Optimization of Deep Drilling Performance – Development and Benchmark Testing of Advanced Diamond Product Drill Bits & HP/HT Fluids to Significantly Improve Rates of Penetration

Topical Report

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DISCLAIMER

ABSTRACT

This document details the progress to date on the OPTIMIZATION OF DEEP DRILLING PERFORMANCE – DEVELOPMENT AND BENCHMARK TESTING OF ADVANCED DIAMOND PRODUCT DRILL BITS AND HP/HT FLUIDS TO SIGNIFICANTLY IMPROVE RATES OF PENETRATION contract for the year starting October 2004 through September 2005.

The industry cost shared program aims to benchmark drilling rates of penetration in selected simulated deep formations and to significantly improve ROP through a team development of aggressive diamond product drill bit – fluid system technologies. Overall the objectives are as follows: Phase 1 – Benchmark 'best in class' diamond and other product drilling bits and fluids and develop concepts for a next level of deep drilling performance; Phase 2 - Develop advanced smart bit-fluid prototypes and test at large scale; and Phase 3 – Field trial smart bit –fluid concepts, modify as necessary and commercialize products.

As of report date, TerraTek has concluded all Phase 1 testing and is planning Phase 2 development.

Accomplishments to date include the following;

4Q 2002
- Project started
- Industry Team was assembled
- Kick-off meeting was held at DOE Morgantown

1Q 2003
- Engineering meeting was held at Hughes Christensen, The Woodlands Texas to prepare preliminary plans for development and testing and review equipment needs.
- Operators started sending information regarding their needs for deep drilling challenges and priorities for large-scale testing experimental matrix.
- Aramco joined the Industry Team as DEA 148 objectives paralleled the DOE project.

2Q 2003
- Engineering and planning for high pressure drilling at TerraTek commenced.

3Q 2003
- Continuation of engineering and design work for high pressure drilling at TerraTek.
- Baker Hughes INTEQ drilling Fluids and Hughes Christensen commence planning for Phase 1 testing – recommendations for bits and fluids.

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- Project held Industry Advisors planning meeting held November 19, 2003 at Hughes Christensen, The Woodlands, Texas.

- TerraTek prepared a paper for publication at the upcoming GTI Gas Technologies Conference.
- One of the Industry Advisors, BP America, provided the project team with some information about deep drilling performance in Louisiana.

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- TerraTek completed internal preparations for its high pressure drilling equipment.

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<u>Current Report</u>

4Q 2004 / 1Q 2005

- TerraTek moves to new facilities after delay of Hughes Christensen auxiliary pump.

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- Phase I testing completed successfully and safely. 16 tests are described in this report.
- TerraTek presents results publicly first to the IADC/Drilling Engineering Association Workshop on HP/HT Drilling in May 2005 (Galveston, TX).

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- Phase II application submitted
- Data analysis conducted and technology transferred via numerous industry presentations; e.g. August 2005 Drilling Engineering Association and review of program September 2005 at NETL's offices in Morgantown, West Virginia

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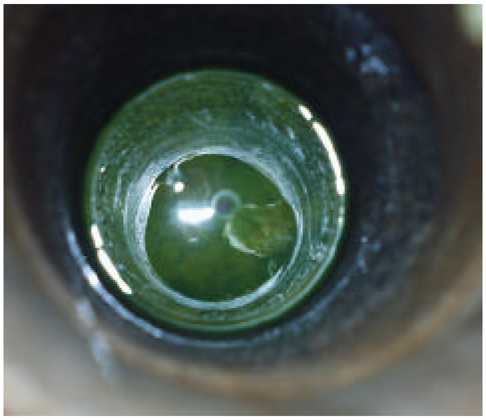
INTRODUCTION

The industry cost shared program aims to benchmark drilling rates of penetration in selected simulated deep formations and to significantly improve ROP through a team development of aggressive diamond product drill bit – fluid system technologies. TerraTek has assembled a team of Industry and Academic contributors who are recognized leaders in a) hostile environment drilling operations, b) engineering development and large-scale testing, c) downhole tool engineering and supply, d) mechanics and rock cutting characterization, e) rig pump manufacturer, and f) commercial experience. Objectives include: Phase 1 – Benchmark 'best in class' diamond and other product drilling bits and fluids and develop concepts for a next level of deep drilling performance; Phase 2 - Develop advanced smart bit-fluid prototypes and test at large scale; and Phase 3 – Field trial smart bit –fluid concepts, modify as necessary and commercialize products.

The focus of the Introduction for this Topical Report is on the successful drilling testing program undertaken at the highest pressures for full scale testing ever achieved worldwide.



EXECUTIVE SUMMARY

Background

TerraTek will assist in the development and testing of innovative bits / new products in the 'Wellbore Simulator'. Confining and overburden stresses are applied to selected rock samples and borehole pressures / hydraulics can be controlled. Weight-on-bit is applied with a servo-controlled system and rotary speed is controlled with variable speed direct drive motors, 5-speed transmission and standard oil-field rotary table. High-pressure fluid ends on the mud pump will facilitate drilling at pressures in excess of 10,000 psi. Computer aided engineering practices will be used by the bit supplier to develop and design features important to the improvement of ROP at great depths. The work proposed to benchmark performance and provide bit developments first for a 6 to 8-1/2" diameter range. In the field new mud pump developments have increased rig capabilities to 7500 psi and have increased capability to 2200 and 3000 horsepower. John Shaughnessy, BP's Senior Drilling Engineering for the Tuscaloosa trend, noted at the March 2001 Deep Trek Workshop that "over 50% of rig time is spent in the last 10% of the hole" and the operator has "high interest in improving ROP deep".

The relevance of benchmarking downhole tool performance at high pressures and developing innovative impregnated bit cutting structures is highlighted by the technical challenges operators are facing. Large-scale laboratory testing of downhole drilling tools at simulated deep conditions has a proven track record in determining actual performance and identifying crucial design parameters. The most familiar work in the industry relates to testing of PDC drill bits using recorded performance data in the engineering designs on innovative new products. In fact most PDC bit developments historically have come from large-scale laboratory testing. DEA Project 90 conducted drilling performance tests at 7,500 psi borehole pressure. This work is a next step in the ability to develop new products for commercialization; the testing will be performed at pressures in excess of 10,000 to 12,000 psi, a capability unique to the TerraTek laboratory drilling facility. In the case of solving deep drilling vibration problems, tests in a large-scale laboratory environment are preferred, as precise control of operating conditions is needed along with high frequency acquisition of data not possible in field wellbore environments.

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As of report date in 2004, TerraTek has concluded all major preparations for the high pressure drilling campaign. Baker Hughes encountered significant difficulties in providing additional pumping capacity before TerraTek's scheduled relocation to another facility, thus the program was delayed further to accommodate the full testing program.

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EXPERIMENTAL

2. TEST EQUIPMENT, PROCEDURES AND PROGRAM

2.1 DRILLING TEST EQUIPMENT

All DeepTrek drilling experiments were performed at TerraTek's Drilling and Completions Laboratory under simulated, downhole conditions in the Wellbore Simulator (Figure 1). Tables 1 and 2 give the maximum capabilities of TerraTek's Drill Rig and Wellbore Simulator.

The rock sample, a cylinder 15 ½-inch diameter by 36" long, is placed on a steel endcap and enclosed inside a urethane rubber jacket. Composite samples, comprising either Crab Orchard sandstone on the top and Carthage marble on the bottom or Crab Orchard sandstone on the top and Mancos shale on the bottom, were glued together with the top section 17" long and the bottom section 19" long. The jacketed rock sample is inserted into the Wellbore Simulator as part of the top vessel plug assembly. This contains the rotary drive shaft and drill bit, the high pressure rotary seal, and the vessel seals. The jacketed rock sample is pressurized with confining fluid to simulate the horizontal earth stresses, and an independent piston applies an axial load to the sample to simulate the overburden stress.

Special 15,000 psi delivery pressure pump fluid ends were fitted to TerraTek's 1,600 HP triplex pump (Figure 2). A 15,000 psi pulsation dampener was supplied by Hydril and fitted to a delivery manifold (Figure 2). Drilling fluid was circulated through the drive shaft and bit, up the drilled annulus, and through a cuttings-removal screen (Figure 1). A series of 15,000 psi rated fixed and adjustable chokes were installed in the drilling fluid return line between the cuttings removal screen and regular adjustable choke to generate the high borehole pressure. As flow rate was increased to the target value of 300 gpm (except for Test 14 with 340 gpm) with the TerraTek 1600 HP Continental Emsco pump (150 gpm supplied) and the Hughes Christensen Sky Brewster 1200 HP pump (150 gpm supplied), the borehole pressure was adjusted to 10,000 psi. The drilling fluid temperature was maintained as constant as possible by passing it through a heat exchanger.

Table 1. Drill Rig Performance Specification

PARAMETER	MAXIMUM CAPABILITY
Stroke	6 ft
Rate of Penetration	165 ft/hr
Weight on Bit	375,000 lb
Rotary Speed	400 rpm
Torque	10,000 ft-lb
Pumping Power	1,600 HP + 1,200 HP

Table 2. Wellbore Simulator Performance Specification

PARAMETER	MAXIMUM CAPABILITY
Overburden Stress	20,000 psi
Confining Pressure	13,000 psi
Wellbore Pressure	12,000 psi
Pore Pressure	4,000 psi
Bit Diameter Range	6 $\frac{1}{8}$ to 12 $\frac{1}{4}$-inches
Fluid Temperature	150 degrees F

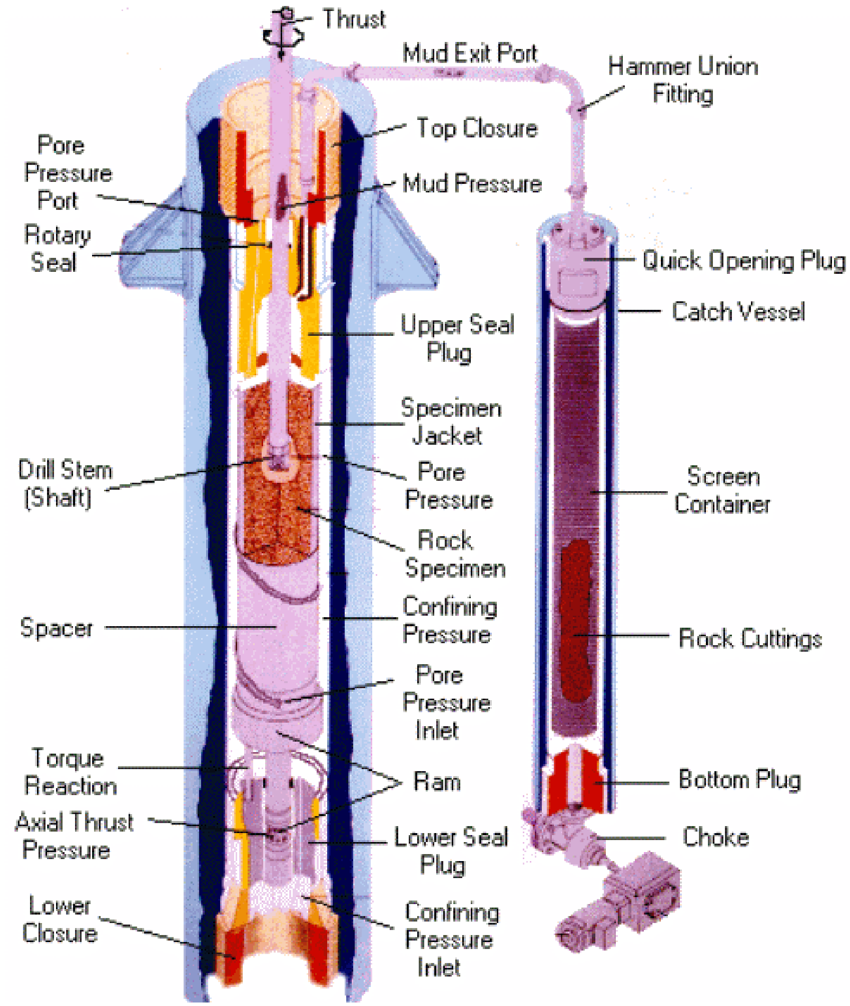


Figure 1: Wellbore Simulator

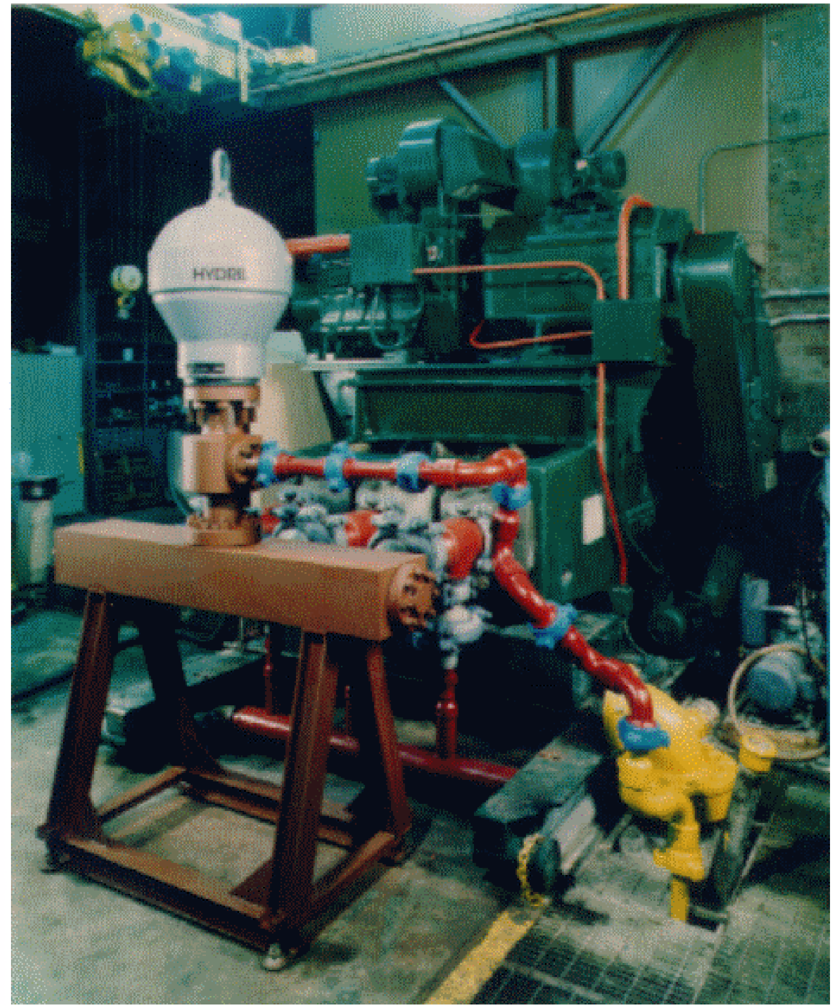


Figure 2: High Pressure Pumping System

2.2 DATA COLLECTION AND TESTING PROCEDURES

The Drill Rig and Wellbore Simulator are instrumented with numerous transducers to measure and control the various drilling parameters. The servo-controlled Drill Rig allows control of constant weight on bit during the drilling tests.

The raw data was recorded on two-recorders: 1) analog x-y-y′ plotter and 2) a digital computer at low data rates (1 data point per second) and bursts of high rate data (2000 data points per second for 2 seconds). The x-y-y′ plotter recorded weight on bit (lb) and penetration (inches) versus time. The computer recorded time (sec), distance drilled (in), weight on bit (lb), torque (ft-lb), swivel (stand pipe) pressure (psi), borehole pressure (psi), confining pressure (psi), ram pressure (psi), pump strokes (gpm), rotary speed (rpm), and drilling fluid temperature (deg F).

A computer program was used to reduce the low frequency (1 Hz) time-based data from each test into a concise record consisting of one averaged data set for each interval of steady drilling conditions. Typically, each data set contains the following: distance drilled, penetration rate (ft/hr), penetration per revolution (in/rev), torque, weight on bit, rotary speed, borehole pressure, swivel (stand pipe) pressure, flow rate, drilling fluid temperature, confining pressure, overburden stress, mechanical horsepower, bit pressure drop, bit hydraulic horsepower per square inch of bit area, and summaries of drilling fluid properties. The mechanical and hydraulic parameters are arithmetic averages over the interval. These reduced data tables are given in Appendix A, except confining pressure and overburden stress are not shown.

Several special procedures were followed in the test program to ensure successful test results.

1. Dye was placed in both the water-base (bright pink) and oil-base fluids (bright green) to allow analysis of drilling fluid invasion in drilled cuttings by Baker Hughes Drilling Fluids.

2. Before and after each drilling test, a sample of drilling fluid was taken and provided to Baker Hughes Drilling Fluids for post-test examination and testing.

3. The drilling fluid was analyzed to determine standard API drilling fluid properties before and after each test including the following: Fann readings to determine plastic viscosity (PV), yield point (YP), apparent viscosity (AV) and 10-second and 30-min gels; drilling fluid density; API filtration (water-base fluid only); pH (water-base fluid only) and HTHP filtration at 500 psi and 200 deg F (oil-base fluid only). The drilling fluid temperature used for the property measurements was typically 120 ^{o}F.

4. The borehole, confining and ram pressures (overburden stress) were controlled to maintain the confining pressure 1000 psi greater than the borehole pressure and 1000 psi less than the ram pressure (overburden stress). The test conditions of 10,000 psi borehole, 11,000 psi confining pressure and 12,000 psi overburden stress were applied to the rock samples, except for Test 16 which was run at 5000 psi borehole, 6000 psi confining and 7000 psi overburden.

5. All drilling tests were run with a slick, small-diameter (4 ½") shaft above the 6” diameter bit as shown in Figure 3. With the slick shaft, a spacer used above the rock samples has a 9-inch inside diameter and is 42 inches long.

6. All drilling tests were run with a flow rate of 300 gpm (150 gpm from the TerraTek pump and 150 gpm from the Hughes Christensen pump) which gave an HSI of about 2 for the PDC and roller-cone bits and an HSI of about 0.6 to 0.9 for the impregnated type bit, except for Test 14 which was run with 340 gpm (about 5 HSI). The actual HSI’s achieved during the testing varied somewhat from the targeted levels.

7. In each drilling test, the bit was spudded into the rock. For the roller-cone bit, impregnated bit and PDC bits, this spud distance was 1”, 2” and 3” respectively. The drilling sequences were carried out immediately after spudding.

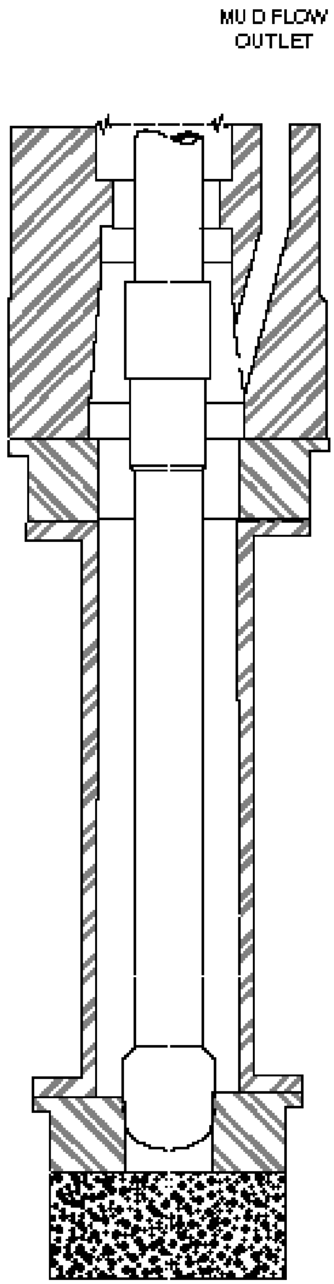


Figure 3 Slick Shaft Assembly

2.3 POST TEST PROCEDURES

After the completion of a drilling test, the following procedures were followed:

1. After removing the rock/bit assembly from the vessel, the sample's top end-cap was unbolted and the top vessel plug/bit assembly was raised up to expose the bit. Any material sticking to the bit (balling) and the bit condition were noted. The only material sticking to the bit was observed after Test 16 when a bit nozzle was plugged with pump rubber seal material.

2. The cuttings collected in the collection screen were examined, photographed and frozen for later analysis by Baker Hughes Drilling fluid.

3. The drilling fluid in the borehole was poured out and the borehole and bottom hole were examined.

4. The sample was cut 4 inches above the bottom-hole pattern. Two core samples were then cored (one along the side which contained rock from both the side and bottom of the hole and one from the bottom hole section only). The bottom hole patterns were photographed and the two core plugs were frozen for later analysis by Baker Hughes Drilling Fluids.

5. The diameter of the boreholes were measured at the top and bottom of the sample and at 90 degrees apart of determine the ending size of the borehole.

2.4 CORRECTIONS AND CALCULATIONS

2.4.1 Corrections

In the data reduction process, several corrections were made to the data. These are summarized below:

1. Torque was corrected to account for seal friction between the rotary shaft and shaft rotary seal.

2. Swivel pressure was corrected for line loss according to the respective drilling fluid density.

3. Flow rate (based on pump strokes) was recorded for the TerraTek mud pump (which has 3.5" plungers) and the flow rate from the Hughes Christensen pump was manually recorded from the pump stroke counter and added during the data reduction step.

4. During the tests with the impregnated bit and at high rotary speeds, there was some electrical feed-back from the system which caused the RPM signal to fluctuate (particularly at high torque conditions) and flow rate to be temporarily offset. Appropriate adjustments were made to the reduced data to account for these fluctuations or offsets.

2.4.2 Calculations

Penetration rate (ft/hr) calculations were based on the ending minus starting penetration intervals divided by the ending minus starting time intervals for each constant drilling condition interval. Penetration rate (in/rev) calculations were based on ROP (ft/hr) divided by (RPM x 5). Mechanical horsepower at the bit was calculated based on Torque (ft lbs) x RPM divided by 5252. Bit pressure drop was calculated based on Swivel Pressure (psi) minus Borehole Pressure (psi) less line loss, HSI was calculated based on Bit Pressure Drop (psi) x Flow Rate (gpm) divided by (1714 x Bit Area (in^2).

2.5. TEST MATRIX

The text matrix followed during the DeepTrek testing program is show below. For all drilling tests except as noted below, the following parameters were held within the levels indicated:

Table 3 Test Matrix

Test Matrix for DeepTrek Phase 1 Updated: May 17, 2005											
Arbuckle Test Series with 11 ppg Water-base Fluid and Crab Orchard and Carthage Marble Samples											
Test #	Bit	Nozzles	Rock	Mud	Flow Rate	HSI	Borehole	Confining	Overburd.	WOB	RPM
Deep1	PDC 7-Blade	3-12 + 1 Port	CO/Carth	Water	300	2 HSI	10,000	11,000	12,000	5-20 kip	90
Deep2	Roller-cone	3-15	Carth	11 ppg WB	300	2 HSI	10,000	11,000	12,000	10-40 kip	70-110
Deep 3	Roller-cone	3-15	CO	11 ppg WB	300	2 HSI	10,000	11,000	12,000	10-40 kip	70-110
Deep4	PDC 7-Blade	2-13, 1-14 + 1 Port	Carth	11 ppg WB	300	2 HSI	10,000	11,000	12,000	5-20 kip	90-120
Deep5	PDC 7-Blade	2-13, 1-14 + 1 Port	CO	11 ppg WB	300	2 HSI	10,000	11,000	12,000	5-20 kip	90-120
Deep6	Impregnated	0.97 TFA	Carth	11 ppg WB	300	0.6 HSI	10,000	11,000	12,000	10-40 kip	60-250
Deep7	Impregnated	0.97 TFA	CO	11 ppg WB	300	0.6 HSI	10,000	11,000	12,000	10-40 kip	60-250
Deep8	PDC 4-Blade	3-13, 1-12	CO/Carth	11 ppg WB	300	2 HSI	10,000	11,000	12,000	5-20 kip	90
Tuscaloosa Test Series with 16 ppg Oil-base Fluid and Crab Orchard and Mancos Shale Samples											
Test #	Bit	Nozzles	Rock	Mud	Flow Rate	HSI	Borehole	Confining	Overburd.	Ram	RPM
Deep9	PDC 7-Blade	3-12 + 1 Port	CO/Mancos	Base Oil	300	2 HSI	10,000	11,000	12,000	5-20 kip	90
Deep10	PDC 7-Blade	2-13, 1-14 + 1 Port	CO/Mancos	12 ppg OB	300	2 HSI	10,000	11,000	12,000	5-20 kip	90
Deep11	Impregated	0.97 TFA	CO/Mancos	12 ppg OB	300	0.65 HSI	10,000	11,000	12,000	20-30 kip	60-250
Deep12	Impregated	0.97 TFA	CO/Mancos	16 ppg OB	300	0.9 HSI	10,000	11,000	12,000	20-30 kip	60-250
Deep13	PDC 7-Blade	3-15 + 1 Port	CO/Mancos	16 ppg OB	300	2 HSI	10,000	11,000	12,000	5-20 kip	90
Deep14	PDC 7-Blade	2-12 + 1-13 + 1 Port	CO/Mancos	16 ppg OB	340	5 HSI	10,000	11,000	12,000	5-20 kip	90
Deep15	PDC 4-Blade	3-14, 1-15	CO/Mancos	16 ppg OB	300	2 HSI	10,000	11,000	12,000	5-20 kip	90
Deep16	PDC 7-Blade	3-15 + 1 Port	CO/Mancos	16 ppg OB	300	2 HSI	5,000	6,000	7,000	5-20 kip	90

As noted in the above test matrix, Tests 1 and 9 were designed as baseline tests to determine the idealized conditions of drilling with an un-weighted, clear fluid (water and base oil) with the 7-bladed PDC bit. Tests 2 through 8 were designed to evaluate the performance of four drill bit designs (roller-cone, 7-bladed PDC, 4-bladed PDC and impregnated) in a hard sandstone (Crab Orchard sandstone) and a hard limestone (Carthage marble) and with an 11 ppg water-base drilling fluid to simulate drilling the Arbuckle formation. Tests 10 through 15 were designed to simulate drilling conditions in the Tuscaloosa formation using a hard sandstone (Crab Orchard sandstone) and a medium-hard shale (Mancos shale) and with 12 ppg and 16 ppg oil-base drilling fluids while measuring the performance of three bit designs (7 bladed PDC, 4-bladed PDC and impregnated). Test 14 was run to determine the effectiveness of increased HSI (increased bit and hole cleaning) on bit performance with a 16 ppg oil-base drilling fluid. Test 16 was run to determine the effect of reduced borehole pressure on performance of the 7-bladed PDC bit.

2.6 BIT DESCRIPTION

All bits tested on the DeepTrek program were 6” diameter and were provided by Hughes Christensen. Eight of the sixteen tests were run with a 7-bladed PDC bit (HC-407), four with an impregnated bit (HH352), two with a 4-bladed PDC bit (ST3554) and two with a carbide insert roller-cone bit (STR70). The nozzles (and port for the HC-407 bit) used in the various tests to achieve the desired HSI levels with the different density fluids are listed above in the test matrix. A photograph of the four bits is shown below:

Figure 4. Hughes Christensen Drill Bits Used in DeepTrek Tests

2.7 DRILLING FLUIDS DESCRIPTIONS

During the DeepTrek project, water, base oil, 11 ppg water-base, 12 ppg oil-base and 16 ppg oil base were used in the drilling tests. The drilling fluid formulations are given in Table 5 and Table 6 provides the measured drilling fluid properties of the water, base oil and weighted drilling fluids.

Table 5
Drilling Fluid Formulations for DeepTrek Tests

<u>11 ppg Water-base</u>

0.0.86 bbls/bbls water
18 ppb bentonite
2 ppb chrome lignosulfonate
0.5 ppb caustic
45 ppb RevDust
94.4 ppb barite

<u>12 ppg Oil-base</u>
0.5435 bbls/bbl mineral oil
12 ppb amidoamine emulsifier
2.34 ppb modified FA emulsifier
3.16 ppb lime
4.2 ppb organoclay
25% calcium chloride brine
45 ppb Rev Dust
0.2 ppb XCD (Barazan D)
189.3 ppb barite

<u>16 ppg Oil-base</u>
0.5047 bbls/bbl mineral oil
12 ppb amidoanine emulsifier
4 ppb modified FA emulsifier
3.89 ppb organoclay
25% calcium chloride brine
45 ppb RevDust
425.4 ppb barite

Table 6 Average Drilling Fluid Properties

	Water	Base Oil	11 ppb Water-base	12 ppg Oil-base	16 ppg Oil-base
Mud Weight, 1b/gal	8.3	6.7	10.9	12.0	16.0
P.V., cps	0.7	1.6	21	21	26.6
Y.P., lb/100 ft^2	0	0	13	20	15.6
Gels, lb/100 ft^2	0/0	0/0	6/14	13/21	10/22
pH	7.0	-	10.0	N/A	N/A
Electrical Stability, volts	Low	>2000	Low	632	861
API Fluid Loss, cm^3	N/A	N/A	5.4	N/A	N/A
HTHP Filtrate @ 200 Deg F, cm^3	N/A	N/A	N/A	2	2.4
Solids, Volume %	0	0	14.0	18.9	34.9
Suspended Phase, Volume %	0	0	14.0	40.3	45.5

2.8 ROCK DESCRIPTION AND CHARACTERIZATION

The rocks used in the tests for the DeepTrek project were selected to simulate formations from the Arbuckle field (hard sandstone and hard limestone) and the Tuscaloosa field (hard sandstone and medium hard shale). The specific rock types and general properties are listed below in Table 7:

Table 7 Rock Properties

Arbuckle Analog Rocks	Bulk Density	UCS	Porosity	Permeability
Crab Orchard sandstone	2.47 gm/cc	19,000 psi	7.0%	0.1 md
Carthage marble	2.65 gm/cc	16,000 psi	1.4 %	.002 md
Tuscaloosa Analog Rocks				
Crab Orchard sandstone	2.47 gm/cc	19,000 psi	7%	0.1 md
Mancos shale	2.54 gm/cc	9,800 psi	7.9%	<0.001 md

The following graph (Figure 5) shows the rock compressive strength versus confining pressure:

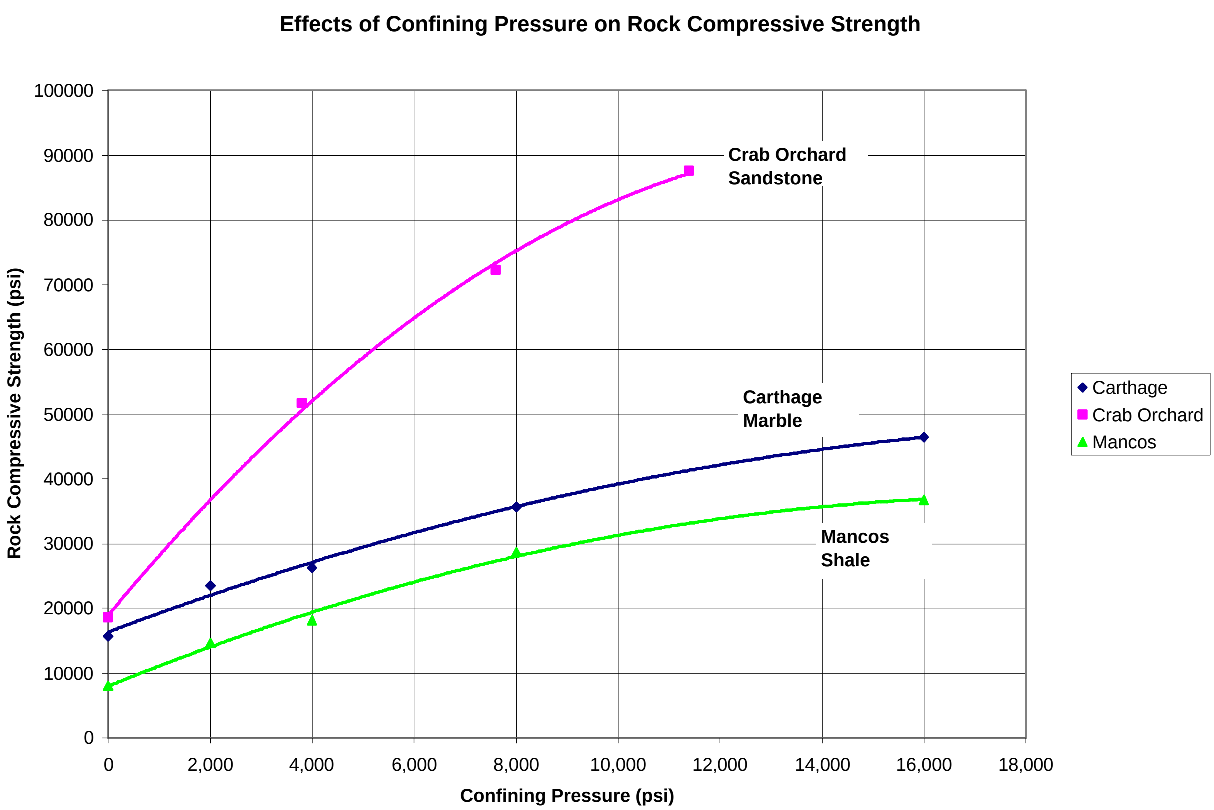


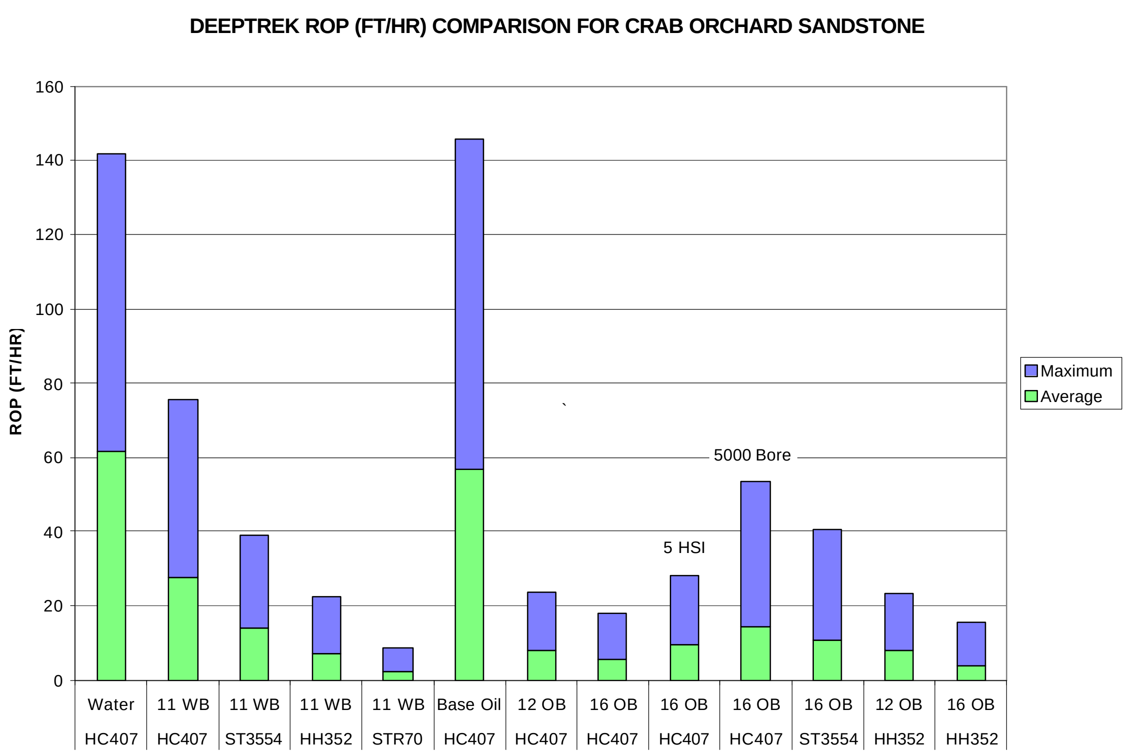
Figure 5 Effects of Confining Pressure on Rock Compressive Strength

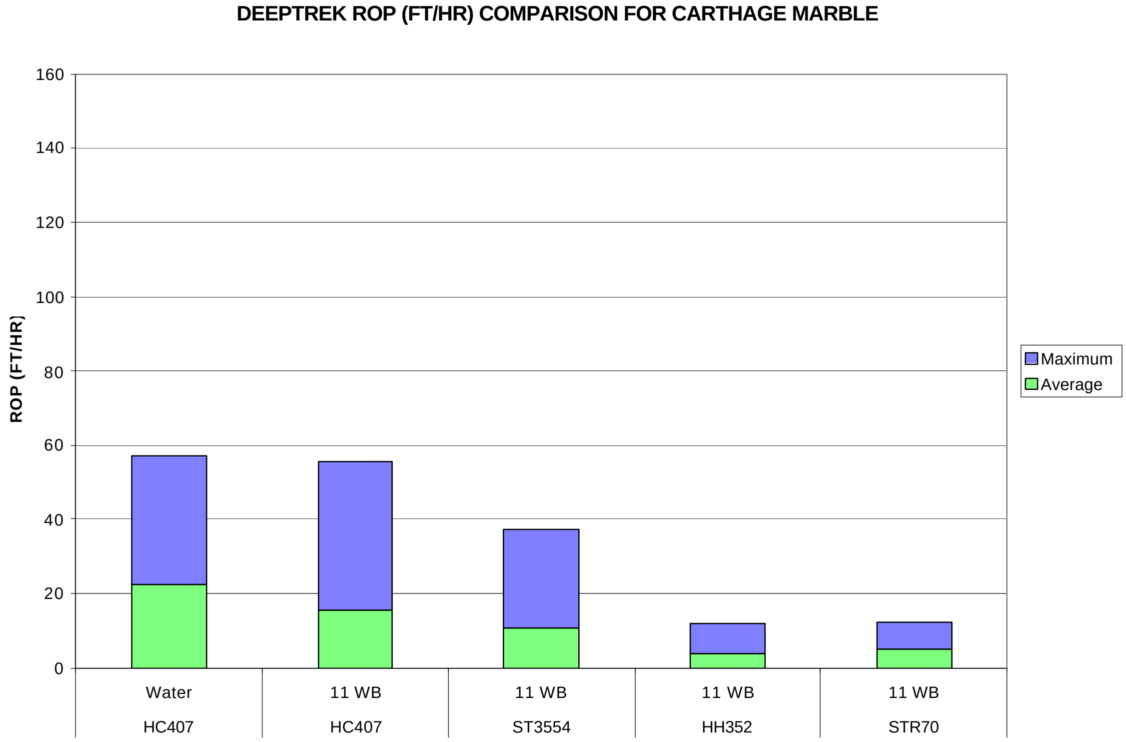
RESULTS AND DISCUSSION

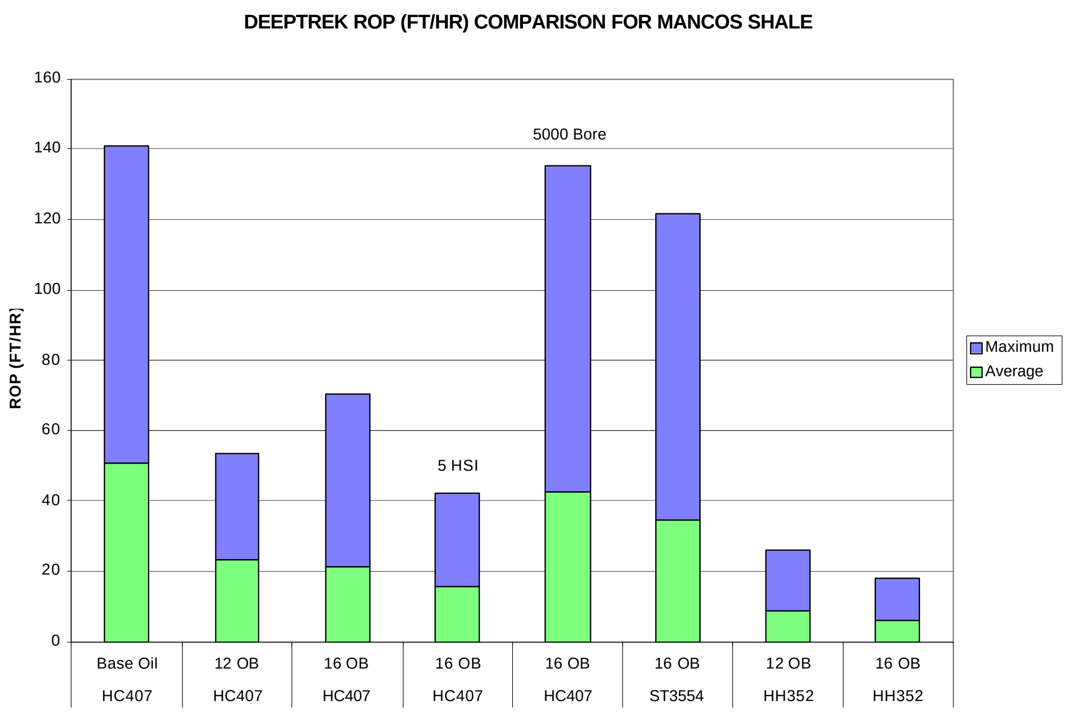
3. TEST RESULTS AND COMPARISONS

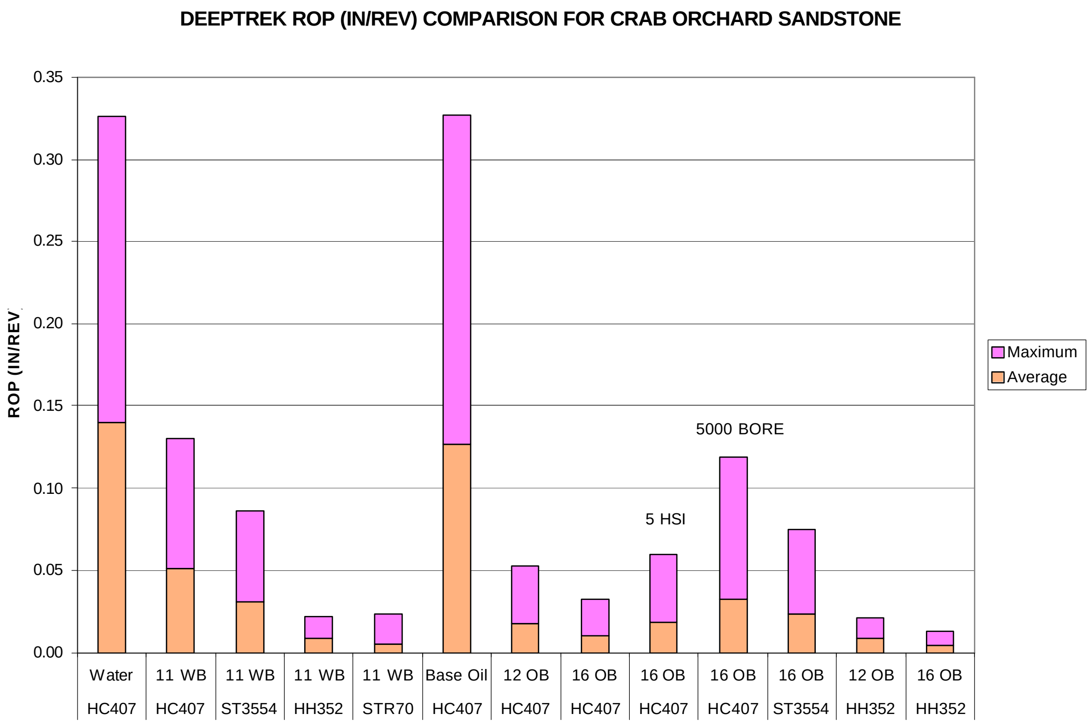
3.1 Generalized Summary of Results

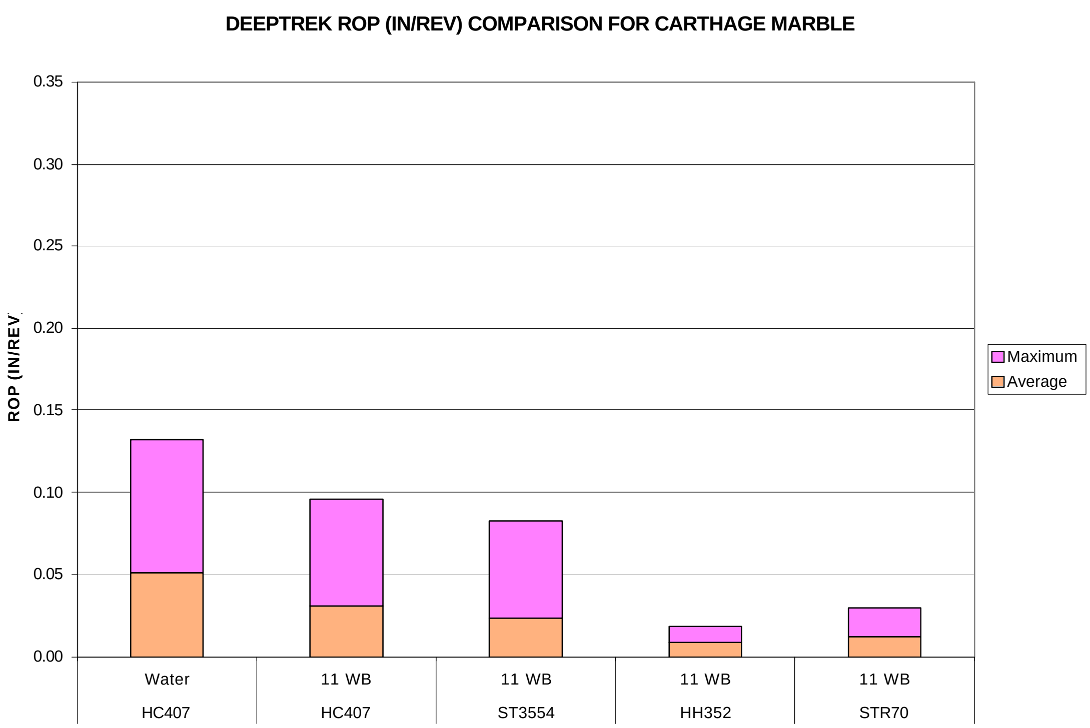
The reduced data tables for each of the sixteen high pressure drilling tests are found in Appendix A. A generalized summary of all results for the DeepTrek high pressure drilling tests are presented in the following six bar charts. The first three bar charts show average and maximum ROP (ft/hr) for the various bits and drilling fluids and are plotted for each of the three rock types (Crab Orchard sandstone, Carthage marble and Mancos shale). The second three bar charts show average and maximum ROP (in/rev) for the various bits and drilling fluids and are plotted for each of the three rock types (Crab Orchard sandstone, Carthage marble and Mancos shale). The ROP (ft/hr) plots do not take into account the different rotary speeds used in each of the tests, while ROP (in/rev) plots presented later do take this into account.

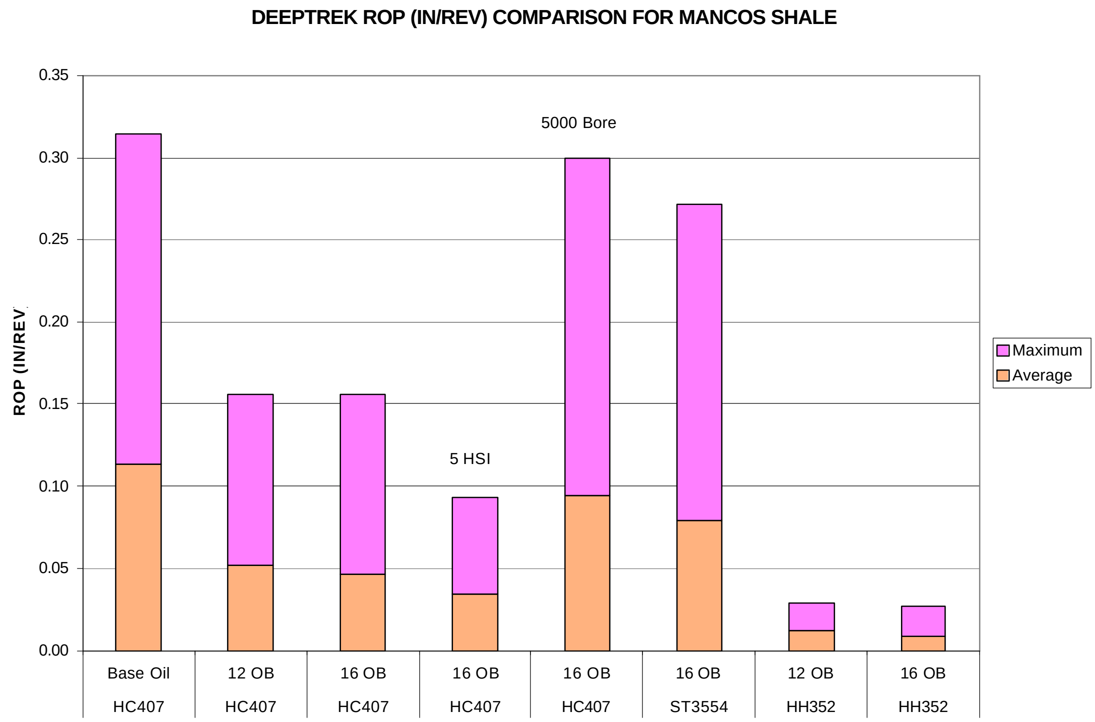



DEEPTREK ROP (FT/HR) COMPARISON FOR CARTHAGE MARBLE
ROP (FT/HR)
160
140
120
100
80
60
40
20
0
Water HC407
11 WB HC407
11 WB ST3554
11 WB HH352
11 WB STR70
Maximum
Average


DEEPTREK ROP (FT/HR) COMPARISON FOR MANCOS SHALE
ROP (FT/HR)
160
140
120
100
80
60
40
20
0
5000 Bore
5 HSI
Base Oil HC407
12 OB HC407
16 OB HC407
16 OB HC407
16 OB HC407
16 OB ST3554
12 OB HH352
16 OB HH352
Maximum
Average


DEEPTREK ROP (IN/REV) COMPARISON FOR CRAB ORCHARD SANDSTONE
ROP (IN/REV)
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Maximum
Average
5000 BORE
5 HSI
Water HC407
11 WB HC407
11 WB ST3554
11 WB HH352
11 WB STR70
Base Oil HC407
12 OB HC407
16 OB HC407
16 OB HC407
16 OB HC407
16 OB ST3554
12 OB HH352
16 OB HH352


DEEPTREK ROP (IN/REV) COMPARISON FOR CARTHAGE MARBLE
ROP (IN/REV)
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Maximum
Average
Water HC407
11 WB HC407
11 WB ST3554
11 WB HH352
11 WB STR70



3.2 Borehole Diameters After Each Drilling Test

After each drilling test, the diameter of the borehole at the top and bottom was measured at 90 degrees. For composite rock samples (i.e. Crab Orchard sandstone on top and Carthage marble on bottom or Crab Orchard sandstone on top and Mancos shale on bottom), the top diameter was measured in one type rock and the bottom diameters were measured in the other rock type. The following table summarized these borehole diameters and shows how close they are to the actual 6 inch diameter bits.

Table 4. Borehole Diameter Measurements

DeepTrek Sample Measurements					
Number	**Top**	**Bottom**	**Number**	**Top**	**Bottom**
1a	6.044	6.032	**9a**	6.025	6.031
1b	6.037	6.036	**9b**	6.041	6.029
2a	6.121	6.106	**10a**	6.017	6.001
2b	6.122	6.090	**10b**	6.013	6.002
3a	6.119	6.108	**11a**	6.008	6.004
3b	6.096	6.118	**11b**	6.007	6.009
4a	6.032	6.041	**12a**	6.051	6.006
4b	6.030	6.037	**12b**	6.078	6.004
5a	6.035	6.036	**13a**	6.017	6.102
5b	6.034	6.032	**13b**	6.017	6.080
6a	6.003	5.995	**14a**	6.016	6.058
6b	5.998	5.990	**14b**	6.017	6.086
7a	6.015	6.017	**15a**	6.024	6.031
7b	6.014	6.015	**15b**	6.026	6.012
8a	6.059	6.060	**16a**	6.053	6.095
8b	6.069	6.055	**16b**	6.040	6.090

Note: All measurements in inches. A and B indicate measurements taken at 90^{o}.

3.3 Problems Encountered During the DeepTrek Program and Recommendations for Future DeepTrek Testing

In general, all of the drilling results from DeepTrek testing were acceptable and used in the analysis of results and comparisons made (except the last data point in Test 16 when the nozzle plugged). There were several problems that occurred during the test program worth noting:

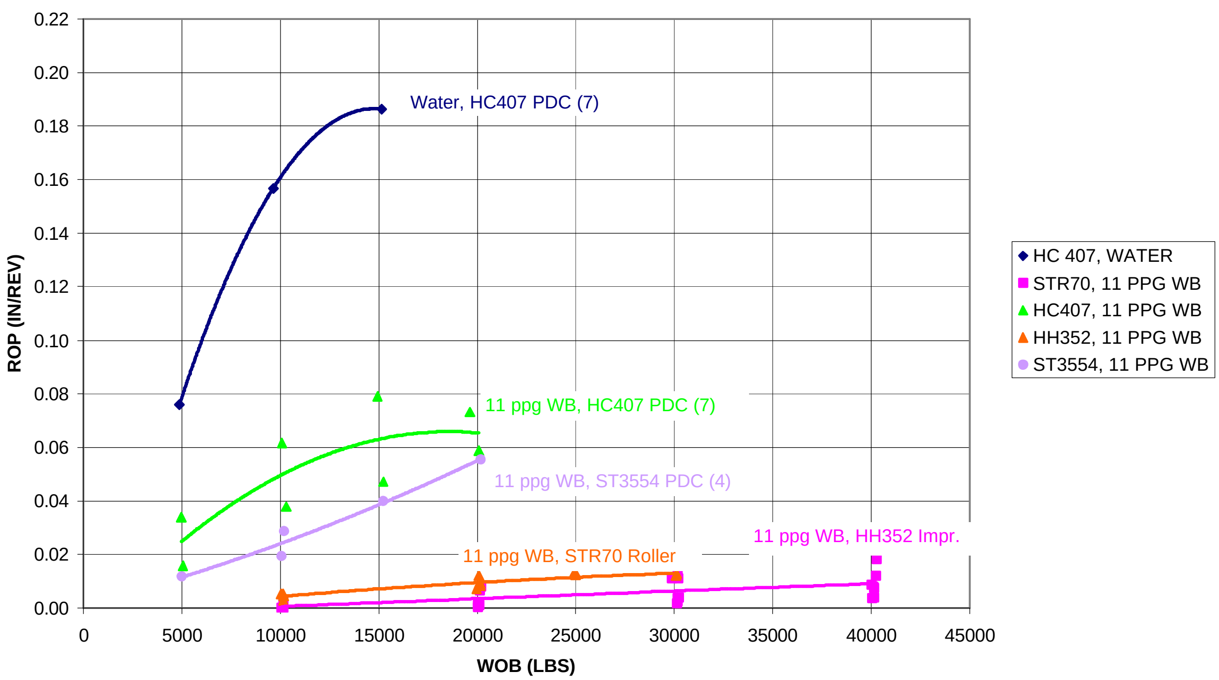
1) Limitations with the Hughes Christensen Sky Bruster Mud Pump: The original borehole pressure target for the DeepTrek program was 10-12,000 psi. It was decided to run the tests at 11,000 psi. During checkout flow and pressure tests with both the TerraTek and Hughes Christensen pumps, it was discovered that the Hughes Christensen pump was not able to supply enough pressure to achieve 11,000 psi borehole pressure and that 10,000 psi borehole pressure was the maximum possible when taking into account the associated bit pressure drops. It was also discovered that the seals on the Hughes Christensen pump deteriorated in the oil-base fluid. Recommendations: If future DeepTrek testing is desired at 11,000 psi borehole pressure, it may be necessary to change the drive belt ratio on the Hughes Christensen pump to allow higher pressure and less flow. Also, pump seals compatible with the oil base fluids will be needed for the Hughes Christensen pump for future oil-base fluid tests.

2) Bit Stalling and Problems with Electrical Feed-back into TerraTek's Instrumentation: During the drilling tests with the impregnated bit at rotary speeds (60-250 rpm range) and weight on bits (10-40,000 lb WOB range), at high WOB and low rotary speed the resulting bit torques exceeded the normal operating capacity of the DC drive motors. As a result, the rig stalled twice during Test 7 at 60 rpm/30000 lbs and 60 rpm/25000 lbs. In addition, as bit torque increased and approached the torque limit of the rig, the two DC drive motors began to interfere and "fight" each other, causing large fluctuations in amperage and at the same time causing interference or electrical feed-back into the instrumentation system. What resulted was occasional erroneous RPM signal measurements (although it is believed that the actual RPM remained relatively constant) and offsets in the flow rate (pump strokes) measurement. Recommendations: Higher weight on bit levels may need to be avoided particularly at low rotary speeds for drilling tests with impregnated bits in the future. Also, TerraTek will check out both the mechanical linkage that ties the two DC drive motors together as well as the SCR controllers for each motor to determine whether the interference between the two motors is due to mechanical or electrical problems. If these electrical interference problems cannot be eliminated, then TerraTek needs to determine if a different method of electrical grounding or active filtering of signals can isolate the instrumentation from these electrical feed-back signals.
3) Bit Nozzle Plugging During Test 16: During the last drilling condition for Test 16, one of the nozzles on the HC-407 bit plugged with a piece of rubber (possibly from a piece of deteriorated seals (affected by oil-base fluid) on the Hughes Christensen pump. As a result, bit pressure drop increased from 275 to 480 psi and also a section of the bit balled up. As this occurred, the rate of penetration decreased from 93.1 ft/hr to 27.9 ft/hr. Because of the unusual circumstance of having a plugged nozzle, that data point was not used in the plots or analysis of the data. Recommendation: Equipping the Hughes Christensen mud pump with oil-base fluid compatible seals should avoid such pump seal deterioration and nozzle plugging in the future.

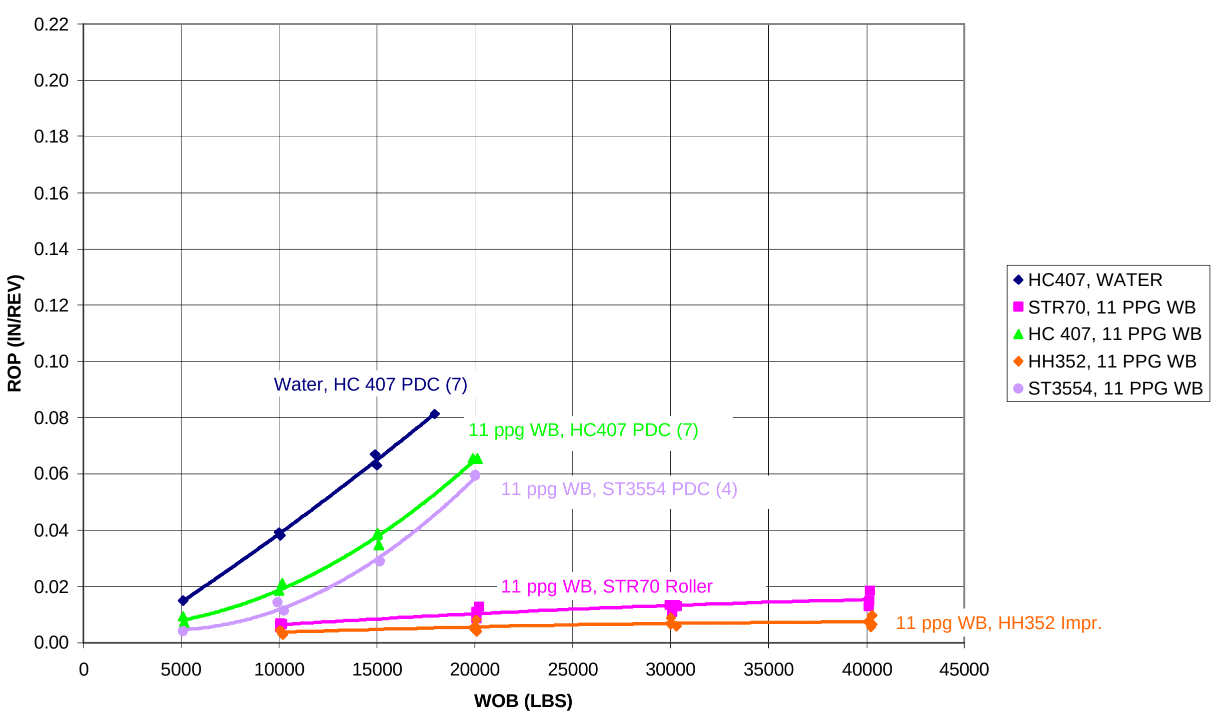
3.4 Specific Summary of Results

The following plots presents the specific results of the DeepTrek high pressure drilling tests based on the relationship of ROP (in/rev) versus Weight on Bit (lbs) for the various combinations of rock type, bit type, drilling fluid type, drilling fluid density and other parameters i.e. increased hydraulics (HSI) for Test 14 and deceased borehole pressure for Test 16. In addition, a limited comparison of MHP versus Weight on Bit (lbs) are shown.

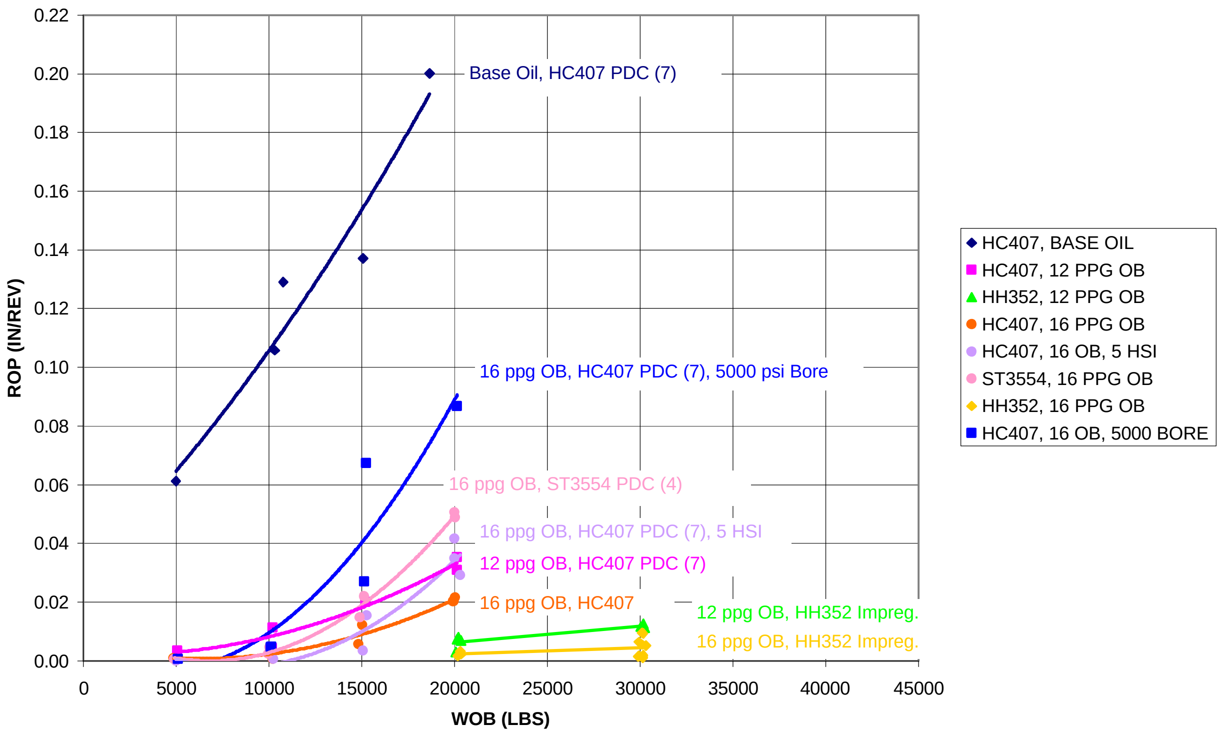
DEEPTREK ROP (IN/REV) VS. WOB SUMMARY FOR CRAB ORCHARD SS & WATER BASE FLUID AT 10,000 PSI BOREHOLE AND 2 HSI



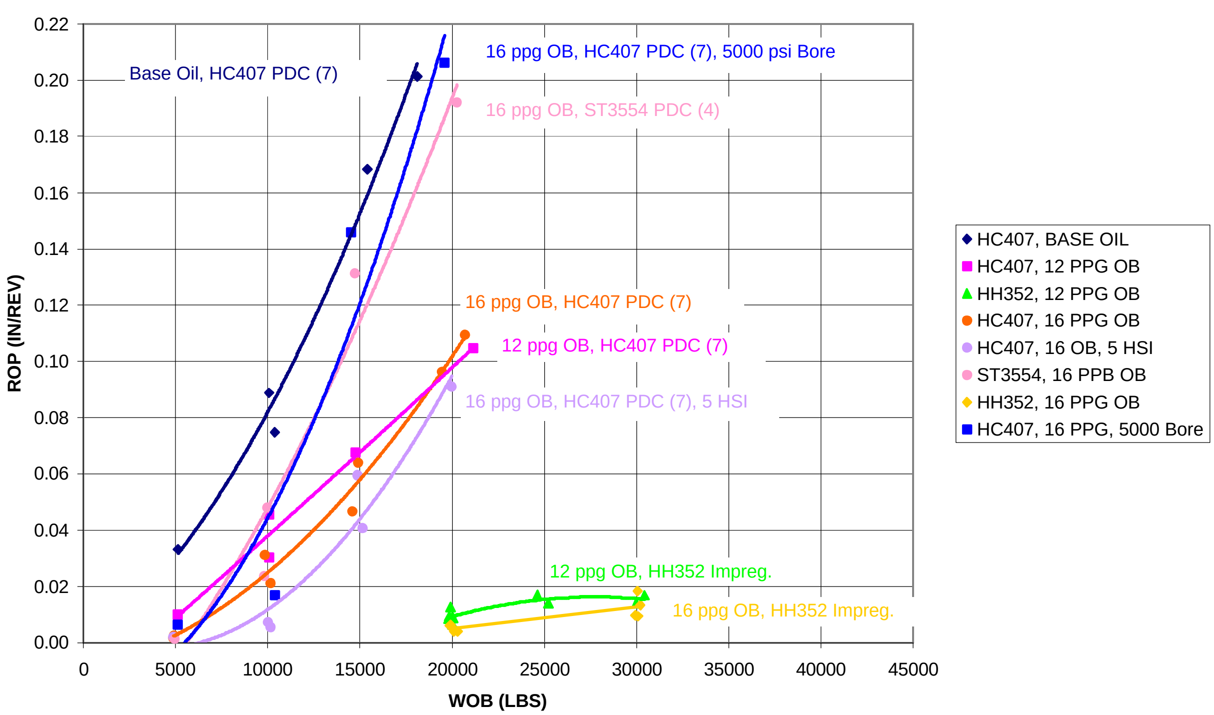
DEEPTREK ROP SUMMARY FOR CARTHAGE MARBLE & WATER BASE FLUID AT 10,000 PSI BOREHOLE AND 2 HSI

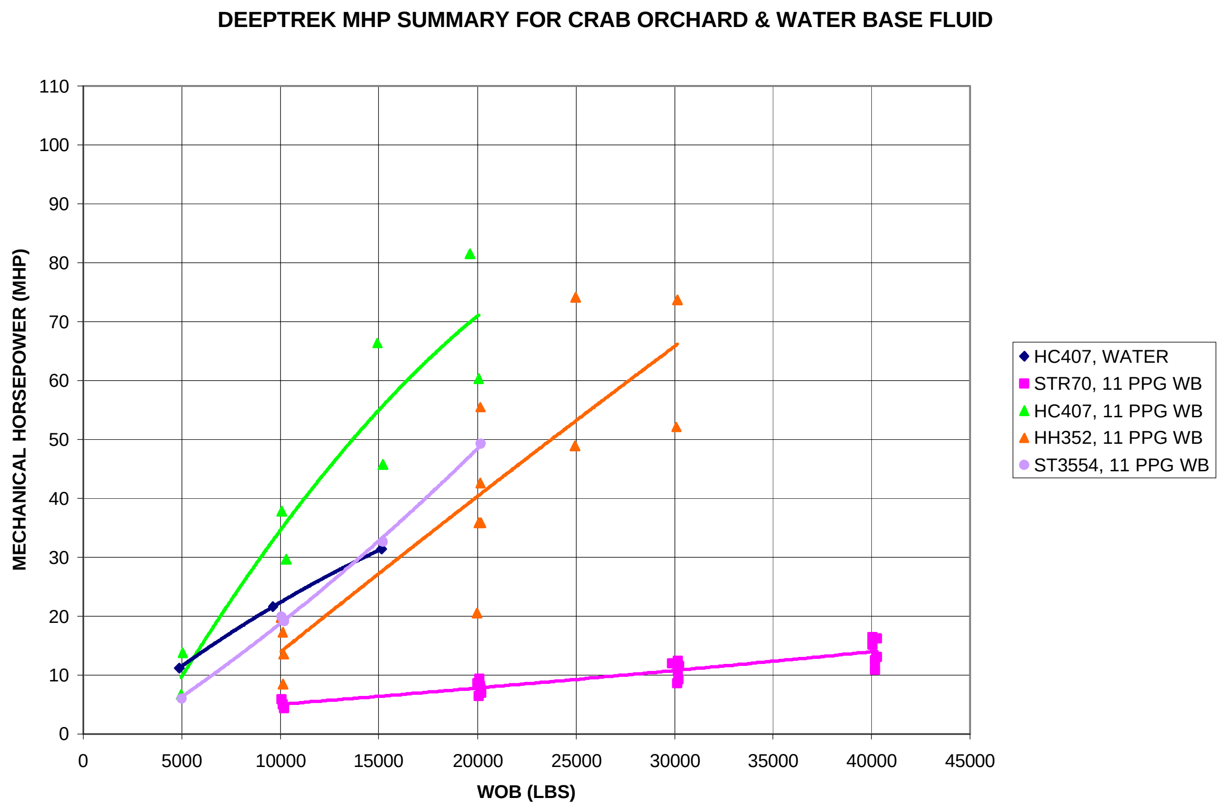


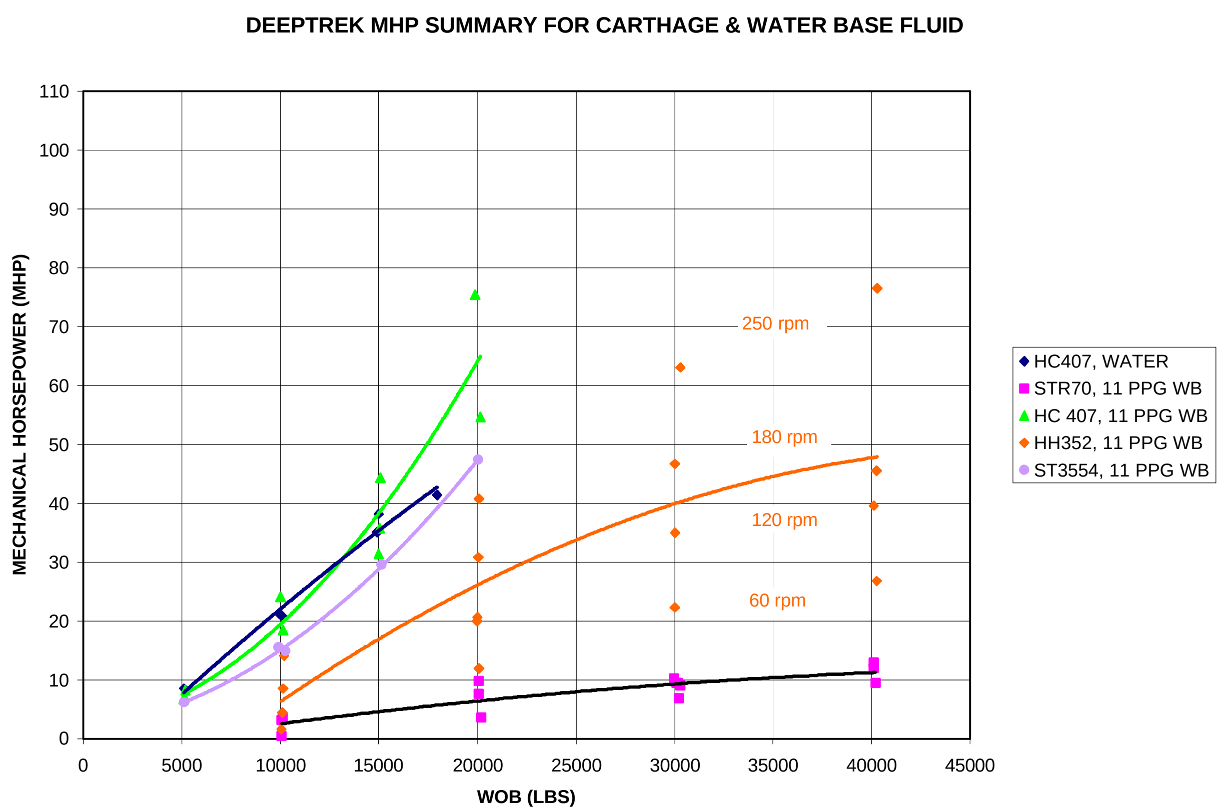
DEEPTREK R0P (IN/REV) vs WOB SUMMARY FOR CRAB ORCHARD SS & OIL BASE FLUID AT 10,000 PSI BOREHOLE AND 2 HSI (EXCEPT AS NOTED)

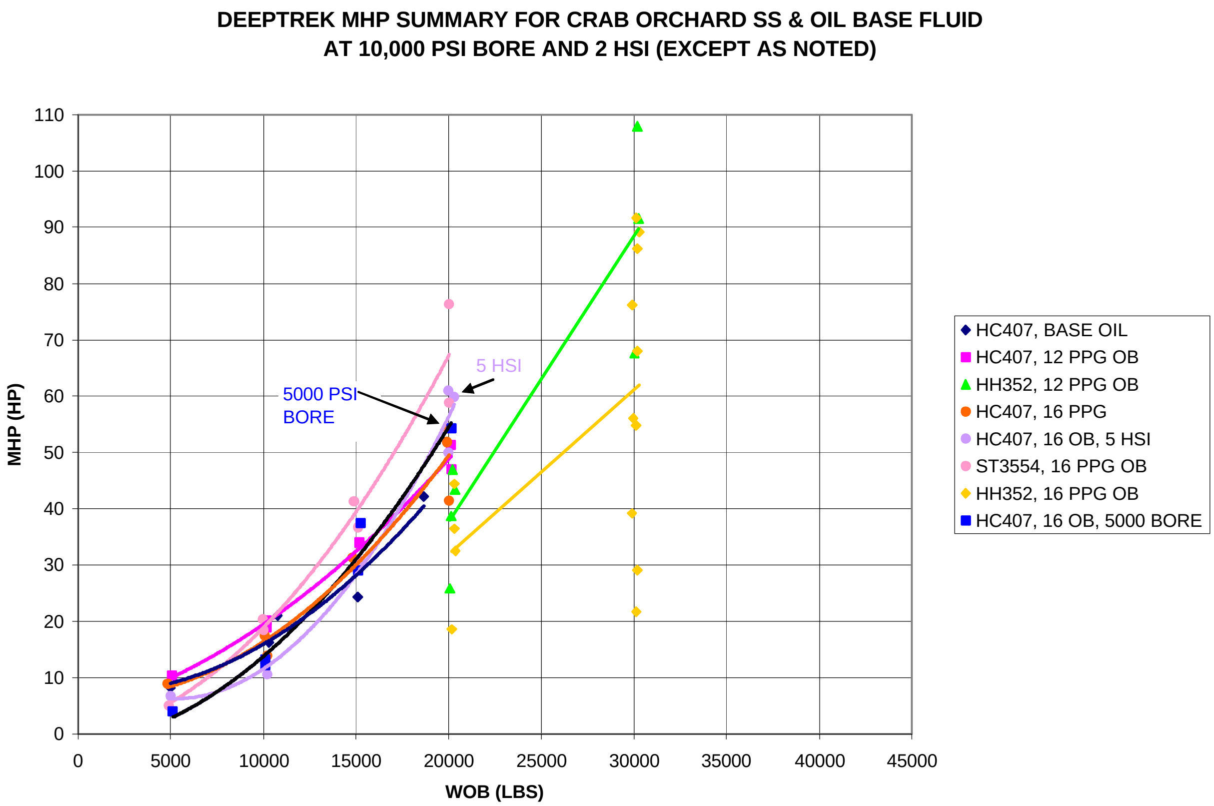


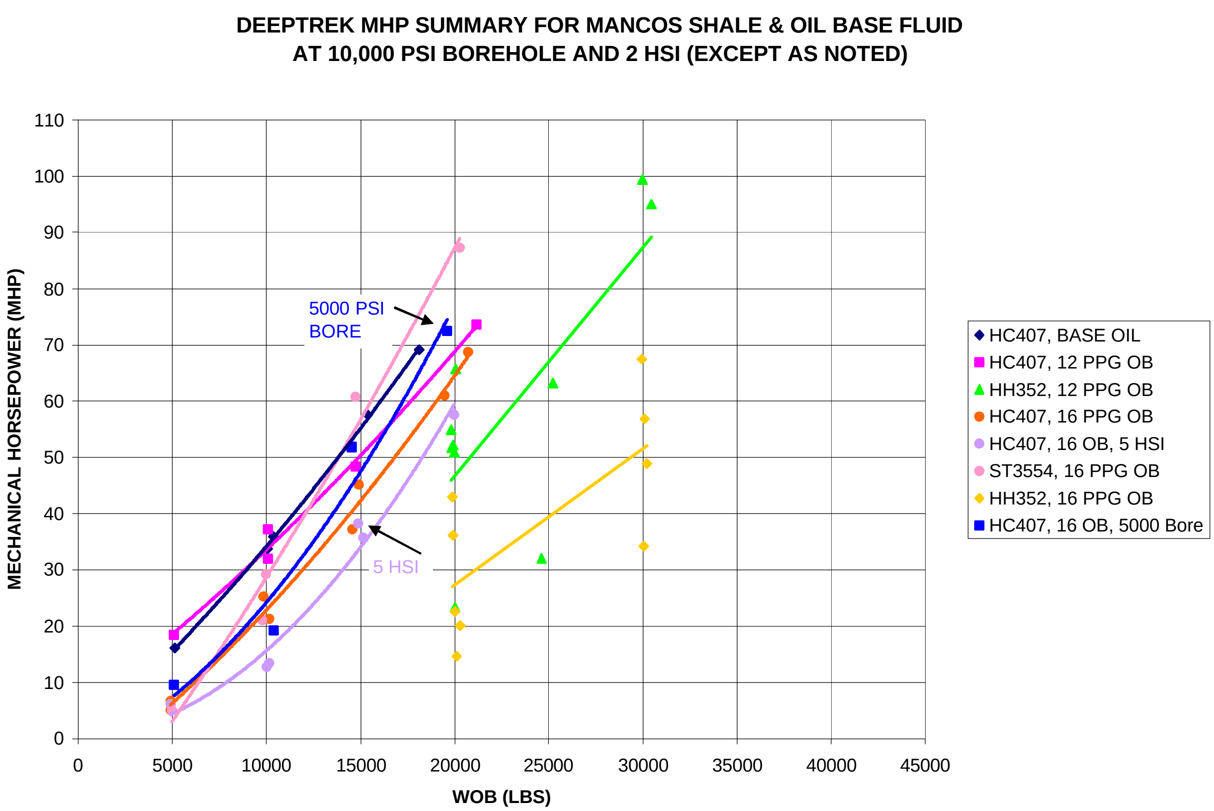
DEEPTREK ROP SUMMARY FOR MANCOS SHALE & OIL BASE FLUID at 10,000 PSI BORE AND 2 HSI (EXCEPT AS NOTED)




DEEPTREK MHP SUMMARY FOR CRAB ORCHARD & WATER BASE FLUID
MECHANICAL HORSEPOWER (MHP)
WOB (LBS)
HC407, WATER
STR70, 11 PPG WB
HC407, 11 PPG WB
HH352, 11 PPG WB
ST3554, 11 PPG WB


DEEPTREK MHP SUMMARY FOR CARTHAGE & WATER BASE FLUID
MECHANICAL HORSEPOWER (MHP)
WOB (LBS)
250 rpm
180 rpm
120 rpm
60 rpm
HC407, WATER
STR70, 11 PPG WB
HC 407, 11 PPG WB
HH352, 11 PPG WB
ST3554, 11 PPG WB

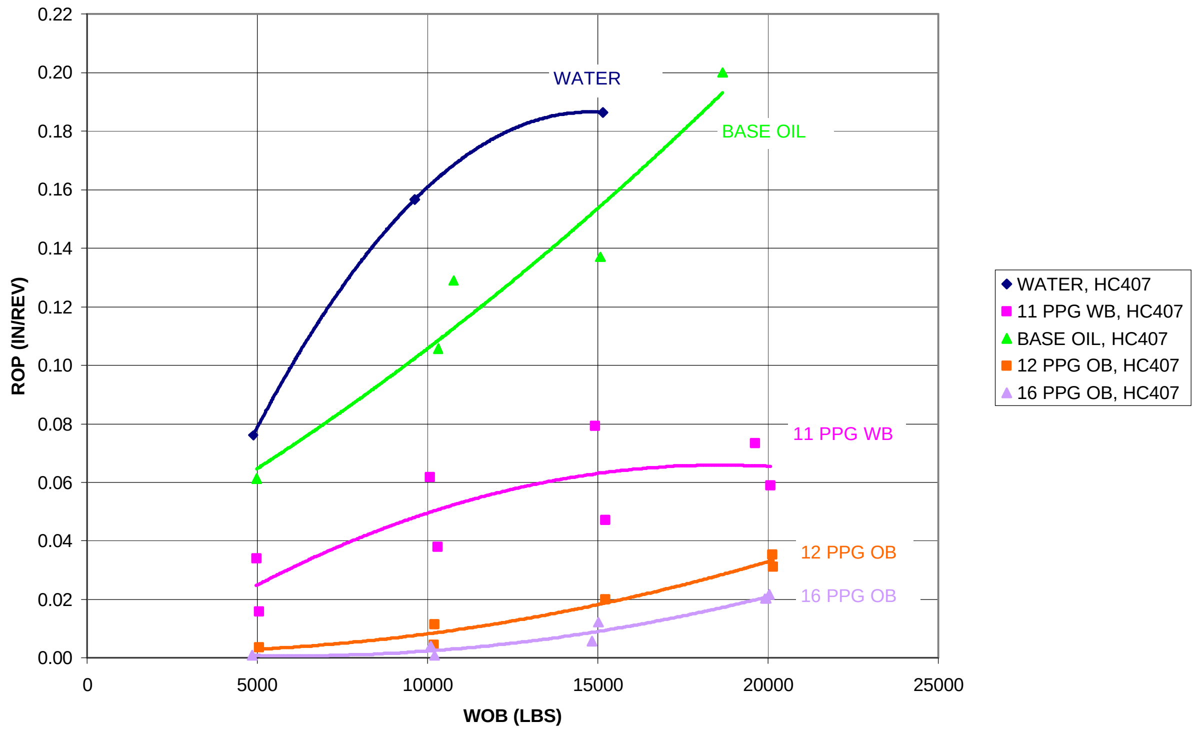

DEEPTREK MHP SUMMARY FOR CRAB ORCHARD SS & OIL BASE FLUID
AT 10,000 PSI BORE AND 2 HSI (EXCEPT AS NOTED)
MHP (HP)
WOB (LBS)
5000 PSI BORE
5 HSI
HC407, BASE OIL
HC407, 12 PPG OB
HH352, 12 PPG OB
HC407, 16 PPG
HC407, 16 OB, 5 HSI
ST3554, 16 PPG OB
HH352, 16 PPG OB
HC407, 16 OB, 5000 BORE


DEEPTREK MHP SUMMARY FOR MANCOS SHALE & OIL BASE FLUID
AT 10,000 PSI BOREHOLE AND 2 HSI (EXCEPT AS NOTED)
MECHANICAL HORSEPOWER (MHP)
WOB (LBS)
5000 PSI BORE
5 HSI
HC407, BASE OIL
HC407, 12 PPG OB
HH352, 12 PPG OB
HC407, 16 PPG OB
HC407, 16 OB, 5 HSI
ST3554, 16 PPG OB
HH352, 16 PPG OB
HC407, 16 OB, 5000 Bore

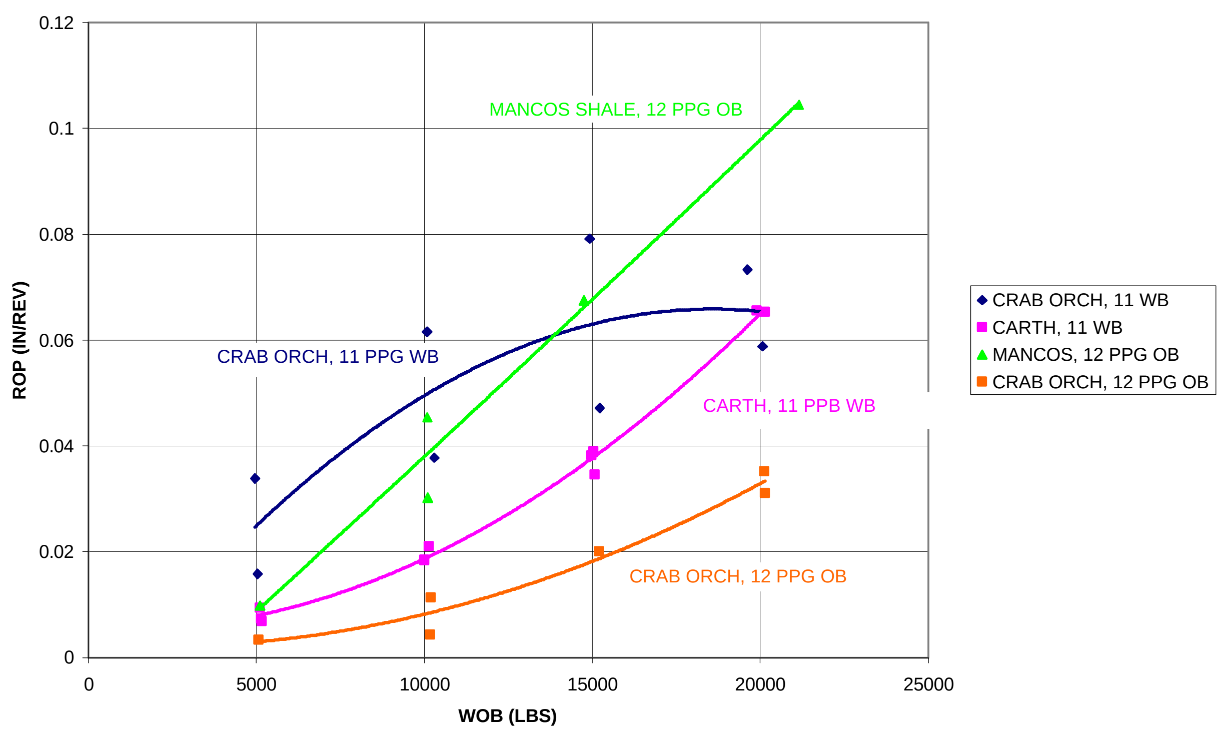
3.5 Comparison Plots of Rock Type and Drilling Fluid Type

The following plots give direct comparison of drilling performance of the HC-407 bit while drilling Crab Orchard sandstone the different fluid types and densities and another plot directly comparing the different bits drilling different rock types with 11 ppg water-base and 12 ppg oil-base fluids.

DEEPTREK ROP (IN/REV) VS. WOB SUMMARY FOR CRAB ORCHARD SS & BOTH WATER BASE & OIL BASE FLUIDS WITH HC407 BIT AT 10,000 PSI BOREHOLE AND 2 HSI



DEEPTREK ROP (IN/REV) VS. WOB SUMMARY FOR CRAB ORCHARD SS, CARTHAGE MARBLE AND MANCOS SHALE WITH 11 PPG WATER BASE & 12 PPG OIL BASE FLUIDS WITH HC407 BIT AT 10,000 PSI BOREHOLE AND 2 HSI



OBSERVATIONS

Drilling Fluid Effects on Drilling Performance: The results indicate a dramatic improvement in ROP with clear, solids fee fluids over both weighted water-base and oil-base drilling fluids. Limited improvement is seen going from 16 ppg oil-base to 12 ppg water-base. The drilling rate performance with the 11 ppg water-base is significantly better than withthe 12 ppg oil-base. Performance in water was somewhat better than in base oil.

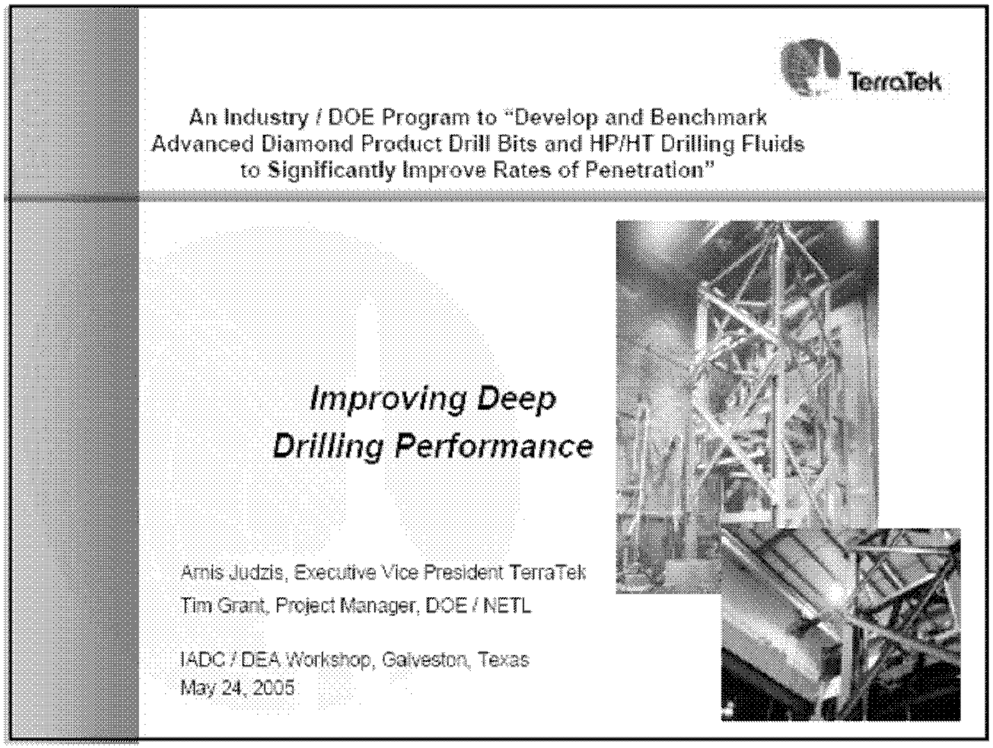
Drill Bit Effects on Drilling Performance: The 7-bladed polycrystalline diamond compact bit (PDC) outperformed the 4-bladed PDC bit in Crab Orchard sandstone and Carthage marble, but the reverse was true in Mancos shale. For Crab Orchard sandstone and Carthage marble with 11 ppg water-base fluid, the greatest to least performance of the drill bits was with 7-bladed PDC, 4-bladed PDC, roller-cone and diamond impregnated, respectively. For Crab Orchard sandstone and oil-base fluid, the best performance in descending order was with 16 ppg oil-base and the 4-bladed PDC, 12 ppg oil-base and the 7-bladed PDC, 16 ppg oil base and the 7-bladed PDC and the 12 ppg oil base and the impregnated bit and the 16 ppg oil-base and the impregnated bit, respectively. In Mancos shale, the best to least performance was seen with the 16 ppg oil-base and the 4-bladed PDC, the 12 ppg oil-base with the 7-bladed PDC, the 16 ppg oil-base and the 7-bladed PDC, the 12 ppg oil-base and impregnated bit and the 16 ppg oil-base and the impregnated bit, respectively.

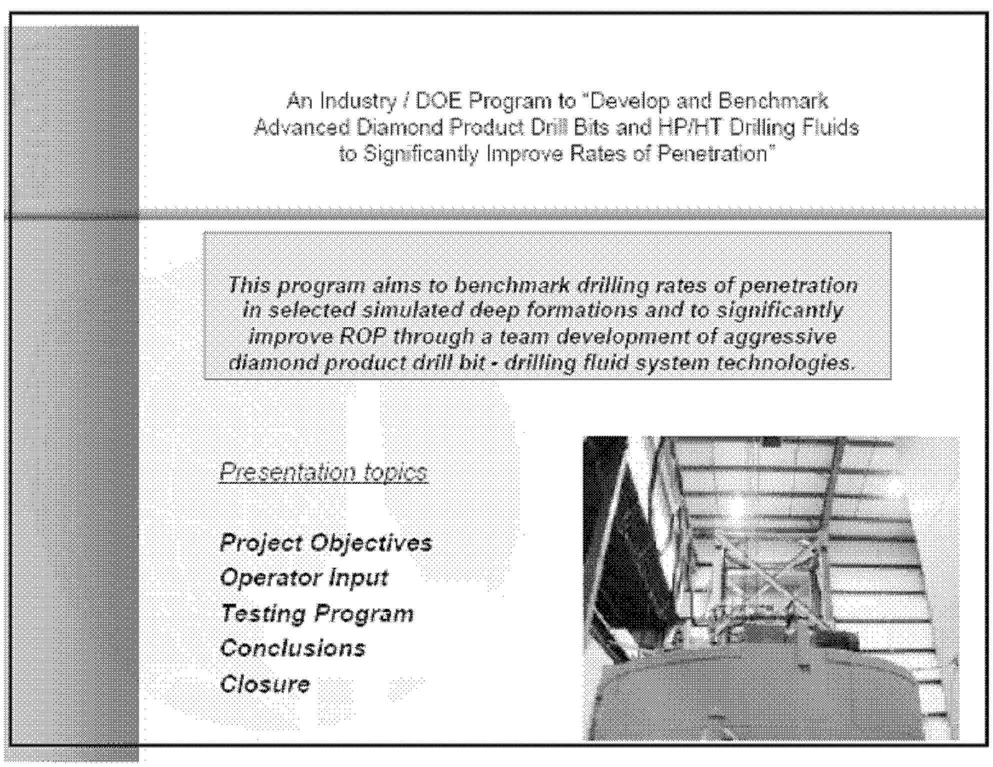
Rock Type Effect on Drilling Performance: For the 7-bladed PDC with and the 11 ppg water-base and 12 ppg oil-base drilling fluids, the greatest to least performance was seen in Mancos shale (12 ppg oil-base), Crab Orchard sandstone (11 ppg water-base), Carthage marble (11 ppg water-base) and Crab Orchard sandstone (12 ppg oil-base), respectively. In general, Carthage marble drilled slower than the Crab Orchard sandstone when using water and 11 ppg water-base fluid. For oil-base fluids, the Crab Orchard sandstone drilled significantly slower than in Mancos shale.

Mechanical Horsepower Performance (MHP): In general, the MHP was greatest in the fastest drilling bits i.e. the 4-bladed PDC and 7-bladed PDC since higher bit torques are required to achieve higher rates of penetration. The only exception was with the impregnated bit, which required relatively high MHP, even though the ROP's were low. For both Crab Orchard sandstone and Carthage marble with 11 ppg water-base drilling fluid, the most to least MHP was seen with the 7-bladed bit, the 4-bladed PDC, the impregnated, and roller-cone, respectively. For both the Crab Orchard sandstone and Mancos shale with oil-base fluids, the MHP was quite similar for all of the bits, except the impregnated bit which showed the least MHP, but also correspondingly the least ROP.

Increased Hyraulic Horsepower per Square Inch (HSI) and Reduced Borehole Pressure Effects on Drilling Performance: Surprisingly, with the 16 ppg oil-base drilling fluid and the 7-bladed PDC, increasing HSI actually resulted in slightly lower ROP and MHP. Lowering borehole pressure from 10,000 psi to 5,000 psi had the expected effect of essentially doubling ROP.

IADC/Drilling Engineering Workshop May 2005, Galveston, TX





Team Roles and Project Management

Project Manager: TerraTek

Service Company Contributors:
Hughes Christensen
Baker HughesDrilling Fluids

DEA 148 Contributors:
Aramco
Statoil

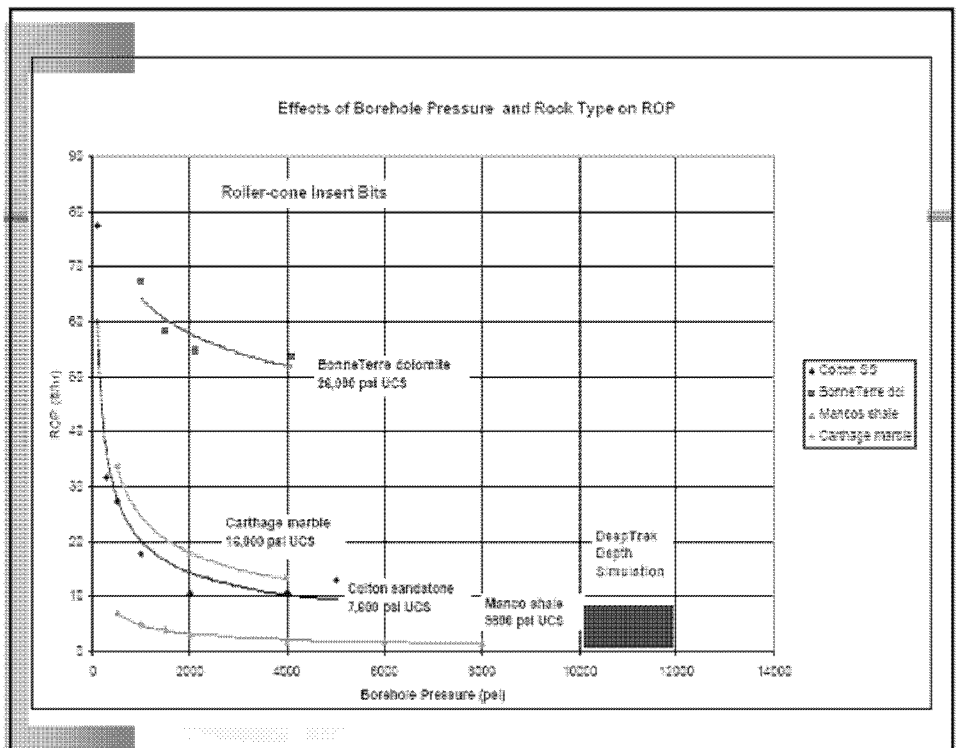
Advisors:
Marathon
ConocoPhillips
Chevron
BP
ExxonMobil

Technical Objectives

- Characterization of applications – (Industry Team has proposed specific tests)
  Determine deep drilling performance issues related to bits and fluids in operators' areas of challenge and commence with suppliers engineering evaluations of promising concepts.
- Benchmark performance of 'best-in-class' products –
  Conduct full-scale drilling tests in TerraTek's Wellbore Simulator at high pressures in hard rock to reveal deficiencies and design features important for improved deep drilling performance.
- Develop aggressive diamond product bits and fluids to improve ROP –
  Test and improve significantly drilling performance via emerging and newly developed drill bits and fluid systems.
- Commercialization and field deployment –
  Test and deploy via field testing on operator wells prototype bits and fluids developed as a result of the prior year effort.

The Challenge of Drilling in Deep/Hard Formations

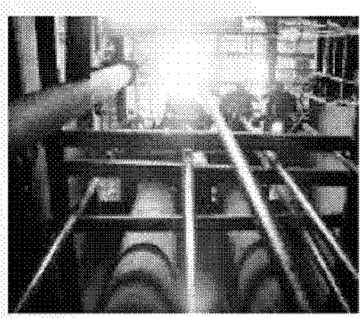
- Rock Strength Increases with Increased Depth and Increased Shale Plasticity and Bit Balling Tendencies
- High Overbalance (Borehole - Pore Pressure) Resulting in Chip Hold Down
- High Mud Solids, High Density, Increased Viscosity, Lower Spurt-loss Fluids in Deep Wells
- Rig and Operational Limitations i. e. Low Hydraulics, Bit Wear, Friction Losses, Differential Sticking, Lost Circulation, etc.

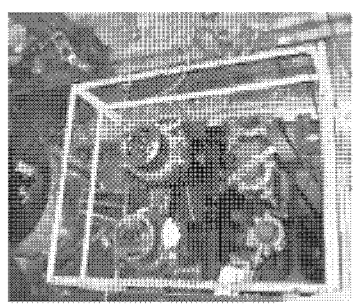


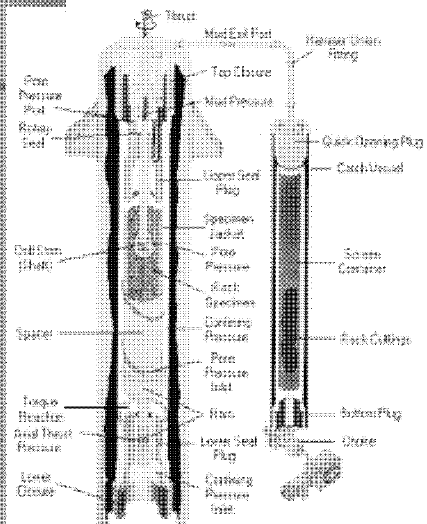
TerraTek Preparations for DeepTrek High Pressure Drilling Tests

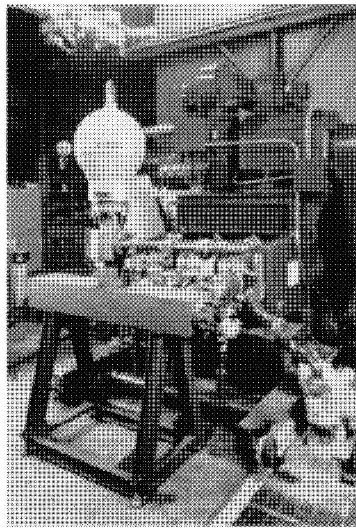
Equipment Upgrades

- Rock Preparation
- Drilling Fluid Cooling
- High Pressure Cuttings Collection and Mud Choking
- High Pressure Mud Sealing and Pulsation Dampening
- High Pressure Pumping Capacity
- Safety and Operational Features



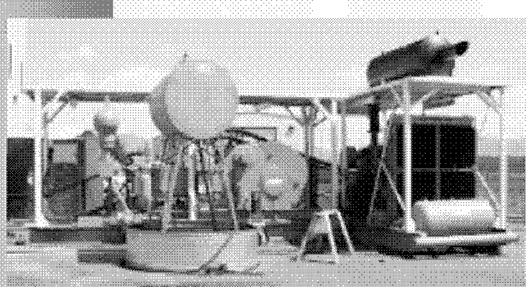


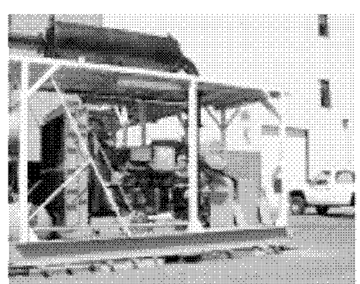




High Pressure Pumping

- Continental Emsco 1600 with High Pressure Fluid Ends
- Hughes Christensen Skytop Brewster
  1200 HP
  Diesel drive





Operator Input

Example Domestic Deep Gas Plays & rock types

- Tuscaloosa
- Arbuckle
- Nugget
- Bromides, etc.
- Mobile Bay
- S. Texas
- Wyoming

Development of Test Matrix for High Pressure Drilling (Industry Team)

Tuscaloosa type (e.g. BP America, etc.)

- OBM ~16 ppg, 22-23 k ft TVD, 6” range bits
- Sand (soft to hard), shale
- Testing
  - Bits; PDC, impregnated diamond, baseline
  - Fluids; OBM, baselines w/oil, novel design
  - Rock samples; shale-sand composites
- Drilling parameters
  - RPM, confining pressure, borehole pressure, pressure drop across bit, WOB, hydraulics

Development of Test Matrix for High Pressure Drilling (Industry Team)

Arbuckle type (e.g. Marathon, etc.)

- WBM ~11 ppg, > 15 k ft TVD, 6" range bits
- Dolomite, limestone, sand, shale
- Testing
  - Bits; PDC, impregnated diamond, baseline
  - Fluids; WBM, baselines, low solid dispersed
  - Rock samples; shale-sand composites & limestone
- Drilling parameters
  - RPM, confining pressure, borehole pressure, pressure drop across bit, WOB, hydraulics

Testing Program (March-May 2005)

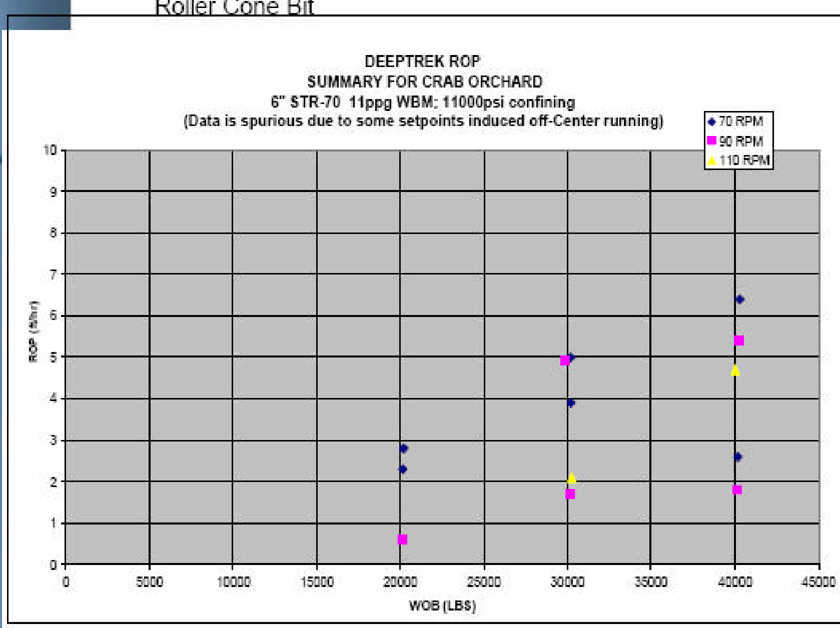
Test Matrix for DeepTrek Phase 1 Updated: May 17, 2005

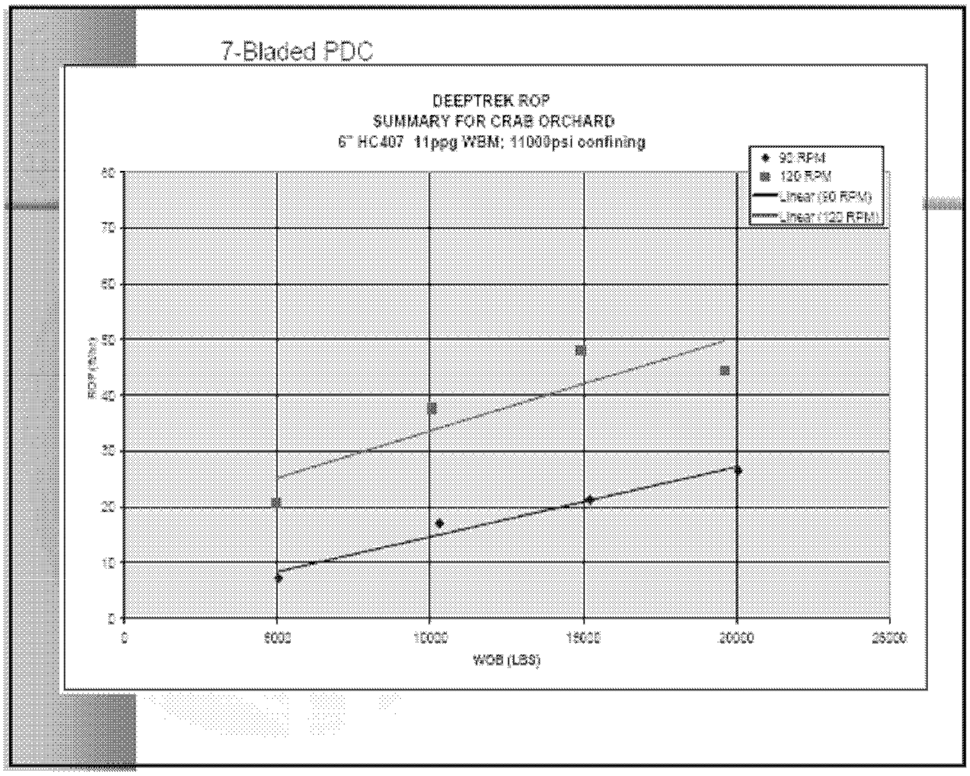
Test #	Bit	Nozzles	Rock	Mud	Flow Rate	HSI	Borehole	Confining	Overburd.	Ram	RPM
Arbuckle Test Series with 11 ppg Water-base Fluid and Crab Orchard and Carthage Marble Samples											
Deep1	PDC 7-Blade	3-12 + 1 Port	CO/Carth	Water	300	2 HSI	10,000	11,000	12,000	13,000	90
Deep2	Roller-cone	3-15	Carth	11 ppg WB	300	2 HSI	10,000	11,000	12,000	13,000	70-110
Deep 3	Roller-cone	3-15	CO	11 ppg WB	300	2 HSI	10,000	11,000	12,000	13,000	70-110
Deep4	PDC 7-Blade	2-13, 1-14 + 1 Port	Carth	11 ppg WB	300	2 HSI	10,000	11,000	12,000	13,000	90-120
Deep5	PDC 7-Blade	3-13, 1-14 + 1 Port	CO	11 ppg WB	300	2 HSI	10,000	11,000	12,000	13,000	90-120
Deep6	Impregnated	0.97 TFA	Carth	11 ppg WB	300	0.6 HSI	10,000	11,000	12,000	13,000	60-250
Deep7	Impregnated	0.97 TFA	CO	11 ppg WB	300	0.6 HSI	10,000	11,000	12,000	13,000	60-250
Deep8	PDC 4-Blade	3-13, 1-12	CO/Carth	11 ppg WB	300	2 HSI	10,000	11,000	12,000	13,000	90
Tuscaloosa Test Series with 16 ppg Oil-base Fluid and Crab Orchard and Mancos Shale Samples											
Test #	Bit	Nozzles	Rock	Mud	Flow Rate	HSI	Borehole	Confining	Overburd.	Ram	RPM
Deep9	PDC 7-Blade	3-12 + 1 Port	CO/Mancos	Base Oil	300	2 HSI	10,000	11,000	12,000	13,000	90
Deep10	PDC 7-Blade	2-13, 1-14 + 1 Port	CO/Mancos	12 ppg OB	300	2 HSI	10,000	11,000	12,000	13,000	90
Deep11	Impregnated	0.97 TFA	CO/Mancos	12 ppg OB	300	0.55 HSI	10,000	11,000	12,000	13,000	60-250
Deep12	Impregnated	0.97 TFA	CO/Mancos	16 ppg OB	300	0.9 HSI	10,000	11,000	12,000	13,000	60-250
Deep13	PDC 7-Blade	3-15 + 1 Port	CO/Mancos	16 ppg OB	300	2 HSI	10,000	11,000	12,000	13,000	90
Deep14	PDC 7-Blade	2-12 + 1-13 + 1 Port	CO/Mancos	16 ppg OB	340	5 HSI	10,000	11,000	12,000	13,000	90
Deep15	PDC 4-Blade	3-14, 1-15	CO/Mancos	16 ppg OB	300	2 HSI	10,000	11,000	12,000	13,000	90
Deep16	PDC 7-Blade	3-15 + 1 Port	CO/Mancos	16 ppg OB	300	2 HSI	5,000	6,000	7,000	8,000	90

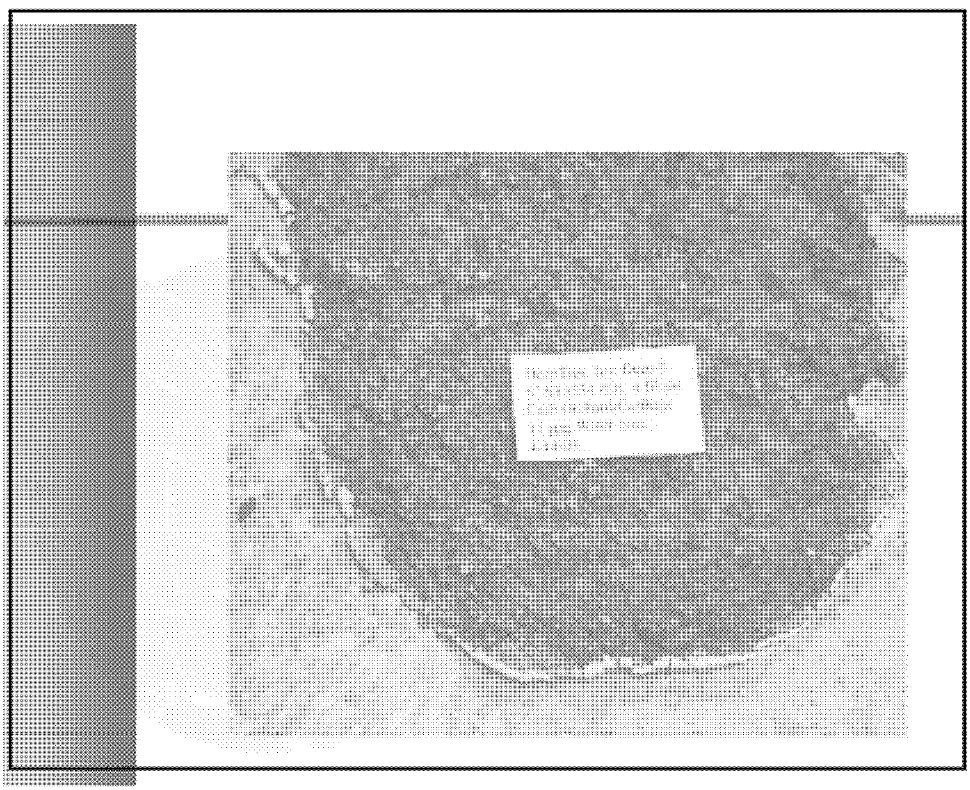
Drill Bits (Hughes Christensen)

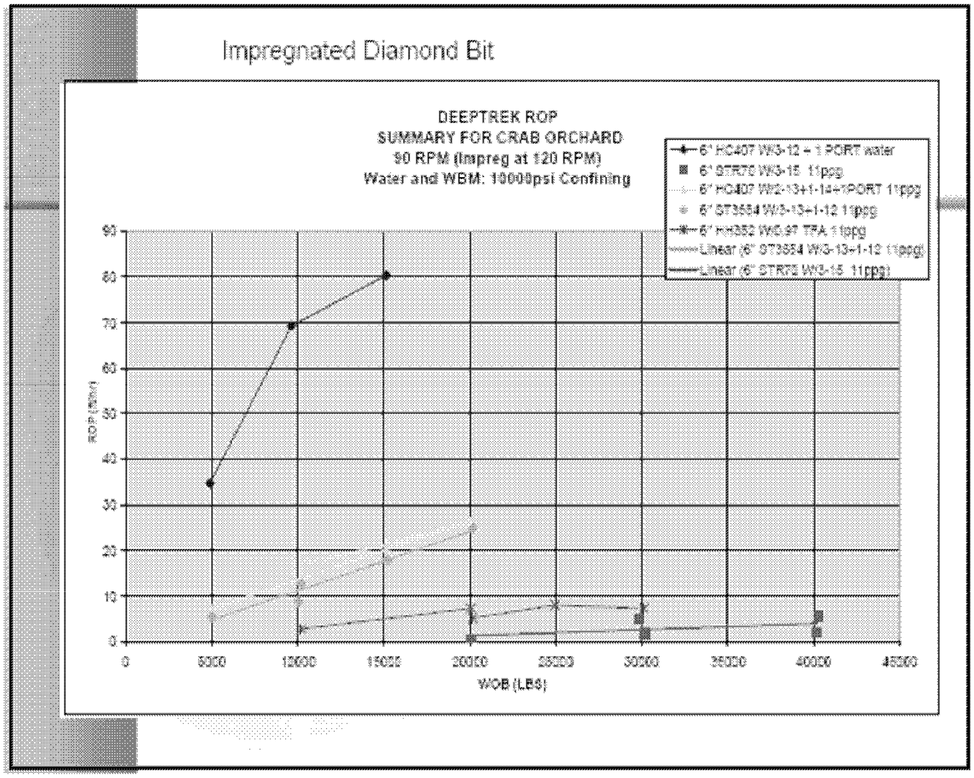
STR 70 Roller Cone Bit
ST 3554 4-Bladed PDC
HC 407 7-Bladed PDC
HH 352 Impregnated Diamond

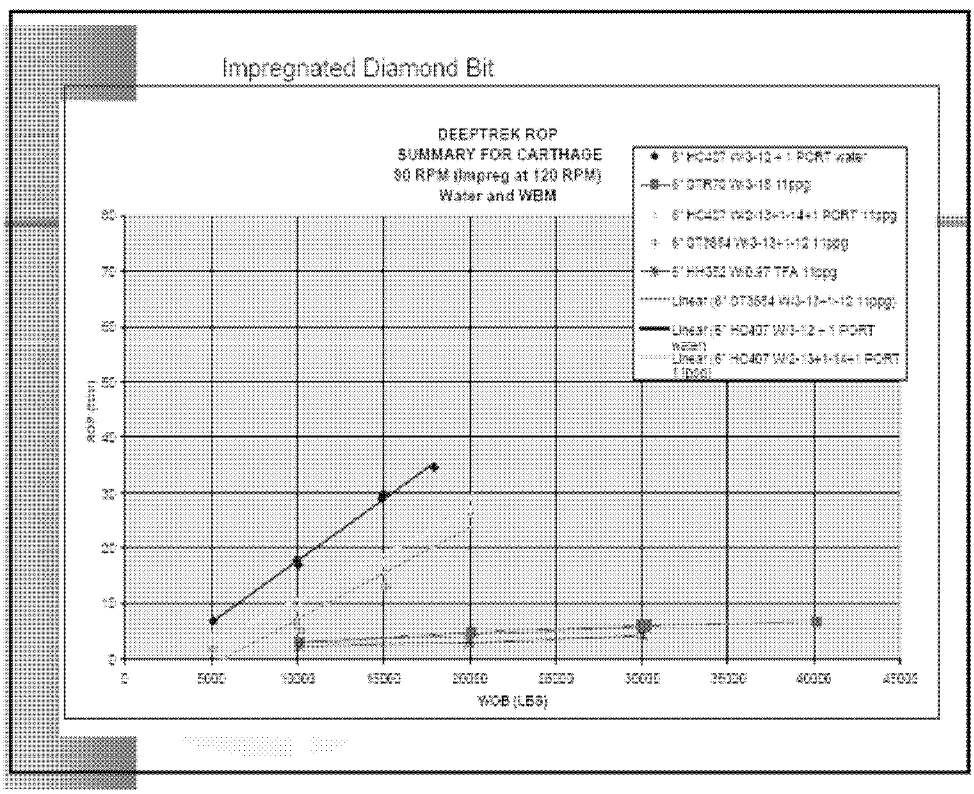
Roller Cone Bit

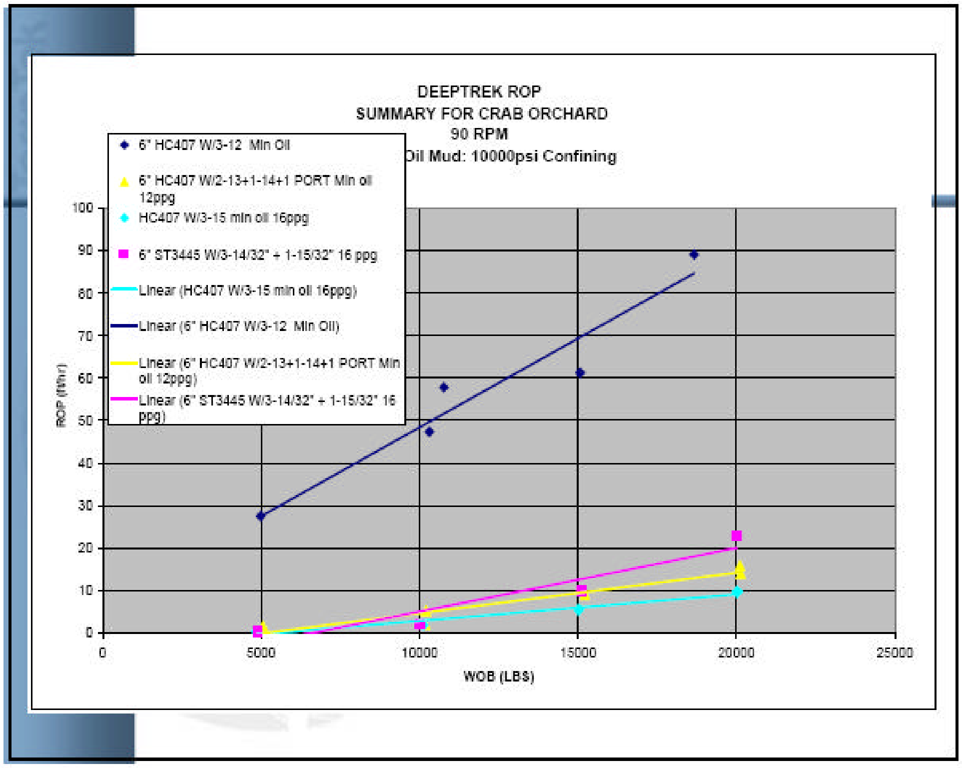


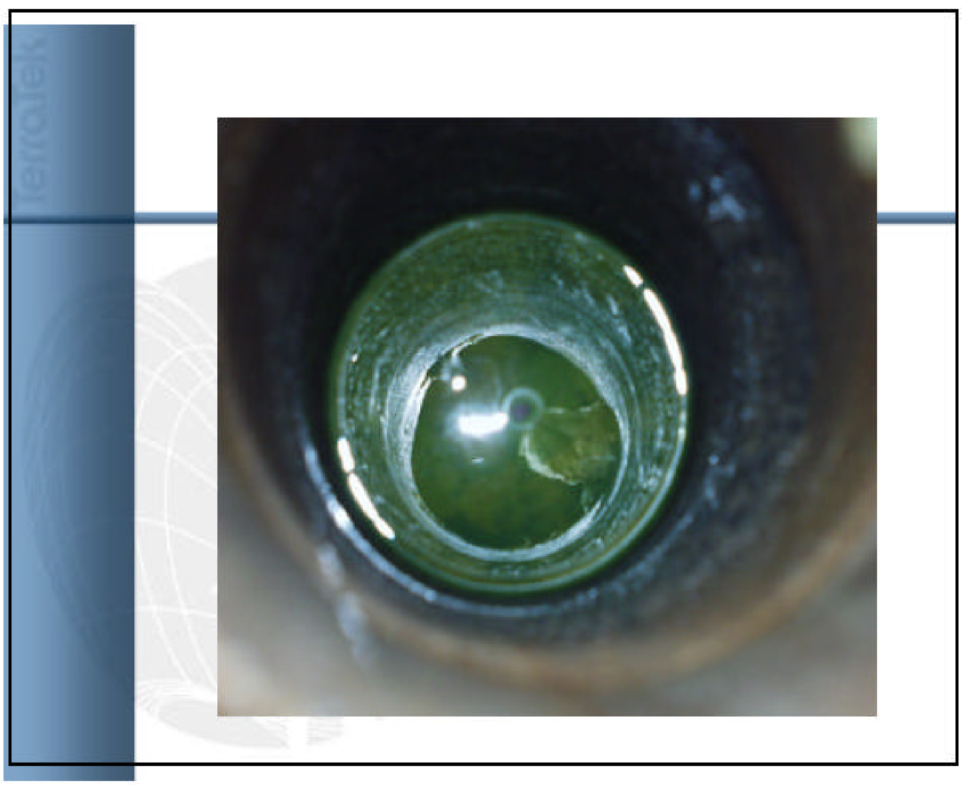

7-Bladed PDC
DEEPTREK ROP
SUMMARY FOR CRAB ORCHARD
6" HC407 11ppg WBM; 11000psi confining
90 RPM
120 RPM
Linear (90 RPM)
Linear (120 RPM)
0
10
20
30
40
50
60
70
80
0
5000
10000
15000
20000
25000
WOB (LBS)

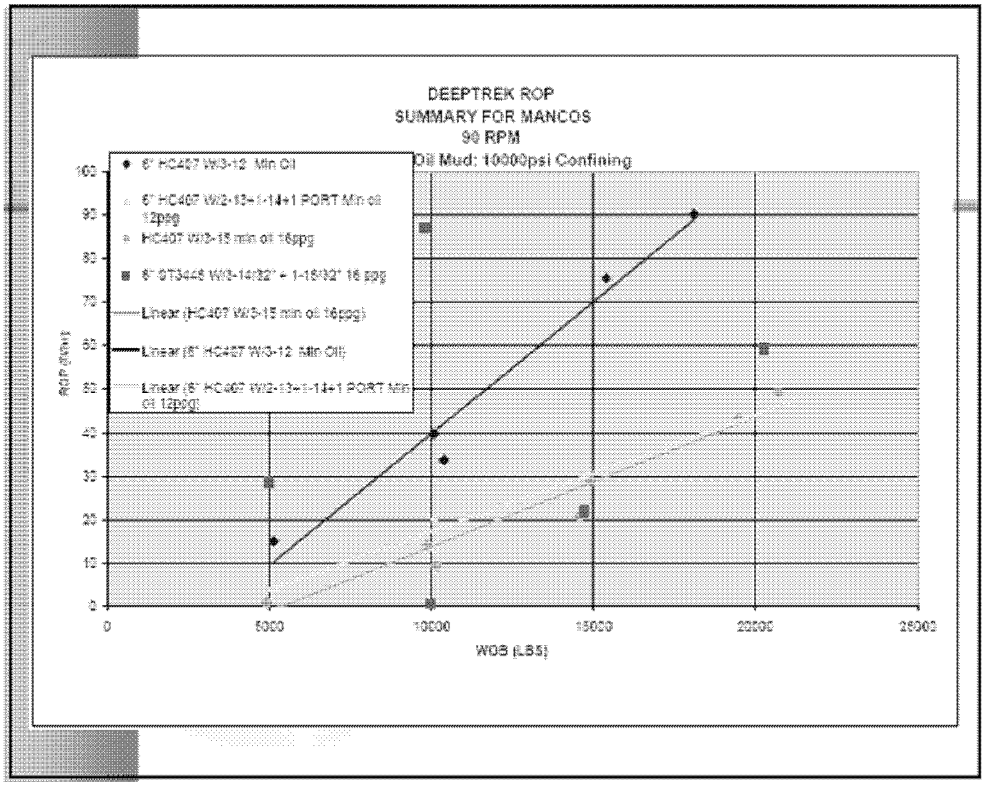


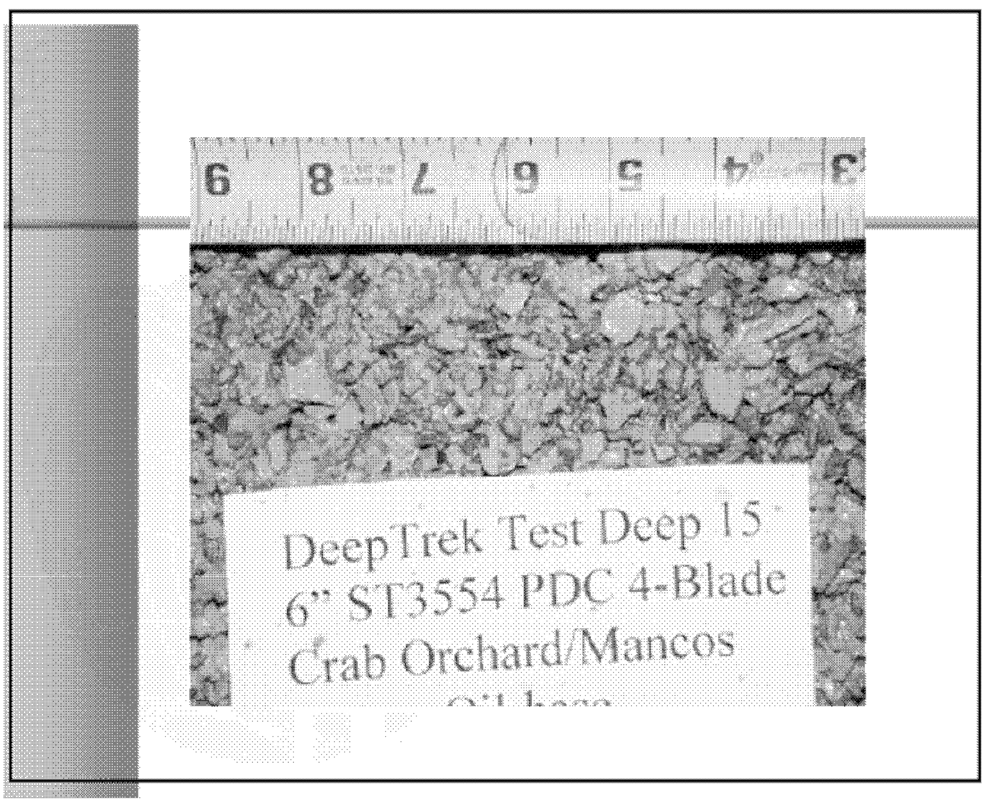

Impregnated Diamond Bit
DEEPTREK ROP
SUMMARY FOR CRAB ORCHARD
90 RPM (Impreg at 120 RPM)
Water and WBM: 10000psi Confining
6" HC407 W/3-12 + 1 PORT water
6" STR70 W/3-15 11ppg
6" HC407 W/2-13+1-14+1PORT 11ppg
6" ST3554 W/3-13+1-12 11ppg
6" HH352 W/0.97 TFA 11ppg
Linear (6" ST3554 W/3-13+1-12 11ppg)
Linear (6" STR70 W/3-15 11ppg)
ROP (ft/hr)
WOB (LBS)
0
10
20
30
40
50
60
70
80
90
5000
10000
15000
20000
25000
30000
35000
40000
45000

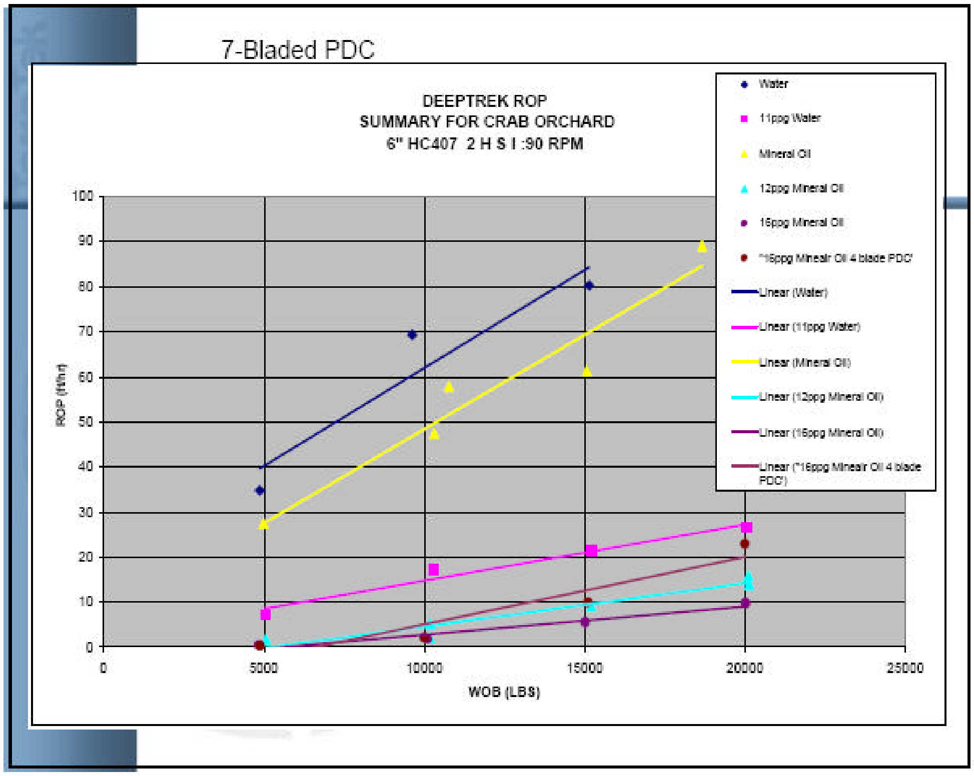

Impregnated Diamond Bit
DEEPTREK ROP
SUMMARY FOR CARTHAGE
90 RPM (Impreg at 120 RPM)
Water and WBM
6" HC407 W/3-12 + 1 PORT water
6" STR70 W/3-15 11ppg
6" HC407 W/2-13+1-14+1 PORT 11ppg
6" ST3554 W/3-13+1-12 11ppg
6" HH352 W/0.97 TFA 11ppg
Linear (6" ST3554 W/3-13+1-12 11ppg)
Linear (6" HC407 W/3-12 + 1 PORT water)
Linear (6" HC407 W/2-13+1-14+1 PORT 11ppg)
ROP (ft/hr)
WOB (LBS)
0
10
20
30
40
50
60
70
80
5000
10000
15000
20000
25000
30000
35000
40000
45000

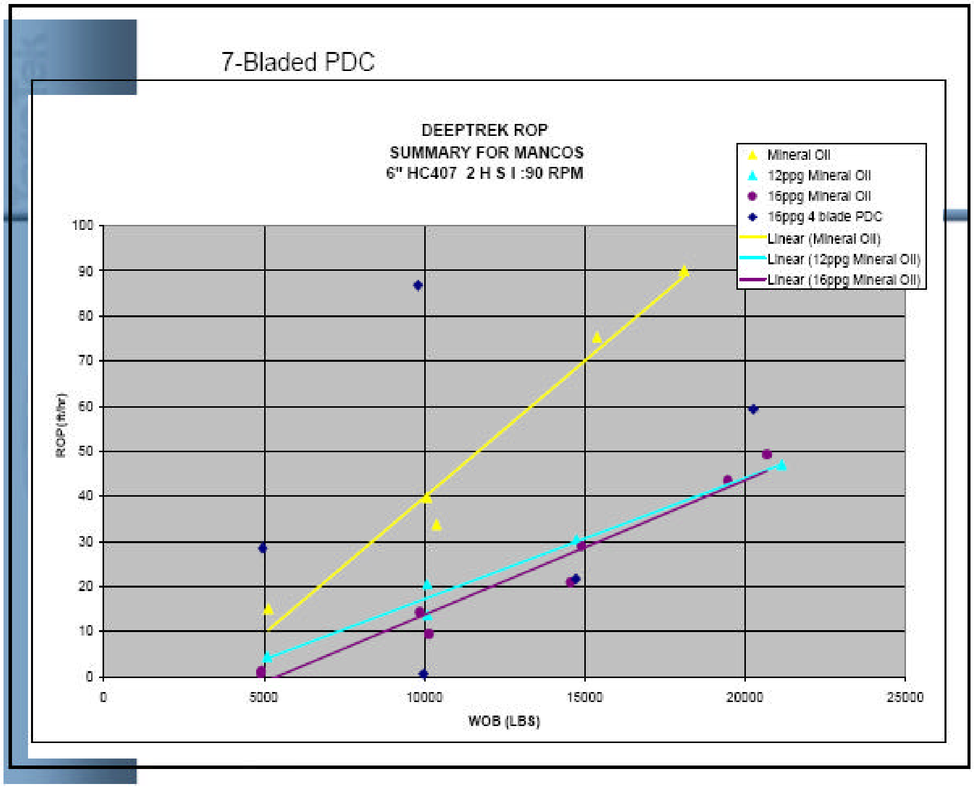

DEEPTREK ROP
SUMMARY FOR CRAB ORCHARD
90 RPM
Oil Mud: 10000psi Confining
6" HC407 W/3-12 Min Oil
6" HC407 W/2-13+1-14+1 PORT Min oil 12ppg
HC407 W/3-15 min oil 16ppg
6" ST3445 W/3-14/32" + 1-15/32" 16 ppg
Linear (HC407 W/3-15 min oil 16ppg)
Linear (6" HC407 W/3-12 Min Oil)
Linear (6" HC407 W/2-13+1-14+1 PORT Min oil 12ppg)
Linear (6" ST3445 W/3-14/32" + 1-15/32" 16 ppg)
ROP (ft/hr)
100
90
80
70
60
50
40
30
20
10
0
0
5000
10000
15000
20000
25000
WOB (LBS)



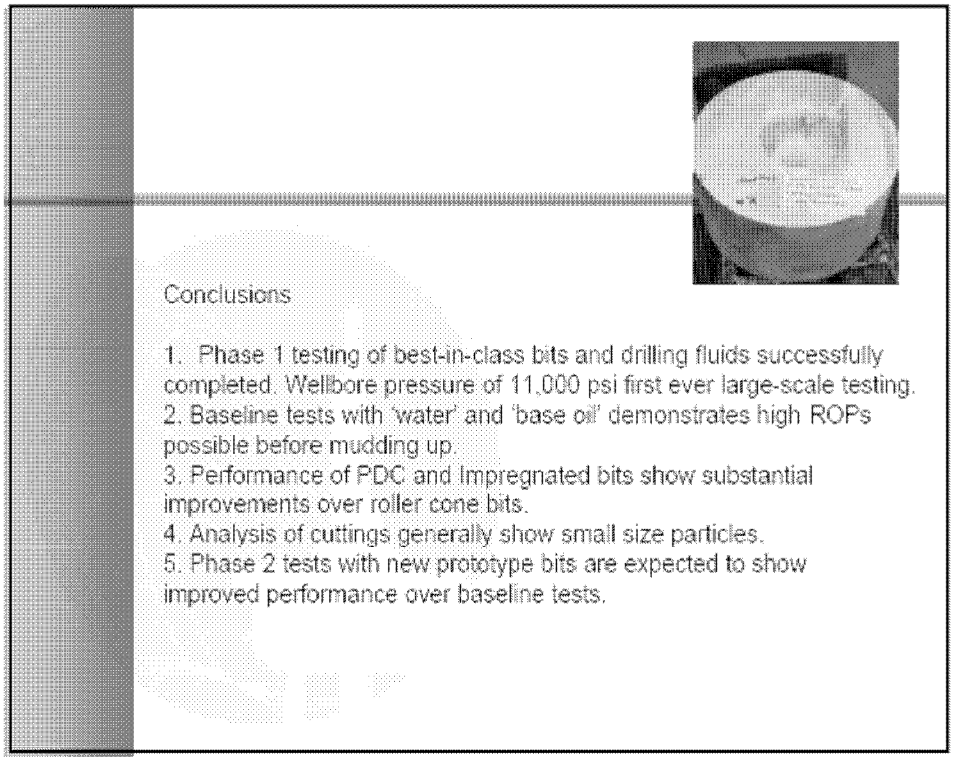

DEEPTREK ROP
SUMMARY FOR MANCOS
90 RPM
Oil Mud: 10000psi Confining
6" HC407 W/3-12 Min Oil
6" HC407 W/2-13+1-14+1 PORT Min oil 12ppg
HC407 W/3-15 min oil 16ppg
6" ST3449 W/3-14/32" + 1-15/32" 16 ppg
Linear (HC407 W/3-15 min oil 16ppg)
Linear (6" HC407 W/3-12 Min Oil)
Linear (6" HC407 W/2-13+1-14+1 PORT Min oil 12ppg)
ROP (ft/hr)
0
10
20
30
40
50
60
70
80
90
100
0
5000
10000
15000
20000
25000
WOB (LBS)

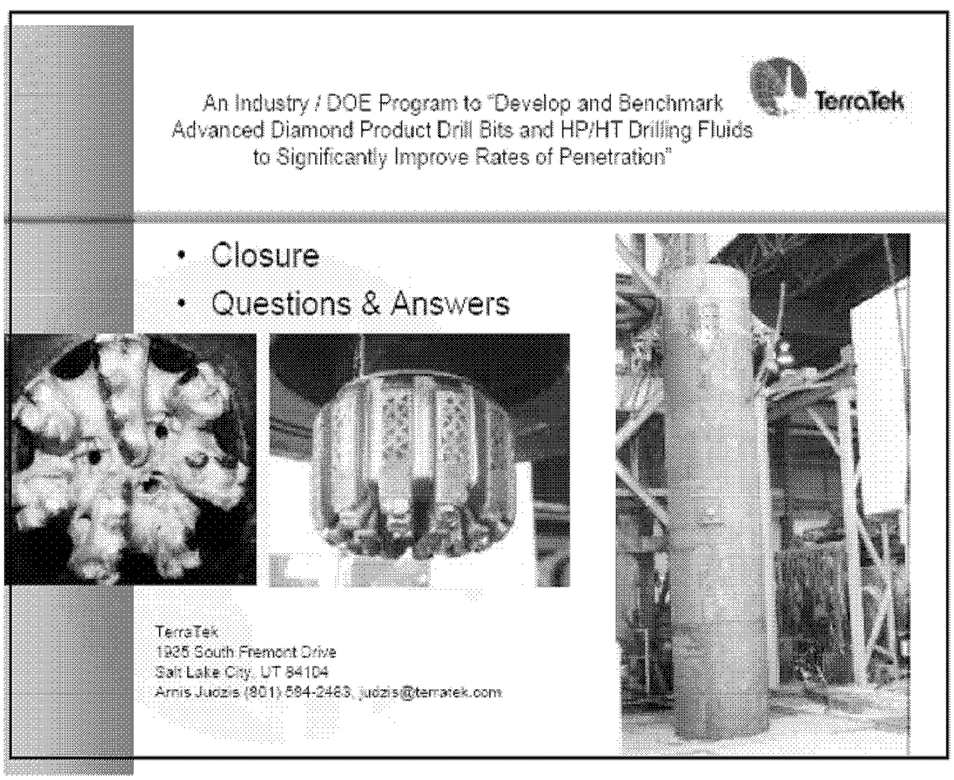

DeepTrek Test Deep 15
6" ST3554 PDC 4-Blade
Crab Orchard/Mancos


7-Bladed PDC
DEEPTREK ROP
SUMMARY FOR CRAB ORCHARD
6" HC407 2 H S I :90 RPM
Water
11ppg Water
Mineral Oil
12ppg Mineral Oil
16ppg Mineral Oil
"16ppg Minealr Oil 4 blade PDC"
Linear (Water)
Linear (11ppg Water)
Linear (Mineral Oil)
Linear (12ppg Mineral Oil)
Linear (16ppg Mineral Oil)
Linear ("16ppg Minealr Oil 4 blade PDC")
ROP (ft/hr)
WOB (LBS)


7-Bladed PDC
DEEPTREK ROP
SUMMARY FOR MANCOS
6" HC407 2 H S I :90 RPM
Mineral Oil
12ppg Mineral Oil
16ppg Mineral Oil
16ppg 4 blade PDC
Linear (Mineral Oil)
Linear (12ppg Mineral Oil)
Linear (16ppg Mineral Oil)
ROP (ft/hr)
WOB (LBS)


DEEP #16

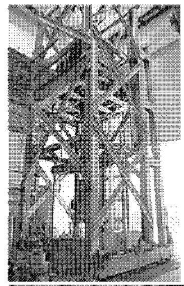

Conclusions
1. Phase 1 testing of best-in-class bits and drilling fluids successfully completed. Wellbore pressure of 11,000 psi first ever large-scale testing.
2. Baseline tests with 'water' and 'base oil' demonstrates high ROPs possible before mudding up.
3. Performance of PDC and Impregnated bits show substantial improvements over roller cone bits.
4. Analysis of cuttings generally show small size particles.
5. Phase 2 tests with new prototype bits are expected to show improved performance over baseline tests.


An Industry / DOE Program to "Develop and Benchmark Advanced Diamond Product Drill Bits and HP/HT Drilling Fluids to Significantly Improve Rates of Penetration"
TerraTek
• Closure
• Questions & Answers
TerraTek
1935 South Fremont Drive
Salt Lake City, UT 84104
Arnis Judzis (801) 584-2483, judzis@terratek.com

September 14, 2005 at Morgantown

TerraTek

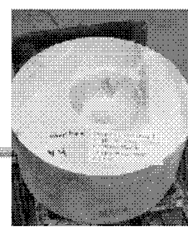
An Industry / DOE Program to "Develop and Benchmark Advanced Diamond Product Drill Bits and HP/HT Drilling Fluids to Significantly Improve Rates of Penetration"



DEEPTREK - Improving Deep Drilling Performance

Arnis Judzis, Executive Vice President TerraTek
Matt Meiners, Hughes Christensen Company
Ron Bland, Baker Hughes Drilling Fluids
(Gary Collins, ConocoPhillips, pre-meeting 9/8/05 with Tim Grant and Arnis Judzis)

Meeting at DOE / NETL
Morgantown, WV
September 14, 2005



Conclusions

1. Phase 1 testing of best-in-class bits and drilling fluids successfully completed. Wellbore pressure of 11,000 psi first ever large-scale testing.
2. Project came in on budget.
3. Baseline tests with 'water' and 'base oil' demonstrates high ROPs possible before mudding up.
4. Performance of PDC and Impregnated bits show substantial improvements over roller cone bits in some cases.
5. Analysis of cuttings generally show small size particles.
6. Phase 2 tests with new prototype bits are expected to show improved performance over baseline tests.

Lessons Learned / Operator Recommendations (Gary Collins – ConocoPhillips 5/8/05)

- Hard rock drilling still very important – don't forget compressive strengths get very high!
- Select formations that will give you most information in Phase 2
- Mechanisms important – 'chipping' or 'grinding' mode
- Both design and operational parameters are opportunities
- Economics make drilling performance improvements compelling; AFE spreads of $200k per day not uncommon and high pressures with weighted mud seen at 15,000 ft.
- At great depth there may be breakpoint where even insert bit performance may not be enough due to weight requirements.
- Fluids and hydraulics important also
- Good development options in Phase 2 for bit design and materials
- Data is useful! – Gary has worked on shallower granite drilling and used the hammer benchmark data to save company money.

Phase 2 Program (October 2005 – September 2006)

Timetable

1. 4Q 2005 – Planning meetings based on lessons learned with Industry Advisors. Preliminary engineering work on testing equipment, bits, and fluid design.
2. 1 Q 2006 – Definition of testing program / matrix; Detailed design work by TerraTek and Service Company (Baker Hughes, Hughes Christensen) contributors. Obtain rock samples and prepare materials.
3. 2 Q 2006 – Execute testing program with prototype bits and fluids; evaluate performance with respect to benchmarks.
4. 3 Q 2006 – Prepare for field demonstration (Phase 3), transfer technology, and provide improvements for re-testing as appropriate from Phase 2 results / development.

Phase 2 Plans (October 2005 – September 2006)

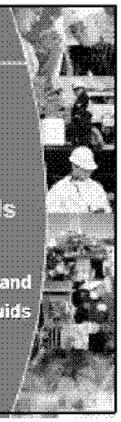
Basis

1. Results significant to Phase 1 findings are crucial to Ph 2 plans
2. Both Hughes Christensen and Baker Hughes Drilling Fluids have completed some analysis of findings
3. The 'mechanisms' holding back improved performance are opportunities to be investigated (materials, designs, etc. for prototype development)
4. Phase 2 improvements are likely to be marketed and accelerate marketplace development further – this is fundamental to the original 'Scope of Work' that operators have future access to technical improvements.
5. The November 2005 issue of Hart's E&P will run a short article on the DeepTrek drilling project and plans for Phase 2 (Judzis, Grant, Bland, and Curry)

September 14, 2005 Baker Hughes drilling Fluids presentation as part of DeepTrek program at NETL, Morgantown

DeepTrek & Drilling Fluids

Ron Bland
Baker Hughes Drilling Fluids



Baker Hughes Drilling Fluids

Presentation Outline

- DeepTrek Phase I Mud Formulations & Properties
- Cuttings Size Distribution
- Preliminary Cuttings & Core Analysis
- Phase II Options

Baker Hughes Drilling Fluids

Water-based Mud Formulation (11 lb/gal)

Tapwater, bbl	0.86
Bentonite, lb	18
Chrome Lignosulfonate, lb	2
Caustic Soda, lb	0.5
RevDust, lb	45
Barite, lb	94.4

Baker Hughes Drilling Fluids

Water-based Mud Average Properties

Mud Weight, lb/gal	10.9
P.V.,cps.	21
Y.P.,lb/100ft^2	13
Gels,lb/100ft^2	6/14
pH	10.0
API FL, cm^3/30 min.	5.4
Solids, vol.%	14.0
Suspended Phase, vol.%	14.0

Baker Hughes Drilling Fluids

Oil-based Mud Formulation (12 lb/gal)

Mineral Oil, bbl	0.5435
Amidoamine Emulsifier, lb	12
Modified FA Emulsifier, lb	2.34
Lime, lb	3.16
Organoclay, lb	4.2
25% Calcium Chloride brine, bbl	0.2141
RevDust, lb	45
Barite, lb	189.3

Baker Hughes Drilling Fluids

12 lb/gal Oil-based Mud Average Properties

Mud Weight, lb/gal	12.0
P.V.,cps.	21
Y.P.,lb/100ft^2	20
Gels,lb/100ft^2	13/21
Electrical Stability, volts	632
HPHT Filtrate @ 200°F, cm^3	2
Solids, vol.%	18.9
Suspended Phase, vol.%	40.3

Baker Hughes Drilling Fluids

Oil-based Mud Formulation (16 lb/gal)

Mineral Oil, bbl	0.5047
Amidoamine Emulsifier, lb	12
Modified FA Emulsifier, lb	4
Lime, lb	3
Organoclay, lb	3.89
25% Calcium Chloride brine, bbl	0.1059
RevDust, lb	45
Barite, lb	425.4

16 lb/gal Oil-based Mud Average Properties

Mud Weight, lb/gal	16.0
P.V.,cps.	27
Y.P.,lb/100ft^2	16
Gels,lb/100ft^2	10/22
Electrical Stability, volts	861
HPHT Filtrate @ 200°F, cm^3	2.4
Solids, vol.%	34.9
Suspended Phase, vol.%	45.5

Clear Water Properties

Density, lb/gal	8.34
P.V. @ 40°C, cps.	0.653
Y.P. @40°C, lb/100ft^2	0
Gels, lb/100ft^2	0/0
Electrical Stability, volts	Low
API FL, cm^3/30 min.	U/C
Solids, vol.%	0.0
Suspended Phase, vol.%	0.0

Clear Mineral Oil Properties

Density, lb/gal	6.68
P.V. @ 40°C, cps.	1.600
Y.P. @40°C, lb/100ft^2	0
Gels, lb/100ft^2	0/0
Electrical Stability, volts	2000
HPHT Filtrate @ 200°F, cm^3	U/C
Solids, vol.%	0.0
Suspended Phase, vol.%	0.0

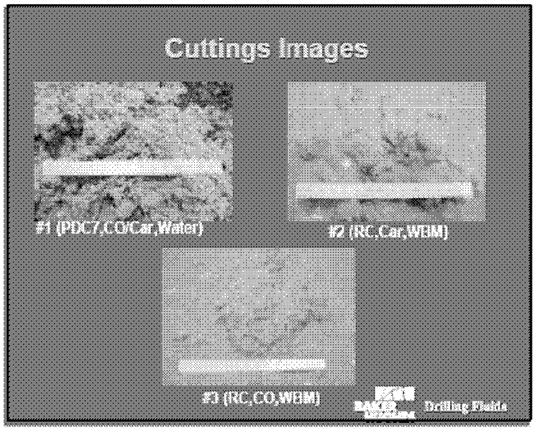
Mud Property Summary

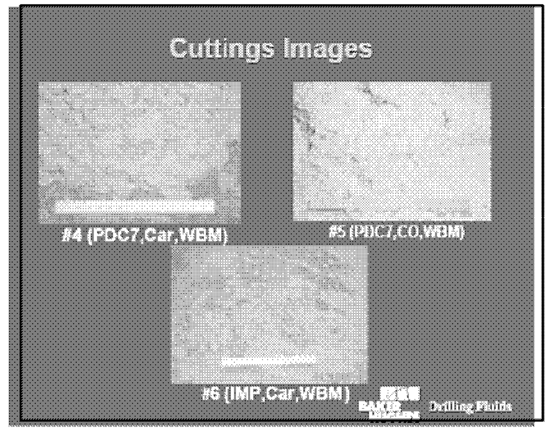
	11lb/gal WBM	12 lb/gal OBM	16 lb/gal OBM	Clear Water	Clear Mineral Oil
Mud Weight, lb/gal	10.9	12.0	16.0	8.3	6.7
P.V.,cps.	21	21	26.6	0.7	1.6
Y.P.,lb/100ft^2	13	20	15.6	0.0	0.0
Gels,lb/100ft^2	6/14	13/21	10/22	0/0	0/0
pH	10.0	-	-	±7	-
Electrical Stability, volts	Low	632	861	Low	>2000
API FL, cm^3/30 min.	5.4	-	-	U/C	U/C
HPHT Filtrate @ 200°F, cm^3	-	2	2.4	U/C	U/C
Solids, vol.%	14.0	18.9	34.9	0.0	0.0
Suspended Phase, vol.%	14.0	40.3	45.5	0.0	0.0

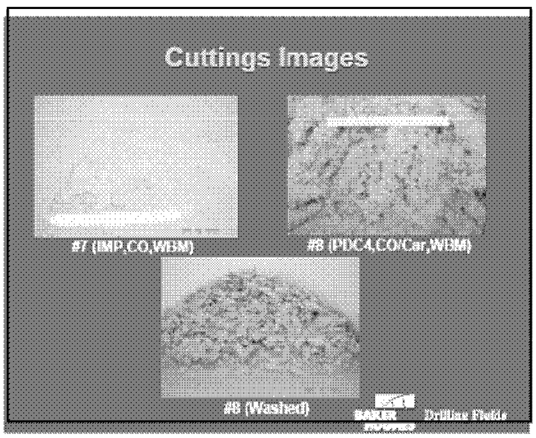
Cuttings PSD in Microns WBM

	Test 1	Test 2	Test 3	Test 4	Test 5	Test 7	Test 8
Bit	PDC7	RC	RC	PDC7	PDC7	IMP	PDC4
Mud	Water	WBM*	WBM*	WBM*	WBM*	WBM*	WBM*
Rock	CO/Crth	Crth	CO	Crth	Crth	CO	CO/Crth
D_{10}	2174	2422	2164	2610	2589	2603	2668
D_{50}	2832	3673	3306	3577	4336	3370	4746
D_{90}	3968	6091	6345	4881	7049	9890	7245

* 11 lb/gal





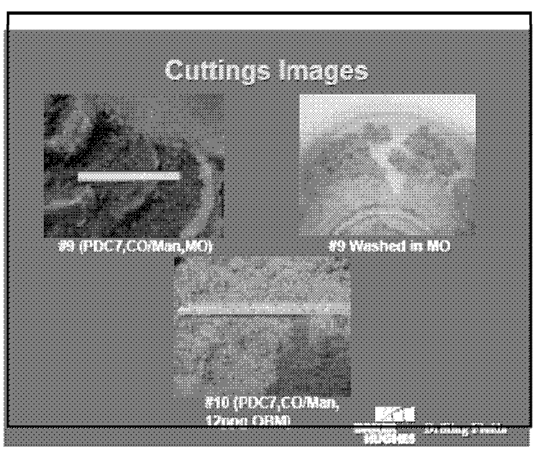


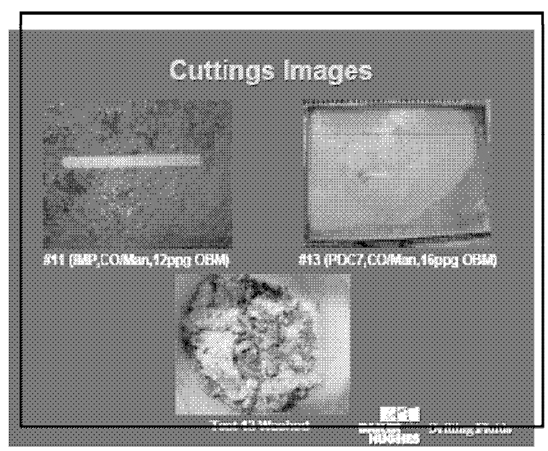
Cuttings PSD in Microns OBM

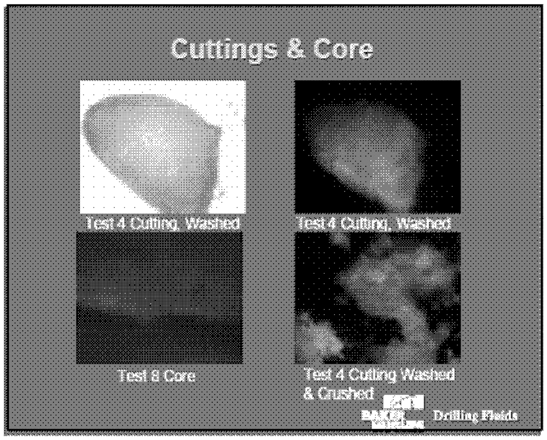
	Test 10	Test 11
Bit	PDC7	IMP
Mud	OBM*	OBM*
Rock	CO/Mancos	CO/Mancos
D_{10}	2888	2349
D_{50}	4746	4347
D_{90}	7245	11751

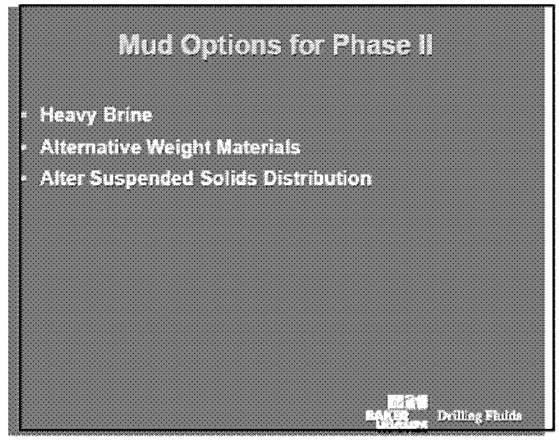
* 12 lb/gal

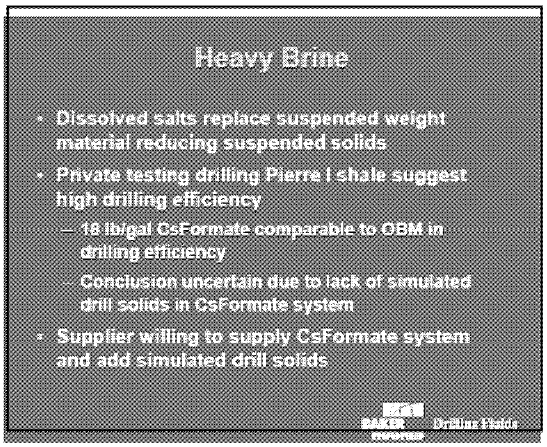
Drilling Fluids

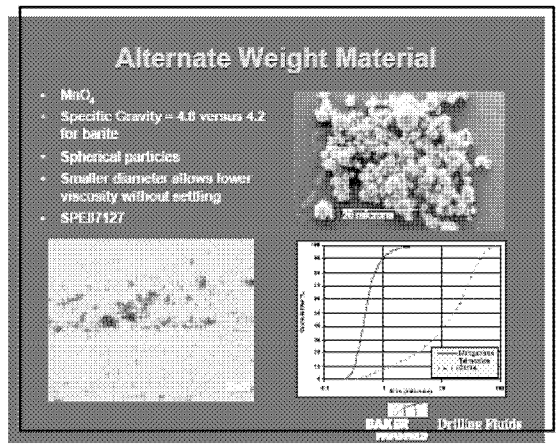


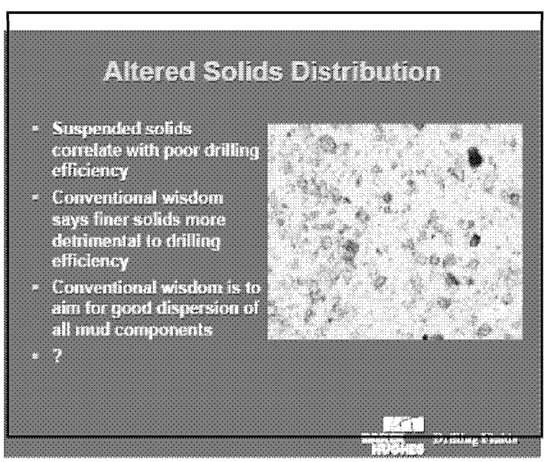



Cuttings & Core
Test 4 Cutting, Washed
Test 4 Cutting, Washed
Test 8 Core
Test 4 Cutting Washed & Crushed
BAKER HUGHES Drilling Fluids


Mud Options for Phase II
Heavy Brine
Alternative Weight Materials
Alter Suspended Solids Distribution
BAKER HUGHES Drilling Fluids


Heavy Brine
Dissolved salts replace suspended weight material reducing suspended solids
Private testing drilling Pierre I shale suggest high drilling efficiency
– 18 lb/gal CsFormate comparable to OBM in drilling efficiency
– Conclusion uncertain due to lack of simulated drill solids in CsFormate system
Supplier willing to supply CsFormate system and add simulated drill solids
BAKER HUGHES Drilling Fluids


Alternate Weight Material
MnO_4
Specific Gravity = 4.8 versus 4.2 for barite
Spherical particles
Smaller diameter allows lower viscosity without settling
SPE87127
BAKER HUGHES Drilling Fluids


Altered Solids Distribution
Suspended solids correlate with poor drilling efficiency
Conventional wisdom says finer solids more detrimental to drilling efficiency
Conventional wisdom is to aim for good dispersion of all mud components
?
BAKER HUGHES Drilling Fluids

CONCLUSIONS

- Task 1 project kick-off meeting with DOE personnel has been completed. An additional engineering meeting was held at Hughes Christensen February 13, 2003 to define testing goals and review deep drilling challenges. Input by Industry
- Task 2 designs and engineering concepts for drilling at high pressure are complete. A pre-drilling meeting was held November 19, 2003 and again May 25, 2004 to resolve any final issues.
- Task 3 was successfully and safely conducted during 2Q 1005. 16 full scale tests at high pressure were completed and reported.
- TerraTek and its partners Hughes Christensen and Baker Hughes Drilling Fluids successfully completed task 4 with data and performance comparisons.
- Task 5 was completed with a GTI publication at the GTI February, 2004 meeting, numerous Drilling Engineering Association presentations, Phase 1 presentation at the IADC / DEA Deep Drilling workshop May 2005, and the submittal of a formal SPE abstract for the 2006 SPE Annual Technical Conference and Exhibition. Additionally a review of Phase 1 results will appear in a November 2005 Hart’s E&P article.

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