A DRILLABLE STRADDLE PACKER FOR LOST CIRCULATION CONTROL IN GEOTHERMAL DRILLING

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ABSTRACT

Lost circulation is a persistent problem in geothermal drilling and often accounts for a significant fraction of the cost of drilling a typical geothermal well. The U. S. Department of Energy sponsors work at Sandia National Laboratories to develop technology for reducing lost circulation costs. This paper describes a downhole tool that has been developed at Sandia for improving the effectiveness and reducing the cost of cementing operations used to treat lost circulation zones. This tool, known as the drillable straddle packer, is a low-cost, disposable assembly used for isolating a loss zone and directing the flow of cement into the zone. This paper describes the tool concept, hardware design, deployment procedure, laboratory testing, and technical issues addressed during the development process.

1. INTRODUCTION

The most costly problem routinely encountered in geothermal drilling is lost circulation, which is the loss of drilling fluids to pores or fractures in the rock formations being drilled. Lost circulation costs represent an average of 10% of total well costs in mature geothermal areas (Carson & Lin, 1982), and they often account for over 20% of the costs in exploratory wells and developing fields. Well costs, in turn, represent 35-50% of the total capital costs of a typical geothermal project (DOE, 1989); therefore, roughly 3.5-10% of the total costs of a geothermal project are attributable to lost circulation. Reducing the cost of lost circulation would help reduce overall project costs and help expand the role of geothermal energy in the electric utility sector.

For this reason, DOE sponsors the Lost Circulation Technology Development Program at Sandia National Laboratories. The god of this program is to develop and transfer to industry new technology to reduce lost circulation costs by 30-50%. The program is developing technology in two general categories: lost circulation diagnostic techniques, and downhole tools for lost circulation control. Details of this program have been described previously in Glowka (1990) and Glowka *et al.* (1993).

Conventional lost-circulation treatment practice in geothermal drilling is to position the lower end of an open-end drill pipe near the suspected loss zone and pump a given quantity of cement (typically 8.5 m^3 [300 ft^3]) downhole. The objective is to emplace enough cement into the loss zone to seal it; however, this does not always occur. Because of its higher density relative to the wellbore fluid, the cement often channels through the wellbore fluid and settles to the bottom of the wellbore. If the loss zone is not on bottom, the entire wellbore below the loss zone must sometimes be filled with cement before a significant volume of cement flows into the loss zone. Consequently, a large volume of hardened cement must often be drilled to re-open the hole, which wastes time and contaminates the drilling mud with cement fines. Furthermore, because of the relatively small aperture of many loss-zone fractures, the loss zone may preferentially pull wellbore fluids, instead of the more viscous cement, into the fractures. This causes dilution of the cement in the loss zone and loss of integrity of the subsequent cement plug. As a result, multiple cement plugs are often required to plug a single loss zone, with each plug incurring significant time and material costs.

2. THE DRILLABLE STRADDLE PACKER CONCEPT

The following subsections describe first the drillable straddle packer concept, then the actual hardware and deployment procedure required to use this concept in a feasible manner downhole.

2.1 General Description

The drillable straddle packer has been developed as a means for improving the effectiveness and reducing the cost of a typical cement treatment. This is accomplished by maximizing the volume of cement that flows into the loss zone, minimizing the volume of cement that remains in the wellbore, and reducing dilution of the cement caused by other wellbore fluids flowing into the loss zone.

The drillable straddle packer concept is shown in Figure 1. A packer assembly on the end of the drillstring employs two fabric bags that straddle the loss zone and provide zonal isolation. The bags are inflated with cement by the differential pressure that develops across the cement ejection ports in the packer tube between the two bags. This differential pressure is easily controlled from the surface by controlling the cement flow rate. The highly flexible bags seal against the wellbore wall, thereby forcing most of the cement to flow into the loss zone. Because the loss zone is already underpressured with respect to the wellbore, a very low-pressure sealing capability is all that is required to effectively force-feed the loss zone in this manner. A bag pressure capability of 1.4-2.8 bar (20-40 psi) should be sufficient to accomplish this function in most cases.

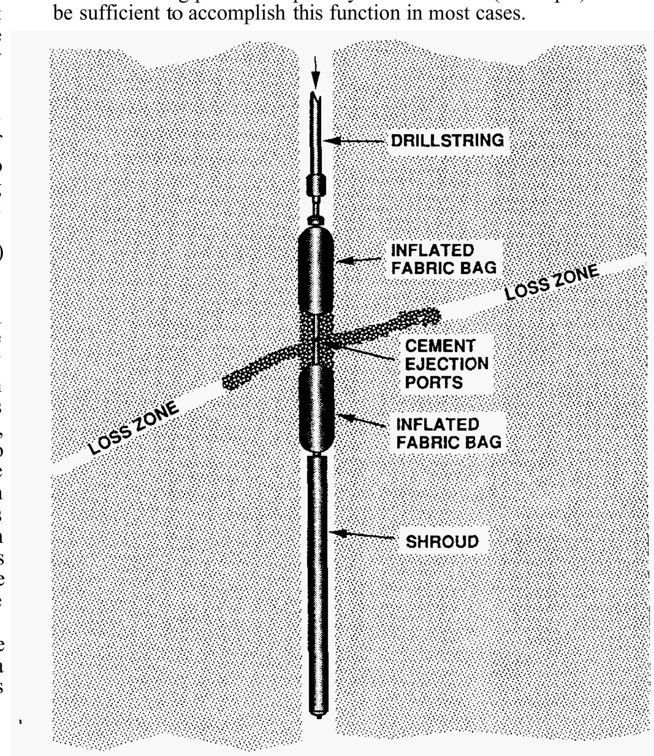

Figure 1 - Drillable straddle packer concept.

As the bags inflate, they also provide blockage to the flow of other wellbore fluids into the loss zone. Drilling mud and connate fluids produced at other wellbore intervals can thereby be prevented from diluting and channeling through the cement to create a leakage path through the loss zone.

After pumping a specified volume of cement, the straddle packer assembly is disconnected from the drillstring and left in the wellbore when the drillstring is tripped out of the hole. The packer assembly is constructed of drillable materials: aluminum, fiberglass, and, in low-temperature applications, CPVC plastic. It is drilled through after the cement sets and the drilling operation resumes.

It is estimated that the use of a drillable straddle packer as described could reduce the cost of a lost circulation treatment by 10-36% using conventional cement and 21-44% using cementitious mud (Glowka, 1990). The lower estimates result from assuming that a smaller volume of cement (4.2 m^3 [150 ft^3] instead of 8.5 m^3 [300 ft^3] per treatment) is required when using the straddle packer because of increased effectiveness. The higher estimated cost savings result from assuming that the straddle packer reduces the number of treatments required to plug a severe loss zone, from two treatments to one. The greater savings associated with the use of cementitious mud result from the assumption that cementitious mud solidifies within three hours while conventional cement requires eight hours to set. A further advantage with the straddle packer that is not included in these estimates is the reduction in drilling mud conditioning costs that results if less cement must be drilled out of the wellbore. Cement fines have deleterious effects on drilling mud properties.

2.2 Hardware Design and Deployment Procedure

The following steps are required to deploy the drillable straddle packer downhole. The accompanying figures show the hardware in schematic form.

1. Thread the drillstring coupler and packer assembly onto the end of the drill pipe (Figure 2). The packer assembly consists of all hardware below the drillstring coupler.

2. Trip the assembly into the wellbore, circulating through the drillstring and packer assembly as necessary during trip in. The circulating passage through the tool is 2.54 cm (1 inch) minimum diameter. The packer shroud protects the fabric bags from abrasion against the wellbore wall during trip in. The packer assembly should be positioned so that it straddles the loss zone.

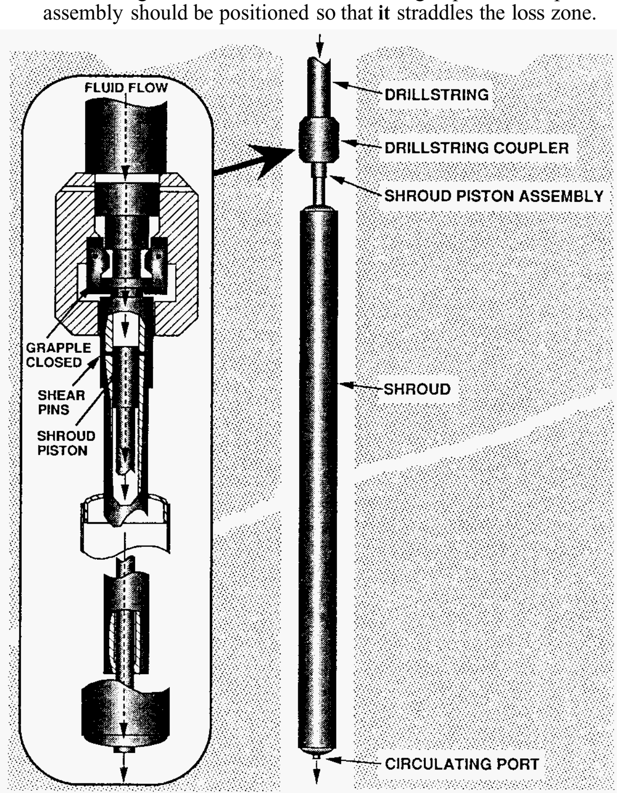

Figure 2 - Drillable straddle packer deployment procedure: Insertion into borehole.

3. Drop a 3.8-cm (1-1/2 inch) nylon ball down the drillstring to deploy the packer shroud and inflate the fabric bags (Figure 3). When the ball reaches the packer assembly, it seats in the top of the shroud piston, causing pressure to build above the piston, thereby breaking the shear pins that hold the piston in the shroud piston assembly. The piston is pumped down through the packer tube, pushing the shroud ahead of it and opening the bag inflation ports and cement ejection ports to the fluid pressure inside the packer tube (Figure 4).

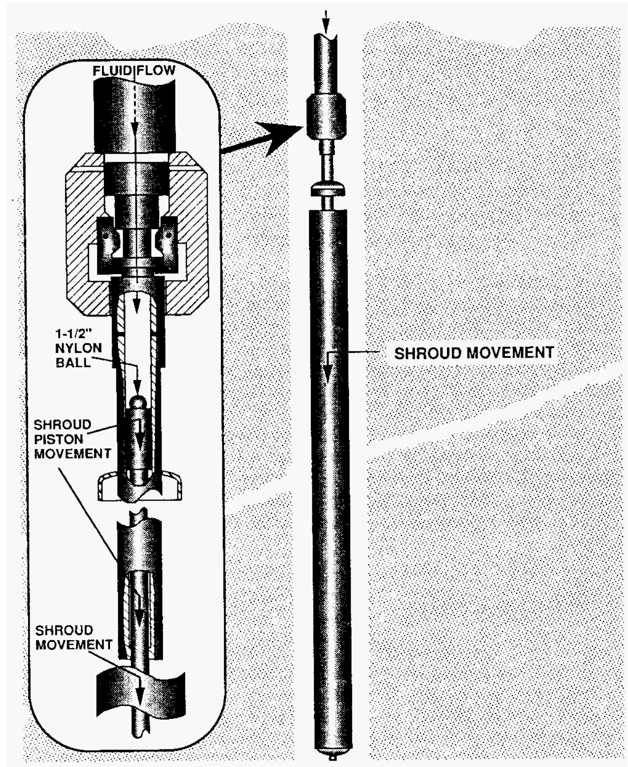

Figure 3 - Drillable straddle packer deployment procedure: Deploying the shroud.

4. Begin pumping cement as soon as the 3.8-cm (1-1/2 inch) nylon ball is dropped into the drillstring. The cement follows the ball downhole and begins to flow out the cement ejection ports shortly after the bags are inflated. Pump a specified volume of cement while controlling the flow rate to achieve the desired bag inflation pressure.

5. After the specified volume of cement is pumped downhole, drop a 6.4-cm (2-1/2 inch) brass ball down the drillstring to decouple the drillstring from the packer assembly (Figure *5).* When the ball reaches the drillstring coupler, it seats in the top of the coupler piston, causing pressure to build above the piston, thereby breaking the shear pins that hold the grapple closed. When the shear pins break, the grapple opens, releasing the top of the packer assembly. Movement of the piston also opens four 1.9-cm (0.7s-inch) circulating ports for pumping through the drillstring and clearing it of residual cement.

6. Trip the drillstring out of the wellbore.

7. When the cement hardens, trip into the wellbore with a bit and drill out the packer assembly and surrounding cement.

3. DEVELOPMENT STATUS

Development of a prototype drillable straddle packer is complete. The following subsections discuss laboratory tests conducted on various key components of the packer during development.

3.1 Packer Bags

A high-temperature, flexible-fabric bag has been developed that can reliably withstand 2.1-3.4 bar (30-50 psi) internal pressure. This bag is fabricated from silicone-coated, woven-fiberglass fabric rated to 260°C (500°F). The fabric tube is closed on each end by attaching it to a rigid through-tube composed of aluminum or aluminum and

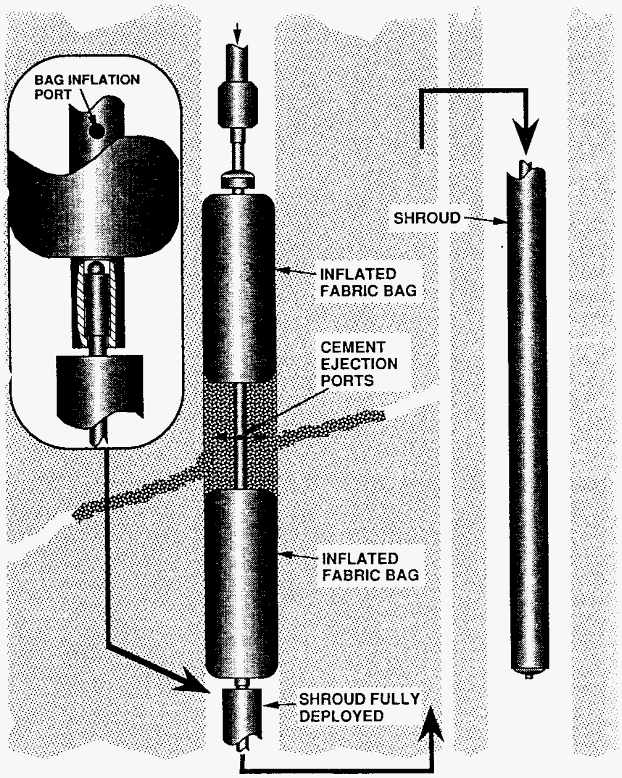

Figure 4 - Drillable straddle packer deployment procedure: Pumping cement

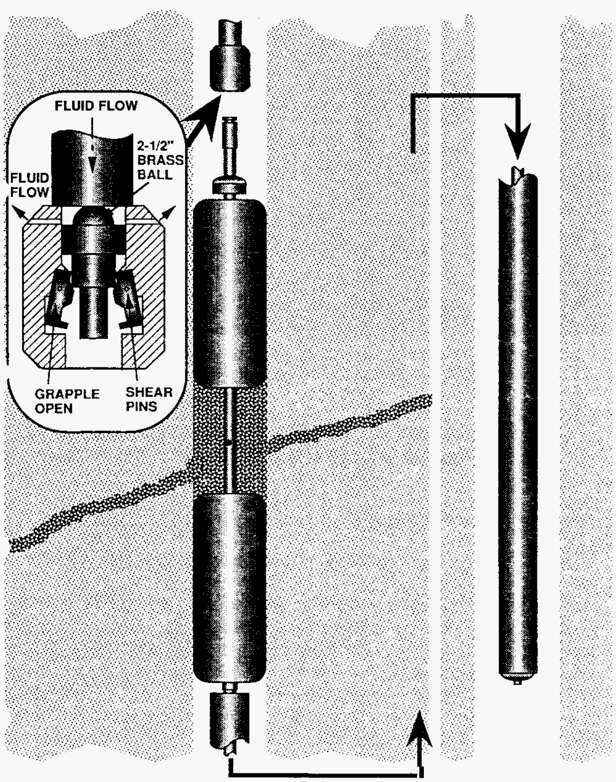

Figure 5 - Drillable straddle packer deployment procedure: Decoupled **from drillstring.**

CPVC plastic, depending on the temperature requirements for a given bag. Photographs of a typical bag are shown in Figure 6, both before and during inflation. The inflated shape of the bag as shown **is** a critical parameter that affects the burst pressure of the bag.

As seen in Figure 6b, a swaging technique is used to attach the bag to the aluminum tube. This technique was developed by Petersen Products Co. of Fredonia, Wisconsin, **USA,** for their pipeline and

Figure 6a (left) - Drillable straddle packer bag before inflation.

Figure 6b (right) - Swage used on **bag to** close **fabric tube ends onto aluminum through-tube.**

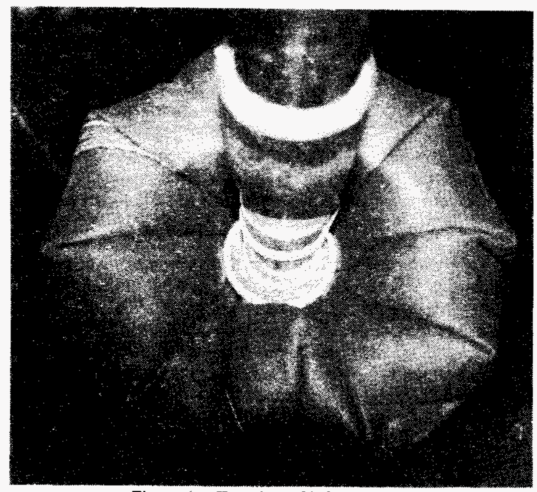

Figure 6c - Top view of inflated bag.

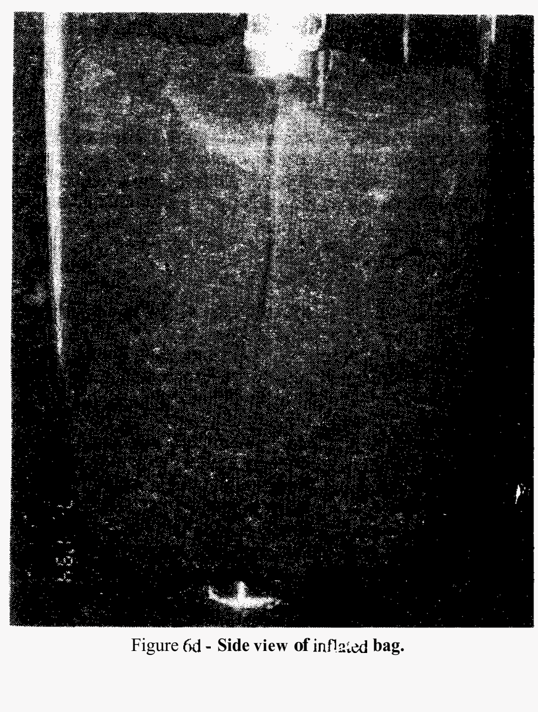

Figure 6d - **Side view of** inflated **bag.**

plumbing stopper plugs. It entails pleating the ends of a fabric tube around a rigid through-tube, placing a short section of aluminum outer tube over the pleats, and using a hydraulic swaging device to squeeze and deform the outer tube. The fabric is thereby clamped between the outer tube and the inner through-tube. This technique has proven to be an efficient and effective way to close the ends of the fabric tube to make a pressure-tight bag.

Laboratory tests were conducted with a variety of bag designs to determine the burst pressure and borehole sealing characteristics of bags ma& with this technique. Typical results are shown in Figures 7 and 8. As seen in Figure 7, the burst pressure achieved with the final bag design is typically greater than **3.4** bar (50 psi). This allows the packer to be operated at a bag differential pressure of 1.4-2.8 bar (20-40 psi) with a significant safety factor. Figure 8 demonstrates that this bag design permits very little leakage, only a few liters/minute, between the bag and the casing wall, even when a significant obtrusion was attached to the casing wall. This result, due to the flexible nature of the fabric bag, indicates that such a bag should seal even a relatively rough wellbore wall.

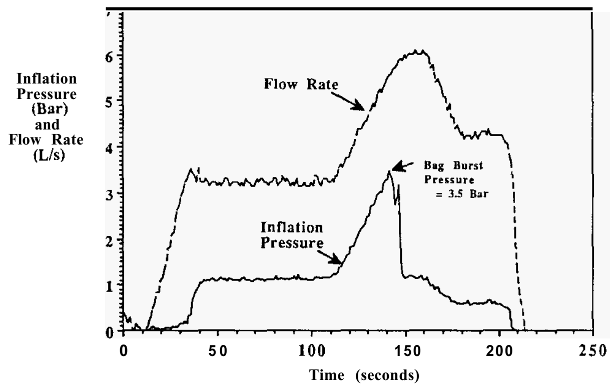

Figure 7 - Typical burst test results for a **40.6-cm (16-inch) diameter bag designed** for **the drillable straddle packer.**

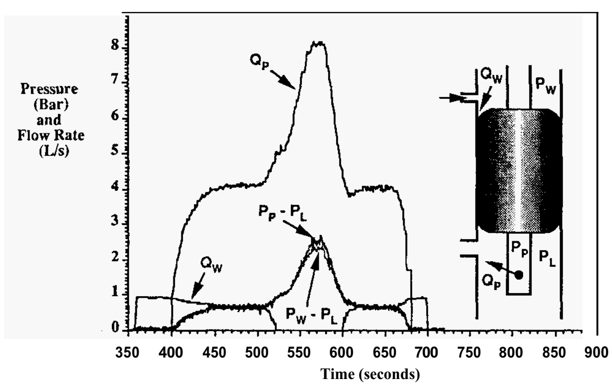

Figure. 8a - Typical flow-by test **results for a drillable straddle packer bag in a 38.1-cm (15-inch) diameter smooth-walled casing.**

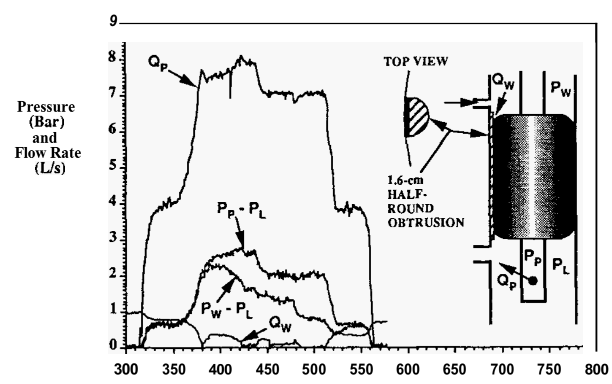

Figure 8b - Typical flow-by test results for **a drillable straddle packer bag in a 38.1-cm (15-inch) diameter casing with an ernplaced obtrusion** to **simulate a rough wellbore wall.**

These packer bags are now commercially available from Petersen Products Co. as individual components that can be used to build a drillable straddle packer assembly. The bag assemblies are typically 1.2 m **(48** inches) long for a 40.6-cm (16-inch) diameter bag, with male pipe threads on each end. Using the current design, packer bags can be fabricated for virtually any borehole diameter.

3.2 Shroud Mechanism

The packer shroud mechanism has been designed, fabricated, and laboratory tested. A photograph of the shroud on a single-bag assembly is shown in Figure 9, both before and after deployment. A description of the shroud assembly is provided in subsection **2.2** and the accompanying drawings.

Results for a typical shroud mechanism test are shown in Figure 10. In this plot, the pressure behind the shroud piston is seen to rise to 17.5 bar **(254** psi) before the shear pins break to release the piston. The shroud mechanism's activation pressure can be adjusted from 6.9-34.5 bar (100 to 500 psi) by selecting appropriate shear pins.

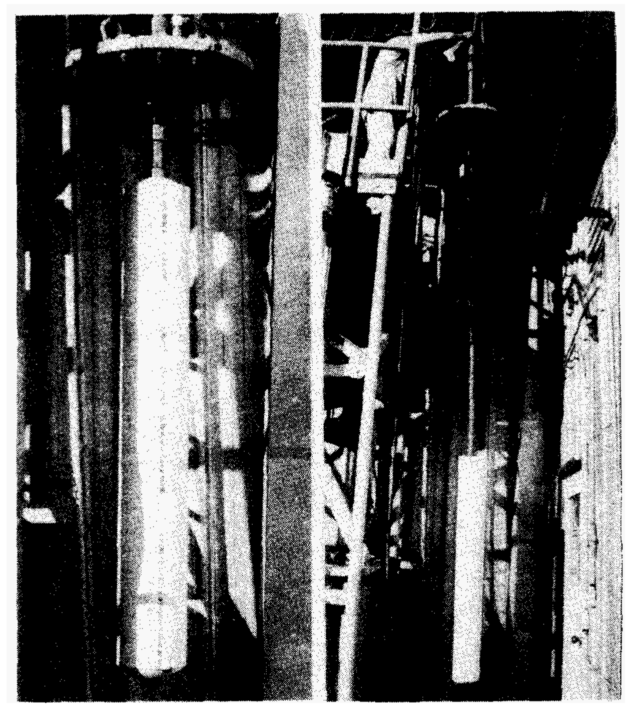

Figure 9 - Drillable straddle packer shroud as tested with a single bag. Left: Before deployment. Right After **deployment.**

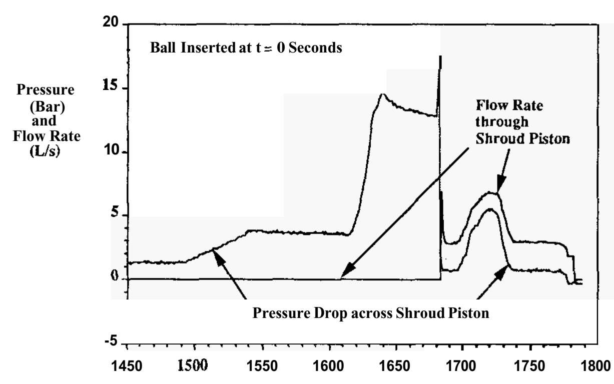

Figure 10 - Typical test results for the drillable straddle packer shroud mechanism.

3.3 Drillstring Coupler

The drillstring coupler has been designed, fabricated, and laboratory tested. A photograph of the inner workings of the coupler is shown in Figure 11. A description of the drillstring coupler is provided in subsection 2.2 and the accompanying drawings.

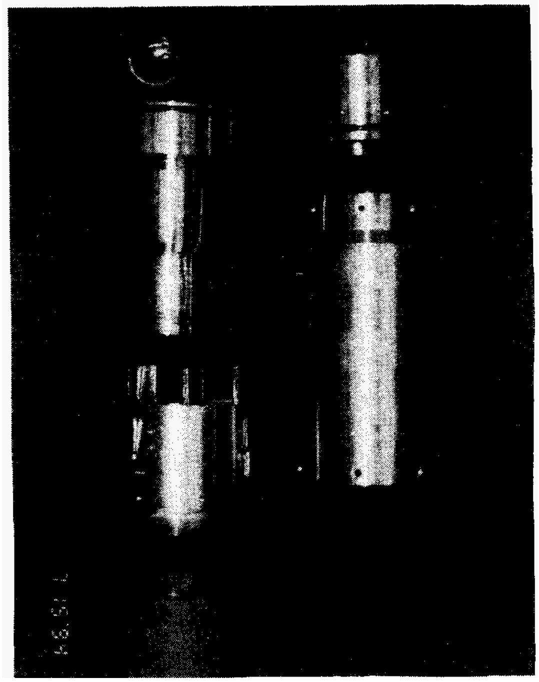

Figure. 11 - Drillstring coupler in exploded view. Couterclockwise from top: Brass ball. piston, grapple assembly, top of packer assembly, outer housing, dnll pipe connector.

Results for a typical drillstring coupler test are shown in Figure 12. In this plot, the pressure behind the coupler piston is seen to rise to 6.4 bar (93 psi) before the shear pins break to release the grapple hooks. This activation pressure can be adjusted from 6.4-34.5 bar (93-500 psi) by selecting appropriate shear pins.

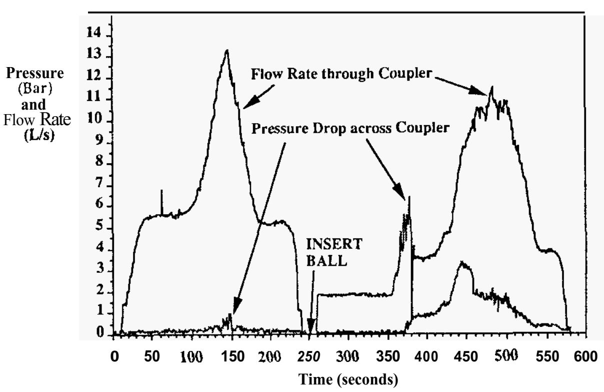

Figure 12 - Typical test results for the drillstring coupler.

3.5 Packer Demonstration Facility Testing

A Packer Demonstration Facility, shown in Figures 13 and 14, has been constructed. This facility consists of a 4.6-m X 4.6 m X 4.6 m (15-ft X 15-ft X 15-ft) concrete box that can be loaded with clay and gravel beds to simulate impermeable rock and loss zones, respectively. The facility will be used to test full-scale packer assemblies with cement. After a test, the clay and gravel layers can be removed to map the flow of the cement and evaluate the effectiveness of the straddle packer in isolating a selected zone. Tests are planned in this facility prior to testing the drillable straddle packer in the field.

4. TECHNICAL ISSUES

The following feasibility issues have been addressed in the development of the dnllable straddle packer:

4.1 Effectiveness of Fabric Bags in Providing Zonal Isolation

Given that the loss zone is, by definition, underpressured with respect to the wellbore, the wellbore fluid in the vicinity of the loss

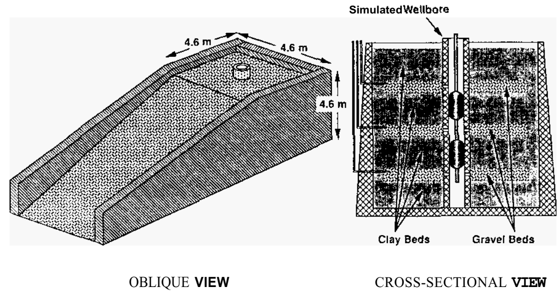

Figure 13 - Schematic of Packer Demonstration Facility, showing alternating gravel (permeable) beds and clay (impermeable) beds.

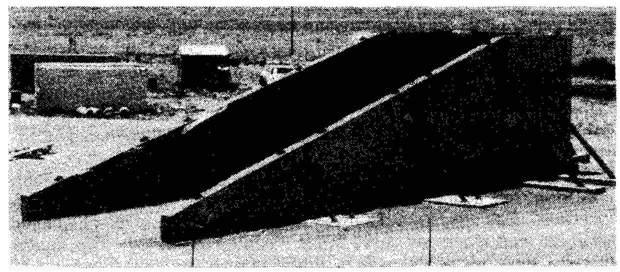

Figure 14 - Photograph of Packer Demonstration Facility prior to installing external plumbing.

zone will flow into the loss zone. One of the purposes of the drillable straddle packer is to ensure that all of the wellbore fluid in the vicinity of the loss zone is cement, so that only undiluted cement will flow into the zone. The nature of the bag inflation scheme employed in the drillable straddle packer is such that the pressure inside the bags is always higher than the pressure in the wellbore region between the two bags (because of the pressure drop through the cement ejection ports). Consequently, given the significant flexibility of the fabric bags, the bags seal the flow paths between the bags and the wellbore wall, forcing all of the cement into the loss zone. At the same time, the pressure in the wellbore region between the two bags increases by an amount equal to the frictional pressure drop of the cement flow in the loss zone. This should have the effect of force feeding the loss zone with cement.

If reservoir fluids are produced at some other wellbore interval above the loss zone, these fluids would normally flow into the loss zone. With the packer in place, the top inflated fabric bag will seal the wellbore to the passage of this fluid. This will cause the wellbore fluid level to rise (assuming it is below ground level), increasing the hydrostatic pressure on the top bag and at the production zone. Significant leakage of this fluid past the top bag will not occur unless the hydrostatic pressure rise exceeds the operating differential pressure of the packer. Assuming a packer operating differential pressure of 2.1 bar (30 psi) the wellbore fluid level would have to rise by approximately 21 m (69 ft) before this happens. A 2.1-bar (30-psi) increase in the wellbore pressure at the production zone may be sufficient to eliminate or significantly reduce the fluid production rate. In any case, the packer should be capable of significantly retarding the flow of produced fluids into the loss zone during cement injection.

4.2 Exceeding the Bag Burst Pressure

If the frictional pressure drop through the loss zone during cement injection is too high or increases as the loss zone becomes plugged, the pressure in the wellbore region between the two bags will increase accordingly. Because of the constant cement flow rate imposed at the surface, the pressure drop across the cement ejection ports is constant; consequently, the pressure inside the packer tube and thus inside the fabric bags will increase in proportion to the increase in frictional pressure drop in the loss zone. If the frictional pressure loss exceeds the bag burst pressure, the bag will develop one or more tears along the top clamp attaching it to the tube. Cement will then flow out of the top bag into the wellbore region above the packer.

Experience has shown that the fiberglass fabric used in these bags fails locally, leading to small, stable tears that act as additional orifices and relieve the bag's internal pressure enough to prevent further tearing. In other words, a bag that "bursts" at some maximum pressure will continue to hold a lower, but significant, pressure as long as the cement flow continues at a steady rate. In this context, the bag has a built-in pressure safety mechanism that allows it to continue to stay inflated and provide a positive-pressure injection of cement into the loss zone, even if the loss zone will not accept the full flow rate being delivered down the drill pipe.

4.3 Effects of Pressure Pulses Caused by Cement Free-Fall

If the wellbore fluid level falls significantly below ground level, as sometimes occurs with a total loss of circulation, fluid pumped down the drill pipe may undergo free-fall near the surface, leading to a waterhammer effect and resultant pressure pulses throughout the drillstring. When large pressure pulses reach the packer, the possibility of exceeding the bag burst pressure exists. The cement ejection ports, however, will tend to moderate pressure pulses: a sudden increased pressure in the packer bag will instantaneously increase the flow through the ejection ports, thereby relieving the pressure pulse to some extent, acting as a fluid dampener. Employing small-diameter bag inflation ports will also dampen the pressure pulses before they reach the fabric. Only field experience will determine whether these effects are sufficient to enable the bags to survive when significant cement free-fall distances are involved.

4.4 Survivability of the Packer in a Deviated Wellbore

If the wellbore is not perfectly straight, as is usually the case, then the drillsmng will impinge on the wellbore wall at one more more locations. The bottom of the drillstring will be the first to contact the wellbore wall along any curve in the wellbore trajectory. This means that the packer assembly will be thrust against the wellbore wall and scraped along a significant length of wellbore. If the forces on the packer assembly were sufficiently high under these circumstances, the packer could break off the drillsmng during the trip in.

The packer assembly is constructed of relatively flexible materials, aluminum and, in some cases, CPVC plastic. As a result, when the lower end of the packer assembly contacts the wellbore wall, the packer will deflect, bending out of the way to enable the drillstring coupler to contact the wellbore wall. Thus the rugged steel coupler will provide the reaction force against the wall required to bend the drill pipe around the curve. The packer assembly will, therefore, undoubtedly contact the wellbore wall, but it will not need to carry the bending forces required to insert the drillsmng into a deviated hole.

The packer shroud consists of a thin-wall aluminum or CPVC tube that protects the bags from contact and abrasion with the wellbore wall. The bags themselves are relatively robust and may withstand insertion without the need for a shroud. Only field experience will determine whether a shroud will be typically required.

Upon inflation of the packer bags, significant forces develop to center and align the packer tube along the central axis of the wellbore. In a deviated wellbore where the uninflated packer assembly may be forced to lie along the wellbore wall, it is possible that the centering forces will not be sufficient upon inflation to bend and center conventional steel drill pipe. It may be necessary under such conditions to run a stabilizer above the drillstring coupler or to employ a section of flexible hose between the drillstring and the drillsmng coupler. Laboratory tests are planned to address this issue prior to testing the drillable straddle packer in the field.

4.5 Reliability of Drop-Ball Remote Activation

The only moving parts in the drillable straddle packer are the pistons and related hardware used in the shroud deployment and drillsmng decoupling mechanisms. Reliability of these drop-ball mechanisms is an issue because operation of the packer assembly depends on proper, consistent operation of these mechanisms.

Laboratory testing has shown that these mechanisms, as designed in the prototype packer assembly, are simple, yet reliable. Sealing between the drop balls and their corresponding piston seats has been found to be absolute, and the mechanisms have always operated in a repeatable fashion in our laboratory tests. Experience in the field will be required to verify performance under actual downhole conditions. Drop-ball remote activation is not a new idea; it is used successfully in other downhole tools.

4.6 Effects of Decoupling from the Drillable Straddle Packer

The question exists as to whether there may be any deleterious effects of decoupling the packer assembly from the drillsmng. An important point here is that after the cement has been injected into the loss zone, the primary purpose of the packer has been accomplished. Some of the cement may flow back out of the loss zone after pumping stops, but because of the underpressured nature of the loss zone, most of the injected cement should remain there. It is probably not critical, but it would be advantageous if the packer would remain in place to retard wellbore fluids from flowing into the loss zone after cement emplacement. In fact, our experience with inflated fabric bags in our laboratory facility has shown that these bags tend to remain inflated even after fluid flow stops. Several hundred pounds of force are typically required to pull a decoupled, inflated bag up out of a 38-cm (15-inch) casing. In the case of a packer assembly in a fluid-filled wellbore, buoyancy forces would reduce gravitational pull considerably, and friction between the fabric bags and the wellbore wall may be sufficient to hold the packer in place until the cement hardens.

4.6 Drillability of the Straddle Packer

The drillable straddle packer is a disposable assembly, to be left downhole and drilled through after the surrounding cement hardens. All materials used in the expendable portion are either aluminum, CPVC plastic, or fiberglass. All of these materials are drillable with roller cone drill bits. Laboratory drilling tests are planned to verify cement drillability with imbedded specimens of various aluminum types that can be used in a packer assembly.

4.7 Cost of the Drillable Straddle Packer

The initial cost goal for the expendable portion of the drillable straddle packer was US$500 (Glowka, 1990). That goal appears to be reasonable. Prototype packer assemblies can be fabricated for less than US$1000. Under routine production conditions, it is predicted that the cost can be reduced to a level near the goal.

5. CONCLUSIONS

A potentially effective downhole tool has been developed for improving the efficiency and reducing the cost of cementing operations for treating lost circulation zones encountered in geothermal drilling. A significant development effort has been completed, involving analysis, hardware design, and laboratory testing, resulting in prototype hardware and deployment procedures. Further testing of the tool is planned in a facility designed to span the gap between laboratory testing and field testing. This facility will allow the tool to be tested under full-scale flow rates with cement, and post-mortem examination of the facility will allow the effectiveness of the tool to be ascertained with significant confidence. Field tests in geothermal wells will then be pursued to determine the technical and cost effectiveness under actual field conditions.

6. ACKNOWLEDGMENT

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