Jet TurboDrill™ for Enhanced Geothermal System Development

Summary

The development of engineered geothermal systems (EGS) has been limited by poor control of the hydraulic conductivity between injection and production wells. The hydraulic fracture technique used to complete these wells either short-circuits the flow or provides low conductivity. Hydraulic fracturing also generates earthquakes that may be unacceptable to the public. The development of multilateral drilling techniques for hard rock would provide an attractive alternative to hydraulic fracturing by providing a distributed flow network that intersects existing fractures or allows stimulation with much smaller hydraulic fractures. Multilateral drilling in hard rock at high temperature requires new drilling tools.

Tempress has developed an ultra-high-rotary-speed high-pressure jet-assisted turbodrill for milling and drilling on coiled tubing. Ultra-high-rotary speed operation allows drilling at low thrust and torque loads. Low thrust and torque allows easy well exits and steering in sliding (non-rotating) mode and operation with lightweight, drillstrings or coiled tubing to reduce cost. The Jet TurboDrill™ is designed to operate at high-temperature for geothermal or other hot well applications. The turbine can also operate on commingled flow, nitrogen or carbon dioxide for underbalanced operations.

A Phase I feasibility project included the development and testing of an engineering prototype turbine motor and several jet-assisted drill bits for geothermal applications. The work included the development of bearings and seals that allow high-pressure turbine operation at ultra-high rotary speed. The engineering prototype tool was used to drill samples of granite basalt and cement. Tests with a jet assisted PDC bit met the project objectives for rate of penetration and specific energy of drilling. Although the estimated PDC cutter life in crystalline rock was below the objective of 250 m, thermally-stabilized diamond cutters and a low vibration bit design will extend cutter life.

The drilling tests have demonstrated that an ultra-high-rotary speed, jet assisted turbodrill is capable of providing high speed drilling in granite at low weight and torque. The primary unresolved issue is whether jet-assist will provide sufficient cutter life in hard crystalline rock.

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Introduction

The U.S. geothermal energy resource available from the earth's heat flow is enormous with the potential to provide renewable electrical power generation energy for centuries[1]. Existing geothermal energy production relies on hydrothermal sources that are limited in availability and currently represent a small fraction of U.S electrical power generation capacity. The recovery of geothermal energy on a large scale is possible though the development of enhanced geothermal systems (EGS) that do not require a naturally hydrothermal system. This development will require new technology to reduce the high cost and high risk currently associated with geothermal energy exploration.

EGS development involves several stages:

1. An injection well is drilled into the high temperature formation – typically hard crystalline rock at a depth of 3000 m or more.
2. High-pressure fluid (water or carbon dioxide) is pumped into the well to fracture the formation.
3. One or more production wells are drilled into the fractured rock.
4. Cold fluid is pumped into the injector, through the fractures and up the production wells as steam or hot fluid for power production.

Attempts to demonstrate the EGS concept have been unsuccessful because of the difficulty in producing the appropriate circulation of the heat transfer fluid between the two wells[2]. Either (1) the circulation of fluid between the two wells is too low for effective heat transfer or (2) the circulation is too high, which also prevents effective heat transfer. Getting the circulation just right is critical for effective power generation but this turns out to be extremely difficult, and may be effectively impossible, because the results of hydraulic fracturing are wildly unpredictable. A further difficulty is that hydraulic fracturing causes earthquakes that may be unacceptable to the community[3].

Drilling a root-like network of multilateral wells, as shown in Figure 1, provides an attractive alternative to hydraulic fracturing. A network of laterals would distribute the flow to ensure good heat transfer. The laterals could be fractured in stages (at much lower flow rates than a conventional hydraulic fracture) to connect the two wells in a highly distributed flow network. Staged fracturing of small multiple laterals would release less seismic energy and reduce the chance of damaging earthquakes.

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[1] Tester, et al. (2006) *The Future of Geothermal Energy; Impact of Enhanced Geothermal systems on the United States in the 21st Century,* Massachusetts Institute of Technology, Cambridge Massachusetts.

[2] Taylor, M.A. (2007) The State of Geothermal Technology Part 1: Subsurface Technology, Geothermal Energy Association, Washington D.C., www.geo-energy.org.

[3] Glanz, J (2009) "In bedrock, clean energy and quake fears," New Yorl Times, June 24.

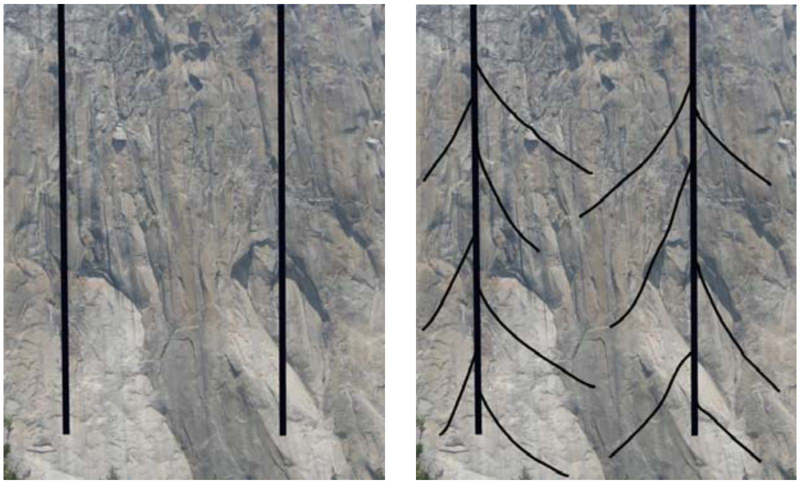

Figure 1. EGS injector/producer pair (left) with multilateral network (right)

Multilateral Productivity

The radial flow into a wellbore from a cylindrical volume with constant pressure on the outer radius is inversely proportional to the logarithm of the wellbore diameter[4]. The weight and power requirements for drilling a unit length of borehole increase in proportion to the cross sectional area of the hole or as the square of the hole diameter. Drilling costs are proportional to weight and power and also increase as the square of the hole diameter. The wellbore conductivity production rate is a weak function of the wellbore diameter while costs rise as the square of the diameter. The drilling cost per unit of hydraulic conductivity – the cost factor – is proportional to $d_w^2\ln(1/d_w)$, where d_w is the drainage hole diameter. The cost factor relationship is shown in Figure 2. A distributed network of small diameter well completions is much more efficient for enhancing well conductivity gathering than a single large completion well. A similar principle is at work in tree root networks – multiple small roots are more efficient than a single root.

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[4] Lyons, W.C. (1996) *Standard Handbook of Petroleum and Natural Gas Engineering Volume II*, Gulf Publishing, Houston.

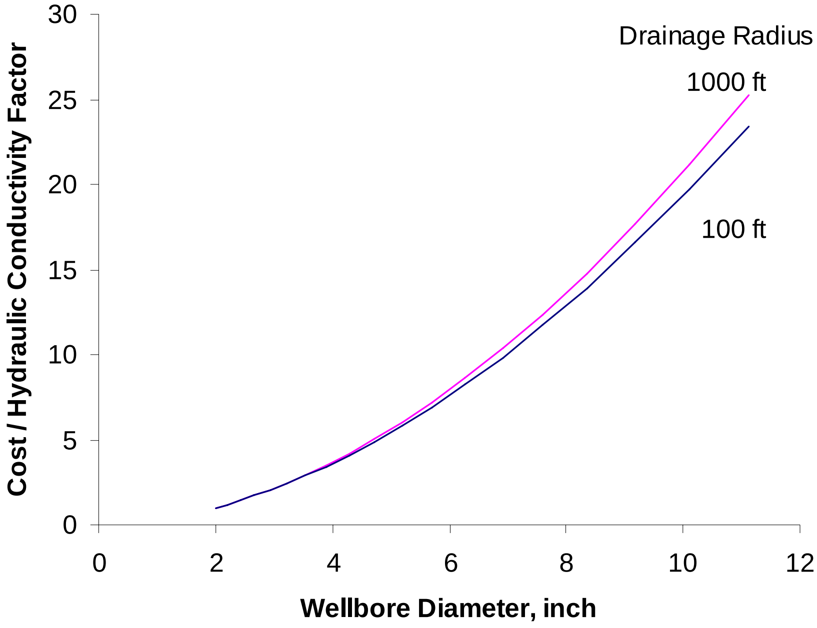

Figure 2. Cost factor as a function of well diameter.

Advanced Resources International (ARI) evaluated costs and performance of a variety of stimulation case histories for marginal gas fields and gas storage wells[5]. The baseline for comparison of the methods is infill drilling, which results in a 100% increase in deliverability for a new well (Table 1). Horizontal directional drilling provided increased deliverability at 37% of the cost of infill drilling. Drilling multiple laterals without active steering would greatly reduce the cost of this approach. Hydraulic fracturing offered the same increase at only 5% of the cost of infill drilling and has become the method of choice for gas well stimulation. Significant problems are now being found with gas leakage, aquifer contamination and water disposal associated with hydraulic fracturing and new environmental regulations may limit this practice.

Table 1. Cost and performance of well stimulation techniques (1999 data).

Method	Cost $000	Deliverability Increase	Cost Factor
Horizontal Drilling	435	400%	37 %
Fracturing	27.5	175%	5%
Infill Drilling	294	100%	100%

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[5] Reeves, S. (1999) "Advanced fracturing technologies for marginal oil and gas wells," Proceedings 1999 DOE Oil and Gas Conference, June 28-30, Dallas. http://www.fetc.doe.gov/publications/.

Drilling multilateral well extensions has become accepted practice in oil drilling but the drilling motors and bits used are not suited for hard rock drilling. Short motors and low bit weight are needed to exit the wellbore and drill the highly deviated laterals. Conventional motors and bits require high bit weight and torque to drill hard rock. Multilateral drilling requires the ability to exit from an existing well at a number of locations without plugging the primary wellbore. This is accomplished in sedimentary rock using openhole packers and whipstocks. Conventional drill motors are not capable of sidetracking from a whipstock in openhole hard rock. The positive displacement motors (PDMs) commonly used for directional drilling incorporate elastomers that break down at high temperature.

Jet TurboDrill™

Tempress has demonstrated an ultra-high-rotary-speed jet-assisted turbodrill (Figure 3) designed to drill hard rock at low thrust load and torque[6]. This tool drills granite and basalt with low WOB at high rates of penetration. The tool is capable of sidetracking[7] in hard formations at low weight on bit and torque as shown in Figure 4.

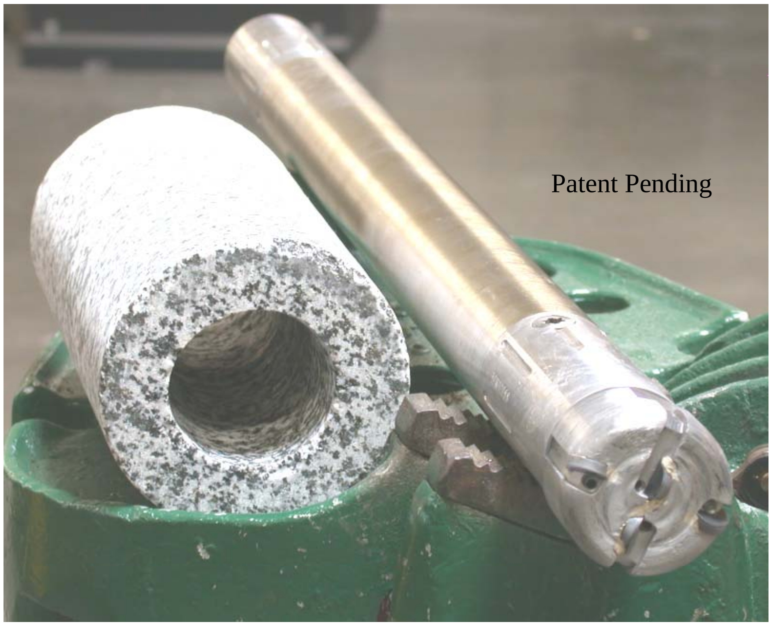

Figure 3. Tempress Jet TurboDrill™ with jet-assisted PDC bit.

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[6] TR-149 Jet Turbodrill, Phase I Final Report, Tempress.

[7] A video of the sidetracking capability can be viewed at http://www.tempresstech.com/book_shelf/32.wmv

Figure 4. Sidetracks in granite (left) and andesite (right).

Orientation and Steering

The proposed technique will require orienting, sidetracking and drilling of laterals from a large diameter primary geothermal wellbore. The most straightforward approach is to deploy a whipstock and openhole anchor on a secondary liner as shown in Figure 5. The liner provides increased velocity for cuttings transport to surface. The whipstock azimuth can be oriented using a thermally insulated tool deployed by sandline or wireline tools to reduce the thermal exposure time on the electronics.

The Jet TurboDrill™ would be deployed on small diameter drillstring (e.g. 2” or 2-3/8” for 3-1/2” hole) to provide the flexibility required to enter the lateral. Drilling of short (100-m) laterals would proceed with no further steering. The Jet Turbodrill would be configured with a bent housing that aligns with the whipstock using a muleshoe and swivel. Sidetracking and curve drilling would occur in sliding mode. The low bit weight and torque associated with jet-assisted drilling allow accurate curve prediction. Once the predicted curve is drilled, the lateral could be extended straight ahead by rotating the drillstring.

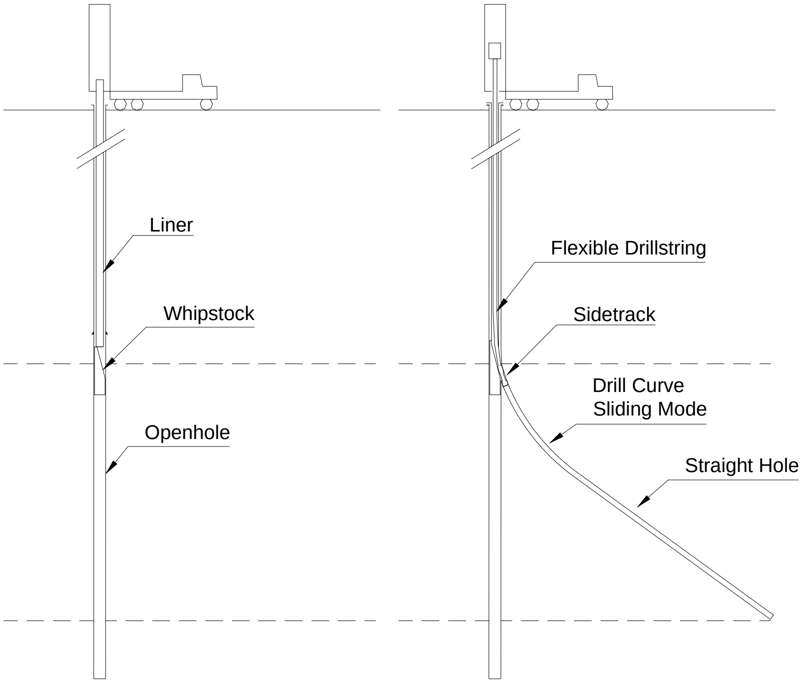

Figure 5. Multilateral drilling approach.

Jet-Assisted, Ultra-High Rotary Speed Drilling

The Tempress Jet TurboDrill™ is designed to couple the advantages of ultra-high rotary speed with jet assist to cool cutters and prevent wear. The basic phenomena associated with drag bit cutting and the benefits of jet-assisted drilling and high-speed cutting are compared in Figure 6. PDC drag bits are commonly used to drill relatively soft, non-abrasive formations. In hard rock, the polycrystalline diamond wears rapidly. Jet assist can reduce PDC cutter wear rates by reducing friction and improving heat transfer at the rock/cutter interface[8].

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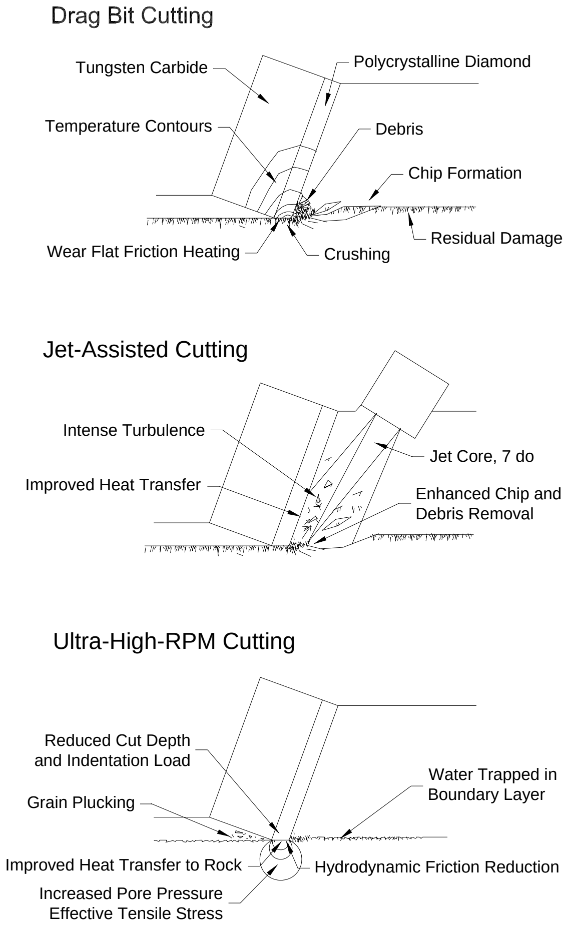
[8] Glowka, D.A. (1995) “Advanced synthetic diamond and waterjet enhanced drill bits,” *NADET Geothermal Workshop*, Reno Nevada.



Drag Bit Cutting

Jet-Assisted Cutting

Ultra-High-RPM Cutting

Figure 6. Comparison of PDC drag bit cutting phenomenon with jet assist and at ultra-high-rpm.

The Jet TurboDrill™ is designed to operate at higher differential pressure through the turbine and higher jet pressure and higher rotary speed than a conventional turbine. The tool incorporates pressure and thrust balanced mechanical seals that allow high-pressure operation at high rotary speed. The motor idles at relatively low rotary speed until weight on bit is applied. Applying weight redirects the flow though the turbine generating high speed and high torque. Specifications for the prototype motor are provided in Table 2.

Table 2. Engineering prototype jet turbodrill, nominal specifications at drilling test flow conditions.

Turbine Diameter	43 mm	1.69”
Turbine Length (including bit)	635 mm	25.0”
Bit Diameter Bit Face Area	48 mm .0018 m^2	1.9”
Flow Rate	114 lpm	30 gpm
Pressure Differential	41 MPa	6000 psi
Turbine pressure Differential	7 MPa	1000 psi
Jet Pressure Differential	34 MPa	5000 psi
Hydraulic Power	60 kW	80 hhp
Observed Stall Torque	15 N-m	11 ft-lbf
Observed Runaway speed (no bypass)	14,000 rpm	
Maximum Mechanical Power	4.4 kW	5.9 shp
Mechanical Power Density	2.4 MW/m^2	
Drilling Specific Energy Objective; Granite **Observed**	2000 MJ/m^3 **1300 MJ/m3**	
Rate of Penetration Objective; Granite **Observed**	5 m/hr **5 m/hr**	15 ft/hr **16 ft/hr**

The observed rotary speed, stall torque and pressure differential though the turbine are shown in Figure 7 and Figure 8. The motor power curve is shown in Figure 9. At 150 lpm the mechanical power output is comparable to a PDM motor of the same size. The motor is also capable of operating with high pressure differential though the jets on the bit. The bit pressure differential is determined by the size of the bit nozzle ports.

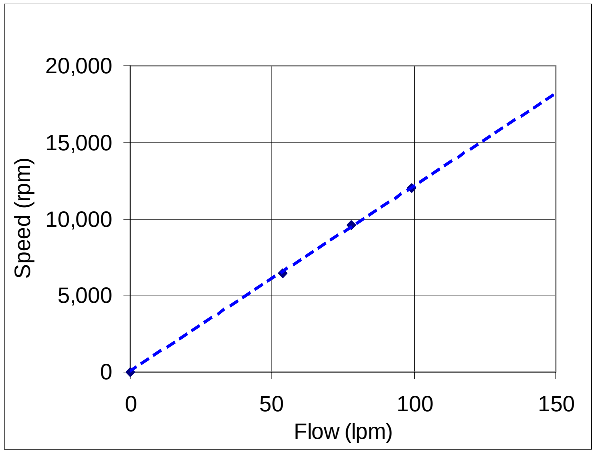


Figure 7. Jet turbodrill runaway speed (bypass closed)

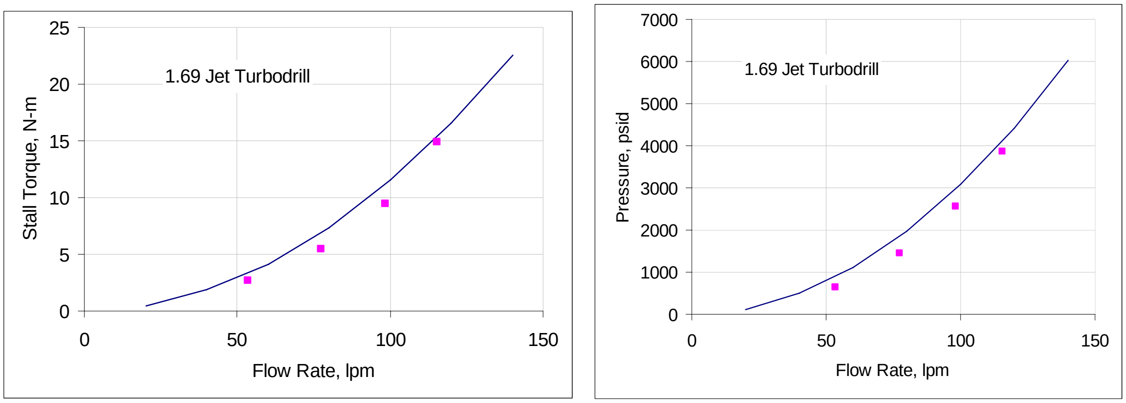


Figure 8. Prototype 43-mm (1.69”), 20-stage turbine stall torque and pressure modeled (line) and observed data points (■).

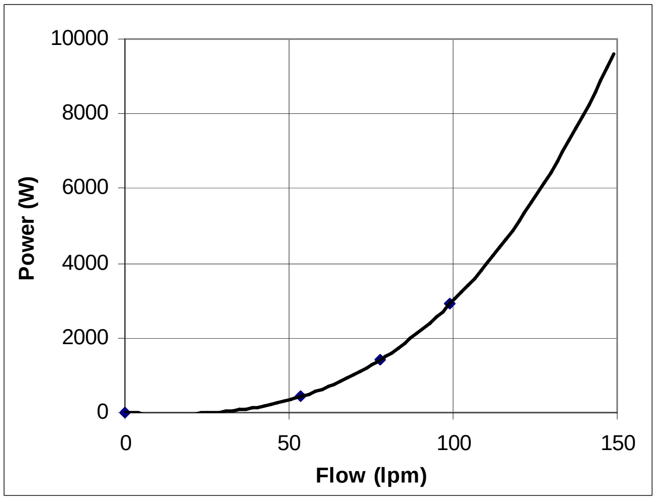


Figure 9. Mechanical power output

Prototype Jet-Assisted PDC Bit

A prototype jet assisted PDC (JA-PDC) bit is shown in Figure 10 along with a bottomhole pattern in granite. The bit incorporates four PDC cutters brazed to a steel body. A jet is directed across the face of each cutter to cool the cutter and flush cuttings.

Figure 10. Jet-assisted PDC bit and bottom hole pattern in granite.

Jet-assisted drilling tests were carried out in the pressurized jetting tool test stand shown in Figure 11. This test stand allows jetting tests at ambient pressures of up to 2200 psi with jet differential pressure up to 20,000 psi. Elevated pressure testing is required while testing the performance of jetting tools to suppress cavitation shrouding of the jets. Jets discharged into a submerged fluid at high enough pressure to suppress cavitation will dissipate rapidly, so elevated ambient pressure is required to accurately test jetting performance downhole.

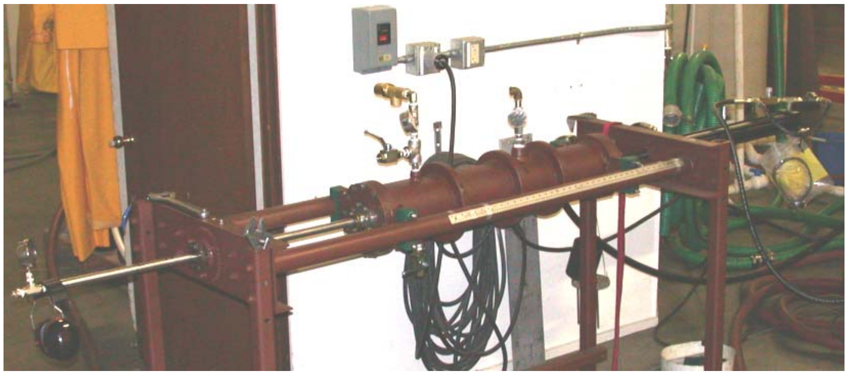


Figure 11. Tempress pressurized jetting tool test stand.

The prototype JA-PDC bit was used to drill 6” long cores of granite and basalt at 130 lpm. The rate of penetration in granite was observed as a function of WOB at 6000 psid as shown in Figure 12. This bit was configured to provide relatively high jet differential pressure (5000 psid) and low turbine differential pressure (1000 psid). The rate of penetration data are fitted to a quadratic curve corresponding to the power output of the turbine. Increasing pressure and flow rate caused an increase in the rate of penetration and stall weight. The peak rate of penetration was 3.2 in/min (16 ft/hr, 4.9 m/hr), which exceeded the objective for this tool. The basalt rate of penetration peaked at 1.2 in/min (6.0 ft/hr, 1.8 m/hr) as shown in Figure 13.

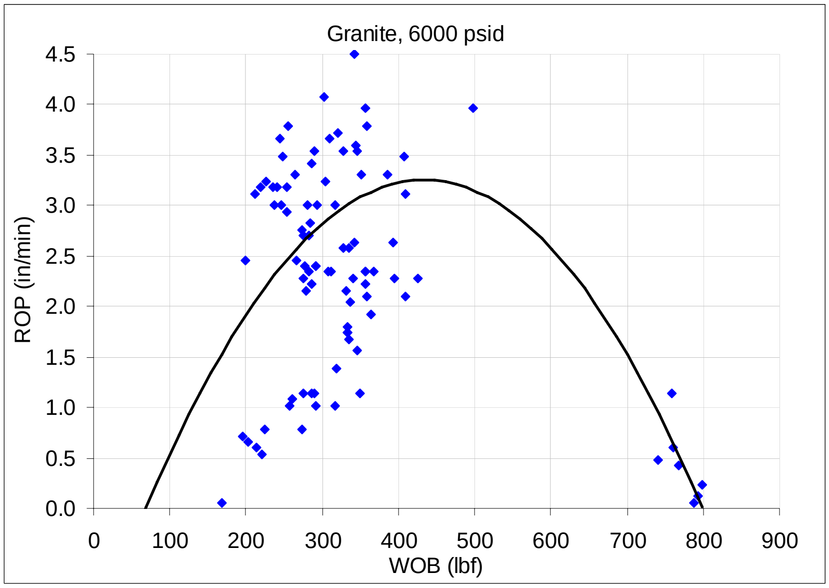


Figure 12. Jet-Assisted PDC bit rate of penetration in granite (3.2 in/min = 16 ft/hr).

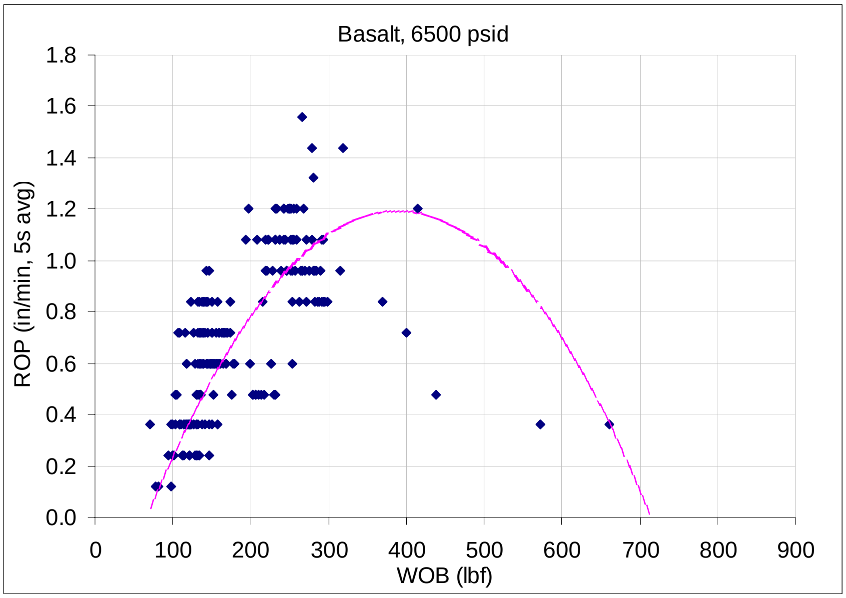


Figure 13. Basalt rate of penetration, jet-assisted PDC bit (1.2 in/min = 6 ft/hr).

Cutter Wear

The PDC cutters developed wear flats after drilling 6” in granite and additional wear after drilling 3” in Basalt. The wear depth on the outer cutters was 0.007” and 0.003” corresponding to the development of a full wear-flat on the PDC table. The innermost cutter was chipped after completing the basalt drilling. The outer diameter of the cutters was unchanged. The 1.898” diameter bit drilled a 2.0” diameter hole. This 4-cutter bit design is not well load balanced and the bit and turbine vibrated while drilling. The bit appeared to be rotating off-center, leading to the 0.1” over-gage hole and possibly contributing to the chipping damage to the inner cutter.

Figure 14. Wear flat on gage PDC cutter.

Assuming an average wear flat depth of .005” after 9” of drilling gives a wear rate of 0.007”/f ft. The PDC cutters are .5” in diameter. Assuming linear wear, the wear would worn down by 0.25” or half its diameter after 40 ft. In fact the initial wear rate can be expected to be considerably higher since the cutters were not evenly loaded and were initially sharp. Optimistically, these factors could double the wear life. The bit was also found to be rotating off center, leading to high vibration loads that could accelerate wear.

Improved Cutter Materials

There are several options for improving cutter life. A new generation of PDC cutters has been developed specifically for abrasive formations where cutter wear is dominated by thermal degradation[9]. As shown in Figure 15, these cutters have a face layer of thermally stabilized diamond on top of the PDC. The thermally stabilized cutter has demonstrated an increase in abrasion resistance of a factor of 20 compared to industry standard. Another new cutter material, incorporates a thermally stabilized diamond table over a

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[9] Clayton et al. (2005) “New bit design, cutter technology extend PDC applications to hard rock drilling,” *SPE/IADC 91840*, presented at SPE/IADC drilling Conference, Amsterdam 23-25 February, Society of Petroleum Engineers, Richardson Texas.

softer carbide support matrix[10]. This design is similar to PDC cutters and provides a self-sharpening effect that limits the wear flat width to the thickness of the diamond table. These new cutters are capable of maintaining penetration rate while undergoing substantial wear. Application of these new cutter materials will significantly increase the JA-PDC bit life.

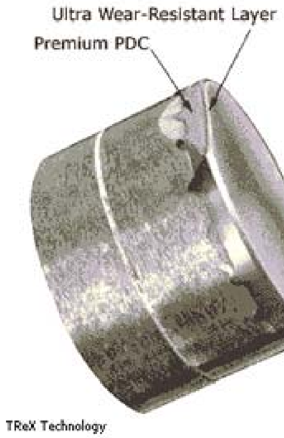

Figure 15. NOV-Reed Hycalog TReX cutter showing thermally stabilized diamond layer on PDC.

Cement Milling

Milling of cement and hard scale is an important commercial application of small drill motors. The jet-assisted PDC bit was used to drill 4-year old neat cement in 2.875" casing. The nozzle ports were opened to maximize turbine mechanical power for this test. Figure 16 shows the drilling parameters as a function of penetration depth for one of the tests. Notice that the drilling rate increased as WOB was reduced and decreased as WOB was increased (3" to 7" interval). Drilling rate averaged 50 ft/hr (15 m/hr) during this interval with a maximum 3-second average of 136 ft/hr (41 m/hr). At about 7" into the sample, the vessel choke screen began plugging with cuttings and the vessel pressure increased. Drilling continued with 550 psig vessel pressure at an average of 22 ft/hr (6.7 m/hr) to the end at 8.8".

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[10] Radtke, R. et al. (2004) "Faster drilling, longer life thermally stable diamond drill bit cutters," *GasTIPS*, Gas Technology Institute, Des Plaines Illinois.

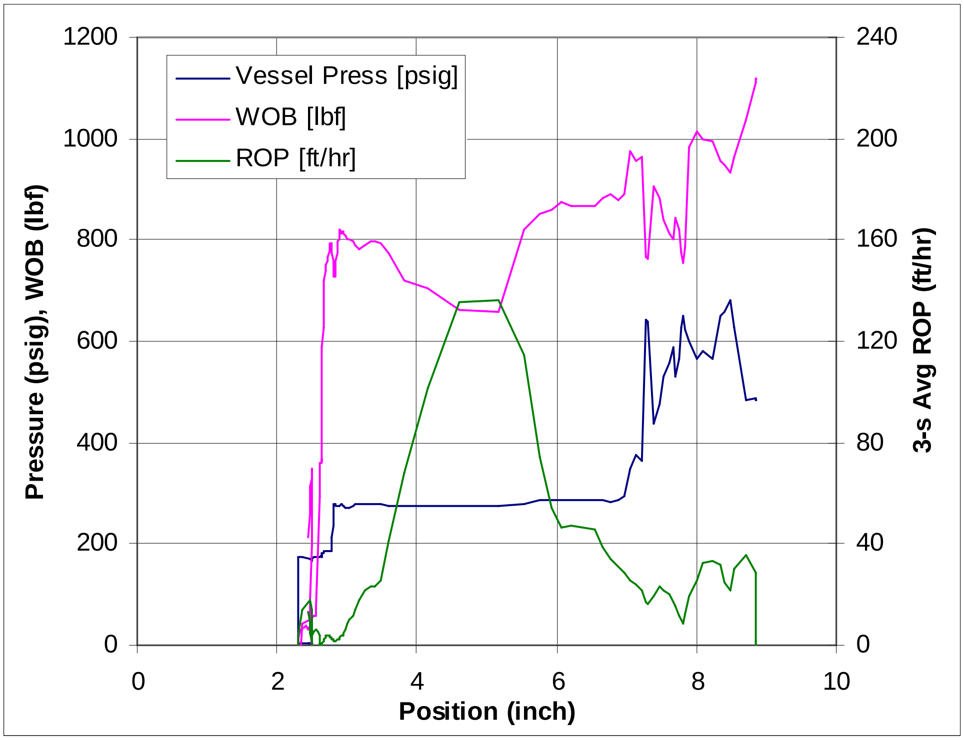

Figure 16. Drilling aged cement with JA-PDC bit

Conclusions and Recommendations

The testing clearly showed that an ultra-high-rotary speed, jet assisted turbodrill is capable of providing high speed drilling in granite and cement with low WOB and torque. The primary unresolved issue is whether jet-assist will provide sufficient cutter life in hard rock. Drilling of multilaterals from EGS wells will require a minimum depth of around 100-m for significant well conductivity.

New bits for granite drilling will incorporate thermally stabilized diamond cutters, which provide significantly better thermal resistance than the PDC cutters used on the prototype bit. These bits will be balanced to reduce vibration and chatter, which should also improve cutter life. The prototype tool incorporated simple drill holes rather than engineered jet nozzles. Jet nozzles will provide significantly better jet erosion and cooling performance. The combination of these factors has the potential to meet the footage objective.