HydroPulse™ Drilling

Final Report

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April 2004

U.S. Department of Energy

Cooperative Development Agreement No. DE-FC26-FT34367

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REV	DATE	DESCRIPTION	ORIGINATOR	REVIEWED	DATE
0	4/13/2004	Final Report	Author: J. Kolle	Hunter/Theimer	4/13/2004
TEMPRESS®				Document No.: TR- 053	

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Abstract

Tempress' HydroPulse™ tool increases overbalanced drilling rates by generating intense suction pulses at the drill bit. This report describes the operation of the tool; results of pressure drilling tests, wear tests and downhole drilling tests; and the business case for field applications. The HydroPulse™ tool is designed to operate on weighted drilling mud at conventional flow rates and pressures. Pressure drilling tests confirm that the HydroPulse™ tool provides 33% to 200% increased rate of penetration. Field tests demonstrated conventional rotary and mud motor drilling operations. The tool has been operated continuous for 50 hours on weighted mud in a wear test stand. This level of reliability is the threshold for commercial application. A seismic-while-drilling version of the tool was also developed and tested. This tool was used to demonstrate reverse vertical seismic profiling while drilling an inclined test well with a PDC bit. The primary applications for the HydroPulse™ tool are deep onshore and offshore drilling where rate of penetration drives costs. The application of the seismic tool is vertical seismic profiling-while-drilling and look-ahead seismic imaging while drilling.

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Executive Summary

Slow penetration rates in over-pressurized formations represent a critical challenge for deep drilling operations. Hard rock, high mud weight and high borehole pressure severely reduce drilling rate of penetration while long drillstrings limit the hydraulic power available at the bit. Tempress' HydroPulse™ tool increases overbalanced drilling rates by generating intense suction pulses at the drill bit. The tool incorporates a self-actuated diverter valve deployed above the bit in a high-speed flow course housing. Momentarily stopping the flow of mud through the flow courses generates the pulses creating locally underbalanced drilling conditions at the bit face. Pressure drilling tests in shale and hard sandstone have verified large increases in rate of penetration at high mud weight and borehole pressure. Field tests have demonstrated that the percussive load applied to the bit face suppresses improper bit motions allowing the application of higher bit weight and faster drilling in hard rock.

In summary the HydroPulse™ tool provides (1) 33% to 200% increased rate of penetration in pressure drilling tests, (2) best performance at low bit weight for straight hole drilling and (3) reduced improper bit motions providing longer bit life. Tool features include (1) conventional rotary or motor drilling operations, (2) conventional roller cone or PDC bits. (3) oil or water-based mud, (4) high-pressure, high temperature operations, (5) over 50 hours demonstrated operation on weighted mud, (6) circulation is always maintained, (7) low operating differential pressure – low hydraulic power requirement and (8) compatibility with lost circulation material.

The HydroSeis™ configuration of the tool, incorporating a sweep modulator, has been used to demonstrate seismic profiling and look-ahead seismic imaging-while drilling. HydroSeis™ benefits include (1) real-time reverse vertical seismic profiling while drilling, (2) high-resolution look-ahead imaging while drilling, (3) independent compression and shear wave source, (4) early warning of gas kicks and (5) operations in vertical or inclined wellbores.

This report describes the operation of the tool; results of pressure drilling tests, wear tests and downhole drilling tests; and the business case for field applications.

Introduction

Slow penetration rates in over-pressurized formations represent a critical challenge for deep drilling operations. Drilling rates in deep wells in the U.S. Mid-continent/Rocky Mountain region can be extremely low because the rock is hard and high mud weight is required[1]. Offshore drilling is now taking place in water depths of over 2 km (6560 ft) where the high mud weight used to control formation pressure reduces drilling rate substantially.

A number of factors limit drilling rates in deep wells[2]. Long drillstrings limit the hydraulic power available at the bit. High-temperature conditions limit the application of mud motors and directional steering systems. Deep onshore wells are commonly drilled with diamond-impregnated bits on turbine motors. Rotary drilling of hard rock with PDC bits is not economic because of improper bit motions, which destroy the cutters. Underbalanced drilling is not an option because of high-pressures and risk of uncontrolled flows in deep wells. Incremental changes in drill bit and fluid technology have not significantly affected penetration rate. New developments such as mud hammers have shown substantially worse performance than conventional rotary drilling under these conditions.

Hydraulic pulse drilling technology is specifically designed to overcome problems encountered during deep drilling in over-pressurized formations. The hydraulic pulse valve, shown schematically in Figure 1, periodically diverts the flow of mud from the bit to exhaust ports above the housing. As shown in Figure 2, a high-speed flow course housing is provided around the valve. Stopping the flow of mud through the flow courses generates an intense suction pulse around the bit. This suction pulse overcomes differential sticking forces that cause bit balling. The pulse also generates effective tensile stresses in the surface of the rock at the bit face. These stresses reduce the drilling strength of the rock by reducing the confining stress cased by heavy mud at high overbalance pressure. Finally, the suction pulse generates a percussive load on the hole bottom that is comparable to the bit weight. If the tool is decoupled from the drillstring using a thruster, these percussive loads can increase hard rock drilling rates.

[1] DeepTrek Worksop Proceedings, U.S. DoE National Energy Technology Laboratory, March 20-21, 2002, Houston.
[2] Shaughnessy et al. (2003) "Problems of ultra-deep high-temperature, high pressure drilling," *SPE 84555*, presented at SPE Annual Technical Conference and Exhibition, Denver.

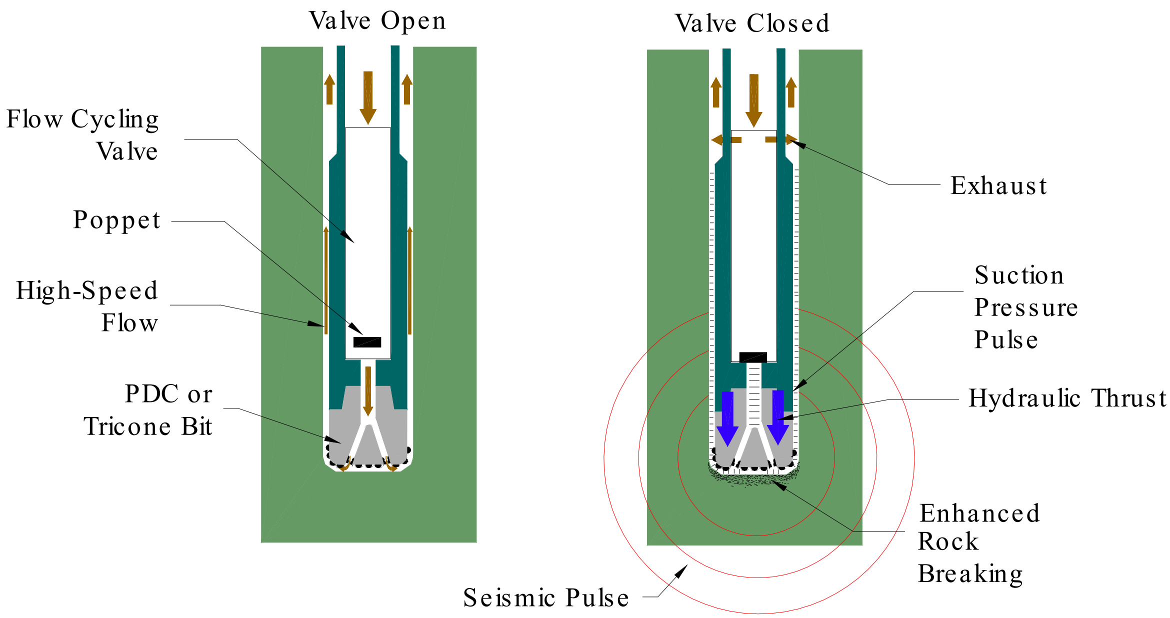

Figure 1. Hydraulic pulse drilling.

Figure 2. Hydraulic pulse tool housing with high-speed flow courses.

Specifications for the HydroPulse™ tool are listed in Table 1. Valve operating characteristics are given for a nominal flow rate of 400 gpm. Higher flow rates can be accommodated with larger bit nozzles. The tool is designed for drilling 8.5" hole however the housing can be modified for 7-7/8" to 9-1/2" hole. The housing is 0.2" smaller in diameter than the bit and incorporates two 1" deep, 1.75" wide flow courses. The OD of the housing is hardfaced and can incorporate inserts for backreaming. The tool operates at relatively low differential pressure with relatively large bit nozzles. The valve cartridge incorporates a shear screen that excludes lost circulation material and other debris in the drilling mud from the working components of the valve.

Table 1 HydroPulse™ tool specifications.

Characteristic	*Units*	*Gen 7*
Bit size	in	8.50 (7.75 min.)
Tool OD	in	8.30 (0.20 less than bit)
Upper connection	-	Box, 4.5 API IF (API NC50)
Lower connection	-	Box, 4.5 API REG
Length	in	40.00
Weight (incl. Cartridge)	lb	450
Cartridge diameter	in	3.50
Cartridge length	in	28.7
Cartridge weight	lb	41.9
Bit nozzle flow area	in^2	0.589 (three 0.500" nozzles)
Valve min. flow area	in^2	0.785
Nominal flow rate	gpm	400
Mud type	-	water or oil based
Differential pressure across tool and bit nozzles	psi	740 @ 10 ppg 1040 @ 14 ppg
Cycle rate range	Hz	20
Suction pulse amplitude	psi	660 @ 10 ppg 790 @ 14 ppg
Return flow slot area	in^2	6.1 (2x 1"x1.75" slots)
Maximum LCM size	in	.375"

Flow Loop Wear Tests

Performance and wear tests of the tool are carried out in a flow loop facility shown in Figure 3. In this facility the tools are operated on weighted drilling mud inside of a pressure vessel to simulate downhole conditions. Two joints of drill collar are located upstream of the tool to accurately simulate upstream flow velocity. Typical upstream and bit face pulse profile are shown in Figure 4. The suction pulse duration is about 3 milliseconds corresponding to the acoustic wave travel time in the flow courses. The pulse amplitude is proportional to flow rate and square root of mud density and inversely proportional to the flow area between the tool and the borehole. The flow area of slots in the valve housing and length of the valve housing my be changed to increase or decrease pulse amplitude.

The tool shown in Figure 2 has been subject to 53 hours of continuous wear testing at a differential pressure of 1000 psi running 9.3 ppg barite/bentonite mud. At this point the primary wear surfaces in the tool were still functional, however several bolted connections had failed in fatigue. With design modifications the tool should be capable of over 100 hours of operation.

Figure 3. Flow loop test facility.

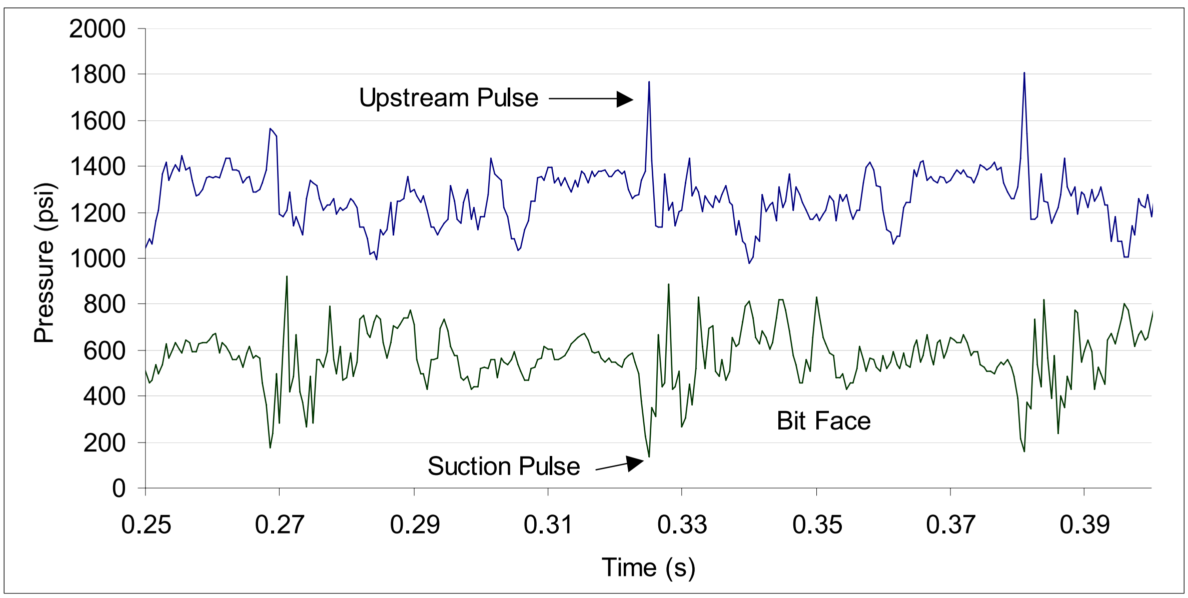

Figure 4. Bit face pressure profile generated by Gen 7 HydroPulse™. (Flow loop; 390 gpm 9.3 ppg mud, 9.5 in^2 flow area[3]).

[3] The test vessel has an internal diameter of 8.75”. The suction pulse pulse amplitude while drilling an 8.5” diameter hole is 56% higher than in the test loop.

Pressure Drilling Tests

Microdrilling

An evaluation of drilling rock mechanics has shown that a fast suction pulse at the bit face generates effective tensile stresses in low permeability formations such as shale[4]. The suction pulse weakens pressure-sensitive formations including shale and argillaceous sandstone. Simultaneously, the suction pulse generates an impulsive mechanical load on the bit that can enhance rate of penetration in hard rock. Figure 5 shows the effect of suction pulse amplitude on micro-drilling rate of penetration in Mancos shale. The micro-drilling data showed that a pulse amplitude of around 10 MPa increased rate of penetration by a factor of 2 to 6 in sandstone, shale and granite. The increased rate of penetration can be attributed to the combined effect of suction pulses on rock strength and the percussive load applied to the microbit.

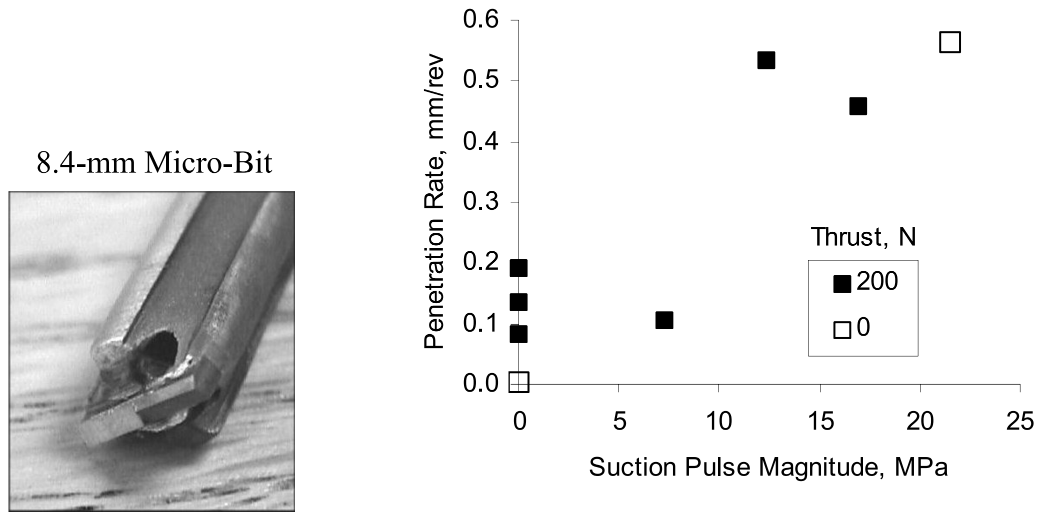

Figure 5. Effect of suction pulse amplitude on drilling rate with a micro-bit in Mancos Shale (10 MPa = 1450 psi).

[4] Kolle, J.J. (2000) "Increasing drilling rate in deep boreholes by impulsive depressurization," *Pacific Rocks 2000*, ed. by Girard et al, Balkema, Rotterdam.

Full-Scale Pressure Drilling

Full-scale pressure drilling tests were carried out at TerraTek in 2001 with a first generation tool design. Mancos shale and Crab Orchard sandstone were drilled with an 8-1/2” diameter IADC 537 insert bit. This tool incorporated High weight mud and high vessel pressure were used to simulate deep well conditions. A comparison of hydraulic pulse drilling with baseline drilling rates shown in Figure 6 verified increases in rate of penetration of 50% to 200% in Mancos shale. The increased rate of penetration occurs at the highest flow rate and pulse amplitude.

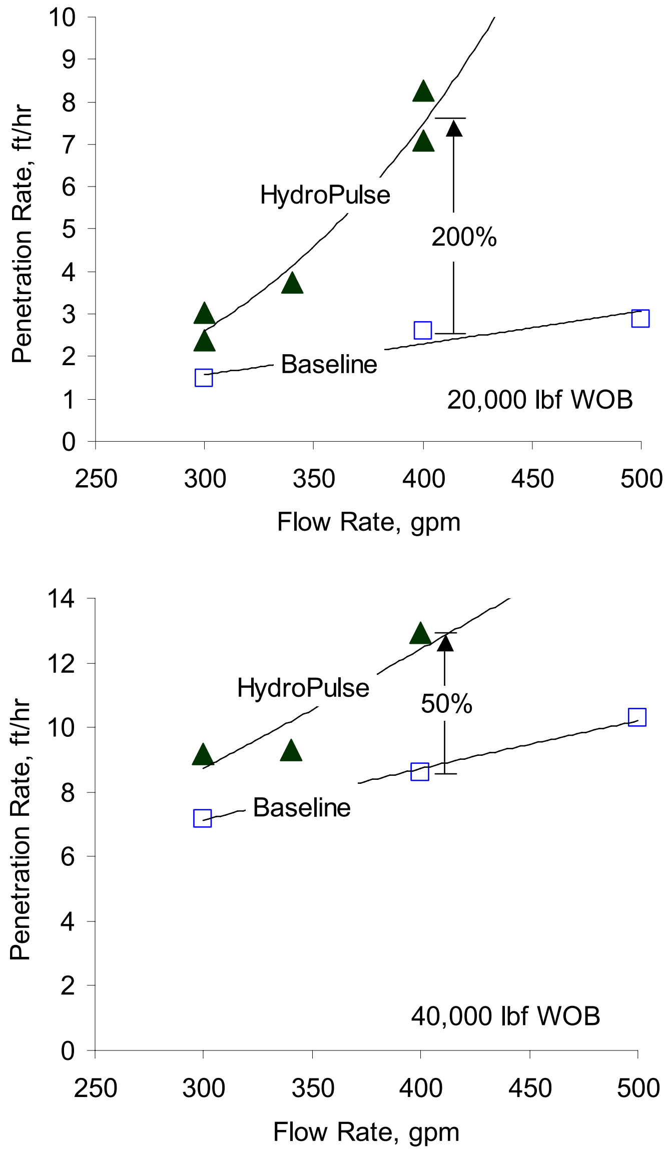

Figure 6. Mancos Shale pressure drilling rate of penetration comparison. 14 ppg mud, 3000 psi borehole pressure, 8.5” IADC 537 insert bit. HydroPulse™ suction pulse amplitude is 5.7 MPa (827 psi) at 400 gpm.

The full-scale pressure drilling tests also showed an increase in rate of penetration in hard Crab Orchard sandstone. As shown in Figure 7, the HydroPulse™ drilling rate was 33% higher than published drilling rates for this same rock under identical conditions. The baseline bit differential pressure was 1200 psi – about twice the differential pressure across the HydroPulse™ tool and bit. The increased rate of penetration was thus achieved with half the hydraulic power. The HydroPulse™ drilling rates were 300% faster than the mud hammer drills tested in this study under conditions of high mud weight and borehole pressure.

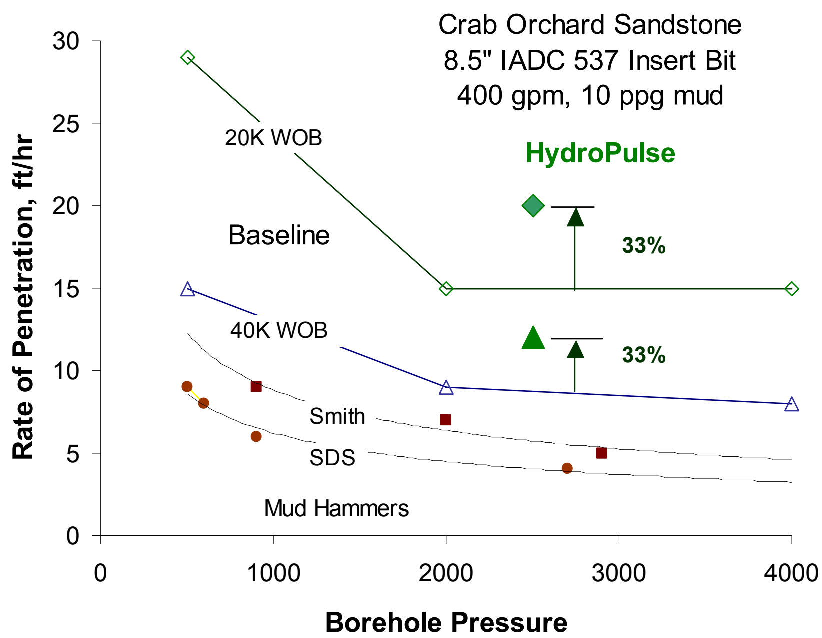

Figure 7. Crab Orchard sandstone pressure drilling rate of penetration comparison. Baseline and mud hammer data from Tibbits et al. [5] and Black and Judzis[6]. HydroPulse™ amplitude is 4.8 MPa (700 psi) at 400 gpm.

[5] Tibbitts, G.A., Long, R.C., Miller, B.E., Judzis, A. and Black, A. D. (2002) "World's First Benchmarking of Drilling Mud Hammer Performance at Depth Conditions," *IADC/SPE 74540*, presented at IADC/SPE Drilling Conference in Dallas Texas, 25-28 February 2002.

[6] Black, A.D. and A. Judzis (2004) "Mud hammer performance optimization," GTI Natural Gas Technologies Conference 8-11 February, Phoenix.

BETA Drilling Tests

Hydraulic pulse drilling tests were conducted at the Baker-Hughes Experimental Test Area (BETA) in September 2003. The objectives of the test were:

1. Evaluate effects of suction pulses on improper bit motions of PDC and insert bits
2. Demonstrate HydroPulse™ operations with a downhole motor.

A total of 24 hours of drilling with a footage of 651' was completed with two valve assemblies in a deviated well. A measurement-while-drilling system was used to record downhole drilling parameters. The valve housing incorporated three 1" deep, 2.75" wide flow courses. The suction pulse amplitude during these drilling tests was 320 to 400 psi at 400-gpm flow rate with 9.5-ppg mud. The well trajectory and sequence are shown in Figure 8.

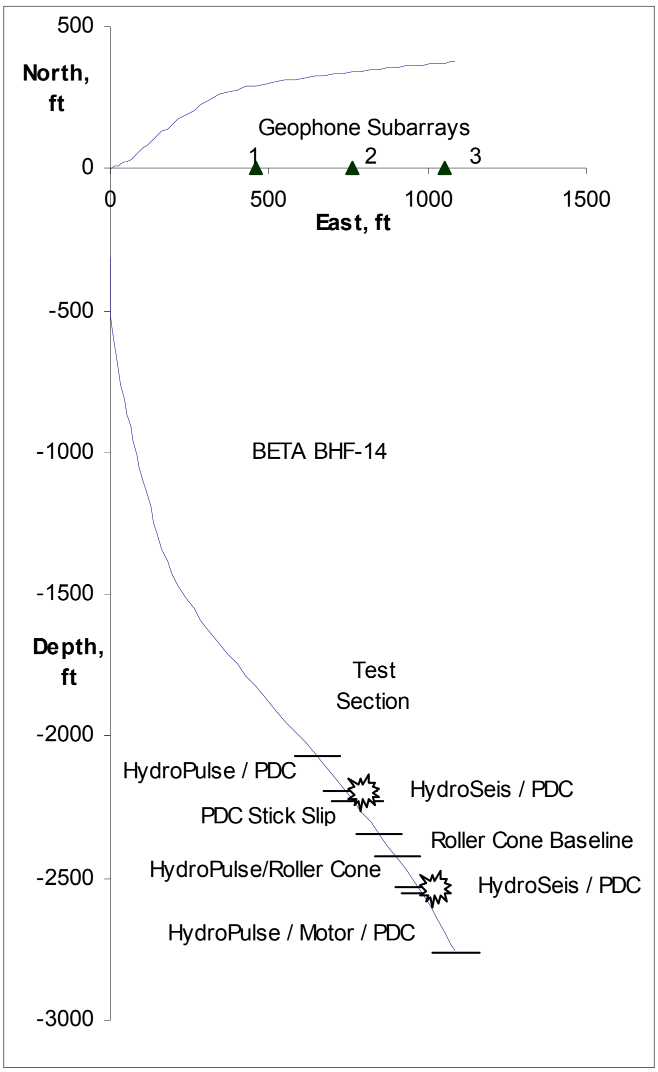

Figure 8. BETA test well trajectory.

PDC Drilling

Stick-slip motions were deliberately excited by drilling at low rotary speed and high weight on bit; with and without hydraulic pulsations. The weight on bit required to stall the top drive was increased 60% by the pulsations as shown in Figure 9. Drilling rates were much higher than offset rates because of high weight on bit. Without the hydraulic pulse tool, the PDC bit stalled at 16 to 18 klb WOB. With the tool, the bit stalled at 25 to 26 klb WOB - an increase of 50%.

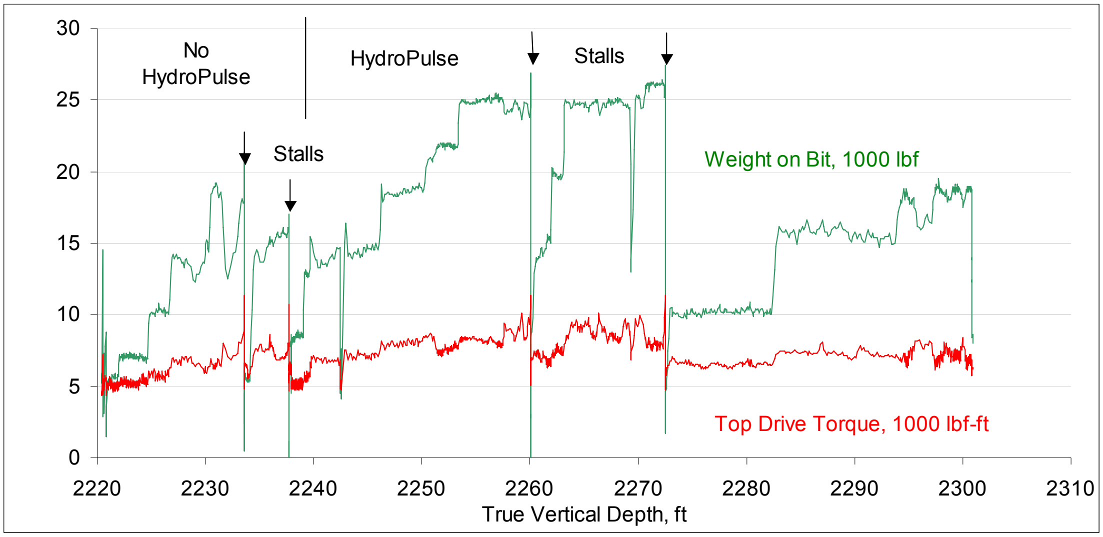

Figure 9. PDC stick slip experiment, with and without hydraulic pulses.

Roller Cone Drilling

Examination of MWD data for the roller cone bit run revealed three stick-slip events as shown in Figure 10. These events are not seen in the surface drilling data. In each case the BHA speed cycled from 0 to 250 rpm. No stick-slip events were observed while drilling with the HydroPulse™ tool as shown in Figure 11.

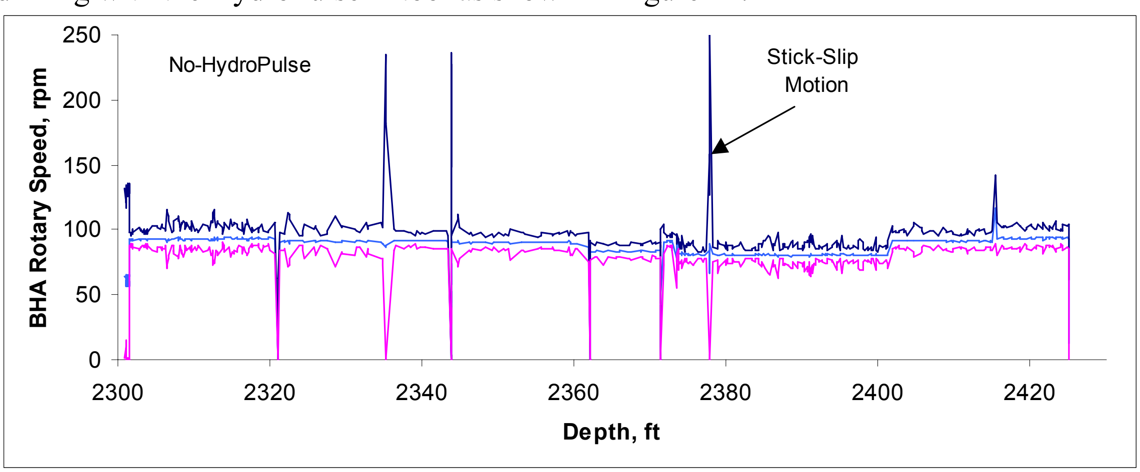

Figure 10. Rotary speed variations, minimum, average and maximum showing stick slip motion during rotary drilling with no hydraulic pulses.

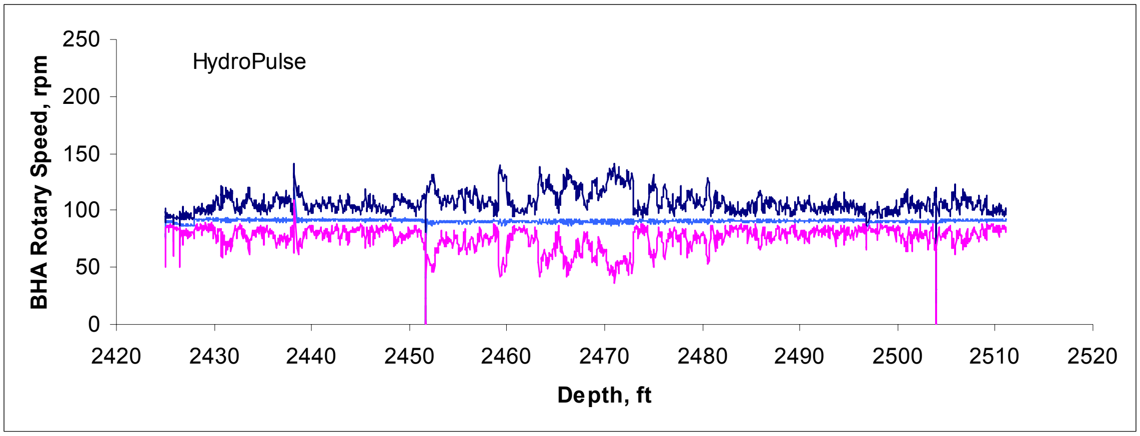

Figure 11. Rotary speed minimum, average and maximum, showing absence of stick slip while drilling with hydraulic pulses.

Motor Tests

The drilling tests included a 200' run with a positive displacement drilling motor. The motor was run at maximum bit weight with no indication of stalling while the pulse tool was operating. Very high rates of penetration were achieved in hard and soft formations. The tool was operated for 2 hours with no indication of adverse loading or wear on the motor.

BETA Drilling Performance Discussion

The full scale drilling tests showed a substantial effect of 320-400 psi suction pulses on improper bit motions of both PDC and roller cone bits. The stall weight for a PDC bit was increased 50% while drilling. Increased stall weight translates into higher penetration rate with a PDC bit before improper bit motion such as stick slip and whirl can cause cutter damage.

The pulses had no direct effect on rate of penetration with PDC or roller cone bits under these conditions of relatively low borehole pressure and low mud weight. The high mass and stiffness of the drill collars reduces the BHA response to the hydraulic percussive load. BHA measurements show a peak axial acceleration of 2 g with a maximum bit displacement of only 25 microns followed by ringing for about 25 ms as shown in Figure 12. At 80 ms the reflection of the pulse from the top of the drill collars generates an additional 20 micron movement. At a cycle rate of 20 Hz the bit advance related to the pulses is limited to 2 m/hr. A hydraulic thruster would decouple the tool from the drill collars allowing much larger bit motions. The peak suction pulse force on an 8-1/2" bit is 200 kN (46,000 lbf). The total mass of the bit, HydroPulse™ tool and the free portion of the thruster is approximately 300 kg. The average acceleration over 3 ms will be 340 m/s^2 (35 gs) and tool will be capable of advancing 1.5 mm per pulse for a maximum advance rate of 108 m/hr. In hard formations, the impulse force will be absorbed by enhanced rock cutting to increase rate of penetration.

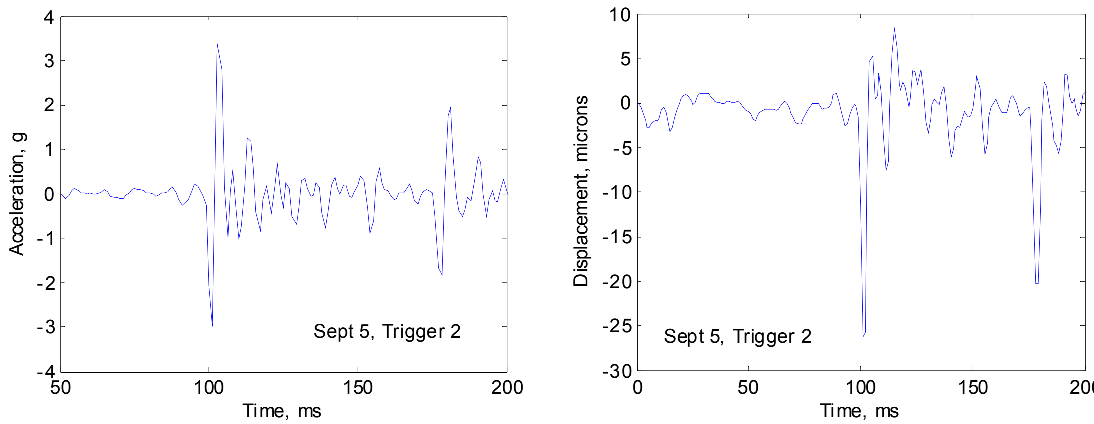

Figure 12. BHA acceleration and displacement obtained from CoPilot MWD system.

Seismic While Drilling

Previous tests of the hydraulic pulse tool have demonstrated good signal propagation to the surface over a depth of 2700'. A mechanism was developed to sweep the cycle rate of the tool through nearly an octave as shown in Figure 13. The cycle rate varies from 11 to 19 Hz and the impulse cycle period sweeps over a period of about 4 seconds. The source spectrum is shown in Figure 14. The power spectrum is broadband to well over 250 Hz. The suction pulse is omni-directional allowing applications in vertical or deviated wellbores. The tool generates a strong shear wave while drilling but no shear wave when the bit is off-bottom. This ability allows profiling of both P- and S-wave velocity with direct application to pore gas detection. The presence of small amounts of free gas at the bit will immediately eliminate the seismic signal – providing early warning of a gas kick.

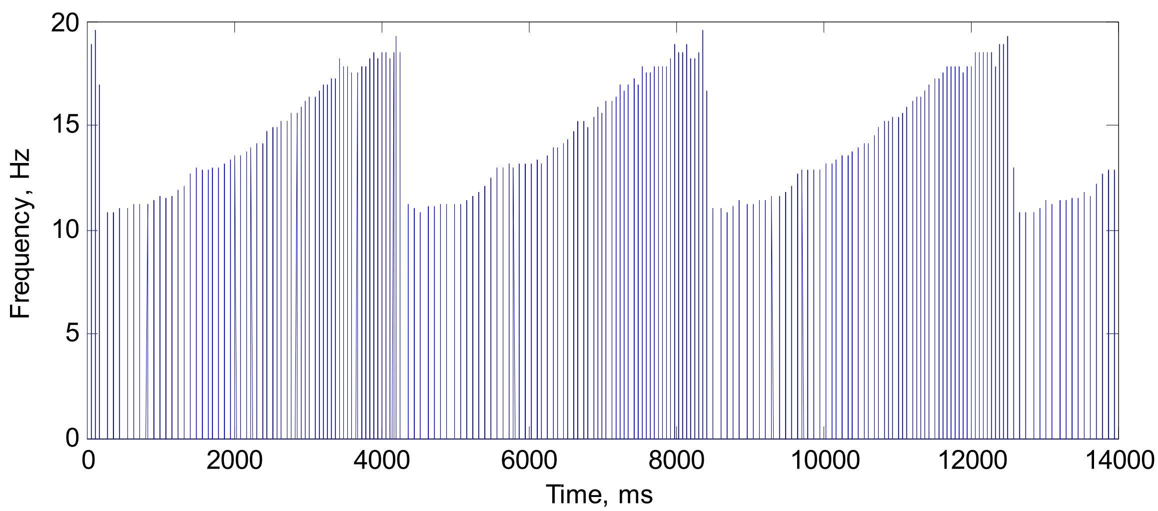

Figure 13. Internal pressure frequency time sample – impulse function times cycle frequency.

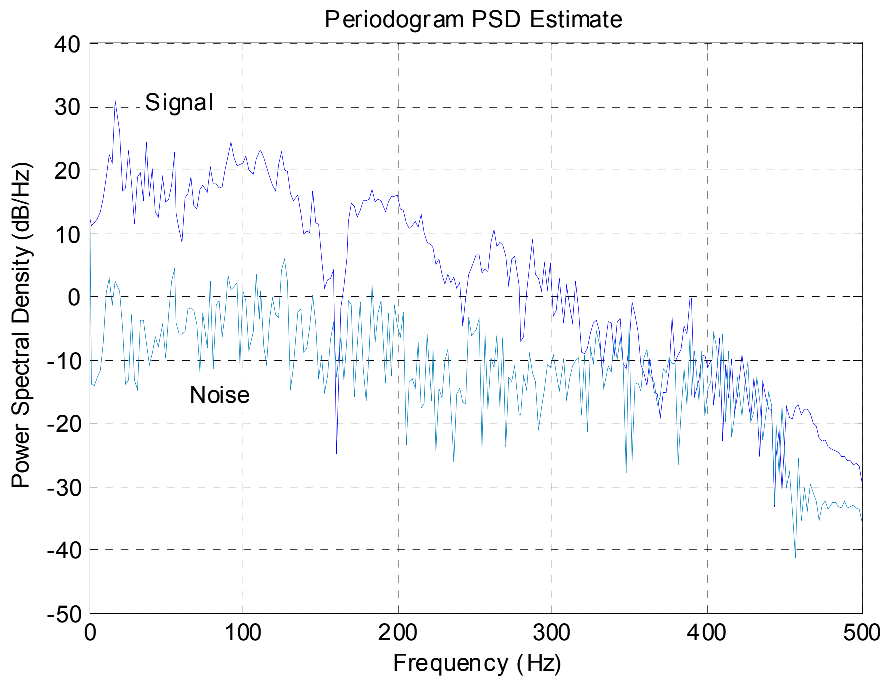

Figure 14. Power spectral density of decoded annulus pressure while drilling.

Sweeping the cycle rate allows seismic profiling and reflection imaging of formations ahead of the bit using a technique known as swept impact seismic profiling (SISP)[7]. The source-receiver configuration for seismic profiling and look-ahead imaging is shown in Figure 15. The signal received by the geophones is cross-correlated with a pressure pilot signal located on the drillstring to generate a vertical seismic profile corridor stack. Processing takes place in real time using a hardware or software correlator. The processed data can be displayed on the rig floor or transmitted offsite.

[7] Park et al. (1996) "Swept Impact Seismic Technique," *Geophysics*, **61 (6)** pp. 1789-1803.

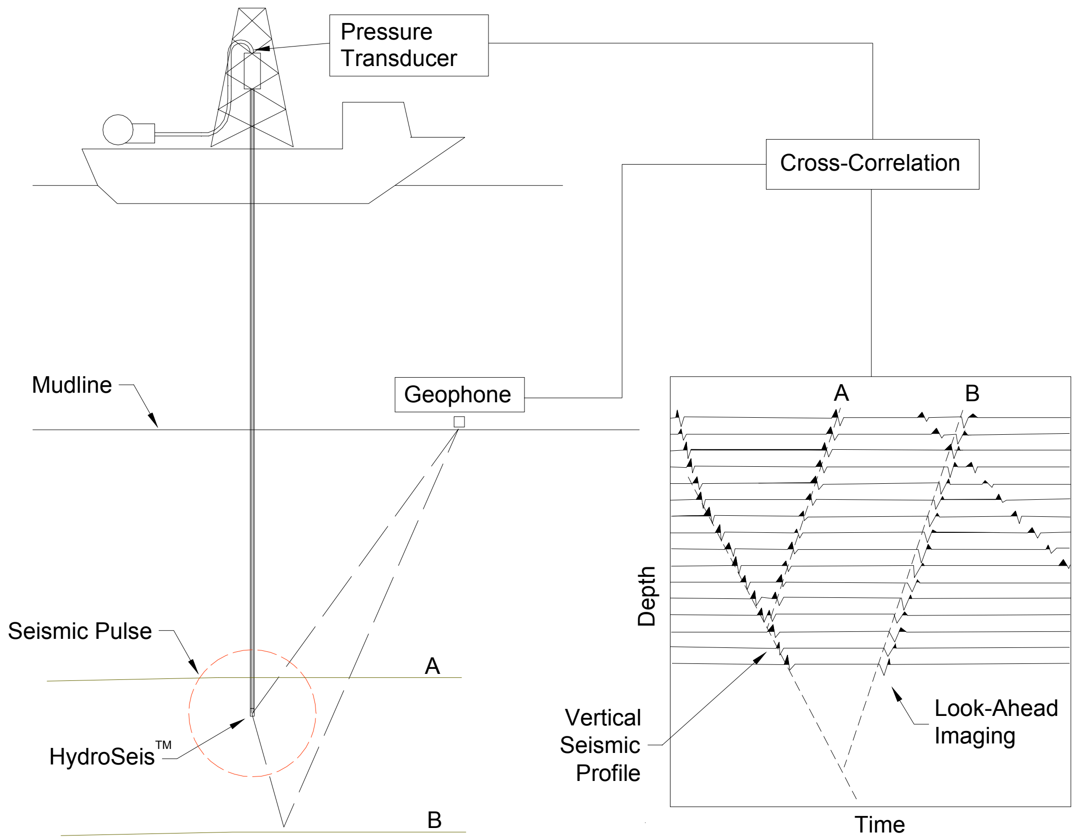

Figure 15. Reverse vertical seismic profiling and look-ahead imaging while drilling.

Seismic profiling tests were carried out at BETA as part of the drilling program. The objectives of this test were:

1. Demonstrate reverse vertical seismic profiling (rVSP) while drilling
2. Demonstrate look-ahead seismic imaging while drilling

The tool was operated while drilling with a PDC bit in a deviated well. Three geophone subarrays were located on surface, roughly inline with the deviated well at radial distances of 460’, 760’ and 1060’ from the drill rig. An example of a cross-correlated seismograph obtained while drilling with a PDC bit at 2200’ true vertical depth is shown in Figure 16. Clear P-wave first arrivals are seen on the two further arrays. Note that the arrivals are tensile waves, consistent with the suction pulse character of the source. The range from the swept impulse tool to the arrays through the earth is approximately equal in this example so the P-wave arrivals are simultaneous. The pilot signal propagates as a pipe wave in the mud, which arrives after the P-waves. A substantial ground roll is also seen propagating across the array. The ground roll originates from rig motions excited by the hydraulic pulse tool and interferes with the P-wave arrival on the closest array. This data represents the first demonstration of seismic profiling-while drilling with a PDC bit and the first demonstration of reverse vertical seismic profiling while drilling in a deviated well.

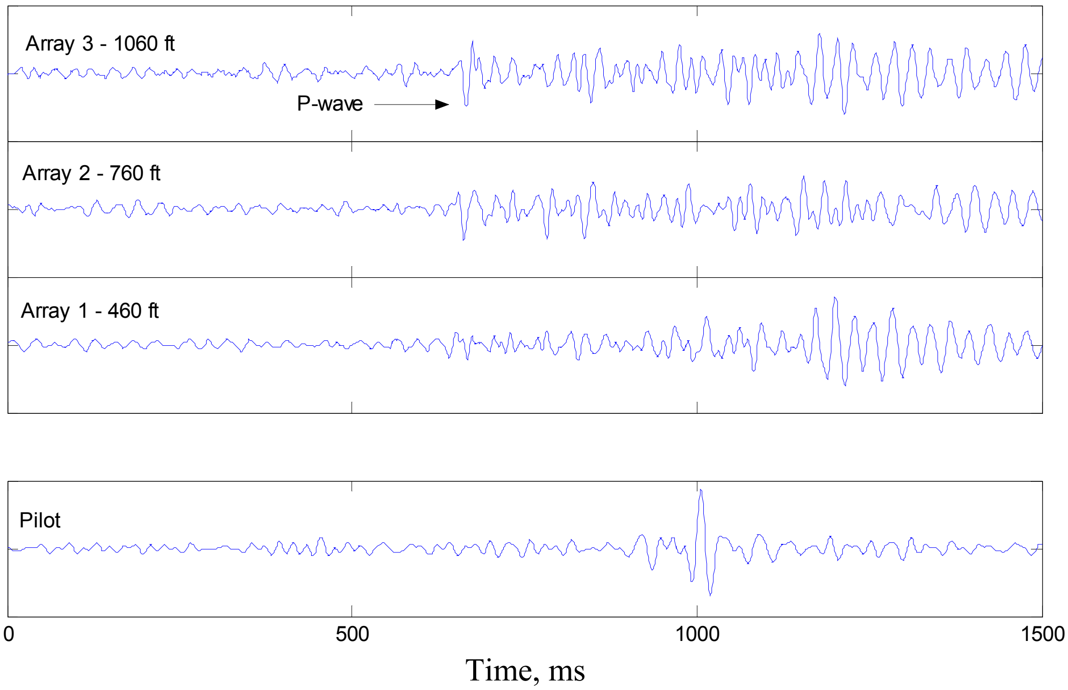

Figure 16. Seismic while drilling example with pressure pilot, TVD=2200'.

Seismic velocities were obtained at two depths during the BETA test. These are compared with a wireline vertical seismic profile obtained in an offset well at the BETA site in Figure 17. The seismic-while drilling velocities agree with the wireline data within 5%.

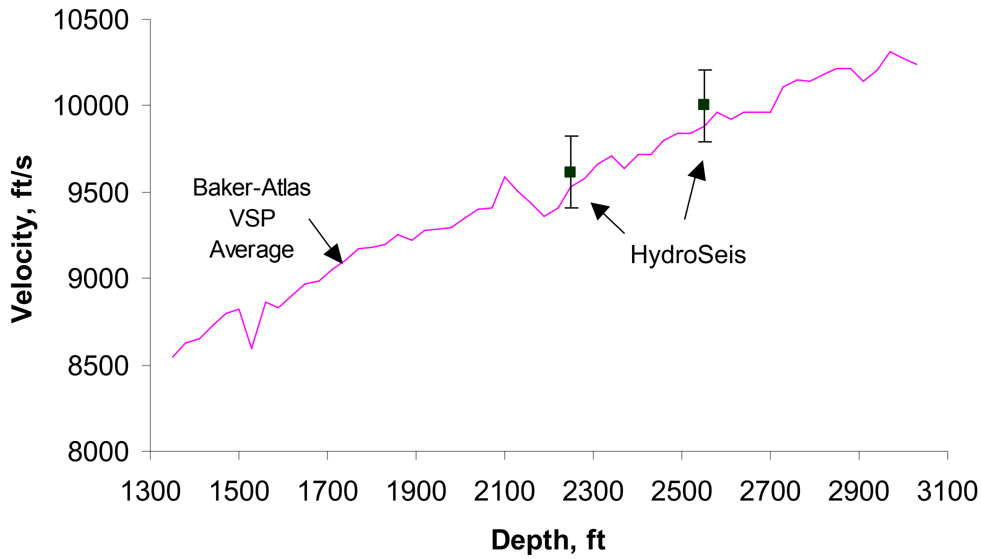

Figure 17. Comparison of swept impulse (HydroSeis) checkshot data with offset VSP.

Results and Discussion

HydroPulse™

Pressure drilling tests have confirmed that the HydroPulse™ tool provides 50% to 200% increases in rate of penetration in shale while drilling with heavy mud in a high-pressure test stand. The effects on penetration rate increase with flow rate and pulse amplitude. The rate of penetration in hard sandstone was 33% higher than offset drilling rates without the tool even though the hydraulic power level was half that of baseline drilling tests. In BETA testing the hydraulic pulses reduced stick slip of a roller cone bit while drilling in a shallow, deviated well. The weight on bit required to stall a PDC bit was increased 60% by the hydraulic pulses. Drilling with a thruster assembly to decouple the BHA from the drill collars should further enhance hard rock penetration performance. In summary the benefits of the tool are:

- 33% to 200% increased rate of penetration in deep formations
- Best performance at low bit weight for straight hole drilling
- Reduced improper bit motions providing longer bit life
- Bit hydraulic power requirement reduced 50%

Tool features include:

- Conventional rotary or motor drilling operations
- Conventional roller cone or PDC bits
- Oil or water-based mud
- High-pressure, high temperature operations
- Over 50 hours operation on weighted mud
- Circulation is always maintained
- Low operating differential pressure
- LCM compatible

A business case analysis for this tool is provided here in Appendix A.

HydroSeis™

A seismic version of the tool was used to demonstrate seismic-while-drilling with a PDC bit in an inclined well. The seismic version of the tool generated a strong seismic signal that is easily identified at surface. The tests demonstrated the capability for vertical seismic profiling while drilling with a PDC bit using the swept impulse source. The continuous source allows long-term stacking to generate high-resolution images. Coherent reflections from formations ahead of the source confirm that look-ahead imaging is possible using this technique with a surface detection array. HydroSeis™ benefits include:

- True real-time seismic while drilling
- Reverse vertical seismic profiling for depth correction
- Pore-pressure ramp detection
- High-resolution look-ahead imaging while drilling
- Independent compression and shear wave source
- Early warning gas kick detection

- Vertical or inclined wellbore
- Crosswell surveys

The HydroSeis™ tool features are common to the HydroPulse™ tool including conventional drilling operations in high-temperature, high-pressure environment. A business case analysis for this version of the tool is provided here in Appendix B.

Conclusion

In conclusion tests have shown that the HydroPulse™ tool provides (1) 33% to 200% increased rate of penetration in pressure drilling tests, (2) best performance at low bit weight for straight hole drilling and (3) reduced improper bit motions providing longer bit life. Tool features include (1) conventional rotary or motor drilling operations, (2) conventional roller cone or PDC bits. (3) oil or water-based mud, (4) high-pressure, high temperature operations, (5) over 50 hours demonstrated operation on weighted mud, (6) circulation is always maintained, (7) low operating differential pressure – low hydraulic power requirement and (8) compatibility with lost circulation material.

The HydroSeis™ configuration of the tool, incorporating a sweep modulator, has been used to demonstrate seismic profiling and look-ahead seismic imaging-while drilling. HydroSeis™ benefits include (1) real-time reverse vertical seismic profiling while drilling, (2) high-resolution look-ahead imaging while drilling, (3) independent compression and shear wave source, (4) early warning of gas kicks and (5) operations in vertical or inclined wellbores.

Business case analyses indicate that there are significant opportunities for commercializing both tools. The primary market opportunities are in the Gulf of Mexico and in deep onshore wells.

Acknowledgments

This work was supported by the U.S. Department of Energy through a cooperative development agreement with the No. DE-FC26-FT34367 and a Small Business Innovative Research Grant DE-FG03-ER83111. Test support services were provided by the Baker-Hughes Experimental Test Area operated by Hughes-Christensen with additional support from Baker-Inteq and Baker Atlas.

Appendix A: HydroPulse™ Business Case

Over 55,000 wells amounting to 239 million feet of borehole were drilled in the United States and Canada in 2001. The cost of drilling and completing these wells was over $50B[8]. Two drilling markets are considered – deep Gulf Coast and deep onshore wells. Additional markets may be addressed by the tool.

U.S. Gulf Coast Market

Approximately 20% of the cost of drilling deep (>10,000') wells can be attributed to the time spent in deep over-pressurized sections[9]. Drilling penetration rates in shale sections with weighted (>13 ppg) water-based mud is slowed substantially by bit balling and other effects of wellbore pressure on rock strength. Shale amounts to around 80% of the formations drilled and for all of the slow drilling where rate of penetration can fall to under 10 ft/hr. The use of oil-based mud can double penetration rates in these formations but is limited by environmental restrictions and high cost.

There are about 100 shallow water rigs operating in the US Gulf coast area with a day rate of around $50K/day with an annual market size of $1.8B/year. About half of these wells target formations deeper than 10,000'. We assume that 20% of these costs is attributed to deep drilling – giving a market of $180M/year A cost benefit analysis for the HydroPulse™ tool in a deep well is provided in Table 2. Assuming a 100 to 200% increase in penetration rate, the cost savings would amount to $100K to $425K in rig time for each tool run. Assuming a performance based tool-rental service[10] where the savings are split between the service company and operator, revenue would be $50K to $212K per HydroPulse™ run.

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[8] Petzet, A. (2002) U.S. Drilling to drop from 15 year high, smaller decline expected in Canada," *Oil and Gas Journal*, Jan 28, p 86.

[9] Smith, J.R. (2000) "Performance analysis of deep PDC bit runs in water-based muds" *TCE2000/DRILL-10123*, Presented at ASME Energy Technology Conference and Exhibition, New Orleans.

[10] Vargas et al. (2001) "Straight-hole drilling device improves performance in tectonically active region," Oil and Gas J., June 25.

Table 2. HydroPulse™ cost/benefit analysis for GOM interval from 10,000 to 15,000 ft. Assumes $50K day rate – $2083/hr.

	Conventional	HydroPulse™			
ROP improvement	-	100%		200%	
Penetration Rate, ft/hr	10	20		30	
Drilling hours	500	250		167	
Drilling cost, $M	$1.0M	$500K		$300K	
Bit/Tool life, hours	100	50	100	50	100
Trips (24 hrs)	5	5	3	4	2
Trip cost	$250K	$250K	$150K	$200K	$100K
Total cost	$1.25M	$750K	$650K	$500K	$400K
Savings	-	$500K	$600K	$750K	$850K
Savings per run		$100K	$200K	$188K	$425K

Deep Continental Drilling

In 1999, 7% of US gas production came from deep (over 16000 ft) onshore wells, this is expected to double by 2010[11]. Deep well costs average over $25M with more than half of this cost accruing in the last 10% of the well because of drilling rates averaging 2 to 4 feet per hour. Deeper wells require a year to complete with up to 200 days spent drilling. Technologies for increasing rate of penetration and drilling accuracy would substantially affect the economics of deep gas production. There are about 250 rigs capable of deep drilling with drilling costs of $80,000 per day. Trip time becomes an important factor in the economics of deep hard-rock drilling. When the HydroPulse™ tool wears out, normal bit circulation is re-established and drilling can proceed until the bit wears out. A cost/benefit analysis for a HydroPulse™ tool run in hard interval from 15,000 to 20,000 foot well is provided in Table 3. The analysis assumes an average trip time of 35 hours. The effect of a 50% and 100% improvement in rate of penetration is evaluated. The effect of increasing tool operating time over 50 hours is also shown. The analysis shows that the tool will generate substantial cost savings assuming at least 50% increase in rate of penetration.

[11] DeepTrek Workshop, March 20-21, 2001, sponsored by National Energy Technology Laboratory and Sandia National Laboratory, proceedings available at www.netl.doe.gov.

Table 3. HydroPulse™ cost/benefit analysis for 5000 ft interval from 15,000 to 20,000 ft. Rig rate =$80K/day

	Conventional	HydroPulse™			
ROP improvement	-	50%		100%	
Penetration Rate, ft/hr	3	4.5		6	
Drilling hours	1667	1111		833	
Drilling cost, $M	$5.6M	$3.7M		$2.8M	
Bit/Tool life, hours	100	50	100	50	100
Trips (35 hrs)	17	22	11	17	9
Trip cost	$2.0M	$2.6M	$1.3M	$2.0M	$1.0M
Total cost	$7.6M	$6.3M	$5.0M	$4.8M	$3.8M
Savings	-	$1.3M	$2.6M	$2.8M	$3.8M
Savings per run		$60K	$236K	$165K	$422K

There are about 200 deep wells drilled every year giving a market of $5B/year. The value of a 50% reduction (100% rate of penetration improvement) in drilling time in the deep sections of these wells would be $500M/year. The potential service company revenue in this market would amount to $250M/year.

Appendix B: HydroSeis™ Business Case

The low margin between fracture gradient and mud density when drilling with a marine riser in deep water results in a conservative approach to casing and liner placement. The broad application of swept impulse seismic will represent a "step change" in deep water drilling cost by allowing more accurate casing point selection and by reducing the risk of drilling geopressurized formations. Drilling success rates in deep (>16,000 ft) onshore wells are under 20%. The size of the producing zone is typically small. The uncertainty of seismic profiles is 15% or more, which leads to large depth errors in deep wells. Deepwater drilling operations are carried out using drillships and platforms with capital costs now approaching $500M and day rates of $250K to $350K[12]. Deep drilling continues despite the high cost and low success rate, because the wells can be highly productive. Penetration of an unanticipated pressurized formation may lead to loss of well control; a blowout of gas and oil; and, in extreme cases, loss of the rig. Between 1960 and 1996 there were over 30 blowouts per year in Texas, Louisiana and the Gulf of Mexico[13]. The economic costs of an offshore blowout average $50M and can approach $1B.

A reliable seismic-while drilling source would provide the ability to image formations ahead of the bit during deepwater drilling operations. This capability would greatly reduce the risk of blowouts due to gas kicks and formation fracture.

Existing Practices

A study by the Gas Research Institute[14] and Deepstar industry consortium planning documents[15] provide the following criteria for real-time look-ahead pore pressure prediction technology.

- No interruption of conventional drilling operations
- Predict depth to over-pressurized formation top at a range of 300 m (1000 ft) with an accuracy of better than ± 15 m (50 ft)
- Real time pore pressure prediction while drilling, where real time is defined as 1/3rd of the daily drilling rate anticipated to penetrate 300 m (1000 ft). For example if drilling is progressing at 10 m/hr the data should be available in 10 hours.
- Predict formation pressure to within ± 5% of actual baseline velocities as defined by a checkshot/VSP or sonic log.

Existing practices for predicting pore pressure and seismic depth correction include pre-drill seismic interpretation, drill-bit seismic-while-drilling and wireline vertical seismic profiling (VSP). The depth uncertainty of pre-drill seismic profiles is 15% or more, which leads to large errors in pressure predictions near the bit Conventional VSP

[12] Von Eberstein, W. (2000) Shell Exploration and Production Company presentation at DeepTrek Planning meeting, Houston.

[13] Skalle, P. and A.L. Podio (1998) "Trends extracted from 1200 Gulf Coast blowouts during 1960-1996," World Oil, June, pp. 67-72.

[14] Hand et al., (1999) Look-Ahead Prediction of Pore Pressure While Drilling: Assessment of Existing and Promising Technologies, *GRI-99/0042*, Final Report prepared for the Gas Research Institute, Chicago.

[15] J. Bruton and M. Czerniak (2001) "Seismic while drilling to improve pore pressure prediction ahead of the bit, Deepstar Project 5501 Data Sheet.

checkshot surveys are run on wireline, which interrupts drilling operations. On deepwater offshore rigs, the rig time costs are high and failure of the wireline may disable the BOP causing a loss of well control. In any event, checkshot surveys do not provide real-time information on pore pressure or horizons ahead of the bit.

The seismicVISION™ service offered by Schlumberger[16] provides seismic receivers located near the bit. A seismic source is activated at surface during pipe connections, when there is a lull in drilling. The seismic data is stored in memory and processed when the tool returns to surface to generate a VSP corridor stack for seismic depth correction. Schlumberger claims that the tool provides a look-ahead imaging, however the range and accuracy of this capability are not known. Mud pulse telemetry of processed velocity is planned but not presently commercial.

None of the existing practices provide formation pressures ahead of the drill bit with the accuracy and reliability required by offshore operators.

HydroSeis™ Reverse Vertical Seismic Profiling

The swept impulse seismic source generates broadband, high-intensity shear and compression waves that can be used for seismic profiling and look-ahead imaging while drilling. The combined compression and shear wave data can be used to predict pore pressure ahead of the bit. Tests have demonstrated prediction of depth to over-pressurized formation top at a range of 1000 ft with an accuracy of better than ± 50 ft. Velocity prediction accuracy is comparable to checkshot/VSP or sonic log and the information is available in real time. The tool provides shear wave energy that can be used to substantially improve pore pressure prediction accuracy relative to VSP. The tool can be used with no interruption of conventional drilling operations, with any bit type in any well geometry.

The HydroSeis™ service would compete directly with seismicVision™[17]. A comparison of the two approaches is provided in Table 4. The primary advantage is the ability to generate and display a VSP corridor stack in real-time while drilling. The tool could also be used in conjunction with a downhole receiver for high-resolution imaging ahead of the bit.

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[16] Armstrong, P. and A. Hawthorn (2004) "Real-time seismic now available from an LWD tool," *Drilling Contractor* , March.April, 41-42.
[17] seismicVISION™ is a trademark of Schlumberger

Table 4. Comparison of HydroPulse™ and seismicVISION™.

Feature	HydroSeis™	seismicVISION™
Real time	Yes real-time rig floor VSP corridor stack display	Limited time data (mud-pulse telemetry is planned)
Resolution	15-m	unknown
Shear Wave	Yes – high-shear energy	No
Temperature	200° C	150° C max
Pressure	No limit	25000 psi
Operations	Continuous	During drilling connections
Source	Broadband-on bottom	Airgun

Market

The cost savings of checkshot data are associated with improved well accuracy, reduced casing uncertainty and reduced risk of fluid loss or gas kick by enhanced mud weight management. The cost of drill bit seismic-while-drilling services on a shallow offshore well in 1997 was $75K to $100K for a two or three month well[18]. Well savings in this study resulted primarily from elimination of casing and liners and ranged from $500K to $3M. The technique would compete with conventional VSP checkshot surveys that cost $10K for the service[19] plus rig costs for a trip and time to run the wireline survey. On an offshore rig, the time required for a trip and wireline run can easily amount to over $500K. In a deep well a survey may be repeated five times. There are about 100 deepwater GOM wells[20] and 200 deep onshore wells in the U.S. annually. Conservatively assuming cost savings of $1M per well, the service market would amount to $300M/year.

[18] M. Jackson and C. Einchcomb (1997) "Seismic while drilling: Operational experiences in Viet Nam," *World Oil*, March, pp. 50-53.
[19] J. Rector (2001) personal communication.
[20] Baud, R.D. et al (2000) "Deepwater Gulf of Mexico: America's emerging frontier," *MMS 200-022*, U.S. Department of the Interior, Minerals Management Service, New Orleans, Louisiana.