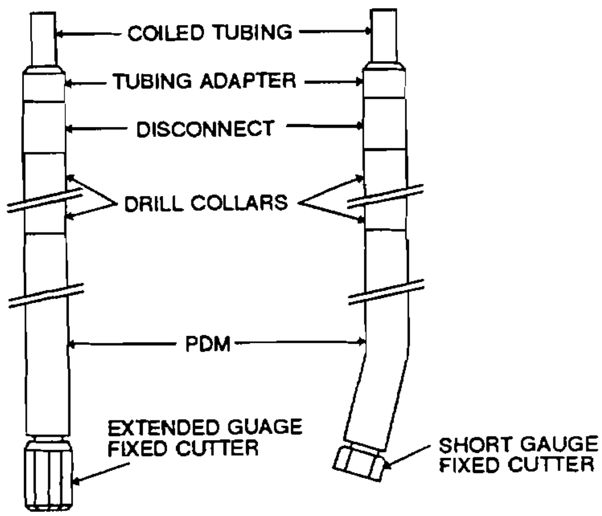

Figure 67. Coiled-Tubing BHAs for Holding Angle (Left) and Building Angle (Right) (Gronseth, 1993)

Downhole orientation tools are required to direct the bit along the designed well path. Several models of coiled-tubing orienting tools are available with costs in line with conventional MWD systems. Most have been through significant lab testing and have been successfully used in many field drilling projects. As with all sophisticated technologies, a certain percentage of failures has occurred, but with declining frequency.

Coiled-tubing drilling is generally limited to small hole sizes. Coiled-tubing OD, torque capacity, and hole-cleaning requirements place limits on the size of hole that can be drilled. Most jobs have been performed with 2- or 2⅜-in. coiled tubing. Larger tubing is available. However, lack of rigs with capability to run larger ODs hinders their use, as well as logistical difficulties of working with large reels.

Coiled-tubing drilling is limited to relatively shallow holes. Depth limitations for the technology are governed as much by the size and weight restrictions of the tubing reel trailer and highway permitting limits as by the mechanical strength of the tubing itself. The larger the coiled-tubing OD, the shorter the length of the string that can be legally transported. Two reels and separate trailers are being used but require careful connection of the tubing reels to maintain the mechanical strength of the tubing at the connection. Several types of tubing connectors are now available for joining the tubing, but improvements are needed.

Coiled-tubing drilling is a new technique. The learning curve for coiled-tubing drilling has begun to fall; however, there is considerable development and industry experience required before the technology can be considered routine. As was the case for horizontal drilling, it can be expected that coiled-tubing drilling costs will decrease when operating companies and drilling contractors become more familiar with the technology. Larger multi-well projects are required.

Coiled-tubing drilling rigs and equipment are expensive. Coiled-tubing rigs must compete against fully depreciated drilling rigs. In areas with low utilization rates for conventional systems, daily rates of coiled-tubing systems are substantially more expensive than conventional rigs. This new technology has also required the development of new tools and assemblies, further increasing costs.

Coiled-tubing rigs cannot run or pull casing or completions. Conventional rig assistance is normally required for well preparation, unsetting production packers, pulling production tubing, and running completions. An exception to this restriction is coiled production tubing or liners. The inability to run jointed tubulars continues to limit the application of coiled-tubing drilling techniques, especially for new well applications. Although hybrid rigs are being developed and deployed, they are not widely available.

Also in cases where long BHAs are used, handling the BHA components without a derrick structure can be very slow because each component must be picked up and/or laid down during each trip. This can be complicated when working under pressure where deployment subs must be used in the BHA. Thus, overall trip times can be comparable to conventional trips with jointed pipe, offsetting one of the potential benefits (faster trip time due to no connections).

Coiled-tubing life in drilling operations is not well defined. Open-hole drilling can subject coiled tubing to loading conditions not typically encountered in cased-hole operations. The tubing is subjected to high forces when buckling occurs that can damage the tubing wall by forcing it into irregularities or washouts downhole.

Techniques to maximize the life of a coiled-tubing drilling string include avoiding pumping corrosive fluids through the tubing, minimizing solids in the mud, using techniques that minimize the number of cycles for any given section of tubing, and avoiding stacking the weight of the coiled-tubing string on the bit.

TABLE 11. Example Coiled-Tubing Drilling Projects

Year	Location	Operator	Type	Deviation	CT Size, in.	Hole Size, in.
1991	France	Elf	Re-entry	Vertical	1.5	3.875
1991	Texas	Oryx	Re-entry	Horizontal	2	3.875
1991	Texas	Chevron	Re-entry	Horizontal	2	3.875
1992	Canada	Lasmo	New	Vertical	2	4.75
1992	Texas	Chevron	Re-entry	Horizontal	2.38	3.875
1992	Canada	Gulf	Re-entry	Horizontal	2	4.125
1992	Canada	Imperial	New	Vertical	2	4.75
1992	Texas	Arco	Re-entry	Horizontal	1.75	3.75
1992	Canada	Pan	Re-entry	Vertical	2	4.75
1992	Canada	Pan	Re-entry	Vertical	1.75	3.875
1992	France	Elf	New	Vertical	1.75	3.875
1992	Canada	Gulf	Re-entry	Vertical	2	4.75
1992	Austria	RAG	Re-entry	Vertical	2	6.125
1992	Alaska	Arco	Re-entry	Deviated	2	3.75
1993	Canada	Petro	Re-entry	Vertical	2	3.875
1993	Holland	Shell-NAM	Re-entry	Horizontal	2	4.125
1993	North Sea	Phillips	Re-entry	Deviated	1.75	3.75
1993	Canada	Petro	Re-entry	Horizontal	2	4.75
1993	Alaska	BP	Re-entry	Deviated	2	3.750
1993	California	Berry	New	Vertical	2	6.25
1993	Alaska	Arco	Re-entry	Deviated	2	3.75
1994	Venezuela	Lagoven	New	Vertical	1.50	3.875
1994	Canada	Co-enerco	New	Vertical	1.50	3.875
1994	California	Shell	New	Vertical	2.00	6.250
1994	Canada	Amerada	Re-entry	Vertical	2.00	6.00
1994	Oman	PDO	Re-entry	Horizontal	2.375	4.75
1994	UK	BP	Re-entry	Deviated	2.0	3.5
1994	Canada	Pan	New	Vertical	2.0	6.25
1994	Indonesia	Vico	Relief	Horizontal	2.0	3.50
1995	Denmark	Maersk	Re-entry	Horizontal	2.375	12.25
1995	Holland	Shell	Re-entry	Deviated	2.0	3.75

3.11.3 Parametric Analysis of Coiled-Tubing Limitations

Leising and Newman performed an engineering analysis of the limits of coiled- tubing drilling with respect to basic parameters of tubing weight, size, and life, achievable down-hole force, and hydraulic limits (Leising and Newman, 1993). While limitations are being pushed and extended regularly with experience and new developments, this study is useful for illustrating some of the issues related to coiled-tubing drilling. *It must also be emphasized that others have performed similar analyses, and results and conclusions can vary significantly.*

Example coiled-tubing weights and capacities used by Leising and Newman are given in Table 12. Greater wall thicknesses and higher capacities are available than those given, especially for larger tubing sizes.

TABLE 12. Coiled-Tubing Weights and Capacities (Leising and Newman, 1993)

Diameter (in.)	Wall Thickness (in.)	Weight (lbm/ft.)	Maximum Tension (lbf)	Maximum Allowable Working Torque (lbf-ft)	Maximum Allowable Working Pressure (psi)	Reel Core Diameter (in.)
1.500	0.156	2.24	32,000	1,044	7,700	76
1.700	0.156	2.66	37,900	1,484	6,700	76
2.000	0.156	3.07	43,900	2,002	5,900	84
2.385	0.156	3.70	78,100	2,926	5,300	84
2.875	0.156	4.53	95,000	4,431	4,400	96
Note: 70,000 psi yield stress material for all coiled-tubing sizes						

Dimensions and mechanical properties of API jointed drill strings are compared to those of coiled tubing in Table 13. The jointed drill-pipe data are for the lightest weight pipe of the same OD as coiled tubing. Coiled-tubing wall thickness was chosen for these examples to be as close as possible to the drill pipe.

TABLE 13. Comparison of Properties of Coiled Tubing and API Drill Pipe (Gronseth, 1993)

	CT	Drill Pipe*	CT	Drill Pipe*	CT	Drill Pipe*
Nominal OD, In.	2.375	2.375	2.875	2.875	3.5	3.5
Tool Joint OD, In.	None	3.37	None	4.126	None	4.75
Nominal ID, In.	1.969	1.995	2.495	2.441	3.12	2.992
Wall Thickness, In.	0.203	0.192	0.19	0.217	0.19	0.254
Weight, ppf	4.71	4.85	5.46	6.85	6.73	9.5
Yield Strength, kips	96.9	97.7	106.7	136	131.4	194
*Grade E Drill pipe						

The maximum length of a string of coiled tubing based on various allowable spool weights (Figure 68) shows that spool size limitations dominate for large-diameter tubing. A typical coiled-tubing trailer and reel can carry about 40,000 lb of tubing and still be legal for U.S. roads. Length limitations can be overcome by connecting or welding multiple spools of coiled tubing at the job-site. However, the cost of this type of solution, which requires the fabrication of larger-than-legal reels on site, often cannot be justified.

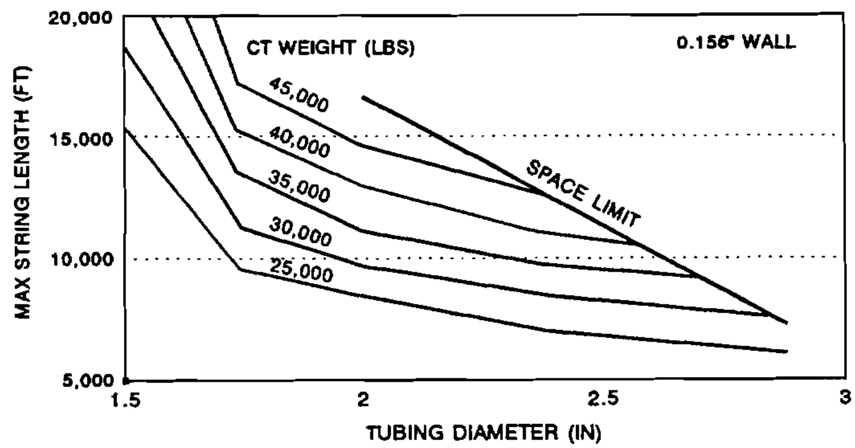

Figure 68. Maximum Coiled-Tubing String Length (Leising and Newman, 1993)

Maximum hanging length for a coiled-tubing drilling string is dependent on material strength, wellbore fluid density, and whether or not the string is tapered. For a non-tapered string, the hanging length at 80% yield stress is given by:

$$D = \frac{\sigma_y}{4.245 - 0.065 W_m} \tag{1}$$

where:
- D = hanging length at 80% yield (ft)
- σ_y = tubing yield stress (psi)
- W_m = wellbore fluid weight (lb/gal)

For example, 70,000 psi tubing in 8.6 lb/gal mud will reach 80% yield at just less than 19,000 ft. It is interesting to note that this calculation is independent of tubing diameter or wall thickness. As more steel is added to the tube either by increasing the diameter or using thicker walls, the weight of the string increases in direct proportion, canceling the benefit of the additional steel.

The use of tapered tubing strings with thicker walls high up in the hole is the most common technique to increase hanging length. Using this approach, conventional coiled-tubing service operations have been performed at depths greater than 23,000 ft.

BHAs for drilling deviated wells with coiled tubing are designed based on the set-down weight available in the vertical section to provide WOB. In vertical hole sections, maximum set-down weight is reached after the tubing buckles into a helix.

Set-down weight for various coiled-tubing sizes was calculated with Schlumberger Dowell's Tubing Forces Model (Figure 69). The results show that greater set-down weights can be achieved with larger coiled tubing and in smaller casing. The model predicts that maximum set-down weight does not vary significantly with depth.

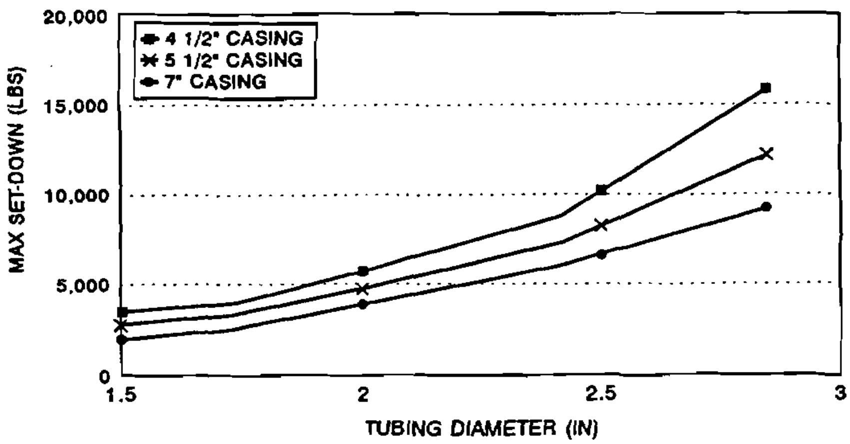

Figure 69. Maximum Coiled-Tubing Set-Down Weight in Vertical Sections (Leising and Newman, 1993)

Friction forces generated in build sections or doglegs also work to reduce the effective WOB. Friction losses for three example BHAs are plotted in Figure 70. BHAs are 60 ft in length. It is seen that the build section friction of a deviated hole can prevent any weight from reaching the bit and limit additional horizontal penetration.

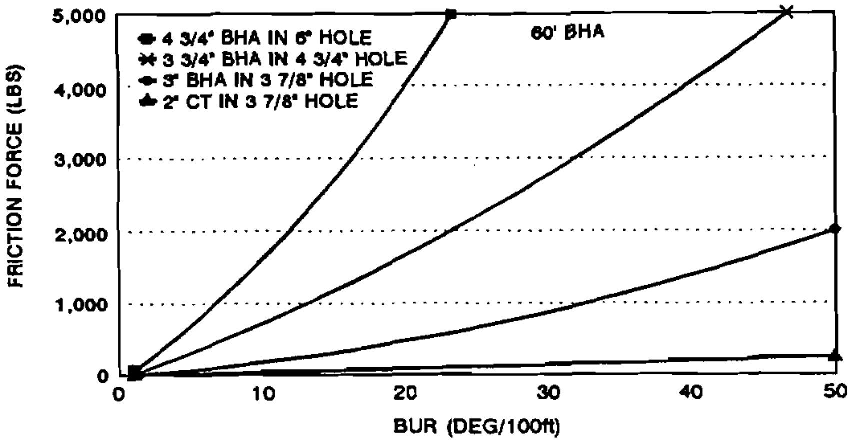

Figure 70. Friction Force on 60-ft BHAs in Build Sections
(Leising and Newman, 1993)

Friction force can be decreased by using flex joints or articulated BHAs. The frictional loss of 2-in. coiled tubing (no BHA) in a 3⅞-in. borehole is shown as the lowest trace in Figure 70.

Five example horizontal re-entry scenarios (Figure 71) were devised to demonstrate basic trends and penetration limits with coiled-tubing drilling. Casing size, bit diameter, BHA size, and downhole weight on bit (DWOB) for the five cases are summarized in Table 14. Cases 1, 2, and 3 drill out of 4½-, 5½-, and 7-in. casing, respectively, with the largest bit possible. Cases 4 and 5 use smaller bits in 5½- and 7-in. casing.

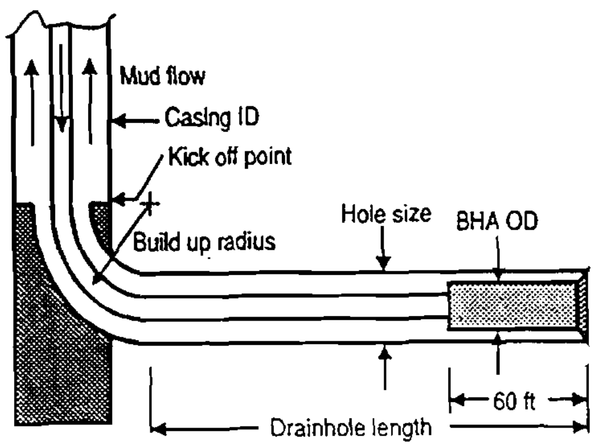

Figure 71. Horizontal Re-entry Model (Leising and Newman, 1993)

TABLE 14. Example Horizontal Re-entries Drilled with Coiled Tubing (Leising and Newman, 19933)

	Case				
	1	2	3	4	5
Casing Diameter, in. Weight, lbm/ft ID, in.	 4.5 10.5 4.052	 5.5 15.5 4.950	 7 29 6.184	 5.5 15.5 4.950	 7 29 6.184
Hole size, in.	3.875	4.750	6.000	3.875	4.750
BHA OD, in.	3.060	3.750	4.750	3.060	3.750
DWOB, lbf	2,000	2,500	3,100	2,000	2,500

Assumptions used in the computer calculations include 15°/100 ft build rates, 8.6 lb/gal brine drilling fluid, and that drilling continues until downhole weight-on-bit requirements cannot be maintained. Calculations were made for each re-entry case (Figure 72) with the coiled tubings listed in Table 11.

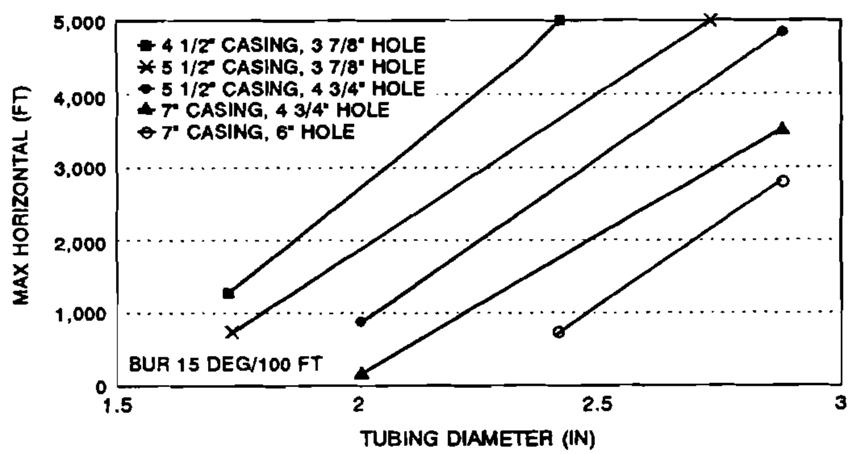

Figure 72. Maximum Horizontal Length for Example Coiled-Tubing Re-entries (Leising and Newman, 1993)

The circled points in Figure 72 are cases where the tubing would lock up in the vertical section before any horizontal hole was drilled.

Coiled-tubing fatigue life is another serious concern in drilling operations. Larger tubing diameters and high pressures resulting from high flow-rate requirements lead to a decrease in coiled-tubing life. Calculations with Schlumberger Dowell's CoilLife Model (Figure 73) show the effects of flow rate and high pressure in 8000-ft wells.

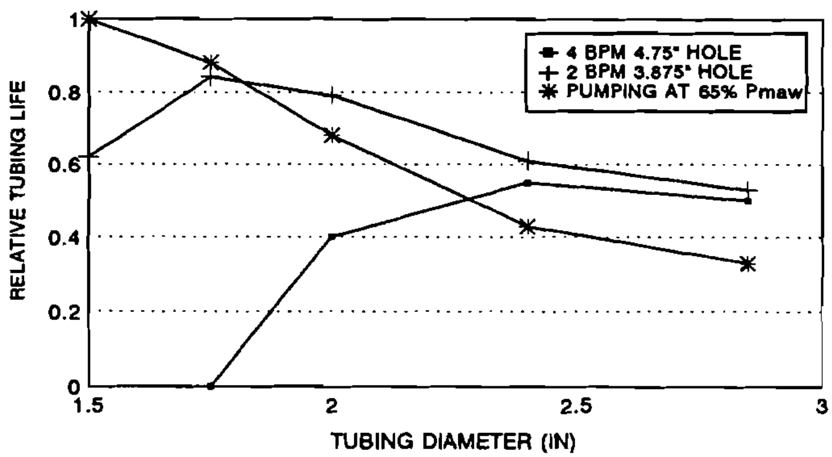

Figure 73. Effect of High Flow Rates on Tubing Life (Leising and Newman, 1993)

The data at 65% P_{maw} (maximum allowable working pressure) show that larger diameter coiled tubing had significantly less life than 1½- and 1¾-in. under these conditions.

Limits in hydraulics must be considered for coiled-tubing drilling. Circulation rates must provide sufficient velocity to carry cuttings from the hole. However, there are other factors that may limit maximum fluid pump rates. Pressure drops through the coiled-tubing string and in the annulus increase significantly at high circulation rates. Another factor is that the maximum flow rate for the downhole motor may set the maximum allowable circulation rate.

Maximum and minimum (critical) flow rates for vertical 4¾-in. open-hole drilling at 8000 ft with coiled tubing are shown in Figure 74. Fluid density of 8.6 lb/gal and annulus velocity of 100 ft/min were assumed.

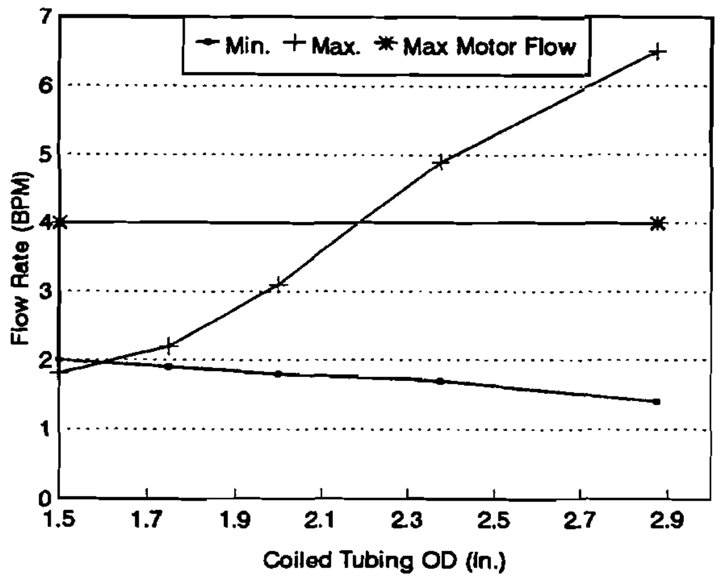

Figure 74. Example Hydraulic Limit for 4¾-in. Vertical Well at 8000 ft
(Leising and Newman, 1993)

The lines in Figure 74 marked "Max. Motor Flow" represent typical maximum allowable flow rates of a motor used in a 4¾-in. hole. This example shows how desired flow rates may be limited by the motor in 2-in. and larger tubing.

Reactive torque is another concern in directional drilling because torsional winding of the tubing affects the tool-face orientation. The maximum wind-up due to torsion is easy to calculate. However, friction along the wellbore, particularly in high-angle and horizontal wells, can significantly reduce the number of turns. This has been shown to be true in field applications. For example, Oryx reported a reactive twist of only 280°, and did not observe the multiple twists predicted by theoretical calculations.

3.11.4 General Drilling Limits

Doremus summarized the current *general* hole size and depth limitations for coiled- tubing drilling. These are presented in Table 15.

TABLE 15. Current Coiled-Tubing Drilling Capability (Doremus, 1994) (Burge and Mieting, 1994)

APPLICATION	HOLE SIZE (IN.)	DEPTH (FT)
Conventional Re-entry (Horizontal)	3½ - 4¾	15,000
New Shallow Well	6¼ / 8½	12,000/6000
THROUGH-TUBING RE-ENTRY	EXISTING TUBING (IN.)	
Vertical Deepening	3½	
Directional	4½	

Rutland and Fowler summarized the current general horizontal penetration limits for drilling with coiled tubing. These are presented in Table 16.

TABLE 16. Penetration Limits for Coiled-Tubing Drilling in Horizontal Holes (Rutland and Fowler, 1994)

Casing x Hole (in.)	Max. Length w/2-in. Tubing (ft)	Max. Length w/2⅜-in. Tubing (ft)
4½ x 3⅞	2700	4600
5½ x 4½	1000	2600
7 x 4½	200	1600

It must be emphasized that these are general guidelines only and these barriers are being pushed continuously with more aggressive applications. For example, it is understood a 12¼-in. hole has now been drilled with 2⅜-in. coiled-tubing out of 9⅝-in. casing.

3.11.5 Case Histories

The recent escalation in the number of coiled-tubing drilling jobs has proven the viability of a variety of drilling-related coiled-tubing operations. This includes setting whipstocks, cutting windows, MWD mud-pulse with gamma-ray, using new steering tools, running liners and hangers, using a variety of roller-cone and fixed-cutter bits, abrasive jet technology, underbalanced drilling with artificial lift and lightweight fluids, air/mist drilling, through-tubing re-entries, and off-pad remote drilling. Several case histories are summarized below to provide details of specific industry activity, including a horizontal re-entry, new shallow vertical wells, near-balanced vertical deepening, and an underbalanced horizontal re-entry.

Horizontal Re-entry

ARCO E&P (Hightower et al., 1993) used coiled tubing to drill a successful sidetrack of a well in the Slaughter Field in West Texas. Several aspects of the job represent the first time coiled tubing was used in these procedures. These include:

- Setting a whipstock in casing
- Milling a window
- Using MWD
- Using a pressure-activated orientation tool
- Using an autodriller system to maintain WOB

Although problems prevented the well from being drilled as planned, project results and well production were successful.

The original wellbore (H.T. Boyd 59X) was drilled to 5245 TD in 1989. Despite acid stimulation and fracture treatment, original production was poor (64 BFPD with 94% water cut). ARCO planned to sidetrack the well, build angle at a rate of 15°/100 ft, and drill about 500 ft of new horizontal section (Figure 75). The 3¾-in. borehole was to be completed open-hole and produced on rod pump.

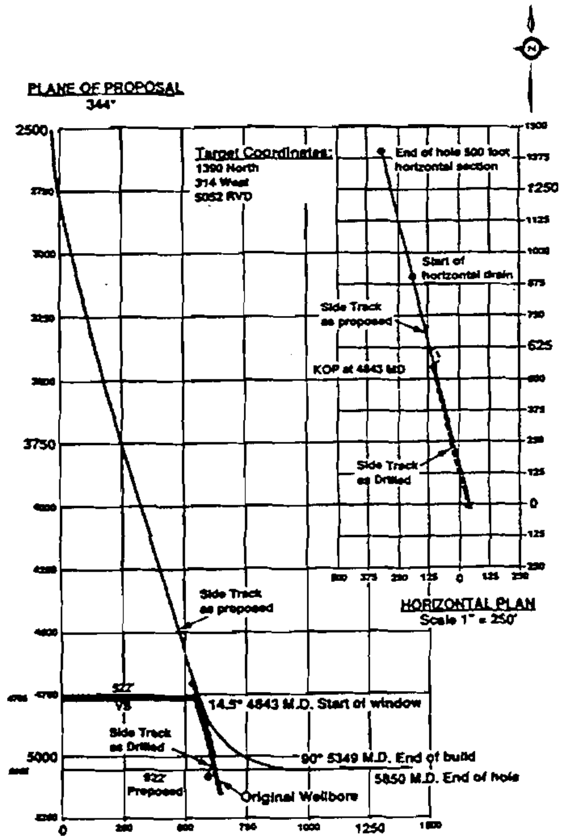

Figure 75. ARCO Re-entry Well Plan (Hightower et al., 1993)

Wellbore inclination was about 14° at the planned kick-off depth (Figure 76).

Drilling system design was based on 1¾ x 0.156-in. 70 ksi coiled tubing. The orienting tool was hydraulically controlled, adjusting about 45° for each pump on/off cycle. A small substructure was used to provide a work platform 11 ft above ground level.

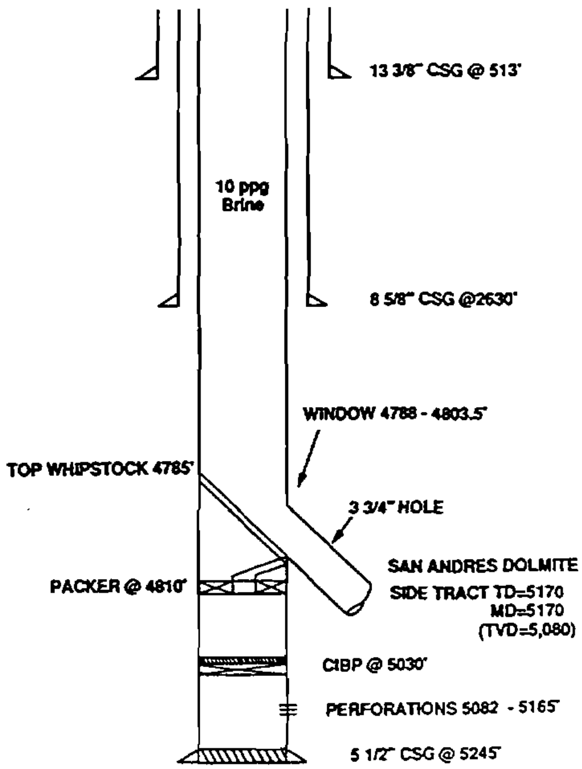

Figure 76. ARCO Re-entry Well Schematic (Hightower et al., 1993

Prior to bringing the coiled-tubing rig on location, wireline was used to set a permanent packer with orientation lug. The whipstock was then run on coiled tubing and stung into the packer. A window was milled and several feet of new hole drilled.

The drilling BHA (Figure 77) was then run in with a 3¾-in. TSD bit. A total of 366 ft of new hole was drilled.

Significant problems were encountered in trying to build angle. Angle remained relatively constant despite several trips for new bits, mills, assemblies, etc. Later, ARCO discovered that the program used to process the MWD data was flawed, resulting in false indications of tool-face angle.

ARCO found that the MWD tools performed well, with readings accurately confirmed by gyro surveys. The orienting tool also performed well.

The use of the autodriller was also counted a success. Sensitivity of the system to maintenance of WOB was judged as better than an experienced coiled-tubing operator.

Fatigue was found to be an important element requiring careful tracking in these operations. As a result of many trips and extended operations at depth, about 80% of coiled-tubing fatigue life in one section of the string was used for this project (Figure 78).

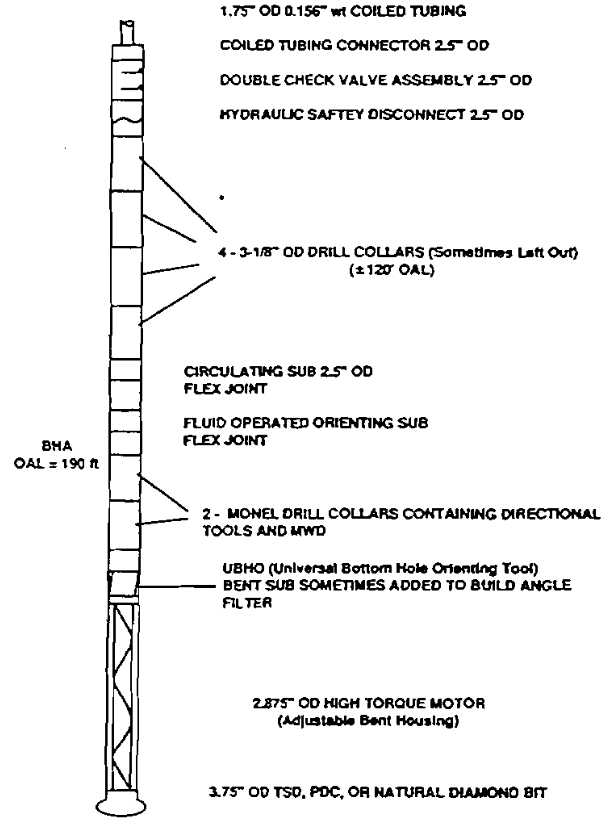

Figure 77. Typical Coiled-Tubing Drilling BHA (Hightower et al., 1993)

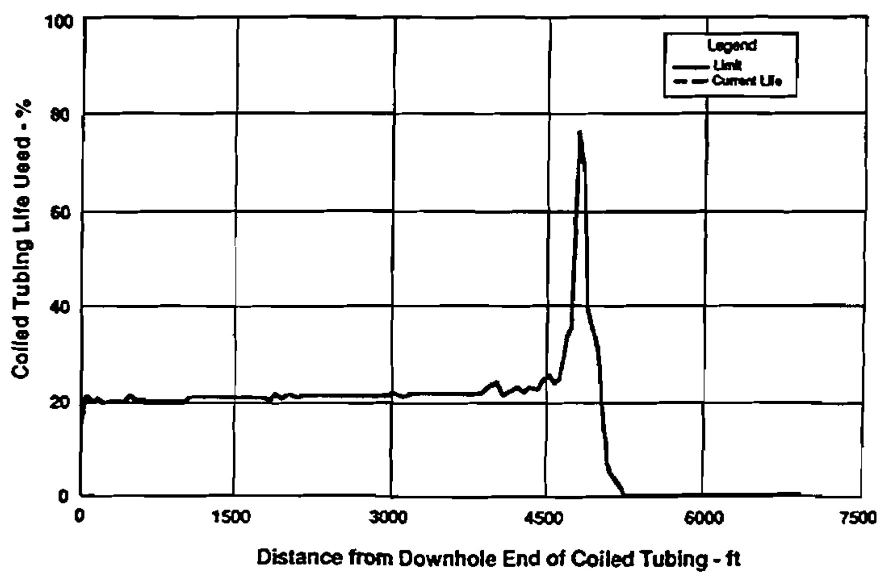

Figure 78. Coiled-Tubing Life for Drilling Project (Hightower et al., 1993)

ARCO estimated that the overall cost of this operation was 50% greater than for a conventional workover rig. However, they believe that, in the absence of the software bug, costs would have been competitive with conventional, and that operations could have been completed in 10 days, rather than 17.

ARCO's initial experiences demonstrated that drilling with coiled tubing is here to stay, and that the tools and technologies required are available and improving steadily.

Shallow Vertical New Well

Berry Petroleum and Schlumberger Dowell (Love et al., 1994) drilled two shallow vertical wells with coiled tubing in the McKittrick Field in California. These wells are believed to be the first grass-roots wells drilled with coiled tubing. In addition, these wells were the first medium-diameter (6¼ in.) boreholes drilled using motors on coiled tubing.

A two-well project was designed to provide data on reservoir extent and evaluate the use of coiled tubing as a means of conveying drilling assemblies in this area. Completion operations were not included in original project plans. Secondary objectives of this project were to test coiled-tubing drilling in the context of slim (6¼ in.) vertical wells with conventional muds, and evaluate economic potential for coiled-tubing drilling for other applications. A hole size of 6¼ in. was chosen based on logging considerations (using conventional tools) and available motor/bit combinations.

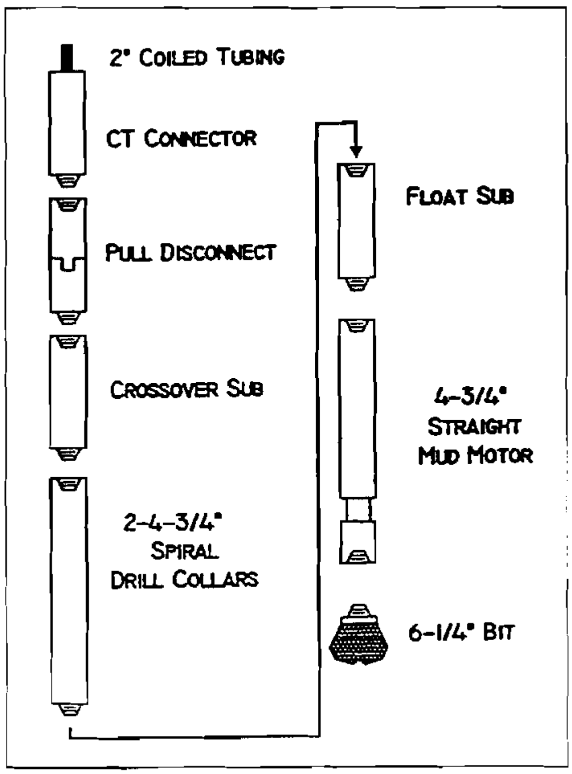

Figure 79. Drilling BHA
(Love et al., 1994)

The production horizon of interest was the Tulare tar zones, located at depths between 600-900 ft. Two wells, BY20 and BC4, were drilled in different edges of the reservoir.

A 4¾-in. medium speed motor was used for drilling operations (Figure 79). Rotational speed was 150-200 rpm at a flow rate of 150 GPM.

A 3500-ft string of 2 x 0.156-in. coiled tubing was used for both wells. Drilling fluid was a cypan-based system. The location was about 90 ft x 90 ft. Love et al. stated that reorganization would permit the location to be reduced to 90 x 70 ft, and that it need not be rectangular.

The first well was spudded using two drill collars. Deviation was checked at 259 ft MD. During this trip, a third drill collar was added to the BHA. Drilling continued successfully to TD at 1257 ft. Deviation along the wellbore was a maximum of 1¼°.

Total drilling time was 35 hr, 10 hr of which were spent checking the survey with a conventional tool. Logging was performed successfully. A cement plug was placed on bottom.

A second well (BC4) was spudded from 80 ft with two drill collars. Good penetration rates were achieved all the way to TD.

No intermediate directional surveys were taken on the second well due to the low deviation noted on the first well. Total drilling time was 21 hr (Figure 80). Dipmeter logs after drilling showed a maximum deviation of 1°.

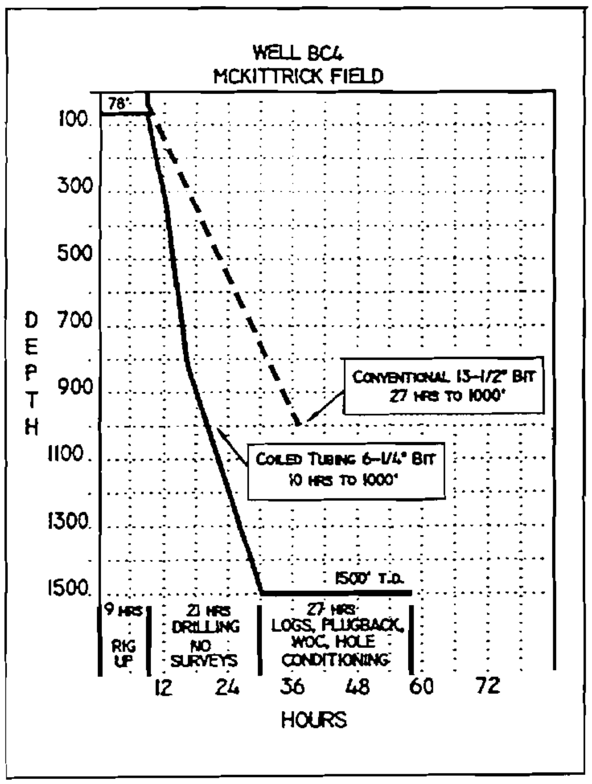

Figure 80. Time Summary for Well BC4 (Love et al., 1994)

Post-drilling analyses showed that drilling time for the second well was about 60% faster than for a conventional (larger diameter) well. Most of the time savings were attributed to faster ROP in the slimmer hole.

An additional benefit was a reduction in hole wash-out. Berry Petroleum believed that improved hole conditions were the result of continuous circulation with the coiled-tubing system, reduced pumping rates, and slimmer hole.

Fatigue life consumption of the string during these operations was moderate. For all operations on both wells, modeling indicated that a maximum of 18% of string life was used.

Berry Petroleum found that costs with coiled-tubing drilling were comparable or less than conventional rigs for this application. Costs would be even more favorable for deviated holes where conventional systems would also have to use motors.

Near-Balanced Vertical Deepening

Petro Canada (McMechan and Crombie, 1994) tested modified equipment and drilling techniques by deepening, completing and fracturing a vertical gas well with coiled tubing. The deepening of the well near Medicine Hat, Alberta was the first field operation in a larger project to evaluate balanced drilling of horizontal wells in sour reservoirs with coiled tubing. This first site was purposely chosen as a safer environment to test fluids handling systems, a new pressure sensor sub, and foam model accuracy.

The subject well (PEX WINCAN MEDHAT 10-9MR-17-3 W4M) was to be deepened from 448 m to 530 m MD (1470 ft to 1740 ft) with a 3⅞-in. hole. Drilling was to be conducted at balanced conditions with foam to avoid formation damage in the currently producing Milk River zone and the target Medicine Hat zone. Fluid modeling showed that foam rates of 33 GPM of water and 440 scfm of nitrogen would be required.

Drilling BHA components are listed in Table 17. Components were assembled to reflect the requirements for horizontal drilling in later phases. However, directional equipment (steering tool etc.) was not used.

TABLE 17. Coiled-Tubing Drilling BHA (McMechan and Crombie, 1994)

COMPONENT	OD (MM)	LENGTH (M)	TOTAL LENGTH (M)
Junk Mill	98.4	0.46	0.46
Crossover Sub	79.4	0.12	0.58
Motor	79.4	3.80	4.38
Crossover Sub	79.4	0.12	4.50
Thruster	60.3	2.84	7.34
Crossover Sub	79.4	0.24	7.58
Crossover Sub	79.4	0.18	7.76
Drilling Release Tool	79.4	1.77	9.53
Quick Latch, Pressure Sensor, Coil Connector	79.4	1.97	11.50

The maintenance of balanced conditions with foam required accurate measurement of downhole pressures. A special sub was designed with two pressure sensors, one measuring pressure in the coiled tubing above the motor and one measuring pressure in the annulus. Pressure in the annulus ranged from about 245-320 psi during drilling operations. Petro Canada and Nowsco wanted to obtain pressure data from drilling operations that could be compared with computer simulation data so that any appropriate empirical corrections could be determined and applied in later phases of the development.

Drilling operations progressed relatively smoothly. To drill out the shoe joint, a junk mill was substituted for the 3⅞-in. TSP bit run initially. The bit was reinstalled to drill the new hole. Drilling time was 9½ hr for 224 ft, for an average ROP of 27 ft/hr.

After drilling was complete, a string of 2⅞-in. coiled tubing was cemented in place as a production liner. After logging and perforating operations, a 55,000-lb frac job was pumped and the well put on production. The final wellbore status is shown in Figure 81.

Underbalanced deepenings with coiled tubing are becoming very routine in Canada. Many of the new coiled-tubing drilling rigs are mounted with air compressors for this purpose. A conventional rig sets casing above the target reservoir and moves to the next well. The coiled-tubing rig is then rigged up and used to deepen the well underbalanced to minimize or eliminate formation damage.

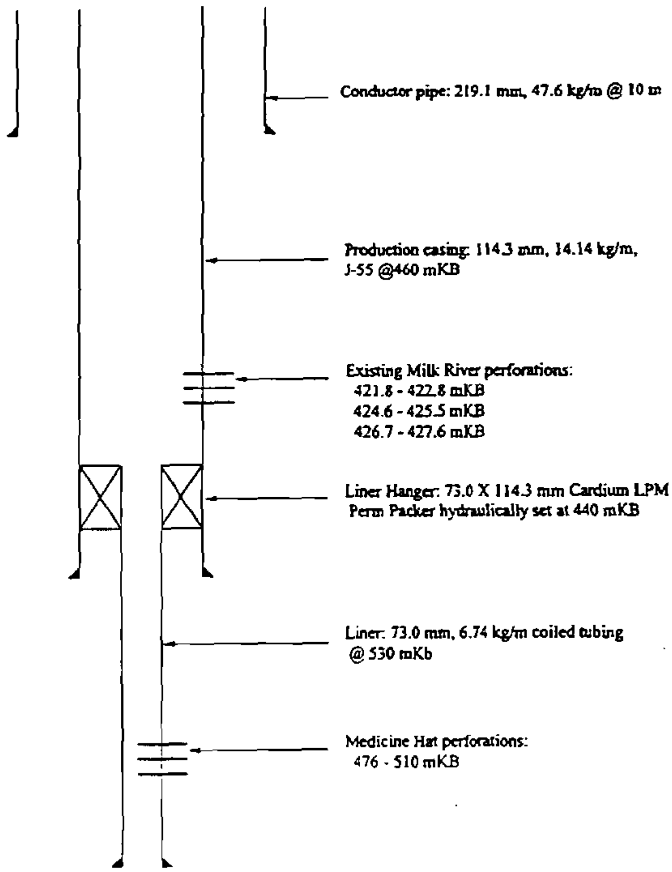

Figure 81. Final Completion of 10-9MR-17-3 W4M (McMechan and Crombie, 1994)

Underbalanced Horizontal Re-entry

Well D-9 was a horizontal well deepening operation. This Prudhoe Bay well was originally completed with a 4½-in. slotted liner and 4½ x 3½ production tubing (Figure 82). Formation damage during original drilling operations was suspected as the cause of the well's less than expected production.

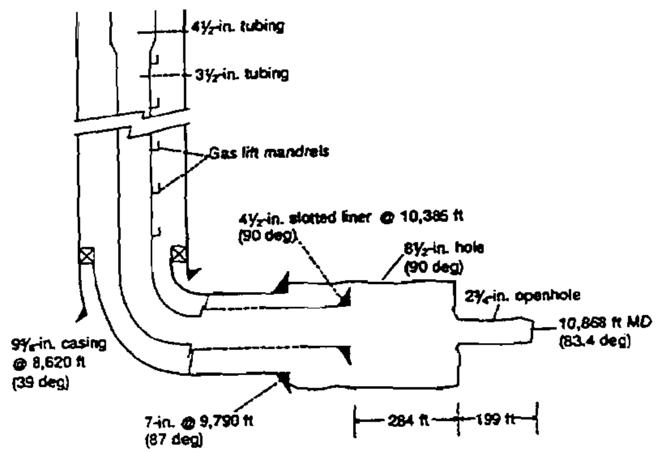

Figure 82. Well D-9 (Leising and Rike, 1994)

The deepening was performed underbalanced with gas lift. Biozan drilling fluid (2.5 lb/bbl) was used for the operation. The drilling BHA consisted of a 2¾-in. bit, motor, drop-ball circulation sub, drop-ball disconnect, dual check valves, and weld-on connector.

A two-phase separator was used along with collection tanks to store the usable fluid before returning it to the suction tanks. A layout of the surface equipment is shown in Figure 83.

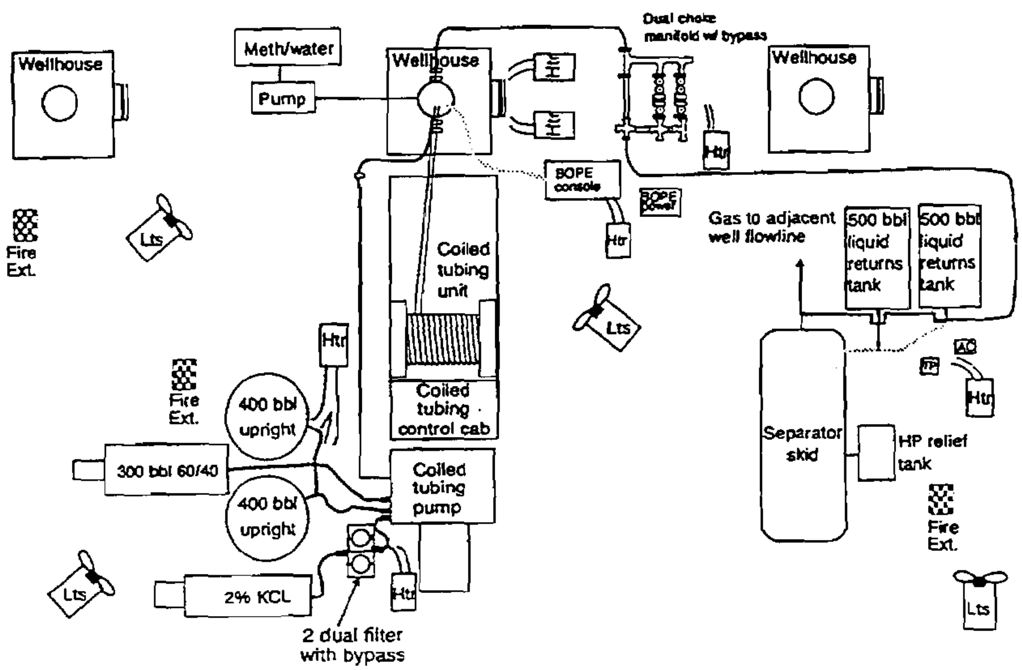

Figure 83. Surface Equipment for Well D-9 (Leising and Rike, 1994)

After a profile nipple was milled out, the BHA was run to the old TD and the hole lengthened 199 ft. A final survey showed that the new wellbore dropped angle along its length at a rate of about 3½°/100 ft. Guidance was not critical for this interval so no attempt was made to measure changes in inclination while drilling.

Problems with job execution included difficulty achieving desired underbalanced conditions. The size of the annulus (2-in. coiled tubing in 3½-in. production tubing) resulted in high pressure losses in the annulus. Smaller coiled tubing (1¾ in.) was not considered feasible due to the large diameter of the original wellbore (8½ in.).

Unidentified fluid contamination and a large wellbore diameter led to stick/slip behavior of the coiled-tubing string, resulting in difficulty getting weight to the bit. ROP ranged from 6–18 ft/hr; the average was about 10 ft/hr.

Production from well D-9 was increased by a factor of 3½ by the coiled-tubing lengthening. The cost for this operation was about 75% less than if a conventional rig were used.

Shallow Vertical New Well

Shell Western E&P used coiled tubing to drill 68 slim-hole injector wells in the McKittrick Field near Bakersfield, California. This project represents the largest coiled-tubing drilling program yet conducted. Costs were reduced significantly for this application. Background and results of this effort are described in detail in DEA-67 *Topical Report No. 1: Shell California Slim-Hole and Coiled-Tubing Drilling Operations*. A summary is presented in this section.

Shell drilled the slim-hole injection wells to improve thermal efficiency, production and economics of the McKittrick field. Steam is injected into these wells in the Tulare reservoir.

Prior to project implementation, the field was shut in for several years due to poor economics. The redevelopment plan was to decrease well spacing by infill drilling 115 new injectors in thirty 5-acre inverted 9-spot patterns to increase thermal efficiency of the reservoir and increase production through existing or reworked conventional production wells.

The McKittrick field has a complex system of pumping equipment, steam distribution, production, and power lines that restrict the space available for conventional rotary drilling.

The slim-hole wells were drilled primarily for two reasons. First, by reducing hole and casing sizes, vertical slim-hole wells could be drilled and completed for approximately half the cost of conventional vertical wells. Secondly, coiled-tubing drilling allowed slim-hole infill wells to be drilled on the required precise patterns in this crowded field. These wells could not have been drilled vertically with conventional drilling because of their location. Many of the new well locations were directly under existing power lines and in close proximity to existing facilities. Drilling conventional directional wells would have been cost prohibitive.

Other benefits of using coiled-tubing drilling were:

1. Low mobilization and de-mobilization costs between wells.
2. Safer working environment (i.e., no couplings to make or break).
3. Decreased noise and emission levels.

A coiled-tubing unit with 2-in. coiled tubing, 5-in. motor and 6⅛-in. bits was used to drill 68 injector wells. Mud and cement were pumped using a service company cement pump truck. A portable, trailer-mounted mud tank, shakers, mud mixer, centrifuge, and desanders were used. A typical wellbore schematic is shown in Figure 84.

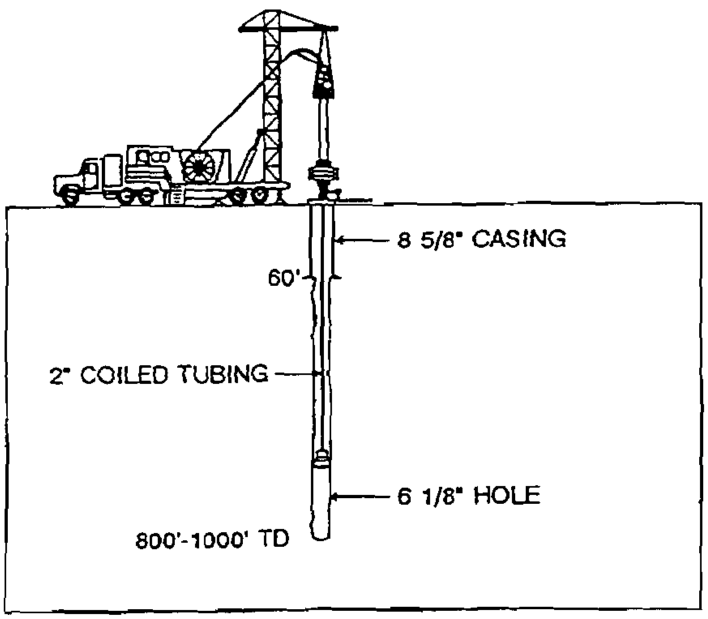

Figure 84. Shell Coiled-Tubing Drilled Injector Well Schematic (Vozniak et al., 1994)

Prior to drilling operations, an 8 ft x 8 ft jacking framework floor was set by crane and a 6-in. diverter line and a 4-in. return line were installed. Power and backup tongs were installed on the working floor. A pump truck, coiled-tubing unit, and trailer-mounted mud system were rigged up on location and a small pit was dug next to the mud unit to handle cuttings and cement returns.

An 8⅝-in. conductor was set at 60 ft to allow the BHA (6⅛-in. rock bit, 5-in. positive displacement motor and 2-in. spiral drill collars) to be run before installing the injector.

After the wells were drilled, 2⅞-in. tubing was cemented to surface and perforated. The workover and coiled tubing drilled slim-hole injectors took less time and costs to drill than conventional 8¾-in. injectors (Table 18). The workover and coiled-tubing rigs were used primarily due to surface constraints. The coiled-tubing rig proved to be ideal for drilling the small injectors due to the shallow location size and ease of mobilization.

TABLE 18. Performance Comparison – Shallow Vertical Wells (Vozniak et al., 1994)

Rig Time	Conventional Offset Well	Coiled-Tubing Well	Workover Rig Well
No. Of Wells	2(100)	68	45
Drill Pipe Size	3½ in.	—	2⅞ in.
Coiled-Tubing Size	—	2 in.	—
Hole Size	8¾ in.	6⅛ in.	6⅛ in.
Casing/Tubing Size	7(2⅞) in.	2⅞ in.	2⅞ in.
ROP	120 ft/hr	50–180 ft/hr	70–80 ft/hr
Days	7	1.25	4
Cost	100%	65%	55%

There was a steep learning curve with coiled-tubing wells, with costs on initial wells being similar to conventional wells and then declining to 65% of the cost of conventional.

3.11.6 Summary and Technology Needs

The current cost and limitations of coiled-tubing drilling generally restrict its economic viability to applications where clear benefits accrue due to the unique advantages it offers. These niche applications include the following:

- Underbalanced drilling
- Vertical deepenings
- Horizontal re-entries
- New wells with severe surface location restrictions

Generally acknowledged technical limits within these applications include the following:

- 8½-in. hole size and 6000 ft depth for new vertical wells
- 4¾-in. hole size and 15,000 ft depth for re-entry drilling
- Minimum casing/tubing size for vertical deepenings of 3½-in.
- Minimum casing/tubing size for directional drilling of 4½-in.
- Horizontal penetration limits ranging from 200 ft (4½-in. hole out of 7-in. casing using 2-in. coiled tubing) to 4600 ft (3⅞-in. hole out of 4½-inch casing using 2⅜-in. coiled tubing).

These limits are only general and will vary for application-specific conditions. In addition, aggressive application is extending these limits continuously.

Technology developments that are needed to make coiled-tubing drilling more cost-effective and reduce the risk in current applications, as well as broaden the application base, include the following:

- *Better Understanding of Coiled Tubing Pipe Behavior*

Current fatigue models use equations assuming zero internal residual stresses, such as for conventional oil-field tubulars. Coiled tubing may have considerable residual stresses. Research into better understanding and modeling of coiled-tubing behavior in general and especially under drilling conditions is needed. This is being addressed by several groups. The results should then be incorporated into advanced coiled-tubing mechanics and life software.

- *Increased Coiled-Tubing Life*

The cycle-life of coiled tubing, especially in the larger 2⅜-in. and 2⅞-in. sizes needs to be increased. 70 ksi pipe is the most common and 100 ksi pipe is available. Higher strength steel pipe or different materials with greater strength capabilities, such as titanium or composites, would allow for larger loads and longer life of the coiled tubing.

- *Coiled-Tubing Connectors*

There are several coiled-tubing connectors in use today. The most reliable to date is the roll-on. Set screws can be added in a drilling application to eliminate potential rotational slippage of the connector. However, there is significant room for improvement in the aspects of strength, stiffness, ID restrictions, installation, and considerations for coiled tubing with internal wireline or hydraulic tubes. One major limitation is not knowing the exact strength of the connector under specific cycles of pressure, axial, tangential, and lateral loads, and thus not being able to predict life.

Internal profiles must be shaped in a way to minimize turbulence and pressure drops during circulating but without cutting into the coiled-tubing body during bending cycles. External upsets must be minimized so that the connector can pass through the stripper without damaging it and not create well control situations by requiring removal of a well control component. Connectors must be easy to install in the field where tight tolerances are difficult to obtain.

- *Downhole Orienters*

Conventional directional drilling systems use bent-housing motors that are oriented by rotating the drill pipe at the surface. Coiled tubing cannot be rotated so less reliable and more expensive methods must be used. These include pulling out of the hole to re-orient, and reciprocation of the pipe to adjust the BHA (which compounds the fatigue life problem). Several downhole orientation tools also now exist. The three types used are: 1) electrical (which uses an electric motor to power a hydraulic pump to actuate the tool), 2) hydraulic (which has two ¼" hydraulic tubes from the surface to actuate the tool, with a separate electric line for signals), and 3) pressure (which uses mud pressure pulses to actuate the tool). All three types have been used successfully in the field. Reliability was a question early in the field trails but has significantly improved. Nonetheless, the need for even more reliable and less expensive, non-umbilical orienters is seen as critical by many in the industry.

- *Downhole Thrusters/Torque Reactors/Locomotion*

The ability to apply more weight to the bit without buckling or failing the coiled tubing is a critical need. This is especially true in horizontal sections where excessive friction and drag are present. Since coiled tubing cannot be rotated, has smaller diameter (usually), has lower axial and torsional loading capacity, and is more flexible than conventional drill pipe, the penetration limit is much less than for conventional drilling. The reactive torque of the motor must generally be absorbed by the bent motor housing or transmitted back to the surface through the pipe. The use of higher power motors and other attempts to increase rates of penetration in deeper and harder formations will amplify this problem. Effective and reliable downhole thrusters, locomotion devices that grip the borehole wall, and/or torque reactors that can provide greater weight-on-bit while essentially de-coupling the coiled tubing from the bottom-hole assembly would be of great benefit. Some approaches have been pursued and tools developed.

- *Downhole Weight-On-Bit Measurement*

In conjunction with the above discussions, the buckling tendencies of the coiled tubing make it extremely difficult to know how much weight-on-bit is being actually applied to the bit. Therefore, it is very difficult to diagnose slow drilling rates. The ability to measure the actual applied weight-on-bit during drilling would greatly enhance drilling performance and technological developments.

- *Telemetry For Underbalanced Drilling*

Underbalanced horizontal re-entry work will most likely be the largest near-term market for coiled-tubing drilling. However, mud-pulse MWD does not work in aerated fluids commonly used for underbalanced drilling. Therefore, the ability to cost-effectively and accurately place the wellbore is compromised. Accurate and reliable MWD tools for use in aerated fluids is a critical need. EMR (electromagnetic resistivity) MWD is available and can be used in compressible fluids. Many runs have been made on conventional drilling assemblies. Current limitations include: 1) the need for some liquid (conductivity to the formation), 2) only directional and GR sensors are available, and 3) formation resistivity contrasts (limited applicable depth). Repeaters are available for conventional drill strings. However, the use of EMR MWD with coiled tubing is unknown.

- *Wireline Installation Methods*

MWD use with coiled tubing often uses wireline inside of the coiled tubing. The installation of this line is expensive and, due to the short life of coiled tubing when used for drilling, must be repeated quite often. Therefore, less costly methods of doing this are needed.

- *Geosteering Capabilities*

Once again, since horizontal re-entry work is a large application for coiled-tubing drilling, the ability to geosteer the bit by the use of logging-while-drilling (LWD) will be of great benefit. Development of these tools for use in smaller diameter holes is needed.

- *Smaller and More Reliable Tools*

Most bottom-hole assembly components and tools required, excluding those needs addressed above, are available for re-entry work out of 5½-in. and 4½-in. casing. However, there is a growing demand for through-tubing re-entry drilling work out of 3½-in., 2⅞-in, and 2⅜-in. installed production tubing strings. Bottom-hole assembly components and other tools are not widely available in these extremely small sizes. In addition, improved reliability for reduction of failure incidence rates of even the existing tools currently used with coiled-tubing drilling is also needed.

- *Ability To Rotate*

Coiled tubing cannot be rotated for even minor rotary drilling modes, downhole orientation, tool setting, etc. The ability to rotate, at least the bottom-hole assembly, would greatly expand the capabilities of coiled-tubing drilling, and coiled-tubing operations in general. This is a very difficult problem.

- *Ability To Handle Jointed Pipe and Bottom-Hole Assemblies*

Standard coiled-tubing rigs cannot pull or run jointed tubulars, such as running production casing and tubing, or pulling production tubing for re-entry work. Therefore, other provisions must be made for these operations, such as the use of a workover rig or crane. There have been several prototype "hybrid" coiled-tubing/snubbing rigs designed and manufactured for this purpose, such as the one shown in Figure 85. This unit uses snubbing jacks and a crane for jointed pipe ranging from 2⅜-in. to 7⅝-in. It allows for rapid transition from continuous to jointed pipe by moving the injector off the wellhead via the injector trolley. No ideal system has been built as of yet. Such units will have to be developed and be made widely available for widespread and streamlined application of coiled tubing as a stand-alone drilling and completion system.

- *Improved Motor and Bit Performance*

Improvements in small diameter motor and bit performance and life, as with conventional slim-hole drilling, are important for coiled-tubing drilling to be able to maximize its beneficial use in a greater number of applications. The cost of the motor is especially crucial when comparing conventional rotary drilling costs to coiled-tubing drilling or slim-hole motor drilling. Longer lasting and higher power motors and better roller cone and fixed cutter bits are needed. An example of a current small diameter motor problem is that the make-up torque on the motor components is apparently insufficient to withstand the variable reactive torque and shock loads encountered while drilling, as evidenced by several back-offs that have occurred.

- *Technology And Personnel Integration*

Integration of existing drilling technologies with coiled-tubing technologies are needed, for example, process control for automated drilling systems for coiled-tubing drilling and safe fluids handling systems for underbalanced drilling. Integration of conventional drilling personnel into the coiled-tubing drilling business is also a need and would help reduce costs.

- *Education*

The education of producer companies on the capabilities, limitations, and risks of using coiled tubing as a drilling system is seen as a great need by service companies offering the service. Service companies report a significant overload of requests for proposals for many different applications, many of which simply are not suitable for application of today's technology level. There is a fear that the current failure rate may dampen enthusiasm while the technology is still immature. This failure rate is often caused by inappropriate, premature use of the system in an overly aggressive application. In a sense, the "romance" of the system may have, in some cases, pushed the technology in inappropriate directions. While this is beneficial from a learning and technology testing standpoint, repeated failures are not usually tolerated very long.

- *Underbalanced Candidate Selection*

As previously stated, underbalanced drilling is a large niche for coiled-tubing drilling. However, producers and service companies are having a difficult time quantifying benefits of underbalanced drilling in different reservoirs and applications. Further research into advantages of underbalanced drilling in different reservoirs and development of candidate selection tools, such as software models, would be of great value.

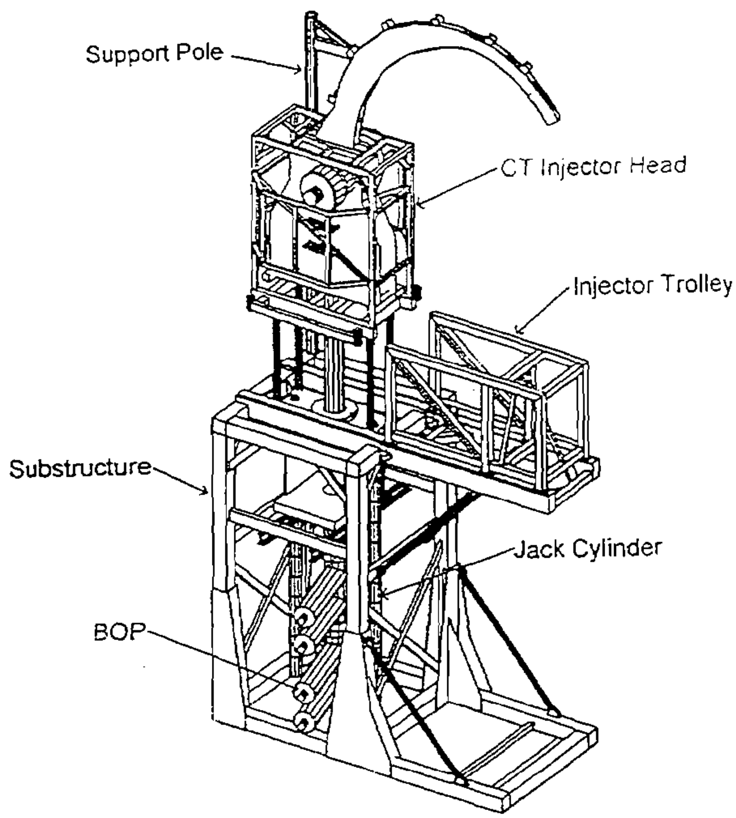

Figure 85 Drexel's Hybrid Coiled/Jointed-Pipe System (Newman and Doremus, 1994)

3.12 SLIM-HOLE DRILLING CONCLUSIONS

Drilling slimmer than conventional holes carries great *potential* for cost reductions in a variety of categories including casing, tubing, rig rate, time, location, transportation, mud, and cement. However, there is a wide range of technical and economic issues that must be addressed before implementing a slim-hole drilling program and realizing total well cost savings. This is especially true in most conventional U.S. gas drilling areas where transportation and location costs are not typically a large percentage of the overall well costs.

Fortunately, many producer and service companies have investigated and developed information and technology for slim-hole drilling conditions over the past five to ten years. These advancements have come in many areas such as bits, motors, drill strings, hydraulics, fluids, kick detection and well control, rig design, and operational procedures. These developments have reduced the barriers to effective and safe slim-hole drilling. However, most of the experience with this technology and information has not been transferred to personnel and companies drilling gas wells in the U.S. There are very few dedicated rigs with the necessary equipment, tools, and crew experience necessary to cost-effectively drill lengthy slim-hole intervals.

In addition, although many new tools and technologies have been developed, low demand has kept the supply limited, resulting in higher costs and reduced availability. This is a common theme across the spectrum of slim-hole issues.

Compounding these problems of lack of experience and knowledge of new technology is a low appetitive for the increased risk that inevitably comes with implementation of new technology. This is especially true for use of a new approach that alters so many factors during the life of a well, as does slim-hole.

Therefore, the near-term critical path for beneficial slim-hole drilling use in U.S. gas wells is the proper design and implementation of a multiple-well, multiple basin new well field test program. Such a program would provide for integration of existing technology, experience, and knowledge and result in rapid dissemination of slim-hole state-of-the-art and cost saving potential relevant to new U.S. onshore drilling. This program will also provide the basis for and stimulate the most beneficial and useful individual slim-hole technology developments necessary for U.S. gas well drilling and completions.

Individual technologies that need addressing in conjunction with such a field test program include the following:

- Small diameter roller cone and fixed cutter bits for use in the variety of formations encountered in U.S. drilling
- Higher power, longer life, and less costly downhole motors
- Improved understanding of slim-hole bit/motor matching and design
- Improved fishing tools and techniques; documentation of slim-hole fishing incidence and success/failure rates
- Advanced hydraulics models

- Downhole motors or improved small diameter circulation subs allowing for fluid by-pass to allow for higher flow rates and lost circulation material pumping
- Laboratory testing to determine proper LCM type, volumes, mixture, concentrations, size distributions, additives, and pumping schedules for use in slim-hole tools and applications
- Higher strength slim-hole drilling tubulars and connections
- Improved understanding and modeling of downhole vibrations in slim conditions
- Development of downhole tools, such as shock absorbers, to minimize vibrations
- For horizontal applications, small diameter MWD and LWD tools and advanced slim-hole guidance technology, such as remote-controlled ("joystick") motors
- For coiled-tubing drilling needs, see Section 3.11.6

3.13 REFERENCES

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4. Logging and Perforating

4.1 INTRODUCTION

Every well drilled will require the use of open-hole and cased-hole logging and other wireline operations during its life. The ability to evaluate the formation(s) of interest using conventional methods, as well as perform the other myriad of services typically conveyed on wireline, is extremely important if operators are to realize benefits from slim-hole drilling and completion techniques. For example, any savings obtained from drilling a slim hole would be of no benefit if the analyses of the wireline logs are not accurate and incorrect completion decisions are made.

This chapter primarily discusses slim-hole logging technology, but also addresses other commonly performed wireline services such as perforating, formation testing, and cutting services.

As with all discussions of slim-hole technology, a definition of slim-hole must be established. The definition of slim-hole for wireline technologies is similar to that previously established for slim-hole drilling and completions.

4.1.1 Service Company Definition of Slim Hole

Boreholes with diameters from 6 to 6½ in. were traditionally considered to be the smallest wells in which open-hole logging tools could be run. However, electric wireline technology has progressed so that now all services can be run in 6½ in. holes. Today, wireline service companies generally consider boreholes less than 4¾ in. in diameter to be slim for open-hole operations. Standard open-hole logging tools typically have an outside diameter (OD) of 3⅜ in. or 3⅝ in. and can be run in holes as small as 4¾ in., provided that the interval to be logged is short (less than 500 ft), relatively straight, and in gauge. Otherwise, in holes of this size and less, smaller-diameter tools are recommended.

In some instances, a wireline company may designate a hole as slim for a particular tool. The usual criterion for this special classification is that clearance (hole diameter minus tool diameter) be less than ¾ in. for the specific hole and tool.

For through-tubing work, a full range of standard cased-hole logging tools is available. Most of these tools have ODs of $1^{7}/_{16}$ or $1^{11}/_{16}$ inches. Since a clearance of ¼ in. is usually sufficient for cased-hole logging, these tools can be used for most cased wells, even those in which production tubing has been cemented in as casing.

In the area of small-diameter perforating services, for years emphasis has been placed on through-tubing work. Thus, perforating services are routinely available for practically any cased well.

4.2 TECHNICAL CHALLENGES IN SLIM-HOLE LOGGING

Service companies have traditionally built large downhole tools. Until recently, boreholes were usually large and there was no need to build small tools. Large tools are technically easier to design and are less expensive to build. Large coil arrays in resistivity tools, large transmitters and receivers in acoustic tools, and large detectors in gamma, density, and neutron tools contribute to the ability to make high-quality measurements. Producing the same quality measurements with slim-hole tools presents a serious design challenge and requires more expensive components.

The demands of developing slim-hole induction and radioactive tools are particularly daunting. In the case of induction tools, reducing the size of the transmitter and receiver coils by a factor of 2 decreases the received signal by a factor of 16. For gamma-ray tools, reducing the size of gamma-ray detectors results in significant decreases in the number of gamma rays that can be sensed by the detectors. For example, gamma-ray count rates from 1-in. by 8-in. sodium detector can be nearly five times smaller than those from a 2-in. by 12-in. detector of the same material.

The size of tools used in slim-hole operations is also limited by tool clearance, tool standoff, and the well's radius of curvature.

4.2.1 Clearance

A tool's clearance requirements determine the minimum hole size in which the tool can be run (Figure 86). As defined earlier, clearance is the difference between borehole diameter and tool diameter. Sufficient clearance is necessary to avoid tool sticking and to allow the tool to traverse doglegs and intervals over which mudcake has built up. In open holes, a clearance of ¾ in. is usually considered an absolute minimum.

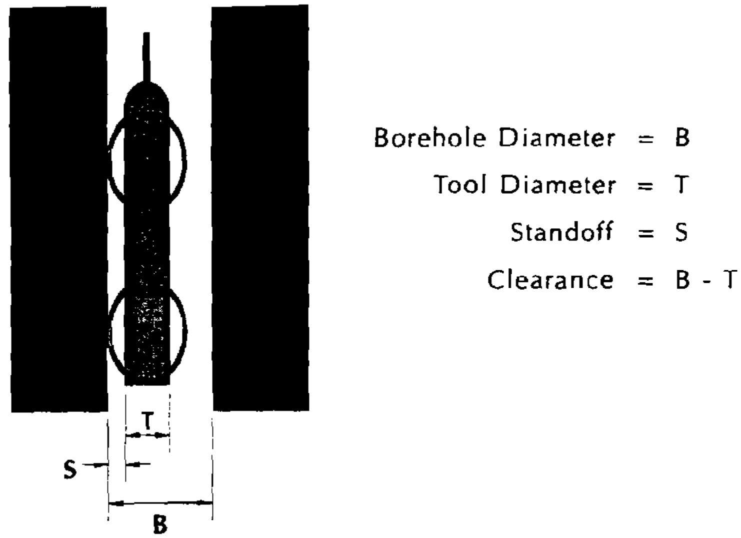


Figure 86. Tool Clearance and Standoff

4.2.2 Standoff

As illustrated in Figure 87, open-hole logging tools may be run free, centered (centralized), eccentered (decentralized), or stood off in the borehole. Decentralized tools, such as compensated neutron tools, are pushed against the borehole wall. Some tools, such as induction tools, can be held away from the borehole wall (stood off) at a certain distance, or standoff. The hole size must allow for these positions.

Some tools, such as dipmeter and density tools, have pad-mounted measurement systems. The pads are mounted on mechanical arms and are pushed against the borehole wall without the main body of the tool touching the wall. The hole must be large enough to accommodate the extra mechanical components of these tools.

Shaped perforating charges require a minimum standoff for optimal performance. When standoff is less than the minimum, perforation entrance-hole diameter or perforation tunnel length usually decreases. Again, hole size must be large enough to allow sufficient standoff for the guns.

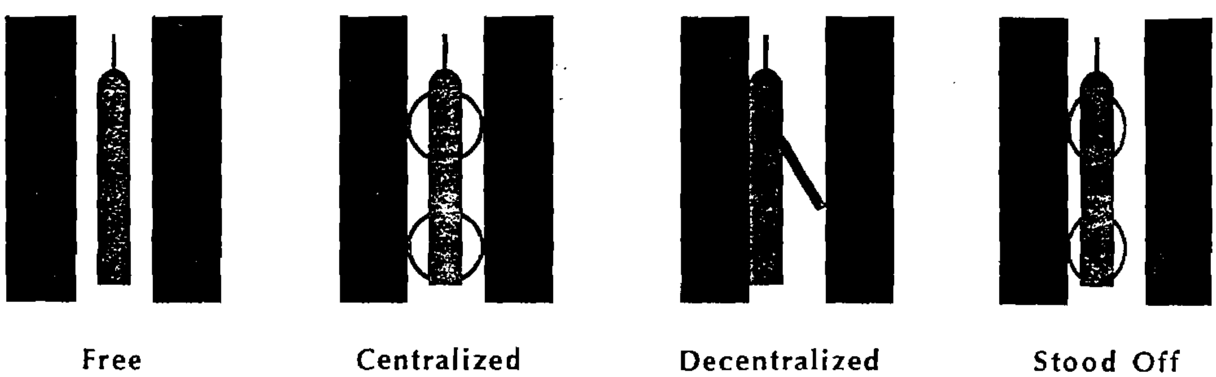


Figure 87. Positioning Definition

4.2.3 Well Radius-of-Curvature Limitation

In a deviated well, the well's radius of curvature imposes a limitation on the length of rigid tools that can be run in the well (Figure 88). This limitation becomes more severe as borehole diameter decreases. Clearly, a long, rigid tool cannot negotiate a well with a small radius of curvature. To allow such a tool to traverse such a deviated well, flex joints can be placed between the sections that comprise the tool.

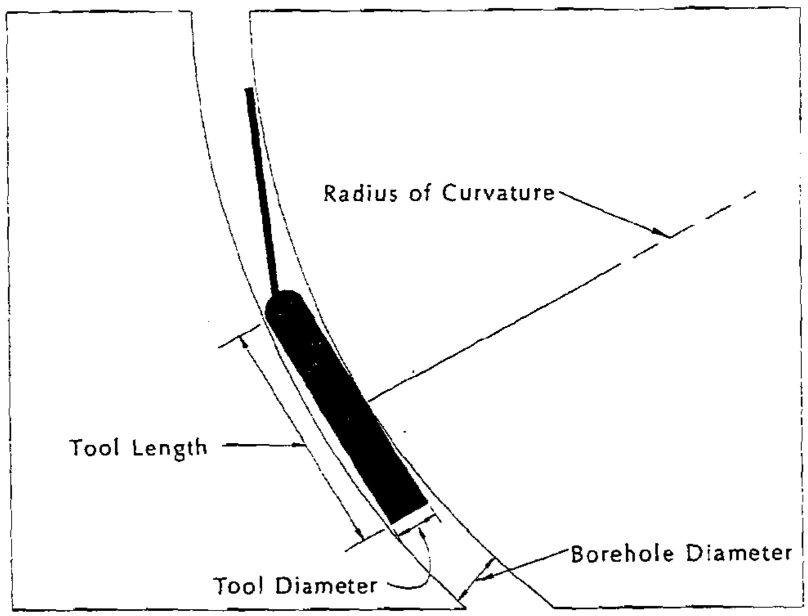


Figure 88. Hole Size, Radius of Curvature, Tool Diameter, and Tool Length Relationships

The maximum length of a *rigid* tool or *rigid* section that can be run in a well is given by

$$L = 2\sqrt{(R+B)^2 - (R+T)^2} \tag{2}$$

where L is tool or section length, R is the well's radius of curvature, B is borehole diameter, and T is tool diameter. All dimensions must be in the same units.

Conversely, the minimum radius of curvature of a well in which a specific rigid tool or rigid tool section can be run is given by

$$R = \frac{\left(\frac{L}{2}\right)^2 + T^2 - B^2}{2(B-T)} \tag{3}$$

Charts such as shown in Figure 89 can be derived from these equations. The charts are used to determine tool configurations in deviated wells for open- and cased-hole applications.

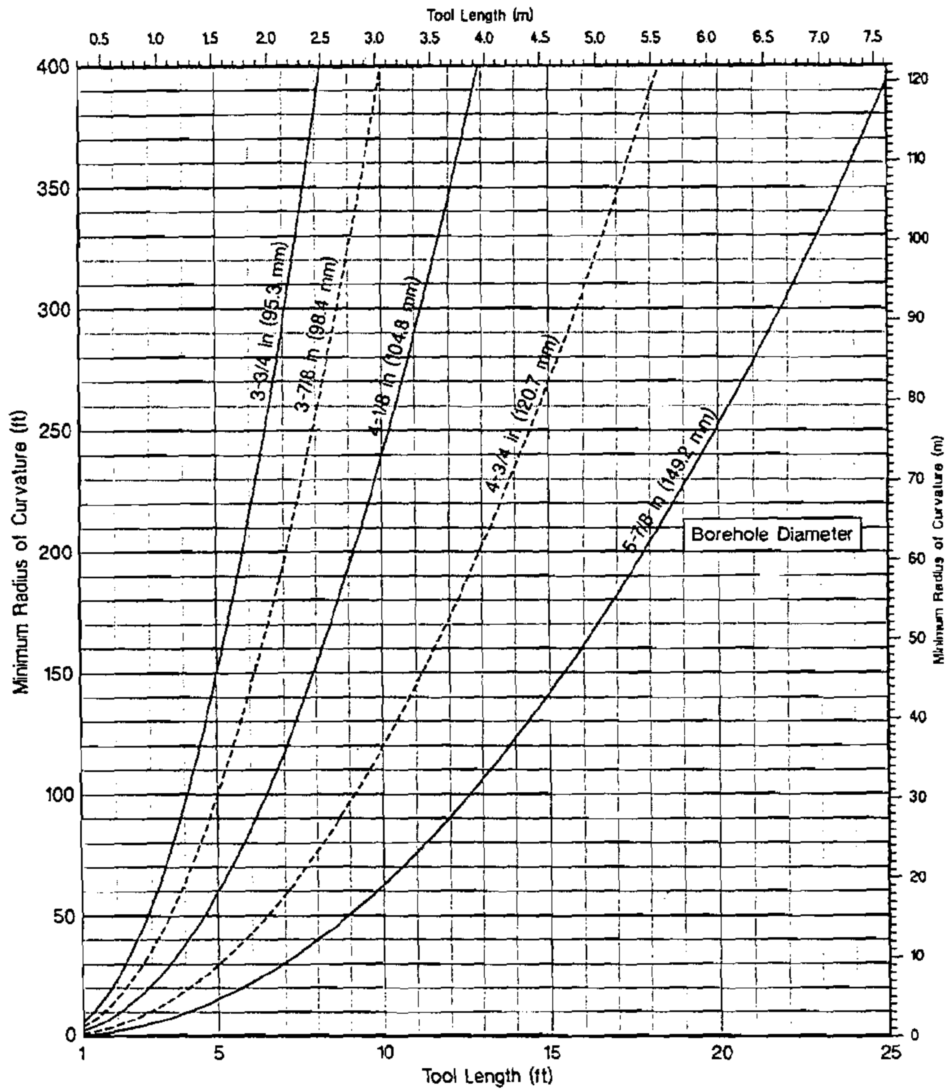


Figure 89. Chart Used for Determining Minimum Rates of Curvature or Maximum Tool Length for 3.5-in. Tool

Figure 90 shows how the minimum radius of curvature for a given tool length and diameter increases with smaller hole size. It also illustrates how the minimum radius of curvature decreases with a smaller tool diameter.

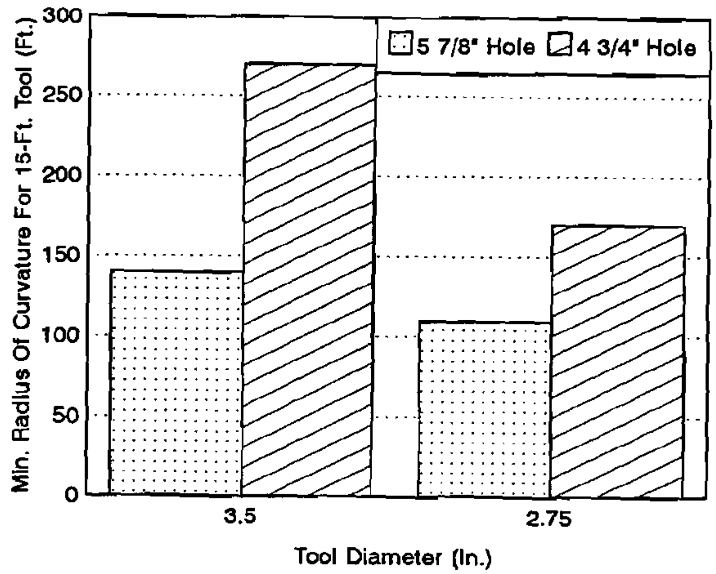


Figure 90. Minimum Radius of Curvature vs. Hole Diameter and Tool Size

4.3 LOGGING TECHNIQUES

The combination of a wireline cable and the earth's gravity is most commonly used to control the descent and ascent of logging tools in a wellbore. This technique increases in difficulty as well deviation increases, and finally becomes impossible in horizontal wells. The technique also becomes more difficult as hole size and the resulting clearance decrease. To better convey wireline tools through deviated wells, and extreme slim conditions, other techniques have been developed. These techniques involve pumpdown, pipe-conveyed, and coiled-tubing-conveyed operations.

4.3.1 Pumpdown-Stinger Technique

With the pumpdown stinger technique, the tools are pumped down through the drill pipe or tubing. Thus, the technique is applicable only with the smallest diameter tools. The tool is pumped down the pipe on a piston that serves as the "locomotive," and the complete assembly (tool and piston) is retrieved by means of a wireline cable. The number of logging tools available for pumpdown services is limited, and the formation evaluation capabilities of the tools are restricted.

4.3.2 Pipe-Conveyed Logging Techniques

The pipe-conveyed logging technique uses drill pipe or tubing to transport the logging tools through the wellbore. The tools are connected to the bottom of the pipe and may or may not be enclosed in a protective shield. Recorded data is transmitted uphole through the wireline, which is pumped down the pipe and is connected to the tools by means of a wet connector. The tools are moved down or up the wellbore, respectively, by the addition or removal of pipe. Several drill pipe-conveyed systems are available in the industry for use with 3½-, 4-, and 4½-in. drill pipe and 2⅜-, 2⅞-, and 3½-in. tubing.

4.3.3 Coiled-Tubing-Conveyed Technique

When the coiled-tubing-conveyed technique is used, the logging tools are mounted at the end of a coiled-tubing string in which an electric wireline has first been inserted. The tools remain electrically connected to the wireline cable throughout the entire operation. Upward or downward movement of the coiled-tubing by a standard coiled-tubing injector head provides the corresponding movement to the attached logging tool string.

4.3.4 Comparison of Techniques

Table 19 compares wellbore deviations and horizontal-extension lengths that can be accommodated with the various logging techniques. The table also indicates the general types of tools that can be used with each technique.

TABLE 19. Comparison of Logging Techniques (Spreaux, 1988)

Technique	Tool	Hole Deviation (degrees)	Horizontal-Length Limit	
			Open Hole (m)	Cased Hole (m)
Wireline	Standard	65 to 70	not applicable	not applicable
	Slimhole and production	65 to 70	not applicable	not applicable
Pumpdown Stinger	Slimhole and production	90	700	700
Pipe-Conveyed	Standard	90	no limit	no limit
Coiled-Tubing-Conveyed	Standard	90	0	200
	Slimhole and production	90	not advised	600

4.4 STUCK PIPE AND FISHING

Stuck pipe can be a problem in slim holes because of the tight clearances. Small-diameter wireline tools can locate the free point in tubulars and subsequently jar the pipe during backoff operations. Explosive and chemical cutters are available for small pipe and coiled tubing.

Logging tools lost in a slim hole can be fished. However, operators should be aware that fishing operations in small-diameter boreholes are more risky than in standard-size holes. These operations may require more time and be more expensive than fishing operations in larger holes.

A standard overshot would probably not be used to fish a lost tool because of the small clearance between the lost tool and the borehole wall. The small clearance usually does not allow an overshot to fit over the tool; therefore, a fishing neck should always be attached to the top of any wireline tool string that is to be run in slim holes. The shape and small diameter of the neck allow the neck to be grasped by a special fishing tool and thus facilitate retrieval of the tool string.

When some wireline cable remains attached to a lost tool string, a spear is used for fishing. The lost cable is generally in an entangled mass in the borehole and can be snared by the spear when the spear is lowered into the mass.

4.5 OPEN-HOLE WIRELINE LOGGING SERVICES

Slim-hole logging originated in coal and mineral exploration. In fact, many wells for such exploration were drilled using a small-diameter, wireline-retrievable continuous coring system. Because of the recent increase in slim-hole drilling and its attendant requirements for logging services, the arsenal of slim-hole wireline logging tools has increased over the past few years and includes most of those services available for conventional wells. However, in some cases, there is a degradation in data quality as hole size decreases. Some of the newer, more advanced slim-hole tools are being more carefully designed and characterized so that their responses are nearly identical to their standard-size counterparts.

In the following sections, some of the main types of open-hole logging tools are presented. Brief explanations of the operational principles of many of the tools are given to facilitate understanding of some of the limitations that might be encountered when designing versions for slim-hole application.

4.5.1 Electric Logging

The first wireline logs to be developed were the spontaneous potential log and, subsequently, the electric normal log. The industry has progressed far beyond these early logs, and today's standard resistivity logs are produced from dual induction or dual laterolog measurements, with even more advanced services being available. The resistivity measurements are used in calculating a formation's water saturation, which gives a direct indication of the formation's hydrocarbon content.

To meet the standards for comprehensive formation evaluation, slim-hole resistivity tools must provide three measurements, each with a different depth of investigation. Because of the three depths of investigations, the measurements can be corrected for invasion of drilling fluids. However, even before invasion corrections are made, each of the three resistivity measurements should be corrected for borehole and bed-thickness effects. Charts and algorithms must be available for making all these corrections.

4.5.1.1 Induction Tools

Induction tools operate on the following principle. A sinusoidal current of constant amplitude is fed into a transmitter coil to excite a magnetic field around the tool. This field causes eddy currents to flow in the borehole and formation in circular paths that are concentric with the tool's axis. The eddy currents are 90° out of phase with the transmitter current, and their magnitude depends upon the electrical conductivity of the formation. The eddy currents create their own magnetic fields, which induce an alternating voltage in the induction tool's receiver coils. This voltage is an additional 90° out of phase and is called the R-signal. The measurement of the R-signal constitutes a basic induction log. However, another important signal is also present, the X-signal. It is a reactive component that arises from the mutual coupling of the transmitter and receiver coils and from the electromagnetic interaction of the conductive ground loop in the formation.

The simplest type of induction tools contain single transmitter and receiver coil arrays and are exemplified by induction electric log (IEL) tools. These tools are generally available in small-diameter versions; however, they make only one formation resistivity measurement, which is not enough to correct for invasion effects. Thus, IEL logs are used more for qualitative than quantitative purposes.

Standard dual induction tools are based on a 6FF40 coil array for the deep-investigation measurement and on a 6FF34 array for the medium-investigation measurement. These tools usually also contain a short-normal device for a shallow-investigation measurement. The traditional log presentation thus contains three resistivity curves representing three different depths of investigation. Some of the more advanced devices, such as Phasor tools, use both R and X signals in the data processing that generates the three resistivity curves, but still rely on the same induction coil arrays.

One advanced induction tool (High Resolution Induction, or HRI) uses a completely new arrangement of transmitter and receiver coils. It has improved the vertical resolution of the resistivity measurement down to about 2 ft and the depth of investigation to 91 in. (The depth of investigation of an induction tool is defined as the radius of the region around the tool from which 50%

of the measured signal derives, based on geometrical factor models.) The recommended minimum borehole diameter for the HRI tool is 4 in.

Induction tools are generally run in boreholes that contain a low-conductivity liquid, a non-conductive liquid, or air. The resistivity of the surrounding formations must usually not exceed 200 ohm-m.

Designing and building a slim-hole induction tool is very challenging. The magnitude of an induction tool's varying magnetic field is proportional to the square of the transmitter coil's radius, and the magnitude of the measured signal at the receiver is proportional to the square of the receiver coil's radius. Consequently, the induction signal as a whole varies with the fourth power of coil radius. In practice, if the radius of the coils of a given induction tool is reduced by a factor of 2, then the level of the received signal is reduced by a factor of 16, all else being equal.

Borehole Signal: Because of the eddy currents in the borehole, the size of the borehole can affect the measurement of formation resistivity. A quantity known as integrated radial geometric factor (IRGF), which depends upon tool design, is used to determine an induction tool's depth of investigation and to study borehole effects on the tool's response. In particular, an induction tool's IRGF can be used to estimate the maximum borehole diameter in which an induction tool can provide useful measurements. Figure 91 plots IRGF as a function of distance from the tool's axis for a conventional induction tool's deep (ILd) and medium (ILm) measurements. Figure 92 plots IRGF attributable to the borehole as a function of borehole diameter. Since borehole effects are negligible when $|IRGF| < 0.001$, the borehole diameter that corresponds to $|IRGF| = 0.001$ is a good estimate of the maximum borehole diameter in which useful measurements can be made. Figure 91 thus shows that both ILd and ILm measurements can be effectively made in boreholes that are about 11 in. or less in diameter. Characterization of the borehole effect is easier for slim-hole induction tools than for standard-size induction tools since the borehole signal becomes almost negligible in small-diameter wellbores.

TABLE 20. Comparison of Depths of Investigation of Several Induction Tools

Coil or Electrode Array	Depth of Investigation (in.)			
	Conventional-Design Tools		Advanced-Design Tools	
	Standard	Slimhole	High Resolution Induction	Array Induction Tool
Deep-Investigating	65	65	91	60 to 90
Medium-Investigating	30	30	39	20 to 30
Shallow-Investigating	15	20	17	10

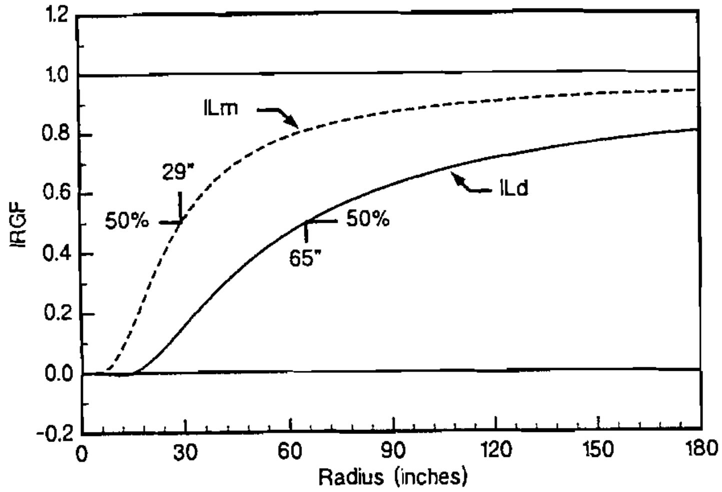


Figure 91. Integrated Radial Geometric Factors vs. Distance from Tool Axis

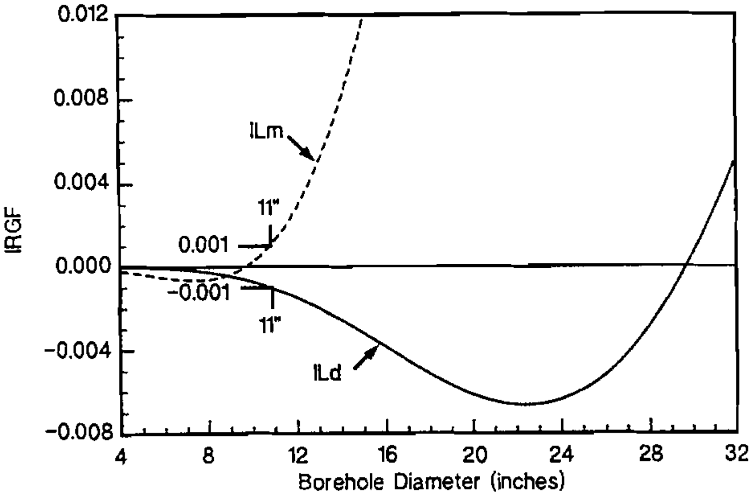


Figure 92. Maximum Hole Size Determination From IRGF

Depth of Investigation: Table 20 compares depths of investigation for several induction tools.

4.5.1.2 Microresistivity Tools

By emitting current from electrodes into formations, microresistivity tools measure formation resistivities at very shallow depths of investigation. The electrodes are traditionally mounted on extendable pads.

A microresistivity tool can be run in combination with a dual induction or a dual laterolog tool to provide the third resistivity measurement to complete the resistivity service. With three resistivity measurements, invasion corrections can be made and true formation resistivity (R_t) can be estimated. Because of the shallow depth of investigation of microresistivity tools, mudcake has a large influence on microresistivity measurements; therefore, mudcake-thickness correction charts are required.

Microresistivity tools with 2¾-in. OD are available.

4.5.1.3 Dual Laterolog Tools

Laterolog tools provide resistivity measurements in highly saline boreholes and in formations having very high resistivities. Dual laterolog tools use a single electrode array that focuses current into a formation to make deep- and shallow-investigation measurements. A primary electrode and two focusing electrodes—one above the primary electrode and one below the primary electrode—are used. The focusing electrodes force the survey current from the primary electrode into the formation. Two sets of monitoring electrodes—one set between the lower focusing electrode and the primary electrode, and one set between the upper focusing electrode and the primary electrode—are connected to electronic circuitry to control the effects of the focusing electrodes on the survey current.

During logging, voltages of approximately the same magnitude are applied to the primary and focusing electrodes. Since the voltages are all in phase, the current from the focusing electrodes repels the survey current from the primary electrode and thus forces the survey current to flow in a disk-shaped pattern directly into the formation. As the tool travels through the borehole, changes in formation resistivity tend to alter the pattern of the survey current and, consequently, to change the electrical potentials between the primary and focusing electrodes. The monitor electrodes sense these changing potentials, and associated control circuitry automatically adjusts the voltage to the focusing electrodes to maintain the desired survey current pattern.

Dual laterolog tools typically make deep and shallow resistivity measurements which, when combined with a measurement from a microresistivity device, furnish the information for making invasion corrections. Borehole size is one factor that affects the accuracy of laterolog measurements, and charts are available to make the needed correction.

4.5.1.4 Dielectric Tools

Besides resistivity measurements, dielectric measurements can also be used to determine a formation's water saturation. Interpretation of dielectric logs is based on the large difference between the dielectric constants of water and hydrocarbons.

Dielectric logging tools are shallow-investigation devices that are particularly useful where formation waters are fresh or are of unknown or changing salinity. These tools also find application in some areas where conventional resistivity-log interpretation does not work.

The most advanced dielectric tools operate at very high frequencies (in the gigahertz range) and have pad-mounted antenna systems. This makes the tools relatively large (3⅜ in. to 6⅞ in. in diameter), and no slim-hole versions are available.

4.5.2 Formation Density

As a primary indicator of porosity, the density of a formation is one of the most important pieces of information in formation evaluation. Combined with other measurements, formation density can be used to indicate lithology and formation fluid type.

Density tools used in open-hole logging contain a chemical source of gamma rays and two gamma-ray detectors. The source and detectors are mounted on a pad which can be extended away from the tool axis on standard-size tools or which may be maintained in an inline position on some slim-hole tools (Figures 93 and 94). Gamma rays emitted by the source travel through the borehole source travel through the borehole and formation, with some reaching the detectors. Traditional density tools measure the intensity of the gamma rays reaching the detectors to determine formation density. Today's more advanced spectral density logging systems also analyze the energy levels of the detected gamma rays to furnish additional lithology-related information, specifically, formation photoelectric factor (P_e).

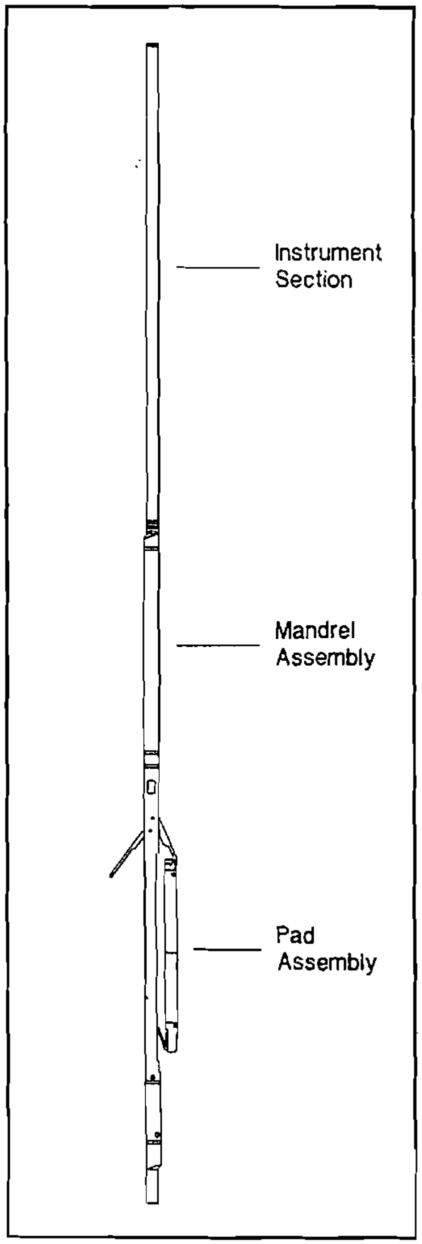
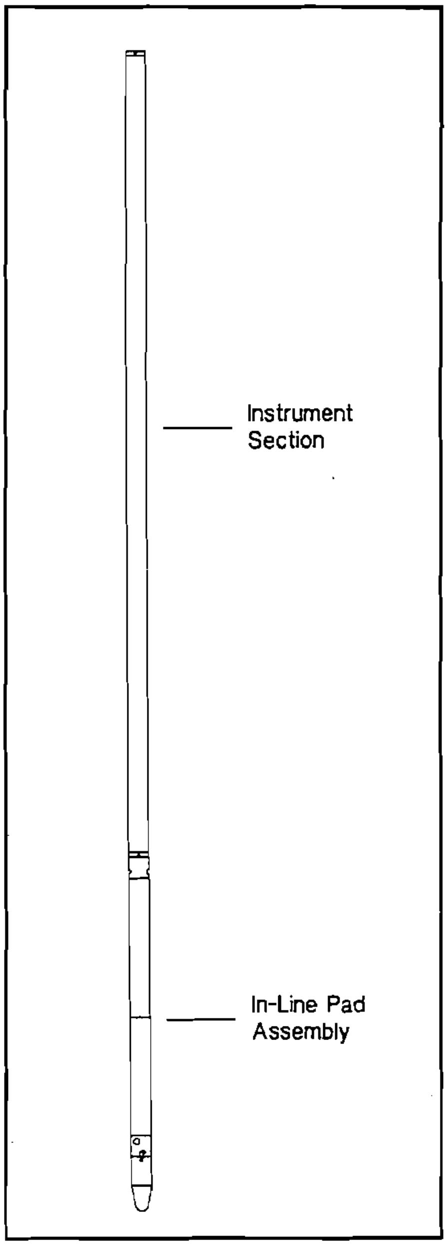


Figure 93. Spectral Density Tool with Extendable Pad Assemblies



The measurement of formation density and lithology in a borehole environment is a fundamentally difficult problem. The measurement depends upon the density and composition of the mud and mudcake, the curvature of the borehole at the point of contact with the pad, and the distance from the pad to the formation. Recently, a technique has been derived to more accurately measure formation density and lithology. It utilizes the full energy spectrum of the near detector and the high-energy portion of the far-detector spectrum to determine improved compensated density and P_e values. The additional application of temperature compensation, dead-time and pulse-pile-up corrections, and background-radiation subtraction yields highly accurate measurements from room temperature to 500°F. Density tools have also been designed with pad faces contoured to minimize the amount of mud and mudcake between the pad and the formation. This design further increases the accuracy of density and P_e measurements (Figure 95).

Figure 94 . Slim-Hole Spectral Density Tools with In-Line Pad Assemblies

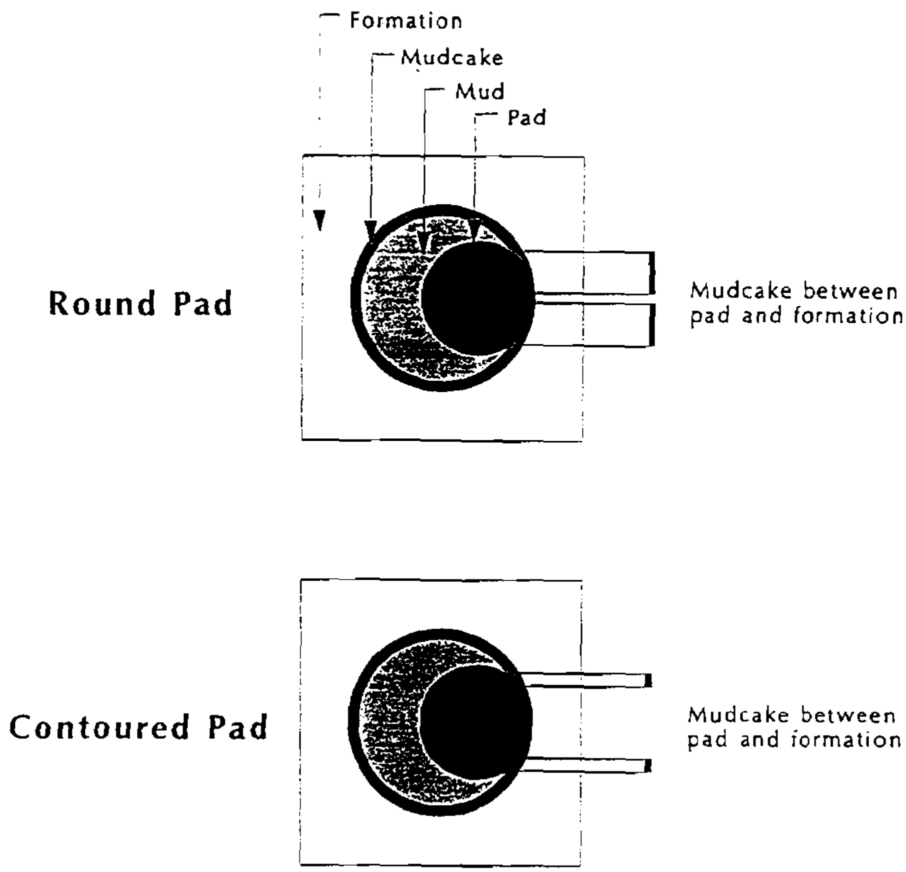


Figure 95. Conventional and Contoured Density Tool Pad Assembly

Slim-hole density tools are available, with some of them providing the spectral P_e measurement. One such tool is Halliburton's Hostile Environment Spectral Density tool, which uses the advanced correction techniques mentioned in the previous paragraph.

4.5.3 Neutron Logging

Open-hole neutron tools use a chemical source of neutrons and one or two neutron or gamma-ray detectors to determine formation porosity. These tools measure the slowing down of neutrons by formation nuclei, particularly those containing hydrogen. Formations containing substances with high hydrogen indices (high hydrogen content), such as water and hydrocarbons, attenuate neutrons more than other formations and so exhibit a greater response on neutron logs. There are several types of neutron tools, each having a slightly different principle of operation. The following tools can be used in open or cased wells. Additional tools that are used only in cased wells are described later.

4.5.5 Gamma-Ray

Gamma-ray tools measure gamma radiation present in the downhole environment. Two types of tools are available: the traditional natural gamma-ray tool and the advanced gamma-ray spectroscopy tool.

4.5.5.1 Natural Gamma-Ray Tools

Natural gamma-ray tools measure the total gamma radiation in a very broad energy band. Their logs are used primarily for correlation and for shale-volume calculations. Slim-hole tools are readily available.

4.5.5.2 Gamma-Ray Spectroscopy Tools

Gamma-ray spectroscopy tools measure gamma radiation in many narrow energy bands and yield logs that display the concentrations of potassium, uranium, and thorium in subsurface formations. The logs allow more precise correlation and shale-volume calculations than natural gamma-ray logs. They also permit radioactive reservoir rock to be distinguished from shales and can be useful in determining clay type.

As mentioned earlier, the count rates from a 1-in. by 8-in. sodium iodide crystal can be nearly five times less than those from a 2-in. by 12-in. crystal of the same material. The smaller crystal is much less efficient at stopping high-energy gamma rays; therefore, it yields gamma-ray spectra that have much less distinct peak structures at high energies and that have relatively high scattered gamma-ray backgrounds at low energies.

The shortcomings of small detectors have hampered the development of open-hole gamma-ray spectroscopy tools. Thus, at present, there are no slim-hole gamma-ray spectroscopy tools for open-hole logging. However, the standard 3⅜-, 3⅝-, and 3⅞-in. OD models are available for logging at the upper end of the slim-hole size range.

4.5.6 Dip Logging

Dipmeter tools typically measure formation microresistivity at several points around the circumference of the borehole. A minimum of three points must be measured per depth level. The resulting resistivity curves are then compared to each other over a certain interval (correlation length) in small steps (step length) to identify and correlate changes in resistivity (features). If the changes in resistivity result from planar features, then the planes can be reconstructed and their dip and strike can be computed.

Standard oil-field dipmeter tools have four or six arms that extend from the tool, with each arm containing a pad on which are mounted one or two resistivity-measurement electrodes. The resistivity measurements are made with very high spatial frequency, typically at every 0.1 in. of borehole interval.

Since three points determine a plane, three arms or pads are the minimum number that can be used on a dipmeter. However, if one of the pads does not contact the borehole wall or if the electrodes on one pad fail, then it is impossible to determine planar features.

With four- and six-arm dipmeters, the probability of good pad contact increases, and there is a corresponding increase in the resolution of the tool or in the confidence in the measured planes. The arms of the six-arm tools open and close independently of one another. This feature promotes better pad contact in irregularly shaped boreholes. It also obsoletes the necessity of good tool centralization in the borehole and thus improves dipmeter logging in highly deviated and horizontal boreholes.

Because of their mechanical linkage assemblies (Figure 97), four- and six-arm dipmeter tools have relatively large ODs; therefore, the minimum recommended borehole diameter for such tools is usually about 6½ in. However, three-arm slim-hole tools are available for running in holes as small as 4 in. in diameter.

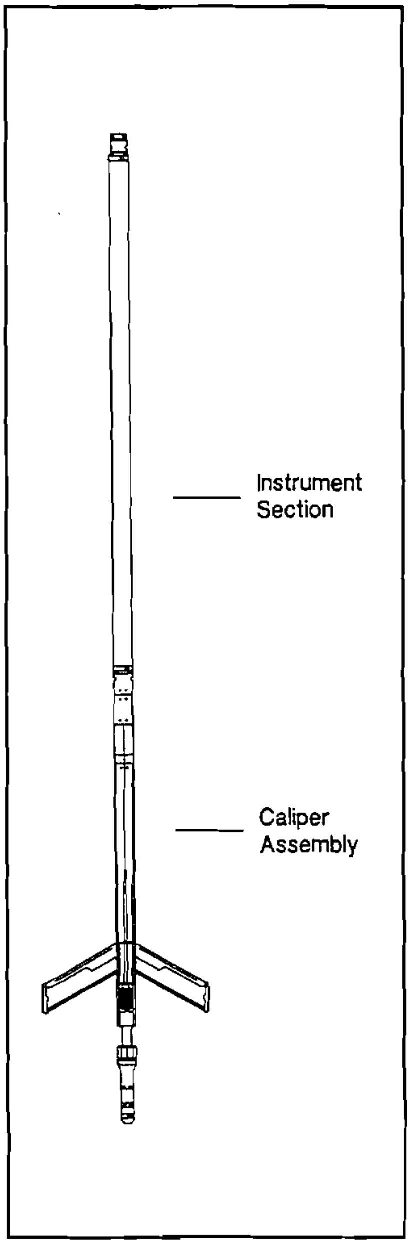


Figure 97. Six-Arm Dipmeters

4.5.7 Imaging

Ultrasonic and electrical imaging tools create photographic-like images of the borehole wall.

4.5.7.1 Ultrasonic Imaging

Ultrasonic imaging tools use a rotating transducer that serves as both a transmitter and a receiver of ultrasonic energy. Images are created from the transit time and amplitude measurements. Different size transducer heads are available for use in different size holes. Even though a $1^{7}/_{16}$-in. OD head is available, minimum hole size is determined by the OD of the main body of the tool. At this time, 4 in. is the smallest recommended borehole diameter for ultrasonic imaging tools.

4.5.7.2 Electrical

Electrical imaging tools use an array of resistivity electrodes mounted on two, four, or six extendable pads. The quality of the images, which are created from resistivity measurements, depends on the fraction of the borehole covered by the pads. In irregularly shaped boreholes, image quality also depends on the capability of the pads to maintain contact with the borehole wall. Because of the better radial distribution of the measurement electrodes when six pads are used, six-pad tools have some advantage over four-pad tools; however, the total borehole-wall coverage of six-pad tools is somewhat less than that of four-pad tools.

Electric imaging tools are based on dipmeter design and thus have the same borehole-size limitations as dipmeters. The best quality images are produced by the four-arm Formation Micro Imager (Schlumberger) and the six-arm Electrical Micro Imaging tool (Halliburton). However, both tools are limited to use in boreholes with ODs of 6¼ in. or larger. The two-pad Formation Micro Scanner (Schlumberger) can be run in somewhat smaller boreholes, and successful imaging has reportedly been performed with this tool in a 4½-in. well.

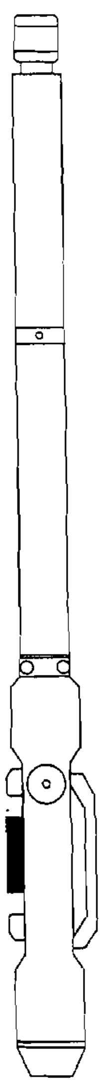
4.5.8 Caliper Logging

Simple caliper tools produce a single continuous measurement of borehole diameter. More complex four-arm caliper tools provide two perpendicular borehole diameter measurements and thus can indicate borehole ovality. Density tools, dipmeters, and imaging tools can also furnish caliper measurements. Caliper tools with 2¾ in. OD are available.

4.5.9 Formation Testing

Wireline formation testers measure formation pressures and retrieve formation fluid samples. These tools provide a means of selectively testing formations for flow potential and reservoir pressure. Typically, at the test depth, pads are extended from the tool and pressed against the borehole wall. One of the pads contains a rubber seal (sometimes referred to as a packer) and a flow tube.

The seal isolates the test point from the borehole fluids. The flow tube provides a path for fluid to flow from the formation to the tool. Inside the tool, the flow tube is connected with a pressure transducer, a pretest chamber, and one or more sample-storage chambers.



The mechanical and hydraulic configuration of formation testers makes them bulky tools (Figure 98). The smallest diameter tools available have 4¾ in. OD with a recommended minimum borehole diameter of 5⅞ in. A 3⅜ in. OD tool has been introduced recently for logging in 4½- to 8-in. boreholes.

Figure 98. Formation Tester

4.5.10 Sidewall Coring

Two systems are available in the industry to take sidewall cores: percussion sidewall-core guns and rotary sidewall-coring tools.

4.5.10.1 Percussion Corers

Percussion sidewall-core guns (Figure 99) use a powder charge ignited by an electric current to shoot a hollow cylinder (core barrel) into the formation. The core barrel containing the formation sample is retrieved by means of a steel cable attached between the gun body and the core barrel. Different types of core barrels are available for formations of different hardness. In addition, barrels are available in different sizes (lengths and ODs).

Percussion sidewall-core guns typically range from 3 in. to 5¼ in. in diameter. A 0.5-in. stand-off between the core barrel and the formation is required to allow the system to build up enough energy to propel the core barrel into the formation.

4.5.10.2 Rotary Corers

Rotary sidewall-coring tools have a hydraulically operated, diamond rotary bit that extends from the tool and cuts into the formation. The mechanics of these tools makes them bulky; thus, no slim-hole capabilities exist for rotary sidewall corers.

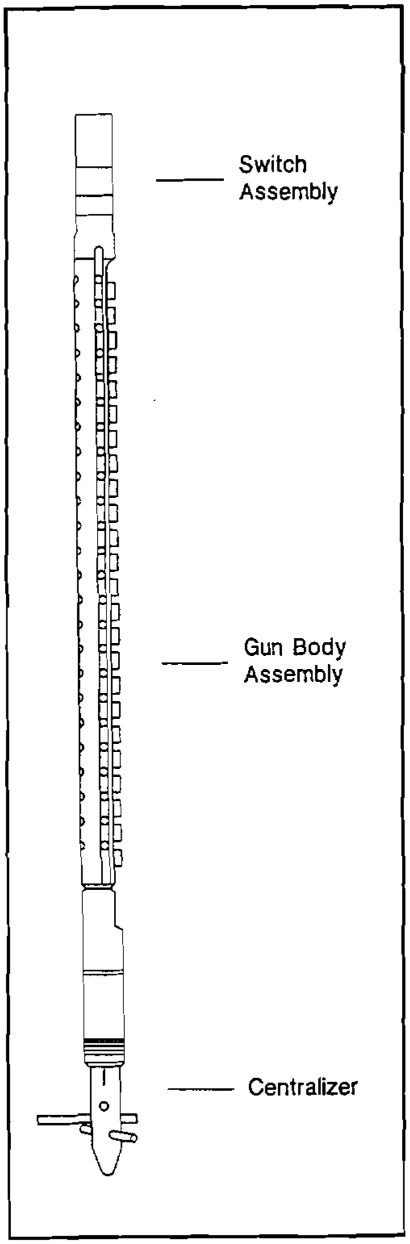


Figure 99. Percussion Sidewall-Core Gun

4.5.11 Borehole Seismic

Borehole seismic logging includes such services as well velocity surveys and vertical seismic profiles. The downhole tools are wireline geophones that measure seismic waves generated at the surface. The geophones must be acoustically coupled to the borehole wall and thus employ hydraulic clamping mechanisms that have single or dual arms and that have a high ratio of clamping force to tool weight. The size of the geophone tools determines the minimum borehole size for seismic logging. Standard geophones or geophone arrays are 3⅜ to 4 in. in diameter. Smaller geophones (2½ in. and 1¹¹/₁₆-in. OD) are available on a limited basis.

4.5.12 Available Slim-Hole Tools

Tables 21, 22, 23, and 24 describe some of the small-diameter logging tools (OD <3 in.) that can be used by major wireline service companies in aggressive slim-hole operations, both in open- and cased-well environments.

TABLE 21. Halliburton Logging Tools With OD 3 Inches or Less (Halliburton, 1993)

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Caliper	HECT-A	2.75	8.54	121	500	25
Caliper	HPDC-A	2.75	9.2	145	500	25
Cement Bond	CBT-FB	1.687	12.36	53	375	20
Cement Bond	HFWS-A	2.75	30.22	340	500	25
Density, Formation Spectral	HSDL-A	2.75	13	176	500	25
Free Point	Dia-Log	1.625	9.4	32	400	20
Free Point and Backoff	Dia-Log	1.625	24.8	80	400	20
Gamma, Directional	RotaScan	1.687	22.53	132	300	20
Gamma, Natural	HNGR-A	2.75	11.55	146	500	25
Gamma Perforator	M187	1.687	7.7	70	350	20
Gamma, Tracer Spectroscopy	TracerScan	1.687	13.91	90	350	20
Gamma-Neutron	GNST-A	1.437	7.91	33	350	15
Gamma-Neutron	CMOS	1.687	10.16	30	350	15
Gamma-Neutron	GNT-AD	1.687	7.2	29.5	350	20
Gamma-Neutron	GNC-A	1.687	8.82	48	350	20
Gamma-Neutron	HGNC-A	1.687	8.82	48	500	20
Induction, Dual	HDIL-A	2.75	31.7	260	500	25
Neutron, Compensated	HDSN-A	2.75	15.3	179	500	25
Neutron, Pulsed Capture	TMD	1.687	32	140	300	15
Pipe Inspection, Mechanical	MAC-2.125	2.125	6	38	320	15
Pipe Inspection, Mechanical	MAC-1.75	1.75	5	25	320	15
Production Log (Casing Collar)	CCL-WA	1.437	2.41	10	375	18
Production Log (Flowmeter, Fullbore)	CFFT	1.687	3.24	9.3	350	15
Production Log (Flowmeter, Continuous Spinner)	FMS-HC	1.687	2.33	8	375	18
Production Log (Fluid Density)	FDT-EC	1.437	3.26	11	375	18
Production Log (Gamma)	GRT-BB	1.437	2.75	9	375	18
Production Log (Hold-Up)	HYD-FC	1.437	2.5	8	375	18
Production Log (Noise)	BATS	1.687	2.42	15	392	15
Production Log (Pressure)	PPGT	1	2.85	4.5	350	10
Production Log (Pressure)	SPT-CC	1.437	2.16	7	375	15

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Production Log (Pressure)	HPA-AA	1.687	6.1	14	350	12
Production Log (Pressure)	CQPT-A	1.687	4.25	22	350	16
Production Log (Temperature)	TLT-IC	1.437	1.92	7	375	18
Sonic, Fullwave	HFWS-A	2.75	30.22	340	500	25

TABLE 22. Schlumberger Logging Tools With OD 3 Inches or Less (Schlumberger, 1991 and 1992)

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Caliper	ECD	2-3/4	7.33	85	500	25
Cement Bond	CBT	2-3/4	19.00	309	350	20
Density, Formation	FGT	2-3/4	10.25	162	500	25
Free Point	FPIT	1-3/8	13.83	52	350	20
Gamma, Induced Spectroscopy	RST-A	1-11/16	36.25	138	300	15
Gamma, Induced Spectroscopy	RST-B	2-1/2	32.33	253	300	15
Gamma, Tracer Spectroscopy	MIST-A	1-11/16	14.58	65	350	20
Gamma, Tracer Spectroscopy	MIST-B	2	14.58	80	350	20
Imaging, Ultrasonic	SBTT	1-3/4	11.83	100	300	15
Induction, Dual	IRT-J	2-3/4	27.92	255	400	20
Laterolog, Dual	MDLT	2-3/4	na	na	na	na
Microresistivity	SRMS	2-3/4	na	na	na	na
Neutron, Compensated	CNT-D	2-3/4	13.17	153	500	25
Neutron, Pulsed Capture	TDT-P	1-11/16	19.50	78	325	17
Pipe Inspection, Electromagnetic	METT	2-3/4	35.33	305	350	20
Pipe Inspection, Mechanical	FTGT	2-1/8	6.75	90	300	10
Production Log (Combined)	PLT-A	1-11/16	15.17	70	350	20
Production Log (Combined)	CPLT-A	1-11/16	21.25	72	350	20
Seismic, Borehole	BGFA	2	na	na	na	na
Seismic, Borehole	MWST	1-11/16	10.08	48	350	20
Seismic, Borehole	TWST	1-11/16	na	na	na	na
Sonic, Compensated	SLT-JE	1-11/16	14.50	115	350	16.5
Sonic, Compensated	SLT-JF	1-11/16	16.00	126	350	16.5
Sonic, Compensated	SLT-SA	2-3/4	28.00	385	500	25

TABLE 23. Western Atlas Logging Tools With OD 3 Inches or Less
(Western Atlas, July 1990)

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Backoff	BO 2523 XA	0.63	10	10	500	20
Caliper	CAL 4216 XA	2.75	9.83	115	375	20
Caliper	CAL 4211 XA	2.75	10.50	130	500	25
Caliper	CAL 4212 XA	2.75	9.75	130	600	25
Cement Attenuation	BAL 1423 XA	2.75	18.00	230	350	20
Cement Bond	CBL 1416 XA	1.70	18.65	60	450	25
Coring, Percussion Sidewall	SWC 1820 XA	3.00	9.00	120	400	20
Density, Formation	CDL 2217 XA	3.00	10.43	218	400	20
Density, Formation	CDL 2213 XA	3.00	13.38	218	400	20
Density, Formation	CDL 2224 XA	3.00	10.07	221	500	25
Free Point	FPST 2506 XA	0.89	12 to 16	40	400	20
Free Point	FPST 2507 XA	1.00	12 to 16	50	400	20
Free Point	PRL 2511 XA	1.38	15	30	400	20
Free Point	FPST 2508 XA	1.38	12 to 16	60	400	20
Free Point	FPST 2505 XA	1.38	11.79	40	450	21
Free Point	FPTM 2515 XB	1.44	10	45	350	20
Free Point	FPMT 2512 XA	1.44	8.5	40	350	20
Free Point	FPTM 2515 XA	1.44	10	45	350	20
Free Point	PRL 2510 XA	1.75	15	40	350	13
Gamma, Natural	GR 1311 XA	1.70	8.38	20	400	17
Gamma, Natural	GR 1310 XA	2.75	8.09	96	400	20
Gamma, Natural	GR 1314 XA	2.75	10.25	120	450	25
Gamma, Natural	GR 1312 XA	3.00	9.78	206	500	25
Gamma Perforator	PFC 732 XA	1.70	5.68	16	400	20
Gamma Perforator	PFC 730 XA	3.00	11.08	206	500	25
Gamma, Spectroscopy	PRSM 1326 XA	1.70	8.38	20	400	17
Induction, Single	IEL 811 XA	2.75	16.50	130	300	20
Neutron, Compensated	CN 2418 XA	2.75	9.13	120	400	20
Neutron, Compensated	CN 2423 XA	2.75	11.28	125	450	25
Neutron, Pulsed Capture	PDK 2735 XA/AA	1.70	32.90	200	340	16
Neutron, Single-Detector	NEU 2421 XA	1.70	6.85	25	400	17
Neutron, Single-Detector	NEU 2419 XA	3.00	10.38	206	500	25

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Pipe Inspection, Mechanical	MFC 2921 XA	1.75	5.00	30	320	15
Production Log (Flowmeter, Continuous Spinner))	FMCS 8235 XA (PCM)	1.70	1.71	5	350	15
Production Log (Flowmeter, Fullbore)	FMFI 8244 XA	1.70	7.83	39	350	15
Production Log (Flowmeter, Fullbore)	FMFI 8244 XB	1.70	5.42	27	350	15
Production Log (Flowmeter, Continuous Spinner)	FMCS 8235 XB (Analog)	1.70	1.46	4.5	400	15
Production Log (Flowmeter, Continuous Spinner)	FMCS 8237 XB (Analog)	1.70	4.48	15	600	15
Production Log (Flowmeter, Continuous Spinner)	FMCS 2175 XA (PCM)	2.75	11.71	135	600	15
Production Log (Flowmeter, Basket)	FMBK 8236 XA (PCM)	1.70	7.42	35	350	15
Production Log (Flowmeter, Basket)	FMBK 8236 XB (Analog)	1.70	7.04	34	400	15
Production Log (Flowmeter, Basket)	FMBK 8239 XA (PCM)	2.13	7.42	37.5	350	15
Production Log (Flowmeter, Basket)	FMBK 8239 XB (Analog)	2.13	7.04	37	400	15
Production Log (Fluid Density)	FDN 8223 XA	1.70	5.13	25.5	350	15
Production Log (Fluid Density)	FDN 8220 XA	1.70	6.63	33.8	350	15
Production Log (Fluid Density)	FDN 2132 XA	1.70	6.15	40	400	15
Production Log (Gamma)	GR 8220 XA	1.70	6.63	34	350	15
Production Log (Hold-Up)	WHI 8228 XA	1.70	3.07	16	350	15
Production Log (Hold-Up)	WHI 2136 XA	1.70	2.21	8.5	400	18
Production Log (Noise)	SON 2123 XA	1.70	3.33	11	350	17
Production Log (Pressure)	SRPL 8238 XE (PCM)	1.25	0.70	1.6	350	15
Production Log (Pressure)	SRPL 8238 XA (PCM)	1.25	0.70	1.6	350	15
Production Log (Pressure)	SRPL 8238 XB (Analog)	1.25	0.70	1.6	350	15
Production Log (Pressure)	SRPL 2172 XE (Analog/PCM)	1.44	2.86	11	350	11
Production Log (Pressure)	SRPL 8226 XA* (PCM)	1.70	6.78	22	350	11
Production Log (Pressure)	SRPL 8227 XA* (PCM)	1.70	2.95	24	350	15
Production Log (Pressure)	SRPL 2135 XB* (Analog)	1.70	5.94	27	350	15

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Production Log (Pressure)	SRPL 8218 XA* (Analog)	1.70	2.79	21	350	15
Production Log (Pressure)	SRPL 2173 XA* (PCM)	2.50	7.58	95	600	15
Production Log (Temperature)	TEMP 8221 XA	1.70	2.38	12.5	350	15
Production Log (Temperature)	TEMP 8202 XB	1.70	2.06	12	400	15
Production Log (Temperature)	TEMP 8202 XC	1.70	5.23	25	600	15
Production Log (Temperature)	TEMP 2175 XA	2.50	11.71	135	600	15
Sonic, Compensated	AC 1605 EA/MA	2.75	23.72	280.5	450	25

TABLE 24. BPB Logging Tools With OD 3 Inches or Less (BPB, 1994)

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Borehole Geometry	BGT	2-1/4	18.5	101	175	5,000
Caliper (3-Arm)	CO1	1-1/2	6.25	28	175	5,000
Cement Bond	CBL	2-1/8	13.7	70	175	5,000
Density, Dual-Detector, Gamma, Natural	DD3	1-7/8	11.9	57	175	5,000
Density, Single-Detector; Gamma, Natural	DD1	1-11/16	11.5	44	175	5,000
Density, Single-Detector; Gamma, Natural; Resistivity, Micro	DR1	1-11/16	11.5	55	175	5,000
Density, Spectral	PNS	2-1/4	11.9	60	275	12,500
Density, Triple-Detector; Gamma, Natural	DD2	1-1/2	8	30	175	5,000
Dipmeter, 3-Arm	DV1	2	14.8	54	175	5,000
Dipmeter, 3-Arm	DV2	2-1/2	17.4	79	175	5,000
Dipmeter, 3-Arm (Precision Strata)	PSD 3	2-1/4	18.6	105	150	5,000
Dipmeter, 4-Arm (Precision Strata)	PSD 4	2-1/4	18.6	105	275	12,500

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Gamma, Spectral	SG3	3	6.9	31	175	5,000
Induction, Array	AIS	2-1/4	15.24	80	275	12,500
Induction, Dual	DIS	2-1/4	15.24	80	275	12,500
Induction, Dual	IGS	2-1/4	15.24	80	175	5,000
Laterolog, Dual	RR1	1-1/2	14.6	31	175	5,000
Laterolog, Dual (High-Resolution)	RR2	1-1/2	14.6	31	175	5,000
Laterolog, Single	RO1	1-1/2	6.3	33	175	5,000
Magnetic Susceptibility	MSU	1-11/16	2.8	10.5	175	5,000
Neutron, Compensated	PNS	2-1/4	8.1	35	275	12,500
Neutron, Dual-Detector	NN1	1-1/2	8.1	30	175	5,000
Neutron, Single-Detector	GO1	1-1/2	7.2	24	175	5,000
Neutron, Single-Detector	NO1	1-1/2	8	24	175	5,000
Resistivity, Micro; Gamma, Natural	MG1	1-7/8	9.2	44	175	5,000
Resistivity, Single-Point	RS1	1-5/16	4.8	13	175	5,000
Scanner, Acoustic	AST	2-1/4	18.6	105	150	5,000
Seismic, Borehole	SR1	2-3/8	18	45	175	5,000
Seismic, Borehole	SR2	2	9	50	175	5,000
Sonic , Sidewall	SS1	2-1/4	12	44	175	5,000
Sonic, Compensated	MS2	2	11.1	35	175	5,000
Sonic, Long-Spaced	MS 1	2-1/4	11.1	60	275	12,500
Temperature	TT1	1-1/2	5.4	24	175	5,000
Verticality, Gyroscopic	GYR	1.81	15.33	52	175	5,000
Verticality, High-Accuracy	HAV	1-11/16	8.6	22	175	5,000
Verticality, Standard	VO1	1-11/16	8.6	22	175	5,000

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Production Log (Pressure)	SRPL 8218 XA* (Analog)	1.70	2.79	21	350	15
Production Log (Pressure)	SRPL 2173 XA* (PCM)	2.50	7.58	95	600	15
Production Log (Temperature)	TEMP 8221 XA	1.70	2.38	12.5	350	15
Production Log (Temperature)	TEMP 8202 XB	1.70	2.06	12	400	15
Production Log (Temperature)	TEMP 8202 XC	1.70	5.23	25	600	15
Production Log (Temperature)	TEMP 2175 XA	2.50	11.71	135	600	15
Sonic, Compensated	AC 1605 EA/MA	2.75	23.72	280.5	450	25

TABLE 24. BPB Logging Tools With OD 3 Inches or Less (BPB, 1994)

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Borehole Geometry	BGT	2-1/4	18.5	101	175	5,000
Caliper (3-Arm)	CO1	1-1/2	6.25	28	175	5,000
Cement Bond	CBL	2-1/8	13.7	70	175	5,000
Density, Dual-Detector, Gamma, Natural	DD3	1-7/8	11.9	57	175	5,000
Density, Single-Detector; Gamma, Natural	DD1	1-11/16	11.5	44	175	5,000
Density, Single-Detector; Gamma, Natural; Resistivity, Micro	DR1	1-11/16	11.5	55	175	5,000
Density, Spectral	PNS	2-1/4	11.9	60	275	12,500
Density, Triple-Detector; Gamma, Natural	DD2	1-1/2	8	30	175	5,000
Dipmeter, 3-Arm	DV1	2	14.8	54	175	5,000
Dipmeter, 3-Arm	DV2	2-1/2	17.4	79	175	5,000
Dipmeter, 3-Arm (Precision Strata)	PSD 3	2-1/4	18.6	105	150	5,000
Dipmeter, 4-Arm (Precision Strata)	PSD 4	2-1/4	18.6	105	275	12,500
Flowmeter, Continuous	FM1	1.5	2.6	12	175	5,000
Fluid Conductivity; Temperature	FT1	1-11/16	2.6	24	175	5,000
Fluid Sampler	FS2	1-1/2	14	18.8	175	5,000
Formation Pressure Tester, Repeat	RFS	2-1/4	32	183	275	12,500
Gamma, Natural (Triple-Detector)	GL1	1-1/2	9.8	31	175	5,000
Gamma, Natural; Caliper, 3-Arm	GC1	1-1/2	9.8	33	175	5,000
Gamma, Spectral	SG1	2-11/16	6.9	29	175	5,000
Gamma, Spectral	SG2	2-11/64	6.4	26	175	5,000

Category	Tool	OD (in.)	Length (ft)	Weight (lbm)	Temp. Rating (°F)	Press. Rating (kpsi)
Gamma, Spectral	SG3	3	6.9	31	175	5,000
Induction, Array	AIS	2-1/4	15.24	80	275	12,500
Induction, Dual	DIS	2-1/4	15.24	80	275	12,500
Induction, Dual	IGS	2-1/4	15.24	80	175	5,000
Laterolog, Dual	RR1	1-1/2	14.6	31	175	5,000
Laterolog, Dual (High-Resolution)	RR2	1-1/2	14.6	31	175	5,000
Laterolog, Single	RO1	1-1/2	6.3	33	175	5,000
Magnetic Susceptibility	MSU	1-11/16	2.8	10.5	175	5,000
Neutron, Compensated	PNS	2-1/4	8.1	35	275	12,500
Neutron, Dual-Detector	NN1	1-1/2	8.1	30	175	5,000
Neutron, Single-Detector	GO1	1-1/2	7.2	24	175	5,000
Neutron, Single-Detector	NO1	1-1/2	8	24	175	5,000
Resistivity, Micro; Gamma, Natural	MG1	1-7/8	9.2	44	175	5,000
Resistivity, Single-Point	RS1	1-5/16	4.8	13	175	5,000
Scanner, Acoustic	AST	2-1/4	18.6	105	150	5,000
Seismic, Borehole	SR1	2-3/8	18	45	175	5,000
Seismic, Borehole	SR2	2	9	50	175	5,000
Sonic , Sidewall	SS1	2-1/4	12	44	175	5,000
Sonic, Compensated	MS2	2	11.1	35	175	5,000
Sonic, Long-Spaced	MS 1	2-1/4	11.1	60	275	12,500
Temperature	TT1	1-1/2	5.4	24	175	5,000
Verticality, Gyroscopic	GYR	1.81	15.33	52	175	5,000
Verticality, High-Accuracy	HAV	1-11/16	8.6	22	175	5,000
Verticality, Standard	VO1	1-11/16	8.6	22	175	5,000
Verticality, Wide-Range	VO2	1-11/16	8.6	22	175	5,000

4.6 MEASUREMENT-WHILE-DRILLING SERVICES

Measurement-While-Drilling (MWD) services utilize special measuring instrumentation that is housed in drill collars. Measured data may be stored in memory devices or transmitted to the surface via pressure pulses in the mud column; no wireline is involved.

MWD services fall into two categories: directional services and formation evaluation services. Directional MWD tools with ODs of 2 and 1¾ in. are available. Formation-evaluation MWD services, also referred to as logging while drilling (LWD) services, are still relatively new to the industry. They furnish resistivity, natural gamma-ray, density, neutron, and sonic measurements. Current tools are generally built for use in 8½ in. boreholes, although there is a smaller-diameter natural gamma-ray tool intended for use in holes as small as 4¾ to 5 inches. Tools with 4¾-in. OD are planned or are under consideration for use in 6¼-in. holes.

4.7 CASED-HOLE WIRELINE LOGGING SERVICES

Cased-hole wireline logging services provide formation evaluation, completion evaluation, production diagnostics, and pipe inspection. Many of the logging tools designed specifically for cased-hole use have $1^{11}/_{16}$-in. OD, which makes the tools suitable for use in 2⅜ in. and larger tubulars. When smaller tubulars are present, even these small-diameter tools may not be applicable.

4.7.1 Formation

Many logging tools are available for formation evaluation in cased wells. Some standard logging tools work equally well in open and cased holes, provided adequate corrections are used to account for the effects of casing and cement. These tools include natural gamma-ray, spectral natural gamma-ray, compensated neutron, and long-spaced full-waveform sonic (monopole and dipole) devices, all of which have been discussed earlier. Other tools that work well in open holes cannot function in cased holes. For example, because casing is electrically conductive, the electromagnetic tools used to determine water saturation in open holes cannot be used in cased wells. This has led to the development of pulsed neutron capture and induced gamma-ray spectroscopy tools for finding water or oil saturation in cased reservoirs. These tools are used for finding hydrocarbons behind casing and quantitatively monitoring their depletion. If only qualitative monitoring of reservoir depletion is desired, other less-sophisticated tools such as a gamma-neutron combination can be used.

4.7.1.1 Pulsed Neutron Capture

Pulsed neutron capture (PNC) tools determine the thermal neutron capture cross section, or sigma, of a formation by measuring the rate at which the formation absorbs thermal neutrons. Formation sigma is primarily a function of porosity, formation water salinity, hydrocarbon type and quantity, and lithology. The formation sigma measurement is used primarily for determining formation water saturation.

PNC technology is relatively mature, and current tools are designed for evaluating reservoirs with moderate to high water salinity. All tools have $1^{11}/_{16}$-in. OD and utilize electrically-activated neutron generators rather than chemical sources of neutrons. All PNC systems compute formation intrinsic sigma by correcting the basic sigma measurement for the presence of tubing, casing, cement, and annular fluid.

4.7.1.2 Induced Gamma-Ray Spectroscopy

Induced gamma-ray spectroscopy tools determine oil saturation in reservoirs having low or unknown water salinity. The tools are also known as C/O tools because they measure a carbon/oxygen ratio that allows a reservoir's oil content to be evaluated.

Because of the small dynamic range of the C/O measurement, C/O tools have historically been run at very low logging speeds (1 to 2 ft/min), and very often stationary measurements have been used. The slow logging speeds and stationary measurements reduce statistical variation and aid in increasing measurement precision. To use as large a measuring crystal as possible and thus further improve the measurements, standard-size tools (3⅜- and 3⅝-in. OD) have been used. Like PNC tools, induced gamma spectroscopy tools contain an electrically-activated neutron source.

Advanced design and data processing techniques allow some PNC tools to log at higher speeds and still maintain acceptable precision. Some small-diameter tools (2½- in. OD and $1^{11}/_{16}$-in. OD) are now available.

4.7.1.3 Gamma-Neutron Tools

Gamma-neutron combination tools are useful for qualitatively monitoring reservoir depletion and for correlation. Usually, only single-detector neutron assemblies are employed. These tools can be found in $1^{7}/_{16}$-in. OD, and larger, models.

4.7.2 Completion

Several services are available for evaluating the effectiveness of such completion operations as cementing, gravel packing, and stimulation.

4.7.2.1 Cement Evaluation

The primary purpose of cement evaluation tools is to determine whether the annular cement sheath provides effective zonal isolation. The sheath must furnish an adequate hydraulic seal over a vertical interval of sufficient length to withstand later completion and production operations.

Conventional cement bond logging (CBL) tools measure acoustic amplitude. An acoustic receiver in the tool responds to the amplitude of acoustic energy that has been generated by an acoustic transmitter in the tool and that has subsequently propagated to the receiver through various paths in the casing, cement, and formation. The receiver is usually 3 ft from the transmitter. The pipe amplitude curve presented on a cement bond log displays the amplitude of the first wave of acoustic energy (denoted E1) to arrive at the receiver after the transmitter has pulsed. The interpretation of cement bond logs is based on the fact that receiver measurements are influenced by the presence or absence of acoustic coupling between the casing and the cement sheath, and between the cement sheath and the formation. CBL tools are available in various sizes from $1^{11}/_{16}$- to 3⅝-in. OD.

Cement attenuation tools measure the energy loss or attenuation of a transmitted acoustic signal as the signal propagates between two receivers. These tools are available with ODs ranging from 2¾ in. to 3⅛ inches.

Ultrasonic cement evaluation tools, also known as acoustic impedance tools, use an ultrasonic transducer to transmit a signal toward the casing and then to measure the amplitude and time of flight of the reflected signal. Ultrasonic tools typically have 3⅝-in. OD, and thus 4½ in. is the minimum casing OD in which they can run.

4.7.2.2 Tracer Gamma-Ray Spectroscopy

Advanced gamma-ray spectroscopy tools can determine the vertical and radial distributions of multiple radioactive tracers pumped downhole during completion operations. Knowledge of these distributions allows hydraulically fractured and propped intervals to be determined, voids in gravel packs to be detected, and cemented intervals to be delineated. These tools were designed to run through tubing and are generally available with $1^{11}/_{16}$-in. OD. The minimum ID of the tubulars in which they can run is thus 2 inches.

4.7.2.3 Directional Gamma-Ray

Directional gamma-ray tools measure the downhole azimuthal distribution of pumped radioactive tracers. They are used in determining the orientation of hydraulically induced fractures and are most frequently run in conjunction with tracer gamma-ray spectroscopy services. Tools are available with $1^{11}/_{16}$-in. OD.

4.7.3 Production

Several cased-hole wireline services are used to diagnose problems that are often related to wellbore tubulars. These services include production logging and pipe inspection.

4.7.3.1 Production Logging

Production logging tools identify the fluids present in the wellbore and characterize the flow of those fluids. Depending upon the type of well, a production or injection profile can be generated from production logging data. From the profile, zones which are producing or accepting fluid can be identified, leaks in tubulars can be located, and flow behind casing can be detected.

Traditional production logging tools include temperature, pressure, flow, fluid-density, and fluid-capacitance (holdup) devices, all of which are usually combinable into one tool string. Auxiliary services include noise logs and fluid-travel/tracer logs. Additionally, PNC logs can provide useful production and injection information. Production logging tools most commonly have $1^{11}/_{16}$-in. OD, although the diameters of some tools can be as small as 1 inch.

4.7.3.2 Pipe Inspection

A wide range of pipe inspection services is available to the industry. Based upon principle of operation, pipe inspection tools may be classed as mechanical, electromagnetic, or ultrasonic. The tools yield information regarding holes and splits in pipe, as well as thinning and deformation of the pipe.

Multi-arm calipers are mechanical devices. Although such tools are comprised of an array of many arms, traditional tools record only two measurements: the minimum and maximum measured borehole diameters. However, the latest tools record the deflection of each arm and so provide better circumferential coverage of the pipe. Multi-arm calipers are available with ODs as small as 1½ inches.

Electromagnetic flux-leakage eddy-current tools provide high-resolution casing inspection. However, they are 3⅝-in. tools and so are not suited for casing smaller than 4½-in. OD.

The ultrasonic tools used for imaging in open hole and those used for cement evaluation in cased wells can also be used for casing inspection. The ultrasonic pulses emitted by these tools make the casing resonate in the thickness mode (that is, part of the pulse reflects back and forth between the inner and outer walls of the casing). Frequency-based processing is used to generate casing-thickness curves and corrosion images. The minimum OD of casing in which ultrasonic tools can operate is 4½ inches.

4.8 PERFORATING, CUTTING, AND RELATED SERVICES

Slim-hole equipment is readily available for perforating, cutting, and freeing various tubulars.

4.8.1 Perforating

Most U.S. vertical gas wells are completed with casing through the zone(s) of interest. This requires the use of perforating equipment to establish a flow conduit for stimulation and then production. Almost all of today's wells are perforated with shaped-charge explosives conveyed through the well with one of a variety of available carriers. Perforating shaped charges depend on explosives to supply the energy needed for effective penetration of casing, cement, and formation. The overall performance of a shaped charge is dependent on the amount of explosives that can be placed in a given perforating "gun." However, design limitations make it is difficult to achieve hole diameter greater than one inch. The available energy can be directed, with limits, into hole diameter or tunnel length, but gains in one are usually associated with reductions in the other.

The key parameters for determining perforating charge performance are entrance hole diameter and tunnel length. By definition, a slim-completion well has a smaller casing size than a conventional completion, restricting the options available for perforating. For example, a well that requires hydraulic fracturing to flow that is conventionally completed with 5½-in. casing retains the option of running a large 4-in. casing gun and obtaining maximized perforation hole diameter and tunnel length. A slim completion with 2⅞-in. casing would be restricted to the use of through-tubing guns that typically have $1^{11}/_{16}$-in. diameter. The amount of shaped-charge explosive material that can be placed in the smaller gun is reduced significantly. While trade-offs are possible between entrance hole diameter and tunnel length in all sizes, the effects are magnified considerably with the smaller charges.

Figure 100 plots the entrance hole diameter and tunnel length of a variety of available charges with smaller guns differentiated from larger guns. These data are from API RP 43 - Fifth Edition, Section 1 tests.

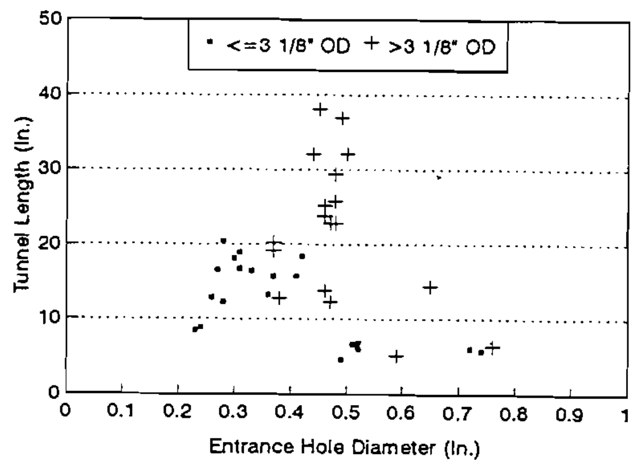


Figure 100. Perforating Charge Performance

This graph illustrates the overall reduced performance in the smaller guns. Entrance hole diameters generally are in the 0.35-in. range vs. 0.5-in. for most of the larger guns. Tunnel lengths are less than 20 in. while the larger guns will achieve around 30 inches. No attempt is made here to distinguish the performance between various types of carriers, which has an effect on the size of charge and resulting performance. Also obvious from this graph is the tremendous trade-off that occurs in tunnel length when a "big-hole" charge is used in the smaller gun to obtain as large as hole as possible. Tunnel length drops are reduced to less than 10 inches.

There has been considerable debate and discussion in the industry over the actual performance of a particular charge downhole as opposed to its performance in surface tests. API has published strict guidelines on how to conduct performance testing for the purposes of comparing various charges for use in a certain application. "Section 1" tests are the most prevalent tests and use sample concrete targets. "Section 2" tests use sample targets of Berea sandstone which is more representative of an actual formation. Gun clearance, or stand-off, and casing material are factors which can alter gun performance appreciably, as are temperature and pressure. Since slim completions are restricted to the smaller equipment and associated reductions in performance, it is necessary for engineers to fully understand the testing procedures and how factors affect downhole performance. Obviously, only small reductions in performance from published data can result in much larger percentage effects on flow and/or injection performance through the perforations.

In addition to hole diameter and tunnel length performance, the smaller guns also have reducing phasing options and maximum shot densities than do larger guns. Table 25 lists available slim-hole perforating equipment available from the major service companies. Reduced hole diameter, tunnel length, maximum shot density, and phasing options all are especially critical in the design, execution, and performance of hydraulic fracturing stimulation treatments. This is covered in more detail in Section 6.

TABLE 25. Halliburton, Schlumberger, and Western Atlas Perforating Guns with OD 3⅛-in. or Less

Carrier Type	Application	Gun OD (in.)	Maximum Shot Density (spf)	hot Phasing (°)
HALLIBURTON:				
Strip	Through-Tubing	1-11/16	4 or 6	0
Strip	Through-Tubing	2-1/8	4 or 6	0
Bi-wire	Through-Tubing	1-53/64	4 or 6	63 or 116
Bi-wire	Through-Tubing	2-1/4	4 or 6	63 or 116
Scalloped Hollow Carrier	Through-Tubing	1-9/16	4	0, 90, or 180
Scalloped Hollow Carrier	Through-Tubing	2-3/4	6	0, 90, or 180
Scalloped Hollow Carrier	Casing	3-1/8	6	60
Ported Hollow Carrier	Casing	3-1/8	4	120
SCHLUMBERGER:				
Strip	Through-tubing	1-11/16	4 or 6	0
Strip	Through-tubing	2-1/8	4 or 6	0
Strip	Through-tubing	2-1/8	4 or 6	90
Scalloped Hollow Carrier	Through-tubing	1-3/8	4	0
Scalloped Hollow Carrier	Through-tubing	1-11/16	4	0
Scalloped Hollow Carrier	Through-tubing	2-1/8	4	0 or 180
Scalloped Hollow Carrier	Through-tubing	2-1/8	4	60
Scalloped Hollow Carrier	Through-tubing	2-7/8	4	0 or 180
Scalloped Hollow Carrier	Through-tubing	2-7/8	6	60
Scalloped Hollow Carrier	Casing	3-1/8	4	90
WESTERN ATLAS:				
Scalloped Hollow Carrier	Through-Tubing	1-9/16	4	0 or 180

Carrier Type	Application	Gun OD (in.)	Maximum Shot Density (spf)	Hot Phasing (°)
Strip	Through-Tubing	1-5/8	6	0
Strip	Through-Tubing	1-11/16	6	0
Scalloped Hollow Carrier	Through-Tubing	2	4	0 or 180
Strip	Through-Tubing	2-1/16	6	0
Strip	Through-Tubing	2-1/8	6	0
Scalloped Hollow Carrier	Through-Tubing	2-1/2	4	0 or 180
Scalloped Hollow Carrier	Through-Tubing	2-3/4	6	60 or Spiral
Ported Hollow Carrier	Casing	3-1/8	4	90, 120, or Spiral

Perforating guns are positioned at the desired perforating depth by casing-collar or natural gamma-ray correlation. To accomplish this, a casing-collar locator or a special natural gamma-ray tool called a gamma-ray perforator must be attached to the gunstring. Standard gamma-ray perforators are $1^{11}/_{16}$-in. in diameter and can be used in $2\frac{3}{8}$-in. OD tubing. When smaller tubulars are used and gamma-ray correlation is the only option (for example, in coiled tubing, which has no collars), correlation devices that are sufficiently small may not be available.

4.8.2 Free-Point and Back-Off

Free-point services are run to locate the lowest point from which a stuck string of pipe can be recovered. The tools typically measure the stretch and torque on the pipe at a downhole point when stretch and torque are applied at the surface. Tools with OD as small as 0.89 in. are available.

Back-off services are usually run in conjunction with free-point services. Back-off tools use the explosive force of a string of detonator cord to uncouple the pipestring at the first collar above the stuck point. As the cord is detonated, left-hand torque is applied to the pipe at the surface.

4.8.3 Cutting

Jet cutters are available for severing practically any size downhole tubing, drill pipe, and casing. The cutting action is produced by a circular-shaped explosive charge. Jet cutters typically produce a flare on the severed pipestring. This may make pipe recovery more difficult in small-diameter pipe where clearance between pipestrings can be very small. Care should be exercised in using jet cutters in multiple pipestrings in which the pipestrings are not concentric; in such situations, an outer string may be partially severed if the proper cutter is not used.

Chemical cutters do not leave a flare on the severed pipestring and do not damage the outer pipe in multiple strings. The small annulus of wellbore fluid between the individual strings is sufficient to stop the chemical cutting action, even when the strings are in contact with one another. Chemical cutters are available for $\frac{3}{4}$- to $6\frac{5}{8}$-in. OD pipe. Several cutters are designed specifically for cutting coiled tubing.

4.9 RECENT PRODUCER RESEARCH

4.9.1 British Petroleum

BP drilled six slim holes in 1986. Four were vertical wells to a depth of 3168 ft and two were drilled to 3531 ft with a maximum inclination of 36 degrees.

The 3⅜-in. slim holes were drilled with 1.97-in. OD drill pipe and 2.17-in. OD drill collars. High rotary speeds were used due to a 4500-lb bit weight limitation. The higher rotary speeds resulted in high dynamic forces and some drill-string failures. Fishing was complicated by the small annular clearances, resulting in the use of taper taps in addition to conventional overshot and grappling fishing tools.

BP successfully logged in the 3⅜-in. holes, but they found that more logging runs were required because it was more difficult to run combination logging suites in the smaller holes.

BP's 3⅜-in. holes had to be surveyed open-hole because it was not possible to survey through the 1.97-in. drill string. BP stated that further development was needed to survey through small drill strings and thus avoid open-hole surveying.

Although open-hole testing was carried out in the 3⅜-in. hole, it was more difficult than in larger holes.

4.9.2 Amoco

Amoco used a mining rig to drill a shallow test well at its Catoosa test site near Tulsa, Oklahoma. A large number of logging tools were successfully tested in this well, demonstrating that most conventional logs can be run in slim holes (Table 26).

TABLE 26. Amoco Slim-Hole Logging Tests (Walker and Millheim, 1989)

	COMPANY A	COMPANY B	COMPANY C
Gamma Ray	✓	✓	✓
Sonic	✓		✓
Dual Induction	✓	✓	✓
Short Normal			✓
Spherical Focuses	✓		
Latero-Log			✓
Short Guard		✓	
SP		✓	✓
Formation Density	✓	✓	✓
Compensated Neutron	✓	✓	
Caliper	✓	✓	✓

In 1990, Amoco and Elf used the Amoco SHADS mining coring system to conduct coring tests in soft, unconsolidated rock in recent age Gulf Coast sediments. The coring tests were conducted in two vertical wells with two sidetracks being used in the first well.

Amoco logged Well 2 (4⅜-in. diameter) with 2¾-in. logging tools including dual induction, spectral density, dual-spaced neutron, and gamma ray with caliper. No problems were encountered during the open-hole logging operations. Logs went to bottom the first time on both runs.

4.9.3 Mobil Exploration

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

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

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

An example log showing results of resistivity measurements (Figure 101) includes 1) conventional shallow laterolog (3⅝ in.), 2) conventional deep laterolog (3⅝ in.), 3) slim-hole deep laterolog (1½ in.), and 4) slim-hole deep induction resistivity (2¾ in.). The zone under investigation is permeable and filled with a mixture of fresh water and hydrocarbons.

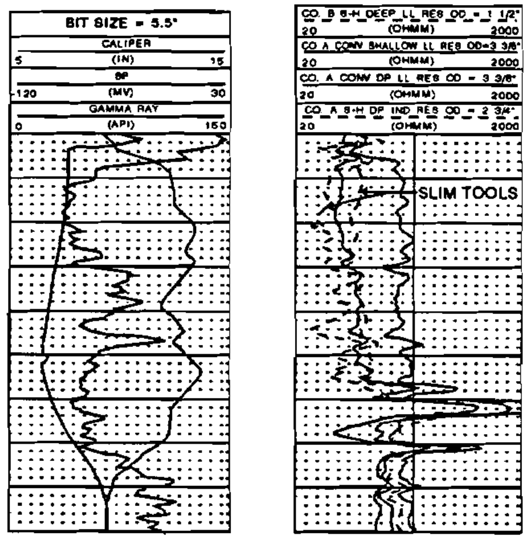


Figure 101. Slim-Hole/Conventional Resistivity Tool Comparisons in Sand (Schulze, 1992)

The same four tools are compared in shale in Figure 102. The two slim-hole tools gave consistently lower measurements than the conventional tools.

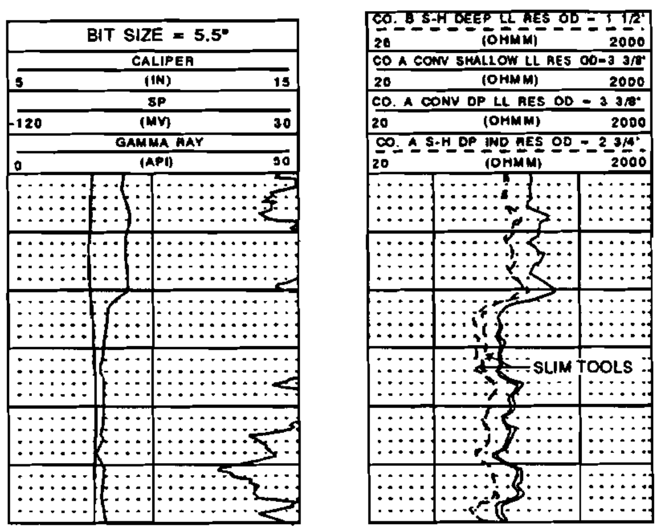


Figure 102. Slim-Hole/Conventional Resistivity Tool Comparisons in Shale (Schulze, 1992)

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

Mobil also tested density tools and found differences between conventional and slim tools. Their tests showed that the difference in tool readings increase as bulk density decreases.

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

Mobil concluded the following as a result of their tests:

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

Fortunately, it is felt that the shortcomings observed by Mobil have been overcome. Updated independent comparison testing would be beneficial to confirm this for producers analyzing slim-hole options.

4.10 CONCLUSIONS AND RECOMMENDATIONS

Considerable progress has been made in recent years in both the expansion and quality of wireline services for slim-hole application. This is especially true for open-hole services where historically the products have been designed and tested for use in greater than 6-in. wellbores. Figure 103 illustrates minimum recommended borehole diameters for a wide spectrum of open-hole wireline logging services. The white bars indicate explicit slim-hole formation evaluation services, light-gray bars indicate services that are more qualitative than quantitative, medium gray bars indicate standard-quality services and dark gray bars indicate advanced quality services.

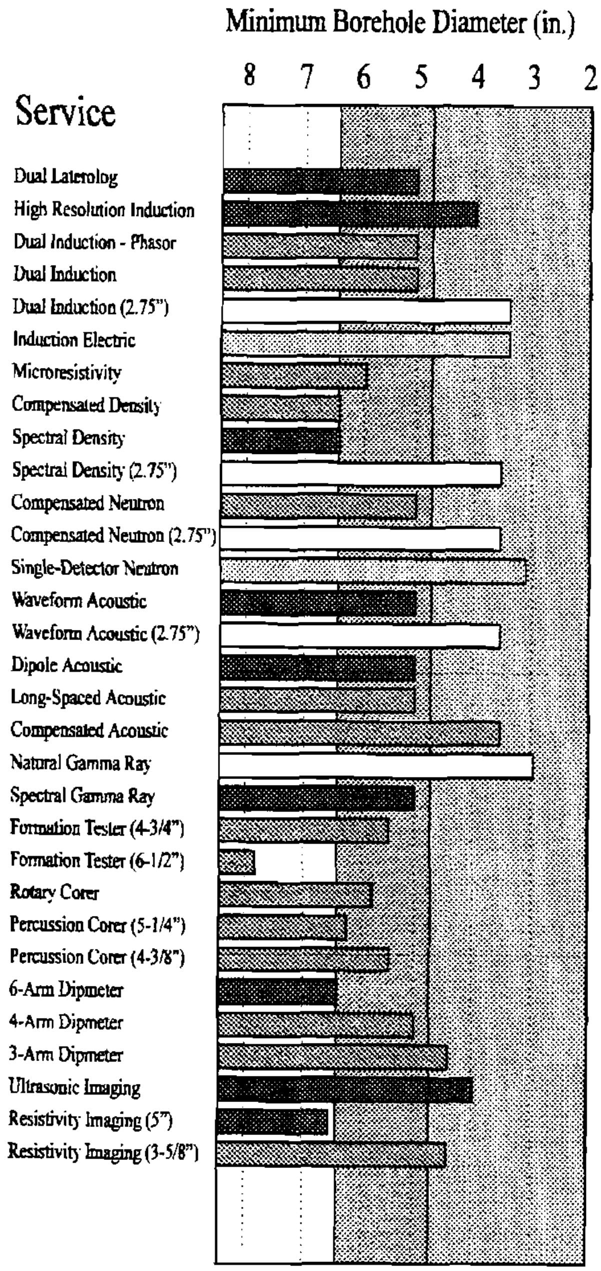


Figure 103. Borehole Diameter Ranges for Open-Hole Services

Conclusions derived from this study include the following:

- Fairly complete formation evaluation can be performed in a hole size as small as 4¾-in. *with standard tools* if borehole conditions are good (no washouts or doglegs) and the interval to be logged is not lengthy.
- The most requested basic open-hole logging service, the "triple combo" (primary resistivity, neutron, and density with secondary caliper and natural gamma), is available in slim-hole sizes from multiple service companies. Log response has been characterized to match standard size tools.

- Advanced formation evaluation tools, focusing on borehole imaging, such as borehole ultrasonic and resistivity imagers have been run in holes as small as 4½-in., but no specific slim 4- and 6-arm dipmeters or imaging tools, open-hole gamma ray spectroscopy, and rotary sidewall coring tools are available. Other specialty tools, such as dipole sonic and dielectric, are also not available in slim-hole models.

- Full wave-form acoustic tools, important in many tight gas reservoirs for determining rock properties etc., are available in slim-hole versions.

- Most slim-hole tools are designed for other "hostile environment" conditions such as high temperature and pressure, and can be more expensive. In addition, there are fewer of these tools manufactured and available. Job planning must consider possible extra mobilization time and cost. Fishing for a slim-hole tool will also require special equipment and is non-routine.

- Small diameter formation testers, also important in many gas reservoirs for completion decisions and behind-pipe reserve determinations, are now available and undergoing field testing.

- Most cased-hole wireline services (cement bond logging, production logging, tracer tools, pipe inspection, free-point and back-off, cutting, etc.) are typically $1^{11}/_{16}$-in. OD or smaller and can be run in most reasonable slim completion designs. Exceptions include ultrasonic cement evaluation tools and electromagnetic flux leakage eddy-current casing inspection tools.

- Performance of perforating charges available for smaller equipment that must be used in a slim completion is limited in terms of hole diameter, tunnel length, phasing options, and maximum shot density.

- The cost of researching, developing, and manufacturing slim-hole logging and other wireline tools is high. Decisions by service companies to pursue new slim-hole tools will be based on careful analysis of whether operating companies will provide service companies with sufficient opportunities to recover their investments in such an effort. Current projections for the demand for such services does not appear to warrant efforts beyond those already underway.

There appears to be a lack of understanding in the industry of the availability and quality of wireline services, especially open-hole, for slim-hole conditions. Three of the top eight individual slim-hole technology barriers identified in the industry survey conducted during this project were related to wireline formation evaluation. These included Existence of Logging Tools, Service Company Experience, and Number Of Logging Tools. Yet, fairly complete formation evaluation is available, especially in 4¾-in. slim holes.

Therefore, a near-term R&D program with benefits for the U.S. gas producer should focus on validation and demonstration of existing capabilities. Expensive tool development to fill any existing gaps should only come after field evidence and experience can prove the additional individual tool(s) is needed to expand the beneficial use of slim-hole techniques. One exception may be in the area of perforating.

Specifically, R&D should be addressed toward the following key areas:

1) Controlled investigations in U.S. gas reservoirs comparing log responses of conventional size tools in conventional holes, conventional size tools in 4¾-in. holes, and slim-hole tools in slim-holes (4¾-in. and smaller). Transfer of the results of such a project will be very beneficial to producers analyzing slim-hole options in difficult-to-evaluate gas formations.
2) Documentation of actual usage of slim-hole wireline services for formation evaluation, completion decisions, and reserve determinations.
3) Encouragement of and participation in slim-hole drilling and completion field tests in U.S. gas reservoirs not now using these techniques. Wireline formation evaluation will be a key component of any such tests conducted.
4) Investigations of existing slim completion perforating practices, especially in areas where significant hydraulic fracturing is required to help determine the need for advanced perforating technology for slim completions.

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5. Slim-Hole Cementing

5.1 INTRODUCTION

The primary cementing process in oil and gas wells involves mixing cement, water, and additives on the surface and pumping the slurry through the casing and casing/hole annulus, as shown in Figure 104. The principal functions of the primary cement job are to prevent fluid movement behind the pipe (hydraulic isolation) and to provide support to the casing.

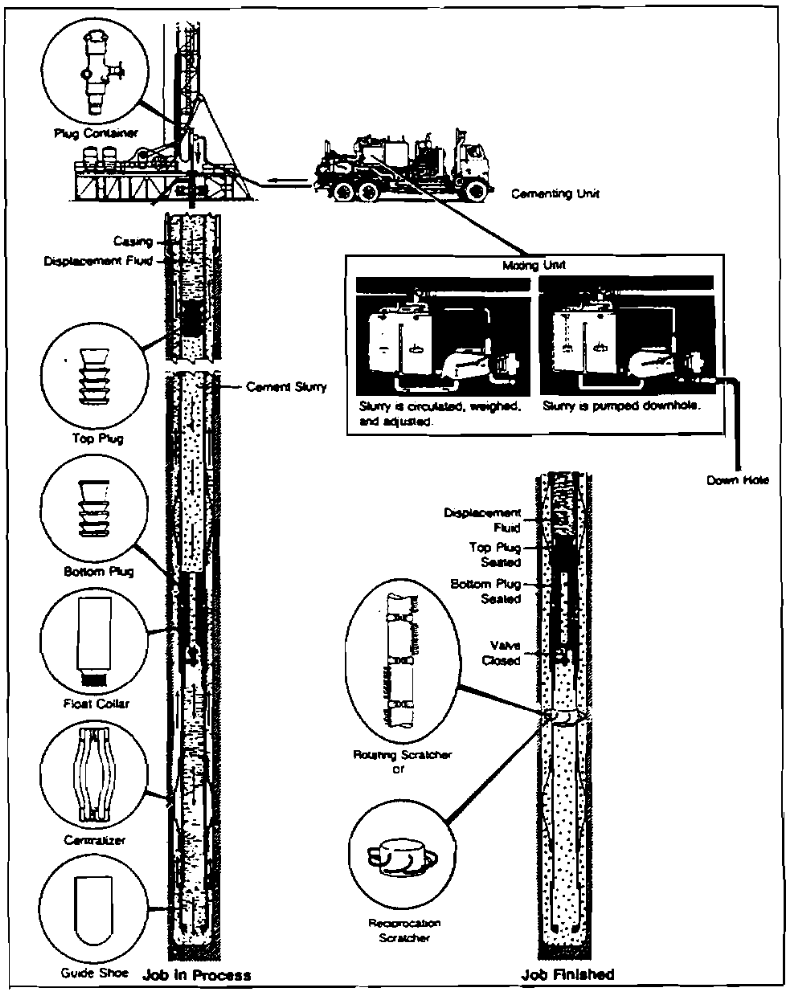

Figure 104. Primary Cementing Process (Smith, 1990)

The slim-hole definition established in this study is generally a final hole size of less than or equal to 6 in. and a production casing size of 4 in. or less. The effects on slim-hole cementing execution and performance, as with most slim-hole issues, arise from the reduced tubular diameter and reduced annular clearances. Figure 105 illustrates this by comparing a conventional 5½-in. completion in a 7⅞-in. hole and an aggressively slim 3½-in. completion in a 4¾-in. hole.

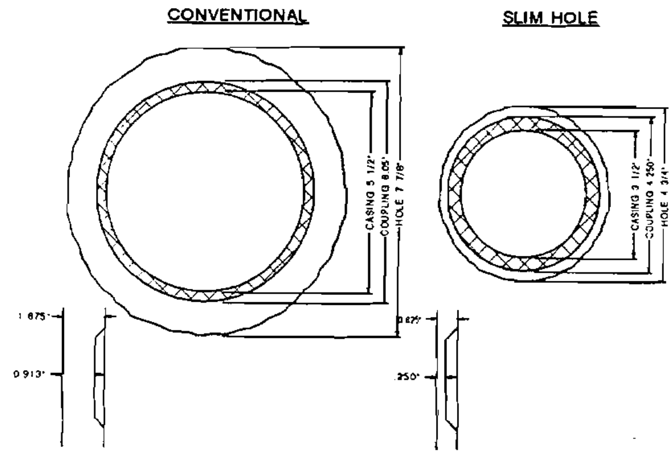

Figure 105. Conventional and Slim-Hole Geometries

While tubular diameters will be reduced (with respect to conventional) in all cases, the annular clearance need not be as restrictive as shown in Figure 105. For example, 2⅞-in. casing in a 4¾-in. hole has an annular pipe clearance of 0.938 in. and coupling clearance of 0.541 inches.

In addition, most current U.S. slim completions are not placed in slim holes, resulting in an annular clearance possibly greater than conventional. The slim completions routinely run in the D-J Basin, 3½-in. casing placed in a 7⅞-in. hole, have a pipe annular clearance of 2.19 in. and a coupling clearance of 1.81 inches. The challenges of obtaining a competent cement job with *reduced clearances* are much greater and will be the focus of this report. This implicitly assumes an integrated slim-hole option is chosen, slim-hole drilling <u>and</u> completion, rather than a slim completion with conventional drilling.

The reduced diameters and clearances and associated challenges with slim-hole cementing are similar to common liner applications. Table 27 shows some typical hole/liner relationships. The distinct difference, assuming the case of a slim completion production casing string from surface to TD, is that the annular clearance is restricted the entire wellbore rather than only a relatively short interval at the bottom of the well.

TABLE 27. Typical Hole/Liner Relationships

Liner (in.)	Hole (in.)	Annular Clearance (in.)
9⅝	10⅝	0.43
7	8⅝	0.8
5½	6⅝	0.56
3½	4¾	0.625
2⅞	4¾	0.938

Balancing rheology, mud displacement, required compressive strengths, and thickening times in aggressive slim-hole conditions is challenging. These challenges will be addressed under the following general categories:

- Thickening Time
- Hydraulics And Mud Displacement
- Cement Volumes
- Lost Circulation Materials
- Cement Sheath Strength
- Downhole Tools and Running Casing
- Remedial Cementing

5.2 THICKENING TIME

5.2.1 Laboratory vs. Field Conditions

The thickening time of a cement slurry is one of the most critical parameters for a successful cement job. Being able to reliably predict this by running tests in the laboratory on various slurry designs is extremely important. The standard API industry test consists of placing the slurry in a cylindrical container that rotates around a stationary paddle. The thickening time tester (consistometer) can run tests at different pressures and temperatures to mimic the downhole condition expected. The container is rotated around the paddle to simulate shear conditions that the cement experiences because shear history affects thickening time, as well as other cement slurry properties.

Current industry test methods, however, allow only a 150 rpm rotational speed of the consistometer slurry cup during a thickening time simulation. This, in turn, limits the range of shear rates found during a normal thickening time simulation to between 705 and 1330 sec^{-1}, depending on the flow behavior index (N′) of the cement. Figure 106 illustrates how the shear rate varies with N′ at 150 rpm. Oil-well cements encounter a much wider range of shear rate conditions during placement due to variable wellbore geometries and changing surface pump rates.

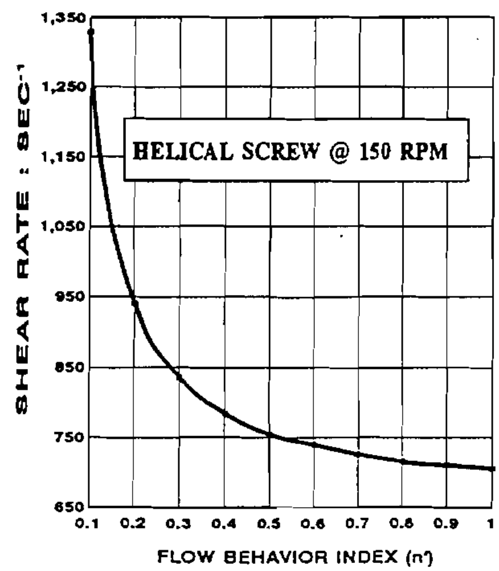

Figure 106. Shear Rate vs. N′ at 150 rpm (Purvis et al., 1993)

The end result of this investigation was the concept of "total mixing energy." The concept holds that at each step of the mixing and pumping process, a certain amount of energy is placed into the system. The sum of all mixing energy input (movement through centrifugal and triplex pumps, chokes, lines, etc) amounts to the total mixing energy expended upon the slurry. As this amount of energy increases, slurry properties begin to change.

It was concluded that an uncontrolled decrease in thickening time was a natural result of pumping cement through coiled tubing. Fifty to seventy percent decreases in thickening time were directly attributable to the energy imparted while pumping through small diameter tubulars. Obviously, this effect must be taken into account when recommending a target thickening time for a cement slurry.

These findings are still the subject of some controversy. Were the results specific to a particular type or brand of cement? Did the additive selection influence the results? More recent research indicates that the energy condition at the moment of cement hydration is the predominant factor in influencing slurry properties and that the mixing and pumping process were *not* important. The conclusions were as follows:

> "For a properly mixed cement slurry, the energy added by either a batch mixer (after initial wetting) or pumping through coiled tubing does not appear to appreciably affect the measurable properties (thickening time, fluid loss, free water/settling, etc.) of a cement slurry.
>
> The variances in performance by each of these slurries when prepared by different mixers, followed by pumping the slurries through the 10,000 ft of 1¼-in. coiled tubing, indicates slurry performance is not appreciably affected by batch size, mixing pumps, nor pumping the slurry through a coiled tubing string.
>
> Lack of adequate cement particle wetting efficiency at this stage of mixing on the part of the mixing process can lead to erratic slurry performance."

As evidenced by the conflicting views, additional research in the area of mixing energy is required to fully understand and predict cement properties in slim-hole conditions.

5.3 CEMENTING HYDRAULICS AND MUD DISPLACEMENT

During primary cementing operations, it is usually desired to pump at high rates to induce turbulent flow to facilitate mud displacement and filter cake removal. However, care must be taken not to create excessive bottom-hole ECDs and pressures such that circulation is lost, the formation fracture pressure is exceeded, or surface pressure becomes excessive. This is complicated even in conventional jobs due to significant differences in densities between the mud being displaced, the cement, and the displacing fluid. For example, a typical cement density is 15.6 lbm/gal to 16.5 lbm/gal, while mud weights rarely exceed 12 lbm/gal. These large density differences result in conditions such "free-fall" that make it difficult to predict true bottom-hole pressures during the job.

Slim-hole cementing compounds the problem of these competing pumping rate objectives due to the higher friction pressures and related ECDs associated with the smaller tubulars and annular clearances for a given rate. However, careful design using modern simulation programs provide the tools necessary to ensure proper slurry and procedure design.

5.3.1 Hydraulics

Simple cases for conventional and slim-hole cementing jobs were run with the DEA-67 computer model "CEMENT" to illustrate the sensitivities inherent in slim-hole cementing.

Table 29 shows the conditions assumed for the sample cases.

TABLE 29. "CEMENT" Case Assumptions

Depth	10,000 ft
Mud Density	10 lb/gal
Cement Density	15.6 lb/gal
Interval	8–10,000 ft
Pressure Gradient	0.465 psi/ft
Frac Gradient	0.7 psi/ft
Mud PV/YP	15.1/8.0
Cement PV/YP	45.0/1.50
Conventional Hole Size	7⅞ in.
Conventional Casing	5½ in.
Slim-Hole Size	4¾ in.
Slim-Hole Casing	3½ in.

The critical job assumption is the pumping rate. A common pumping rate for cementing casing is about 8 BPM. With conventional 5½-in. casing in a 7⅞-in hole, this equates to a annular velocity of about 24 ft per second (fps). To achieve this annular velocity in a slim completion with 3½-in. casing in a 4¾-in. hole requires only about 2 BPM. Figures 109 and 110 plot the pressure histories for the conventional and slim cases, respectively.

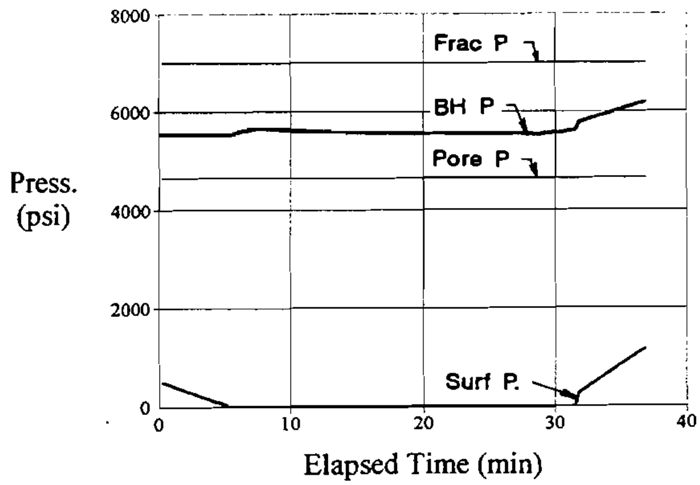

Figure 109. Pressure History For Conventional Case (8 BPM)

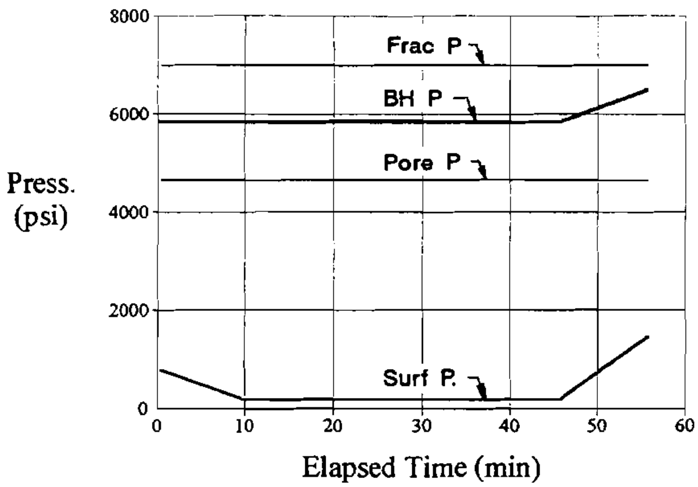

Figure 110. Pressure History For Slim-Hole Case (2 BPM)

These illustrate that comparable velocities can be obtained in a slim-hole while staying below fracturing pressure. However, because of the tight clearance, the slim-hole condition is closer to the fracturing pressure and is much more sensitive to variations in pumping rate than the conventional case. Also, not included in this analysis is surge effects from pipe reciprocation, which is discussed below. The ECDs for these two cases are plotted in Figure 111 and 112 and reveal how close the tolerance is for the slim-hole case relative to the conventional case.

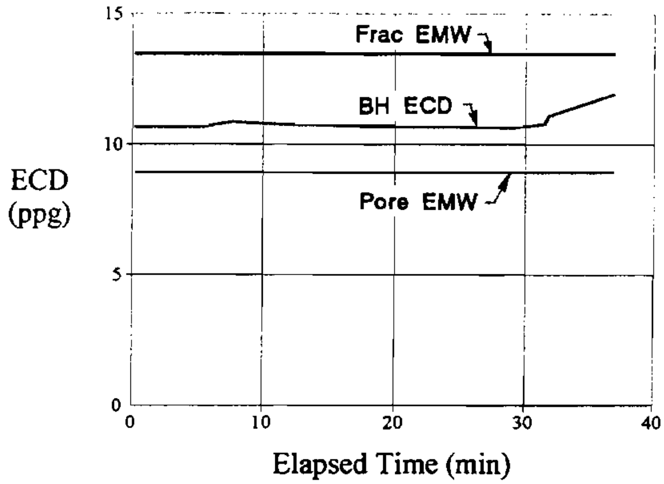

Figure 111. ECD History For Conventional Job (8 BPM)

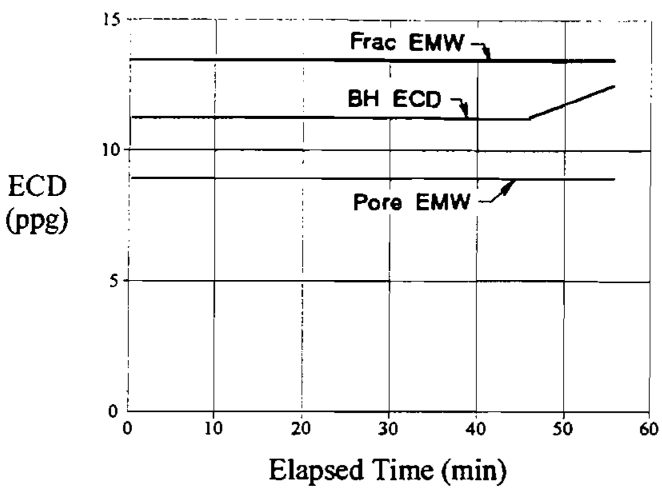

Figure 112. ECD History For Slim-Hole Job (2 BPM)

To further illustrate this point, another case was run for the slim-hole condition with the rate increased to 4 BPM. While this is a 100% increase, it must be realized that these are very low rates for the equipment commonly used for primary cementing. Without thorough pre-job analysis, there would likely be tendencies to increase the pumping rates to something approaching a more common rate. In addition, normal job fluctuations of 2 BPM in this low range would be possible. Figure 113 (pressures) and Figure 114 (ECDs) show that at 4 BPM the bottom-hole pressure now exceeds the fracture pressure.

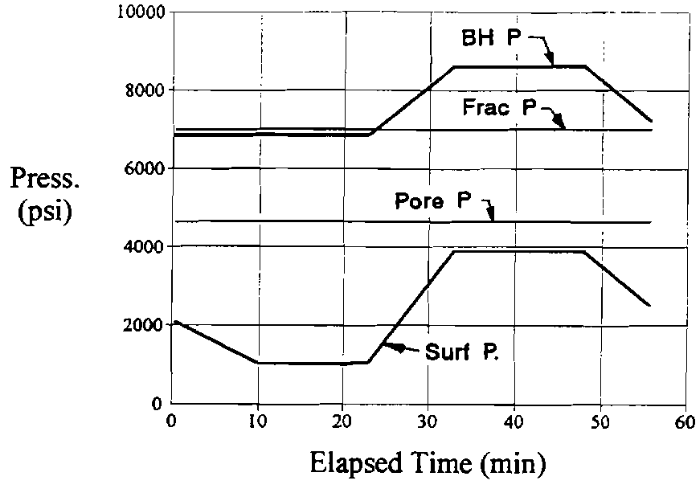

Figure 113. Pressure History For Slim-Hole Job (4 BPM)

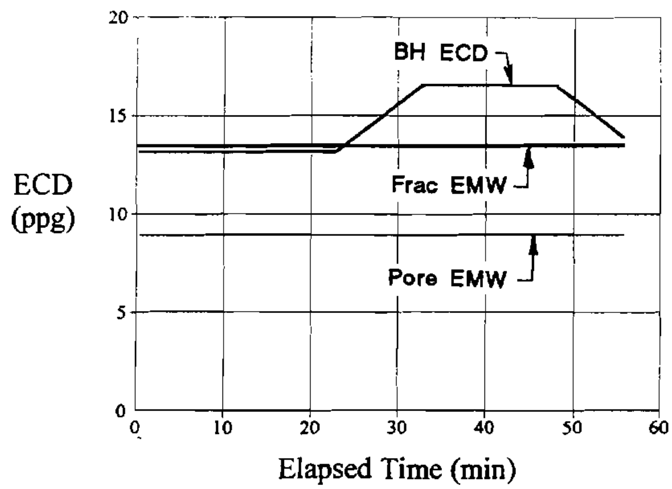

Figure 114. ECD History For Slim-Hole Job (4 BPM)

Also interesting is the surface pressure comparisons between the conventional and slim-hole cases. Notice that there is no surface pressure for most of the conventional job at 8 BPM, but several hundred psi for the slim-hole job at 2 BPM and almost 2000 psi at 4 BPM. This indicates that there is free-fall of the cement during the conventional job but not during the slim-hole job. This is confirmed by the rate-in and rate-out plots provided by CEMENT. These are shown in Figure 115 and 116.

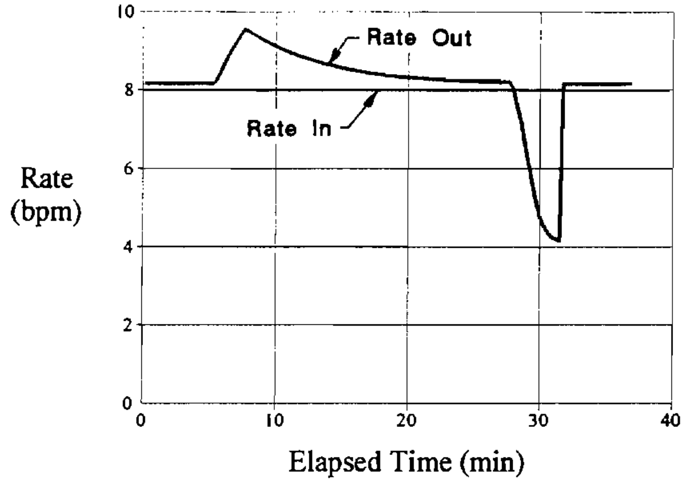

Figure 115. Pump-In and Return Rates for Conventional Job

Notice the rate fluctuations as the cement free-falls during most of the job with the rate-out exceeding the pump-in rate of 8 BPM.

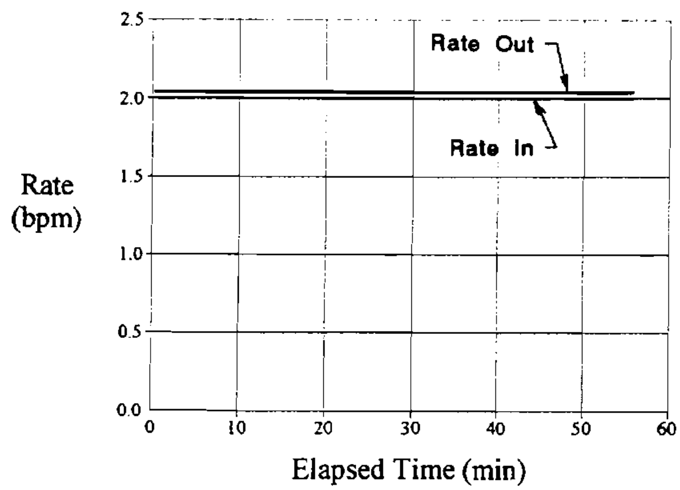

Figure 116. Pump-In and Return Rates For Slim-Hole Job

In the slim-hole job the rate-out equals the pump-in rate throughout the job indicating no free-fall as the friction pressure in the annulus dominates the cement-to-mud density differences. Results are the same at both 2 and 4 BPM.

5.3.2 Pipe Centralization

The above examples illustrate that conventional velocities can be achieved in slim-hole conditions. However, other detrimental effects, such as those due to eccentric pipe, further complicate the problem. Casing that is not centered in the hole (100% stand-off) creates non-uniform velocities and mud displacement, as shown in Figure 117. There is greater probability of eccentered pipe with reduced annular clearances. The use of accurately placed centralizers thus becomes even more important.

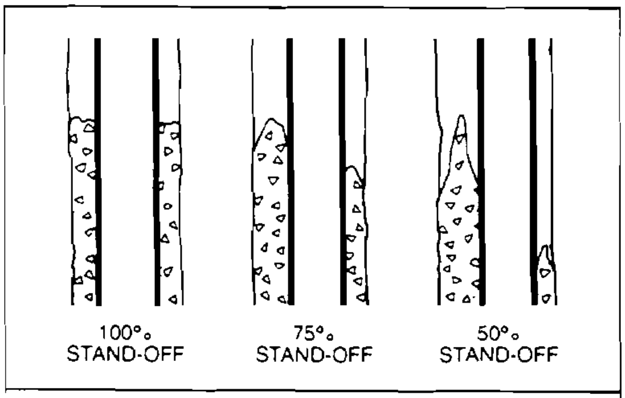

Figure 117. Pipe Centralization and Cement Placement (McLean et al., 1967)

5.3.3 Movement

Pipe movement, rotation and reciprocation, is a heavily recommended practice for assisting mud displacement. However, the tight clearances in slim-hole configurations will amplify surge-and-swab effects. The downward movement of the casing during reciprocation causes a piston-like force on the fluid which increases the bottom-hole pressure (surge). This can result in a greater sensitivity to exceeding the formation fracturing pressure and resulting lost circulation. Upward pipe movement during reciprocation can reduce bottom-hole pressure, possibly to the extent of allowing formation fluid to enter the wellbore. In either case, the effectiveness of the cement job execution and performance (cement bond) can be compromised. These effects must be explicitly evaluated during a slim-hole cementing procedure development.

As discussed in Chapter 3 of this report, slim-hole drilling research has determined that rotation of drill pipe in an aggressive slim-hole configuration (annular clearances of less than 0.5 in.) results in an increased friction pressure. This may be a factor in cementing as well, but effects are probably minimal.

5.3.4 Recent Research

A recent study on liner cementing performance in the Prudhoe Bay field, Alaska holds insight into how to successfully cement slim-hole wells (Saleh and Pavlich, 1994). While these are liner applications in deviated holes (45-55°), the clearances and depths make the experience germane to this discussion. The wells studied are 9000-ft TVD, 9500 to 15,000-ft measured depth with 500 to 1000 ft of productive interval cased with either 5½-in. liner in a 6¾-in. hole (0.625-in. clearance) or a 7-in. liner in an 8½-in. hole (0.75-in. clearance). Notice that this is the same clearance as the sample cases previously discussed (3½-in. casing in a 4¾-in. hole). Use of the practices highlighted below has resulted in the liner cementing success rate increasing from less than 50% to 92%, as measured by cement bond log evaluation and production history.

Current practices leading to this substantial improvement in success include:

1. Thin cement slurries
2. Displacement at highest possible rates
3. Rigid centralization with turbulators, two per joint in open-hole
4. Reciprocation more effective than rotation, use of turbulators removes need for rotation
5. 250-350 psi back pressure applied for few hours after placement to prevent gas migration
6. Condition mud and hole with wiper trip, but limit to two hours if possible

5.4 CEMENT VOLUMES

One of the tangible benefits of slim-hole wells is the reduction of required cement and mud volumes due to the smaller wellbore volumes. Figure 118 shows a comparison of the cement volume required for a conventional hole and two slim-hole designs.

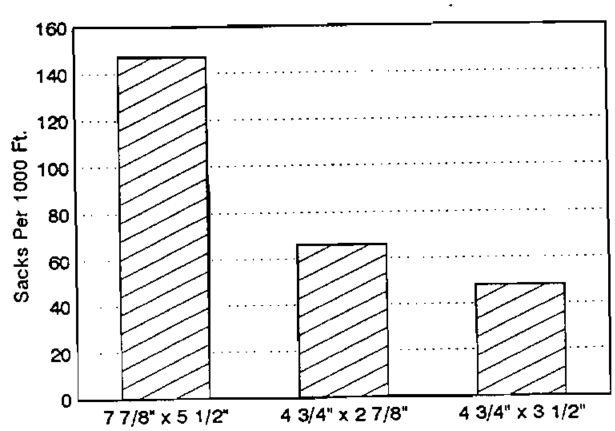

Figure 118. Comparison of Cement Volumes

Although the prospect of small cement volumes can be very attractive from a cost perspective, it can also create unexpected complications in the cementing process. Accordingly, there are several procedural and equipment considerations that should be taken into account in order to mitigate the uncertainties created by the smaller volumes of cement.

The cement mixing equipment available around the world varies widely. State-of-the-art recirculating mixing systems are easily capable of controlling cement density to within a 0.2 lbm/gal tolerance. On the other hand, operations in some areas may be performed with 1960s vintage venturi-style ground mixers which can produce large fluctuations in cement density. When cementing slim-hole wells, the considerably smaller cement volume requires greater consistency in cement density due to the greater interval a given volume will occupy.

One of the solutions to this problem is to "batch mix" the cement. Truck or skid-mounted batch mixers are commonly available in capacities ranging from 50 to 150 bbl. Many of the newer cement recirculating mixing systems incorporate large (20 bbl) averaging tubs to ensure uniformity of the cement slurry while allowing for <u>precision</u> control of cement density.

The time spent batch mixing the cement can also impact the overall thickening time. For many years conventional wisdom held that a slurry retarded for downhole conditions, while exposed to only ambient temperature and pressure, did not lose any thickening time. In other words, batch mix time at surface did not subtract from actual thickening time. In reality, this is not the case. Laboratory simulations indicate that with certain retarders, batch mix time does count toward thickening time. In practical terms, the laboratory thickening time simulation should include a 15–45 minute batch mix simulation before the cement is ramped to final temperature and pressure.

Smaller cement volumes also make it much more critical to reduce the amount of contamination at the cement-spacer interface. One solution is to install a flush line valve in the displacement line. By using a flush line the operator can make certain that only competent cement is being pumped downhole. Flush lines are used regularly in coiled tubing squeeze operations where only a few barrels of watered-down or contaminated cement will occupy a large linear distance within the coil.

Past research investigating the cement wiper plug contamination has shown that substantial contamination can occur at the tail end of the slurry due to the top wiper plug. Apparently the top plug picks up mud residue from the casing/tubulars that was not cleaned off by the bottom plug or the cement that followed. The residue builds up immediately in front of the top plug, thus contaminating the portion of the cement at the cement-plug interface.

To alleviate this problem, one recommendation is to pump double wiper plugs in front of the cement. Using a double plug system will clean the tubing in front of the cement thereby limiting contamination that could build up in front of the top plug. This is especially critical in slim-hole applications where even a small amount of contamination an occupy a large linear annular distance.

5.5 LOST CIRCULATION PROBLEMS

Conventional methods and materials used for lost circulation control may be unsuitable in slim-hole wells due to the limited clearances. This is an important concern due to the likely lower tolerances between returns and lost returns. Fortunately, work done for coiled-tubing squeeze work has identified several lost circulation materials for use in narrow clearance cementing operations.

The addition of LCM to cement in coiled-tubing squeeze operations has been avoided by many operators. The principle concern is that the LCM will clog the jet nozzle ports resulting in a cemented-up coiled-tubing string. With selection of proper LCM materials, however, nozzle blockage has been successfully avoided in coiled-tubing squeeze operations.

Sand has been one of the more common coiled-tubing LCM materials. Although useful in some applications, there can be problems associated with its use. The high specific gravity of sand (2.65) can cause it to settle out of the slurry. The spherical shape of the particles furthers this tendency. As a consequence, many wells for which sand was the LCM have required extensive underreaming after cementing.

The most successful LCM for use in coiled-tubing squeeze operations has been expanded aggregate. Expanded aggregate is a mined clay-bearing soil which has been baked in a rotary kiln. The expanded aggregate particles are inert, porous, stable up to 1000°F, and exhibit relatively high compressive strengths. This material is less likely to settle out of the slurry, due to its low specific gravity (2.0) and angular shape. In addition, expanded aggregate has a particle size distribution ideal for bridging dense sand. The normal concentration of expanded aggregate is 20 lbm/bbl. The use of the expanded aggregate has not produced a significant increase in underreaming. Fine-grained cement, fiber reinforced cement, sand pack and gel squeezes, and isotropic cements have also been successfully used with coiled tubing for troublesome intervals.

5.6 CEMENT SHEATH

Cementing the small annular area found in a slim-hole completion produces a correspondingly small cement sheath. Intuitively, as the cross-sectional area of the cement sheath is reduced, the overall integrity of the sheath is also reduced. Relatively little information has been published on the long-term problems associated with thin cement sheaths. The majority of information available in this area has been focused on the amount of compressive strength required for zonal isolation, but not necessarily for thin versus conventional sheaths. The findings of these investigations do suggest that an optimal compressive strength can reduce the amount of shattering during perforating or rubbleizing due to thermal cycling. In a slim-hole environment, these effects would be more pronounced. A review of the literature related to compressive strength and zonal isolation by Daulton (1991) highlighted the following generalized conclusions.

1. A critical compressive strength value of approximately 1300 psi or higher did not appear to affect the hydraulic bond when perforated with scallop jet perforating guns.
2. For expendable jet perforating guns, the optimal compressive strength is over 2000 psi.
3. Perforating under confining pressures of 3000 to 5000 psi generally did not affect the hydraulic bond of strong cement, but destroyed the hydraulic bond of weak cement. However, Goodwin and Crook (1990) found that for casing cemented inside casing, higher compressive strengths were more supportive of the inner casing, but failed to seal the annulus at much lower internal casing test pressures (2000 to 4000 psi). The authors attribute this to a lack of conformability exhibited by high compressive strength, high elasticity modulii cement. The results indicated that a more ductile 2000 psi cement more readily reproduced an acoustic signal than did a 3000 psi cement under extreme casing stress.

In summary, the results included in the literature review indicate that cement slurries exhibiting moderate compressive strengths (2000-3000 psi) provided an adequate annular seal from both a hydraulic and shear bond standpoint. These cements also appear to provide hydraulic isolation when casings were expanded under pressure, indicating that the slurries were resilient enough to allow a reconforming of the casing/cement interface after disruption by pressure. Slurries with low compressive strength may not have sufficient integral strength for casing support after pressure stress or perforation damage. Higher compressive strength cement, while providing excellent casing support and annular sealing, may lack sufficient elasticity to reconform after casing deformation.

In practical terms, perforation damage and thermal cycling stresses on a narrow cement sheath are in all probability greater than those found in a conventional-sized cement sheath. The use of latex-type or fiber additives, reinforcing agents, or moderate compressive strength cements may limit this damage.

Microdrill reports they have successfully cemented about 150 ultra slim-hole wells with 2.13-in. casing in 2.6-in. holes (0.24-in. annular clearance). They typically cement about a 900-ft interval at very low pumping rates (less than 0.1 BPM).

While most evidence indicates that a competent sheath that provides zonal isolation can be obtained in slim holes, additional work is recommended to help verify initial and long-term strength and competency. One area where this is needed is to assist with convincing regulatory bodies to relax regulations on required annular clearances. For example, the Minerals Management Service (MMS) regulations call for a minimum casing/hole annular clearance of 0.422-in. This would disallow the use of, for example, 3½-in. casing with normal couplings in a 4¾-in. hole on federal lands, such as is prevalent in the Greater Green River Basing, Wyoming.

5.7 DOWNHOLE TOOLS AND RUNNING CASING

Common downhole tools used in primary cementing includes guide shoes, float collars, float shoes, centralizers, scratchers, plugs, formation packer collars and shoes. Since the 1950s and 1960s, most tools needed for slim-hole primary cementing have been developed. One exception is stage cementing equipment for casing sizes less than 4-in.

Although most tools have been developed, their availability may be limited so, as with many slim-hole tools, planning should account for possible extra time required for mobilization of the required tools.

Running casing in the aggressive slim hole (small annulus) can be problematic. Shoulders and upsets on the casing can hang up on borehole ledges. Premium connections with reduced external upsets or externally flush casing can reduce this problem, but can be costly with low equipment availability. The OD of the casing coupling can be reduced by reducing the ID or using higher strength steel. Use of casing centralizers and scratchers, while preferred, may further hinder getting the casing to the bottom as well as safely moving pipe during the cement job.

A wiper trip with a fairly stiff stabilized assembly can be used to identify and wipe out ledges and doglegs. A float shoe with a bladed bottom can be run to provide limited reaming capability.

5.8 REMEDIAL CEMENTING

One of the major problems associated with slim-hole approaches is the inability to effectively workover slim-hole wells. For example, a mechanically set expandable bridge plug is typically run on tubing or wireline to perform a squeeze cement job. Cement is spotted above the plug or above fill which had been previously placed in the rat hole up to the interval to be squeezed. Dump bailers can be used to spot the cement across the interval to be squeezed. Upon actuation of the dump bailer, the cement flows by gravity down the wellbore. Squeezing is accomplished by filling the wellbore with fluid and applying pressure. Alternately, cement plugs can be spotted through tubing (balanced plugs) or pumped under a squeeze packer.

Today, remedial operations can be performed using coiled tubing instead of dump bailers. Since the early 1980s hundreds of coiled-tubing squeeze operations have been performed successfully. ARCO and BP have led the way in perfecting the equipment, cement design, and procedures such that coiled-tubing jobs are not only more successful than conventional squeeze jobs, but are substantially less costly.

A typical coiled-tubing squeeze is conducted using a cement slurry with very specific properties. Normal slurry specifications call for a fluid loss at BHCT of between 45 and 65 cc/30 min, a ⅝- to 1-in. hard filter cake, and a 6- to 8-hour thickening time. Having established these properties at the service company laboratory, the cement is transported to location and batch mixed. A "live" sample of liquid cement is than tested on-site for fluid loss and filter cake thickness/hardness. If the results fall out of the specified range, the cement is rejected. By adhering to such stringent specifications, a high degree of success has been established. This success is due, in part, to the development of slurry formulations whose properties are predictable and repeatable from the laboratory to the field. This level of precision, while rarely achieved in conventional cementing operations, will be the standard for slim-hole cementing operations. As with coiled tubing squeezing, slim-hole cementing requires precision control from the laboratory to the field of several slurry properties including 1) fluid loss, 2) rheology, and 3) free water/stability.

The importance of controlling filter cake thickness and hardness in squeeze cementing cannot be overstated. In a coiled-tubing squeeze operation, the cement nodes formed in the perforations act as a "check valve", prohibiting cement flow after squeezing. The nodes must be competent enough to serve as a check valve without growing so large as to hinder washing through the cement after squeezing. Measuring the filter cake thickness and hardness after a fluid loss test gives an indication as to the integrity of cake. A soft, thin filter cake, while easily washed out, would not be able to withstand a large pressure differential. A filter cake that is too thick would restrict the casing, not allowing the coil to pass through, necessitating underreaming.

Given the small diameter of casing used in slim-hole completions, a squeeze cement with excessive fluid loss would build perforation nodes large enough to obstruct the casing. Perforations located below the restriction would not receive an adequate volume of cement to affect a hydraulic seal.

5.9 ADDITIVES AND SLURRY TECHNOLOGY

The ability to control the rate of cement fluid loss is central to the success of slim-hole cementing operations. In the presence of differential pressure, cement slurries lose filtrate to permeable strata. As the liquid phase (filtrate) of the cement enters the formation, a deposited layer of solids (filter cake) forms at the wellbore/formation interface. Without the use of a fluid loss control agent, the deposited filter cake is very thick and permeable. This type of filter cake could easily restrict the narrow annulus of a slim-hole completion, causing the cessation of pumping before the cement is in place.

Under less severe conditions, the loss of filtrate to permeable strata can increase the viscosity of the cement. This change in rheology can lead to abnormally high pressure drops which could also compromise the slim-hole cementing operation. In these cases, the small annular clearances typical of a slim-hole completion serve to magnify the possible negative implications of inadequate fluid loss control. Because of this importance, the following sections are presented to review fluid loss control fundamentals and resulting slim-hole ramifications.

5.9.1 Fluid Loss Agent Functionality

Cement fluid loss agents function primarily by promoting the deposition of a low permeability filter cake. The exact mechanism of this phenomenon is still a matter of scientific debate, yet it can be stated in general terms that the fundamental process controlling fluid loss is that of dynamic filtration. Under differential pressure the solids suspended in a liquid medium are "filtered out" by a bridging effect at the formation pore throat. The deposited solids form a filter cake whose structure and thickness are influenced by:

1. Particle size distribution
2. Particle electrostatic interaction
3. Particle packing efficiency
4. Particle specific gravity
5. Degree of particle compressibility

As this "latticework" of solids is being formed, the fluid loss agents restrict the flow of fluid within the interstitial areas between cement particles. As the permeability is lowered, fewer solids are added at the top of existing structure at the filter cake/fluid interface. The net effect is a thin impermeable filter cake as compared to the thick permeable cake formed if solids are continually deposited by the free movement of fluid.

The mechanisms responsible for the creation of a low permeability filter cake include:

1. Attachment of the fluid loss polymer onto the cement surface and extension of a portion of the polymer into the interstitial voids between particles. The water-binding property of the polymer creates a large increase in hydrodynamic volume. This in turn, serves to immobilize fluid within the interstitial voids of the filter cake.
2. A film-forming process in which the fluid contents of the interstitial spaces are bound by a polymer layer. Fluid movement through the filter cake is restricted by this entrapping process.
3. Mechanical blocking of the pore throats within the filter cake. Certain polymers are both adhesive and deformable. These materials can agglomerate into particles of a proper size to plug the pore throats.

4. By simple viscosification of the interstitial fluid. This will reduce fluid movement by the Darcy effect, thereby lowering fluid loss.

These mechanisms may be primary or secondary. While one mechanism may predominate others, they are usually interrelated.

5.9.2 Fluid Loss Additive Chemistry

The additives used to control the rate of fluid loss in oil-field cements have become increasingly sophisticated over time. The earliest fluid loss additives in common use was simple bentonite (sodium montmorillinite). During the 1940s small concentrations of bentonite served to lower the fluid loss rate of the oilwell cements of the day to approximately 250-350 cc/30 min. The dramatic increase in slurry viscosity caused by the addition of the bentonite did limit the usefulness of the product, however. By the late 1950s, the cellulose-based water soluble polymers were becoming commercially available. The most notable of these, carbomethylhydroxy-ethylcellulose (CMHEC), provided the means of controlling fluid loss at high (+250°F) temperatures. CMHEC could be mixed with a naphthalene sulfonate formaldehyde condensate (NSFC) dispersant, serving to lower the viscosity brought on by the CMHEC while synergistically enhancing fluid loss control. Additives based on CMHEC-NSFC type chemistries are still in use today.

Variants of cellulose, including hydroxyethylcellulose (HEC), followed. As is the case with CMHEC, the HECs also exhibited a synergistic fluid loss effect with NSFC-type dispersant. Polymers such as polyvinyl pyrrolidone (PVP) were also found to enhance fluid loss when combined with cellulose and dispersants. In specific ratios and combinations, formulations based on HEC, NSFC dispersant, and PVP-type chemistries represent a large percentage of the so-called "conventional" fluid loss additives currently used in field operations.

During the 1980s, other technologies came into vogue for use as fluid loss control agents. These include: polyvinyl alcohol (PVA), polyethylene imine (PEI), and styrene-butadiene (SBR) lattices. The PVA and SBR lattices are especially notable not only for fluid loss control, but for anti-gas capabilities as well.

As with any cementing product, the fluid loss products mentioned above all have limitations. CMHECs and HECs by themselves are quite viscous and tend to retard thickening time and compressive strength development. HEC-dispersant blends have a diminished efficiency in salt (NaCl) and KCl environments and are generally limited to temperatures below 220°F. CHMEC-dispersant blends are also quite viscous and are subject to thermal thinning. PVA-based fluid loss additives exhibit a threshold effect of fluid loss efficiency versus polymer concentration and have low salt tolerance. The PEI-based systems have to activated by auxiliary materials and are prone to settling. SBR latex systems require sophisticated slurry designs in order to function properly, require high concentrations of the product, and can be costly.

During the mid-1980s fluid loss additives based on the 2-acrylamido-2-methylpropane sulfonic acid (AMPS™)monomer were being used in increasingly diverse cementing environments. AMPS™ derivatives possess favorable salt tolerance, thermal stability, high efficiency, minimal retardation, and good solids support. While costly, AMPS™-BASED fluid loss additives are well suited for use in the most demanding of engineering circumstances, and therefore have become the preferred chemistry for use in extreme applications such as liners and coiled-tubing squeezes.

The type of fluid loss agent recommended for cementing a slim-hole well will vary by service company, location, and design engineer. Yet, technical requirements for successful zonal isolation will normally dictate that fluid loss chemistries allow for low viscosity, low fluid loss, and good solids support. Based on these criteria, AMPS™-containing additives, SBR-based products, and PVA technologies would most likely meet the required specifications.

5.9.3 Fluid Loss Control Guidelines

The annular geometries found in a slim-hole environment are similar to those common to liner completions. The industry standard fluid loss requirement for liners is usually less than 50 cc/30 min. Accordingly, it is recommended that slim-hole cement design guidelines also adhere to the 50 cc/30 min fluid loss criteria. For those situations were annular gas migration is expected, the fluid loss design requirement may be lowered to 20-30 cc/30 min.

5.9.4 Rheology Control (The Use of Dispersants in Slim-Hole Cementing)

Cement slurries can be classified as colloidal suspensions. The electrostatic forces at the particle/liquid interface greatly influences the dynamic interaction between the cement particles. The overall electrostatic charge of a cement particle is positive. However, the cement particle surface is most likely composed of areas of "patches" of positive charge separated by neutral and negatively charged "patches." This "patch" theory explains well the physical effects of dispersants on oilwell cements. In a cement and water environment the attractive forces between oppositely charged patches hold the cement slurry in a three-dimensional gel structure. A specific amount of force is required to overcome the attraction between particles thereby inducing fluid flow. For non-Newtonian fluids this point of transition is known as the yield point (Bingham plastic model).

The charged surfaces of a cement particle attract oppositely charged ions (counter-ions) that are firmly attached to the surface of the particle. This layer of fixed counter-ions is called the stern layer. Outside the stern layer, at a greater distance from the particle surface, there exists a diffuse layer of similarly charged particles (co-ions) and counter-ions that have reached dynamic equilibrium. This region is known as the diffuse layer. Together the stern layer and diffuse layer form the basis of the electrical double layer model.

How all of this affects the actions of dispersants on oil-field cements is as follows. Typical dispersants used today are sodium salts of naphthalene sulfonic acid. These materials are highly anionic water soluble polymers. The polymers attach themselves to the cationic "patches" on the cement particle surface. The positive charges are canceled out by the anionic polymers, while the neutral patches are also converted to a negative charge. The net surface charge thereby becomes negative. Also, the polymers not only change the surface charge, but by extending out into the stern layer they change the charge density further from the particle surface.

By changing the net surface charge and the charge density of the stern and diffuse layer, the particles are made to repel one another. As a result, the contribution of viscosity due to the electroviscous effect is lessened and the slurry "thins."

5.9.5 Rheological Guidelines for Cement Design

In a slim-hole environment the necessity for a low rheology cement slurry is obvious. An overly viscous slurry can produce excessive pressures during placement. This may result in formation breakdown, compromising the zonal isolation of the well. The key factor in slurry design, as it relates to viscosity, is to allow for the lowest possible rheologies without inducing solids settling. Adding too much dispersant to the slurry can be as serious as not having enough dispersant. An over-dispersed slurry will cause an excessive breakout of supernatant water from the slurry. Given the small annular volumes found in slim-hole completions, a small percentage of free water can translate into a large linear annular distance.

5.9.6 Free Water Control/Slurry Stability

The ability to control free water and maintain slurry stability under downhole conditions is a vital engineering consideration in a slim-hole environment. Failure to account for these properties can compromise zonal isolation, leading to a loss of production and/or annular fluid migration.

A cement slurry can be classified as a concentrated colloidal suspension. In general terms, the cement particles are held in a loose three-dimensional structure. The ability to control free water and solids settling are greatly influenced by this structure. The strength of the gel structure governs the amount of supernatant (free) fluid that can flow up through the structure as the particles settle.

The settlement of solids within a cement slurry can be described by stokes law. As such, the individual particles will settle at a rate determined by their size and density. If the interparticle attraction is strong enough, the cement particles will settle at the same rate, thereby maintaining the same relative position to one another. As the structure subsides the larger cement particles, if not supported by the gel network, can settle at a rate faster than the finer particles. This sedimentation can produce a large density gradient within the cement column.

Once again, given the small annular areas common to slim-hole completions, an unstable slurry can result in a large interval of the wellbore being covered with a cement of below-optimal density.

To determine the stability of a cement slurry, a specialized settling test has been developed. The proposed slurry is prepared under operating conditions, then placed in a 203mm x 25mm brass tube, and allowed to set in a curing chamber. After curing for 16-24 hours the cement is removed from the tube and cut into sections. The density of each section is then determined. In this way the stability of the slurry is determined by the degree of density difference between the sections from the top and bottom of the tube. Ideally, the density difference should be no more than 0.2–0.4 lbm/gal.

5.9.7 General Slim-Hole Guidelines

1. Keep cement density fluctuations to a minimum – use averaging recirculating cement mixers or batch mixers.
2. Design the cement to have the lowest practical rheologies while maintaining low free water breakout and minimal slurry density variation.
3. Use computer programs as a design tool in the optimization of slurry rheologies as they relate to wellbore flow phenomena. Real-time computer analysis can also be used to determine when the maximum practical mud displacement efficiency has been reached.
4. Where warranted, consider underreaming the productive interval to establish a more competent cement sheath.
5. The normal fluid loss values for slim-hole cements is 50 cc/30 min and should not exceed 100 cc/30 min for most applications. Under normal conditions, free water control of the slurry should be less than 1 ml. Under deviated conditions, reduce the allowable free water to zero. Design the cement slurry to produce less than a 0.4 lbm/gal density variance on the slurry stability test. Design the slurry with additive systems that offer proven reproducibility in physical properties from the lab to the field.
6. In slim-hole cementing, adequate centralization is a prerequisite for success. Computer programs should be used to determine optimal centralizer placement, as well as for torque and drag analysis. Cautious use of casing rotation and/or reciprocation techniques will further improve mud displacement efficiency. Treating the mud to provide the lowest possible PV, YP, and yield strength without compromising solids support capabilities will also assist in the preparation of the wellbore for cementing. Turbulator type centralizers are recommended.

5.10 CONCLUSIONS AND RECOMMENDATIONS

Past research and experience indicate that the barriers to slim-hole cementing are not great. Successful, competent cement jobs can be performed. However, smaller diameter tubulars and tight annular clearances create conditions that demand much greater care and control in slurry and procedure design. The barrier survey conducted during this project indicates perceived barriers are also not generally significant. However, the Service Company group did rank Cementing considerably higher than did Producers. If truly representative, this opinion could result in discouragement of producers by service companies of the use of slim-hole options because of the additional uncertainties involved with cementing in slim-hole conditions.

Therefore, near-term R&D is needed to advance understanding and technology and facilitate acceptance of slim-hole cementing in aggressive applications. Recommended research areas include the following:

1. Focused study of the long-term competency and zonal isolation capability of thin cement sheaths subjected to various perforating, production, and workover stresses.
2. Additional reconciliation of API testing procedures and actual downhole conditions experienced in slim applications, and quantification of expected variations in slurry properties.
3. Further investigations in mixing energy concepts to help reconcile current uncertainties of the effects of high-shear conditions on fluid properties. If appropriate, incorporate these effects into slurry and job design tools.
4. Investigate new slurry, additive, and mud-to-cement technologies for use in slim-hole applications.
5. Develop or document optimized casing reciprocation, rotation, and centralization techniques for slim-hole applications.
6. Document and transfer actual experience in U.S. gas applications by producers and service companies.
7. Facilitate field testing and actively transfer results of slim-hole cementing in new U.S. gas applications.

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6. Slim-Hole Stimulation

6.1 INTRODUCTION

Stimulation is frequently used in natural gas wells to increase productivity. By the definition previously established, choosing a slim-completion option implies a reduction in production casing size from greater than 4 in. (commonly 4½ in., 5½ in., and 7 in.) to 4 in. or less (commonly 3½ in. and 2⅞ in.). The production tubing likewise reduces from usually either 2⅜ in. or 2⅞ in. to 2¹⁄₁₆ in. or less, with options including a tubingless completion or use of coiled tubing. Since the stimulation is conveyed to the formation through the production tubulars, either casing or tubing, the impact of a slim completion on stimulation design options, implementation, and effectiveness is a very important issue. This importance is heightened by the fact that the wells that are most sensitive to the benefits of cost-saving technologies, such as slim hole, are also very likely to need significant stimulation, usually hydraulic fracturing (i.e. low permeability, high-cost, and marginal economics).

The two general types of stimulation are matrix acidizing and hydraulic fracturing. Matrix acidizing increases well productivity by decreasing or removing formation permeability damage, or "skin" (usually near-wellbore) imposed by the drilling, completion, production, and workover processes. Reactive fluids, usually acids, are pumped at relatively low injection rates and pressures. Pressures are intentionally maintained below fracturing pressure to avoid fluid loss from the zone(s) of interest. The fluid dissolves the damaging material (drilling solids, formation fines, emulsions, scale, etc.) and some portion of the rock material.

Hydraulic fracturing increases well productivity by creating a much larger contact surface between the well and the reservoir and is usually most economic in lower permeability reservoirs. This is accomplished by pumping proppant-laden (usually sand) viscous fluid at sufficient rates and pressures to create, extend, and prop a vertical fracture at a distance usually hundreds of feet into the reservoir. The resulting highly-conductive flow-channel has much greater permeability than the surrounding formation and results in a larger effective wellbore radius, the effects of which are usually expressed and quantified in terms of "negative skin."

Because of the high rates and pressures, slim-hole implications for hydraulic fracturing are much greater than for matrix acidizing.

6.2 HYDRAULIC FRACTURING ISSUES

There are two primary areas where slim completions impact the hydraulic fracturing process, tubular size and perforation dimensions. Table 30 shows commonly used conventional and slim- completion tubulars as well as perforation diameters.

TABLE 30. Common Slim vs. Conventional Completions

	Conventional	Slim
Production Casing (in.)	7, 5½, 4½	3½, 2⅞
Production Tubing (in.)	2⅞, 2⅜	≤2¹/₁₆
Perforation Diameter (in.)	0.4–0.5	0.25–0.35
Perforation Tunnel Length (in.)	25–35	10–20

The ramifications of these variations with a conventional fracture treatment can be captured under the following concerns or barriers:

- Unacceptable friction pressure in smaller tubulars
- Unacceptable fluid shear rates in smaller tubulars
- Unacceptable friction pressure in small-diameter perforations
- Unacceptable fluid shear rate in small-diameter perforations
- Limited perforation tunnel length and reduced phasing and density options increasing near-wellbore tortuosity problems
- Small-diameter perforations and tubulars increase proppant bridging tendencies
- Small-diameter perforations and tubulars decrease diversion options and effectiveness

Hydraulic fracture treatments can be performed through production tubing, casing, or the tubing/casing annulus. The decision is based on design factors that include desired injection rates, corresponding injection pressures, fluid type and volumes, proppant type and volume, leak-off characteristics, flowback considerations, casing condition, and company policy. Important to note in Table 30 is that the tubular size through which the stimulation is conveyed does not *necessarily* change when comparing a conventional completion to a slim completion. For example, if treatments have historically been performed down 2⅞-in. tubing, then a slim completion treated down 2⅞-in. casing is similar in terms of tubular friction pressure.

The friction pressure loss through the tubing or casing and perforations is an important factor in the treatment design and the required hydraulic horsepower (and resulting job cost). Respondents to the slim-hole barrier questionnaires reported in Chapter 9 of this report indicated that stimulation friction pressure was one of the largest barriers to increased usage of slim-hole techniques.

Similarly, the shear rates imposed on a fracturing fluid through the tubing or casing are critical and must be well understood to maximize probability of treatment success. The majority of fluids used today exhibit non-Newtonian behavior, meaning the apparent viscosity, or proppant-carrying ability, is dependent on shear stress exerted on the fluid. Increasing the shear stress, as happens when tubular size is decreased, decreases the fluid viscosity and the ability of the fluid to carry proppant. Figure 119 shows how viscosity decreases with increasing shear rate.

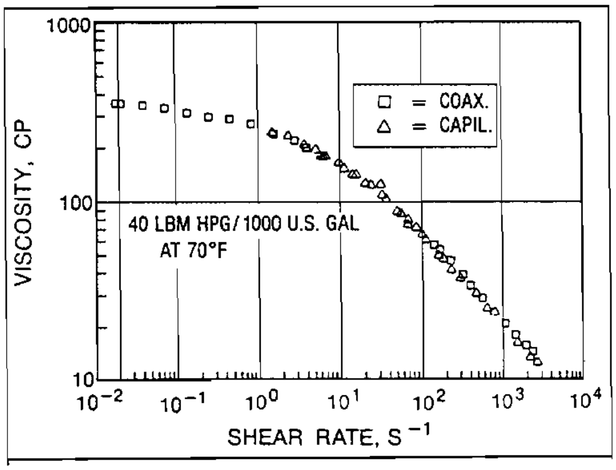

Figure 119. Viscosity vs. Shear Rate for a 40 lbm/1000 gal HPG Solution (Guillot and Dunand, 1985)

Since two key slim-hole fracturing issues, friction pressure and shear-dependent viscosity, are heavily dependent on the fluid being pumped, a discussion of the evolution of fracturing fluids is helpful to understand modern fracturing technology as it relates to slim-completion issues and perceived barriers.

6.3 FRACTURING FLUID EVOLUTION

Fracturing fluids generally need the following characteristics to provide for a successful treatment (after Ely, 1989):

- Compatibility with formation material and fluids
- Capable of suspending and transporting proppants into the fracture
- Capable of creating sufficient fracture width through its viscosity
- Be efficient, or have low fluid loss characteristics
- Exhibit low friction pressure
- Exhibit stable/predictable characteristics (viscosity) throughout treatment
- Capable of breaking down after treatment for recovery
- Must be cost-effective and easily prepared and handled

The first fracturing fluid used in 1947 used a napalm gellant to viscosify gasoline to carry a small amount of proppant. The treatment was executed successfully, but fracturing was not commercially applied until almost 10 years later when lease crude became a popular base fluid. Lease crude treatments increased production but it became obvious that the prevailing technology did not allow for important conditioning to the base fluid for improvements in friction reduction and increased viscosity for proppant transport.

Starch was the first water viscosifier used for frac fluids but was quickly replaced by the naturally occurring guar polymer in the early 1960s. Wide application of linear water-based gels made with guar polymers almost displaced lease crude fracs, except in a few fresh-water sensitive reservoirs. Linear water-based gels are still extremely popular today, but cleaner polymers (less residue) have been developed. These include hydroxypropyl guar (HPG), hydroxyethylcellulose (HEC), and other derivatives.

The only way to obtain increased viscosities with linear gel fluids is to substantially increase the polymer concentration. In the late 1960s, technology was introduced which allowed lower concentrations of polymer to be hydrated and then "crosslinked" with an ion of boron commonly known as either borax or its derivatives. The beneficial aspects of crosslinking include tremendous gain in viscosity with improved fluid loss control, reduced friction pressure, controlled breaking mechanisms via enzymes (improved clean-up), and cost reduction.

In the 1980s, a critical step with important ramifications for slim-completion fracturing was taken with the ability to delay the crosslinking, and resulting increases in viscosity, until the fluid is past the tubulars and perforations and into the fracture itself. This reduces the friction pressure and, even more important, reduces the damaging effects of shear rate on the fluid. Shear rate history is very important to crosslinked gel stability.

Low levels of temperature stability and difficulty in achieving a controllable crosslinking mechanism led, until recently, to replacement of borate fluid systems with titanium, zirconium, and aluminum crosslinking agents. However, temperature stability aside, borates are more shear stable with better transport capability than other systems. Reduced shear stability of non-borate fluids are often accommodated with larger tubulars or lower injection rates.

Most recently, the concern for enhanced shear stability coupled with temperature stability has led to the development of an organoborate fluid that has the preferred shear stability of conventional borates, the ability to delay crosslinking, and thermostability to 325°F. These "delayed borate" systems hold promise for helping to escalate the acceptance and use of slim-completion fracturing.

Foamed and energized fluids generated with nitrogen and carbon dioxide were more fully developed in the mid-1970s. Interest in these fluids for low pressure and water-sensitive reservoirs increased rapidly in the 1980s. Advantages include excellent proppant transport capability, reduced liquid (water) on the formation, and more rapid clean-up. Disadvantages include increased friction pressure and limited sand concentrations.

Figure 120 shows the breakdown of fracturing fluid usage by general type as of about 1990, based on a GRI survey.

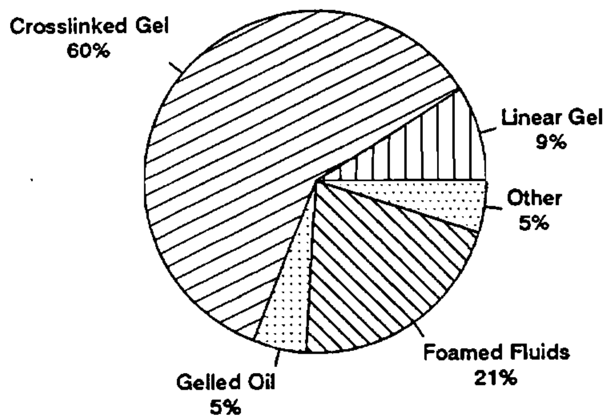

Figure 120. Fracturing Fluid Usage (Carter & Holditch, 1990)

6.4 TUBULAR FRICTION PRESSURE

As previously stated, tubular friction pressure is an important component in job design, horsepower requirements, and cost. Excessive friction pressure can result in the need to use a less than desired injection rate in order to stay below equipment pressure limitations or minimize the equipment required on location.

Figure 121 graphs the friction pressure vs. injection rate for conventional 5½-in. and 4½- in. casing and for slim 3½-in. and 2⅞-in. completions for a delayed-borate crosslinked fluid (no proppant). As shown, using a delayed cross-linking system keeps the friction pressure manageable at rates up to about 20 BPM in 2⅞-in. casing and up to about 30 BPM in 3½-in. casing.

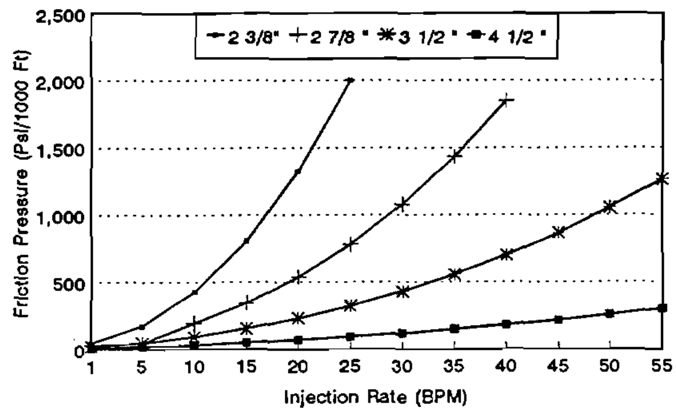

Figure 121. Friction Pressure vs. Injection Rate for Various Tubular Sizes

Figure 122 illustrates how important the development of the delayed cross-linking technology has been for slim-completion fracturing. This shows the friction pressure in a 2⅞-in. pipe for different fluids. The delayed borate crosslinked system experiences considerably less friction pressure (approximately one-half) than does a fully crosslinked borate or foamed frac fluid.

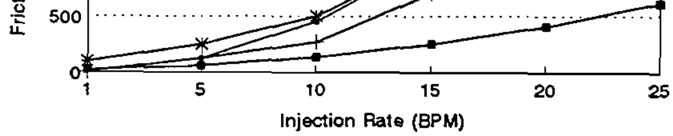

Figure 122. Friction Pressure vs. Rate in 2⅞-in. Tubular

Other beneficial developments for slim-completion fracturing have been improvements in fracturing fluid leak-off behavior, additives, and basic understanding. These have reduced the injection rates required to ensure the placement of a desired proppant volume.

An important consideration for slim-completion friction issues is the effect of proppant on friction pressure. As the tubular size decreases, the sensitivity of the friction pressure, and corresponding required surface injection pressure, to the fluid properties is increased. The addition of proppant is an important example. As proppant is added to the frac fluid, the density and viscosity increase. The increase in density increases the hydrostatic pressure of the fluid and effectively decreases the required surface pressure for a given rate, all else being equal. However, the increase in viscosity increases the friction pressure, as illustrated in Figure 123, increasing the required surface pressure for a given rate. Which factor dominates is dependent on the sand concentration. A rule of thumb is that at concentrations of 1 to 3 lb/gal, the hydrostatic pressure increase is greater than the friction pressure, but at higher concentrations, the friction pressure effect is greater.

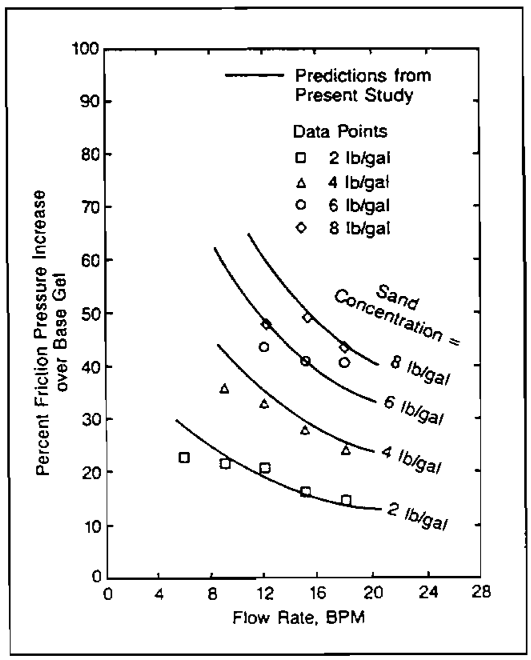

Figure 123. Friction Pressure vs. Proppant Concentration (Shah, 1986)

This is not a clearly understood relationship and is difficult to model. The effect, and associated uncertainty, increases with smaller diameter completions.

6.5 TUBULAR SHEAR RATES

Most fracturing fluids used today exhibit power-law behavior over the shear-rate ranges commonly experienced in the tubulars and fracture. This means the viscosity of the fluid is dependent on the shear rate and is commonly expressed in a relationship such as:

$$\mu = 47{,}880\ K'\dot{\gamma}^{(n'-1)}$$

μ = viscosity (cp)

$\dot{\gamma}$ = shear rate (Sec^{-1})

K' = consistency index

n' = power-law index

Although each fluid is specific and overall shear history (time exposed) is crucial, in general, shear rates of less than 1000 to 1500 sec^{-1} are desired for non cross-linked fluids. Figure 124 shows the shear rates experienced by a fluid down various size tubulars. As shown, injection rates of 25 BPM in 3½-in, and 12 BPM in 2⅞-in would not pose shear limitations for non-cross linked fluids. 12 to 25 BPM injection rates are very common in a large number of gas stimulation treatments. However, these rates would be detrimental to the performance of a mature cross-linked structure in the tubulars. Since cross-linked fluids are the preferred fluid in 60% of the jobs today, the development of delayed cross-linking has been an important advancement for expanding slim-completion usage. Where only linear gels might be used in a slim completion in the past due to shear degradation, cross-linked gels can now be used if the cross-linking is delayed.

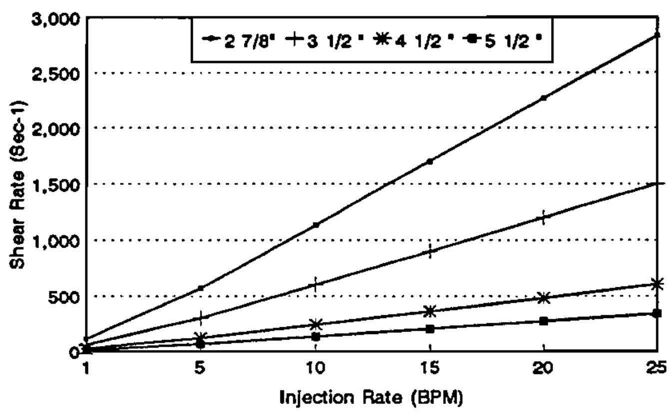

Figure 124. Shear Rate vs. Injection Rate

Also, the more recent development of a delayed borate cross-linked fluid is an important development for slim completions. Borate cross-linked bonds are reversible, so after the cross-link bond is broken due to shear or temperature, it will heal, or form again, after the shear or heat is removed. Zirconium and titanium cross-linkers do not have this trait and once the bond is broken, it will not form again. However, the rapid cross-linking rate and very viscous nature of the borate gel cause higher tubular friction pressure. This, in addition to its prior temperature limitations of 200 to 225°F restricted its use in the past despite its favorable shear qualities. The capability now to delay the crosslink of the borate system is very favorable to enhancing the ability to adequately fracture down smaller tubulars in a greater number of applications.

6.6 PERFORATION FRICTION

The smaller casings in a slim completion will likely result in the need to perforate with smaller perforating guns than would have been used in a conventional casing size. If fracture treatments in a particular field are normally performed down, for example, 2⅞-in. tubing, then the use of 2⅞ in. for casing will not result in an appreciable variation in the tubular friction pressure and shear rates experienced by the fluid, assuming the treatment is now performed down the casing. However, the conventional completion retains the option of perforating with larger guns, such as 4-in., prior to running the tubing in the hole for the treatment. The slim completion, on other hand, will be restricted to only smaller perforating guns. These smaller guns, 1 11/16-in. to 3⅛-in., generally do not have the performance characteristics of the larger "casing" guns. This includes entrance hole diameter, tunnel length, shot density, and phasing flexibility. Figure 125 shows that entrance hole diameters may be restricted to 0.25–0.35 and tunnel lengths less than 20 inches while larger guns can provide diameters up to 0.5 in. and 0.6 in. and lengths of 25–35 inches. This was covered in more detail in Chapter 4 of this report. Important to consider is that it is well accepted that a number of downhole variables affect the actual performance of perforating guns, including casing grade and stand-off (clearance).

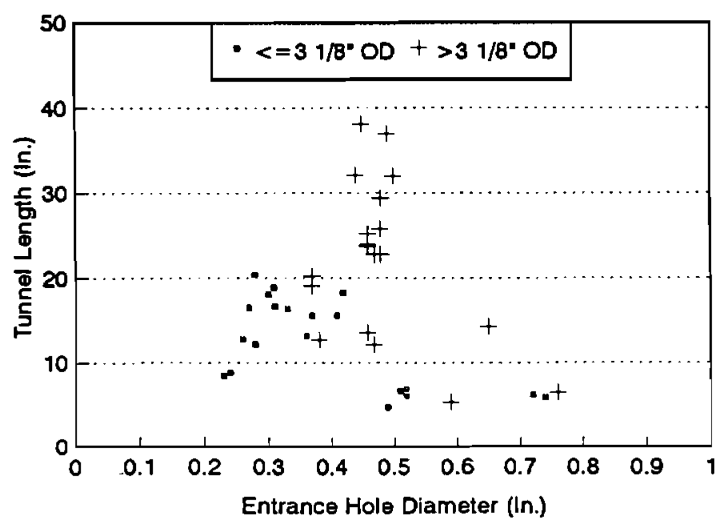

Figure 125. Typical Perforating Charge Performance

Smaller diameter perforations will increase the friction pressure through the perforations. Figure 126 compares the friction pressure through various size perforations. As shown, perforation friction increases rapidly as diameter is reduced from 0.5 to 0.25 inches. Although this increase is dramatic, the typical injection rates per perforation are usually low enough such that the friction pressure increase alone is manageable, especially with delayed cross-linking. However, this places an even greater emphasis on pretreatment ball-outs etc. to ensure that all perforations are open and receiving fluid as per the job design.

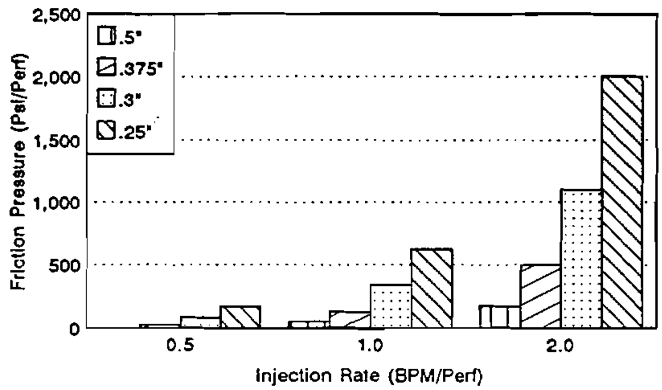

Figure 126. Perforation Friction

Uncertainty and greater inaccuracies in the calculation of friction pressure are also magnified with smaller diameter perforations. Accurate calculation or measurement of perforation and near-wellbore friction pressure have been shown to be extremely critical for accurate analysis of treating pressure and real-time decision making. Friction pressure is generally calculated from the flow equation for a sharp-edged orifice:

$$\Delta p = \frac{.000134 \; \varrho \; q^2}{C_d^2 \; d_o^4}$$

Δp = pressure loss, psi

ϱ = fluid density, lbm/gal

q = flow rate per perforation, gal/min.

d_o = perforation diameter, in.

C_d = discharge coefficeint

An important parameter with a large effect on calculated friction is the discharge coefficient, C_d, which accounts for errors associated with the sharp-edged orifice assumption (flow profiles, tunnel lengths, etc.). Perforation friction and the assumptions for C_d has been the subject of several studies in relation to hydraulic fracturing due to the importance of perforation friction in job design and treating pressure analysis. A recent study at the GRI/DOE/OU Fracture Fluid Characterization Facility (FFCF) concluded that actual perforation friction may differ by as much as 200% from that predicted by standard industry methods. Figure 127 from this study illustrates how C_d can vary substantially with fluid type and perforation diameter for non-cross linked fluids.

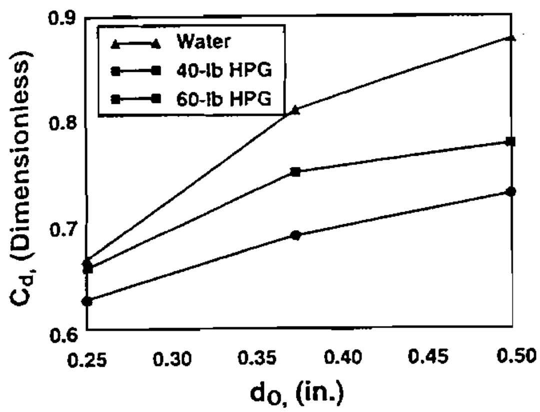

Figure 127. Perforation Discharge Coefficient vs. Perforation Diameter
(Lord et al, 1994)

Note the dramatic decrease in discharge coefficient with perforation diameter. This contrasts with usual industry practice of varying only the perforation diameter and not the discharge coefficient. Important to note is that this assumes the perforation diameter is consistent with the published performance data for the particular charge used, which may not be true due to downhole conditions that will vary with the API testing procedures.

The importance of the measurement of *actual* perforation friction, or total near-wellbore friction (perforation and tortuosity), by the use of rate changes or interruptions during treatments, has been well documented (Cleary et al, 1990). The use of these modern techniques is even more important in slim completions for more accurate treatment analysis and more accurate design of subsequent jobs in the immediate area.

6.7 PERFORATION EROSION

The erosion of perforations and the resulting decrease in perforation friction is an important component of fracture treatment design and analysis. It is accepted that all perforations erode with the pumping of a proppant-laden slurry during a treatment. Studies have validated that smaller diameter perforations will experience greater perforation erosion than larger perforations, as illustrated in Table 31.

TABLE 31. Perforation Erosion (Crump & Conway, 1988)

Perf. Dia. (in.)	% Area Increase
0.28	96
0.38	61
0.44	69
0.50	34

Perforation erosion during a treatment again increases the uncertainty of perforation friction associated with smaller diameter perforations that may be necessary in slim completions. Coupling erosion with the FFCF conclusion would indicate that not only will the diameter be increasing, but the discharge coefficient will also be changing throughout the job.

Perforation erosion is especially important to understand in the design and execution of limited-entry type treatments. Real-time and post-treatment analysis must also take perforation erosion into account.

6.8 NEAR-WELLBORE TORTUOSITY

The excessive near-wellbore friction associated with tortuous fluid paths and/or multiple fractures from the wellbore to the preferred fracture direction may also be increased with the reduced tunnel lengths, density, and phasing options available in smaller perforating guns. Interesting to note here is that most recent small diameter completions are placed in more conventional hole sizes. This increases the cement sheath thickness, in relation to a conventional completion, and increases the problems associated with reduced tunnel lengths.

The reduced phasing and density may be handled with multiple oriented gun runs, but this extra cost reduces the savings available from the slim-completion approach.

6.9 PERFORATION SHEAR

Considered an even more important concern with perforation diameter is the shear degradation to the fluid as it passes through the perforations. Figure 128 shows the shear rates seen by the fluid passing through various perforation sizes. It is important to note the magnitude of the perforation shear rates and injection rates in comparison to the rates shown for tubulars in Figure 128.

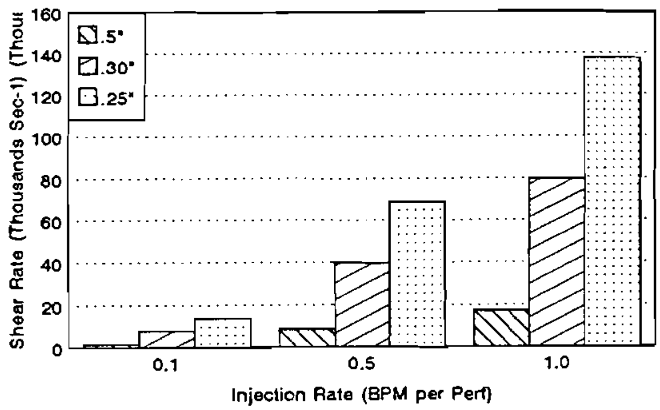

Figure 128. Shear Rate vs. Perforation Diameter

While the exposure time of the fluid through the perforations is small, the very large magnitudes of shear at the modest injection rates through the smaller perforations can still cause severe degradation to fracturing fluids, especially fully cross-linked systems. This once again points to the beneficial aspects of a cross-linking delay until the fluid is past the perforations, as well as the re-healing capabilities of a borate system.

6.10 TREATMENT DIVERSION

Techniques used to hydraulically fracture multiple horizons with differing fracture gradients include the use of ball sealers, limited-entry, ball-and-baffle, solid diverting agents, and conventional mechanical.

The use of ball sealers in slim completions may be more difficult because of the reduced clearances for the balls to pass each other. Bridging of the balls could be fatal to treatment execution.

Limited-entry diversion uses strategic perforation placement and associated perforation friction pressure to place desired volumes in various horizons. As discussed earlier, the magnitude of perforation friction pressures, inaccuracies in the calculation of friction pressure, and erosion tendencies of the smaller diameter perforations all contribute to greater uncertainties with the design, execution, and analysis of a limited-entry, multiple-zone fracture treatment in slim completions.

Conventional mechanical diversion with the use of retrievable or drillable bridge plugs and separate treatments remains an option with slim completions.

6.11 PROPPANT BRIDGING

Proppant diameter is chosen based on a required fracture conductivity to achieve a targeted fracture-to-formation permeability contrast. All else being equal, a larger proppant size provides greater fracture conductivity. This choice is then evaluated against operational constraints such as those imposed by perforation diameter, and other factors such as closure stress, fracture width, and proppant transport.

Perforation-to-proppant diameter guidelines vary with proppant concentration. In general, ratios of 6 or greater are recommended, but this can be relaxed with lower sand concentrations. Figure 129 illustrates proppant bridging tendencies with various ratios and sand concentrations.

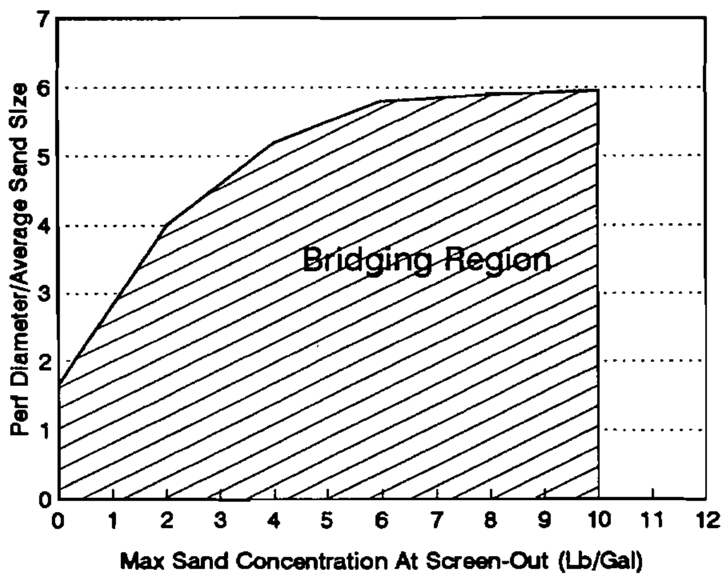

Figure 129. Proppant Bridging (Gruesbeck & Collins, 1978)

Recent laboratory research by Willingham et al. agrees with the prior work. In this study, proppant bridging of perforations occurred at 2 lb/gal with a ratio of 3.1, but with a ratio of over 7, the data indicated that bridging did not occur up to 10 lb/gal. The study concludes that a ratio greater than 5 is necessary for adequate proppant flow through perforations.

Table 32 shows that larger proppant sizes will approach this limit in the smaller perforation diameters. Therefore, proppant bridging tendencies may be greater than conventional in some slim-completion applications if forced to use smaller perforating equipment.

TABLE 32. Perforation-To-Proppant Diameter Ratios

PROPPANT	ENTRY HOLE SIZE			
	0.5-IN.	0.375-IN.	0.3-IN.	0.25-IN.
20/40	15	11	9	7
16/30	11	8	6	5
12/20	7	6	5	4

6.12 RECENT R&D WITH SLIM-COMPLETION RAMIFICATIONS

Recent cooperative field work between GRI and producers has demonstrated two important concepts that have important competing ramifications for slim-completion fracturing:

1) The use of higher sand concentrations in low permeability gas formations could be the most important design factor influencing well performance and can usually be successfully pumped.

2) Lower injection rates do not hinder the ability to pump successful jobs.

The use of higher sand concentrations will increase the friction pressure and erosion tendencies in smaller diameter perforations. This escalates the associated uncertainties in friction pressure and job performance, especially in limited-entry techniques. Fear of premature screen-outs with higher sand concentrations in smaller diameter perforations may limit the use of slim completions. However, the demonstrated use of lower injection rates helps slim-completion fracturing by lowering the friction pressure barrier that may have existed for some applications.

6.13 RECENT ACTIVITY

Chapter 2 of this report reviewed recent U.S. slim-completion activity. The use of 2⅞-in. and 3½-in. casing is increasing in Texas, Colorado, and Oklahoma gas wells. Most of the targeted formations in these slim-completion gas wells require substantial hydraulic fracturing. For example:

South Texas: Wilcox, Frio
East Texas: Cotton Valley
Oklahoma: Red Fork (Anadarko Basin)
Colorado: Codell, Niobrara (D-J Basin)
Wyoming: Mesaverde

Fracturing injection rates typically quoted for 2⅞-in. completion fracturing were 15 to 20 BPM with sand volumes of around 200,000 lb. However, rates of 30 BPM with 600,000 lb of sand were also mentioned. The use of 3½-in. casing, as has become prevalent in the D-J Basin, greatly expands the capability and reduces the concerns associated with hydraulic fracturing in slim completions.

6.14 CONCLUSIONS AND RECOMMENDATIONS

As expected, the greatest perceived barrier for slim-completion hydraulic fracturing is the friction pressure associated with smaller diameter tubing and perforations. While this is unavoidable, recent advancements in fluid technology and field research on the role of injection rate should reduce this perceived barrier in a greater number of applications. Recent increases in slim-completion activity in gas reservoirs requiring hydraulic fracturing reinforce this point.

The greatest barriers for increased use of slim completions in gas wells requiring hydraulic fracturing are decreased perforating options. Hole diameter, tunnel length, and phasing and shot density options all decrease with the smaller equipment that must be used in smaller diameter casing. This increases perforation friction, shear, and proppant bridging tendencies. The uncertainties with calculation of friction pressure, which becomes critical in limited-entry diversion, is increased.

To assist with greater cost-beneficial utilization of slim completions, GRI should consider focused research on the following subjects:

- A comprehensive review of current slim-completion practices in reservoirs requiring hydraulic fracturing. This should include thorough treatment of fracturing practices such as depths, casing design, perforating techniques, fluid and proppant volume and type, sand concentrations, injection rates, diverting techniques, design methodology, etc. To help in transferring existing technology in use today to a greater number of operators and applications, a slim-completion database could be developed and distributed containing selected completion information.

- Better understanding of clean and proppant-laden tubular and perforation friction pressure under slim-completion conditions with modern frac fluids, especially energized fluids.

- Better understanding of fluid rheology, shear rates and associated fluid damage on modern frac fluids under slim-completion conditions.

- Better understanding of proppant bridging tendencies under slim-completion conditions.

- Perforating technology for possible alternatives to current small diameter tool limitations with respect to hole diameter, tunnel length, shot density, and phasing options.

- Proppant bridging tendencies under vertical and deviated slim-completion conditions.

- Development and testing of advanced diversion techniques for use in small diameter tubulars.
- Development of advanced fracture fluids with low friction and shear damage characteristics.

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7. Slim-Hole Completion, Workover, and Fishing Tools

7.1 INTRODUCTION

Retaining completion and workover flexibility is an important consideration when analyzing slim-hole options. In each case, the savings in initial drilling and completion costs must be compared with any potential reductions in productivity or operability. This chapter addresses the tools most commonly associated with the completion, recompletion, and mechanical repair of oil and gas wells and the limitations in availability, or reductions in performance standards, for smaller diameter completions.

7.2 COMPLETION TYPES

7.2.1 Conventional U.S. Standard Size Completion

This completion, characterized by 5½-in. casing, a production packer and no liner, is widely used in U.S. land applications. It provides maximum flexibility, a fairly large production ID (usually 2⅞- or 2⅜-in.) and uses widely available casing and tubing sizes. Workover operations (i.e., squeeze perfs, change intervals, or scrape casing) usually require the tubing to be removed to use conventional workover tools. Through-tubing inflatable wireline and coiled-tubing workover tools are now allowing more flexibility in performing workovers and recompletions without having to pull tubing.

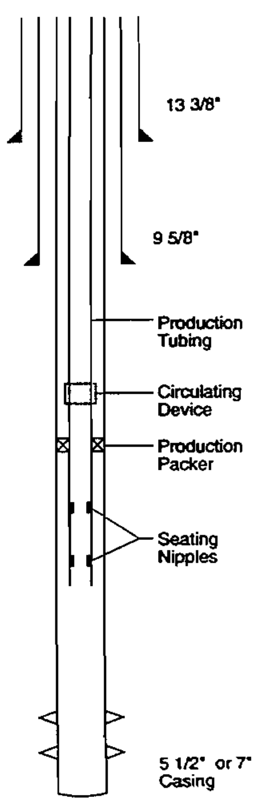


Figure 130. Typical Domestic Onshore Completion

7.2.2 Conventional International Completion

This completion, common to offshore operations and many areas outside the U.S., utilizes 9⅝-in. casing and allows the use of a liner across the formation to control drilling or reservoir problems. Like the U.S. standard size completion, it offers maximum flexibility and widely available material sourcing. Considerations are similar to those described for the conventional U.S. completion.

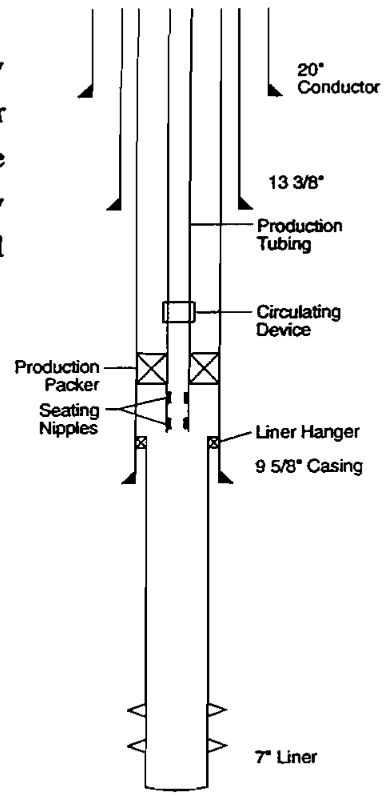


Figure 131. Typical International Offshore Completion

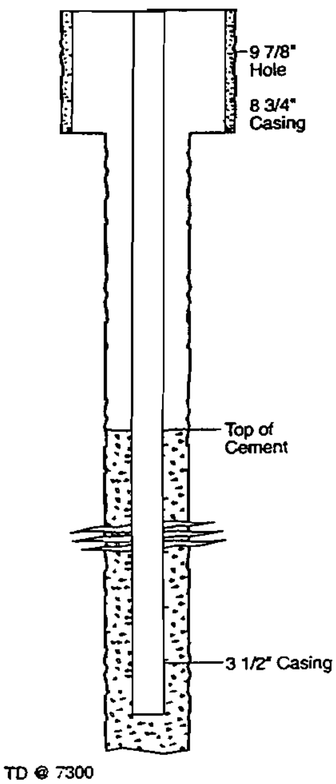


Figure 132. Tubingless Completion

7.2.3 Tubingless Slim-Hole Completion

The simplest of all slim-hole completions, tubingless completions are often the most cost effective alternative for applications where there is no production casing annulus required for artificial lift and where consequences of a casing leak are minor. Tubingless slim-hole completions are common in South Texas Wilcox and Frio, the Anadarko Basin, and the D-J Basin.

This type of completion is most suitable for shallow formations with relatively mild temperatures and little or no corrosion. However, it becomes problematic if fracing operations require pumping cold fluid into warmer environments. In these instances, the pipe may part at the surface. Additionally, with the tubing cemented in place, there are only limited remedial alternatives to handle thread leaks or corrosion.

7.2.4 Slim-Hole Conventional Completion

In many areas, a conventional well design modified for 3½- versus 5½-in. casing offers a cost-effective alternative to a standard size completion. This type of completion is particularly effective for certain wells where production tubing is required for vertical flow stability or artificial lift. They also allow zonal selectivity it that multiple packers and sliding sleeves can be utilized.

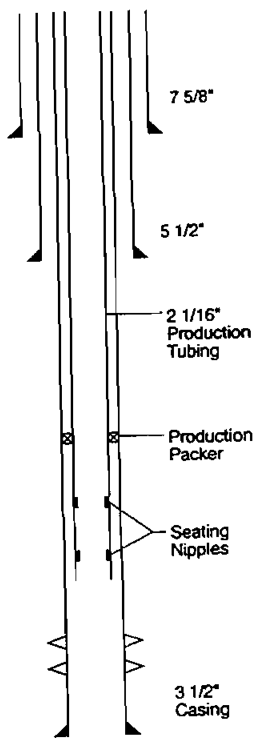


Figure 133. Slim-Hole Standard Completion

7.2.5 Slim-Hole Velocity String Completion

The availability of coiled tubing in diameters of 2 in. and larger has made it a viable alternative to jointed tubulars for slim-hole completions, both for initial and recompletion applications. In fact, it has become routine to install coiled tubing in existing gas wells to increase the velocity of the produced fluid. In this application, the coiled tubing is run inside the existing well and then sealed off in the packer. The smaller ID causes the fluid velocity to increase and as a result, more fluid is carried out of the hole. An alternative completion uses coiled tubing to create an annular flow path between the coil OD and the tubing ID.

The only real limitation to this type of completion is the coil itself. Because stainless steel coiled tubing is not yet available, applicability is limited to relatively non-corrosive, carbon steel environments.

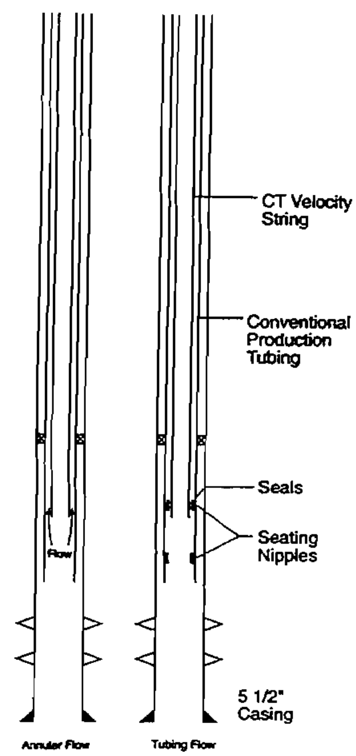
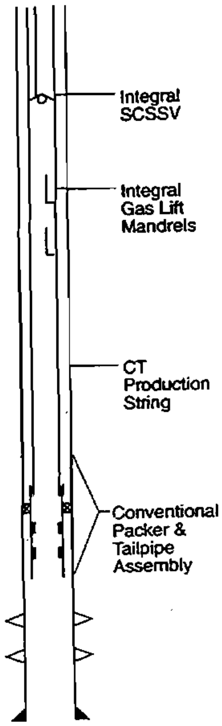


Figure 134. Velocity String (Retro-Fit Applications)



7.2.6 Slim-Hole Coiled-Tubing Completion

Recent innovations have made it possible to install coiled tubing complete with packers, subsurface safety valves and gas lift mandrels to serve as either an initial well completion or a recompletion. Both conventional and spoolable coiled tubing completions are available. However, a major limitation is that because the accessories are fixed, it is not possible to run tools through the inside of the coiled tubing. As a result, the entire coiled tubing string must be retrieved before work can take place downhole. Workover time is reduced, however, due to the quick retrieval rate of the coil.

Figure 135. Coiled-Tubing Completion

7.2.7 Slim-Hole Monobore Completion

An emerging trend in slim-hole wells, particularly in areas where a high degree of reservoir workover activity is anticipated, is to complete the wells as "monobores." The primary feature of a monobore completion is that the production tubing is the same diameter or larger than the production liner, and there are no permanent diameter restrictions such as restrictive nipples or locator seal assemblies to limit full-bore access to the productive horizon. As a result, access to the reservoir for workover purposes is unlimited, and the tubing can be left in the well for the life of the completion.

The key advantage of monobore completions is that the opportunity for effective low-cost (i.e., rigless) well intervention is maximized, which increases the ease with which wells and therefore reservoirs can be managed. Another major advantage is that well impairment and formation damage are avoided, since intervention operations can be safely conducted via wireline, braided line and coiled tubing on live wells without the use of kill fluid.

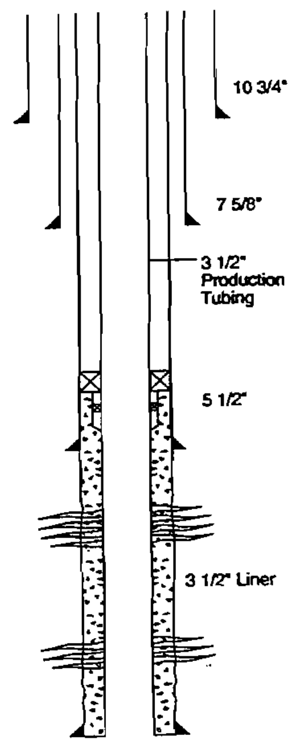


Figure 136. 3½-in. Monobore Completion

Other advantages of monobore completions are:

- Initial completion is simple and requires a minimum of equipment to be installed in the well; advanced options can be installed later.
- Workover costs are reduced. When workovers must be performed in the liner, rather than having to mill out the packer and pull the pipe out of the hole, all the equipment stays in the hole; workovers are accomplished on wireline, electric line, coiled tubing or snubbing and can be carried out without shutting down operations on an offshore platform.
- The smooth bore reduces pressure loss.
- Full-bore production logging tools can be run.
- Larger perforating guns can be run into the production liner through the tubing.
- Reliable and widely available low-expansion, selective placement tools can be used within the liner.
- The completion is less sensitive to scale/paraffin problems, and full bore casing milling is achievable if the problem does occur.

Monobore completions are particularly advantageous in situations where water or gas breakthrough and/or the presence of scale or paraffin necessitate constant reservoir workover procedures. Monobores are also recommended for stacked reservoirs with plug-and-abandon intervals, such as bottom-up water encroachment. In these situations, a monobore completion makes it possible to run a bridge plug and continually shut off the water from below, and move up the hole without having to move a lot of equipment to location.

The major limitation to monobore completion technology is in the area of multiple zone completions. The monobore completion is not well suited to wells where zonal selectivity and the absence of commingling are required.

7.3 COMPLETION TYPE FUNCTION COMPARISON

The following table presents a comparison of operability functions for five completion types: standard size, slim-hole conventional, slim-hole coiled tubing, slim-hole monobore and slim-hole tubingless. Basic advantages and disadvantages of each type are shown in Table 33.

TABLE 33. Comparison of Completion Operability Functions

Function	Conventional Size Completion	Slim-Hole Standard	Slim-Hole Coiled Tubing (1)	Slim-Hole Monobore	Slim-Hole Tubingless
Temporary abandonment of zones...lower	Use of CT or E-line to set inflatable bridge plugs	Same as conv. down to 2⅞"	Not practical w/o tubing retrieval	Retrievable plug set on E-line	Retrievable plug set on E-line
Temporary abandonment ...intermediate or upper	Use of CT to set inflatable straddle tool which limits ID or do cement squeeze with inflatable	Same as conv. down to 2⅞"	Not practical w/o tubing retrieval	Mechanical straddle assembly or conventional block squeeze	Mechanical straddle assembly or conventional block squeeze
Permanent abandonment ...lower	Cement or inflatable	Same as conv. down to 2⅞"	Not practical w/o tubing retrieval	Cast iron plug or cement	Cast iron plug or cement
Permanent abandonment ...intermediate or upper	Cement squeeze with inflatable packer assembly	Same as conv. down to 2⅞"	Not practical w/o tubing retrieval	Mechanical straddle assembly or conventional block squeeze	Mechanical straddle assembly or conventional block squeeze
Remedial and stimulation work	Mechanical tools can be used after tubing is pulled or inflatable thru-tubing products	Same as standard down to 2⅞"	Conventional available down to 2⅞" after tubing retrieval	Conventional available down to 2⅞"	Conventional available down to 2⅞" after tubing retrieval
Recompletion	Conventional methods	Same	Pull coil then conventional	Straddle assemblies and inflatable products	Straddle assemblies and inflatable products
Artificial lift	ESP, gas lift, rod pump, jet pump	Gas lift, rod pump, jet pump	ESP, gas lift	ESP, gas lift, rod pump and jet pump	Rod pump

Notes: (1) Assumes CT completion has concentric accessories which restrict ID such as gas lift valves, if not, see slim-hole standard.

7.4 SLIM-HOLE TOOLS

The following section outlines the types of equipment available in slim-hole sizes. One of the major barriers to increased utilization of slim-hole techniques is making this slim-hole equipment as accessible to operators as the current 5½ in. to 9⅝-in. standards are in their respective areas. Standard size tools are generally available "off-the-shelf" while slim-hole sizes may require increased lead times for initial procurement as well as servicing of workover tools. Pricing may also be at a premium for some small diameter equipment.

7.4.1 Completion Equipment

Liners and liner hangers	Liner hangers, both hydraulic and mechanical, have been developed for use with 3½-in. liners. The hydraulic version can be set in 5 in. or larger casing, while the mechanical version can be set in 5½ in. or larger casing. These hangers allow the liner to be rotated to bottom as necessary and can include a reaming shoe on bottom if required. A two-plug cementation system ensures separation of the cement from the drilling fluid during displacement. These plugs can wipe drill pipe as small as 2-in. ID and still effectively wipe the 3½-in. liner.
Production bridge plugs	Wireline set (E-line or slickline) and wireline retrievable bridge plugs for use in production applications have been developed in sizes as small as 2⅞ in. These tools typically have a 5000 psi pressure rating with 7500 psi available on request. Applications are illustrated in Figure 137.
Retrievable straddle systems	Retrievable straddle systems that can be set by electric line or coiled tubing are available for use in 3½-in. and larger liners. The ID through the coiled tubing set version is large enough to allow remedial work through it with inflatable products. Straddle lengths range from 10-300 ft.
Artificial lift equipment	Side pocket mandrels are available for use in 5½ in. x 3½ in. completions that utilize a ¾-in. gas lift valve. ESP pumps with a 4.00-in. OD are standard in the U.S., with pumps as small as 3.375-in. OD available for use in 4½-in. casing.

Rod pumps can be used in tubing as small as 1.660-in. OD with plunger ODs as small as 1- $^{1}/_{16}$ in. Jet pumps which can be landed in sliding sleeves are available in tubing sizes as small as 2⅞-in. OD.

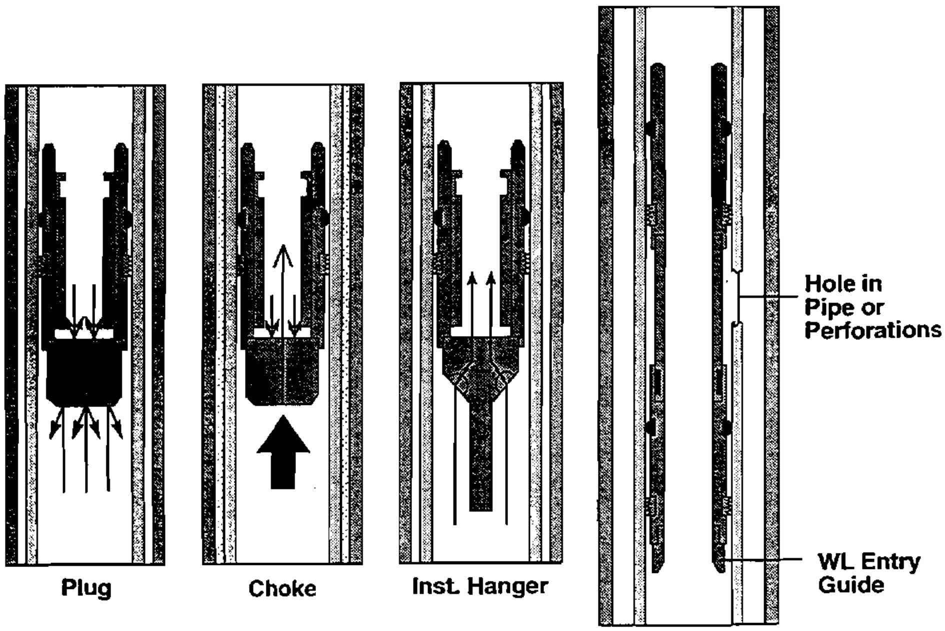


Figure 137. Production Bridge Plug Applications

Production packers

Production packers are available for 2⅞ in. through 5½-in. casing. These tools have a proven history of providing long-term isolation even in the most hostile environments. Retrievable packers for use in 2⅞-in. casing and 1.315 in. OD tubing are available as are permanent packers as small as 2⅜-in. x 0.750-in. ID. In the more common 5-in. and 5½-in. casing sizes, tubing sizes of 2⅞ in. can be accommodated (Table 34). However, the ID of the permanent packer for use in less than 4-in. casing and retrievable packers for use in less than 4½ in. casing is less than the OD of most common wireline tools ($1^{11}/_{16}$ in).

TABLE 34. Production Packers

Packer Type	Casing	Packer Max OD	Min. ID thru Packer
Permanent	2.375	1.75	0.75
Permanent	2.875	2.22	1.25
Permanent	3.5	2.562	1.375
Permanent	4	3.187	1.875
Permanent	4.5	3.609	2.39
Permanent	5	3.968	2.39
Permanent	5.5	4.437	3.055
Packer Type	**Casing**	**Packer Max. OD**	**Min. ID thru Packer**
Retrievable	2.875	2.234	0.75
Retrievable	3.5	2.782	1.375
Retrievable	4	3.303	1.5
Retrievable	4.5	3.786	1.89
Retrievable	5	4.14	1.89
Retrievable	5.5	4.66	2.375

Inflatable completion packers

Full-bore external casing packers (ECPs) are available for 3½ in. production liners. The OD has been reduced so that the ECP can be run in a 4¾-in. hole with a buildup rate of up to 20 deg/100 ft. For open holes that are drilled smaller than 4¾ in., production injection packers (PIPs) can be run with ODs as small as 1.50 in.

An inflatable packer is also available for short radius reentry completions. The 2.125-in. OD tool can be run and set inside 4¾-in. hole drilled with a radius as small as 20 ft.

Safety valves

Tubing retrievable safety valve sizes range from 6000 psi 2⅜-in. valves with 3.625-in. OD for use in 4½-in. casing to 3000 psi 3½-in. valves with 4.76-in. OD for use in 5½-in. casing. Work on slimmer envelope valve designs will continue as the market progresses.

Wireline retrievable safety valves are available in sizes for use in tubing as small as 2⅜ in. with 0.80 in. flow areas.

Flow control

Standard flow control equipment in the form of nipples, sliding sleeves and blanking plugs is available in tubing sizes ranging from 1.660-in. OD x 1.187-in. ID through 3½-in. OD x 2.813-in. ID. Maximum ODs are compatible with most casing combinations.

Sand control options

Conventional gravel packs inside 3½-in. tubing are available. Equipment is currently available which allows zones to be gravel packed using the squeeze or circulation method. The ID of such assemblies is about 1.0 in., making this method of sand control potentially unsuitable for higher rate production wells (Table 35).

Prepacked screens or slotted liners can be run in as part of the production string. This method may only be appropriate when limited sand production is expected.

Frac packs, whereby resin-coated proppant is squeezed into perforations to control sand production, can be used in slim-hole wells with fairly short production intervals.

The reservoir sand can also be consolidated in situ currently available consolidation chemicals, provided zone length is around 10 ft. To reliably consolidate longer zones requires a resettable selective stimulation tool which has not yet been developed for 3½-in. sizes.

TABLE 35. Gravel Pack Equipment

Pipe Size	Weight lb/ft	Pipe ID inches	Coupling ID inches	Screen OD inches
2$^{1}/_{16}$"	3.25	1.751	2.5	2.63
2⅜"	4.6	1.995	2.875	2.97
2⅞"	6.4	2.441	3.5	3.48
3½"	9.2	2.992	4.25	4.13
4	9.5	3.548	4.5	4.65

Coiled tubing	Integral gas lift mandrels and surface-controlled subsurface safety valves are available for use in spoolable coiled tubing completion strings. These integral tools provide a smooth OD but restrict the ID, so the passage of wireline tools is not possible. Conventional flow control equipment and hydraulic packers can also be used on coiled tubing by simply making a welded splice at the required locations. However, these tools require the use of specialized handling equipment as the OD will not pass through standard injector heads. Splices are typically made between the injector are used and the BOPs, or specialized injectors that allow a temporary OD increase.

7.4.2 Workover Equipment

Remedial and stimulation equipment (mechanical)	Remedial cementing and stimulation packers are available in sizes from 2⅞ in. Mechanical selective wash tools are currently available only in sizes down to 4½ in.
Inflatable workover	Inflatable workover packers are relatively new innovations. They are designed with inflatable packer elements that allow you to pass through restrictions and set in larger IDs. Electric wireline set retrievable bridge plugs and CT tubing set plugs can be used for permanent or temporary zone abandonment. These are available as small as 1.69 in. uninflated. The retrievable bridge plugs can be retrieved on coiled tubing or slick line. A resettable, inflatable, selective straddle tool with a 2.125-in. OD is available for use in slim-hole wells. It can be used for selective stimulation of production intervals.
Cast iron products	Cast iron bridge plugs and cement retainers are currently available in sizes down to 2⅜ in. for plugs and 2⅞ in. for retainers.
Retrievable bridge plugs	Wireline set (E-line or slickline) and wireline retrievable bridge plugs for use in production applications have been developed in sizes as small as 2⅞ in. These tools typically have a 5000 psi pressure rating with 7500 psi available on request.

Reperforation options — Tubing-mounted guns as small as 2¾ in. are available as are wireline retrievable guns as small as $1^{11}/_{16}$-in. OD.

7.4.3 Fishing Equipment

Open hole fishing tools — Fewer options for fishing tubulars and BHAs are available in slim-hole wells because of hole size restrictions. Table 36 and Table 37 summarize the currently available tools and options.

As shown, preferred external (washover-overshot) fishing tools are available for aggressive slim-hole conditions, such as 2⅞-in. drill pipe and 3⅛-in. drill collars in a 4¾-in. hole. However, the ability to jar and the allowed amount of overpull are more limited than in conventional operations. This is simply due to the reduced amount of strength available (less steel) with the thin-wall tools.

Thru-tubing fishing tools — Proven tools are now being downsized to work in thru-tubing or slim-hole applications. Currently available are hydraulic and mechanically actuated thru-tubing fishing tools, descaling and underreaming tools, internal hydraulic cutting tools and thru-tubing whipstocks.

TABLE 36. Fishing Tools

Size of Fish	Fishing Tools	Size of Tool	Action
2⅞" DP body 2⅜" DP body	Overshot or Spiral Grapple	4" FS 3¾" SH	Pulling and jarring Pulling only
3⅛" DC or OD tool joint 3⅜" OD tool joint	Overshot or Spiral Grapple	4" SH or 3⅞" SH 3⅞" XSH	Pulling and jarring Pulling only
3½" DC or OD tool joint	TSWP washover shoe TSWP top sub TSWP washover extension Slim-hole overshot w/3½" slips	4" $4^{1}/_{16}$"	Pulling Pulling 44,000 lbs maximum
3¾" tools	Slim-hole overshot w/3¾" slips	$4^{1}/_{16}$"	Pulling 44,000 lbs maximum

TABLE 37. Fishing Options

Hole Size	Fish Size	Maximum Size for Current Overshot	Optional Fishing tools
4.750	3.750	4.625 x 3.875	Box Tap, Spear or Taper Tap
4.500	3.750	4.375 x 3.500	Box Tap, Spear or Taper Tap
4.125	3.750	4.0625 x 3.875 (Bull Dog)	Box Tap, Spear or Taper Tap
3.875	3.125	3.750 x 3.063	Box Tap, Spear or Taper Tap
2.625	2.375	2.313 x 2.000	Box Tap, Spear or Taper Tap

7.5 CONCLUSIONS

There is a wide range of downhole conditions found in wells across the U.S.and completion and workover tools are available in conventional sizes to address just about every special need. The fact that this entire range of tools is not available in smaller sizes drives the perceptions regarding limited tool and workover options for slim completions. This wide range of tools and needs is evidenced by respondents to the recent Worldwide Market Assessment of Slim-Hole Technology by Resource Marketing International. In this assessment, similar to the GRI survey, 40% of the respondents indicated limited completion options were a problem and 30% indicated limited workover hardware needed development, 21% (the largest single response item) did not know what specific tool developments were needed. However, basic small completion and workover tools for conditions found in many U.S. gas well applications are available, ***especially for 3½-in. slim completions.*** Systemization and refinement of the existing tools, as well as development of a wider range of tools for more specific and hostile conditions, is ongoing by suppliers. This effort will be accelerated only by increased usage and demand.

Although tubulars are not considered completion tools per se, recent developments illustrate how demand in slim completions can drive equipment availability and increased options. Twelve months ago, there was only one supplier (each) for 3½-in. casing and $2^1/_{16}$-in. tubing, severely limiting availability and relative price advantage. Large projects in the D-J Basin have resulted in the number of suppliers increasing to five with significant decreases in price and increased availability.

Slim-completion economics must be assessed with realistic limitations and workover risks included; however, options have expanded considerably and these should be explicitly investigated when determining the risks, without reliance on dated opinions within an organization.

The specific objectives of this effort were to identify the current drilling and completion methods, concerns of D-J Basin operators related to slim-hole techniques, cost-savings they were achieving over conventional-sized wells, and what further cost reductions might be expected by solving some of their particular problems. The approach taken was to interview operators to understand their current slim-hole procedures, costs and views on needed technology development, to forecast future potential slim-hole drilling activity in the basin (for the period 1996-2005), and to estimate the benefits to industry and potential market for slim-hole drilling over the same time period.

8.1 DESCRIPTION OF PLAYS

As one of the largest basins in the Rocky Mountain region, the D-J Basin covers over 60,000 square miles (Figure 139). Located at the foot of the Rocky Mountains, this asymmetric basin covers most of the eastern Colorado and portions of Wyoming and Nebraska and has produced most of its hydrocarbons from stratigraphic traps in Cretaceous age rocks. The majority of the gas production has been from five Cretaceous horizons (Figure 140 and Table 38). These are described in the following sections.

8.1.1 The Muddy (J) Sand and D Sand

The first plays to be established in the D-J were the Muddy (J) Sand and the D Sand along the eastern flank of the basin in the 1950s. These plays dominated D-J drilling activity into the early 1970s with Muddy (J) Sand drilling continuing at a strong pace into the early 1980s. This later drilling activity was largely a result of the Wattenberg Field development (Figure 141), which was first developed as a Muddy (J) Sand field. Similar to the D Sand, oil and gas is produced from a series of fields between Wattenberg and the Nebraska panhandle. Production depths range from 3900 ft to 8400 ft. This reservoir consists of fine- to medium-grained, well-sorted sandstones, siltstones, and mudstones. The Muddy (J) Sand thickness ranges from a few feet to approximately 150 ft, although it is generally less than 100 ft thick. The D Sand reservoir consists of fine-grained, well-sorted, cross-stratified sandstone and is found at depths of 4000 to 8200 ft in the production fairway. The gross thickness of the D Sand ranges from a zero depositional edge to 100 ft thick. Some of the major Muddy (J) Sand fields are illustrated in Figure 142 with specific field information presented in Table 39. Similar information for the D Sand is presented in Figure 143 and Table 40.

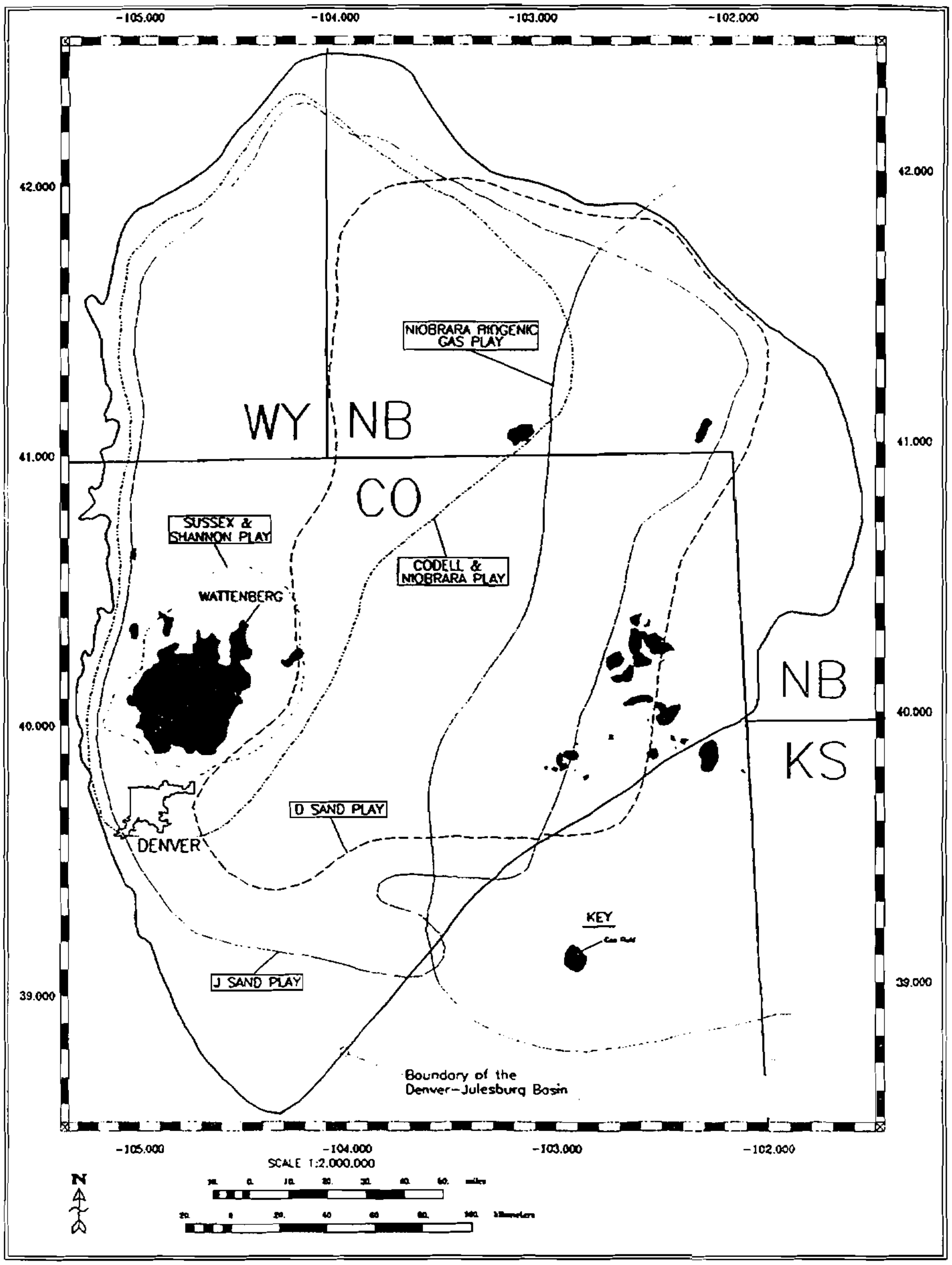


Figure 139. D-J Basin Play Areas (Hemberg and Hjellming, 1933)

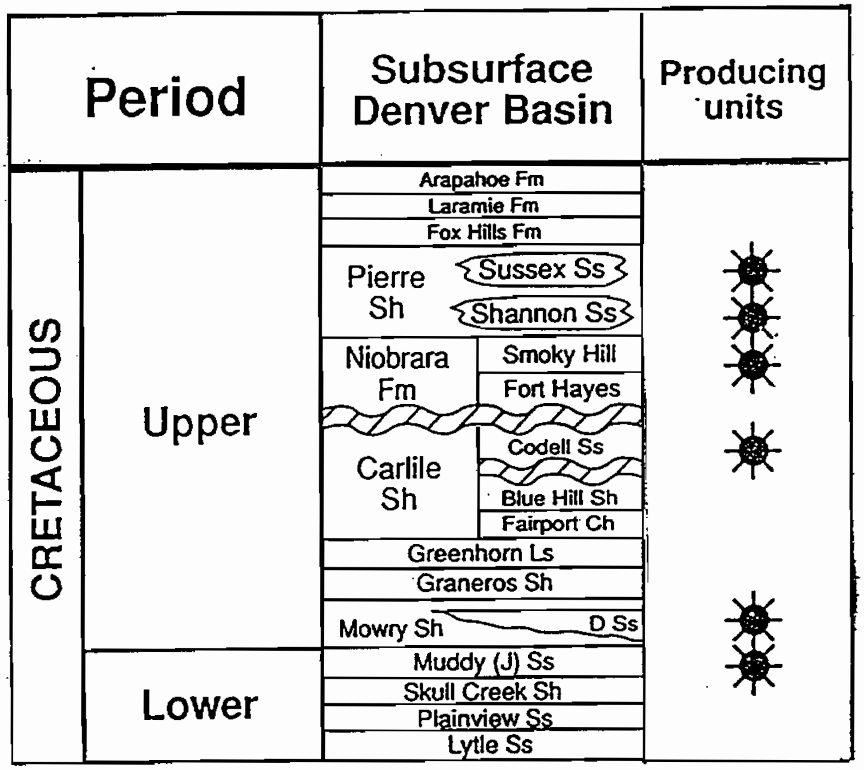


Figure 140. Cretaceous Stratigraphy of the D-J Basin (Hemberg and Hjmelling, 1933)

TABLE 38. D-J Basin Gas Production and Wells By Play (Colorado Portion)

Figure Play/Reservoir	Cumulative Gas Production (Tcf)	Active Gas Wells
Muddy (J) Sand	0.81	1500
Sussex/Shannon	0.28	1350
D Sand	0 20	240
Codell/Niobrara Formation	0.17	2400
Niobrara Chalk Biogenic Gas Play	0.10	450
TOTALS	**1.56**	**5940**

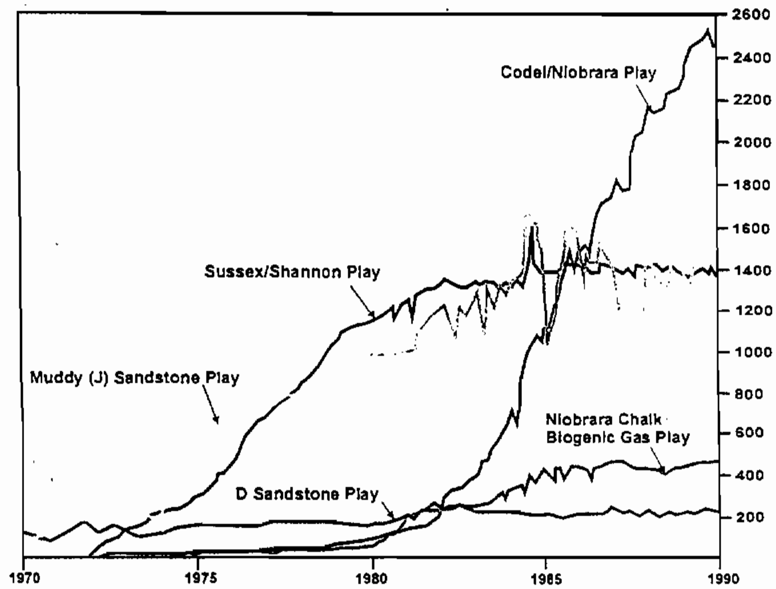


Figure 141. D-J Basin Historical Drilling Activity

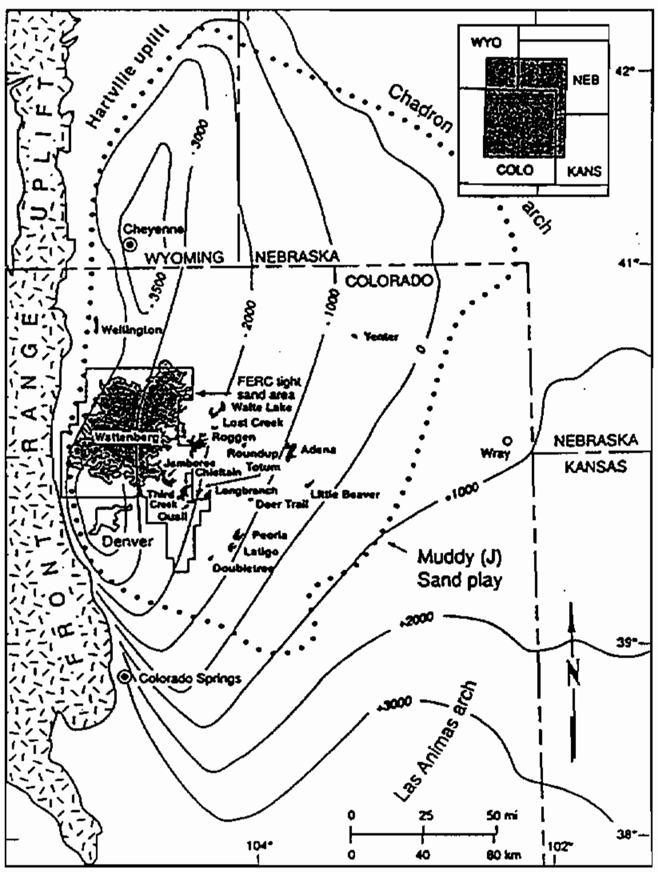


Figure 142. Major Fields in the Muddy (J) Sandstone Play

TABLE 39. Summary of Major Muddy (J) Sandstone Fields

Field	Discovery	Wells	Spacing (Acres)	Depth (ft)	Type of Gas	Drive Mechanism	Cum. Prod. (BCF)
Yenter	1950	7 (76 aban.)	20	5200	Associated	Gas Cap	24
Adena	1953	146 (29 aban.)	40	5600	Associated	Pressure Depletion	71
Wattenberg	1970	1360 (117 aban.)	320	7600	Associated	Pressure Depletion	521
Peoria	1970	19 (44 aban.)	80	6500	Associated	Solution Gas	25
Third Creek	1971	51 (1 aban.)	80	8150	Associated	–	31
Longbranch	1972	10 (4 aban.)	320	7100	Associated	Pressure Depletion	22

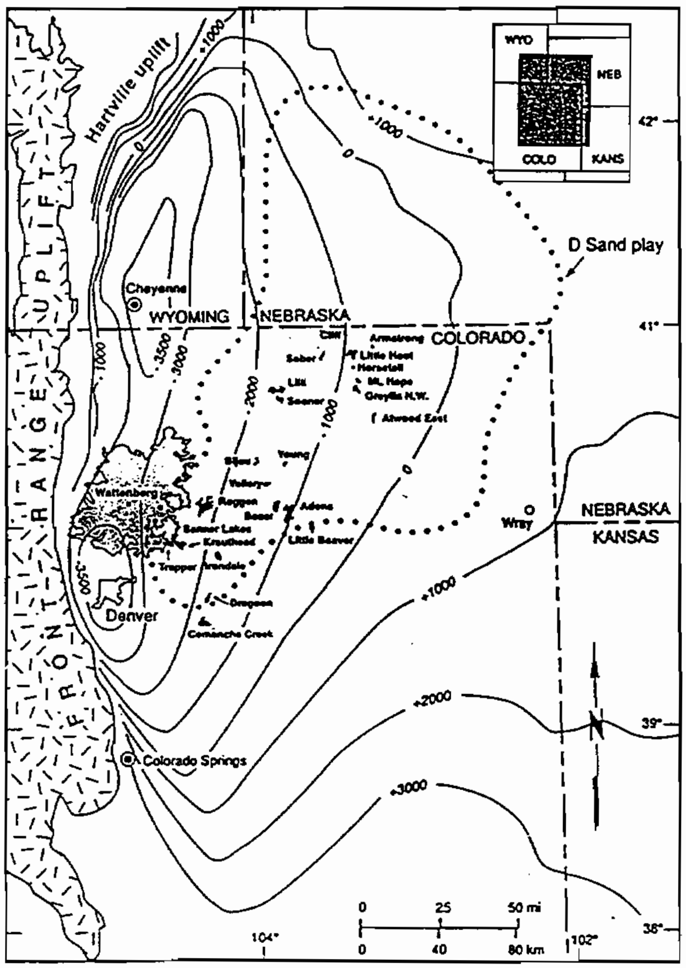


Figure 143. Major Fields in the D Sand Play

TABLE 40. Major D Sand Fields

FIELD	DISCOVERY	WELLS	SPACING (ACRES)	DEPTH (FT)	TYPE OF GAS	DRIVE MECHANISM	CUM. PROD. (BCF)
Little Beaver	1951	15 (54 aban.)	20	5233	Associated	Solution Gas	11
Adena	1953	7 (24 aban.)	40	5656	Associated	Pressure Depletion	19
Cliff	1955	7 (25 aban.)	40	5495	Associated	Pressure Depletion	13
Saber	1962	1 (14 aban.)	40	5620	Associated	Solution Gas	14
Boxer	1965	4 (31 aban.)	40	5840	Associated	—	10
Lilli	1987	60	80	6300	Associated	Pressure Depletion	15

8.1.2 Sussex (Terry) and Shannon (Hygiene) Sandstones

Also in the 1970s, the Spindle Field, located within the Wattenberg Field but producing from the Sussex/Shannon sandstones, was developed. The Sussex and Shannon reservoirs occur in the Terry and Hygiene Members, respectively, of the middle Pierre Shale (Figure 140). These members are marine shelf deposits of upward-coarsening sequences of interbedded sandstones, siltstones, and shales. The best wells produce from cross-bedded, fine- to medium-grained sands, deposited in the high energy, crestal position of offshore marine bars. Drilling depths to the Sussex and Shannon Sandstones in this area are 4300 ft and 5000 ft, respectively. Pay zones are 25 ft thick in the Sussex and 20 ft in the Shannon. The Spindle field is the second largest gas field in the D-J Basin and has produced 239 Bcf from the Sussex and Shannon reservoirs. This and other major Sussex/Shannon fields are illustrated in Figure 144, with specific field information presented in Table 41.

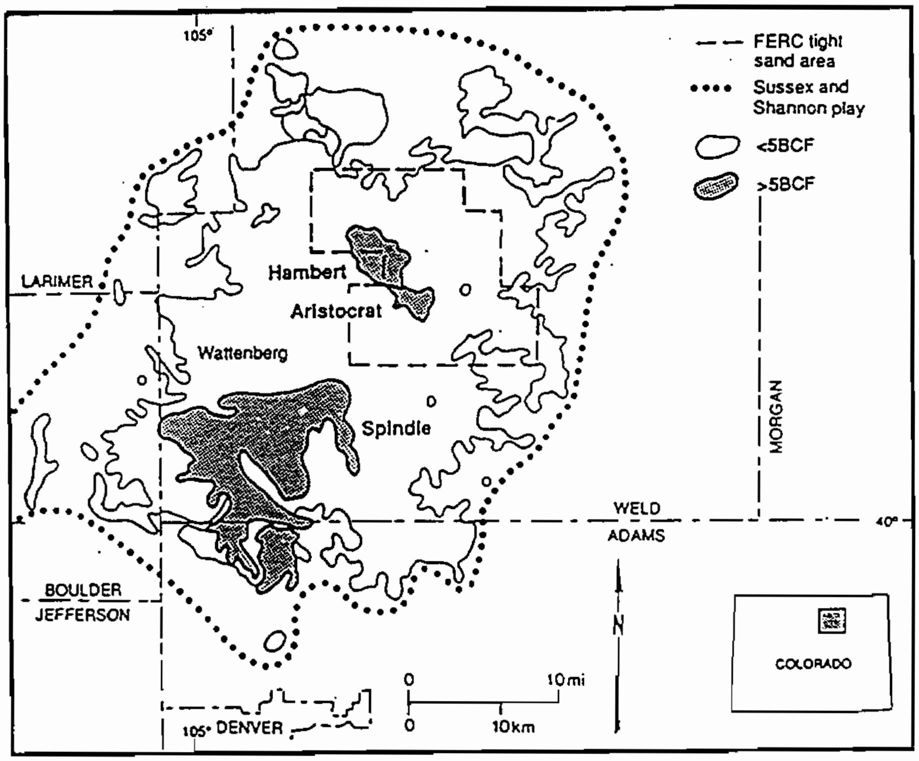


Figure 144. Major Fields in the Sussex/Shannon Play

TABLE 41. Summary of Major Sussex/Shannon Fields

FIELD	DISCOVERY	WELLS	SPACING (ACRES)	DEPTH (FT)	TYPE OF GAS	DRIVE MECHANISM	CUM. PROD. (BCF)
Spindle (Sussex)	1972	909 (21 aban.)	40	4800	Associated	Solution Gas	127
Spindle (Shannon)	1972	444 (12 aban.)	40	4738	Associated	Solution Gas	112
Hambert (Sussex)	1975	69 (10 aban.)	160	4660	Non-Associated	Solution Gas	37
Aristocrat (Sussex)	1978	17 (1 aban.)	40	4400	Non-Associated	Solution Gas	10

8.1.3 Niobrara Formation

In the 1980s and continuing today, the Niobrara is an active drilling horizon in the D-J Basin. The Niobrara Formation consists of alternating chalks and organic-rich calcareous shales. This formation is divided into two members, the basal Ft. Hays Limestone and the overlying, gas producing Smokey Hill Member. Production is derived from four 20-30 ft chalk zones dispersed throughout the formation. Two portions of the D-J Basin produce gas from the Niobrara Formation. In the Wattenberg area, the Niobrara produces gas from depths from between 4000 and 8000 ft, whereas in eastern Colorado, this sand reservoir is at depths of 900 to 3200 ft. The type of gas produced in these two areas also differs. Niobrara gas production in eastern Colorado is dry, biogenic gas, in contrast to the wet condensate that is produced in the Wattenberg area. Figures 145 and 146 illustrate the location of major fields in the eastern biogenic gas play and those in the Wattenberg area respectively, with specific field information by play provided in Tables 42 and 43.

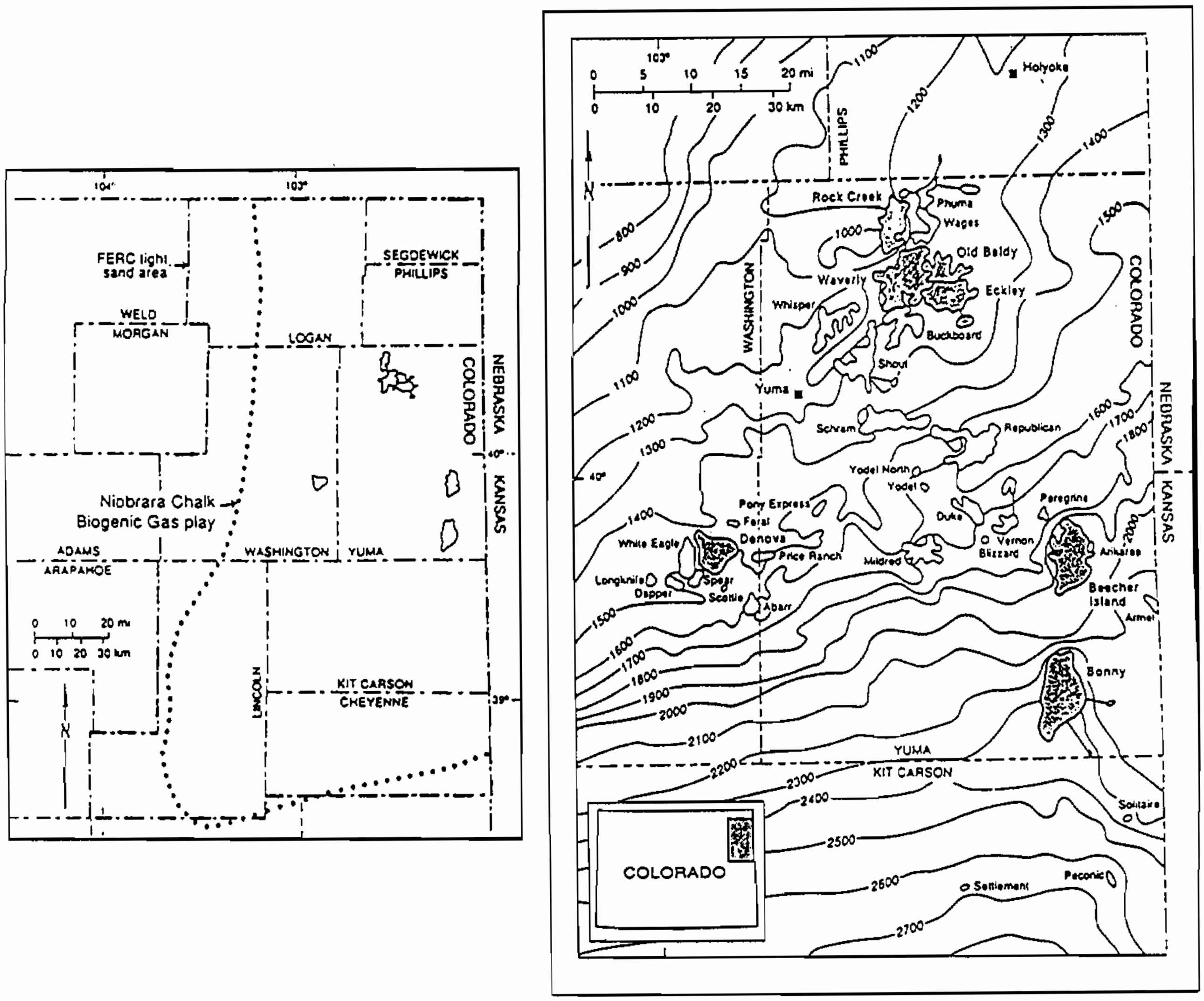


Figure 145. Major Fields in the Niobrara Chalk Biogenic Gas Play

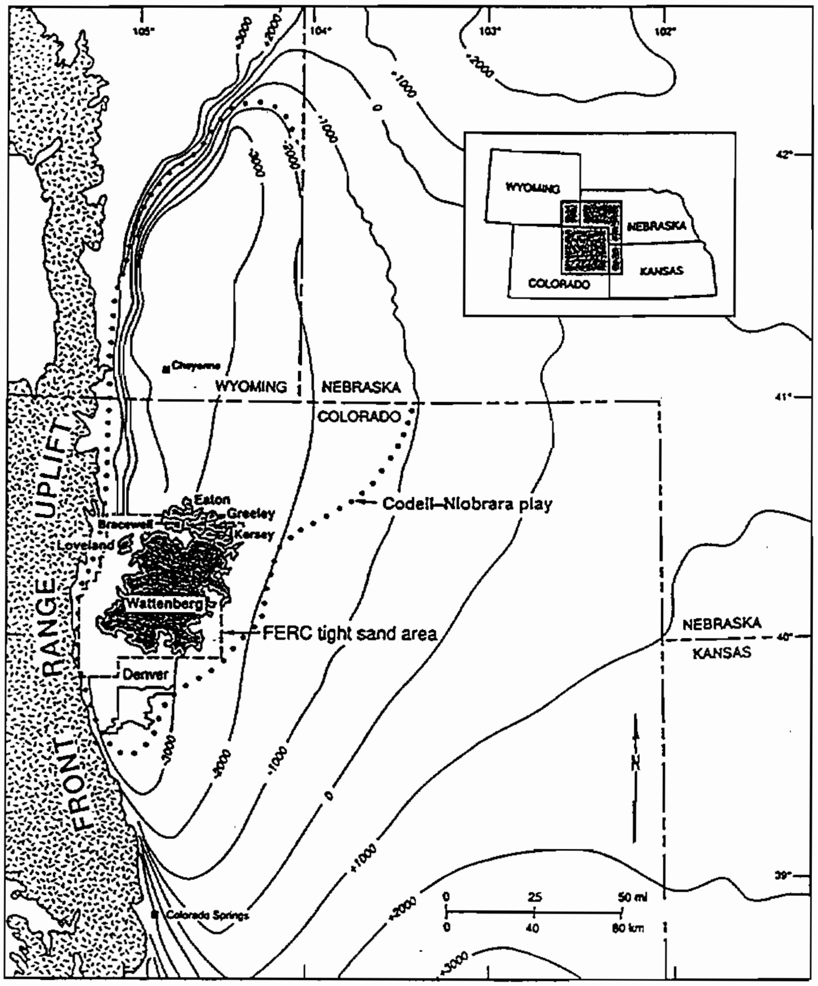


Figure 146. Major Fields in the Codell/Niobrara Play

TABLE 42. Major Niobrara Chalk Biogenic Gas Fields

Field	Discovery	Wells	Spacing (Acres)	Depth (ft)	Type of Gas	Drive Mechanism	Cum. Prod. (BCF)
Beecher Island	1919	81	160	1500	Non-Associated	Pressure Depletion	17
Eckley	1977	91	160	2500	Non-Associated	Pressure Depletion	28
Waverley	1977	91 (1 aban.)	160	2700	Non-Associated	Pressure Depletion	15
De Nova	1977	43	160	2900	Non-Associated	Pressure Depletion	11
Old Baldy	1977	41	160	2600	Non-Associated	Pressure Depletion	9
Bonny	1978	52 (9 aban.)	160	1600	Non-Associated	Pressure Depletion	4
Rock Creek	1979	55	160	2700	Non-Associated	Pressure Depletion	9

TABLE 43. Major Codell/Niobrara Fields

Field	Discovery	Wells	Spacing (acres)	Depth (ft)	Type of Gas	Drive Mechanism	Cum. Prod. (Bcf)
Loveland	1957	70 (21 aban.)	80	4660/ 4900	Associated	Pressure Depletion	5
Wattenberg	1981	1891 (14 aban.)	80	6800/ 7100	Associated	Pressure Depletion	146
Bracewell	1982	125	80	6850/ 7150	Associated	Pressure Depletion	9
Kersey	1982	111	80	6550/ 6850	Associated	Pressure Depletion	7
Greeley	1982	105	80	6750/ 7050	Associated	Pressure Depletion	6
Eaton	1982	132 (4 aban.)	80	6900/ 7200	Associated	Pressure Depletion	6

8.1.4 Codell Sandstone

Finally, the most recent drilling activity has targeted dual Codell/Niobrara completions in the Wattenberg area. This activity has been so feverish that Weld County, in the heart of the play, was ranked #1 for gas well completions in the U.S. during 1993.

The Codell Sandstone is a blanket sand that is a moderate gas producer in the Wattenberg portion of the D-J Basin. This sandstone is divided into three facies types based upon lithology and interpreted depositional environment. The producing facies in the Wattenberg field is the Type 2 Codell Sandstone, which is primarily a poorly sorted, clayey to silty, very fine- to medium-grained sandstone, with extensive bioturbation. Depths to the Codell Sandstone at Wattenberg range between 7100 ft and 7300. The average thickness is 14 to 16 ft. Major Codell/Niobrara Fields and relevant data are presented in Figure 146 and Table 43.

8.2 DRILLING AND COMPLETION PRACTICES AND COSTS

8.2.1 Current Practices

An understanding of current drilling and completion practices in the D-J Basin is an important pre-cursor to an evaluation of how slim holes can be applied to reduce well costs. To determine the typical drilling/completion practices, a questionnaire was mailed to each operator and follow-up interviews were conducted with six of the most active operators, specifically Basin Exploration, Gerrity Oil and Gas, North American Resources, Plains Petroleum, Prima Oil and Gas, and Snyder Oil. At the end of 1993, these companies operated over 4800 D-J wells, or about 80% of the total gas wells in the basin.

In essence, there are about five different types of completions corresponding to the various target horizons. These are, in the approximate order of current activity; 1) Sussex/Shannon and Codell/Niobrara dual completion (within the Sussex/Shannon play area), 2) Codell/Niobrara completion outside of Sussex/Shannon play area, which appears to be trending northeast of the Wattenberg Field, 3) Niobrara Chalk biogenic gas play completions in the eastern portion of the basin, 4) D Sand completions, and 5) Muddy (J) Sand completions. In each case, the traditional approach has been to drill a 7⅞- in. hole with a fresh-water mud to total depth, run and cement 4½-in. casing, perforate and fracture-stimulate the target horizon(s), and install 2⅜-in. production tubing. Drilling conditions are considered to be straightforward, with no problem zones requiring bit changes or intermediate strings of casing. Wells can now frequently be drilled to total depth below surface casing in a single PDC bit run on a downhole motor.

The greatest amount of recent drilling activity has targeted the Codell/Niobrara formation in the western portion of the basin (Wattenberg area). These wells can generally be categorized as tight sand wells; most are drilled within a FERC-approved tight sand area for these horizons. Well production usually begins at relatively high rates of flow, but is characterized by extremely rapid rates of decline. However, highly consistent production results can be relied on over large geographic areas, resulting in almost no dry holes.

These characteristics of the Codell/Niobrara play have forced operators to aggressively reduce costs to minimize well payout times (i.e., to "outrun" the rapid production decline). Furthermore, to maintain cash flow, operators must also aggressively drill replacement wells to offset declining production. These requirements have resulted in the adoption of unique cost savings measures, such as slim completions, plus the creation of a large aggregate market for services/supplies as a result of massive (multi-hundred well) drilling programs.

The latest slim completion procedure being used by operators is to run 2⅞- or 3½- in. production casing in a conventional 7⅞-in. hole. This is because there is considerable experience with these bits, which have been optimized for the area, and it is believed that smaller holes, 6¼-in. for 3½-in. casing or 4¾-in. for 2⅞-in. casing, cannot be drilled as quickly and hence would cost more. Operators, drilling contractors and bit manufacturers are jointly working to improve the performance of smaller diameter drilling components to cut drilling costs. For example, one operator alliance reports success with drilling 6¼-in. holes in equal time to 7⅞- in. holes. Further improvements, after a short learning curve, are expected. Smaller rigs and locations, and lower transportation costs, are the primary incentives for this approach.

The primary source of current cost savings captured through the use of slim-hole completion technologies, therefore, is less expensive tubulars. Initially, the availability of slim-hole tubulars, specifically 3½-in. casing and $2^1/_{16}$-in. tubing, was limited and their costs could frequently exceed that for the more traditional larger sizes. Operators overcame this supply problem by consolidating their requirements and placing larger tubulars orders directly with manufacturers. This creative approach has achieved the savings in tubulars costs that were initially sought.

Figure 147 shows how the consolidated demand for the slim completion equipment resulted in a dramatic increase in the number of supplier of 3½-in. casing and $2^1/_{16}$-in. tubing from only one to five and four respectively over a nine-month period. Also shown are the resulting decreases in cost of 15% for the 3½-in. and 23% for the $2^1/_{16}$-in. This is despite an approximate 10% <u>increase</u> in the price of steel over the same time period. Therefore the real decrease in price was actually greater. Also shown is the price differential with larger casing and tubing sizes. Notice that $2^1/_{16}$-in. tubing was actually more expensive than 2⅜-in. in September of 1993, but was less by June of 1994. Also important to note is that this analysis is for 3½-in. <u>casing</u> used by D-J operators, not the more common but more expensive 3½-in. <u>tubing</u>.

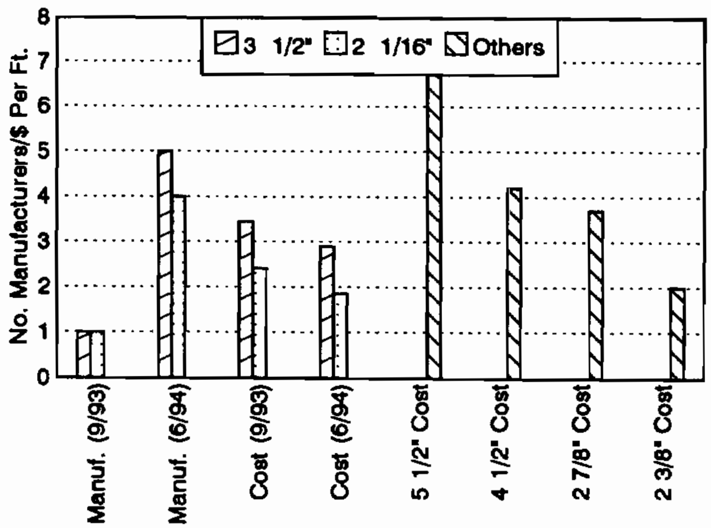


Figure 147. D-J Basin Tubulars

8.2.2 <u>D-J Basin Regulatory and Landowner Issues</u>

The use of slim completions in the D-J Basin was the subject of regulatory and land/mineral owner scrutiny during 1993 and 1994. Concerns were based on several factors consisting of environmental concerns and mineral owner correlative rights. For example:

- Smaller, weaker, tubulars could be more prone to failure and represent a greater potential detrimental environmental impact, such as casing leaks in a fresh-water zone, as well as possibly shortened well life and reduced reserve recovery.
- Fracture treatments would be smaller resulting in lower producing rates and less reserve recovery.
- Inability to install production tubing and higher-volume artificial lift would limit the ability to lift liquids, also reducing production and reserve recovery.

The scrutiny was initiated, at least in part, by the inadvertent use of poor-quality (such as rod-cut) 2⅞-in. tubing for casing which did in fact lead to several early casing failures. In addition, consequences of the high overall activity level in the basin in 1993 (such as a high backlog of reserve pits waiting to be reclaimed) caused frustration on the part of some surface owners which then resulted in a response misdirected at slim completions.

At one point, a ban on all production casing less than 4½-in. was being considered by Colorado. Fortunately, the concerns were appropriately addressed by a coordinated industry response to the technical issues voiced by the State of Colorado and Weld County regulatory agencies. No action of this extreme nature was taken by the state.

While not technically valid, the concerns of the regulatory agencies and landowners in the D-J Basin serve as a good example of how multi-well, documented field test programs are necessary for gaining experience and long-term data.

8.2.3 Opportunities for Slim Holes

Clearly, while operators have captured some cost savings by adopting selected slim completion techniques, there remains potential for additional savings by using an integrated slim-hole drilling and completion approach. Most of the operators in the area have already answered "yes" to the first question related to the slim-hole option: "Can I live with a slim completion?" Commitment to multi-well programs to allow for learning the subtleties of effective slim-hole drilling, as well as continued improvement in individual technologies, such as small-diameter bits and motors, is needed to permit the faster and lower cost drilling of 6¼-in., and ultimately 4¾-in. holes. With this improvement an even greater opportunity for cost-savings will also emerge – the development and utilization of purpose-built slim-hole drilling rigs. These rigs, which will be characterized as being smaller and more easily transportable than their conventionally sized counterparts, will provide further cost savings in the form of smaller pad sizes, lower mobilization/demobilization costs, and lower rig day rates (as a result of a smaller capital investment, a smaller crew, less fuel consumption, etc.). Some specific differences between a dedicated slim-hole rig and a conventional rig that lead to these cost savings are listed in Table 44.

TABLE 44. Characteristics of Dedicated Slim-Hole Rigs

• Greater Mobility
• Less Hookload Capacity
• Lower Floor Height
• Power Swivel/Top Drive
• Low-Volume Mud System
• Smaller Mud Pumps
• Advanced Monitoring Systems

More detailed discussion of slim-hole rig issues and current state-of-the-art systems is covered in Chapter 3 of this report.

At the current time, however, dedicated slim-hole rigs are in relatively short supply, and hence can be costly to contract. This situation is exacerbated by the current surplus of drilling rigs throughout the U.S., which is forcing conventionally-sized rig day rates to artificially low prices. With a combination of a consortium approach to contract drilling services by operators (similar to the tubulars example cited earlier), plus a shift to a balanced supply/demand environment for drilling services, significant further cost savings could be captured by D-J operators.

8.3 POTENTIAL D-J BASIN SLIM-HOLE DRILLING SAVINGS

It was desired to forecast the potential savings of aggressive slim-hole drilling and completion approach over the 1996-2005 time period. To do this, the cost savings realized per well was estimated and the potential application of slim holes to total forecast D-J drilling activity was determined. The approach taken to estimate these two parameters and the results obtained are discussed below.

It must be noted that this is a distinctly different task from that reported in Chapter 10 of this report. In that Chapter, near-term savings assumptions are based on an average, conventionally-completed U.S. gas well. More conservative assumptions are then used for estimating the percentage of U.S. gas wells using a slim-hole approach. This task is looking at a very specific application in a basin already employing slim completion techniques.

8.3.1 Conventional vs. Slim-Hole Well Costs

Current well costs, *which incorporate the use of slim completions (i.e., 3½-in. casing with $2^1/_{16}$-in. tubing)*, were estimated assuming a 7200 ft Codell/Niobrara completion, and were based on the results of the questionnaire mailed to operators, the follow-up interviews, and published data.

The slim-hole costs, which also assumed the same completion horizon but drilled with a 4¾-in. bit and a purpose-built slim-hole rig, and utilizing 2⅞-in. casing and 1½-in. tubing, were then estimated based on reduced drilling times, lower rig day rates, a smaller pad, less mud and cement volumes, etc. Published information on the cost savings expected from slim holes was also used to verify the validity of the estimates. Schematics of the two well types are illustrated in Figure 148, and the cost comparison is provided in Table 45.

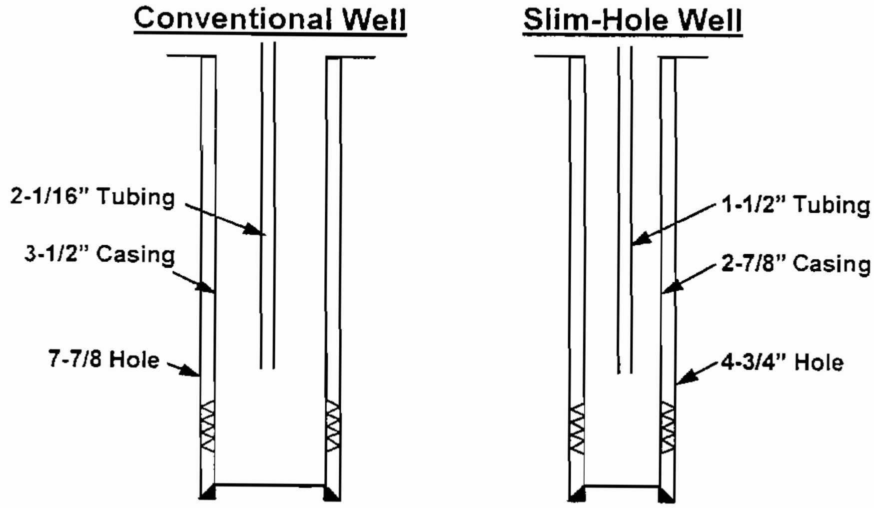


Figure 148. Comparison of Assumed Well Profiles

TABLE 45. Well Cost Assumptions
(7200 ft. D-J Well, 2 Stimulation Treatments)

Cost Category	Description	Conventional	Slim-Hole	Savings
Intangible	Location	$9,500	$7,100	$2,400
	Drilling	34,000	19,100	14,900
	Mud	7,000	5,600	1,400
	Trucking	1,200	400	800
	Mud Logging	3,600	2,600	1,000
	Cementing	6,400	3,200	3,200
	Logging/Perforating	1,800	1,800	0
	Stimulation	49,500	54,500	(5,000)
	Completion Rig	7,500	7,500	0
	Labor & Construction	5,300	5,300	0
Tangible	Production Casing	29,000	23,200	5,800
	Wellhead	1,500	1,500	0
	Tubing	8,100	6,500	1,600
	Surface Facilities	19,500	19,500	0
	TOTAL	$183,900	$157,800	$26,100

Based on these estimates, advanced slim-hole drilling can provide as much as a 40% ($16,000) savings in drilling costs and a 15% ($26,000) savings in total well costs. As mentioned previously, due to the current surplus of drilling rigs and artificially low day rates, simply using a slightly smaller rig does not provide substantial cost savings over today's costs. This is reflected in Table 45; most of the cost savings are strictly related to reduced drilling times. When the rig surplus evaporates and day rates climb to more stable levels, the cost savings will be considerably greater. In addition, this savings is for a conventional case which already uses slim completion tubulars. If the conventional case assumed the more typical U.S. completion of, for example, 5½-in. casing and 2⅞-in. tubing, the savings would increase by approximately another $40,000.

The costs shown in Table 45 are for a 7200 ft Codell/Niobrara well. These cost savings are also believed to be reasonable estimates for Sussex/Shannon and Codell/Niobrara dual completion wells. Cost savings for deeper D Sand and Muddy (J) sand wells were estimated to be $33,000 per well; the higher cost savings is directly attributed to faster penetration rates over a longer drilling period (i.e., a deeper hole). The estimated cost savings for each well completion (by horizon) is provided in Table 46.

TABLE 46. Cost Savings by Completion Type

Play	Cost Savings ($/well)
Sussex/Shannon and Codell/Niobrara	$26,000
Codell/Niobrara	26,000
D Sand	33,000
Muddy (J) Sand	33,000

8.3.2 Forecast Potential Slim-Hole Drilling Activity

In the second step of this benefits analysis, the number of slim holes that might be drilled in the D-J was estimated. This was accomplished using GRI's Baseline Projection of gas well drilling in the Rocky Mountain Foreland Region and the National Petroleum Council's (NPC) projection of tight sands drilling in the D-J Basin. The total D-J gas well drilling activity was then conservatively forecast as an intermediate level between these two projections. The resulting forecast is shown in Figure 149, which suggests that a total of 4600 new gas wells will be drilled in the D-J Basin over the period 1996-2005.

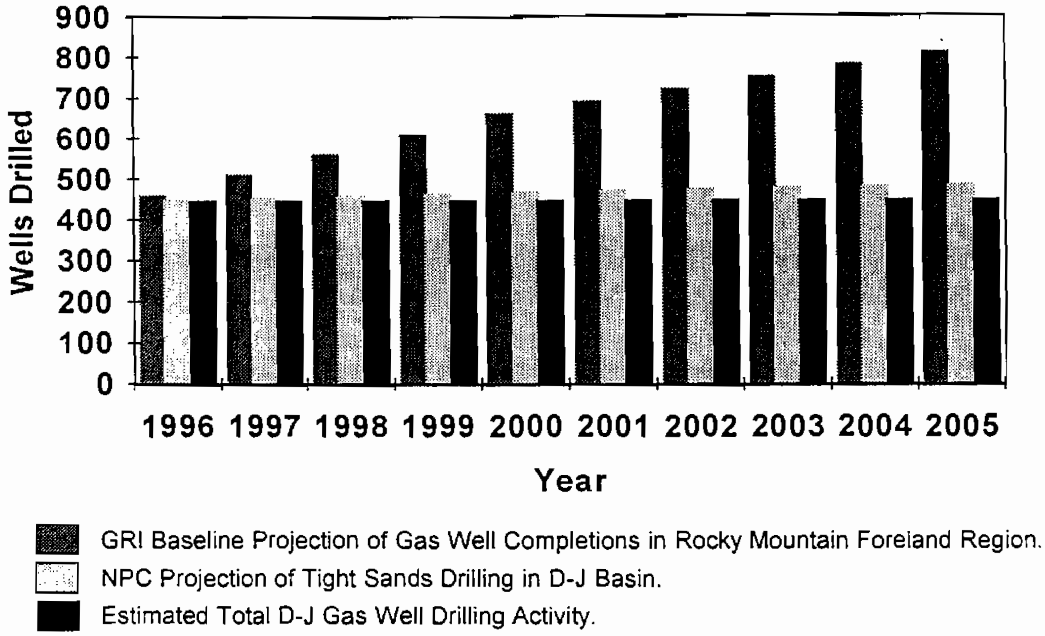


Figure 149. D-J Basin Gas Well Drilling Activity Forecast 1996-2005

Assumptions were then necessary to determine the distribution of these wells by completion target, and the reasonable candidates for aggressive slim-hole application. It was assumed that recent drilling trends will continue. That is to say mostly Codell/Niobrara wells will be drilled (50%), with intermediate levels of Sussex/Shannon (15%), Muddy (J) Sandstone (15%) and Niobrara Chalk activity (15%), and with little D Sand activity (5%). The forecast based on this split, provided in Table 47, suggests that about 3000 wells will be Codell/Niobrara completions, about a quarter of which will also be completed in the Sussex/Shannon, about 900 wells will target the deeper D Sand or Muddy (J) Sand and about 700 wells will be drilled in the Niobrara Chalk biogenic gas play.

TABLE 47. Estimated Total Drilling Activity by Play 1996-2005

Play	Total Wells
Sussex/Shannon and Codell/Niobrara	700
Codell/Niobrara	2,300
Niobrara Chalk	700
D Sand	200
Muddy (J) Sand	700
TOTAL	**4,600**

With this estimated breakdown of forecast drilling activity (by play), the next step was to determine how many of these wells would actually be reasonable candidates for slim holes.

Common concerns among the operators interviewed suggested that aggressive slim completions were not viable in the following two scenarios:

- In low gas/oil ratio (GOR) wells where liquid buildup could hinder gas production. Operators prefer to install plunger lift systems in these wells to remove liquids, and the small plungers required for $2^1/_{16}$-in. and more importantly 1½-in. tubing were too susceptible to malfunction as a result of paraffin buildup and sand production. This problem has been particularly prevalent in wells where the Sussex/Shannon is (or can be) completed, since this horizon tends to produce significant quantities of associated liquids. In addition, the Codell/Niobrara appears to have lower GOR's on the periphery of the established Wattenberg area. Finally, large volumes of liquids are produced from the Niobrara Chalk biogenic gas play on the eastern margin of the basin, virtually eliminating the application of slim holes for this play.
- A percentage of D Sand and Muddy (J) Sand wells are prolific high-rate gas producers. Operators are reluctant to utilize slim-hole completions in these cases as it will restrict gas production.

These two constraints of slim holes were considered when estimating the potential application of slim-hole drilling to total forecast activity. In specific, it was assumed that technological advances in slim-hole artificial lift systems would permit the reliable use of slim completions in all Sussex/Shannon and Codell/Niobrara dual completions. However, the volume capacities would not be sufficient to permit their use in the Niobrara Chalk biogenic gas play. Therefore it was assumed that slim holes would not be utilized at all for these wells (i.e., for Niobrara Chalk biogenic gas wells in the eastern D-J Basin). In addition, it was assumed that a third of all D Sand and Muddy (J) Sand wells, specifically the prolific wells, would not utilize slim holes. The resulting forecast of potential slim-hole drilling activity by play is presented in Table 48. This forecast suggests that of a total 4600 gas wells forecast for the D-J Basin, 3600, or over 75%, potentially could be drilled as slim holes.

TABLE 48. Estimated Slim-hole Drilling Activity by Play 1996-2005

Play	Total Wells	Possible Slim-Hole Wells
Sussex/Shannon and Codell/Niobrara	700	700
Codell/Niobrara	2,300	2,300
Niobrara Chalk	700	0
D Sand	200	130
Muddy (J) Sand	700	470
TOTAL	**4,600**	**3,600**

8.3.3 Benefits Computation

The last step of the benefits analysis was to take the information developed in the earlier sections and compute the benefits. The resulting analysis, shown in Table 49, indicates a potential cost savings to industry of about $100 million over the period 1996-2005, in today's dollars, by utilizing slim holes.

TABLE 49. Benefits Calculation
1996-2005

Play	No. Slim-Hole Wells	Cost Savings/ Well	Total Cost Savings (MM$)
Sussex/Shannon and Codell/Niobrara	700	$26,000	18.2
Codell/Niobrara	2,300	26,000	59.8
Niobrara Chalk	0	0	0
D Sand	130	33,000	4.3
Muddy (J) Sand	470	33,000	15.5
		TOTAL	**$97.8 million**

No attempt has been made to quantify well life-cycle assumptions regarding possible increased workover incidence rates or costs, or possible reserve loss due to premature well abandonment. While these issues are important concerns of all operators considering slim completions/slim-hole drilling, D-J Basin operators believe the use of 3½-in. casing and $2^1/_{16}$-in. tubing has resulted thus far in no apparent loss of production capability of increased workover costs. The more aggressive slim completion scenario contemplated in this potential savings analysis (2⅞-in. casing and 1½-in. tubing) would reduce workover and production flexibility to some degree (current technology level) and may increase life-cycle costs and reduce the above benefits. It is not felt that these future (discounted) incremental costs would appreciably affect the general magnitude of the benefits calculation.

This case study sheds light on the magnitude of potential benefits of slim-hole drilling. If this estimate of cost savings (i.e., $100 million) can be realized in one basin, the total potential benefits to the domestic gas producing industry must certainly be very large.

8.4 CONCLUSIONS

Based on the work presented in this section, the following conclusions may be drawn:

- D-J Basin operators are using slim completions to save considerable investment costs in an economically-marginal gas play.

- Slim-hole drilling is not being widely used for these slim completions.
- Operators have identified that improved bits and downhole motors, integrated systems, and experience from multi-well testing programs are the most pressing need for low-cost slim-hole drilling in the D-J Basin.
- With improved downhole drilling assemblies, purpose-built or modified (lower-cost) slim-hole rigs could be utilized, resulting in further cost savings to operators.
- Better, more reliable artificial lift systems for aggressive slim completions could broaden their applicability to liquid-producing wells.
- These technologies, in combination, could reduce drilling costs by at least 40% and total well costs by 15% over today's current practices, in an *area where slim completions are already being used.*
- Up to 3600 of the forecast 4600 gas wells expected to be drilled in the D-J Basin from 1996-2005 are potential candidates for slim holes. The savings due to developing and implementing these technologies for this geographical segment of the gas-producing industry is estimated to be $100 million.

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9. Barrier Surveys

To assist with assessment of industry perceptions of slim-hole technology limitations, a Slim-Hole Technical Barrier Questionnaire was prepared, distributed, and the results analyzed. In addition, a recent slim-hole technology market assessment report was purchased and analyzed for additional information.

9.1 SLIM-HOLE TECHNICAL BARRIER QUESTIONNAIRE

A questionnaire was prepared to identify the perceptions of various industry segments regarding the relative size and ranking of technical barriers to greater slim-hole utilization. The questionnaire was structured to gauge opinions on broad issues as well as individual technologies in a manner consistent with the overall project framework. The final questionnaire consisted of the following sections:

- Overall Barriers
- Drilling Barriers
- Cementing Barriers
- Completion And Workover Tools/Artificial Lift Barriers
- Stimulation Barriers
- Formation Evaluation And Perforating Barriers

An additional section addressed effective slim-hole technology transfer channels.

Respondents were requested to rank the issues presented in the questionnaire on a scale of 1 to 5. A response of 1 indicates an opinion of "No/Small" or "Not Important" barrier and a response of 5 indicates an opinion of "Large/Critical" or "Very Important" barrier. The questionnaire was comprehensive, with a total of 78 responses requested (excluding personal information).

Respondents were asked to indicate their company affiliation, title, and whether they considered themselves an "engineer" or a "manager." The company affiliations were used to break down the results into **Producers** and **Service Companies**. The producer companies were further segregated into **Engineers** and **Managers**.

A copy of the questionnaire is included in the Appendix.

9.1.1 Questionnaire Distribution and Response

A focused distribution of the questionnaire was carried out with a strategy of targeting individuals within the industry who were expressing interest in slim-hole technology, or those it was thought had some exposure to consideration and evaluation of slim-hole issues. Towards that end, the following groups were targeted:

- DEA-67 Slim-Hole and Coiled-Tubing Technology Project Participants
- DEA-67 Project Slim-Hole Forum Attendees (open forums)
- DEA-67 Field Test Meeting Attendees
- Resource Marketing's Worldwide Market Assessment of Slim-Hole Technology Respondents
- Operators identified in the activity database as slim-completion operators

Table 50 lists the distribution and response rates for the targeted groups:

TABLE 50. Questionnaire Distribution and Response

Group	Distributed	Received	Response Rate %
DEA-67 Contacts	50	15	30
DEA-67 Forums	125	94	75
DEA-67 FT Meeting	19	8	42
RMI Study	45	17	38
Operators' Database	33	9	27
TOTAL	272	143	53

The statistics above represent unique responses. Duplicate questionnaires from single individuals were discarded, with the latest questionnaire received used for analysis.

Table 51 provides demographic statistics on company affiliation and function for respondents.

TABLE 51. Questionnaire Response Demographics

GROUP	NUMBER	PERCENTAGE OF RESPONSES
Producers	105	73
Service Companies	38	27
Engineers	98	69
Managers	45	31
Producer Engineers	79	55
Producer Managers	26	18
Service Company Engineers	19	13
Service Company Managers	19	13

As shown, **Producer Company** and **Engineering** function are the largest groups. However, the total **Service Company** group and the **Producer-Manager** group are large enough to warrant analysis of those individual groups.

9.1.2 Questionnaire Analysis

The objective of the questionnaire analysis was to determine the perceived importance and size of slim-hole technology barriers and obtain relative rankings. To this end, the responses to each questionnaire section were ranked according to mean and median. As expected, the response means tended to fall very close to 3, and the overwhelming majority of medians were 3. Because of this, an alternative approach was also used to graphically represent the perceived relative importance of the various technology issues.

This alternative approach defines a response of a 4 or a 5 as a "large barrier." The percentage of those responding with a 4 or a 5 is then calculated and the relative results plotted. The intent is to further define those issues that a large number of respondents believed were significant barriers. This is referred to as "percent responding large" on the graphs, and abbreviated as "PRL" in the text that follows.

The following sections present the results of the analysis by questionnaire section: *Overall Barriers, Completion and Workover Tools/Artificial Lift, Formation Evaluation/Perforating, Stimulation,* and *Drilling*. The individual technology sections are addressed in the order of apparent importance as determined from responses to the Overall Barriers section.

9.1.3 Overall Barriers

All Respondents

Table 52 shows the mean and median rankings for All respondents to overall slim-hole barrier issues. Figure 150 graphs the "PRL" responses. As shown, *Workover Problems* and

Management Attitude dominate as the largest perceived barriers. *Completion Tools* and *Formation Evaluation* also rank fairly high with a PRL of over 40%. *Artificial Lift, Stimulation, Cementing*, and *Drilling* issues all appear to be perceived as about equivalent. *Limited Flow Rate* and *Perforating* are the lowest ranked barriers. As expected, barriers for *Oil Well Applications* far outranked barriers for *Gas Well Applications*. This is no doubt due to the general need for higher-volume artificial lift, more complex completions, and greater workover frequency commonly associated with oil wells.

TABLE 52. Overall Barriers — All Respondents

Barriers	Mean	Median
Workover Problems	3.8	4
Management Attitude	3.6	4
Completion Tools	3.5	3
Formation Evaluation	3.2	3
Artificial Lift	3.2	3
Stimulation	3.1	3
Oil Well Applications	3.1	3
Cementing	3.0	3
Drilling	2.9	3
Limited Flow Rate	2.8	3
Perforating	2.7	3
Gas Well Applications	2.4	2

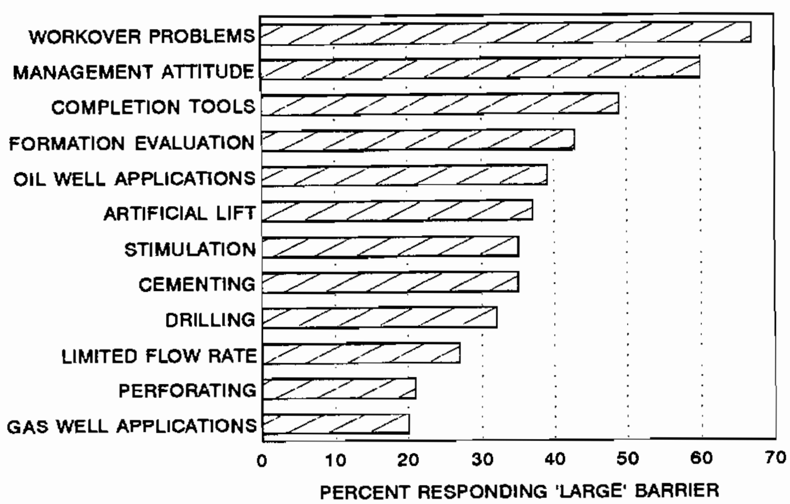

Figure 150. Overall Barrier Responses from All Respondents

Producers vs. Service Companies

Table 53 and Figures 151 and 152 display the ranked responses of the Overall barriers for **Producers** and **Service Companies**. The results for **Producers** are essentially the same as for **All** respondents. The exceptions are that **Producers** rank *Artificial Lift* ahead of *Formation Evaluation* and *Drilling* ahead of *Cementing*.

Comparisons between **Producers** and **Service Companies** are more interesting. In contrast to **Producers**, **Service Companies** rank *Management Attitude* and *Formation Evaluation* ahead of *Workover Problems*. *Formation Evaluation* had a median response of 4 from **Service Companies** with a 53% PRL. This contrasts with a median of 3 and PRL of 38% for **Producers**. *Cementing* and *Perforating* are ranked considerably higher, and *Drilling* and *Artificial Lift* considerably lower by **Service Companies** than by **Producers**. **Service Companies** also view barriers to *Oil Well Applications* as considerably less than do **Producers**, but still greater than *Gas Well Application* barriers.

TABLE 53. Overall Barriers — Producers and Service Companies

PRODUCERS			SERVICE COMPANIES		
Barriers	Mean	Median	Barriers	Mean	Median
Workover Problems	3.9	4	Management Attitude	4.0	4
Management Attitude	3.5	4	Formation Evaluation	3.5	4
Completion Tools	3.5	3	Workover Problems	3.5	3.5
Artificial Lift	3.3	3	Completion Tools	3.4	4
Oil Well Applications	3.2	3	Cementing	3.2	3
Formation Evaluation	3.2	3	Perforating	3.1	3
Stimulation	3.1	3	Stimulation	2.9	3
Drilling	3.1	3	Limited Flow Rate	2.8	3
Cementing	2.9	3	Oil Well Applications	2.8	3
Limited Flow Rate	2.8	3	Gas Well Applications	2.8	3
Perforating	2.5	2	Drilling	2.8	2
Gas Well Applications	2.3	2	Artificial Lift	2.7	3

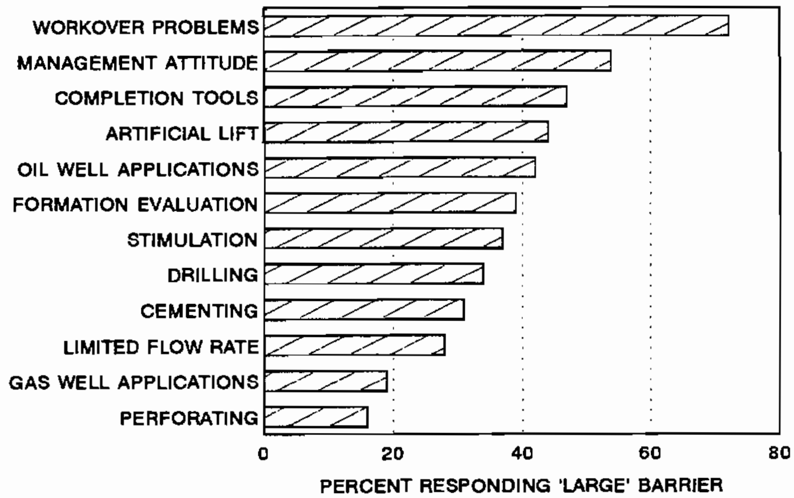

Figure 151. Overall Barrier Responses from **Producers**

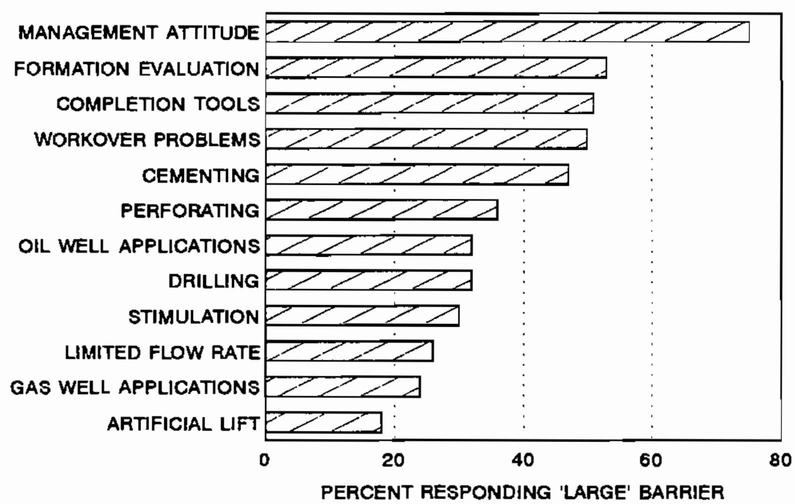

Figure 152. Overall Barrier Responses from **Service Companies**

Engineers vs. Managers

Table 54 and Figures 153 and 154 show the responses for Overall Barriers for **Producer Company Engineers** and **Managers**. *Workover Problems* and *Management Attitude* are regarded as the largest barriers by both **Engineers** and **Managers**, both responding with medians of 4. **Engineers** rate *Completion Tools* considerably higher than do **Managers**, while *Artificial Lift* is ranked higher by **Managers** than by **Engineers**. *Formation Evaluation* is ranked substantially higher by **Engineers** than by **Managers** (47% responding large vs. 17%). The other interesting comparison is *Limited Flow Rate*. **Managers** believe this to be a greater issue than do **Engineers**.

TABLE 54. Overall Barriers — Producer Engineers and Managers

Engineers			Managers		
Barriers	Mean	Median	Barriers	Mean	Median
Workover Problems	4.0	4	Workover Problems	3.7	4
Completion Tools	3.6	3.5	Oil Well Applications	3.7	3
Management Attitude	3.5	4	Artificial Lift	3.6	3
Formation Evaluation	3.3	3	Management Attitude	3.5	4
Artificial Lift	3.2	3	Stimulation	3.3	3
Stimulation	3.1	3	Drilling	3.2	3
Drilling	3.0	3	Completion Tools	3.2	3
Oil Well Applications	3.0	3	Limited Flow Rate	3.1	3
Cementing	3.0	3	Formation Evaluation	2.8	3
Limited Flow Rate	2.6	3	Gas Well Applications	2.7	2
Perforating	2.5	2.5	Cementing	2.6	2.5
Gas Well Applications	2.2	2	Perforating	2.5	2

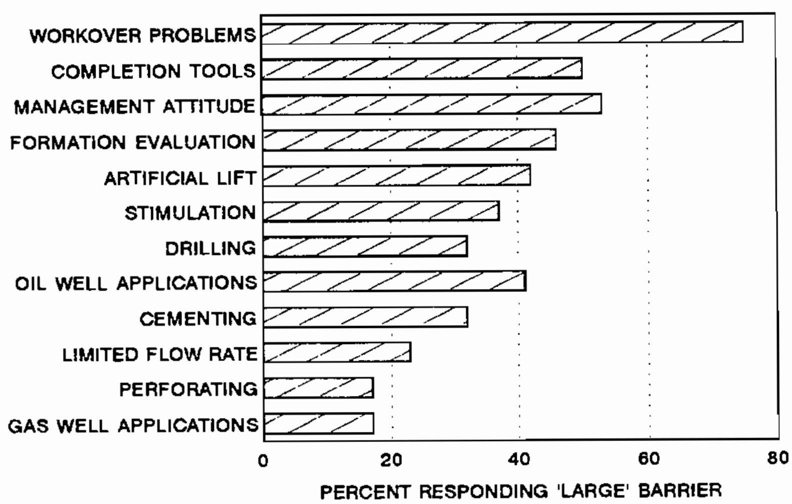

Figure 153. Overall Barrier Responses from **Engineers**

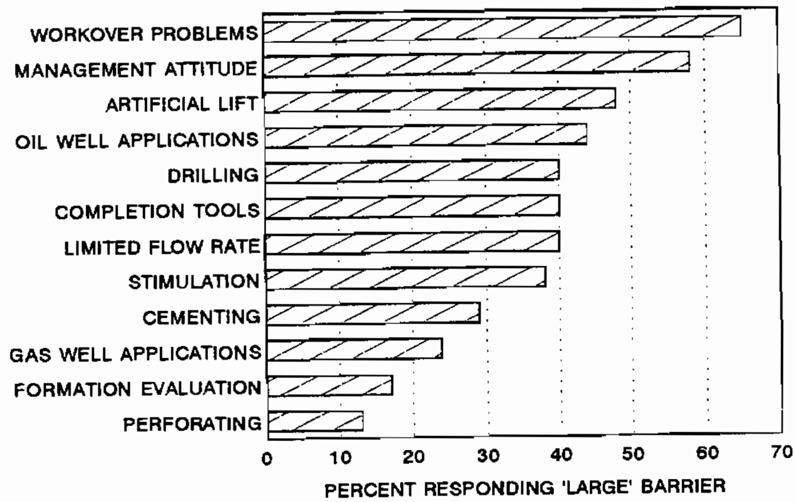

Figure 154. Overall Barrier Responses from **Managers**

9.1.4 *Completion/Workover Tools* and *Artificial Lift* Barriers

The responses from the Overall Barriers section of the questionnaire indicate *Completion Tools* and *Workover Problems* are considered by all segments analyzed to be the largest barriers to greater slim-hole usage. This section of the questionnaire is analyzed below.

All Respondents

The responses from **All** respondents to the Completion/Workover Tools and Artificial Lift section of the survey are shown in Table 55 and Figure 155. The ranked responses indicate that the main concern relates to the ability to mechanically repair wells. *Workover Limitations* and *Fishing Tools* are the only categories with a median response of 4 and greater than 50% PRL. No other actual "tool" category has a median response of over 3. The highest ranked completion tool barrier is *Mechanical Packers*, followed by *Inflatable Packers*. *Sliding Sleeves*, *Tubing*, and *Nipples* are all ranked as fairly low barriers. *Electric Submersible Pumps* and *Rod Pumps* are ranked as fairly large artificial lift barriers.

TABLE 55. Tool Barriers — All Respondents

BARRIERS	MEAN	MEDIAN
Workover Limitations	3.9	4
Fishing	3.6	4
Mechanical Packers	3.3	3
ESP	3.2	3
Inflatable Packers	3	3
Rod Pumps	3	3
Liner Hangers	2.9	3
Gas Lift	2.8	3
Prog. Cavity Pumps	2.6	3
CT Wash Tools	2.6	3
Safety Valves	2.6	2.5
Jet Pumps	2.5	3
Sliding Sleeves	2.5	2
Tubing	2.4	2.5
Nipples	2	2

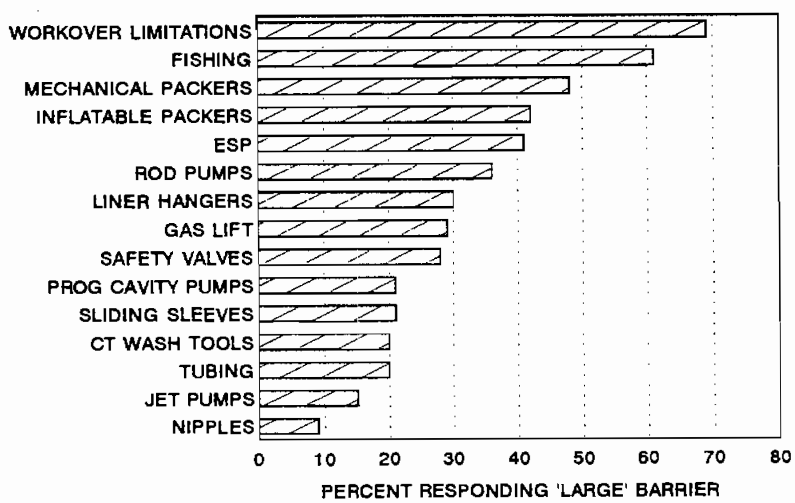

Figure 155. Tool Barrier Responses from **All** Respondents

Producers vs. Service Companies

Producer to **Service Company** comparisons are shown in Table 56 and Figures 156 and 157. **Producer** responses are similar to the results for **All** respondents. **Service Companies** also rank *Workover Limitations* as the largest barrier, but *Fishing Tools* is ranked considerably lower than by **Producers** (38% PRL vs. 67%). *Tubing Limitations* are also perceived to be greater by **Service Companies** than by **Producers**. ESPs are the highest ranked artificial lift barrier, but **Service Companies** do not believe *Rod Pump* barriers are near as large as do **Producers** (12% PRL vs. 44%).

TABLE 56. Tool Barriers — Producers and Service Companies

Producers			Service Companies		
Barriers	Mean	Median	Barriers	Mean	Median
Workover Limitations	4.0	4	Workover Limitations	3.6	3.5
Fishing	3.7	4	Inflatable Packers	3.1	3
Mechanical Packers	3.3	3.5	Mechanical Packers	3.1	3
ESP	3.3	3	ESP	3	3
Rod Pumps	3.2	3	Fishing	3	3
Inflatable Packers	3.0	3	Gas Lift	2.8	3
Liner Hangers	2.9	3	CT Wash Tools	2.8	3
Gas Lift	2.8	3	Liner Hangers	2.7	3
Prog. Cavity Pumps	2.7	3	Tubing	2.7	3
CT Wash Tools	2.6	2	Safety Valves	2.7	2.5
Safety Valves	2.5	2.5	Prog. Cavity Pumps	2.6	3
Jet Pumps	2.5	3	Jet Pumps	2.6	3
Sliding Sleeves	2.5	2	Rod Pumps	2.6	3
Tubing	2.4	2	Sliding Sleeves	2.5	2.5
Nipples	2.0	2	Nipples	1.9	2

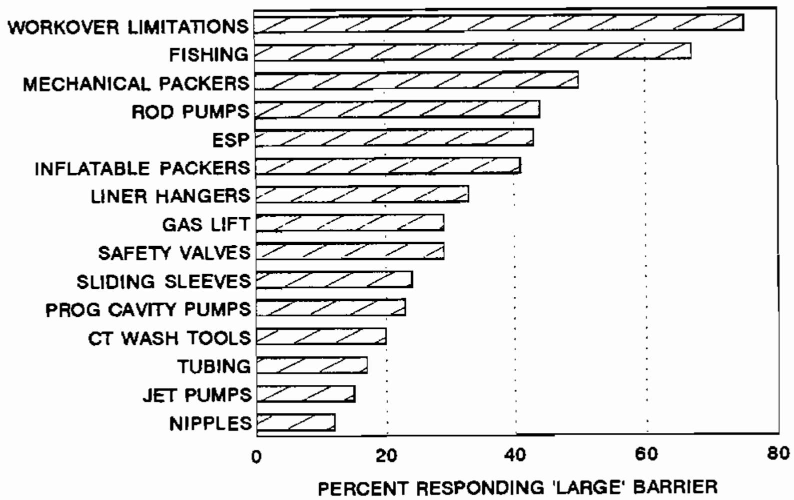

Figure 156. Tool Barrier Responses from **Producers**

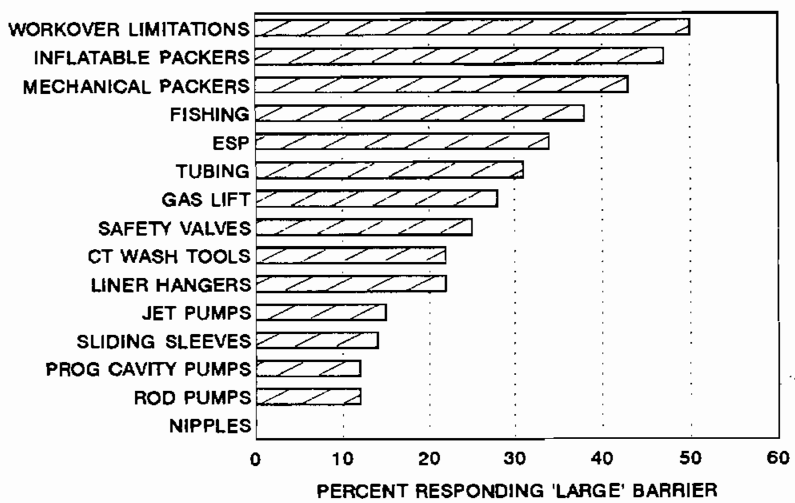

Figure 157. Tool Barrier Responses from **Service Companies**

Engineers vs. Managers

Table 57 and Figures 158 and 159 display **Engineers** and **Managers** responses. *Fishing Tools* and *Workover Limitations* are regarded as large barriers by both functions, but **Managers** rank *Fishing Tools* ahead of general *Workover Limitations* (vice versa for engineers). Most of the highly ranked barriers are similar between the two groups. The exception is *Safety Valves*. **Managers** felt strongly about this category with a PRL of 50% and a median of 3.5. **Engineers** responded with only a 21% PRL with a median of only 2. There are also some shifts in the order of some lesser ranked barriers. For example, *Tubing* is ranked higher by **Managers** than by **Engineers** with a median of 3 versus 2.

TABLE 57. Tool Barriers — Producer Engineers and Managers

Engineers			Managers		
Barriers	**Mean**	**Median**	**Barriers**	**Mean**	**Median**
Workover Limitations	4.2	4	Fishing	3.8	4
Fishing	3.7	4	Workover Limitations	3.8	4
Mechanical Packers	3.3	3	Mechanical Packers	3.4	4
ESP	3.3	3	ESP	3.5	3
Rod Pumps	3.1	3	Rod Pumps	3.3	3
Inflatable Packers	3.1	3	Gas Lift	3.0	3
Liner Hangers	2.9	3	Liner Hangers	3.0	3
Gas Lift	2.7	3	Safety Valves	2.9	3.5
Prog. Cavity Pumps	2.6	3	Prog. Cavity Pumps	2.8	3
CT Wash Tools	2.6	3	Inflatable Packers	2.8	3
Sliding Sleeves	2.5	2	Jet Pumps	2.7	3
Jet Pumps	2.5	3	Tubing	2.6	3
Safety Valves	2.4	2	Sliding Sleeves	2.5	2
Tubing	2.3	2	CT Wash Tools	2.4	2
Nipples	1.9	2	Nipples	2.4	2

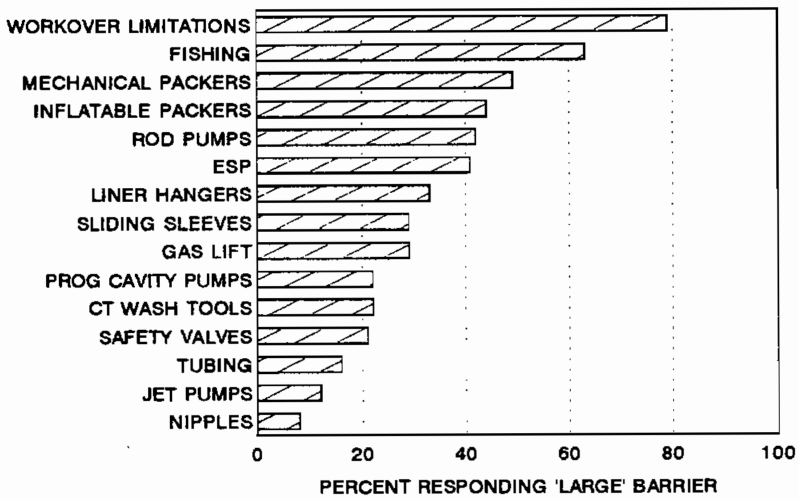

Figure 158. Tool Barrier Responses from **Engineers**

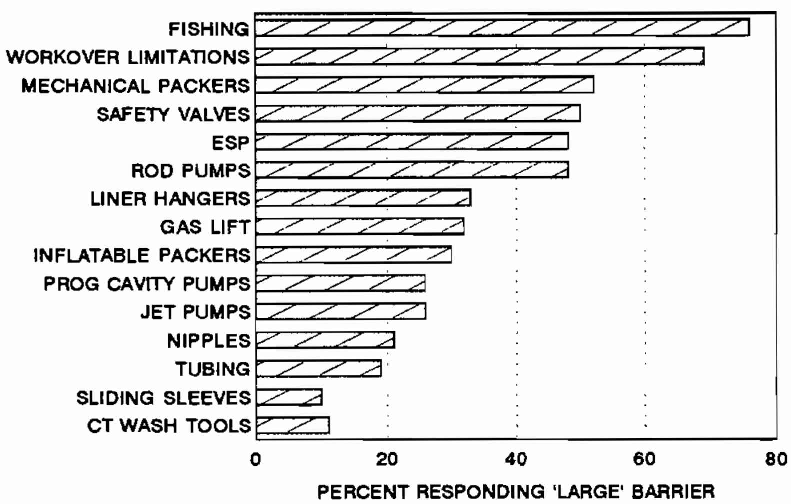

Figure 159. Tool Barrier Responses from **Managers**

9.1.5 *Formation Evaluation* and *Perforating*

Formation Evaluation is the next largest *Overall Barrier* category as ranked by **All** respondents (i.e., that corresponds to a questionnaire section). This section includes perforating issues, but *Perforating* alone was not ranked as a large barrier by **All** respondents or **Producers** (**Service Companies** ranked it higher).

All Respondents

Table 58 and Figure 160 show the responses from **All** respondents for *Formation Evaluation* and *Perforating* issues. The *Number of Slim-Hole Logging Tools Available*, the *Existence of Slim-Hole Logging Tools*, and *Service Company Experience* are considered large barriers (medians of 4 and greater than 50% PRL). *Perforating Charge Effectiveness* was felt to be a greater barrier than either the *Existence* or *Number of Perforating Tools.*

TABLE 58. Formation Evaluation and Perforating Barriers — All Respondents

BARRIERS	MEAN	MEDIAN
No. of SH Logging Tools	3.8	4
SH Logging Tool Existence	3.6	4
Service Company Experience	3.5	4
Drill Stem Testing	3.3	3
Perf. Charge Effectiveness	3.1	3
Logging Tool Accuracy	3.0	3
No. of Perf. Tools	2.8	3
Perf. Tool Existence	2.8	3

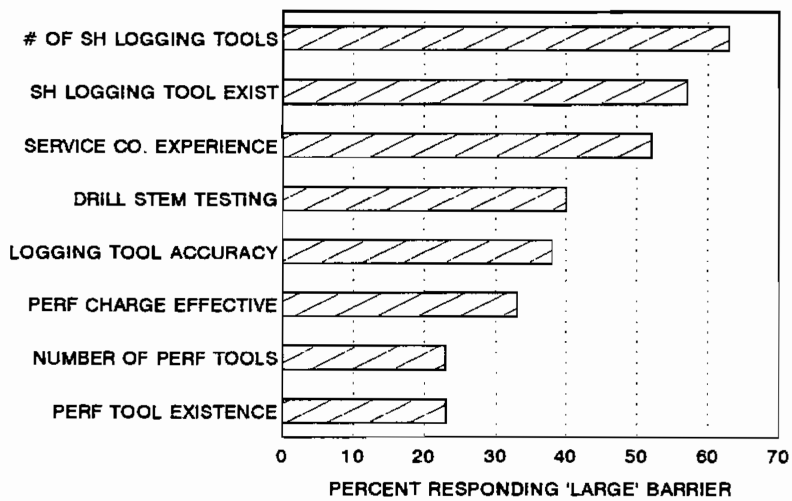

Figure 160. Formation Evaluation Barrier Responses from All Respondents

Producers vs. Service Companies

As shown in Table 59 and Figures 161 and 162, **Producer** responses are about equivalent to responses from **All** respondents. However, **Service Companies** believe *Drill Stem Testing* represents a greater barrier (50% vs. 37% PRL) and do not feel quite as strongly about *Service Company Experience* (median of 3 vs. 4) as do **Producers**.

TABLE 59. Formation Evaluation and Perforating Barriers — Producers and Service Companies

Producers			Service Companies		
Barriers	**Mean**	**Median**	**Barriers**	**Mean**	**Median**
No. of SH Logging Tools	3.8	4	No. of SH Logging Tools	3.6	4
SH Logging Tool Existence	3.6	4	SH Logging Tool Existence	3.6	4
Service Co. Experience	3.5	4	Drill Stem Testing	3.6	3.5
Drill Stem Testing	3.2	3	Service Co. Experience	3.4	3
Perf. Charge Effectiveness	3.1	3	Perf. Tool Existence	3.0	3
Logging Tool Accuracy	3.1	3	Perf. Charge Effectiveness	3.0	3
No. of Perf. Tools	2.8	3	Logging Tool Accuracy	2.9	3
Perf. Tool Existence	2.7	3	No. of Perf. Tools	2.9	3

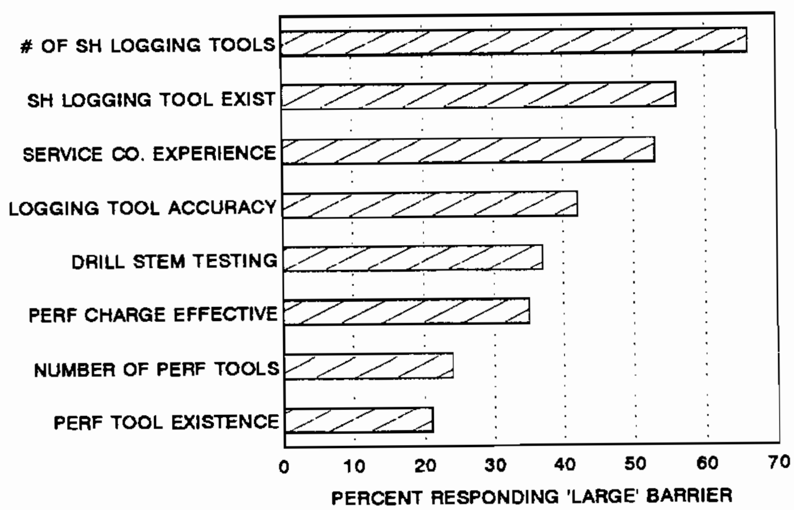

Figure 161. Formation Evaluation Barrier Responses from **Producers**

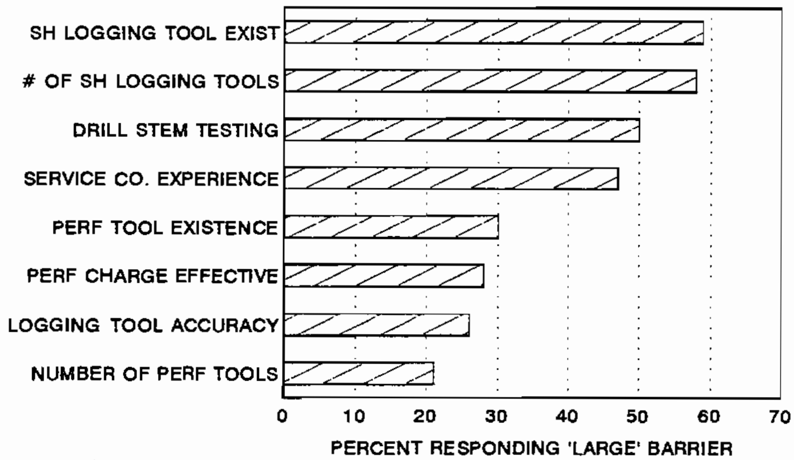

Figure 162. Formation Evaluation Barrier Responses from **Service Companies**

Engineers vs. Managers

Both **Engineers** and **Managers** rank *Number of Slim-Hole Logging Tools Available* as the largest barrier in Formation Evaluation (Table 60 and Figures 163 and 164). **Engineers**, however, feel much more strongly than do **Managers** about the barriers of the *Existence of Slim-Hole Logging Tools* and *Service Company Experience* (medians of 4 vs. 3 and PRL greater than 50 vs. less than 40). **Managers** are much more concerned about *Logging Tool Accuracy* than are **Engineers**. While *Perforating Charge Effectiveness* ranks higher in this section for **Managers**, the quantitative measures are approximately equivalent with that of **Engineers**.

TABLE 60. Formation Evaluation and Perforating Barriers — Producer Engineers and Managers

ENGINEERS			MANAGERS		
Barriers	Mean	Median	Barriers	Mean	Median
No. of SH Logging Tools	3.9	4	No. of SH Logging Tools	3.6	4
SH Logging Tool Existence	3.8	4	Perf. Charge Effectiveness	3.4	3
Service Co. Experience	3.7	4	SH Logging Tool Existence	3.1	3
Drill Stem Testing	3.2	3	Service Co. Experience	3.0	3
Logging Tool Accuracy	3.2	3	Drill Stem Testing	2.9	3
Perf. Charge Effectiveness	3.1	3	No. of Perf. Tools	2.9	3
No. of Perf. Tools	2.8	3	Logging Tool Accuracy	2.7	3
Perf. Tool Existence	2.7	3	Perf. Tool Existence	2.6	3

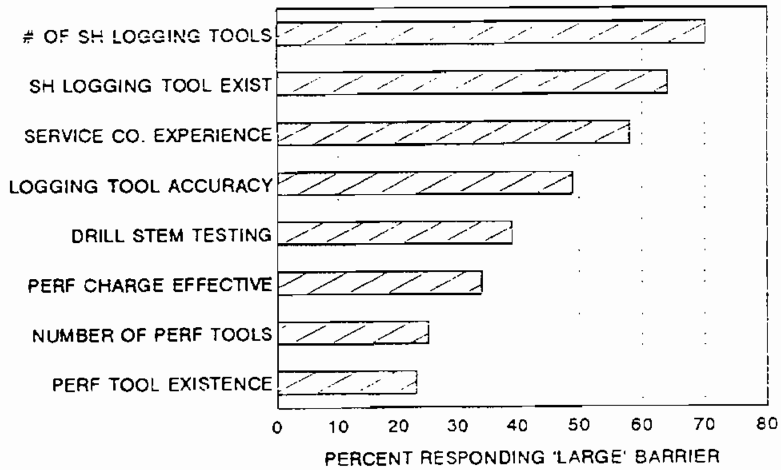

Figure 163. Formation Evaluation Barrier Responses from **Engineers**

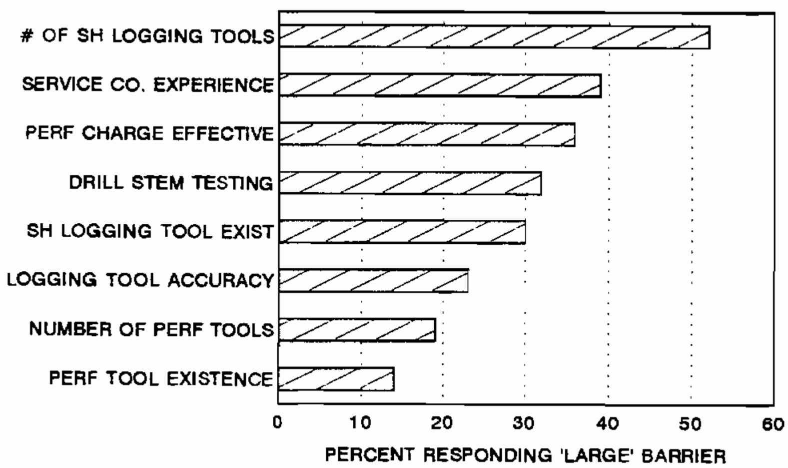

Figure 164. Formation Evaluation Barrier Responses from **Managers**

9.1.6 *Stimulation* Barriers

In the Overall Barriers section, *Stimulation* barriers consistently generated a response with medians of 3 and percentages responding "large" between 30% and 40% from the various segments analyzed.

All Respondents

Table 61 and Figure 165 show the responses from All Respondents to the Stimulation issues. *Friction Pressure* is ranked substantially higher than the other barriers listed and is the only one with a median of 4 and PRL greater than 37%. *Proppant Transport* and *Zone Coverage* were the next largest concerns, while *Perforation Friction* and *Perforation Erosion* ranked low with medians of only 2.

TABLE 61. Stimulation Barriers — All Respondents

BARRIERS	MEAN	MEDIAN
Friction Pressure	3.6	4
Proppant Transport	3.1	3
Zone Coverage	2.9	3
Shear Rates	2.8	3
Tortuosity	2.7	3
Downhole Gauges	2.6	2
Perforation Friction	2.5	2
Perforation Erosion	2.2	2

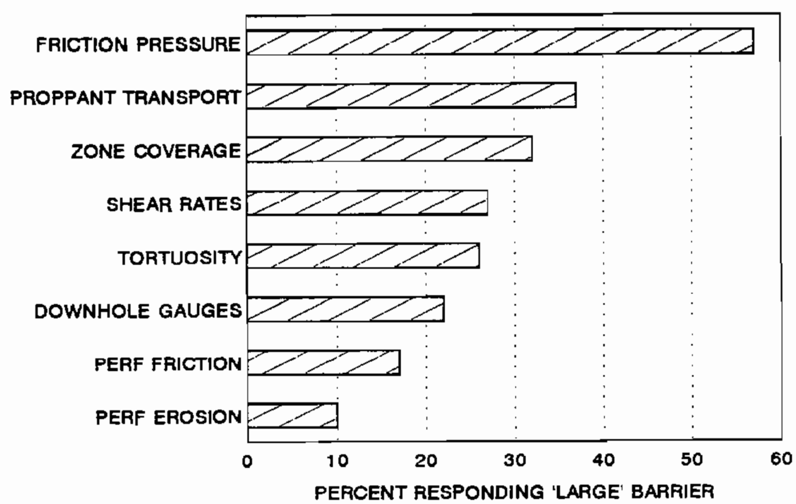

Figure 165. Stimulation Barrier Responses from All Respondents

Producers vs. Service Companies

Producers and **Service Companies** are in agreement on *Friction Pressure* being the largest *Stimulation* barrier (Table 62 and Figures 166 and 167), both responding with a median response of 4 and a PRL greater than 55%. **Producers** feel much stronger about *Proppant Transport* than do **Service Companies** (40% PRL vs. 27%), ranking it ahead of *Zone Coverage* (*Zone Coverage* measures are about equivalent). **Producers** also apparently believe *Shear Rate* and *Tortuosity* are larger barriers than do **Service Companies**.

TABLE 62. Stimulation Barriers — Producers and Service Companies

PRODUCERS			SERVICE COMPANIES		
Barriers	Mean	Median	Barriers	Mean	Median
Friction Pressure	3.6	4	Friction Pressure	3.7	4
Proppant Transport	3.2	3	Zone Coverage	3.0	3
Zone Coverage	2.8	3	Downhole Gauges	2.9	3
Shear Rates	2.8	3	Proppant Transport	2.8	3
Tortuosity	2.7	3	Shear Rates	2.7	3
Downhole Gauges	2.5	2	Tortuosity	2.7	3
Perforation Friction	2.4	2	Perforation Friction	2.7	3
Perforation Erosion	2.0	2	Perforation Erosion	2.5	2

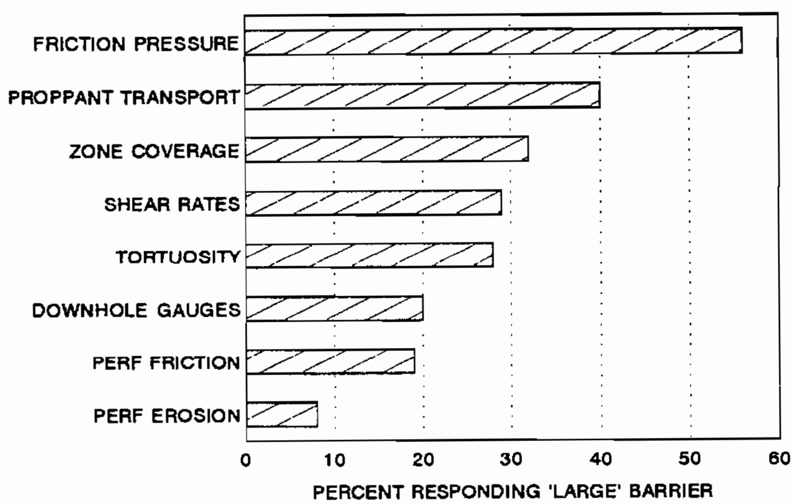

Figure 166. Stimulation Barrier Responses from **Producers**

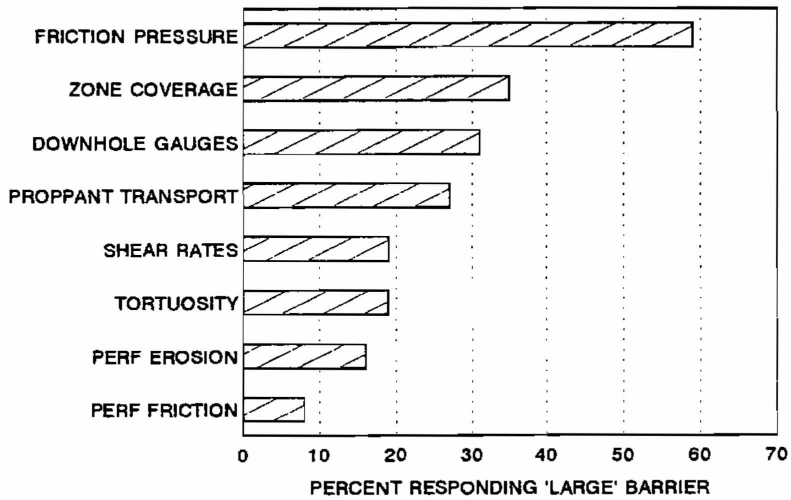

Figure 167. Stimulation Barrier Responses from **Service Companies**

Engineers vs. Managers

Table 63 and Figures 168 and 169 compare *Stimulation* Barrier responses for **Engineers** and **Managers.** Once again, *Friction Pressure* is considered a large barrier by both **Engineers** and **Managers.** *Proppant Transport* is ranked as the second largest barrier by both **Engineers** and **Managers**, but **Managers** felt more strongly with a median of 4 and PRL of 57% (versus 3 and 34%).

Managers are also more concerned about *Shear Rates* than are **Engineers**.

TABLE 63. Stimulation Barriers — Producer Engineers and Managers

Engineers			**Managers**		
Barriers	**Mean**	**Median**	**Barriers**	**Mean**	**Median**
Friction Pressure	3.5	4	Friction Pressure	3.7	4
Proppant Transport	3.1	3	Proppant Transport	3.6	4
Zone Coverage	2.8	3	Shear Rates	3.2	3
Tortuosity	2.7	3	Downhole Gauges	2.7	2
Shear Rates	2.7	3	Tortuosity	2.7	3
Downhole Gauges	2.4	2	Zone Coverage	2.7	3
Perforation Friction	2.3	2	Perforation Friction	2.6	3
Perforation Erosion	2.1	2	Perforation Erosion	2.2	2

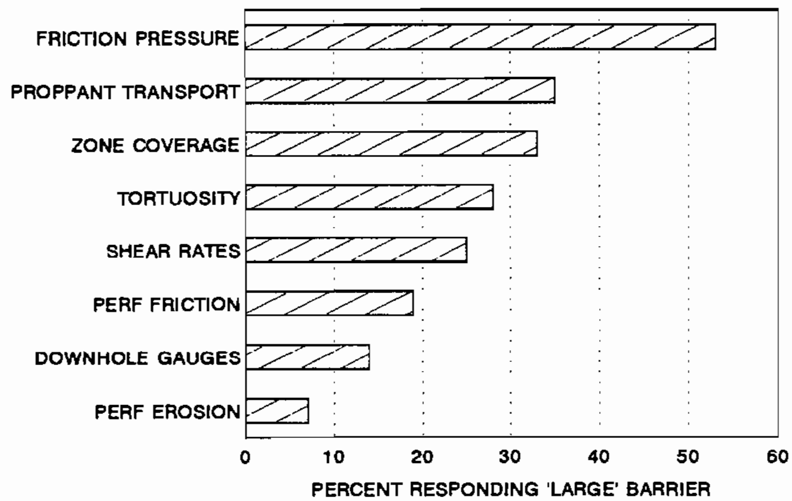

Figure 168. Stimulation Barrier Responses from **Engineers**

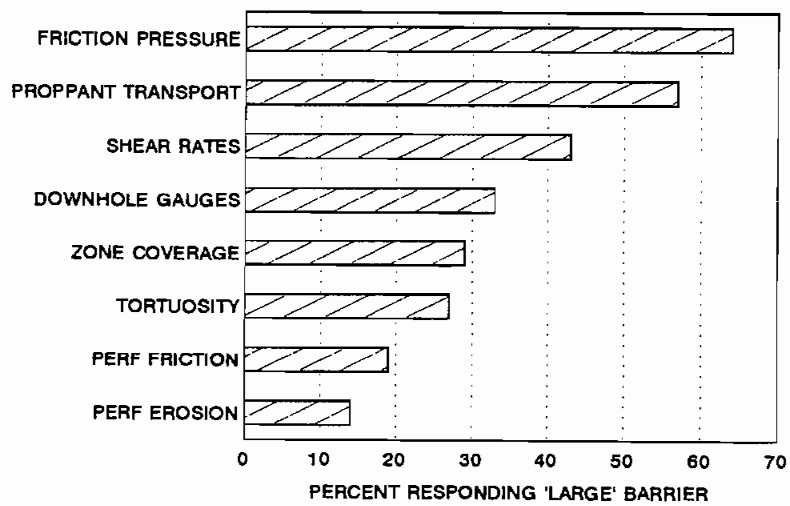

Figure 169. Stimulation Barrier Responses from **Managers**

9.1.7 Drilling Barriers

Similar to *Stimulation*, *Drilling* consistently carried a median response of 3 with a PRL between 30% and 40% in the Overall Barriers section of the survey. Deviation in the **Service Company** responses pushed the median down to 2, but the PRL remained above 30%.

All Respondents

Two topics, *Fishing* and *MWD*, dominate as the two largest perceived Drilling barriers with medians of 4 and PRLs of over 57% (Table 64 and Figure 170). All of the remaining topics addressed carried a median response of 3 with the exception of *Core Barrels* (median of 2). The PRLs reveal other large perceived drilling barriers as being *Downhole Motors*, *Directional Guidance*, *Well Control*, and *Bits* (all with PRL of 40% or greater).

TABLE 64. Drilling Barriers — All Respondents

BARRIERS	MEAN	MEDIAN
Fishing	3.7	4
MWD	3.5	4
Downhole Motors	3.3	3
Directional Guidance	3.2	3
Well Control	3.1	3
Hydraulics	3.1	3
Bits	3.1	3
Lost Circulation	3.1	3
Coiled Tubing	3.0	3
Rigs	2.9	3
Drill String Dynamics	2.8	3
Differential Sticking	2.8	3
Borehole Stability	2.8	3
Tubulars	2.7	3
Drilling Fluids	2.6	3
Core Barrels	2.4	2

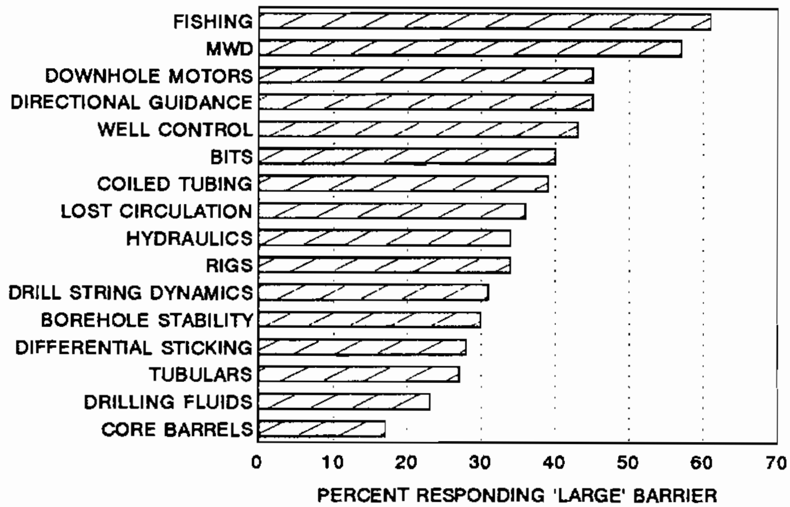

Figure 170. Drilling Barrier Responses from **All** Respondents

Producers vs. Service Companies

Table 65 and Figures 171 and 172 show the *Drilling* barrier results for **Producers** and **Service Companies**. **Producers**, as do **All** respondents, rank *Fishing* and *MWD* as the largest barriers by a considerable margin (medians of 4, PRLs over 53%). Other barriers highly ranked by **Producers** are similar to those ranked by **All** respondents, with the exception that *Coiled Tubing* and *Well Control* are ranked slightly lower by **Producers** than by **All**.

There are greater differences between **Producers** and **Service Companies**. **Service Companies** agree with **Producers** that *MWD* is a large barrier, with both responding with medians of 4; however, the PRL of **Service Companies** is much higher at 69% (**Producers** = 53%). While **Producers** rank *Fishing* as the highest overall *Drilling* barrier (median of 4, PRL of 67%), **Service Companies** rank *Fishing* fifth on median and PRL (median of 3, PRL of 47%), although the ranking on mean is third. Surprisingly, **Service Companies** feel much stronger about *Well Control* barriers than do **Producers** (median of 4 vs. 3, PRL of 63% vs. 37%), ranking it as their second largest *Drilling* barrier.

The ranked position of *Downhole Motors* is about equivalent between **Producers** and **Service Companies**, but **Service Companies** apparently feel stronger about the magnitude or importance of the barrier since their median response is 4 with a PRL of 54%, while **Producers** responded around a median of 3 with a PRL of 41%.

Rig barriers is another surprising comparison. **Producers** rank *Rigs* seventh out of sixteen on PRL (40%) and ninth on mean. **Service Companies** rank *Rigs* as their lowest Drilling barrier with a median of 2 and PRL of only 17%. Similarly, **Service Companies** ranked *Tubulars* very low with a median of 2 and PRL of 18%, while **Producers** believe more strongly with a median of 3 and PRL of 30%. Conversely, **Service Companies** feel stronger about *Drilling Fluid* barriers than do **Producers** (PRL of 31% vs. 21%).

Coiled Tubing also shows a large difference of opinion between **Producer** and **Service Company** groups. **Service Companies** rank *Coiled Tubing* very high (median of 4, PRL over 66%). **Producers** felt much less strongly with a median of 3 and PRL of only 30%. This is interpreted to mean that **Service Companies** are more aware of and sensitive to the limitations of coiled tubing as a drilling system relative to great interest and large number of requests for proposals from producers in increasingly difficult applications.

TABLE 65. Drilling Barriers — Producers and Service Companies

Producers			Service Companies		
Barriers	**Mean**	**Median**	**Barriers**	**Mean**	**Median**
Fishing	3.8	4	MWD	3.9	4
MWD	3.4	4	Well Control	3.6	4
Downhole Motors	3.2	3	Coiled Tubing	3.5	4
Directional Guidance	3.2	3	Fishing	3. 5	4
Bits	3.1	3	Downhole Motors	3.4	4
Hydraulics	3.1	3	Directional Guidance	3.3	3
Lost Circulation	3.1	3	Hydraulics	3.2	3
Rigs	3.0	3	Lost Circulation	3.1	3
Well Control	3.0	3	Drill String Dynamics	3.1	3
Coiled Tubing	2.8	3	Bits	3.0	3
Tubulars	2.8	3	Borehole Stability	3.0	3
Differential Sticking	2.8	3	Drilling Fluids	2.9	3
Drill String Dynamics	2.8	3	Differential Sticking	2.9	3
Borehole Stability	2.7	2	Core Barrels	2.8	3
Drilling Fluids	2.5	2.5	Tubulars	2.5	2
Core Barrels	2.3	2	Rigs	2.5	2

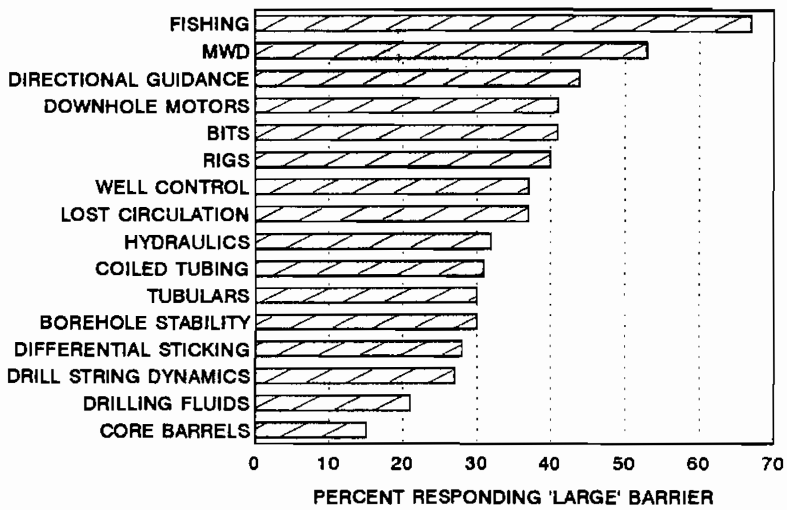

Figure 171. Drilling Barrier Responses from **Producers**

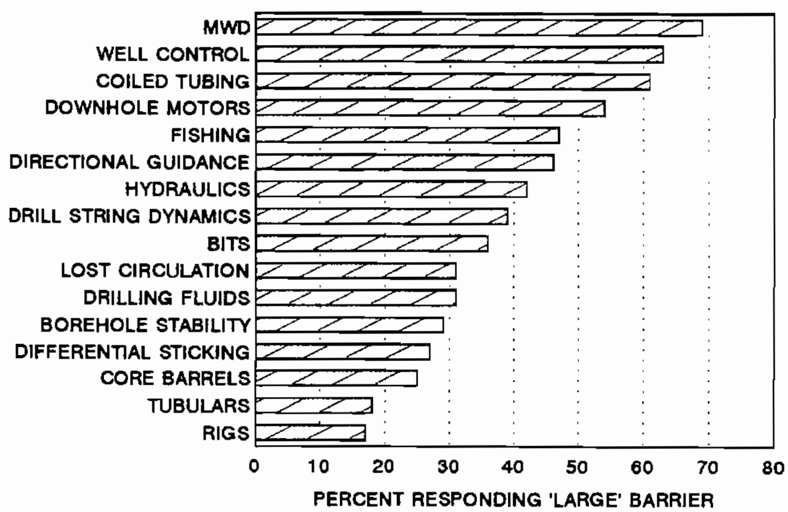

Figure 172. Drilling Barrier Responses from **Service Companies**

Engineers vs. Managers

Fishing is ranked as the largest Drilling barrier by both **Engineers** and **Managers** with medians of 4 and PRLs of over 63% (Table 66 and Figures 173 and 174). *Downhole Motors* and *Directional Guidance* concerns are also ranked relatively high by both **Engineers** and **Managers.** **Managers** have much stronger opinions about slim-hole bits, ranking *Bits* as their second largest *Drilling* barrier with a median of 3.5 and PRL of 50%. **Engineers** rank *Bits* eighth with median of 3 and a PRL of 38%. **Engineers** are more concerned about *MWD* barriers, ranking *MWD* second on median (4) and PRL (59%) while **Managers** ranked *MWD* seventh on PRL (35%) with a median of

3. Both **Engineers** and **Managers** rank *Coiled Tubing* relatively high, but **Engineers** have a stronger opinion with a PRL of 50% and median of 3.5, vs. 40% and 3 for **Managers**. *Well Control* barriers are of much more concern to **Managers** than **Engineers** with the third highest ranking on PRL with 44%. **Engineers** pushed *Well Control* down to an eleventh place ranking with a PRL of 33%. There is a substantial difference of opinion on *Rig* barriers, with **Engineers** ranking them sixth with a median of 3 and PRL of 43%, while **Managers** rank *Rigs* 12th on mean with a median of only 2 and PRL of 32%. **Managers** are more concerned about *Drilling Fluids* issues, while **Engineers** are more concerned about *Differential Sticking* and *Tubular* barriers.

TABLE 66. Drilling Barriers — Producer Engineers and Managers

Engineers			Managers		
Barriers	Mean	Median	Barriers	Mean	Median
Fishing	3.8	4	Fishing	3.7	4
MWD	3.5	4	Bits	3.2	3.5
Downhole Motors	3.3	3	Hydraulics	3.2	3
Directional Guidance	3.2	3	Well Control	3.1	3
Rigs	3.2	3	MWD	3.0	3
Lost Circulation	3.2	3	Directional Guidance	3.0	3
Bits	3.1	3	Downhole Motors	3.0	3
Hydraulics	3.1	3	Lost Circulation	2.9	3
Coiled Tubing	3.0	3	Drill String Dynamics	2.8	3
Differential Sticking	3.0	3	Drilling Fluids	2.7	3
Well Control	3.0	3	Rigs	2.6	2
Tubulars	2.9	3	Tubulars	2.5	3
Borehole Stability	2.8	3	Borehole Stability	2.5	2
Drill String Dynamics	2.7	3	Differential Sticking	2.4	2
Drilling Fluids	2.5	2	Coiled Tubing	2.3	2
Core Barrels	2.4	2	Core Barrels	2.2	2

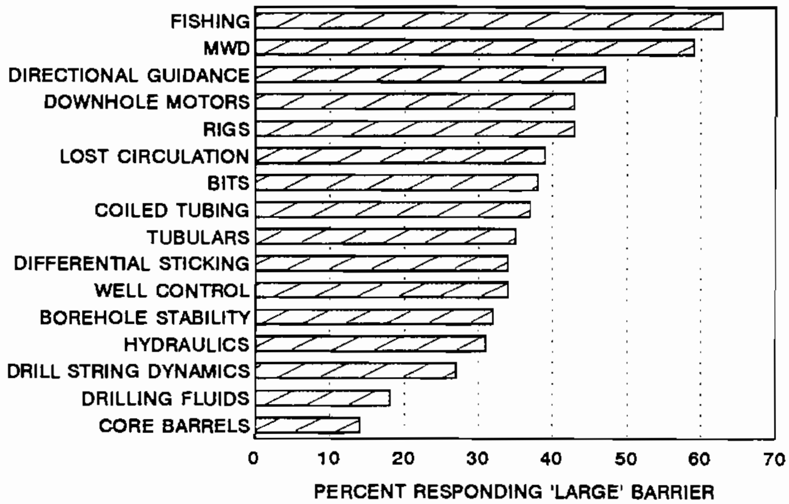

Figure 173. Drilling Barrier Responses from **Engineers**

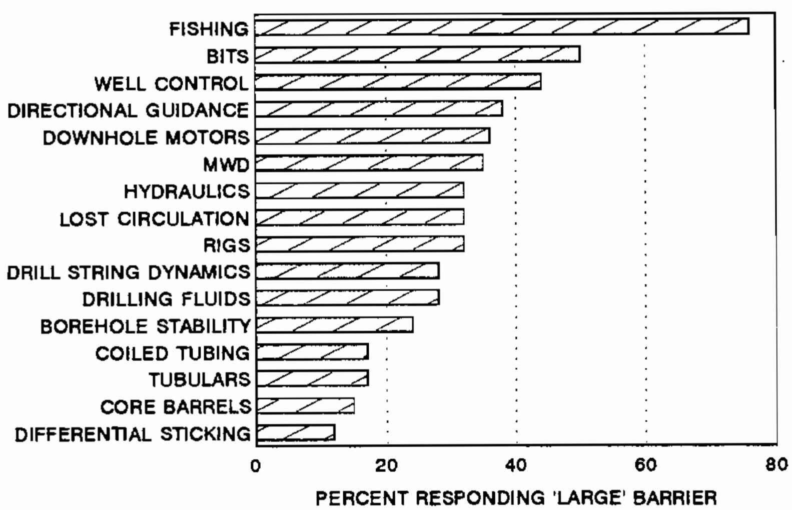

Figure 174. Drilling Barrier Responses from **Managers**

9.1.8 Cementing Barriers

Cementing is the only section of the questionnaire that did not generate any categorical responses with a median over 3 or PRL over 50% in the **All** respondents analysis.

All Respondents

Table 67 and Figure 175 show the results for **All** respondents to the *Cementing* Barrier section of the questionnaire. The greatest perceived barrier, based on PRL, is, not surprisingly, again related to workover issues covered in other sections, *Remedial Work*. *Annular Friction, Thin Sheath*, and *Tool Availability* are the other highly ranked barriers. Interestingly, *Regulatory* barriers are not considered much of a problem, ranking last with a median of 2 and PRL of only 10%.

TABLE 67. Cementing Barriers — All Respondents

BARRIERS	MEAN	MEDIAN
Annular Friction	3.3	3
Remedial Work	3.3	3
Tool Availability	3.2	3
Thin Sheath	3.1	3
Rotating/Reciprocating	2.9	3
Mud Displacement	2.8	3
Lost Circulation Material	2.7	3
Small Volumes	2.6	3
High Shear Rate	2.6	3
Pipe Buckling	2.6	3
Regulatory	2.1	2

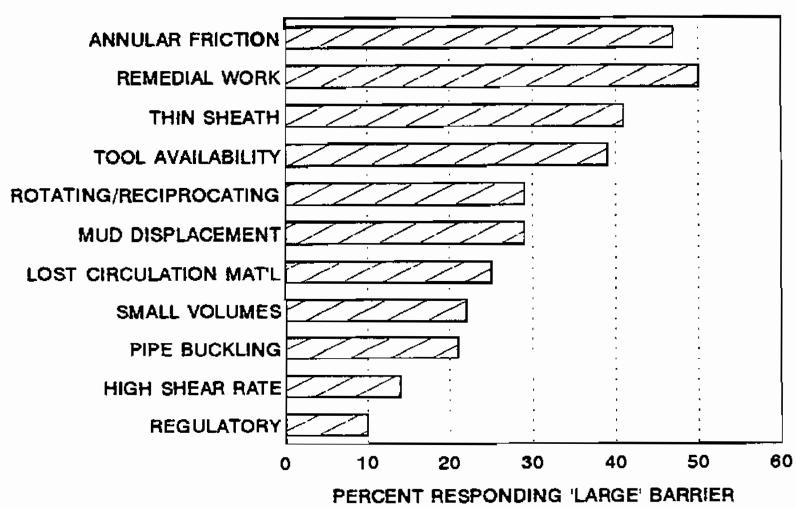

Figure 175. Cementing Barrier Responses from **All** Respondents

Producers vs. Service Companies

As shown in Table 68 and Figures 176 and 177, there is no substantial variance of opinion between **Producers** and **All** respondents or between **Producers** and **Service Companies.**

TABLE 68. Cementing Barriers — Producers and Service Companies

PRODUCERS			SERVICE COMPANIES		
Barriers	**Mean**	**Median**	**Barriers**	**Mean**	**Median**
Annular Friction	3.3	3	Remedial Work	3.5	3.5
Remedial Work	3.3	3	Annular Friction	3.5	3
Tool Availability	3.2	3	Tool Availability	3.3	3
Thin Sheath	3.2	3	Rotating/Reciprocating	3.3	3
Mud Displacement	2.8	3	Thin Sheath	3.1	3
Rotating/Reciprocating	2.8	3	Mud Displacement	3.0	3
Lost Circulation Material	2.6	3	Lost Circulation Material	2.9	3
Small Volumes	2.6	2.5	Pipe Buckling	2.9	3
High Shear Rate	2.5	2.5	Small Volumes	2.8	3
Pipe Buckling	2.5	2	High Shear Rate	2.7	3
Regulatory	1.9	2	Regulatory	2.6	3

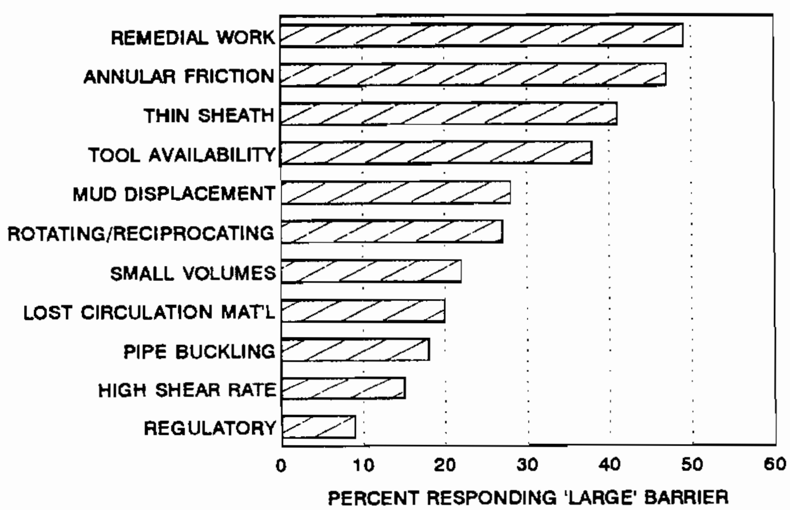

Figure 176. Cementing Barrier Responses from **Producers**

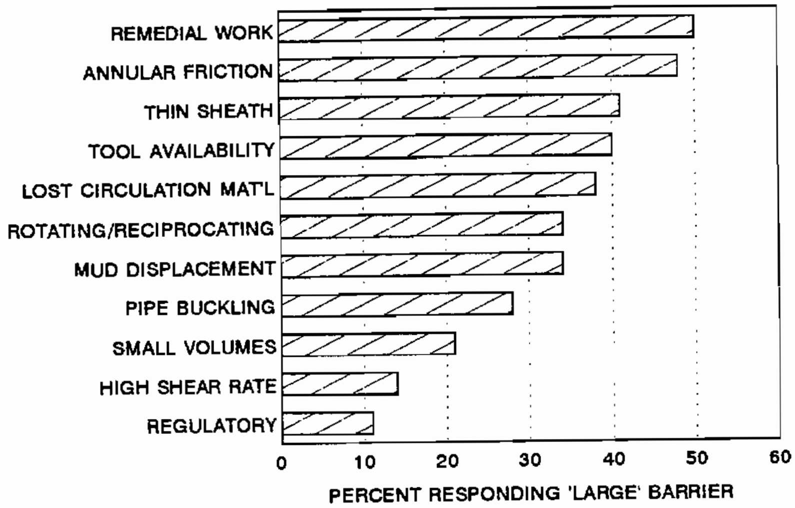

Figure 177. Cementing Barrier Responses from **Service Companies**

Engineers vs. Managers

Likewise, no strong variance of opinion exists between **Engineers and Managers** on *Cementing* Barriers (Table 69 and Figures 178 and 179).

TABLE 69. Cementing Barriers — Producer Engineers and Managers

Engineers			Managers		
Barriers	**Mean**	**Median**	**Barriers**	**Mean**	**Median**
Annular Friction	3.3	3	Remedial Work	3.2	3.5
Remedial Work	3.3	3	Annular Friction	3.2	3
Tool Availability	3.2	3	Tool Availability	3.1	3
Thin Sheath	3.2	3	Thin Sheath	3.0	3
Mud Displacement	3.0	3	High Shear Rate	2.6	2.5
Rotating/Reciprocating	2.9	3	Lost Circulation Material	2.5	3
Small Volumes	2.7	3	Pipe Buckling	2.4	2
Lost Circulation Material	2.6	3	Rotating/Reciprocating	2.3	2.5
High Shear Rate	2.5	2.5	Mud Displacement	2.2	2
Pipe Buckling	2.5	2	Small Volumes	2.1	2
Regulatory	1.9	2	Regulatory	2.1	2

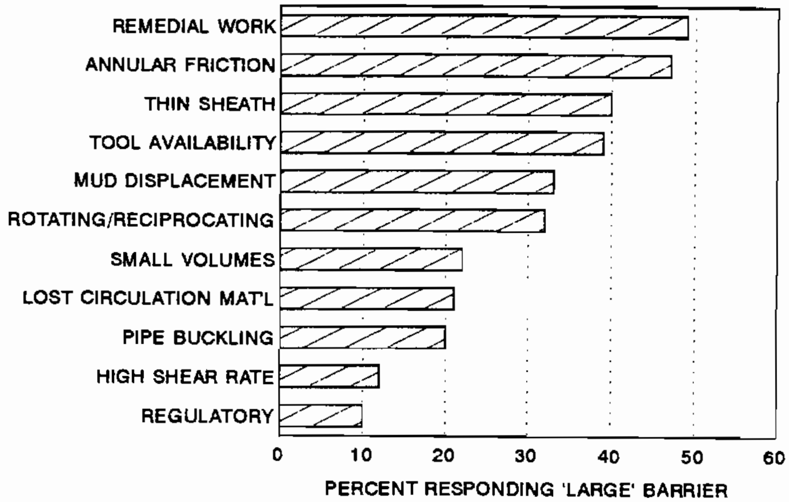

Figure 178. Cementing Barrier Responses from **Engineers**

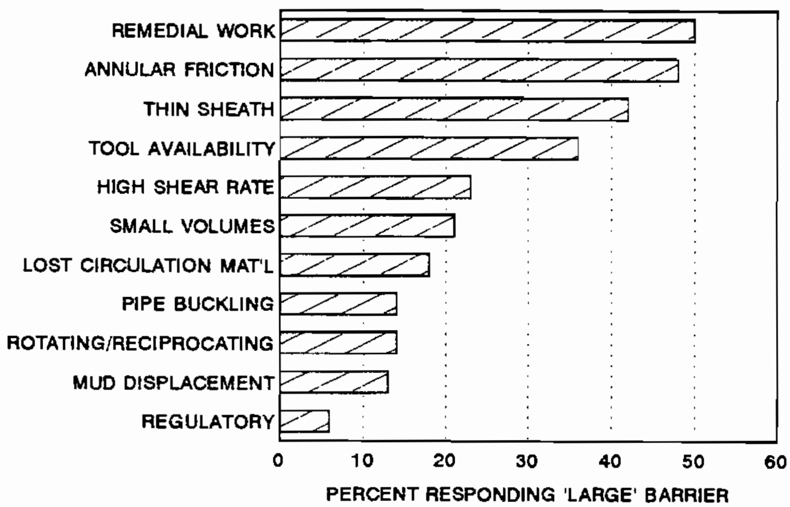

Figure 179. Cementing Barrier Responses from **Managers**

9.2 SUMMARY OF LARGEST PERCEIVED BARRIERS

The largest perceived barriers, based on the GRI questionnaire results, are best determined based first on median and second on PRL. If a median of 4 is used as the most meaningful statistical measure, approximately eight issues are the largest barriers according to **All** respondents and **Producers**. This corresponds to PRLs of greater than 50% in all cases. Eight issues represent 14% of the individual technology issues that were listed on the questionnaire. **Service Companies** responded with medians of 4 on only seven issues, but responded with a median of 3.5 on an additional three issues. **Producer Engineers** have eight issues with a median of 4, but **Managers** only seven. However, similar to **Service Companies**, **Managers** responded with a median of about 3.5 on an additional three issues.

It must be noted that no aspect of the second-ranked overall barrier, *Management Attitude*, is included in the individual technology rankings discussed below. No individual technology issues were associated with that Overall barrier in the questionnaire.

All Respondents

Table 70 presents the "top eight" individual slim-hole technology barriers of **All** respondents from all areas addressed, listed in ranked order according to PRL.

TABLE 70. Top Eight Perceived Barriers - All Respondents

AREA	ISSUE
Tools	*Workover Limitations*
Formation Evaluation	*Number of Logging Tools Available*
Drilling	*Fishing*
Tools	*Fishing Tools*
Formation Evaluation	*Existence of Logging Tools*
Stimulation	*Friction Pressure Loss*
Drilling	*MWD*
Formation Evaluation	*Service Company Experience*

Producers

Table 71 lists the top eight barriers as perceived by **Producers**. As shown, the issues for **Producers** are identical to **All** respondents. The only difference is slight variation in the PRL ranked order.

TABLE 71. Top Eight Perceived Barriers - Producers

AREA	ISSUE
Tools	*Workover Limitations*
Drilling	*Fishing*
Tools	*Fishing Tools*
Formation Evaluation	*Number of Logging Tools Available*
Formation Evaluation	*Existence of Logging Tools*
Stimulation	*Friction Pressure*
Formation Evaluation	*Service Company Experience*
Drilling	MWD

Service Companies

Table 72 shows the top seven barriers as perceived by **Service Companies.** Similar between **Producers** and **Service Companies** are *MWD, Friction Pressure (Stimulation),* and *Logging Tools (Existence and Number).* However, *Fishing* issues and **Workover Limitations** do not appear in the **Service Company** top seven, replaced by *Well Control, Downhole Motors,* and *Coiled Tubing.*

TABLE 72. Top Seven Perceived Barriers - Service Companies

AREA	ISSUE
Drilling	*MWD*
Drilling	*Well Control*
Stimulation	*Friction Pressure*
Formation Evaluation	*Existence of Logging Tools*
Formation Evaluation	*Number of Logging Tools Available*
Drilling	*Downhole Motors*
Drilling	*Coiled Tubing*

Engineers

The top eight barriers as perceived by **Producer** company **Engineers** are shown in Table 73. These are similar to the **Producers** and **All** responses, with slight variance in the PRL-ranked order.

TABLE 73. Top Eight Perceived Barriers - Engineers

AREA	ISSUE
Tools	*Workover Limitations*
Formation Evaluation	*Number of Logging Tools Available*
Formation Evaluation	*Existence of Logging Tools*
Drilling	*Fishing*
Tools	*Fishing Tools*
Drilling	*MWD*
Formation Evaluation	*Service Company Experience*
Stimulation	*Friction Pressure*

Managers

The top seven barriers as perceived by **Producer** company **Managers** are shown in Table 74 Similar to **Engineers**, *Fishing* issues, *Workover Limitations, Friction Pressure (Stimulation),* and *Number of Logging Tools* are highly ranked barriers. **Managers** include *Proppant Transport* and *Mechanical Packers* in their top barrier list, but not *MWD*, *Service Company Experience (Formation Evaluation)*, and *Existence of Logging Tools.*

TABLE 74. Top Seven Perceived Barriers - Managers

AREA	ISSUE
Tools	*Fishing Tools*
Drilling	*Fishing*
Tools	*Workover Limitations*
Stimulation	*Friction Pressure*
Stimulation	*Proppant Transport*
Formation Evaluation	*Number of Logging Tools Available*
Tools	*Mechanical Packers*

9.3 TECHNOLOGY TRANSFER

Items regarding effective slim-hole technology transfer channels were included for ranking on a revised version of the questionnaire distributed to several respondents. This produced about 75 responses for use in ranking industry opinion on the best methods for GRI to transfer slim-hole technology and information. About 75% of the responses to this section were from **Producer** companies. The ranked results for **All** and **Producers** are similar, so only the results from **All** respondents will be discussed. The ranking criteria was again from 1 to 5, with a 1 being "Least Effective" and 5 being "Most Effective."

All Respondents

Table 75 presents the ranking of the results for the general technology transfer vehicles. As shown, *Workshops/Forums*, *Technical Papers* and *Trade Publication Articles* dominate as the preferred methods for slim-hole technology transfer.

TABLE 75. Technology Transfer Responses

VEHICLE	MEDIAN	MEAN	PRL
Workshops/Forums	4	3.9	64
Trade Publications	4	3.8	65
Technical Papers	4	3.8	62
Exhibitions	3	3.1	39
Schools	3	3.1	36
Brochures	3	3.0	32
GRI Reports	3	2.9	32
Videos	2	2.4	14

Additional responses were solicited on the trade publications felt to be the most effective for transferring slim-hole technology. Table 76 shows these results. *Oil & Gas Journal, Journal of Petroleum Technology*, and *SPE Drilling & Completions* are the most highly ranked.

TABLE 76. Trade Publication Effectiveness

MAGAZINE	MEDIAN	MEAN	PRL
Oil & Gas Journal	4	3.9	68
JPT	4	3.9	65
Drilling & Completion	4	3.8	62
World Oil	4	3.6	54
Petroleum Engineering	3	3.2	37

Similarly, detailed rankings were requested on *Exhibitions*. As shown in Table 77, the *SPE Annual Meeting* and the *SPE/IADC* meeting are felt to be the most effective *Exhibitions* for transferring slim-hole technology.

TABLE 77. Exhibition Effectiveness

Exhibition	Median	Mean	PRL
SPE Annual	4	3.7	61
SPE/IADC	4	3.8	60
OTC	3	3.4	42
SPE Regionals	3	3.2	35

9.4 RESOURCE MARKETING INTERNATIONAL ASSESSMENT

As part of this project, GRI purchased the report on a slim-hole technology market assessment carried out by Resource Marketing International (RMI) in 1992 and 1993 under the sponsorship of eight different service companies. These included Schlumberger Anadrill, Baker Hughes, Halliburton, IFP, Dresser Security, Shell Chemical, Sperry-Sun Drilling Services, and Western Atlas International.

The complete report, "Worldwide Market Assessment of Slim-Hole Technology," contains information on various aspects of slim-hole technology based on the results of questionnaires and interviews with 55 operator contacts and 29 service company contacts from around the world. In this section, only the results pertaining to specific technology barriers will be reviewed.

The RMI questionnaire was structured such that respondents only checked a particular item and did not provide a quantitative ranking. Therefore, the results are analyzed and ranked based on percentage of respondents who checked the particular category (referred to in the following tables as "percent").

9.4.1 Slim-Hole Drilling Problems/Concerns

The results of the RMI assessment regarding slim-hole drilling problems and concerns are shown in Table 78. It is difficult to make direct comparisons between the GRI and the RMI results since the surveys were structured differently. However, some general observations are possible. Comparisons are made to the Producer responses to the GRI questionnaire Drilling section (Table 65 and Figure 171) since the rankings given in the RMI report are for "Operators." *Tubular* concerns were the highest ranked concern in the RMI assessment, while *Tubulars* were ranked eleventh out of sixteen by the **Producer** respondents to the GRI questionnaire. *Fishing* was the highest ranked area on the GRI questionnaire, but was ranked seven out of eleven in the RMI analysis. *Bits* and *Motors* were moderately ranked by both groups. *Formation Evaluation* is highly ranked in the RMI survey, and *MWD* and logging issues were highly ranked in the GRI questionnaire.

TABLE 78. RMI Assessment - Drilling Problems/Concerns

PROBLEM/CONCERN	PERCENT
Drill Pipe/Collar Strength	26
Limited Drilling Options	25
Bits/Availability	23
Formation Evaluation Limitations	21
Well Control Limitations	18
Motors	15
More Fishing Jobs	12
Kick Detection Limitations	9
Drill Pipe/Collar Availability	7
Reservoir Characteristics	6
Small Hole Size	2

9.4.2 Slim-Hole Completion/Workover/Production Problems

Two sections of the RMI assessment report on completion, production, and workover issues. One question addressed "Problems" and one question addressed "Needed Developments." Table 79 and 80 shows the results from these two questions. Once again, direct comparison between the surveys is difficult, but the RMI assessment results are generally consistent with the GRI questionnaire results. *Workover Limitations* and completion tools are felt generally to be problems or barriers. Interestingly, *Fishing* issues are again ranked lower in the RMI assessment, while very strong opinions were discovered in the GRI questionnaire. Also of interest is that while *Limited Completion Options* is ranked first in the RMI "Problems" question, the leading individual technology need was "Don't Know," and the fifth-ranked (out of twelve listed) was "None," implying a tremendous need for slim-hole education and existing technology transfer.

TABLE 79. RMI Assessment - Completion/Workover/Production Problems

PROBLEMS	PERCENT
Limited Completion Options	40
Production Rate Limitations	32
Limited Workover Options	30
Sand Control Limitations	9
Perforation Limitations	5
Production Logging/Monitoring	5

TABLE 80. RMI Assessment - Completion and Workover Development Needs

NEEDED DEVELOPMENTS	PERCENT
Don't Know	21
Artificial Lift	12
Coiled Tubing Compatibility	12
Gravel Packs	10
None	10
Cementing/Stimulation Techniques	9
Packers and Accessories	9
All Equipment	9
Fishing Capabilities	8
Liner Hangers	5
Zone Isolation	3
Perforation Capability	3
All Others (5)	7

9.5 REFERENCES

Resource Marketing International Staff: "Worldwide Market Assessment of Slim-Hole Technology," Special Report for Maurer Engineering, (July 1993).

10. Potential Impact Analysis

The objective of the analysis in this section is to ascertain a range of potential savings that could accrue to U.S. gas producers as a result of successful development, transfer, and implementation of cost saving slim-hole technology. Most recent documented slim-hole examples pertain to exploration drilling in remote and difficult international areas. In general, most projects have pointed towards significant reductions in location and logistics costs as the greatest driving force in their slim-hole programs, although savings in other categories are also significant. There are costly locations in the U.S. as well. However, when attempting to estimate potential future savings on slim-hole technology for an average U.S. gas well, historical costs are relied upon and location costs are not a great percentage of total well costs in generally accepted cost models (less than 5%).

In addition, the current project has determined the necessity of distinguishing between slim-hole drilling and slim-hole completions in the U.S. Most savings in new U.S. onshore gas wells (excluding deepenings and horizontal re-entries) from slim techniques are being obtained simply by using small production casing strings in conventional size holes, instead of the more common 5½-in. casing with a 2⅞-, or 2⅜-in. production tubing string. True slim-hole drilling (hole sizes smaller than 6 in.) is not being currently used in a material number of onshore vertical wells. A valid savings model must accommodate the distinction between slim completions and slim-hole drilling.

10.1 METHODOLOGY

A slim-hole potential impact model has been constructed to allow for varying assumptions about increases in slim completions, slim-hole drilling, and cost savings associated with each technique. Base cases and two escalation cases each for slim completions and slim-hole drilling have been constructed. These are based on percentage-capture of the onshore U.S. gas well forecast from the 1994 GRI Baseline Projection. A total cost savings potential associated with each technique is assumed based on categorical analysis of the cost model used in the Hydrocarbon Supply Model. Nominal and present value savings are calculated for the *incremental* slim-hole technique capture percentage that would be attributable to successful new or expanded research programs.

This effort results in a total of eight cases presented which provide a broad range of potential savings. However, the model easily accommodates any range of slim-hole technique capture percentages and cost savings assumptions. The cases are listed in Table 81.

TABLE 81. Savings Cases

CASE NAME	SLIM-COMPLETION ESCALATION	SLIM-HOLE DRILLING ESCALATION
LO-BASE	Low	Base
LO-LO	Low	Low
LO-HI	Low	High
HI-BASE	High	Base
HI-LO	High	Low
HI-HI	High	High
BASE-LO	Base	Low
BASE-HI	Base	High

10.2 SLIM-HOLE CASE DESCRIPTIONS

As previously discussed, it is important to distinguish slim completion savings from slim-hole drilling savings. Significant savings in initial well cost are immediately available from running smaller production casing strings. It is appreciably more difficult and less certain, to realize savings from slim-hole drilling in most U.S. locations. The decision process accompanying slim technique analysis also supports this approach. An operator must convince himself he can "live with" a slim completion first, before even considering a slim-hole drilling alternative. As has been presented in Chapter 3, many operators are using slim completions for an increasing number of gas wells. However, most of these slim completions are not placed in slim holes. That is, more conventional size holes are drilled which easily accommodate smaller pipe. Therefore the cases have been constructed to represent the most likely scenario for slim-hole technique escalation in the U.S.:

1. SLIM COMPLETION Cases - An increasing percentage of *U.S. onshore gas wells* use slim completion techniques in <u>conventional</u> size holes and achieve savings in production casing and tubing only.

2. SLIM-HOLE DRILLING Cases - An increasing percentage of *slim completions* use slim-hole drilling and achieve cost savings in various additional well cost categories.

Two different escalation scenarios have been built for slim completions and slim-hole drilling, as well as baseline, or base, cases. The forecast period begins in 1995 and proceeds through 2010 (15 years).

10.2.1 Slim Completion Cases

The slim completion cases are base, low escalation, and high escalation.

SLIM COMPLETION-BASE: This assumes the current level of slim completion percentage usage in the U.S. stays flat at 7%. Note that the current percentage was stated at 6% in the Activity Section. This adjustment is due to slightly different total gas well counts used in the PI data analysis in this report and the GRI Baseline Projection. Recall that this percentage has doubled in the last few years, so a flat 7% is a reasonable approach for a baseline since increased usage in new areas may be offset by declining activity in the areas accounting for the recent escalation.

SLIM COMPLETION-LO: Slim completions increase by 50% from 7 to 10.5% by 1999 and remain flat throughout the forecast period.

SLIM COMPLETION-HI: Slim completions increase by 100% from 7 to 14% by 1999.

Figures 180 and 181 graphically depict the well count assumptions for the slim completion base and escalation cases.

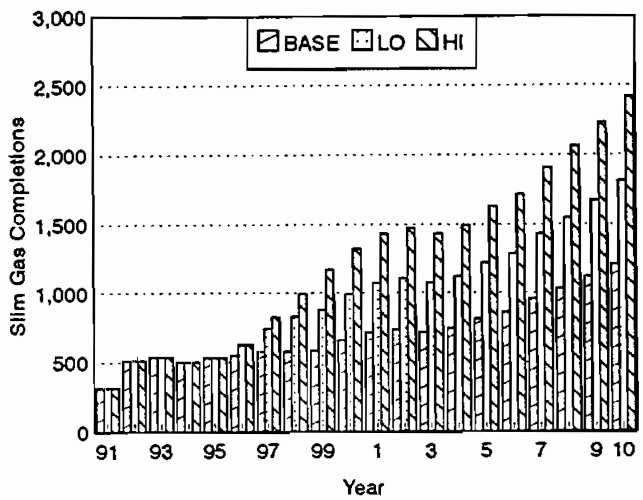

Figure 180. Slim Completion Base and Escalation Cases

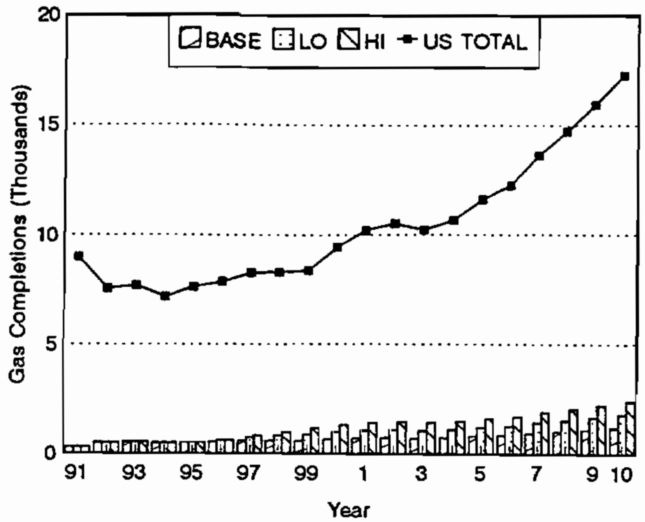

Figure 181. Slim Completion Cases and Total U.S. Onshore Gas Wells

It is important to note that only the incremental number of slim completions (escalation case minus base case) is used to calculate the potential savings from expanded use of slim-hole techniques. Table 82 shows the total and incremental well counts for these cases.

TABLE 82. Slim Completion Case Well Counts (1995-2010)

Case	Wells	% of U.S. Total*	Incremental	% of U.S. Total*
BASE	12,399	7.0	—	—
LO	17,968	10.1	5569	3.1
HI	23,293	13.2	10,894	6.2
*U.S. Total Onshore Gas Wells = 177,123				

10.2.2 Slim-Hole Drilling Cases

The slim-hole drilling cases are built based upon percentages of slim completions using slim-hole drilling instead of the total well count. Therefore, ***a slim-hole drilling case must relate to assumptions about the escalation of slim completion usage***:

> *SLIM-HOLE DRILLING-BASE:* Assumes the current level of 5% *of slim completions* remains flat through the forecast period. It is felt this is a reasonable assumption for slim-hole drilling for new onshore U.S. gas wells absent a focused research program since it is very difficult for an operator in today's drilling market to plan, justify, and fund a multi-well slim-hole drilling program without outside assistance, despite the

potential savings. A multi-well program is needed in order to obtain the experience necessary to realize any potential savings.

SLIM-HOLE DRILLING-LO: Slim-hole drilling doubles to 10% *of slim completions* by 1999 and remains flat through the projection period.

SLIM-HOLE DRILLING-HI: Slim-hole drilling increases to 25% *of slim completion* activity by 2000.

Figures 182 and 183 graph the well count assumptions for the slim-hole drilling cases, relevant to the slim completion cases.

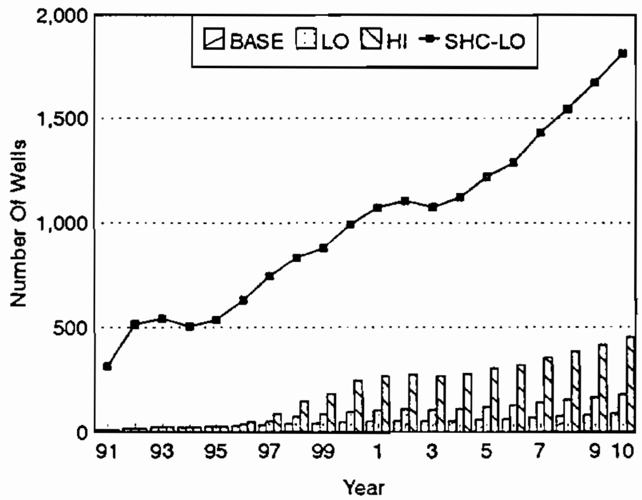

Figure 182. Slim-Hole Drilling Cases for Low Completion Case

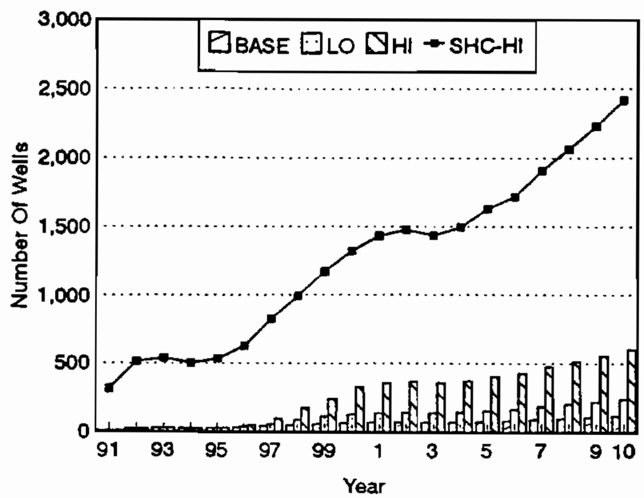

Figure 183. Slim-Hole Drilling Cases for High Completion Case

Even though these escalations seem aggressive, it must be re-emphasized that these are percentages of slim completions, not total U.S. onshore gas wells. Therefore, the maximum aggregate case of SLIM COMPLETION-HI (14% of total wells) and SLIM-HOLE DRILLING-HI (25% of *slim completions*) still results in only 3½% of the total U.S. wells using slim-hole drilling by the year 2000. Table 83 shows the case and incremental well counts for the various slim-hole drilling cases.

TABLE 83. Slim-Hole Drilling Case Well Counts

	SHC Case	Case	% of U.S.	Incremental	% of U.S.
SHD-BASE	LO	898	0.5	—	—
SHD-LO	LO	1714	1.0	816	0.5
SHD-HI	LO	4088	2.3	3190	1.8
SHD-BASE	HI	1165	0.7	—	—
SHD-LO	HI	2243	1.3	1078	0.6
SHD-HI	HI	5385	3.0	4220	2.4
SHD-BASE	BASE	620	0.4	—	—
SHD-LO	BASE	1168	0.7	548	0.3
SHD-HI	BASE	2760	1.6	2140	1.2

10.3 COST ASSUMPTIONS

It is beyond the scope of the current study to investigate each region of the country and make estimates for conventional completion and drilling costs and potential slim-hole completion and drilling scenarios and costs. Therefore, the approach adopted uses adjusted Hydrocarbon Supply Model cost data for application to one scenario that was felt best represented an "average," or "type," U.S. gas well that would be using slim techniques. Categorical analysis was then done to make technical-based assumptions for a base cost savings case to apply to the various slim-hole escalation cases.

A concerted effort has been made to put forth realistic cost savings assumptions with a tendency towards conservatism for realistic near-term impact projections. However, implicit in this savings analysis is the assumption that a focused testing program <u>is</u> funded and improvements <u>are</u> made in various technologies, market factors (such as integrated services), and education and experience of producer company engineering staffs (transfer of existing and new technology).

10.3.1 <u>Base Costs</u>

Table 84 presents the Joint Association Survey (JAS) data for Onshore Gas Well Costs as presented in the December 1992 NPC report.

TABLE 84. Onshore U.S. Gas Well Costs (Thousands of 1988 Dollars)

Region		0–5000 ft	5–10,000 ft	10–15,000 ft	>15,000 ft
Appalachia	A	115	250	1420	3760
MAFLA Onshore	B	130	304	1574	3425
Midwest	C	125	519	1809	—
Arkla-E. Texas	D	90	495	1101	3760
So. Louisiana	E	—	536	1556	4013
Texas Gulf Coast	G	101	453	1608	3605
Williston	WL	45	350	1400	—
Rockies Foreland	FR	202	322	1395	5010
San Juan Basin	SJB	202	322	1395	5010
Overthrust	OV	212	335	1465	5260
Midcontinent	JN	122	381	1079	33216
Permian	JS	173	326	1303	3445
Pacific	L	201	437	1013	3760
AVERAGE		143	387	1392	4033
Additional Stimulation Cost Applied to Low-Permeability Gas Wells:					
Lower-48 Average		78	89	103	118
Source: Joint Association Survey as reported in 1992 NPC Report					

An average gas well in the U.S. is believed to be around 8000 ft in total depth. Where a specific depth assumption is called for, such as in calculating tubular and cementing savings, 8000 ft is used. However, it was desired to determine a representative cost for an average well that would likely be a candidate for slim techniques instead of building a very specific, depth-related AFE. For example, a depth assumption of 8000 ft using the JAS survey results in an overall average (all regions) completed well cost for the 5 to 10,000-ft range of $476,000 (with stimulation). It is felt that this cost figure is too low to use as a base cost for our baseline conventional calculations purposes. Wells more typical of those likely to use slim techniques are better represented by those studied in the recent GRI tight gas sands well cost study. Table 85 shows the average well costs and depths for Cotton Valley (East Texas), Wilcox (South Texas), and Frontier (Wyoming) formation wells investigated in this study.

TABLE 85. GRI Tight Gas Well Cost Study

Formation	Median Depth (ft)	Median Cost ($)
Cotton Valley	10,276	941,713
Wilcox	10,000	891,559
Frontier	8,000/12,000	621,492
Average		818,255

Since the median depth range is around 10,000 ft for the wells studied, and these are considered representative candidates for slim techniques, an alternative approach would be to use the 10–15,000 ft JAS cost range. The average completed well cost for all regions in that depth range is $1,495,000. This appears to be excessive by comparison to the $818,000 figure shown for the three formations discussed above. The average <u>between</u> the 5–10,000 ft depth and the 10–15,000 ft depth JAS costs is $985,600. This also appears excessive for use as "type" well. A reasonable baseline conventional well cost was found by simply doubling the average 5–10,000 ft JAS cost of $387,000 (excluding stimulation) to $774,000. This figure compares favorably with the range of median values in the three "type" gas formations discussed above, and also satisfies several other reasonableness tests when allocated to individual categories. These tests are discussed within the various category discussions in the next section.

Therefore, the base conventional completed well cost assumption is $774,000 and is used for further allocation to individual cost categories for calculation of potential slim-hole savings.

10.3.2 <u>Category Allocations</u>

To allocate the base conventional completed well cost of $774,000 to individual well cost categories, Independent Petroleum Association of America category data was used, as grouped by ICF Resources to accurately analyze historical drilling costs for the NPC report. Table 86 shows the 1989 expenditure percentage, the allocation of the base conventional cost to the pertinent categories and the associated near-term slim-hole savings assumptions used for this analysis. Also shown in this table is the savings potential of slim-hole approaches from a broadening mid- to long-range term perspective.

TABLE 86. Categorical Allocations and Assumptions
Base Conventional Cost = $774,000

WELL COSTS	% of Total Expenditure (1989)	Allocated Costs	Slim-Hole Savings ($)	Near-Term Slim-Hole Savings (%)	Potential Savings (%)
Casing Hardware	0.9	7	0	0	25
Casing and Tubing	13.7	106	47*	44	50
Cement and Cementing	4.8	37	11	30	50
Drill Bits and Reamers	2.3	18	0	0	50
Drilling Mud and Additives	5.8	45	14	30	70
Payments to Drill Contractors	30.7	238	29	12	40
Road and Site Preparation	4.4	34	7	20	50
Special Tool Rentals	2.7	21	0	0	50
Transportation	2.4	19	6	30	50
Directional Drilling Services	1.6	12	0	0	20
Formation Treating	4.4	34	0	0	20
Misc. Equipment and Supplies	3.0	23	0	0	30
Perforate	1.4	11	0	0	0
Plugging	1.3	10	0	0	10
Wellhead Equipment	1.8	14	0	0	40
Fuel	0.6	5	0	0	40
All Other Physical Tests	0.6	5	0	0	0
Logging and Wireline Evaluation	1.1	8	0	0	0
Logs and Wireline Evaluation	3.7	29	0	0	0
Supervision and Overhead	5.6	43	0	0	20
Other Expenditures	7.1	55	0	0	20
TOTAL		774	114	14.7	38
*$40,000 for Slim Completion Costs; $7,000 for Slim-Hole Drilling Costs					
Source: IPAA as Aggregated by NPC Technology Work Group					

The rationale behind the cost savings shown in Table 86 is discussed in the following sections.

10.3.3 Slim Completion Savings

Savings due to using a slim completion are assumed to fall under only the tubulars category with reductions in production (long string) casing and production tubing size. It is assumed in the conventional well that no intermediate casing or liner is run (see *Reasonableness Test*). Also, implicit in the methodology for slim completions is conventional hole drilling which means no reduction in surface casing is possible under a slim completion scenario. These savings will be applied in the slim-hole drilling cases.

In order to estimate a reasonable savings, a range of possible conventional and slim scenarios are compared. Tables 87 and 88 show these combinations and approximate tubular costs per foot.

TABLE 87. Completion Tubular Costs - Conventional

Production Casing	Tubing	Cost/Ft
7	2⅞	12.98
5½	2⅞	10.22
5½	2⅜	9.57
4½	2⅜	6.85

TABLE 88. Completion Tubular Costs - Slim

Production Casing	Tubing	Cost/Ft
3½	2 1/16	4.75
2⅞	—	5.48
2⅜	—	4.15

Notice that two of the scenarios above assume a tubingless completion. There certainly are other options for future slim completion scenarios, such as the use of 1- to 2½-in. coiled tubing for internal tubing strings inside smaller casing. However, a conservative, realistic assumption for near-term usage calls for a more incremental change in practices, such as the use of 3½-in. casing and 2 1/16-in. jointed tubing. This completion still provides considerable flexibility for the producer while using conventional workover rigs and equipment. This is not to imply that there is not tremendous potential for the use of coiled tubing in production applications.

The overall average savings in going from the conventional designs to the slim designs is \$5.11 per foot. This average obviously covers a wide range of scenarios. Once again, this study did not investigate overall completion practices with the intent of obtaining a statistical baseline from which to base more accurate regional-based projections. However, it is felt an average of \$5 per foot for completion tubular savings is a realistic assumption for forecasting purposes.

For example, the most likely candidates for slim completions are considered to be in applications where wells typically use 5½-in. casing and 2⅞- or 2⅜-in. tubing, as opposed to those routinely using 7-in. production casing. The dominant slim completion practice is currently the use of 2⅞-in. tubing as casing with no tubing string, at least on initial completion. The savings between a 5½- in. x 2⅞ in. completion and a 2⅞-in. tubingless scenario is approximately \$4.09 per foot. However, this also assumes a heavier weight of 2⅞ in. for casing that may not be necessary. The use of lighter 2⅞ in. would increase the savings to approximately \$6.09 per foot.

The other example which is representative of likely near-term slim completion scenarios is the 3½ in. x 2¹⁄₁₆ in. completion. The overall average savings from the conventional completions to this design is \$5.15 per foot. Using the most likely base conventional completions of 5½ in. x 2⅞ in. and 5½ in. x 2⅜ in. results in savings of \$5.47 and \$4.82 per foot respectively. Once again, \$5 per foot appears to be a realistic assumption for slim completion savings extrapolation.

Therefore, the tubular savings assumption for the slim completion cases is \$5 per foot applied to an average 8000-ft well, resulting in a \$40,000 savings. Important to realize is that these savings are based on approximately third-quarter 1994 prices and are subject to change with the price of steel. Also, although existing tubulars are assumed herein, there is an implied technology assumption that adequate tubulars in smaller sizes will be provided for applications in sufficient number to satisfy the number of wells forecast in the completion cases previously outlined.

Reasonableness Test: The assumption of 8000 ft of 5½-in. casing with 2⅞-in. tubing, in addition to 1000 ft of 9⅝-in. surface casing, results in a conventional well tubular cost of \$104,040. Notice that this is within 2% of the \$106,000 that results from the allocation scheme of the \$774,000 conventional well cost, as shown in Table 86.

10.3.4 Slim-Hole Drilling Savings

Potential cost savings attributable to implementing true slim-hole drilling practices have been determined by categorical analysis. Baseline drilling costs by category were calculated based on the conventional total completed well cost assumption of \$774,000. This figure was allocated to individual categories based on the IPAA data as previously shown in Table 86. The analysis and assumptions leading to the estimated slim-hole savings are discussed in the following sections.

Casing Hardware

No savings are assumed in this category. However, there is potential for savings as centralizers, scratchers, and cementing equipment is reduced in size. This can be considered one source of upside potential.

Casing and Tubing

Production casing and tubing savings are discussed in the previous section. Surface casing savings assumptions are applied to the slim-hole drilling cases based on using 5½-in. casing instead of 9⅝-in. casing to a depth of 1000 ft. *This is a $6.55 per foot savings, or approximately $7,000.*

Additionally, this methodology is ignoring the possible savings from intermediate strings of casing. For example, the reduction of an intermediate casing string from 7 to 5½ in., which means drilling out with 4¾-in. slim hole instead of 6⅛-in. conventional hole, would likely add an additional $2 per foot (applies to an intermediate depth level) completion savings.

Cement and Cementing

It is assumed that slim-hole drilling results in significantly reduced annular space as casing size is maximized for the smaller holes. These dimensions and issues have been previously discussed in Chapter 5. Cement volumes reduce dramatically with annular space, but other services may not change. To assist in determining cementing cost savings, BJ Services provided conventional and slim-hole estimates for cementing a typical 8000-ft U.S. gas well. As shown in Tables 89 and 90, the conventional case assumes 9⅝-in. surface casing in a 12¼-in. hole and 5½-in. casing in an 8½-in. hole, with top of cement at 5000 ft. The slim-hole case assumes 7-in. surface casing in an 8½-in. hole and 3½-in. production casing in a 4¾-in. hole.

TABLE 89. Conventional Well Cementing Cost

Conventional Well			
9⅝" Casing x 12¼" Hole 100% Excess		5½" Casing x 8½" Hole TOC - 5000' - 30% Excess	
820 sks 35:65:6 + 2% $CaCl_2$ + 95% H_2 + 360 sks H + 2% $CaCl_2$ + 35% H_2		850 sks H + 0.7% Fl-25 + 0.1% R-3 + 38% H_2O	
1 pump to 3000'	$1,450.00	Pump to 8000'	$2,650.00
Mileage on pump 50 @ $2.85	142.50	Mileage on pump	142.50
2 — 9⅝" plugs	425.00	2 — 5½" plugs	219.00
533 sks A @ $7.60	4,050.80	850 sks H # $8.45	7,182.50
287 sks Poz @ $3.96	1,136.52	560# FL-25 @ $6.95	3,892.00
360 sks H @ $8.45	3,042.00	80# R-3 @ $1.45	116.00
2104# $CaCl_2$ @ $.39	820.56	Ton mileage 2013.5 @ $.98	1,973.23
4281 lbs gal @ $.19	813.39	850 ft^3 @ $1.45	1,232.50
Ton mileage 2789 @ $.98	2,733.22		
1287 ft^3 @ $1.45	1,866.15		
SURFACE TOTAL	$16,480.14	PRODUCTION TOTAL	$17,407.73
		TOTAL COST	$33,888.00

TABLE 90. Slim-Hole Cementing Cost

Slim Hole			
7" Casing x 8½" Hole 100% Excess		3½" Casing x 4¾" Hole TOC - 5000' - 30% Excess	
330 sks 35:65:6 + 2% $CaCl_2$ + 95% H_2 + 145 sks H + 2% $CaCl_2$ + 38% H_2		210 sks H + 0.7% Fl-25 + 0.1% R-3 + 38% H_2O	
1 pump to 3000'	$1,450.00	Pump to 8000'	$2,650.00
Mileage on pumps	142.50	Mileage on pumps	142.50
2 — 7" plugs	285.00	2 plugs	200.00
215 sks A @ $7.60	1,634.80	210 sks H # $8.45	1,774.50
115 sks Poz @ $3.96	455.40	139# FL-25 @ $6.95	866.05
145 sks H @ $8.45	1,225.25	20# R-3 @ $1.45	29.00
1723 lbs gel @ $.19	327.37	Ton mileage 498 @ $.98	488.04
847# $CaCl_2$ @ $.39	330.37	210 ft^3 @ $1.45	304.50
Ton mileage 1173 @ $.98	1,100.54		
518 ft^3 @ $1.45	751.10		
SURFACE TOTAL	$7,701.53	PRODUCTION TOTAL	$6,554.59
		TOTAL COST	$14,256.00

The total cement and service charges under these assumptions is $14,256 for the slim-hole well and $33,900 for the conventional well, a savings of 58%. However, to remain conservative and account for variations in cementing programs across the country, and perhaps additional cement costs (additives, etc.) for slim-hole conditions, the savings percentage has been reduced approximately in half to 30%.

Therefore, slim-hole cementing savings are estimated to be 30% of the allocated conventional cementing costs, resulting in a savings of $11,000.

Reasonableness Test: The allocated conventional well cementing cost of $37,000, based on a total well cost of $774,000, is within 9% of the conventional scenario costs independently estimated by BJ Services ($34,000).

Drill Bits and Reamers

No dollar savings against conventional are assumed in this category. However, there are technology improvements required in this assumption. Current uncertain performance and reliability of slim-hole bits is one of the greatest barriers to slim-hole drilling. Near-term improvements targets must address achieving comparable performance and reliability between slim-hole and conventional size bits. In addition, roller cone bits will likely be replaced by more expensive fixed-cutter bits in more formations when using slim-hole techniques. Also, there currently is only marginal differences in price between, for example, 6⅛- and 4¾-in. bits.

Therefore, the base assumption is comparable costs for bits between conventional and slim-hole drilling. Significant technology improvements to the extent that savings are available can be considered a source of upside savings.

Drilling Mud and Additives

The volume of mud to build and maintain is reduced significantly with slim-hole drilling. Hole volumes for three conventional sizes and a 4¾-in. slim hole are shown in Table 91.

TABLE 91. Hole Volumes

Hole/Casing	Size (in.)	Volume (bbl/ft)
Hole	8⅞	.0744
Hole	7⅞	.0602
Hole	6⅛	.0364
Hole	4¾	.0219
Casing	9⅝	.0787
Casing	7	.0393
Casing	5½	.0238

The hole volume reduction between a conventional scenario of 1000 ft of 9⅝-in. surface casing and 7000 ft of 8¾-in. hole and a slim scenario of equivalent depths of 5½-in. casing and 4¾-in. hole is 70%. The savings with an alternative conventional design with 7-in. surface casing and 6⅛-in. hole size is about 40%. To account for fixed costs and additional costs due to possible slim-hole requirements, this percentage savings for mud and additives is estimated at approximately 30%.

Therefore, the savings associated with drilling mud and additives is 30% of conventional, or $14,000.

Payments To Drill Contractors (Rig Costs)

One of the primary savings associated with an integrated slim-hole drilling approach is the potential to reduce the rig size required to drill a particular hole. Reductions in drill pipe weight, casing weight, and hydraulic power requirements can lead to significant decreases in required rig sizes and capacities. In some instances, workover rigs may be equipped for drilling. Achieving these savings, however, is probably the greatest barrier to slim-hole drilling as other barriers, such as bit and drill-pipe limitations, all work to offset these savings (by increasing the time to drill and drill pipe failures). Over-supply of rigs in the U.S. and resulting rate competition among contractors also make achieving appreciable savings *today* with slim hole in this category difficult.

A very specific example where dropping hole size has resulted in rig savings is in the D-J Basin. One operator dropped from 7⅞ to 6⅛ in. for 7500-ft wells and reduced his rig size from a 6000 to 8000 ft rated rig to a 4000 to 6000 ft (conventionally) rated, truck-mounted rig. After several wells, drilling performance was comparable to the larger size. Savings from this program are still being determined, but preliminary results indicated 15–20% overall well cost savings (completions were not changed).

In order to estimate potential drilling contractor savings to apply across the board, it is assumed that rig size is reduced depth one rating from conventional. Land Rig Newsletter's Third Quarter 1993 Rate and Wage Survey was used as the basis for this calculation. Figure 184 graphs the data points from this survey showing the rate percentages of one shallower depth rating rig.

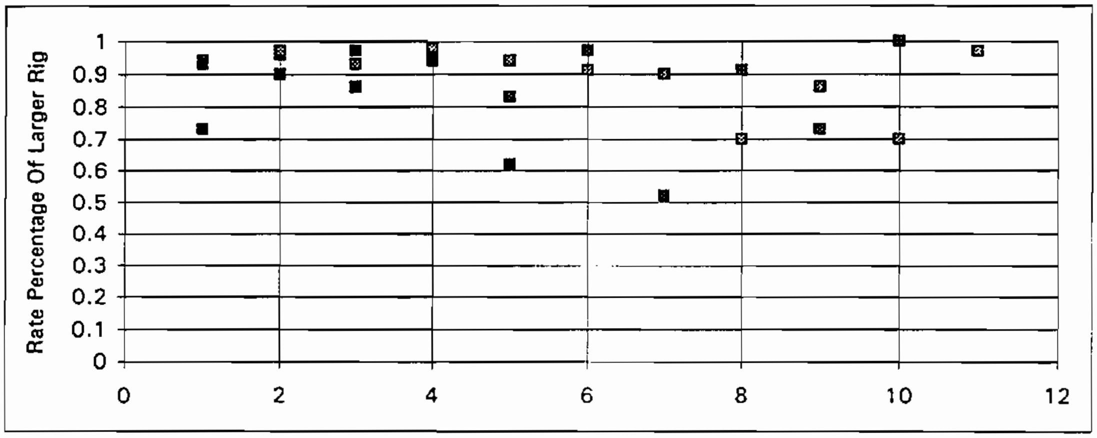

Figure 184. *Land Rig Newsletter* Data

The average day rate when dropping one depth rating is 92% of the conventional depth rating day rate. The average footage rate is 79% of the next depth interval. The overall average for one depth category reduction for dayrate and footage is 88% of the base depth. *Therefore, a 12% savings on the $238,000 conventional cost, or $29,000, is assumed for the drilling contractor savings for slim-hole drilling.*

This is a very difficult category to estimate due to the sensitivities of day rates to regional competition and overall over-supply of rigs for onshore U.S. drilling. However, the objectives of a focused slim-hole research program should include successfully facilitating integrated systems such that rig reductions, and associated cost savings, are possible. Ultimately, supply and demand for rigs in the U.S. will likely cross and rate reductions with size may become considerably greater than those forecast here.

Due to the uncertain nature of estimating possible savings, this category can be considered a substantial source of upside *and* downside.

Road and Site Preparation

Location costs can be reduced with slim-hole drilling due to reductions in rig and ancillary equipment size and mud pit requirements. These savings are substantial in remote international locations, as site reductions as much as 75% have been documented with a coring approach. U.S. locations are not typically as difficult, and tremendous reductions in rig size, while possible, probably will not happen in the near term.

The D-J Basin example mentioned previously serves as a case study to follow for typical reductions that may be possible in the U.S. In that case, a smaller, truck-mounted rig was substituted for a larger conventional rig when dropping from 7⅞-in. hole to 6⅛-in. hole size.

Location size is reduced from 275 ft x 150 ft to approximately 200 ft x 150 ft. This is a 27% reduction in surface area. To account for fixed costs, this has been reduced to a 20% reduction in location and road costs.

Therefore, a 20% reduction on the $34,000 base conventional well costs, or $7,000, is assumed for location and road savings for slim-hole drilling. This category is a source for considerable upside.

Special Tool Rentals

No savings are assumed in this category. If special tools <u>are</u> necessary for slim-hole applications, the assumption is that technology improvements occur such that these are provided at no additional incremental cost.

Transportation

With reduced rig size and the possible use of carrier-mounted rigs, transportation is a source for considerable savings with slim-hole drilling. Once again, the D-J Basin example serves as a typical case. The use of the smaller rig resulted in from 25 to 40% savings in transportation costs, depending on the length of the move. Obviously this will vary considerably from region to region. *For the purposes of these savings calculations, a modest 20% savings on the conventional baseline cost of $19,000 is assumed. This equates to a $6,000 savings in transportation.*

Other Categories

No savings are assumed for the slim-hole drilling cases in the other categories listed in Table 86. Arguments can be given for possible reductions available immediately in some of these categories, such as wellhead. Other categories, such as logging, may actually cost more today with slim-hole tools.

These individual potential variances have been ignored with the assumption that some products and services may have a greater cost at the current technology level, while others may be available for less than conventional. Therefore, it is assumed that for the near-term, these offset each other and in the mid- to long-term, technology will have to advance such that the more expensive services will be available at a price comparable to conventional. Ignored savings then become upside.

10.3.5 Other Assumptions

No escalation is assumed for baseline drilling and completion costs. Therefore, inflationary or market-based increases in costs over the time period are ignored.

No increase in per well slim-hole savings over time is assumed.

This is an initial investment analysis only and does not attempt to quantify possible increased workover cost scenarios or sacrificed production or reserves due to increased well risk. Alternatively, this can be considered an assumption that technology improves to the extent that this risk is negligible.

No forecasts for offshore Gulf of Mexico wells are included.

10.3.6 Summary of Savings Estimates

Table 92 summarizes the total well cost savings estimated for this savings study.

TABLE 92. Slim-Hole Savings Summary

Conventional Completed Well Cost	$774,0000
Slim Completion Savings	$40,000 (5.2%)
Slim-Hole Drilling Savings	$74,000 (9.6%)
Total Slim-Hole Savings	$114,000 (14.7%)

10.4 RESULTS

Figure 185 shows output from the model for the HI-HI case. Table 93 provides the total savings impact for the various cases from the model using the assumptions previously discussed. The nominal savings range from a minimum of $41 million incremental slim-hole savings with the base completion-low drilling case to a maximum of $749 million with the high completion/high drilling case. The present value of these savings using a discount rate of 7% (PV7) ranges from $14 million to $175 million.

TABLE 93. Slim-Hole Savings Impact ($ million)

Case	Nominal	PV7
LO-BASE	223	76
LO-LO	283	95
LO-HI	454	154
HI-BASE	436	148
HI-LO	516	175
HI-HI	749	254
BASE-LO	41	14
BASE-HI	327	111

GRI SLIM-HOLE IMPACT MODEL

Case: HI-HI

SHC Savings: 40 M$ Per Well

SHD Savings: 74 M$ Per Well

Discount Rate: 0.07

Year	Gas Wells	Base SHC %	Base SHC Wells	SHC Esc %	Esc SHC Wells	Delta SHC Wells	M$ SHC Sav Per Well	M$ SHC Sav Total	M$ SHC PV	Base SHD % Of SHC	Base SHD Wells	Esc SHD % Of SHC	Esc SHD Wells	Delta SHD Wells	M$ SHD Sav Per Well	M$ SHD Sav Total	M$ SHD Sav PV	M$ SHC + SHD Sav	M$ SHC + SHD PV Sav
1995	7641	0.07	535	0.07	535	0	40	0	0	0.05	27	0.05	27	0	74	0	0	0	0
1996	7871	0.07	551	0.08	630	79	40	3148	2942	0.05	31	0.08	50	19	74	1398	1306	4546	4249
1997	8278	0.07	579	0.1	828	248	40	9934	8676	0.05	41	0.12	99	58	74	4288	3746	14222	12422
1998	8304	0.07	581	0.12	996	415	40	16608	13557	0.05	50	0.18	179	130	74	9586	7825	26194	21382
1999	8373	0.07	586	0.14	1172	586	40	23444	17886	0.05	59	0.21	246	188	74	13879	10588	37323	28474
2000	9452	0.07	662	0.14	1323	662	40	26468	18870	0.05	66	0.25	331	265	74	19585	13964	46050	32833
2001	10225	0.07	716	0.14	1432	716	40	28630	19077	0.05	72	0.25	358	286	74	21166	14117	49816	33195
2002	10540	0.07	738	0.14	1476	738	40	29512	18379	0.05	74	0.25	369	295	74	21839	13600	51351	31979
2003	10250	0.07	718	0.14	1435	718	40	28700	16704	0.05	72	0.25	359	287	74	21238	12361	49938	29064
2004	10681	0.07	748	0.14	1495	748	40	29907	16267	0.05	75	0.25	374	299	74	22131	12038	52038	28305
2005	11640	0.07	815	0.14	1630	815	40	32592	16568	0.05	81	0.25	407	326	74	24118	12260	56710	28829
2006	12274	0.07	859	0.14	1718	859	40	34367	16328	0.05	86	0.25	430	344	74	25432	12082	59799	28410
2007	13652	0.07	956	0.14	1911	956	40	38226	16973	0.05	96	0.25	478	382	74	28287	12560	66513	29532
2008	14733	0.07	1031	0.14	2063	1031	40	41252	17118	0.05	103	0.25	516	413	74	30527	12668	71779	29786
2009	15940	0.07	1116	0.14	2232	1116	40	44632	17309	0.05	112	0.25	558	446	74	33028	12609	77660	30118
2010	17269	0.07	1209	0.14	2418	1209	40	48353	17525	0.05	121	0.25	604	484	74	35781	12969	84135	30494
TOTALS	177123		12399		23293	10894		$435,771	$147,611		1165		5385	4220		$312,302	$105,788	$748,074	$253,398

Figure 185. Slim-Hole Impact Model Run For HI-HI Case

Figure 186 and 187 graphically represent the nominal and present value savings for the various cases.

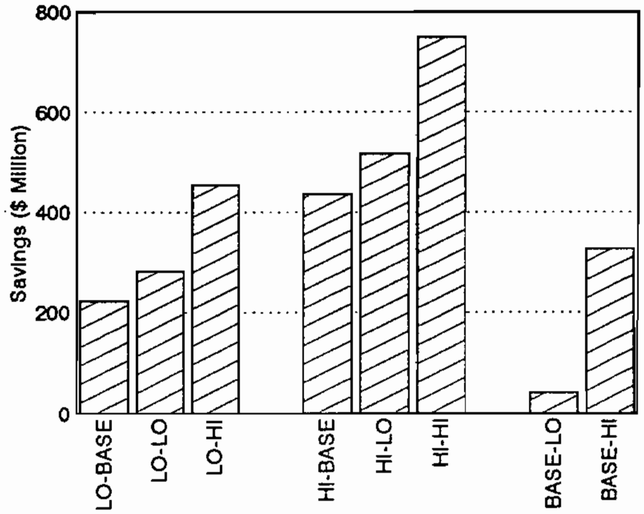

Figure 186. Nominal Industry Savings for Various Cases

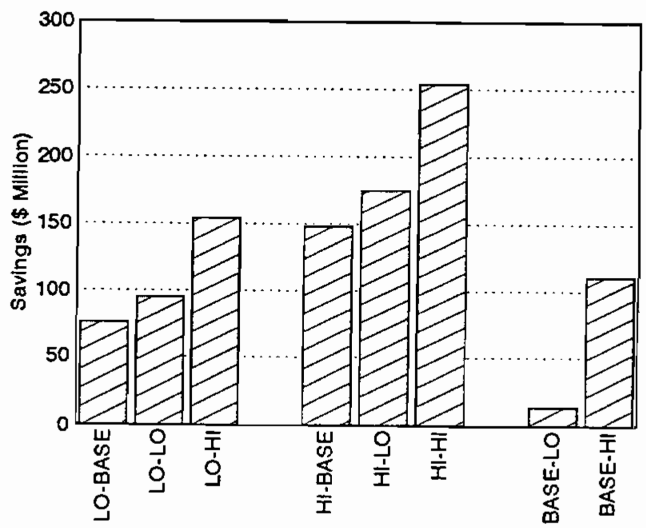

Figure 187. Present Value Savings for Various Cases

10.5 SUMMARY

An analysis of several slim-hole completion and drilling scenarios and conservative cost savings estimates reveal a broad range of potential savings associated with advancing and transferring slim-hole technologies. All of these point to considerable savings accruing to U.S. onshore gas producers with only minor increases in use of the techniques. Almost $100 million in *incremental present value* savings are attainable even with very modest assumptions of 10.5% of U.S. onshore gas wells using slim completions and 1.1% of U.S. gas wells using slim-hole drilling techniques by 1999. These are calculated with conservative, realistic savings estimates equating to less than 15% of total completed well cost on candidate "type" wells averaging $774,000 for conventional drilling and completion costs.

10.6 REFERENCES

National Petroleum Council, *The Potential for Natural Gas in the United States, Volume II — Source and Supply*, U.S. Department of Energy, (December 1992).

Robinson, B.M., Saunders, B.F., and Voncíff, G.W.: "Evaluation of Drilling and Completion Costs in Various Tight Gas Sands," S.A. Holditch & Associates, Gas Research Institute Topical Report, (January-December 1993).

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11. Overall Conclusions

The primary objective of this project was to identify and assess the barriers to greater use of slim-hole techniques for reducing the cost to drill and complete U.S. gas wells. The primary tasks undertaken to accomplish this objective included activity analysis, survey analysis, analysis of slim-hole issues in various technical areas (drilling, cementing, logging and perforating, stimulation, completion and workover tools), and a basin case study. The most significant conclusions include the following:

1. The use of slim completions for gas wells, as a percentage of total U.S. gas completions, doubled from 1991 to 1993 (3 to 6%).

2. Most of the increased slim completion activity occurred in Colorado (D-J Basin), but activity has also increased in Oklahoma, Texas, and Wyoming.

3. Most U.S. slim completions (89%) are 2⅞-in. tubingless completions placed in more conventional size holes (i.e., not in slim holes). The use of 3½-in.casing is becoming more prevalent.

4. There has been a substantial advancement of technology and knowledge for drilling slim holes over the past five to ten years, including the areas of bits, downhole motors, fluids, hydraulics, kick detection and well control, rig design, and operational procedures.

5. There has been little integration or use of new slim-hole technologies for vertical U.S. gas well drilling. An integrated multi-well, multi-basin field test program is desperately needed to demonstrate and test state-of-the-art technology as well as drive the appropriate developments for U.S. gas drilling, establish standards, and allay regulatory and landowner concerns.

6. Continued improvements for drilling are needed in the areas of bits, motors, fishing tools and techniques, hydraulics models, lost circulation material testing, tubulars and connections, vibration damping and modeling, and MWD/LWD and guidance technology for horizontal applications. Dedicated rigs and experienced crews are greatly needed.

7. Coiled-tubing drilling is a growing and important subset of slim-hole drilling. Costs and limitations make it most advantageous for re-entry, deepening, underbalanced, and shallow wells with location restrictions.

8. Coiled-tubing drilling needs include better understanding and modeling of pipe behavior, increased pipe life, improved downhole orienters, downhole thrusters/torque reactors/locomotion devices, downhole weight-on-bit measurement, telemetry for

underbalanced drilling, less costly wireline installation methods, ability to rotate, ability to handle jointed pipe, more reliable tools, tools for through-tubing re-entry work, improved motor and bit performance, and education and training of producers and service company personnel.

9. Most commonly requested logging services, such as the triple-combo, are available in slim-hole tools, but equipment can be more costly and less available than standard size tools. Imaging tools, dipmeters, and formation testers are examples of slim-hole limitations. An independent study comparing slim-hole tool response to standard tool response is needed. Standard tools can be run in 4¾-in. holes if hole conditions are good.

10. Cementing in aggressive slim-hole geometries is similar to many liner applications and requires greater diligence and care in design and job execution. An investigation of long-term competency of thin cement sheaths subjected to various stresses is one need.

11. The most important hydraulic fracturing uncertainty with slim completions is the reduced perforation charge performance and resulting effects on friction pressure, shear rates and fluid damage, proppant bridging, and near-wellbore tortuosity. Nonetheless, most recent slim completion activity is in areas requiring substantial treatments that are being pumped successfully.

12. Through-tubing and coiled-tubing activity has resulted in the development of most small-diameter completion and workover tools necessary for many U.S. gas well applications. This is especially true for the use of 3½-in. production casing. Needs include increased strength with increased minimum diameters of many of the existing tools, such as packers, improved fishing tools and techniques, and advanced sand control technology for slim completions.

13. Analysis of distributed barrier surveys indicate that workover, completion, and logging areas are perceived to contain the greatest barriers to use of slim-hole techniques. Individual issues that were highly ranked include logging tool existence and availability, workover tool limitations, fishing tool limitations, and stimulation friction pressure.

14. Analysis of barrier survey results relative to the overall project analyses indicates actual barriers may be less than perceived in many areas, including workover and completion tools and logging tools.

15. Variances among producer/service company and engineer/manager segments in the responses to the Drilling section of the survey reinforces the need for integration and demonstration of modern slim-hole technologies, education, and technology transfer.

16. *Management Attitude* was the second overall ranked barrier, indicating a low appetite for learning curves and risk associated with implementation of new techniques that potentially affect the entire life of a well, such as slim-hole. This reinforces the need for a cooperative, integrated field test program.

12. Recommendations

The analyses conducted during this barrier study lead to the following recommendations for escalating the beneficial usage of slim-hole drilling and completion techniques in U.S. gas wells.

1. Slim-Hole Field Testing/Demonstration Program

A program should be implemented to test and demonstrate state-of-the-art slim-hole drilling and completion technologies in new vertical U.S. gas wells. Suggested guidelines include the following:

- Multiple wells in multiple basins
- Initial slim-hole drilling tests should focus on current slim completion/conventional hole areas such as South Texas, the D-J Basin, and the Greater Green River Basin.
- Initial slim completion tests in areas where slim completions are not currently used can use conventional hole drilling
- Maximize use of latest technologies and information from domestic and worldwide projects

2. Analysis and Transfer Of Current And Future U.S. Slim Activity

Detailed analysis and transfer of current and future U.S. slim-hole drilling and completion activity should be implemented immediately. Operators are using these techniques, but the details of these efforts are not widely published or discussed. Studies of life-cycle costs, workover histories, and production of slim completions relative to conventional offsets would be extremely valuable for assessing benefits and true workover barriers. A detailed database of current slim completion fracturing practices across the U.S. would also be helpful for reducing perceived stimulation barriers. In general, an independent focal point for all U.S. slim-hole activity would be of great benefit to producer company engineers and management considering slim-hole options.

3. Development Of Slim-Hole Drilling and Completion Manual

A detailed manual documenting how to effectively drill slim holes and perform slim completions in slim holes or conventional size holes in U.S. gas basins would be a logical end-product of a field test program and detailed analyses of current activity. *It is believed that the experience of the field test program is extremely important to the accuracy and benefits of such a manual.* This is analogous to the coalbed methane manuals developed by GRI toward the end of their field projects and other research efforts in the Black Warrior and San Juan Basins.

4. *Individual Technology Development*

This project has identified several drilling and completion technologies that need to be improved, tested, or developed. This activity should be pursued with continuous interaction with the field test program to ensure the most relevant developments for beneficial impact on the U.S. gas drilling industry. Some of the most important include small diameter bits and motors for rotary, motor, and coiled-tubing drilling, higher strength drilling tubulars and bottom-hole assemblies, improved fishing tools, improved small-diameter perforating options, and expanded completion tool options.

Appendix A

Slim-Hole Technical Barrier Questionnaire

(Responses will be kept confidential)

NAME: ______________________________ PH: ____________________

TITLE: ______________________________

COMPANY: ______________________________ FAX: ____________________

☐ Engineer ☐ Manager ☐ Rig/Field Supervisor ☐ Yes, send summary of survey results

(Above personal data is optional; however, information is needed if you elect to receive summary of survey results)

The following is a list of potential barriers that might limit greater utilization of slim-holes as a means of reducing well cost. Please rank the importance of these problems on a scale of 1–5 and add and rank any problems that you feel should be emphasized. For the purposes of this questionnaire, slim hole is defined as a final hole (bit) size less than 5 inches.

POTENTIAL BARRIER RANKING SCALE	1	2	3	4	5
	Not Important *No/Small Barrier*				*Very Important* *Large/Critical Barrier*

OVERALL SLIM-HOLE IMPLEMENTATION BARRIERS

____ Artificial Lift
____ Cementing
____ Completion Tools
____ Drilling
____ Formation Evaluation
____ Gas Well Applications
____ Oil Well Applications
____ Limited Flow Rates
____ Management Attitude
____ Perforating
____ Stimulation
____ Workover Problems

Others:

____ ____________________ ____ ____________________

SLIM-HOLE DRILLING

____ Bits
____ Borehole Stability
____ Coiled Tubing
____ Core Barrels
____ Differential Sticking
____ Drilling Fluids
____ Drill-String Dynamics (Vibration)
____ Fishing
____ Guidance
____ Hydraulics
____ Lost Circulation
____ Motors
____ MWD (Directional)
____ Rigs
____ Tubulars
____ Well Control/Kick Detection

Others:

____ ____________________ ____ ____________________

SLIM-HOLE CEMENTING

____ High Shear Rates
____ Small Cement Volumes
____ Hole Cleaning
____ Thin Cement Sheath
____ Lost Circulation Materials
____ High Annular Pressure Drops
____ Rotation and Reciprocation Procedures
____ Pipe Buckling
____ Tool Availability
____ Remedial Cementing
____ Regulatory Constraints

Others:

____ ____________________ ____ ____________________

POTENTIAL BARRIER RANKING SCALE	1	2	3	4	5
	Not Important *No/Small Barrier*				*Very Important* *Large/Critical Barrier*

SLIM-HOLE COMPLETION TOOLS/ARTIFICIAL LIFT/WORKOVERS

____ Sliding Sleeves
____ Inflatable Packers
____ Mechanical Packers
____ Gas Lift
____ Coiled-Tubing Wash Tools
____ Safety Valves
____ Nipples
Others:
____ ____________________

____ Liner Hangers
____ Rod Pumps
____ Screw Pumps
____ Electric Submersible Pumps
____ Jet Pumps
____ Fishing Tools
____ Tubing
____ Workover Limitations
____ ____________________

SLIM-HOLE STIMULATION

____ Zone Coverage
____ Frictional Pressure Losses
____ Shear Rate
____ Perforation Friction Losses
Others:
____ ____________________

____ Perforation Erosion
____ Fracture Communication & Tortuosity
____ Proppant Transport
____ Downhole Gauges
____ ____________________

SLIM-HOLE FORMATION EVALUATION AND PERFORATING

____ Existence of Small Logging Tools
____ No. of Logging Tools Available
____ Perforating Charge Effectiveness
____ Perforating Tool Existence
Others:
____ ____________________

____ Logging Tool Accuracy
____ Service Company Experience
____ Drill Stem Testing
____ No. of Perforation Tools Available
____ ____________________

TECHNOLOGY TRANSFER

As slim-hole technology and information is developed by GRI, and others, what will be the most effective and timely methods of transferring this technology and information to the industry (1-5).

1 = LEAST EFFECTIVE   5 = MOST EFFECTIVE

____ GRI Reports
____ Schools
____ Videos
____ Trade Publication Articles
  ___ OGJ ___ World Oil
  ___ JPT ___ Pet.Engr.Int.
  ___ SPE Drilling/Completion
____ Other ____________________

____ Workshops/Forums
____ Product/Technology Brochures
____ Technical Papers (SPE)
____ Exhibitions
  ___ SPE Annual ___ SPE Regional
  ___ OTC ___ SPE/IADC
  ___ Other ____________________

Please complete and return by mail or fax to: Allen Shook, Maurer Engineering Inc.
2916 West T.C. Jester, Houston, Texas 77018-7098
FAX: (713) 683-6418

Companies Responding to Questionnaire

PRODUCERS:

ADNOC
American Exploration
Amoco Canada
Amoco Production Company
ARCO E&P
Astra-Capsa Argentina
Auoryx Petroleum
Bechtel Petroleum
Bow Valley Energy
BP Exploration
Canadian Hunter
Canadian Occidental
Chevron Petroleum Tech.
Chevron USA Production
Conoco
Cox & Perkins Exploration
Dugan Production Company
Elan Energy Inc.
Enron Oil and Gas
Exxon Co. USA
Gotland Oil
Hanna Oil and Gas
Haston Enterprises Inc.
Harrison Interest Ltd.
Howell Petroleum Co.
Howell Petroleum Co.
Intevep, S.A
Japan Drilling Company
JRB Oil and Gas Company
Kachina Exploration
Kerr-McGee
Lynch Management, Inc.
Marathon
Maraven, S.A.
McRae Exploration
Meridian Oil Inc.
Maersk Oil
Meyrfor-Weir
Mobil
Mobil E&P Tech. Center
Mull Drilling Company
Neyrfor-Weir
Norcen Energy
Orxy Energy
Oxy USA
Pajarito Enterprises
Pan Canadian
Parker & Parsley Dev.
Petro-Canada
Phillips Petroleum Company
Phillips Petroleum UK Ltd.
Plains Petroleum Company
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Scout Geophysical
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Sonat Exploration
Tecpetrol S.A.
Texaco
Texaco China B.V.
Thums Long Beach Co.
Torch Energy Advisor
Total Minatome Corporation
U.S. DOE
Union Texas Petroleum
Unocal
UPRC
Vastar Resources Inc.
Wascana Energy Inc.
Williford Energy Company

SERVICE COMPANIES:

Anadrill Schlumberger
Antelope Engineering Inc.
Baker Hughes INTEQ
Baker Oil Tools
BJ Services
Cobb Directional
Cudd Pressure Control
Cymax-Southwestern Pipe
Drexel Oilfield
EG&G/TSWV
H. Elkins & Assoc.
H&P International
Halliburton Energy Ser.
Hughes Christensen
Hydril
M-I Drilling Fluids
MicroDrill
Nabors Drilling Intl.
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Appendix B

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