CONTROL OF WELL KS-8 IN THE KILAUEA LOWER EAST RIFT ZONE

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ABSTRACT

In June 1991, a high-pressure/high-temperature well located in Hawaii kicked and unloaded at 3,476 ft (1,059 m). This well was estimated to have a possible bottomhole temperature of 650°F (343°C) and a reservoir pressure approaching 2,300 psi (15,858 kPa). Immediate attempts to kill the well were unsuccessful, and the long process of well control was started.

Besides the harsh geological and reservoir conditions encountered, the scarce availability of materials in a remote location and long-distance transportation of necessary equipment figured heavily into the time delay of the final kill procedure of the well.

Regaining the control of the well in a remote, tropical environment was accomplished using state-of-the-art well control techniques. These techniques were applied through the operating company's careful coordination of service companies and personnel during a 3-month period.

1. INTRODUCTION

Studies by the Department of Scientific and Industrial Research in Wairakei, Taupo, New Zealand[1] indicate that the power potential of the Kilauea Lower East Rift Zone in Hawaii ranges from 500 to 700 MWe. The report also documents two phenomena of the area that are essential for a successful geothermal prospect: fluid and heat.

In 1981, the State of Hawaii built a demonstration 3 MW wellhead generator plant that operated for approximately 8 years before it was permanently closed.[2] From 1982 to 1990, six geothermal development wells and three exploratory/development wells were drilled, ranging in depth from 1,678 ft (511 m) to 8,400 ft (2,560 m). Of these wells, seven encountered commercial-grade geothermal resources. Progress was being made toward construction of a 25 MW (net) hybrid cycle steam/binary turbine generation facility to be powered by geothermal wells yet to be drilled into the Kilauea Rift Zone. Studies indicated an underground conduit for lateral migration of molten basalt from Kilauea's crater. The reservoir was described as a high-temperature (over 600°F), two-phase vapor/liquid resource. It was believed that the geothermal reservoir was heated by a dike complex radiating from a secondary magma chamber, or pocket of molten rock, beneath the reservoir.

In 1991, Puna Geothermal Venture was drilling a well intended to be a producer for the 25 MW generator facility under construction. However, on June 12, while operators were drilling at 3,476 ft (1,059 m), the well kicked, unloaded, and flowed. For 30 hours, flow was diverted at the surface until the well could be shut-in. Cold water was pumped down the drillpipe and annulus. Following the initial procedures, the operator and service companies worked several months to salvage the well. The well was successfully secured and produced; eventually, it was plugged and abandoned as a result of operational considerations.

As a direct consequence of the kick, the following problems occurred:

(1) While attempting to raise the Kelly out of the blowout preventer equipment (BOPE), the driller was blown off the brake. (2) the round seals on the BOPE would not seal around the hexagonal Kelly. (3) steam flowed to the surface. Within 1 hour, previously defined emergency procedures were implemented, the steam was vented through a diverter line, and restoration to the floor was begun. Over the next 30 hours, damage assessment indicated that most of the BOPE seals and seal elements were damaged, the rotary table was displaced to the draw works, and the control panel failed. Temperature logs indicated that a crossflow or thief zone was located at the 13 3/8-in. (33.97-cm) casing shoe, which was set at 2,128 ft (649 m). Emergency procedures were followed to preserve the integrity of the well, maintain surface control of the well, and to monitor the environmental aspects of the event, such as H_2S emissions and excessive noise levels.

Service company personnel immediately connected pumping equipment to the standpipe and a wellhead side outlet valve, and began pumping water to cool the surface wellhead equipment. The drillstring was picked up, and the BOPE was closed around the drillpipe. The BOPE continued to leak until lost-circulation material was pumped intermittently into the annulus to provide a complete seal. As repairs were being made and fluid was being continuously pumped, lines were being prepared to perform a kill operation to salvage the well and eventually make it a producer.

Several attempts to kill the well over the next 2 weeks were unsuccessful. The volume of water required to cool the well necessitated drilling a water well. Specialists in the area of well control began transporting snubbing equipment and personnel to Hawaii. Their snubbing operation was critical in the final kill operation.

This paper presents advanced technology in snubbing operations, cementing methods, and isolation procedures.

2. KS-8 DIVERTED FLOW EVENT AND PROCEDURES TO CONTROL THE WELL

2.1 KS-8 Diverted Flow Event

May 1, 1991, the drilling crew moved onto location and began drilling well KS-8. During the next 6 weeks, drilling continued to a depth of 3,350 ft (1,021 m); 20-in. (50.8 cm) and 13 3/8-in. (33.97-cm) casings were set, and cemented drilling continued. The well was surveyed and temperature logs were run to establish a correlation between KS-8 and previous wells drilled in the area.

Temperature comparison to KS-3 well indicated that KS-8 had similar temperature conditions, but they were encountered 500 ft (152 m) deeper than KS-3. Well KS-8 had temperatures of 370°F (188°C) at 3,400 ft (1,036 m), whereas KS-3 had encountered the same temperatures at 2,850 ft (869 m). After the well was drilled to 3,400 ft (1,036 m), the mud weight was increased, and several cement plugs were set to control minor flow from high-pressure, low-permeability zones that had been encountered. Additional temperature logs were attempted to determine the rate of temperature buildup in the well. These logs were unsuccessful because the temperatures were

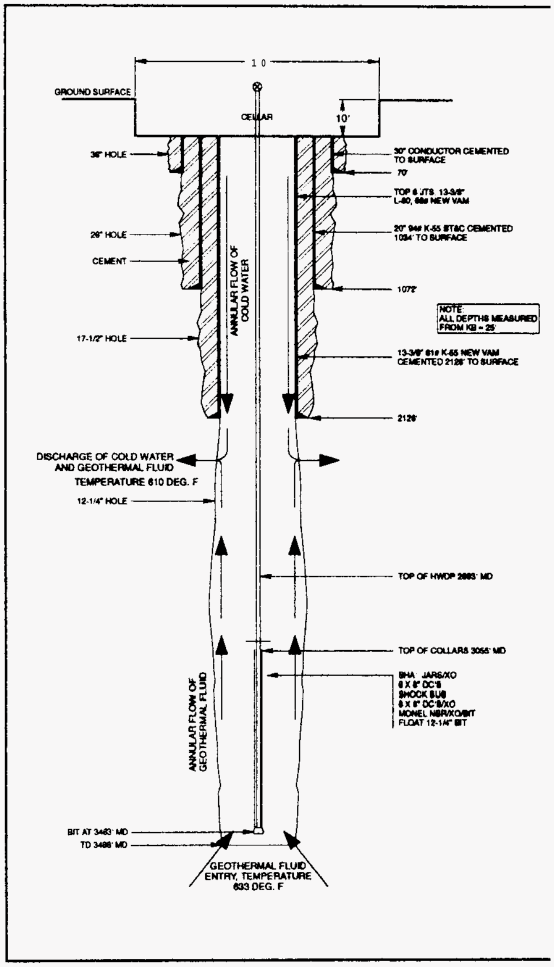

Figure l - Well conditions, 23 June 1991.

in excess of rated temperatures for the logging tools and wireline. The wireline was rated to a maximum temperature of 500°F (260°C); wireline failure was not discovered until much later.

On June 12, cement was drilled out of the 12 1/4-in. (31.12-cm) hole from 3,350 ft (1,021 m) to 3,400 ft (1,036 m). As the driller continued to drill new formation from 3,400 ft (1,036 m) to 3,476 ft (1,059 m), he observed a 2-ft drilling break with an almost instantaneous rate of penetration. He was picking up on the Kelly to close the BOP equipment when the well unloaded and blew him off the brake.

The annular BOP failed, and the 5-in. pipe rams were closed around the 6-in. hexagonal Kelly. A 4-in. choke bypass line was opened to divert as much flow as possible away from the rig floor.

2.2 Well Condition

After the initial diversion of fluids at the surface on June 21, operators picked up the Kelly and closed the bottom pipe rams. Even though the rams were closed, they leaked steam and water. Initially, service personnel rigged up a Kelly hose to the standpipe and began pumping water to cool the well at 9 bbl/min (1.43 m^3) down the drillstring. Later, trucks were rigged up to the 13 3/8-in. (33.97-cm) casing head valves in the cellar. The choke line that was opened to divert flow from under the rig was then closed and water was pumped at 5 bbl/min (0.79 m^3) and 1,700 psi (11,721 kPa). This situation caused the wellhead annular pressure to drop to 1,000 psi (6,895 kPa).

Lost-circulation material was pumped into the 13 3/8-in. (33.97-cm) wing valves. This material successfully sealed off leaks around the pipe rams and in the BOP equipment stack. The top drillpipe rams in the BOP equipment stack were replaced. The top and bottom sets of rams were successfully tested. As repairs continued, such as replacing floor plates, flowlines, air lines, electric lines, and Kelly valves, any attempt to reduce the water displacement down the annulus or drillpipe resulted in the surface pressure increasing. For over 2 months, water was pumped down the annulus and the drillpipe, usually averaging 3.5 bbl/min (0.56 m^3/min), with wellhead pressures from 650 psi (4,482 kPa) to 1,000 psi (6,895 kPa).

Throughout the process of restoration, there was always concern that the BOP equipment had been compromised at the kick. Because of this safety concern, maintenance of reduced wellhead pressure by continuous cold water injection was a high priority, especially *after* attempts to kill the well with high volumes of cold water were unsuccessful.

Material and equipment transportation to Hawaii delayed the snubbing and kill operations for several weeks. Location equipment performed well over long periods, continually displacing water down the drillpipe and annulus, and keeping the temperatures and pressures controlled in the well.

2.3 Temperature Surveys and Determination of Crossflow

Temperature surveys run on July 15 showed a temperature increase at 1,650 ft (503 m). The temperature at 2,100 ft (640 m) was 340°F (171°C). Temperature at 3,124 ft (952 m) was 475°F (246°C). The temperature survey results indicated that a crossflow existed at 2,128 ft (649 m) at the 13 3/8-in. (33.97-cm) casing shoe (Fig. 1). Temperature surveys on June 21 indicated a maximum bottomhole temperature of 633°F (334°C). When pressure/temperature surveys were attempted on June 26, the survey was terminated at 1,800 ft (549 m) because of increased pressure on the drillpipe. Attempts to plug off the upper thief zone with LCM pills were unsuccessful (Fig. 2).

Throughout control operations, the attempted temperature surveys were complicated or suspended because of temperatures beyond the rating and capability of the wireline and/or logging tools.

2.4 Snubbing Operation

When the 450 snubbing unit arrived in Hawaii, an attempt was made to replace the leaking TIW valve at the top of the drillstring before rigging up to snub the drillstring out of the hole. A delay occurred

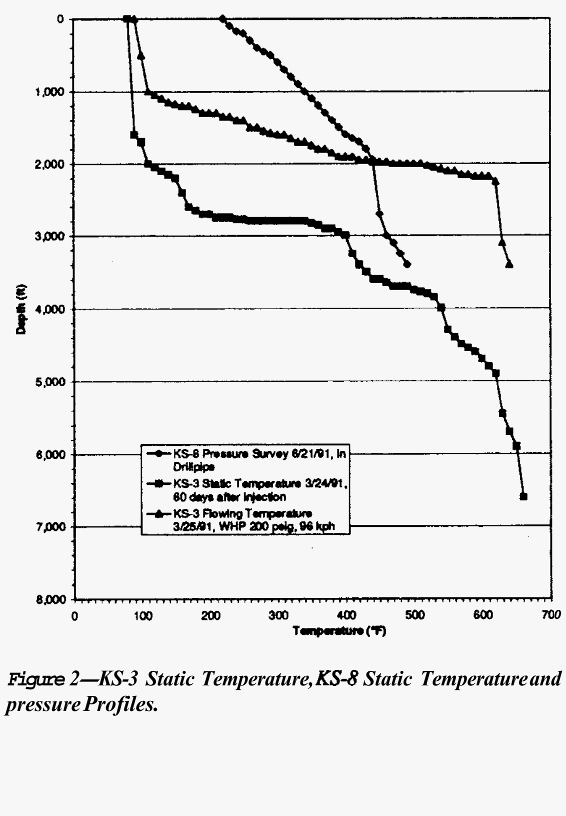

Figure 2—KS-3 Static Temperature, KS-8 Static Temperature and pressure Profiles.

when retrievable bridge plugs were set inside the 5-in. drillpipe and did not hold. One of the inflatable bridge plugs could not be retrieved. A 150 hydraulic snubbing unit was flown in and rigged up on the drillstring. A 1 3/4-in. (3.175-cm) workstring with an overshot was used to fish the bridge plug. Shortly after the bridge plug was engaged, the workstring became stuck. Several attempts were made to free the fish, resulting in backing off above the fish and leaving some of the 1 1/4-in. (3.175-cm) workstring in the hole. A new fishing assembly was run in, and part of the bridge plug with the fishing toolstring was ultimately recovered. The 150 snubbing unit was then removed and the 450 rig assist unit was rigged up. Permanent bridge plugs were set inside the drillstring by wireline at 1,486 ft (453 m), which was above the extreme temperatures associated with the crossflow. The drillpipe was snubbed out of the hole one joint at a time until the plugged joint was encountered. During snubbing out, tight hole was encountered at 3,179 ft (969 m). The drilling jars were set off once, and the pipe was pulled free. Snubbing continued without any additional hole problems.

The joint of pipe with the bridge plugs was then pulled above the 450 snubbing unit. A hot tap was then made below the bridge plug into the drillstring. A viscous gel pill was pumped through the hot tap and placed in the next joint of pipe below the hot tap. The viscous pill was then frozen in place to form a plug. Dry ice was packed around the outside of the drillpipe in a freeze barrel. M e r the dry ice was packed for at least 5 hours, the freeze plug was checked by bleeding back through the hot tap. When the freeze plug was solid, the joint with the bridge plug and hot tap was laid down. A TIW valve was then installed above the freeze plug, and the plug was allowed to thaw.

Next, a second permanent bridge plug was set in the drillstring above the drilling assembly. The remaining drillpipe was snubbed out of the well, and the hot tap and freeze process was repeated at the top of the drilling assembly. Because of the debris left in the drilling assembly from the inflatable plugs, the 150 hydraulic snubbing unit was again rigged upon the drillstring. This unit was used to clean out the drilling assembly through the use of a 1 1/4-in. (3.175-cm) workstring with a flat bottom mill. After this operation was completed, the drilling assembly was snubbed out of the hole through the use of a 450 rig assist snubbing unit.

While the drilling assembly was being snubbed out, the hot tap and freeze process was used several times instead of bridge plugs because of scale buildup, small and variable inside diameters, and obstructions that remained in the drill collars even after the cleanout. The drill collars, because of their spiral shape and different sizes, were snubbed out through a Hydril snubbing stack having inverted collar clamps. The inverted collar clamps serve as a safety measure because drill collars have no upsets or couplings for the snubbers to grab if a slip occurs.

After this time-consuming process was completed, a 7-in. (17.78-cm) casing was snubbed in to 3,346 ft (1,020 m) as a kill string without incident.

2.5 Staged Kill Approach

The goal of the kill operation was to salvage the well and make it a producer. The plan to kill and plug off the downhole flow included pumping successive stages of water, weighted mud, and cement down the kill string. The reaction of the crossflow to the high volumes of cold water would be the determining factor in the procedure. Two alternatives were considered:

- If high volumes of cold water successfully controlled the well, barite-weighted mud would be used to stabilize bottomhole pressures. A cement plug would then be pumped.
- If high volumes of cold water only cooled the hole, weighted mud designed to lose its suspending characteristics at high temperature would be pumped to deliver a barite plug to the bottom.

It was determined that water could be pumped at 20.35, and 50 bbl/min (3.18, 5.56, and 7.95 m^3/min) in 30-minute stages using extra pumping units with no significant change in the wellhead pressure. Mud weights would begin at 12 lb/gal (1.44 g/mL) and increase to 18 lb/gal (2.16 g/mL) The mud would be weighted with barite material. Mud could be pumped at 30 bbl/min (4.77 m^3/min) for 12 lb/gal (1.44 g/mL) mud and 20 bbl/min (3.18 m^3/min) for 18 lb/gal (2.16 g/mL) mud. The weighted mud could only stop the crossflow a maximum of 15 minutes. The decision was made to use a combination of weighted mud and cement to stop the crossflow.

2.6 Cementing Operations

Following unsuccessful attempts to contain the crossflow with dynamic fluid pumping and barite plugs, cementing operations became critical to ultimately securing the well for production. Slurry performance for initial cement plugs was rigorous, requiring pumpability at 600°F (316°C) and bridging properties to contain the estimated 250,000 lb/hr (114 metric ton/hr) annular flow.

A special testing apparatus incorporating a high-temperature consistometer, testing chamber fluid preheated to 400°F (204°C), and both internal and external heating elements totaling 8,200 watts was designed and built to conduct thickening time tests. A cement blend containing perlite, silica flour, dispersant, and bentonite retarded with a chemically modified lignosulphonate with organic acid and high molecular weight cellulose polymer was designed with a pump time of 1 hour and 26 minutes at 600°F (316°C).

An initial 125 ft^3 (3.54 m^3) volume of this formulation was pumped through the killstring into the crossflow following 500 bbl (7.95 m^3) of weighted mud after the hole was cooled as much as possible with high volumes of water, resulting in a partial annular bridge. After additional diagnosis, a second 250 ft^3 (7.08 m') volume was pumped in a similar manner. This volume was preceded by 250 bbl (3.97 m') of mud and 250 ft^3 (7.08 m^3) of 400°F (204°C) retarded cement slurry. This slurry displaced just out of the killstring effected an annular pressure decrease from the usual 650 psi (4,482 kPa) to 1,000 psi (6,845 H a) to 193 psi (1,321 kPa) by the completion of pumping, and to 14 psi (96 H a) within 2 hours, isolating the crossflow from the 13 3/8-in. (33.97-cm) casing shoe. Cement bond logs indicated good cement from 2,100 ft (640 m) to 2,670 ft (814 m) and fair cement from 2,670 ft (814 m) to 2,770 ft (844 m). Subsequent placement of wireline bridge plugs and cement inside the 7-in. (17.78-cm) casing secured the well for postkill procedures. It was apparent at this time that all crossflow was stopped at the shoe of the 13 3/8-in (33.97-cm) casing.

When the 7-in. (17.78-cm) casing was cut off and removed from the cased hole section of wellbore, it was then necessary to seal off the interval below the 13 3/8 in. (33.97-cm) casing shoe to enable a competent 9 5/8-in. (24.45-cm) tieback casing cement job. The interval was successfully squeezed off on a first attempt through the use of staged volumes of calcium chloride water, reactive silicates, and cement sluny containing silica flour, high-strength microspheres, bentonite, and dispersant. Conventional geothermal materials and methodology were used for cementing the 9 5/8-in. (24.45-cm) tieback casing string to surface. The tieback casing was installed on the top of the 7-in. (17.78-cm) casing stub. A typical geothermal wellhead expansion spool and surface equipment were installed. The equipment was, however, rated at 5,000 psi (34,255 H a) to handle the expected combination of over 600°F (316°C) temperature and 2,100 psi (14,375 H a) pressures.

3. SAFETY

Safety meetings and information meetings were conducted at each project change to coordinate the project with the multiple companies, personnel, and regulatory agencies involved. The operator provided a safety instructor on site to hold H_2S certification classes and geothermal well safety classes, The safety instructor monitored all safety aspects of the project, modifying the safety plan as conditions changed.

H_2S and noise levels were monitored throughout the project. Monitoring stations were set up on site and throughout the surrounding area to accumulate the data. During the initial 30-hour controlled flow, personnel were required to wear Scott Air Packs. A maintenance station was set up off the drilling pad to refill and inspect the air packs. An on-site maintenance station provided immediate information of damage to the individual packs and limited downtime for servicing the packs.

4. RESULTS

After 3 months of restoring the rig and equipment, pumping water to cool the well, snubbing out the drillstring and replacing it with 7-in. (17.78-cm) casing, and pumping mud and cement to block the crossflow, the final kill procedure was successfully performed. and well KS-8 was under control. On September 30, 1991, the well was temporarily suspended to wait for permits to be reissued. The permits were needed to drill out and continue completing the well as a producer for the 25 MW turbine generator.

Subsequently, a 5-in. (12.7-cm) liner was cemented inside the 7-in. (17.78-cm) casing to cover damaged sections (Fig. 3). The 7-in. (17.78-cm) casing was damaged when it was cooled during completion operations. **All** operations after the plug was drilled out of the 7-in. (17.78-cm) casing were performed using the 450 rig-assist snubbing unit. The well was placed on line to the power plant and produced over 12 MWe during power plant startup.

Sound principles of well control and innovative state-of-the-art techniques were combined to avert disaster and turn a severely damaged well into a producer. Experienced operators took immediate action to control the well. Long-term repairs were accomplished with operating company personnel, service company personnel, local agencies, and well control specialists coordinating strategies and information. In the end, the well was successfully completed and placed on line, where anticipated production rates were achieved.

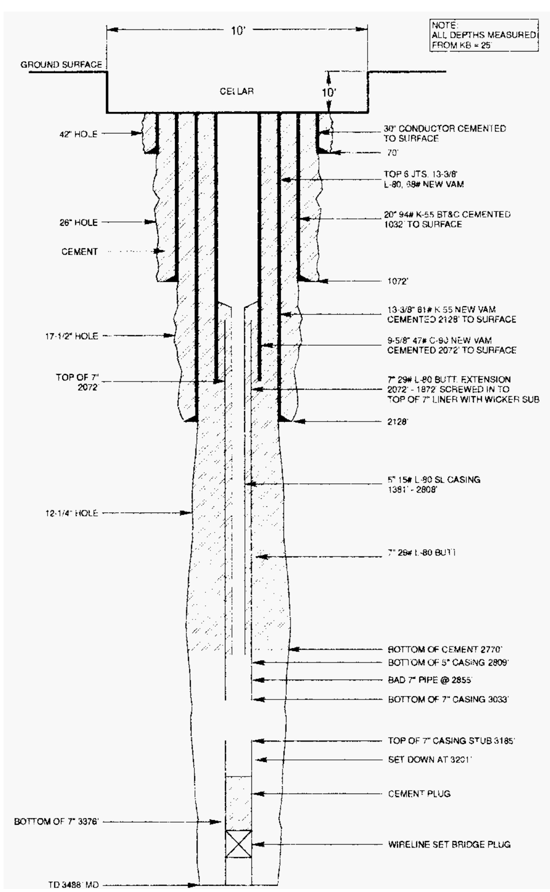

*Figure 3 - **Well** condition, 3 August 1992*

Because of the unconventional completion and operational problems, the well was plugged and abandoned after only a few months ofproduction. Changes in wellhead pressure caused similar changes in wellbore temperature. At low flow rates, the wellhead pressure was very high, but the wellhead pressure was very low during high rates of production because of the choke effect ofthe 5-in. liner. The lightweight kill cement and the relatively lightweight 5-in. (12.7 cm) and 7-in. (17.78-cm) liners were assumed to be deteriorating quickly because of the significant temperature fluctuations in the wellbore. This assumption was proven to he true, or was at least supported by the casing problems encountered during the subsequent plug-and-abandon operation. The well had proven that a valuable resource could be tapped and used. It was determined that the most prudent route was to plug and abandon this well and use welis that were designed to withstand the severe conditions to exploit this resource.

5. CONCLUSIONS

The KS-8 experience was valuable to officials involved with the Hawaii geothermal projects. Speculation and studies indicated powerful geothermal activity. KS-8 removed any doubt of the temperatures and pressures available for commercial exploitation in the Kilauea Lower East Rift Zone.

The experience was also valuable to people in the industry as awareness of what problems a powerful geothermal resource can cause and what innovative procedures will be required to safely exploit these resources.

The operating company and service companies gained insight into the importance of communicating with and educating the public affected by the environmental aspects ofdrilling a well. Contradictory information concerning the safety of the geothermal plant and conservation of natural resources must be addressed so that citizens understand the benefits of the project. Drilling a well can be inconvenient to the surrounding population. Their cooperation and support of the project should be sought upfront to minimize the inconvenience and misunderstandings which can in turn, lead to excessive regulatory delays by local agencies.

Production companies and service companies are now aware of the necessity to prepare a risk assessment and to provide adequate solutions for those risks. Risk assessment and solution provision is especially critical in remote locations where importing the necessary equipment is cumbersome and time-consuming.

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