Advanced High-Pressure Coiled-Tubing Drilling System

Final Report

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by

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Disclaimer

Abstract

The majority of time and cost in drilling a gas or oil well is consumed by the actual drilling process ("turning to the right"). The most effective approach to significantly reduce costs of drilling wells is to increase penetration rates. Researchers have for many years investigated means to drill rock faster, and jet-assisted drilling is one method that has been considered several times. In most cases it was found that, while jet-assisted drilling was very effective in increasing penetration rates, the implementation cost was too high because special equipment and pumps were required. Research has shown that most formations can be drilled significantly faster and that well depth is not a significant factor in the results.

This project was undertaken to develop and test a high-pressure (HP) drilling system that was based on conventional equipment except for a special HP downhole motor and jet bit specially designed to erode radial kerfs (grooves) in the rock which are then broken off by the cutters. These items would be manufactured commercially once the concept was proven. Related past R&D efforts reported significant problems with leaks at the tool joints in the drill string. This project's original concept was to employ coiled tubing (CT) to convey the BHA into the well. Using CT would eliminate most of the pipe connections where leaks could occur from HP fluids. CT operators also routinely use HP fluids for clean-outs and frac jobs. These factors would reduce concerns about safety that are often raised regarding HP drilling.

The first series of field tests conducted during the project used CT to deploy the special HP motor and jet kerf bit. A number of problems occurred that prevented CT jet kerf drilling from being adequately tested. These problems, although deemed to be solvable, led to a loss of interest by the CT company participating in the project. As a result, the second series of field tests was performed using conventional rotary drilling. Another factor in the decision to switch to conventional rotary drilling was the high cost of CT operations. Higher costs require even higher drilling rates to achieve an economically viable operation.

The conventional rotary drilling tests provided highly promising results that exceeded the team's expectations. Jet kerf drilling was accomplished by modifying a standard rig by adding off-the-shelf equipment, including a HP pump. The cost to modify the rig was very reasonable. New drill pipe with double-shoulder tool-joint connections was used and found to eliminate leak problems observed in previous HP drilling operations. The only item specifically fabricated for this test was the drill bit, which only required slight modification (smaller nozzles).

Figure A-1. RMOTC's Rig Used for Field Tests

The second test sequence was conducted at the Rocky Mountain Oilfield Test Center (RMOTC) in Wyoming. RMOTC's rig (Figure A-1) is an older unit capable of pulling doubles. The ease and modest cost of upgrading this rig to 10,000-psi service clearly demonstrated that larger and newer rigs may also be upgraded for HP jetting service at

reasonable cost. Modifications consisted of new 10,000-psi piping and valves, a 15,000-psi swivel, and a 15,000-psi rotary hose, all for a total cost of about $100,000. A HP pump was also required for a cost of less than $500,000.

Figure A-2 compares penetration rates achieved with the HP jet kerf system (blue) to that in offset wells drilled conventionally (red). The data show that jet kerf drilling was able to significantly increase penetration rates.

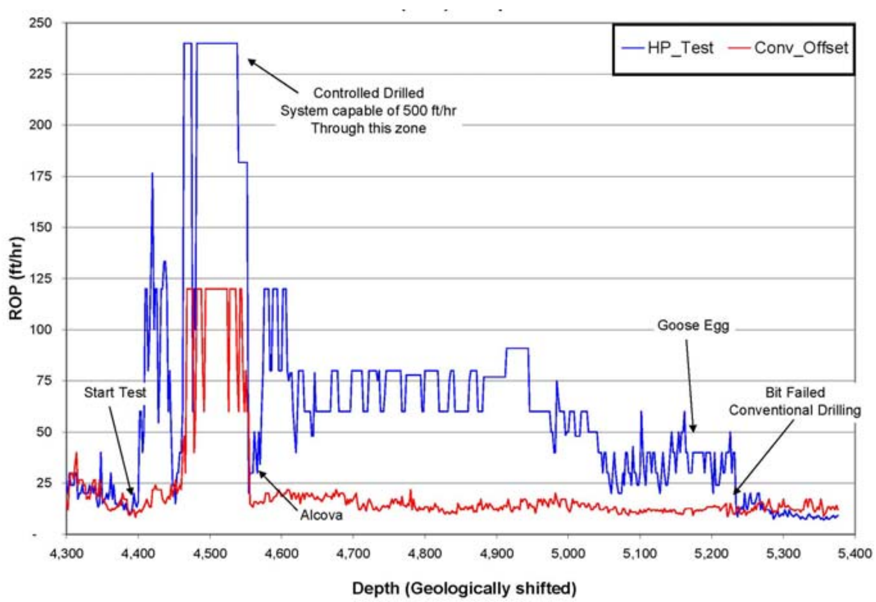

Figure A-2. Comparison of Jet Kerf Drilling to Conventional Offset Wells

Figure A-3 shows the increase in drilling rate as a percentage of conventional rates. Rates over 500% above conventional were achieved. Typical rates were 100–200% faster than conventional rates.

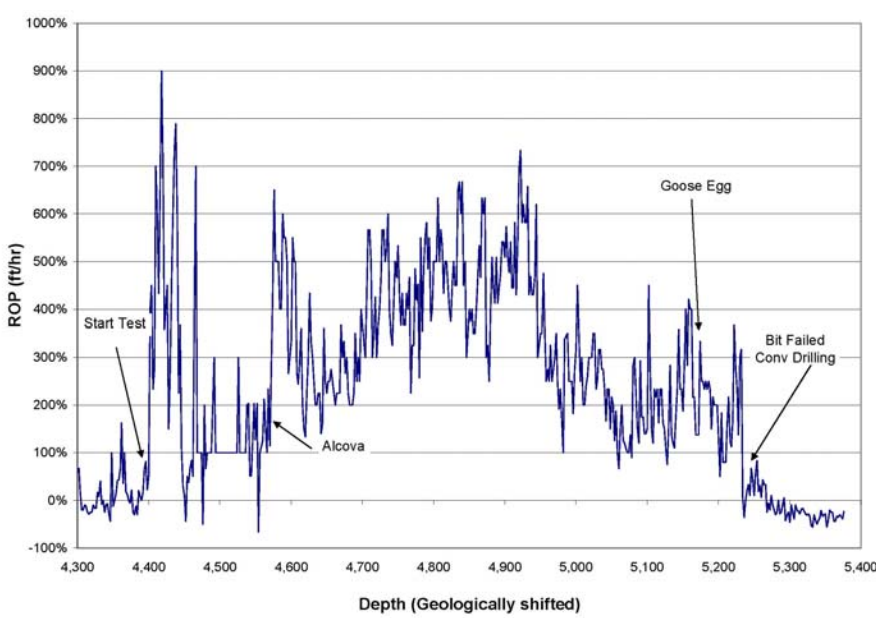

Figure A-3. ROP Increase with Rotary HP Jet Kerf Drilling

A simple economic model was prepared and is summarized in this report. The model indicates that, based on a two-year payback period, jet kerf drilling can be commercially successful in typical economic settings. Test data from this project also demonstrate that the concept is clearly technically feasible. Work remains to extend the life of jet kerf bits. Premature erosion of the steel body of the bit was observed. A proposed extended nozzle is described that will significantly reduce erosion and extend the life of the bit. (This nozzle has not yet been tested with the system.)

The only true impediment to commercialization of HP jet kerf drilling is that no single company can by itself serve as a champion for the new technology. Commercialization requires a combination of a motivated rig contractor, operator, and bit manufacturer, with each company being properly educated to understand the overall benefits of the new technology. Assembling a commercial consortium will not be easy because jet kerf drilling will reduce the number of days to drill a well, potentially reducing the contractor's revenue. Likewise, jet kerf bits may wear less that conventional bits and drill more footage, resulting in lower revenue for the bit manufacturer. Business practices and/or cost structures will need to be modified with the support of all commercial parties involved.

HP jet kerf drilling will only become a reality through an evolutionary process of ever-increasing pressures. Its acceptance, however, could be accelerated through a DOE-sponsored demonstration project based on modifying conventional rotary equipment and procedures for HP operation. A well-designed field demonstration would make a commercial rig ready for HP operation and demonstrate to operators the value of paying a slightly higher day rate to have wells completed in fewer days and brought onto production sooner. Contractors also need to be presented with clear evidence that higher day rates will more than offset any lost revenue due to fewer drilling days on each well.

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1. Introduction

1.1 System Concept

The oil and gas drilling industries have always sought to develop technologies that drill rock faster. There are substantial economic benefits to be gained by increasing the rate of rock removal and hole construction. Drilling faster reduces overall field time, which directly translates into reduced costs for producing oil and gas resources. Objectives of this project were to develop a complete jet-assisted drilling system that uses high-pressure (HP) drilling fluid to increase the rate of rock removal to three to five times above conventional rates. Jet-assisted drilling combines HP fluid jets with rotating mechanical cutters to remove the rock very aggressively. HP fluid jets erode radial slots in the rock ahead of the bit and leave only thin rock kerfs (ledges or grooves) for the mechanical cutters to break off (Figure 1). A variety of laboratory tests conducted at Maurer Technology Inc. (MTI) (Maurer et al., 1986) showed that this combination of rock-removal processes is capable of higher penetration rates than either jet erosion drilling or mechanical cutters alone.

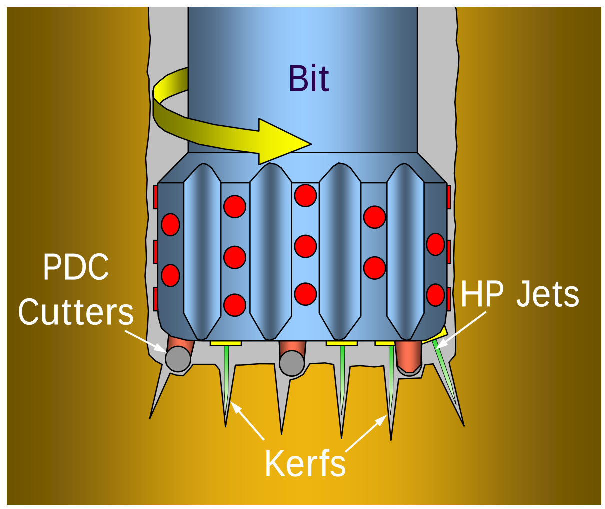


Figure 1. Jet Kerf Drilling Mechanism

While the phrase “jet-assisted drilling” has been used in the past, the use of HP fluid jets in the present effort was different from previous developments. There has typically been only a single jet aimed at the gauge of the hole. This project used several jets carefully positioned and aimed across the entire bottom of the hole to cut several radial kerfs ahead of the cutters to reduce the work the cutters must do. A more descriptive term is used for the work reported here—“jet kerf drilling.”

For this DOE project, an innovative HP drilling concept was initially pursued based on using coiled tubing (CT) to transport the drilling assembly downhole and to deliver HP fluid to the bit. Two system design concepts were proposed initially. The first approach uses a concentric dual-tube system (Figure 2, left). HP fluid would be pumped down the center CT string and low-pressure (LP) fluid simultaneously pumped down the larger CT string in the annular space outside the smaller CT string. HP fluid would be channeled past the motor to the bit nozzles to jet-drill the rock, while the LP fluid would supply power to the mud motor and clean cuttings from the bit face and hole.

The second CT drilling system concept is more conventional and uses a single large CT string to deliver HP fluid downhole to power the mud motor, jet the rock face and remove cuttings from the well (Figure 2, right).

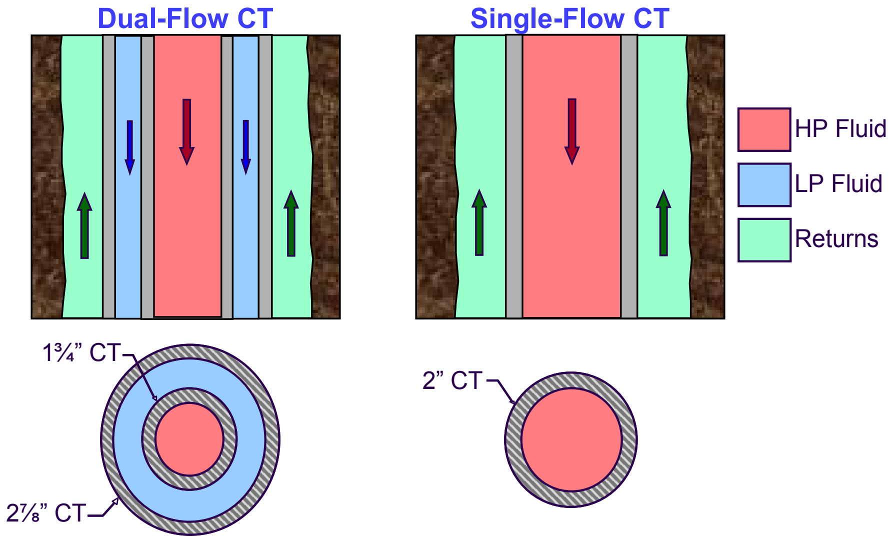


Figure 2. HP-CT Drilling Concepts

After analysis of the advantages/disadvantages of proposed equipment for both CT systems as well as input from the Advisory Board of industry experts, it was determined that the single-flow system was the best approach and presented the highest potential for success. New motors and bits were developed and tested in the laboratory. In Phase III, a series of tests was conducted of a single-string HP-CT system at the GTI Catoosa test facility in Tulsa, Oklahoma. Results (see Section 3.3) indicated that equipment and economic factors are not yet favorable for commercializing a CT-based system for jet kerf drilling.

Following field tests with the single-flow CT-based system, the project team determined that the HP jet kerf drilling concept should also be tested on jointed drill pipe to prove the concept and begin to establish a knowledge base regarding system limits (depths, formations, etc.). These field tests were conducted at the Department of Energy Rocky Mountain Oilfield Testing Center (RMOTC) in Casper, Wyoming (described in Section 3.4). These field operations demonstrated that jet kerf drilling can substantially increase penetration rates in a variety of formations and at depths applicable to a wide range of wells.

The rotary jet kerf drilling tests also showed what additional equipment and skills are needed for a commercial HP drilling system. Somewhat surprisingly, the conventional rig was readily upgraded for HP jetting using equipment that is currently available commercially. Project tests showed that jet kerf drilling can be practical and that barriers are no longer related to engineering, but only to economics. Costs and rig modifications for these operations are described in Section 2.6.

1.2 Justification

Economic studies of oil and gas wells have repeatedly demonstrated that drilling efficiency is a major factor in the overall economics of gas and oil exploitation. Figure 3 presents the time break-down for drilling a group of wells from a survey study (Andersen, 1990) conducted by MTI and sponsored by GRI. These data, representing 3111 wells, show that about one-third of the time to construct a well was spent drilling. This is the single largest component in the entire process of well construction. When Andersen reviewed data from only the deeper wells in this data set, the percentage of time spent drilling was even higher (over 50%). Therefore, to reduce well construction costs substantially, drilling time must be reduced. Major reductions of time spent in other activities or categories would not have an overall impact as significant as reducing drilling time.

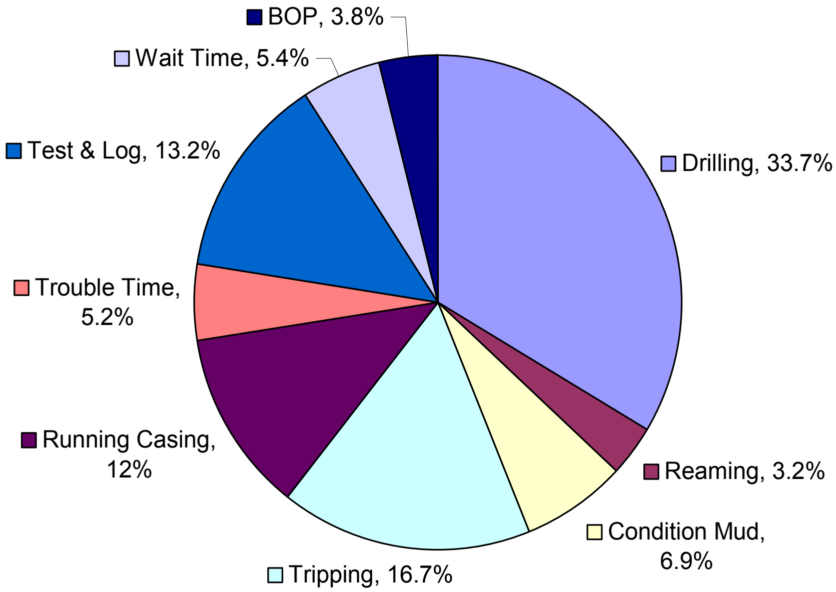


Figure 3. Well Time Analysis (Andersen, 1990)

Several approaches may be possible for reducing total drilling time; however, the most effective way is to improve drilling efficiency. Moreover, an increase in drilling rate (ROP) must be accompanied by equal (or greater) equipment reliability so that overall trip time is maintained. Because benefits from relatively modest increases in ROP are quickly offset by increased equipment costs or extra trip time, it is easy to demonstrate that significant increases in drilling rate (100% and more) are necessary for a significant overall impact.

Jet-assisted drilling is highlighted as one technology that has the potential to increase penetration rates significantly and achieve these goals. In past experience with jetting technologies, the industry has shown that drilling rates can be markedly increased. However, increases in costs due to HP equipment and operations have offset the benefits. The project team believes that it is time to revisit this approach because current commercial equipment and technology will allow increases in operating pressures that will enable jet-assisted drilling and preserve the benefits and cost savings that accompany it.

1.3 History of Jet-Assisted Drilling

Jet-assisted drilling is not a new concept. During the 1950s, Russian teams conducted extensive laboratory tests that showed that HP jet bits can effectively drill hard rocks. In the 1960s and 1970s, Exxon, Shell and Gulf conducted extensive full-scale field tests that demonstrated that HP bits operating at pressures of 10,000–15,000 psi (69–103 MPa) can increase drilling rates by two- to four-fold in many formations.

Exxon developed and tested jetting systems in the early 1960s. By extrapolating laboratory data from previous work, Exxon determined that medium-strength rocks could be drilled at rates of

70 to 280 ft/hr compared to 30 to 170 ft/hr for conventional drilling (Maurer et al., 1972). Based on these predictions, Exxon conducted a number of laboratory and field tests using roller, drag and jet-only bits. A jet-only bit (Figure 4) was constructed for which the only rock removal mechanism was HP fluid jets (i.e., it had no mechanical cutters).

Figure 4. Exxon Jet-Only Bit (Deily et al., 1977)

The jet bit was used on several shallow field tests and found to drill significantly faster than conventional bits in offset wells: 107–285 ft/hr compared to 10–20 ft/hr, respectively. Exxon continued with tests using drag and roller bits with conventional and extended nozzles. These tests also demonstrated that HP jets have the potential to substantially increase drilling rates.

Exxon conducted field drilling tests where four HP frac pumps were used to pump conventional drilling mud at pressures up to 15,000 psi. HP flow lines, HP drill pipe, and special HP bits were used. Exxon used conventional frac trucks (Figure 5) for their tests.

Figure 5. Frac Trucks used for HP Drilling (Deily et al., 1977)

In one test, Exxon's HP jet bits drilled from a depth of 2400 to 6000 ft in an East Texas oil well in 24 hours, compared to a drilling time of 67 hours for conventional bits (Figure 6).

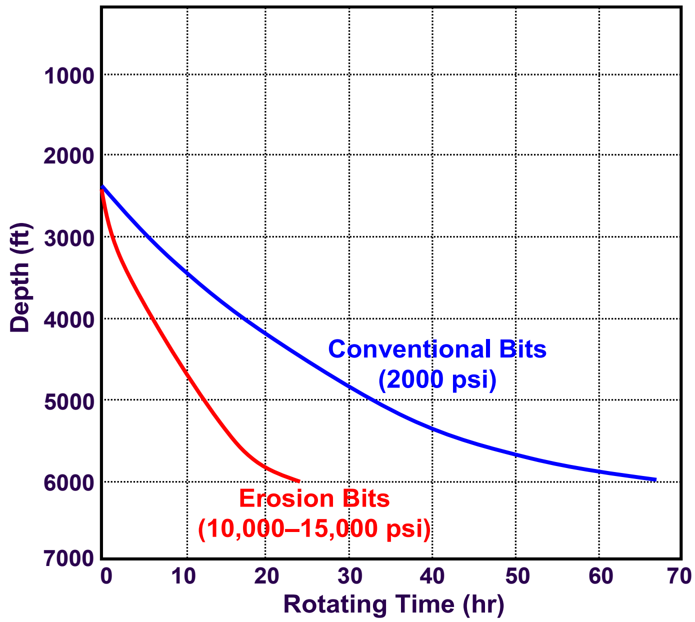


Figure 6. Exxon HP Field Test Results (Deily et al., 1977)

In the 1980s and 1990s, FlowDril (Butler et al., 1990) developed a system with concentric drill pipe to drill at high rates using ultra-HP (Figure 8). They reportedly drilled over 20,000 ft of hole with their drilling system. Two streams of fluid were used, one at conventional pressures and a second at very HP (30,000 to 40,000 psi). Only a small portion of the flow is HP, thereby reducing overall horsepower requirements for the system so that they might remain economically feasible.

Special roller bits were used that were outfitted with one extended nozzle for HP fluid and two other nozzles for LP fluid. Dual-wall drill pipe was used; the inner string carried HP fluid and the annulus between the strings carried LP fluid (Figure 7). FlowDrill's work centered around making the use of HP jet-assisted drilling safer, easier, and less dependent on the specialized equipment that had been required on earlier attempts.

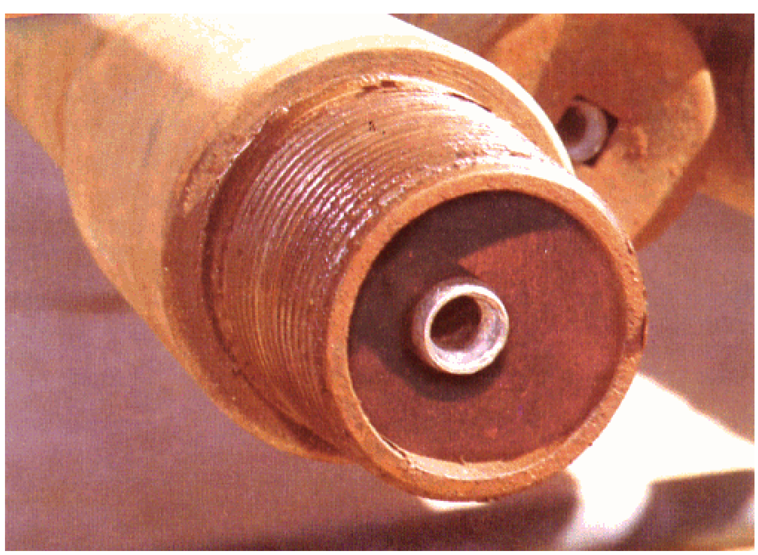


Figure 7. FlowDril Dual-Flow HP Drill Pipe (Kolle et al., 1991)

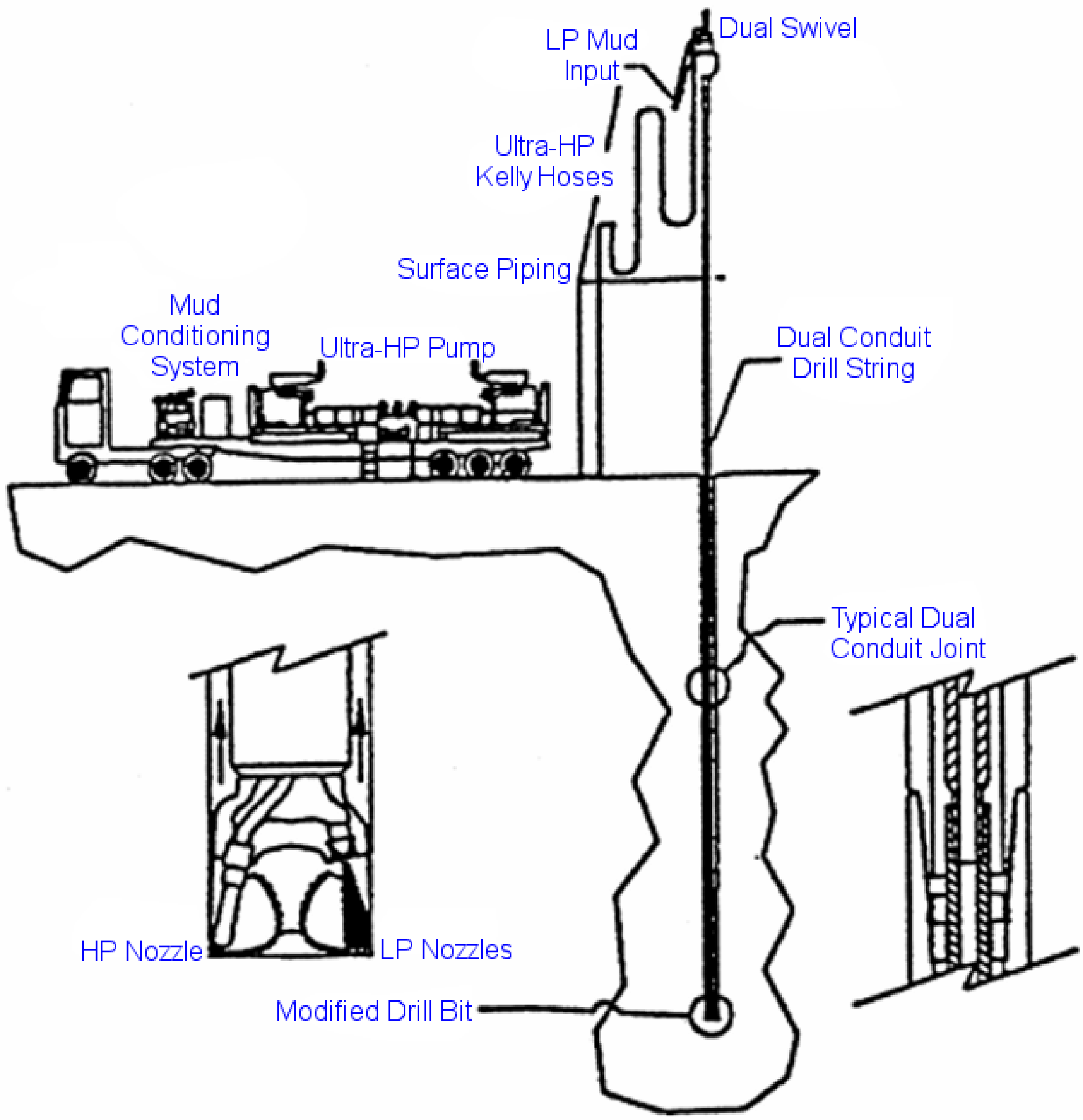


Figure 8. FlowDril Jet-Drilling System (Kolle et al., 1991)

FlowDril's special concentric drillstring cost in excess of $1 million. Field trials showed that the system increased drilling rates 2.2 to 3.6 times conventional rates. Although excellent drilling performance was reported (Figure 9), the operator's fear of losing the complex and expensive drillstring in the well severely limited application of this system. They also reported that operational and reliability problems with the concentric drillstring further hindered its use.

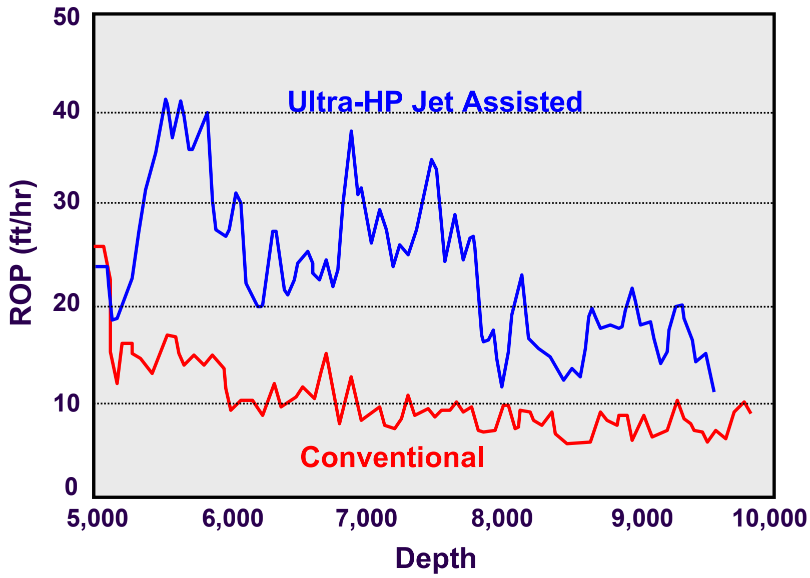


Figure 9. FlowDril Field Data (Kolle et al., 1991)

In the 1980s, MTI developed a special high-speed drilling system to drill 8-in. holes in medium-strength rocks (5000–10,000 psi strength) at rates of 500–1000 ft/hr. Based on the requirements of MTI's client, a new drilling system was investigated to achieve very high penetration rates. MTI developed a new downhole drilling motor (Figure 10) that operates at HP (10,000 psi) and uses high rotary speeds (400–1000 rpm).

Figure 10. MTI HP Motor

This 4¾-inch motor was tested in the laboratory. Based on the client's typical formation strengths, conventional rotary rigs drill similar rocks at rates of 50–100 ft/hr and standard downhole motors improved performance to 100–300 ft/hr. The HP motor/jet-bit combination drilled about 1000 ft/hr in rocks of medium strength (Figure 11).

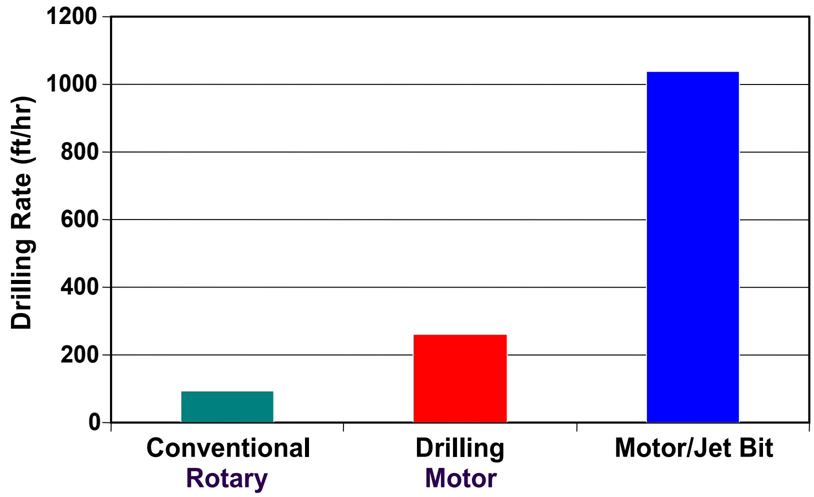


Figure 11. Comparison of Drilling Methods

Development of this motor then led to MTI's subsequent development of a matched 8-inch HP jet bit (Figure 12) that used jets to cut kerfs to weaken the rock and dramatically increase drilling rate. MTI analyzed parameters that impact cutting efficiency (rotary speed, depth of rock removed per revolution, nozzle diameter, etc.) to minimize the hydraulic horsepower required to drill. They found that the specific energy required to drill with these PDC jet bits decreased significantly from 10,030 to 2,270 ft-lb/in^3 as bit diameter was increased from 2.5 to 8 inches.


Figure 12. MTI's 8-inch HP Bit (left) Cut Kerfs into Rock (right)

The combination of kerf-cutting by fluid jets and PDC cutters to break off the rock allowed the 8-in. bit system to drill 650 ft/hr compared to 150 ft/hr for conventional bits (Figure 13).

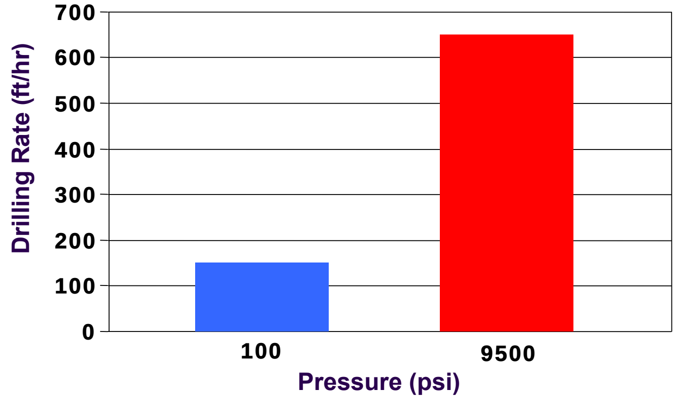


Figure 13. Drilling Rates with MTI 8-inch HP Bit

Laboratory and field tests by these and other researchers conclusively demonstrated that HP jet-assisted bits have the potential to drill oil and gas wells two to four times faster than conventional bits. The *major limitation* of these systems was *reliability problems* associated with jointed drill pipe, since over 300 threaded connections (potential leak paths) are required in a 10,000-ft well. It is very difficult to prevent leaks and washouts from occurring with such a large number of threaded connections, especially when operating at HP. Implementation of these innovative jet-drilling systems has remained largely unutilized awaiting the development of a drill string that would solve problems with threaded connections.

The development of large-diameter CT (2⅜- to 3½-in. OD) in the 1990s is one obvious answer to HP drill-string problems since several thousand feet of continuous CT containing no threaded connections can be placed on one reel and transported to the well. (CT reel capacity is reduced for larger OD strings.) High tripping speed with CT further enhances its use in drilling.

Goals of this project included applying CT to HP jet technology developed earlier by Exxon, Shell, Gulf, FlowDril and MTI and thereby solve leakage problems encountered with these earlier systems. Results showed that this may be feasible by combining advanced jet kerf bits with existing CT technology and equipment.

2. Experimental

2.1 Objectives

Objectives of the project, as originally proposed, are summarized below. The present report includes results from Phases II and III. The project was also extended in scope and time beyond the initial plan (see Section 3.1).

The objective of **Phase I** was to demonstrate the feasibility of the high-pressure (HP) coiled-tubing (CT) drilling system. This included theoretical analyses, component design and review of potential barriers in field applications through meetings held with subcontractors, service companies, and operators.

The objective of **Phase II** was to manufacture and laboratory-test the drilling system components. Detailed machine drawings were prepared and prototype components manufactured. Reliability and performance of the system components, including tests for hard rock drilling conditions, were to be tested individually (i.e., HP swivels, concentric CT, downhole motors and downhole bits). Once reliability of system components is demonstrated, the total system was assembled and laboratory tested in blocks of sandstone and limestone to measure performance and reliability of the entire system.

The objective of **Phase III** was to field-test the prototype drilling system and demonstrate its effectiveness (including effectiveness in hard rock drilling conditions) for increasing drilling rates and reducing drilling costs in preparation for commercializing this system.

2.2 Scope of Work

Phase I consisted of performing a detailed analysis of the system to (1) identify potential problems and barriers, (2) use computer analyses to calculate life and performance of the system and (3) select the best candidate downhole motor (Moineau or turbine) for development on the project. Once the system was specified, layout drawings and preliminary machine drawings were made of all system components in preparation for compiling detailed drawings and manufacturing the tools in Phase II.

Phase II consisted of: (1) making detailed manufacturing drawings of all system components (e.g., HP swivels, CT strings, downhole motors, and jet bits); (2) manufacturing all system components; (3) laboratory testing individual components on test stands; (4) assembling and testing the total CT drilling system in blocks of sandstone and limestone; (5) modifying system components to overcome any problems encountered during laboratory tests; and (6) retesting the system including tests for hard-rock drilling conditions.

Phase III activities were to field-test the prototype HP jet kerf drilling system developed from the components of Phases I and II. Effectiveness of the system(s) in increasing drilling rates while reducing drilling costs was to be demonstrated, including effectiveness in hard-rock drilling conditions. Phase III was envisioned to include at a minimum two field tests at specified maximum depths.

The first tests were conducted at the Catoosa test facility in Oklahoma to shake out or "field harden" the equipment and develop the HP operating procedures needed for safe and effective field application of the drilling system. After tests at Catoosa, additional shallow field tests of the HP drilling system were to be conducted as appropriate. An overall reliability target of 100 hr mean time between failures is the goal during the shallow field tests.

Based on the original plan, the project team was to conduct deeper tests at depths up to 10,000 ft. Various applications of the system were to be tested including drilling and scale clean-out operations. The project team might also demonstrate the application of the system for wells requiring clean out of cement.

2.3 Advanced Drilling System Concepts

2.3.1 Introduction

Previous attempts to develop HP drilling systems that employed jets to increase drilling rates had extensive problems with fluid leaks from tool joints and tubulars (see Section 1.3). To avoid this, the project team first proposed drilling systems based on CT (coiled tubing) so that the number of joints (potential leak locations) could be minimized. CT technology made dramatic strides in capability during the 1990s. CT is also well suited for pumping HP fluids; for example, CT-based frac jobs are routine.

During the development, the project team changed the preferred design of the HP jet kerf drilling system. These changes resulted from engineering design reviews, laboratory tests, and performance of the systems during field testing. Concept and design reviews were conducted on a regular basis so that the final system would best meet industry needs and have the greatest potential for commercialization. The review team included MTI technical personnel along with members of an industry Advisory Board comprised of expert personnel from BJ Services Company (a major CT service company), ConocoPhillips, BP, and Quality Tubing, Inc. (a leading manufacturer of CT).

Various aspects of the first concept systems were modified or eliminated based on design reviews and results of field testing. At the end of the project phase, a relatively simple design based on conventional jointed tubulars and rotary drilling was successfully used and achieved excellent results. Each system considered and tested is described below along with changes incorporated during the project.

2.3.2 Dual-Flow CT System

The first concept pursued during Phase I was a dual-flow system (Figure 14) that would pump HP fluid down the center string of a double string of CT and low-pressure (LP) fluid down the annulus between the strings. This concept included a special dual-flow mud motor and bit. The motor would contain a swivel and flex sub at the top to allow HP fluid to pass through the center of the rotor down through the drive shaft to the bit and exit through HP jets in the bit. These HP jets would rapidly erode rock and increase ROP while drilling. The LP fluid would be used to power the motor and then pass through the bearing pack and exit through LP jets in the bit. The combined fluid streams would then carry the cuttings up the wellbore annulus to the surface.

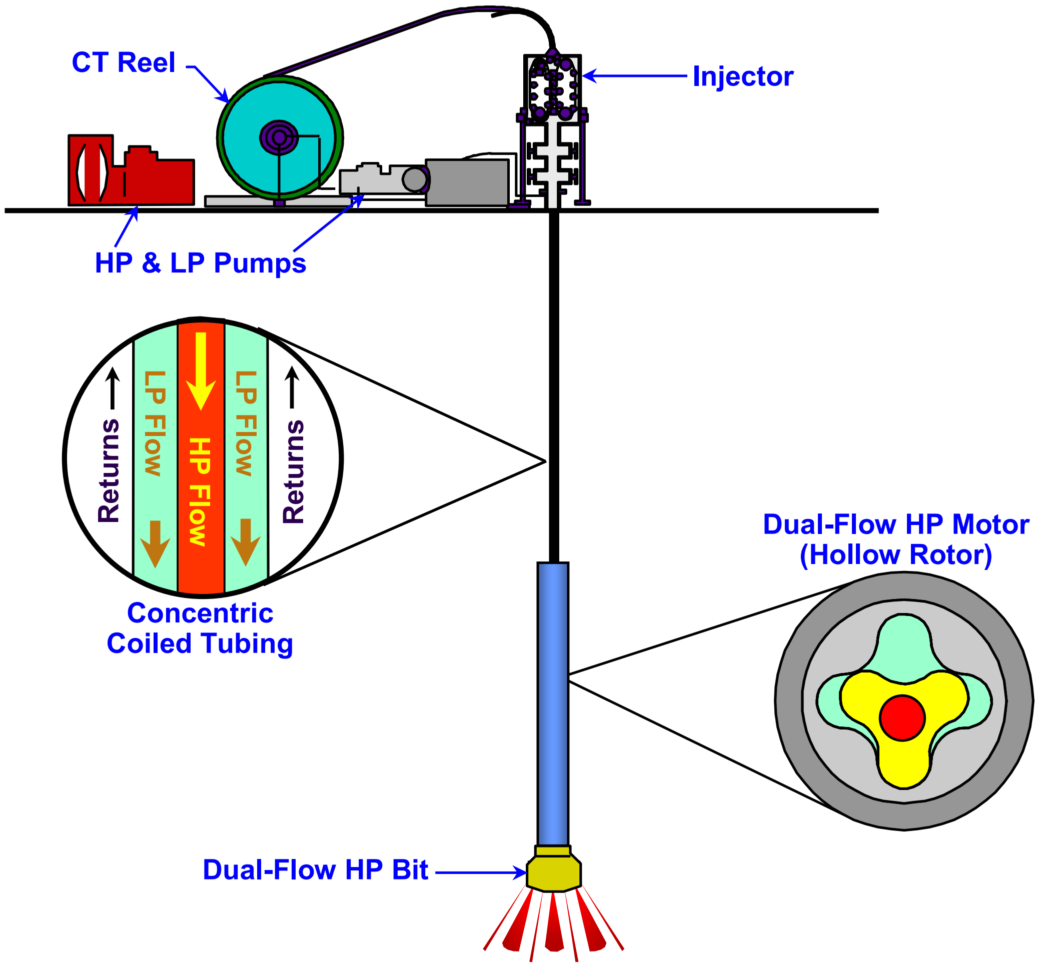


Figure 14. Dual-Flow CT Jet Kerf Drilling System

This dual-flow system, although considered to be relatively complicated, offered several benefits. It would minimize the volume of HP fluid required, and thereby reduce the overall power required to generate high pressures. (Early in the effort, the team believed that horsepower requirements would be a critical economic hurdle for jet kerf drilling. This had been reported in previous efforts and failed field applications of the technology (see Section 1.3).) In addition, providing LP fluid to run the motor and clean the bit assured that sufficient fluid flow rates could be provided to adequately circulate cuttings from the wellbore.

A dual-flow system with reduced volume requirements for HP drilling fluid also allowed the use of smaller diameter CT strings. Engineering analysis showed that smaller CT would provide significantly longer life before fatigue failure. (CT is plastically bent on/off the reel and over the gooseneck during standard operations. Fatigue failure from this plastic bending, always a serious concern for CT, is much more rapid when internal pressures are high.) While larger CT can be specified to safely pump 10,000-psi fluid, it would have a substantially shorter service life when run in/out of the well with pressure inside the tubing. To mitigate this problem, typical CT applications avoid moving the CT back and forth across the gooseneck (i.e., bending it) when high pressures are applied. That approach would not be practical for the HP-CT drilling system, that is, movement of the string with HP would be required as the bit advances.

The dual-flow system was not pursued beyond the concept phase during Phase I. During early design review meetings, the Advisory Board determined that several critical weaknesses existed and that the system would be unreliable. Primary issues included:

1. The swivel that would be required downhole to direct HP fluid into the center of the motor would present major challenges. Designing a positive seal would be very difficult, and if a labyrinth-type seal were used, the high rotary speed and eccentric motion would make seal construction and maintenance very difficult. This requirement would likely result in a short service life for the motor.

2. Within a double string of CT, an internal slip joint would be required to compensate for variations in lengths of the inner CT string relative to the outer CT string (i.e., slack of the internal string). Changes in relative lengths in concentric CT strings are expected and can be caused by various factors including internal pressure and geometry of the strings as they are spooled on and off the reel. Field experience with concentric CT strings has demonstrated that this effect can be significant. A required telescoping slip joint would dramatically increase the complexity of the swivel as well as the joint between the motor and end of the CT string.

3. It would be very difficult to monitor the service condition of the inner string of CT. It is not well established how the inner string would age with respect to stress and fatigue. There is no convenient method to accurately monitor the inner string or measure it to determine its useful remaining service life.

4. The team also foresaw challenges with the LP fluid, which would need to be routed through the bearing pack and into LP nozzles on the bit. This would require a complicated dual-flow system within the bit.

While the dual-flow CT system was analyzed and deemed to be technically feasible, the Advisory Board concluded that the disadvantages outweighed the advantages, and recommended that this concept not be pursued at this time.

2.3.3 Single-Flow CT System

The second concept considered by the project team in Phase I was a single-flow CT-based system (Figure 15). This approach uses a conventional design with a single string of CT to pump HP fluid down through a mud motor and out the bit. This system has the important advantage of eliminating problems associated with a swivel above the mud motor and a bit with dual flow paths. However, challenges with this single-string approach include:

1. Requires a motor that can operate at 10,000 psi

2. Imposes limits on the total volume of fluid that can be pumped due to CT ID

3. Requires large-OD CT to be run across the gooseneck under HP (thereby greatly accelerating fatigue damage to the CT string and shortening its service life)

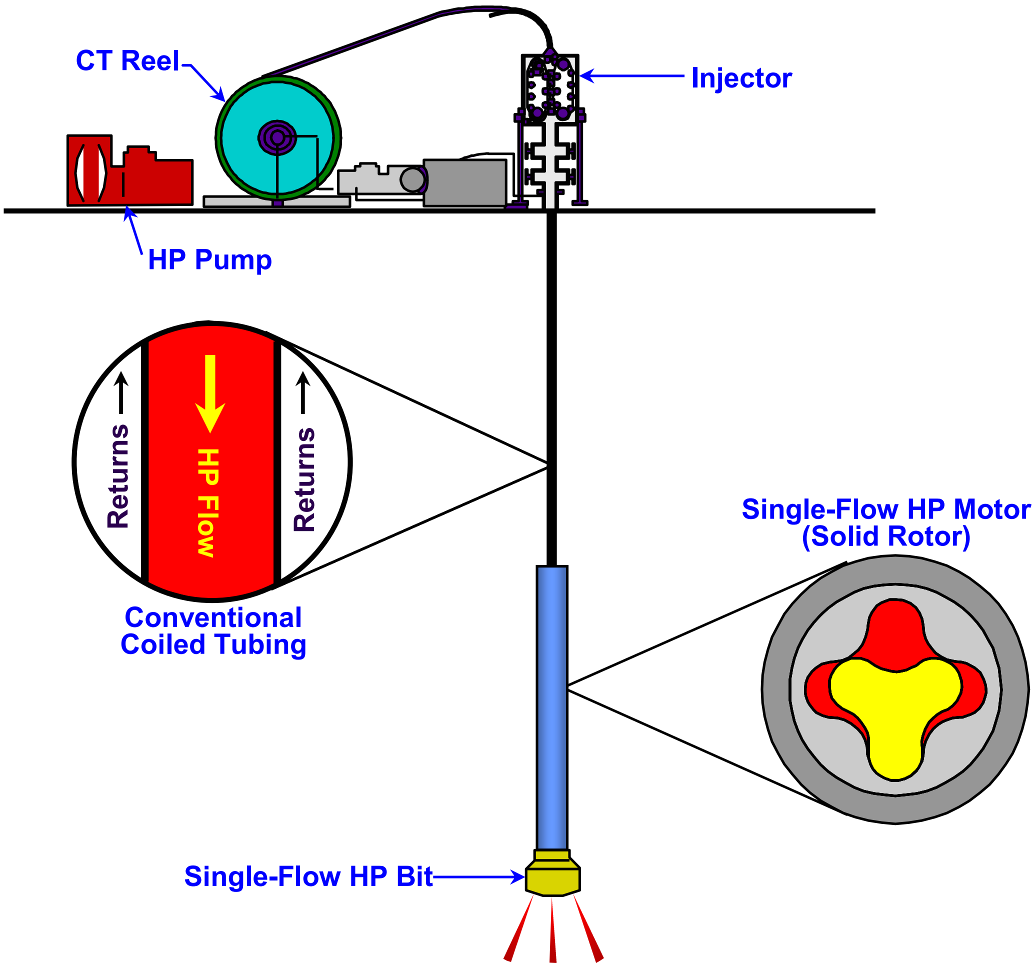


Figure 15. Single-Flow CT Drilling System

After the single-flow design was reviewed by the Advisory Board, it was selected as the preferred system for detailed development in the project. At the outset, CT service life was foreseen as a critical issue. Calculations from MTI's proprietary CT engineering software and data produced by Roderick Stanley of Quality Tubing indicated that conventional CT would fail after only a few cycles in/out of the well. Consequently, improved material properties for CT were identified as an area for investigation during Phase I along with HP mud motors and bits.

2.4 Equipment Developed for HP Drilling

2.4.1 HP Motors

During Phase I, HP motors were designed (Figure 16) for use with the single-flow CT drilling system. Prototype motor seals and bearings were successfully tested. During Phase II, HP motors were manufactured and used to drill rocks at rates of up to 1600 ft/hr compared to 300 ft/hr for conventional motors and 150 ft/hr for rotary drills.

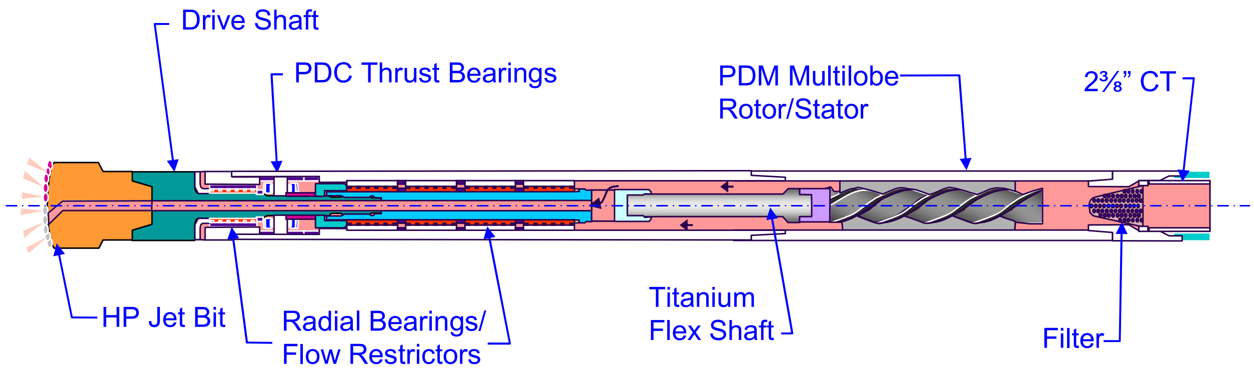


Figure 16. Design of HP Mud Motor

This HP drilling motor operates at pressures up to 10,000 psi and typically drills at penetration rates of three to five times faster than rotary drills in most sedimentary rocks. It is capable of delivering sufficient mechanical power to drill as fast as conventional motors in hard rocks that cannot be eroded by HP jets.

Several special features and modifications were needed for mud motors for operation in a HP environment (described in Section 3.2.1). HP mud motors were developed with modifications required to operate with the CT deployed system (described in Section 2.3). These motors were extensively tested in the laboratory to measure performance and reliability. Three different sizes of tools were developed:

- 4¾-in. (121-mm) tool for use with 6-in. (152-mm) bits
- 3⅛-in. (79-mm) tool for use with 4¾-in. (121-mm) bits
- $1\frac{11}{16}$-in. (43-mm) tool for use with 2½-in. (64-mm) bits plus a modified version with a gear box to slow the rotary speed for use with side-cutting and cleaning jets

Performance data for these motors were measured at the Drilling Research Center using the dynamometer motor test stand for a complete tool fitted with a bearing pack using diamond thrust bearings.

2.4.2 HP Jet Kerf Bits

Special bits for HP jet kerf drilling were also manufactured for use on this project. These were developed based on MTI's significant experience gained through previous projects and R&D efforts. Figure 17 shows an older HP bit developed by MTI based on modifying a Reed Tool PDC bit (see Section 1.3 for more information).

Nozzle placement is critical for efficient drilling action of these bits. For the modified Reed Tool bit, it was not possible to reposition the nozzles;


Figure 17. HP Bit (8-in.) Previously Developed by MTI

existing nozzles were only resized to produce HP jets to erode the rock face. This bit included sufficient existing LP nozzles to allow its conversion to a HP bit.

Two types of bits were manufactured for use on this DOE project—test bits that were intended for drilling tests in the laboratory and field bits for drilling in wells. These results are described in Section 3.2.2.

2.4.3 CT String

The initial design of the HP drilling system was based on the use of CT (coiled tubing) as the deployment string. This technology offered many advantages at the onset of this project. (More information is presented in Appendix F.) Previous developmental efforts for HP drilling systems were plagued by problems with leaks at drill pipe connections. HP fluid flow caused erosion and wash-outs at the joints. CT, now commercially available in sufficiently large diameters, would eliminate the multiple joints in a conventional drill string. In addition, high pressures created for jet drilling presents an important safety concern that must be addressed. CT rigs and crews routinely deal with HP fluids during many operations that are typical for CT, such as fracing and scale clean-out. Safety concerns and equipment to address them are already in place.

The fundamental disadvantage of using CT in HP operations is its limited fatigue life due to plastic bending. As the tubing is spooled on and off the reel and across the guide arch (“gooseneck”), it undergoes plastic yielding. This causes CT to fail from fatigue damage after a relatively few cycles in/out of the well. In addition, high internal pressures cause fatigue damage to accumulate much more rapidly than at lower internal pressures. For example, Figure 18 shows how the service life of 1¾- and 2-in. CT is reduced as internal pressure is increased. These data show how CT life at pressures around 10,000 psi is dramatically reduced with this particular CT material.

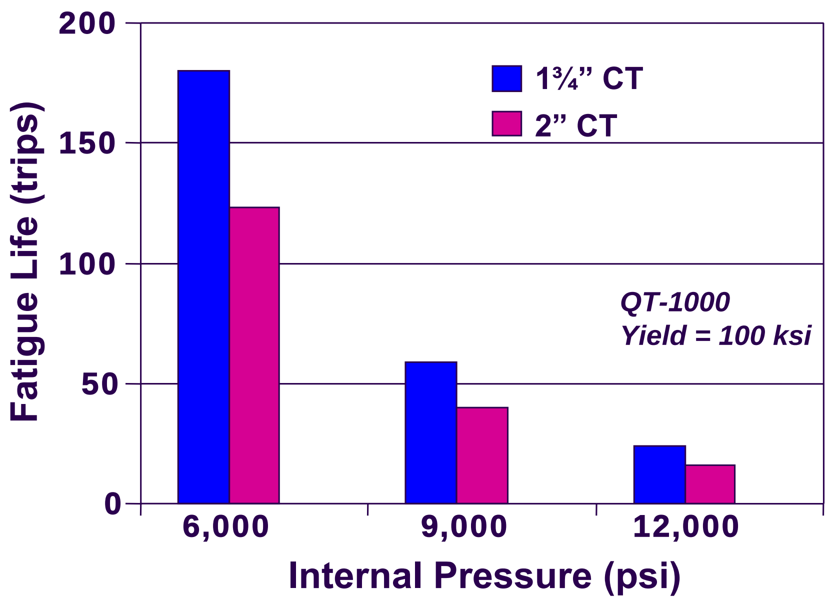


Figure 18. CT Fatigue Life with Internal Pressure

In an effort to reduce the severity of this problem, a major manufacturer of CT (Quality Tubing, Inc.) was enlisted to join the project and investigate new tubing materials for the conditions foreseen for HP-CT drilling. They successfully developed and fabricated a string of CT based on a high-strength (120,000-psi yield strength) material. These developments are summarized in Section 3.2.3.

2.4.4 CT BHA Components

The bottom-hole assembly (BHA) for drilling with CT is comprised of a number of components that protect the assembly, allow operations in underbalanced conditions, and allow the CT to be disconnected in an emergency. When this development was initially undertaken, none of the motor BHA components available commercially were rated for operation at 10,000 psi. MTI contracted with a supplier of these components to design and build special sets of required components for use with the different motors being developed. However, the first company failed to deliver designs or components as promised and the team was forced to seek an alternative solution because a test using CT had been scheduled.

Several CT equipment suppliers were contacted for equipment rated at 10,000 psi. Only Weatherford responded positively. They believed that their equipment, while rated at 5,000 psi, could safely work at 10,000 psi. Weatherford also agreed to participate in the project by providing, at no cost, the BHA components for testing at 10,000 psi. Their equipment was tested at the Drilling Research Center at 10,000 psi. No failures occurred and inspection after the test indicated no damage from high pressures. This same equipment was then used for the CT-based field tests.

2.4.5 Fluid Swivel for CT Rig

A special HP swivel is another critical component needed to deliver the drilling fluid from the pump to inside the CT through the reel as it rotates. At the beginning of this development project, most CT swivels were only rated to 5,000 psi. During the course of the project Hydra-Rig (Conroe, Texas) introduced a commercial 15,000-psi swivel (Figure 19).

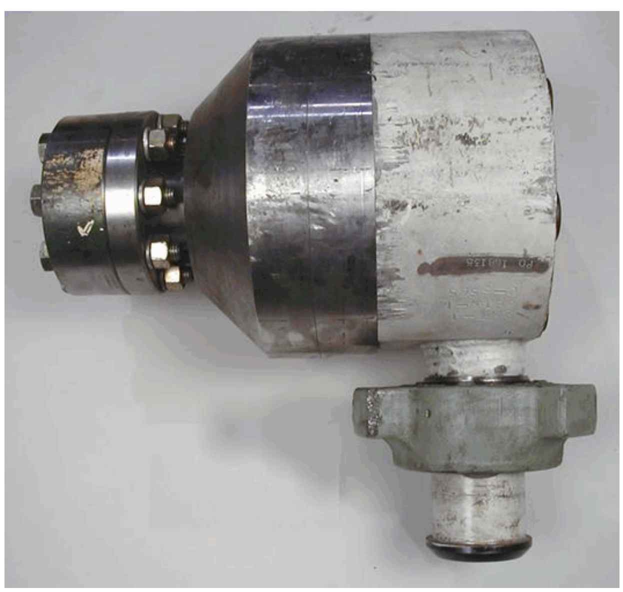


Figure 19. Hydra-Rig HP-CT Swivel

Tests of this HP swivel for CT are described in Section 3.2.5.

2.4.6 HP Jointed-Pipe System

After the project team conducted one field test of the CT-based drilling system, it was decided to conduct further tests using jointed pipe. This testing was performed at the DOE's Rocky Mountain Oilfield Testing Center (RMOTC) in Wyoming at the Tea Pot Dome field. The first step at RMOTC was to upgrade the rig so that it could be operated at 10,000-psi surface pressure. Upgrading the rig required replacing the piping running from the pumps to the rig, including the standpipe and rotary hose. This included a HP rotary swivel and a HP rotary hose. These were obtained from commercial suppliers. The swivel (Figure 20) was manufactured by Western Rubber (Texas) and the hose by Nephi Rubber Products (Nephi, Utah). Both of these items were available commercially and were not special-order.

Figure 20. HP Rotary Swivel used on RMOTC Rig

A new HP pump was also added to the rig. This pump, the most expensive single item, was a Gardner Denver 1100-hp model HD2000 plunger pump powered by a 2508 DI TA 1050-hp, 1800-rpm Caterpillar diesel engine (Figure 21).

Figure 21. Gardner Denver HP Plunger Pump

Another critical area of concern was the drill pipe and tool joints. During previous HP drilling operations the tool joints leaked and/or washed out (see Section 1.3). This problem had to be prevented and was addressed by placing O-rings in the thread relief groove. A rental string was used that incorporated recently developed double-shoulder tool joints manufactured by Grant Prideco (Figure 22). (The pipe was rented from Weatherford and brought in from California.) These advanced tool joints were designed to seal HP gas for use in underbalanced drilling. This special drill pipe was used successfully on this test, with no leaks or washouts observed. The drill pipe was 3½-in. OD, 13.3 lb/ft S-135 drill pipe with 3½-in. HT threaded connections.

Figure 22. Double-Shoulder Tool Joint for HP Tests

The original tests with the jointed-pipe drilling system incorporated the project's 4¾-in. HP downhole mud motor. Later, the motor failed and the project team decided to continue the drilling tests in conventional rotary mode. This was very successful, which demonstrated that HP jet kerf drilling can be accomplished with conventional modifications to a standard rotary rig.

2.5 Equipment for Catoosa Field Tests

Introduction

Two series of field tests of HP jet kerf drilling systems were completed. These were performed at the:

1. Gas Technology Institute (GTI) Catoosa test facility in Tulsa, Oklahoma, in February 2002 (described below)
2. Rocky Mountain Oilfield Testing Center (RMOTC) in Casper, Wyoming, in March, April and May 2004 (three separate trips) (described in Section 2.6)

These facilities offer the essential ability to test equipment in actual drilling conditions. Without the opportunity to test at these locations, this development could not have proceeded as far as it did. Understandably, commercial drilling companies are reluctant to test new equipment or systems in their ongoing field operations due to the high costs associated with any failure. Even small problems added to normal operations by the testing protocol can be very costly if they result in an unnecessary trip or any loss of efficiency.

Tests at the GTI Catoosa facility used CT to convey the bottomhole assembly (BHA) and highlighted problems with that method.

The RMOTC tests used conventional jointed pipe to convey the BHA downhole. At first, a HP mud motor was run on jointed pipe. Then, after the motor failed, the operation was continued using conventional rotary drilling. This test demonstrated that HP drilling can be performed by most rigs with only a few modifications.

Field Test Plan

The first field test of the system was conducted at GTI Catoosa using CT to convey the BHA. BJ Services Company was participating in the project as the ultimate commercializer of the new CT drilling systems, and thus provided CT equipment and expertise at Catoosa. Tests were conducted over a five-day period from February 11–15, 2002. A log of activities at Catoosa is presented in Appendix B.

A detailed test plan was prepared prior to the test. The plan listed one primary and two secondary objectives. The primary objective was to test the jet kerf drilling system starting with the largest motor/bit (4¾-in. motor with 6-in. bit) and progressing down in size (3⅛-in. motor with 4¾-in. bit, $1\frac{11}{16}$-in. motor with 2-in. bit). Only after the primary objective had been completed were the secondary objectives to be pursued—testing the side-cutting jet and the QT-1200 high-strength CT string. BHA designs and equipment lists were provided in the test plan along with a step-by-step procedure for conducting the test.

MTI Equipment

Maurer Technology Inc. (MTI) was responsible for providing BHA equipment including: (1) bit, (2) HP mud motors, (3) CT motor head assembly, and (4) drill collars. The bits and motors were developed under this project and the motor-head assembly consists of components typically run with CT when a downhole motor is used. These components were proof-tested to 10,000 psi in preparation for this field test. (Previously, these were only rated to 5,000 psi.) The drill collars were provided as a back-up solution in the event that the CT injector could not provide enough weight on bit to drill at substantial rates of penetration.

MTI also provided HP mud pumps (Figure 23) as a back-up to those supplied by BJ Services. These MTI pumps were to be used as supplemental or emergency flow should the BJ pumps fail or be unavailable.

Figure 23. MTI HP Mud Pump

MTI also supplied and tested a special set of tongs for making up the BHA components (Figure 24). One of the disadvantages of using CT is the absence of a standard rotary table and make-up tongs for assembling the BHA. The special tongs worked well on items with identical diameters; however, even small differences in diameter caused the tongs to slip. Although making up the assembly with these tongs was a slow process, these tongs were essential to this test procedure.

Figure 24. Make-Up Tongs for CT BHA

These experiences highlighted the need for an effective means to make up BHAs on CT. Assembling the first BHA consumed almost the entire first day of testing. Even after the workers had practiced using the tool, the fastest time for making up the BHA was a half day. If HP-CT drilling is to be economic, this problem must be solved. A small rotary table and derrick with lifting capacity are most likely needed.

Figure 25 shows the HP-CT BHA being lifted for insertion into the well. The crane at Catoosa was very valuable for this process. This capability represents an additional crane as compared to typical CT jobs (and an added expense). However, without a derrick, this was the only way to lift the BHA into place. Different procedures were tested during the operation. In Figure 25 the BHA (motor and collars) was assembled on the ground and then lifted into the well. In other tests all components were individually picked up and assembled in the well.

Figure 25. Lifting BHA for Insertion into Well

GTI Catoosa Equipment

The GTI Catoosa test site provided a well and wellhead, and support equipment such as a forklift and crane. This equipment and office space are included in the daily rental charge. Figure 26 shows the well head being prepared.

Figure 26. Well Head Preparation at Catoosa

BJ Services Equipment

BJ services provided all CT equipment required for these field tests. This equipment set-up (Figure 27) was relatively elaborate due to the requirements for HP and high flow rates. The CT unit includes the reel (Figure 28), control cabin (Figure 29), injector and blowout preventer stack. Figure 30 shows the CT being rigged through the gooseneck and then into the injector.

Figure 27. HP-CT Equipment for Field Test

Figure 28. CT Reel

Figure 29. CT Control Cabin

Figure 30. Rigging up CT through Gooseneck

BJ provided two pumps (Figure 31)—a conventional frac pump (part of most CT jobs) and a large frac pump. The standard pump could not supply the required fluid flow rate at HP for the 4¾-in. motor. Its capacity was adequate for the smaller HP motors; however, the 4¾-in. motor required 200 gpm. At 10,000 psi, this equates to almost 1200 hydraulic horsepower, a value beyond the limit of the conventional frac pump. BJ's large (2000-hp) frac pump was capable of providing HP fluid at high flow rates as required.

Figure 31. BJ Frac Pumps

2.6 Equipment for RMOTC Field Tests

The second series of field tests was conducted at the Rocky Mountain Oilfield Testing Center (RMOTC) near Casper, Wyoming on the Navel Petroleum Reserve No. 3 (the infamous Teapot Dome Field) (Figure 32). This DOE-run facility allows testing of oilfield equipment in actual drilling conditions.

Figure 32. RMOTC Field Test Site

While similar to the GTI Catoosa test facility, RMOTC is much larger and provides the opportunity to drill at much greater depths (up to 7,000 ft). A number of different lithologies are encountered in a typical wellbore, as summarized in Table 1.

It was necessary to implement several modifications to the RMOTC drill rig (Figure 33) prior to conducting tests of the HP drilling system. In addition, a HP mud pump had to be provided as auxiliary equipment. RMOTC purchased a new pump to add HP capability to their facility and to conduct this test. Modifications to the rig were to the mud-handling system and consisted of three major items. These were:

1. Rig piping had to be obtained from the mud pump to the rotary hose
2. Rotary hose had to be upgraded to handle high pressures
3. Rig swivel had to be upgraded for operation at 10,000 psi

More discussion of these items is presented in Section 2.4.6.


Figure 33. RMOTC Drill Rig

Table 1. RMOTC Formations

Formation	Member	KB (ft)	Thick (ft)	ASL (ft)
Steele Shale	Shannon A	247	80	4868
Steele Shale	Shannon B	332	145	4783
Steele Shale	Telegraph Creek	477	132	4638
Steele Shale	Brittle	609	393	4506
Steele Shale	Fishtooth	1002	516	4113
Steele Shale	Grey Dust	1518	102	3597
Steele Shale	Ardmore	1620	125	3495
Niobrara Shale	White Specks	1745	244	3370
Niobrara Shale	Smokey Gap	1989	219	3126
Carlisle Shale		2208	242	2907
Frontier	1 Wall Creek	2450	384	2665
Frontier	2 Wall Creek	2834	254	2281
Frontier	3 Wall Creek	3088	267	2027
Mowry Shale		3355	237	1760
Muddy Sand		3592	18	1523
Thermopolis Shale		3610	133	1505
Dakota Sand		3743	72	1372
Lakota Conglomerate		3815	7	1300
Morrison		3822	213	1293
Sundance		4035	82	1080
Sundance	Lak	4117	95	998
Sundance	Lak Evaporite	4212	12	903
Sundance	Huelett Sand	4224	4	891
Sundance	Stockdale Beaver Shale	4228	43	887
Sundance	Canyon Springs Sand	4271	82	844
Chugwater/Crow Mtn		4353	86	762
Chugwater/Alcova		4439	22	676
Chugwater/Red Peaks		4461	590	654
Goose Egg		5051	167	64
Goose Egg	Forelle	5218	73	-103
Goose Egg	Minnekahta	5291	17	-176
Goose Egg	Opeche	5308	34	-193
Tensleep		5342	11	-227
Tensleep	Top A Sand	5353	50	-238
Tensleep	Base A Sand	5403	29	-288
Tensleep	Top B Sand	5432	66	-317
Tensleep	Base B Sand	5498	47	-383
Tensleep	Top C Sand	5545	20	-430
Tensleep	Base C Sand	5565	95	-450
Amsden		5805	240	-690

KB Elev = 5115 ft ASL

The cost of these upgrades to the RMOTC rig was minimal (Table 2). It is noteworthy that these upgrades were readily performed on an older rig, clearly indicating that adding HP capability is not overly expensive nor are the costs an impediment to implementing HP drilling.

Table 2. Cost of Upgrades to RMOTC Rig for HP Operation

Description	Cost
HP Kelly Hose rated at 10,000 psi	$16,200
HP 150-ton Drilling Swivel	$33,500
HP Swivel Joints (Chicksans)	$10,600
Stand Pipe Master Valve $3\frac{1}{16}$" (15,000 psi)	$11,800
Stand Pipe Fill Up Valve $2\frac{1}{16}$" (15,000 psi)	$5,300
Gooseneck, unions, hardline, tees, and misc.	$16,700
Welding and X-ray	$1,650
Labor	$10,000
TOTAL:	**$105,750**

The new HP rotary hose (Figure 34) did present some problems. The first new hose leaked at one fitting, and was returned to the manufacturer for repair. However, after the hose was re-installed on the rig, the joint continued to leak. A complete new hose was then supplied and worked well throughout the test sequence.

Figure 34. HP Rotary Hose

The swivel also had to be upgraded. A commercially available HP swivel (see Figure 20 on page 18) was purchased and found to work well. The packing and wash pipe had to be replaced at the beginning of the HP work because sand had collected at the edge of the packing during conventional drilling and was being forced under the packing when HP was applied. While not enough evidence was obtained to confirm it, the team theorized that this problem could have been avoided by greasing the packing at regular and more frequent intervals.

In previous tests of HP drilling systems by various companies, leaks at the tool joints have been a major problem. Leaking HP fluid quickly results in washouts that, at best, require stopping the drilling process and tripping the drill string out of the hole. At worst, washouts result in lost equipment downhole and a fishing job. For RMOTC, the team rented a string of pipe with Grant

Prideco HT-38™ tool joints (see Figure 22 on page 19), which included double shoulders. The tool joints performed well and did not leak during HP field operations.

No special equipment was ordered for the mud system. Primary cleaning was via the shale shaker on the rig. The team was concerned that the small nozzles on the bit (0.080–0.100 in.) would become plugged. Steps were taken to avoid problems. Prior to the start of HP drilling, the mud tanks were cleaned (Figure 35) and fresh mud prepared for HP operations.

Figure 35. Cleaning Mud Tanks

Drill-pipe screens (filters) were placed in-line at the surface and immediately above the bit. Figure 36 shows two bit screens. The upper screen broke open after the mud motor failed, which caused the filter screen to be filled with rubber debris.

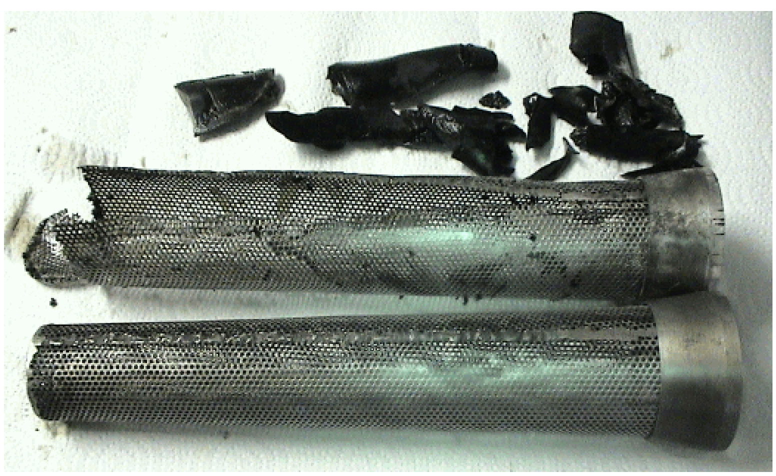


Figure 36. Bit Filter Screens

The most expensive piece of equipment obtained for these tests was a new HP pump. RMOTC purchased a Gardner Denver HD 2000 pump (see Figure 21 on page 18) with 3.75-in. plungers. The pump is powered by a 3508 Caterpillar Diesel Engine capable of producing 1100 hp. The engine is coupled to the pump via an Allison 8962 five-speed transmission. The pump can produce 192 gpm at 8800 psi. This flow rate is sufficient to achieve increased penetration rates in many formations.

3. Results and Discussion

3.1 Summary of Project Activities

Accomplishments for this project can be categorized into three distinct areas:

1. **Design and manufacture** of specialized prototype HP jet kerf drilling equipment based on the concepts developed in Phase I of the project

2. **Laboratory testing** of the prototype drilling system and confirmation of its performance in Phase II of the project

3. **Field testing** the equipment performed in Phase III of the project and later in a Phase II(B) effort.

Field testing of this equipment demonstrated that, unlike many other engineering developments, tools for oil and gas drilling often require staged prototype development under field conditions. It was found that laboratory testing was not as effective as field testing in shaking out system performance. In recognition of these lessons (demonstrated clearly in Phase III), the DOE allowed the project to continue by stepping back from Phase III field testing (considered the final step prior to commercialization) to a Phase II(B) effort where prototype development and laboratory testing were extended to encompass field testing conditions. This allowed the team to operate the equipment under actual field conditions for extended periods, thereby revealing areas that required further development. Various weaknesses in tool design were not (and possibly could not be) observed in conventional laboratory tests. The project team found that the field must be the final laboratory for these types of downhole drilling equipment and tools.

In addition to these efforts, an economic model was constructed to illustrate commercial feasibility of developing a HP infrastructure to support HP jet kerf drilling. While simple, the model showed the costs associated with such a development, potential savings, and how service companies could recover their investments.

Phase I—Concept Development

The objective of Phase I was to demonstrate engineering feasibility of the HP-CT drilling system. This included theoretical analyses, component design, and review of potential barriers to field application through meetings with subcontractors, service companies, and operators.

A chronology of Phase I activities follows:

1. An industry Advisory Board was formed to guide the project. This was comprised of experts from MTI, operators, a CT service provider, and a CT manufacturer.

2. Concepts for the deployment of HP drilling bits using CT were developed and expanded.

3. Project engineers and the Advisory Board evaluated concepts for CT-based jet kerf drilling system.

4. Mud motor designs were developed and analyzed for applications with HP fluids. These included:
    a. Motors for single-string CT deployment
    b. Motors for dual-string (concentric) CT deployment
    c. Special HP swivel for CT and mud motor for dual-string CT system
    d. Expansion (slip) joint for inner CT string for dual-string CT system
5. The Advisory Board then evaluated program alternatives based on all engineering studies. The system recommendation for development and testing was a single-string CT running a HP motor and combination PDC/jet bit.
6. The Phase I Final Report was prepared and submitted to DOE. A proposal for continuing to Phase II and III was also submitted and accepted by DOE.

Phase II(A)—Develop and Test HP Motors and Bits

The objective of the initial Phase II effort (referred to here as Phase II(A)) was to manufacture and laboratory-test HP-CT drilling system components. Detailed machine drawings were prepared and prototype components manufactured. Reliability and performance of the system components, including use under hard rock drilling conditions, were to be tested. Next, the total drilling system was to be assembled and laboratory-tested in blocks of sandstone and limestone to measure performance and reliability.

A chronology of Phase II(A) activities follows:

1. A 3⅛-in. HP mud motor was designed and developed. Its target hole size was 4¾ inches. This was to be the principal size of tool for the project.
2. A 1¹¹⁄₁₆-in. HP mud motor was designed and developed based on a target application of through-tubing drilling. Its target hole size was 2 to 2⅞ inches. Applications of this small system were later expanded to include:
    a. Cleaning scale from casing and tubing
    b. Drilling hardened cement out of drill pipe
    c. Jetting slots into formation for production enhancement (by bypassing skin damage)

    A transmission was also added to the motor for operation at low rotation rates.
3. HP mud motors were tested in the laboratory. Dynamometer tests included basic life tests (50 hours). Motors were modified to correct any problems and retested.
4. HP mud motors were tested in the laboratory for simulated drilling. Several types of rock samples were drilled with various combinations of HP motors and jet bits.
5. Many tests were conducted with the HP 1¹¹⁄₁₆-in. motor. The new and promising system applications for cement clean-out and production enhancement (bypassing skin damage) were pursued via multiple series of tests in the laboratory and yard.

6. Discussions of the Advisory Board determined that successful commercialization of HP jet kerf drilling technology depends on development of larger tools for use with bit sizes that are more typical in the industry. A bit size of 6 in. was selected. Consequently, a 4¾-in. mud motor was designed and developed. This motor was designed, built, tested and modified.

7. The team tested and confirmed that CT “motor head” assemblies from at least one manufacturer could be adapted for this system and would be available for use in field tests.

8. Based on promising laboratory test results, the CT systems were deemed to be ready to test in the field during Phase III.

Phase III—Field Testing

The initial objective of Phase III was to field-test the prototype CT drilling system and demonstrate its performance for increasing drilling rates and reducing drilling costs in preparation for commercializing this system.

A chronology of Phase III activities follows:

1. The project team conducted drilling tests with the system at the GRI Catoosa facility. Various problems plagued the operation over the scheduled test period. As a result, no open-hole drilling was successfully conducted.

2. Experiences at Catoosa clearly illustrated the difficulties with CT deployment and the high costs of CT equipment and operations.

3. The test sequence was halted due to the inability to run CT to the bottom of the well. The actual cause of this failure was significant ballooning (diametric growth) of the CT string that prevented the string from passing through the stripper elements. This condition was not discovered until the CT was inspected several days after operations were halted.

4. MTI determined that the project effort could not continue due to (1) high cost-share requirements and (2) lack of a commercialization partner for the HP-CT system. MTI decided to end the project at this point (pending a change in project design/focus).

Phase II(B)—Additional Prototype Development

Based on significant challenges encountered in Phase III field tests, the DOE and MTI agreed that more development work and laboratory testing of components and subsystems were needed. The project was accordingly returned to a Phase II status.

A chronology of Phase II(B) activities follows:

1. John Rogers (DOE Project Manager) worked with DOE’s RMOTC test facility to conduct additional testing of HP drilling systems. This included funding of equipment upgrades needed for HP drilling at RMOTC.

2. MTI worked with RMOTC personnel to develop specifications for the required upgrades for HP operations and helped RMOTC obtain a HP pump.

3. MTI and RMOTC developed a Test Plan for testing the 4¾-in. motor and bit developed in Phase II(A).

4. MTI and RMOTC signed a cooperative research and development agreement (CRADA) for conducting high-pressure tests (see Appendix C).

5. RMOTC acquired a HP pump and upgraded its rig for HP operations.

6. MTI and RMOTC worked together to locate and rent a string of specialized drill pipe that has double-shoulder connections for HP operation.

7. A series of tests was conducted at RMOTC. The initial test design was to drill with HP motor on jointed pipe rather than CT.

8. After the HP motor failed, another approach was tested—conventional rotary drilling with a HP bit. This test was very successful with high ROPs recorded.

9. During rotary drilling tests, HP bits exhibited short life due to erosion of the bit body occurring near the point fluid enters the nozzle. The project team then developed a concept to reduce erosion and increase bit life, but lack of participation (and cost sharing) by commercial companies resulted in the project being terminated.

10. A Final Report describing Phases II(A), III and II(B) was prepared for submission to DOE (the present report).

3.2 Equipment Developed for HP Drilling

3.2.1 HP Motors

During Phase I, HP motors were designed for use with the single-string CT drilling system (see Figure 16 on page 15). Prototype motor seals and bearings were successfully tested. During Phase II, HP motors were manufactured and used to drill rocks at rates of up to 1,600 ft/hr compared to 300 ft/hr for conventional motors and 150 ft/hr for rotary drills.

Several special features and modifications were needed to design mud motors for operation in a HP environment. The *fit between the rotor and stator* is a critical parameter that must be carefully adjusted. If there is too much interference, the rotor will compress the stator elastomer too deeply, which will in turn cause excessive heat build-up and shorten the life of the elastomer. Conversely, If the fit does not compress the stator rubber sufficiently, the pressure drop of the seal between the rotor and stator will be reduced, and the motor will not be able to develop rated power.

High pressures cause the stator housing diameter to increase and the stator elastomer to compress. As a first step, the stator housing must be checked for excess stress. Some motor housings can be used safely at HP; others must have their wall thickness increased to support the increased stress. The latter was the case for our 3⅛-in. motor. The stator configuration was designed for a conventional 2⅞-in. motor housing. However, to maintain stresses in a safe range, it was necessary to increase housing diameter to 3⅛ inches.

After the stress level is checked, the expansion of the housing dimensions is calculated at the operating pressure (10,000 psi for this design). Fit between the rotor and stator is then adjusted based on this expansion and the expected compression of the stator elastomer. The exact adjustment factor used is based on previous experience of the motor designer after considering all operational parameters.

The *seal for mud motor bearing packs* is a critical component. For HP operations, the team decided that a leaking bearing pack (i.e., uses a portion of the fluid to cool and lubricate the bearings) was the best solution to avoid the need to seal against 10,000 psi. Sealing against pressures that high presents many challenges; for example, elastomer seals work well statically but in a dynamic environment exhibit drag on mating parts and have short lives. Metal-to-metal face seals can overcome the drag problem but are very complicated and expensive.

The team determined that an effective labyrinth seal (Figure 37) would be necessary to support the large pressure drop. A number of laboratory tests were conducted on carbide labyrinth seals with close tolerances and optimized grooves to maximize pressure drop while minimizing seal length. The appearance of the labyrinth seal is deceptively simple. However, maintaining flow at acceptable levels at 10,000 psi is difficult, and erosion occurs very quickly, destroying the seal. Development and successful testing of this HP labyrinth seal is one of several major accomplishments of the project.

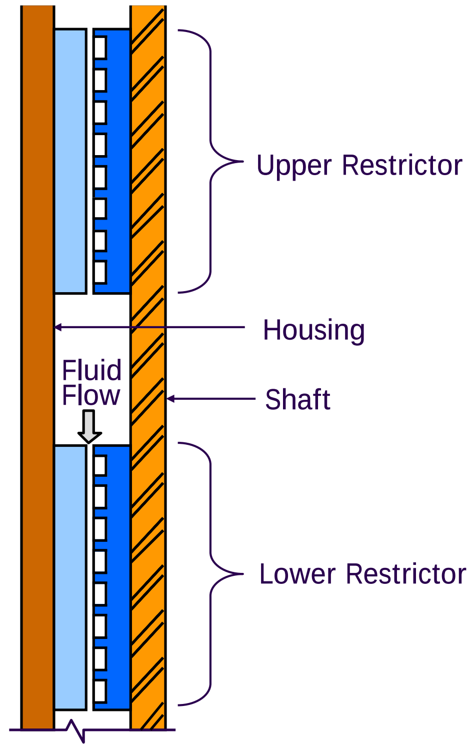


Figure 37. HP Labyrinth Seal

Several different seals were produced with varying groove depths and spacings. These grooves were to act as flow interrupters to cause turbulence in the flow, thereby increasing the pressure drop across the seal. A series of laboratory experiments was conducted to determine the optimal gap between the inner and outer labyrinth members and the spacing of flow interrupter grooves (Figure 38). This optimization process provided the maximum pressure drop across the shortest labyrinth possible. The grooves were placed on the inner member (Figure 39) because it was less expensive to grind grooves on the outside of a sleeve.

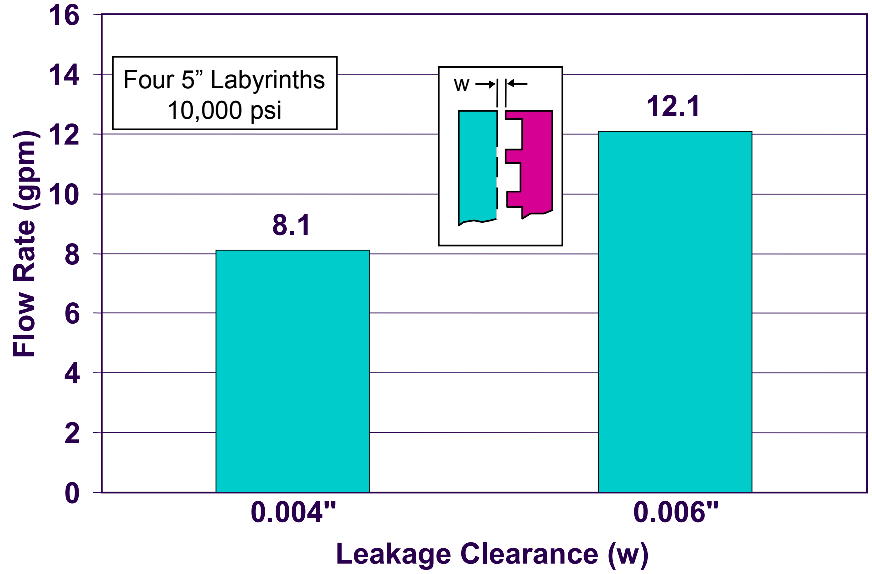


Figure 38. Flow Rate through Labyrinth Spacing

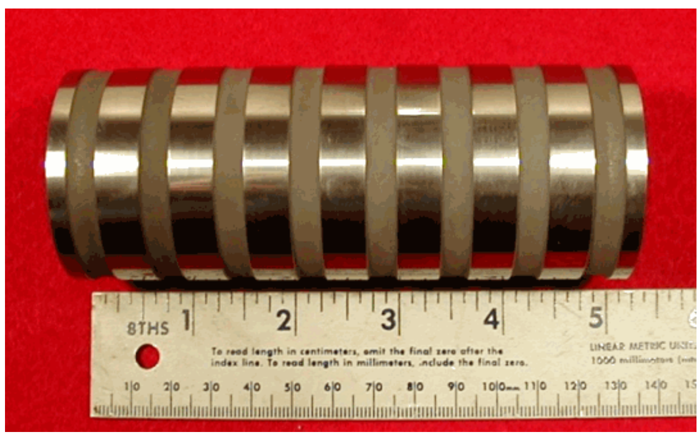


Figure 39. Labyrinth Sleeve

The *flex shaft* is another important component of mud motors that requires adjustment for HP operations. The power section of a standard Moineau mud motor rotates eccentrically. This motion must be converted to regular (centered) circular motion at the bearing pack. A flexible shaft is often used to connect the output of the power section to the input of the bearing pack and convert eccentric to rotary motion. In HP motors, this process is complicated by the pressure drop, which causes very high thrust loads that must be carried by the flex shaft. To support these loads, titanium flex shafts (Figure 40) were incorporated into the HP motors built under this project.

Figure 40. Titanium Flex Shaft

Titanium flex shafts have important advantages as compared to conventional flex shafts, which use mechanical components similar to a U-joint to allow the shaft to bend during rotation. These conventional mechanical components can fail due to the high loads imposed when operating at HP. In titanium flex shafts there are no moving parts to wear; as a consequence, reliability is excellent. No seals are required in titanium shafts to prevent particles from damaging the mechanical components used in conventional flex shafts. Although initial manufacturing costs for titanium shafts are relatively high, overall operational cost is low because the shaft can be used many times and will not limit or terminate a run. Care is needed in designing the shaft to maintain stresses below the fatigue endurance limit. These stresses are controlled by adjusting the length of the shaft. The need to reduce stresses can result in a slightly longer motor, but this is normally not a concern (except in short-radius drilling). If the flex shaft is too stiff, it can shorten stator life. It is very important that the shaft be as flexible as possible while maintaining its length to a reasonable limit and that any buckling tendency be avoided.

The *thrust bearings* are another component subjected to increased loading under HP operations. Conventional mud motors use ball thrust bearings (Figure 41). Several bearings are often stacked using springs to form a parallel configuration to react to high drilling loads encountered in mud motors. Two sets of bearings are needed—one set to absorb loads when the tool is off bottom (or the bit weight is lower than the down thrust) and one set for on-bottom loads when bit weight is higher than down-thrust loads. Ball bearings are normally used because they are more tolerant to debris and solids than roller bearings. Roller bearings will crack if they roll over a grain of sand while loaded. A ball bearing will either push the sand out of the way or roll over it and continue functioning. Balls used in these motor bearings are very tough compared to most applications. The races are usually custom-made and are carburized so that the surface is very hard and wear-resistant.

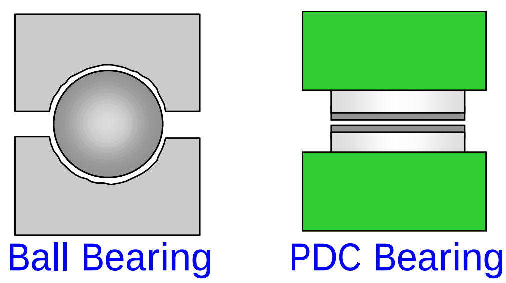


Figure 41. Bearing Types for HP Motor

A HP mud motor was tested with stacked ball bearings. The results showed that the balls crack or were crushed after only a few operating hours (see Figure 46 on page 39). Diamond thrust bearings were then used instead of the ball thrust bearings in the HP motors. These bearings (Figure 42) are made using polycrystalline diamond compact (PDC) cutters and brazing them into steel rings. Both an upper and a lower ring are needed for each bearing. The PDCs ride on one another with very low friction.

Figure 42. PDC Thrust Bearings

Diamond-on-diamond has one of the lowest friction coefficients of any material: 0.1 clean and dry and 0.05 lubricated. This type of bearing can support considerably higher loads than a ball bearing (Figure 43). A PDC bearing is suitable for use in a leaking bearing pack. It can also operate in an environment with high solids and not experience accelerated wear.

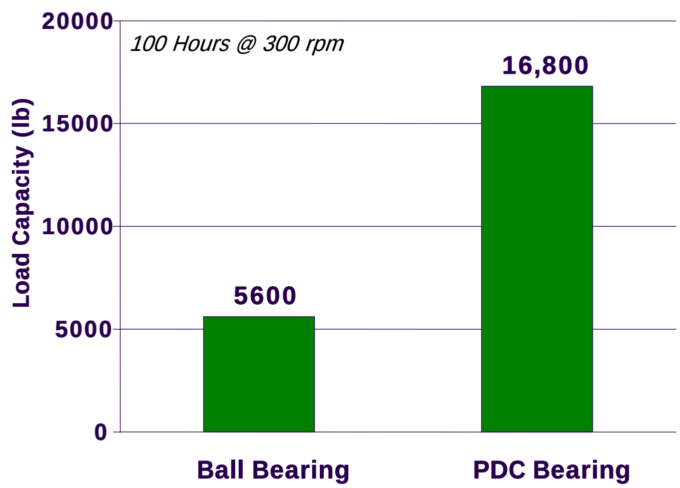


Figure 43. Motor Bearing Load Limits

In the design process for the HP motors, proprietary data were used to adjust the relationship of the size between the rotor and stator. These elements needed to be modified from conventional designs to allow efficient operation at elevated pressures as well as deliver the power necessary to drill HP jet erosion resistant rocks. In case these types of rocks are encountered the drilling motors and bits need to be able to drill ahead conventionally.

Special HP mud motors were developed with these modifications to operate with the CT-deployed system. These motors were extensively tested in the laboratory to measure performance and reliability. Three different size tools were developed:

- 4¾-in. (121-mm) tool for use with 6-in. (152-mm) bits
- 3⅛-in. (79-mm) tool for use with 4¾-in. (121-mm) bits

- $1\frac{11}{16}$-in. (43-mm) tool for use with 2½-in. (64-mm) bits plus a modified version with a gear box to slow the rotary speed for use with side-cutting and cleaning jets

4¾-in. HP Motor

The largest HP motor developed was a 4¾-in. motor for drilling 6- and 6½-in. holes. This motor was added late in the project based on suggestions from the Advisory Board. Board members believed that this range of hole sizes presents the greatest opportunity for use of the system in the field. Only one 4¾-in. tool was built due to budgetary constraints.

The 4¾-in. power section is a 3:4 lobe design with five stages. Operating parameters for the power section (according to the manufacturer's specifications) are:

- flow = 100–250 gpm
- speed = 125–390 rpm
- operating torque = 1265 ft-lb

These performance parameters made it a good selection for use in the HP motor. Various modifications from the standard product line were needed to accommodate the unique operating conditions for the HP motor. The fit between the rotor and stator was modified to compensate for compression of the rubber and expansion of the housing when operating under HP. Analysis of the housing showed that, even at 10,000 psi internal pressure, stresses were in an acceptable range.

Figure 44 shows power curves for the 4¾-in. tool as measured after integration with the bearing pack designed for this project. This motor exhibited a very high starting pressure due to a number of losses in the system including: (1) pressure losses due to high flows through the small bore of the drive shaft, (2) increased friction between the rotor and stator due to a tight rotor fit after being adjusted for HP operation (note: these data were recorded at low pressure), and increased friction due to the stiffness of the titanium flex shaft.

This high starting pressure, while problematic, is not as important in HP drilling conditions as it would be for conventional drilling since the system pressure will be 10,000–13,000 psi as compared to typical pressures of 2,000–3,500 psi in oil drilling. This starting pressure does result in lower efficiencies and will need to be addressed in future designs.

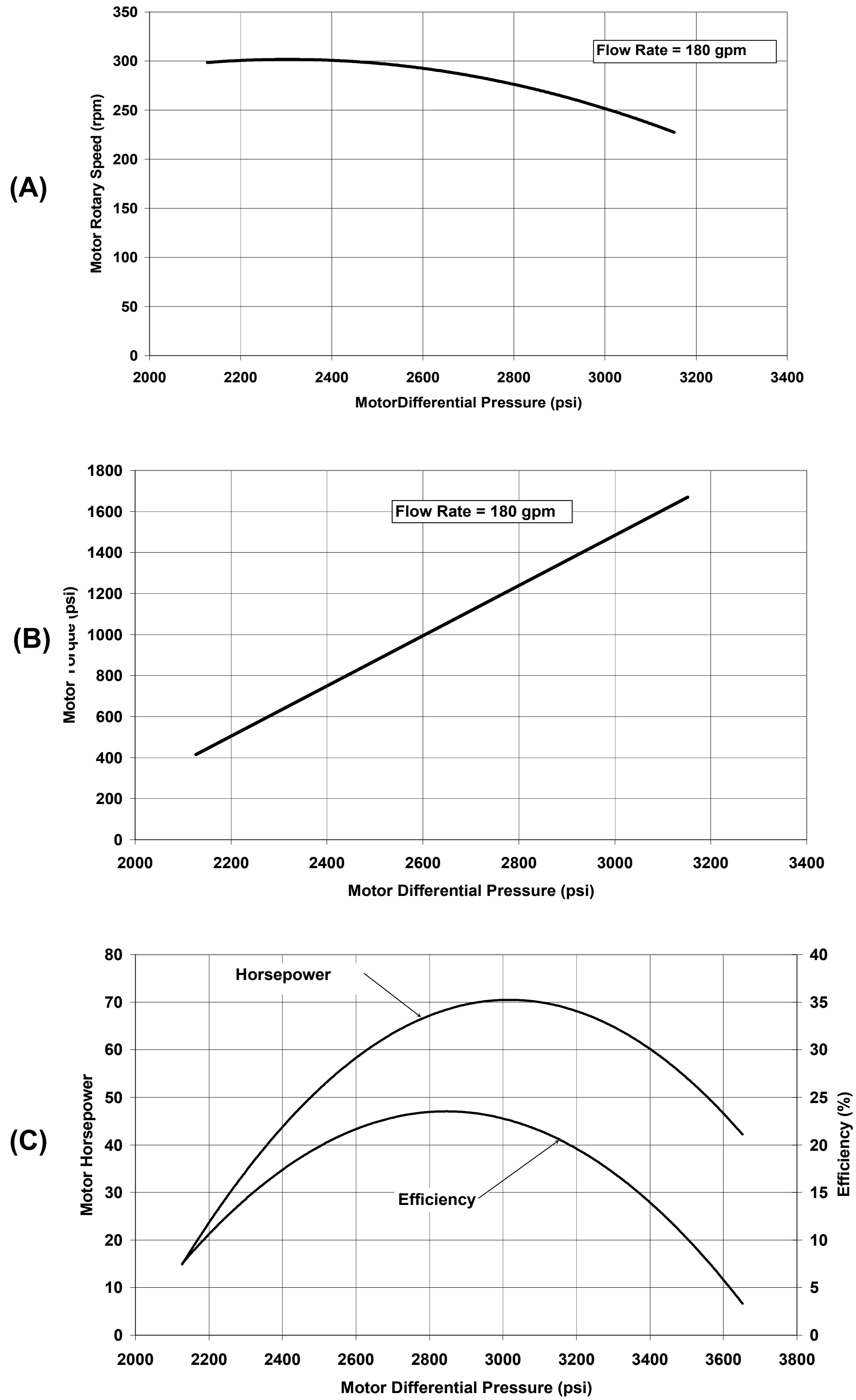


Figure 44. 4¾-in. Motor – (A) Speed; (B) Torque; and (C) Power and Efficiency

Testing showed that drag from the diamond thrust bearings was negligible at low pressures. Figure 45 shows the difference in torque with the different bearing types on a 2⅞-in. motor. The drag from diamond thrust bearings increases to measurable levels under HP conditions. Diamond thrust bearings are necessary for HP operations as testing showed that conventional ball bearings fail after only a short time under HP (Figure 46). Differential pressure between high-torque and low-torque operation of the motor is approximately 1000 psi (very similar to that of a conventional motor).

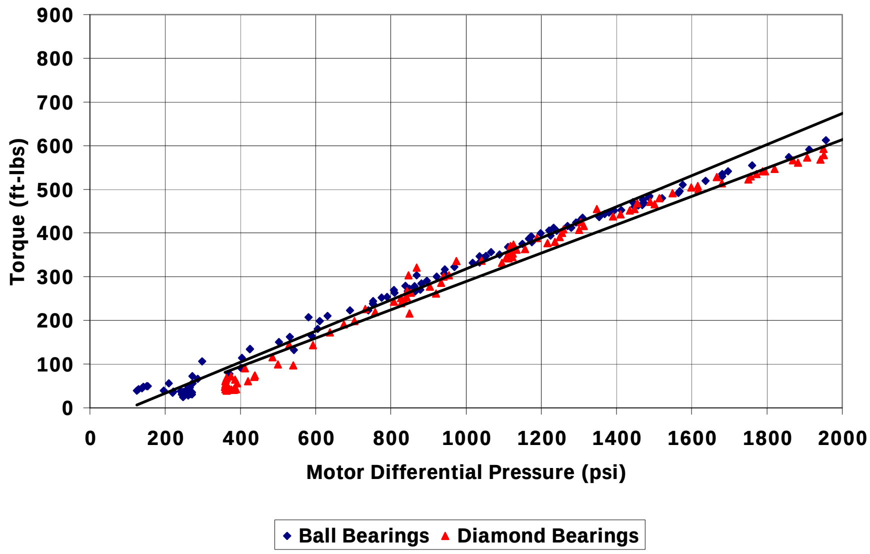


Figure 45. Difference in HP Motor Torque—Ball versus Diamond Bearings

Figure 46. Broken Ball Bearings after HP Operation

Demonstration and successful use of these diamond thrust bearings was another important development on this project. Without diamond bearings, mud motors could not have functioned in this application. Successful demonstration of diamond bearings also indicates that they could be used in conventional motors. This would allow using shorter bearing packs that are less reliant on seals without a significant loss of power.

Tests on this motor included a 20-hour life test in the laboratory. During the first test the stator rubber was damaged at the bottom of the power section. This was caused by the titanium flex shaft, which transfers eccentric rotary motion of the rotor to pure rotary at the drive shaft. The flex shaft based on the original design was too stiff because it had been designed assuming an endurance limit of 40,000 psi for titanium. The manufacturer of the titanium was contacted; they reported that a more accurate value is 80,000 psi. The new flex shaft design based on this value was much more flexible. A second endurance test showed that the motor could operate for 20 hours with no signs of damage.

3⅛-in. HP Motor

The second motor size developed was 3⅛ in. OD and was based on a conventional 2⅞-in. motor. The additional diameter was needed to thicken the housing so that it could support higher stresses from high pressures. The 3⅛-in. motor was designed for through-tubing and slim-hole CT drilling. Figure 47 shows theoretical performance curves for this power section.

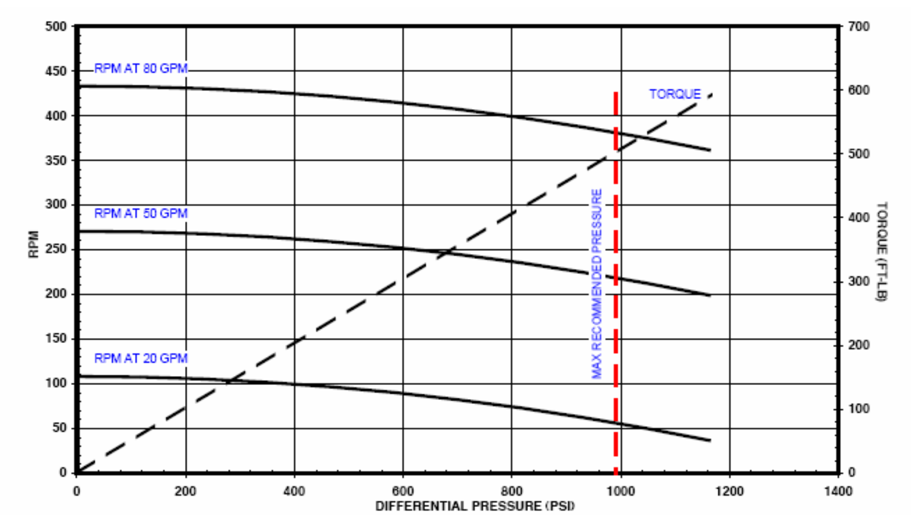
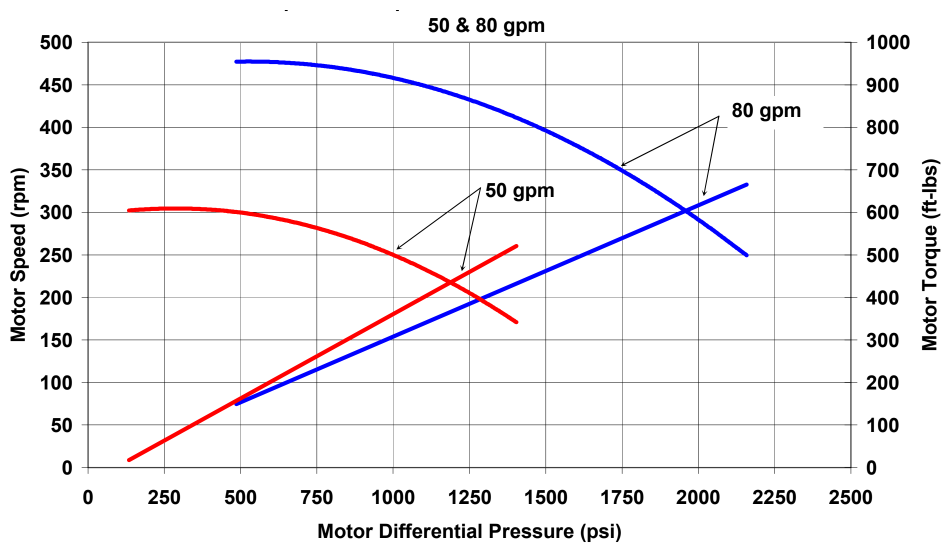


Figure 47. Theoretical Performance Curves for 3⅛-in. Power Section (R&M Energy Systems)

Speed and torque curves (Figure 48 (A)) were measured for this motor on the Drilling Research Center's dynamometer test stand, as well as power and efficiency curves (Figure 48 (B)). Actual speed of this tool was slightly faster than theoretical. This could have been due to less leakage (due to a tighter fit between the rotor and stator), but no explanation was confirmed. The torque curves show lower than expected torque at a given differential. This could be due to pressure losses in the bearing pack not accounted for on the theoretical curves.



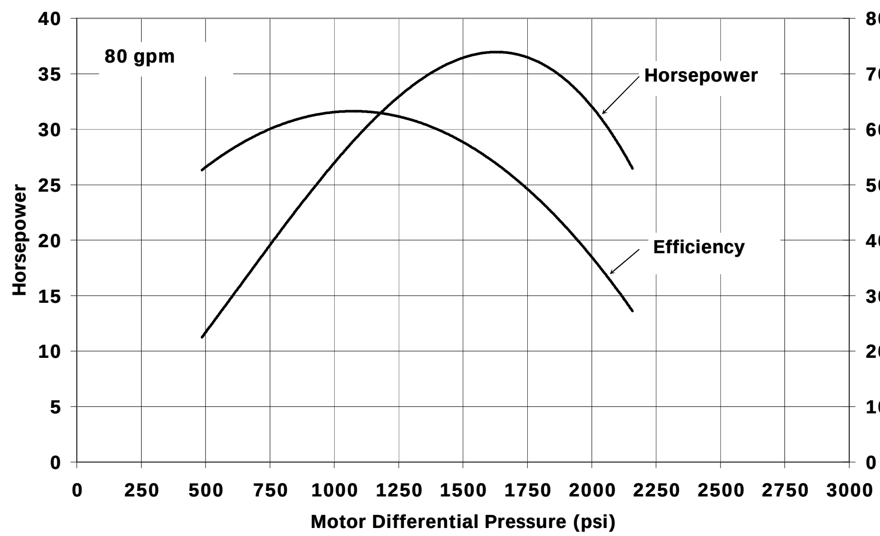


Figure 48. 3⅛-in. HP Motor – (A) Speed and Torque and (B) Power and Efficiency

1¹¹⁄₁₆-in. HP Motor

The smallest HP motor developed was 1¹¹⁄₁₆-in. diameter and was developed for clean-outs and production enhancement. Two versions of the motor were developed. The first was similar to the larger tools described above and incorporated diamond thrust bearings and a titanium flex shaft to transmit power from the power section (rotor and stator) to the bearing pack. The second design of the 1¹¹⁄₁₆-in. motor included a transmission fitted between the power section and the bearing pack that reduced the rotation rate of the bit. This was thought to be of benefit for several reasons:

1. The dwell time of the jets in the bit on the medium being drilled would be increased. It was determined that this would be important for clean-out of scale, which can be very hard and tenacious. The increased dwell time would allow the HP jet to erode the scale and more thoroughly remove it from the pipe or screen.

2. A reduced rotation rate provided a means to cut a spiral groove in the formation for enhancing production. With a slow-turning side jet, the pitch of the spiral could be controlled by how fast the drill sting was advanced. This has two advantages: (1) in tight formations the pitch can be made very small so more of the formation is exposed to the borehole, increasing the area for production and (2) in hard formations the dwell time of the jet against the rock can be increased by moving the drill string slowly.

3. This allows the jet to cut a deeper groove. In softer, more productive formations, the drill string can be moved quickly, creating a longer spiral and increasing production, but minimizing the operation time.

The manufacturer's published specifications and performance curves for the 1¹¹⁄₁₆-in. motor are presented in Figure 49.

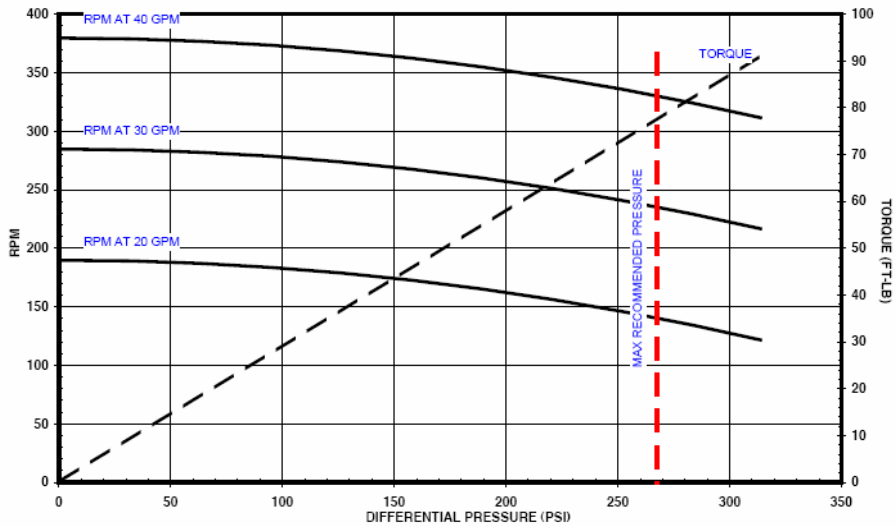


Figure 49. 1¹¹⁄₁₆-in. Motor – Manufacturer's Performance Curves (R&M Energy)

Performance data were also measured at the Drilling Research Center using the dynamometer motor test stand for a complete tool fitted with a bearing pack using diamond thrust bearings. The data shown in Figure 50 are for lower pressure operation. The data indicate that, when configured with diamond thrust bearings, speed of the motor is reduced slightly when compared to the theoretical curves, and speed falls off very quickly as differential pressure is increased. This indicates drag, which could be from the bearings or friction from the increased interference between the rotor and stator. Increased interference is added to account for expansion of the stator section and compression of the rubber when operated under HP conditions.

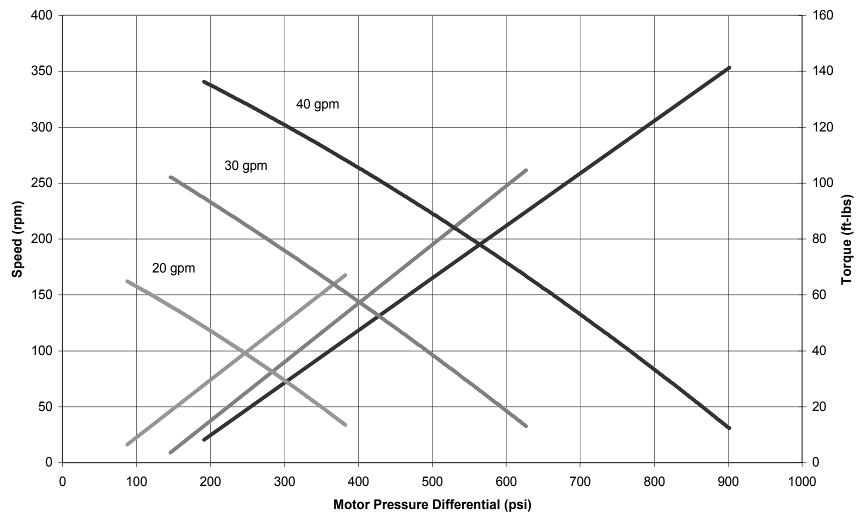


Figure 50. 1¹¹⁄₁₆-in. Motor Performance Data (Measured)

A block of Glacier Bluff dolomite was slotted using a HP side-directed jet and the slow-speed 1¹¹⁄₁₆-in. motor (Figure 51). The jet can cut slots 1–2 in. deep into the formation to improve production. This jet design can also be used to clean out tubing, screens, and perforations, as well as for removing scale.

Figure 51. Helical Slots Jetted with 1¹¹⁄₁₆-in. Motor

3.2.2 HP Jet Kerf Bits

Special bits for HP jet kerf drilling were manufactured for use on this project. These were developed based on MTI's significant experience gained through previous projects and R&D efforts. Figure 17 shows an older HP bit developed by MTI based on modifying a Reed Tool PDC bit. Nozzle placement is critical for efficient drilling action of these bits. For the modified Reed Tool bit, it was not possible to reposition the nozzles; existing nozzles could only be resized to produce HP jets to erode rock. This bit included sufficient existing LP nozzles to allow its effective conversion to a HP bit.

Two types of kerfing bits were manufactured for use on this DOE project—test bits that were intended for drilling tests in the laboratory and field bits for drilling in wells. Nozzle patterns on the field bits are the same as test bits. The most effective method to ensure the jet kerfing pattern covers the entire bottom of the hole is to drill in the laboratory with a prototype bit and then adjust the nozzles (size and direction) as necessary. The design process starts by laying out, in a single plane, the jet pattern desired (Figure 52).

Kerfs must be cut at regular intervals across the entire bottom of the hole. In addition, one nozzle near the center must jet-cut the center of the hole or a stalk will remain. The angle of this nozzle is critical and is often not optimal. Laboratory drilling tests are the best method to make sure the angle is correct.

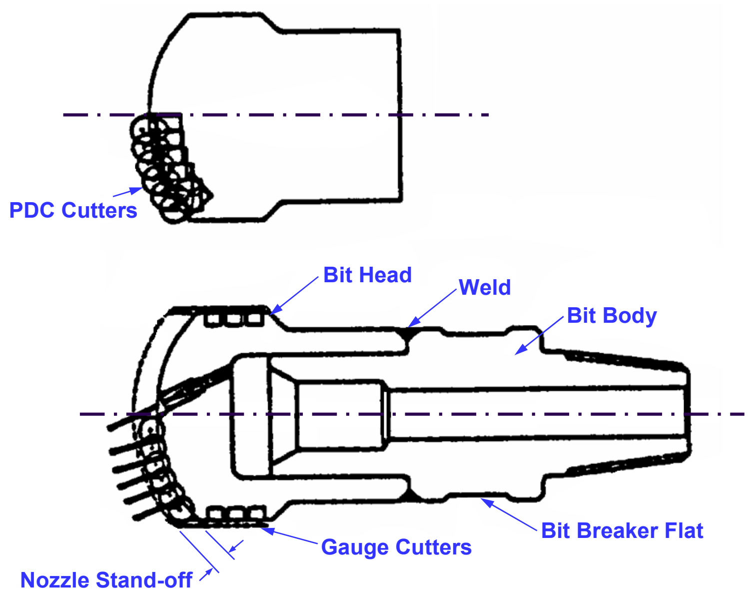


Figure 52. Basic Nozzle Pattern for HP Bit

Figure 53 shows jetting patterns produced by test bits designed for this DOE project. The photo on the left shows an early design where the nozzle spread pattern missed the center of the hole and left a center stalk. After that jet was removed and welded over, a new jet was placed at the correct angle and the bit tested again. The improved jetting pattern is shown in the photo on the right.


Figure 53. Jet Kerfing Patterns of Original and Improved Nozzle Design

All of the field bits and most of the laboratory bits had replaceable nozzles. This is beneficial for several reasons:

1. Allows the size and configuration to be customized for the flow that will be used in each particular well. In this way, pressure drop (jet force) can be kept constant for different drilling situations.

2. Allows larger nozzles to be placed at the outside diameter where more rock must be cut and smaller nozzles toward the center
3. Allows nozzles that are eroded from fluid and/or solids to be easily replaced

The smaller bits shown in Figure 53 were fabricated for laboratory testing. Figure 54 shows one of the larger bits that were fabricated for field tests. This bit was manufactured by DPI (now owned by Grant Prideco). This 6-in. bit was used to drill at the Rocky Mountain Oilfield Testing Center (RMOTC).

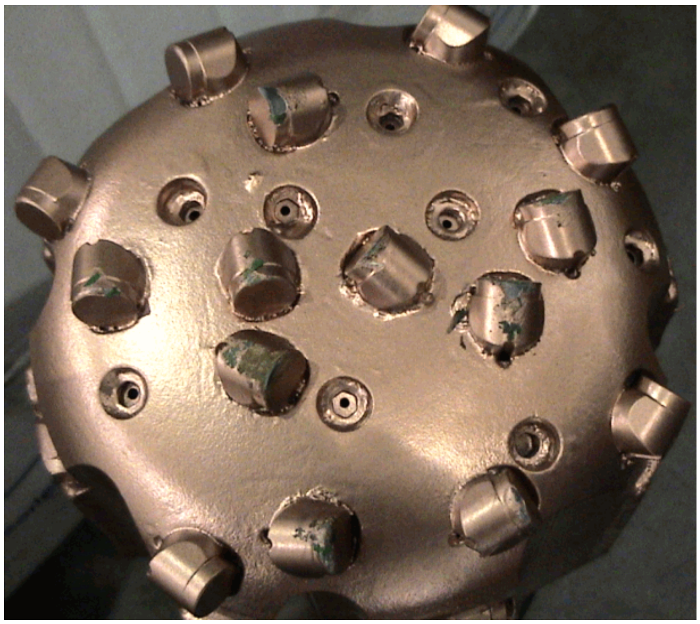


Figure 54. 6-inch HP Jet Kerf Bit used at RMOTC

This bit incorporated three different nozzle sizes. The four central nozzles were 0.082 in. (2.08 mm); the next three nozzles were 0.100 in. (2.54 mm); and the remaining nozzle was 0.125 in. (3.18 mm). Larger nozzles were placed near the outside because more rock must be cut (eroded) in this region. The total flow area (TFA) for this bit was 0.057 in^2 (36.8 mm^2). Calculated pressure drop at 200 gpm with 8.6 lb/gal mud was 6,100 psi (42.0 MPa). These values were confirmed with flow and pressure data recorded on the rig before drilling was initiated (Figure 55). Theoretical and measured pressure drops were very similar.

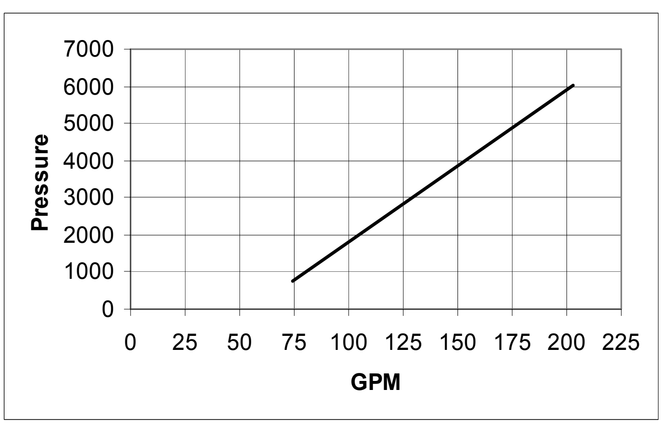


Figure 55. Measured Pressure versus Flow for Bit

3.2.3 CT String

The initial design of the HP drilling system was based on the use of coiled tubing (CT) as the deployment string. This technology offered many advantages at the onset of this project. (More information is presented in Appendix F.) Previous developmental efforts for HP drilling systems were plagued by problems with leaks at drill pipe connections. HP fluid flow caused erosion and wash-outs at the joints. CT, now commercially available in appropriately large ODs, would eliminate the many joints in a conventional drill string. In addition, the high pressures created for jet drilling present an important safety concern that must be addressed. CT rigs and crews routinely deal with HP fluids during many typical CT operations, such as fracing and scale clean-out. HP safety concerns and equipment to address them are already in place.

The fundamental disadvantage of using CT in HP operations is its limited fatigue life due to plastic deformation during bending. As the tubing is spooled on and off the reel and across the guide arch ("gooseneck"), it undergoes plastic yielding. This causes CT to fail from fatigue damage after a relatively few cycles in/out of the well. In addition, high internal pressures cause fatigue damage to accumulate more rapidly than at lower internal pressures. For example, Figure 56 shows how the service life of CT is reduced as internal pressure is increased. These data show how CT life, at pressures around 10,000 psi, is dramatically reduced with this particular CT material and wall thickness.

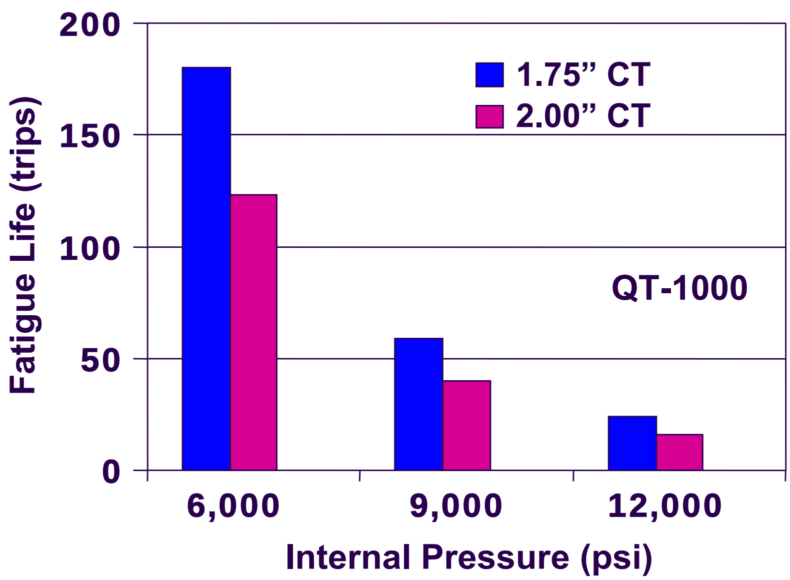


Figure 56. CT Fatigue Life with Internal Pressure

In an effort to reduce the severity of this problem, a major manufacturer of CT, Quality Tubing, Inc., was enlisted to join the project and investigate new tubing materials for the conditions foreseen for HP-CT drilling. Quality Tubing developed QT-1200 (Table 3), a high-strength material for use at elevated pressures when the CT must be spooled in/out of the well.

Table 3. Properties of QT-1200 High-Strength CT

Yield Strength	120,000 psi
Tensile Strength	130,000 psi
Wall Thickness	0.134 in. (and above)
N.D.E.	Eddy-Current tested to ASTM E-309

String

Mfg/Grade	Mtr	Yield 0.2% FF	Tensile	% Elongation	Hardness	
					Material	Weld
Y/P120	E01128	130	133.5	19.5	27C	28C

Chemistry

C	Mn	P	S	Si	Cr	Cu	Ni	Mo	V	Nb
0.14	1.61	0.007	0.0008	0.34	0.61	0.23	0.09	0.20	0.066	0.05

Quality Tubing used their in-house CT fatigue test machine (Figure 57) to quantify the performance of different types of steels as they developed QT-1200 tubing. Figure 58 summarizes the results of fatigue tests on three CT materials (QT-800 is 80-ksi steel; QT-1000 is 100-ksi steel; QT-1200 is 120-ksi steel). These tests verified that QT-1200 has significantly more fatigue life than other conventional CT when spooled at high pressures. The number of cycles prior to failure was increased from below 25 to over 150 cycles at 12,000 psi. While QT-1200 did exhibit some brittle fracture problems when first developed, these have since been overcome. This product is now offered by Quality Tubing as a standard commercial item. (Unfortunately, QT-1200 was never adequately tested under this project. The only string produced during the project was too small and too short for a meaningful test.)

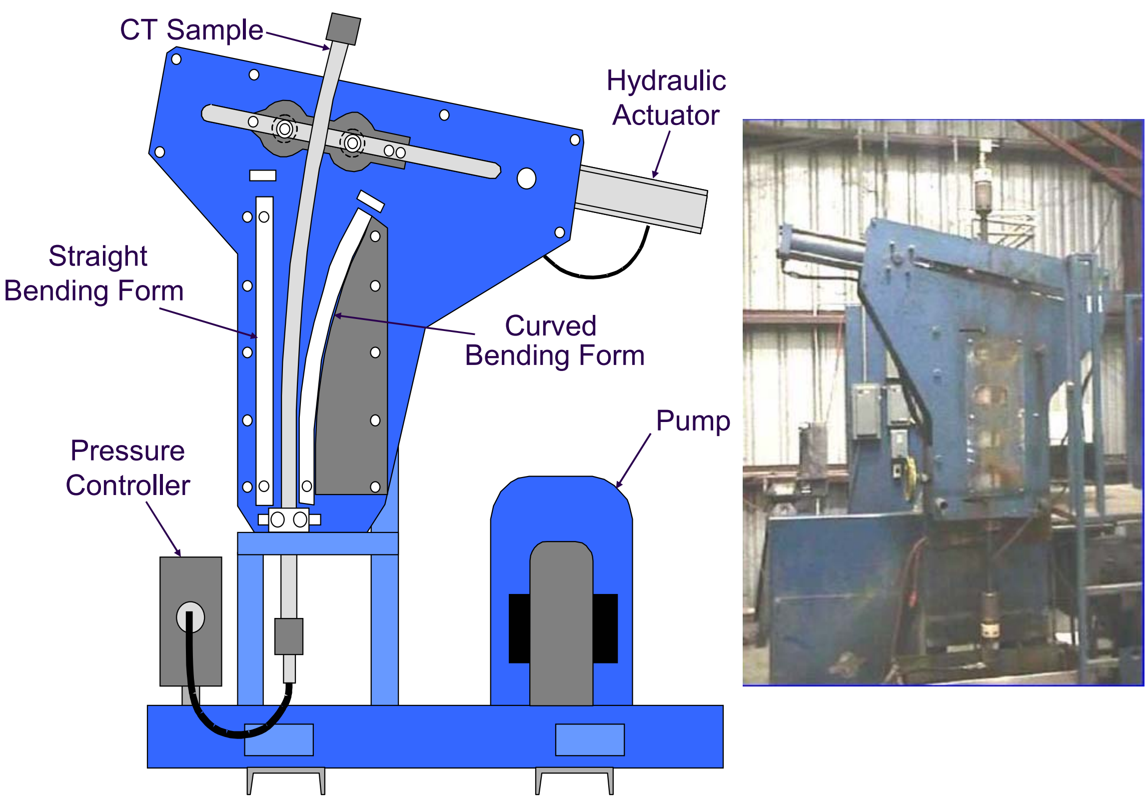


Figure 57. Standard CT Fatigue Testing Machine

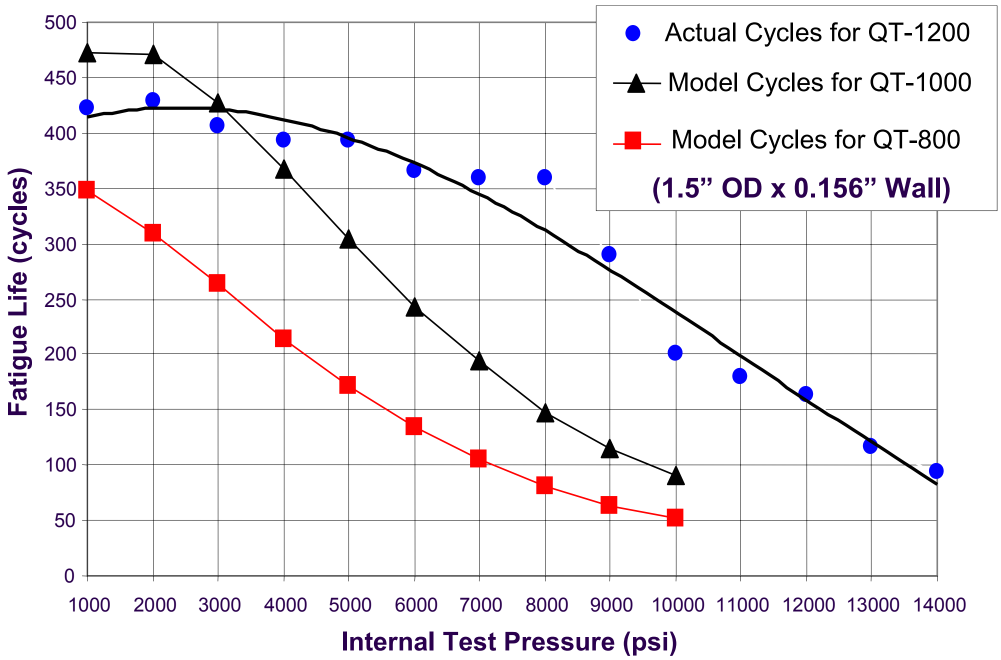


Figure 58. Fatigue Test Data for New High-Strength CT (Quality Tubing, Inc.)

In a parallel investigation to provide another option to high-strength steel CT, the project team monitored progress in the development of composite CT (Figure 59). Initial results reported with composite CT were very promising. However, after composite CT products were applied in the field in various environments, reported burst strength and fatigue life data were revised downward. This technology was not pursued further during the project.

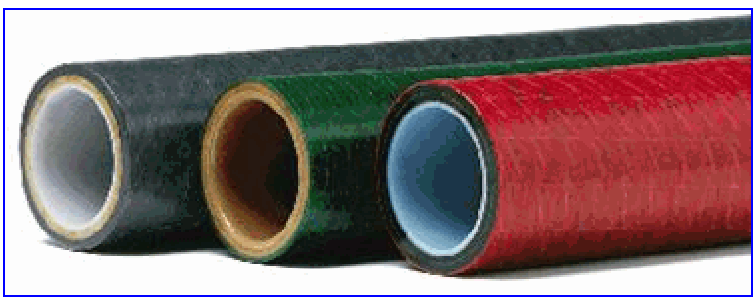


Figure 59. Composite CT (Fiberspar Spoolable Products)

During the field test using high-strength CT, it was observed that the tubing ballooned (Figure 60) after only a few cycles. This occurred much earlier than the software models had predicted. This experience suggests that current fatigue algorithms are not well calibrated for high internal pressures. The models had predicted 10–12 in/out cycles prior to fatigue failure; the tubing achieved approximately half that (5–6 cycles).

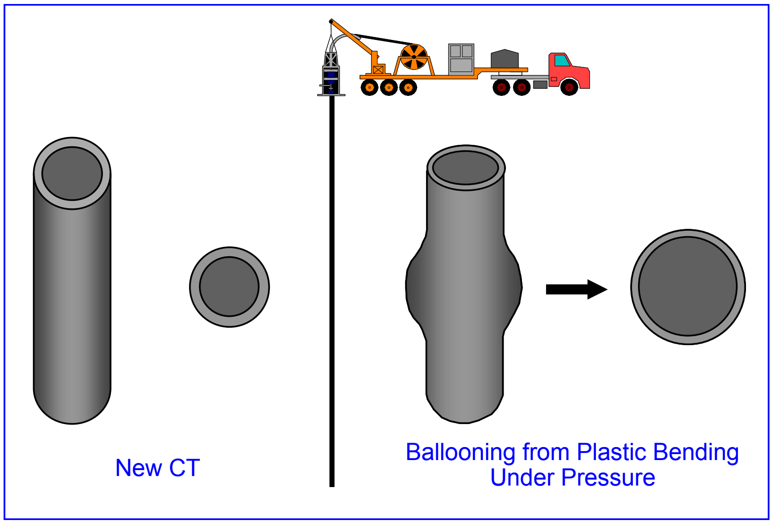


Figure 60. Ballooning of CT Caused by Bending with Internal Pressure

3.2.4 CT BHA Components

The bottom-hole assembly (BHA) for drilling with CT is comprised of a number of components that protect the assembly, facilitate operations in underbalanced conditions, and allow the CT to be disconnected in an emergency. Figure 61 shows the complete BHA designed by the project team for running the HP motor and bit on CT. In addition to typical BHA components, a screen sub was placed above the bit to collect any debris large enough to plug the bit nozzles. The HP nozzles are relatively small, with diameters of 0.080–0.125 inches. This is much smaller than conventional bit nozzles, making these HP nozzles more susceptible to plugging by what are otherwise normal contaminants in the mud (cuttings, rust flakes, etc).

When this HP-CT development was initially undertaken, none of the motor BHA components were rated for operation at pressures as high as 10,000 psi. MTI contracted with a supplier of these components to design and build special versions of required components for use with the HP motors being developed. However, the first company failed to deliver designs or components and the team was forced to seek an alternative solution. Several CT equipment suppliers were contacted for equipment rated to 10,000 psi. Only Weatherford responded positively, stating that their equipment, while rated at 5,000 psi, could safely work at 10,000 psi. Weatherford also agreed to participate in the project by providing, at no cost, the BHA components for testing. Their equipment was tested at the Drilling Research Center at 10,000 psi. No failures occurred and inspection after the test indicated no damage from high pressures. This same equipment was then used for the CT-based field tests.

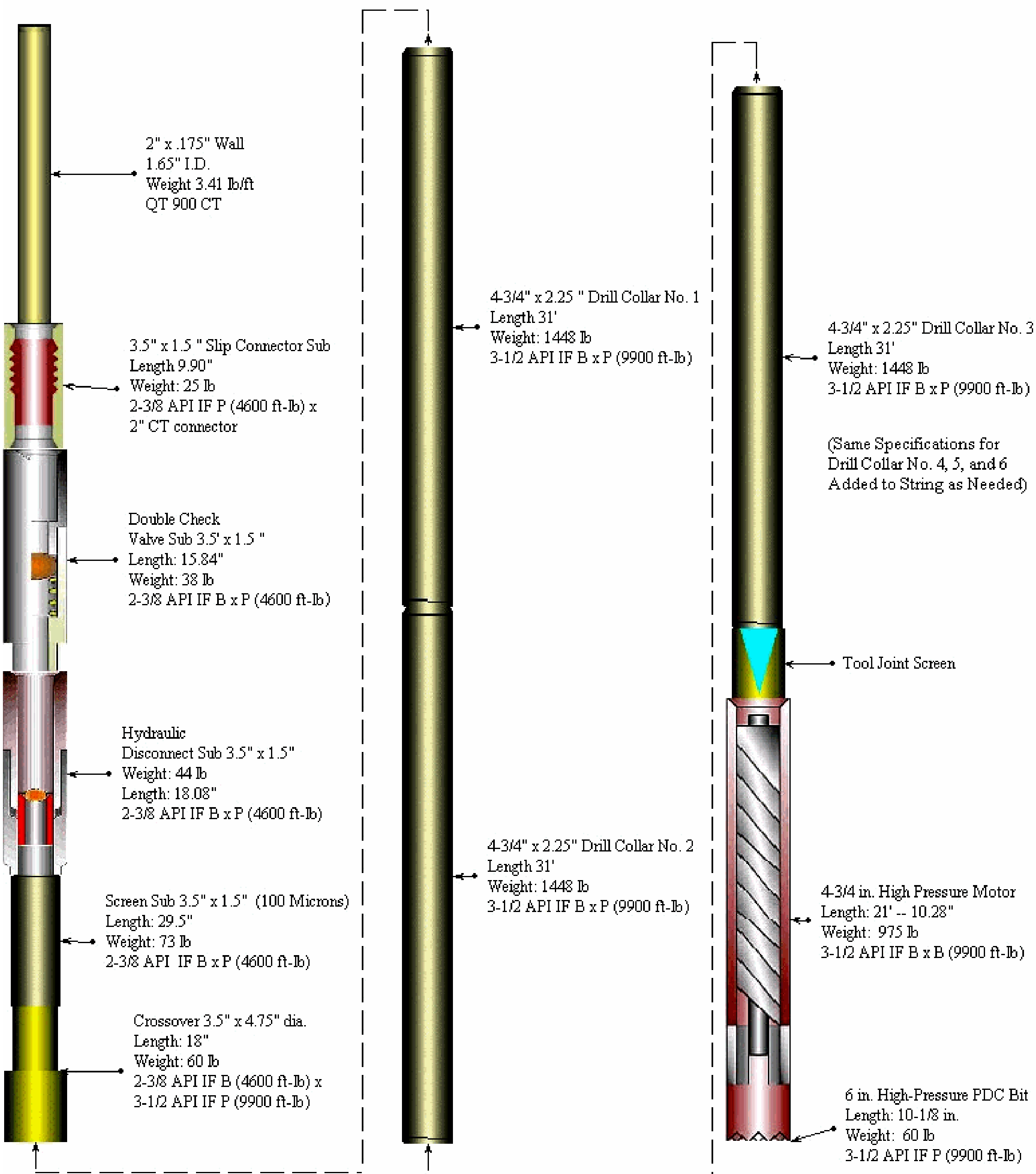


Figure 61. CT BHA for HP Drilling (6-in. Bit on 4¾-in. Motor)

3.2.5 Fluid Swivel for CT Rig

A special HP swivel is another critical component needed to deliver the drilling fluid from the pump to inside the CT on the reel as it rotates. At the beginning of this development, most CT swivels were only rated to 5,000 psi. During the project, Hydra-Rig (Conroe, Texas) introduced a commercial 15,000-psi swivel.

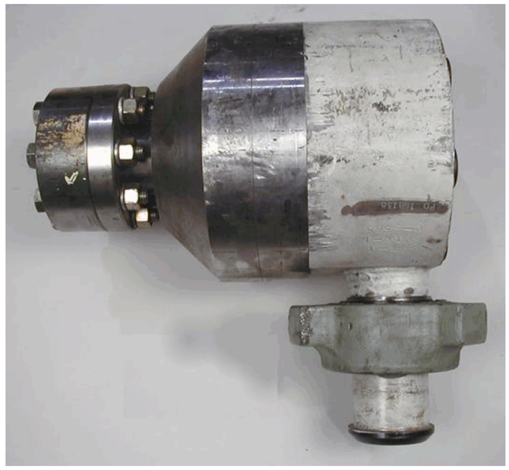


Figure 62. Hydra-Rig HP-CT Swivel

Hydra-Rig then provided a swivel for the project's use at reduced cost. This was tested at the Drilling Research Center (Figure 63) to measure torque, pressure drop, and leakage at different flows and pressures. This swivel performed well and did not leak or fail during the tests.

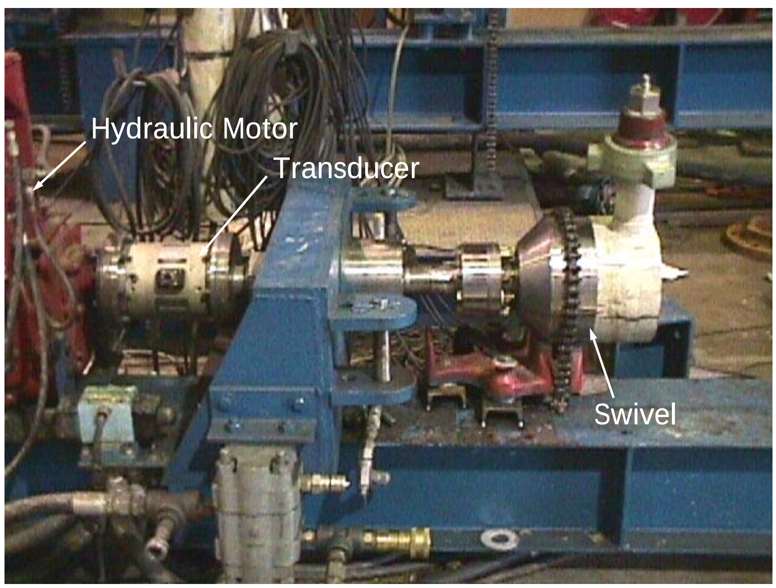


Figure 63. Testing Hydra-Rig HP CT Swivel

The tests showed that as pressure was increased from 0–15,000 psi, swivel start-up torque increased from 215–379 ft-lb and operating torque increased from 175–243 ft-lb. These levels are acceptable for typical CT rigs. In addition, pressure drop through the swivel as flow increased was minimal (Figure 64).

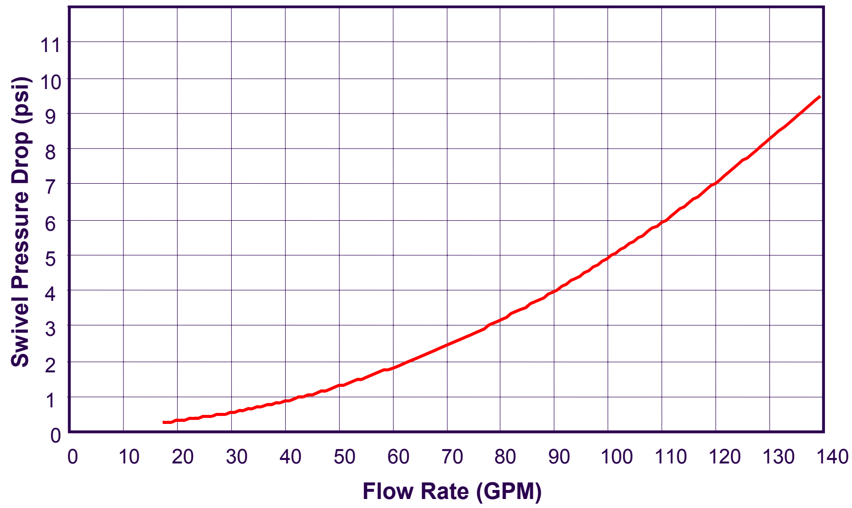


Figure 64. Pressure Drop through Hydra-Rig Swivel

3.3 GTI Catoosa Field Tests

The first series of field tests of HP jet kerf drilling systems was conducted at Gas Technology Institute (GTI) Catoosa test facility in Tulsa, Oklahoma. The project team was on site over a five-day period from February 11–15, 2002. Appendix B contains a log of the activities.

Tests at the GTI Catoosa facility used CT to convey the bottom hole assembly (BHA) and highlighted problems with that method. Later, tests at RMOTC (see next section) used conventional jointed pipe to convey the BHA downhole.

Testing was initiated on February 11, 2002. Each day of operations was begun with a safety meeting of personnel from GTI Catoosa, BJ Services, and MTI. On the first day, Ron Bray (Director at GTI Catoosa) presented safety regulations for use of the test facility. Contact persons for each company were identified and introduced to the crews. John Cohen of MTI summarized objectives of the test and described the inherent dangers of working with HP fluids. Doug Freeman of BJ Services summarized safety rules for BJ's equipment and identified areas personnel were to avoid during operations.

BJ Services supplied the CT equipment, consisting of a CT unit, a crane, two HP pumps, and a nitrogen truck. The location of the well was identified and a BJ supervisor spotted the equipment in appropriate locations for servicing the well. Two pumps were used so that adequate flow could be supplied for drilling with the 6-in. HP jetting bit. The nitrogen truck was used to blow down (purge) the equipment and CT after each day's tests since overnight temperatures fell below freezing and it was undesirable to freeze liquids in the equipment.

While the CT equipment was being positioned and set up by BJ, Catoosa personnel began preparing the well head. The well had been capped off with a metal plate. The cap was cut off with a torch and a flange for mating to the BJ BOP stack was welded onto the casing. MTI personnel unpacked the mud motors, bits and other support equipment for the test. The wellhead was prepared and the CT equipment was in place by the end of the first day. Figure 65 shows the CT being threaded into the gooseneck (CT guide arch). The tubing was run into the hole and blown down to confirm that the hole was open. The BHA was partially assembled on the ground in preparation for pick up.

Figure 65. Worker Threading CT into Gooseneck

On the second day, the HP drilling BHA was picked up. Unfortunately, this proved to be a very difficult operation, and the entire second day was consumed in attempting to make up the BHA. Improvements in procedures for making up the BHA were implemented as testing continued, but the fastest time the BHA could be rigged up during the test series was one-half day. This is clearly too much time for a commercial operation. The major problem encountered was the lack of either a derrick or a rotary table. Without these, two cranes were needed, one to support the injector and one to pick up the BHA components. As the BHA is assembled, all connections must be made up and pressure tested. Make up was accomplished with special wrenches purchased for this job (Figure 66).

Figure 66. Special Wrenches for Making Up CT BHA

Testing the BHA assembly for pressure integrity proved to be very challenging. The motor head assembly (the various valves, disconnects and other components that are placed above the motor) was first made up and then capped while pressure was applied. Leaks were found several times and the corresponding joints had to be tightened. After the motor head assembly was tested, the HP motor was attached and its connection checked. For this equipment design, the joint had to be checked dynamically (with flow) since the motor could not be blocked off. Flow through the bit nozzles created back-pressure to check the joint seal.

Two inline valves were used to block flow for pressure-checking the other BHA components for operation at 10,000 psi. After each pressure test, pressure was released from the CT system. Unfortunately, these inline valves could not be opened while under high pressure. Another joint (a WECO hammer union) had to be broken to bleed pressure off at each stage of the pressure test sequence. (This is not a desirable solution for field operations due to time it takes to break the connection and the safety issues of loosening a connection to relieve HP fluid. For any future application of this CT system, threaded connections that are well tested and known to be reliable at 10,000 psi need to be employed. When the crew has basic confidence in the integrity of the BHA connections (which was not the case in this field test), only one pressure test will be needed, and this can be performed in an open condition flowing against the bit nozzles.) Finally, at the end of the second day, the BHA was assembled, all joints pressure tested, and was deemed ready to go into the hole.

The HP-CT drilling assembly was run into the hole on the third day. The crew started drilling at a depth of 175 ft, and good penetration rates were achieved (about 300 ft/hr). Drilling was paused after about 15 minutes to dump old mud and build new polymer mud. Drilling was then resumed. After drilling another 45 minutes, a pressure spike was observed and the tool was pulled from the well. Drilling was not able to be continued after this point.

The team first assumed that the motor had failed and that a piece of rubber from the stator had been torn free and blocked the shaft. A smaller motor was made up to the BHA, but the flow problem persisted. The downhole screen was then inspected and it was discovered that the screen was full of frac sand (Figure 67). This was determined to be the source of the pressure spike. (The sand had been present in the CT string from a previous field operation.) The downhole screen was cleaned and the system checked for proper operation. A surface screen was added to the flow path so that this problem could not recur. (The team noted that the surface screen should have been in place from the start of the operation. It had been listed in the test plan, but had been inadvertently left out.) This sand blockage had occurred even though the entire system had been blown down on the first day after setting up the CT unit.

Figure 67. Frac Sand Removed from Downhole Screen Sub

The team decided to replace the BHA with the larger motor previously run and go back into the hole. After being reassembled, the drilling BHA was placed in the well. However, it could not be run to the bottom of the well. A blockage was encountered at a depth of 147 ft. The team speculated that the casing had collapsed and was preventing the assembly from passing. The BHA was pulled from the well and refitted with the smaller motor to confirm whether a smaller assembly could bypass the blockage. It could not, so drilling was terminated.

The well was inspected with a video camera. It was found the well was clear and that the casing had not collapsed. Next, a sinker bar was run after the camera. It was determined that the well was over 600 ft deep, not 175 ft as previously indicated by CT drilling operations. The short interval where the tool had appeared to be drilling (cuttings were coming over the screen) must have been washing a bridge or hole collapse that had occurred immediately below the casing. Apparently, no drilling had been accomplished.

Why the assembly could not be run to bottom (past the apparent obstruction) remained a mystery until the CT string was inspected after the conclusion of the field test sequence. The inspection showed that the CT had ballooned. (For more discussion on CT ballooning, see Section 3.2.3.) The enlarged section of the CT string could not pass through the injector and had stopped the advance of the BHA assembly into the well. This substantial ballooning had occurred after only a very few cycles over the gooseneck even though it had been predicted that 12 passes were possible before the CT would fail.

Conclusions

While the HP-CT drilling system was not effectively tested at Catoosa, the team learned several valuable lessons. Make-up of the CT BHA was very difficult due to the lack of a derrick or rotary table. If CT drilling is to be feasible for the future, a rotary table, tongs and derrick will be needed. Although this adds cost to the operation, without this equipment BHA make-up may require days to complete instead of hours.

CT will need to be improved to allow more operating life before the tubing fatigues or balloons beyond equipment dimensional limitations. Software for predicting CT service life needs to be improved for high internal pressure and low cycles.

Another factor currently making CT drilling less attractive is high cost. The bill for the five-day test at the Catoosa facility would have been over $225,000 had the CT provider not contributed a generous discount of 63%.

3.4 Cement Drilling Tests

During wellbore cementing operations, cement can set up prematurely in drill pipe and casing due to delays before or during pumping, improper cement chemistry, contamination, high temperatures, and other factors. This can cause expensive delays in drilling operations or loss of equipment. To recover the tubulars, the cement must be drilled out of the drill pipe or casing either in the well or in a pipe yard.

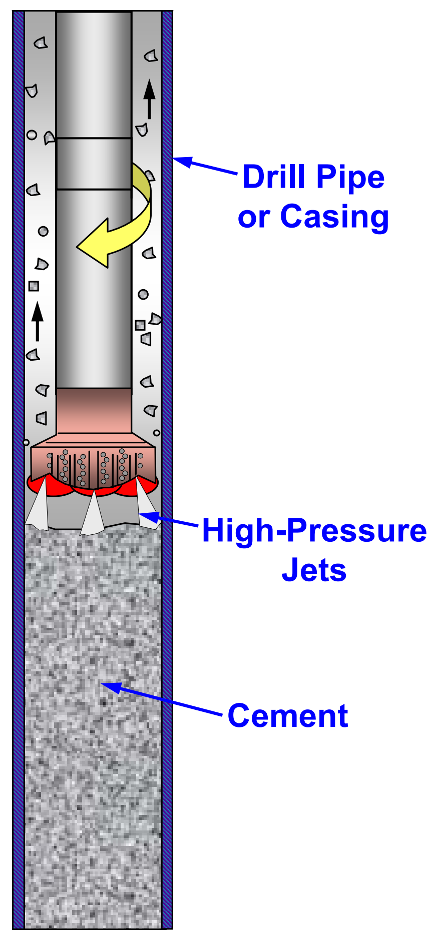


Figure 68. Drilling Cement with HP Jets

With conventional drilling technology, this is an expensive and time-consuming problem because hard cement can be drilled at only about 60 ft/hr with rotary drills or conventional motors. Cleaning a 10,000-ft string would therefore require about 167 hours of drilling time.

HP jetting was considered as a potential alternative for cleaning cement from tubulars. During Phase II, tests were conducted in MTI's laboratory and yard facilities using 10,000-psi jets to drill cement out of sections of tubing (Figure 68). These tests were very successful and showed that HP jets can remove hard type H cement at up to 1420 ft/hr compared to about 60 ft/hr for conventional motors. HP jetting could therefore reduce the time to drill cement out of tubulars by over 90%. Results of a test of HP jetting in 4½-inch tubing containing hard type-H cement and the clean tubing after the cement was drilled out are shown in Figure 69.

Figure 69. Cement Drilled from 4½-in. Tubing

HP jets drill cement at high rates because they erode channels and break the cement into large pieces (see Figure 69), whereas conventional bits grind the cement into much smaller cuttings. Because of the high clean-out rates possible, HP jetting of cement should have significant commercial application.

These operations are ideal for the specialized markets that CT serves well. Drilling out cement would not be an everyday service, but represents another tool for CT service companies that could generate significant revenue. The high cost of cement removal operations justifies the use of CT even when the additional cost is considered. In addition, assemblies that would be used for this are small and easily assembled. Unlike larger tools, these small BHA assembles can be assembled with chain tongs and pipe wrenches, eliminating the need for a rotary table and derrick as described above. Cement cleanout using HP jet kerf drilling represents an excellent market area for this technology.

The next logical step for this potential application would be to assemble the necessary equipment, complete several small trial runs at a test facility such as GTI's Catoosa test site, and then announce the capability to the industry. This could be accomplished on a small scale by limiting the initial market to one region, for example the Gulf Coast. This technology would be ideal for offshore applications due to the high costs of shutting down an offshore rig when cement is cleaned from a pipe. With jet kerf clean-out, the job could be completed in a few hours rather than days.

3.5 RMOTC Field Tests

While much was learned during the CT tests at the GTI Catoosa test site, one critical test was not able to be conducted, namely, the effect of HP jets on drilling rate. An additional field test location was sought. Due to the requirement for HP pumps and equipment, a location in the commercial sector could not be found. However, RMOTC was willing to work with MTI and the DOE Morgantown office to conduct this HP test. RMOTC, with assistance from MTI and DOE, purchased a new HP Gardner Denver Pump (see Figure 21) and upgraded the rig with new piping, swivel and rotary hose, all with ratings sufficient for working pressures up to 10,000 psi. The cost to upgrade the rig is shown in Table 2. The pump cost was under $500,000.

After rig modifications were incorporated, only one key area remained to be addressed that had caused problems in previous HP drilling projects—leaking tool joints. Leaks at tool joints often resulted in washouts. This is a very dangerous and potentially costly problem. O-rings have often been used to seal tool joints to prevent leakage of HP fluid. O-rings are placed in the thread relief of the pin. In these cases, the thread relief and diameter of the top of the box must be controlled to effect a seal; however, these tolerances are not typically found on strings in the field. New tool joints have been developed that use a double-shouldered connection, and are used where higher torques and/or pressures are expected. For the RMOTC tests, performance specifications for the tool joints were developed and a search conducted for a rental string that met those requirements. A tool joint manufacturer helped the team locate a company that owned a string near the site. This string was rented for the HP tests.

A test plan was then written and a CRADA signed to conduct the testing (see Appendix C). Several visits were made to RMOTC before testing was able to proceed. There were equipment problems in early attempts, some related to the rig and some to the jet kerf bit. In hindsight, this test could not have been performed as part of a commercial operation. The flexibility that RMOTC could provide in starting and stopping operations for several hours, days or weeks was essential for the team to complete the test successfully.

The first test sequence was conducted 22–26 March 2004. Unfortunately, no drilling was completed during this period. The new HP kelly hose developed a leak at one of the end connections. It was returned to the manufacturer for repair. After the hose was returned to the rig, it was tested and still found to leak. The manufacturer then fabricated a new hose, which was pressure-tested successfully on 20 April 2004. Drilling tests were then commenced by running into the hole and conditioning the mud with the HP BHA assembly. After fluid was pumped at high pressure for 1.5 hours, the pressure dropped off from over 6,000 psi to 4,800 psi. The assembly was tripped out of the hole and it was observed that one of the bit nozzles had washed out (Figure 70). That bit was returned to Houston along with the back-up bit. The nozzles were repaired by brazing them into the bit (previously threaded, Figure 71). Epoxy was applied to the backup bit to support the nozzles and prevent erosion (Figure 72).

Figure 70. Washed Nozzle on First Bit

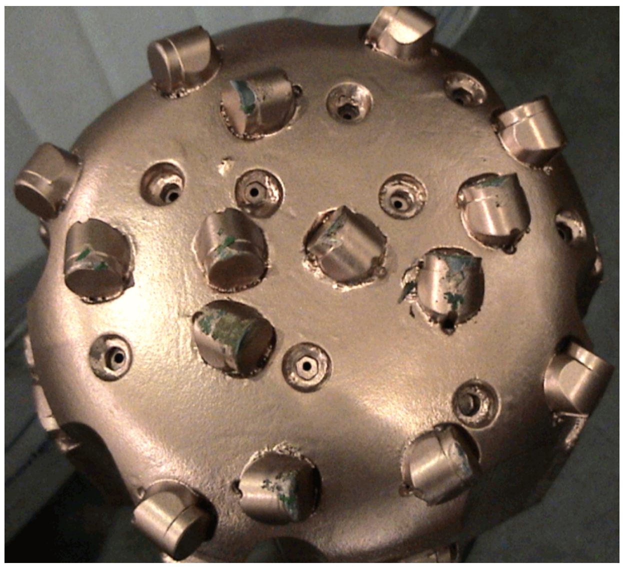


Figure 71. First Bit After Nozzle Brazing

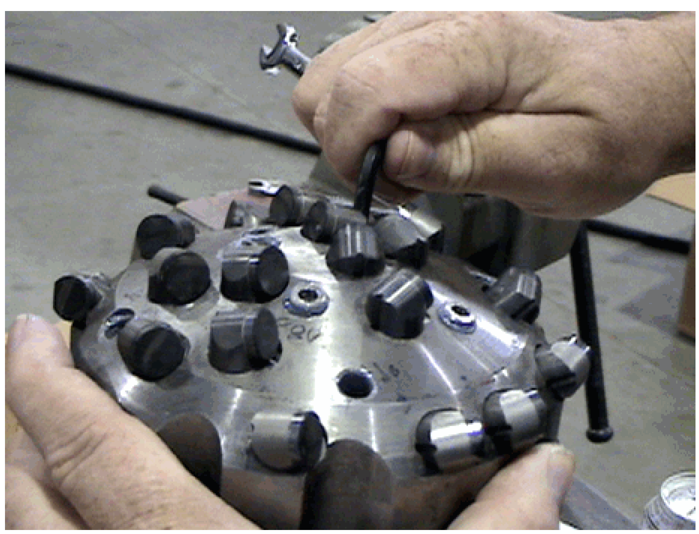


Figure 72. Epoxied Nozzles on Back-up Bit

Testing at RMOTC was resumed on 25–29 April 2004. After only a short time a pressure spike occurred that ruptured the relief valve on the pump. The team checked the surface equipment, found no problems, and determined that the problem was downhole. The BHA was then tripped out of the well and inspected. The mud motor had a severely damaged stator (a “chunked” rubber). The stator manufacturer believed (although is was not possible to confirm his diagnosis) that the stator had aged prior to the field tests, which resulted in its failure. This stator had been purchased two years previously. A back-up HP motor was not available and a new stator could not be obtained for several weeks. Consequently, the team decided to continue the test using rotary drilling.

Failure of the downhole motor had resulted in plugging of the nozzles in the bit. A review of the drilling data revealed that, during the previous short run, pressure had dropped. The bit was inspected and it was observed that nozzle erosion was still occurring. This had most likely caused the drop in pressure. The back-up HP bit was used for the next run.

Rotary drilling began again after the new BHA was run into the hole. This test also only lasted a short time at which time the new rig HP swivel packing burned up. The packing and wash pipe assembly were removed and inspected. Sand had been deposited into the packing, resulting in its burning up. It was decided that failure to regularly grease the packing was the prime contributor to this problem. Several days were consumed waiting for new parts for the swivel, after which the unit was repaired and drilling continued. Each of the first two short runs showed good penetration rates higher than those from offset wells. However, drilling times were too brief to allow any positive conclusions.

Drilling operations were resumed on April 27 using conventional rotary drilling and the back-up HP bit. System performance was excellent using conventional drilling. The first run lasted about 5 hours and drilled 186 ft of new hole. Drilling rates over each joint ranged from 42 ft/hr to as high as 166 ft/hr (corresponding to 1.2–3.8 times rates in offset wells). The assembly was then pulled from the hole so that more drill collars could be added for additional bit weight. During this first rotary drilling test, drilling rates in some formations were purposefully limited to ensure that the hole was being cleaned adequately. It was also found that effective bit weight was being reduced by the thrust from the HP jests. While drilling one formation, the Crow Mountain Sand, drilling rate could have been maintained as high as 500 ft/hr. Maximum drilling rate was not maintained for more than a few minutes so that the hole would not load up with cuttings.

A second run of rotary drilling with the back-up bit was begun on April 28. This run continued for approximately 3.5 hours, after which pressure was lost. The team determined the problem was downhole, and the bit was pulled out of the hole to reveal that a nozzle had washed out. Drilling rates during this run ranged from 50 ft/hr to 90 ft/hr, or 3.4 to 7.8 times faster than in offset wells.

The first (primary) bit had been sent back to the manufacturer to be rebuilt during the run of the backup bit and a new bit was ordered from the manufacturer at the same time. The rebuilt bit was run back into the hole but only lasted 30 minutes before the nozzle washed out again.

Up to this point in the test, the team had operated under the premise that the nozzle material was washing out or that the material (thread, braze, thread+epoxy) was leaking and thus washing out. This assumption was proved wrong during drilling with the new bit that had been manufactured most recently. The new bit was constructed rapidly due to time constraints. Substandard cutters were the only available option and were included in the bit. After this new bit was run, it was found that these substandard cutters, while not detrimental to the test, did result in damage to the bit evident at the end of the next drilling cycle.

After a pause of several days (waiting on completion of the new bit), drilling was continued on May 2 with the new bit. The bit drilled for 5.5 hours before washing out. Penetration rate ranged from 35 ft/hr to 92 ft/hr (2.5 to 7 times the rate in offset wells). Interestingly, the new bit did not wash out at the nozzle as did the first two bits, but rather, on the side. Figure 73 shows the bit after it was pulled from the well. To discover exactly why these bits were washing out, the team carefully considered bit design, including proximity of the nozzle to the trim cutter (Figure 74). This parameter proved to be the final clue for determining why the bits were washing out.

Figure 73. Side Washout on New Jet Kerf Bit

Figure 74. Drawing of Bit Showing Nozzle and Cutter Proximity

The team decided to field-repair the bit and continue drilling. The eroded hole in the side of the bit was welded over and drilling resumed. Several PDC compacts had fallen off the low-quality cutters (Figure 75). The repaired bit was run again on May 4 and drilled for another five hours before washing out again. Penetration rates ranged from 34 to 47.5 ft/hr even with missing PDC cutters (2.5 to 3.4 times faster than offset data).

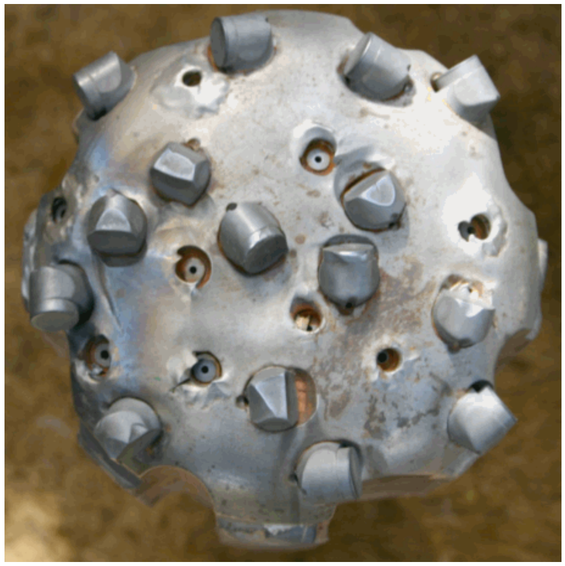


Figure 75. New Bit with Missing PDC Cutters

Figure 76 shows the new bit at the end of its second HP drilling test. The damage was considered to be the result of inferior cutters.

Figure 76. New Bit after Final Run

At the conclusion of this HP drilling sequence, a final run was conducted with a conventional bit to provide data for direct comparison. The conventional bit drilled an interval of about 150 ft in the Goose Egg formation at rates of 7 to 16 ft/hr. This can be directly compared to 35 ft/hr with the HP bit at the end of the previous run when most of the cutters had been broken.

Table 4 compares each bit run to offset data for each formation drilled. Jet kerf drilling rates are 1.3 to 6 times conventional rate in offset wells. These data clearly document the benefit of jet kerf drilling.

Table 4. Drilling Rate Comparison for Bit and Formation

	Formation	Jet Kerf Drilling Rate	Conventional Rate	Ratio HP to Conventional
Bit 2 – Run 1	Crow Mountain Sand	156	120	1.30
Bit 2 – Run 1	Crow Mountain Sand/ Alcova Limestone	49.8	13.5	3.69
Bit 2 – Run 1	Red Peaks Shale	55.1	14.8	3.72
Bit 2 – Run 2	Red Peaks Shale	77.7	12.9	6.02
Bit 1 – Run 2	Read Peaks Shale	61.9	13.3	4.65
Bit 3 – Run 1	Red Peaks Shale	66.0	13.8	4.78
Bit 3 – Run 2	Read Peaks Shale	39.8	14.1	2.82
Bit 3 – Run 2	Goose Egg	39.3	14.1	2.79
Conventional Bit	Goose Egg		10.4	

Drilling rate data from Table 4 are plotted in Figure 77. The graph shows that jet kerf drilling rates were consistently much faster than in offset wells.

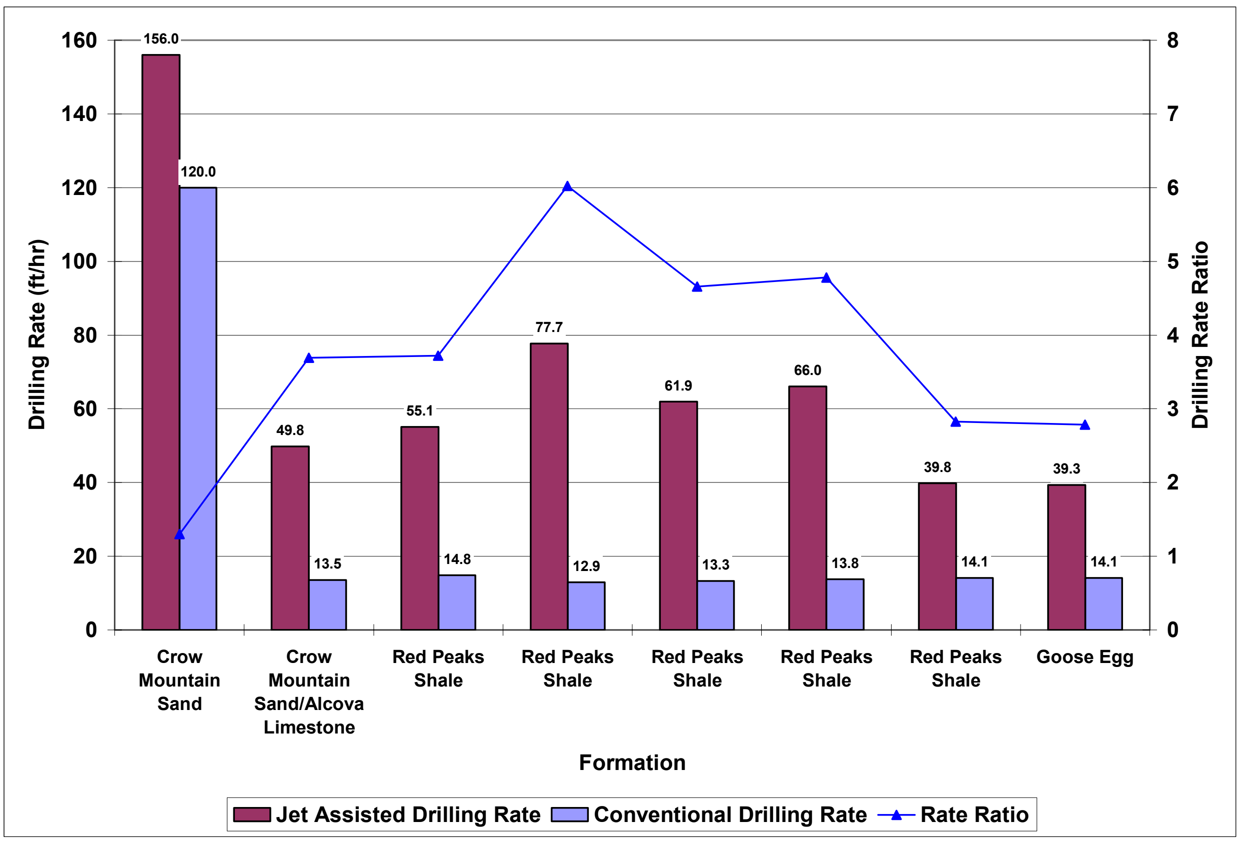


Figure 77. RMOTC Drilling Rate Comparison

As previously stated, the team originally believed that the jet kerf bits were eroding through the nozzles or the material around the nozzles. During the final run with the new HP bit, a hole formed in the side of the bit, presenting an obvious clue on the erosion process. That bit was returned to the manufacturer for analysis. The bit head was sectioned (Figure 78) to view the nozzles from the inside.

Figure 78. Sectioned HP Bit

Figure 79 shows the hole that was eroded in the bit from the inside. This hole corresponds to the uppermost nozzle opening in Figure 78. This damage was noted by the manufacturer as similar to what they had observed on rental bits. Their rental bits, whose profit is directly impacted by the number of times the bit can be rebuilt and rerun, were exhibiting erosion of the steel around the nozzle on the inside of the bit. If left unchecked, this erosion continues until the supporting material is washed away and the nozzle is lost. This was found to be caused by turbulence around the edges of the nozzle as fluid enters the nozzle. If, for example, the bit has nine nozzles, holes in the bit to allow for these nozzles are 0.34 in. diameter, and flow rate through the bit is 200 gpm; then the speed of the fluid through the nozzle holes is over 4,700 ft/min. Mud at this velocity will readily erode a steel head.

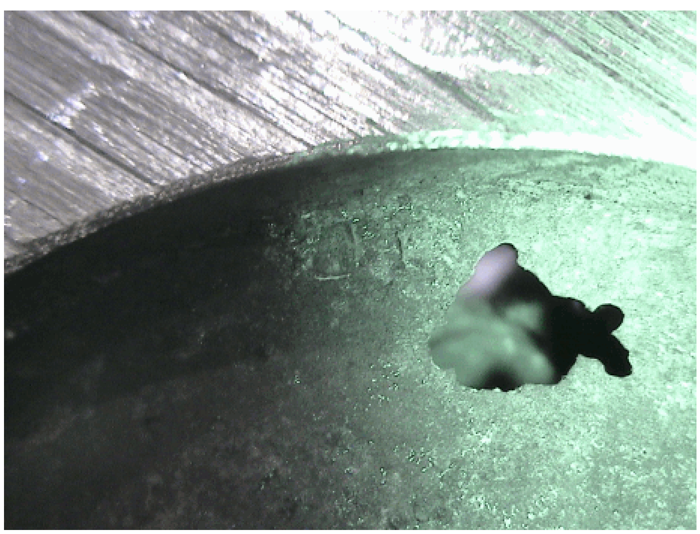


Figure 79. Section of Damaged Bit

The bit manufacturer had developed and patented (US Patent no. 6,142,248) a nozzle to minimize erosion from HP fluid (Figure 80). The body of the nozzle (typically made from erosion-resistant carbide) is extended into the cavity of the bit body. This moves the point of high-velocity fluid entering the nozzle and the corresponding turbulence away from the steel head, thereby minimizing erosion of the steel bit body.

The next drilling test in the project test sequence would be to test a HP bit fitted with this type of anti-erosion nozzle. These tests are yet to be conducted at RMOTC because no commercial partner has been found to provide the cost sharing necessary to return to RMOTC and conduct additional HP drilling tests.

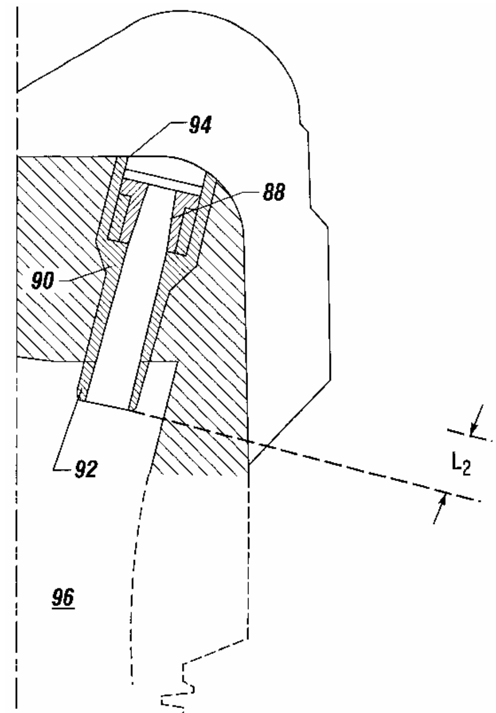


Figure 80. Anti-Erosion Nozzle

4. Economic Model

4.1 Assumptions

The ultimate goal of the project is to develop a commercial jet kerf drilling system that reduces overall costs to construct an oil or gas well. Laboratory and field testing provided valuable data regarding technical potential for the system, but did not answer the second fundamental question—can HP jet kerf drilling be accomplished economically? A model was constructed to analyze economic potential of the system.

The following assumptions were part of the economic model:

- The mechanical process of drilling rock is complex, difficult to model, and entails considerable uncertainty in assigning representative values to physical parameters; consequently, the economic model was kept relatively simple.
- All aspects of the drilling process are lumped together into the rig time and drilling time.
- Jet drilling is less practical for larger holes due to the expense of pumping HP fluid at high flow rates. Accordingly, HP jet kerf drilling is assumed to be conducted only in hole sizes 6½-in. and smaller.
- Jet kerf drilling is applied only to the final 1/3 of the drilling days (i.e., in the deepest, smallest-OD sections) based on a typical well design.
- No additional maintenance costs are added.
- The internal rate of return is 12%.
- Bit life problems due to erosion that were observed during field testing are solved with anti-erosion nozzles as described in Section 3.5.
- The drilling rig is always available to be contracted as needed (no scheduling conflicts, no downtime for maintenance, etc.).

4.2 Base Case

A base-case drilling program was derived to place a fixed value on a typical well for the economic model. The base-case well requires 28 days to complete inclusive of time to mobilize and demobilize the rig; 24 days of the total are drilling days. The value of the base case well (Table 5) is $280,000 based on 28 days using a rig that costs $10,000/day. In the remainder of the development of the economic model, it is then assumed that $280,000 is the basic value of this well to the operator and that he is willing to pay at least this amount to a contractor to have the well constructed. The well delivered to the operator will not change in the analysis; only the method to drill the well. The impact of these changes on the well cost will be compared to the well's value.

Table 5. Base Case for Economic Model

	Base Case
Daily rig cost	$10,000
Total days per well	28
Drilling days per well	24
Small hole drilling days (≤6½ in.)	8
Revenue per well	$280,000
Wells per year	13.0

The basic economic impact of HP jet kerf drilling on the operation is to increase drilling rate (in the smaller hole sections) and thereby reduce the number of days to complete the well. Figure 81 shows that the total cost (i.e., revenue to the contractor) would decrease as the penetration rate multiplier increases if the rig were to continue charging the same daily rate. As stated in Section 4.1, jet drilling is only applied to the final third of the drilling days. For this case, that corresponds to eight of the 24 drilling days. Thus, if the rate over this interval is increased two-fold (2X), the number of drilling days drops from eight to four days and the rig generates less income per well. At a jet drilling rate 4X conventional, drilling days for the smaller sections of the well decrease from eight to two so the well is completed in 22 days instead of 28.

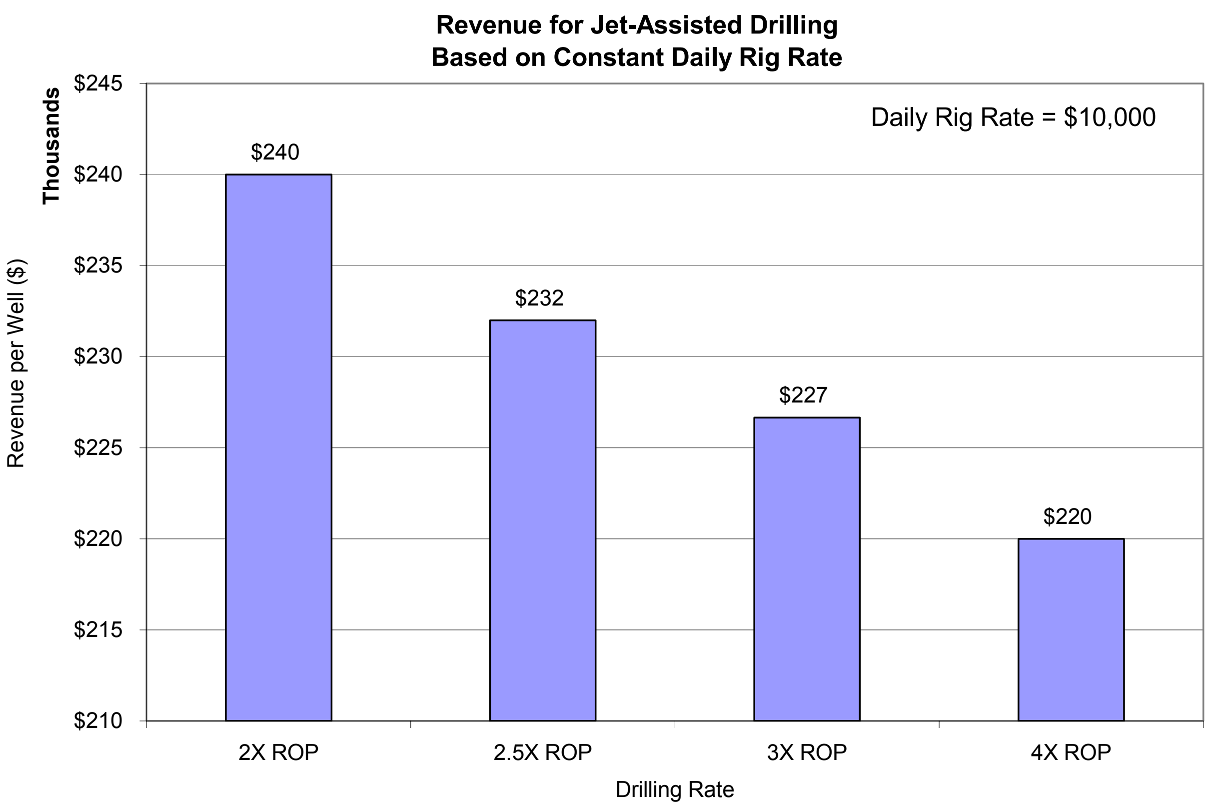


Figure 81. Revenue Per Well Using HP Jet Kerf Drilling

As stated, these results are based on the simplifying assumption that the rig contractor would charge the same daily rate. The next critical factor to consider is that the contractor would need to purchase HP equipment to upgrade the rig. These costs must be recovered by increasing the daily rate for HP jet kerf drilling. The cost increment was calculated that would recover the initial investment at an internal rate of return of 12%. The initial investment was estimated based on that reported by RMOTC to upgrade for the tests (as described in Table 2): $100k to modify the rig and $500k to purchase a HP pump, for a total of $600k. An increase to the daily charge rate of $1,754 would recover the upgrade costs in one year; an increase of $929 would recover the costs in two years.

Figure 82 shows the value (cost to drill) the well if the daily rate increase listed above was added to the original rate (for a new rate of $11,754/day for a one-year payback and $10,929 for a two-year payback) and this new rate charged for each day the rig was on the well.

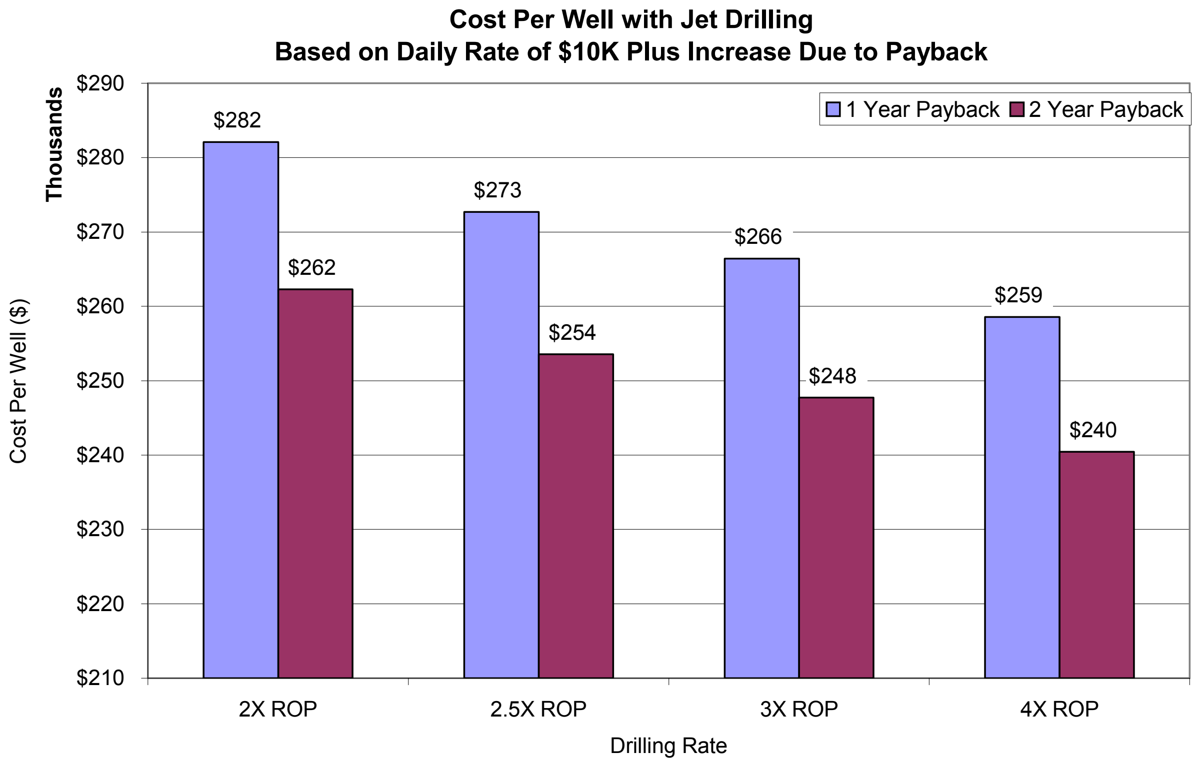


Figure 82. Value of Well Including Capital Expense Recovery

From the operator's perspective, he is obviously willing to pay as much as $280k for the well, that is, the cost of the conventional base case (28 days at $10,000/day). If the contractor charges a flat fee of $280k per well, then he will receive additional revenue per well as shown in Figure 83. The graph shows that a one-year payback cannot be achieved if the ROP is only 2X the conventional. For faster drilling rates or a two-year payback, significant additional revenues can be earned. It is also important to note that, after the second year when capital payback is complete, additional revenues will accrue directly as profit.

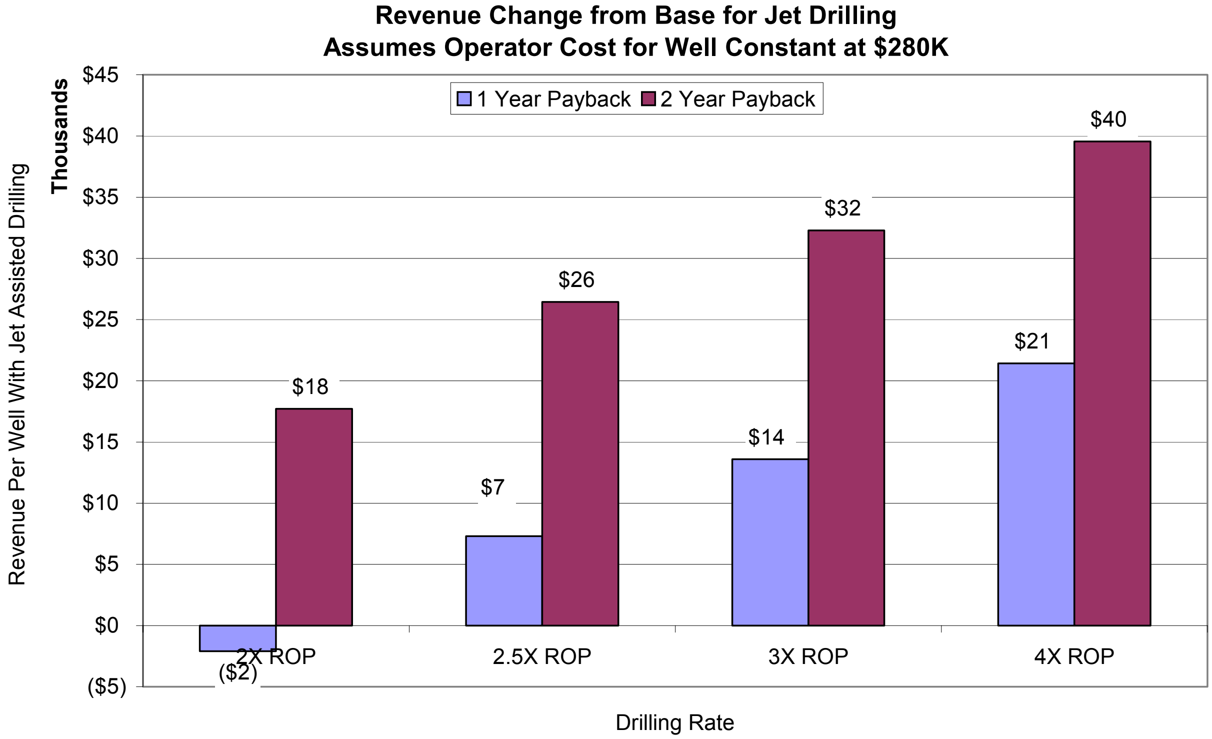


Figure 83. Additional Revenue Per Well Based on Standard Charge of $280k

The operator also enjoys significant benefits with this business model. While his well costs remain constant (at $280k), each well will be completed and put on production sooner. There will also be an increase in the number of wells that are drilled each year. For example, at an ROP of 2X, each well will be completed four days sooner, resulting in two more wells being drilled each year. The contractor could in many cases afford to charge the operator less than $280k per well and thereby become even more competitive in that area. HP jet kerf drilling promises economic benefits for both operator and contractor.

4.3 Increased Initial Equipment Cost

Sensitivity of the economic model to equipment cost was investigated. Figure 84 shows the increase in daily rig rate required to recover the initial investment if it were increased to $800k and $1,000k. Table 6 and Table 7 summarize cost increases for each category for this example.

Table 6. Initial Investment of $800k for HP Equipment

Cost to Upgrade Rig	$200,000
Cost of HP pump	$600,000
Total	$800,000

Table 7. Initial Investment of $1000k for HP Equipment

Cost to Upgrade Rig	$200,000
Cost of HP pump	$800,000
Total	$1,000,000

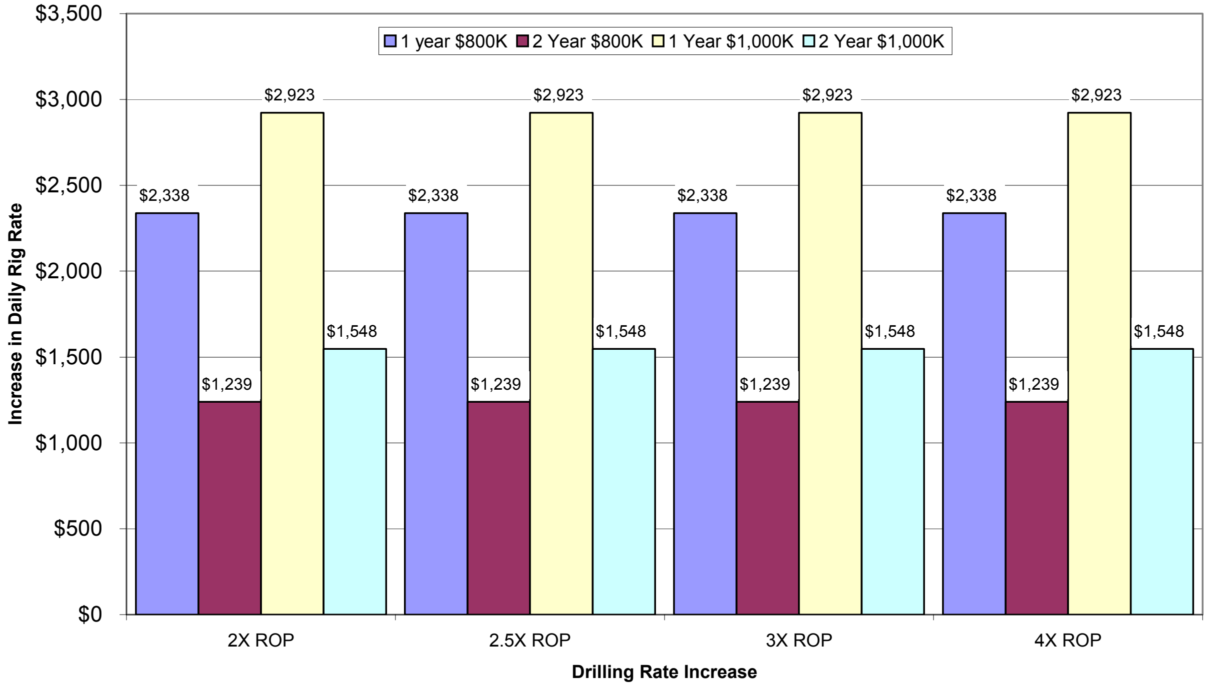


Figure 84. Increase in Daily Rig Rate for Higher Initial Investments

If the above rate increments were added to the original day rate, additional per-well revenue would be as shown in Figure 85. For equipment costs of $800k, payback is achieved in one year for a 3X or faster drilling rate. The data show that payback is not possible in one year if the initial investment in rig and pump costs is $1,000k. Even if a 4X rate could be maintained, it would take two years to recover the initial investment.

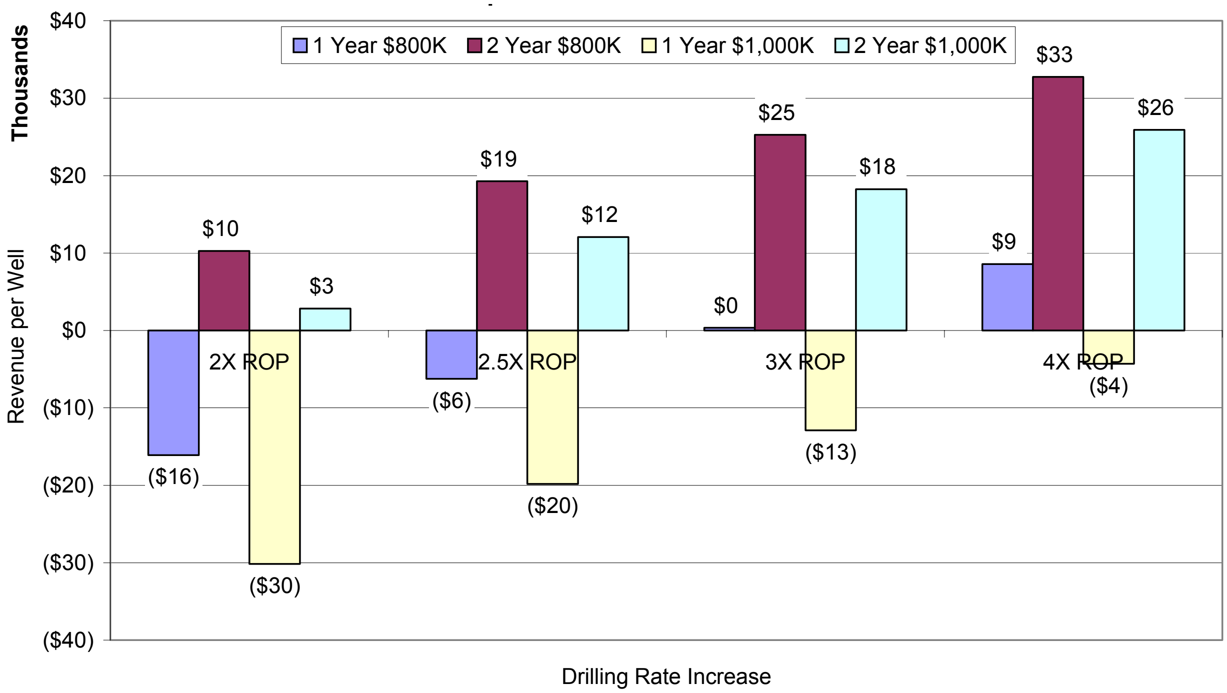


Figure 85. Revenue Per Well with Increased Rates and Increased Initial Cost

4.4 Increase Pump Utilization

The economic model shows relatively high sensitivity to initial equipment cost. One reason for this is the low utilization of the HP pump. The HP equipment is relatively expensive and is only employed for a few days near the end of the drilling operation. If the pump could be shared by two rigs, the economics improve further. Figure 86 shows the per-well and yearly additional revenue when effective pump cost is reduced to $250k per year (the pump is shared equally by two rigs). For all these cases the rig has additional revenue and pays for its share of the pump if the initial base case well value is used ($280k).

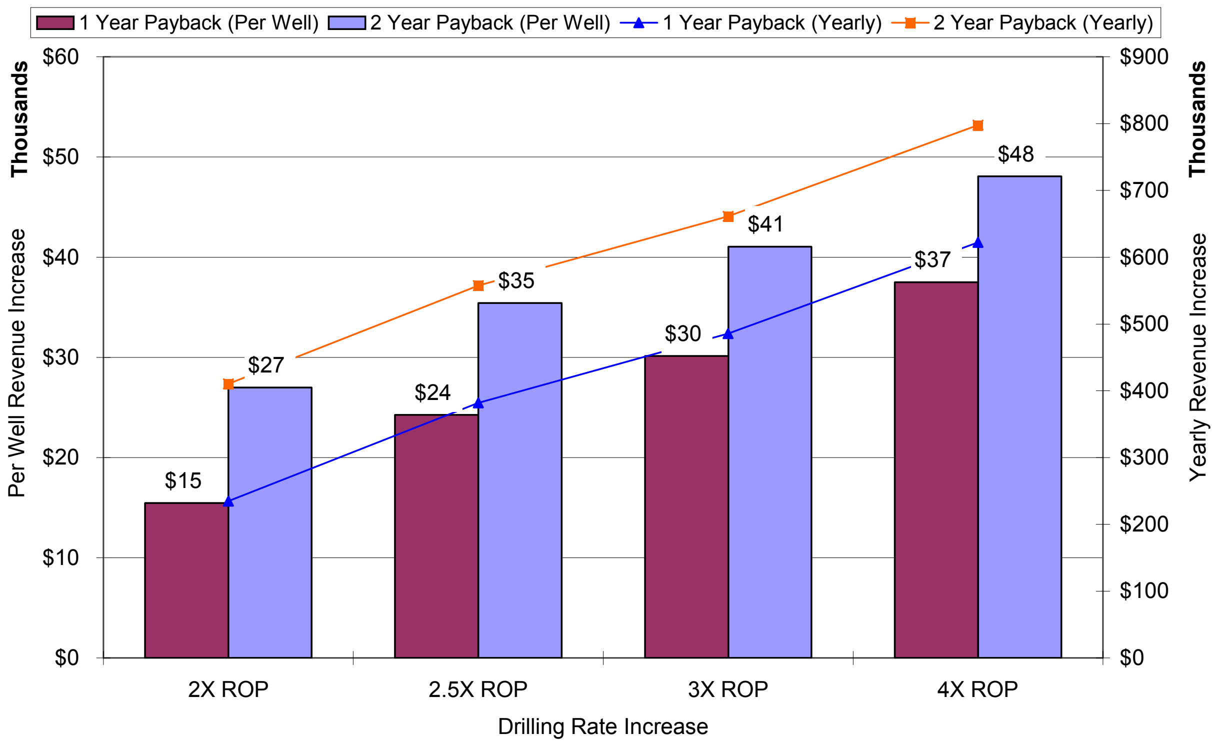


Figure 86. Per Well and Yearly Payout with Pump Shared Between Two Rigs

4.5 Increase in Daily Rig Rates

As the contractor's daily rig rate is increased, a one-year payback period becomes very feasible. Figure 87 shows per-well revenue for rig rates of $15k/day and $20k/day. (Rig contractors have recently reported that rates in the current tight rig market have increased in many cases to $15k/day.) At $20k/day, the upgrade to the rig not only can be paid out in one year, but the rig has increased revenue of $13k per well for only doubling the penetration rate (2X). As test data have shown, this is very conservative estimate. It is likely that in most wells HP jet kerf drilling could achieve 2.5 to 3 times the rate consistently.

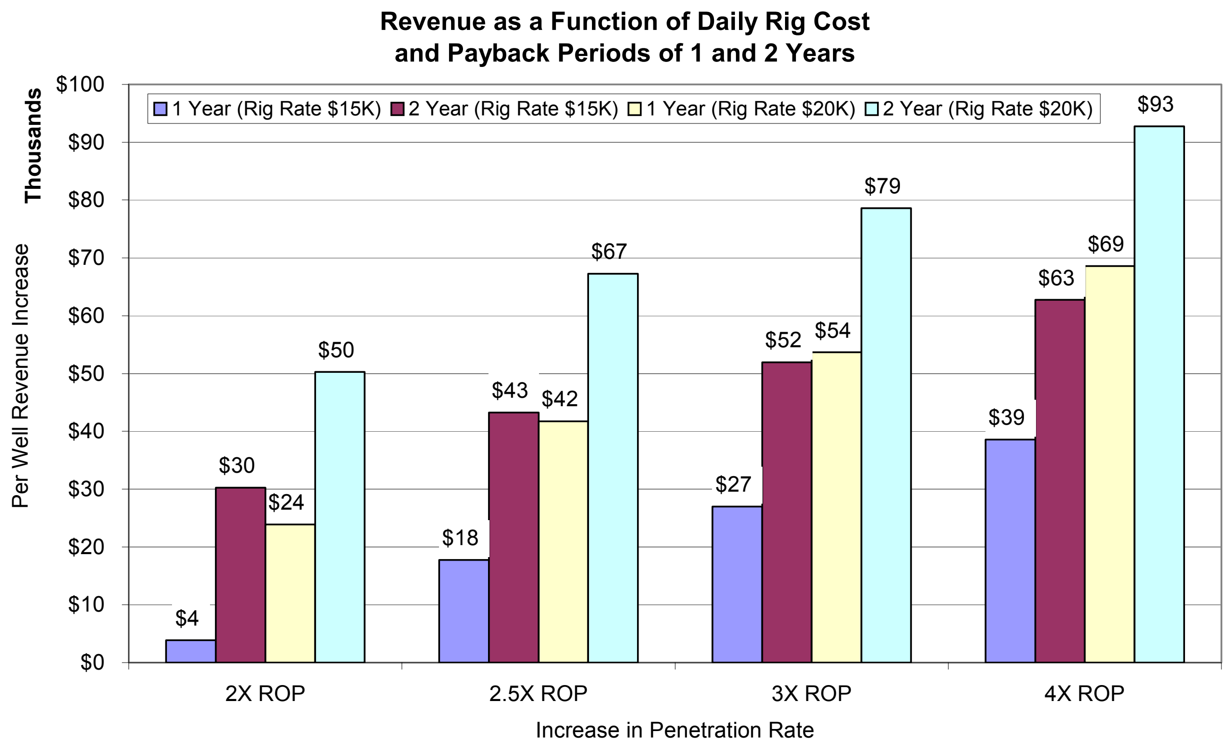


Figure 87. Revenue Per Well for Rig Daily Rates of $15k and $20k

5. Implementation of HP Jet Kerf Drilling

Implementation of HP jet kerf drilling tools and techniques within the USA gas and oil industry will not be a simple process. Project developments and field testing showed that technology or economics are no longer the predominant barrier; rather, it is the business environment. Jet kerf drilling most likely cannot be implemented by any single business or company. Successfully implementation will require a cooperating consortium of at least three companies—the drilling contractor, the operator, and the bit manufacturer.

First, the **drilling rig contractor** must have a favorable attitude toward HP jet kerf drilling and recognize its overall benefits for improving his efficiency and profits, even though it will reduce the number of drilling days on a particular well. Under the current economic climate in the drilling industry, this technology makes good sense because the current shortage of rigs means that finding jobs is not the problem, but rather completing them efficiently with a good profit. However, drilling contractors will immediately recognize that there is no benefit to completing a drilling job faster if it means total revenue drops because day rates are fixed. Thus, new pricing paradigms may need to be developed for areas where fixed daily rates are in widespread use.

Operators also play a critical role for implementation of this technology. They direct the market and often insist on one or more technologies that a rig must incorporate before they will initiate a contract with that rig contractor. These operator-imposed requirements often include environmental and safety issues. In a tight rig market, operators may be inclined to demand less because rig contractors can go elsewhere to find jobs. However, the operator still plays a key role and must agree to special technology such as jet kerf drilling. Operators need to be educated on the benefits to them of jet kerf drilling, specifically, faster completion and production of each well and (in long-term contracts) more wells drilled per year.

Bit manufacturers must also be an active participant in developing this technology. Unfortunately, without a change in industry attitudes, manufacturers have an existing disincentive to pursue HP jet bits. Similar to the impact of PDC bits on bit sales, jet kerf drilling has the potential to reduce the number of bits sold to drill a given section of formation. This means less revenue for the bit company unless they are allowed to charge more for each bit. That option has proven to be difficult to implement in the past, so the incentive of bit companies to develop jet kerf bits is low. They will, of course, respond with enthusiasm if operators insist on this technology.

It will be challenging to build a consortium of companies that will adopt HP jet kerf drilling and make it into a commercial application. This project has clearly demonstrated, however, that technology and economics are no longer the hurdles they were previously.

6. Conclusions

A number of important accomplishments were achieved during this project. Highlights include development and testing of high-pressure (HP) motors and bits, a field test using a coiled-tubing (CT) based drilling system, and a field test of jet kerf drilling using conventional rotary equipment. Following are conclusions from work completed under this project:

1. HP jet kerf drilling can significantly increase penetration rates. During field tests, the system drilled at 1.3 to 6 times faster than conventional rates recorded in offset wells.

2. Jet kerf drilling was successful in a variety of formations.

3. Jet kerf drilling based can be accomplished using off-the-shelf equipment to upgrade rotary drilling rigs for HP operation.

4. Jet kerf drill bits will require anti-erosion nozzles to ensure that bit life extends beyond a few hours.

5. Jet kerf drilling was effective in field tests to a depth of 5100 ft with no indication of slowing drilling rate with depth.

6. Safety issues for handling HP fluids were successfully addressed on all field tests conducted under this project.

7. Increased drilling rate is a key factor in reducing overall well costs.

8. The project team demonstrated that HP jet kerf drilling can be accomplished economically.

9. HP jet kerf drilling based on CT deployment will require special CT rigs that include the capability to make up and test the BHA efficiently. Otherwise, CT deployment will most likely not be economic.

10. CT strings now commercially available have significantly improved performance with respect to ballooning (OD swelling) and fatigue when operated under HP. However, better CT materials and improved operating methods will be needed to improve the service life of CT for application in jet kerf drilling.

11. The high cost of CT rigs will increase the minimum penetration rates needed to make jet kerf drilling an economic option unless savings from reduced trip time are sufficient to offset the difference between CT and conventional operations.

12. HP motors (10,000 psi) were successfully manufactured for use in jet kerf drilling.

13. Laboratory tests showed that very high drilling rates are achievable in many types of rock formations.

14. Practical issues, especially hole cleaning, will require that the maximum speed of jet kerf drilling be limited in the field.

15. Small HP motors fitted with bits having side-cutting jets could be used to clean scale out of tubing, or to improve production by cutting a spiral groove into the rock, thereby exposing more surface area to the bore hole.

16. HP jet kerf drilling can be used to quickly clean out drill pipe or tubing in which cement has set.

17. At least one motor manufacturer's CT motor head assembly was found to operate successfully at 10,000 psi.

18. In field tests, debris plugged the small jet kerf bit nozzles and halted progress. Drill-pipe screens were then successfully implemented to prevent debris from entering the bit.

19. Erosion of the internal bit body was observed to occur relatively rapidly near the body of the HP nozzles. A possible solution to reduce erosion was found and should be implemented in future applications of jet kerf drilling.

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8. Acronyms and Abbreviations

BHA = bottom-hole assembly

CRADA = cooperative research and development agreement

CT = coiled tubing

GRI = Gas Research Institute

HP = high pressure

hp (lower case) = horsepower

LP = low pressure

MTI = Maurer Technology Inc. (prime contractor)

RMOTC = Rocky Mountain Oilfield Testing Center (DOE-funded test facility)

ROP = rate of penetration (drilling rate)

WOB = weight on bit

Appendix A

Engineered Test Plan
DOE High-Pressure Coiled-Tubing Jet Kerf Drilling

Topical Report
TR01-24

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November 2001

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Objective

The first test of the DOE High-Pressure Coiled-Tubing Jet Kerf Drilling (HP-CT) System will be in a shallow well approximately 2000–3000 ft TVD, conducted at the Catoosa test site in Tulsa, Oklahoma. This test will have one primary and two secondary objectives. It is important that the primary objective be completely satisfied and judged by the DOE COR, John Rodgers, before any work is done on the secondary objectives. The three objectives are stated below in decreasing order of importance.

1. To test the HP-CT jet kerf drilling system including bottom hole assembly (BHA) components (motor, screen sub, bit, and tubing connectors) and the surface components (coiled tubing, high-pressure pumps, and high-pressure swivel). Test data will be taken to measure effectiveness of the HP-CT system and determine which components need modifying to make the system commercially viable and ready for the deep field tests. The shallow tests will have a minimum target depth of 2000 ft so jet effectiveness as a function of depth can be observed.

   Three sizes of motors and four bit sizes will be tested. The small motor, a 1¹¹⁄₁₆-in. tool, has been designed for through tubing operations such as well deepening, scale cleanout, and cement removal, and uses a 2 in. diameter bit. The middle size is a 3⅛-in. diameter motor and is run with 3¾-in. and 4¾-in. bits. The large tool is 4¾-in. diameter and will be used with 6 in. bits.

2. If all work is completed on the HP-CT jet kerf drilling system, further testing will be conducted on the high-pressure side cutting production enhancement system. This system consists of a 1¹¹⁄₁₆-in. diameter motor that has been fitted with a gearbox and side-jetting bit. The gearbox slows the rotation of the tool so that the side jet can be used to cut a helical slot into formations in the borehole wall. This system can also be used to clean out pipe scale, perforations, and slotted liners. The tool has been laboratory tested, but field testing is needed to determine which components need hardening for commercialization.

3. If funds remain and the first two objectives are met, tests will be run on coiled tubing made from Quality Tubing's QT 1200 material. A 1500 ft string of 1¼-in. CT will be used to conduct fatigue tests while the tubing is cycled under pressure.

Laboratory Tests

MTI will thoroughly test the mud motors and other components of the BHA for form, fit, and function before going to the field. All threads will be checked to ensure that components will screw together no matter what combination of tools is used. New threads will be broken in at the laboratory to prevent galling in the field. Other BHA components will also be inspected and assembled in the laboratory before going into the field.

The mud motors will be tested both on the dynamometer and drilling test stands. Samples of rock that closely match the Catoosa formations will be used during the drilling tests. These data will be compared to actual rates so that predictive rates can be made during the deep field tests.

Motors will also be run on the dynamometer stand after the field tests to document any change in performance resulting from the test. The motors will then be disassembled and critical components such as bearings and shafts inspected for wear and damage. If a change in performance is recorded during the dynamometer tests, the cause of the change will be identified and subjected to a post engineering analysis to determine what improvements or changes are needed to keep the motors at peak performance. This information will be documented and included in project reports. The goal is to provide a BHA system that will provide 100 hours MTBF. The motors and other BHA components will be modified if necessary after the shallow field tests to repair any problems observed.

During the dynamometer testing, each motor will be tested at three flow rates. These rates will be selected to cover the operating range given by the power section manufacturer. These rates, where appropriate, will match power data supplied by the manufacturer for ease of comparison. (Power section manufacturers do not include losses due to bearing packs so there is always some difference between published data and data as recorded on the DRC test stand.) The flow rates (anticipated) for testing are given in the table below.

Motor	Flow no. 1 (gpm)	Flow no. 2 (gpm)	Flow no. 3 (gpm)
1 11/16	10	20	30
3 1/8	50	65	80
4 3/4	100	175	250

The drilling tests will be conducted in three different rock types. These three rocks range in hardness from soft to medium hard, comparable to many of the Catoosa formations. The test rocks will be Texas Cream Limestone, Leuders Limestone, and Glacier Bluff Dolomite. The compressive strength of these rocks are 5000 psi, 10,000 psi, and 16,000 psi, respectively. Figure 1 below shows rock strength, as estimated from sonic log data, at Catoosa.

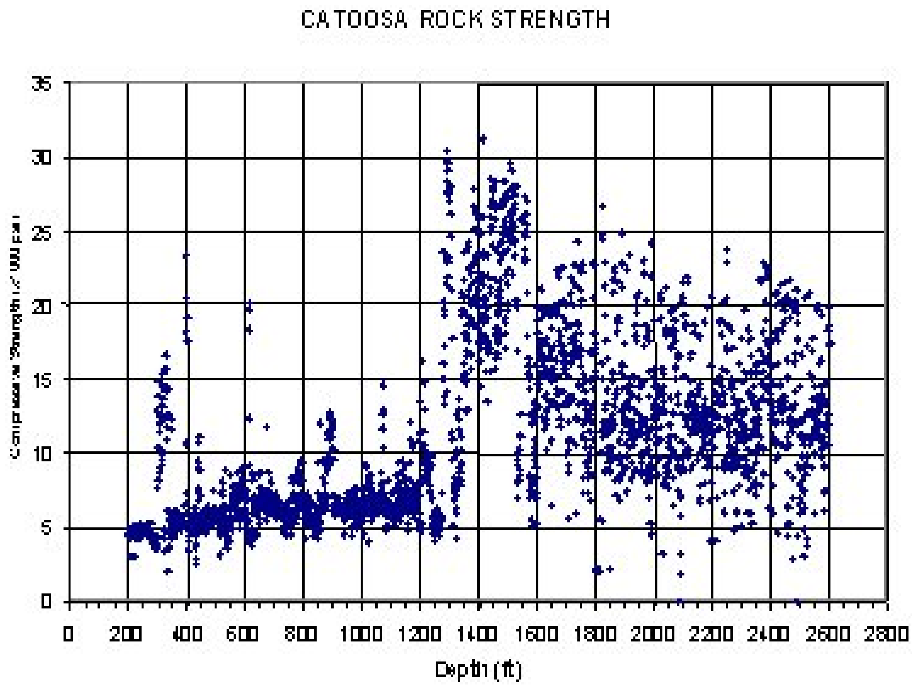


Figure 1. Rock Strength at Catoosa

The test samples selected are very representative except for the very hard Mississippi Limestone rock known as "The Wall" at a depth of approximately 1300 ft. Laboratory tests in rocks this hard could damage the bit, so drilling of this hard rock will only be done during the field test.

Mobilization

MTI will mobilize from the Drilling Research Center in Houston, Texas. MTI will be responsible for the components in BHAs 2 and 3 (list included in Attachment C). MTI will also supply a set of tongs to make and break the BHA components plus two high-pressure (10,000) psi mud pumps. This equipment will be shipped to Catoosa and will arrive the week before the test. Catoosa has facilities where the BHA components can be uncrated and checked before use in the wells. This will be done on the first day of testing while setting up the coiled tubing rig. Figure 2 below shows how the mud pumps and other equipment will be placed so that they can be plumbed together for the test. These pumps will be used in conjunction with BJ pumps to supply the necessary flow for drilling.

BJ Services will mobilize out of their field office in Ardmore, Oklahoma. BJ will be supplying a complete coiled-tubing rig and a high-pressure pumping unit capable of supplying 180 gpm at 10,000 to 12,000 psi. A meeting is scheduled with BJ for November 26, 2001 to confirm the equipment that will be used. This equipment list will become an attachment to this report when it is completed.

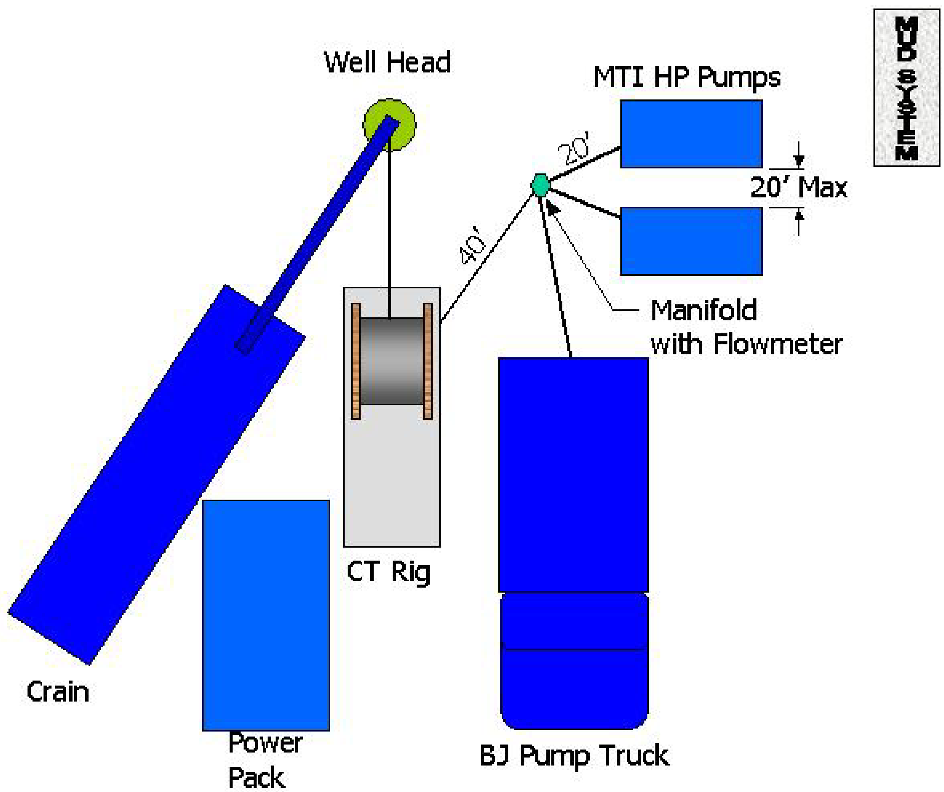


Figure 2. Catoosa Test Layout

Catoosa Test Site

Safety

Catoosa will set the ground rules for safety while at the site. A safety meeting will be held prior to beginning work. Catoosa will cover general safety procedures used at their test site and MTI and BJ will cover safety specific to this test.

BJ will take the lead role in safety issues concerning high-pressure and CT operations. Their daily use of this equipment at high-pressure makes them best qualified to recognize potential hazards. BJ will cover high-pressure safety rules at the safety meeting.

The report "Sound Coiled-Tubing Drilling Practices" prepared by MTI for the U.S. Department of the Interior Minerals Management Services was a part of this test plan. A copy of the report can be obtained from MTI on request.

Anyone can stop the test for safety concerns. If a safety violation is observed, that person should notify Ron Bray, John Cohen, or Jay Albrecht, who will stop operations. If this occurs, a meeting will be held to correct the violation before work continues.

Cost

The basic lease fee is $2,000/day. This includes support equipment and office space during the test. Ron Bray suggests using $2,500/day as a budgetary number to cover other incidentals. The wells that are used must be plugged back. The cost for this is $5.75/ft plus ½ day rig time ($2,950 for small rig). Plug and abandon cost will be a major expenditure ($10,000 to $18,000) depending on depth drilled.

Operating hours are from 7:00 am to 5:00 pm. Work can continue past 5:00 pm with our own crews, but all loud equipment must be shut down by 8:00 pm.

Catoosa's level of support for this project will be one to two technicians on an as needed basis. If work takes place on weekends, one Catoosa technician will be required to be at the site, and we will have to pay overtime charges. **Attachment A** contains a Catoosa price list.

Test Time

The test of the large HP-CT system will take 5 to 10 days. Additional trips to Catoosa will be used to test other sizes of bits and motors and the production enhancement tool. The first run will use the large drilling system, which consists of a 6 in. bit and a 4¾-in. motor. This large system provides the best assembly to demonstrate the advantages of jet kerf drilling, and has the highest probability of success. After testing the large motor, the 3⅛-in. motor will be tested with a 4¾-in. bit. Due to flow and cleaning concerns, the smaller BHA will be tested in a second well (see Figure 3).

Well Head

There are a number of wellheads at the Catoosa facility that could be used for testing the HP-CT systems. Three that appear to be best suited are AS-3, DM-30, and DM-20. These wells are completed as follows:

1. AS-3 is completed with 9⅝-in. casing and 7-in casing, both set to 162 ft. This is the first choice since it will require no work to start drilling in this well. There is some cement at the well bottom that will be need to be drilled out, but this should not be a problem for the HP-CT system as it is type H cement.

2. DM-30 has 9⅝-in. casing set at 162 feet, but the casing is not cemented in place so it can be pulled and replaced with 7 in. casing which will supply the necessary annular velocity to clean the well. A flow rate of 180 gpm with the 4¾-in. motor would produce an annular velocity of 60 ft/min in the current 9⅝-in. casing with 2 in. coiled tubing, which is too slow for good hole cleaning. If the 9⅝-in. casing is replaced with 7-in. casing, the velocity goes up to 124 ft/min., which is adequate to clean the hole.

3. DM-20 is completed with 9⅝-in. casing set at 162 ft and 7 in. casing at 800 ft. However this well has a bridge plug, making it the lease desirable of the three wells. If we want to use this well it would be advisable to have Catoosa drill out the bridge plug with their small rig.

The wellheads all have flanges on them, but BJ will need a 7-1/16 in., 5,000 lb flange to make up to. Catoosa will either cut the current flange off and replace it with the appropriate flange, or use a crossover sub will supply. The current flanges are 1 to 2 ft above the ground. The height of the BOP stack will determine if we need to rent scaffolding to make a platform for making up the BHA.

Site preparation is important to the success of any coiled-tubing job. Figure 2 shows placement of equipment for this test. Although not carved in stone, the relative placement is very important. The pumps and mud system need to be close together for easy manifolding and connection to the coiled-tubing rig. Deviation from this basic plan needs to be discussed so that the operation is optimized and the probability of success is increased.

Figure 3. Flow Rates and Annular Velocities

Mud System

Catoosa can supply the tanks, shale shakers and water for the mud system. They also have a centrifuge that will clean up to 100 gpm of mud. The fine screens for the shaker are 210 mesh which should be fine enough to clean the mud for the high-pressure nozzles (0.060 in.). Water is supplied as part of the lease fee. A polymer friction reducer can be used during the test to help lower overall pressure and to help keep cuttings suspended. BJ typically uses Xan Vis. BJ will supply an MSDS sheet on this material for Catoosa to review. Catoosa's only concern is that some polymers use an oil carrier, making them difficult to dispose of. Catoosa will check and make sure that this polymer is not using an oil-based carrier.

Sufficient annular velocity is critical to achieve good hole cleaning. Figure 3 shows the velocity in different parts of the proposed well at different flow rates. The annular velocities are such that the smaller assembly can not be run in the same well as the larger assembly without either using a parasite string or putting smaller casing or a liner into the well. Since neither of these solutions is practical for this test, a second well will be used to test the smaller tool and bit.

Formations

Figure 4 shows the lithology of the formations at the Catoosa test site. Most drilling tests are run in the formations from 0 to 2000 ft. Most of the upper formations drill at high rates (50 to 100 ft/hr). The Mississippi Lime at 1275 ft is very hard and has a reputation of damaging PDC bits. During our tests, drilling the Mississippi lime with the HP-CT system will be attempted even though it is not expected that the jets will help in this formation. This formation will be approached carefully to avoid damaging the bit and, if necessary, the HP-CT BHA will be pulled and a conventional low pressure roller bit will be used to drill through this formation. MTI will acquire a roller bit for this purpose. During the test a low-pressure bit will be used to obtain comparative data. Which will mean tripping several times during the test. The Red Fork Sandstone and the Booch Sandstone would be good formations for this comparison.

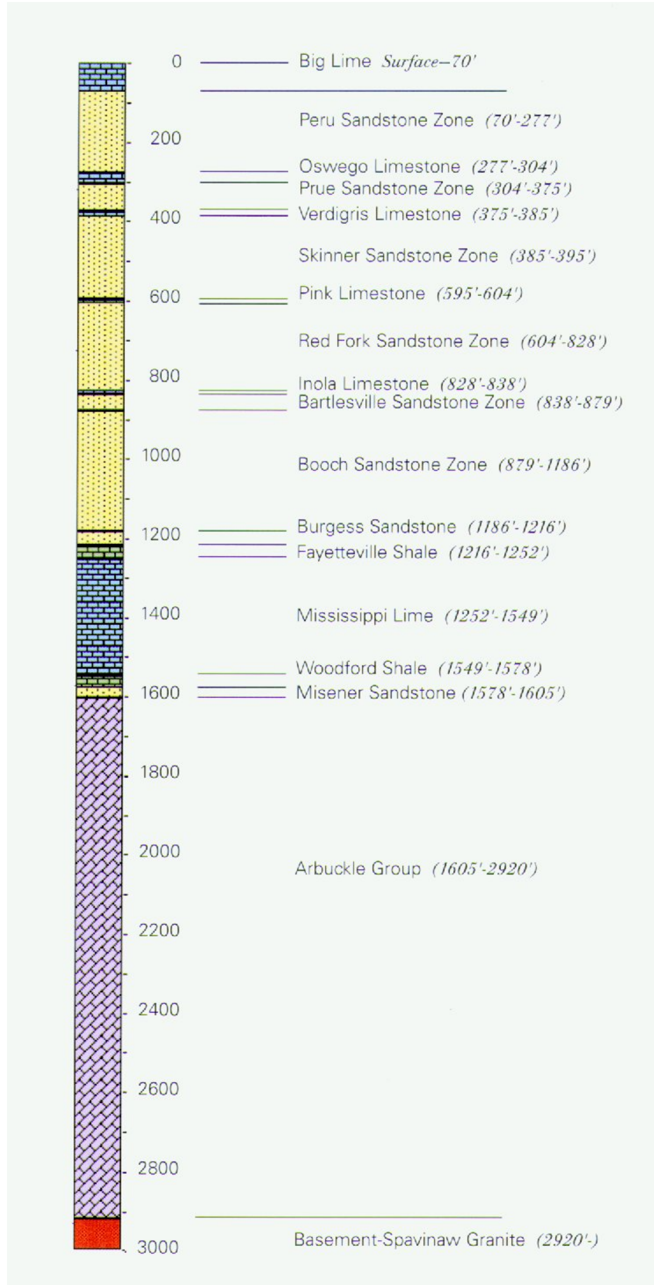


Figure 4. Catoosa Lithology

The formations at Catoosa are stable and should present no wellbore stability problems. However, the Bartlesville Sandstone can take water and it may be necessary to add some bentonite to control lost circulation. Caution will be taken when drilling this formation. Also some of the shale formations will sluff. This problem will be avoided by not leaving the assembly in the hole at night. The short duration of the test will help solve this problem as well.

To maximize hours on the BHA, considering the high drilling rates expected, this test will drill down to the granite basement at 3,000 ft. In addition the most uniform drilling formation is the Arbuckle, a hard dolomite. This formation will be another good location to get comparative rates between the HP-CT and conventional system.

Test Sequence

1. BJ Services will mobilize on Monday and drive to Catoosa from Ardmore, Oklahoma on Monday night or Tuesday morning.

2. BJ will rig up at Catoosa on the first wellhead. Which Catoosa will prepare prior to test date.

3. BJ will put on a jet head and wash to the well bottom, making sure it is clean and to test the mud system.

4. BJ will pump through the CT to clean the system.

5. The jet head will be pulled and the HP-CT BHA will be assembled in the well. Attachment B has a diagram of the each BHA.

6. The 6 in. PDC jet bit will be made up to the 4¾-in. HP motor and the assembly lifted into the well where, using a collar clamp, it will be suspended on the BOP stack.

7. Using portable tongs, the individual BHA comments will be added including drill collars to provide 3,000 to 4,500 lb of bit weight (2 to 3 collars). Each BHA component will be raised into position using a crane and a lifting sub. A swivel on the crane hook will allow the components to be rotated during make up.

8. Once the BHA has been made up and attached to the coiled tubing, the pumps will be started at low flow and low pressure and the BHA run to bottom. The low pressure and low flow rates will keep the bit from plugging and mud from entering the motor during the trip into the well.

9. Once on bottom, the flow will be increased to approximately 180 gpm or until the proper pressure (10,000 psi) is reached. Drilling will then begin.

10. Drilling will continue down to 450 ft, into the Skinner Sand stone. Weight on bit (WOB) will be varied which drilling and data taken to document the change in performance.

11. Periodically while drilling, the driller will conduct on bottom and off bottom pressure tests. If the motor is operating, there should be 300 to 1000 psi difference in the two pressure readings. These tests are to make sure that the motor is operating and that we are only jet drilling.

12. At 450 ft, the BHA will be tripped and a low-pressure bit will replace the high-pressure bit. Simply replacing the nozzles in the bit will make this change. The bit pressure drop minimum will be 1000 psi to ensure that enough cooling fluid passes through the bearing pack and the diamond thrust bearings. Nozzle combinations, as shown in the chart below, allow the bit to have pressure drops of 9000, 7000, and 1000 psi. Several different bit pressure drops will be used to measure the effect on the penetration rate. After selecting the desired pressure and changing the nozzle configuration the assembly will be run back into the well and drilling continued. A minimum of three different pressures will be tested in the Skinner Sandstone (9,000, 7,000 and 1,000 psi). If 7,000 psi shows good results, then a test will be conducted

6 Inch High Pressure Bit Nozzle Set-up

Nozzle Factor 0.97

	Existing Nozzles						Nozzles to be Added		
	(3) Gage	(2) Center	(1) Crossfeed				1 Nozzle	2 Nozzles	3 Nozzles
	0.106	0.100	0.082						
Bit Pressure		Flow		Total	Operating Flow	Flow Req'd.			
9000	92.6	54.9	18.5	166.0	165	0.0			
7000	81.7	48.4	16.3	146.4	165	18.6	0.088	**0.062**	0.051
5000	69.0	40.9	13.8	123.7	165	41.3	0.142	0.100	**0.082**
1000	30.9	18.3	6.2	55.3	165	109.7	0.346	0.245	0.200

	Existing Nozzles (Change (2)@.100 to (2)@.167)								
	(3) Gage	(2) Center	(1) Crossfeed				1 Nozzle	2 Nozzles	3 Nozzles
	0.106	0.167	0.082						
Bit Pressure		Flow		Total	Operating Flow	Flow Req'd.			
1000	30.9	51.1	6.2	88.1	165	76.9	0.290	0.205	**0.167**

Color Code

Orange	Change Existing
Cyan	Add to Existing
Yellow	Not Available

at 5,000 psi in the Red Fork Sandstone. A major comparison between conventional drilling (1,000 psi) and high-pressure drilling (9,000 psi) will be conducted in the Booch Sandstone and in the Arbuckle dolomite.

13. After comparative data are gathered with a low-pressure bit in the Skinner, Red fork, and Booch, the BHA will be tripped out again and high-pressure drilling resumed.

14. After drilling to a depth of 1800 ft, the BHA will again be tripped out and the bit replaced with a low-pressure bit. The BHA will be tripped back into the well and data collected to compare drilling performance with high and low bit pressure drops.

15. At a maximum depth of 2000 ft, the BHA will be tripped out and the well completed to 3000 ft with the high-pressure system.

16. ROP, pressure, flow, and formation data will be recorded throughout the test.

17. At 3000 ft, the BHA will be tripped and testing of the 6-in. system completed.

18. The CT rig will be moved to the second well and rigged up for testing the 4¾-in. system consistency of the 3⅛-in. motor with a fluid by-pass nozzle in the rotor so that adequate cleaning can be achieved with the 4¾-in. bit. The motor can be run at 100 gpm, over speeding the motor, with no nozzle. However, this is 25% more than the rated flow, which will shorten the life of the motor significantly. The manufacturer's opinion will be solicited on this before the test.

19. The new BHA will be assembled in the same manner as the previous assembly. Once made up, the assembly will be run to bottom and drilling begun.

20. Bit weight and flow will be varied during the drilling and data taken to document the change in performance as a function of these parameters.

21. Drilling will continue to a depth of 1000 ft (Booch sandstone). Where the BHA will be tripped from the well and the high pressure bit replaced with a low-pressure bit.

22. After drilling proceeds to 1200 ft (or enough time to obtain comparative drilling data), the BHA will be tripped and the high-pressure bit put back into the BHA.

23. Drilling will continue into the Arbuckle where a second test will be run to get comparative data between high-pressure and low pressure drilling. Location and duration of this test will be based on data taken from the test using the 6-in. bit and the 4¾-in. motor.

24. After low-pressure drilling is complete, the well will be completed to 3000 ft using the high-pressure assembly.

25. ROP flow, pressure, and formation data will be recorded throughout the test.

Test Conclusion

The test will be concluded on fulfillment of the test plan or when MTI, BJ, and DOE mutually conclude that (1) enough data have been obtained or (2) continuing no longer makes sense. Reasons for terminating the test may include equipment failure, better or poorer than expected performance, completion of test objectives etc.

Data Analysis

After tests are completed, MTI will return to Houston and analyze the data and present the results to BJ and DOE for comment. A topical report will be issued summarizing the test results. Modification of the motor and/or bits will be based on these first shallow field tests.

Continued Shallow Field Tests

At the conclusion of these tests, more shallow field tests will be run if necessary. These tests may be run at the Catoosa facility or on actual wells. Items to be tested will include the small 1$^{11}/_{16}$-in. drilling and side-jetting system and fatigue tests on the QT 1200 CT string purchased by MTI in Phase II. If tests in actual wells are conducted, it is expected that the operator will cost-share the test by paying for BJ's services, motor rental, and bits. The project will only supply engineers to observe and record data during drilling.

The shallow field tests will be followed by deep field tests (8,500 to 10,000 ft).

Bottom Hole Assembly (BHA)

Three BHAs will drill in the shallow test wells. The first is a simple jetting assembly to clean out the wells before drilling begins. This assembly is shown in Attachment B. The second BHA will test the 4¾-in. motor and 6-in. bit, while BHA 3 will use the 3⅛-in. motor and 3¾- and 4¾-in. bits.

Proper torquing of the tool joints in the BHA of the HPCT system is critical. Failure to torque threads to appropriate levels could result in a washout from the high-pressure drilling mud. This is not typically a problem in coiled tubing applications so the lack of tongs to aid in this effort has not been addressed in conventional coil-tubing applications. Current practices us pipe wrenches and cheater pipes to make up joints; this is unacceptable, so a method to make up joints for these tests was needed. A system using manual tongs energized with a hydraulic cylinder has been located. In Figure 5, the tongs are suspended from wire rope passed through a pulley. This pulley is then suspended from a crane or other support. The cable and pulley system allows the position (top to bottom) to be easily adjusted. This allows the operator to quickly change from make up to breakout on any joint.

Since the weight of the tongs and cylinder are supported, the system is much safer than using pipe wrenches, which can be dropped. The cylinder also prevents injury to personnel by eliminating the need to push or pull on cheater pipes. Because of the configuration of the well head and the equipment that mounts on the well head, such as the blow out preventer stack and the injector, it may be necessary to make up joints above ground level. This tong system will make these operations much safer and easier to accomplish. Correct make-up of the joints is improved with the tong system since a gauge on the cylinder will give the exact load being applied to the tongs.

Figure 5. Hydraulic Tongs

Attachment A-1 – Catoosa Price List

GRI Catoosa Test Facility, Inc. *2002 Rates*

P.O. Box 1590, Catoosa, OK 74015		revised:	30-Aug-01
UNIT / SERVICE			
10 hour day = 7 am - 5 pm (after 5 pm = overtime rate)	**	***	
Rig 11, per 10-hour day (includes lease fee)	$ 9,985	$ 1,200 per hour, overtime	
Charged in 1/2 day increments		- 2-day minimum	
Rig 2, per hour (includes lease fee)	$ 590	per hour w/ 3-man crew	
		- 10-hour minimum	
LEASE FEE (if not using GRI rig 11 or rig 2)	$ 2,000	per day, plus personnel & equipment charge	
P&A well (for < 9" hole size) *(+ 1/2 day rig time)*	$ 5.75	per foot of hole drilled	Min. $1000 + 1/2 day
P&A well (for 9" - 13" hole size) *(+1/2 day rig time)*	$ 8.75	per foot of hole drilled	Min. $1500 + 1/2 day
P&A well (for > 13" hole size) *(+1/2 day rig time)*	$ 13.85	per foot of hole drilled	Min. $2000 + 1/2 day

P&A charges are a cost per foot, plus 1/2 day rig time - includes cost of cement

*** Rate is for a normal 10 hour day; motors MUST be shut down by 8:00 p.m. *** Overtime is in excess of 10 hrs per day*

Note: The rig is allowed 1 hour per testing day DOWNTIME at regular rig rate - see "standard terms and conditions" in contract.

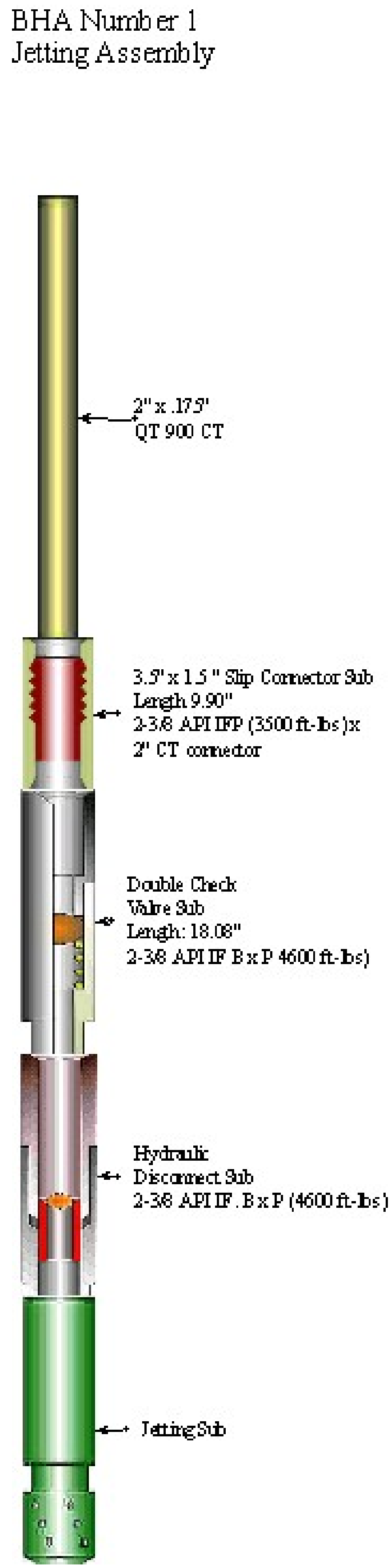
EXTRA EQUIPMENT - per day charge	Per day w/ GRI rig	Per day w/ no rig	Comments
***Wireline Unit (white - electric) (plus operator)**	$ 200.00	$ 425.00	2 day minimum charge
***Rig 2 - no pumps, pipe or crew - per day**	n/a	$ 225.00	2 day minimum charge
***HT 400 pump (plus operator)**	$ 250.00	$ 625.00	2 day minimum charge
***HT 150 pump (plus operator)**	$ 175.00	$ 400.00	2 day minimum charge
***FMC pump (plus operator)**	n/c	$ 200.00	2 day minimum charge
***Vacuum Truck (per hour) (plus operator)**	n/c	$ 75.00	2 hour minimum
***Forklift (per hour) (plus operator)**	n/c	$ 100.00	2 hour minimum
***Crane (per hour) (plus operator)**	n/c	$ 150.00	2 hour minimum
***Crane, not operating - per day, no operator**	n/c	$ 450.00	1 day minimum
** See operator charges below*			
GRI Drill Pipe (any size)	n/c	$0.25/ft/day	2 day minimum
GRI Drill Collars (< 4 inch)	n/c	$0.75/ft/day	2 day minimum
GRI Drill Collars (> 4 inch)	n/c	$1.00/ft/day	2 day minimum
Centrifuge (other than the one on rig 11)	$ 195.00	$ 295.00	2 day minimum
Mud System (tanks, pumps, agitators)	n/c	$ 495.00	2 day minimum
Tandem shale shakers (plus screens)	n/c	$ 225.00	2 day minimum
Data acquisition system (unmanned)	n/c	$ 250.00	2 day minimum
Rotating Head (plus rubbers)	$ 50.00	$ 65.00	2 day minimum
Mud Chemicals (bentonite)	n/c	Cost, plus 20%	
Cement & other chemicals	Cost, plus 15%	Cost, plus 20%	cement included in P&A
All external services & materials (charges)	Cost, plus 15%	Cost, plus 20%	
Bits & other BHA rental or purchase	Cost, plus 15%	Cost, plus 20%	
Package Solids Control System - Includes:			
Centrifuge, Mud System and Tandem Shale Shakers	n/a	$ 850.00	4 day minimum

~Note: Equipment rental day rate begins when contracted, and ends when released, whether used or not. No charge for Saturdays or Sundays unless used. GRI will do its best to provide the equipment and materials that are available at the rig site. However, it may be necessary to rent third-party equipment. If this is the case, thrid-party charges will be billed back to the customer at cost, plus a handling fee. Cancellations with less than 96 hours notice will be subject to 2 days charge.

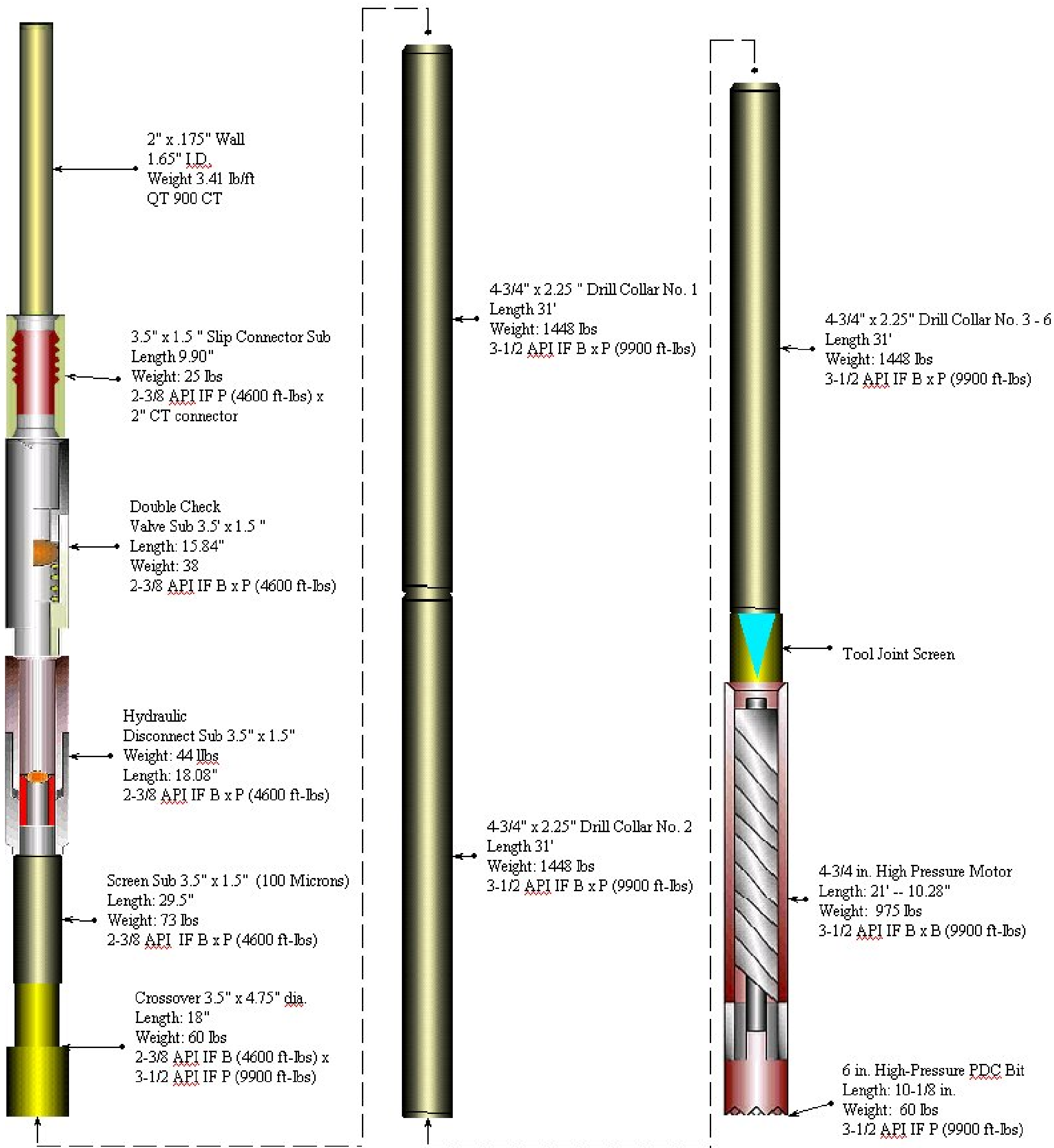
Rig 11 crew consists of toolpusher, driller, derrickman and 3 roughnecks. Rig 2 crew: Driller & 2 roustabouts.

Personnel Rates (per hour)	**w/o rig charge**	*** w/ rig extra person*	**OT, after hours rate**
Engineer (per hour)	$ 165.00	*$ 150.00*	$ 250.00
Technologist, Toolpusher,(per hour)	$ 160.00	*$ 110.00*	$ 200.00
***Pump/Wireline etc. OPERATOR (per hour)**	$ 160.00	*$ 110.00*	$ 200.00
Driller (per hour)	$ 130.00	*$ 85.00*	$ 175.00
Welder (per hour)	$ 160.00	*$ 85.00*	$ 200.00
Roughneck/Roustabout (per hour)	$ 110.00	*$ 65.00*	$ 150.00

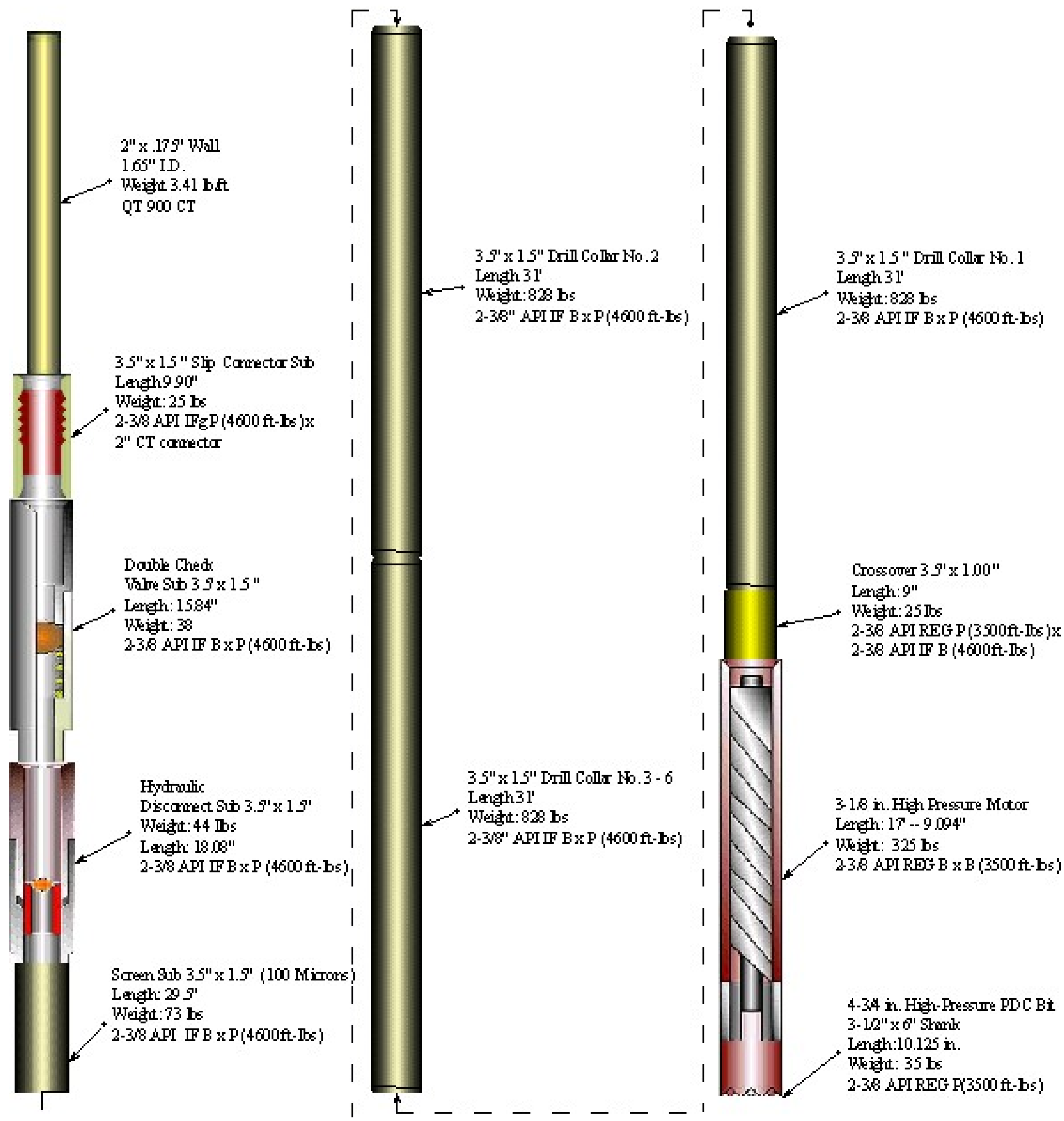
Attachment A-2 – Bottom Hole Assemblies


BHA Number 1
Jetting Assembly
2" x .175"
QT 900 CT
3.5" x 1.5 " Slip Connector Sub
Length 9.90"
2-3/8 API IFP (3500 ft-lbs) x
2" CT connector
Double Check
Valve Sub
Length: 18.08"
2-3/8 API IF B x P 4600 ft-lbs)
Hydraulic
Disconnect Sub
2-3/8 API IF. B x P (4600 ft-lbs)
Jetting Sub

BHA Number 2
6 in. Bit with 4-3/4 in. Motor



BHA Number 3
4-3/4 in. Bit with 3-1/8 in. Motor



Attachment A-3 – MTI Equipment List

1. 2 – 440 horsepower Ellis Williams Mud pumps with high-pressure (10,000 psi) fluid ends
2. Controller for mud pumps in item no. 1
3. High-pressure hose to hook pumps to coiled-tubing manifold
4. 1 set of hydraulically actuated tongs to make up BHA components (15,000 ft-lb)
5. 2 – 6 in. diameter PDC bits. Nozzle configuration will allow this bits to be used at high-pressure (10,000 psi) or low-pressure (1,000 psi) operation
6. 2 – 4¾-in. diameter PDC bits. Same as item 5
7. 1 – 3¾-in. diameter PDC bits. Same as item 5
8. 1 – 4¾-in. diameter high-pressure Moineau motor
9. 2 – 3⅛-in. diameter high-pressure Moineau motors
10. 6 – 4¾-in. drill collars
11. 6 – 3.5 in. drill collars
12. 2 – 3.5 in. screen sub
13. 2 – 3.5 in. hydraulic disconnect sub
14. 2 – 3.5 in. double Check valve sub
15. 2 – 3.5 in slip connector sub
16. 1 –2⅜ Reg pin x 2⅜ IF box crossover sub
17. 1 – 2⅜ IF box x 3-1/3 IF pin crossover sub

Appendix B

Catoosa HP-CT Shallow Field Test Log

February 11, 2002

7:30 AM

Arrived on site at GRI Catoosa facility.

8:00 AM

BJ arrived on site. Had meeting with GRI, BJ, and MTI to determine placement of CT equipment including, HP pumps, pump charge line, return line. Decision is made to use main rig tanks and mud systems.

8:55 AM

Held safety meeting, Ron Bray presided. He covered site regulations and passed out a one-page flyer with rules. Contacts are Steve Andrews for GRI, Doug Freeman for BJ, and John Cohen for MTI. BJ will hold a second meeting on high-pressure safety after rig-up is completed.

9:10 AM

Began rig-up of CT unit and preparation of wellhead. A new flange will have to be welded onto the current wellhead, as the flange in place is too large.

1:10 PM

CT rig is in place and tubing has been stabbed into the injector. BJ pump trucks are in place and have plumbed HP lines to connect to coil rig. Working on supply and placing MTI pumps. Using charge pump on Catoosa big rig water from the main tank will be feed through a screen assembly supplied by MTI. Flow out of the screen assembly will be plumbed to BJ and MTI pumps.

Ordered lunch for crew to keep progress on set up moving forward. Curtis Leitko has set up nozzles on 6-in. bit to start test. Charles Evans is concentrating on supply lines to the pumps.

Catoosa welder is setting up wellhead by welding on a nipple for a 7-1/16 in. flange. BJ has flange x-over to go from this to 4-1/16 flange which is what is on the bottom of the injector and BOP stack.

BJ brought out two pump trucks—one that goes with the rig and has approximately 1000 hp and a second out of the pump division that is much larger (V-16 diesel) and can supply 4 barrels at 15,000 psi.

3:51 PM

Rigged up flow system and injector assembly. Plan is to go to bottom with tube only to make sure well is clear. If it is, we will make up BHA components so that we will be ready to start drilling tomorrow morning.

4:15 PM

Rigged up to well preparing to run into hole.

4:33 PM

Running to bottom with bare coil. Ran in 200 ft and did not tag bottom. Well should have been 165 ft. Made up BHA components. Have installed CT connector onto tubing and pull tested.

6:16 PM

Have completed for the day. Will resume tomorrow completing BHA and start drilling.

February 12, 2002

7: 00 AM

Arrived on site starting equipment and beginning to complete BHA make up.

9:04 AM

All BHA components that can be made up on the bench have been completed. The CT connector and motor head assembly have been installed onto the coil. The next step is to load the coil with water and pressure test the assembly. Then the motor will be lifted into the well and mated with a drill collar. This assembly will be pressure tested if the crane can lift the assembly from the hole. Two drill collars will be used to help reduce vibration at the CT connector.

11:45 AM

Still trying to get a pressure test of the CT components. Had a bad valve on the coil truck in the reel and plugged the needle valve on the pull plate with sand. Took off QC and plumbed through unit and are now retesting to see if joints hold pressure. Had leak at QC joint, needed larger O-ring to make up joint. This has been accomplished.

Talked to John Rogers about test sequence. Trying to explain the need to be flexible to gain as much useful data as possible. John arrived on site this morning at 7:30 AM.

12:43 PM

Still trying to get good pressure test. Have removed MTI pumps from the line.

1:43 PM

Have completed pressure test. Making up BHA with two drill collars. After make up will pressure test all joints up to the motor. The only joint that will not be tested is the one between the motor and the Kelly valve.

2:51 PM

Making up last of joints on BHA.

4:09 PM

Still fighting with assembly. Trying to lower into hole, but cannot get onto upper small components (motor head assembly). Will not be able to drill today, but hope to get pressure test done.

4:25 PM

Have leaking joint on CT motor header assembly. Trying to tighten joint.

5:44 PM

Pressure tested motor and collar. Testing upper connection. If good, will set injector on well and blow out motor and coil with nitrogen. Will start drilling tomorrow.

6:12 PM

Completed second pressure test. Have made injector up to wellhead. Plan to start drilling tomorrow.

February 13, 2002

7:00 AM

Arrived on site. Will have safety meeting and then go into hole. Must first find bottom, and begin drilling.

10:23 AM

Started drilling at a depth of 175 ft. Had good rates of 300 ft/hr. Continued until 10:43 AM when we stopped to clean old mud and build polymer.

12:17 PM

Started drilling again. Pump pressure increased from 8500 psi to 9500 psi. Drilling at very good rates. Unusual pressure spikes at 12:36. Slowed flow and pump pressure returned to normal. Increased flow and pressure went up again. Decided to pull system from well at 1:00 PM to check screens, motor and bit.

3:35 PM

Found rubber in the bit screen. This must be from the stator. We will rig up the small motors and go back into hole with those.

5:24 PM

BJ is pressure testing small assembly at this time. Will finish pressure test and button up wellhead and start drilling in the morning.

John Rogers suggested having a lesson-learned meeting after this test. I believe this is a good idea.

6:36 PM

Found screen sub above collars full of ceramic frac sand. This is what caused the problem. We will go back in with the large motor in the morning.

February 14, 2002

7:00 AM

Arrived on site, held safety meeting and went over plans for day. We will come out of the hole and remove the small assembly. While we are rigging up the large motor BJ will reattach to the wellhead with open coil. A high-pressure inline filter will be added before the coil. While the well is open, BJ will pump 5 barrels per minute and try to remove all the frac sand that we found in the filter yesterday.

9:36 AM

Still cleaning out frac sand. Have found some in inline filter. Will start going back in with larger motor assembly.

10:52 AM

A BJ worker was injured while making up large motor assembly. The MTI-supplied tongs were used improperly. A keeper pin was not put into place before torquing up a joint. The hydraulic cylinder that energizes the tongs slipped off the wrench and the stored energy in the wrench caused it to swing and hit a worker in the arm. The worker is being taken to an area hospital for an X-ray.

1:12 PM

Cannot get out of casing and pressure is lower than it should be. Will pull out to see if circulation sub opened.

6:56 PM

Have prepared small tool for drilling tomorrow. Due to budget constraints tomorrow is the last day of drilling. We are worried that the large tool could not go through the casing. It is possible that the small tools could get stuck.

February 15, 2002

7:00 AM

Arrived on site and continued preparing for small motor test. Held safety meeting and then rigged up MTI pumps.

9:00 AM

Started going to bottom, but hit constriction at 147 ft. Decided to pull tool from well and blow hole dry and get camera shot of obstruction.

12:00 PM

Went in with CT and got stuck at 150 ft. Had to pull with 9,000 lb to free coil. Cleared hole with nitrogen and ordered camera inspection.

Appendix C

Joint Work Statement
for
CRADA No. 2004-046

BETWEEN

U.S. Department of Energy
Naval Petroleum Reserve No. 3 (NPR-3)
Rocky Mountain Oilfield Testing Center

AND

Maurer Technology Inc.

High-Pressure Drilling Test

The purpose of this test is to determine the performance of a high-pressure jet kerf drilling system. The drilling system, as developed by Maurer, uses high-pressure water jets to cut radial slots in the rock ahead of the drill bit and PDC diamond cutters to break off rock ledges between these slots.

1. Scope

The test will consist of drilling a new grass roots well at the Naval Petroleum Reserve 3. The proposed location, 48-X-28, will target the Tensleep formation at an approximate depth of 5500 ft with additional footage drilled as needed to complete the test. The location will use the most recent 3D seismic information and mapping interpretation.

The location for the rig will be constructed. Rat-hole/mouse-hole drillers will be used to prepare the conductor, rat hole, and mouse hole for DOE #2 rig. RMOTC will construct a new reserve pit. DOE Rig 2 will be moved to location and rigged up.

Surface casing (9-5/8”) will be set across the Shannon formation at approximately 500 ft. Note: Seismic test with Idaho National Engineering and Environmental Laboratory (INEEL) will be conducted for approximately 24 hours prior to setting casing and cementing.

RMOTC will drill out of surface pipe with a 8½” bit to approximately 4200 feet. The attached drilling prognosis (Attachment C-1) details the specific operation. RMOTC will run a suite of openhole logs before intermediate casing is set. Attachment C-2 details Maurer’s summary to date of their technology development and proposal to work with RMOTC for this test of their drilling system.

At depth, 7” 23# casing will be run and cemented. Smaller BOP equipment will be rigged up after cement is set. The remaining high pressure equipment will be rigged up and pressure tested to 10,000 psi. RMOTC will trip in with 3½” drill pipe and conventional bit and drill out the shoe and 5 feet of new formation. At this time, if conditions permit, a single trip test of Maurer's downhole sub will be communication tested. After this initial test is complete, the high-pressure downhole drilling equipment will be run in the hole.

Prior to commencing high-pressure drilling operations, the mud tanks will be dumped and all possible drillings solids removed from the system. High-pressure drilling will commence starting at approximately 4200 feet down to an estimated TD of 6200 ft.

TASK 1: RMOTC will submit an Application for Permit to Drill (APD) with the Wyoming Oil and Gas Conservation Commission (WOGCC). RMOTC will build the location for testing. Rat hole/Mouse hole will be drilled and conductor set. DOE Rig N0 2 will be moved to 48-X-28 location. Surface casing will be set at approximately 500 ft.

TASK 2: RMOTC will deepen 48-X-28 to approximately 4200 feet. Open-hole logs will be run. 7" 23# intermediate casing will be set and cemented. The mud system will be cleaned to remove solids from the system.

TASK 3 RMOTC will test the high pressure system to 10,000 psi. One trip communication test of Maurer's equipment will be completed. High pressure drilling will commence from 4200 to an estimated TD of 6200 ft.

TASK 4: At the end of the project, in accordance with Article XI of the CRADA, RMOTC and Maurer will jointly prepare a final report summarizing the test results.

2. Personnel

RMOTC will provide the following personnel:
Drilling Crews
Tool pusher
Field Engineer
Project Engineer
Vac Truck Driver(s)
Heavy Equipment Operator(s)
Other field support personnel as needed

Maurer will provide the following personnel:
Test engineer
Technical Representative to work jointly on final report
Other outside personnel as required

3. Equipment and Material

RMOTC will provide the following equipment:
Drilling Rig with associated existing equipment
BOP equipment, if required
Vac Truck to haul fluids
Field Heavy equipment as needed
Forklift
Other field equipment as needed
Rat hole/mouse hole drillers

Cementing services and equipment
Rental high pressure drill pipe
High pressure mud pump
High pressure drilling swivel
High pressure kelly hose
High pressure standpipe and surface lines
High pressure valves.
Casing 9-5/8" and 7"
Casing crew
Openhole loggers
Drill bits – 6-1/8"
Drilling mud
Mud logging services

<u>Maurer will provide the following Equipment and Materials:</u>

Specialized high pressure drilling equipment including bit, mud motor, and collars.

4. Milestones

Spud Date	Estimated	February 28, 2004
Start of Test:	Estimated	March 14 2004 (4200 ft)
Completion of Test:	Estimated	March 31, 2004
Report completion:	Estimated	June 30, 2004
CRADA expiration date:	December 31, 2004	

The test will be deemed complete upon meeting the objective as set forth in the JWS. If the objective of the test is not met due to drilling problems, cost issues, Health, Safety and/or Environmental issues, or other reasons, the project can be terminated by mutual agreement in accordance with Article XXIII Termination.

5. Budget Considerations

RMOTC and Maurer will cost share in this test. Maurer cost share will be governed by their agreement with National Energy Technology Laboratory (NETL). See Attachment C-2. Maurer's in-kind contribution is estimated at $184,350 based on their agreement with NETL.

NETL has also funded RMOTC $250,000 to perform this test. This funding will be used to offset operational costs involved with the testing from 4200–6200 ft. Remaining funding will be used in a systematic manner to offset costs to reach 4200 ft including rental of high pressure equipment, casing, cementing, drilling operations, and other costs as identified.

RMOTC's contribution includes approximately $500,000 toward the purchase of a new mud pump. Additional costs include the purchase of a high pressure Kelly hose, drilling swivel, surface valves, and hard line. RMOTC will also provide mud loggers, drilling mud, open-hole loggers, etc.

At the conclusion of testing operations, RMOTC will assume full responsibility for Plug and Abandonment (P&A) operations.

RMOTC will provide equipment and materials as set forth in Section 3 above.

6. Environmental, Safety, and Health

Participant shall comply with all applicable Federal, State, and local environmental, safety and health laws, rules and regulations. RMOTC will be responsible for all Plug and Abandonment. The well will remain as completed until it is deemed necessary to plug and abandon the Amsden/Madison.

7. Required Insurance

The Participant shall procure and maintain during the entire period of the CRADA the following minimum insurance. Prior to commencement of work under this CRADA the Participant shall furnish to the Contracting Officer a certificate or written statement of the required insurance. The policies evidencing required insurance shall contain an endorsement to the effect that cancellation or any material change in the policies adversely affecting the interests of the Government in such insurance shall not be effective for such period as may be prescribed by the laws of the State in which this CRADA is to be performed and in no event less than 30 days after written notice thereof to the Contracting Officer.

TYPE	AMOUNT
Worker's Compensation & Occupational Disease	Statutory
Employer's Liability Insurance	$100,000
Comprehensive General Liability	Bodily Injury $500,000 per occurrence
Automotive Liability	$200,000 per person $500,000 per occurrence for bodily injury $20,000 per occurrence for property damage

The Participant shall procure and maintain during the entire period of the CRADA the required minimum insurance. Prior to commencement of work under this CRADA the Participant shall furnish to the Contracting Officer a certificate or written statement of the required insurance.

8. Budget Reporting

At the conclusion of the test, the Participant shall supply the Department of Energy a summary of expenses involved in the testing operation including in-kind travel, labor, subsistence, etc.

Attachment C-1
Drilling Prognosis

Rocky Mountain Oilfield Testing Center & Maurer Technology Inc
13135 South Dairy Ashford Rd. Suite 800
Sugar Land, Texas 77478
DRILLING PROGNOSIS
February 17, 2004
U.S. Naval Petroleum Reserve No. 3 Natrona County, Wyoming

Well Number: 48–X-28 CRADA No:
API well number: 49-025-TBA
Location: 490' FSL, 2,449' FWL, Sec. 28, T39N-R78W
Elevations: 5104.65' GL. 5114.65' K.B. Lat 43.314785 Long 106.221955
Estimated T.D.: 6200'
Objective: Test High Pressure Drilling System from 4200 – 6200 ft
Secondary Targets: Seismic Test with INEEL
Core Tensleep for CO2 Pilot Design

PROCEDURE

1. Survey and build location.
2. Prepare APD and forward to the WOGCC.
3. Drill rat hole, mouse hole, and conductor hole. Set 13-3/8" conductor pipe to 45'(+/-) depth. Cement with ready mix concrete.
4. MIRU DOE Rig #2 with substructure. Revamp standpipe and surface valves.
5. Install 13-3/8" drilling nipple
6. Drill out conductor and drill 12-1/4" hole to ±500' with water.
7. During drilling, add KCL for 3% KCI mud to stabilize shale. Let water mud up as drilling proceeds
8. Perform mud sweeps with polymer as needed to clean hole.
9. At depth, short trip to surface and back to depth to ensure hole is clean.
10. Rig Up Idaho National Labs (INEEL) for seismic test. Shut down rig for 24 hrs for minimal noise. Complete seismic test. RD INEEL.
11. RIH with 12-1/4” bit to TD. Wash and ream as necessary. POOH.
12. RU casing crew to run 12 jt 9-5/8" 47# casing to TD. Set and cement casing.
13. WOC. If necessary, give crews time off.
14. Nipple up 9-5/8 casing head using 2-2" ball valves.
15. Nipple up 11" BOP and test to 500 psi with test plug. RU drilling nipple.
16. Rig up mud loggers.
17. Drill out surface casing with 8½" bit using LSND mud. Maintain good fluid loss.

18. Drill through the Wall Creek zones slowly and with LCM to build good wall mud cake to control lost circulation.
19. Drill to about ±4200 (top of the Crow Mountain). Short trip as necessary to maintain hole.
20. At depth, condition hole. POOH. RU loggers. Log intermediate hole from 500–4200 ft with gr/density/neutron/ HRLA and sonic or other logs as directed. RD loggers.
21. TIH with 8½” bit. Circulate and condition hole. TOOH for casing. LD 4½” DP and 6” drill collars.
22. RU casing crew. Run 7” 23# casing to depth. Set and cement casing.
23. WOC. If necessary, give crews time off.
24. Nipple up 7” casing head using 2-2" ball valves.
25. Nipple up 7-1/16”" BOP and test to 500 psi with test plug. RU drilling nipple.
26. RU rental equipment. Pressure test system to 10,000 psi using BOP testers. RIH with 3½” XT drillpipe and 6⅛” bit. Drill out casing shoe and 5 ft of new formation. POOH. Dump and clean mud tanks. Ensure no solids are contained in mud system. Build new mud system.
27. PU Maurer bit, mud motor, collars. RIH to 1000 ft. Perform rate/pressure calibration run. RIH to depth. Begin drilling after mud system complete and equipment performing satisfactorily.
24. Drill with Maurer system from 4200 to 6200 or as test results dictate.
25. POOH. RU openhole loggers. Log bottom interval of 4200–6200 ft.
26. If the Tensleep appears productive based on mud logs and openhole logs or possibly even core, procedures will be developed to run a liner in the hole, cement, and complete.

At this point, the Maurer test will be complete. Several possibilities are possible prior to end of the test. One possibility is that the Maurer test does not reach TD because of unknown reasons. It is assumed that drilling will continue, in some manner, to reach the Tensleep core point for the CO2 effort. At that point, procedures will be presented to govern the Tensleep coring operation.

48-X-28 ESTIMATED LOG TOPS

KB Elev = 5115

FORMATION	**MEMBER**	**KB**	**Thick**	**ASL**
STEELE SH	SHANNON A	247	80	4868
STEELE SH	SHANNON B	332	145	4783
STEELE SH	TELEGRAPH CREEK	477	132	4638
STEELE SH	BRITTLE	609	393	4506
STEELE SH	FISHTOOTH	1002	516	4113
STEELE SH	GREY DUST	1518	102	3597
STEELE SH	ARDMORE	1620	125	3495
NIOBRARA SH	WHITE SPECKS	1745	244	3370
NIOBRARA SH	SMOKEY GAP	1989	219	3126
CARLISLE SH		2208	242	2907
FRONTIER	1 WALL CREEK	2450	384	2665
FRONTIER	2 WALL CREEK	2834	254	2281
FRONTIER	3 WALL CREEK	3088	267	2027
MOWRY SH		3355	237	1760
MUDDY SS		3592	18	1523
THERMOPOLIS SH		3610	133	1505
DAKOTA SS		3743	72	1372
LAKOTA CGL		3815	7	1300
MORRISON		3822	213	1293
SUNDANCE		4035	82	1080
SUNDANCE	LAK	4117	95	998
SUNDANCE	LAK EVAPORITE	4212	12	903
SUNDANCE	HUELETT SS	4224	4	891
SUNDANCE	STOCKDALE BVR SHALE	4228	43	887
SUNDANCE	CANYON SPRINGS SS	4271	82	844
CHUGWATER/CROW MTN		4353	86	762
CHUGWATER/ALCOVA		4439	22	676
CHUGWATER/RED PEAKS		4461	590	654
GOOSE EGG		5051	167	64
GOOSE EGG	FORELLE	5218	73	-103
GOOSE EGG	MINNEKAHTA	5291	17	-176
GOOSE EGG	OPECHE	5308	34	-193
TENSLEEP		5342	11	-227
TENSLEEP	TOP A SS	5353	50	-238
TENSLEEP	BASE A SS	5403	29	-288
TENSLEEP	TOP B SS	5432	66	-317
TENSLEEP	BASE B SS	5498	47	-383
TENSLEEP	TOP C SS	5545	20	-430
TENSLEEP	BASE C SS	5565	95	-450
AMSDEN		5805	240	-690

MUD PROGRAM:

12-l/4"Hole to 500 ft -3% KCl Mud (per mud engineers direction)

8-1/2" Hole to 4200 ft LSND Mud with the fluid loss control to minimize shale sloughing and promote hole stability for openhole logs. Fluid loss below 10 cm^3. Lost Circulation Control as needed with LCM. Cement squeeze of Second Wall Creek with fiberglass tail pipe to be considered.

6” Hole from 4200 to 6200. 6%KCl with NaCl for weight or as directed by mud engineer.

ELECTRIC LOGGING PROGRAM:

HRLA/ GR/ Cal/ CNL CDL from 500 to 4200 ft. Second run with sonic log.
Logging from 4200–6200 TBD. Other logging as requested.
Logging Subcontractor: Schlumberger Wireline Phone: (307) 234-8981

CASING PROGRAM:

Conductor Casing

1 joint of 13-3/8" 54.5# K-55 Cementing Hardware – None

Surface Casing

12 Joints of 9-5/8" 47# P-110 Cementing Hardware
1 - 9-5/8" Guide Shoe
1 - 9-5/8" Insert Float Collar
1 - 9-5/8" Stop Ring
1 - 9-5/8" Top Rubber Plug
6 - 9-5/8" Centralizers
1 - Threadlock Kit

Install centralizers on bottom 3 collars and alternating collars above

Production Casing:

About 100 joints - 7" , 23#, J55, LT&C
Cementing Hardware:
1 - 7" Float Shoe (fill-up type)
1 - 7" Float Collar (differential fill type)
1-7" Stop Ring (limit clamp)
1 - Top Rubber Plug
15 - 7" Centralizers
1 - Threadlock Kit

NOTES:

1. Production Casing program is approximate.
2. Install float shoe.
3. Use threadlock compound on float shoe and float collar.
4. Install centralizer 5 ft above float shoe and on alternate collars.

CEMENTING PROGRAM

Cementing Subcontractor: Rocky Mountain Cementers (307) 234-2212

Surface Casing: TBD

1. Preflush with 36 bbl. *3%* KCl water containing 3 sacks KCl, 3 sacks gel, and 5 gallons surfactant. Lost circulation material may also be added to preflush. Preflush may be varied according to hole conditions.

   If hole is drilled with non-dispersed mud, add an 18 bbl spacer containing KCl and surfactant.

If hole contains weighted mud, add a weighted mud sweep to avoid cement contamination. At maximum anticipated density, the mud will be heavier than the cement slurry.

2. Cement with ___sx. Class "G" cement containing *2%* CaCl and l/4#/sk celloflake. Cement volume is based on annular volume + __ % excess.

Yield: ___cu ft/sk Density: ___ lb/gal Water Req.: 5.0 gal/sk

Production Casing: TBD

1. Preflush with 36 bbl, 3% KCl water containing 3 sacks KCl, 3 sacks gel, and 5 gallons surfactant. Lost circulation material may also be added to preflush. Preflush may be varied according to hole conditions.
2. If hole is drilled with non-dispersed mud, add an 18 bbl. spacer containing KCl and surfactant.
3. Cement with ___ sx. Class "G" cement containing 50% Pozlan, 2% CaCl. and l/4#/sk celloflake and tail in 1st stage with 50sx of neat class "G". 1st stage is about ___ sacks of 50-50 Poz and 2nd stage is about ___ sacks. Exact number of sacks will be calculated from open hole caliper log.

Cement volume is based on annular volume + ___ % excess covering critical zones. Yield: ____ cu ft/sk Density: ____1bs/gal Water Req.: ____ gal/sk

Wall Creek or Crow Mountain Squeeze: To be determined.

REPORTS:

1. All pertinent data and operations such as DST's, coring and casing shall be recorded on the IADC-API Daily Drilling report. The White, Yellow, and Pink copies shall be given each morning to the RMOTC Project Manager, along with all delivery tickets signed and received. The green copy shall remain with the tool pushers and the white copy will remain in the book.
2. As of 7:00 a.m. each morning, a report by the tool pusher or the RMOTC Project Engineer shall be e-mailed or faxed into the Casper Office and include all pertinent data or operations.

MAILING LIST:

Department of Energy Director
Naval Petroleum Reserve #3
907 N. Poplar
Suite 150 Casper, Wyoming 82601
B.
DISTRIBUTION OF LOGS. REPORTS. ETC.:

1.	Government	
2.	Field Office (for State)	2
3.	Field Files	2
4.	RMOTC Project Engineer	1
5.	Geologist	1
6.	Misc.	

PHONE NUMBERS:

NAVAL PETROLEUM AND OIL SHALE RESERVES
COLORADO, UTAH AND WYOMING
907 North Poplar, Suite 150 Casper, Wyoming 82601
261-5000 / 1-888-599-2200
FIELD ADDRESS: 7290 Salt Creek Route, 40 miles north of Casper, Wyoming
E-Mail Address: first.last@rmotc.doe.gov

CASPER OFFICE

FAX (Main Office) 261-5817

MILLIKEN, Mark.............................. 5162
SCHULTE, Ralph............................ 5024
Cell phone……………..262-5106
SPAHR, Larry 5025
Cell phone 262-7812
RECEPTION (Kari) .... …………..5000
TAYLOR, Mike…………………………5071
TUNISON, Doug 5006
Cell………… 262-8675
RMOTC PRESENTATION ROOM... 5003

9. FIELD OFFICE

FAX (ES&H - Kiki).................... 437-9623

CRNICH, Dave 437-9610
Cell 262-7883
DAVIS, Dee… 437-9620
Smith, Tom ……………………437-9607
Cell…………………….262-8674
FOOTE, Cecil……………………437-9631
Cell phone. 262-7813
HARDY, Steve 437-9632
Cell phone……………...262-7808
HOYER, Dave.......................... 437-9634
Cell phone 262-7807
SMALLWOOD, Dan 437-9637
Cell phone 262-7814
TAYLOR, Mike ……………………437-9606
Cell…………………….262-7033

ES&H TRAINING ROOM.......... 437-9672

DIALING 911: From the field, press tab marked local line, dial 911.

All other field phones: Pick up the receiver, press intercom button then 71 plus number. Local calls simply dial number. FTS, dial area code then number.

SUBCONTRACTORS

Schlumberger 234 8981
Rocky Mtn. Cementers 234- 2212
Rick Husk
WY. Casing Service
Anchor Drilling Fluids USA, Inc. 237-258 l
Mud Engineer
Rat Hole Driller. RMR
Notify WOGCC verbally (234-7147) within 24 hours of spud and prior to BOP testing.

PREPARED BY: Ralph Schulte

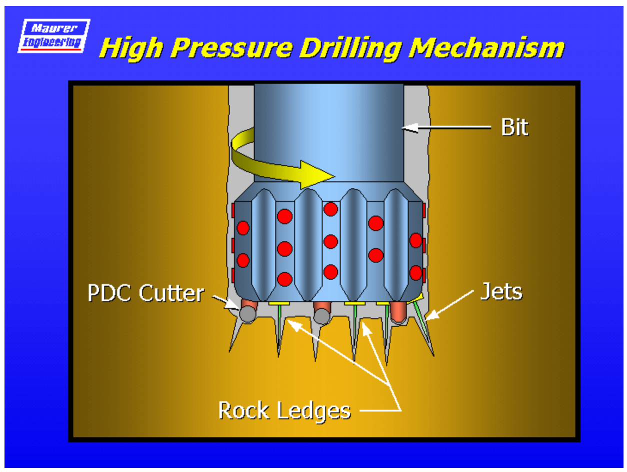
February 18, 2004
Draft Version 1.01

Attachment C-2

ADVANCED HIGH-PRESSURE COILED-TUBING DRILLING SYSTEMS

Continuation Application Phase IIB for Budget Period 4
Cooperative Agreement No. DE-FC26-97FT33063

TP03-10



Submitted to:

U.S. DEPARTMENT OF ENERGY
National Energy Technology Laboratory
Attn: Lisa Kuzniar, Contract Specialist
3610 Collins Ferry Road
PO Box 880
Morgantown, West Virginia 26507-0880

August 8, 2003

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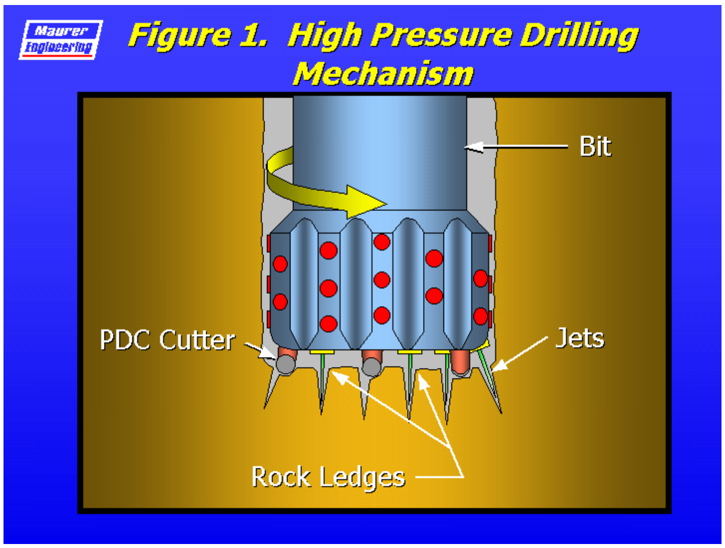
Introduction

High drilling costs limit the development of many marginal gas reservoirs in the USA. This project consists of the development of a high-pressure jet kerf drilling system that can drill three to five times faster than conventional drills and thereby reduce drilling costs by 25 to 50%.

This drill utilizes high-pressure water jets to cut slots in the rock ahead of the drill bit and PDC diamond cutters to break off rock ledges between these slots (**Figure 1**).

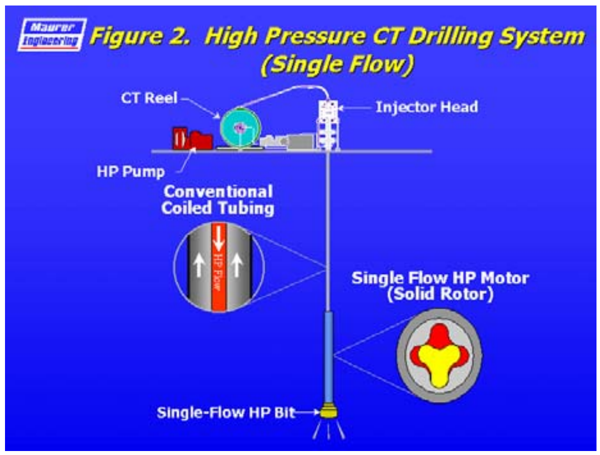


During Phase II, high-pressure motors were designed and manufactured along with high-pressure PDC bits for use with this drilling system. This system was laboratory tested, and drilled rocks at rates up to 1,600 ft/hr compared to 300 ft/hr for conventional motors and 150 ft/hr for rotary drilling.

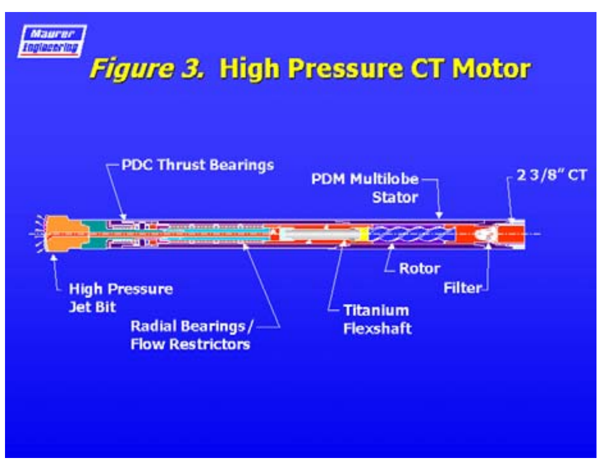
Field tests conducted during phase III at the GRI Catoosa test site proved inconclusive due to numerous problems during the test not associated with the drilling system. Details of the test are covered in the Phase III field testing section. However, the problems concerned the coiled tubing delivery system and the condition of the test well. As a result, the effectiveness of the jet drilling system was never tested. Based on these results, the project was moved to a Phase II B where a test, using jointed pipe, could be conducted on the jet drilling system itself. This test will be run at the Rock Mountain Oil Test Center (RMOTC) in Wyoming.

Phase II-A Accomplishments

This project developed a high-pressure coiled drilling system to drill in difficult slow drilling formations. The system was to be conveyed into the hole with high-pressure coiled tubing. A major oil field coiled tubing manufacturer was part of the team and worked on the development of new tubing that would have long life while operating at high pressures. **Figure 2** shows the initial configuration of the system.

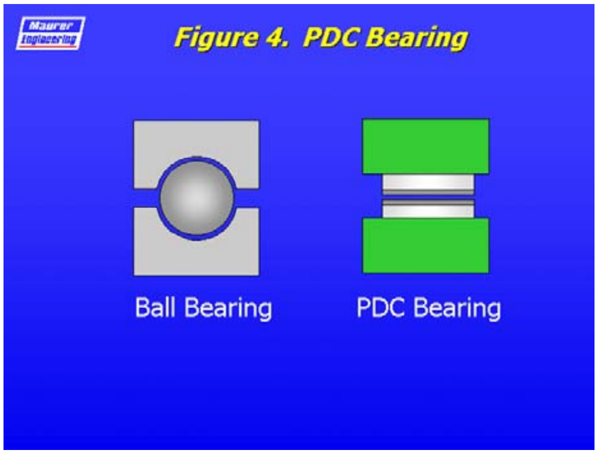


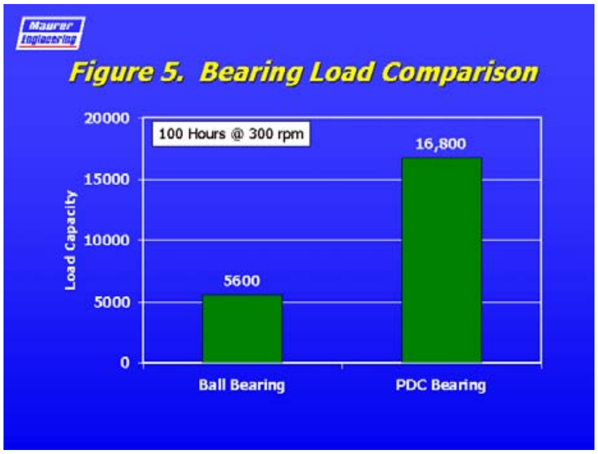
A major component of the system is a specially designed downhole mud motor. This motor is equipped with a modified power section, diamond thrust bearings, and a high-pressure labyrinth seal system. **Figure 3** shows the high-pressure (10,000 psi) motor that was successfully developed during Phase II.



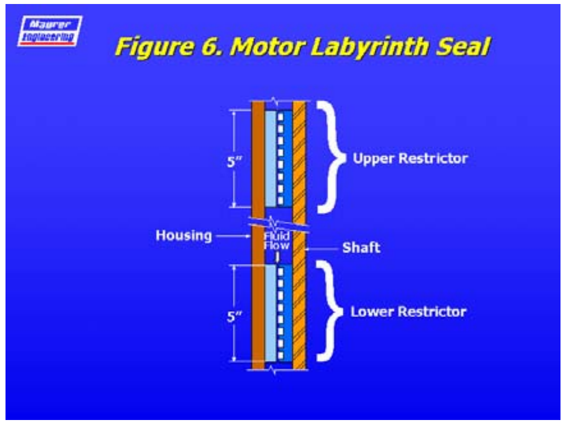
Polycrystalline diamond (PDC) motor thrust bearings were developed that utilize PDC diamond cutters to carry the thrust loads instead of steel ball bearings (**Figure 4**).

These PDC bearings allow much higher thrust loads than conventional ball bearings (16,800 lbs vs. 5,800 lbs), thus significantly increasing motor life and reliability (**Figure 5**).



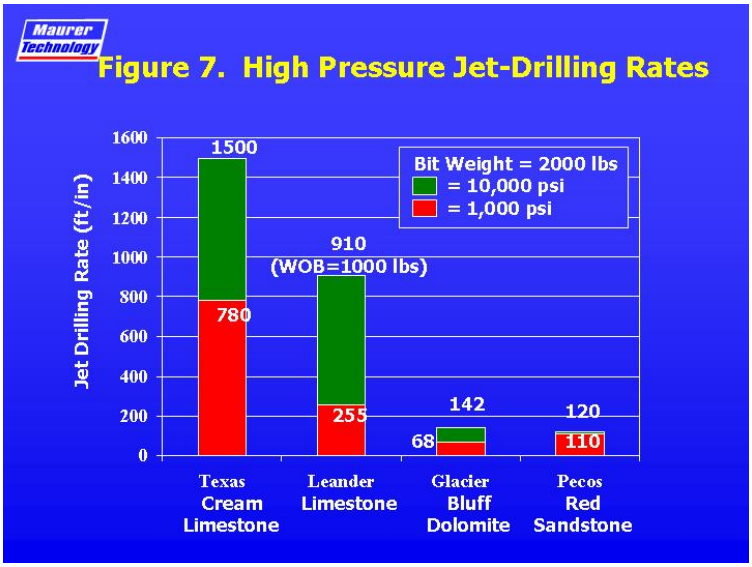


High-pressure labyrinth seals were developed that allow the drilling motors to operate reliably at 10,000 psi pressure (**Figure 6**). About 10% of the high-pressure fluid is diverted through the diamond bearings to cool and lubricate them, the remaining fluid passes through jets in the drill bit.



An early concern of this project was that standard 1.5-inch QT-800 coiled tubing operating at 10,000 psi pressure failed in fatigue after only 51 cycles in/out of the well. As a result, Quality Tubing, a major oil field coiled tubing manufacturer, developed QT-1200 coiled tubing which theoretically can be cycled 238 times at 10,000 psi before failure. The first reel of QT-1200 CT was developed for use on this DOE project. Subsequent field testing of the QT-1200 showed problems with the mode of failure and the life. Quality is doing more work on the metallurgy, but the tubing cannot be used for this project at this time. In addition composite coiled tubing that was seen as a backup tubing for this project has failed to meet expectations as well. These set backs have lead to the field test that is being proposed for a Phase IIA. This field test will use jointed pipe to convey the system.

Laboratory drilling tests of the high-pressure jet kerf drilling system showed its ability to increase penetration rates in a number of different rock types. **Figure 7** shows the results of these tests. Glacier Bluff Dolomite has a compressive strength of 20,000 psi. In this formation the rate increased over 208%.


Maurer Technology
Figure 7. High Pressure Jet-Drilling Rates
Jet Drilling Rate (ft/in)
1600
1400
1200
1000
800
600
400
200
0
Bit Weight = 2000 lbs
= 10,000 psi
= 1,000 psi
1500
780
910
(WOB=1000 lbs)
255
142
68
120
110
Texas Cream Limestone
Leander Limestone
Glacier Bluff Dolomite
Pecos Red Sandstone

Phase III Field Testing

A field test of the coiled tubing deployed, high-pressure jet kerf drilling system was conducted at the Catoosa test site in February of 2002 (**Figure 8)**.

Figure 8 Catoosa Test Site

BJ, the systems commercializer at the time, set up a coiled tubing rig with a large frac pump over one of the test wells at the Catoosa site (**Figure 9 & 10**). After the coiled

Figure 9. CT Rig Over Well Head

tubing (CT) unit was in place, the bottom hole assembly (BHA) was rigged and run into the hole (RIH). The coil and piping was flushed with drilling fluid before rig up to remove any frac material left in the lines. Drilling was commenced and continued at approximately 300 ft/hr for a short time. The drill string pressure spiked and flow decreased. During this period, large quantities of cutting were coming over the shaker. These appeared to be cement and/or shale.

The BHA was pulled to inspect the mud motor to see if the rubber stator had been damaged and was plugging the tool. A surface examination could not reveal any damage, but a smaller tool was rigged anyway and preparations made to run this tool. During pressure tests of the small tool, it was determined that the cause of the problem was not the mud motor but a plugged downhole screen. Despite blowing the pump and iron down, frac material remained in

Figure 10. Frac Truck

the lines until the flow was increased to run the tool. With the increased flow and pressure trapped frac sand was loosened and pumped down hole. A surface screen-sub, that would have caught this sand, had been left out of the system. This allowed the frac sand (**Figure 11**) that should have been caught at the surface to plug the downhole screen.

Figure 11. Frac Sand Caught in Downhole Screen

Once this discovery was made, the larger 4-3/4 in. motor was rigged up again and RIH. However, the tool encountered resistance before reaching bottom and could not be run. Maurer Technology personnel asked BJ at the time if the problem could be swelled tubing. BJ indicated that this could not be the problem and stated that the injector would be strong enough to push the tubing through the injector even if it was swelled. Since no other cause could be determined it was assumed that the casing had collapsed and this was preventing the tool from reaching the bottom. The small motor was again rigged to see if it could get by the collapsed casing. Since it could not, the test was terminated.

The hole was camera inspected after the test and this showed that the casing was not collapsed. Maurer Technology requested that BJ inspect the coiled tubing and it was then discovered that the tubing had indeed swelled. The swelling was severe enough that there was no way for the tubing to pass through the stuffing box no matter how strong the injector was. As part of the camera inspection, a sinker bar was run as well. It was discovered at this time that the well was not 275 ft deep as was thought, but 600 ft deep. There is no explanation as to why so many cuttings were coming across the screen during the first drilling test, but clearly the tool was not drilling new formation.

While many valuable lessons were learned about running the tool and rigging up, no drilling data was gathered during this test. It was determined that another test was needed and that jointed pipe be used to avoid the problems with fatigue on the coiled tubing.

Phase II-B Work Statement

Task 1 Rebuild High-Pressure Mud Motors

Under this task Maurer Technology will disassemble, inspect, and reassemble the 3-1/8 in. (two) and 4-3/4 in. (one) mud motors that make up the HP drilling system. Any parts that are found to be out of specification will be replaced. Once completed all of the motors will be prepared for the tests. The deliverable for this task will be three mud motors that have been rebuilt and are ready for field operation.

Task 2 Modify Rig

Under this task, RMOTC will prepare the rig for high pressure drilling. These preparations will include purchasing a new pump capable of operation at 10,000 psi, upgrading rig piping and stand pipe to 10,000 psi working pressure, and purchasing a rotary hose that has 10,000 or greater working pressure. RMOTC will also manufacture a swivel for use during the test. This swivel will be designed to be stationary during high-pressure operations, but will rotate to facilitate make up of tool joints on the drill pipe. RMOTC will also review safety issues with Maurer Technology engineers and install any necessary blast shields or other safety equipment to protect rig hands and technical personnel during the test. Together, Maurer and RMOTC will develop a safety plan addressing the use of high pressure drilling fluids. The deliverable for this task is an upgraded rig capable of 10,000 psi operating pressure, safety equipment and a safety plan.

Task 3 Test Rig at High Pressure

Under this task, RMOTC will test all of the modifications made to the rig for high-pressure operation. If any equipment is found to be inadequate, RMOTC will further modify or upgrade to meet the necessary minimum specifications. They will compile a report of the tests and this will be the deliverable under this task.

Task 4 Locate HP Drill String

RMOTC, working with Maurer Technology, will determine the specifications needed for a high-pressure drill string. RMOTC will then locate and secure a suitable drill string for this test. RMOTC will test the tool joints for leaks at 10,000 psi and demonstrate that the joints can be repeatedly made up without leaking. Failure to do this could result in a downhole washout and loss of the drilling string and BHA. RMOTC and Maurer will produce a report on the drill string specifications and results of the pressure tests. This report and the drill string will be the deliverable for this task.

Task 5 Test Coordination

Under this task, Maurer will work with RMOTC to plan the test, arrange logistics, and conduct safety and rig modifications. Maurer personnel will travel to the rig site prior to the test and meet with RMOTC personnel to review test plans, well plan, rig safety, and rig modifications. The deliverable under this task will be a complete test plan for the high-pressure jet kerf drilling test.

Task 6 Field Testing

Under this task, Maurer and RMOTC will test the high-pressure jet kerf drilling system in an RMOTC well. The test will be conducted in such a manner to determine and demonstrate the potential of the system including improved drilling rates, ease of field deployment, and commercial potential. During the test different formations will be drilled and the performance of the system in each documented. In addition, weigh-on-bit and flow rate will be varied to determine system performance under varying operationing conditions. Data of critical parameters such as flow, pump pressure, penetration rate, formation, and others will be recorded during the test.

Task 7 Test Analysis

Once the test has been completed, Maurer engineers will analyze the test data. This analysis will include a comparison to drilling rates on offset wells. The data will be compiled and prepared for presentation in the final report and for use in technical papers and talks.

Task 8 Final Report

Under this task, Maurer Technology will prepare the final report and presentation on the preparation (including rig modifications and HP system development) test plan, and test results. The data analysis conducted in Task 7 will be used and presented in this final report. In addition, Maurer Technology will prepare a technical paper on the test results for presentation at the spring SPE meeting or other major technical conference. Maurer personnel will present this paper at the conference. The deliverable under this task will include the final report and presentation at Morgantown, WV, and the technical paper.

Deliverables

Task 1

- 4-3/4 in. high-pressure mud motor rebuilt
- two 3-1/8 in. high-pressure mud motors rebuilt

Task 2

- o Upgraded rig with 10,000 psi working pressure capability
- o High-pressure safety equipment
- o Safety plan

Task 3

- o Report on high pressure test of upgraded rig

Task 4

- o High-pressure drill string suitable for use on the test
- o Report on the string specifications and results of pressure proof tests demonstrating that joints can consistently be made up without leaking

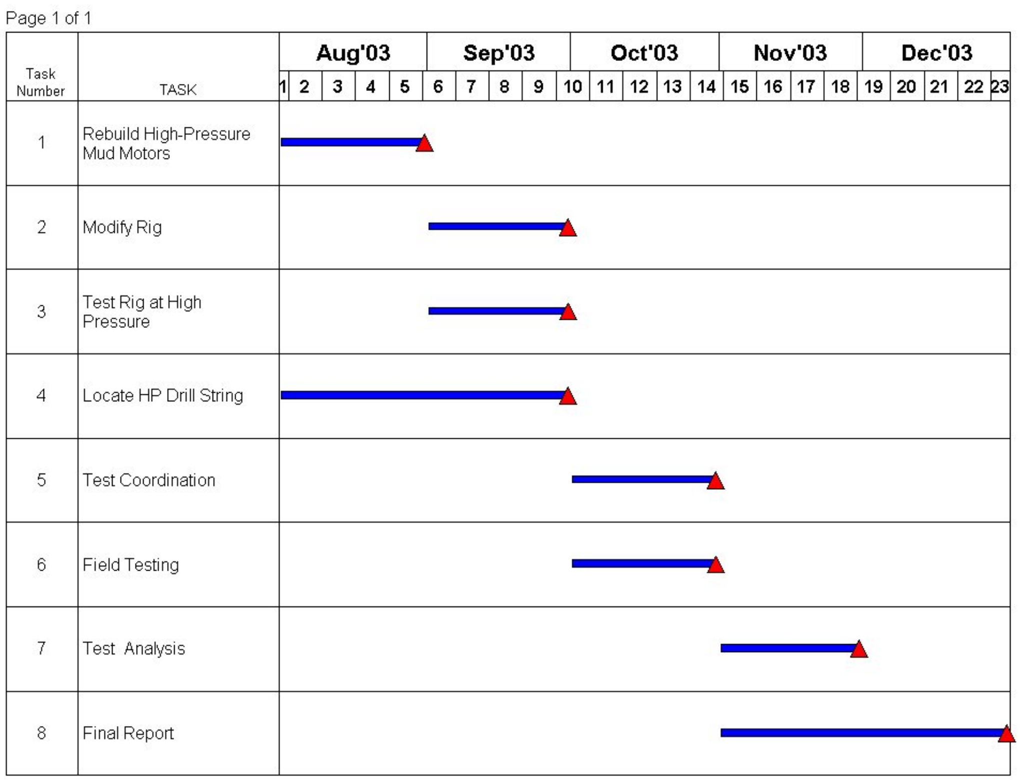
Task 5

- o Completed test plan

Task 8

- o Final report
- o Final presentation at FETC in Morgantown, WV
- o Technical paper for SPE spring meeting or other major conference
- o Technical paper presentation at technical conference

Project Schedule



Phase II-B Budget Summary

The entire cost of the project is $184,530, of this amount $130,950 is for labor including overhead, $8,000 for direct costs (shipping), $10,458 for travel and $35,113 in G&A. The project cost sharing is 25.08%, or $46,280. The Department of Energy cost is $138,251.

Cost sharing comes from three sources; (1) Maurer Technology Inc. is supplying a back up high pressure pump for the project at a value or $15,000. (2) Maurer Technology Inc. is cost sharing the time for one technician during the field test and Dr. William Maurer's time on the project., and (3) Smith international is supplying and engineer to monitor the project to determine if they see any commercial possibility from the technology. If they do, Smith will consider commercializing the system.

DOE-RMOTC-71014

Appendix D

MAURER TECHNOLOGY INC.:
HIGH-PRESSURE JET KERF DRILLING

Final Report for the Period of February 1–May 15, 2004

Date Completed: July 22, 2004

By Ralph Schulte

Prepared for the United States Department of Energy
Office of Fossil Energy

Work performed under Rocky Mountain Oilfield Testing Center (RMOTC)
CRADA 2004-046

Abstract

An extensive high-pressure drilling test has been completed with Maurer Technology Inc. of Houston, Texas. During the test, drilling pressures exceeded 8000 psi at mud circulation rates of 200 gpm. The total interval drilled was from 4363 feet to 5156 ft over a variety of formations ranging from clean, high-porosity sandstone to a limestone interval, shales and siltstones. The majority of the formation drilled was the Red Peak Shale. Significant increases in drilling rate were evident over specific intervals. Further testing of this technology may be warranted to reduce drilling costs and increase ROP.

Disclaimer

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List of Figures

Summary

An extensive, high pressure drilling test has been completed with Maurer Technology of Houston, Texas. During the test, drilling pressures exceeded 8000 pounds per square inch (psi) at mud circulation rates of 200 gallons per minute (gpm). The total interval drilled was from 4363 feet to 5156 feet over a variety of formations. The formations ranged from clean, high porosity sandstone to a limestone interval, shales and siltstones. The majority of the formation drilled was the Red Peak Shale at the Rocky Mountain Oilfield Testing Center located in the Powder River Basin of Wyoming.

The Rocky Mountain Oilfield Testing Center (RMOTC) is located at the Naval Petroleum Reserve 3 (Teapot Dome Field). The Teapot Dome oil field (NPR-3) is located 35 miles north of Casper, Wyoming (See Figure 1).

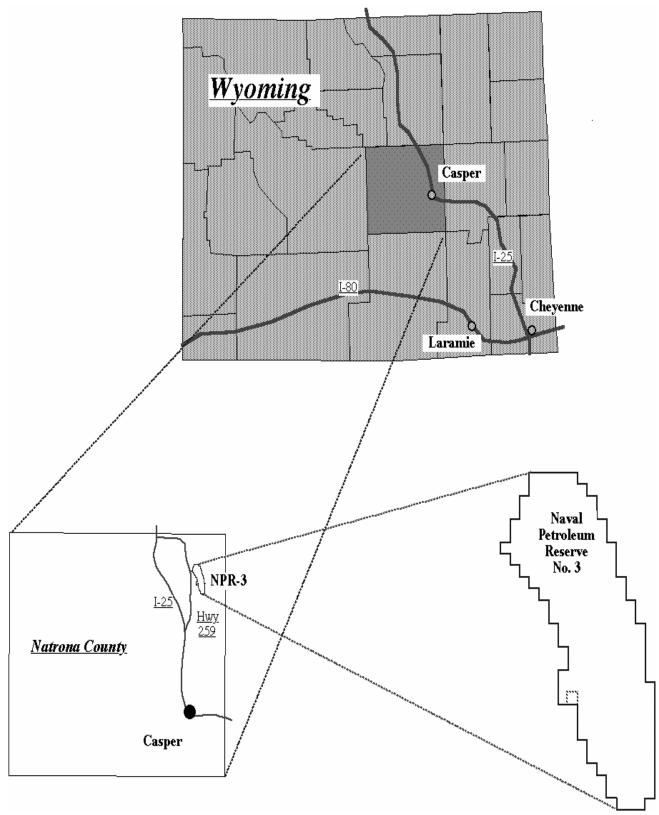


Figure 1. Location of Teapot Dome

The results of the test were essentially two fold. Significant increases in drilling rate were evident over specific intervals resulting in 2–7 times the normal historical drilling rate in the field. Although the highest rates of penetration (150 ft/hr) were achieved in the clean, high porosity sand of the Crow Mountain, the percentage of drilling rate increase (20–40% increase) was the lowest achieved due to the high rate of even conventional drilling. The Alcova limestone which is a typically harder formation had over a three fold increase in drilling rate (50 ft/hr) over the baseline rate of 13.5 ft/hr (See Table 1).

The highest percentage or fold increase occurred in the Red Peak formation (shale, siltstone, anhydrites) where drilling rates of 60–90 ft/hr were common with the high pressure drilling bits (See Table 1). The baseline rate for the Red Peak Shale estimated from offset data and deepening data of the well is 12–16 ft/hr.

The second aspect of the test was the limiting mechanical difficulties encountered with the high pressure mud motor, jets and PDC drill bits. The high pressure mud motor's stator failed quickly while drilling and the remainder of the test was completed without the downhole motor utilizing a mechanical rotary table, high pressure drilling swivel, high pressure kelly hose, and high pressure mud pump. During this testing phase, multiple drilling jets were lost or blown out from the bit body. As each jet was lost, the drilling pressure would drop from 8000 psi to approximately 3000 psi and the bit would be tripped out of the hole. The exact cause of this bit jet lost is being investigated with detailed mechanical review.

Mechanical problems with the cutters on one bit were also evident during the test. This bit (third bit) was a new bit which had been manufactured quickly at the end phase of testing operations. It is believed that a bad bond existed between the PDC compacts and the carbide studs. The suspect bad bonds resulted in a loss of cutter faces and ultimately breakage of the some of the posts. The other two bits did not indicate the same mechanical problem.

Initial mechanical problems with the surface equipment, including the high pressure kelly hose and drilling swivel were corrected to allow full testing of the high pressure downhole drilling equipment. The use of specialized drill pipe eliminated any leaks within the drill string. Pressure testing, drilling and safety procedures allowed the operation to proceed without incident.

Background

The Rocky Mountain Oilfield Testing Center has been involved with two major initiatives within the past several years to dramatically increase drilling rates by the use of novel or non-mainstream drilling procedures. The first series of drilling tests were completed with Prodril Services, Inc. of Cody, Wyoming. The second series of tests were completed Maurer Technology Inc. of Houston, Texas in May 2004.

The technology as demonstrated by ProDril relied on steel or metal “shot” in the drilling mud to cut a groove or kerf in the bottom of the drilling wellbore to increase drilling rate. The shot or small diameter metal spheres would then be recovered from the drilling mud and re-used again. See Reference 1.

The technology developed by Maurer Technology Inc. under partnership to the National Energy Technology Laboratory (NETL) was two fold utilizing high pressure drilling mud to drive a high pressure mud motor along with a high pressure bit. The high pressure drilling mud in conjunction with the small diameter drilling jets results in extreme velocity fluid streams. The high velocity fluid streams have, in principle, a similar effect on the bottom of the wellbore as the steel shot of ProDril, Inc. The high velocity streams kerf or cut a groove in the bottom of the hole to increase drilling rates.

Maurer summarizes the technology and history of development in their report, “Coiled-Tubing High Pressure Jet Drilling System” available on the NETL website. See Reference 2.

Historical Testing

The use of high pressure jet bits operating between 10,000 and 15,000 psi dates back to the early 1970s with Exxon, Shell, Gulf Oil and FlowDril case histories. The case history presented by Maurer[2] included an Exxon field test where conventional bits drilled a 3500-ft interval in approximately 65 hours of rotating time (54 ft/hr). The erosion bit or high-pressure bit drilled the same interval in approximately 22 hours of rotating time (159 ft/hr) or approximately three times as fast. Maurer states however, "These systems were not commercialized because of difficulties in pumping the high-pressure fluids to the hole bottom through conventional threaded drill pipe."

The concerns with threaded drill pipe connections resulted in the initial development of the Maurer High Pressure mud motor and drill bits to be used on coiled tubing (CT). This CT system was tested with masked results due to several mechanical surface issues with the coiled tubing, mud system, and well conditions at a field test site. A conclusive test of the system was not achieved because of the surface mechanical difficulties.

As a second option with conventional drill pipe, RMOTC was contacted in 2003 to determine if the drilling system could be tested a second time with conventional threaded drill pipe with the downhole mud motor and high pressure bits. General drilling objectives were given for interval length (2000 ft), formation lithology (shales, sands, dolomites, etc) and rock properties (competent rock with ROP not a factor for hole cleaning).

Design of Test

Well Selection

The geologic column of RMOTC is shown in Figure 2. The field, located in the Powder River Basin of Wyoming has nine producing horizons ranging from approximately 500 ft in depth to 5500 ft.. The deepest producing horizon is the Tensleep, a strong water drive sandstone reservoir, at 5500 ft. The shallow formations (<3000 ft) are easily drilled with mud or more often with air for underbalanced drilling. The high rates of penetration for the shallow Steele and Niobrara shales are similar to the Exxon field test as presented by Maurer. The shallow formations (Steele and Niobrara Shales) are naturally fractured and are produced openhole from the fractures.

The shallow Upper Cretaceous Steele and Niobrara shales have been historically drilled with either roller cone bits (such as a Hughes GT-1 or IADC code 116) or fishtail bits using air. Rates of penetration (ROP) are often as high as 50–100 ft/hour using air.

Typically, the deeper horizons are harder and slower to drill. Recent RMOTC tests in the Lower Tensleep/Amsden formation were drilled with a medium hard bit (Hughes STX-30 or IADC code 537). Tensleep and Amsden are Pennsylvanian age and are sandstones, dolomites, and dolomitic sandstones. ROPs are generally 10 ft/hr using a light mud.

Table 1
Drilling Performance Summary

Date	Time Start	Time End	Elapsed Time Hrs:Min:Seconds	Depth Begin	Depth End	Interval Feet	ROP Feet/hr	Drilling System	Formation	Comments	Offset Well ROP 41-2-X-3	Offset Well ROP 71-1-X-4	Average Offset	Drilling Ratio ROP/Ave ROP
April 25, 2004	1:33 AM	1:54 AM	0:20:48	4363.0	4370.9	7.9	22.8	HP Mud Motor	Lower Sundance Sands	First Bit (repaired) Limited Run Data. Dropping Pressure with Spikes.	21.8	33.3	27.6	0.83
			0:5:00	4364.0	4368.0	4	48	HP Mud Motor	Lower Sundance Sands	Data Subset - Estimate			27.6	1.74
			0:5:00	4368.0	4370.0	2	24	HP Mud Motor	Lower Sundance Sands	Data Subset - Estimate			27.6	0.87
				4370.0	4370.9	1	4	HP Mud Motor	Lower Sundance Sands	Curve Fit Estimate			27.6	0.15
April 27, 2004	1:00 PM	1:46 PM	0:45:38	4371	4403	32	42.1	HP Rotary	Unnamed Transition	Second Bit - Initial run	20.0	17.1	18.6	2.27
	2:07 PM	2:20 PM	0:13:16	4403	4435	32	144.7	HP Rotary	Crow Mountain Sand	Second Bit - Initial run	120.0	120.0	120.0	1.21
	2:32 PM	2:44 PM	0:11:32	4435	4467	32	166.5	HP Rotary	Crow Mountain Sand	Second Bit - Initial run	120.0	120.0	120.0	1.39
	2:56 PM	3:34 PM	0:38:33	4467	4499	32	49.8	HP Rotary	CM/Alcova Limestone	Second Bit - Initial run	15.0	12.0	13.5	3.69
	3:48 PM	4:38 PM	0:35:27	4493	4525	32	54.2	HP Rotary	Red Peaks Shale	Time adj. for downtime	17.6	12.0	14.8	3.65
	4:45 PM	6:02 PM	0:34:18	4525	4557	32	56.0	HP Rotary	Red Peaks Shale	Time adj. for downtime	17.6	12.0	14.8	3.78
April 28, 2004	12:56 AM	1:22 AM	0:26:33	4557	4579	22	49.7	HP Rotary	Red Peaks Shale	2nd Bit - Second Run. Change in BHA	17.6	12.0	14.8	3.36
	1:37 AM	2:00 AM	0:22:08	4579	4611	32	86.7	HP Rotary	Red Peaks Shale	Second Bit -Second Run	17.6	12.0	14.8	5.86
	2:13 AM	2:38 AM	0:24:47	4611	4643	32	77.5	HP Rotary	Red Peaks Shale	Second Bit -Second Run	13.3	12.0	12.7	6.12
	2:51 AM	3:13 AM	0:22:19	4643	4675	32	86.0	HP Rotary	Red Peaks Shale	Second Bit -Second Run	13.3	10.0	11.7	7.38
	3:30 AM	3:55 AM	0:25:24	4675	4707	32	75.6	HP Rotary	Red Peaks Shale	Second Bit -Second Run	13.3	10.0	11.7	6.49
	4:08 AM	4:29 AM	0:21:10	4707	4739	32	90.7	HP Rotary	Red Peaks Shale	Second Bit -Second Run	13.3	10.0	11.7	7.79
April 29, 2004	6:03 AM	6:34 AM	0:31:01	4739	4771	32	61.9	HP Rotary	Red Peaks Shale	First Bit - Second Run	13.3	13.3	13.3	4.65
May 2, 2004	1:21 PM	1:50 PM	0:29:55	4772.0	4804.1	32.1	64.4	HP Rotary	Red Peaks Shale	Third Bit (New)	13.3	13.3	13.3	4.84
	2:06 PM	2:28 PM	0:21:13	4804.1	4836.7	32.6	92.2	HP Rotary	Red Peaks Shale	Third Bit (New)	13.3	13.3	13.3	6.93
	3:15 PM	3:46 PM	0:23:37	4837.0	4868.7	31.7	80.5	HP Rotary	Red Peaks Shale	Time adj. for downtime	13.3	13.3	13.3	6.06
	3:56 PM	4:24 PM	27:53.0	4869.0	4899.1	30.1	64.8	HP Rotary	Red Peaks Shale	Third Bit (New)	15.0	13.3	14.2	4.58
	4:37 PM	5:05 PM	27:34.0	4899.0	4931.6	32.6	71.0	HP Rotary	Red Peaks Shale	Third Bit (New)	15.0	13.3	14.2	5.01
	5:16 PM	5:55 PM	0:35:16	4932.0	4964.4	32.4	54.4	HP Rotary	Red Peaks Shale	Time adj. for downtime	15.0	13.3	14.2	3.85
	6:08 PM	7:06 PM	0:57:08	4964	4997.1	33.1	34.8	HP Rotary	Red Peaks Shale	Third Bit (New)	12.0	16.2	14.1	2.47
May 4, 2004	8:40 PM	9:33 PM	0:53:36	4999.2	5029.4	30.2	33.8	HP Rotary	Red Peaks Shale	Third Bit (Repaired Second run)	12.0	16.2	14.1	2.40
	9:45 PM	10:36 PM	0:51:12	5029.5	5062.1	32.6	38.2	HP Rotary	Red Peaks Shale	Third Bit (Repaired Second run)	12.0	16.2	14.1	2.71
	10:48 PM	11:29 PM	0:41:02	5062.1	5094.5	32.4	47.4	HP Rotary	Red Peaks Shale	Third Bit (Repaired Second run)	12.0	16.2	14.1	3.36
May 5, 2004	11:42 PM	12:27 AM	0:45:27	5094.0	5127.0	33.0	43.6	HP Rotary	R.P./Goose Egg	Third Bit (Repaired Second run)	12.0	16.2	14.1	3.09
	12:36 AM	1:33 AM	0:57:01	5124.7	5157.9	33.2	34.9	HP Rotary	Goose Egg	Third Bit (Repaired Second run)	12.0	16.2	14.1	2.48
May 6, 2004	2:16 PM	4:14 PM	1:58:41	5161.0	5192.8	31.8	16.1	Conventional	Goose Egg	Conventional Bit	12.0	16.2	14.1	1.14
	4:31 PM	7:33 PM	3:02:27	5193.0	5224.9	31.9	10.5	Conventional	Goose Egg	Conventional Bit	12.0	16.2	14.1	0.74
	7:42 PM	11:06 PM	3:24:33	5225.2	5257.1	31.9	9.4	Conventional	Goose Egg	Conventional Bit	12.0	16.2	14.1	0.66
May 7, 2004	11:20 PM	3:02 AM	3:41:31	5257.0	5289.6	32.6	8.8	Conventional	Goose Egg	Conventional Bit	12.0	16.2	14.1	0.63
	3:11 AM	4:36 AM	1:25:16	5289.7	5300.0	10.3	7.2	Conventional	Goose Egg	Conventional Bit	12.0	16.2	14.1	0.51

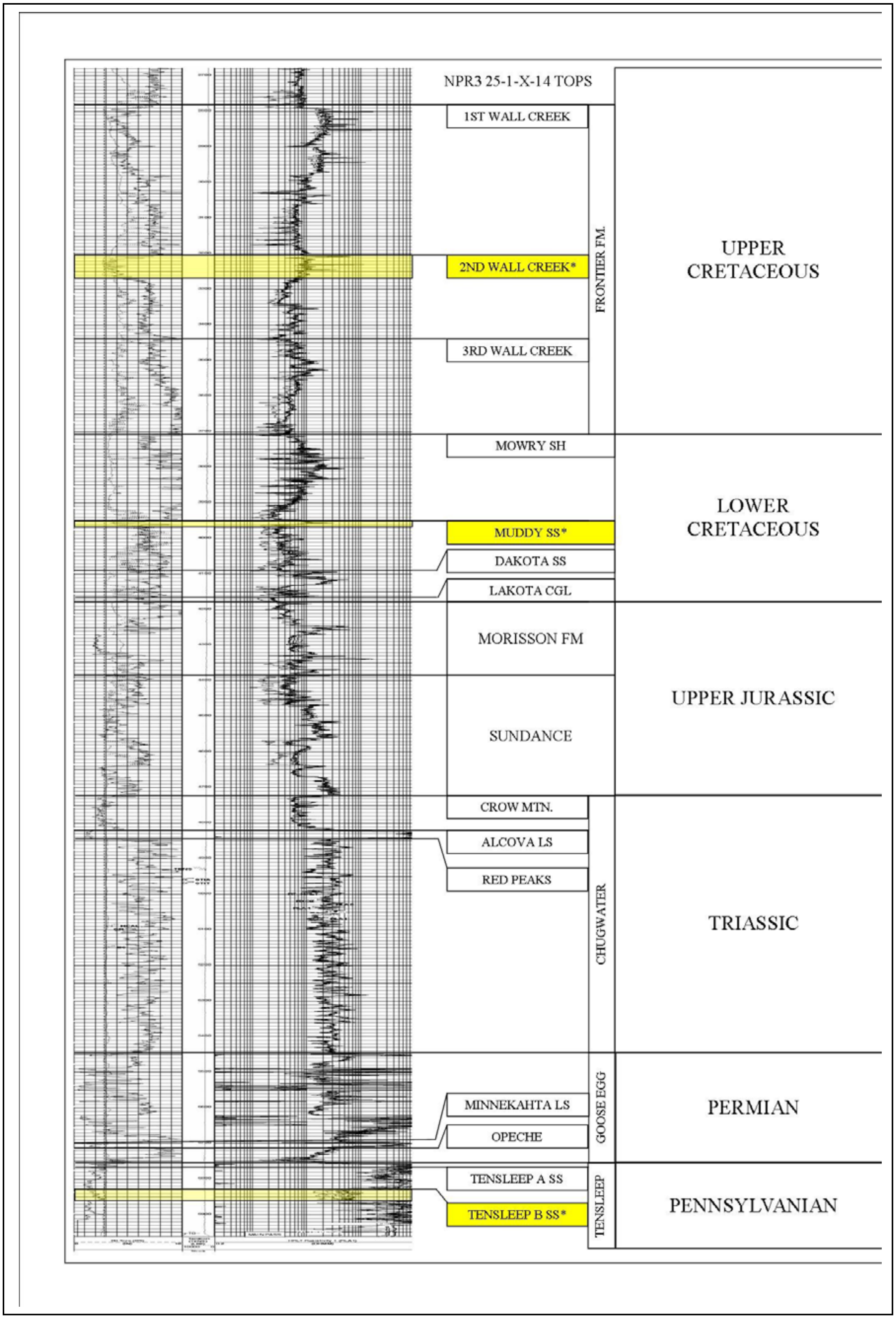


Figure 2. RMOTC Geologic Column

Lost circulation is often encountered in the Second Wall Creek at 3000 ft due to pressure depletion. Based on the drilling objectives, reservoir and drilling histories, the interval from 4300 ft to 6300 ft was selected. This interval avoided the majority of the problematic fractured intervals and depleted zones and had a variety of formations including high porosity sandstone, a hard limestone, a lengthy interval of mixed lithology, and a lower porosity sandstones, and dolomites.

Based on desired casing size, depth requirements, operational objectives, a recent 3-D seismic interpretation, a new well site was selected in the northern end of the field.

Equipment Design

The technical effort at RMOTC focused on two primary areas. The first area was the geology and drilling aspects of the test and the second area was the surface and downhole equipment to accomplish the high pressure drilling test.

Normal drilling pressures are generally 3000 psi or lower. Some of the deeper wells in Wyoming (20,000 ft+) have drilling pressures of 4000 psi based on the personal drilling experience from our crews. The use of high pressure drilling mud in the range of 8,000 – 10,000 psi greatly exceeds all normal operations. Several initial options were investigated in the early stages to determine the best course of action for the high pressure pumping services.

High Pressure Mud Pump

ProDril Services, Inc. due to their use of steel shot in the mud system utilized contracted pumping services from Halliburton. Similar considerations were explored for the Maurer test. One stumbling block appeared to be the use of a high pressure kelly hose required for the drilling operation. The operational liability of utilizing a high pressure hose was a hindrance in using contract pumping services. The use of steel hard line with swivel joints was discussed to replace the kelly hose but was determined to be only a second or third option.

National manufacturers of drilling equipment were contacted to determine if a high pressure mud pump system rated for approximately 10,000 psi could be built or developed to meet the test requirements. Mid-coast Diesel of Victoria, Texas responded with an existing system which could be modified with a new fluid end to meet the stated objectives. The existing system was developed for offshore use for pumping mud, cement, or other services. The existing fluid end had 5 inch plungers which would be replaced with 3¾-inch plungers to reach the desired objective. The modifications to the pump package included the addition of a pulsation dampener rated at 10,000 psi.

Surface Equipment

Surface equipment such as standpipe, standpipe valves, gooseneck, and mud line were replaced on the drilling rig (DOE#2) to meet testing specifications. The existing Kelly hose was replaced with a new hose rated for 10,000 psi. The existing drilling swivel was also replaced with a new unit specifically modified to handle 10,000 psi while rotating. The new kelly hose and drilling swivel proved to be the most troublesome items of the surface equipment.

The intent of the above modifications to the drilling rig was to allow maximum flexibility during the test phase. The drilling rig was modified in such a manner to allow either high pressure drilling with a mud motor (drill string non-rotating) or high pressure drilling without a mud motor and using a mechanical rotary table. The combination of rotating the drill string and using the downhole mud motor could also be performed with the above system. This initial design selection turned out to be instrumental in completing the Maurer test.

Drill String

As previously stated by Maurer, early high pressure systems developed in the 1970's were not commercialized due to difficulties with threaded drill pipe connections. This problem was a major stated concern at a very early stage of test design. National pipe manufacturers were contacted along with local oilfield service companies to determine the best available technology to address possible leaks in the tool joint connections. Based on technical discussions and possible pipe availability, Weatherford's 3½" S-135 drill pipe with the HT tool joint connection was used. The HT connection is designed for high pressure and high temperature work with primary and secondary sealing faces on the pin and box.

During the entire drilling operation at 8000 psi, no leaks developed in the drill pipe. The drill collars and some surface crossover subs had a more standard thread design, 3½ IF. No leaks were detected in the IF connections either.

Although the HT thread is a better design for high pressure work, it may be possible to use a more standard thread connection at this pressure range, 8000 – 10,000 psi. The burst pressure of the S-135 pipe is almost twice the anticipated maximum working pressure so there was little concern with pipe body strength. .

Mud Cleaning System

No significant capital investment was made to upgrade the solids removal system; however, several operational changes were made to minimize the presence of drill solids in the mud system. Due to the small jets in the high pressure PDC bit (~2/32 inch), there was concern that any extraneous material or drill solids in the mud system would plug the bit resulting in a quick high pressure spike in the system.

The first operational change was to completely empty and clean the mud tanks after the 7” 23# casing was set at 4300 ft above the Crow Mountain formation. At this point, the tanks were refilled with clean water and an inhibited mud system was mixed. The inhibited mud system was used to minimize clay swelling and hole sloughing while drilling. The use of the inhibited mud system would therefore also lower wellbore risks.

Another operational change was the use of new, properly sized drill pipe screens to catch any extraneous material and drill solids before going downhole. During testing operations, the screen was checked regularly and was useful on several occasions in preventing large pieces of material from entering the drill string. Another screen, provided by Maurer, was present downhole to catch any debris of the drill pipe wall.

During testing operations, no problems or obstacles with the mud cleaning system were identified.

The remaining downhole equipment was the high pressure mud motor and high pressure drill bits.

High Pressure Mud Motor and Drill Bits

The technical features of the high pressure mud motor and drill bits are described in some detail elsewhere (see Reference 2). Maurer states, “This motor is equipped with a modified power section, diamond thrust bearings and a high pressure labyrinth seal system.”

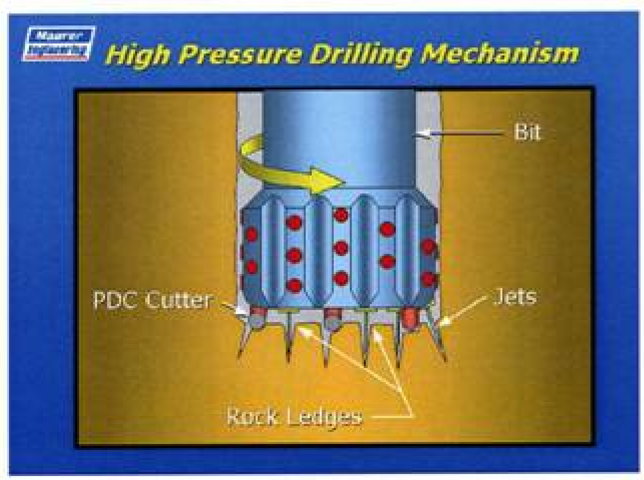


Figure 3. High Pressure Drilling Mechanism.

Figure 3 (after Maurer) shows a generalized schematic of the high pressure drill bit and the high pressure drilling mechanism. Maurer states, “This drill uses high-pressure water jets to cut slots in the rock ahead of the drill bit and PDC diamond cutters to break off rock ledges between these slots.”

This system was originally planned to be used on coiled tubing; however, field testing was discouraging due to surface equipment difficulties (swelled coil tubing, etc). No usable data were gained by the initial field test utilizing coiled tubing.

Well Site Selection - Well 48-X-28

The well site was selected based on test objectives for depth, interval length, and rock properties. In addition, a possible Tensleep target was identified based on recent 3D seismic studies. Possible coring opportunities were also considered if the drilling test did not reach the proposed core point.

The location for the test well, Well 48-X-28, was built in early 2004. The RMOTC drilling rig was being utilized on a different test well until late January, 2004. The rig was modified for high pressure during February 2004 and moved to location. The well was spudded on March 2, 2004 with two short RMOTC tests on the upper portion of the hole. Seven inch (7” 23lb/ft) casing was set mid March and cemented. Initial pressure testing and mechanical break-in operations began during the latter part of March, 2004.

Initial Mechanical Difficulties

The initial pressure tests of the drilling system were not successful due to leaks present in the end couplings of the new kelly hose. The hose was returned to the manufacturer for repair. Prior to return, some limited rate and pressure data was collected on the high pressure mud motor and drill bits. The pressure was estimated to be approximately 1000 psi low at the test rates. Although not apparent at that time, the lower pressure may have been the first evidence for some of the mechanical difficulties to follow with the drill bits.

The repaired kelly hose was retested in early April with poor results. A new hose was requested from the manufacturer under warranty. The second hose was delivered mid April and pressure tested on April 20 with adequate results.

Other minor mechanical problems associated with throttle control of the new pump, rupture disks on the nitrogen bladder of the pulsation dampener, and pressure bleed off operations were corrected. Some other small mechanical problems would be evident as the test progressed further and corrected at that time.

After successful testing of the second new kelly hose, the bit was tripped to 4200 ft to circulate and condition the mud in the wellbore. The circulation operation utilized the high pressure bit is described below.

Performance of First High Pressure Bit while Circulating

Figure 4 summarizes the pressure and rate data for the initial bit while circulating and conditioning mud at 4200 ft in the 7” casing. Initial pressures exceeded 6000 psi at a pump strokes per minute (spm) of 167. Over a period of an hour and a half, the pressure continually dropped. The final test pressure was 4800 indicating a drop of over 1200 psi.

The bit was tripped out of the hole and inspected. Picture 1 shows the beginnings of erosion around one of the jets present. At least several other jets were beginning to erode. The bit was returned to Houston for inspection along with a second bit that was to be used only as a standby.

Upon inspection of the threaded jet connection, it was decided to weld or braze the jets into the body of the bit. The second bit, which had not been used, was modified by using epoxy to hold the jets in place and prevent fluid from eroding the small threaded connections. Even though a temporary fix for both bits, it was anticipated that additional test data could be collected without delaying the project.

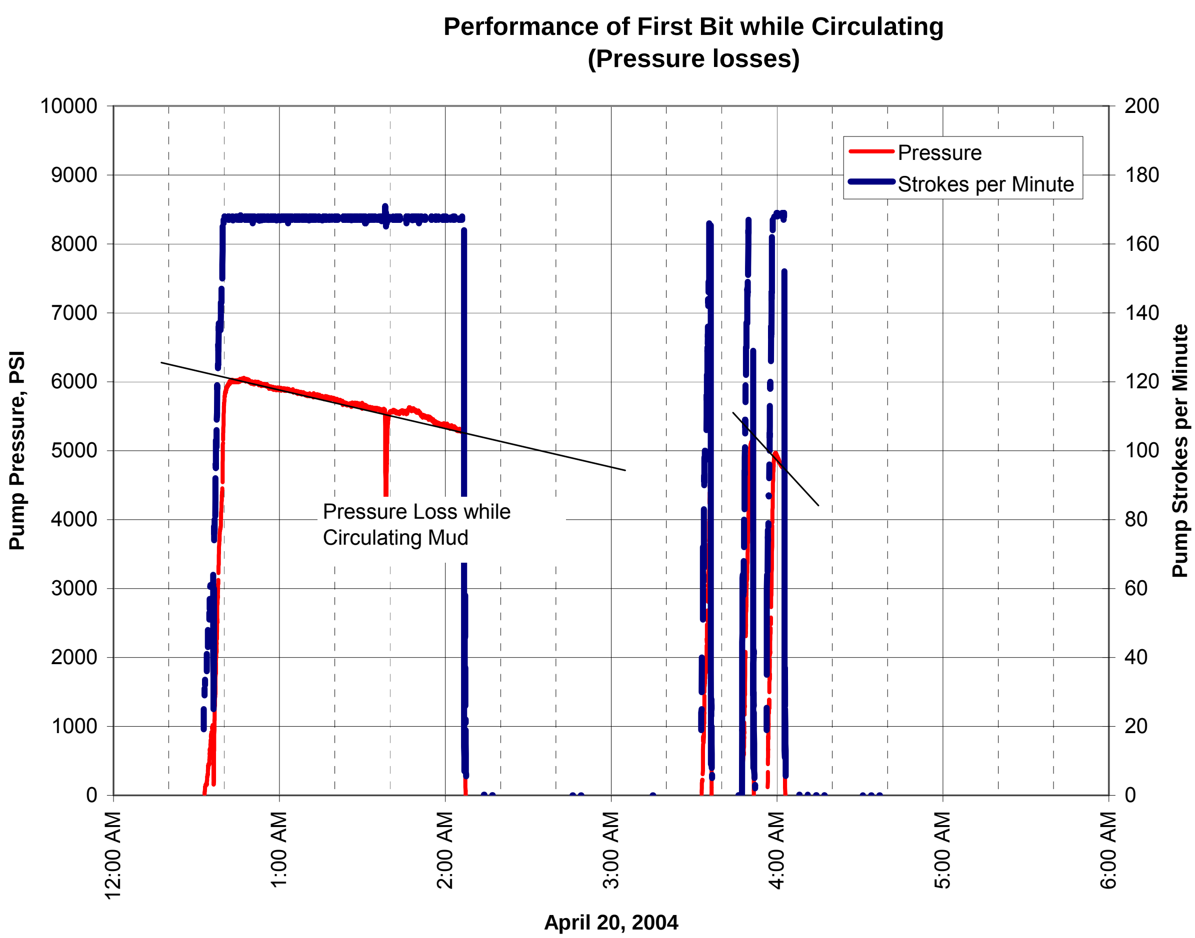


Figure 4. Performance of First Bit While Drilling.

Drilling Performance of First Bit with HP Mud Motor

After the bits were repaired and returned to Casper, Wyoming. The high pressure mud motor and bit was tripped in the hole on April 25, 2004. The initial starting depth of the well was 4363 feet at this time. Drilling began early morning with the mud motor at 1:33 AM and only lasted 21 minutes until a high pressure spike opened the pressure relief valves. Table 1 summarizes the results of the motor run. Figure 5 and Figure 6 show the real time drilling data.

From Figure 5, it is seen that the drilling pressure was continually dropping during the short run with multiple short pressure spikes. The pressure drop indicated that the temporary fix to the threaded jet erosion was not successful. The jets were still eroding around the exterior of the jets. The pressure spikes probably indicated or were a precursor to the final large pressure spike (10,500 psi). The large pressure spike which ended drilling operations was the result of the elastomer of the high pressure mud motor stator failing. After tripping the drill string, the bit was plugged with elastomer debris for the motor. Since the jets of the drill bit are small (~2/32 inch), the jets are easily plugged. The downhole drill pipe screen was also damaged with a split along its length allowing the rubber particles to plug the bit.

From Table 1, the formation at the test depth was the sands of the Lower Sundance which lie some 30 feet above the top of the Crow Mountain sandstone. The Sundance at RMOTC is not an oil or gas producing interval so reservoir knowledge of the horizon is limited. Based on the openhole porosity logs, the Lower Sundance sands appear to be fairly clean and porous sands. See Attachment D-2 for the Openhole Logs. Shading has been applied to the log display for density porosity above 10%.

Initial drilling rates were estimated at 48 ft/hr dropping to 24 ft/hr and finally 4 ft/hr. Curve fit data was used to estimate the final drilling rate. See Table 1 and Figure 6. Offset drilling data from two recent wells, 41-2-X-3 and 71-1-X-4, indicated a drilling rate of 22–33 ft/hr or an average of 28 ft/hr. See Table 1. The initial drilling rate of 48 ft/hr over the interval 4364 to 4368 compares favorably with the offsets; however, the interval is too short to be of much statistical use. The dropping rate of penetration (ROP) from 4368 to 4371 may be the result of the continually dropping pressure, pressure spikes of the failing stator elastomer, or a change in lithology.

Whatever the determining causes, the short interval drilled before elastomer failure limits any significant comparative analyses.

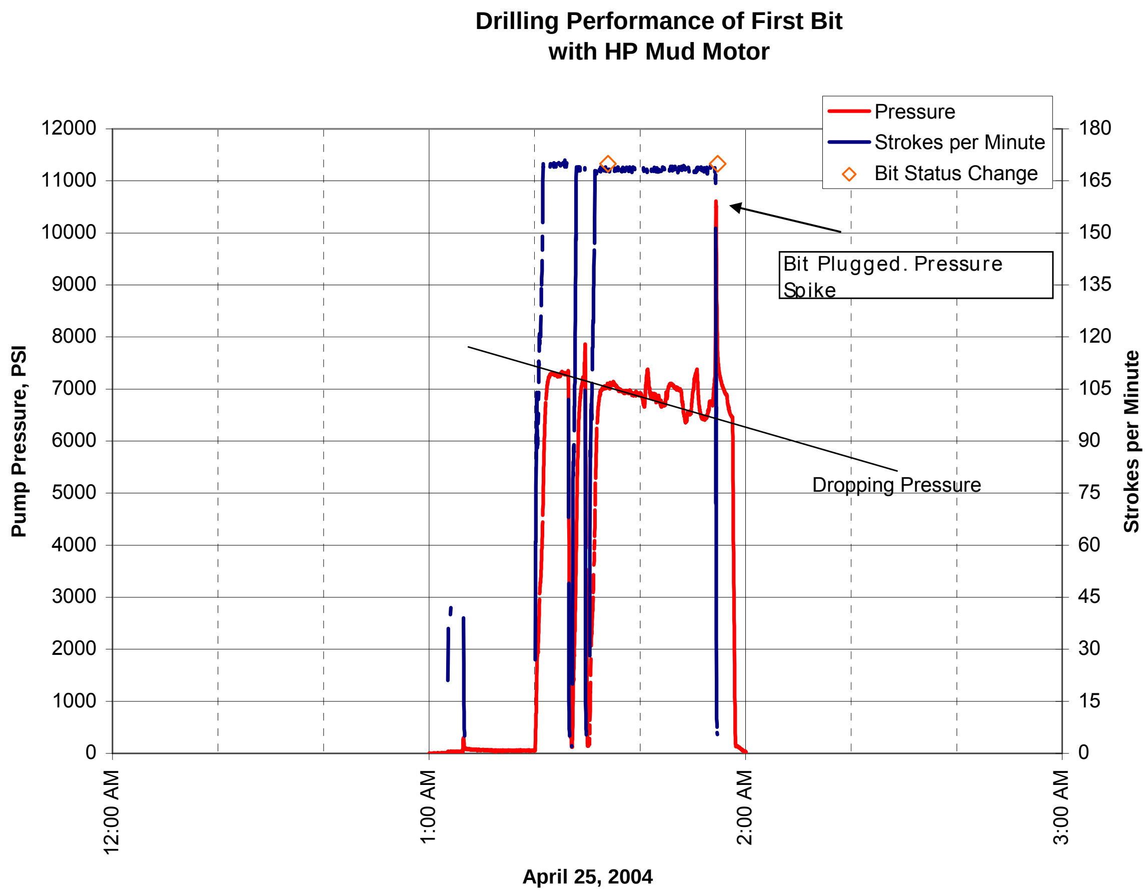


Figure 5. Pump Pressure and Strokes per Minute, First Bit with HP Mud Motor.

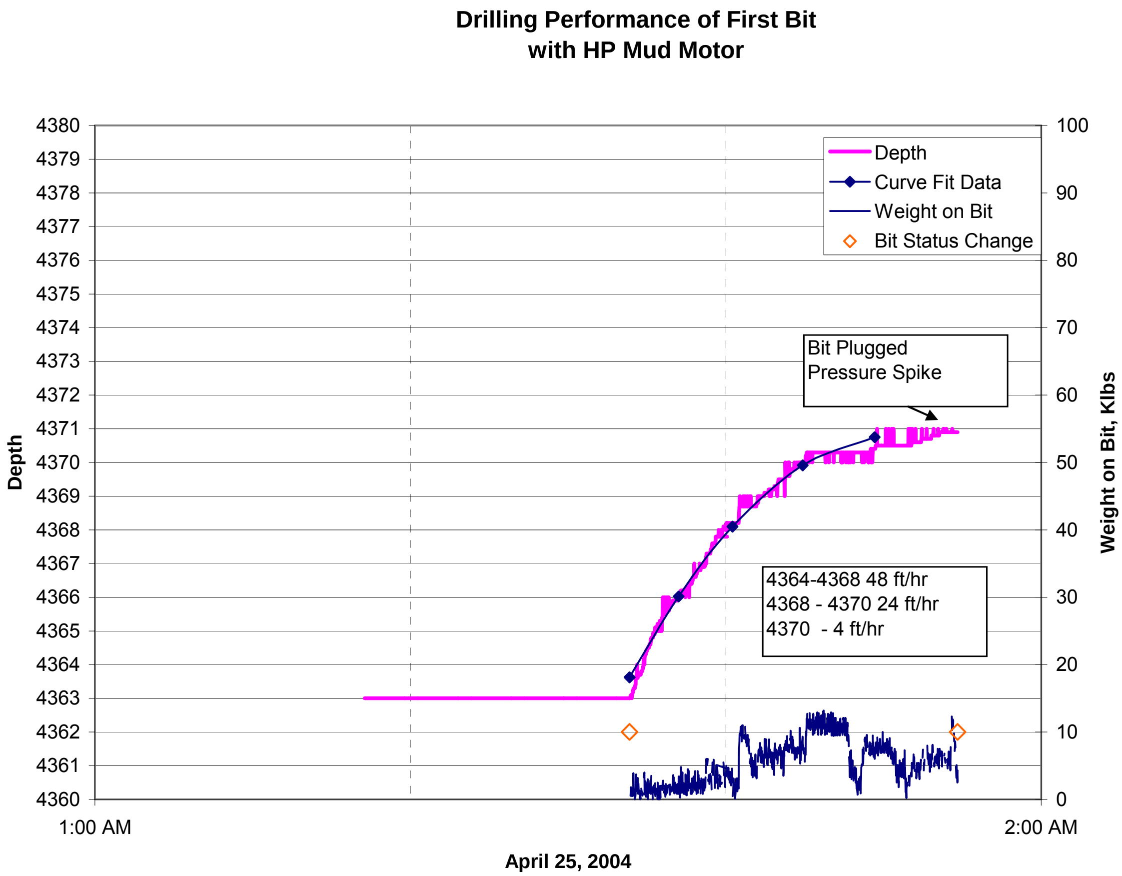


Figure 6. Drilling Performance of First Bit with High Pressure Mud Motor.

Drilling Performance of Second Bit – Initial Run

At this point in the testing operation, the failure of the high pressure mud motor, with no replacement, resulted in a change of operation. As stated previously, the initial design of the test included the capability of conventional high pressure drilling utilizing a mechanical rotary table, high pressure kelly hose, and a new high pressure drilling swivel modified for rotation at high pressure.

The initial run of the conventional high pressure system was on April 25, 2004. The swivel had some bearing difficulties and required several days for replacement parts to be ordered and arrive. After a rebuild of the swivel packing, no further mechanical problems were evident with the swivel for the remainder of the test. The swivel was greased and inspected regularly due to the high pressure (8000 psi) being applied during rotating.

The backup high pressure drill bit (Second Bit) was run in the hole on April 27, 2004. The starting depth of the well was 4371 feet at this time. Drilling began early afternoon and the run lasted for approximately five hours when it was decided that additional collar weight was required. Table 1 summarizes the results of this initial run of the second bit. Figure 7 and Figure 8 show the real time drilling data.

DOE #2 utilizes a kelly and mechanical rotary table picking up single joints of drill pipe as the well is drilled. This initial run resulted in six joints of drill pipe being picked up (six kellys down) as shown in Figure 8. The detailed data record as stored by the electronic data system was used to estimate the start and end times for each specific drilling interval. The change in bit status as recorded by the software was utilized to delineate the time intervals. Adjustments were made for mechanical or operational downtime. The time intervals were correlated with hand written field notes to ensure validity.

For part of the testing operations, third party equipment was recording incorrect depth measurements. The third party was under contract to RMOTC and not associated with the testing partner. The depth measurements appeared to be about 12.5% high. i.e.: for every 32 ft drill pipe joint used, the depth interval would advance 36 feet or more. The depth correlation problem (hardware, calibration) would not be fixed until May 2. Tallies of the drill pipe were used to track the current depth until the third party was able to correct the problem.

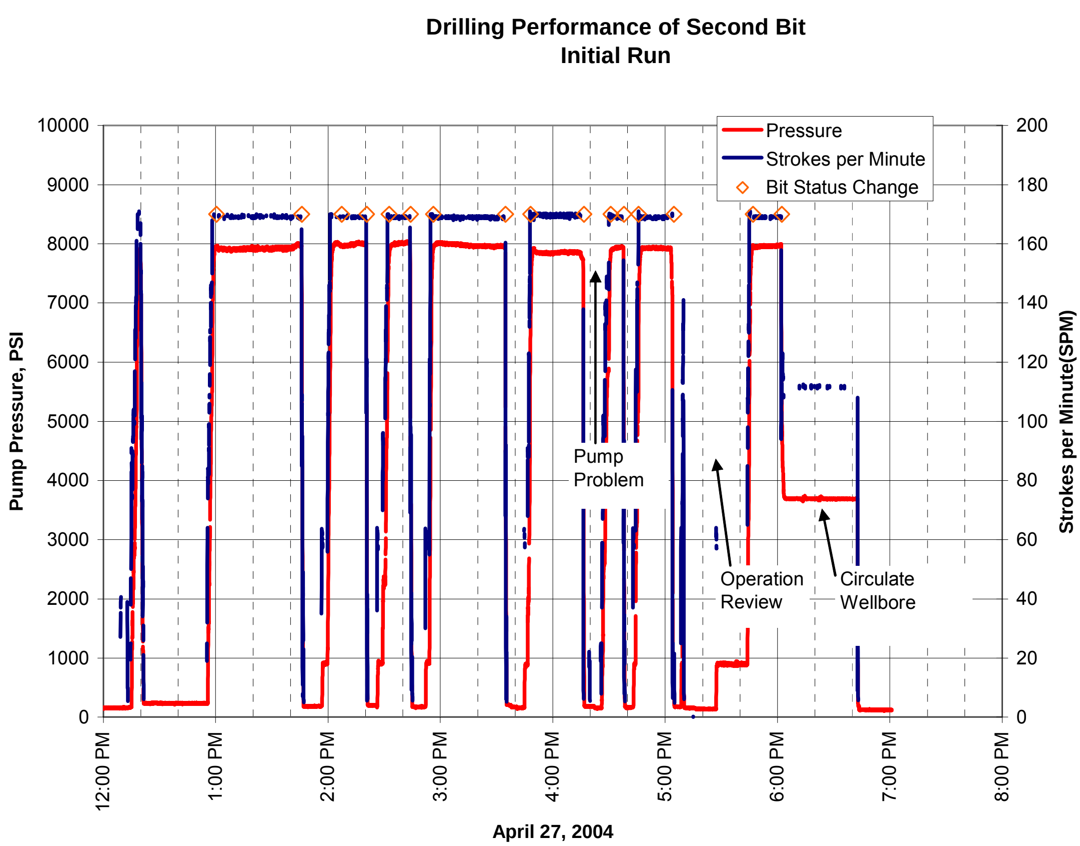


Figure 7. Drilling Performance of Second Bit, Initial Run

Unnamed Transition Zone – Second Bit Initial Run

The initial run of the second bit encompassed several different formations and lithologies. From Table 1 and the openhole log section in Attachment D-2, the first kelly down (4371–4403 ft), drilled an unnamed transition between the Lower Sundance sands and the Crow Mountain sands. This unnamed transition has a much lower density porosity than the sands and relatively low neutron porosity. The gamma ray would indicate some shale content while the resistivity would indicate some dolomite or limestone content with a high resistivity.

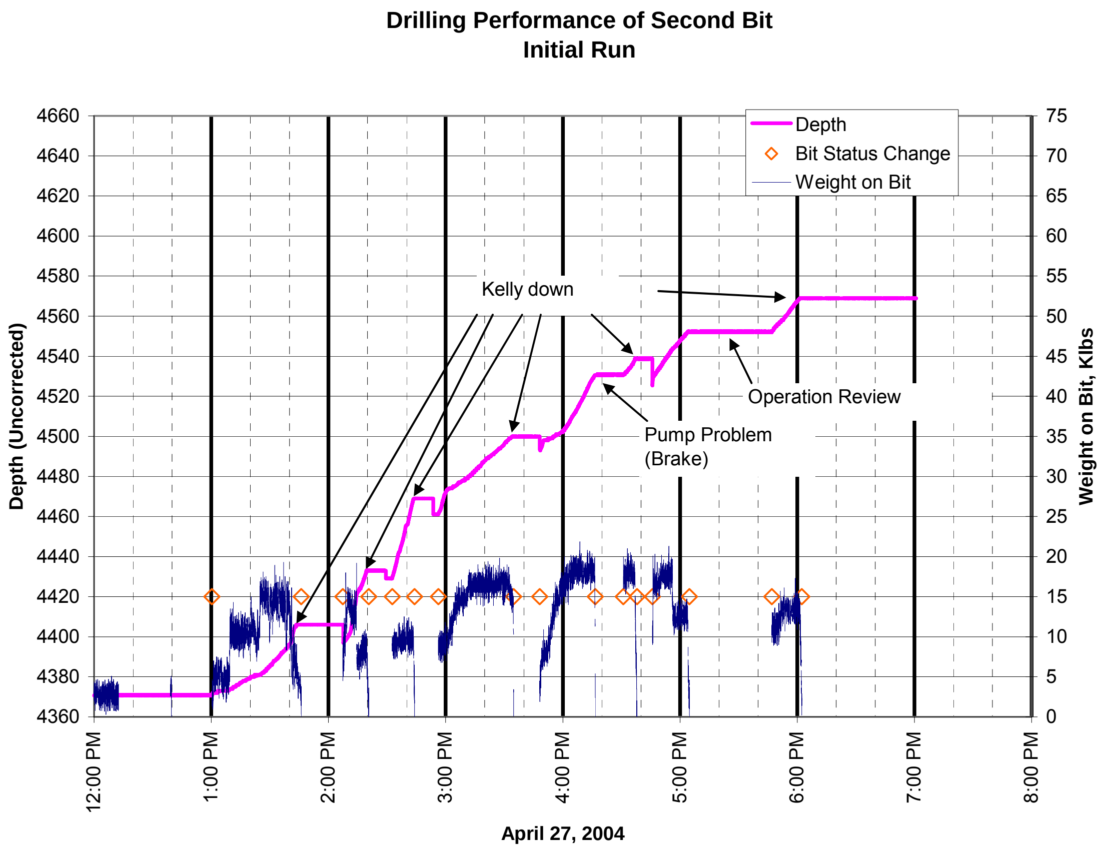


Figure 8. Depth (uncorrected) and Weight on Second Bit

The time required was 45 minutes, based on the bit status change, to drill this 32-ft interval or 42 ft/hr. Two recent offset wells drilled in the last few years were used for comparison. The two wells were Well 41-2-X-3 and Well 71-1-X-4. Table 1 summarizes the offset results for the entire test interval. The wells were drilled with roller cone bits (HTC GT-30 and STC F-2H).

The offset ROP average was 18.6 ft/hr with a range of 17–20 ft/hr. The incremental drilling rate increase utilizing the high pressure PDC bits was approximately 2¼ fold increase (ROP/Avg ROP) or 125% increase in drilling rate. The last few feet of this first Kelly (~4400 ft) showed a marked increase in drilling rate which would correspond well with the top of the Crow Mountain based on the openhole log. Since the correlation is close and repeats itself over other formation transitions, no depth corrections have been used between the openhole logs and the drilling data recorded.

During this first kelly down, the weight on bit (WOB) was increased from approximately 5,000 lb to 15,000 lb to develop the expected drilling rate. This increase of WOB was somewhat unexpected due to the envisioned drilling mechanism where the high pressure jets would get groove or kerf the bottom of the wellbore, and the PDC cutters would knock off the ledges. The use of WOB was inferred to be required due to the impact force of the high velocity streams on the bottom of the wellbore essentially lifting the bit off bottom. This requirement of WOB may be a critical factor if the drilling system is once again considered for use on coiled tubing.

Crow Mountain – Second Bit Initial Run

The next two kellys (4403–4435 and 4435–4467 ft) spanned the majority of the high porosity (~18%), clean sandstone of the Crow Mountain formation. See Attachment D-1. Consequently, the drilling time required was the lowest seen over the entire test interval (13 and 11½ minutes, respectively). See Table 1 . The short drilling times resulted in high ROPs for the two kellys (145 and 167 ft/hr). The ROP of the high pressure drilling system was controlled, at this early stage, by concern for hole cleaning. If the cuttings weren't properly transported, the bottom hole assembly (BHA) may have become stuck.

The offset ROP average was also high in this clean, high porosity sandstone at 120 ft/hr. Even though the drilling rates of the high pressure system were high, the incremental increase in drilling rate (21–39%) was the lowest achieved. The smaller increase in drilling rate can be attributed to the relatively high ROP of even conventional drilling and controlled drilling due to hole cleaning concerns.

Cutting size of the formations was significantly finer or smaller than the conventional bits used above or below the drilling test. The size of the cuttings was of interest to see the effects of the high pressure jets on the formations. The cutting size may indicate that the high pressure jets were performing the majority of the work and that only a small amount of work was being done by the PDC cutters. The small cutting size and high ROP may also have aided sealing some of the smaller fractures or lost circulation zones present in the offset well.

Alcova Limestone – Second Bit Initial Run

The next kelly (4467–4499 ft) spanned the lower porosity, hard Alcova limestone which lies beneath the Crow Mountain sand. See Attachment D-2. The Alcova has low density porosity along with low neutron porosity. The gamma ray is low indicating little shale content and the resistivity is high reflecting the limestone content. The transition from Alcova Limestone to the Red Peaks formation starts at approximately 4500 ft.

The drilling time to cover this relatively hard zone was 38 minutes in stark contrast to the Crow Mountain sand. See Table 1. The ROP for the Alcova was estimated at 50 ft/hr. The first few feet of the kelly (4470) drilled relatively fast because of the transition between the Crow Mountain sands and the limestone. Once again, the depths between the drilling data and the open hole logs seem to be very close.

The offset ROP average was also lower in this limestone interval at 13.5 ft/hr with a range of 12 – 15 ft/hr. The incremental drilling rate increase utilizing the high pressure PDC bits was approximately 3½ fold increase (ROP/avg ROP) or 270% increase in drilling rate.

Red Peaks Shale –Second Bit Initial Run

The next two kelly downs (4493–4525 ft and 4525–4557 ft) were in the Read Peak Shale. The Red Peak Shale, which is actually a mixed lithology, lies beneath the Alcova limestone and is approximately 600 feet thick. The formation contains varying amounts of shale, siltstone, sandstone, anhydrites. The gamma ray response is fairly high reflecting the shale content; however, the gamma ray response does vary over the interval.

The higher gamma ray generally corresponds to zones of higher neutron porosity and lower resistivity as would be expected. The density porosity response, calculated on a sandstone matrix, is oftentimes near zero or even negative. The negative response is indicative that heavy minerals, such as anhydrite are present in significant quantities and the matrix is not entirely quartz. The density porosity remains near zero for the interval 4500 – 4700 feet. From 4700, till the top of the Goose Egg at 5116, the density porosity grows even more negative reflecting possibly an increasing content of anhydrite.

The drilling times to cover the two kellys were 35 and 34 minutes respectively. The elapsed times were slightly higher than the hard Alcova limestone. The elapsed times were adjusted for any downtime. The first downtime was a mechanical problem with a brake on the mud pump transmission. The second downtime was to review the use of additional collars to be added for more WOB. See Table 1. The ROP for the Red Peak Shale was 54 and 56 ft/hr.

The offset ROP average was 15 ft/hr with a range of 12–18 ft/hr. The incremental drilling rate increase utilizing the high pressure PDC bits was approximately 3¾-fold increase (ROP/Avg ROP) or 278% increase in drilling rate. This rate of increase is slightly higher than the Alcova interval.

Red Peaks Shale –Second Bit Second Run

The high pressure drill bit (Second Bit – Second Run) was run in the hole early morning April 28, 2004 after tripping to the collars only. The bottomhole assembly (BHA) length was changed with the addition of more drill collars. The additional collar weight was necessary to maintain or increase the WOB without running the drill pipe in compression. The starting depth of the well was 4557 feet. Drilling began early morning and the run lasted for six kellys down or approximately 3½ hours before the first jet was blown out of the drill bit body. The total time on the second drill bit was about 8½ hours. Table 1 summarizes the results of this initial run of the second bit. Figure 9 and Figure 10 show the real time drilling data.

The first kelly down (4557 – 4579) was only twenty two feet in length due to the change in bottomhole assembly and required 26 minutes to drill. WOB was gradually increased during the drilling from lower than 5,000 lb to over 15,000 lb. The ROP for this first short kelly down was 50 ft/hr.

The next five kelly downs (4579–4611, 4611–4643, 4643–4675, 4675–4707, and 4707–4739) took place over a span of three hours. The times for each kelly ranged from 21 to 25 minutes. The calculated ROP were much higher than previous, except for the Crow Mountain, ranging from 76 to 91 ft/hr. The WOB was generally held above 20,000 lb. See Figure 10. The increase in WOB may have aided the drilling rate.

The offset ROP average, for comparable intervals, was 12 -15 ft/hr with a range of 10 – 18 ft/hr. The incremental drilling rate increase utilizing the high pressure PDC bits was approximately a six or sevenfold increase (ROP/avg ROP) or 500–600% increase in drilling rate. The increases of drilling rate were among the highest obtained during the entire testing operation.

At the end of the last drilling interval, pump pressure dropped from over 8,000 to under 3,000 psi. Surface equipment was checked for leaks with none found. Upon tripping the bit out, one jet was missing from the bit. This jet loss occurred several more times on subsequent runs and was one of the major hindrances found with the drill bits. The loss of jets was the major impetus for purchasing a new bit, slightly re-enforced, for later runs. At the time of this writing, the bit redesign necessary for future testing is still being reviewed.

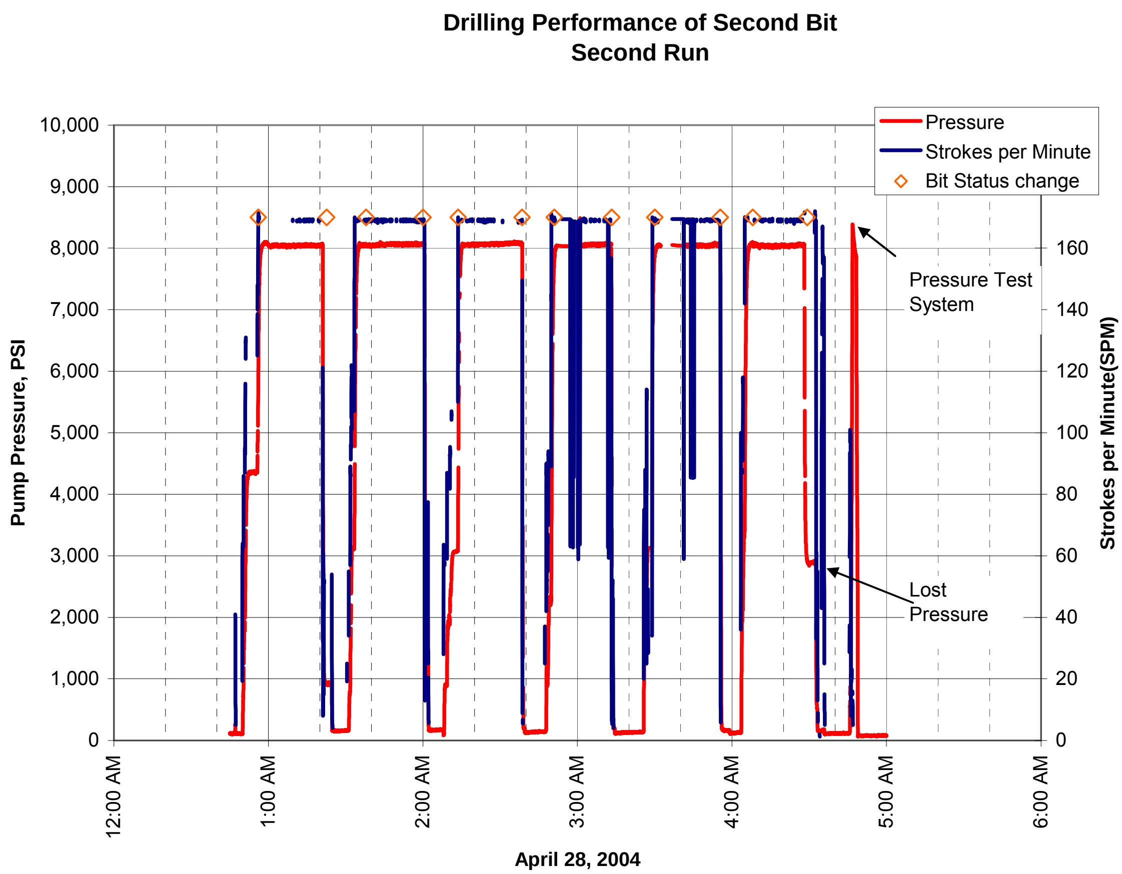


Figure 9. Pump Pressure and Strokes per Minute, Second Bit, Initial Run

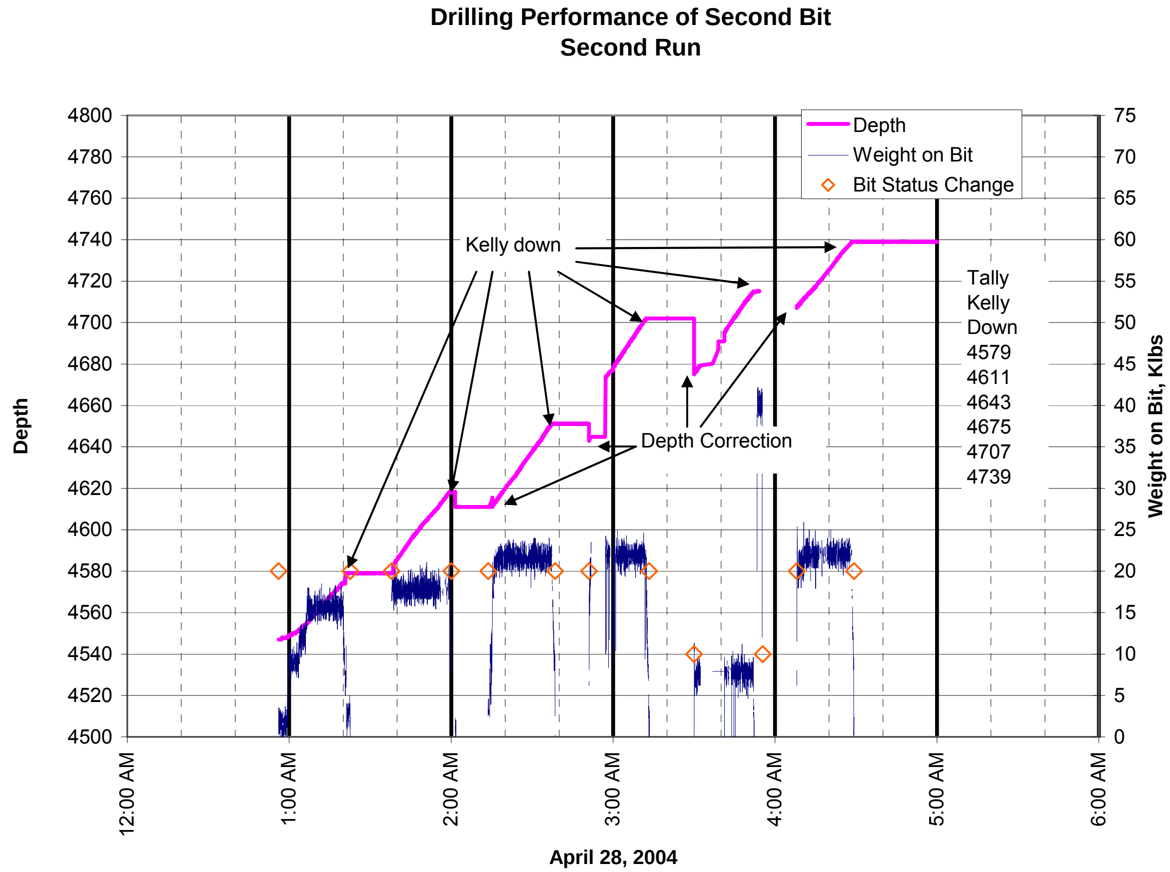


Figure 10. Drilling Performance of Second Bit, Second Run

Red Peaks Shale –First Bit Second Run (After Mud Motor)

The original high pressure drill bit (First Bit – Second Run) was run in the hole early morning April 29, 2004. This bit was the original bit, which had been repaired before which was used on the first circulating run (April 20) where pressure losses were noticed. This bit was also used on the first run with the mud motor (April 25). During this run, pressure losses were also evident. The bit had been repaired and returned to RMOTC as a backup.

The starting depth of the well was 4739 feet. Drilling began early morning and the run lasted for less than one hour. No continual pressure losses were evident with the bit. Pressure maintained at near 8000 psi for the entire first kelly down; however, at end of the run, pressure dropped below 3000 psi indicating that a jet was lost Table 1 summarizes the results of this short run of the first bit. Figure 11 and Figure 12 show the real time drilling data.

The only kelly down (4739 – 4771) required 31 minutes to drill. WOB was gradually increased during the drilling from lower than 10,000 lb to over 20,000 lb. The ROP for this kelly down was 62 ft/hr.

The calculated ROP was lower than the second run of the second bit (76 – 91 ft/hr). See Table 1. The lower ROP may be related to a change in openhole logs. The interval has a fairly high neutron porosity, a consistently high gamma ray, and a slightly more negative density porosity. Of course, the change in ROP, may be related to the bit itself.

The offset ROP average, for comparable intervals, was 13 ft/hr. The incremental drilling rate increase utilizing the high pressure PDC bits was approximately a 4½ fold increase (ROP/avg ROP) or 350 % increase in drilling rate. The increases of drilling rate, even though short-lived, was once again very encouraging.

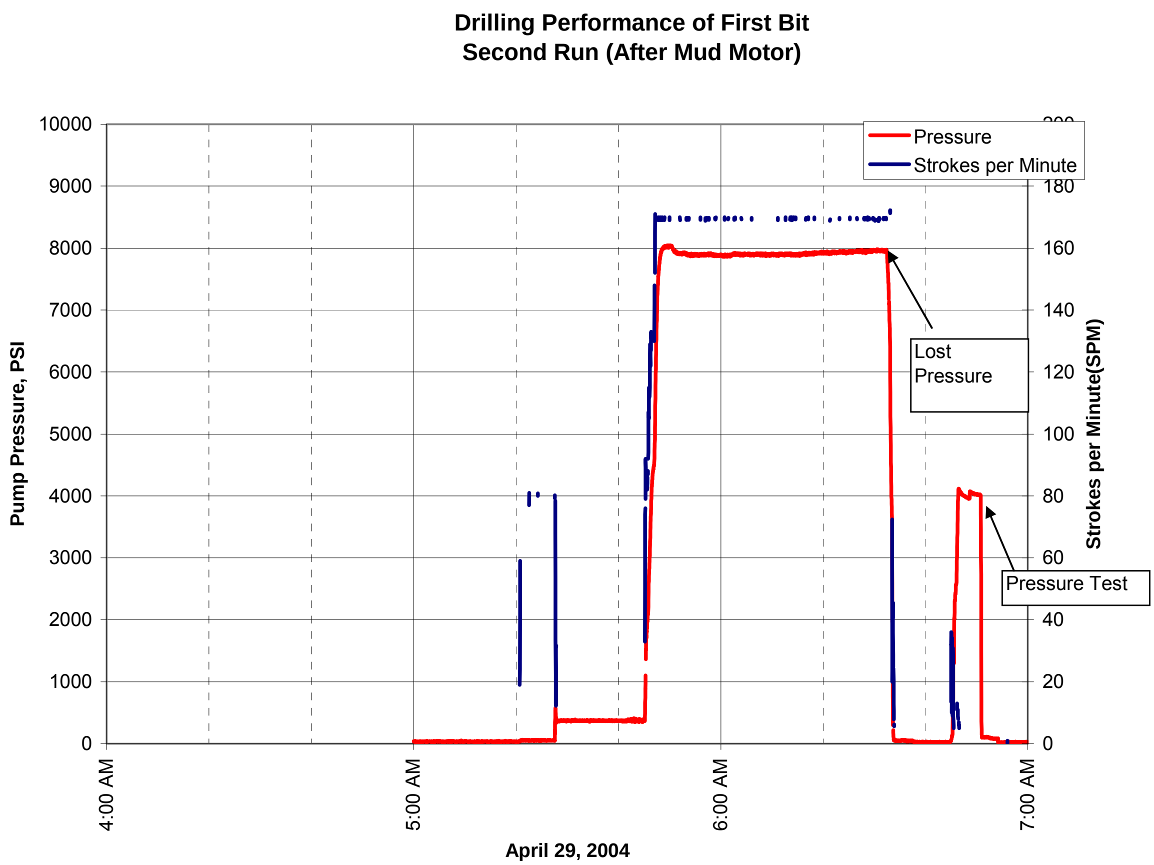


Figure 11. Drilling Performance of First Bit, Second Run

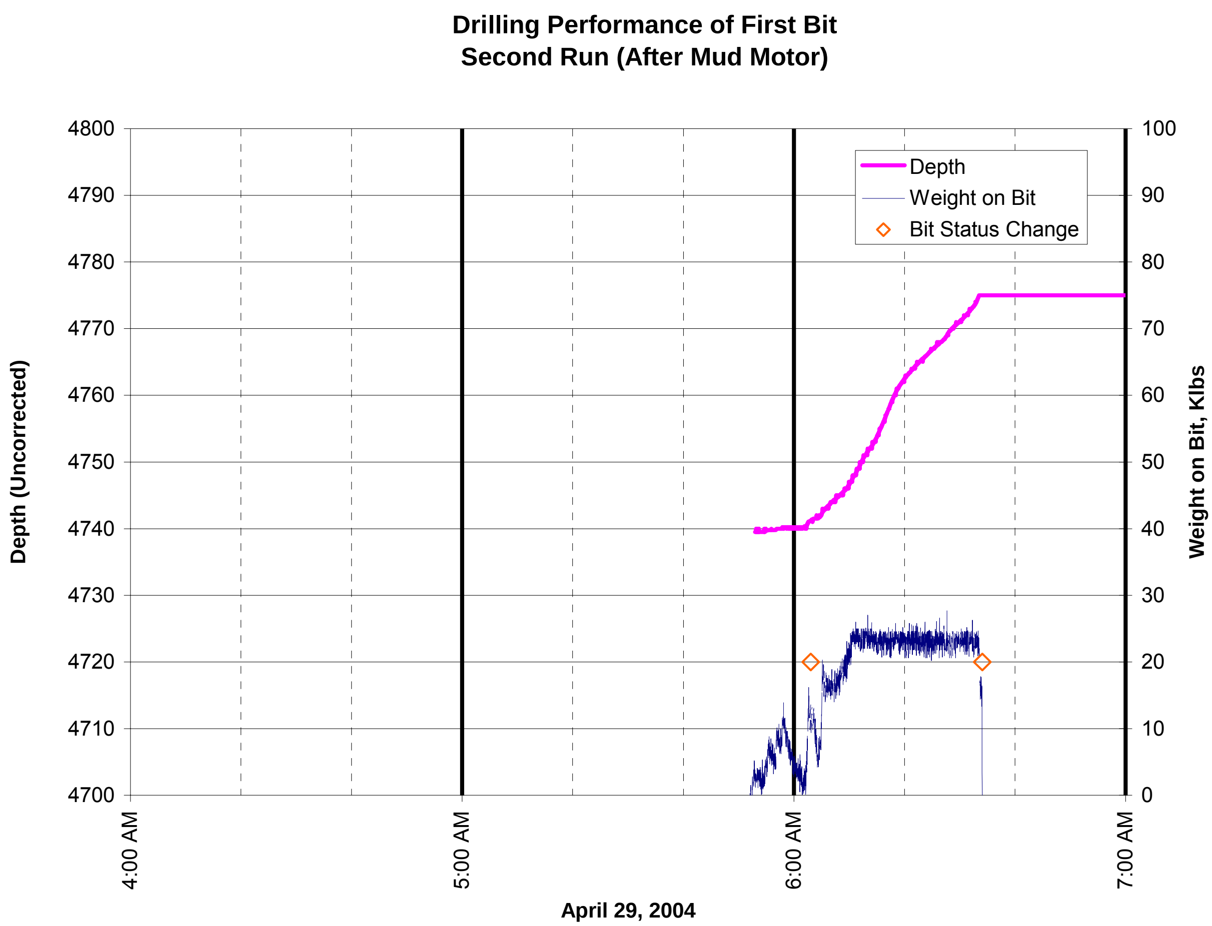


Figure 12. Depth (uncorrected) and Weight on First Bit, Second Run

Red Peaks Shale –Third Bit (new) Initial Run

With the failure of the first two bits due to bit jet loss, it was decided to purchase a new bit. The new bit was to be re-enforced around the exterior of the jets on the bit face. It appeared that some erosion being caused by fluid “ricochet” off the bottom of the hole.

This fluid ricochet or rebound would direct fluid energy back to the bit face where fluid erosion around the jets would occur; however, detailed inspection of the bits in Houston indicated that the erosion that causes the majority of the failure is from inside the bit. High velocity fluid entering the nozzle holes washes or erodes the body material around the holes.

As the metal was eroded around the jets, the interior bit pressure (8000 psi would cause the jets to be expulsed from the bit body. This same effect was not noted on earlier high pressure drilling documented in the early 1970s. It is not known, at this time, the difference between the earlier tests (1970s) and the recent test performed at RMOTC. It is speculated the nozzle design may be different causing the loss of the jets.

The high pressure drill bit (Third Bit – Initial Run) was run in the hole the afternoon of May 2, 2004. The starting depth of this interval was 4772 feet. Drilling began early afternoon and the run lasted for seven kellys down or approximately 5¾ hours. The pressure loss at the end of the run was due to a hole that developed behind one of the cutters on the side of the bit. The hole may have been related to the position of a fluid passageway to the bit face. See Picture 4 in Attachment D-1.

After tripping the bit out, it was also noted that six cutter faces were missing. See Picture 2 in Attachment D-1. The loss of the cutters was possibly due to the high pressure fluid streams, drilling parameters such as WOB, or other unknown effects. Manufacturer defect has not been ruled out either. It was also noted that the re-enforced areas around the jets were being eroded presumably by the ricochet or rebound effect of the fluid stream.

Table 1 summarizes the results of this initial run of the third bit. Figure 13 and Figure 14 show the real time drilling data. Depth data as recorded by the electronic system was tracking well at this point after additional work and calibration.

The seven kelly downs (4772–4997 ft) took place over a span of 5¾ hours. The times for each kelly ranged from 21 to 57 minutes. The calculated ROP were similar to the second bit ranging from 35 to 92 ft/hr. The WOB was generally held above 25,000 lb. See Figure 14. The slowest ROP was for the last kelly down (4964–4997.1). Although it is not known when, during the course of this run, that the cutter faces failed, there was a significant change in drilling rate or slope of the drilling curve during the last kelly. See Figure 14. The change in slope may indicate that the cutter faces were failing at this point.

The offset ROP average, for comparable intervals, was 13–14 ft/hr with a range of 12–16 ft/hr. With the exception of the last kelly, the incremental drilling rate increase utilizing the high pressure PDC bits was between a four to sevenfold increase (ROP/avg ROP) or 285–593% increase in drilling rate. The increases of drilling rate were slightly lower than second run of the second bit which may be due to a slight change in lithology or a change in the bit itself.

The change in lithology is basically a decrease in density porosity evident from 4700–5000 ft. The neutron porosity is also varying with higher, more blocky zones of projected shale content.

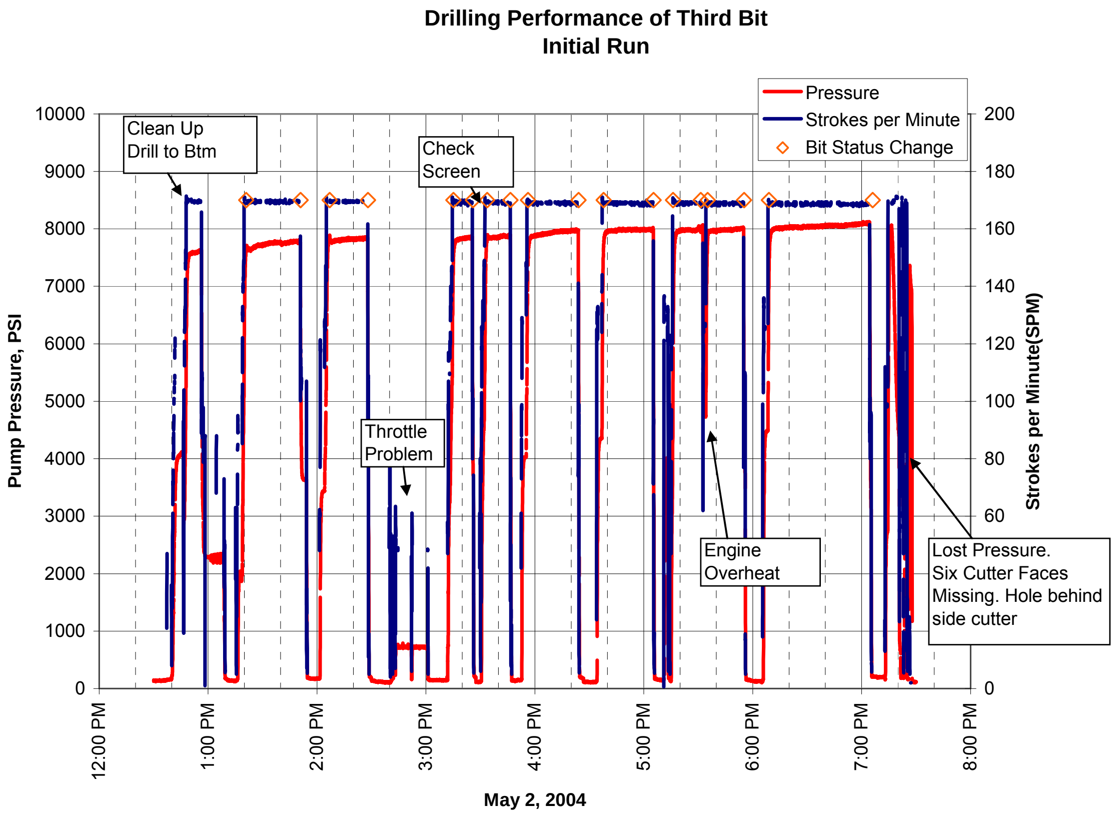


Figure 13. Drilling Performance of Third Bit, Initial Run

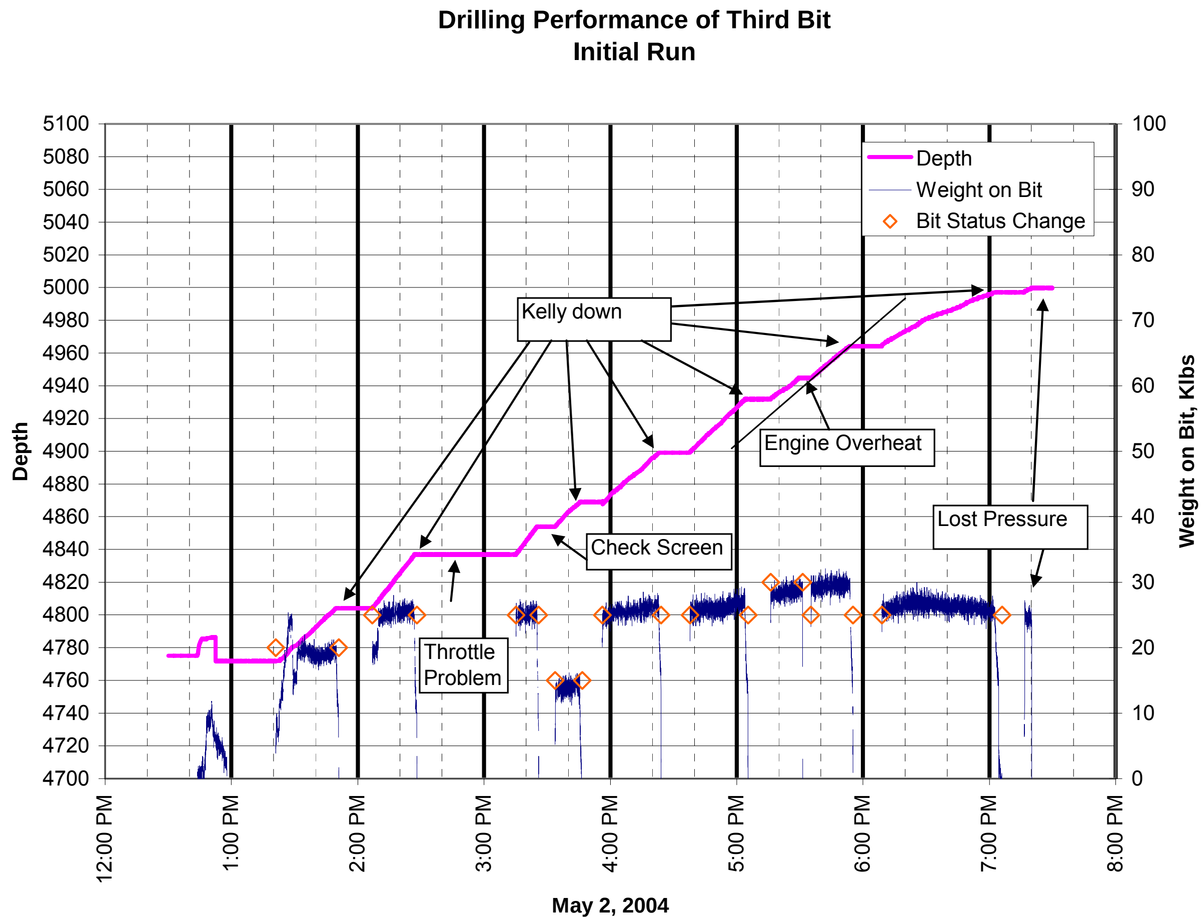


Figure 14. Depth and Weight on Bit, Third Bit, Initial Run

Red Peaks Shale/Goose Egg –Third Bit (new) Second Run

With the failure of the third bit, it was decided to perform a quick repair in Casper and return the bit to service. This repair was intended to fill the hole behind the side cutter and not to repair the cutter faces. It was anticipated that some additional data could be gained before complete termination of the drilling test. See Picture 3 in Attachment D-1.

The high pressure drill bit (Third Bit – Second Run) was run in the hole the night of May 4, 2004. The starting depth of this interval was 4999 feet. Drilling began and lasted until the early morning of May 5. Drilling spanned five kellys and the run lasted for five hours. The pressure loss at the end of the run was due to a large hole that developed on top of the bit adjacent to the previous failure which had been filled. See Picture 6 in Attachment D-1.

After tripping the bit out, the bit was in very poor condition with several of the posts completely sheared or broke off and additional cutters with severe damage. See Picture 5 in Attachment D-1. The additional damage to the bit was a continuation of the first run.

Table 1 summarizes the results of this second run of the third bit. Figure 15 and Figure 16 show the real time drilling data. Depth data as recorded by the electronic system continued to track closely.

The five kelly downs (4999.2–5157.9) took place over a span of 5 hours. The times for each kelly ranged from 41 to 57 minutes. The calculated ROP were similar to the last kelly drilled previously (4964–4997) - ranging from 34 to 47 ft/hr. The WOB was held close to 30,000 lb. See Figure 16.

The offset ROP average, for comparable intervals, was 14 ft/hr. The incremental drilling rate increase utilizing the high pressure PDC bits was similar to the previous last kelly between two and three fold increase (ROP/avg ROP) or 140–236 % increase in drilling rate. Even with serious mechanical damage, the bit continued to perform indicating, possibly, the positive effects of the high velocity mud streams.

The last two kelly (5094–5127 ft and 5127–5158 ft) penetrated the top of the Goose Egg formation. The top of the Goose is typified by a drop in gamma ray, a lower neutron and density porosity, and a high resistivity. The Goose Egg top has been described as a limestone with anhydrite present which is reflective of the openhole logs. See Attachment D-2.

The Goose Egg interval, although changing in lithology compared to the Red Peaks shale, has a similar rate of penetration (ROP). This similar ROP afforded the opportunity to establish a baseline within the same wellbore using a conventional bit to deepen the well from 5161 to 5300 feet. The depth of 5300 feet was selected as the core point for further RMOTC testing.

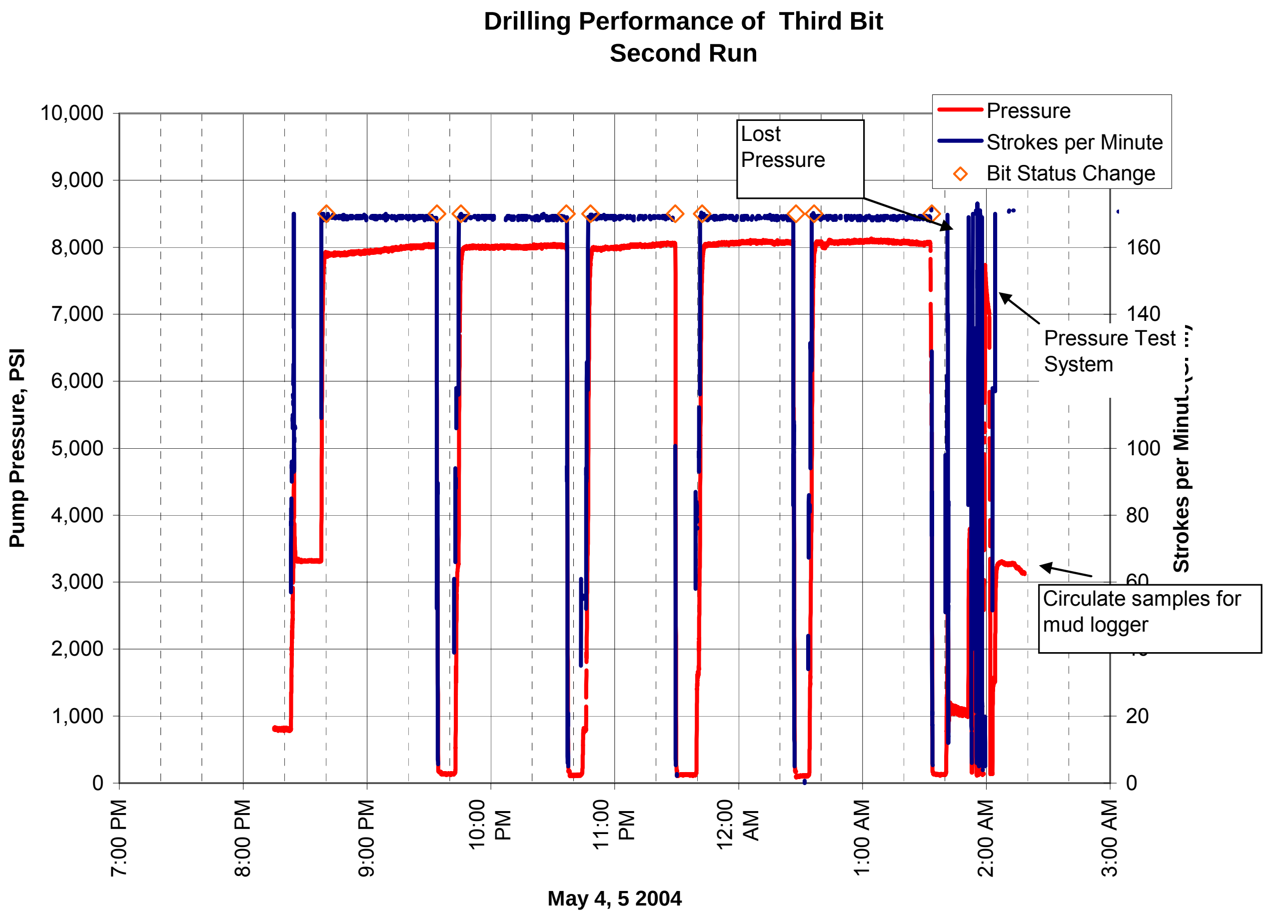


Figure 15. Drilling Performance of Third Bit, Second Run

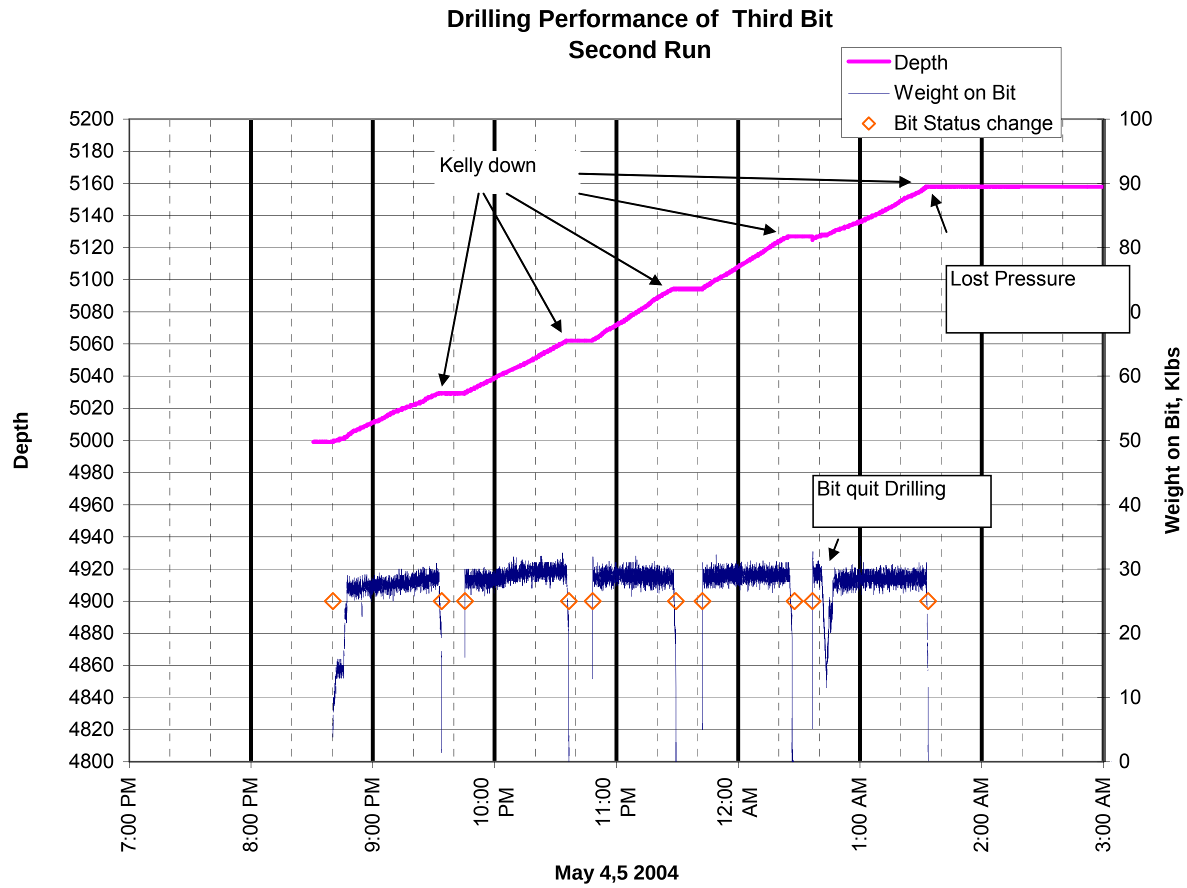


Figure 16. Depth and Weight on Bit, Third Bit, Second Run

Goose Egg – Conventional Bit with Low Pressure Drilling

To further validate some of the drilling rate increases demonstrated within Well 48-X-28, a conventional bit was used to deepen the well from 5161 to 5300. The new conventional bit selected was a modern Hughes 6⅛" STX-30. This drill bit was selected based on its outstanding performance on a previous RMOTC in the Lower Tensleep/Amsden formation. The pump pressure dropped from 8000 psi to around 1200 psi even at a higher pump rate. See Figure 17. Weight on bit (WOB) was held around 20,000 lb for comparative purposes on the first kelly .

The conventional drill bit was run in the hole the afternoon of May 6, 2004. The starting depth of this interval was 5161 feet. Drilling began and lasted until the early morning of May 7. Drilling spanned 4-1/3 kellys and stopped at the designed core point at 5300 feet.

Table 1 summarizes the results of this conventional run of the bit. Figure 17 and Figure 18 show the real time drilling data for May 6, 2004.

The first kelly down (5161 – 5192.8) is probably the best baseline comparison due to the WOB and interval closest to the Red Peaks shale. The time for this kelly was almost two hours. The calculated ROP was 16 ft/hr.

The offset ROP average, for comparable intervals, was 14 ft/hr. The demonstrated drilling rate is close to the offsets (14 ft/hr) especially considering that a new bit was used which may have aided the drilling rate. This comparison further validates the argument that the demonstrated rates of 60 – 90 ft/hr in the Red Peak shale is a very significant increase in drilling rate using a high pressure PDC bit over a modern conventional roller cone bit.

Similar folds of increase were evident in softer formations based on the Exxon test of the 1970s.

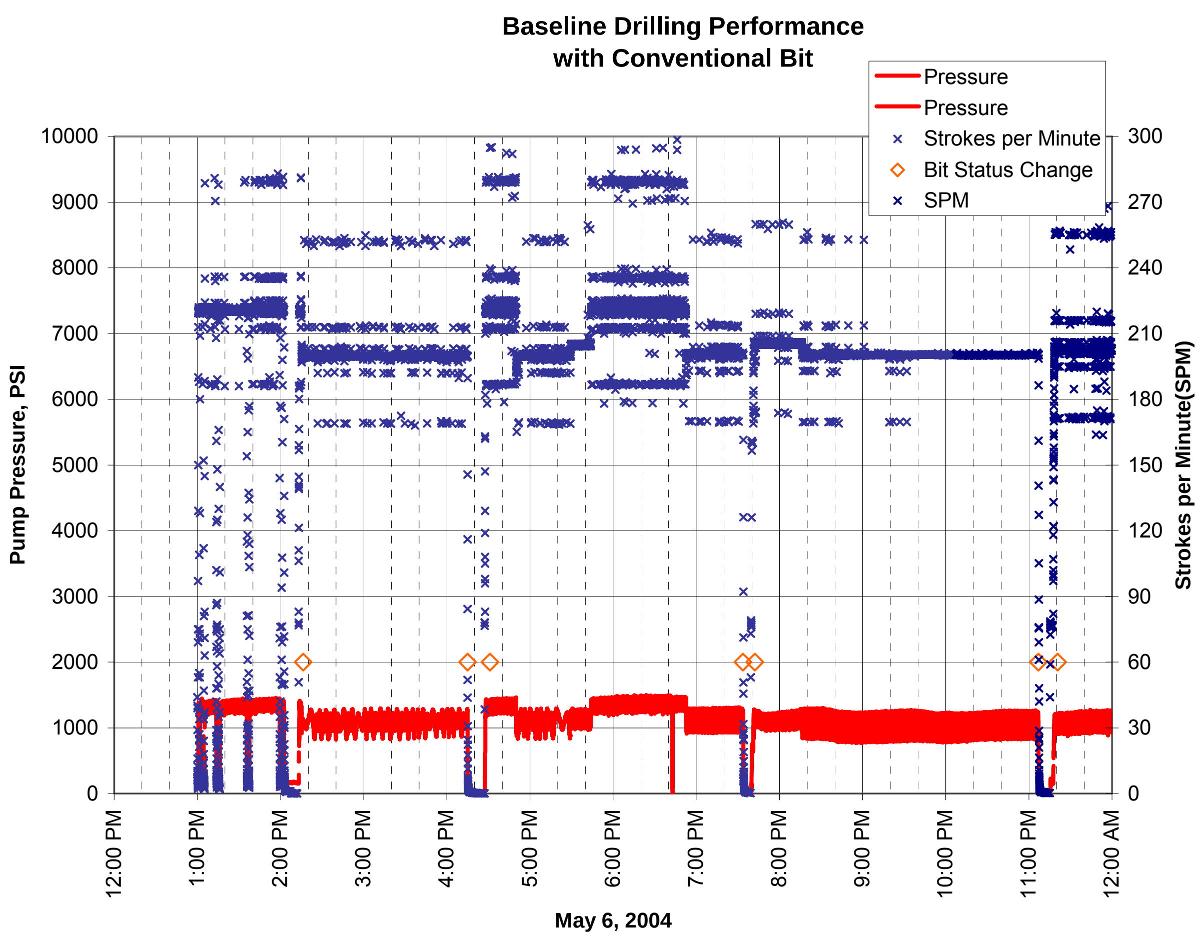


Figure 17. Baseline Drilling Performance with Conventional Bit

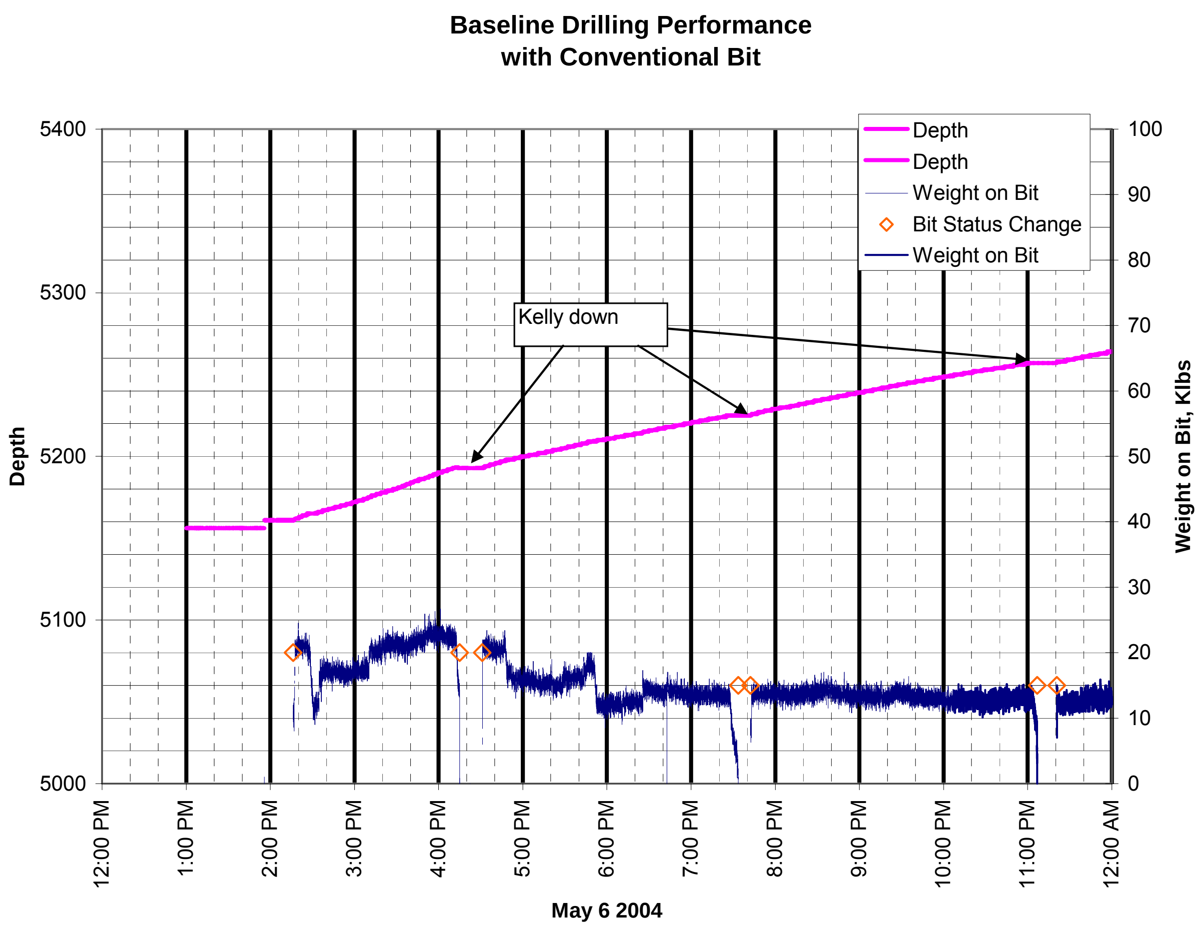


Figure 18. Depth and Weight on Bit, Baseline Drilling Performance with Conventional Bit

Conclusions

High pressure jet kerf drilling (8000 psi) has been successfully performed at the Rocky Mountain Oilfield Testing Center (RMOTC).

Significant increases in drilling rate (2–7 times) were evident over a variety of formations.

Mechanical difficulties with loss of bit jets remain a technical challenge. Other mechanical difficulties with PDC cutters and posts are being investigated.

Further testing of this technology may be warranted to reduce drilling costs and increase ROP.

References

Meidinger, Brian, “RMOTC Internal Report – Prodril Services Incorporated,” 2003.

Maurer, W.C. and Leitko, C.E., “Coiled-Tubing High-Pressure Jet Drilling System,” downloadable report from National Energy Technology Laboratory NETL.DOE.GOV.

Cohen, John, “Advanced High-Pressure Coiled-Tubing Systems,” continuation Application Phase II-B, August 2003.

Attachment D-1 – DRILL BIT PHOTOS

Picture 1

Picture 2

Picture 3

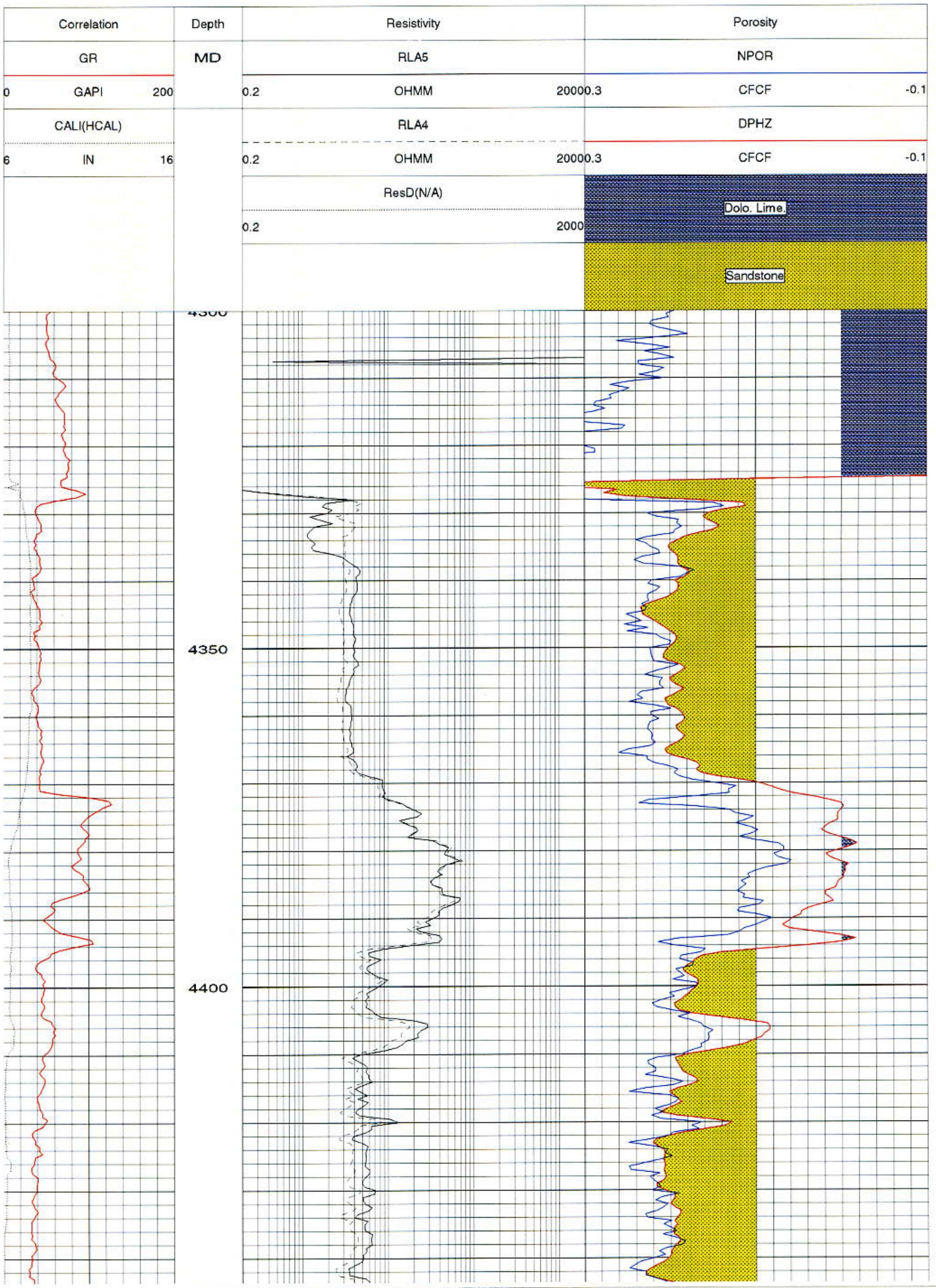
Picture 4

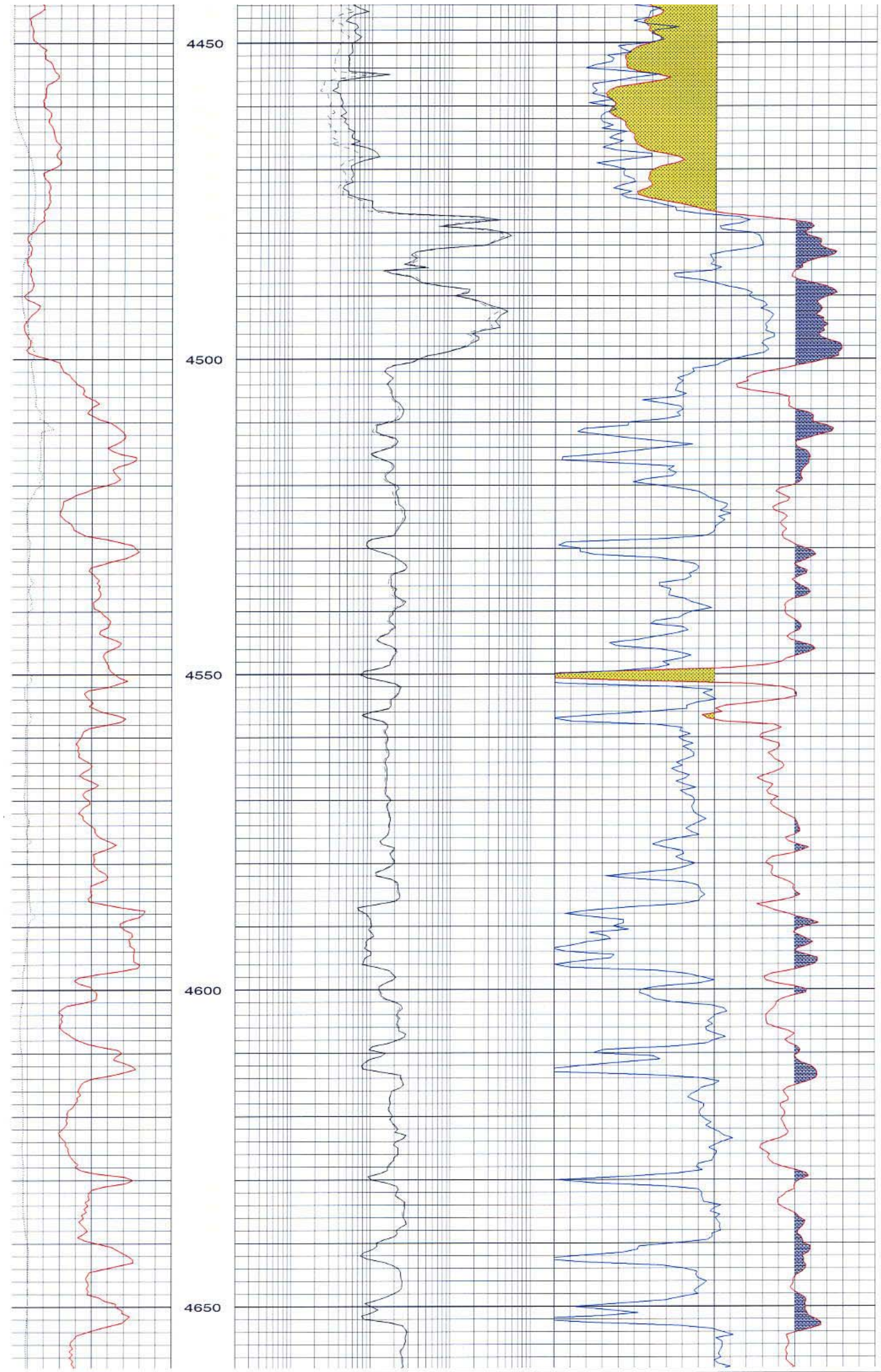
Picture 5

Picture 6

Attachment D-2
OPENHOLE LOGS
WELL 48-X-28

Well	48X - 28
Well ID	49-025-23195
Field	NAVAL PETROL
County	NATRONA
State/Prov	
Country	
Legal Description	
Well Status	

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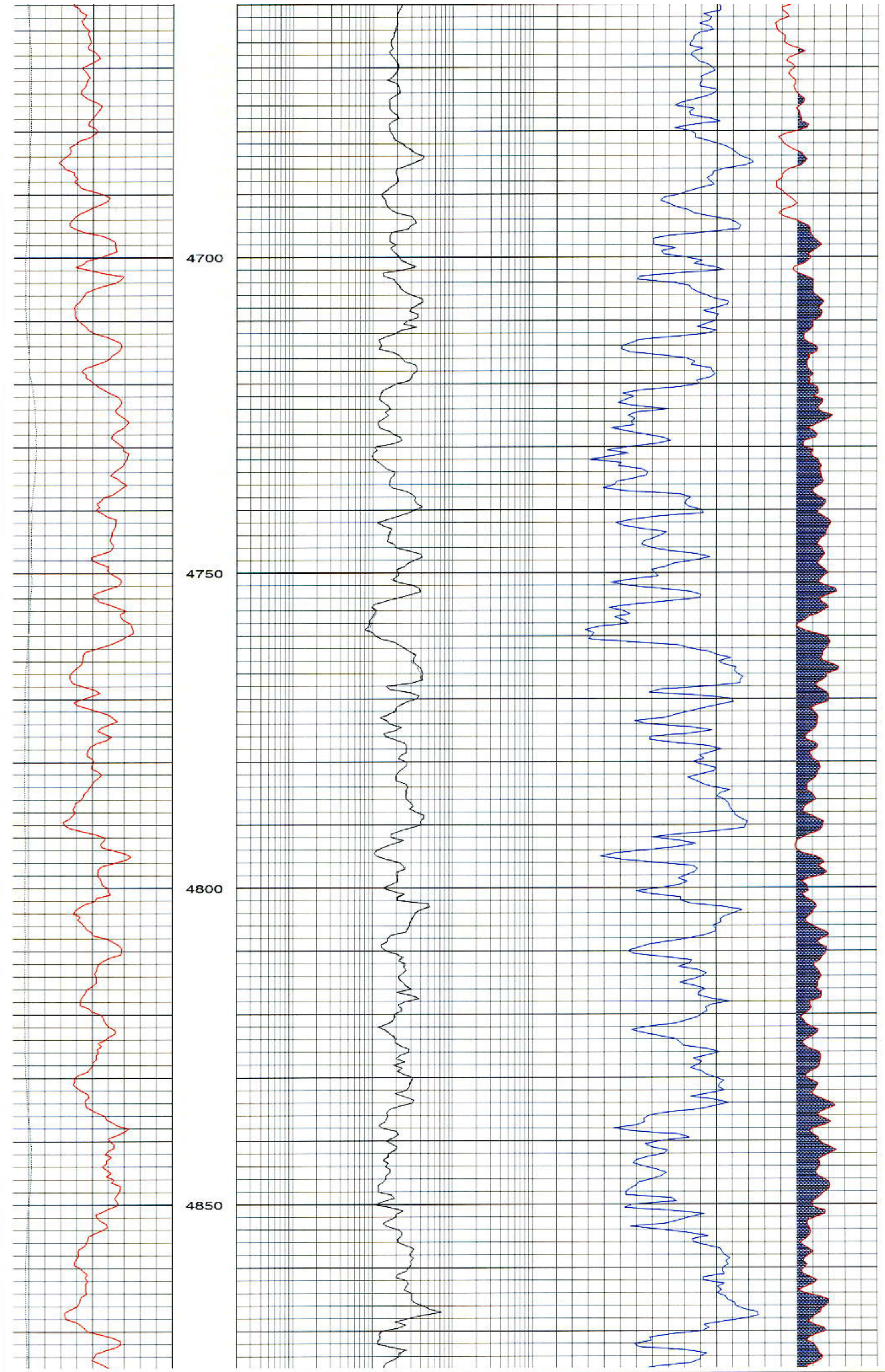
4500
4550
4600
4650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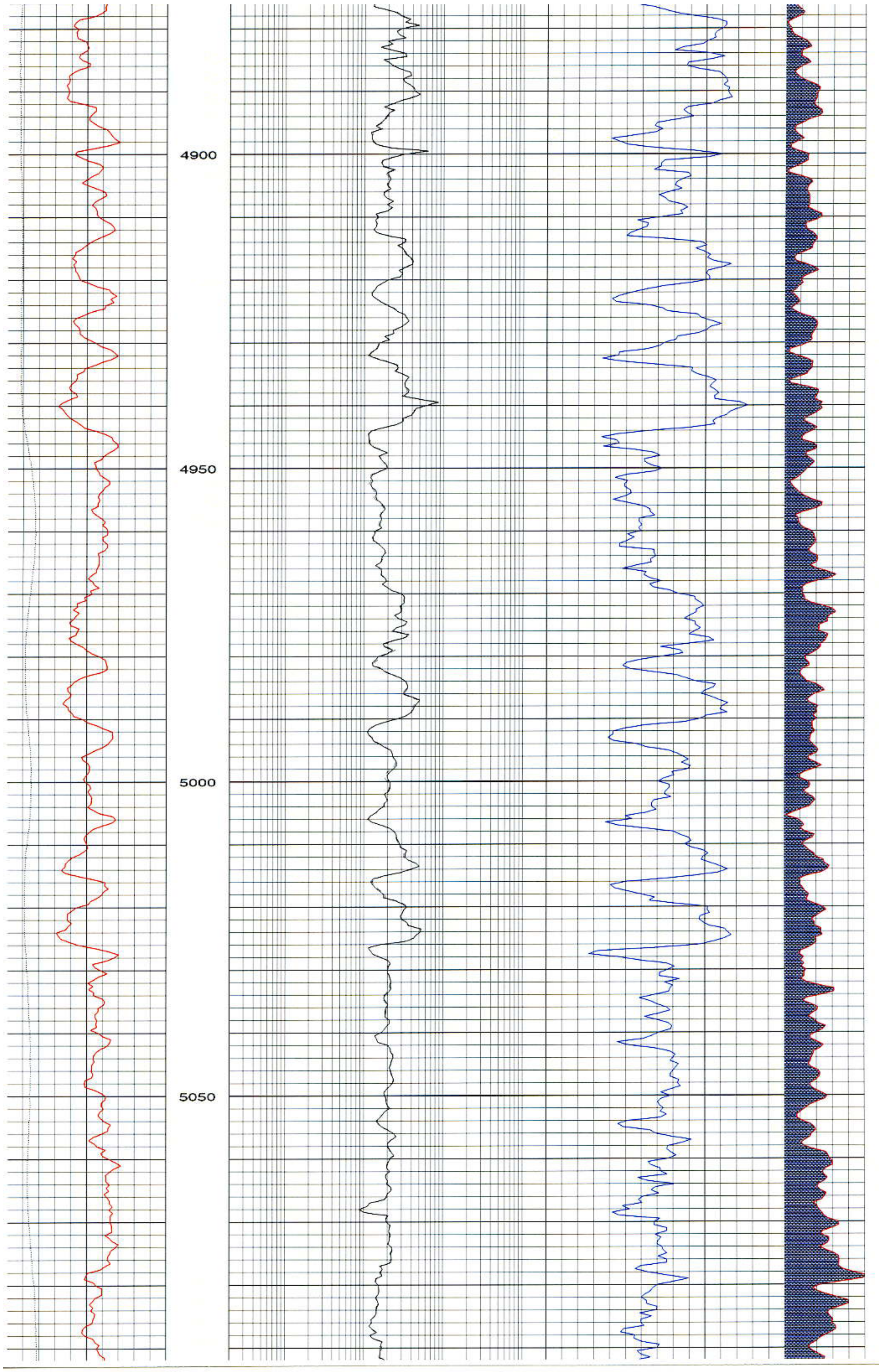
4850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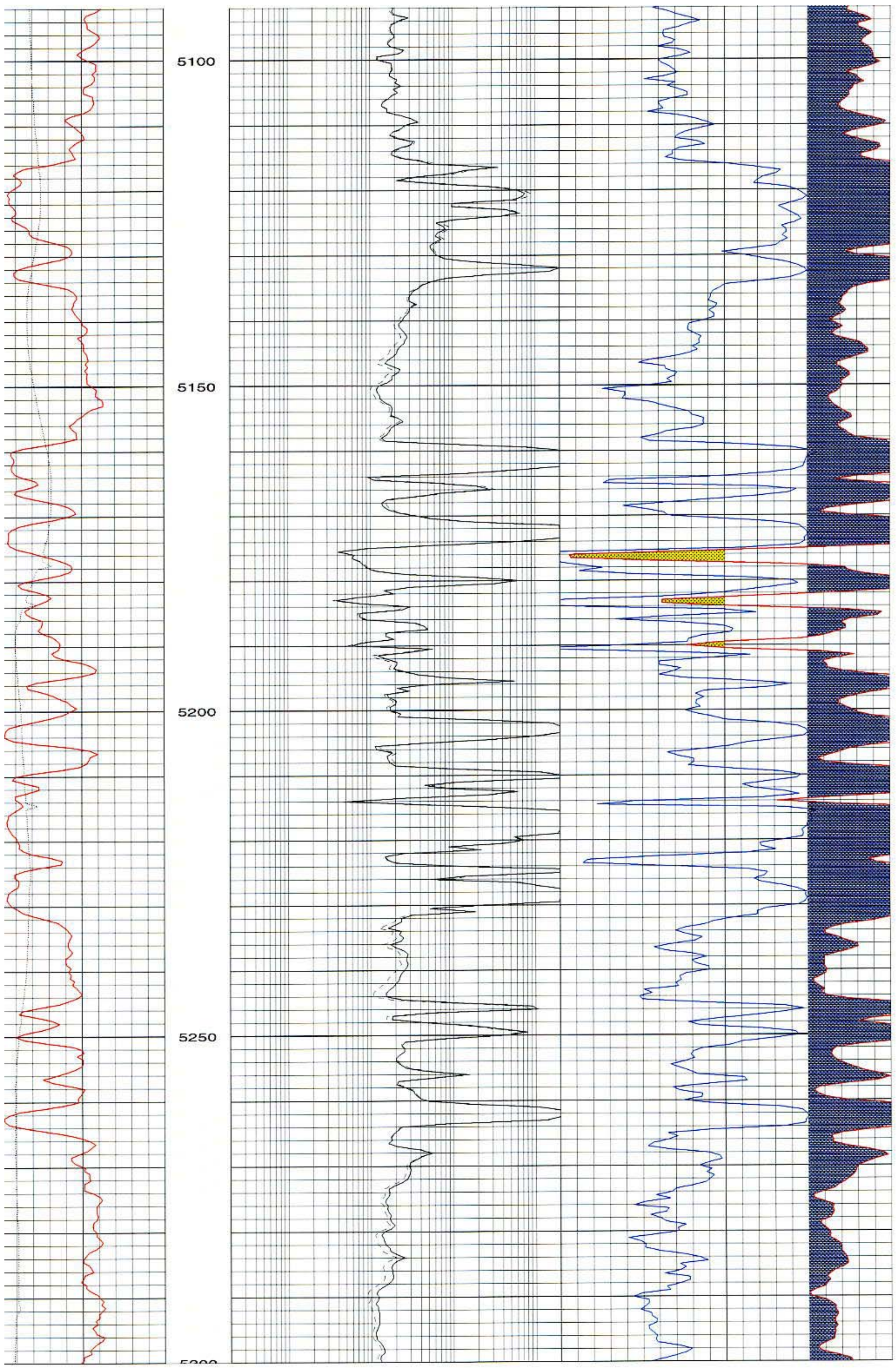
4950
5000
5050


5100
5150
5200
5250

Appendix E

Rocky Mountain Oilfield Testing Center & Maurer Technology Inc.
13135 South Dairy Ashford Rd. Suite 800
Sugar Land, Texas 77478

DRILLING PROGNOSIS

February 17, 2004

U.S. Naval Petroleum Reserve No. 3 Natrona County, Wyoming

Well Number: 48–X-28
CRADA No: 2004-046
API well number: 49-025-TBA

Location: 490' FSL, 2,449' FWL, Sec. 28, T39N-R78W

Elevations: 5104.65' GL. 5114.65' K.B. Lat 43.314785 Long 106.221955
Estimated T.D.: 6200'

Objective: Test High Pressure Drilling System from 4200–6200 ft

Secondary Targets: Seismic Test with INEEL

Core Tensleep for CO_2 Pilot Design

PROCEDURE

1. Survey and build location.

2. Prepare APD and forward to the WOGCC.

3. Drill rat hole, mouse hole, and conductor hole. Set 13-3/8" conductor pipe to 45'(±) depth. Cement with ready mix concrete.

4. MIRU DOE Rig #2 with substructure. Revamp standpipe and surface valves.

5. Install 13-3/8" drilling nipple

6. Drill out conductor and drill 12-1/4" hole to ±500' with water.

7. During drilling, add KCL for 3% KCl mud to stabilize shale. Let water mud up as drilling proceeds

8. Perform mud sweeps with polymer as needed to clean hole.

9. At depth, short trip to surface and back to depth to ensure hole is clean.

10. Rig Up Idaho National Labs (INEEL) for seismic test. Shut down rig for 24 hrs for minimal noise. Complete seismic test. RD INEEL.

11. RIH with 12-1/4" bit to TD. Wash and ream as necessary. POOH.

12. RU casing crew to run 12 jt 9-5/8" 47# casing to TD. Set and cement casing.

13. WOC. If necessary, give crews time off.

14. Nipple up 9-5/8 casing head using 2-2" ball valves.

15. Nipple up 11" BOP and test to 500 psi with test plug. RU drilling nipple.

16. Rig up mud loggers.

17. Drill out surface casing with 8-1/2" bit using LSND mud. Maintain good fluid loss.

18. Drill through the Wall Creek zones slowly and with LCM to build good wall mud cake to control lost circulation.

19. Drill to about ±4200 (Top of the Crow Mountain). Short trip as necessary to maintain hole.

20. At depth, condition hole. POOH. RU loggers. Log intermediate hole from 500 – 4200 ft with gr/density/neutron/ HRLA and sonic or other logs as directed. RD loggers.

21. TIH with 8-12" bit. Circulate and condition hole. TOOH for casing. LD 4-1/2" DP and 6" drill collars.

22. RU casing crew. Run 7" 23# casing to depth. Set and cement casing.

23. WOC. If necessary, give crews time off.

24. Nipple up 7" casing head using 2-2" ball valves.

25. Nipple up 7-1/16"" BOP and test to 500 psi with test plug. RU drilling nipple.

26. RU rental equipment. Pressure test system to 10,000 psi using BOP testers. RIH with 3-1/2" HT drill pipe and 6-1/8" bit. Drill out casing shoe and 5 ft of new formation. POOH. Dump and clean mud tanks. Ensure no solids are contained in mud system. Build new mud system.

27. PU Maurer bit, mud motor, collars. RIH to 1000 ft. Perform rate/pressure calibration run. RIH to depth. Begin drilling after mud system complete and equipment performing satisfactorily.

28. Drill with Maurer system from 4200 to 6200 or as test results dictate.

29. POOH. RU openhole loggers. Log bottom interval of 4200–6200 ft.

30. If the Tensleep appears productive based on mud logs and openhole logs or possibly even core, procedures will be developed to run a liner in the hole, cement, and complete.

At this point, the Maurer test will be complete. Several possibilities are possible prior to end of the test. One possibility is that the Maurer test does not reach TD because of unknown reasons. It is assumed that drilling will continue, in some manner, to reach the Tensleep core point for the CO_2 effort. At that point, procedures will be presented to govern the Tensleep coring operation.

48-X-28 ESTIMATED LOG TOPS

FORMATION	**MEMBER**	**KB**	**thick**	**ASL**
STEELE SH	SHANNON A	247	80	4868
STEELE SH	SHANNON B	332	145	4783
STEELE SH	TELEGRAPH CREEK	477	132	4638
STEELE SH	BRITTLE	609	393	4506
STEELE SH	FISHTOOTH	1002	516	4113
STEELE SH	GREY DUST	1518	102	3597
STEELE SH	ARDMORE	1620	125	3495
NIOBRARA SH	WHITE SPECKS	1745	244	3370
NIOBRARA SH	SMOKEY GAP	1989	219	3126
CARLISLE SH		2208	242	2907
FRONTIER	1 WALL CREEK	2450	384	2665
FRONTIER	2 WALL CREEK	2834	254	2281
FRONTIER	3 WALL CREEK	3088	267	2027
MOWRY SH		3355	237	1760
MUDDY SS		3592	18	1523
THERMOPOLIS SH		3610	133	1505
DAKOTA SS		3743	72	1372
LAKOTA CGL		3815	7	1300
MORRISON		3822	213	1293
SUNDANCE		4035	82	1080
SUNDANCE	LAK	4117	95	998
SUNDANCE	LAK EVAPORITE	4212	12	903
SUNDANCE	HUELETT SS	4224	4	891
SUNDANCE	STOCKDALE BVR SHALE	4228	43	887
SUNDANCE	CANYON SPRINGS SS	4271	82	844
CHUGWATER/CROW MTN		4353	86	762
CHUGWATER/ALCOVA		4439	22	676
CHUGWATER/RED PEAKS		4461	590	654
GOOSE EGG		5051	167	64
GOOSE EGG	FORELLE	5218	73	-103
GOOSE EGG	MINNEKAHTA	5291	17	-176
GOOSE EGG	OPECHE	5308	34	-193
TENSLEEP		5342	11	-227
TENSLEEP	TOP A SS	5353	50	-238
TENSLEEP	BASE A SS	5403	29	-288
TENSLEEP	TOP B SS	5432	66	-317
TENSLEEP	BASE B SS	5498	47	-383
TENSLEEP	TOP C SS	5545	20	-430
TENSLEEP	BASE C SS	5565	95	-450
AMSDEN		5805	240	-690

MUD PROGRAM:

12-l/4"Hole to 500 ft -5% KCl/Polymer Mud (per mud engineer's direction)

8-1/2" Hole to 4200 ft LSND Mud with the fluid loss control to minimize shale sloughing and promote hole stability for openhole logs. Fluid loss below 10 cc. Lost Circulation Control as needed with LCM. Cement squeeze of Second Wall Creek with fiberglass tail pipe to be considered.

6" Hole from 4200 to 6200. 3% KCl/polymer or as directed by mud engineer.

See Attached Recommendation.

ELECTRIC LOGGING PROGRAM:

HRLA/GR/Cal/CNL CDL from 500 to 4200 ft. Second run with sonic log.

Logging from 4200–6200 TBD. Other logging as requested.

Logging Subcontractor: Schlumberger Wireline Phone: (307) 234-8981

CASING PROGRAM:

Conductor Casing

1 joint of 13-3/8" 54.5# K-55 Cementing Hardware – None

Surface Casing

12 Joints of 9⅝" 47# P-110 Cementing Hardware

1 – 9⅝" Guide Shoe

1 – 9⅝" Insert Float Collar

1 – 9⅝" Stop Ring

1 – 9⅝" Top Rubber Plug

6 – 9⅝" Centralizers

1 – Threadlock Kit

Install centralizers on bottom 3 collars and alternating collars above

Production Casing:

About 100 joints – 7" , 23#, J55, LT&C

Cementing Hardware:

1 – 7" Float Shoe (fill-up type)

1 – 7" Float Collar (differential fill type)

1 – 7" Stop Ring (limit clamp)

1 – Top Rubber Plug

15 – 7" Centralizers

1 – Threadlock Kit

NOTES:

1. Production Casing program is approximate.
2. Install float shoe.
3. Use threadlock compound on float shoe and float collar.
4. Install centralizer 5 ft above float shoe and on alternate collars.

<u>CEMENTING PROGRAM</u>

Cementing Subcontractor: Rocky Mountain Cementers (307) 234-2212

Surface Casing: TBD

1. Preflush with 36 bbl. 3% KC1 water containing 3 sacks KC1, 3 sacks gel, and 5 gallons surfactant. Lost circulation material may also be added to preflush. Preflush may be varied according to hole conditions.

If hole is drilled with non-dispersed mud, add an 18 bbl. spacer containing KC1 and surfactant.

If hole contains weighted mud, add a weighted mud sweep to avoid cement contamination. At maximum anticipated density, the mud will be heavier than the cement slurry.

2. Cement with ___sx. Class "G" cement containing 2% CaCL. and l/4#/sk celloflake.

Cement volume is based on annular volume + __ % excess.

Yield: ___cu ft/sk Density: ___ lb/gal Water Req.: 5.0 gal/sk

Production Casing: TBD

1. Preflush with 36 bbl, 3% KC1 water containing 3 sacks KC1, 3 sacks gel, and 5 gallons surfactant. Lost circulation material may also be added to preflush. Preflush may be varied according to hole conditions. If hole is drilled with non-dispersed mud, add an 18 bbl. spacer containing KC1 and surfactant.

2. Cement with ___ sx. Class "G" cement containing 50% Pozlan, 2% CaCl. and l/4#/sk celloflake and tail in 1st stage with 50sx of neat class "G". 1st stage is about ___ sacks of 50-50 Poz and 2nd stage is about ___ sacks. Exact number of sacks will be calculated from open hole caliper log.

Cement volume is based on annular volume + ___ % excess covering critical zones. Yield: ____ cu ft/sk Density: ____1bs/gal Water Req.: ____ gal/sk

Wall Creek or Crow Mountain Squeeze: To be determined.

REPORTS:

1. All pertinent data and operations such as DST's, coring and casing shall be recorded on the IADC-API Daily Drilling report. The White, Yellow, and Pink copies shall be given each morning to the RMOTC Project Manager, along with all delivery tickets signed and received. The green copy shall remain with the tool pushers and the white copy will remain in the book.

2. As of 7:00 a.m. each morning, a report by the tool pusher or the RMOTC Project Engineer shall be e-mailed or faxed into the Casper Office and include all pertinent data or operations.

Anchor
Drilling Fluids USA, Inc.
410 17th Street
Suite 540
Denver, Colorado 80202
Tel.: (303) 892-5610
Fax: (303) 893-2733

Attachment E-1

RECOMMENDED DRILLING FLUIDS PROGRAM

U. S. DEPARTMENT OF ENERGY
NPR #3

6,200'± TENSLEEP TEST
48-X-28
SECTION 28, T39N, R78W
NATRONA COUNTY, WYOMING

PREPARED FOR
MR. RALPH SCHULTE

BY
TOM STOKES
OPERATIONS MANAGER

FEBRUARY 23, 2004

RECOMMENDED DRILLING FLUIDS PROGRAM

INTERVAL (feet)	MUD WEIGHT (lbs/gal)	VISCOSITY (sec/qt)	FLUID LOSS (ml/30 min)	MUD TYPE
0' - 500'	8.6 - 8.8	34 - 42	10 cc's	5% KCL/Polymer

Prior to spud build a 5% KCL/Flowzan system. Add approximately 18-20 ppb of Potassium Chloride to the make up water. Also add ¾ ppb of Flowzan and approximately ½ ppb of Drispac to provide the recommended fluid loss properties. Use all available solids control equipment while drilling this interval to maintain minimum mud weights and reduce excessive pit cleaning and water dilution.

Some foaming can be expected with the use of a KCl fluid. This should be limited to the surface of the fluid and therefore should not cause problems with pump pressure, depending on the volume and size of the mud pits. The use of a defoamer prior to mud up of the KCL system will eliminate this problem and allow the operations to proceed in the most effective fashion. Avoid discharging solids control equipment near the pump suction to minimize problems.

Recommended Fluid Properties:

Plastic Viscosity	:	6 to 10
Yield Point	:	8 to 14 (increased if conditions dictate)
API Filtrate	:	10 cc's (decreased if conditions dictate)
pH	:	8.5 to 9.5
Drill Solids	:	3% or Less

Possible Problems: There is a possibility that lost circulation or fluid seepage will be encountered in the Shannon formation. We recommend pumping LCM sweeps containing Multi-Seal and Cedar Fiber as needed. In severe cases, allow the LCM to remain in the system to maintain fluid circulation to reach casing depth.

Set 9-5/8" surface casing at 500'±.

RECOMMENDED DRILLING FLUIDS PROGRAM

INTERVAL (feet)	MUD WEIGHT (lbs/gal)	VISCOSITY (sec/qt)	FLUID LOSS (ml/30 min)	MUD TYPE
500' - 4,200'	8.6 - 9.2	26 - 45	Natural to 10 cc's	LSND

Drill out of surface casing using the 5% KCL system. Add fresh water to dilute back the system while drilling ahead. Use Anco Drill sweeps for hole cleaning until a complete mud up of the system at approximately 2,500'.

Use all available solids control equipment along with water additions to keep the mud weight below 9.2 ppg, both as a precaution to avoid lost circulation and also to maximize rate of penetration. Efficient solids control equipment will save on both the mud cost as well as on water costs and can not be overemphasized. Some dumping and cleaning of the mud pits will be required and we recommend that fresh water be used for make up water.

At 2,500' or sooner if hole conditions dictate, clean the mud pits of drill solids add fresh water and mud up the system. Add 0.25 ppb of Caustic Soda, 12 to 15 ppb of Anco Gel and 0.25 ppb of Anco Drill to achieve approximately 34 to 38 viscosity. Add approximately 0.25 ppb of Drispac to the system to reduce the fluid loss to the 10-12 cc/30 minute range.

Recommended Fluid Properties:

Plastic Viscosity	:	8 to 16
Yield Point	:	8 to 14 (increased if conditions dictate)
API Filtrate	:	8 to 12cc's/30 minutes (10 cc's or less for logs)
pH	:	9.0 to 10.0
Drill Solids	:	5% or Less

Seepage and/or lost circulation is anticipated while drilling the Second Wall Creek formation. Prior to drilling the Second Wall Creek, add 20 to 25 ppb LCM to the system consisting of 10 to 15 ppb Multi-Seal, 5 to 10 ppb Cedar Fiber and 5 to 10 ppb of Mica and/or Sawdust to help seal the loss zone. By-pass the shaker and continue with LCM throughout the system until the drill collars are below the formation. It may not be necessary to maintain the 20-25 ppb concentration. Allow wellsite observations to dictate the percentage of LCM necessary to allow

DEPTH INTERVAL .... 500' - 4,200' .... CONTINUED

continued drilling without extreme loss of mud. Should seepage of fluid continue once the LCM is shaken out, use sweeps of Mica Fine and Nutshell Fine mixed at 5 to 10 ppb each, depending on the severity of the problem. If losses are serious and sustained, it may become necessary to bypass the shale shaker and maintain LCM throughout the system again. For extreme "total loss" situations, drilling "blind" can be considered. However, caution should be exercised to insure that enough carrying capacity (pump output and rheology) is available to transport the drilled cuttings above the drill collars and into the loss zone(s). Also in extreme loss situations the use of a Diaseal or Cement squeeze may be considered.

While drilling, tourly additions of Anco-Drill (PHPA) will help provide wellbore stability and supplemental viscosity to keep effective hole cleaning properties as well as improved lubricity to the fluid without adding solids to the system. The Anco-Drill polymer works through encapsulation of the shale, which slows down the movement of water into the shale. The polymer also plays a significant role in strengthening the surface of the shale so that it withstands mechanical abrasion due to its strong adsorption onto clay materials. Additional benefits from using the Anco-Drill polymer include increased ROP due to the low solids make up of the system and more efficient solids removal as the polymer will also encapsulate the drill cuttings allowing the solids control equipment to remove them easier, to avoid their dispersion into the drilling fluid. The amount of Anco-Drill required will be dependent on the penetration rate, formation and amount of water dilution that is added to the system. Anco-Gel will be used as the main viscosifier for an increase in viscosity and/or yield point as hole conditions dictate.

As drilling progresses, adjust the fluid properties as dictated by wellsite observations of hole conditions in order that this project can be completed in a safe and effective manner.

Set 7" intermediate casing to 4,200'.

RECOMMENDED DRILLING FLUIDS PROGRAM

INTERVAL (feet)	MUD WEIGHT (lbs/gal)	VISCOSITY (sec/qt)	FLUID LOSS (ml/30 min)	MUD TYPE
4,200' - 6,200'	8.5 - 8.9	34 - 42	10 cc's	3% KCL/Polymer

Drill out the cement in the 7" intermediate casing with fresh water. After the shoe is drilled dump and clean the mud pits and refill with fresh water. While circulating the hole, add 10-12 ppb of Potassium Chloride and 0.75 ppb of Flowzan to the system to achieve a 34 - 38 viscosity and 3% KCL concentration. Reduce the fluid loss to the 10 cc's range utilizing Drispac (approximately 0.25 ppb). Maintain the pH of the system at 9.0 to 10.0 with Caustic Soda added through a chemical barrel.

Recommended Fluid Properties:

Plastic Viscosity	:	6 to 10
Yield Point	:	6 to 12 (increased if conditions dictate)
API Filtrate	:	10 cc's (decreased if conditions dictate)
pH	:	8.5 to 9.5
KCL %	:	3% to 4 %
Drill Solids	:	4% or Less

Monitor the potassium ion concentration and treat the system accordingly to maintain a minimum of 15,000 to 16,000 ppm K+. Do not rely upon the chloride readings as an indicator of KCl concentration as the potassium ion will be base exchanging with the sodium ion and being depleted as drilling progresses. This system is designed to be a very inhibitive to provide sufficient wellbore stability for the duration of the well in the highly reactive clays being drilled. For this reason, bentonite (Anco-Gel) will not yield effectively for viscosity in this type of system. Therefore we recommend that additional viscosity be achieved by the use of Flowzan or Sea Mud during the duration of the well.

Anticipated anhydrite contamination will not effect this type of mud system and the use of Soda Ash will not be required as the Goose Egg and other anhydrite bearing formations are drilled.

Utilize all available solids control equipment to minimize drill solids concentration in the mud system. Use water additions for dilution of the mud system to keep the drill solids concentration at 4% or less.

If mud density is required, Anco Bar will be added to achieve the desired mud weight due to water flow from injection wells in the field.

Attachment E-2

Drill Pipe Specifications

1300.doc

WEATHERFORD

DRILL PIPE SPECIFICATIONS	
Connection Type	HT 38
Interchangeable With	
Nominal Weight per Foot	13.30#
API Grade	S-135

TOOL JOINT DATA	
Outside Diameter	4-7/8"
Minimum Outside Diameter	4-5/8"
Inside Diameter	2-9/16"
API Drift, New	2-7/16"
Rabbit OD, Suggested	2-3/8"
Minimum Make-up Torque	**16,000 Ft Lbs**
Max Recom'd Make-up Torque	17,700 Ft Lbs
Torsional Yield Strength	29,500 Ft Lbs

TUBE DATA	
Adjusted Weight w/Tool Joint	13.77#
Outside Diameter	3-1/2"
Inside Diameter	2.764"
Wall Thickness – New	.368"
- Premium	.294"
Cross Sectional Area – New	3.621 Sq in
- Premium	2.829 Sq in
Minimum Yield Strength	135,000 Psi
Minimum Ultimate Strength	145,000 Psi
Maximum Pull – New	488,800 #
Recom'd Max Pull – Premium	**381,900 #**
Burst Pressure – New	24,800 Psi
- Premium	22,700 Psi
Collapse Pressure – New	25,400 Psi
- Premium	21,600 Psi
Torsional Yield Strength – New	33,400 Ft Lbs
- Premium	25,900 Ft Lbs
Tube Capacity	311.7 Gal/1000'
Tube Displacement	193.2 Gal/1000'

TOOL JOINT THREAD INSPECTION	MPI, Profile/lead, Visual, Dimensional
TUBE INSPECTION	EMI, Wall Verification, Visual, Dimensional

Tool joint make-up torque is 60% of tool joint torsional yield and is based on thread compound that conforms to API 7A1 and has a friction factor of 1.

Technical Services 12-99 HT 38 S, 10.40#

Attachment E-3 – ENGINEERED TEST PLAN
DOE High-Pressure Jet Kerf Drilling
Test to be Conducted at RMOTC

Introduction

The following engineered plan is for conducting a test of the jet kerf drilling system developed by Maurer Technology Inc. under contract to Federal Energy Technology Center (DE-FC26-97FT33063). This document concentrates on the major elements needed to successfully test the Maurer jet kerf drilling system at the Rocky Mountain Oil Technology Center (RMOTC) in Wyoming.

Safety

Safety will be a critical item, as the surface fluid pressures will be at or near 10,000 psi. Any failure of piping, hoses, or other equipment could cause serious injury or death to personnel in the area. Even a small pin-hole leak at these pressures is dangerous. The stream will act like a knife cutting flesh and bone. Every operation and modification will be examined with the above in mind. Exposure of personnel will be limited as much as is possible.

A safety meeting covering the dangers of high-pressure fluids must be held and all personnel need to be on the watch for potential failures or dangers.

Objective

The objectives of this test are three fold. They are: 1) Establish that high-pressure (8,000 to 10,000 psi) jet kerf drilling increases penetration rate in a different types of formations at depths of 4,000 to 6,000 ft., 2) Measure and quantify the amount of increase in penetration rate compared to conventional rotary drilling, and 3) Test the durability, reliability and functionality of the high-pressure drilling motor and bit designed and built for this project.

These objectives will be met by drilling 2,000 ft of 6 in. diameter hole through formations typically encountered during oil and gas drilling. The test will be conducted at the RMOTC in Wyoming. The high-pressure jet kerf drilling will begin at a depth of approximately 4,300 ft drilling out from 8-1/2 in. 20 or 23 lb/ft casing. Drilling rates will be compared to conventional rates that have been recoded at the site on many wells drilled over several years and under many conditions.

Preparation

RMOTC: RMOTC will prepare a drill site and set up their rig. After setting surface pipe 12-1/4 in. diameter hole will be drilled to a depth of approximately 4,300 ft. RMOTC will then set 8-5/8 in. 20 or 23 lb/ft casing. The casing shoe will be drilled out and the hole prepared for the test.

RMOTC will then modify their rig and mud system for pumping at high (10,000 psi). These modifications will include the installation of a new pump with a high pressure fluid end, piping and accumulator. The stand pipe and piping to the stand pipe will be replaced with high pressure pipe, the rotary hose will be replaced with a high pressure hose and the swivel will be replaced with a high pressure swivel. Once the modifications have been made RMOTC will test the system for proper operation.

Before the high pressure drilling assembly is run RMOTC will empty and clean the mud pits replace the mud with clean water and add a centrifuge to the mud cleaning equipment. The hole will be conditions and then the high pressure portion of the test begun.

Maurer will also supply a high pressure pump as an emergency back to the RMOTC pump. This pump will have only 80 to 100 gpm capability, but is necessary in case the primary pump fails and the test halted. This pump can also be used to add additional flow incase the primary pump is horsepower limited.

Maurer: Maurer will disassemble, clean, lubricate, and reassemble the high pressure mud motors in preparation for the test. Both the 3-1/8 in. and the 4-3/4 in. motors will be prepared. Well hydraulic calculations will be done to determine the correct nozzle size based upon the well parameters. The high pressure PDC bit will be fitted with the correct nozzles for the test. Maurer will also supply drill collars for the test. A Special screen will be manufactured to place into the bottom collar to keep any stray particles from plugging the high pressure nozzles in the bit. A second screen will be run just above the bit as added insurance. This equipment will be shipped to ROMTC before the test.

The drill collars will be run using o-rings that fit on the conventional oilfield pin and form a seal in the thread relief on the box. This will help prevent was outs in the threads. Depending on the drill string (tool joint type) selected o-rings may be used on these threads as well.

Test Plan Outline

RMOTC will after building a pad and moving a rig onto site will construct a well, using conventional drilling techniques, to a depth of approximately 4,300 ft. A surface hole, 12-1/4 in. dia., will be drilled to a depth of 300 to 400 ft were 9-5/8 in. casing will be set to isolate the Shannon formation.

From this point the well will be drilled to a depth of 4,200 ft. using 8-3/4 in. bits, were 7 in. x 23lb/ft casing will be set. The shoe will be drilled out and then RMOTC will up grade the rig for 10,000 psi operation. Prior to drilling the hole will be conditioned and then the mud tanks empted, cleaned and filled with fresh water for the high pressure test.

<u>High-Pressure Drilling Plan</u>

1. Rig up high-pressure bit, motor and a minimum of one drill collar.

2. Insert screen into drill collar

3. Test motor at flow 180 to 200 gpm to check pressure drop across tool

4. Total pressure drop during drilling should not exceed 10,000 psi or be below 8500 psi. If pressure drop across bit and motor will not allow this range adjust nozzles in bit.

5. Once bit nozzles are correct rig up remainder of drill collars. Each tool joint should receive o-ring before make up

6. Run BHA into hole

7. Tag bottom, lift off start pumps.

8. Pressure up to 10,000 PSI (200 gpm) while rotating and stroking tool

9. Avoid holding tool in one location when pumps are running

10. Start drilling and record ROP every foot as often as possible (ROP can be given as minutes/ft)

11. Continue drilling running sweeps or short tripping as necessary to clean well.

12. When not drilling rotate and stroke pipe to keep jets from washing out side wall.

13. Slow ROP down at each formation break during drilling to avoid damaging bit.

14. Continue drilling to TD

15. If test is going well flow may be varied to measure effect on ROP.

16. Monitor well for sticking if ROP becomes too high

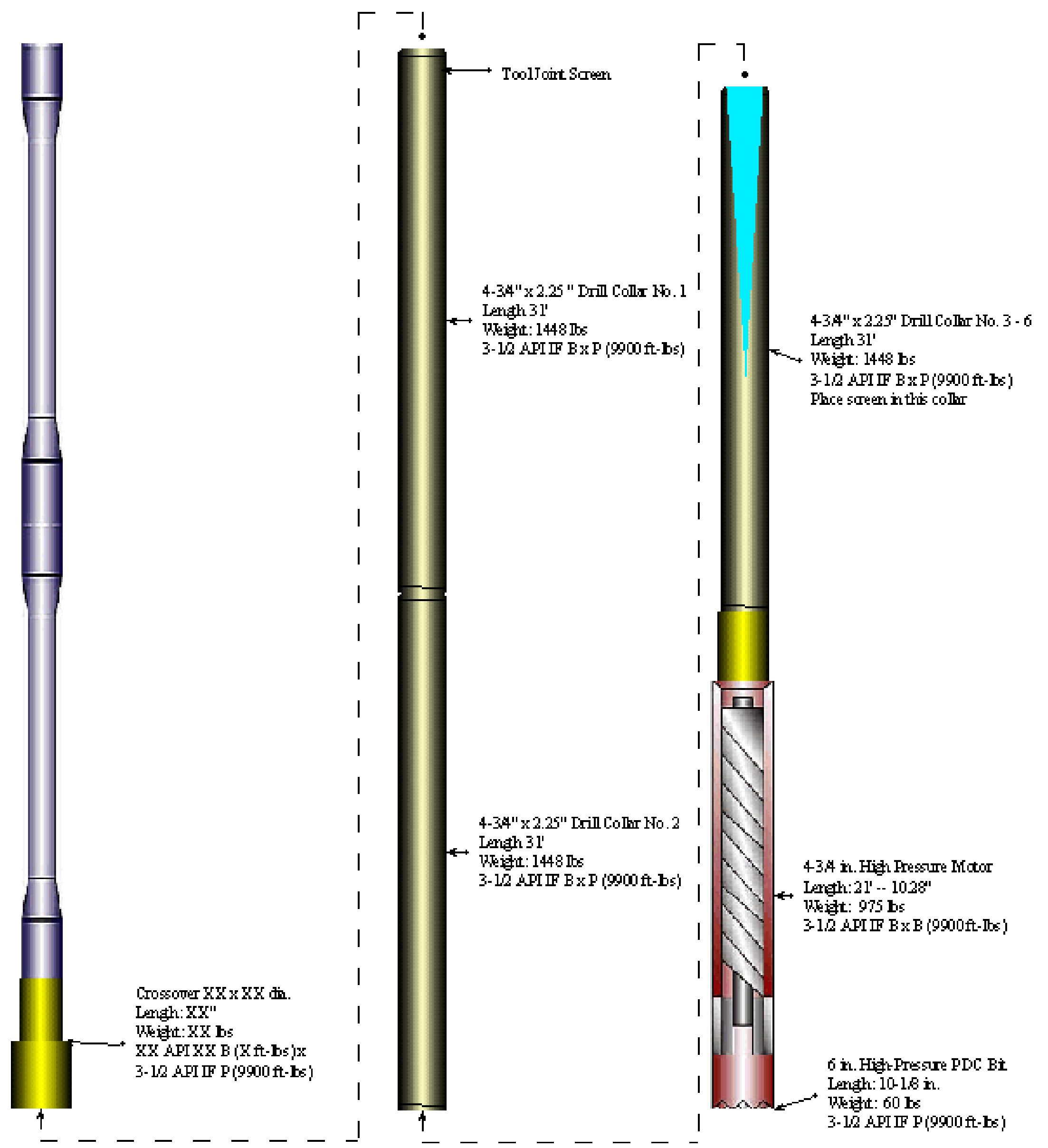
17. After reaching TD pull BHA from well

18. Retest motor and bit at surface to determine pressure drop at same flow rate when staring well

Attachment E-4

BHA

BHA Number 1
6 in. Bit with 4-3/4 in. Motor



Appendix F

Coiled-Tubing Equipment

History

Since its introduction to the oilfield in 1963, CT has been heralded as a technology that has the potential to revolutionize gas and oil operations. Unfortunately, early mechanical failures, high oil prices, and the industry's reluctance to adopt change limited the growth of CT technology. During the 1990s, however, interest in CT increased dramatically. The fall of oil prices in the 1980s triggered increased use of and interest in cost-saving technologies such as CT. Significant advances in tubing reliability and increased equipment versatility have transformed the industry.

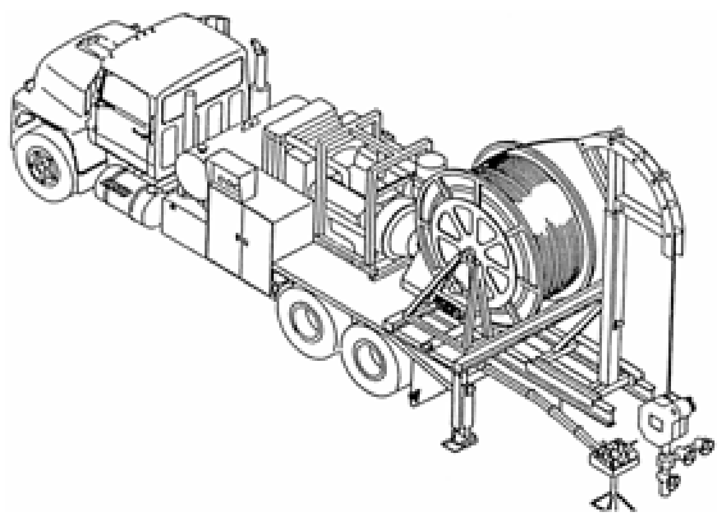


Figure 1. Basic CT Rig for Workovers

CT rigs (Figure 1) have found widespread use in the oil field for drilling, completion, and workover operations. Reduced rig costs and trip times allowed CT rigs to reduce cost by as much as 50–70% when compared to conventional workovers, especially in harsh environments such as Arctic fields and offshore. In addition to cost savings, CT has also proven to be more versatile than other competing systems. As shown in Table 1, CT has specific advantages and disadvantages as compared to conventional systems.

Table 1. Advantages/Disadvantages of CT

Coiled Tubing	Jointed Pipe
Faster Trip Time	Rotation from Surface
Continuous Pumping	Low Pipe Fatigue
Low Mobilization Costs	Greater Push/Pull
Operations in Live Wells	Higher Torque
Workovers in Slim Holes	Proven/Accepted

Due to the advantages of CT in the right applications, its use has continued to expand in the oil field. Development of larger tubing (up to 3½ in. OD) and advanced downhole drilling tools in the 1990s led to new applications, most notably drilling open hole. Drilling with CT has received considerable interest from the industry during the past few years. With its ability to be tripped in and out of the hole rapidly under pressure, CT holds great promise to reduce costs when applied under appropriate conditions.

Basic CT equipment and systems as used for most drilling operations are shown in Figure 2. In some cases, individual items may be modified to suit a specific application, but generally the equipment is interchangeable between applications. The trend toward larger CT sizes for drilling often results in larger equipment that is not easily compatible with well-intervention operations. For example, 2-in. or 2⅜-in. CT strings are not commonly used for well-intervention operations.

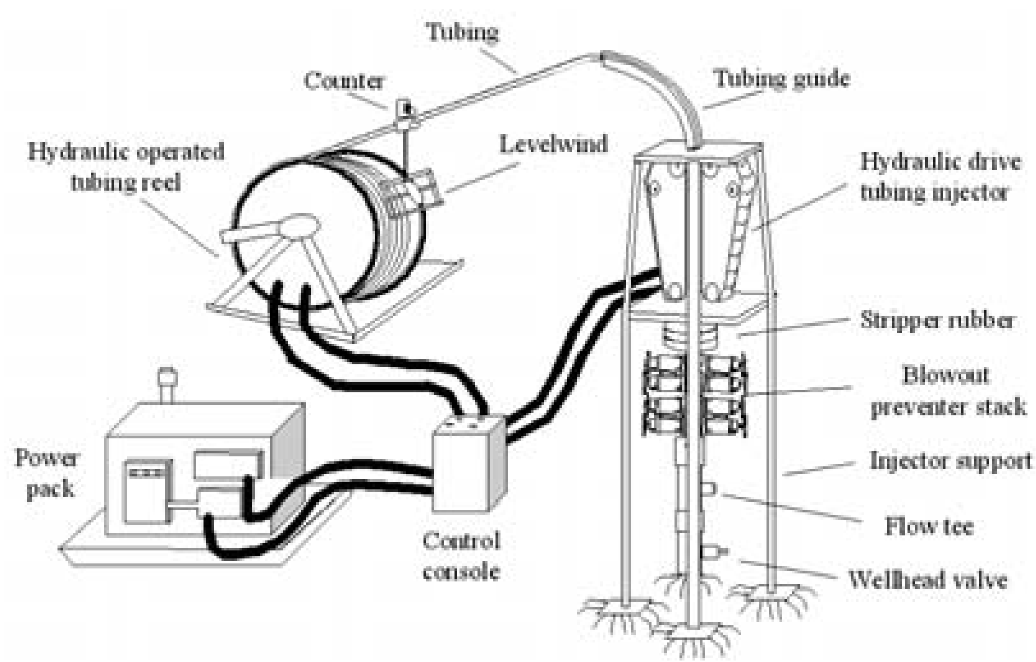


Figure 2. Basic CT Equipment Subsystems

A brief overview of key components for CT operations is provided in the sections below.

CT String

CT is a continuous string of tubing loaded onto a spool. It is made from rolling strip material into a tubular form and resistance welding along its length. After its manufacturing, the tubing is rolled onto large spools with core diameters ranging from 8–12 feet. Quality Tubing developed the continuous milling process that is capable of producing a single tube over 30,000 ft (varies with wall thickness and pipe size) in length. When milled into a finished tube, the entire length is non-destructively inspected, gauged and hydrostatically tested to assure quality.

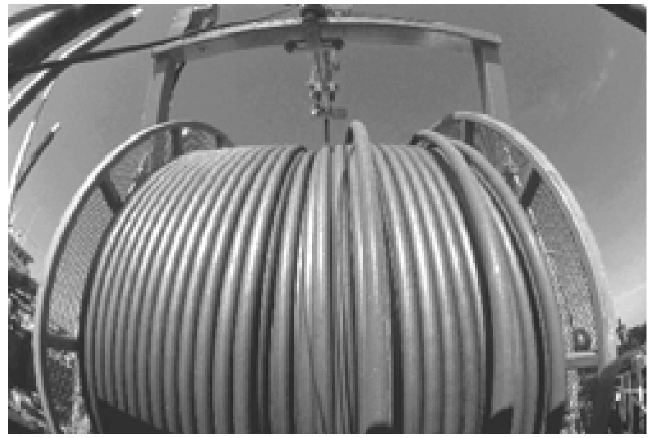


Figure 3. CT String

Even basic CT drilling operations can require high performance from the CT string. For example, if drilling operations require multiple passes over the same hole section (e.g., wiper trips), fatigue of the string can quickly accumulate and lead to failure. In addition, the likelihood of stuck pipe is greater during CT drilling than in most conventional well-intervention applications since there is no ability to rotate the string. This not only means that performance characteristics of the CT string must be optimum, but that operating limits of CT strings for drilling must be known at all times.

CT of 2⅜ or 2⅞ in. OD is typically used for drilling new and directional wells. For some simple well deepenings with limited hydraulic requirements, a 2-in. CT string may be sufficient. In almost all applications, CT strings with wall thickness of at least 0.156 in. manufactured from 70,000- or 80,000-psi yield strength material are recommended. However, for deeper vertical wells or longer step-out horizontal wells, a 100,000- or 110,000-psi yield strength material may be required.

During the design phase of most CT drilling applications, the optimum size, wall thickness and yield strength are determined using CT modeling software and design data from the intended application. Some of the design data required are: (1) the well path; (2) open-hole diameter; (3) drilling fluid weight and viscosity; (4) length and diameter of existing tubulars if drilled through tubing; (5) length and diameter of the BHA; (6) maximum overpull allowed; and (7) required weight on bit (WOB) at total depth.

In general, the size of CT selected for a given job will be a compromise based on tubing life (smaller sizes have a longer fatigue cycle life, but provide lower strength and limited flow rates) and flow area (larger CT sizes have greater strength and flow area, but shorter fatigue service life). Consequently, CT drilling is usually done with 2⅜- or 2⅞-in. CT. Another critical consideration is the amount of CT that can be reeled onto a given spool to achieve the desired depth or the maximum weight the crane can support.

CT Injector

The CT injector head (Figure 4) provides the power and traction necessary to run and retrieve a CT string into and out of the wellbore. Several hydraulic systems are used to enable the CT unit operator to exercise control over any string movement.

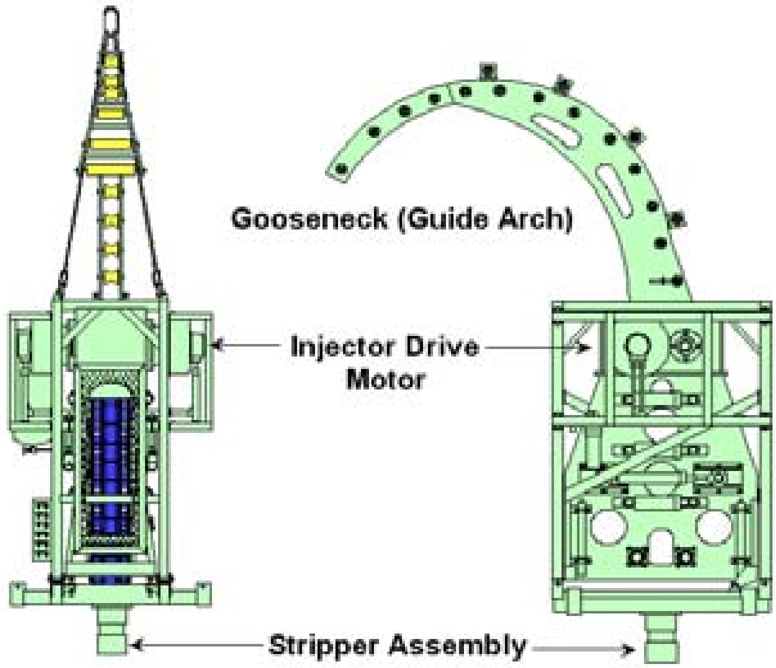


Figure 4. Typical CT Injector

For CT drilling operations, an injector with at least a 60,000-lb pull capacity is required. For simple well deepenings, a 40,000-lb capacity injector may be adequate if conditions allow. A minimum gooseneck radius of 72 in. is required for 1¾-in. and larger CT strings. While the majority of drilling is done with standard CT injectors, special hybrid units have been developed which allow running both continuous CT and jointed pipe. These units allow the CT unit to complete more of the tasks associated with drilling, such as running and pulling completion tubing. Key performance data and specifications of common CT injectors are listed in Table 2.

Table 2. CT Injector Specifications

Injector Model	Height (in.)	Width (in.)	Depth (in.)	Weight (lb)	Snub	Pull	CT Sizes (in.)
					(x1000 lb)		
HR440	80	52	55	6750	20	60	1 to 2⅜
HR480	109	60	60	11200	40	100	1¼ to 3½
SS 400	82	42	58	5700	20	40	¾ to 2⅜
SS 800	82	42	58	6125	20	80	¾ to 2⅜

CT Reel

The primary function of a CT reel (Figure 5) is to safely store and protect the CT string. This must be achieved while avoiding excessive damage to the string through fatigue (bending) or mechanical damage from spooling. The reel typically incorporates a swivel assembly which allows fluids to be pumped through the tubing string while the reel drum rotates. For CT drilling applications incorporating a CT string with wireline installed, a bulkhead and collector assembly is required to enable the electrical conductors to pass from within the CT string (from a pressure seal) and out of the rotating reel drum (electrical swivel/collector).

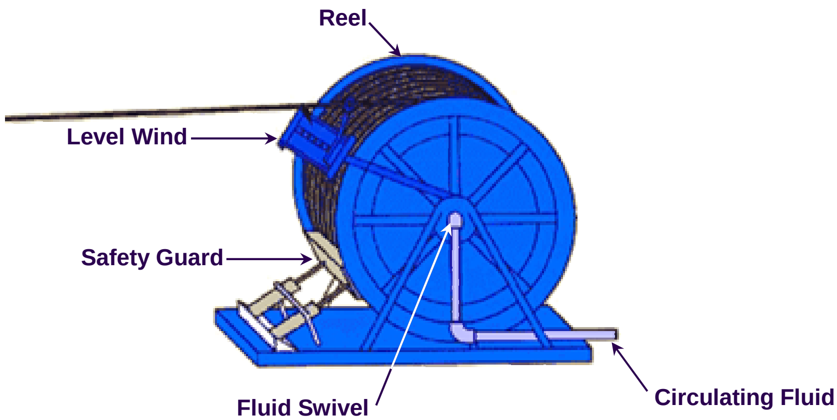


Figure 5. CT Reel

In addition to the hydraulic connections required to operate the drive, braking and spooling guide (level-wind) systems, reels used in CT drilling operations are typically fitted with additional monitoring equipment and connections (for example, pressure monitoring sensors used with MWD mud-pulse technology, or CT string monitoring equipment such as a diameter and ovality monitoring device).


Figure 6. CT Power Pack

CT Power Pack

The function of the power pack is to provide hydraulic power to operate the CT unit and primary/secondary pressure-control systems (e.g., stripper and BOP systems). In addition, the power pack incorporates an accumulator facility to allow limited operation of pressure-control equipment following engine shut-down. If nonstandard equipment or auxiliary equipment is to be powered by the CT power pack during drilling operations, it should be confirmed that the output of the power pack is adequate and that the pressures and flow rates are compatible.

Crane and Substructure

All CT drilling operations require lifting, moving and placing of equipment of tools (BHA). Local conditions and configuration of the equipment will determine the size (height) and capacity of the crane. The crane is often used to place the injector on top of the BOP and then to hold the injector in place. The CT drilling engineer must determine if a substructure is needed and then the size and type required for the given project parameters.

The substructure (**Error! Reference source not found.**) provides stability to the wellhead equipment and can include additional features ranging from a simple platform to a complex jacking frame capable of running and pulling wellbore tubulars.

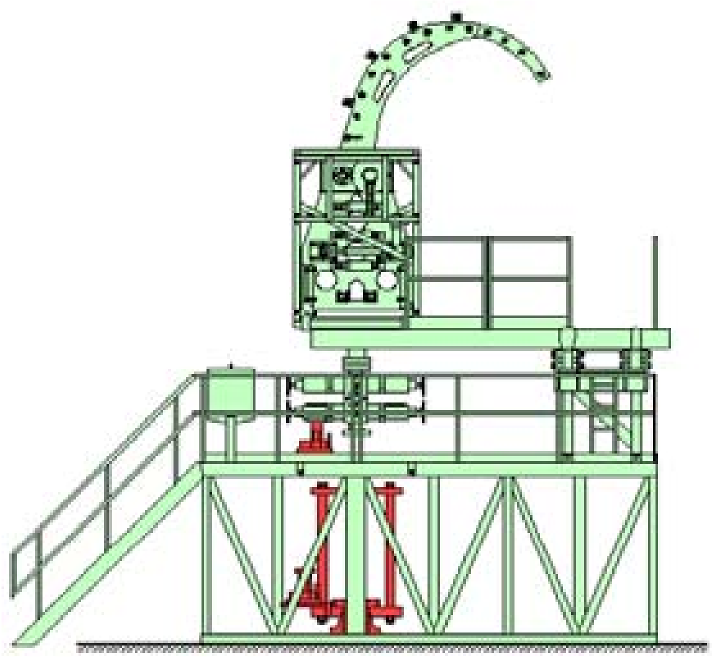


Figure 7. Multipurpose CT Support Structure

The key features of a drilling substructure are:

- Elevates the working area above the wellhead for easier access to the wellbore
- Allows supporting the injector head without the crane and provides a means for raising/lowering the injector for make-up. Also allows skidding the injector on/off the wellhead when rigging BHAs.
- Provides a safe working platform for personnel while handling the BHA and injector hook-up
- Provides a means for supporting the BHA/tubulars during make-up using a “false rotary” opening and use of spider and slips

Substructures are designed for use within a limited range of vertical adjustment, enabling the substructure to be adjusted to suit the specific wellhead and surrounding conditions. Typically, sub-structure legs are adjusted to an appropriate height and fixed (pinned) in place.

A more complex version of the CT drilling substructure is the hybrid unit, or jacking frame. This structure is equipped with an upper platform mounted on hydraulic rams that can be raised and lowered from the lower substructure base. By using power slips on the upper and lower platform openings, tubulars can be run or pulled from the well by raising/lowering the upper platform. Advantages of this type of substructure are flexibility in position adjustment, and a reduced dependence on high-capacity cranes or derricks for running or pulling well tubulars.

Well-Control Equipment

The configuration of BOP equipment required for any CT drilling operation largely depends on the type of application and the anticipated "worst case" conditions that may be encountered.

The configuration may change as work progresses, i.e., as the likelihood of higher pressures increases, so must the operating capacity of equipment increase. There are several categories of BOP systems which require significantly different approaches to equipment configuration.

CT well-control equipment used for the majority of CT drilling operations is very similar to that used for CT well-intervention services. In some cases the individual items may be modified to suit a specific application, but generally the equipment is interchangeable between applications.

Quad BOP

If the size (ID) allows, a standard 4-in. quad BOP (Figure 8) provides adequate functionality with convenient rig-up and operation. Larger hole sizes typically require use of 7⅟₁₆-in. BOPs.

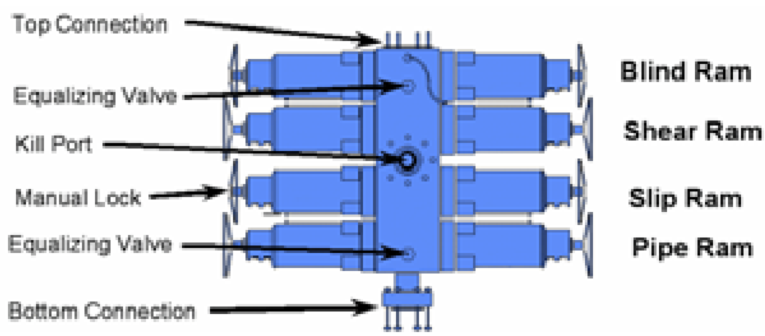


Figure 8. Quad BOP for CT Operations

Single/Dual BOP

For applications requiring through-bore access greater than 5⅛ in., the BOP stack, or part thereof, may be assembled for single or dual-ram BOPs in 6⅛- or 7⅟₁₆-in. sizes.

Annular BOP

The annular BOP is an extremely flexible component enabling a wide variety of contingency options over a range of tool/BHA sizes.

CT Control Console

All CT operations are controlled from the operator's console (Figure 9) or control cabin area. In some cases, it may also be desirable or necessary to include a repeat/remote control located in a safe area for emergency operation, e.g., remote operation of shear/seal tertiary pressure control equipment.

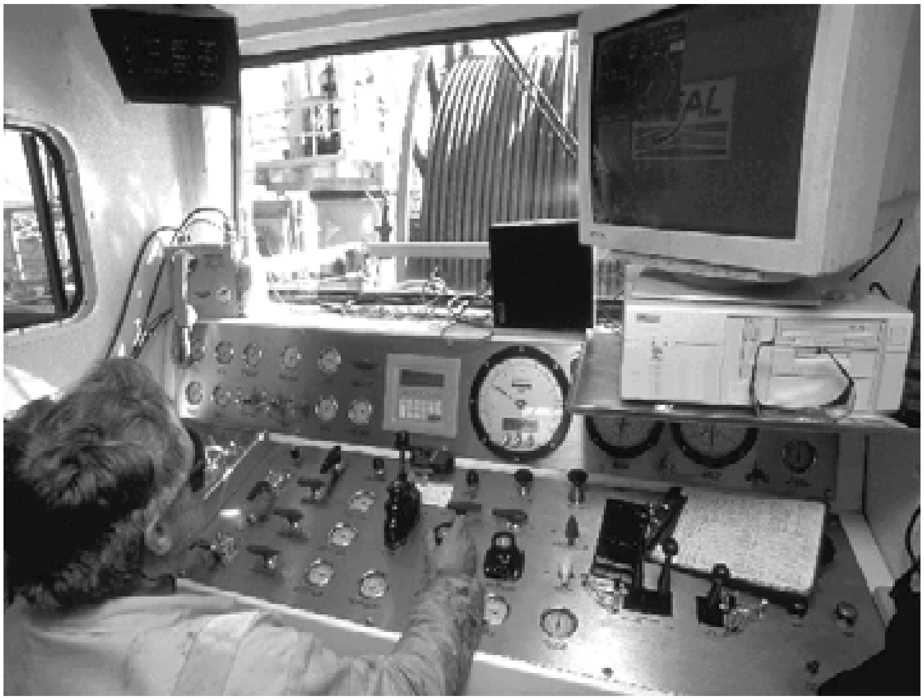


Figure 9. CT Unit Control Console

Appendix G

Reviewer's Comments

“Advanced High-Pressure Coiled-Tubing Drilling System”

By
E. Lance Cole
Petroleum Technology Transfer Council
Registered Engineer in Oklahoma
June 9, 2005

Overall Comments:

Significant steps forward were made in this project, but I do believe stating it is clearly “technically feasible” may be overstating the case. Performance of the jet-assisted bit was never confirmed, although there is a new design that purportedly solves that problem. Other individual components performed, but some not for long and testing was inadequate to determine if the “system of components” would perform with the reliability required for commercialization. All of the above said, the ability to achieve significantly improved penetration rates in a field environment was confirmed – but that had been confirmed in earlier work by others. It's the performance of a “system” that remains the challenge. Comments on individual components follow, ending with thoughts on an approach to bring about the additional field testing that is definitely required before commercialization will be near.

Jointed Pipe

The double-shouldered drill pipe did perform satisfactorily in the RMOTC field test, but the tests were only for a few days at a time. In my mind there is still a question about whether it would continue to perform under continued “daily usage” conditions. Does this need to be confirmed in a longer duration test, or is there performance data for the drill pipe in other applications that would confirm its longer-term durability?

Coiled Tubing

Laboratory testing of Quality Tubing's QT-1200 tubing did show an increase from below 25 to over 150 cycles @ 12,000 psi. Although offered as a standard commercial item, it was unfortunately never used in this project. Before rejecting the CT approach, is it worthwhile to test a commercial string at RMOTC?

Bit Nozzle

Although an anti-erosion nozzle has been developed and patented, there was no data presented to show it would perform any better. Until this problem is solved and performance in field test conditions confirmed, the entire HP drilling approach is at risk. Further testing in a field environment like RMOTC is essential.

4¾” HP Downhole Mud Motor

In testing on April 25–29, the mud motor failed after only a short time. Although the stator manufacturer offered an explanation for the failure, there was no way to confirm the explanation offered was really the culprit. No further testing with a HP downhole mud motor was attempted in the RMOTC test. Although it is stated that HP motors were "extensively tested in the laboratory," there was no mention of any other field tests of the HP motor. Without further data, it seems that the question of long-term field reliability of the HP downhole mud motor remains to be confirmed. Again, further testing in a field environment like RMOTC is essential.

The Next Steps for Commercialization (two-step process)

First, there needs to be longer-duration testing at RMOTC to confirm (1) performance of individual components and (2) performance of the system under field conditions. This testing will likely require significant DOE funding – private industry does not have the incentive until the "system" comes closer to demonstrating commercial reliability.

Then, given positive results from a second field test at RMOTC, one has the data to approach an operator that has a very active drilling program regarding working with them and their drilling contractor to test the "system" on a few holes. An operator that comes to mind is Williams – they have a 10-yr supply of Piceance Basin drilling locations, as evidenced by their recent order for 10 new drilling rigs. They have the incentive to reduce their drilling times and the stroke with a drilling contractor to push them to a test. Once one operator drills a few holes with the higher penetration rates, technology acceptance and commercialization will accelerate.

Reviewer’s Comments

“Advanced High-Pressure Coiled-Tubing Drilling System”

By
Ralph Schulte
Critique, Inc.
Project Manager
Rocky Mountain Oilfield Testing Center

Recommendations:

1. The use of high-pressure drilling or jet-assisted drilling has shown significant promise to continue with further testing. It is believed that a constant, small-scale development effort, similar to the Microhole Drilling initiative, is warranted.
2. Future testing might be on a small scale but should be sufficient to further the technology or address the current problems areas already identified.
3. The problem areas include the loss of jets due to internal erosion of the steel adjacent to the jets. The difficulties of the high pressure mud motor should also be further researched.
4. Testing operations could be structured to allow for a compromise between laboratory testing and a full-scale drilling test. Testing operations could be conducted in shallow test wells with concrete targets of varying compressive strengths or actual rock targets.
5. It is believed that high pressure drilling will occupy a niche drilling market in the future. This drilling market may include wells with drilling times measured in months instead of days. If sufficient technology can be demonstrated then operators and possibly contractors should be willing to adopt the technology based on economic incentives.

Reviewer's Comments

"Advanced High-Pressure Coiled-Tubing Drilling System"

By
Roy Long
Technology Manager, Oil Program
National Energy Technology Laboratory
United States Department of Energy

DOE's Advanced High-Pressure Coiled-Tubing Drilling System, developed by Maurer Technology, was another of those excellent concepts / expertly-developed technologies that did not reach commercialization primarily because of market forces which did not allow adequate deployment and demonstration required to achieve market penetration. The concept of high penetration rates achievable by cavitation to depths of at least 3,000 feet is well documented. Based on the likelihood of additional abrasion effectiveness adequate to enhance kerfing effects to augment positive displacement motors, drilling below cavitation depths is also soundly based and demonstrated, at least on a limited basis, by this project. The problems encountered in this project that prevented commercialization were as follows: (1) Industry pressure to drill at least 7-7/8" boreholes resulted in surface pumping requirements which pushed the envelope of existing pumping systems of "commercial interest". (2) The field demonstration CT drilling partner had full utilization of its CT drilling rigs and had inadequate interest in deep drilling via CT.

Despite the lack of commercialization, the following concepts were established: (1) High pressure (10,000 PSI) positive displacement (Moineau type) motors can successfully be manufactured with existing technology (2) High penetration rates (over 1,000 ft/hr) are achievable with this system in cavitation drilling environments. The effectiveness of this drilling energy for kerfing at depths greater than cavitation depths is given further confidence based on this performance. (3) The basis of high speed drilling via a similar system used with CT in smaller boreholes is still a viable concept to enhance overall CT drilling efforts within the U.S. This is the basis of award of a new proposal for DOE's Microhole Technologies Program where rapid drilling of boreholes of 3½" diameter is expected to provide a basis for revitalization of U.S. existing mature fields. This resource target less than 5,000' is in excess of 200 billion barrels of known oil that will not be developed unless cost effective systems such as this are deployed.

Based on the above demonstrated concepts, this program was successful.

Reviewer's Comments

"Advanced High-Pressure Coiled-Tubing Drilling System"

By
Mladen Ruzic
Gulf Coast Region – Senior Region Engineer
Baker Oil Tools
Fluid Pumping Services
Houston, Texas

Dear John,

I reviewed your report and am attaching a list of observations for your reference. Let me say that I am duly impressed by the depth of the scope of the project and your accomplishments as there are many significant positive conclusions listed in the report. My comments are more or less of the cosmetic nature. I appreciate the opportunity to review your report.