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Author(s):

Donald S. Dreesen, EES-4

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**Final Project Report
DOE NN-20 Microboreholes Project
March 12, 1997**

**Don Dreesen, Principle Investigator
EES-4 GeoEngineering Group
Earth and Environmental Sciences Division
Los Alamos National Laboratory**

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**FINAL PROJECT REPORT
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MARCH 12, 1997**

Don Dreesen, Principle Investigator

EXECUTIVE SUMMARY

Los Alamos National Laboratory (LANL) and its contractors have developed a conceptual design for a directional microborehole drilling system for hard-rock boring. Analytical calculations, simulations, and the results of laboratory testing of critical prototype drilling components have influenced the design. Two reduced-size drilling systems to produce small diameter, 500-ft-long, directionally drilled river crossing trajectories are proposed to prove feasibility of the concept: 1) a 2-1/4-in. diameter, early demonstration unit to drill directional **ultraslimholes**; and 2) a 1-1/8-in. diameter, ultimate design to drill directional **microboreholes**. Both concepts use versatile, coiled-tubing-deployed, hydraulically-powered drilling assemblies, and a surface platform that includes a tubing injector unit to develop high load insertion (snubbing) of the tubing into the sealed borehole. Surface injection will be used to develop the required bit thrust, and both concepts provide for the use of a commercial, real-time, location and steering system that is readily and routinely adapted for deployment on a coiled-tubing drilling platform. The conceptual drilling platform and its subassemblies are shown in **Fig. 1**.

The project team established the major performance challenges as: 1) a target drill rate of 20-ft/hr in granite rock, and 2) a design that will, in time, support a full directional drilling capability. In addition, the project team conducted an investigation of drilling processes, hydraulic power and cuttings transport processes, and coiled-tubing thrust transport performance in a microbore to identify any theoretical limitations for the proposed drilling system. High bit-thrust loads were projected for drilling granite at the target rate, and tubing buckling and friction loading calculations indicated that there might be severe limits on the loads that could be developed by surface snubbing. No downhole bit thrust systems that were identified appeared to be compatible with a coiled-tubing-deployed, hard rock, directional drilling system.

Simulations were run to 1) optimize the bit-thrust performance of a 500-ft-long drill stem in a river crossing trajectory, and to 2) determine if the required bit thrust could be developed from surface injection. Hydraulics simulations were also run to check analytical results that predicted adequate hydraulic power transport for the drilling and for cuttings transport processes.

Rotary bottom-hole drilling assemblies were designed, procured, assembled and tested; penetration rates of up to 20-ft/hr in granite and 280-ft/hr in limestone (**Fig. 2**) were demonstrated with rotary drag bits powered by hydraulic (rotary) positive displacement motors. The bit thrust required to produce these drill rates were within the range of the higher simulated thrust predictions, once the design tubing sizes were

increased by one nominal size for each system. In addition, the increased tubing size improved the calculated hydraulic performance of the systems; however, it also increased the required annular flow rate to a magnitude where erosion of unconsolidated formations could occur when operating the drilling assembly at the high power levels required for granite.

The project team assembled and demonstrated a hydraulically-powered, percussion-rotary drilling assembly at rates of up to 15-ft/hr in granite rock. Compared to the pure rotary drilling assembly it required: 1) lower power, 2) a lower circulating rate, and 3) similar thrust loads. Percussion drilling did not achieve high penetration rates in softer rock. The coiled-tubing drilling platform supports rapid conversion from rotary to percussion-rotary drilling when hard rock is encountered.

The project team developed a concept for a coiled-tubing microdrilling platform, and completed preliminary layout drawings (**Fig. 3**). A preliminary cost estimate for a drilling platform to support the DOE NN-20 interest areas, is \$260K (see **Table 15**). A preliminary cost estimate for a multi-program drilling platform to support various microdrilling research activities, primarily deeper oil field drilling (**Dreesen et al. 1997**) but well suited to support the DOE NN-20 interest areas, is \$750K.

PROPOSAL FOR ADDITIONAL WORK

- 1) A two-year-long project with a \$1000K budget is proposed to conduct a field demonstration of a 2-1/4-in. directional drilling system and refine the design to support drilling in hard rock.
- 2) A concurrent two-year project with a \$ 1000K budget is proposed to develop specifications, solicit industry proposals, fabricate prototype downhole drilling assemblies, and conduct bench testing of a half-scale, 1-1/8-in. diameter microborehole drilling system.
- 3) A one-year-long project with a \$500K budget to conduct a field demonstration of a 1-1/8-in. drilling system would follow item 2) if bench test results were promising.

INTRODUCTION

In December 1995, the DOE NN-20 program funded a proposal to develop a microborehole drilling system. The original proposal intended to develop a conceptual drilling system that used a coiled-tubing deployed drilling system to drill up to 5000-ft-deep vertical holes in soft to medium-hard formations. Once the project was funded, the objectives of the project were modified to meet the requirements of targeted future funding sources for the NN-20 program. These modifications included: 1) the maximum depth was reduced from 5000 ft to 500 ft, 2) the requirement for a 1-in. nominal bore size was removed, 3) the required rock types were expanded to include and focus on granitic rocks, and 4) the vertical straight-hole trajectory was modified to require a full directional drilling capability.

Three sub-contracts were placed to obtain oil field and mining drilling expertise and support services:

- 1) Maurer Engineering Inc. (MEI) was retained to provide technical support for selecting and testing critical downhole components for the drilling system. The Drilling Research Center (DRC), an MEI facility, provided the component testing services.
- 2) Coiled-Tubing Engineering Services (CTES) was retained to provide coiled-tubing performance modeling and conceptual designs, components lists, and cost estimates for an early prototype drilling platform.
- 3) Dr. Michael Y. Gelfgat was retained as a Laboratory Consultant to investigate, select, and recommend appropriate Russian and former Soviet Union (FSU)-manufactured drilling equipment for evaluation. Dr. Gelfgat also coordinated testing of selected Russian equipment at the MEI DRC.

While the subcontracts were being placed, an internal review of drilling technology suitable for microdrilling was undertaken as well as a brief theoretical calculation and analytical modeling effort to identify any limitations on current drilling practices that would preclude successful downsizing of drilling components to the 1-in. nominal size originally proposed.

The statement-of-work for each of the subcontracts was prepared to address specific potential problems identified in both the theoretical investigation and in readily accessible drilling papers, as well as from discussions with vendors and drilling experts. Problems identified in the review included:

- 1) Selection of bits and downhole motors suitable for drilling 1- to 2-in. diameter bores in granitic rock. MEI provided extensive experience from worldwide oil drilling technology and directional drilling technology. Dr. Gelfgat provided experience in hard-rock drilling research and development in support of the FSU and, presently, the Russian mining and oil drilling industries.
- 2) Developing adequate bit thrust for hard rock drilling using a coiled-tubing (reeled) tubing approach. CTES furnished industrial coiled-tubing performance analysis simulators, CerberusTM and sub-component OrpheusTM software, that provided a more complete evaluation of the onset of tubing buckling and the resulting achievable bit thrust than could be projected using analytical methods available in published, peer-reviewed, drilling papers.
- 3) Development of a prototype microdrilling platform using a coiled-tubing (reeled) tubing approach. This study was limited to coiled-tubing drilling because of 1) its perceived high suitability for automated or nearly automated drilling, 2) its relative simplicity as compared to drilling with coupled short sections of drill stem, and 3) its capability to support, with only modest modification, novel nontraditional drilling methods that might be well suited to special requirements desirable for potential DOE NN-20 program sponsors.

BACKGROUND

In the 19th century, oil field drilling was traditionally conducted with cable-tool percussion drilling; however, this was almost completely replaced by rotary drilling by the middle of the 20th century. For the past decade, specific rotary drilling techniques have been adapted to allow their application on a continuous, reeled drill stem. The reeled or coiled-tubing drill stem provides much more rapid insertion and removal for bit replacement and bottom-hole-(drilling) assembly (BHA) adjustments, maintenance, or replacement. Coiled-tubing-drilling (CTD) also offers more reliable pressure control of a bore during insertion and removal. CTD is presently an infrequent but increasingly-specified, drilling technique used for oil-field exploration and development wells, and has also been applied to other specialty areas including the clean-out of existing underground utilities and the installation of utilities using trenchless methods. Recently, coiled-tubing manufacturing has been augmented to allow the insertion of telemetry cables and small hydraulic tubing inside the coiled-tubing. This development holds promise for a versatile and relatively simple drilling platform that can support both 1) traditional, but complex, drilling methods such as real-time bit location and steering for directional drilling, as described by **Leismer et al. (1996)**, and 2) nontraditional drilling methods that require multiple telemetry, power, and utility transport conduits. A number of nontraditional drilling methods have been successfully demonstrated in laboratory testing and shallow-field drilling and boring operations but have, thus far, failed to achieve widespread acceptance in the field due to incompatibility with a coupled drill-stem system. These include: electric-motor-powered drilling, high-pressure water-jet-assisted rotary drilling, flame-jet spallation drilling, rock-melting drills, and abrasive-jet drilling.

It is believed that as CTD receives more wide spread use in deep-well drilling, the revolution in oil-field drilling practices that has been under way since the mid-1980's will accelerate, and CTD will find many

applications in non-oil-field drilling. The coiled-tubing drilling platform for microholes (**Fig. 1**) is the most versatile and adaptable of any available platform; it will meet the various needs identified by potential customers for a continuing microborehole program.

MICROBOREHOLE AND DRILL SYSTEM SPECIFICATION

The project team proposed a performance specification for a microborehole and drilling platform in the first DOE NN-20 project review presentation in January, 1996. This specification was revised slightly in the project's second quarterly report dated April 5, 1996.

Borehole Specification. Sponsors require a 500-ft-long underground borehole that can be used for temporary or permanent installation of utilities.

1. **Trajectory.** A typical worst-case trajectory and target requires real-time directional drilling of a river-crossing trajectory up to 500-ft-long. The trajectory that penetrates within several feet of a target bottom-hole location is desired.
2. **Lithology.** Penetration of firm consolidated soils, soft to hard rocks (including granite), and short sections of concrete (including reinforcing steel) is required.
3. **Hydrology.** Parched zones or sub-hydrostatic (not artesian) aquifers may be penetrated. A fluid-filled hole will need to circulate with small losses of drilling fluid to the penetrated formation. Air drilling will be required where high loss rates are expected.
4. **Completion Requirements.** A stable cased hole with a minimum inside diameter greater than 1/2 in. is required, and coiled-tubing can be reinstalled after drilling is completed and the bottom hole assembly is removed. Cementing or grouting of the completion casing is assumed to be feasible but this was not investigated in this project.

Drilling System Specification. A simple, easily deployable drilling system that can be assembled and operated by non-drilling specialists is required.

1. **Comminution.** A highly automated drilling system shall support bit replacement and BHA modification as lithology and trajectory dictate. Bits suitable for the lithology described, as well as mills for boring through reinforcing steel in concrete, piping, and junk, shall be compatible with the drilling assemblies.
2. **Power and Cuttings Transport.** A hydraulic or pneumatic bottom-hole-powered drilling assembly will be used with excess power provided for hole cleaning. Water-based, viscous drilling fluids with fluid-loss additives to seal the bore in porous, unconsolidated, and micro-fractured formations will be used. Air drilling is desirable where it is feasible.
3. **Performance.** The system shall develop adequate bit power and bit thrust to drill at rates up to at least 20-ft/hr in hard rock (e.g., Sierra White Granite) in the worst case trajectory with a reach of 500-ft.
4. **Drill Stem.** A non-rotating coiled-tubing or reeled-hose will be specified as opposed to a more traditional, surface-rotated, coupled-section drill stem.

Drilling Platform. A covert and highly portable drilling platform that can be readily disassembled, transported as small components, and reassembled is needed.

1. **Coiled-tubing Reel Platform.** A self-contained, highly-automated, hydraulic-powered and controlled, skid-mounted reel and tubing-injection unit will be mounted on a drilling-unit skid. It will provide for essentially unmanned drilling with appropriate process upset alarms, but will require manned operation

for bit and BHA changes, initial drilling of a conductor pipe, and final completion of the bore during drilling. Manned drilling would be required in unusual lithologic or hydrologic conditions or during drilling of structures or milling of steel reinforcing of piping.

2. **Auxiliary Platform.** Self-contained prime movers will drive a hydraulic-fluid pump, drill-fluid pump and/or compressor. They will be mounted on an auxiliary skid with piping and supports for a drill-fluid circulation system that includes a drill-fluid tank and drill-solids separator. A hydraulic or pneumatic control system will also be installed on the skid.
3. **Dimensional Requirements.** A 5-ft-wide by 10-ft-long by 8-ft-high platform will be assembled from much smaller, highly portable components.
4. **Operating Requirements.** A low acoustic, electromagnetic (radio waves), and visual impact is required. Engines shall be acoustically isolated, and exhaust shall be clean when vented. Electrical components shall be completely shielded. Drilling fluids shall be contained within the tanks on the platform, and cuttings shall be filtered from the discharge during air drilling.

THEORETICAL AND ANALYTICAL INVESTIGATION

The bore size and drilling power requirements determine the ultimate size of any drilling system, and the initial and operating costs of the system. An investigation to predict drilling performance as hole size is reduced was conducted for the proposed drilling system. Technical papers from petroleum technology journals and publications provided methods to calculate the effect of wellbore diameter on drilling process parameters. The effect of bore diameter on the requisite bit thrust and power for comminution at the specified rate of penetration was compared with projected maximum hydraulic power and mechanical thrust that can be transmitted through the coiled tubing and efficiently converted to mechanical power in hydraulic drilling motors.

Bit Thrust. For this study, it was assumed that bit thrust, as opposed to weight-on-bit applied with drill collars, will be applied through the coiled tubing using a tubing injector on the drilling platform. Drill collars are ineffective in highly inclined wells, reduce bit thrust in the upward-sloped section of a river-crossing trajectory, and give rise to large hydraulic losses in the circulation system. It is assumed that the bit-thrust limit is reached when buckling of the tubing occurs. A sinusoidal buckling load (**Wu and Juvkam-Wold 1994**) was used, with the assumption that the tubing-to-bore diameter ratio and tubing diameter-to-thickness ratio are held constant. A thrust limit in an inclined hole with low curvature was found to scale as bore diameter to the $5/2$ power, or $D^{5/2}$. The thrust that causes the onset of buckling can be increased by reducing the radial clearance between the drill stem and the bore. Allowable compressive loading of the drill stem varies as the bore area or as D^2 , but the onset of buckling typically occurs long before compressive yield of the pipe.

PDC Bits. Polycrystalline Diamond Compact (PDC) cutter bits are well suited to coiled-tubing deployment because they provide a high rate of penetration at low input power and bit thrust as compared to other bits (**Glowka, 1989**). Unfortunately, PDC bit technology does not presently provide bits that are suitable for drilling hard, abrasive rocks such as granite. Typical PDC cutter sizes range from 0.3- to 0.5-in.-diameter, so bits as small as 1-in.-diameter can be fabricated with commercial cutters. Detournay and Defourny's (1992) drag bit drilling model was used to predict theoretical performance limits as a function of bore size for shear bits. Using this model, the effect of increasing bit speed to compensate for the limited thrust available before the onset of buckling can be quantified. A method to determine the allowable bit speed is needed to determine the theoretical maximum penetration rate.

A PDC cutter thermal performance model was developed by **Ortega and Glowka (1984)** and refined by **Glowka and Stone (1985)**. Cutter performance data (**Glowka 1989, Part 1**) was input into the thermal performance model to calculate the maximum bit thrust that limits the cutter temperature to a value that assures acceptable cutter wear rates. The temperature-limited thrust was set equal to the buckling-limited thrust. This equation was simplified to a quadratic function that defined the theoretical bit speeds that maximize bit power and rate of penetration (**Fig. 4**).

The two bit speeds and the maximum bit thrust (the critical buckling load) are entered into the drilling model (**Detournay and Defourny, 1992**) with typical values for rock and bit cutter properties; two calculated penetration rates as a function of bit diameter are presented in **Figure 4**. The higher curve is the assumed maximum theoretical penetration rate for the rock properties, heat transfer coefficients, and cutter properties; it varies as $D^{-3/2}$ over the larger hole sizes, and the negative slope increases to $D^{-5/2}$ in the transition region between slimhole and microhole. Therefore, as bore size is reduced, the maximum theoretical penetration rate for a shear bit increases significantly.

General Commminution. Substituting reciprocating frequency for rotary speed, and modeling percussive drilling performance using methods presented by **Hartman (1963)** and **Fairhurst (1959)**, yields results similar to those obtained using **Detournay and Defourny's (1992)** drilling model. To the extent that multi-cone bits rely on combined shear and impact drilling processes, the theoretical PDC performance projections are presumed to be applicable to multi-cone rotary drilling, as well as rotary, percussion-rotary, and rotary-percussion. Bearing wear in multi-cone bits was not investigated and may have a greater influence on multi-cone bit performance than cutter wear.

Percussion Drilling in Granite. The DOE Geothermal Drilling and Completion Technology Development Program also sponsored work to evaluate percussive drilling for penetration of hard rock associated with geothermal drilling. **Finger (1984)** reported percussive drilling tests in Sierra White Granite at penetration rates up to 70-ft/hr with 5000-lb_f bit thrust. These drilling tests used a pneumatic hammer and an 8.5-in.-diameter solid head bit. Assuming that the scaling for penetration rate and bit-thrust described for PDC shear bit can also be applied to percussion drilling, a 1-in.-bore, pneumatic-percussive drilling system would be projected to drill at similar rates with bit thrust of 600 lb_f. Assuming that small drills are better suited for higher frequency operation, even higher penetration rates may be possible with small bore percussion drilling systems.

Bit Power and Cuttings Transport. Hydraulic and pneumatic drilling systems combine the power transport to the BHA and cuttings transport into a single medium. By operating hydraulic power transport systems at high pressure and relatively low flow rates, power losses are kept low. Hydraulic power transport with a fixed, high maximum operating pressure, produces a maximum power transport per unit area that is constant (varies as D^0), when a maximum annular velocity is specified. Hydraulic power transport does not limit the minimum diameter of a microborehole if relatively high-pressure circulating pressures are assumed. It can be shown that the optimum tubing-diameter- to hole-diameter ratio for maximizing hydraulic power transport varies between 0.6 and 0.7 for a large range of drilling fluid properties and depths. The calculated hydraulic power transport plots in **Fig. 5** are typical; they predict that for microhole dimensions the transport is maximized at a 0.65 tubing-to-bore ratio, and reasonable power can be transported as far as 10,000 ft in a microborehole if the surface pressure is operated at 11,000 psi. Another result is that coiled-tubing diameters optimized for hydraulic energy transport, will transmit the calculated bit thrust required to drill microboreholes at reasonable rates in granitic rocks, and high penetration rates in most sedimentary rocks.

Cuttings transport in vertical wells was modeled with a Stokes Law settling criteria. This model predicts that efficient cuttings transport is readily achieved with the same hydraulics that would be needed to produce a reasonable rate of penetration in hard rock with a downhole rotary motor. For penetration rates up to several hundred feet per hour, the effect of the cuttings removal process on energy transport can be ignored in vertical wells. Stokes Law settling models particle transport in moderately to highly inclined wells. Mechanistic models for churning, rolling, and cuttings-bed formation are significantly more difficult to apply to the model, and predictions for highly inclined wells rely on simulations using commercial software as discussed under SIMULATION AND DESIGN STUDY RESULTS.

Reeling Power and Reel Dimensions. Tubing is plastically deformed as it is coiled onto the reel and uncoiled from the reel and inserted into the well; some drilling platform power will be used to deform the tubing during insertion and retraction. The power to deform the tubing during unreeling is proportional to the product of the tubing velocity, the yield stress of the steel tubing, and the tubing diameter cubed (D^3); it is inversely proportional to the reel diameter. An estimate of the power required for tubing insertion and retraction was made using 1) a maximum tubing velocity of 300-ft/hr at a maximum tubing thrust of 15000 lb_f for drilling, and 2) 200-ft/min. at 300 lb_f for bottom-hole-assembly (BHA) replacement. The power to unreel and insert tubing and develop bit thrust during drilling is calculated to be about 10% of the calculated power for BHA replacement with a 1-1/4-in.-diameter tubing. The effect of reel radius on the total reeling power is not significant using these input values.

Tubing tension is used to bend the tubing onto the reel and to unbend the tubing off the reel. The calculated tubing load is inversely proportional to the reel size. Minimum reel size will need to be selected to assure: 1) tubing reliability by maintaining maximum strains well below the minimum elongation specification for the steel tubing, 2) reasonable structural and bearing loads for the reel, and 3) reasonable reeling power requirements. A reel-to-tubing diameter-ratio greater than 25 is normally used, but this can be reduced to a ratio of 20 without creating excessive reel loads or tubing strain. Further reductions may be feasible but will require some experimental work to assure that the practice of tubing reeling is adequately modeled with the simple algorithm used.

Conclusions from Theoretical Work. To determine effect of bore size on rate-of-penetration, theoretical comminution results were compared to both bit-thrust and energy. Increased penetration rates with reduced bore size are indicated where bit-cutter temperature controls the penetration rate. Models to predict penetration as a function of diameter as limited by cutter loading have not been developed yet. By using coiled-tubing that has a diameter that is 65 to 75% of the bore diameter, a coiled-tubing drilling platform can apply sufficient bit thrust and hydraulic power to drill granitic rocks at moderate rates and sedimentary rocks at high rates. As bore size is reduced, the platform reel dimensions will be reduced proportionally to the bore diameter, and the power and drill-fluid storage and separation volume requirements will be reduced proportional to the bore area.

EXPERIMENTAL RESULTS

Experimental work focused on three areas: 1) selecting and evaluating appropriate bits for hard-rock drilling, 2) selecting and evaluating appropriate hydraulic motors to provide the power required for hard-rock drilling, and 3) evaluating promising combinations of bits and motors to demonstrate the feasibility of their application to a coiled-tubing system.

Rotary-bit Testing. Rotary-bit testing was conducted in the MEI DRC using a standard horizontal bit test stand. A speed-controlled, electric motor rotated the drilling assembly while two hydraulic cylinders were

used to pull the rock sample into the drilling assembly. A 40-gpm flow of water was circulated through the bit and bore while drilling, since this was the typical operating flow rate required for the rotary hydraulic motors that were selected for evaluation. None of the bits tested had jet nozzles, and it is assumed that hydraulic energy had a minimal effect on the drilling specific energy. **Table 1** shows a summary of the bit test results and calculated drilling-process specific-energy values based on the mechanical input to the bit, torque and rotary-bit speed.

Three rock types were selected for drill-bit testing: Berea Sandstone (**BS**), a uniform, fine-grained, abrasive sandstone; Carthage Marble (limestone) (**CM**), a very fine to fine grained (0.05 to 1/0-mm) biosparite with clastic texture and calcite clasts; and Sierra White Granite (**SWG**), a uniform, fine-grained (1.25-mm), very abrasive, metamorphic rock. Typical values of compressive strength are 7,500 psi, 12,000 psi, and 22,000 psi, respectively.

Two bits were procured from a US-based mining bit supplier, Bort Longyear, US Products Group:

- 1) 1-3/4-in. directional, Stratapax drag bit with six-each, 0.34-in. circular, polycrystalline diamond compact (**PDC**) cutters
- 2) 1-3/4-in. directional, diamond impregnated (**DI**) cutter drag bit.

The PDC bit drilled the Carthage Marble with rates as high as 380-ft/hr and calculated specific energy values as low as 16-kpsi; the latter is lower than any reported values in reviewed drilling publications. The PDC bit failed to successfully drill the Sierra White Granite, and the cutters were damaged beyond repair before two inches were drilled. The DI bit drilled the Carthage Marble with rates as high as 65-ft/hr and calculated specific energy values as low as 96 kpsi. This bit was not tested in Sierra White Granite on the bit test stand, but was tested using a hydraulic motor (see **PDM DRILLING PERFORMANCE**).

Five bits were procured from Russian-based mining bit suppliers:

- 1) a 2.32-in. diameter (59-mm), 3-roller-cone (**3-C**), III 59K-TsA type, rotary/percussion bit;
- 2) a 2.32-in. diameter (59-mm) 2-roller-cone (II 59TK-TsA type) rotary/percussion bit
- 3) a 1.81-in. diameter (46-mm) 3-roller-cone (**3-C**), III 46K-TsA type rotary/percussion bit
- 4) a 1.81-in. diameter (46-mm) 2-roller-cone (**2-C**), II 46TK-TsA type rotary/percussion bit
- 5) a 2.32-in. diameter (59-mm) surface diamond (**SD**) cutter rotary drag bit.

Only the three best results, #512, #517, and #519, of the ten tests run are included in the bit summary on **Table 1**. The 1.81-in., 3-cone Russian bit rotary drilled satisfactorily in granite at bit thrusts exceeding 2500 lb_f. Rates of penetration ranged from 15- to 22-ft/hr as the bit thrust was increased from 3000 to 3600 lb_f. The calculated specific energy ranged from 440 to 370 kpsi which is 7 to 6 times higher than the calculated specific energy for a single PDC cutter in Sierra White Granite based on **Glowka (1989, Part 1)**. Although the bit had significant bearing wear after drilling 45-inches of granite and 30-inches of sandstone it had some remaining life at the end of the testing. Test #528 was run with the 2.32-in., 3-cone bit in granite at a bit thrust of 1500 lb_f to provide a comparison of rotary drilling with rotary-percussion drilling (Test #527A). The low penetration rate achieved is a result of the low bit thrust used and not a failure of the bit. The 2-cone bit failed during its first test in granite due to severe bearing wear, which allowed the cone positions to shift enough to interfere with each other. The 2.32-in.-surface diamond bit performed best in granite with a rate-of-penetration between 16- and 26-ft/hr, with bit thrusts increasing from 1500- to 2750-lb_f. The calculated specific energy ranged from 110 to 80 kpsi, which is only 72% to 25% higher than the calculated specific energy for a single PDC cutter in Sierra White Granite. This bit showed no sign of wear after drilling 16-inches of granite.

TABLE 1 - BIT TEST SUMMARY

Test No.	Control Ramp	Rock Type	Bit		Bit Performance				
			Size	Type	Speed	Thrust	Torque	ROP*	SE**
			(in)		(rpm)	(lb _f)	(ft- lb _f)	(ft/hr)	(kpsi)
496	Thrust	CM	1.75	PDC	650	500	30	0	210
					650	3400	55	325	19
498	Thrust	CM	1.75	PDC	1300	500	22	0	230
					1300	3200	52	550	18
497	Thrust	CM	1.75	DI	650	500	28	10	280
					650	3800	51	23	144
499	Thrust	CM	1.75	DI	1300	500	20	17	235
					1300	3700	32	65	96
504	Speed	CM	1.75	PDC	50	1000	43	6	112
					1350	1000	26	60	112
505	Speed	CM	1.75	DI	50	1000	40	2	280
					1400	1000	21	31	255
506	Speed	CM	1.75	PDC	50	1750	40	0	24
					1150	1750	26	210	30
507	Speed	CM	1.75	DI	50	1750	44	3	210
					1400	1750	27	40	160
508	Speed	CM	1.75	PDC	100	2500	60	60	16
					1200	2500	32	380	25
509	Speed	CM	1.75	DI	0	2500	60	0	200
					1400	2500	30	60	100
512	Thrust	BS	1.81	3-C	300	600	16	6	250
					300	2000	25	40	100
517	Thrust	SWG	1.81	3-C	300	3000	43	15	440
					300	3700	52	22	370
519	Thrust	SWG	2.32	DS	700	1500	24	16	110
					700	2750	36	26	80
528	Comp	SWG	2.32	3-C	150	1500	28	1.5	1500
	523D				150	1500	32	1.5	1700

*ROP = rate of penetration,

** SE = specific energy = specific total process energy based on hydraulic input energy.

Rotary-bit Testing Summary. Based on the bit testing results: 1) a rotary drilling motor will need to deliver an output power of at least 5 hp at 700 rpm and 2000-lb_f-thrust to bore 20-ft/hr in SWG with a 2.323-in. diamond-surface, set-rotary drag bit; 2) a rotary drilling motor will need to deliver an output power of at least 8.25 hp at 300 rpm and 2500-lb_f-bit thrust to bore 20-ft/hr in SWG with a 2.323-in. 3-cone rotary bit.

PDM Testing. Hydraulic-powered rotary drilling uses positive displacement motors (PDM) based on the Moineau (Moyno) Principle. Two rotor/stator units were fabricated by Roper Pump Company: A 1.50-in. diameter, 54-in.-long, three-stage, single-lobe motor (1:2 or one rotor lobe and two stator cavities) and 2) a 1.69-in.-diameter, 99-in.-long, five-stage, multi-lobe motor (5:6 or five rotor lobes and six stator cavities). Each unit was furnished with two stators since they have a shorter operating life cycle than the rotors. The theoretical performance specifications for the rotor/stator unit are shown in **Table 2**; complete dimensional data for the rotor stator unit are shown in **Table 3**.

TABLE 2 - PDM ROTOR/STATOR PERFORMANCE SPECIFICATION (Theoretical motor performance only--not including losses in the flexible shaft and radial/thrust bearing packs)								
<u>Motor</u>		<u>Input</u>			<u>Output</u>			
<u>Lobes</u>	<u>Stages</u>	<u>Flow</u> (gpm)	<u>Pressure</u> (psi)	<u>Power</u> (hhp)*	<u>Speed</u> (rpm)	<u>Torque</u> (ft- lb _f)	<u>Power</u> (hp)	<u>Efficiency</u> %
(1:2)	3	35	600	12.3	1300	32	7.9	64
(5:6)	5	45	600	15.7	680	87	11.3	72

* HHP = hydraulic horse power

TABLE 3 - PDM MOTOR DIMENSIONS							
<u>Motor</u>		<u>Stator Diameters</u>		<u>Rotor</u>		<u>Housing</u>	
<u>Lobes</u>	<u>Stages</u>	<u>Major</u> (in.)	<u>Minor</u> (in.)	<u>Major Dia.</u> (in.)	<u>Eccentricity</u> (in.)	<u>OD</u> (in.)	<u>Length</u> (in.)
(1:2)	3	1.172	0.676	0.893	0.149	1.5	54
(5:6)	5	1.106	0.826	0.980	0.07	1.69	99

MEI designed and fabricated a bent housing (with a 0-degree bend for laboratory evaluation), a bearing pack, a flexible shaft, a top sub, and a bit sub that are assembled on the rotor/stator unit to create a complete downhole directional rotary drilling PDM assembly. A single accessory package was designed to adapt to either rotor/stator unit. A summary of selected dimensional and performance specifications for the complete PDM are shown in **Table 4**.

TABLE 4 - PDM SPECIFICATION WITH FLEXIBLE SHAFT AND BEARING PACK								
<u>Motor</u>		<u>Bearing Packs</u>			<u>Titanium Flexible Shaft</u>		<u>Total Housing</u>	
<u>Lobes</u>	<u>Radial</u>	<u>Thrust</u>			<u>Diameter</u>	<u>Length</u>	<u>OD</u>	<u>Length</u>
		Up	Down	(lb _f)	(in.)	(in.)	(in.)	(in.)
(1:2)	2	2	2	4000	0.625	14	1.50	78.5
(5:6)	2	2	2	4000	0.625	14	1.69	123.5

the two stators. Results of Test #500 (**Fig. 6**) and Test #502 show that the theoretical 64% conversion efficiency for the rotor/stator unit was reduced to 48% and 46% in the total PDM assemblies, respectively.

PDM Dynamometer Testing. Both rotor/stator units were tested as assembled PDM drilling units on a dynamometer to determine the actual performance of the motor with the power losses that occur in the flexible shaft and the bearing packs. Results of the dynamometer test are summarized on **Table 5**.

TABLE 5 - PDM DYNAMOMETER TEST SUMMARY									
Test/ Stator No.	Control Ramp	PDM Stage/ Lobe	Input Parameters			PDM Performance			
			Flow (gpm)	Dif. Press (psi)	HHP (hp)	Torque (ft-lb _f)	Speed (rpm)	BHP* (hp)	EFF %
500 1	Torque	3	32	570	11	3	1700	0.3	3
		1:2	32	1450	27	56	1420	13	48
			32	1750	33	70	900	5	16
501 1	Torque	3	43	400	21	7	2250	3	14
		1:2	43	1900	47	60	1700	20	42
			43	2000	56	80	1050	8	14
502 2	Torque	3	32	400	9	0	1600	0.3	3
		1:2	32	1325	24	45	1300	11	46
			32	1620	30	55	1000	10	35
503 2	Torque	3	42.5	600	16	3	2250	2	10
		1:2	43	1850	46	60	1675	19	45
			42.5	2050	52	65 [*]	1500	18 [*]	36
504 2	No load	3	47	519	14	nm	nm	na	na
		1:2	27	133	2	nm	nm	na	na
			33	224	4	nm	nm	na	na
505 1	Torque	5	20	600	6	10	220	0.3	6
		5:6	22	1025	14	80	90	1.2	9
			20	2050	16	125	0	0.1	3
506 1	Torque	5	33	330	6	20	420	1	22
		5:6	35	1225	26	115	275	6.6	25
			36	1700	33	160	220	4	20
507 1	Torque	5	43	150	3	10	620	1	24
		5:6	43	1075	27	130	440	10.2	38
			43	2050	52	175	300	10	26
531 1	No load	5	20	450	3	5	220	0.2	4
		5:6	30	580	24	10	400	0.5	5
			41	855	52	18	600	0.7	4

nm = not measured, na = not available

*BHP = Bottom hole pressure

The single lobe (1:2) motor was tested at the design flow rate with both stators, #1 and #2, to ascertain the variability in the performance between identical units. There was some variation in performance between Test #507 showed that the theoretical 72% conversion efficiency for the rotor/stator unit was reduced to 38% in the PDM assembly. Only one stator was tested for the multi-lobe (5:6) motor. Roper had great

difficulty fabricating the multi-lobe stator, and excessive interference between the rotor and stator is believed to be causing the large reduction in efficiency and erratic performance observed in the multi-lobe PDM. This is evidenced by the very high no-load differential pressure, 855 psi, at the design flow rate in Test #531 for the multi-lobe PDM as compared to 224 psi, at the design flow rate in Test #504 for the single-lobe PDM.

PDM DRILLING PERFORMANCE.

Single-lobe PDM / surface set diamond drag bit. There is a good match between the single-lobe PDM performance in Tests 502 and 503, and the speed and power required for the surface set diamond bit at a 20-ft/hr penetration in Test #519. Projecting flow rates lower than in Test #502, at 22-gpm flow, 5 hp would be available at about 800 RPM with a conversion efficiency of 40%. The bit would be operating 14% above its recommended maximum rotary speed with a significant predicted reduction in operating life. A bottom-hole 15-hydraulic horse power (hhp) source would be sufficient.

Multi-lobe/3-cone bit. There is a good match between the multi-lobe PDM performance in Tests 506 and 507, and the speed and power required for the 3-cone bit at 20-ft/hr penetration in Test #517. Interpolating between tests 506 and 507, it appears that at 40-gpm flow, 8 to 9 hp would be available at about 300 RPM with a conversion efficiency of about 30%. A bottom-hole, 30-hhp source would be sufficient.

PDM Drilling Tests. MEI DRC conducted two tests with each of the PDM's and a bit suitable for the rock type to be drilled. A summary of the 4 PDM rotary-bit tests is shown on **Table 6**.

TABLE 6 - PDM/BIT DRILLING TEST SUMMARY									
Test No.	Rock	PDM	Bit	Hydraulic Input			PDM Bit Performance		
				Flow	DP*	HHP	Thrust	ROP	SE
				(gpm)	(psi)	(hp)	(lb _f)	(ft/hr)	(kpsi)
526	BS	1:2	PDC	32	375	7	415	37	925
				30	1275	22	1835	912	20
529	CM	1:2	PDC	31	775	14	575	50	245
				29	1300	25	1875	280	60
530G	SWG	5:6	DI	30	625	12	600	2	3000
				32	940	18	1940	20	720
				30	1350	26	3025	60	350
537	SWG	5:6	3-C	42	1150	29	950	5	2200
				40	1400	33	3025	20	800

*DP = Differential pressure

Single-lobe PDM / PDC drag bit. This combination was assembled to drill in Berea Sandstone and Carthage Marble. Penetration rates of 912-ft/hr were achieved in the sandstone and 280-ft/hr in the marble (Fig. 2.).

Multi-lobe PDM / Diamond Drag Bit. This combination was assembled to drill in Sierra White Granite. A penetration rate of 60-ft/hr with 3025-lb_f thrust was achieved with a 1.75-in.-diamond impregnated drag

bit and 20-ft/hr with 3025-lb_f thrust was achieved with a 2.32-in.-diamond-surface set drag bit. However, the fact that the diamond-impregnated bit was smeared at the end of this test indicated that the bit was probably over-loaded. The thrust needed to drill 20-ft/hr was 3025 lb_f for the impregnated bit and 1950 lb_f for the surface set bit or about 1115 lb_f/in and 1302 lb_f/in for each bit. The power needed to drill 20-ft/hr was 17.5 hp for the impregnated bit and 33 hp for the surface set bit or about 7.5 hp/in² for each bit. The specific process energy was calculated using the hydraulic power supplied to the PDM.

Percussion Rotary Drilling Tests. MEI DRC conducted 23 tests with a GHH G-59UO hydraulic hammer, powered in tandem with a 1/2 hp, 150 rpm, hydraulic rotary motor and various 2.32-in.-diameter, 2-cone, 3-cone, and diamond-surface set bits (Melamed et al. 1997). A schematic of the test stand is shown in Fig. 7. The required inlet hydraulic power was estimated by adding 1.5 hhp to the hydraulic power supplied to the hammer to account for the power needed to operate a 30% efficient PDM delivering an estimated 1/2 bottom-hole pressure (BHP) to rotate the hammer and bit. A summary of the four best drilling runs is shown in Table 7.

TABLE 7 - PERCUSSION ROTARY DRILLING TEST SUMMARY All tests run at 150 RPM rotation speed with the 2.125-in. OD, 90.5-in.-long GHH G-59UO Hydraulic Hammer Drill Motor operating at 40 to 60 Hz.								
<u>Test</u>			<u>Hydraulic Input</u>			<u>PDM Bit Performance</u>		
No.	Rock	Bit	Flow	DP	HHP*	Thrust	ROP	SE
			(gpm)	(psi)	(hp)	(lb _f)	(ft/hr)	(kpsi)
521A	CM	2-C	8.75	570	4.4	2175	14.8	140
522D	CM	3-C	7.7	530	3.9	2980	17	110
523D	SWG	3-C	10.5	705	5.9	2200	9.5	295
527A	SWG	3-C	11.1	660	4.3	1540	10.6	330
527B	SWG	3-C	11.6	710	6.4	3030	13.3	230
*HHP = hydraulic horse power input (includes an assumed 1.5 hp for the rotary power required to rotate the HHM and bit.								

While the penetration rates achieved with the hammer are not particularly high, the process-specific energy and hydraulic power requirement compare favorably with the PDM rotary drilling. If bit life is significantly longer for the 3-cone bits in percussion rotary drilling service as compared to diamond bits in very high-speed rotary drilling, the lower penetration rates may be acceptable in very hard formations such as Sierra White Granite. The percussion drilling system is operated at significantly lower circulation rates than required for the PDM's. This is an advantage when drilling unconsolidated, unstable formations that may wash out or collapse if exposed to high circulation rates.

Another advantage of percussion rotary drilling is that the threshold bit-thrust required to develop a reasonable penetration rate is considerably lower than with pure rotary drilling using multi-cone bits. Comparing Test #527A in Table 7 with Test #528 in Table 2, it is evident that the penetration rate with 1500-lb_f-bit thrust is increased from 1.5-ft/hr to 11-ft/hr. In hard-rock, percussion rotary drilling may be more compatible with a coiled-tubing drilling system than pure rotary drilling.

SIMULATION AND DESIGN STUDY RESULTS

Coiled-tubing buckling and pressure losses. Analytical methods were used to calculate the maximum bit thrust that could be applied before the tubing begins to buckle. Once buckling begins, analytical calculations can no longer accurately predict the force transmitted through the tubing. These calculations predicted that buckling would occur before required bit-thrust magnitudes were reached. The required thrusts were first based on scaling of data for PDC drilling in Sierra White Granite from **Glowka Parts One and Two (1989)**, and were later revised to reflect results from experiments summarized in **Tables 1, 6, and 7**.

The analytical methods rely on a number of simplifying assumptions. Several methods in the literature, based on differing assumptions regarding well curvature, provide significantly different results. In order to develop a higher level of confidence in quantifying bit-thrust magnitudes that could be developed in a coiled-tubing, deployed-drilling assembly, a statement-of-work (SOW) was prepared and CTES was retrained to run an industry-proven simulation of coiled-tubing performance in drilling service. Results from their final report were used to prepare this report (CTES, 1996).

The SOW required simulation of tubing performance in three trajectories:

- 1) an 18-degree/100-ft trajectory starting at 45-degrees (from the vertical) and reaching a final inclination of 135-degrees as the surface level is penetrated
- 2) a 12-degree/100-ft trajectory starting at 60-degrees and reaching a final inclination of 120-degrees as the surface level is penetrated
- 3) an essentially vertical trajectory as a worst case buckling simulation.

Simulations were run for three bore sizes: 1) a 2.25-in. ultraslimhole, 2) a 1.75-in., sized to a smaller straight-hole drilling system comprised of off-the-shelf components to be demonstrated, and 3) a 1.125-in. microborehole. Preliminary results from the CTES simulation using **Cerberus™** and **Achilles™** were reviewed at a midterm project review meeting and it was decided to rerun the simulation with tubing sizes increased by one nominal size over those originally specified in the SOW. This would assure that the simulations predicted bit thrusts sufficient to drill 20-ft/hr in granite based on the recently available bit testing results. A summary of the rerun simulations is shown on **Table 8**.

MudLite™ Hydraulics Simulation. A foam simulator for underbalanced drilling was run with a water-based drilling fluid to calculate the pressure drops in a 500-ft-long, 18-degree/100-ft, curved river-crossing trajectory with a 45-degree (from vertical) entrance, and a 135-degree exit. The bottom-hole pressure drops needed to power the drilling motor and take a reasonable pressure drop through a non-jetted bit were input with a complete well-bore configuration to predict the surface pressure drop. Five configurations were simulated to develop a range of surface pump requirements to support a microbore directional drilling system. A summary of the results are shown on **Table 9**.

In order to support a 20-ft/hr drilling rate in granite with a rotary drag bit drilling system, a 50-hp pump will be needed to pump drilling fluid up to 40-gpm capacity at pressures up to 2200-psi. Annular velocities between 240-ft/min for a 2.323-in. bore and 550-ft/min for a 1.75-in. bore with 1.25-in. coiled-tubing are needed to provide the hydraulic power required by the bottom-hole drilling assembly. The velocity in the annulus can be reduced to 450-ft/min in the 1.75-in. bore by reducing the coiled-tubing size to 1.00-in. These annular velocities are excessive for softer formations but will be acceptable when only medium to very hard formations are penetrated.

TABLE 8 - SUMMARY OF COILED-TUBING LOADING SIMULATIONS					
		HTB 1-OD	HTB 2-OD	HTB 3-OD	HTB 3-1
Borehole	ID (in)	1.125	1.875	2.250	2.250
CT	OD (in)	0.750	1.000	1.250	1.000
	Wall (in)	0.067	0.087	0.095	0.109
Target Bit Thrust		1500	2500	3000	3000
Minimum Bit Thrust	(lb _f)	(bit thrust in a vertical section the trajectory)			
	0.2	1450	2050	3460	1900
Friction Coefficient	0.4	940	1330	2190	1300
	0.6	740	1060	1710	1050
Snubbing Force (lb.)		(surface thrust needed to develop bit thrust for the 18 degrees/100-ft trajectory)			
	0.2	7850	13680	18810	
Friction Coefficient	0.4	7840	13690	18810	
	0.6	7870	13660	18800	
Maximum Snubbing Force (lb.)		-7890	-13,700	-18,830	-16,870
Maximum Pulling Force (lb.)		7900	13,700	18,830	16,870
Stress (psi), POOH + 1000 lb.		21,680	18,030	17,730	15,550

TABLE 9 - HYDRAULIC ENERGY TRANSPORT- MUDLITE™ SIMULATIONS									
Summary results for 18-degree/100-ft river crossing trajectory (45-135 degree)									
Test	Bit	Tubing	Drilling Motor			Differential Pressure			Platform
		OD/ID	PDM	Flow	BH	BHA	Tubing	Total	HHP
	(inch)	(inch)	Motor	Rate	Power	Motor	Annulus	(psi)	Input
				(gpm)	(hhp)	(psi)	(psi)		(hhp)
531	DI/DB	1.250	PDM	30	26	1350	380	2050	36
	1.750	1.060	(5:6)						
531	DI/DB	1.000	PDM	30	26	1350	380	2180	38
	1.750	0.826	(5:6)						
537	SD/DB	1.250	PDM	40	33	1400	1160	1800	42
	2.323	1.060	(5:6)						
523D	3-C	1.250	HHM	10.5	5.9	705	70	775	4.8
	2.323	1.060							
527B	3-C	1.250	HHM	11.6	6.4	710	80	790	5.4
	2.323	1.060							

In order to support a 10-ft/hr drilling rate in granite with a **percussion-rotary** 3-cone bit drilling system, a 7-hp pump will be needed to pump drilling fluid at up to 12-gpm capacity at pressures up to 1000-psi. Annular velocities of 75-ft/min for a 2.323-in. bore with 1.25-in. coiled-tubing are needed to provide the hydraulic power required by the bottom-hole drilling assembly. This velocity is suitable for drilling below

unconsolidated or unstable formations where excessive erosion could occur if velocities exceeding 150-ft/min are applied

Dimensional Requirements for a Coiled-tubing Reel. The minimum diameter of the coiled-tubing reel must be sized to meet a number of requirements: 1) prevent tubing failures during bending, and provide the required fatigue life cycle for the tubing in drilling service, 2) allow reeling and unreeling of the tubing at reasonable tension loads based on reasonable design requirements for the reel bearings and reel support frame, 3) reeling and unreeling power levels during bit tripping that can be provided by redirecting the hydraulic power required for drilling.

The minimum elongation for coiled-tubing steel is typically 30%, so failure of the tubing from a single bending only requires a reel (ID)-to-tubing (OD) diameter-ratio of 7 to limit the strain in the tubing to 15% with a 2:1 safety factor. CTES ran a low-cycle fatigue simulation for a 1-in. OD coiled tubing which is more relevant than single bending analysis. Assuming that: 1) fewer than 20 bending cycles or 10 bit replacements are needed to drill a 500-ft hole, and 2) a linear interpolation of the CTES chart (CTES 1996) provides a very conservative estimate of life at low reel-to-tubing diameter ratios, then a reel-to-tubing diameter ratio of 17 is estimated for 2000 psi drilling. Assuming the minimum reel-to-tubing diameter ratio is 20, loading and power requirements were calculated for a reeling and unreeling operation at 200-ft/min.

Reeling Tension and Power. A simple ideal analysis of the force and power needed to reel tubing on a reel was developed. It predicts that for a 20-to-1, reel-to-tubing ratio and a 200-ft/hr reeling rate, 500-lb_f tension and 3 bhp would be required to reel 3/4-in. tubing; and 1350-lb_f tension and 8-1/4 bhp would be required to reel 1-1/4-in. tubing.

Tripping and Drilling Snubbing Power. Power to move the coiled tubing during bit replacement trips and during drilling will need to be summed with the reeling power to size the hydraulic power unit for the reel drive and tubing injector. CTES (Figs. 7 and 8 in (Quigley, 1996)) projects run-in-hole snubbing forces and pull-out-of-hole tensile forces that are less than 275-lb_f for the original tubing sizes (5/8-in. to 1-in.). Assuming the revised tubing sizes would require a maximum tripping load of 325-lb_f, a 200-ft/min trip rate requires a 2.0-bhp, high-speed, low-load drive. CTES (Quigley, 1996, Table 13) predicts a maximum surface snubbing force of 19,000 lb_f. At a 200-ft/hr drilling rate this requires a 2.0-bhp, low-speed, high-load drive. A single power unit with at least a two-speed drive should provide both the tripping and drilling thrust required.

Directional Accuracy. A quick calculation using methods described in Ref. 10 was performed to estimate the target accuracy possible using a typical off-the-shelf steering tool for a 45-degree to 135-degree river crossing trajectory. Assumed values for the accuracy of the output of the steering tool were: ± 0.5 -degree azimuth, ± 0.25 -degree inclination, and ± 0.5 -degree tool face. The simple calculation ignores the tool face error and the error that results from uncertainty of the drilled length of the wellbore which is estimated to be $\pm 0.1\%$ using conventional coiled-tubing depth counters. Based on this simple calculation, a reasonable target for the trajectory is a sphere with a 5-ft radius.

CONCEPTUAL DESIGN

Two conceptual coiled-tubing drilling systems are proposed: 1) A **full-scale**, "ultraslimhole" 2-1/4 to 2-3/8-in.-diameter, nominal bore drilling system which can be assembled from existing major components and readily designed and fabricated minor components; 2) A **half-scale**, "microborehole" 1-1/8-in.-diameter,

nominal bore drilling system which will require that components be redesigned, fabricated, and successfully bench-tested before a field-scale drilling demonstration can be initiated. It is believed that the half-scale components can be designed based on appropriate scaling of current designs, and will require no breakthrough technology to achieve the required performance. However, breakthrough technology may be needed to successfully fabricate some of the critical components needed.

Development of the full-scale system as an operating prototype ready for field testing and evaluation can be accomplished in a nominal one-year, \$1000K program, and is believed to have a 90% chance of successful completion. Development of a half-scale system will require two phases: **Phase 1** includes redesign and bench testing of critical half-scale prototype components including, bits, drilling motors, and a steering tool; **Phase 2** includes design of an optimized drilling system based on bench-test performance results, and assembly and field testing of the half-scale system. A very preliminary estimate for the Phase 1 project is a two-year, \$1500K effort, and Phase II would have a schedule and cost essentially equivalent to the full-scale project. These costs assume that a complete, operational surface platform would be assembled to conduct field tests, and that a shared surface system would be suitable for both of the proof-of-concept demonstrations. It is also assumed that off-the-shelf, highly versatile, oversized, surface components, as described or similar to those described in Attachment 1, would be used as opposed to the final minimum size and weight components that are proposed as being ultimately feasible in the conceptual design.

Bottom-hole Drilling System. The ultimate drilling system needs to be self-contained and self-powered. It will include a bottom-hole drilling assembly, a coiled-tubing drill stem with a permanent internal telemetry cable, a coiled-tubing unit and an auxiliary power unit. The initial specification for the drilling system requirements was described in detail previously. The conceptual design described has deviated only slightly from the original objectives. The major unfulfilled objective of the original specification is the lack of an air-drilling alternative where fluid circulation in a bore cannot be supported by the local hydrology and lithology.

Bottom-hole Drilling Assembly. The bottom-hole assembly includes: a bit, a hydraulic-powered drilling motor, an oriented bent housing to steer the drilling assembly, an orientation sub (this is the only component in the full-scale system that has not been sourced as an existing component), a steering tool attached to the telemetry cable and seated in a non-magnetic drill collar, and a connector to attach the bottom-hole assembly to the coiled tubing. Both of the candidate drilling assemblies are shown on **Fig. 8**.

A complete description of the bottom-hole-assembly components, starting from bottom of the assembly, is listed in **Table 10**, for the rotary system, and **Table 11**, for the percussion-rotary system. Two hydraulic drilling motors are sized based on the bench test results: 1) A pure rotary drilling, high power, PDM motor that should produce high drilling rates but may not provide acceptable bit life in the very hardest formations, and 2) a percussion rotary drilling motor that includes a lower power percussion motor below a very low power PDM. Other methods of rotating the percussion bit are also under investigation but are not presently "off-the-shelf" products. Percussion drilling is much better suited to drilling hard formations at lower power levels and reasonable circulation rates, and with relatively long bit lives exceeding 100 ft in granite (based on bit manufacturers estimates). The bits for both soft- and hard-rock, granite drilling are proposed as variations in the rotary drilling assemblies.

Coiled-tubing Assembly. The dimensional specifications and operating performance limits for the coiled-tubing proposed for both full-scale and half-scale systems are listed in **Table 12**. Both 1.25-in. OD and 0.75-in. OD coiled-tubing are commercial grades of tubing used for clean-out and work-over service of deep wells.

**TABLE 10 - BOTTOM-HOLE-ASSEMBLY COMPONENTS
ROTARY ASSEMBLY 1**

<u>Assembly Component</u>		<u>Off-the-Shelf Prototype</u>	<u>Half-scale Prototype</u>
Bits	Granite	2-1/4-in. DI Drag Bit 450 rpm @ 3000 lb _f	1-1/8-in. DI Drag Bit** 900 rpm @ 1500 lb _f
	Soft Rock	2-1/4-in. PDC Drag Bit 1300 rpm @ 2000 lb _f	1-1/8-in. PDC Drag Bit 1300 rpm @ 1000 lb _f
PDM Output Assembly	Bearing Pack	1.50-in. ϕ , 10-in.-long, 4000-lb _f -thrust	0.75-in. ϕ , 10-in.-long** 2000-lb _f -thrust
	Bent Housing	0 - 3 degree 1.50-in. ϕ , 4-in.-long	0 - 3 degree 0.75-in. ϕ , 3-in.-long
PDM Motor Section	Granite	1.69-in. ϕ , 104-in.-long 5 stage (5:6) multi-lobe 10-hp @ 450 rpm	0.875-in. ϕ , 52-in.-long** 4 stage (3:4) multi-lobe 5-hp @ 900 rpm
	Soft Rock	1.50-in. ϕ , 59-in.-long 3 stage (1:2) multi-lobe 7-hp @ 1300 rpm	0.75-in. ϕ , 59-in.-long 3 stage (1:2) multi-lobe 3-hp @ 1300 rpm
Orientation Sub		1.875-in. ϕ , 18-in.-long*	0.983-in. ϕ , 12-in.-long**
Drill Collar	Non Magnetic	1.875-in. ϕ , 84-in.-long	0.938-in. ϕ , 84-in.-long**
	Steering Tool	1.375-in. ϕ , 30-in.-long	0.688-in. ϕ , 50-in.-long
Total (no bit included) Dimensional	Max. OD	1.875-in. ϕ	0.938-in. ϕ
	Length	157-in.-long soft rock	156-in.-long soft rock**
		202-in.-long hard rock	149-in.-long hard rock

* This component is presently available as a hydraulic-controlled unit in 2.5-in.-diameter.
A prototype 1.875-in. will have to be developed to do real-time steering.
** These component are not presently available and require half-scale prototype development.

The proposed tubing ODs are one nominal size larger than originally proposed in the initial feasibility investigation because drilling assembly tests revealed that the bit thrust required to achieve the specified penetration rates was higher than expected. To develop the bottom-hole thrust using "surface snubbing" (oil-field terminology for "high load insertion of tubing into well"), larger tubing with a smaller radial clearance is required to prevent compressive buckling and friction lockup of the tubing in the bore. The increased tubing OD's specified are also closer to the optimum diameters for maximizing hydraulic energy transport; this is not a major element of a system for 500-ft-long bores, but will be very important if drilling of bores several-thousand-feet-long or longer is required.

Surface drilling platform. A preliminary design for a prototype surface drilling platform was developed by CTES. Their design depicted in **Fig. 3** was developed to provide a versatile field-testing platform that would be suitable for proof-of-concept demonstrations for this system and also for other deeper or longer drilling applications that other potential sponsors may require. CTES made an effort to keep the size of the

**TABLE 11 - BOTTOM-HOLE-ASSEMBLY COMPONENTS
PERCUSSION ROTARY ASSEMBLY 1**

<u>Assembly Component</u>		<u>Off-the-Shelf Prototype</u>	<u>Half-scale Prototype</u>
Bits	Granite	2.323-in. 3-cone Bit Hard Rock Inserts 300 rpm @ 3000 lb _f	1-1/8-in. Solid-Head Bit** Hard Rock Inserts 300 rpm @ 1500 lb _f
	Soft Rock	2.323-in. 3-cone Bit Soft Rock Milled Tooth 300 rpm @ 3000 lb _f	1-1/8-in. Solid-Head Bit Drag/percussion Bit 300 rpm @ 1500 lb _f
	Hydraulic Hammer		2.125-in. ϕ , 90.5-in.-long 12-joule, 40 Hz Reflector Assembly
			1.063-in. ϕ , 46-in.-long** 6-joule, 80 Hz Reflector Assembly
	PDM Output Assembly	Bearing Pack	1.50-in. ϕ , 10-in.-long, 4000-lb _f
Bent Housing		0 - 3 degree 1.50-in. ϕ , 4-in.-long	0 - 3 degree 0.75-in. ϕ , 3-in.-long
PDM Power Section		Granite 1.69-in. ϕ , 45-in.-long 2 stage (5:6) multi-lobe 3-hp @ 300 rpm	
		0.875-in. ϕ , 23-in.-long** 2 stage (3:4) multi-lobe 2-hp @ 600 rpm	
Orientation Sub	Hydraulic	1.875-in. ϕ , 18-in.-long*	0.983-in. ϕ , 12-in.-long**
Drill Collar	Non Magnetic	1.875-in. ϕ , 84-in.-long	0.938-in. ϕ , 84-in.-long**
	Steering Tool	1.375-in. ϕ , 30-in.-long	0.688-in. ϕ , 50-in.-long
Total (less bit)	Max. OD	2.125-in. ϕ	0.938-in. ϕ
Dimensions	Length	234-in.-long	166-in.-long

ϕ diameter symbol

* This component is presently available as a hydraulic controlled unit in 2.5-in.-diameter.

A prototype 1.875-in. will have to be developed to do real time steering.

** These components are not presently available and require half-scale prototype development.

platform as small-as possible but emphasized versatility and use of off-the-shelf components rather than size and weight minimization. A complete description of their design is contained in the CTES publication, "Micro Borehole Drilling Platform, October 1996." The proposed conceptual design adheres to the major design features in the CTES study, but specifies a minimum size platform to bore the 500-ft ultraslimhole and microborehole trajectory based on rudimentary calculations and estimates.

Surface drilling platform. A preliminary design for a prototype surface drilling platform was developed by CTES. Their design depicted in Fig. 3 was developed to provide a versatile field-testing platform that would be suitable for proof-of-concept demonstrations for this system and also for other deeper or longer drilling applications that other potential sponsors may require. CTES made an effort to keep the size of the

TABLE 12 - OFF-THE-SHELF COILED-TUBING DRILL STEM

<u>Tubing Description</u>			<u>Full Scale</u>	
OD		(in.)	1.25	0.75
Wall Thickness		(in.)	0.095	0.067
ID		(in.)	1.06	0.616
Minimum Yield Strength		(psi)	70,000	70,000
Load Capacity	Yield	(lb _f)	24,120	10,060
	Ultimate	(lb _f)	27,570	11,500
Internal Pressure	Yield	(psi)	10,080	11,570
	Burst	(psi)	12,720	14,730
External Pressure	Collapse	(psi)	9830	11,380
Minimum Elongation			30%	30%
Weight (empty)		(lb./ft)	1.175	0.489
Weight (full, 9 ppg fluid)		(lb./ft)	1.588	0.628
Length		(ft)	510	510
Total Weight (empty)		(lb.)	600	250
Total Weight (full, 9 ppg fluid)		(lb.)	810	320

platform as small-as possible but emphasized versatility and use of off-the-shelf components rather than size and weight minimization. A complete description of their design is contained in the CTES publication, "Micro Borehole Drilling Platform, October 1996." The proposed conceptual design adheres to the major design features in the CTES study, but specifies a minimum size platform to bore the 500-ft ultraslimhole and microborehole trajectory based on rudimentary calculations and estimates.

Reel Skid. In response to the current microborehole application, an estimate of the minimum reel-skid size is developed in **Table 13**, and the auxiliary skid size (including drilling fluid tank and drill solids separator, as well as pumps and prime mover), is developed in **Table 14**. These are the largest two components of a drilling platform; lacking a firm future sponsor for the microboreholes project at this time, only a modest effort has been made to develop these estimates, although they are believed to be achievable. Two reels are proposed: a near minimum volume reel and a reel with a minimum diagonal measurement between opposing spool walls. The dimensions of each reel probably scope the optimum reel dimensions that would be finally selected. Reel weight includes the tubing full of a water-based drill fluid.

Tubing Injector. The tubing injector is used 1) to run the bottom-hole assembly and tubing into and out of the bore at relatively high speeds, and 2) to provide a much higher snubbing force at much lower speeds to develop the required bit thrust through the coiled tubing. If the bottom-hole-assembly becomes stuck and needs to be removed, the tubing injector may also need to develop high-tension loads on the tubing. The proposed CTES injector is the smallest injector unit identified which was capable of developing the

TABLE 13 - REEL PLATFORM DIMENSION AND WEIGHT ESTIMATES

		Full-Scale Prototype	Half-Scale Prototype
Coiled Tubing OD		1.25 in.	0.75 in.
Reel Platform Dimensions and Weights			
Near Minimum Volume Spool			
Spool diameter	(in.)	50	31
Spool width	(in.)	7.5	7.5
Maximum Tubing Length	(ft)	512	512
Estimated Reel weight	(lb.)	1000	500
Near Minimum Diagonal Spool			
Spool diameter	(in.)	42	27
Spool width	(in.)	15	15
Maximum Tubing Length	(ft)	613	613
Estimated Reel Weight	(lb.)	1100	550
Frame and Bearing Load	(lb _f)	3000	1500
Swivel Specification	(psi)	3000	3000
Misc. Piping and Supports	(lb.)	325	150
Skid Dimensions - Length	(in.)	60	40
Width	(in.)	36	30
Height	(in.)	60	40
Weight	(lb.)	375	200
Tubing injector	(lb.)	2200	1100
Total Skid Weight*	(lb.)	4000	2000
* Does not include injector unit.			

required snubbing load based on CTES tubing performance simulations. This unit is recommended for a prototype drilling demonstration because it can be procured without engineering and redesign expense; however, it is believed to be considerably oversized, and it is anticipated that once field demonstrations are evaluated, it will be feasible to reduce the size of the injector significantly.

The CTES design calls for a 100-hp hydraulic pump rated for 80 hp continuous duty power for the tubing injector and the tubing tension maintenance and reeling system. This large pump is appropriate for the early proof-of-concept demonstrations; it is anticipated that the size of the hydraulics unit can be reduced significantly when its use is limited to shallow and short-bore drilling operations. The CTES specified injector and power unit is sized to inject and retrieve 1.25-in.-OD coiled tubing at 50-ft/min in deep-well operations where continuous high-tension loads (the hanging weight of a very long tubing) during high speed tubing operations (running into and out of the hole). The injector is also sized to bend, straighten, and re-bend the tubing as it is extracted from the bore, run over a gooseneck, and bent onto the reel under

TABLE 14 - AUXILIARY PLATFORM DIMENSION AND WEIGHT ESTIMATES

		<u>Full-Scale Prototype</u>	<u>Half-scale Prototype</u>
Drilling Fluid Tank			
Capacity (2 x bore volume)	(gal)	230	60
Dimensions	(in)	42 x 42 x 30	30 x 30 x 15
Estimated weight	(lb.)	110	50
Estimated weight full	(lb.)	2025	550
Fuel Tank			
Capacity (2 x bore volume)	(gal)	230	70
Dimensions	(in)	42 x 42 x 30	30 x 30 x 19
Estimated weight	(lb.)	110	50
Estimated weight full	(lb.)	1650	385
Pumps			
Drill-fluid Pump	(hhp)	50	12.5
Hydraulic Pump	(hhp)	10	5
Pump Weight @ 5 lb./hp	(lb.)	300	90
Prime-mover			
Weight @ 3 lb./hp	(lb.)	270	75
Misc. Piping and Supports	(lb.)	300	150
Skid Dimensions - Length	(in)	72	60
Width	(in)	36	30
Height	(in)	60	30
Weight	(lb.)	450	300
Total Skid Weight*	(lb.)	5000	1250
Weight of Surface Platform*	(lb.)	9000	3250
* Includes tanks full of water-based drilling fluid and diesel			

tension. The proposed CTES design calls for elimination of the goose neck, and this recommendation has been included in the conceptual designs. With a shallow bore limitation, no goose neck, and a maximum tubing injection rate of 200-ft/hr = 3-1/3-ft/minute for snubbing, the power requirements for the injector have been reduced from 80-hp-continuous to 10-hp-continuous for the conceptual design of the full-scale system, and 5-hp for the half-scale system. In order to achieve this reduction in power requirements, a significant change in the hydraulic control system will be necessary.

Conductor Pipe. The tubing injector is mounted on the diverter head which is attached to a conductor pipe. To seal the conductor pipe to the earth, the conductor pipe is drilled through any loose soil into at

least five-feet of firm, compacted soil, or two-feet of rock or concrete. The total length of the conductor pipe, diverter head, and a clamshell bit window on the bottom of the injector, should be long enough to contain the shortest drilling assembly that can be assembled to produce the first (straight-hole) bit run. The assembly will be inserted through the injector and attached to the end of the coiled-tubing position just below the tubing snubber. The first bit run should drill far enough to allow insertion of a complete directional drilling assembly.

Auxiliary Platform. The auxiliary platform includes: 1) the drilling fluid tank (filled with a water-based drilling fluid), 2) a single prime mover that powers both a hydraulic pump and a drilling fluid pump, and 3) piping and supports for the pumps and tanks. The platform also includes a fuel tank filled with petroleum-based fuel, and sized to operate long enough to drill and complete a single 500-ft-long drilling operation in hard rock. Weight estimates for pumps and the prime mover are based on scaling of catalogue equipment: 1) pump weights are based on oil-field submersible pumps of comparable capacities and operating pressures, and 2) the prime mover weight is based on an industrial gas-turbine drive for a 60 Hz AC generator unit. These low weight components assume relatively high-speed operation of essentially throw-away components. Proof-of-concept components would be more conventional, larger, and much heavier.

Circulation System. The drill-fluid circulation system is a closed but vented system that includes: a suction pipe on the bottom of the drill-fluid tank, a high-pressure injection pump, a discharge pipe, a high-pressure swivel to connect to the discharge to the dead end of the coiled tubing, the coiled-tubing drill stem, the bottom-hole assembly, the bit, the bore annulus, the diverter head, the flow line return pipe, and the storage tank. A schematic of the circulation system is shown in **Fig. 9**. The storage tank includes: a baffled settling tank that drops the cuttings to replace the volume of fluid lost to the growing bore volume, a screened overflow to a suction tank, and the suction tank to provide the suction head required for the circulation pump. The pump will be located on the bottom of the platform, while the tank is on the top of the other components (the fuel tank, pumps and prime mover[s]). Assuming no loss of fluid in the bore or at the tubing seal in the diverter, the fluid level should remain constant once the surface piping and conductor pipe are full. The settling tank volume is 1.5 times the volume of the maximum bore volume, and the suction tank volume is half the maximum bore volume. The baffles and overflow to the suction tank should be level-controlled with floats to assure that the suction tank supply is not interrupted if some fluid is lost to the bore.

Cost Estimate and Schedule. **Table 15** shows a preliminary cost estimate for the drilling systems. These costs are intended to be used for proposal preparation, and are not engineering cost estimates suitable for procurement guidance. Based on the procurement of components to date, the full-scale components can be specified, procured and assembled for testing in six months. Delivery time for prototype half-scale components and assemblies are much less certain until a more specific performance requirement is developed for a specific sponsor; however, it is believed that first prototypes for evaluation can probably be delivered within an eighteen-month schedule.

DISCUSSION

Pneumatic Air Drilling. The initial investigation of components for the microborehole-drilling system included a brief survey of pneumatic-powered drilling components. It was anticipated that a concept for an air-drilling alternate system would allow drilling in areas where fluid returns would not be anticipated. The air drilling system was de-emphasized when it became apparent that air turbine motors that would fit in a microborehole were severely under-powered for drilling granite, and that pneumatic hammers were not

TABLE 15 - Cost Estimate for First Prototype Drilling System

	Full-Scale Prototype	Half-Scale Prototype
	(\$1000)	(\$1000)
Bottom-hole Assembly		
Bits - 5 each per bore	5	3
PDM - Motor	20	20
HHD-Motor	10	10
DC's and Subs	5	3
Orientation Sub	10	10
Steering Tool	45	100*
Total BHA	95	146
Coiled-Tubing With Telemetry Wire	5	4
Surface Platform		
Tubing Injector	100	100
Hydraulic System	60	40
Divertor and Conductor	5	5
Drill-fluid Pump	15	12
Prime Mover	20	12
Reel with frame and drive	40	35
Skid piping and supports	10	8
Tanks and Separators	10	8
Total Surface Platform	260	220
Total Drilling System	360	370
Assembly and Performance Check	40	30
Total	400	400
* Includes one-time design and engineering costs for miniaturization.		

sourced in a 2-1/4-in. (or smaller) size. There has been some success reported operating PDM's with air, but little information has been published on the performance of these motors with compressible fluids. The life expectancy of PDM stators using air is greatly reduced due to excessive friction heating of the stator and bearings. Injection of detergent in water at 2- to 5-gpm will provide good lubrication and also may avoid explosive decompression of the stator and other elastomeric parts when the air pressure is reduced (Graham 1996).

Pneumatic systems will require little drilling fluid if mist or foam is used. This potential reduction in weight and size of the drill platform will be somewhat offset by the significantly lower efficiency of the compressors and air motors as compared to pumps and hydraulic motors. Reduction of drill-fluid weight and tank volumes may be more than offset by a larger fuel tank, a larger prime mover, compressor, and solids separator.

RECOMMENDATIONS

Directional ultraslimhole drilling and microborehole drilling systems for hard rock should be assembled, field tested, and demonstrated for potential sponsors of high performance drilling research and development. The proposed conceptual design promises a highly versatile drilling platform that can be the basis of a comprehensive drilling research and development program.

Various drag bits, including several designs of PDC and thermally stable diamond cutter bits, need to be evaluated for drilling granite. The Sandia work on PDC bits for geothermal drilling showed promising results for 8-1/2-in. PDC bits in Sierra White Granite. Theoretically, PDC bits should perform better in microborehole dimensions due to the greatly reduced velocity of the outside cutters. The calculated specific energy of single PDC cutters (**Glowka 1989, Part 1**) is 20% lower than the diamond bit (**Test 519, Table 1**), and 85% lower than the 3-cone bit. PDC bits should operate at lower bit thrust than diamond-impregnated bits or multi-cone bits.

Prototype air-drilling systems should be developed as full-scale, 2-1/4-in.-diameter bore systems and evaluated in a drilling laboratory. There is no theoretical reason that they should not provide a high performance drilling system. PDM dynamometer testing with air, mist, and foam should be conducted, and the results reported in the open literature. Sandia has reported penetration rates as high as 70-ft/hr in Sierra White Granite (**Finger 1984**), using 8-in.- and 8-1/2-in.-diameter, solid-head percussion bits on an industrial air hammer.

Tubing injection systems need to be optimized for shallow drilling. An investigation needs to be completed to determine if commercial sources for a system, or components that can be used to assemble a system, are available before a conceptual design effort is initiated.

CONCLUSIONS

A conceptual design for a full-scale, ultraslimhole-sized drilling system has been developed from essentially off-the-shelf commercial components and subassemblies. This system can be procured, assembled, and evaluated under field-drilling conditions within a 12-month schedule.

A conceptual design for a half-scale, microborehole-sized drilling system has been developed by scaling off-the-shelf commercial components and subassemblies. No obvious need for breakthrough technology was discovered; development of prototype assemblies for bench testing should be developed within a 12- to 18-month schedule. Once the prototypes are successfully tested, this system can be procured, assembled, and evaluated under field-drilling conditions within a 24-month schedule.

No rationale was found that precludes the construction of 500-ft-long, 1-1/8-in.-diameter bore holes using a coiled-tubing deployed, hydraulically powered, drilling assembly. In fact, drilling process analysis projects that the proposed conceptual-system design can readily be adapted to support drilling 3000- to 5000-ft-long trajectories in soft and medium-hard rocks that will require lower bit thrust and bit power.

Drilling demonstrations of critical bottom-hole components and straight-hole drilling-assemblies determined that penetration rates of 20-ft/hr can be achieved in granite, and that much higher rates are readily produced in softer rocks. The drilling power and trust required to produce these results can be delivered through a coiled-tubing drill stem, and supplied by a relatively conventional surface-drilling assembly with appropriately scaled components.

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Figure 1. Schematic of the microdrilling concept.

Figure 2. Test 529- rotary drilling results for the single-lobe PDM and PDC bit in Carthage Marble.

Figure 3. Schematic of coiled-tubing unit configured to drill a vertical trajectory Side View.

Figure 4. Theoretical maximum drilling rates versus hole diameter.

Figure 5. Bottom-hole-hydraulic power available normalized to unit bore area as a function of hole diameter for various ratios of $\xi = D_o / D_h$, the ratio of tubing to hole diameter: Coiled-tubing depth = 10,000 ft, $OD = \xi * D_h$, $D/t = 8$; Drilling Fluid, $\rho = 8.34$ lb/gal, $n = 0.7$, $K = 0.15$ lb_f *secⁿ/ 100 ft². Pump pressure = 11,000 psi, $Q = 4.7$ gpm for 1.125 in diameter hole.

Figure 6. PDM dynamometer testing results for single lobe , 1.5-inch diameter motor.

Figure 7. Schematic of percussion drilling test stand.

A. PDM Rotary Drilling Assembly for Directional Drilling

B. HHM Percussion Rotary Drilling Assembly for Directional Drilling

Figure 8. Schematic of proposed conceptual drilling assemblies.

Figure 9. Schematic of the drilling fluid circulation loop.