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Balanced Pressure Techniques Applied to Geothermal Drilling

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BALANCED PRESSURE TECHNIQUES
APPLIED TO GEOTHERMAL DRILLING

Sandia Contract #62-7201

TR81-4

by

Don W. Dareing

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SUMMARY

Geothermal drilling often takes place in high surface relief areas where ground water tables are a considerable distance (1,000 ft) below rig level. Above the water table, formation pore pressure is zero. Below the water table, formation pore pressure increases with depth at a rate depending on formation temperature. Pressure unbalance between wellbore drilling fluid and formation pressures exists from spud-in and drives drilling fluid into the formation when voids are encountered at the drill bit. When this happens, portions or all of the drilling fluid does not return up the drill pipe/wellbore annulus to the rig, instead it flows into the voids. Thus, the term "lost circulation."

When lost circulation occurs, it is common practice to add lost circulation material to the drilling mud to plug the voids or to squeeze cement into the voids to plug them. Other approaches, sometimes called balanced pressure drilling techniques, eliminate the unbalance between undisturbed formation pressure and circulating fluid pressure. The mud circulating system and drilling mud are designed to produce a hydrostatic downhole pressure distribution which matches or closely approximates the vertical formation pore pressure distribution. This report covers only the later techniques.

The objective of the study is to evaluate balanced pressure drilling techniques for use in combating lost circulation in geothermal drilling. Drilling techniques evaluated are:

- . Aerated drilling mud
- . Parasite tubing
- . Concentric drill pipe
- . Jet sub
- . Low density fluids

Based on the present state of the art of balanced pressure drilling techniques, drilling with aerated water has the best overall balance of performance, risk, availability, and cost. Aerated water with a 19:1 free air/water ratio reduce maximum pressure unbalance between wellbore and formation pressures from 1,000 psi to 50 psi. This pressure unbalance is within acceptable operating limits; however, air pockets could form and cause pressure surges in the mud system due to high percent of air.

Low density fluids used with parasite tubing has the greatest potential for combating lost circulation in geothermal drilling, when performance only is considered. The top portion of the hole would be aerated through the parasite tube at a 10:1 free air/mud ratio and the low density mud could be designed so that its pressure gradient exactly matches the formation pore pressure gradient. The main problem with this system at present is the high cost of ceramic beads needed to produce low density muds.

I. INTRODUCTION

Lost circulation can be defined as excessive loss of drilling mud to exposed formations. Slight "seepage" losses or loss of the liquid portion of the mud by filtration is usually not considered lost circulation.

Lost circulation occurs when there are openings in the formation large enough to accept and store the lost mud, and there is sufficient pressure differential to force the mud into the formation. Drilling experience has suggested that these openings vary in width from a fraction of an inch to several feet, and the necessary annulus pressures to force the fluid into the formation vary from a few psi to many thousands of psi.

The loss of drilling fluids and their costly constituents is only one of the detrimental effects experienced when circulation is lost. The loss of drilling time, plugging of potentially productive formations, stuck drill pipe, blowouts, excessive inflow of water, and excessive caving of formations are other effects which make the control and prevention of lost circulation one of the most challenging problems of the geothermal drilling industry. It is not uncommon to abandon wells due to failure to regain circulation.

Types of formations or subsurface conditions which cause or are susceptible to, lost circulation fall into four categories:

1. Natural or Intrinsic Fractures
2. Induced or Created Fractures
3. Cavernous Formations (crevices and channels)
4. Unconsolidated or Highly Permeable Formations (loose gravels)

Lost circulation can be eliminated by two techniques: 1) sealing formations so that drilling fluid will not flow into them and 2) reducing drilling fluid pressure in the wellbore so that it very nearly balances the formation fluid pressure. In the case of induced fractures, the wellbore fluid pressure must be reduced since the fractures are produced by the fluid itself.

Lost Circulation Materials

When lost circulation occurs in geothermal wells, it is common practice to add lost circulation materials to the drilling mud to attempt to plug the formation (Figure 1).

Figure 1. Sealing Fractures with Lost Circulation Material

Various types of lost circulation materials are used in geothermal wells including:

1. Cottonseed Hulls	7. Saw Dust
2. Crushed Nut Hulls	8. Chopped Automobile Tires
3. Wood Fibers	9. Cellophane
4. Asbestos	10. Polyethylene
5. Paper Pulp	11. Phenolic Resin Chips
6. Rock Wool	

Extensive R&D has been conducted to determine the optimum size mixtures of materials to effectively bridge matrix dominated lost circulation zones (Figure 2).

Figure 2. Lost Circulation Bridging Phenomenon

Studies show that the presence of a suitable lost circulation material in the mud at the instant fractures occur or are encountered, plug the fractures immediately and thereby prevent the fluids from entering and widening the fractures. Such a preventive measure achieves its effectiveness by sealing the fractures in their incipient state rather than after they have been widened and extended by inflow of drilling mud.

Although there are lost circulation materials which are very effective in oil and gas drilling, they are often ineffective in geothermal drilling because the natural fractures occurring in geothermal wells are often much larger than those occurring in oil and gas wells.

Squeeze Cementing

If lost circulation cannot be controlled in geothermal wells by the use of lost circulation materials, the next corrective measure usually taken is to locate the lost circulation zone with various surveys (e.g., temperature or spinner) and then squeeze cement into the formation (Figure 3).

Figure 3. Squeeze Cementing

With this technique, the lost circulation zone is isolated with one or more packers and cement is pumped into the formation. Squeeze cement jobs often fail and it is common to have to run 3 or 4 squeeze cement jobs before the lost circulation zone is sealed off.

Pressure Reduction Methods

In many geothermal formations ground water is located a considerable distance below ground level. This is typical of high surface relief areas (e.g., mountainous terrain). In addition natural fractures may exist in both the dry upper formation and in the lower wet formation (Figure 4). This type of geology is difficult to drill through because drilling fluid can be lost to the formation through the natural fractures. Lost circulation occurs when the hydrostatic pressure in the wellbore exceeds the hydrostatic pressure of fluids in the formation.

Figure 4. Shallow Drilling in High Surface Relief Areas

Serious lost circulation problems can exist when drilling the dry upper zone with water or mud as shown in Figure 4, since there is no fluid pressure in the natural fractures of the dry zones. Air, mist or foam are often used to drill these dry zones to avoid fluid loss to the formation.

If air drilling is used in the formation below the water level, formation fluids will invade the wellbore and cause air drilling to become ineffective (Figure 5). Air is too light for drilling in these wet formations.

Figure 5. Deep Drilling with Air

If water is used as a drilling fluid in the wet region of this example well, lost circulation can occur because the column of water in the wellbore is longer than the equivalent column of water in the formation, i.e., there is higher fluid pressure in the wellbore (Figure 6). The difference in pressure between the borehole and formation fluids (Δp) tends to force the fluid in the wellbore into the formation.

Figure 6. Deep Drilling with Water

For example, if the formation water level is 2,000 ft below ground level, hydrostatic water pressure in the annulus will be approximately 870 psi greater than water pressure in the formation. This pressure differential (ΔP), can create a high flow rate into a large natural fracture system.

In this example, water is too heavy and air is too light. A drilling fluid with an effective density less than water and greater than air is therefore needed to balance the pressures.

To eliminate fluid flow into the formation, the pressure difference, p must be reduced to zero. When Δp is zero, wellbore fluid pressure is balanced with formation pressure and fluid will not leak into the formation or into the wellbore. If these pressures are balanced, it is not necessary to seal off the lost circulation zones. This type of drilling is sometimes referred to as balanced pressure drilling. Balanced pressure drilling also refers to techniques that reduce Δp to acceptable levels, not necessarily zero.

In this report we evaluate various pressure balanced drilling techniques as alternatives to plugging lost circulation zones in geothermal boreholes. Drilling techniques that are evaluated are:

- . Aerated Drilling Fluids
- . Parasite Tube Method
- . Concentric Drill Pipe
- . Jet Sub Method
- . Low Density Fluids

These techniques were developed for oil and gas drilling for two main reasons: 1) to combat lost circulation by reducing pressure difference between drilling mud and formation fluid and 2) to increase rate of penetration by reducing hydrostatic overburden pressure at the bit.

II. OBJECTIVE OF STUDY

Present techniques for combating lost circulation include squeeze cementing and pumping lost circulation materials into the fractured zones. As much as 30 percent of the cost of drilling geothermal wells is related to lost circulation. There is incentive, therefore, to explore other techniques to reduce those costs since these techniques have not proven to be very effective for geothermal drilling. Balanced pressure techniques have been used successfully in drilling areas of high relief for oil and gas, and there is reason to believe these techniques may be effective in geothermal drilling.

The objective of this study is to evaluate balanced pressure drilling techniques for possible use in drilling geothermal wells and recommend a preferred technique for further development. The scope of the work covers the early stages of the engineering development process (Figure 7) but stops short of developing a preliminary design.

Cement may also be lost to the formation while casing a hole. If pressure reduction techniques are applied to get through the fractured zone, and the lost circulation zone is not plugged during drilling, cement will most likely be lost to the formation. Until balanced pressure cementing techniques are developed, balanced pressure drilling techniques apply only to geothermal production intervals which are uncased.

Figure 7. Engineering Development Process

III. DEFINITION OF OPERATING CONDITIONS

Before the evaluation can begin, it is necessary to establish what the pressure balance techniques should do and to document specific requirements. This documentation becomes the engineering baseline for the study.

In general, all requirements placed on a typical onshore drilling system apply to the pressure balanced techniques. In this section we identify additional requirements as related to geothermal drilling.

Since balanced pressure techniques equalize wellbore pressure with formation pressure, one specification is definition of formation pressure magnitude and distribution. Two pressure profiles were defined, based on field data, as formation pressure requirements. One is typical of hot liquid production areas (Figure 8) such as the Baca area and the other is typical of steam production areas (Figure 9) such as The Geysers.

In both cases formation fluid pressure is zero from the surface to a depth of 1,000 ft since this is the water table level. Beyond this depth the formation pressure increases with a pressure gradient depending on formation temperature. In areas of high relief, surface ground water has been drained out causing an unbalanced pressure condition from the start of drilling. Formation pressure starts from the underground water level, not from the surface. Linear pressure distribution with depth assumes vertical permeability which is usually the case in geothermal wells.

The slope of the formation pressure distribution line is less than the slope of pressure distributions corresponding to unheated water

Figure 8. Drilling and Completion Condition in the Baca Region

Figure 9. Drilling and Completion Condition in the Geysers

(8.34 lbm/gal) and drilling mud (10 lbm/gal). The slope of the formation pressure line corresponds to a water density of 6.13 lbm/gal which is the density of water heated to 550°F (288°C). Table 1 shows volume expansion ratios and densities for water at various temperatures.

Table 1
Temperature Effect on Water Properties

<u>Temperature</u>	<u>Expansion Ratio</u>	<u>Density (lbm/gal)</u>
68°F (20°C)	1.00	8.34
350°F (177°C)	1.12	7.45
400°F (204°C)	1.16	7.19
450°F (232°C)	1.20	6.95
500°F (260°C)	1.27	6.57
550°F (288°C)	1.36	6.13
600°F (316°C)	1.47	5.47

Assuming a formation temperature of 550°F gives a formation water density of 6.13 lbm/gal which corresponds to a pressure gradient of 0.319 psi/ft.

The bottom portion of the assumed formation pressure (Figure 8) agrees with measured pressures in the Baca area (Figure 10). Saturation pressures corresponding to measured formation temperatures are lower than the formation pressures assumed in Figure 8, therefore 550°F ground water is in the liquid phase. According to reference (1), measured reservoir pressure at 3,000 ft above sea level (about 6,000 ft downhole) is 1,695 psi. The assumed pressure at 6,000 ft agrees with this measured pressure.

The pressure distribution corresponding to cool water (8.34 lbm/gal) and 10 lbm/gal mud are also shown in Figures 8 and 9 to show the pressure unbalanced condition causing lost circulation. Temperature of the circulating fluid is assumed to be 200°F, which does not change the density of drilling fluids significantly.

In The Geysers, the formation pressure is assumed to be 500 psi in the production zone and this formation pressure change is shown in Figure 9. The discontinuity in formation pressure is due to an impermeable caprock covering the reservoir. Steam in the Geysers reservoir is known to be superheated. Saturation temperature of steam at 500 psi is 467°F. Therefore a 550°F reservoir temperature superheats the steam (2).

Specific operational requirements placed on the various pressure balance drilling techniques are:

- 1) Annulus drilling fluid pressures must match formation pressures or produce pressure differences that constrain fluid flows either into or out of the formation to an acceptable operational level. The acceptable level of pressure unbalance depends on fracture permeability or Darcy permeability and will have to be established on site.
- 2) Downhole equipment must operate in the borehole and casing sizes identified in Figures 8 and 9. These sizes are consistent with present geothermal drilling and completion practices.
- 3) Pressure balance and well control should be maintained while tripping.
- 4) Cuttings lifting capability must be achieved without hole or equipment damage caused by velocity related erosion.

Figure 10. Current Static Conditions at Baca 11

- 5) Techniques must interface with standard drilling equipment and practice.
- 6) They must operate in high temperature environment.
- 7) They should have operational flexibility.

In the volume and pressure calculations in this report the average drilling fluid temperature was assumed to be 200°F. In high elevations such as the Baca, this means mud returns may flash into steam near the surface. This, however, has no significant effect on downhole pressure.

Absolute air pressure for different altitudes was taken from the data in Table 2. The absolute pressure at the Baca was assumed to be 10.5 psia and the absolute pressure at the Geysers to be 13.7 psia.

Table 2

ABSOLUTE AIR PRESSURE VERSUS ALTITUDE

<u>Altitude Above Sea Level, Ft.</u>	<u>Pressure, PSI</u>	<u>Altitude Above Sea Level, Ft.</u>	<u>Pressure, PSI</u>
0	14.70	6,000	11.77
500	14.42	6,500	11.55
1,000	14.16	7,000	11.33
1,500	13.91	7,500	11.12
2,000	13.66	8,000	10.91
2,500	13.41	8,500	10.70
3,000	13.16	9,000	10.50
3,500	12.92	9,500	10.30
4,000	12.68	10,000	10.10
4,500	12.45	10,500	9.90
5,000	12.22	11,000	9.71
5,500	11.99		

Calculations in the report use the following weights and measurements:

1 ft³ = 7.48 gal

1 barrel = 42 gal

Drilling mud is a mixture of

- . low solid gel
- . lignite
- . fresh water

and has a density of 10 lbm/gal with a 0.519 psi/ft pressure gradient.

Fresh water density is 62.4 lbm/ft³ (8.34 lbm/gal) with a 0.433 psi/ft pressure gradient.

IV. PRESENT DRILLING AND COMPLETION PRACTICE

The purpose of this section is to give a brief review of present drilling and completion practices for the Baca and the Geysers areas. Each individual well has its own unique drilling problems so the discussion below will not exactly fit all cases.

Baca

Reservoir formations in this area are considerably under pressure. As a result, drilling mud often causes severe lost circulation due to the large pressure differential between the wellbore and the formation. Drilling with air causes hole sloughing and possible loss of the hole. In order to combat lost circulation and maintain hole stability, aerated water is sometimes used as a drilling fluid. Air is injected with water under pressure at the surface and expands in the annulus as wellbore pressure reduces. Most of the air expansion takes place over the top 2,000 ft of the annular fluid column. Drill pipe corrosion is often a major problem with aerated water. Various inhibitors are used in an attempt to combat this corrosion problem. The general procedure followed in drilling wells in the Baca area is outlined in Table 3 (3).

Table 3

DRILLING PROCEDURE FOR BACA

- (1) Drill 17-1/2 inch hole to ~200 ft using mud.
- (2) Open 17-1/2 inch hole to 26 inch.
- (3) Run and cement to surface 20 inch 94# H-40 STE+C casing at ~200 ft with Class "B" cement mixed with CaCl_2 .
- (4) Drill 17-1/2 inch hole to ~1,500 ft using gel-water mud.
- (5) Run IES log from 1,500 ft to 200 ft.
- (6) Run and cement to surface 13-3/8 inch 54.5# K-55 buttress blank casing at ~1,500 ft. Cement design will depend on hole conditions to ensure returns to surface.
- (7) Land casing and install 12 inch - 600 series casing head, 12 inch -900 series BOP including kill and blow down lines. Test casing and BOP to 0.8 psi/ft with water.
- (8) Drill 12-1/4 inch hole to ~3,000 ft using treated water, aerated if necessary, to maintain circulation.
- (9) Run, hand, and cement 9-5/8 inch 36# K-55 buttress blank liner from ~3,000 ft to ~1,300 ft. Cement design will depend on hole conditions to ensure returns above liner lap.
- (10) Test 9-5/8 inch casing and lap to 0.8 psi/ft with water.
- (11) Drill 8-3/4 inch hole to ~6,000 ft using aerated water. Total depth is controlled by definitive evidence in drill cuttings that Paliza Canyon Andesite has been penetrated.
- (12) Test well through a two-phase orifice meter to the drilling mud sump for sufficient duration to establish evidence of productivity in the Bandelier Tuff.
- (13) Clean out to bottom and cool hole with water.
- (14) Run and hang 7 in 26# K-55 buttress liner with combination of blank and slot perforated joints.

- (15) Set drillable bridge plug in 9-5/8 inch liner at ~1,400 ft. Test liner lap and bridge plug to 0.8 psi/ft with water.
- (16) Run and cement 9-5/8 inch 36# K-55 buttress blank tie back casing string from top of liner hanger to surface.
- (17) Drill out cement, wash over and retrieve bridge plug.
- (18) Install production head and valves and release rig.

The Geysers

Wellbore and casing sizes for The Geysers are the same as for the Baca; hole depth and casing length are somewhat different. The overburden formation covering the production zone is drilled with a drilling fluid made up of a mixture of low-solids gel, lignite, and fresh water.(4)

Lost circulation zones are large fractured zones. Lost circulation is usually controlled with cottonseed hulls. Occasionally, lost circulation zones must be cemented.

Air is also used as a circulating medium because of the increased drilling rates and lost circulation control. Many times air cannot be used in the top section of the hole because of water zones. However, air is used in drilling the steam producing zone to avoid damaging the producing capacity of the well.

When lost circulation is encountered, the formation is plugged before drilling proceeds. It is common practice to never bypass a lost circulation zone without plugging it.

V. BALANCED PRESSURE DRILLING TECHNIQUES

Ideally, the pressure unbalance or pressure difference would be zero so that no fluid flows either from the wellbore into the formation or from the formation into the wellbore. This may not be practical. Balanced pressure drilling techniques are practical when fluid loss to the formation or formation fluid invasion of the wellbore is within acceptable limits.

In this section we describe six pressure balance or pressure reduction techniques used to combat lost circulation problems in oil and gas drilling. They are

- Aerated Drilling Fluids
- Parasite Tube Method
- Concentric Drill Pipe
- Jet Sub Method
- Low Density Fluids

In discussing each, we point out advantages and disadvantages based on experience in drilling oil and gas wells. Their application to geothermal drilling will be covered in the next section.

Aerated Drilling Fluids

Aerated drilling fluids as used here refers to mixtures of

- 1) air and mud (aerated mud) and
- 2) air, surfactants, and mud (foam).

In both cases the mixtures are developed at the surface and pumped downhole. Pressure reduction in the annulus is due mainly to the

expansion of the air and corresponding reduction in density of the aerated mud as the aerated mud travels up the annulus. Both types of aerated mud systems are currently used to control lost circulation and/or increase penetration. While the downhole pressure profiles are almost identical for aerated muds and foams for a given air/mud ratio, there are basic differences in the application of these systems.

Air injected at the surface is injected at the same pressure as the mud pump pressure (about 500 psi) and as a result air is highly compressed and has an insignificant effect on the density of the drilling mud inside the drill pipe. In other words, the hydrostatic pressure distribution of the air/mud mixture inside the drill string is very nearly the same as the hydrostatic pressure distribution (gradient) of nonaerated drilling mud.

Even the pressure drop across a drill bit does not allow significant expansion of the air/mud mixture because of the high bottom-hole fluid pressure. As the air/mud mixture travels up the annulus toward the surface, the air does not expand significantly until it nears the 2,000 ft depth level (5). Below 2,000 ft, the density of the air/mud mixture is nearly the same as the density of nonaerated mud. This is shown in Figure 11 by the nearly parallel pressure curves below 2,000 ft.

Pressure distribution curves for different air/water mixtures, given in Figure 11, show the impact of air/water ratios on downhole pressure. If water is not aerated, the pressure varies linearly with a 0.433 psi/ft gradient and there is about a 1,000 psi bottom-hole pressure difference into the formation. An air/water ratio of 20:1 produces a 50 psi bottom-hole pressure difference into the wellbore. Tables A1 to A5 give bottom-hole pressure conditions for air/mud ratios ranging from 0 to 20 (6).

Figure 11. Aerated Water Pressure Profiles

Air/water ratios are ratios of volume of air (at mud exhaust temperature and pressure; 200°F average mud temperature and ambient atmospheric pressure at drilling site elevation) to a unit volume of water. This ratio, however, reduces downhole due to increases in hydrostatic annulus pressure. The specified air/water ratio is sometimes called free air/water ratio, except in this case, we take 200°F as the free air temperature. Free air can be converted to standard air by the perfect gas law.

The pressure curve for a given air/mud ratio would be the same in the annulus had the air been injected at the drill bit level instead of at the surface. Furthermore, the pressure curve above any depth level would be the same had the air been injected at the corresponding air/mud ratio at the given depth level.

Aerated mud drilling is a direct extension of conventional mud drilling. Air compressors are used to inject air at the desired pressure and volume rate. The pressure required depends on pressure losses in the fluid circuit. Air volume rates depend on the selected air/mud ratio and on the mud flow rates delivered by the mud pumps, but normally range between 10:1 to 20:1. The higher the air/mud ratio, the lighter the mud column pressure and the higher the risk of fluid heading or slugs of air moving in the mud. Bit hydraulics is unaffected by the entrapped air because the air is still highly compressed around the drill bit. The air/mud mixture is separated at the surface and the mud pumped back to the mud pits. Some of the advantages of aerated mud are:

- Successful in reducing hydrostatic pressure to combat lost circulation.
- Increases drilling rate

Disadvantages of aerated mud are:

- Air separation or heading in the annulus produces pressure surges which can damage the wellbore and surface equipment.
- Air/mud ratios are limited to a maximum of 20:1 due to air pockets or heading (5).

- Drill pipe corrosion is a serious problem due to oxygen dissolution in the mud. Corrosion can destroy a string of drill pipe in the time required to drill one well.

Foam is another type of aerated drilling fluid and is a further extension of air/mud drilling. The main difference is the injection of detergent into the air/mud mixture at the surface. The air/detergent/mud mixture is highly compressed in the drill pipe and across the bit with expansion taking place in the annulus near the surface as in the case of air/mud mixture. As the air expands, it is entrapped in foam. The foam inhibits heading or the forming of large bubbles in the mud. It maintains a homogeneous mixture of air and mud at lower velocities and allows greater air/mud ratios so that greater annulus pressure reductions can be achieved. Principal foam equipment includes an air compressor; tanks for blending water, surfactant and additives; surfactant solution pump; foam generator, and injection manifold.

Foams can be prepared with densities as low as 2 lbm/ft by carefully controlling components mixing and selection. Bottom-hole pressure measurements have indicated actual pressures of 15 psi at 1,000 ft and 50 psi at 2,900 ft while circulating. Foam should have a gas-to-liquid volume ratio from 3 to 50 cu ft/gal (7) which is equivalent to air/mud ratios of 22:1 to 374:1.

One detrimental feature of foam mud systems is that the foams cannot be recirculated. There is no means yet to economically break down the discharged foam for reuse. Foam disposal is therefore a major problem in many drilling operations.

Both stiff and stable foams are used for drilling. Stiff foams were developed by the Atomic Energy Commission in the 1950's to lift cuttings out of large diameter holes in Nevada. A combination of gel-based mud and surfactants is used which has excellent hole cleaning and

wall building capabilities. These stiff foams are difficult to break down and they are therefore unattractive from an environmental standpoint.

Stable foams are a completely mixed air/liquid dispersion in which the liquid is the continuous phase and the air is the discontinuous phase. They have the consistency of shaving lather and can support solids entrained in them.

Advantages of foams as drilling fluids are:

- More stable than straight aerated muds because air pockets do not form
- High penetration rate
- High solids carrying capacity
- Good hole cleaning capability
- Can handle large influxes of formation fluids
- Can maintain air/mud ratio at low velocities and thus allow much higher air/mud ratios
- Useful in big holes where annular mud velocity is low
- Useful where hole sloughing is a problem and annular velocity must be kept low

Disadvantages of foams as drilling fluids are:

- High foamer cost
- Careful proportioning required
- Specialized equipment required for measuring and regulating liquids and air proportions and quantities
- Foam is not reusable and must be discharged into surroundings
- Must meter carefully to know what is in the hole; in straight aerated muds, volume of mud in pits indicates air/mud ratio

Parasite Tube Method

This method consists of attaching tubing to intermediate casing as a means of injecting air into the drill pipe/casing annulus at depths of about 2,000 ft (Figure 12). This allows air expansion over the top portion of the annulated mud column without circulating air down the drill pipe. The lower air/mud density reduces mud pressure downhole and thus reduces the pressure unbalance into the formation. The parasite tube should be set as deeply as possible, but beyond 2,000 ft it does not reduce bottom-hole pressure significantly.

The pressure profile above the point of injection is the same as the pressure profile for surface aerated mud system having the same air/mud ratio. Below the point of injection the pressure profile is linear with a pressure gradient corresponding to the mud density.

The parasite tube method has been used successfully in oil and gas drilling in high relief areas such as in the Rocky Mountains. Shell was one of the first to use this method to combat lost circulation problems. They attached a 1-1/2 inch ID tubing to a 13-3/8 inch intermediate casing string and injected air into the annulus at about 2,500 ft. Tenneco (8) used this method successfully in Garfield County, Utah to solve lost circulation problems. Other techniques such as the use of lost circulation material, conventional aerated mud, and stiff foam were unsuccessfully tried prior to using the parasite tube method.

The main attraction of the parasite tube method is the aeration is separate from the drilling system and does not interfere with the normal drilling operation. Conventional hydraulics and standard bit nozzles can be used.

Figure 12. Parasite Tube Arrangement

Other advantages of the parasite tube method are:

- Aeration can continue while making trips (major advantage).
- Avoids major pressure surges after trips and connections.
- Lower pressure required by compressor
- Technical supervision is not required so average rig crews can aerate successfully with this technique
- There is no lost time while making connections and reestablishing circulation after trips
- Minimum equipment is required
- Bottom-hole conditions are essentially the same as conventional mud drilling. Jet-bit programs and good hydraulics can be utilized
- Air does not contact the open hole so air erosion of the formation is non-existent
- Corrosion is minimized and easily controlled

Disadvantages of the parasite tube method are:

- Parasite tubing and casing are made up together requiring special handling and torquing equipment.
- There is risk of damaging the tubing during installation

Concentric Drill Pipe

Concentric drill pipe is another means of injecting air into the annulus mud stream downhole. Special dual wall drill pipe is used along the upper (about 2,000 ft) portion of the drill string. Compressed air travels down an annular space within the dual drill pipe and is injected into the mud stream through a jet sub containing nozzles (Figure 13). Only the drilling mud above the jet sub is aerated (9).

Figure 13. Concentric Drill Pipe Arrangement

The annular pressure profiles using the concentric pipe method are the same as pressure profiles using parasite tubes if the point where air is injected into the annular mud stream is at the same downhole level. The difference in the two techniques is how compressed air is transported downhole. The concentric drill pipe technique affects normal drilling operations more than the parasite tube technique because the concentric drill pipe is much more difficult to handle than conventional drill pipe. A major operational limitation of concentric drill pipe is that hydrostatic pressure control is lost while tripping the drill string since air flow is stopped.

ARCO has used this drilling technique successfully to combat lost circulation problems in Utah (10). They found that the optimum injection point was at a depth of about 3,400 ft. This allowed 2,000-2,100 SCFM at 700-800 psi operating pressure on the air side to handle 290-310 gpm of 8.8-9.0 ppg mud at 1,000-1,200 psi on the mud side. ARCO found that one of the side benefits was increased penetration rate.

Advantages

- Successful in combating lost circulation in sub-normal pressure areas
- Increases penetration rate by reducing mud pressure at the bit

Disadvantages

- Requires special equipment such as
 - high-pressure, high-volume compressors
 - special concentric dual drill pipe
 - dual swivel
 - rotating head
 - jet sub
- Special Casing Program
 - large ID to give clearance to receive 6-1/2 inch tool joints of concentric dual drill pipe

- larger casing string so that jet sub is within intermediate casing
- Corrosion inhibitors must be used in mud to protect drill pipe and casing
- Limited tensile strength of dual pipe
- O-Ring seal can withstand relatively low differential pressure across inner tube
- Pressure control in case of a blowout is a limitation because the concentric drill pipe kelly has no stop cock.
- Differential expansion between pipes causes sealing problems.

Another version of concentric drill pipe (Figure 14) has been used in exploration drilling to combat lost circulation in shallow holes (11). The purpose in this case is to isolate the drilling fluid from the formation by containing the mud fluid flow circuit within the dual pipe. In this case the fluid and cuttings are reversed up the center of the inner drill pipe.

Using complete strings of concentric drill pipe in geothermal drilling requires pressure balance between the aerated mud and formation at the bit at all times. Full depth concentric pipe was tested by one geothermal operator and failure of the elastomeric seals occurred at the high bottom-hole temperatures, with connection time also being a problem.

Figure 14. Full Depth Concentric Drill Pipe (Walker-Neer)

Jet Sub Method

The jet sub method is similar to the complete aerated mud technique and the concentric dual drill pipe technique (Figure 15). Air is injected into the mud at the surface and the air/mud mixture is pumped down standard single walled drill pipe. A jet sub, located in the drill string some distance down hole, allows part of the air mud mixture to flow into the annulus while the remaining air/mud mixture continues down to the drill bit and up the annulus. This method has been used successfully to combat lost circulation and prolific water influx problems in Libya (12). Our pressure calculations indicate this method is no more effective than straight mud aeration. Supportive pressure calculations are given in Section VI.

Figure 15. Jet Sub Application

Low Density Fluids

The term low density fluids, as used here, refers to fluids having density less than cool water or less than 8.34 lbm/gal (62.4 lbm/ft³). Few liquids have a density below water. Organic liquids do but are not practical as drilling fluids. Decane for example has a density of 42.8 lbm/ft³ or 5.72 lbm/gal at 200°F and 2,000 psi.

One technique for lowering the density of fluids uses hollow glass beads. These beads are being used successfully to lower the density of casing cement. Many types of glass beads have been developed, however, physical properties of glass beads are proprietary. Available information indicates glass beads used in casing cement range between 20-130 microns in diameter and have a specific gravity of about 0.7.

Halliburton markets a glass bead called Spherelite® to reduce the density of casing cement. This ceramic bead, when mixed with water, can reduce the bulk density of water from 8.34 to 7.34 lbm/gal. Lighter glass beads can reduce the bulk density of water to about 5 lbm/gal.

Advantages of glass beads for lowering fluid density are:

- Eliminate hazards of organic liquids
- Effect of pressure on bulk density not as great as air bubbles.

Disadvantages of glass beads in drilling fluids are:

- High cost. One gallon of "low, density" water would cost between \$1 to \$2.80.
- Glass beads are susceptible to shear damage. The beads lose their density reduction effect when broken.
- Recycling glass beads could be a problem. Recovering the beads and repeated circulation through the mud pumps could also be problems.

Air is the ultimate low density drilling media. Hard formations which are dry or produce relatively few formation liquids provide the best air drilling results. Annular air velocities required to lift cuttings to the surface range from 2,500 to 3,000 fpm. Air compressors are available which provide adequate air volumes along with portability. Air volumes of 2,000 to 2,400 cubic ft per minute are usually adequate to keep the hole clean. Air pressure requirements are about 300 psig. The biggest problem in air drilling is influx of water from water bearing formations. As ground water is prevalent in most geothermal regions, air drilling will probably be confined to steam production zones such as in The Geysers.

VI. APPLICATION OF PRESSURE BALANCE TECHNIQUES TO GEOTHERMAL DRILLING

In this section, we consider how each of the balanced pressure or pressure reduction techniques can be applied to geothermal drilling. This data will be used as a basis to evaluate each system against the operational requirements given earlier. The discussion of each system will cover performance, risk, availability, and cost. Costing will be the estimated increase of each system over the cost of a generic Baca well as defined by Sandia (14).

Aerated Drilling Fluids

The term aerated drilling fluids as used here refers to drilling fluids aerated at the surface. Downhole aeration, such as through parasite tubes, will be discussed separately. Aerated water is presently being used in geothermal drilling and will be the basis for our calculations.

The purpose of aerating drilling fluids is to reduce the hydrostatic pressure (Figure 16) and hopefully match it with the formation pressure. The two pressure curves will not match exactly because the density of the aerated water is pressure dependent while formation water density is constant as assumed. Nonetheless with the proper mixture of air to water, the pressure unbalance can be minimized and may be acceptable for operational purposes. Our pressure calculations show that an air to water volume ratio of 19:1 gives a maximum pressure unbalance of about 100 psi in comparison with a maximum pressure unbalance of 1,000 psi without aeration. The 19:1 air/water ratio would produce an unbalance pressure into the wellbore, which is more desirable than fluid losses into the formation.

Table A6 gives the calculated pressure distribution for a 19:1 ratio of free air to water as well as local densities and air/mud ratios. Note that while the free air/water mixture is 19:1, the standard air/ water mixture would be 10.9:1.

Figure 16. Pressure Unbalance Reduction by Aeration (Baca)

A 17:1 free air/water ratio produces a slightly heavier aerated mixture and a maximum unbalance pressure of about 50 psi (Figure 17 and Table A7). Over part of the drilling interval, the pressure unbalance is into the formation.

A parameter study of various air/mud ratios indicated the 14:1 air/water ratio produces a maximum pressure unbalance of about 50 psi in The Geysers (Figure 18 and Table A8). This 50 psi unbalance is significantly less than a 900 psi maximum produced by nonaerated water. The pressure unbalance is even greater when 10 lbm/gal mud is used.

Figure 17. Pressure Unbalance Reduction by Aeration (Baca)

Figure 18. Pressure Unbalance Reduction by Aeration (The Geysers)

The volumetric flow rate required from air compressors to produce the 19:1 free air/water mixture and pressure distribution shown in Figure 16 is determined as follows.

It is common practice to maintain mud velocity in the annulus of at least 100 fpm to lift the cuttings to the surface. Corresponding mud flow rate while drilling the 12-1/4 inch hole then is 530 gpm; assuming 4-1/2 inch drill pipe (15). Compressor volume requirement is

$$Q_{air} = 10.9 \left(\frac{530}{7.48} \right) \text{ SCFM}$$

or

$$Q_{air} = 772 \text{ SCFM}$$

This air delivery rate would have to be supplied at the mud pump manifold pressure, which is normally about 500 psi.

To maintain a 100 ft/min mud velocity in the 8-3/4 inch hole, mud pump delivery rate would be 230 gpm. The air compressor delivery rate required to achieve a 19:1 air/water ratio is

$$Q_{air} = 10.9 \left(\frac{230}{7.48} \right) \text{ SCFM}$$

or

$$Q_{air} = 335 \text{ SCFM}$$

As air expands in the annulus, the velocity of the aerated mixture increases to maintain mass continuity according to

$$\rho_1 A_1 V_1 = \rho_2 A_2 V_2 .$$

The average velocity of the mixture past a given cross section (V_2) was determined by assuming the annulus velocity at the bit to be $V_1 = 100$ fpm. Local densities (ρ_1, ρ_2) of aerated mud, which are pressure dependent, are listed in our computer printout (Table A6). A_1 and A_2 are annulus cross sectional areas. These parameters were substituted into

$$V_2 = \frac{\rho_1 A_1}{\rho_2 A_2} V_1$$

to determine the average velocity at each annulus cross section displayed in Figure 19. While these higher velocities are a natural result of fluid expansion, they are necessary to lift the cuttings because of the reduction in fluid density.

Figure 19. Annular Velocity Distribution Caused by Aeration (Baca)

Additional equipment required to modify a conventional rig in order to drill with aerated mud are:

- A four stage 1,000 horsepower air compressor/diesel unit that can supply 1,500 CFM at 1,500 psi.
- Air-mud manifold
- Air volume meter
- Rotating head
- Air separator
- Degasser

The incremental cost of an aerated water system over the cost of the Sanida generic well is estimated at \$48,000. Increase in cost comes from time related changes over the 1,500 ft to 3,000 ft interval.

Foam drilling is a direct extension of aerated mud drilling. Pressure distributions predicted for aerated mud are also the pressure distributions for foam drilling assuming the same air/mud ratio. Therefore, an air/mud ratio of 19:1 would also be required in the foam.

Lower pressures could be achieved with foam since air/mud ratios of 100:1 are possible. However, air/water ratios greater than 20:1 begin to significantly increase the magnitude of the pressure unbalance into the wellbore (Figure 20 and Tables A9 and A10) and defeat the purpose of aeration.

Equipment required to modify a conventional rig for foam drilling are:

- A four stage 1,000 horsepower air compressor/diesel unit that can supply 1,500 CFM at 1,500 psi.
- Air-mud manifold
- Air volume meter
- Rotating head
- Injection pump
- Disposal pit

The incremental cost to foam drill is estimated at \$73,000. This cost increase is mainly due to aeration, disposal pit, injection pump and surfactants.

Figure 20. Pressure Unbalance Using Foam (Baca)

Drilling with aerated muds and foam are established techniques with several years of field application. Aerated mud drilling is also being used successfully in geothermal drilling. However, there is little or no field experience with foam in geothermal wells. Temperature effects on foam stability may be a problem. Foam handling at the surface is another potential problem since the foam must be broken down to protect environmentally sensitive areas.

Parasite Tube Method

This drilling method would be applicable to the section of the borehole below the 13-3/8 inch casing. In this case, the parasite tube would be attached to the 13-3/8 inch casing, providing air to the mud as shown in Figure 21. Following the design of reference (8), see Figure 22, the largest diametral distance using 2-1/16 inch (3.25# integral point, type GST seamless 8 RD) tubing would be

13-3/8" Casing Coupling OD	14.375
2-1/16" Tubing Coupling OD	<u>2.330</u>
	16.705"

Clearance in the borehole would be

Borehole Diameter	17.5"
Diametrical Distance	<u>16.7</u>
	.8"

This clearance is much smaller than the 3.045 inch clearance available in the design of reference (8). Smaller OD tubing, however, could be used if necessary.

Figure 21. Parasite Tube Drilling System

Figure 22. Parasite Tube Design

Air would be injected into the drilling annulus through the 13-3/8 inch casing aerating only the top 1,500 ft of the annulus. This would produce a straight line hydrostatic pressure distribution below the point of air injection and a nonlinear pressure distribution above the point of air injection.

An air/water ratio of 17:1 matches annulus pressure and formation pressure at 1,500 ft or at the bottom of the 13-3/8 inch casing. Below this point the two linear pressure lines, one being the formation and the other being the annulus pressures, diverge. This divergence is due to the difference in density of the heated formation fluid and drilling fluid; the 550°F formation water has a density of 6.13 lbm/gal while water used for drilling has a density of 8.34 lbm/gal.

Herein lies a major problem in trying to match wellbore hydrostatic pressure with the pressure of heated formation fluids. Because of the difference in fluid densities, the two pressure lines will not be parallel or match perfectly.

One alternative is to increase the air/mud ratio as the hole is deepened thus progressively shifting the wellbore pressure curve toward lighter pressures. This will require air/water ratios much higher than 17:1 and may lead to heading and pressure surges in the mud system. For air/water ratios exceeding 20:1, foam would be necessary to prevent these problems.

Still another alternative is to attach the parasite tube to the 9-5/8 inch casing and use this aerated system to drill through the production zone. In other words one parasite tube attached to the 13-5/8 inch would be used in drilling the 12-1/4 inch hole. The 9-5/8 inch intermediate casing would carry a second parasite tube for drilling through the production zone. This use of successive parasite tubes would reduce the pressure difference between wellbore and formation pressures as the wellbore is deepened.

Figure 23. Pressure Unbalance Reduction by Parasite Tube Technique (Baca)

This alternative has space problems. First, the annular space between the O.D. of 9-5/8 inch casing coupling and the I.D. of the 13-3/8 inch casing which must accommodate the parasite tubing coupling is very limited (this space is 1.99"). Second, in order to minimize the unbalance while drilling the production interval, the air/water ratio would need to be 20:1 or greater, creating the risk of heading unless foam is used.

When a parasite tube is used, mud velocity below the injection point is the same for each annular cross section because density does not change. Above the point of injection, density of the air/water mixture changes with pressure and produces an increase in velocity as discussed earlier. Figure 25 shows fluid velocity changes in the annulus caused by injecting air into the drilling fluid. Annular velocity increases from 100 fpm below the point of air injection to 1,350 fpm at the surface and perhaps greater in the blowby line. Erosion of surface casing and piping is therefore a potential problem.

To achieve a 100 fpm annular flow velocity in a 12-1/4 inch hole using 4-1/4 inch drill pipe, the mud pump must deliver 530 gal/min. Corresponding air compressor requirements are:

$$Q_{air} = 9.293 \left(\frac{530}{7.48} \right) \text{ SCFM}$$

or

$$Q_{air} = 658 \text{ SCFM}$$

Table 5

AIR/MUD RATIO (FREE AIR, CF/CU FT) 12.5

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F 200

BACK PRESSURE AT WELLHEAD, PSIA 13.66

UNCUT MUD DENSITY, LB/GAL 8.34

AIR/MUD RATIO (SCF/CU FT) = 9.293

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	0.000	0.618	12.500
200.000	7.996	0.939	7.885
400.000	19.892	1.370	5.089
600.000	36.821	1.903	3.382
800.000	59.658	2.505	2.329
1000.000	88.931	3.130	1.664
1200.000	124.648	3.732	1.235
1400.000	166.300	4.280	0.949
1600.000	213.332	4.760	0.752
1800.000	264.948	5.171	0.613
2000.000	320.540	5.520	0.511

Figure 24. Pressure Unbalance Reduction by Parasite Tube Technique (The Geysers)

Figure 25. Annular Velocity Distribution with Parasite Tube Technique (The Geysers)

Pressure requirements from air compressors depends on fluid friction, nozzle pressure drops, and hydrostatic pressure in the annulus at the point of injection. The greatest pressure is required when starting up the aeration process because hydrostatic pressure is greatest under this condition.

One of the side advantages of the parasite tube is its possible use to bring a geothermal well back into production after it has been killed. Presently, a geothermal well is brought back into production by using a workover rig to pump nitrogen in the water column.

Additional equipment required to modify a standard drilling rig for the parasite tubing method are

- A two-stage 300 horsepower air compressor/diesel unit that can supply 1,000 CFM at 500 psi.
- Air volume meter
- Rotating head
- Air separator
- Degasser

The added cost to the generic well to use the parasite tube method is estimated at \$39,000. This cost covers lower hourly charges for a smaller compressor and increases in the cost of installing the 13-3/8" casing with a 2-1/16" parasite tubing.

Concentric Pipe

Concentric pipe is another means of injecting air into the annulus to lighten the mud column. Air is transported downhole to the injection point through the space between two concentric pipes (see Figure 26) instead of through casing tubes. The fluid mechanics is the same as for the parasite tube method, only the hardware is different. Concentric drill pipe allows some operational flexibility which the parasite tube method does not have. For example, it does not affect the casing program and does not have to be used until lost circulation is encountered. Also the point of air injection is not fixed or tied to the casing program and this allows more flexibility to adjust annulus pressure profiles.

The pressure profiles given in Figure 23 for the parasite tube method are also the same pressure profiles predicted for the concentric pipe method assuming the air/mud ratios and points of air injection are the same. Velocity distribution would be slightly greater due to the smaller annulus cross sectioned area caused by the large O.D. of the concentric pipe. Compressor requirements are comparable.

Intermediate pressure profiles can be generated by drawing straight lines below a given point of injection parallel to the nonaerated mud pressure line (Figure 11). Annulus pressure lines cannot match the formation pressure line because of the difference in slopes, but pressure differences between the two can be greatly reduced by varying the point of injection and air/mud ratio.

By using concentric drill pipe, it is possible to inject air near the bottom of 9-5/8 inch casing (Baca). Pressure calculations indicate that a 20:1 free air/water mixture over the top 3,000 ft interval reduces the pressure unbalance in the production zone interval to about 150 psi (Figure 27).

Figure 26. Concentric Drill Pipe System

Figure 27. Pressure Unbalance Reduction by Concentric Drill Pipe Technique (Baca).

Additional equipment required to modify a standard drilling rig for the concentric drill pipe method are:

- . A two-stage 300 horsepower air compressor/diesel unit that can supply 1,000 CFM at 500 psi.
- . Dual drill pipe
- . Dual swivel
- . Jet sub
- . Air separator
- . Degaser
- . Rotating head

The additional cost to drill with dual drill pipe in the upper 2,000 ft of a drill string is estimated at \$95,000. Surface air system charges are the same as for parasite tubing. The estimated cost of dual drill pipe is twice the cost of standard drill pipe. Trip time is also increased due to dual pipe handling.

Figure 28. Details of Concentric Drill Pipe

Jet Sub Method

The jet sub, single drill pipe method requires mud aeration from the surface (Figure 29). This technique only slightly modifies the pressure profile below the jet sub location. The annulus pressure profile above the jet sub is the same as the pressure profile without a jet sub.

Assume that the jet sub is located 1,500 ft below the surface as shown in Figure 30 and the free air/mud ratio of the aerated mud pumped into the standpipe is 17:1. Without a jet sub the annulus pressure profile is as indicated by the solid line. This is the same profile predicted for straight aerated mud.

If air is injected through a parasite tube at a point 1,500 ft downhole, the pressure profile will be as indicated by the dashed line. Below 1,500 ft there is no air, above 1,500 ft the mud is cut by a 17:1 ratio.

When the jet sub is active, part of the aerated mud (17:1) is bled into the annulus and part continues downhole. The part which continues down has an air/mud ratio of less than 17:1. This causes the annulus pressure curve below 1,500 ft to shift within the shaded area shown in Figure 30. The annulus pressure curve above 1,500 ft is the same in all three cases because over this section the air/mud ratio is 17:1 for all three cases.

There appears to be no major advantage in applying a jet sub to combat lost circulation in geothermal drilling, because pressure profiles below a jet sub are close to the pressure profiles of conventional aerated mud systems.

Figure 29. Drilling System Using a Jet Sub

Figure 30. Pressure Unbalance Reduction Using a Jet Sub (Baca)

Additional equipment required to modify a standard drilling rig for the jet sub method are:

- A four-stage 1,000 horsepower air compressor/diesel unit that can supply 1,500 CFM at 1,500 psi.
- Air-mud manifold
- Air volume meter
- Rotating head
- Jet sub
- Air separator
- Degasser

The incremental cost, using a jet sub, over the cost of the Sandia generic well is estimated at \$49,000.

Low Density Mud

Using low density mud is probably the simplest way to reduce hydrostatic mud pressure. A simple application is illustrated in Figure 31 to show that a fluid having a specific gravity of 0.58 would be required to significantly reduce unbalanced pressure without aeration or downhole equipment. These data show that a low density fluid having a density of 5 lbm/gal would allow drilling through the bottom 3,000 ft with a maximum pressure unbalance of 100 psi.

According to available data, hollow glass beads are available which can reduce the density of water to 4.84 lbm/gal (sp gr = 0.58, $\gamma = 36.2$ lbm/ft³). Further reduction in bulk density with a glass bead/water mixture may not be possible with present technology.

The use of low density muds with either the parasite tube method or the concentric pipe is attractive. For example, a 10:1 mixture of air to mud matches the annulus pressure with the formation pressure at 1,500 ft, a possible parasite tube injection point. A low density fluid matching the density of the heated formation water (about 45.8 lbm/ft³) would produce a hydrostatic pressure distribution below the injection point that would completely balance formation pressures and eliminate pressure differences between annulus and formation (Figure 32, Table A11). Developing a bulk density of 45.8 lbm/ft³ with hollow glass beads and water is within the capability of present technology.

The use of glass beads to reduce drilling mud density would increase total drilling cost by about \$200,000. This is due mainly to the high cost of the beads which makes mud cost about \$2.00 per gallon. If glass beads are used in conjunction with a parasite tube the added cost would be about \$239,000.

Figure 31. Pressure Unbalance Reduction Using Low Density Mud (Baca)

Figure 32. Pressure Unbalance Reduction Combining Parasite Tube with Low Density Mud (Baca)

VII. EVALUATION SUMMARY

This section gives an evaluation scheme and ranks the various pressure balance drilling techniques for application to geothermal drilling.

Specific drilling and completion concepts evaluated are

- Aerated Drill Fluid (Aerated Mud)
- Aerated Drill Fluid (Foam)
- Parasite Tube Method
- Concentric Drill Pipe
- Jet Sub
- Low Density Drilling Fluid
- Low Density/Parasite Tube

Evaluation Scheme

In our evaluation scheme we gave numerical values to engineering judgments and gave each concept a single score.

Evaluation criteria are defined under categories of performance, risk, cost, and schedule;

Performance - the capability to achieve needed operational characteristics, plus reliability.

Risk - the possibility that performance may not be met because of the design approach, absence of testing, or some specific technical consideration.

Schedule - the availability of a design depending upon the stage of development.

Cost - the estimated cost of the system including development and manufacturing costs.

Each category is weighted as follows

. Performance	40%
. Risk	30%
. Schedule	20%
. Cost	<u>10%</u>
	100%

Our approach was to break each category of evaluation criteria (performance, risk, etc.) into key evaluation elements and give each element an appropriate weight.

The numerical evaluation scheme had two key objectives. The first is to have a way to quantify our judgment against a fixed scale so that each pressure balance drilling technique would be rated in the same manner, thus showing their truest level of merit in comparison with each other.

The second objective was to give a way to examine the rationale of the final scores by looking at each element of the concept that was given a grade and see where the strong and weak points are in each. Since all design selections are the result of trade-offs, the scoring system aided in selecting a preferred concept.

Evaluation elements under each of the four categories (performance, risk, schedule, cost) are identified below.

EVALUATION CRITERIA

Performance

Pressure Balance: This refers to the ability of the drilling system to effectively combat lost circulation while drilling geothermal wells.

Pressure Maintenance: The annulus pressure distribution should be maintained during tripping to avoid losing drilling mud to the formation.

Reliability: The surface and subsurface drilling equipment must operate in a hostile drilling environment without excessive wear or damage to equipment or wellbore.

Maintenance: The system should operate with minimum amount of maintenance.

Risk

Stage of Equipment Development: The drilling techniques may require equipment and procedures that are not fully developed. Some of the proposed equipment is conceptual only while other equipment is fully developed and operational. Conceptual equipment has no track record and therefore carries with it a high risk level.

Drilling and Completion Experience: This refers to the level of experience in the use of a given drilling technique.

Schedule

Equipment Availability: Drilling equipment may not be readily available. Equipment may be conceptual, have a preliminary design, have a final design, been prototype tested, or fully developed and operational. Another aspect of availability is incentive for tool companies to invest in new products for in situ leach mining.

Personnel: The level of expertise and availability of trained personnel will impact job planning.

Cost

Comparison with Aerated System: Cost estimates given for each drilling method are incremental additional cost to the generic Baca well as defined by Sandia. These incremental costs are compared with the incremental cost of the aerated system to arrive at a weighted numerical value. Incremental costs are summarized in Table 6.

Table 6

Incremental Cost for Each Drilling Technique

Aerated System	\$48,000
Foam Drilling	73,000
Parasite Tube Method	39,000
Concentric Drill Pipe	95,000
Jet Sub Method	49,000
Low Density Mud	200,000
Low Density Mud/Parasite Tube	\$239,000

The cost evaluation numbers (Table 7) were determined by dividing the lowest cost estimate (Parasite Tube Method) by the individual cost estimates (Table 6) and then multiplying by the cost weighting value (taken as 10%).

For example, the numerical value given in the cost of the concentric drill pipe method was determined as follows.

$$\frac{\$ 39,000}{\$ 95,000} \times 10 = 4.1$$

which was rounded off to 4.

Table 7
EVALUATION SUMMARY

	WEIGHTING	CONCEPT						
	%	A	B	C	D	E	F	G
PERFORMANCE								
• Pressure Balance	15	14	14	10	10	2	5	15
• Pressure Maintenance	5	0	0	5	0	0	2	5
• Reliability	10	8	8	10	8	9	9	9
• Maintenance	<u>10</u>	9	3	9	6	9	8	8
	40							
RISK								
• Stage of Equipment Development	15	15	15	14	10	10	15	15
• Drilling & Completion Experience	<u>15</u>	15	15	7	7	3	12	10
	30							
SCHEDULE								
• Equipment Availability	10	10	10	9	9	8	10	10
• Personnel Training	<u>10</u>	10	10	8	6	5	9	9
	20							
COST								
• Comparison with Aerated System	<u>10</u>	<u>8</u>	<u>5</u>	<u>10</u>	<u>4</u>	<u>8</u>	<u>0</u>	<u>0</u>
TOTAL SCORE	100%	89	80	82	60	54	70	81

- A. Aerated Drill Fluid (Aerated Mud)
- B. Aerated Drill Fluid (Foam)
- C. Parasite Tube Method
- D. Concentric Drill Pipe
- E. Jet Sub
- F. Low Density Drilling Fluid
- G. Low Density/Parasite Tube

VIII. CONCLUSIONS

Lost circulation in geothermal drilling can be alleviated by balanced pressure drilling techniques. These techniques eliminate the pressure difference between the wellbore drilling fluid and formation pressure thus eliminating the fluid driving force into the formation. The two pressures should be balanced at each open hole location to prevent loss of drilling mud.

Fluid pressure in geothermal formations is lower than hydrostatic wellbore pressure because the ground water level is some 1,000 ft below the surface and ground water density is significantly reduced by formation temperature. On the other hand, wellbore hydrostatic pressure begins at the surface and has a lower average circulating temperature than the surrounding foundation, thus it has a higher density than geothermal formation fluids.

It is not our intention to rule out any of the balanced pressure techniques for geothermal drilling. Most of the techniques have been used successfully in combating lost circulation and each have merit. The ability of each technique to perform against specific operational requirements was weighted heavily in our evaluation. Under other performance requirements the evaluation results might be different.

According to our evaluation of balanced pressure drilling techniques, aerated water, (i.e., drilling fluid aerated at the surface) has the best overall balance of performance, risk, schedule and costs. Even though drilling fluid pressure cannot be made to exactly balance formation pressure, the unbalance pressure can be reduced from a maximum of 1000 psi to about 50 psi. The 50 psi is within exceptable Δp limits. The shape of the aerated water pressure curve very nearly

matches the assumed formation pressure line when the air to water ratio is 19:1. This ratio is within the limits of nonfoam aerated fluids, however, heading is a potential problem. The greatest risk is corrosion to the drill string and other drill equipment. Aerated water is presently being used in geothermal drilling and it is not suprising that this technique received a high rank in our evaluation.

The parasite tube method using a low density fluid as a drilling mud has the potential of outperforming the aerated drilling technique. A parasite tube would be attached to the 13-3/8 inch casing and air injected at a rate to produce a 10:1 air/mud mixture within the 13-3/8 inch casing. This air/mud mixture would balance the drilling fluid with formation pressure at the point of air injection. A low density fluid having a density of 45.8 lbm/ft³ (6.13 lbm/gal) which matches the density of 550°F water would balance the borehole pressure everywhere below the air injection point. By reducing costs and increasing experience, this technique could be ranked higher than the aerated system. Because of its potential to completely eliminate the difference between formation and wellbore pressures, there is incentive to develop this technique further. The main problem with this system at present is the high cost of ceramic beads needed to produce low density muds.

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X. APPENDIX

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Table A-1

AERATED WATER PRESSURE DISTRIBUTION (BACA)

AIR/MUD RATIO (FREE AIR, CF/CU FT)?0

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

BACK PRESSURE AT WELLHEAD, PSIA?10.5

UNCUT MUD DENSITY, LB/GAL?8.34

AIR/MUD RATIO (SCF/CU FT) = 0.000

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	0.000	8.340	0.000
200.000	86.643	8.340	0.000
400.000	173.287	8.340	0.000
600.000	259.930	8.340	0.000
800.000	346.573	8.340	0.000
1000.000	433.217	8.340	0.000
1200.000	519.860	8.340	0.000
1400.000	606.503	8.340	0.000
1600.000	693.147	8.340	0.000
1800.000	779.790	8.340	0.000
2000.000	866.433	8.340	0.000
2200.000	953.077	8.340	0.000
2400.000	1039.720	8.340	0.000
2600.000	1126.363	8.340	0.000
2800.000	1213.007	8.340	0.000
3000.000	1299.650	8.340	0.000
3200.000	1386.293	8.340	0.000
3400.000	1472.937	8.340	0.000
3600.000	1559.580	8.340	0.000
3800.000	1646.223	8.340	0.000
4000.000	1732.867	8.340	0.000
4200.000	1819.510	8.340	0.000
4400.000	1906.153	8.340	0.000
4600.000	1992.797	8.340	0.000
4800.000	2079.440	8.340	0.000
5000.000	2166.083	8.340	0.000
5200.000	2252.727	8.340	0.000
5400.000	2339.370	8.340	0.000
5600.000	2426.013	8.340	0.000
5800.000	2512.657	8.340	0.000
6000.000	2599.300	8.340	0.000

Table A-2

AIR/MUD RATIO (FREE AIR, CF/CU FT) ?5

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

BACK PRESSURE AT WELLHEAD, PSIA?10.5

UNCUT MUD DENSITY, LB/GAL?8.34

AIR/MUD RATIO (SCF/CU FT) = 2.857

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	0.000	1.390	5.000
200.000	24.104	3.313	1.517
400.000	67.900	4.995	0.670
600.000	125.473	6.017	0.386
800.000	191.368	6.619	0.260
1000.000	262.227	6.994	0.193
1200.000	336.252	7.243	0.151
1400.000	412.487	7.419	0.124
1600.000	490.271	7.549	0.105
1800.000	569.232	7.647	0.091
2000.000	649.077	7.725	0.080
2200.000	729.699	7.788	0.071
2400.000	810.862	7.839	0.064
2600.000	892.506	7.882	0.058
2800.000	974.598	7.918	0.053
3000.000	1057.059	7.949	0.049
3200.000	1139.785	7.976	0.046
3400.000	1222.758	7.999	0.043
3600.000	1305.989	8.020	0.040
3800.000	1389.385	8.039	0.038
4000.000	1472.995	8.055	0.035
4200.000	1556.751	8.070	0.033
4400.000	1640.662	8.083	0.032
4600.000	1724.674	8.095	0.030
4800.000	1808.815	8.106	0.029
5000.000	1893.122	8.116	0.028
5200.000	1977.481	8.125	0.026
5400.000	2061.936	8.134	0.025
5600.000	2146.463	8.142	0.024
5800.000	2231.117	8.149	0.023
6000.000	2315.787	8.156	0.023

Table A-3

AIR/MUD RATIO (FREE AIR, CF/CU FT)?10

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

BACK PRESSURE AT WELLHEAD, PSIA?10.5

UNCUT MUD DENSITY, LB/GAL?8.34

AIR/MUD RATIO (SCF/CU FT) = 5.714

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	-0.000	0.758	10.000
200.000	11.072	1.421	4.867
400.000	30.436	2.339	2.565
600.000	60.005	3.350	1.489
800.000	99.738	4.271	0.952
1000.000	148.139	5.018	0.662
1200.000	203.389	5.594	0.491
1400.000	263.878	6.032	0.383
1600.000	328.366	6.367	0.310
1800.000	395.939	6.628	0.258
2000.000	465.874	6.834	0.220
2200.000	537.784	7.000	0.192
2400.000	611.241	7.135	0.169
2600.000	685.997	7.247	0.151
2800.000	761.753	7.342	0.136
3000.000	838.446	7.422	0.124
3200.000	915.930	7.491	0.113
3400.000	994.112	7.551	0.105
3600.000	1072.849	7.603	0.097
3800.000	1152.029	7.649	0.090
4000.000	1231.676	7.690	0.085
4200.000	1311.852	7.726	0.079
4400.000	1392.201	7.759	0.075
4600.000	1473.054	7.789	0.071
4800.000	1554.074	7.815	0.067
5000.000	1635.404	7.840	0.064
5200.000	1716.961	7.862	0.061
5400.000	1798.797	7.883	0.058
5600.000	1880.10	7.901	0.056
5800.000	1962.909	7.919	0.053
6000.000	2045.342	7.935	0.0

Table A-4

AIR/MUD RATIO (FREE AIR, CF/CU FT)?15

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

BACK PRESSURE AT WELLHEAD, PSIA?10.5

UNCUT MUD DENSITY, LB/GAL?8.34

AIR/MUD RATIO (SCF/CU FT) = 8.571

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	0.000	0.521	15.000
200.000	6.916	0.830	9.044
400.000	17.706	1.267	5.584
600.000	33.669	1.827	3.566
800.000	55.955	2.475	2.370
1000.000	85.205	3.152	1.646
1200.000	121.344	3.800	1.195
1400.000	163.935	4.383	0.903
1600.000	212.169	4.885	0.707
1800.000	265.177	5.308	0.571
2000.000	322.212	5.660	0.473
2200.000	382.577	5.954	0.401
2400.000	445.698	6.200	0.345
2600.000	511.266	6.406	0.302
2800.000	578.760	6.581	0.267
3000.000	647.853	6.730	0.239
3200.000	718.478	6.858	0.216
3400.000	790.309	6.969	0.197
3600.000	863.274	7.066	0.180
3800.000	937.104	7.151	0.166
4000.000	1011.804	7.227	0.154
4200.000	1087.293	7.294	0.143
4400.000	1163.378	7.353	0.134
4600.000	1240.020	7.407	0.126
4800.000	1317.175	7.456	0.119
5000.000	1394.869	7.500	0.112
5200.000	1472.992	7.540	0.106
5400.000	1551.509	7.576	0.101
5600.000	1630.394	7.610	0.096
5800.000	1709.603	7.640	0.092
6000.000	1789.135	7.669	0.088

Table A-5

AIR/MUD RATIO (FREE AIR, CF/CU FT) 220

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F 72.00

BACK PRESSURE AT WELLHEAD, PSIA 710.5

UNCUT MUD DENSITY, LBS/GAL 78.34

APPROXIMATE MUD ID (IN) = 11.429

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/M
0.000	0.000	0.397	20.000
200.000	5.039	0.575	13.514
400.000	12.119	0.811	9.284
600.000	22.091	1.120	6.443
800.000	35.652	1.503	4.550
1000.000	53.550	1.949	3.279
1200.000	76.313	2.439	2.419
1400.000	104.274	2.947	1.830
1600.000	137.550	3.448	1.418
1800.000	175.863	3.921	1.127
2000.000	218.829	4.353	0.916
2200.000	266.117	4.741	0.759
2400.000	317.199	5.083	0.641
2600.000	371.604	5.382	0.550
2800.000	428.899	5.643	0.478
3000.000	488.711	5.870	0.421
3200.000	550.766	6.069	0.374
3400.000	614.801	6.243	0.336
3600.000	680.429	6.396	0.304
3800.000	747.653	6.531	0.277
4000.000	816.107	6.650	0.254
4200.000	885.688	6.757	0.234
4400.000	956.386	6.852	0.217
4600.000	1028.031	6.937	0.202
4800.000	1100.495	7.014	0.189
5000.000	1173.732	7.084	0.177
5200.000	1247.661	7.147	0.167
5400.000	1322.214	7.205	0.158
5600.000	1397.357	7.257	0.149
5800.000	1473.008	7.306	0.142
6000.000	1549.136	7.350	0.135

Table A-6

AIR/MUD RATIO (FREE AIR, CF/CU FT)?19

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

BACK PRESSURE AT WELLHEAD, PSIA?10.5

UNCUT MUD DENSITY, LB/GAL?8.34

AIR/MUD RATIO (SCF/CU FT) = 10.857

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
000	0.000	0.417	19.000
20.000	5.319	0.613	12.611
400.000	12.958	0.877	8.504
600.000	23.816	1.2	5.814
800.000	38.664	1.	4.058
1000.000	58.278	2.	2.901
1200.000	83.224	2.666	2.129
1400.000	113.716	3.200	1.606
1600.000	149.661	3.714	1.246
1800.000	190.702	4.188	0.992
2000.000	236.452	4.613	0.808
2200.000	286.364	4.988	0.672
2400.000	339.997	5.315	0.569
2600.000	396.650	5.597	0.490
2800.000	456.110	5.842	0.428
3000.000	517.986	6.054	0.377
3200.000	581.868	6.239	0.337
3400.000	647.454	6.400	0.303
3600.000	714.707	6.541	0.275
3800.000	783.379	6.665	0.251
4000.000	853.39	6.775	0.231
4200.000	924.026	6.873	0.213
4400.000	995.889	6.960	0.198
4600.000	1068.612	7.039	0.185
4800.000	1142.112	7.109	0.173
5000.000	1216.310	7.173	0.163
5200.000	1291.14	7.232	0.153
5400.000	1366.547	7.285	0.143
5600.000	1442.486	7.333	0.137
5800.000	1518.900	7.378	0.130
6000.000	1595.760	7.419	0.124

Table A-7

AIR/MUD RATIO (FREE AIR, CF/CU FT)?17

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

BACK PRESSURE AT WELLHEAD, PSIA?10.5

UNCUT MUD DENSITY, LB/GAL?8.34

AIR/MUD RATIO (SCF/CU FT) = 9.714

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	0.000	0.463	17.000
200.000	6.064	0.708	10.776
400.000	14.999	1.042	7.000
600.000	28.016	1.480	4.634
800.000	46.058	2.007	3.156
1000.000	69.902	2.590	2.220
1200.000	99.921	3.187	1.617
1400.000	136.018	3.760	1.218
1600.000	177.844	4.282	0.948
1800.000	224.810	4.742	0.759
2000.000	276.210	5.140	0.623
2200.000	331.377	5.479	0.522
2400.000	389.875	5.768	0.446
2600.000	451.070	6.014	0.387
2800.000	514.669	6.224	0.340
3000.000	580.308	6.405	0.302
3200.000	647.643	6.561	0.271
3400.000	716.573	6.696	0.246
3600.000	786.811	6.814	0.224
3800.000	858.080	6.918	0.206
4000.000	930.517	7.010	0.190
4200.000	1003.773	7.092	0.176
4400.000	1077.776	7.165	0.164
4600.000	1152.527	7.230	0.153
4800.000	1227.956	7.289	0.144
5000.000	1303.973	7.343	0.136
5200.000	1380.503	7.391	0.128
5400.000	1457.536	7.436	0.122
5600.000	1534.990	7.476	0.115
5800.000	1612.865	7.514	0.110
6000.000	1691.101	7.548	0.105

Table A-8
THE GEYSERS

AIR/MUD RATIO (FREE AIR, CF/CU FT)?14

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

BACK PRESSURE AT WELLHEAD, PSIA?13.66

UNCUT MUD DENSITY, LB/GAL?8.34

AIR/MUD RATIO (SCF/CU FT) = 10.408

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	-0.000	0.556	14.000
200.000	7.116	0.817	9.205
400.000	17.239	1.160	6.189
600.000	31.462	1.592	4.238
800.000	50.587	2.097	2.977
1000.000	75.188	2.646	2.152
1200.000	105.570	3.203	1.604
1400.000	141.643	3.738	1.231
1600.000	183.067	4.229	0.972
1800.000	229.367	4.667	0.787
2000.000	279.863	5.050	0.652
2200.000	334.074	5.381	0.550
2400.000	391.541	5.666	0.472
2600.000	451.682	5.911	0.411
2800.000	514.242	6.122	0.362
3000.000	578.800	6.305	0.323
3200.000	645.144	6.464	0.290
3400.000	712.979	6.602	0.263
3600.000	782.267	6.724	0.240
3800.000	852.644	6.832	0.221
4000.000	924.128	6.927	0.204
4200.000	996.516	7.012	0.189
4400.000	1069.896	7.089	0.176
4600.000	1143.797	7.157	0.165
4800.000	1218.480	7.219	0.155
5000.000	1293.777	7.276	0.146
5200.000	1369.635	7.327	0.138
5400.000	1446.000	7.374	0.131
5600.000	1522.828	7.417	0.124
5800.000	1600.104	7.456	0.119
6000.000	1677.755	7.493	0.113

Table A-9

AIR/MUD RATIO (FREE AIR, CF/CU FT) ? 50

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F ? 200

WELLHEAD PRESSURE AT WELLHEAD, PSIA ? 10.5

MUD DENSITY, LB/GAL ? 8.34

AIR/MUD RATIO (SCF/CU FT) = 28.571

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	0.000	0.164	50.000
200.000	1.910	0.193	42.306
400.000	3.999	0.224	36.208
600.000	6.524	0.262	30.839
800.000	9.461	0.305	26.301
1000.000	12.902	0.356	22.434
1200.000	16.868	0.413	19.183
1400.000	21.522	0.479	16.395
1600.000	26.895	0.555	14.039
1800.000	33.058	0.639	12.053
2000.000	40.164	0.734	10.362
2200.000	48.401	0.841	8.913
2400.000	57.686	0.959	7.699
2600.000	68.307	1.089	6.662
2800.000	80.381	1.231	5.777
3000.000	93.899	1.383	5.029
3200.000	109.088	1.547	4.390
3400.000	126.063	1.722	3.844
3600.000	144.908	1.905	3.378
3800.000	165.672	2.095	2.980
4000.000	188.472	2.292	2.639
4200.000	213.321	2.493	2.346
4400.000	240.272	2.696	2.094
4600.000	269.335	2.900	1.876
4800.000	300.524	3.103	1.688
5000.000	333.782	3.303	1.525
5200.000	369.141	3.500	1.383
5400.000	406.494	3.692	1.259
5600.000	445.830	3.878	1.150
5800.000	487.059	4.058	1.055
6000.000	530.122	4.231	0.971

Table A-10

AIR/MUD RATIO (FREE AIR, CF/CU FT)?100

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

WELL PRESSURE AT WELLHEAD, PSIA?10.5

UNCUT MUD DENSITY, LB/GAL?8.34

AIR/MUD RATIO (SCF/CU FT) = 57.143

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	0.000	0.083	100.000
200.000	0.969	0.090	91.549
400.000	1.869	0.097	84.888
600.000	2.934	0.105	78.163
800.000	4.049	0.114	72.168
1000.000	5.321	0.124	66.370
1200.000	6.642	0.134	61.253
1400.000	8.109	0.145	56.424
1600.000	9.678	0.157	52.036
1800.000	11.350	0.170	48.056
2000.000	13.208	0.184	44.288
2200.000	15.186	0.199	40.879
2400.000	17.384	0.216	37.656
2600.000	19.718	0.233	34.748
2800.000	22.184	0.252	32.124
3000.000	24.719	0.272	29.646
3200.000	27.800	0.294	27.415
3400.000	30.979	0.317	25.314
3600.000	34.386	0.342	23.393
3800.000	38.081	0.369	21.613
4000.000	42.048	0.397	19.982
4200.000	46.333	0.428	18.475
4400.000	50.956	0.461	17.086
4600.000	55.932	0.496	15.806
4800.000	61.279	0.534	14.628
5000.000	67.015	0.573	13.546
5200.000	73.201	0.616	12.545
5400.000	79.836	0.661	11.623
5600.000	86.940	0.708	10.776
5800.000	94.533	0.759	9.994
6000.000	102.712	0.812	9.275

Table A-11

AIR/MUD RATIO (FREE AIR, CF/CU FT)?10

AVERAGE MUD TEMPERATURE IN ANNULUS, DEG F?200

BACK PRESSURE AT WELLHEAD, PSIA?10.5

UNCUT MUD DENSITY, LB/GAL?6.13

AIR/MUD RATIO (SCF/CU FT) = 5.714

DEPTH FT	PRESSURE PSI	DENSITY LBS/GAL	RATIO AIR/MUD
0.000	-0.000	0.557	10.000
200.000	7.449	0.895	5.850
400.000	19.064	1.347	3.552
600.000	35.648	1.872	2.275
800.000	57.945	2.419	1.534
1000.000	85.773	2.932	1.091
1200.000	118.620	3.381	0.813
1400.000	155.763	3.757	0.632
1600.000	196.464	4.067	0.507
1800.000	240.095	4.320	0.419
2000.000	286.077	4.527	0.354
2200.000	334.023	4.698	0.305
2400.000	383.591	4.840	0.266
2600.000	434.538	4.960	0.236
2800.000	486.549	5.061	0.211
3000.000	539.594	5.147	0.191
3200.000	593.505	5.222	0.174
3400.000	648.066	5.287	0.159
3600.000	703.305	5.344	0.147
3800.000	759.141	5.394	0.136
4000.000	815.342	5.439	0.127
4200.000	872.109	5.478	0.119
4400.000	929.157	5.514	0.112
4600.000	986.650	5.546	0.105
4800.000	1044.404	5.575	0.100
5000.000	1102.529	5.602	0.094
5200.000	1160.852	5.626	0.090
5400.000	1219.403	5.643	0.085
5600.000	1278.119	5.663	0.081
5800.000	1337.163	5.687	0.078
6000.000	1396.261	5.704	0.075