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FIELD ACTIVITIES

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SPERRY LOW TEMPERATURE GEOTHERMAL
CONVERSION SYSTEM - PHASE I
Contract No. DE-AC03-78ET27125
(Formerly ET-78-C-02-4633)
and PHASE II
Contract No. DE-AC03-79-ET27131

FINAL REPORT - VOLUME IV
SRC-CR-83-41
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MASTER

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FOREWORD

This final report covers the work performed under the "Sperry Low Temperature Geothermal Conversion System" project, both Phase I under Contract No. DE-AC03-78-ET27125 (formerly ET-78-C-02-4633) and Phase II under Contract No. DE-AC03-79-ET27131.

Vols. I and II, submitted in 1982 covered a portion of the work accomplished under Phase I. Vols. III, IV, V, and VI submitted at this time cover the balance of work performed under Phase I and work performed under Phase II.

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VOLUME IV

.0 INTRODUCTION

This volume describes those activities which took place at the Sperry D.O.E. Gravity Head plant site at the East Mesa Geothermal Reservoir near Holtville, California between February 1980, when site preparation was begun, and November 1982, when production well 87-6 was permanently abandoned. *Construction activities were terminated in July 1981 following the liner collapse in well 87-6. Large amounts of program time manpower, materials, and funds had been diverted in a nine-month struggle to salvage the production well. Once these efforts proved futile, there was no rational for continuing with the site work unless and until sufficient funding to duplicate well 87-6 was obtained.

In spite of exhaustive efforts to obtain support from both public and private sources, sufficient funding to complete the project was not forthcoming. Until oil prices tumbled in late 1982, the prospects were quite favorable for a privately funded continuation of the Gravity Head demonstration effort. However, the drop in oil prices (and the resulting electric energy cost-increase avoided, in California), diminished the private interest in moderate temperature geothermal wane.

At the time of the well liner collapse, all of the surface components required to perform the stand-alone down hole organic turbine pump test were on site, installed, tested, and "ready to go". The system was charged with refrigerant R114 and we were rigged up, preparing to install the down-hole turbine-pump unit on the day that the well caved in. That such a protracted struggle to save a crippled well (nine months of continuous effort) should end so suddenly, so unexpectedly, and with such utter finality, left the many participants in a state of disbelief.

*(Definitions of some technical terms used in this volume are given in Appendix C.)

4.1 PLANT CONSTRUCTION AND PRE-OPERATIONAL CALIBRATION AND TESTING

4.1.1 Site Preparation

A 400 foot by 530 foot site was filled, graded, compacted, and fenced. A 20 foot by 30 foot drilling mud pit was excavated. A 100 foot by 115 foot flashed brine pond for well testing and emergency blowoff was excavated and lined with clay. A layer of fines was spread to control wet-weather mud problems. Construction and Main power entrances, including transformers, disconnects, circuit breakers, and overhead lines were installed. Field office and equipment storage trailers were moved in and a pipe filter's working shed was erected. Following completion of well drilling activity the mud pit was excavated, filled, compacted, and graded.

4.1.2 Evaporative Condensers (BACs)

Twenty 6 X 10^6 Btu/hour evaporative condensers were purchased, transported, and erected on permanent concrete pads and steel support structures which had been fabricated by Mustang Engineering Company (MEC). Four of the units were piped up with barometric legs, skimmers and isolation values required to conduct the downhole pump-turbine tests. Fans and pumps were wired into the site 480 V auxiliary power system. Scientific and operating instruments were installed. An automatic startup and shutdown cycling system was installed, complete with local and remote status indications and controls. The four BACs were watered up and exercised from both local and remote (control room) control stations. Automatic blowdown and water treatment systems were adjusted and tested. The units were leak tested, evacuated, and charged with R114. Off-site power failures were simulated and the automatic diesel-powered restart and recovery system was tested.

4.1.3 Main Generator

Because the main power turbine was expected to operate at 3,600 RPM, a two-pole, 3,600 RPM synchronous generator was desirable. It would eliminate the need for a speed reducing gear box between turbine and generator. However, manufacturer quotes for a new non-salient pole, two-pole machine ranged from $600K to $800K vs. $175K for a salient pole, four-pole, 1,800 RPM generator. A used two-pole, 3,600 RPM, 4,160 volt, 5 MVA generator was located in Long Beach, CA. After tracing the history of the machine and inspecting and hi-potting the unit, it was determined that it could be purchased and rehabilitated at approximately 1/3 the cost of a new 4-pole machine.

The generator and exciter were purchased and transported to the Reliance Electric shops in Anaheim, CA for overhaul. The shaft and pedestal bearings were modified to accept a direct-coupled power turbine. After completion of the modification and rehab work, the generator and exciter were balanced and hi-potted successfully. They were then transported to MEC for storage in a dry, heated environment.

4.1.4 Barber-Nichols (B/N) Skid

The Barber-Nichols (B/N) R114 handling and lube oil make-up skid was delivered to the site,mounted on a concrete pad, piped into the R114 and vacuum piping systems, and wired into the site 480 volt auxiliary power system. Instrumentation and controls were wired into the control room, the instruments were calibrated, and the control valves were calibrated and exercised, both locally and from the control room. The oil de-gassing system was tested, modified, and successfully operated. The R114 pumping system was exercised at full flow and pressure while cycling R114 through the BACs and ERU. The automated R114 pumps startup and shutdown sequencing was tested.

4.1.5 Scrubber System

The vacuum scrubber system for cleaning R114 was piped in, wired and vacuum tested. It was not functionally tested, since a hot R114 vapor stream would be required but was never available on site.

4.1.6 R114 Piping

All R114 process piping was completed (except for connection to well head), leak tested, and vacuum tested. The system was charged with R114 and cleaned by cycling liquid R114 through the piping while extracting rust and other debris with cartridge and magnetic filters. R114 was loaded into and unloaded from the system. The various system sectionalizing, isolating, and R114 evacuation and charging scenarios were executed withut incident. The only surprise was the amount of time required, even during summer weather, to get enough natural heat transfer into the piping low points to effect full R114 evacuation. Unvaporized pools of R114 could readily be visually detected during evacuation by external icing of the affected piping.

4.1.7 Auto Welding Equipment

The automatic pipe welding and arc air weld removal equipment, which had been developed at the Sperry Research Center and successfully tested at Mustang Engineering Company, was deliverd to the site. The equipment, which was designed to automatically apply and remove seal welds between each forty-foot section of downhole hardware as the hardware was inserted during installation or withdrawn for maintenance, was fitted with a counter-weighted suspension system and ultraviolet shields. Transport speed, wire speed, current, gun angles, air flow, and gas flow were adjusted to the optimum values which had been experimentally derived at SRC.

4.1.8 TPU Lube-Signal Line and Insertion Equipment

Two spools of specially fabricated 2,000 foot long half-inch tubing were received on site. The tubing was laid out in a straight line along the roadway and a leader was nitrogen propelled through the tubing. The two-wire multiplex signal cable was then pulled through without difficulty. The tubing was then rewound on the spools and returned to the site. The lube tube insertion equipment, which had been fabricated at MEC, was delivered to the site. It consisted of a hydraulically driven feeder spool, tubing straightner, and boom (rooster tail) for inserting and retrieving the lube line to the downhole TPU, (turbine pump unit)One spool of tubing was mounted on the insertion equipment.

4.1.9 Condenser Fouling Test Fixture

The test fixture, which had been fabricated by B/N, was delivered to the site. The spray tubes were damaged in transit and were replaced by field personnel. The unit was charged with R114 and exercised. The test tubes corroded at a very rapid rate, leading us to suspect that an electrical ground loop was causing electrolytic damage. An internal wiring error was found and corrected; the corrosion ceased. The unit was relocated to the D.O.E. test pad and given a two week shakedown run using well water as the evaporative fluid. There was no detectable corrosion or fouling of the test condenser tubes.

4.1.10 Brine Handling System

The brine handling piping was completed and pressure tested. The automatic well pressure control instrumentation and valving was calibrated and tested. The flash tank level and pressure controls, the automatic mode transfer system, and the automatic shutdown systems were tested. The equipment was utilized during well flow tests, operating in the "flash" mode. Although the flash tank level and pressure controls, which were designed for a 1,300 gpm flow rate, were difficult to stabalize at the reduced (300 gpm) test rate, the system operated very well once it was properly adjusted. The reinjection pumps were mounted on concrete pads, piped up, and wired into the 480 volt auxiliary power system. The pumps were electrically "bumped" but were never run.

4.1.11 Vacuum System

The vacuum skid, which had been fabricated by MEC, was delivered to the site, mounted on a concrete pad, piped into the R114, cooling water, and instrument air systems, and wired into the station service 480 V electrical auxiliary power system. The instruments were calibrated and the vacuum pump and compressor were exercised. The skid was used to evacuate air from the R114 storage vessel, ERU, BACs, R114 piping system, and B/N skid prior to loading freon. The skid was used on numerous occasions to evacuate R114 from the system and transfer it back to the storage tank. No problems developed.

4.1.12 <u>I&C System</u>

The Sperry instrument van for scientific instrument recording and the plant control board for operational instrumentation and control were delivered to the site. The field transmitters were wired to the control board and MUX system. The control board and Sperry van were wired to the Uninterruptable Power Supply (U.P.S.) and the MUX system was wired to the Sperry van. All instruments were wire checked and calibrated. The "three-term" electronic valve controllers were adjusted and exercised. MUX channels to the Sperry van were checked and exercised. The Sperry Data Recording & Computer systems were activated and checked. The van air conditioning was not sufficient to prevent computer malfunction during the heat of summer days. A sun shield was erected above the van, but we continued to experience problems. Eventually we were forced to run both the site powered air conditioner and the van engine-powered air conditioner to prevent equipment from overheating during the midday hours.

4.1.13 <u>R114 Storage Vessel</u>

The R114 storage vessel was fabricated by MEC, delivered to the site, mounted on a concrete pad, and piped into the R114 and vacuum systems. 30,000 pounds of R114 were loaded into the tank. The working fluid was subsequently transferred back and forth between the storage vessel and the surface system on several occasions. The R114 was finally off-loaded and re-sold to the refrigerant manufacturer.

4.1.14 <u>Enthalphy Recovery Unit</u> (ERU)

The ERU for the Stand Alone was fabricated by MEC, delivered to the site, mounted on a concrete pad, and piped into the R114 and vacuum systems. The unit was evacuated and loaded with R114 from the storage vessel. R114 was cycled through the units during functional surface system tests. Its instrumentation was wired into the control room and calibrated.

4.1.15 Uninterruptable Power Supply (U.P.S.)

A 120 Vac Uninterruptable Power Supply, consisting of solid-state converter-inverter, a nickel-cadium battery bank, and high speed automatic throwover equipment, was purchased by MEC, delivered to the site and installed in the control trailer. The system was wired into the plant auxiliary power system and connected to the Main Control Board and Sperry van for 120 Vac uninterruptable power to the I&C and Scientific Data Recording systems. The equipment was calibrated and exercised. Off-site power failures were simulated while the I&C and computer systems were up and running. Powers supply transfer and recovery was within specifications and the powered systems continued to operate normally. Transfers back to restored off-site power were effected with identical results.

4.1.16 Emergency Diesel-Generator Set

A 200 KVA, 3-phase, 60 Hz, 480 volt diesel driven generator set with automatic throwover equipment was leased by Republic Geothermal, Inc. (R.G.I.), delivered to the site, and wired (by MEC) into the 480 volt auxiliary power system. The purpose of the set was to prevent an interruption of the downhole TPU test when off-site power was lost. Loss of off-site power is a frequent event at East Mesa - apparently usually caused by insulator flashovers.

Because the diesel generator system could not be economically sized to carry the entire plant load, an automatic load-shedding and operating-mode change system was installed. Upon loss of off-site power this system would automatically shed specified electrical loads, start the diesel, switch the 480 volt auxiliary power source from off-site to diesel-generator, change the brine handling system from "Direct Injection Mode" to "Flash Mode", and sequentially restart selected 480 volt loads. Upon restoration of off-site power, the transfer back to off-site power was initiated by the plant operators.

The equipment was calibrated and tested by simulating loss of off-site power. All aspects of the system performed flawlessly.

4.1.17 Instrument Air System

The compressor skid, which had been assembled and mounted at MEC, was delivered to the site and mounted on a concrete pad. The instrument air piping was completed and leak tested by MEC field personnel. The compressor skid was piped in and wired to both the site 480 volt auxiliary power system and the control room alarm system. The completed system was calibrated, tested, and put into regular operation.

4.1.18 Arc Air System

The arc air compressor skid was assembled at MEC, delivered to the site, and mounted on a concrete pad. The piping was completed and leak tested. The compressor was wired to the site 480 volt auxiliary power system and the compressor unit was calibrated and tested.

4.1.19 Dummy Downhole Heat Exchangers

Dummy tubular and annular heat exchangers for practice insertion into the 30 inch and 24 inch casings, respectively, were constructed by Mustang Engineering and shipped to the site. The dummy exchangers were repeatedly inserted to the bottoms of both the 30 inch and 24 inch well bore sections without difficulty. Procedures for transferring the exchangers from the horizontal, truck mounted shipping cradles to the vertical insertion position over the well head were also executed without incident. The dummy exchangers were of larger diameter and higher beam stiffness than the working exchangers would be.

4.2 DRILLING AND COMPLETION OF WELL 87-6

The well was spudded in by Republic Drilling Company on March 2, 1980. On March 5th, the 36 inch hole for the 30 inch casing was completed to 1,234 feet. (all elevations refer to depth below grade). On March 6th, the 30 inch casing was run in. In became stuck at 919 feet and could not be moved. It was decided to modify the well design in order to "live with" less than the designed depth of 30 inch casing. The casing was cemented in place on March 7th. Cement returns at the surface indicated a poor cement job. Returns appeared after much less than the calculated volume of cement had been injected, indicating that serious "channeling" of the cement had occurred.

In order to compensate for part of the loss of usable 30 inch casing depth, it was decided to shorten the 30 inch/24 inch casing lap from the designed 200 feet to a much shorter 50 feet See Fig. 4 in Appendix D. Unfortunately, this meant milling out the prefabricated 24 inch hanger receptacle which was welded inside the 30 inch casing 715 feet below grade. The mill was withdrawn from the well after 12 hours of extremely rough operation without having completed removal of the hanger receptacle. The mill was badly worn. It appeared that, because of its "spoked shoulder" design, the mill had been ripping and tearing at the hanger pads instead of grinding them out as intended (and very possibly had damaged the casing in the process). After the mill had been repaired and its shoulder design modified to present a more uniform grinding surface to the hanger receptical, completion of milling the operation went smoothly.

By March 17th a 30 inch hole for the 24 inch casing had been completed with an underreamer to 2,214 feet. On March 18th, the 24 inch casing was run in. It became stuck 469 feet short of its planned depth and could not be moved. The casing was jarred for 6 hours without effect. Although the well was usable for the Gravity Head system with both the 30 inch and 24 inch casing terminated at shallower than desired depths, the excess 24 inch casing which now extended above elevation 869 feet (the location of the desired top of the 24 inch casing) would have to be cut off and retrieved before cementing.

The first cut was made on March 23rd at elevation 410 feet; 10 feet below the top of the 24 inch casing upon which a casing hanger was mounted. The second cut was made at elevation 868 feet. The excess 458 feet of 24 inch casing was removed. The cut was very ragged, so an additional four feet of 24 inch casing was cut and removed. The top of the 24 inch casing was now wedged against the side of the 30 inch casing and had to be forcibly centralized with an adapter which was rotated onto the top of the 24 inch casing. After installation, the top of the adapter rested at 868 feet below grade.

On March 25th, the 24 inch casing was cemented. Again, premature returns indicated channeling and the probability of a poor cement job. The casing was pressure tested and failed. Cement was squeezed into the lap twice before the casing successfully held pressure.

From March 30th through April 6th a 12-1/4 inch hole was drilled to 6,274 feet without unusual problems.

On March 8th, 9-5/8 inch casing with a 1,500 foot slotted liner, cement baskets, and cement ports attached was run in without incident. However, once the hydraulic hanger was set, circulation was lost. During futile efforts to re-establish circulation, 2,800 bbl of drillng mud was lost - the casing could not be worked because the hanger had set. The 9-5/8 casing was cemented without circulation. A cement bond log showed only the bottom 300 feet of 9-5/8 inch casing was cemented. The 13-3/8 - 9-5/8 inch lap was squeezed with cement twice before the casing passed a 1000 psi pressure test.

On March 12th & 13th the float collar was drilled out and the well bore was cleaned up and bailed (found slotted liner filled with siltstone - an occurrence for which a plausible explanation was never discovered). The drilling mud was replaced with fresh water and on March 14th the well began to flow naturally, without benefit of a nitrogen "kick-off". Approximately 6,000 bbl of brine was produced to the site "flash pit" to clean up the well. The drilling rig was released on March 24th but remained over the well until April for the convenience of the drilling contractor.

The one-inch side string, which had been installed as an integral part of the well, was tested and found to be damaged. The damaged side string would later prove to be the source of a major casing leak 700 feet below grade.

With benefit of hindsight and discussions with various authorities outside the geothermal and oil drilling communities, it becomes apparent that the drilling and completion problems encountered with well 87-6 were preventable. Water well drillers, for example, routinely install well casings of even larger diameter than those used in well 87-6. The basic lessons learned are listed below.

(1) Use larger hole-to-casing diameter ratios.
(2) Use a well profile which does not require the use of under-reamers.
(3) If side-strings are utilized, properly armor them to prevent tubing damage.
(4) Pay strict attention to mud conditions and the maintenance of adequate mud velocities.
(5) Do not trust O-ring sealed buttress threaded casing connectors to join the large-bore casing - weld all large-bore casing connectors.
(6) Use casing centralizers liberally.

For an analysis of the well damage and recommended preventative measures see section 2 of the report "Well 87-6 Abandonment," (SRC-CR-83-3), which was submitted under this Contract in January, 1983. There is no evidence to indicate that, with adequate well design and installation techniques applied, a large-bore well such as 87-6 cannot be routinely installed without adnormal risks or difficulties.

In preparation for final well-bore cleanup and calipering operations, well 87-6 was killed to an unknown depth of open hole on December 14, 1980. The well killed normally with 850 bbl of 9.4 lb/gal. kill fluid plus 350 bbl of 8.3 lb/gal. fresh water.

On the morning of December 15, 1980 the well had come back in (water level at surface and slightly pressurized). When an additional 100 bbl of 8.3 lb/gal cold water did not kill the well, 200 bbl of brine was back-flowed, heavied up to 9.4 lb/gal., and reinjected into the well bore. This effort killed the well to 17 feet of open hole.

An underwater TV camera and lighting system was run into the hole with the intention of inspecting the 30"/24" casting lap for concentricity. The camera failed at 800 feet below grade. Attached temperature recording thermometers indicated 240^{O}F at 800 feet - much higher than expected.

On the morning of December 16th, the well remained killed with 14 feet of open hole. After having added 15 bbl of 9.4 lb/gal. kill fluid, the master valve was removed and a blowout preventer (BOP) was stripped over a 22 inch hole opener and installed on the well head. The hole opener was to be used to clean the 24 inch casing. At the end of the day the BOP pipe rams were closed with hole opener, drill collars, and drill pipe extending 120 feet into the well bore.

On the morning of December 17th, the well came back in and began to pressurize. The BOP leaked profusely. 50 bbl of 8.3 lb/gal. cold water were pumped in without effect. Because of the 22 inch hole opener on the end of the drill string, it was not possible to withdraw the string and try the blind rams. A blind flange was welded to a section of drill pipe. The pipe section was then added to the string which was already in the hole and then lowered until the blind flange was flush with the top of the BOP, where it was gasketed and bolted down. Although the flange held reasonably well, it leaked enough to encourage frantic efforts to kill the well.

On December 20th, 950 bbl of 9.4 lb/gal. kill fluid and 250 bbl of fresh water failed to kill the well. Minimum welhead pressure achieved was 12 psig.

By this time, it had become obvious that well 87-6 was responding most abnormally to conventional kill procedures. Analysis of the problem was complicated by an absolute absence of any experience base in the hydraulic behavior of hydothermal wells of such large diameter. There was considerable speculation that possibly the kill fluid was not traveling down the bore in the usual "piston" fashion; that possibly, in so large a well-bore, the heavier fluid channeled down in some mysterious fashion. At this point we considered two major possibilities which could have caused the observed behavior: (1) channeling of the kill fluid and (2) a serious casing leak.

If it had been possible to run well logs at this time, the problem could have been resolved rather quickly. However, the drill string which was trapped in the well was topped off with a valve which would not accept a lubricator. Consequently, there was no way to insert a logging tool into the pressurized well bore. An additional puzzle was why the well would kill normally on December 14th and 15th but not during subsequent attempts.

On December 21st, 950 bbl of 9.7 lb/gal. kill fluid, 313 lb of 9.4 lb/gal. kill fluid, and 77 bbl of 8.3 lb/gal. fresh water were pumped into the well at more than twice the flow rate previously achieved. The minimum well head pressure achieved was 32 psi. Whatever the problem was, it seemed to be getting worse! Adding to the urgency of the situation was the worsened leakage of the temporary flange which had been installed to seal the defective BOP and which was the only element between ourselves and a catastrophic blowout.

On December 23rd, operating on the theory that some mysterious mixing phenomenon was at work, a 150 foot column of viscous polymer fluid was pumped into the well, to be followed by 1,000 bbl of 9.5 lb/gal. kill fluid plus 159 bbl of 9.6 lb/bbl kill fluid. The minimum wellhead pressure achieved was 8.7 psig. The December 23rd effort resulted in two distinct accomplishments:

(1) The polymer entirely sealed the leaking surface flange, eliminating the frantic atmosphere surrounding the effort and allowing time to work out alternative solutions to the problem at hand; and

(2) Well-head pressure readings taken as the killing effort progressed, and which had been inconclusive on previous attempts, clearly showed evidence of a leak toward the bottom of the 30 inch casing (the pressure effect became nonlinear as the column of kill fluid approached the 700 to 900 foot zone).

The entire effort up to this point had been complicated by the failed B.O.P., the inability to get logging tools into the well, and a casing leak which had apparently become progressively worse with each killing attempt, and thereby had produced different behavior during each attempt.

Now that there was clear evidence of a high casing leak, suspicion focused on the 30" to 24" casing lap. This lap had failed to pressure test during the original well completion and had been squeezed twice before a successful cement seal had been achieved. Operating on the assumption that the major casing leak was at the 30"-24" lap, the following plan was developed:

(1) Purchase premixed kill fluid which is heavy enough to kill the well in the upper 800 feet of well bore,

(2) Kill the well,

(3) Strip off defective B.O.P., withdraw drill string, and 22 inch hole opener,

(4) Install replacement B.O.P.,

(5) Install rotating collar (so well could be worked "hot" in the event it did not remain in a killed condition),

(6) Run in a 13 inch bridge plug to be set above the 13-3/8 - 9-5/8 inch casing lap, and

(7) Install a tubing valve suitable for accepting a logging tool lubricator,

On January 6, 1981, a 110 bbl polymer pill was pumped into the well to be followed by 570 bbl of 11.7 lb/gal. kill fluid. The well was killed to an unknown depth. The blind flange was unbolted from the B.O.P. and the top section of drill pipe with flange attached was withdrawn from the well and laid down. At this time the well was killed to 5 feet below kelly. As the second pipe section was being withdrawn the well started to come back in, the level rising at a rate of 2 feet per minute. The B.O.P. pipe rams were closed with almost no effect - very heavy leakage! Another 220 bbl of 11.7 lb/gal. kill fluid were pumped in while picking up the drill pipe section which had the blank flange attached. No effect. The pipe rams were opened, a pipe section with flange was run in and the flange was bolted to the B.O.P. - leakage was still moderate.

At 8:00 P.M. on January 6th, the well began to blow out around the blind flange. Under very hazardous conditions, site personnel burned additional bolt holes and installed additional hold-down bolts in the leaking flange. The effort served to moderate but not eliminate the leakage. The well was finally sealed by pumping cotton-seed hulls into the side port; these were then blown by escaping steam through the leaking flange where they eventually lodged to create a seal.

Up to this point using drilling mud to kill the well had been avoided for fear of damaging the production formation. After the event of January 6th, it was decided that the well had become dangerous to an extent which precluded any consideration of possible formation damage. The alarming behavior of the well now convinced us that an underground blowout was probably in progress and that gaining control of the well as quickly as possible was of singular importance.

On January 7th, drilling mud was trucked in and mixing operations were begun. Fresh cold water was pumped into the well while a running temperature survey of the well bore was performed. The survey showed two things: (1) the cold kill column travelled down the well in a piston fashion with no evidence of "channeling" and (2) that an underground blowout was in progress at 700 feet, the location of the ill-fated side string. Mud mixing operations continued throughout the night. At 7:00 A.M. on January 8th, the cellar box began filling with brine, indicating that the underground blowout had migrated to the surface outside the well casing. As mud preparation was being completed, a vacuum truck was used to evacuate the cellar box. During a thirty-minute period, the rate of flow into the cellar increased noticeably, boiling up on both the north and south sides of the casing. The workover rig crew became alarmed and moved their tool truck and themselves to the far side of the lot. When the mud was ready to pump, the rig crew returned to the well site to execute the killing effort, it is suspected, only because of Academy Award caliber acting performances on the part of certain supervisory personnel who stood over the well, which was in the process of blowing out to the surface, while effecting an air of serenity.

The well was killed to 100 feet of empty hole with 250 bbl of 16.7 lb/gal. drilling mud. The defective B.O.P., drill string, and 22 inch hole opener were removed from the well. A replacement B.O.P. was installed. A bridge plug was set in the 13-3/8 inch casing at 3:00 A.M. on January 9th.

On January 10th a larger workover rig was moved in.

On January 13th & 14th a rotating collar was installed above the B.O.P. and the mud in the wellbore was replaced with fresh water. On January 14th an underwater TV camera was run into the well in an attempt to inspect for damaged casing. The well fluid proved to murky for effective viewing.

From January 15th through February 27th, well repairs were undertaken on an around-the-clock basis. The effort was complicated by the unavailability of standard well working tools such as bridge plugs and packers for large-bore applications. The only available method for locating and repairing leaks in the large casing was the very time-consuming and expensive process of injecting and drilling out cement plugs. Power swivels on standard workover rigs were never intended for such heavy-duty chores as drilling out several hundred feet of 28-1/2 inch diameter cement while reverse circulating. Blowout of rotating collar rubbers, clogged mud lines, and mud pump failures were common occurances.

Major leaks were located and squeezed off with cement at the 30"/24" casing lap and at 700 feet. Minor leaks were located and squeezed off at several of the upper level (above 500 feet) 30 inch casing joints.

On February 28th we began unloading kill fluid from the well. At 7:00 a.m. on March 1st, the well kicked off and began flowing. By March 3rd the flow had stabilized at 7,410 bbl/day at 48 psig wellhead presure. On March 4th, the well was shut in for a pressure buildup test. The building test was completed on March 5th.

On March 7th, 1,000 bbl of 9.7 lb/gal. kill fluid followed by 300 bbl of fresh water failed to kill the well. Minimum well-head pressure achieved was 63 psig, indicating that thermal stress had reopened the casing leaks.

A "last ditch" plan was developed to permanently seal the leaking casing while preserving sufficient inside well diameter to accommodate the Gravity Head and Pump Test systems. It involved the installation of a continuous, thin-walled, liner extending from the bottom of the 24 inch casing up to the well head. The greatest perceived risk in the proposed operation involved the possibility of collapsing the liner during the cementing operation. Analysis indicated that once a proper cement bond had been installed between the proposed liner and the defective casing the risk of collapse would be minimal because the mechanical response of the liner to external pressure would more resemble a supported arch than an unsupported cylinder.

4.3 FINAL REPAIR EFFORT ON WELL 87-6

4.3.1 Background

Because Well 87-6 had a history of developing multiple leaks in the upper bore and since there was evidence that the leaks had reappeared following recent efforts to sqeeze them off with cement, it was decided to sleeve the upper 1754' with a specially fabricated 3/16" wall liner. The object of the operation was to permanently eliminate leaks while preserving the inside well diameters required for both the pump test and gravity-head systems.

It was recognized that the use of the thin-walled lined posed an element of risk. Analysis indicated that unsupported by cement, the liner could withstand internal pressures in excess of 650 psi. However, collapse pressure would be a very low 22 psi. Analysis also indicated that once supported by good cement, the liner could be expected to withstand all of the conditions which were predicted to develop during installation and operation of both the pump test and gravity-test systems. Therefore, it was concluded that the highest element of risk would be encountered during the cementing operation.

Halliburton Engineers were consulted. The lightest available high-temperature cement was found to weigh 11 lb/gal. The heaviest kill fluid available at reasonable expense weighed 9.5 lb/gal. Analysis revealed that if the cement job were performed in a conventional manner, (i.e. stabbed into a cement shoe at the bottom of the liner), the differential pressure that would be developed toward the completion of a 1751' cement lift would be 136 psi plus friction loss; far in excess of the unsupported liner collapse value.

4.3.2 Plan

The following plan was devised:

(1) Run-in a 9-5/8" retreivable bridge plug to 2050' through a 12" valve B.O.P. and rotating head with the well hot;

(2) Pressure test the well;

(3) Spot a 150' cement plug above the bridge plug which would straddle the 13-3/8" - 9-5/8" casing lap;

(4) Load the upper well bore with 9.5 lb/gal. kill fluid;

(5) Install 1751' of continuous 21.5" and 27.5" o.d. 3/16" wall liner with a cement shoe on bottom; plus a packing gland, vent line, fill line, 500 psi relief valve, and pressure gauge at the top;

(6) Stab into the cement shoe with a 3-1/2" drill string; pack off the top, fill and vent the liner, and pressure test the liner to 450 psi;

(7) Pull up 5' above the shoe, pack off the top, and establish forward circulation;

(8) Switch over to cement and perform the job "open-ended" at the bottom so that the liner internal pressure at all times exceeds external pressure. Cement to be injected at a rate no higher than that which generates an internal pressure of 450 psi at the top of the liner.

(9) Displace drill string with kill fluid and shut-in at surface with a holding pressure of 145 psi. Allow cement to cure;

(10) Cut off excess liner and weld top of liner to 30" casing below the Braden head;

(11) Drill out cement using reverse circulation;

(12) Change over to clean kill fluid at average density of 9.2 lb/gal. (2.6 psi over balance);

(13) Retreive bridge plug;

(14) Tag sand fill in production zone and bail if necessary;

(15) Install downhole pump;

4.3.3 Summary of Well Repair Effort

Beginning on June 1, 1981, Steps #(1) through #(14) were executed; good cement return at calculated volume indicated an excellent cement job. However, several anomalies developed during the effort:

(a) Following installation of the bridge plug, the well continued to flow at a 15 gpm rate. A shut-in test revealed a pressure buildup of 14 psi. A column of kill fluid was spotted above the 13-3/8" to 9-5/8" casing lap with no effect; thus eliminating the bridge plug and lower lap as possible sources of the flow. Flow ceased and level stabilized 40' below grade when the upper bore was loaded with kill fluid (estimate average density of 9.2 lb/gal.

(b) During the cement drilling operating, the drill pipe clogged, the mud pump relief valve failed to function, and rotating rubbers were blown out. This event effected a sudden decompression of the liner top from an estimated 600-800 psi to atmospheric. Subsequent inspection revealed a 4" inward "dimple" of about 12" in diameter, approximately 12' from the top of the liner. A 20-1/4" 'pig' was subsequently run to 1745' with no resistance.

(c) When the retreivable bridge plug was pulled, the water level fell to 430' below grade.

(d) In preparation for Step #(15) of the plan, double stands of drill pipe were run into the hole in order to lay down singles. At 569' a liner collapse was encountered. Five hours later the collapse had extended up to 553'. After 14 additional hours, the top of the collapse was tagged at 513'. A flow test revealed that fluid could be moved down through the collapse. After having pumped away 300 bbl of water the level stabilized at 372' indicating that the liner had not ruptured and exposed the upper zone leak.

At this point we were faced with the possibility that:

(1) The liner would rupture in a manner which would allow the production zone to communicate with the upper zone high leak;

(2) The collapse would worsen to an extent that would eliminate our ability to move fluid past it.

Had the two above conditions developed, we would have been presented with an underground blow-out which could have eventually broken through to the surface outside the well casing as it had done previously on the morning of January 8, 1981 and would have precluded our ability to control the situation. We therefore porposed and received approval from both D.O.E./WASH and USGS to immediately squeeze a cement plug into the 9-5/8" casing. This operation was performed on July 2, 1981. A log of the 6/1/81 through 7/2/81 activity is in Appendix A. A memorandum from our oil well drilling consultant recommending abandonment of Well 87-6 is in Appendix B.

4.3.4 CONCLUSIONS

Available evidence suggests the following as the probable cause of the liner failure:

(1) Previous attempts to repair the well had revealed multiple leaks at the VETCO connectors, a leaking lap, and a major leak at 716'; the known location of the entrance of a ruptured one-inch side string is 716'. The fact that the shut-in pressure developed by the leak with fresh fluid in the bore was 14 psi and that the equilibrium level with 9.2 lb/gal. kill fluid in the bore was 40' of empty hole, yields a calculated depth of the over-pressured zone of 736';

(2) The cement was contaminated in the area of the leak, thus allowing a hydraulic pressure of hydrostatic plus 14 psi to develop outside the liner;

Immediately following the plugging operation, the water level in the well was 72' below grade and slowly climbing. This suggested several possibilities:

(1) Production zone making fluid;

(2) High leak making fluid;

(3) Thermal expansion;

(4) Continuing liner collapse.

After seven days the level stabilized at 8' of empty hole. The Site was attended at all times, and the well behavoir was closely monitored.

(3) When the water level inside the liner dropped 430' the counter-balancing internal pressure was reduced by that amount and collapse was imminent;

(4) Once the collapse began, the leak zone produced fluid to fill the developing void between casing and liner. The collapse continued to migrate upward in the direction of decreasing counter-balancing internal liner pressure.

4.4 ABANDONMENT OF WELL 87-6

A Technical Report, (SRC-CR-83-3) on "Well 87-6 Abandonment" was submitted under this Contract in January, 1983. The Summary section from that report is quoted below.

"Well 87-6 has been plugged and abandoned in strict accordance with existing U.S. Department of Interior Minerals Management Service regulations.

On December 8, 1982, Mr. Claude Harvey, Sperry Consultant, received from M.M.S. approval of the plug and abandonment plan as presented.

The actual work was commenced on November 4, 1982, and completed on November 17, 1982, with no significant deviations from plan. On December 17, 1982, Minerals Management Service formally approved the work accomplished and the Sundry Notice was signed by Mr. Moroz. (See Appendix A.)

Disposal of the flash pond is not required at present since that Sperry site will be maintained as part of the government-operated Geothermal Test Facility."

4.5 PERFORMANCE EVALUATION OF WELL 87-6

The performance evaluation of the Gravity Head production well prepared by Republic Geothermal, Inc. in November, 1980, is attached as Appendix D. Wellbore tests were also performed by Lawrence Berkeley Laboratory. Their report of December, 1980 is attached as Appendix E. At the time that the well flow tests and subsequent evaluation were performed, no attempts had yet been made to kill the well; symptoms of casing integrity failure had not yet appeared. Because flow velocity is drastically reduced in the upper 800 feet of well bore due to the large diameter, the spinner surveys which were performed for this evaluation would not have revealed the casing leaks which were later discovered. As the report concludes, Well 87-6 bottom hole temperature, productivity, and brine chemistry were well within the expected boundaries.

APPENDIX A

LOG OF WELL 87-6 OPERATIONS

6/1/81 - 7/2/81

SPERRY RESEARCH CENTER

INTER-OFFICE MEMO

TO	H. B. Matthews	FROM	C. Harvey
cc:	W. D. McBee B. Toekes	DATE	July 10, 1981
		SUBJECT	Monthly Activity Report June 1981

FIELD ACTIVITIES

06/01/81 Stood up workover rig and tested equipment.

06/02/81 Ran in with well hot and set retreivable bridge plug at 2045'.

06/03/81 Spotted 150' cement plug above bridge plug.

06/04/81 Pressure tested well and loaded upper bore with kill fluid.

06/05/81 Ran in "pigs" and strapped drill string to positively locate the 30" to 24" and 24" to 13" transition points. (original drilling records inadequate).

06/06/81
06/17/81 Ran in 44 joints of liner with cement shoe to 1750.73' (below Braden head).

06/18/81 Established forward circulation and pressure tested liner to 450 psi; good test.

06/19/81 Cemented in liner - good returns at calculated volume.

06/22/81
06/24/81 Drilled out 24" cement plug and pressure tested liner 550 psi; good test.

06/25/81 Drilled out and scraped cement in 13-5/8" casing.

06/26/81 Drilled out cement from 9-5/8" casing and replaced kill fluid with clean load.

06/27/81 Pulled out of hole - workover crew walked off job complaining of heat and long hours.

06/29/81 New crew on job - ran 20-1/4" pig to 1745 feet - no obstructions. Pulled the bridge plug.

06/30/81 Measured water level at 420 feet below Braden head. Ran in bailer on sand line - tagged fill at 1778' B.C. - no change in 3 months. No obstructions found; later, while running in drill string in preparation of laying down same, hit solid obstruction at 569'. Pulled out of hole and ran in impression block. Found solid obstruction at 553'. Block showed steep angle of approach.

07/01/81 Tagged obstruction at 513'; obtained DOE/WASH and USGS approval to plug well with cement while flow-through collapse still possible.

07/02/81 Spotted 1400 sacks of cement plus 40% silica flour and displaced with 500 barrels of water.

Claude Harvey

Claude Harvey

CH:j

APPENDIX B

CONSULTANT'S RECOMMENDATIONS

RE WELL 87-6

July 13, 1981

C. H

MEMO TO Warren McBee

FROM Forrest K. Harrell, Oil Well Drilling Consultant

DATE July 13, 1981

SUBJECT A brief history of conditions and recommendations for Sperry Well 87-6.

Sperry Well 87-6 was originally drilled with 30" casing from surface to 873', plus 24" casing 873' to 1753', plus 13 3/8" casing 1753' to 1833', plus 9 5/8" blank and perforated casing 1833 to 6280'. It was later discovered that the casing had some bad leaks between the area of 700' up to 400'. An interliner was run consisting of 3/16" spiral welded pipe 20 1/2" OD and 27 1/2" OD - the 27 1/2" surface to 868' and the 21 1/2" to 1750'. The casing was cemented in place with no problems. A 20 1/2" OD feeler was run to the bottom to check the size, without incident. The 3 1/2" drill pipe was run in the hole in preparation to lay it down, and it stopped at 546'. An impression block was run which confirmed the pipe had collapsed. The next morning the 3 1/2" drill pipe was rerun and stopped at 513'. Fluid level in the hole was at 400'. When fluid was added to the well fluid stayed at 400', which confirmed we still had some opening to bottom. The general opinion was that if we did not get the well shutoff in the bottom of the hole the well would overcome the hydrostatic head and flow up the casing; out the hole at 700' to 400' level and into the surface water or even breakout to the surface without any way to kill the well. Therefore, we mixed and pumped into the well 2200 cu. ft. of cement slurry, and displaced it to approximately 1500'. This should have filled the bottom of the hole with cement. After cementing, the fluid in the well was 70' and has gained fluid and is at present standing full.

We feel there is no economical, feasible or justifiable reason to try to repair the well. Note the following:

1. The well servicing unit over the hole is not suitable for a fishing and workover operation. The positioning fee for a suitable rig to work on the well would be $75,000 to $100,000, plus $7,000 to $7,500/Day rental fee, plus an additional $3,000 to $4,000/Day for support equipment. Fishing tool equipment would add a substantial cost per day. There is no way to even estimate the number of days it would take to recover the bad casing and replace it with some other type of liner. It would have to be done in less than 60 days to be cheaper than drilling a new well. Also, the well would still be a cripple.

2. Another problem of great importance is the inability to circulate the hole. The bad 30" casing at 700' to 400' will not hold fluid, which would eliminate reverse circulation and it would be a detriment to try to do any type of fishing operation or milling operation in this large casing.

3. I do not know of any fishing equipment that is a shelf item for the sizes needed to either mill or fish. A 28" mill can run as high as $15,000 to be manufactured and can be worn out in 12 to 14 hours of use. Special equipment would be as expensive or higher.

4. I understand the 9 5/8" casing was cemented without circulation and reports have suggested the top 400' of the zone has very little productivity, possibly because of the cementing. It is also possible there has been considerable damage with the last cement job, so it is very possible the well might be repaired and have poor productivity and still be a crippled well.

After a very thorough study of all the different approaches to improve Well 87-6 to be a usable well, it is our feeling that no more money be spent on the well and monies available be applied to drilling a new well for this worthy project.

Forrest K. Harrell

Forrest K. Harrell

Oil Well Drilling Consultant

FKH/rh

13230 Cambridge Street *Mustang Engineering Company* Santa Fe Springs, CA 90670

APPENDIX C

DEFINITIONS

Definitions

"Kill" a well - add sufficient weighted fluid to the standing liquid col. in a well to counter-balance or "kill-off" the excess formation pressure which is tending to force artisian flow.

Kill fluid - the weighted fluid used to "kill" a well. Cold Shutin Pressure - the gauge pressure at wellhead taken after a well has been shut-off (not flowing) for a period of time sufficient for the liquid col. in the well to have reached thermal equilibrium.

Hot shutin pressure- the gauge pressure at wellhead taken immediately following the cessation of flow while the standing liquid col. in the well is still relatively uniformly hot.

B.O.P. - blowout preventer

Rotating head - a device which forms a rotating seal around drill pipe at wellhead and which allowsthe pipe to be inserted, rotated, and withdrawn while the well is internally pressurized.

<u>Power Swivel</u> - a hydraulically powered device which is attached to a workover rig and which rotates a drill string while feeding or accepting circulation fluid. It substitutes for the rotating table and kelly bushing which perform similar functions on a drilling rig.

<u>Reverse Circulation</u> - moving circulating fluid <u>in</u> and <u>down</u> the well annulus <u>outside</u> the drill pipe and <u>up</u> and <u>out</u> of the well <u>inside</u> the drill pipe.

APPENDIX D

PERFORMANCE EVALUATION

SPERRY EAST MESA WELL 87-6

PERFORMANCE EVALUATION

SPERRY EAST MESA WELL 87-6

November 1980

Prepared by

Republic Geothermal, Inc.
11823 East Slauson Avenue
Santa Fe Springs, California 90670

for

Sperry Research

Under DOE Contract No. DE-AC03-79ET27131

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INTRODUCTION

A large diameter geothermal production well has been drilled and completed at the East Mesa 87-6 location for use in the DOE-sponsored Sperry pump and gravity head systems field tests. This well has demonstrated the ability to produce fluid at temperatures greater than 355°F and that its productivity index (PI) is about 2.4 gpm/psi. Both of these parameters exceed the original objectives for the well. The total dissolved solids (TDS) content of the produced fluid is 2,450 ppm. Therefore, problems associated with scaling or potential environmental contamination are not expected to be significant. The noncondensable gas content of the fluid is 958 ppm by weight and the total vapor pressure of the fluid is 205 psia. Scaling is not expected to occur if the pressure of the fluid is maintained above this level. The discussion which follows provides an analysis of the original well location expectations, drilling operations, completed well costs, petrophysics and production data.

WELL LOCATION SELECTION

A study of the East Mesa KGRA was made to determine the optimum location for a new well in which the Sperry systems could be tested. Selection of location 87-6 (see map, Figure 1) was based upon a review of all available geological, reservoir, and geochemical information. Previous studies and reports by Republic Geothermal, Inc. (RGI), the U.S. Bureau of Reclamation (USBR), and the Lawrence Berkeley Laboratory (LBL) were the primary data sources. The principal criteria for location selection were: (1) a reservoir temperature in excess of 350°F; and (2) reservoir permeability-thickness (kh) capable of yielding 1,100 gpm, with the pump set at approximately 1,750 feet (i.e., a PI of 1.6 gpm/psi or better). A brief summary of location considerations is provided below.

Reservoir Temperature

Isothermal surface contour maps such as the 300°F surface shown on Figure 2 were utilized to determine the area of consideration for the new well. The highest temperature within the available leases is near USBR Wells 6-1, 6-2, and 8-1. The expected temperature gradient for a well at location 87-6 is shown on Figure 3.

A well completed between 4,500 and 6,000 feet at this location could expect a minimum inflow temperature of 350°F. The average temperature in the interval was predicted to be about 365°F, well above the 350°F objective. See following "Production Data Analysis" for subsequent measured temperatures.

Reservoir Productivity

Table 1 gives the theoretical productivity of the existing USBR wells calculated on the basis of well log analyses by Intercomp Resource Development and Engineering, Inc. Completion of Well 87-6 in the 4,500-6,000 foot interval was predicted to result in a well with a theoretical PI of 2.7 gpm/psi based upon the average of the surrounding producers. This is considerably higher than the required 1.6 gpm/psi.

Actual measured well performance in the area (also shown on Table 1) has been somewhat lower. The poorer actual well performance is thought to be due to formation damage incurred during drilling. This interpretation is supported by analysis of pressure interference responses between wells which indicate reservoir kh's in the "theoretical" range (Table 1). An expectation of a PI equal to 2.0 gpm/psi or better appears reasonable for location 87-6. (See following "Production Data Analysis" for subsequent calculations of PI based on flow tests of this well.)

The presence of a hydrologic boundary in the area was inferred by LBL based on pressure interference tests. There is continuity between Wells 6-1, 6-2, 31-1, and 44-7; but the relationship with 8-1 is not clearly defined. Interference tests between 6-2 and 8-1 indicated no response; however, other tests indicated continuity between 8-1 and 44-7 and between 6-2 and 44-7.

It is believed that the lack of proven continuity between 8-1 and 6-2 is due to insufficient test rates and durations. Nonetheless, a single layer, radial flow numerical model of the Sperry well site was prepared to investigate the effects of a sealing barrier located near the well. Simulations were run in which a barrier was placed at 100 feet and 1,000 feet from the wellbore, and the results compared with the case of no barrier. In all cases, the well was capable of producing more than 1,100 gpm with an average permeability-thickness of 20,000 md-ft. The wellbore pressure drawdown was greater, of course, when a sealing barrier was present, but the drawdown pressure did not exceed 570 psi in any case. Thus, the presence of a sealing barrier in this area, if it exists at all, is not a major concern.

Geology

The subsurface geology of East Mesa was interpreted from seismic and well data including logs, cores, and cuttings. Due to the deltaic nature of the sand/shale sequence, individual stratigraphic units generally are difficult to correlate regionally with confidence and may be difficult to correlate from one well to another because of variations and discontinuities in the lithology between wells. This is particularly true of the area of the 87-6 location where the USBR Wells 6-1, 6-2, and 8-1 can only be roughly correlated above 5,000 feet. No correlations of reasonable consistency were found in the producing intervals of these wells.

This lack of correlation between the southern USBR wells is in marked contrast to the good correlations found between all of RGI's East Mesa wells to the north and the USBR Well 31-1. This indicates a basic difference in the depositional environment of the two areas. The southern wells are probably in an area of deltaic channel type deposits with rather abrupt horizontal facies changes, whereas the northern wells are in a deltaic fringe region with more gradational facies.

From review of the log and seismic data, it can be concluded that there is no evidence of a major fault between Wells 6-1 and 8-1. The correlations possible (above 5,000 feet) indicate elevation differences between these wells of only 80-150 feet which can easily be accounted for by dip corrections, stratigraphic changes, and/or minor faulting. The dipmeter data in 6-2 and 8-1 is quite uniform and compatible, with no indication of major faulting, although a small fault may be indicated around 4,100 feet in 6-2. If there is a barrier between these wells as suggested by LBL, the available evidence indicates it is most probably stratigraphic in nature.

It should be noted that RGI's structural interpretation of East Mesa differs somewhat from those in the LBL/USBR reports. Their fault patterns trend basically NW-SE whereas RGI's trend NE-SW. LBL/USBR indicate that correlation is essentially impossible and depend principally on seismic interpretation. RGI finds good to excellent correlations in the northern area, as mentioned above, even with the 31-1 well. LBL depicts 31-1 as being structurally lower than 38-30 when, in fact, it is structurally higher based on excellent correlations between the wells. However, there is general agreement as to interpretation in the 87-6 area, principally because of the lack of good data and the inability to correlate.

Fluid Chemistry

Tables 2 and 3 show the chemical composition of fluids from the two wells with completion intervals comparable to that proposed for 87-6. The TDS of the unflashed water ranges from 1,600 ppm (Well 8-1, Table 2) to 5,000 ppm (Well 6-2, Table 3). The Ca^{++} ion concentration ranges from 1.4 ppm to 26 ppm. The CO_2 (or HCO_3^- or CO_3^{--}) concentration is approximately 600 mg/l, which is probably low (i.e., CO_2 "flash" losses occur even though steam flash is not allowed). However, both the TDS and Ca^{++} values, as well as the CO_2 data, indicate that a $CaCO_3$ scale problem must be expected with these waters. This problem can be readily overcome in the Sperry systems by maintaining a sufficiently high back-pressure to retain all the CO_2 in solution.

No other constituent of these waters appears to be of normal operational or environmental concern. However, the Sperry systems rely upon efficient heat exchange between the produced brine and the R-114 working fluid. The resulting temperature and pressure drop of the flowing brine within the well may cause minor non-$CaCO_3$ scale formation which could result in deterioration of the critical heat exchange efficiency.

Some scales (e.g., silicates, silica, sulfates, sulfides) are promoted by temperature drops as well as pressure drops. If the scale forming compound is dissolved in the brine at or near its solubility product, a temperature drop of a few degrees can form a thin skin on the outside of the heat exchange tubing. The solubility of almost all scale forming compounds is also similarly pressure controlled. This should not be confused with the pressure effects on the solubility of CO_2 and its subsequent effects on the formation of $CaCO_3$. Such minor scale build-ups normally do not play any significant role in East Mesa operations, but could pose problems in Sperry's systems. Provision for downhole cleaning is therefore recommended.

DRILLING OPERATIONS

The following is a brief analysis of the Sperry East Mesa Well 87-6 drilling operations which is intended to:

a) Summarize the drilling operations on a day-to-day basis;

b) Identify the major problems encountered and describe the corresponding courses of action taken;

c) Recommend changes in the basic drilling program which will help prevent a recurrence of the same problems in future similar wells.

Drilling History

The attached Appendix A is a day-to-day history of drilling operations. This is a routine report required for submittal to the USGS.

Figure 4 shows the planned casing profile vs the actual profile obtained for the well. Casing installation complications resulted in the depicted compromise, which is considered functionally and economically acceptable.

Problem Areas

The major problems encountered while drilling (e.g., stuck casing) were related to casing size, overall string weight, and hole size. The unusually large surface casing (30" O.D.) and intermediate liner (24" O.D.) were quite cumbersome and difficult to work with. The extreme weight of these casing strings limited the amount of "pull" which could be exerted at the surface in efforts to free stuck casing. It is theorized that sticking problems were primarily the result of insufficient hole size.

The first problem occurred during the installation of the 30" casing. The casing "stopped" and became stuck with the shoe at 935 feet, 265 feet higher than the desired setting depth. Subsequent attempts to move the casing up or down the hole were unsuccessful. The probable cause for the casing becoming stuck was differential sticking. Differential sticking occurs when the pressure differential between the wellbore and the formation exerts enough lateral force on the casing resting against the wall of the hole that it holds the casing in place, preventing vertical movement. Sticking tendencies increase dramatically when pipe movement into or out of the hole decreases for a period of time. The probability of differential sticking can be reduced by:

a) Minimizing the overbalance between the wellbore pressure and the formation pressure;

b) Keeping the pipe moving as much as possible;

c) Minimizing the contact area between the pipe and the open hole; and

d) Maintaining a low filtration rate in the mud system.

In the case of the Sperry well, the item which could most be improved upon is "c." It is felt that "a," "b," and "d" were accomplished satisfactorily.

Since the 30" casing became immovable at 935 feet, it was necessary to either cement the casing at this point or abandon the well, skid the rig, and start a new well. The former course of action was taken. However, in order to be able to install the minimum acceptable number of heat exchanger tube bundles inside the 30" casing (during the test phase of the project), it was essential to mill out the interior flutes on the 30" hanger sub to allow the intermediate liner to be hung deeper (see Figure 4). Also, the 24" x 30" liner hanger had to be modified to set by means of slips rather than resting on flutes.

The second problem occurred while running the combination 24" x 13-3/8" intermediate liner. The liner stopped abruptly 470 feet above its desired setting depth. It is not clear what caused this but it possibly was a hole irregularity. Initially, the casing was still free in the upward direction, but quickly became stuck while being worked. Attempts to free the stuck casing were unsuccessful.

In order to provide enough footage inside the 30" casing for the heat exchanger tube bundles, the 24" casing had to be cut and the 24" x 30" hanger and the top section of 24" casing were pulled out of the hole. A 24" x 30" drive-over adapter was fabricated and installed on top of the 24" casing stub at 888 feet to provide a tapered entry into the 24" casing. (See Figure 4 for revised casing detail.)

Problems of a more routine nature occurred in the cementing phases of the drilling operation. Inadequate annular cement fill up in the 24" x 30" lap and the 9-5/8" x 13-3/8" lap necessitated remedial cement jobs in both locations. It is theorized that the poor cement job on the 24" x 30" lap was due to channeling of the cement in the very large annular cross-sectional area. Good cement returns were circulated from above the liner top following the cement placement. Inadequate cementing in the 9-5/8" x 13-3/8" lap was most likely due to a combination of unusually thick mud and insufficient annular clearance around the 9-5/8" x 13-3/8" liner hanger which prevented free circulation of viscous mud and cement. Although the total by-pass area, 12.5 sq in, and the 1/3" clearance normally are sufficient, it is apparent that bridging and plugging with mud solids occurred in the gap between the hanger and the 13-3/8" liner. As a result, the entire cement job on the 9-5/8" liner was done without circulation. A subsequent cement bond log showed that only partial annular fill-up with cement was obtained (indicated top of cement is at 4,400 feet). However, calculated thermal stresses which will occur in the uncemented section of 9-5/8" casing do not exceed acceptable design parameters.

When circulation was first attempted with the 9-5/8" liner at the desired setting depth, the 9-5/8" x 13-3/8" hydraulic hanger was inadvertently set. This could have been a major problem if stage circulation had been used while running the liner, i.e., the liner hanger could have set prematurely, above the desired depth.

Recommendations

In order to minimize the probability of the same problems recurring in future wells of the same configuration, recommended changes in the drilling program are as follows:

1. Install larger conductor pipe, e.g., 42" instead of 36". This will permit the use of positive hole openers as opposed to expandable arm-type tools.

2. Utilize positive hole openers in lieu of expandable arm-type tools whenever possible. This will ensure a fully open, smooth hole.

3. Open surface hole to 40" instead of 36". This will reduce the chances of the 30" casing becoming differentially stuck due to a reduction in contact area.

4. Install 30" fluted liner hanger sub 50 feet above the 30" casing shoe instead of 200 feet above shoe. The USGS requires a 200-foot lap, but an exception can be obtained allowing a 50-foot minimum lap. Thus, if the 30" casing does not reach the desired depth, the 24" x 30" lap can be shortened and still utilize the 24" x 30" fluted liner hanger.

5. Utilize a mechanically set liner hanger if the liner is to be cemented. Stage circulation while running casing can prematurely set a hydraulic hanger.

6. Modify the conventional design of the 9-5/8" x 13-3/8" liner hanger to provide larger passages for mud and cement by-pass, e.g., use a fluted or ported configuration.

WELL COSTS

Table 4 compares actual drilling costs with those originally estimated for the well. Since the original cost estimate dated 8/1/79 was based on cost data that were seven months to one year old at the time of spud, inflation is a considerable factor in some of the overexpenditures. As of September 30, 1980 the total actual cost for the production well was $1,660,000.

Table 5 itemizes the major overexpenditures and summarizes the reason(s) for each.

PETROPHYSICAL EVALUATION

A full Schlumberger Coriband suite of well logs consisting of the DIL-SP, FDC-CNL, Sonic-Gamma Ray, and Dipmeter-Caliper was run in the well at intermediate casing points and TD. These logs were analyzed by Intercomp. The petrophysical evaluation technique utilized was the same as that used on all East Mesa wells for RGI.

A 100-foot zonal summary of the foot-by-foot log analysis of net sand, porosity, permeability, and salinity is shown on Table 6. Excellent sand development in the completion interval, 4,700-6,200 feet, is apparent. The indicated permeability-thickness of 185 Darcy-feet in the interval is two-to-three times greater than that observed in the adjacent USBR wells.

This is probably only a localized sedimentological phenomenon, inasmuch as two sand bodies account for almost all of the increase.

PRODUCTION DATA ANALYSIS

The following summarizes two separate flow tests which were performed at the Sperry Well 87-6 between April 17 and August 22, 1980. The results of both tests are in substantial agreement and show that the produced fluid temperature is greater than 355°F and that the productivity index is about 2.4 gpm/psi. Both values exceed the original objectives for the well.

Production Testing - April 17-May 8, 1980

An initial clean-up and flow test of the well was performed in mid-April with the drilling rig still on the hole. Table 7 summarizes the production data obtained during this five-day test. Rate data are approximate as no separator or permanent facilities were installed for these preliminary tests. The initial flow rate averaged 259,000 lb/hr for the first 19 hours. The rate was then reduced to an average 164,000 lb/hr for the remaining 98 hours. Bottom-hole pressure transient data were obtained during the drawdown and build-up phases of the test, as well as a flowing temperature survey using Kuster instruments.

The measured drawdown during the final stage of the production test yields a PI of 2.1 gpm/psi. The Horner Plot (Figure 5) analysis of the pressure build-up data yields a permeability-thickness of 17,880 md-ft and a PI of 2.6 gpm/psi. Both values are well above the 1.6 gpm/psi objective for the well. No indication of near wellbore damage or a flow barrier near the well was noted in the transient pressure data.

The flowing temperature profile measured with a Kuster instrument on the last day of the test (April 22) is shown in Figure 6. The indicated flowing temperature at 4,700 feet (the top of the completion interval) is 369°F, substantially greater than the 350°F objective for the well. However, the critical nature of this value to the success of the Sperry project warranted additional confirmation surveys. Normal confirmation of the 369°F reading by a follow-up calibration check of the instrument was not possible because it was damaged in a subsequent survey. Testing discussed later in the report indicates the temperature is closer to 355°F at 4,700 feet.

A second flow test (Table 8) was initiated on May 1 with the intent of obtaining continuous temperature and spinner production logs. No pressure build-up tests were planned. The primary purpose was to: (1) confirm the downhole flowing temperature measurement; (2) confirm that the liner laps are not leaking by checking for cooler water inflows; and (3) define the inflow profile in the completion interval to help evaluate the completion. Secondary objectives were to measure pre-flow and flowing temperature profiles to obtain parameters necessary for wellbore heat loss calculations. Only the pre-flow temperature log was obtained. The electronic temperature logging and spinner tools failed before any useful flowing data were obtained, and the well was shut in pending repair of the logging tools. The well was opened again by May 7 (Table 9) expecting to rerun the repaired spinner/temperature equipment; however, the tools did not arrive.

A successful spinner survey (Figure 7) was obtained on May 8 while flowing approximately 168,000 lb/hr (Table 10). The survey, by United Wireline Service, indicated that essentially all of the production was from the interval 5,100-6,000 feet, with little or no production from the upper 400 feet of slotted liner. A continuous flowing temperature log was again attempted, but the logging tool failed below 1,700 feet. This partial result, however, was sufficient to confirm that the upper liner lap is not leaking (Figure 6). As commonly observed with the commercially available electronic temperature logging tools, the absolute accuracy of this survey is poor; but, because it is continuous, it is well suited to locating fluid inflow zones.

A temperature survey using Kuster temperature instruments was then run with sufficient data stops to bracket both liner laps and measure the flowing temperature. This May 8 survey (Figure 6) confirmed that there are no liner lap leaks and indicated a temperature of 355°F at 4,700 feet. At the approximate pump intake depth of 1,800 feet, the temperature was indicated to be at least 352°F.

The fact that the lower zones are generally producing suggests that the drilling mud was not the cause of plugging in the top 400 feet. It is possible that cement or formation material has plugged the upper 400 feet of slotted liner. Remedial action is definitely not warranted, as it might lead to a much higher productivity but lower average temperature. This series of flow tests clearly indicated that Well 87-6 is capable of achieving the desired rates and fluid temperature necessary for operation of the Sperry pump and gravity head systems. However, longer term flow testing of the well, with a separator installed, was recommended at the conclusion of the May tests to further confirm flow potential and flowing temperature as well as to obtain fluid chemistry data.

Production Testing - August 15-22, 1980

An eight-day flow test was initiated on August 15, 1980 to more accurately evaluate the well productivity and obtain definitive fluid chemistry data. The well was flow tested using separator facilities to measure the flow rate and allow the sampling of steam, water, and noncondensable gases. Before the well was allowed to flow, static temperature and pressure baseline measurements were made. The results of these surveys are shown in Figure 8.

After 172 hours of flow at an average rate of 145,000 lb/hr, pressure instruments were lowered into the well on August 22. After a flowing bottom-hole pressure was measured at 4,700 feet for three hours, the well was shut in and the pressure build-up recorded for a period of 69 hours. The production data are summarized in Table 11. The pressure build-up data are shown in the Horner Plot of Figure 9. The flowing bottom-hole pressure was 1,840 psig and the pressure extrapolated to infinite shut-in time in Figure 9 is 1,968 psig. This is in agreement (within the accuracy of the interpretation method and the pressure instruments) with the static pressure survey which measured 1,986 psig at 4,700 feet as shown in Figure 8. Based on these data, the permeability-thickness was calculated to be 14,100 md-ft and the PI was 2.4 gpm/psi. These values are comparable to those obtained in the first test run in April.

On August 18, 1980, Lawrence Berkeley Laboratory ran flowing spinner and temperature surveys. The surveys are plotted in Figures 10 and 11, respectively. The flowing temperature at 2,000 feet was 355°F which is in agreement with prior temperature data. The flash point was measured at a depth of approximately 225 feet at a flow rate of about 250 gpm. The temperature tool failed at 4,300 feet and the spinner tool failed to record data past 5,100 feet. It appears from the spinner survey that there is a substantial inflow at the top of the slotted completion interval. In this case, the increase in upward fluid velocity is not due to inflow but rather to convergence of the flow from outside the slotted liner into the blank liner above the producing interval. Because the spinner tool failed to record fluid flow below 5,100 feet, the accuracy of this data is questionable.

On August 21, 1980, temperature and spinner surveys were run by Triangle Services. Analysis of the data, along with that previously reported, is shown in Figure 7. Based on analysis of Triangle's temperature and spinner surveys, most of the inflow is between 5,050 and 5,200 feet. There is no evidence of inflow in the top 400 feet of the open liner. Approximately 40 percent of the fluids reaching the wellbore do so from intervals between 5,300 and 6,000 feet. These results confirm the United Wireline spinner data obtained during the May 8, 1980 production test. The discrepancies between the log kh, United's results, and Triangle's spinner and temperature survey are typical of the measurement scatter different tools can give. Some of the reasons an exact one-to-one correspondence is not always achieved are:

1. Log-derived kh values indicate a capability for near wellbore flow but do not tell which intervals will actually flow fluids;

2. Log-derived kh values are only as good as the assumptions relating porosity (from logs) to permeability. There exists no log which measures permeability directly; therefore, the rock property must be deduced from a porosity-permeability correlation. The correlation utilized in this study was developed from East Mesa core data.

3. Spinner surveys are not quantitative in a true sense of the word. The tools used for gathering downhole flow data are influenced by many parameters that may change rapidly downhole but whose effects will be measured only as an average over a period of time. The principal variables are wellbore diameter, flow rate, and direction and velocity of incoming fluid.

Flowing temperature surveys are capable of yielding useful inflow profile data. Circumstances which allow the calculation of inflow from flowing temperature surveys are single-phase production through the inflow region in the wellbore and perfect mixing of inflow from the reservoir with fluid already traveling up the pipe. The inflow profile calculated from the Triangle flowing temperature survey (Figure 7) confirms the two spinner surveys.

FLUID CHEMISTRY

Behavior of noncondensable gases, tendencies to deposit mineral scales, and considerations of potential environmental effects are based on several kinds of chemical analyses performed on samples of steam condensate, noncondensable gases, and residual (post-flash) liquid. Regardless of the phase actually sampled (gas, condensate, or residual) the results are recalculated to a reference fluid, namely, the pre-flash geothermal fluid at 350°F.

Noncondensable gases were sampled in the separate steam phase according to a method described in Appendix B. Results are listed in Table 12. Carbon dioxide (CO_2) comprises more than 90% of the (molar) noncondensable gases. Methane and nitrogen are significant, especially because their contribution to the vapor pressure is proportionally much greater than their relative mass. Noncondensable gases collectively contribute about 70 psia of vapor pressure which, added to the vapor pressure of water, yields a total vapor pressure near 205 psia at 350°F. Setting depth of the pump should be adequate to assure that pressure on the first-stage impellers does not go below 205 psia when allowance is made for drawdown, annulus pressure, fluid friction below the pump, net positive suction head, and contingency. $CaCO_3$ mineral scale will not deposit if pressure is maintained above the total vapor pressure of the fluid. This will prevent the escape of CO_2 (g) and consequent chemical reactions. Silica scale is unlikely at temperatures above 150°F.

Dissolved solids are 2,450 ppm (parts per million by weight), of which two-thirds are due to NaCl. The thermodynamic properties of this liquid are sufficiently near those for pure water that no special compensation is needed. Other major and minor components are listed in Table 13.

Condensable gases H_2S and NH_3 were analyzed in both steam (condensate) and flashed liquid; flashing was in the range 9 to 11% (wt.). Essentially all of the H_2S goes with the steam phase upon flashing. About 80% of the NH_3 went with the steam phase. Both contribute to a mild corrosive potential for copper-containing materials. In the pre-flash liquid the H_2S and NH_3 concentrations were 0.79 and 6.3 ppm, respectively. In flashed steam, the concentrations will be proportionally greater than in the liquid. The actual concentrations in steam initially will be on the order of 8 and 50 ppm for the H_2S and NH_3, respectively. Concentrations as effluent when steam is discharged to the atmosphere will be negligible. H_2S smells during testing were generally not present and were never strong enough to be offensive.

Potential environmental effects of the liquid are nil because the non-benign components are at low concentrations. Available data are listed in Table 14.

Suspended solids were filtered from 1-liter samples of post-flash liquid. Collection was on Millipore filters having pores 0.45 pm diameter. Four collections showed a statistical (16) range of 0.17 to 0.37 ppm. A specific mineral analysis was not made; the amount of material recovered was too small to manipulate. Some is suspected to be $CaCO_3$ which formed from liquid during flashing. This data applies only to fine-grained, easily suspendable solids. No attempt was made to sample for formation sand (particles larger than 100 μ); representativity of such sampling cannot be assured. Indications of a relative sanding problem may be found by looking for sand-size particles in process equipment when it is dismantled.

Table 1
East Mesa Wells
Theoretical and Measured Productivity

	Existing Wells 6-1	6-2	8-1	Predicted 87-6
A. Theoretical[1]				
1. Completed interval of existing wells				
a. log analysis kh (D-ft) (air)	29.7	74.7	43.1	-
b. productivity index (gpm/psi)	1.10	3.11	1.79	-
c. production @700 psi drawdown (gpm)	770	2180	1260	-
2. Total potential for 4500' to 6000'				
a. log analysis, kh (D-ft) (air)	62.7	74.7	59.9	65.8[2]
b. productivity index (gpm/psi)	2.33	3.11	2.49	2.73
c. production @700 psi drawdown (gpm)	1630	2180	1740	1920
B. Measured				
1. Individual Well Tests				
a. PBU kh (D-ft)	11.9[3]	9.6[4]	10.2[5]	-
b. Productivity index (gpm/psi)	1.77	1.60	1.70	-
c. Production @700 psi drawdown (gpm)	1240	1120	1190	-

2. Interference Test Data[5]

	6-1 to 6-2	6-1/6-2 to 31-1
a. kh (D-ft)	18.9	25.0
b. PI	3.14	4.16
c. Prod @700 psi	2200	2910

NOTES:

1. Theoretical PI is based upon 1/4 of the Intercomp log analysis (air) kh values to account for insitu conditions.
2. Average of Wells 6-1, 6-2 and 8-1
3. Data from USBR, 1975
4. Data from RGI, 1980
5. Data from LBL, 1977

Table 2

East Mesa Geothermal Fluid from Well 8-1

Unflashed Liquid Chemical Analysis
(Concentration in ppm)

SAMPLE	Aug. 3 1978	Aug. 24 1978	Sept. 19 1978	1976	1974
Fe	.03	.50		.10	1.1
Mn				.05	
Sr	1.6	1.7	2.4	2.1	1.6
Mg	<.05	.13		.05	1.6
SiO_2	246	235	244	389	263
B	1.6	2.0		1.6	3.3
Ca	1.4	12.6	12.0	8.5	41
Na	539	6.5	557	610	723
K	36	42	36	70	42
Li	1.1	1.5		1.1	2.0
Cl	705	820	695	500	555
HCO_3	445	455	470	420	670
SO_4	150	120		175	225
TDS	1756	1940	1790	1600	2463
S				1.0	
F				1.6	
NO_3^-				.34	
pH	6.20	6.00	6.98	6.27	7.68
Cond	2850	3250	2660	3200	

Table 3

East Mesa Geothermal Fluid from Well 6-2

Unflashed Liquid Analysis
(Concentration in ppm)

SAMPLE	Sept. 1975	Feb. 1976	June 1976	June 1 1978	June 14 1978	July 3 1978	July 18 1978	July 24 1978	Aug. 14 1978	Sept. 19 1978
Fe	.90	<.02	<.10	.03	.03	.20	.20	.18		
Mn			.05	.03	.03	N.D.	.03	.04		
Sr	1.0		6.4	2.1	2.1	2.0	1.9	3.1	3.1	2.8
Mg	.47	.73	.24	.5	.4	.5	.4	.4		
SiO_2	220	240	269	263	250	250	242	247	279	263
B	9.65	7.1	7.45	5.6	6.4	7.7	8.6		7.6	
Ca	20.0	5.0	16.4	14.0	13.0	17.0	13.8	13.4	26.0	18.4
Na	1450	1306	1700	1440	1410	1400	1392	1422	1389	1355
K	155	124	150	132	130	125	168	128	125	134
Li	.4	3.8	4.0	4.6	4.5	4.2	3.6	4.4	4.5	
NH_4	13.0	13.9	14.7				1.6	1.9	18.2	
Cl	1920	1738	3242	1960	2120	2120	2090	2110	2130	2035
HCO_3	744	595	560	624	635	630	620	633	676	655
SO_4	160	170	156	183	184			175	174	
TDS	4000	3860	5000	4272	4250	4230	4180	4172	4240	4180
S	1.6		1.5	.05	.05	.08				
F	1.5	3.4	1.23						3.9	
NO_3	<.2									

pH	5.9	6.7	6.12	6.47	6.10	5.85	5.97	5.86	5.82	5.81
Cond	6510	6520	6000	8087	7015	7070	6960	7350	6750	6430

TABLE 4
REPUBLIC GEOTHERMAL, INC.

WELL COST

Well: Sperry #87-6 T.D.: 6290' Date: 9/30/80

Project Description: Drill a production well with a profile to install the Sperry Gravity Head Pump System

		M$ Estimated	M$ Actual
I.	Intangibles		
1.	Location	-	10
2.	Mobilization/Demobilization	110	100
3.	Contractor: Days @______ = ______	262	328
4.	Fuel, Power, and Water		
5.	Drilling Fluids	32	50
6.	Bits and Reamers	43	51
7.	Supplies and Services	100	130
8.	Equipment Rentals		
9.	Cement and Services	61	138
10.	Directional Tools and Services	-	-
11.	Logging	38	58
12.	Coring	-	-
13.	Completion and Testing	-	18
14.	Fishing	-	31
15.	Transportation and Hauling	20	33
16.	Direct Supervision	26	29
	SUBTOTAL ON INTANGIBLES	692	976
17.	Indirect_____on_____		
II.	Tangibles		
18.	Casing/Tubing ______ ______	350	553
19.	Subsurface Equipment	22	71
20.	Wellhead Equipment	76	60
21.	Surface Facilities	-	-
22.	Tax on Tangibles	26	0
	SUBTOTAL ON TANGIBLES	474	684
23.	Indirect on Tangibles		
	SUBTOTAL		
24.	Contingency		
	TOTAL WELL COST	1,166	1,660

TABLE 5
AFE #100032 SPERRY 87-6
OVEREXPENDITURES
9/30/80

Category	Major Unscheduled Expenses Item	$M Cost	Reason(s) for Overexpenditure
Contract Drilling	Same	66	Time required to drill well - 10 days in excess of estimate.
Cementing	Overexpenditures		
	(1) 30" casing job	22	a) Inflation
	(2) 24" x 13-3/8" casing job	15	b) Used more cement than original calculated
	(3) 9-5/8" casing job	14	
	Squeeze cementing, 24" x 30" lap	6	Nonuniform lap fill-up necessitated squeeze.
	Squeeze cementing, 9-5/8" x 13-3/8" lap	20	Cement did not reach lap section in original job due to loss of circulation.
Fishing Expenses	Fishing tool rentals	17	Fishing was necessitated by the sticking of the 24" x 13-3/8" liner.
	Cutting tool rentals	14	
Casing	30" Vetco connectors	124	No funds allocated for this on original cost estimate. Original plan was to field-weld jts. together.
	Overexpenditures on 24" connectors	61	Inflation
Subsurface Equipment	Overexpenditure on liner hanger equipment	9	a) Inflation
	Modify 24" x 30" liner hanger	27	b) Final equipment design different from original. Necessitated by the misrun of the 30" csg., i.e., the fact that the casing stopped "high."
	Fabricate 24" x 30" adapter	13	Sticking of the 24" x 13-3/8" liner
Supplies, Services, & Rentals	Fabricate 28-7/16" mill	11	28-7/16" mill was used to mill out interior flutes on 30" liner hanger sub. This was necessary since the 30" liner stopped "high."
	Equipment rentals	19	Time for rental of drilling equipment exceeded estimate.
Drilling Fluids	Same	18	Additional drilling time necessitated additional mud costs.
Completion & Testing	Same	18	No money allocated for well testing on original estimate.
Logging	Same	20	Inflation.
TOTAL		494	

Table 6

Petrophysical Analysis 100-ft Zone Summary

Republic Geothermal East Mesa #87-6

Gross Interval	Net Sand	Average Porosity (%)	Average Permeability (Geom.)	Average Permeability (Arith)	Perm.-Ft. Darcy-Feet	Salinity PPM NaCl
2550-2599	27	24.6	75.4	965.5	2.036	11,922
2600-2699	90	26.6	190.9	1281.8	17.18	10,982
2700-2799	63	28.3	406.5	1807.8	25.61	10,962
2800-2899	73	23.7	50.6	574.2	3.69	14,021
2900-2999	70	23.1	37.	338.6	2.59	11,854
3000-3099	62	21.9	21.7	319.1	1.35	7,049
3100-3199	89	25.9	134.8	466.3	12.	6,840
3200-3299	58	21.9	21.7	68.5	1.26	12,020
3300-3399	58	16.9	2.2	20.3	.13	10,682
3400-3499	66	23.1	36.9	422.2	2.44	10,032
3500-3599	37	14.1	.605	1.04	.022	9,237
3600-3699	92	19.5	7.0	43.1	.64	5,605
3700-3799	74	17.0	2.3	30.1	.17	6,203
3800-3899	89	20.7	12.3	105.7	1.09	5,609
3900-3999	64	20.2	9.8	114.7	.63	7,574
4000-4099	100	22.6	30.6	269.1	3.06	4,751
4100-4199	72	21.5	18.4	102.5	1.32	5,221
4200-4299	93	24.0	57.3	456.4	5.33	4,683
4300-4399	60	19.1	5.9	35.5	.35	6,423
4400-4499	72	29.6	739.4	2224.8	53.24	3,871
4500-4599	90	26.5	179.5	930.1	16.16	3,624
4600-4699	80	25.2	98.5	430.6	7.88	3,873
4700-4799	83	27.8	324.8	1771	26.96	4,487
4800-4899	87	28.5	448.2	1830	39.	3,577
4900-4999	79	24.7	79	770.3	6.24	3,488
5000-5099	96	29.7	805	1374.6	77.3	2,114
5100-5199	93	23.8	51.0	419.1	4.7	2,167
5200-5299	48	16.8	2.1	22.1	.1	2,976
5300-5399	98	23.3	41.7	293	4.09	2,575
5400-5499	90	19.8	8.4	81	.756	3,069
5500-5599	100	24.3	64.5	270	6.45	2,285
5600-5699	96	25.5	115.1	306.5	11	2,729
5700-5799	89	17.5	2.8	32	.249	3,596
5800-5899	100	24.1	58.6	235.1	5.86	5,051
5900-5999	79	22.3	26.6	123.5	2.1	6,950
6000-6099	78	16.7	----	94.8	----	9,389
6100-6199	67	8.2	----	.448	----	11,225
6200-6299	17	8.9	.054	.176	.0009	----

TABLE 7

FIELD EAST MESA — PRODUCTION WELL SUMMARY OF FLOW TEST DATA — DATA DATE 04/17/80

WELL NO P876 — MON, JUN 2, 1980, 10:35 A

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
2 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
3 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
4 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
5 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
6 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
7 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
8 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
9 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
10 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
11 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
12 AM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
1 PM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
2 PM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
3 PM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
4 PM	1941.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
5 PM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
6 PM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
7 PM	.0	.0	.0				.0	.0	.0	.00	.0	.00	.0
8 PM	.0	26.0	269.0				34.3	233.1	267.4	12.82	.1	.28	.0
9 PM	.0	23.0	270.0				34.7	236.2	270.9	12.82	.1	.55	.0
10 PM	.0	28.0	270.0				33.8	230.0	263.8	12.82	.1	.81	.0
11 PM	.0	28.0	271.0				33.8	230.0	263.8	12.82	.1	1.07	.0
[illegible]M	.0	28.0	271.0				33.8	230.0	263.8	12.82	.1	1.34	.0

NOTES

WELL NO: P876 DATE: 04/17/80

1. OPEN WELL AT 1730 HRS. FOR PRODUCTIVITY/TEMPERATURE ASSESSMENT.

2. NO SEPARATOR FACILITY. STEAM FRACTION CALCULATED ASSUMING FLASH FROM WELLBORE CONDITIONS (ENTHALPY=306 BTU/LB) TO ATMOSPHERE PRESSURE.

FIELD EAST MESA

PRODUCTION WELL SUMMARY OF FLOW TEST DATA

DATA DATE 04/18/80

WELL NO P876

FRI, MAY 30, 1980, 8:57 AM

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	WATER (M LB/HR)	TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	28.0	271.0				33.8	230.0	263.8	12.82	.1	1.68	.0
2 AM	.0	28.0	272.0				32.4	220.7	253.1	12.82	.1	1.85	.0
3 AM	.0	28.0	271.0				32.4	220.7	253.1	12.82	.1	2.11	.0
4 AM	.0	28.0	272.0				32.9	223.8	256.7	12.82	.1	2.29	.0
5 AM	.0	28.0	272.0				32.9	223.8	256.7	12.82	.1	2.46	.0
6 AM	.0	28.0	271.0				32.4	220.7	253.1	12.82	.1	2.63	.0
7 AM	.0	28.0	271.0				32.0	217.6	249.5	12.82	.1	2.81	.0
8 AM	.0	28.0	271.0				32.0	217.6	249.5	12.82	.1	2.98	.0
9 AM	.0	28.0	270.0				32.4	220.7	253.1	12.82	.1	3.15	.0
10 AM	.0	28.0	270.0				32.4	220.7	253.1	12.82	.1	3.48	.0
11 AM	.0	28.0	270.0				32.0	217.6	249.5	12.82	.1	3.74	.0
12 AM	.0	28.0	270.0				31.5	214.5	246.0	12.82	.1	3.99	.0
1 PM	.0	28.0	270.0				32.9	223.8	256.7	12.82	.1	4.25	.0
2 PM	.0	28.0	270.0				37.5	254.8	292.3	12.82	.1	4.49	.0
3 PM	.0	31.0	274.0				22.0	149.3	171.2	12.82	.1	4.70	.0
4 PM	.0	32.0	280.0				22.0	149.3	171.2	12.82	.1	4.87	.0
5 PM	.0	38.0	281.0				21.5	146.2	167.7	12.82	.1	5.04	.0
6 PM	.0	38.0	282.0				22.0	149.3	171.2	12.82	.1	5.21	.0
7 PM	.0	38.0	283.0				21.5	146.2	167.7	12.82	.1	5.38	.0
8 PM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	5.55	.0
9 PM	.0	38.0	284.0				21.5	146.2	167.7	12.82	.1	5.72	.0
10 PM	.0	37.0	285.0				21.0	143.1	164.1	12.82	.1	5.88	.0
11 PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	6.04	.0
12 [illegible]	.0	40.0	284.0				21.5	146.2	167.7	12.82	.1	6.21	.0

NOTES

WELL NO: P876 DATE: 04/18/80

ME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	WATER (M LB/HR)	TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	6.38	.0
2 AM	.0	40.0	284.0				31.5	214.5	246.0	12.82	.1	6.60	.0
3 AM	.0	40.0	284.0				22.0	149.3	171.2	12.82	.1	6.77	.0
4 AM	.0	40.0	284.0				21.5	146.2	167.7	12.82	.1	6.94	.0
5 AM	.0	40.0	284.0				21.5	146.2	167.7	12.82	.1	7.11	.0
6 AM	.0	40.0	285.0				30.6	208.2	238.9	12.82	.1	7.27	.0
7 AM	.0	40.0	285.0				21.5	146.2	167.7	12.82	.1	7.44	.0
8 AM	.0	40.0	287.0				21.0	143.1	164.1	12.82	.1	7.61	.0
9 AM	.0	40.0	287.0				21.5	146.2	167.7	12.82	.1	7.77	.0
0 AM	.0	40.0	287.0				21.5	146.2	167.7	12.82	.1	7.94	.0
1 AM	.0	40.0	287.0				21.5	146.2	167.7	12.82	.1	8.11	.0
2 AM	.0	41.0	287.0				21.0	143.1	164.1	12.82	.1	8.28	.0
1 PM	.0	42.0	287.0				21.0	143.1	164.1	12.82	.1	8.44	.0
2 PM	.0	42.0	287.0				21.0	143.1	164.1	12.82	.1	8.61	.0
3 PM	.0	42.0	287.0				21.0	143.1	164.1	12.82	.1	8.78	.0
4 PM	.0	42.0	286.0				21.0	143.1	164.1	12.82	.1	8.95	.0
5 PM	.0	42.0	286.0				21.5	146.2	167.7	12.82	.1	9.11	.0
6 PM	.0	42.0	287.0				21.0	143.1	164.1	12.82	.1	9.28	.0
7 PM	.0	41.0	287.0				21.0	143.1	164.1	12.82	.1	9.45	.0
8 PM	.0	42.0	286.0				21.5	146.2	167.7	12.82	.1	9.61	.0
9 PM	.0	40.0	287.0				21.0	143.1	164.1	12.82	.1	9.77	.0
0 PM	.0	40.0	287.0				21.0	143.1	164.1	12.82	.1	9.94	.0
1 PM	.0	40.0	287.0				21.0	143.1	164.1	12.82	.1	10.10	.0
2 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	10.27	.0

NOTES

WELL NO: PB76 DATE: 04/19/88

IELD EAST MESA

ELL NO P876

PRODUCTION WELL SUMMARY

OF FLOW TEST DATA

DATA DATE 04/20/80

FRI, MAY 30, 1980, 8:57 AM

	DOWNHOLE	WELLHEAD DATA		SEPARATOR DATA			FLOWRATES DOWNSTREAM OF SEPARATOR						
IME	PRESSURE (PSIG)	PRESS (PSIG)	TEMP (F)	PRESS (PSIG)	STEAM TEMP (F)	WATER TEMP (F)	STEAM (M LB/HR)	WATER (M LB/HR)	TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	10.43	.0
2 AM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	10.60	.0
3 AM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	10.76	.0
4 AM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	10.92	.0
5 AM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	11.09	.0
6 AM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	11.25	.0
7 AM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	11.42	.0
8 AM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	11.58	.0
9 AM	.0	41.0	286.0				21.0	143.1	164.1	12.82	.1	11.74	.0
0 AM	.0	41.0	287.0				21.0	143.1	164.1	12.82	.1	11.91	.0
1 AM	.0	41.0	287.0				21.0	143.1	164.1	12.82	.1	12.07	.0
2 AM	.0	41.0	287.0				21.0	143.1	164.1	12.82	.1	12.24	.0
1 PM	.0	41.0	287.0				21.0	143.1	164.1	12.82	.1	12.40	.0
2 PM	.0	41.0	287.0				21.0	143.1	164.1	12.82	.1	12.56	.0
3 PM	.0	41.0	287.0				21.0	143.1	164.1	12.82	.1	12.73	.0
4 PM	.0	40.0	287.0				21.0	143.1	164.1	12.82	.1	12.89	.0
5 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	13.06	.0
6 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	13.22	.0
7 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	13.38	.0
8 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	13.55	.0
9 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	13.71	.0
0 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	13.88	.0
1 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	14.04	.0
2 PM	.0	40.0	286.0				21.0	143.1	164.1	12.82	.1	14.21	.0

NOTES

WELL NO: P876 DATE: 04/28/88

LD EAST MESA

PRODUCTION WELL SUMMARY

OF FLOW TEST DATA

. NO P876

DATA DATE 04/21/80

FRI, MAY 30, 1980, 8:57 AM

	WNHOLE	WELLHEAD DATA		SEPARATOR DATA			FLOWRATES DOWNSTREAM OF SEPARATOR						
	SSURE (PSIG)	PRESS (PSIG)	TEMP (F)	PRESS (PSIG)	STEAM TEMP (F)	WATER TEMP (F)	STEAM (M LB/HR)	WATER (M LB/HR)	TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
AM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	14.37	.0
AM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	14.53	.0
M	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	14.70	.0
AM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	14.86	.0
AM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	15.03	.0
M	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	15.19	.0
AM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	15.35	.0
AM	.0	42.0	285.0				21.0	143.1	164.1	12.82	.1	15.52	.0
AM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	15.68	.0
AM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	15.85	.0
AM	.0	40.0	285.0				21.0	143.1	164.1	12.82	.1	16.01	.0
AM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	16.17	.0
PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	16.34	.0
PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	16.50	.0
M	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	16.67	.0
PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	16.83	.0
PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	17.00	.0
M	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	17.16	.0
PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	17.32	.0
PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	17.49	.1
M	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	17.65	.0
PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	17.82	.0
PM	.0	40.0	283.0				21.0	143.1	164.1	12.82	.1	17.98	.0
PM	.0	40.0	282.0				21.0	143.1	164.1	12.82	.1	18.14	.0

NOTES

WELL NO: P876 DATE: 04/21/80

FIELD EAST MESA

WELL NO P076

PRODUCTION WELL SUMMARY OF FLOW TEST DATA

DATA DATE 04/22/

FRI, MAY 30, 1980, 8:57

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	WATER (M LB/HR)	TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PS
1 AM	.0	972.0	282.0				21.0	143.1	164.1	12.82	.1	18.31	.
2 AM	.0	40.0	282.0				21.0	143.1	164.1	12.82	.1	18.47	.
3 AM	.0	40.0	282.0				21.0	143.1	164.1	12.82	.1	18.63	.0
4 AM	.0	40.0	283.0				20.6	140.0	160.5	12.82	.1	18.79	.0
5 AM	.0	40.0	283.0				20.6	140.0	160.5	12.82	.1	18.95	.0
6 AM	.0	40.0	284.0				20.6	140.0	160.5	12.82	.1	19.11	.0
7 AM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	19.28	.0
8 AM	.0	40.0	284.0				20.6	140.0	160.5	12.82	.1	19.44	.0
9 AM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	19.61	.0
10 AM	.0	38.0	284.0				20.6	140.0	160.5	12.82	.1	19.77	.0
11 AM	.0	40.0	284.0				20.6	140.0	160.5	12.82	.1	19.93	.0
12 AM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	20.10	.0
1 PM	.0	40.0	284.0				22.0	149.3	171.2	12.82	.1	20.26	.0
2 PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	20.43	.0
3 PM	.0	40.0	284.0				21.0	143.1	164.1	12.82	.1	20.59	.0
4 PM	1779.0	40.0	284.0				22.0	149.3	171.2	12.82	.1	20.76	1056.9
5 PM	.0	.0	.0				.0	.0	.0	.00	.0	20.76	.0
6 PM	.0	.0	.0				.0	.0	.0	.00	.0	20.76	.0
7 PM	.0	.0	.0				.0	.0	.0	.00	.0	20.76	.0
8 PM	.0	.0	.0				.0	.0	.0	.00	.0	20.76	.0
9 PM	.0	.0	.0				.0	.0	.0	.00	.0	20.76	.0
10 PM	.0	.0	.0				.0	.0	.0	.00	.0	20.76	.0
11 PM	.0	.0	.0				.0	.0	.0	.00	.0	20.76	.0
12 PM	.0	.0	.0				.0	.0	.0	.00	.0	20.76	.0

NOTES

WELL NO: P876 DATE: 04/22/80

1. RAN FLOWING PRESSURE/TEMPERATURE SURVEY WITH KUSTER TOOLS.
2. SHUT IN WELL AT 1800 HRS. PRESSURE BOMBS IN-HOLE FOR PBU.

TABLE 8

FIELD EAST MESA

PRODUCTION WELL SUMMARY

DATA DATE 05/01/80

WELL NO P876

OF FLOW TEST DATA

FRI, MAY 30, 1980, 8:57 A

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
2 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
3 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
4 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
5 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
6 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
7 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
8 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
9 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
10 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
11 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
12 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
1 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
2 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
3 PM	.0	40.0	280.0				32.4	220.7	253.1	12.82	.1		.0
4 PM	.0	40.0	280.0				30.6	208.2	238.9	12.82	.1		.0
5 PM	.0	40.0	280.0				31.1	211.3	242.4	12.82	.1		.0
6 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
7 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
8 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
9 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
10 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
11 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
12 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0

NOTES

WELL NO: P876 DATE: 05/01/88

1. OPEN WELL AT 1230 HRS.

2. ATTEMPTED CONTINUOUS SPINNER/TEMPERATURE SURVEY; EQUIPMENT FAILED.

3. SHUT IN WELL AT 1730 HRS.

TABLE 9

FIELD EAST MESA — PRODUCTION WELL SUMMARY — DATA DATE 05/07/8

WELL NO P876 — OF FLOW TEST DATA — FRI, MAY 30, 1980, 8:57

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI
1 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
2 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
3 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
4 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
5 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
6 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
7 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
8 AM	.0	32.0	225.0	9			36.1	245.5	281.6	12.82	.1		.0
9 AM	.0	39.0	256.0	9			24.7	167.9	192.6	12.82	.1		.0
10 AM	.0	44.0	287.0	9			25.6	174.1	199.7	12.82	.1		.0
11 AM	.0	44.0	285.0	9			27.9	189.6	217.5	12.82	.1		.0
12 AM	.0	48.0	286.0	9			28.3	192.7	221.1	12.82	.1		.0
1 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
2 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
3 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
4 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
5 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
6 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
7 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
8 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
9 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
10 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
11 PM	.0	.0	.0				.0	.0	.0	.00	.0		.0
[illegible] PM	.0	.0	.0				.0	.0	.0	.00	.0		.0

NOTES

WELL NO: P876 DATE: 05/07/80

1. OPEN WELL AT 0700 HRS. FOR CONTINUOUS SPINNER/TEMPERATURE SURVEY, BUT REPAIRED TOOLS DID NOT ARRIVE.

2. SHUT IN WELL AT 1300 HRS.

TABLE 10

FIELD EAST MESA — PRODUCTION WELL SUMMARY — DATA DATE 05/08/80

WELL NO P876 — OF FLOW TEST DATA — FRI, MAY 30, 1980, 8:57 A

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTIO (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
2 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
3 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
4 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
5 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
6 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
7 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
8 AM	.0	.0	.0				.0	.0	.0	.00	.0		.0
9 AM	.0	39.0	280.0				27.0	183.4	210.4	12.82	.1		.0
10 AM	.0	48.0	290.0				25.6	174.1	199.7	12.82	.1		.0
11 AM	.0	49.0	292.0				24.2	164.8	189.0	12.82	.1		.0
12 AM	.0	49.0	292.0				23.8	161.7	185.5	12.82	.1		.0
1 PM	.0	49.0	292.0				23.8	161.7	185.5	12.82	.1		.0
2 PM	.0	49.0	292.0				23.3	158.6	181.9	12.82	.1		.0
3 PM	.0	49.0	292.0				22.4	152.4	174.8	12.82	.1		.0
4 PM	.0	49.0	292.0				22.0	149.3	171.2	12.82	.1		.0
5 PM	.0	49.0	292.0				22.0	149.3	171.2	12.82	.1		.0
6 PM	.0	49.0	292.0				22.0	149.3	171.2	12.82	.1		.0
7 PM	.0	50.0	292.0				21.5	146.2	167.7	12.82	.1		.0
8 PM	.0	50.0	291.0				22.0	149.3	171.2	12.82	.1		.0
9 PM	.0	50.0	290.0				21.5	146.2	167.7	12.82	.1		.0
10 PM	.0	50.0	289.0				21.5	146.2	167.7	12.82	.1		.0
11 PM	.0	50.0	289.0				21.5	146.2	167.7	12.82	.1		.0
PM	.0	.0	.0				.0	.0	.0	.00	.0		.0

NOTES

WELL NO: P876   DATE: 05/08/80

1. OPEN WELL AT 0700 HRS.

2. RAN CONTINUOUS SPINNER SURVEY; TEMPEATURE FAILED.

3. SHUT IN WELL AT 0030 HRS. 5/9/80.

TABLE 11

FIELD EAST MESA — PRODUCTION WELL SUMMARY — DATA DATE 08/15/80

WELL NO P076 — OF FLOW TEST DATA — THU, AUG 28, 1980, 2:56 P

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
2 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
3 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
4 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
5 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
6 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
7 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
8 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
9 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
10 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
11 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
12 AM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	.39	.0
1 PM	.0	80.0	235.0	3.0	219.0	219.0	11.6	127.4	139.0	8.35	.0	.53	.0
2 PM	.0	82.0	239.0	4.0	220.0	220.0	12.7	125.0	137.7	9.21	.0	.67	.0
3 PM	.0	82.0	238.0	3.0	220.0	220.0	12.2	123.6	135.8	9.00	.0	.80	.0
4 PM	.0	80.0	238.0	5.0	223.0	225.0	14.2	118.9	133.1	10.69	.0	.93	.0
5 PM	.0	68.0	230.0	6.0	228.0	226.0	17.5	146.6	164.1	10.65	.0	1.10	.0
6 PM	.0	65.0	228.0	6.5	228.0	226.0	18.6	146.4	165.0	11.25	.0	1.26	.0
7 PM	.0	64.0	227.0	6.5	228.0	226.0	18.5	143.6	162.1	11.41	.0	1.42	.0
8 PM	.0	68.0	232.0	6.5	226.0	225.0	17.5	138.9	156.5	11.21	.0	1.58	.0
9 PM	.0	70.0	234.0	6.5	230.0	225.0	17.2	123.9	141.1	12.17	.0	1.72	.0
10 PM	.0	70.0	232.0	6.5	224.0	224.0	17.0	131.5	148.4	11.44	.0	1.87	.0
11 PM	.0	70.0	232.0	6.5	225.0	224.0	16.7	116.4	133.1	12.52	.0	2.00	.0
12 PM	.0	69.0	232.0	6.0	230.0	224.0	16.7	126.0	142.7	11.72	.0	2.15	.0

NOTES

WELL NO: P876 DATE: 08/15/80

1. OPENED WELL AT 0930 HRS; ESTIMATED PRODUCTION FROM 0930 HRS TO 1300 HRS IS 390,000 LB.

2. ALL PRODUCED FLUID TO POND AT GTF.

FIELD EAST MESA

PRODUCTION WELL SUMMARY

DATA DATE 08/16/8

WELL NO P876

OF FLOW TEST DATA

THU, AUG 29, 1980, 2:56

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI
1 AM	.0	68.0	232.0	6.5	226.0	224.0	16.8	116.4	133.2	12.59	.0	2.28	.0
2 AM	.0	69.0	234.0	6.5	228.0	224.0	16.7	116.4	133.2	12.57	.0	2.41	.0
3 AM	.0	69.0	232.0	6.0	227.0	224.0	16.5	120.4	136.9	12.08	.0	2.55	.0
4 AM	.0	69.0	234.0	6.0	227.0	224.0	16.5	120.4	136.9	12.08	.0	2.69	.0
5 AM	.0	68.0	234.0	6.5	229.0	226.0	16.7	120.2	136.9	12.20	.0	2.82	.0
6 AM	.0	68.0	234.0	7.0	226.0	226.0	16.9	120.0	136.9	12.35	.0	2.96	.0
7 AM	.0	66.0	233.0	6.8	228.0	226.0	17.1	123.8	140.9	12.15	.0	3.10	.0
8 AM	.0	66.0	233.0	6.6	228.0	227.0	17.5	125.7	143.2	12.22	.0	3.24	.0
9 AM	.0	65.0	233.0	6.5	227.0	227.0	17.4	120.1	137.5	12.63	.0	3.38	.0
10 AM	.0	65.0	232.0	6.0	226.0	227.0	17.2	122.2	139.4	12.36	.0	3.52	.0
11 AM	.0	67.0	233.0	5.5	227.0	225.0	16.4	118.7	135.1	12.17	.0	3.66	.0
12 AM	.0	68.0	234.0	5.0	225.0	220.0	16.2	115.2	131.4	12.34	.0	3.79	.0
1 PM	.0	70.0	235.0	4.5	226.0	221.0	15.9	119.1	135.1	11.81	.0	3.92	.0
2 PM	.0	70.0	235.0	5.0	226.0	223.0	15.6	115.1	130.7	11.93	.0	4.05	.0
3 PM	.0	70.0	235.0	4.5	226.0	223.0	15.0	109.6	124.6	12.00	.0	4.18	.0
4 PM	.0	70.0	234.0	4.0	223.0	219.0	14.6	109.9	124.5	11.69	.0	4.30	.0
5 PM	.0	70.0	234.0	4.0	224.0	220.0	14.2	102.3	116.5	12.18	.0	4.42	.0
6 PM	.0	69.0	234.0	4.5	228.0	225.0	15.2	109.6	124.8	12.17	.0	4.54	.1
7 PM	.0	68.0	234.0	4.5	226.0	222.0	15.2	111.6	126.8	12.02	.0	4.67	.0
8 PM	.0	67.0	234.0	5.0	228.0	225.0	15.4	109.4	124.8	12.31	.0	4.80	.1
9 PM	.0	65.0	234.0	5.5	226.0	225.0	16.1	116.8	132.9	12.10	.0	4.93	.0
10 PM	.0	64.0	231.0	6.0	228.0	225.0	16.9	118.5	135.4	12.48	.0	5.06	.1
11 PM	.0	64.0	231.0	6.5	227.0	225.0	17.0	120.2	137.2	12.39	.0	5.20	.0
12 PM	.0	64.0	231.0	6.5	227.0	224.0	17.2	122.1	139.2	12.33	.0	5.34	.0

NOTES

WELL NO: P876 DATE: 08/16/88

FIELD EAST MESA | PRODUCTION WELL SUMMARY | DATA DATE 08/17/80

WELL NO P876 | OF FLOW TEST DATA | THU, AUG 28, 1980, 2:56 P

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	64.0	231.0	6.0	227.0	225.0	16.7	105.3	122.0	13.65	.0	5.46	.0
2 AM	.0	64.0	231.0	6.0	228.0	225.0	17.1	127.9	144.9	11.78	.0	5.61	.0
3 AM	.0	64.0	232.0	6.0	228.0	224.0	17.1	122.3	139.3	12.26	.0	5.75	.0
4 AM	.0	64.0	233.0	6.5	228.0	224.0	17.1	118.3	135.4	12.61	.0	5.88	.0
5 AM	.0	64.0	233.0	6.5	228.0	224.0	17.0	116.4	133.5	12.76	.0	6.02	.0
6 AM	.0	64.0	233.0	6.5	227.0	224.0	17.1	118.3	135.4	12.62	.0	6.15	.0
7 AM	.0	64.0	233.0	6.0	227.0	225.0	16.9	118.5	135.4	12.49	.0	6.29	.0
8 AM	.0	64.0	233.0	5.5	228.0	224.0	16.7	118.7	135.4	12.34	.0	6.42	.0
9 AM	.0	65.0	234.0	5.5	228.0	223.0	16.4	114.9	131.3	12.49	.0	6.55	.0
10 AM	.0	65.0	234.0	4.5	227.0	220.0	15.2	109.7	124.9	12.17	.0	6.68	.0
11 AM	.0	65.0	234.0	5.5	228.0	223.0	15.5	109.3	124.8	12.45	.0	6.80	.0
12 AM	.0	65.0	235.0	5.5	228.0	223.0	15.5	107.4	122.9	12.62	.0	6.93	.0
1 PM	.0	73.0	234.0	10.0	230.0	225.0	15.4	111.6	127.0	12.12	.0	7.05	.0
2 PM	.0	65.0	235.0	7.0	228.0	224.0	11.0	106.9	117.9	9.29	.0	7.17	.0
3 PM	.0	65.0	235.0	4.5	228.0	224.0	15.2	109.6	124.8	12.17	.0	7.30	.0
4 PM	.0	68.0	234.0	3.0	225.0	221.0	14.1	110.3	124.4	11.36	.0	7.42	.0
5 PM	.0	68.0	235.0	3.0	222.0	220.0	14.2	108.4	122.5	11.55	.0	7.54	.0
6 PM	.0	69.0	233.0	5.0	226.0	224.0	14.8	105.7	120.5	12.30	.0	7.66	.0
7 PM	.0	70.0	236.0	5.0	225.0	224.0	14.8	101.9	116.7	12.66	.0	7.78	.0
8 PM	.0	69.0	236.0	5.0	224.0	221.0	14.9	102.0	116.9	12.76	.0	7.90	.0
9 PM	.0	69.0	231.0	5.5	225.0	224.0	15.1	101.7	116.8	12.90	.0	8.01	.0
10 PM	.0	70.0	233.0	5.0	224.0	222.0	14.9	101.9	116.9	12.76	.0	8.13	.0
11 PM	.0	70.0	234.0	5.5	226.0	223.0	15.1	101.8	116.8	12.89	.0	8.25	.0
12 PM	.0	69.0	233.0	4.0	225.0	222.0	14.2	102.3	116.5	12.17	.0	8.36	.0

NOTES

WELL NO: P876 DATE: 08/17/80

1. LBL RAN SPINNER AND TEMPERATURE SURVEYS; TEMPERATURE TOOL FAILED AT 4350 FEET.

PRODUCTION WELL SUMMARY DATA DATE 08/18/

WELL NO P876 OF FLOW TEST DATA THU, AUG 28, 1980, 2:5

	DOWNHOLE	WELLHEAD DATA		SEPARATOR DATA			FLOWRATES DOWNSTREAM OF SEPARATOR			STEAM	NON-CONDENSBL	CUMULATIVE	
TIME	PRESSURE (PSIG)	PRESS (PSIG)	TEMP (F)	PRESS (PSIG)	STEAM TEMP (F)	WATER TEMP (F)	STEAM (M LB/HR)	WATER (M LB/HR)	TOTAL (M LB/HR)	QUALITY (WT%)	GAS (LB/HR)	PRODUCTION (MM LB)	P.I. (LB/HR/PS
1 AM	.0	72.0	237.0	5.5	224.0	225.0	14.3	101.7	116.1	12.35	.0	8.48	.
2 AM	.0	72.0	237.0	5.0	222.0	224.0	14.2	101.9	116.1	12.23	.0	8.60	.
3 AM	.0	72.0	237.0	5.0	226.0	224.0	14.2	101.9	116.1	12.28	.0	8.71	.
4 AM	.0	72.0	237.0	5.5	223.0	225.0	14.3	101.7	116.1	12.36	.0	8.83	.
5 AM	.0	72.0	237.0	6.0	226.0	225.0	14.5	101.6	116.0	12.47	.0	8.94	.0
6 AM	.0	72.0	237.0	5.0	227.0	226.0	14.1	101.9	116.0	12.19	.0	9.06	.0
7 AM	.0	72.0	237.0	6.0	225.0	226.0	14.5	101.6	116.0	12.48	.0	9.18	.0
8 AM	.0	72.0	310.0	6.0	225.0	226.0	14.4	97.8	112.2	12.84	.0	9.28	.0
9 AM	.0	72.0	305.0	6.0	225.0	226.0	12.9	90.3	103.2	12.52	.0	9.38	.0
10 AM	.0	74.0	300.0	6.0	225.0	226.0	15.7	142.9	158.5	9.88	.0	9.54	.0
11 AM	.0	57.0	303.0	15.0	245.0	243.0	18.2	130.1	148.3	12.28	.0	9.69	.0
12 AM	.0	57.0	306.0	15.0	247.0	243.0	18.0	124.6	142.6	12.60	.0	9.83	.0
1 PM	.0	57.0	301.0	15.0	245.0	243.0	17.3	122.8	140.1	12.34	.0	9.97	.0
2 PM	.0	57.0	310.0	15.0	245.0	243.0	17.7	124.6	142.3	12.46	.0	10.12	.0
3 PM	.0	61.0	300.0	15.5	248.0	248.0	18.5	124.4	142.8	12.93	.0	10.26	.0
4 PM	.0	56.0	304.0	16.5	250.0	247.0	21.3	133.2	154.5	13.78	.0	10.41	.0
5 PM	.0	56.0	304.0	18.0	245.0	241.0	21.1	136.6	157.8	13.40	.0	10.57	.0
6 PM	.0	56.0	300.0	17.0	245.0	240.0	20.7	138.8	159.5	12.99	.0	10.72	.0
7 PM	.0	57.0	300.0	7.0	230.0	226.0	18.2	134.0	152.3	11.97	.0	10.87	.0
8 PM	.0	55.0	308.0	7.5	230.0	227.0	18.4	134.7	153.2	12.04	.0	11.03	.0
9 PM	.0	55.0	300.0	7.5	231.0	227.0	18.8	134.7	153.5	12.25	.0	11.18	.0
10 PM	.0	54.0	300.0	7.5	231.0	228.0	19.0	134.7	153.8	12.39	.0	11.34	.0
11 PM	.0	54.0	300.0	7.5	230.0	227.0	19.1	134.7	153.8	12.39	.0	11.49	.0
12 PM	.0	54.0	300.0	8.5	231.0	227.0	19.5	136.2	155.7	12.50	.0	11.65	.0

NOTES

WELL NO: P876 DATE: 08/18/88

1. NON-CONDENSABLE GAS SAMPLES AND WATER SAMPLES OBTAINED FOR ANALYSIS.

WELL NO: P876 OF FLOW TEST DATA THU, AUG 28, 1980, 2:56 P

	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	54.0	300.0	8.5	231.0	227.0	19.5	136.2	155.7	12.50	.0	11.81	.0
2 AM	.0	54.0	300.0	8.5	231.0	227.0	19.4	134.4	153.8	12.63	.0	11.96	.0
3 AM	.0	52.0	299.0	8.0	232.0	226.0	19.2	132.7	151.9	12.62	.0	12.11	.0
4 AM	.0	52.0	298.0	8.5	231.0	226.0	19.5	136.3	155.7	12.50	.0	12.27	.0
5 AM	.0	52.0	298.0	8.5	231.0	226.0	19.5	136.3	155.7	12.50	.0	12.42	.0
6 AM	.0	52.0	298.0	8.5	232.0	225.0	19.5	138.2	157.7	12.37	.0	12.58	.0
7 AM	.0	52.0	298.0	8.5	232.0	225.0	19.5	138.2	157.7	12.37	.0	12.74	.0
8 AM	.0	52.0	298.0	8.5	232.0	227.0	19.5	136.2	155.7	12.49	.0	12.89	.0
9 AM	.0	52.0	298.0	8.5	232.0	227.0	19.5	136.2	155.7	12.49	.0	13.05	.0
10 AM	.0	52.0	298.0	8.5	232.0	227.0	19.5	136.2	155.7	12.49	.0	13.20	.0
11 AM	.0	51.0	298.0	8.5	232.0	227.0	19.4	134.4	153.8	12.62	.0	13.36	.0
12 AM	.0	52.0	298.0	8.5	232.0	227.0	19.3	130.6	150.0	12.87	.0	13.51	.0
1 PM	.0	52.0	300.0	8.0	232.0	227.0	19.1	129.0	148.0	12.89	.0	13.66	.0
2 PM	.0	52.0	300.0	7.0	232.0	227.0	18.8	131.2	150.0	12.51	.0	13.80	.0
3 PM	.0	52.0	300.0	7.0	231.0	227.0	19.0	140.6	159.5	11.90	.0	13.95	.0
4 PM	.0	52.0	300.0	7.5	230.0	227.0	19.1	134.7	153.8	12.39	.0	14.11	.0
5 PM	.0	52.0	300.0	6.5	230.0	227.0	18.6	134.2	152.8	12.20	.0	14.26	.0
6 PM	.0	52.0	300.0	7.0	231.0	227.0	18.9	134.9	153.8	12.26	.0	14.42	.0
7 PM	.0	52.0	300.0	7.5	232.0	229.0	19.1	135.6	154.7	12.32	.0	14.57	.0
8 PM	.0	52.0	299.0	8.0	232.0	228.0	19.2	132.7	151.8	12.63	.0	14.73	.0
9 PM	.0	51.0	297.0	8.0	232.0	228.0	19.2	132.7	151.8	12.63	.0	14.88	.0
10 PM	.0	51.0	297.0	8.0	232.0	228.0	19.3	136.4	155.7	12.38	.0	15.03	.0
11 PM	.0	51.0	297.0	8.5	232.0	228.0	19.4	134.4	153.8	12.62	.0	15.18	.0
12 PM	.0	51.0	298.0	8.5	232.0	227.0	19.4	134.4	153.8	12.62	.0	15.34	.0

NOTES

WELL NO: P876 DATE: 08/19/80

WELL NO P876

OF FLOW TEST DATA

THU, AUG 28, 1980, 2:56

E	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PSI)
1 AM	.0	51.0	298.0	8.5	232.0	227.0	19.4	133.4	152.8	12.68	.0	15.49	.0
2 AM	.0	51.0	298.0	8.5	232.0	227.0	19.4	134.0	153.4	12.64	.0	15.64	.0
3 AM	.0	50.0	298.0	8.5	232.0	226.0	19.4	134.6	154.0	12.60	.0	15.80	.0
4 AM	.0	50.0	298.0	8.5	232.0	226.0	19.4	133.5	152.8	12.68	.0	15.95	.0
5 AM	.0	50.0	298.0	8.5	232.0	227.0	19.8	133.8	153.6	12.90	.0	16.11	.0
6 AM	.0	50.0	298.0	8.5	232.0	227.0	19.8	134.2	154.0	12.88	.0	16.26	.0
7 AM	.0	50.0	297.0	9.0	234.0	228.0	20.0	136.0	156.1	12.84	.0	16.42	.0
8 AM	.0	50.0	296.0	11.0	238.0	235.0	20.6	132.4	153.0	13.45	.0	16.57	.0
9 AM	.0	50.0	297.0	11.5	238.0	235.0	20.1	132.2	152.4	13.21	.0	16.73	.0
10 AM	.0	50.0	296.0	11.5	238.0	235.0	19.8	132.2	152.1	13.03	.0	16.88	.0
11 AM	.0	50.0	296.0	11.5	238.0	235.0	19.9	137.8	157.7	12.65	.0	17.03	.0
12 AM	.0	50.0	296.0	11.5	238.0	235.0	19.9	133.2	153.1	13.02	.0	17.19	.0
1 PM	.0	50.0	298.0	11.0	238.0	235.0	17.7	131.1	148.8	11.91	.0	17.34	.0
2 PM	.0	50.0	298.0	12.0	242.0	235.0	19.7	134.9	154.6	12.77	.0	17.49	.0
3 PM	.0	49.0	296.0	12.5	242.0	238.0	19.8	131.9	151.6	13.05	.0	17.64	.0
4 PM	.0	50.0	296.0	12.5	242.0	238.0	19.8	132.8	152.6	12.99	.0	17.80	.0
5 PM	.0	50.0	297.0	12.5	240.0	240.0	19.8	132.7	152.6	13.01	.0	17.95	.0
6 PM	.0	50.0	297.0	12.5	243.0	240.0	20.0	133.7	153.7	13.02	.0	18.10	.0
7 PM	.0	49.0	297.0	12.0	240.0	242.0	19.9	132.8	152.7	13.01	.0	18.26	.0
8 PM	.0	49.0	296.0	12.5	243.0	240.0	20.0	134.0	154.0	13.00	.0	18.41	.0
9 PM	.0	48.0	296.0	10.5	237.0	235.0	24.9	134.8	159.7	15.59	.0	18.57	.0
10 PM	.0	49.0	296.0	10.5	237.0	237.0	20.5	134.7	155.3	13.23	.0	18.72	.0
11 PM	.0	49.0	296.0	10.5	238.0	237.0	20.5	135.3	155.8	13.14	.0	18.88	.0
12 PM	.0	49.0	296.0	10.5	237.0	237.0	20.5	134.4	154.9	13.25	.0	19.04	.0

NOTES

WELL NO: P876 DATE: 08/28/80

1. NON-CONDENSABLE GAS SAMPLES AND WATER SAMPLES OBTAINED FOR ANALYSIS.

WELL NO P876 OF FLOW TEST DATA THU, AUG 28, 1980, 2:56

	DOWNHOLE	WELLHEAD DATA		SEPARATOR DATA			FLOWRATES DOWNSTREAM OF SEPARATOR			STEAM	NON-CONDENSBL	CUMULATIVE	
TIME	PRESSURE (PSIG)	PRESS (PSIG)	TEMP (F)	PRESS (PSIG)	STEAM TEMP (F)	WATER TEMP (F)	STEAM (M LB/HR)	WATER (M LB/HR)	TOTAL (M LB/HR)	QUALITY (WT%)	GAS (LB/HR)	PRODUCTION (MM LB)	P.I. (LB/HR/PS
1 AM	.0	49.0	296.0	10.5	238.0	237.0	20.4	139.0	159.4	12.79	.0	19.19	.0
2 AM	.0	49.0	296.0	10.5	238.0	237.0	20.3	135.3	155.6	13.03	.0	19.35	.0
3 AM	.0	49.0	296.0	10.3	237.0	237.0	20.4	135.4	155.7	13.07	.0	19.51	.0
4 AM	.0	48.0	296.0	10.5	238.0	238.0	20.5	135.3	155.8	13.18	.0	19.66	.0
5 AM	.0	48.0	296.0	10.5	238.0	237.0	20.5	135.3	155.8	13.18	.0	19.82	.0
6 AM	.0	48.0	296.0	10.5	238.0	236.0	21.0	135.3	156.3	13.41	.0	19.97	.0
7 AM	.0	48.0	296.0	10.0	238.0	234.0	20.8	135.5	156.3	13.30	.0	20.13	.0
8 AM	.0	48.0	296.0	10.0	236.0	232.0	20.8	135.6	156.4	13.31	.0	20.28	.0
9 AM	.0	48.0	296.0	10.0	236.0	233.0	20.2	137.4	157.6	12.81	.0	20.44	.0
10 AM	.0	48.0	294.0	10.0	236.0	232.0	20.1	133.7	153.8	13.05	.0	20.60	.0
11 AM	.0	46.0	294.0	10.0	236.0	233.0	20.1	135.6	155.7	12.93	.0	20.75	.0
12 AM	.0	47.0	294.0	10.0	236.0	232.0	20.1	133.7	153.8	13.05	.0	20.91	.0
1 PM	.0	47.0	294.0	10.0	236.0	232.0	20.1	133.7	153.8	13.05	.0	21.06	.0
2 PM	.0	48.0	294.0	9.0	236.0	232.0	19.7	134.1	153.8	12.83	.0	21.22	.0
3 PM	.0	48.0	294.0	8.5	236.0	233.0	19.6	134.2	153.8	12.71	.0	21.37	.0
4 PM	.0	47.0	295.0	8.2	236.0	233.0	19.4	134.3	153.8	12.64	.0	21.52	.0
5 PM	.0	48.0	295.0	8.5	236.0	233.0	19.9	136.1	156.0	12.78	.0	21.68	.0
6 PM	.0	47.0	294.0	9.0	236.0	233.0	20.1	135.9	156.0	12.90	.0	21.83	.0
7 PM	.0	47.0	294.0	10.0	236.0	233.0	20.8	135.6	156.4	13.31	.0	21.99	.0
8 PM	.0	47.0	295.0	10.5	236.0	233.0	21.0	133.5	154.5	13.59	.0	22.15	.0
9 PM	.0	47.0	295.0	11.0	236.0	234.0	20.8	133.4	154.2	13.50	.0	22.30	.0
10 PM	.0	46.0	296.0	10.5	236.0	233.0	20.6	137.2	157.9	13.07	.0	22.46	.0
11 PM	.0	47.0	295.0	10.5	235.0	233.0	20.6	137.2	157.9	13.07	.0	22.61	.0
12 PM	.0	46.0	294.0	10.5	236.0	233.0	20.6	137.2	157.9	13.07	.0	22.77	.0

NOTES

WELL NO: P876 DATE: 08/21/80

1. TRIANGLE RAN SPINNER AND TEMPERATURE SURVEYS.

WELL NO. P876

OF FLOW TEST DATA

THU, AUG 28, 1980, 2:56

TIME	DOWNHOLE PRESSURE (PSIG)	WELLHEAD DATA PRESS (PSIG)	WELLHEAD DATA TEMP (F)	SEPARATOR DATA PRESS (PSIG)	SEPARATOR DATA STEAM TEMP (F)	SEPARATOR DATA WATER TEMP (F)	FLOWRATES DOWNSTREAM OF SEPARATOR STEAM (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR WATER (M LB/HR)	FLOWRATES DOWNSTREAM OF SEPARATOR TOTAL (M LB/HR)	STEAM QUALITY (WT%)	NON-CONDENSBL GAS (LB/HR)	CUMULATIVE PRODUCTION (MM LB)	P.I. (LB/HR/PS
1 AM	.0	46.0	294.0	10.5	236.0	233.0	20.6	137.2	157.9	13.07	.0	22.93	.0
2 AM	.0	46.0	294.0	10.5	236.0	234.0	20.6	137.2	157.8	13.07	.0	23.09	.0
3 AM	.0	47.0	294.0	10.0	237.0	234.0	20.4	137.4	157.8	12.95	.0	23.24	.0
4 AM	.0	47.0	294.0	10.5	237.0	234.0	20.6	137.2	157.8	13.06	.0	23.40	.0
5 AM	.0	47.0	294.0	10.0	236.0	234.0	20.5	137.4	157.8	12.96	.0	23.56	.0
6 AM	.0	47.0	294.0	10.0	237.0	234.0	20.6	137.4	158.0	13.02	.0	23.71	.0
7 AM	.0	46.0	292.0	10.0	237.0	232.0	20.5	135.6	156.1	13.14	.0	23.87	.0
8 AM	.0	46.0	292.0	10.0	236.0	232.0	20.6	137.4	158.0	13.03	.0	24.03	.0
9 AM	.0	46.0	294.0	10.0	236.0	232.0	20.5	137.4	157.9	12.96	.0	24.19	.0
10 AM	.0	46.0	294.0	10.0	236.0	233.0	20.3	133.7	154.0	13.21	.0	24.34	.0
11 AM	.0	46.0	294.0	10.0	236.0	232.0	20.3	131.9	152.2	13.33	.0	24.50	.0
12 AM	.0	47.0	294.0	9.5	236.0	232.0	20.2	133.9	154.1	13.09	.0	24.65	.0
1 PM	.0	47.0	294.0	9.0	234.0	231.0	20.0	132.2	152.2	13.12	.0	24.80	.0
2 PM	.0	47.0	294.0	9.0	234.0	231.0	20.0	132.2	152.2	13.12	.0	24.95	.0
3 PM	.0	47.0	293.0	8.5	236.0	230.0	19.8	132.4	152.2	12.99	.0	25.11	.0
4 PM	.0	47.0	294.0	8.0	234.0	231.0	19.5	132.6	152.1	12.81	.0	25.26	.0
5 PM	.0	47.0	294.0	8.0	234.0	231.0	19.5	132.6	152.1	12.81	.0	25.41	.0
6 PM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	25.41	.0
7 PM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	25.41	.0
8 PM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	25.41	.0
9 PM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	25.41	.0
10 PM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	25.41	.0
11 PM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	25.41	.0
12 PM	.0	.0	.0	.0	.0	.0	.0	.0	.0	.00	.0	25.41	.0

NOTES

WELL NO: P876 DATE: 08/22/80

1. WELL SHUT IN AT 1700 HRS.
2. LBL PRESSURE INSTRUMENT FAILED; RAN RGI WIRELINE INSTRUMENTS FOR PRESSURE BUILDUP DATA.
3. ALL PRODUCED FLUID FROM TEST PUT TO POND AT GTF.

TABLE 12

VAPOR PRESSURE OF FLUID FROM
87-6 AT 350°F

Component	ppm	psi/1,000ppm	psi
CO_2	923	42	38.8
N_2	20.4	824	16.8
CH_4	13.2	844	11.4
Ar	.82	311	.3
	SUM		67.3
H_2O			134.6
	TOTAL VAPOR PRESSURE		201.9
			205 psia

TABLE 13

DISSOLVED SOLIDS IN FLUID FROM EAST MESA WELL 87-6
parts per million by weight, pre-flash basis

Constitutents	ppm
Cl	928
HCO_3	290
SO_4	179
F	5.2
B	2.98
TDS	2450
Na	768
K	56.1
Li	2.4
Ca	24 (est)
SiO_2	232

TABLE 14

COMPONENTS OF ENVIRONMENTAL CONCERN IN FLUID
FROM EAST MESA WELL 87-6

H_2S	0.79 ppm
Benzene	0.012 ppm
Non-methane hydrocarbons	0.37 ppm
Radon	0.26 p Ci/kg
Total alpha activity	less than 5 p Ci/kg
Total beta activity	18 p Ci/kg

FIGURE 1
SPERRY EAST MESA WELL 87-6 LOCATION

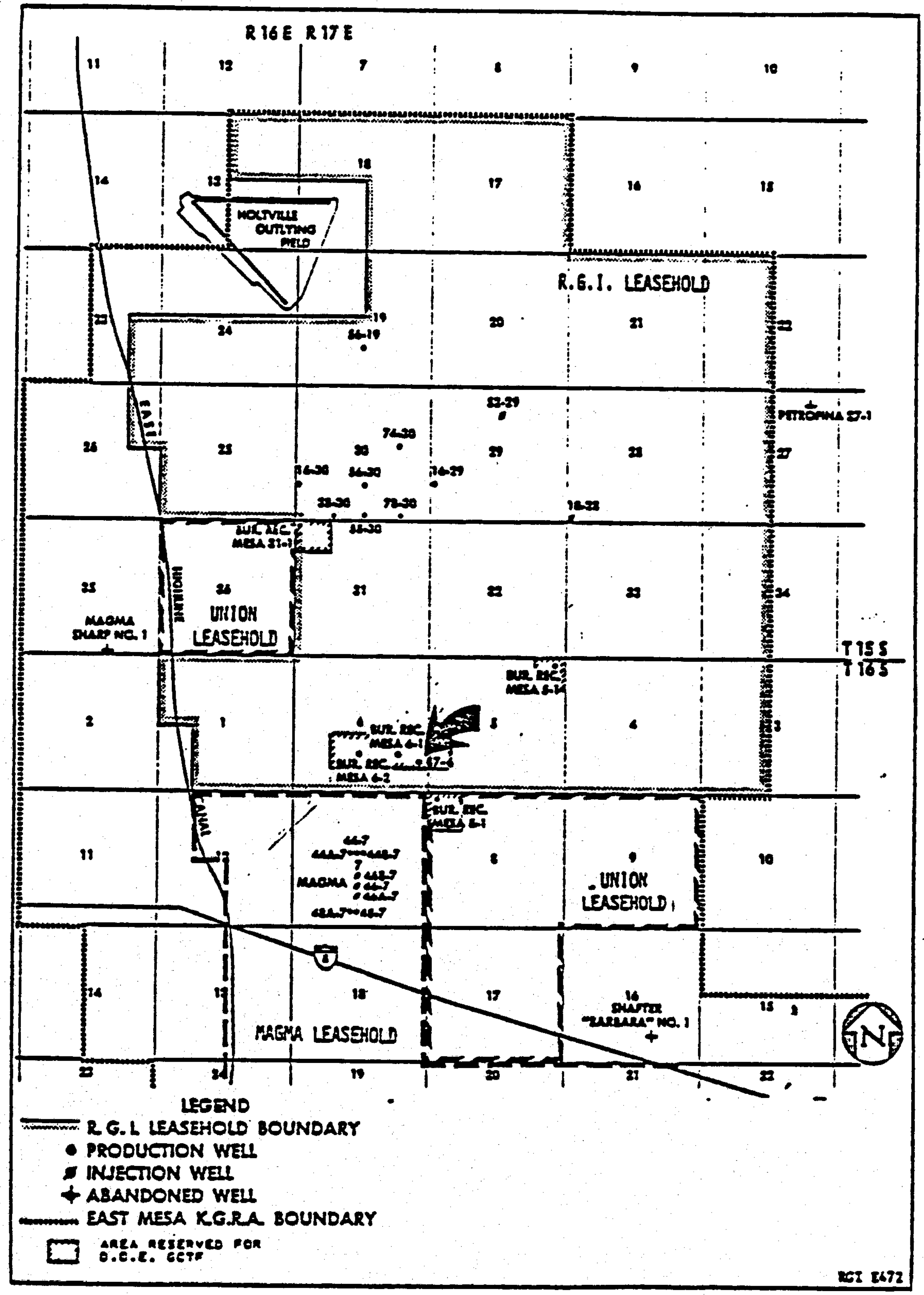


FIGURE 2

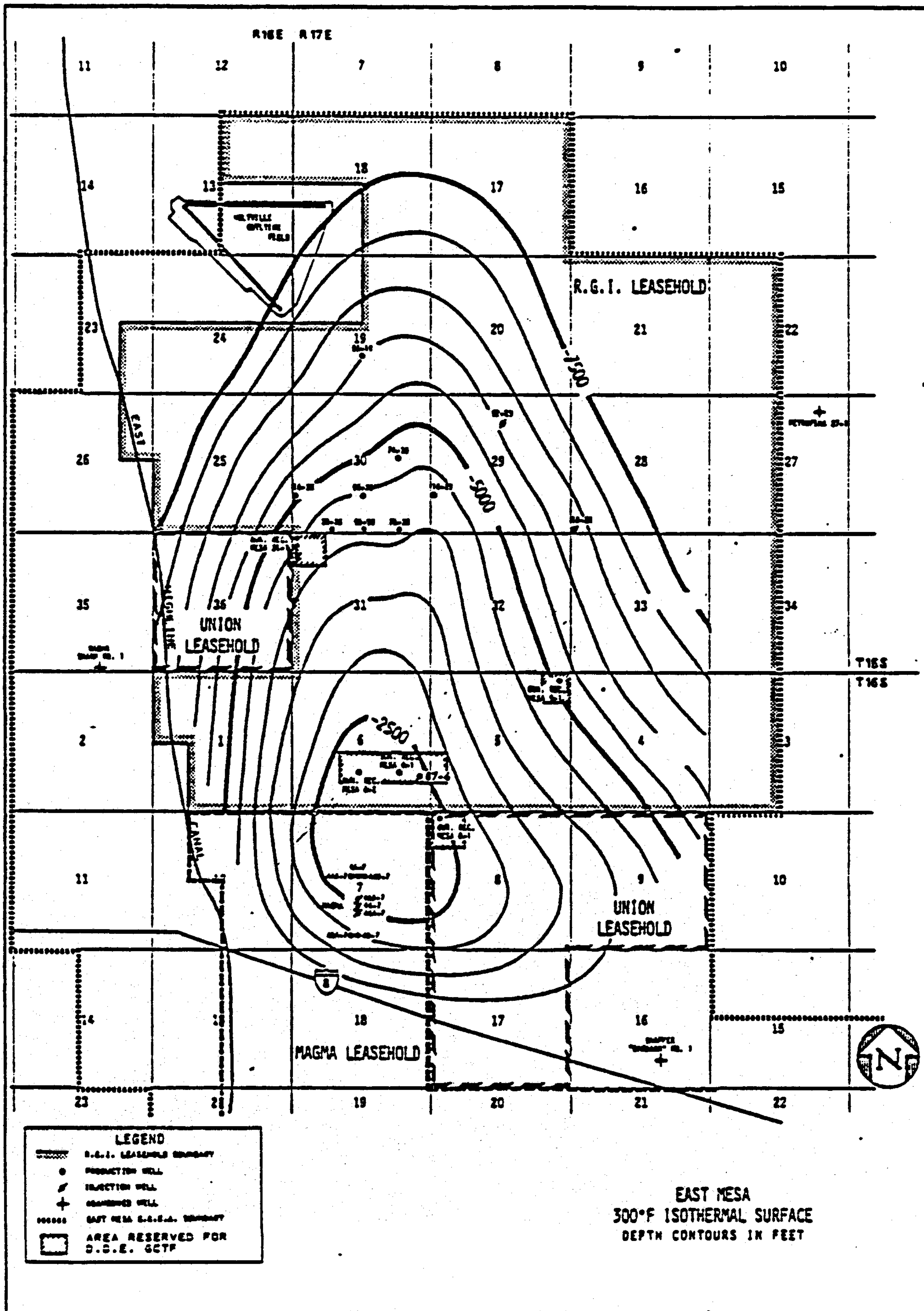

R16E R17E
R.G.I. LEASEHOLD
-1500
-2000
-2500
UNION LEASEHOLD
UNION LEASEHOLD
MAGMA LEASEHOLD
EAST
CANAL
T15S
T16S
LEGEND
AREA RESERVED FOR D.O.E. GCTF
EAST MESA
300°F ISOTHERMAL SURFACE
DEPTH CONTOURS IN FEET

FIGURE 3
EAST MESA STATIC
TEMPERATURE PROFILES

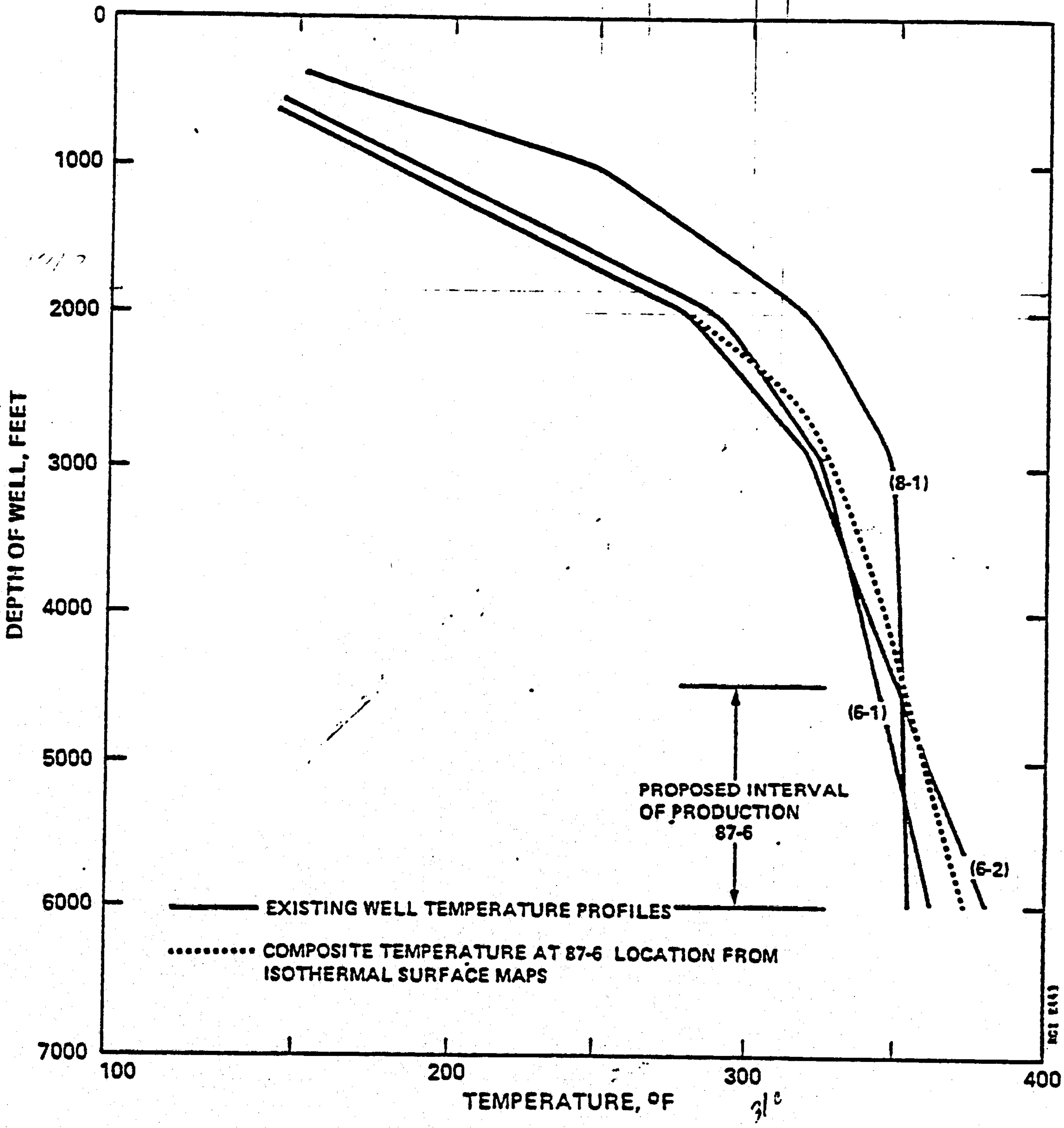


FIGURE 4

SPERRY EAST MESA WELL 87-6
CASING DETAIL

ALL DEPTHS REFER TO KELLY BUSHING ELEVATION
WHICH IS 16' ABOVE GROUND LEVEL

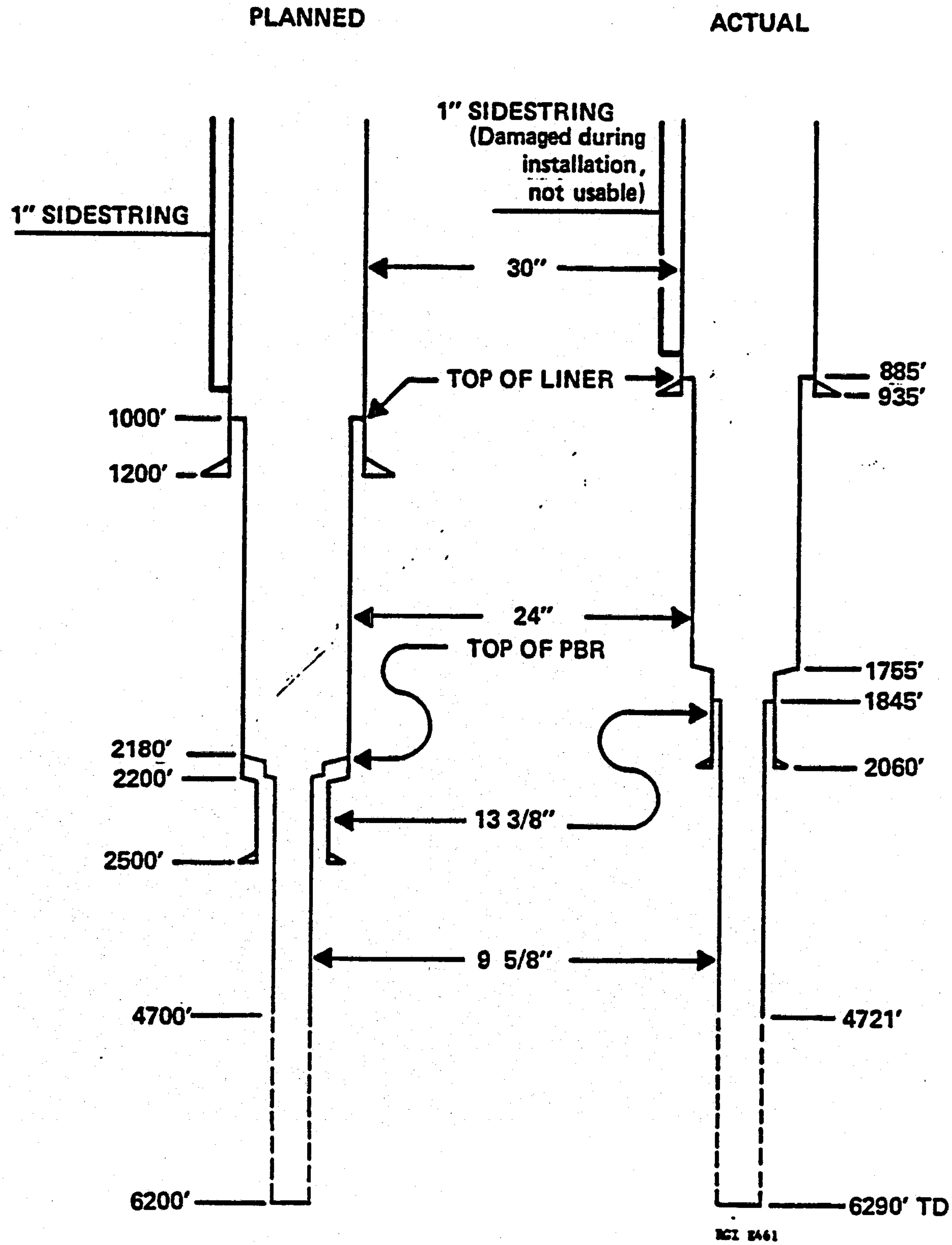


FIGURE 5
SPERRY EAST MESA WELL 87-6
PRESSURE BUILDUP ANALYSIS
(4/22/80)

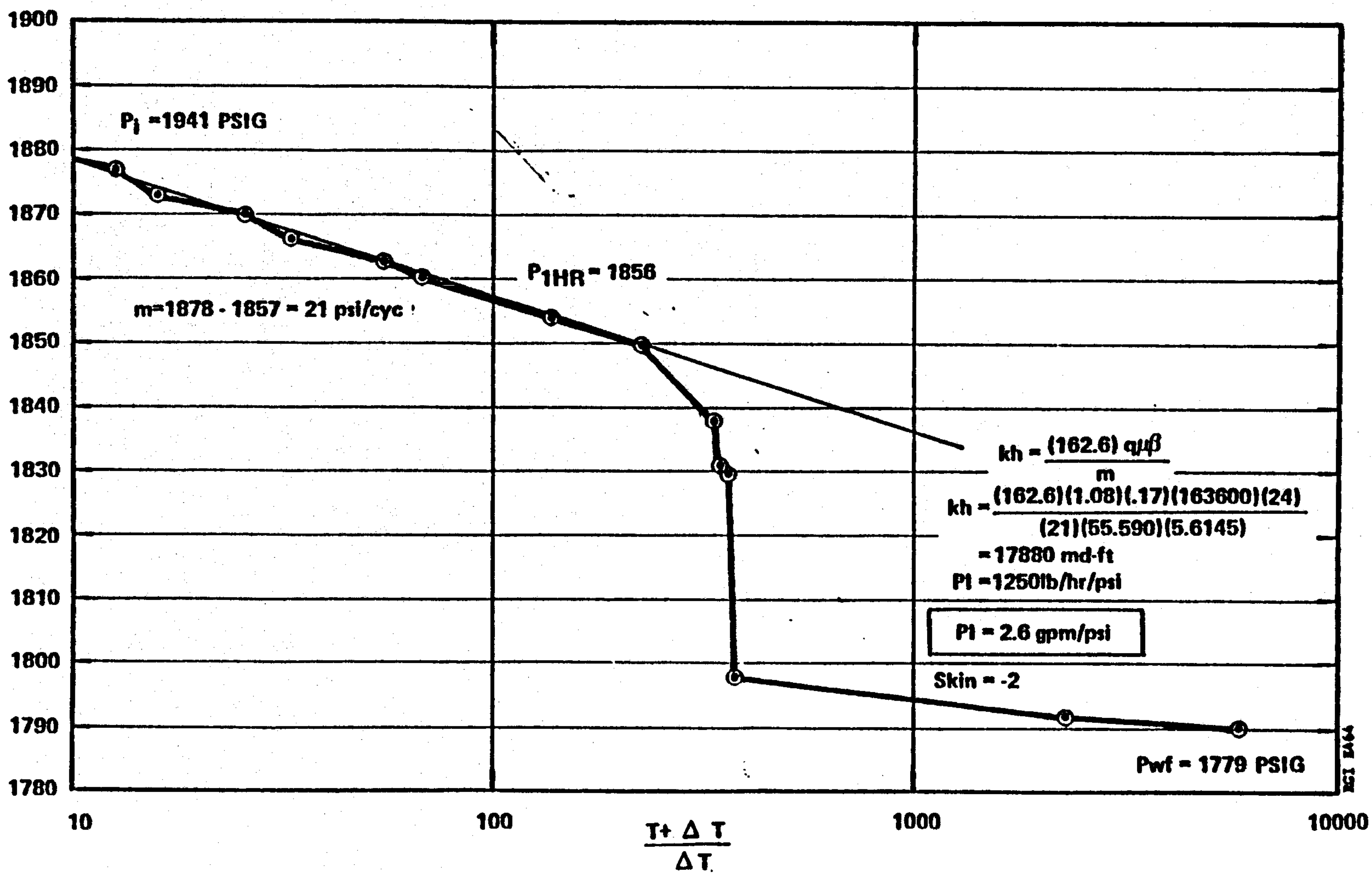


FIGURE 6
SPERRY EAST MESA WELL 87-6
FLOWING TEMPERATURE SURVEYS

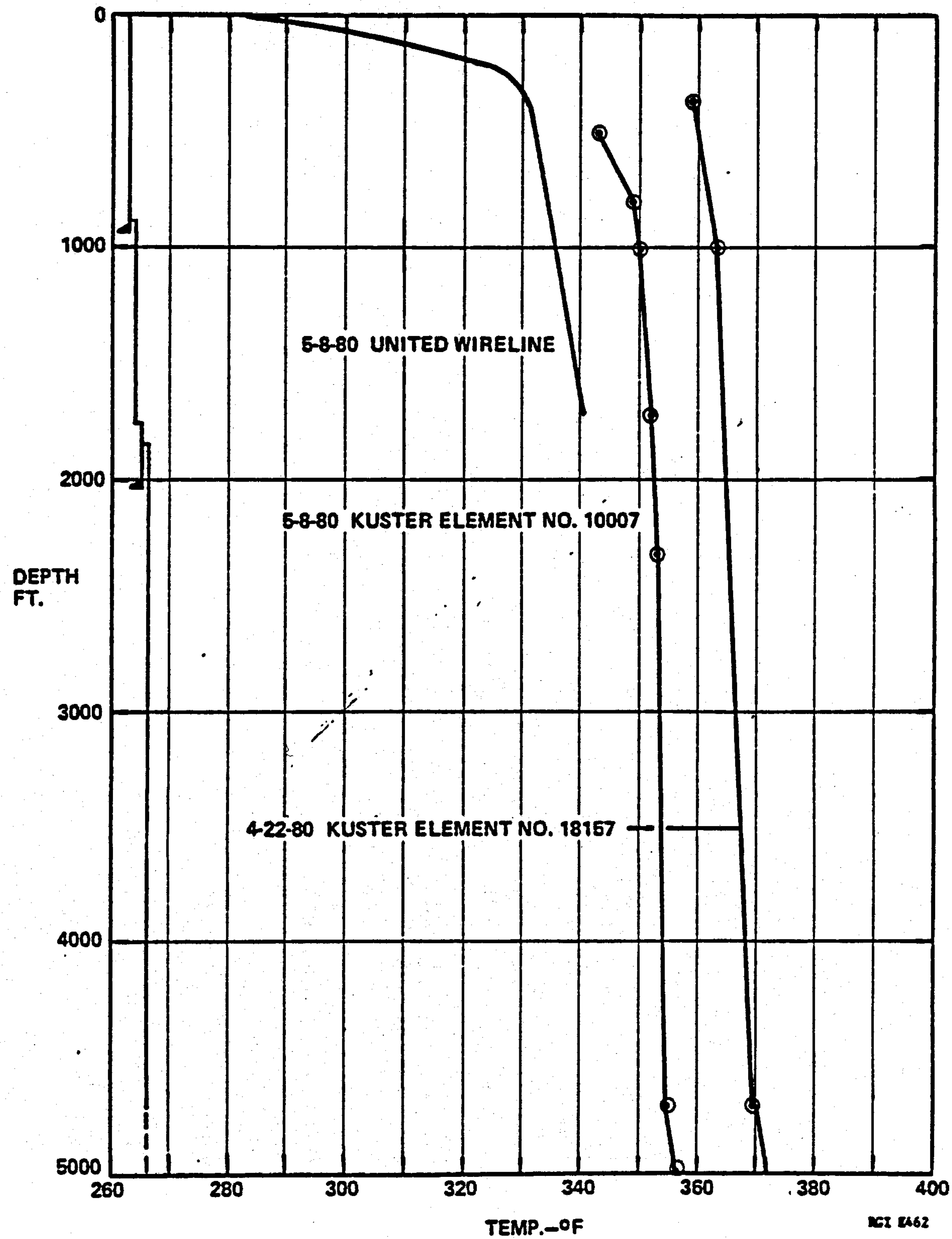


FIGURE 7
SPERRY EAST MESA WELL 87-6
INFLOW AND kh PROFILES

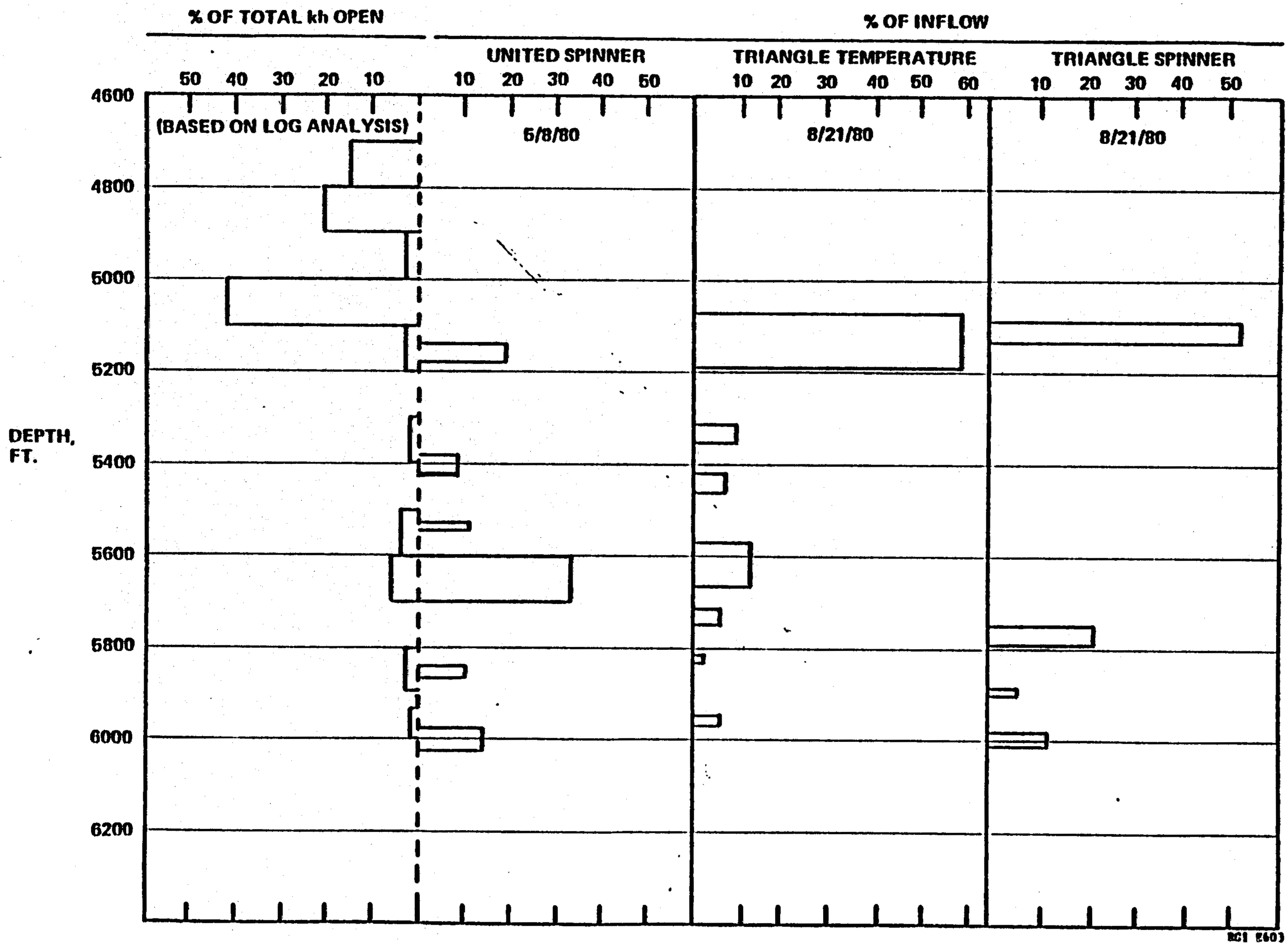


FIGURE 8
SPERRY EAST MESA WELL 87-6
STATIC PRESSURE AND TEMPERATURE SURVEY
8/13/80

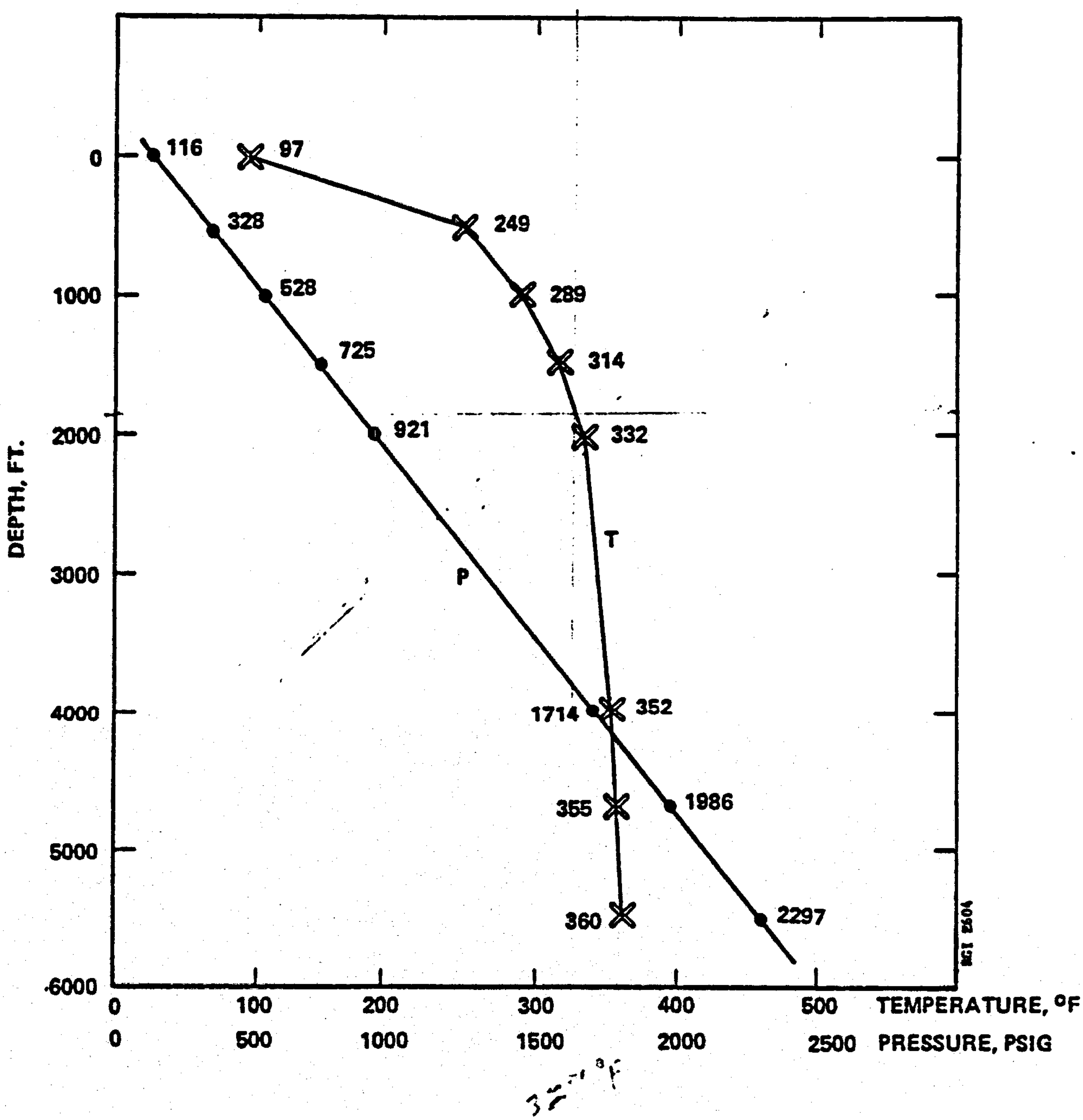


FIGURE 9
SPERRY EAST MESA WELL 87-6
PRESSURE BUILDUP DATA ANALYSIS
8/22/80 - 8/25/80

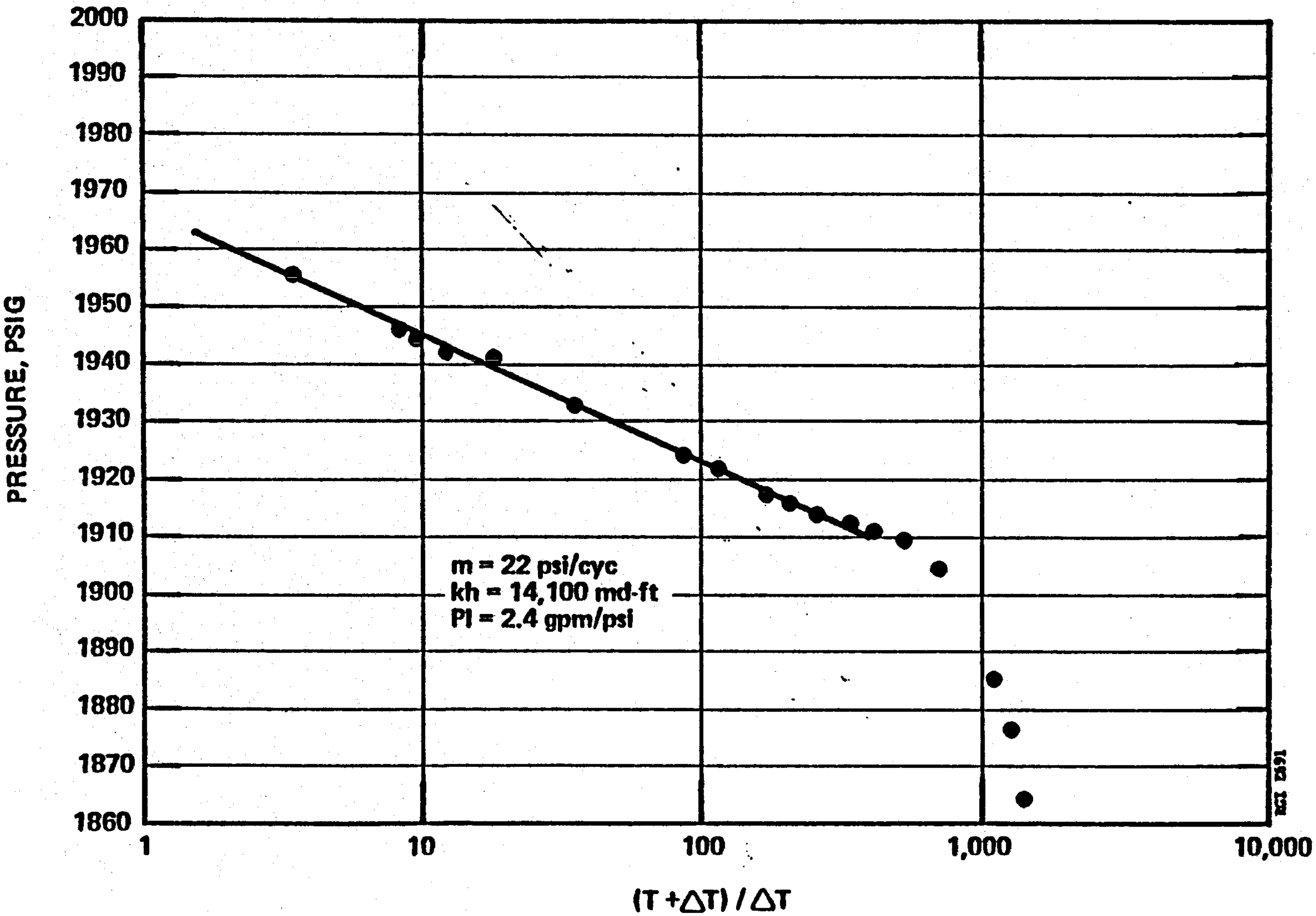


FIGURE 10
SPERRY EAST MESA WELL 87-6
LBL SPINNER SURVEY

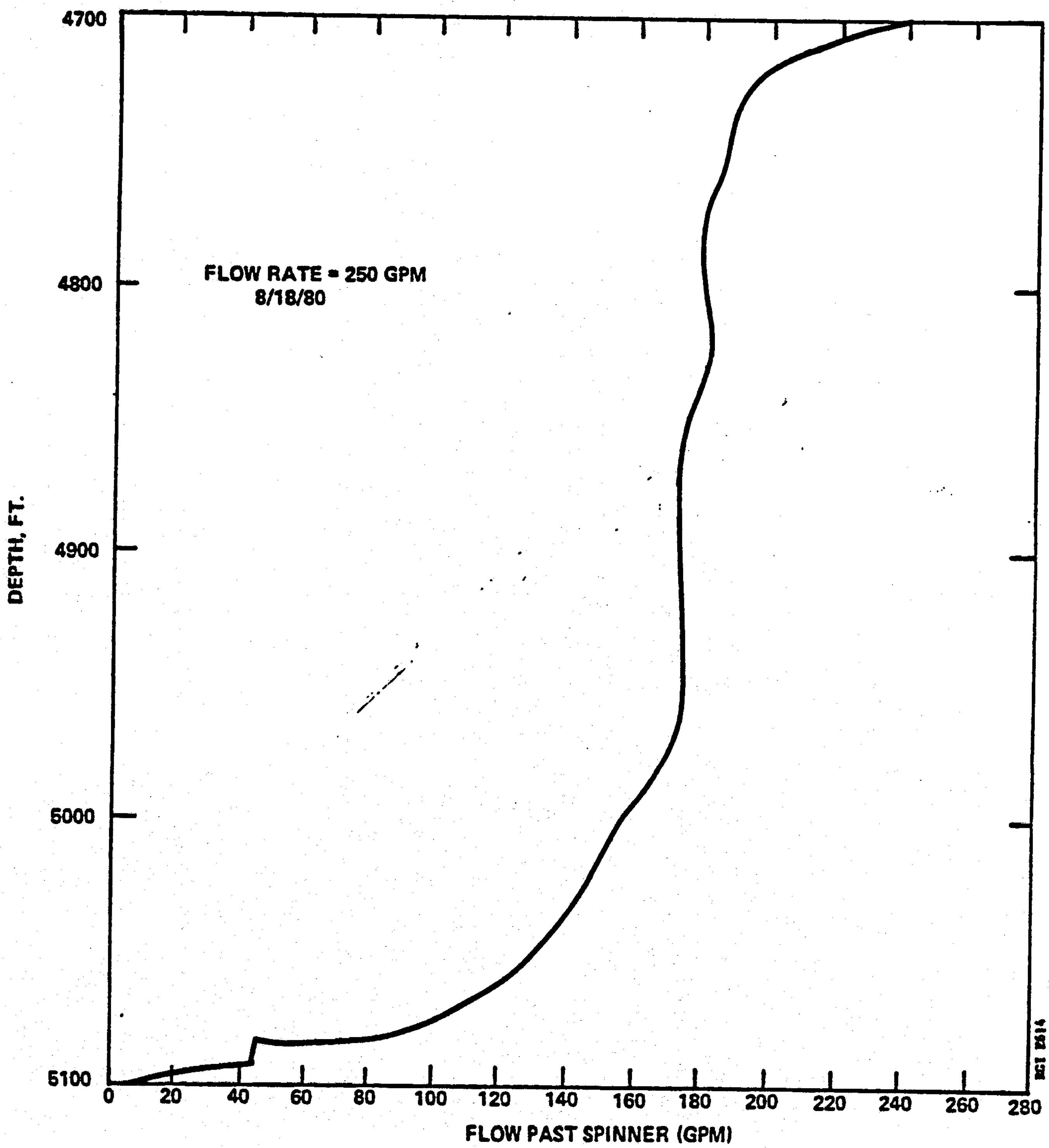
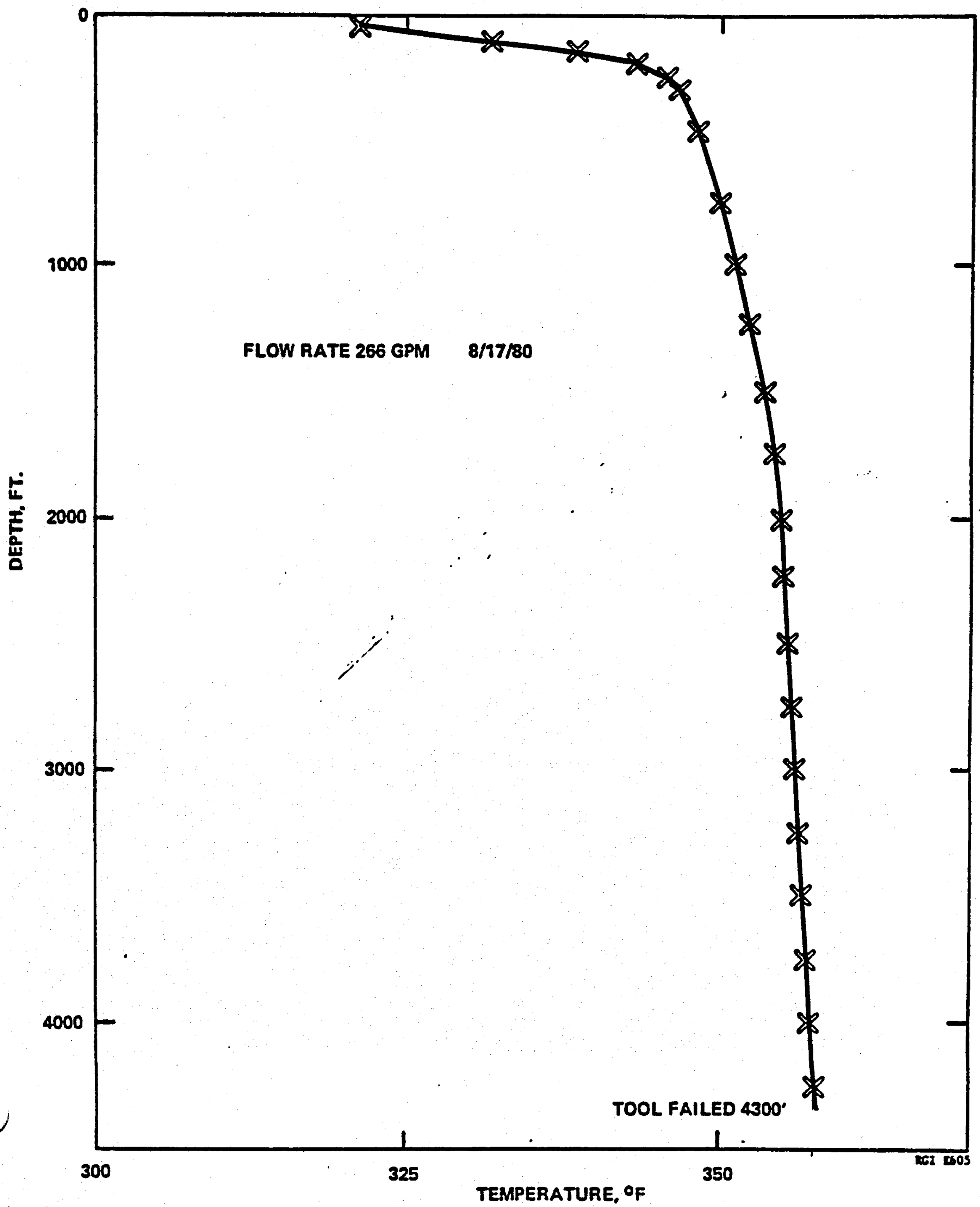


FIGURE 11
SPERRY EAST MESA WELL 87-6
LBL FLOWING TEMPERATURE SURVEY



APPENDIX A

REPUBLIC GEOTHERMAL, INC.
SPERRY #87-6

HISTORY OF DRILLING

(All measurements refer to K.B., #16' above ground level.)

Location: 1150'N. & 455'W. from SE corner of Sec. 6, T16S, R17E, S.B. B&M

Elevation: Ground, 48' V.S.S. K.B., 32' V.S.S.

DATE:	OPERATION
3/2/80	Spudded well @ 4:00 A.M. Drilled 17 1/2" hole to 1250'. Rigged up loggers. Ran DIL and dipmeter logs.
3/3/80	Opened 17 1/2" hole to 26" from surface to 1250'.
3/4/80-3/5/80	Opened 26" hole to 36" from surface to 1250'.
3/6/80	Conditioned mud. RIH w/30" casing. Casing stopped @ 935', would go no farther. Worked casing to 450 M lb., no movement. Hooked up circulating head. Circulated O.K. Spotted 120 bbl diesel pill. Pulled 450 M lb., pipe still stuck.
3/7/80	Cemented 30" casing @ 935' w/2488 $ft.^3$ slurry. WOC ± 18 hrs.
3/8/80-3/9/80	RIH w/17 1/2" bit. Cleaned out cement from 914'-935'. Drilled 17 1/2 hole from 1250' to 2550'.
3/10/80	Rigged up loggers. Logged hole from 2550' to 1250' (DIL/GR, FDC/CNL, & Dipmeter). RIH w/28 7/16" tapered mill. Milled on hanger receptacle @ 731' for 12 hrs. POH. Mill badly worn.
3/11/80	RIH w/22" hole opener. Opened 17 1/2" hole to 22" from 1250' to 2216'. POH. RIH w/26" bit. Cleaned out cement in 30" shoe joint.
3/12/80-3/13/80	RIH w/30" hole opener. Built 30" shoulder @ 1258'. POH. RIH w/redressed 28 7/16" mill. Milled out remainder of hanger receptable @ 731'. Cleaned out cement inside 30" casing to bottom of 30" casing.
3/14/80-3/15/80	Rig on standby pending arrival of 24" x 30" modified liner hanger.

3/16/80- 3/17/80	RIH w/30" under reamer. Opened hole to 30" from 1250' to 2230'. POH. RIH w/17 1/2" bit. Cleaned out 17 1/2" hole from 2230' to 2550'.
3/18/80	Picked up & RIH w/1644' of 24" x 13 3/8" liner. Liner stopped @ 2060'. Pulled on liner, no movement.
3/19/80- 3/23/80	RIH & stabbed into 13 3/8" float collar at 2018'. Circulated 7 hrs., O.K. POH. RIH w/24" section mill. Cut 24" liner @ 426' (10' below top of hanger). Fished 24" x 30" liner hanger. Jarred on casing for 6 hrs., no good. Cut 24" casing at 884'. RIH w/24" spear. Recovered 458' of 24" casing (bottom very ragged). Cut 24" casing @ 888'. RIH w/ 24" spear. Recovered 4' piece of 24" casing (clean cut).
3/24/80- 3/25/80	Circulated hole clean down to top of float collar @ 2018'. Picked up & RIH w/new 24" x 30" adapter. Installed adapter on top of 24" casing @ 888' - top of adapter @ 885'. RIH w/ 13 3/8" drillable retainer. Set retainer @ 2015'. Circulated & conditioned mud. Cemented 24" x 13 3/8" liner w/3838 ft.^{3} of slurry. Circulated out excess cement from top of liner.
3/26/80- 3/29/80	WOC $\pm$ 18 hrs. Ran 28 7/16" mill to 884'. Ran 22" hole opener to 1755'. Circulated hole clean. Nippled up wellhead & BOPE. Pressure tested casing, BOPE, & lap section, leak in 30" x 24" lap. Squeezed lap w/ 400 ft.^{3} cement, Retested, no good. Resqueezed lap w/200 ft.^{3} cement. Retested. Lap section, casing, & BOPE held 500 psi pressure for 30 minutes. Test O.K. RIH w/12 1/4" bit. Drilled out 13 3/8" retainer, float collar, and shoe.
3/30/80- 4/6/80	Drilled 12 1/4" hole from 2550' to 6290'. Survey @ 6200' = 2°.
4/7/80	Logged well from 6290' to 2550' (FDC/CNL, DIL, Sonic, and Dipmeter). RIH, conditioned mud for running casing.
4/8/80	Ran 4363' of 9 5/8", 43.5# N-80 liner to 6208'; hanger set @ 1845'. Cemented 9 5/8" liner through ports @ 4701' w/2131 ft.^{3} slurry. No circulation during cement job. WOC $\pm$ 18 Hrs.
4/9/80- 4/11/80	Ran cement bond log. Indicated top of cement @ 4400'. Set 13 3/8" retrievable packer @ 1769'. Squeezed 13 3/8" x 9 5/8" lap w/525 ft.^{3} cement. WOC. Pressure tested lap to 1000 psi, no good. Resqueezed lap w/200 ft.^{3} cement. WOC. Pressure tested lap, held 1000 psi from 30 min. O.K. Removed BOPE.

4/12/80	Cleaned out cement inside 30" casing w/28 7/16" mill from 782' to 884'. Cleaned out 24" casing to 1755' w/ 22" hole opener. Reinstalled BOPE. RIH w/8 1/2" BHA. Drilled out 9 5/8" float collar @ 4664, hard cement 4664' - 4701' & solid baffle @ 4701'.
4/13/80	Cleaned out siltstone fill inside 9 5/8" liner from 4701' to 6208'. Circulated hole clean. Changed over mud system to lease water.
4/14/80	Rigged surface facilities for flow test. Flowed well for clean up. Produced approximately 6000 bbls @ 15,000 B/D maximum flow rate.
4/15/80	SI well @ 2:00 A.M. Tagged fill w/sinker bar on wireline. Top of fill @ 6169' (39'). Suspended rig operations @ 3:00 P.M.
4/24/80	Released rig.

APPENDIX B

VOLATILE COMPONENTS OF GEOTHERMAL FLUID FROM WELL E.M. 87-6

General Results

Carbon dioxide, nitrogen, and methane comprise most of the non-aqueous volatile constituents. Samples were taken at four periods during the flow test of 15 to 22 August. Cumulative production at the times of sampling were from 9.8 to 17.7 million pounds. Results show a relatively uniform composition, compared to results for other wells. A summary of the concentration data is given in Table B-1. The earliest set of data, collected at 9.8 million pounds of cumulative flow, is statistically distinct from the others. The best estimates for subsequent concentrations are based on weighted averages of the last three data sets and are presented as a separate column on the right.

Results in Table B-1 are due to many kinds of samples taken from separated steam and brine. As reported, they refer to the geothermal fluid before flashing. All gas components tend to follow the steam phase if flashing is allowed.

Prior to flashing, these gases contribute to the vapor pressure of the geothermal fluid. The fluid will begin to develop a steam phase at a higher pressure than gas-free water would at the same temperature. Henry's Law describes this effect in terms of a pressure which is

TABLE B-1

VOLATILE COMPONENTS OF FLUID FROM WELL E.M. 87-6
PRE-FLASH BASIS -- PARTS PER MILLION BY WEIGHT

Date	18/Aug. a.m.	18/Aug. p.m.	20/Aug. a.m.	20/Aug. p.m.	Best Estimate
CO_2*	824±25	926±34	923±7.3	906±13	923±22
N_2	19.3	20.06	20.30	20.26	20.42
CH_4	12.2	12.45	13.96	12.81	13.20
Ar	.76	.84	.84	.74	.816
C_2H_6	.25	.27	.28	.26	.28
C_3H_8	.085	.094	.101	.075	.091
C_6H_6	.012	.012	N.D.	.012	.012
H_2	.0074	.0080	.0078	.0072	.0077
Millimoles NCG/kg of Produced Fluid*					
	20.21±.61	22.58±83	22.61±.80	22.15±.32	22.57±.53
Average Molecular Weight					
	42.38	42.50	42.39	42.44	42.44
Condensable Gases					
NH_3	5.4	6.4	6.4	6.1	6.3
H_2S*	N.5	0.78	0.85±.05	0.74±.03	0.79±.03
Number of Samples Used For Statistics					
CO_2	12	10	11	8	29
H_2S		1	3	3	7
Mmole/kg	12	10	11	8	29
Post-Flash Brine Concentration					
HCO_3	207	193	199	196	
CO_3	58	65	62	66	
Pre-Flash Fluid Concentration					
HCO_3	323	323	322	328	
Suspended Solids (ppm)					
	1.2	1.2	0.3±.2	0.2±.2	
Total Dissolved Solids					
Cum. Prod. lb x 10^{-6}					
	9.8	10.7	16.8	17.7	

* Mean volume ± 1-Sigma uncertainty of the mean

proportioned to the concentration of a gas species in the liquid. Solubility coefficients are available in the chemical literature. Table 2-B shows the pressures due to the most important gases, appropriate for a temperature of 50°F and salt content of 3,000 ppm. It shows that the noncondensable gases contribute nearly 70 psi to the vapor pressure and that a steam phase will begin to develop from this fluid at about 205 psia and 350°F. This constitutes a critical circumstance to be considered when selecting a setting depth for the pump and other engineering criteria.

Failure to maintain this pressure on the fluid risks partial flashing of the fluid and consequent deposition of $CaCO_3$ scale. This risk applies to places where cavitation is possible as well as specially turbulent places and flow lines.

Noncondensable gases H_2S and NH_3 (as NH_4+) were sampled from both steam and liquid. About 75% of the NH_3 and at least 80% of the H_2S followed the steam under the flashing conditions of the test.

Sampling Methods and Reduction of Data

Seven kinds of samples are required to fully characterize the geothermal gases. Coordination among them is required in both sampling and data interpretation. All the analytical data must be adjusted in making it apply to the pre-flash liquid.

TABLE B-2

VAPOR PRESSURE OF FLUID FROM
87-6 AT 350°F

Component	ppm	psi/1,000ppm	psi
CO_2	923	42	38.8
N_2	20.4	824	16.8
CH_4	13.2	844	11.4
Ar	.82	311	.3
	SUM		67.3
H_2O			134.6
	TOTAL VAPOR PRESSURE		201.9
			205 psia

CO_2

Carbon dioxide was determined by a field assay technique in which steam coming out of the separator is collected through a tubing inserted into the steam pipeline. The tubing leads through an ice-water bath which condenses the H_2O; the entire flow of condensate and noncondensable gas is collected into a syringe. After solubility equilibrium is established in the syringe at ice-water temperature, the pressure and gas/liquid volumes in the syringe are recorded as field data. One collection allows all the gas components to distribute between gas and liquid compartments of the syringe. A counterpart collection solubilizes all the CO_2 and H_2S into the liquid phase by using a spike of NaOH. The two sets of pressure and gas/liquid volumes permit one to calculate the weight/percent CO_2 in the steam phase and the mole/percent CO_2 in the suite of noncondensable gases. A single collection/analysis of this kind takes 5 to 10 minutes in the field and several collections can be got conveniently in order to develop a statistical reliability.

The CO_2 results obtained with just the above procedure apply to the steam phase, not to the pre-flash liquid. Three items must be accounted for in making the change in reference, namely ammonia, bicarbonate, and flash fraction. (Note that Table B-1 applies to the liquid before flashing.)

Ammonia in the steam solubilizes some of the CO_2, which increment then exists outside the calculational method developed for the syringe data. A separate analysis for NH_4 is made and the result used to make an adjustment proportional to the amount of NH_4 in the steam. This adjustment is done separately for each datum. The adjustments made in these cases were additions equivalent to about 1/90 of the raw CO_2 value.

The bicarbonate effect must be considered because a main point of interest is the (Henry's Law) vapor pressure in the fluid due to the CO_2; whereas not all of the CO_2 determined by analysis of flashed steam participates in the Henry's Law relation before flashing. Before flashing, $CO_3^{=}$ is near zero in concentration but during flashing it builds up due to reaction (1) which also generates an equal amount of CO_2 (g).

$$2HCO_3^- \qquad H_2O + CO_3^{=} + CO_2 \tag{1}$$

The CO_2 from (1) is collected with the Henry's Law CO_2 upon sampling the steam. Analysis for $CO_3^{=}$ in the residual brine yields data enabling one to adjust each CO_2 analytical datum. Among these data, the adjustment was a subtraction of about 6% of the raw CO_2 value.

The apparent concentration of CO_2 determined during the flow test results jointly from the amount of CO_2 released from the fluid and the amount of water vapor which dilutes it in the steam phase. The concentration there varies directly with the fraction of fluid which flashes to steam, if flashing exceeds about 2% of the liquid mass.

That actual fraction varies from day to day and even from moment to moment due to variations of several origins, the most important being the operational settings on the steam separator and their oscillations. Chart recordings of the steam and brine flow rates were used to obtain data needed to calculate the flash fraction relevant to each of the CO_2 field assays. The range during the sampling was 9.0 to 12.2 percent. The mathematical product of flash fraction times CO_2 in steam yields (nominally) the CO_2 content in pre-flash liquid.

Because the three adjustments involve different numerical bases, they must be done in the proper sequence, namely,

$$(\text{Raw } CO_2 - NH_3 \text{ adj}) (\text{flash fraction}) - CO_3 \text{ adj} = \text{Net } CO_2$$

Non-CO_2 Noncondensable Gases

Samples of CO_2-free noncondensable gases are available in the syringe from the collection which used NaOH to solubilize the CO_2 and H_2S. In these field assays, about 12 ml (STP) of gas were present in the syringe upon each collection. Three such collections were combined into one syringe, sealed and later analyzed by mass spectrometer in a laboratory. This kind of sample and treatment has several attributes. The absence of CO_2 makes the analytical method about ten times more sensitive for the non-CO_2 components, compared to samples which retain CO_2. The relationship between CO_2 and the non-CO_2 suite is accurately established from the syringe sampling, hence the mass spectrometer needs to yield data only on relative amounts among the non-CO_2 species. Detection of oxygen by the mass spectrometer signals an air contamination and yields data with which to make an adjustment.

Data in Table B-1 are based on one mass spectrometer result for each sampling period. The raw N_2, O_2, and Ar results were adjusted downward, assuming the O_2 originated from air, and the results recalculated to sum 100 mole/percent. The number of moles of non-CO_2 gases per unit weight of pre-flash liquid was based jointly on the result for ppm of CO_2 and the mole/percent non-CO_2 gases of the total noncondensable suite, as averaged for the sampling period. The resulting value for total number of moles of non-CO_2 gases was distributed according to the adjusted mass spectrometer data, and then converted to the ppm units reported in Table B-1.

Condensable Gases

H_2S is available in the liquid in a syringe from the field collection which used NaOH to solubilize the CO_2 and H_2S. Measured portions of these liquids were mixed with measured amounts of zinc acetate (preservative) solutions. They were subsequently analyzed in a laboratory using a standard (iodometric) method for H_2S.

The true concentration of H_2S in the steam is given by multiplying the analytical value by ratios based on the several volumes of fluids involved with the sampling/preserving.

Two samples of brine from the third sampling period were treated with zinc acetate preservative, similarly to the steam samples, and analyzed along with the others. The result was analytically zero (less than 0.1 ppm H_2S) which corresponds to less than 0.2 ppm in freshly flashed, but otherwise unaltered brine.

The concentration of H_2S in pre-flash brine is given as a weighted average concentration for steam and flashed brine. The detection limit of 0.2 ppm for H_2S concentration in flashed brine was used in this averaging. Concentrations in treated steam condensate were near 4 ppm. This is in the range of good analytical precision, as reflected by the concordance of values in Table B-1.

Ammonium samples were collected separately from the other gases, mainly because the preservative (H_2SO_4) is not compatible with the other techniques. A pair of samples, one from flashed brine and one from steam, are required since a substantial portion of the NH_4 remains with the brine upon flashing. The ammonium concentration in pre-flash fluid is given by a weighted average of the concentrations found in steam and (flashed) brine samples.

APPENDIX C

DISSOLVED SOLIDS

EAST MESA WELL 87-6

Samples of brine were collected through a probe inserted into the brine pipeline exiting the separator. The probe led to a stainless steel cooling coil that was chilled by cold water. Liquid samples of several types were collected in order to fully characterize the fluid. Anions and TDS were determined individually from a filtered sample which was otherwise untreated. Cations were determined in a sample which was made acid with HCl and analyzed by inductively coupled plasma (ICP) in order to scan for 40 elements. Silica is determined by the ICP and also, and more authoritatively, by a colormetric method applied to a specially collected sample. The silica sample as collected was immediately diluted with 1-1/2 volumes of distilled water in order to inhibit polymerization.

Since the concentrations of interest are for the fluid before flashing, the percent of flash at the time of sampling must be used in adjusting the reported data to a pre-flash basis. Concentrations of dissolved solids are given in Table C-1. The reported values reflect adjustments from the laboratory reports to account for dilutions due to preservative solutions and to flashing.

Calcium in the flashed brine is near zero because of losses as $CaCO_3$ scale upon flashing. The amount previously present can be estimated from the contents of CO_2 and HCO_3 combined with thermodynamic data from the chemical literature. This procedure yields 24 ppm Ca as the probable concentration before flashing. That amount can yield about 60 ppm of $CaCO_3$ scale which will deposit near and downflow from the place of first flashing.

Although carbonate ($CO_3^{=}$) is present in substantial amounts at the time of analysis before flashing, the carbon it represents is present as bicarbonate (HCO_3^-) which is the form reported in Table C-1.

The four sets of analyses are similar, and there are no serious complications in sampling, analysis, or interpretation. The column "Best Estimate" may be used as a reliable characterization of the fluid before flashing.

TABLE C-1

SPERRY EAST MESA WELL 87-6

DISSOLVED SOLIDS

Sampling Date	18 Aug. a.m.	18 Aug. p.m.	20 Aug. a.m.	20 Aug. p.m.	Best Estimate
	Concentrations (Parts per Million by Weight)				
Constitutents					
Cl	935	928	914	937	928
HCO_3	293	291	284	293	290
SO_4	180	177	183	175	179
F	4.77	4.84	4.40	6.61	5.2
B	2.98	3.01	2.94	2.98	2.98
Na	772	775	756		768
K	57	55.6	55.7		56.1
Li	2.4	2.3	2.4		2.4
Ca	.07	<.01	<.01		est. 24.
SiO_2 (ICP)	216	211	225		
SiO_2 (Color)			231	232	232
			231	232	
Dissolved Solids	2469	2448	2433		2450
TDS		2442			2450
% Flash	9.2	9.9	12.1	10.8	
Cummulative Prod. Millions of Pounds	9.8	10.7	16.8	17.7	

APPENDIX E

GEOTHERMAL WELLBORE TESTS

PERFORMED IN EAST MESA

SPERRY TEST WELL 87-6

GEOTHERMAL WELLBORE TESTS PERFORMED

IN EAST MESA SPERRY TEST WELL 87-6

By C. Gorenson

December 1980

This report covers part of the work performed under PO 4507010 for Lawrence Berkeley Laboratory by the Berkeley Group Incorporated.

Geothermal Wellbore Tests Performed on
East Mesa Sperry Test Well 87-6

Introduction

A series of production wellbore tests were performed on well 87-6 located in the East Mesa KGRA. This well was drilled under contract to the D.O.E. by Republic Drilling Company for Sperry Research Inc. Sperry plans to use this well for testing of a downhole gravity fed heat exchanger system developed for moderate temperature geothermal wells. The planned production well tests were to include production well temperature versus depth, production well spinner profile and a pressure buildup test. These tests would allow for calculations of net power output, wellbore integrity and long term fluid production characteristics.

Casing Design

Figure 1 illustrates the casing record of well 87-6. The upper casing sections of the well were drilled to accomodate the gravity fed heat exchanger and downhole well pump system. A slotted liner was inserted from 4700 ft. to total depth. A swage nipple was inserted for the transition from 24 in. ϕ to 13 3/8 in. ϕ. Wellbore tool insertion capabilities are greatly enhanced by this transition zone. A blank 9 5/8 in. ϕ casing was set between 1855′ and 4700 ft.

Wellbore Equipment

The spinner profile was obtained using a modified Kuster downhole flowmeter. The flowmeter was modified to be run on a single conductor wire line unit. A modified magnetic pickup is used. This pickup uses two magnets rotating on the shaft driven by the impeller. A reed switch is located near these magnets. The output from the magnetic pickup is twice the frequency of the impeller shaft. The magnet and reed switch are submersed in turbine oil.

This oil also serves to lubricate the bearings.

Temperature data was obtained using a standard Gearhart Owens temperature tool. Rated accuracy is ± 2°F.

Pressure data were obtained using a Bell and Howell CEC-1000-4 sputtered strain gauge transducer. An RTD is located near the pressure transducer for temperature correction. The pressure-temperature system is operated through a seven-conductor cable. A constant 10-volt excitation voltage is supplied at the transducer.

The surface electronics consist of an LSI-11/2 microprocessor, constant voltage supply, Hewlett-Packard scanner, and a Hewlett-Packard Digital Multimeter. An IEE-488 bus card is used by the LSI-11/2 for control operations and measurement of data. The microprocessor manipulates data from the pressure-temperature transducer to account for the temperature characteristics of the pressure transducer. Output from the computer consists of: excitation voltage (V); current (mA); resistance of the RTD (ohms) and source voltage (V). Output calculations are made for downhole pressure and temperature. Data are recorded on disk and printed out at any selected intervals greater than two seconds.

<u>Wellbore Tests</u>

A flowing production well temperature survey is shown in Figure 2. The well had been flowing for about three days at approximately 8600 BBLs/day (57 tons/hr), wellhead pressure was 67 psig (462 KPa), with a temperature of 310°F (154°C) at the wellhead. In the figure, the abrupt drop in temperature above 250 ft. in depth is indicative of flashing in the wellbore. Lower portions of the wellbore obtain a gradient of 1.4 F/Mft (2.55°C/km) which is characteristic of three nearby wells[1]. There is no indication of any casing failure zones or liner-lap leaks within the depth of the survey. The temperature tool failed* at 4300 feet. However, estimates of temperature based on the gradient obtained from the survey indicate an approximate temperature of 360°F (182°C) at 6000 ft (1829 m). This temperature is similar to downhole temperatures of wells in the vicinity of 87-6(1).

A casing spinner profile is shown in Figure 3 from ground level to 4700 ft. The spinner data are obtained by lowering the tool into the well and setting the tool at specified depths (usually 100 ft intervals). The tool has an accuracy of about ± 2 RPM and a minimum velocity of 0.25 ft/sec (40 RPM ≅ 40 gpm in a 9 5/8 in pipe). The lowering of the velocity with increasing depth in the upper 225 ft of the well is due to flashing. Due to the large size casing between 250 ft and 1855 ft the readings approach zero because the velocity of the fluid is below that which is necessary to spin the turbine blade. Another problem is caused by the large upper casing diameters. The tool was inserted into the well through a 3 in. schedule 120 lubricator. The largest centralizer available on site that would allow the tool to exit the lubricator was capable of expanding to only 9 inches. This would allow the tool to move horizontally in the flow stream between the casing walls in the larger casing sections. This could drastically lower the velocity readings.

The spinner profile, as in the temperature profile, illustrates a flash depth of about 225 ft. Due to the fact that the spinner tool disturbs the wellbore velocity profile (increases it locally) the accuracy of the flash depth is suspect. However, due to the large casing diameter in this well, the spinner occupies only about 1% of the flow area. This fact is offset due to the small centralizer expansion diameter, which would allow the flow tool to wander randomly between the casing walls. The well is vertical through this depth and an 80 lb. sinker bar was used. However, this amount of weight cannot insure that the flow tool will be centered in the velocity profile of the wellbore.

The flowmeter is actually a velocity measurement device. The data obtained from a turbine type spinner device is dependent on many factors including location in the flow stream, density and viscosity of the measured media[2], and single or multiphase fluid, etc. The data obtained from spinner devices should be analyzed carefully.

However, as mentioned above, the flow tool occupies only a small percentage of the horizontal wellbore area. The flash depth measurement in this well is probably accurate.

At 1855 feet the velocity increases rapidly up to its value in a 9 5/8 in ϕ pipe. Below 1855 feet the velocity drops to a lower value. This would indicate a constriction in the wellbore at this elevation. (Subsequent removal of the tool noted a constriction in the casing at this point.) The velocity immediately above the perforations was 240 RPM at 4700 ft.

Figure 4 is a plot of the open interval spinner profile. Forty gallons per minute (gpm) is the minimum measurable velocity in a 9 5/8 in. well ($\approx$.25 ft/s). With this information in mind, I chose to assume that the well produces about 20% of the fluid below the point where the spinner drops to zero (rather than assuming zero flow). This minimum flow is assumed below the 5100 foot zone in the Sperry Well. The right side of the figure illustrates the percentage flow versus depth (with the above assumptions in mind).

Flowing pressure data was obtained using a Bell and Howell CEC 1000-4 high temperature sputtered strain gauge transducer. The compensated temperature range of the transducer is 80°-400°F The surface electronics uses the downhole temperature measured by an RTD located near the pressure diaphragm for pressure corrections related to temperature changes. Compensation in pressure output for temperature changes at the pressure transducer are performed by the computer. The equation used for correction is shown in Figure 5. The terms used in the pressure correction equation are illustrated in this figure for clarity.

Figure 6 shows a graph of flowing pressure and temperature. Measured surface flowing pressure at the beginning of the pressure survey varied between 44-47 psig due to well surging. The pressure tool signal began varying rapidly while approaching the 5000 foot depth. The tool was removed from the well. Due to the short time available for downhole well testing, a Kuster pressure and temperature tool was inserted.

The problem in the pressure signal was isolated after removal of the tool from the well. The rubber boot that is utilized in making up the seven conductor cable head was the cause. This boot had been tested (due to lack of test facilities) at pressure and temperature separately. As it turned out, the boot becomes electrically conductive at high temperatures and pressure. The boot had been oven tested to 220°C at atmospheric pressure. However, as the pressure increased, the boot came in contact with the stripped conductors. This allowed current to flow freely through the boot into other conductors. This boot had not been used in other tests. The normal process is to use vacuum grease (max. temperature 500°F) in the LBL modified cable head systems to isolate the brine from the conductors.

Discussion

The large casing diameters noted in this well are unusual when compared to previously drilled wells in the area. The integrity of the wellbore casing is very good. The increase in spinner revolutions at 1855 feet is most likely due to a constriction in the wellbore at this point. A diameter of approximately 9 inches is calculated for the observed increase in spinner velocity. The cause of the constriction at this point is unknown. Further mechanical wellbore testing (caliper, impression block, etc.) should assist in outlining of the problem. However, this small change in casing diameter should not alter wellbore flow characteristics.

Extrapolation of the temperature gradient to surface yields a temperature of $\approx 355^{o}F$ at the wellhead during pumped conditions, with a setting depth of $\approx$ 1500 ft (neglecting non-condensable gas). This temperature has been realized at a nearby well under artesian flowing conditions.

The spinner profile shows that pressure transient testing in this well may be complicated by multiple layers. This is a factor of great importance in subsequent reservoir analysis procedures. The production of fluid from these specific zones encountered by the wellbore is also illustrated in nearby wells, and therefore, of no surprise.

The pressure-temperature flow tool developed at Lawrence Berkeley Laboratory for moderate temperature geothermal well testing offered no data used in determination of long term flow characteristics of the Sperry well. However, both the flow and temperature tools offered information on several other aspects associated with geothermal reservoir engineering. The problems encountered with the pressure tool have been located and resolved. Further utilization of this tool will assist in the evaluation of geothermal reservoirs and proper well workover evaluation.

Conclusions

The well was drilled to a large diameter, with only minor completion problems. Expected pumped well head temperatures should be on the order of 350°F. This temperature should be more than adequate for the expected use of the well and compares to existing wells in the area. (This temperature calculation ignores non-condensable gases.) The wellbore constriction is noted in the spinner data between 1840-1900 feet. However, this should not drastically affect well productivity. Linear velocity interpolation would indicate a restriction down to 9 in. in diameter. The multiple production zones encountered in this well are not unusual for geothermal wells in this locality. Large sedimentary zones combined with the long open intervals are the rule and not the exception in many geothermal areas. This multiple layer production zone characteristic can change as a function of surface flow rate. As the most productive zones drop in pressure, other zones may begin to flow. This is an interesting aspect, and further research should be performed to delineate reservoir testing procedures. Another important aspect relates to fluid injection in nearby surrounding wells. A layer 100 feet in height, with large permeability, will severely alter heat sweep characteristics of injection. Breakthrough calculations based on total wellbore open interval can be off by orders of magnitude if only a few thin zones accept fluid readily.

References

1) Geothermal Resource and Reservoir Investigations of U.S. Bureau of Reclamation Leaseholds at East Mesa, Imperial Valley, California, LBL-7094.

2) "Performance Characteristics of Turbine Flowmeters," Montgomery R. Shafer, NBS, Paper #61-WA-25, Journal of Basic Engineering Transaction of ASME.

Figure Captions

Figure 1. Casing Diagram of Sperry Well 87-6.

Figure 2. Flowing Wellbore Temperature Survey.

Figure 3. Spinner Profile through Casing. (Production Interval Begins at 4700 ft.)

Figure 4. Open Interval Spinner Profile.

Figure 5. Equation Used in Correcting Pressure Calculations for Temperature Changes.

Figure 6. Graph of Flowing Pressure and Temperature Distributions in the Wellbore.

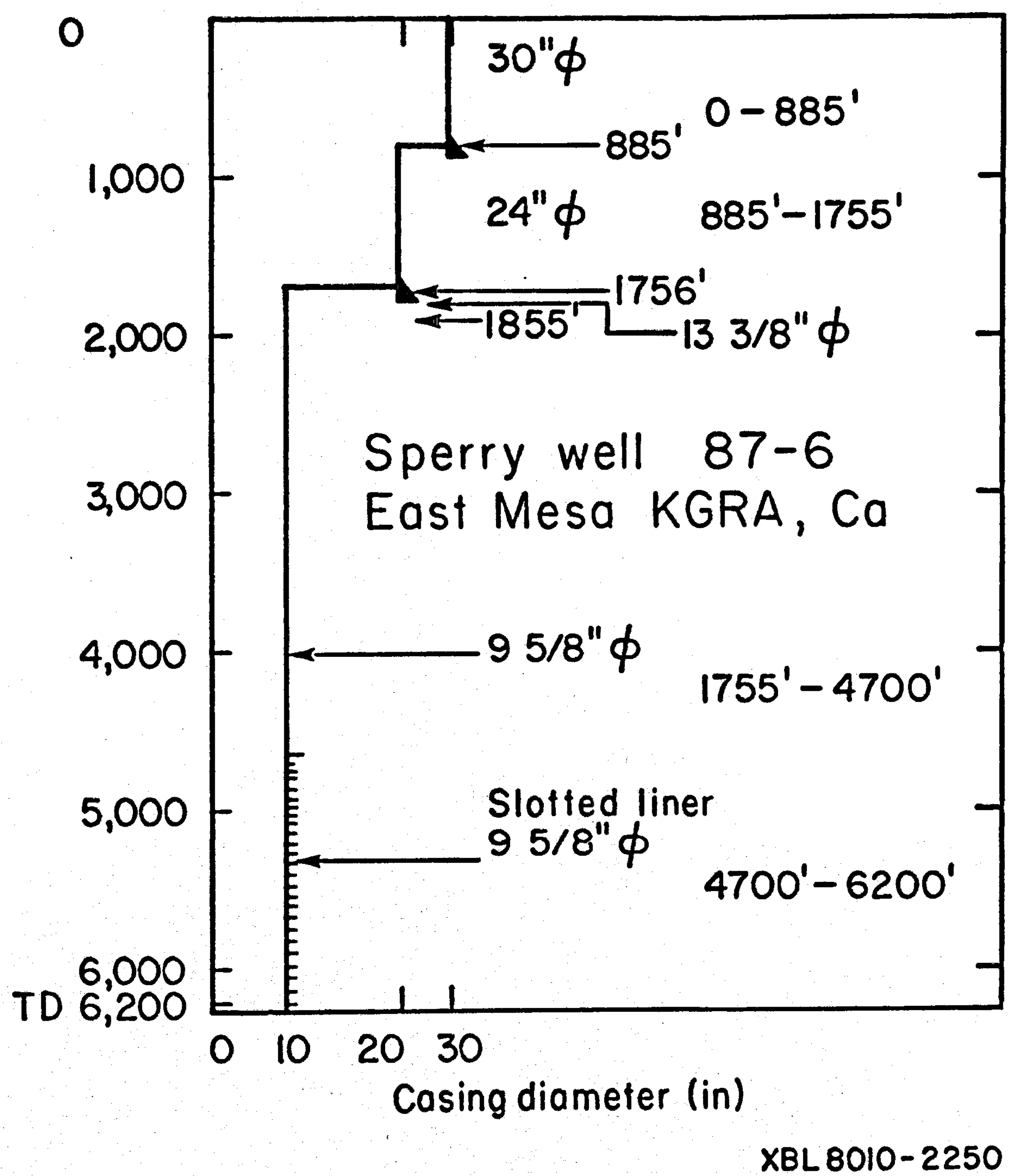


FIGURE 1: Casing Diagram of Sperry Well 87-6.

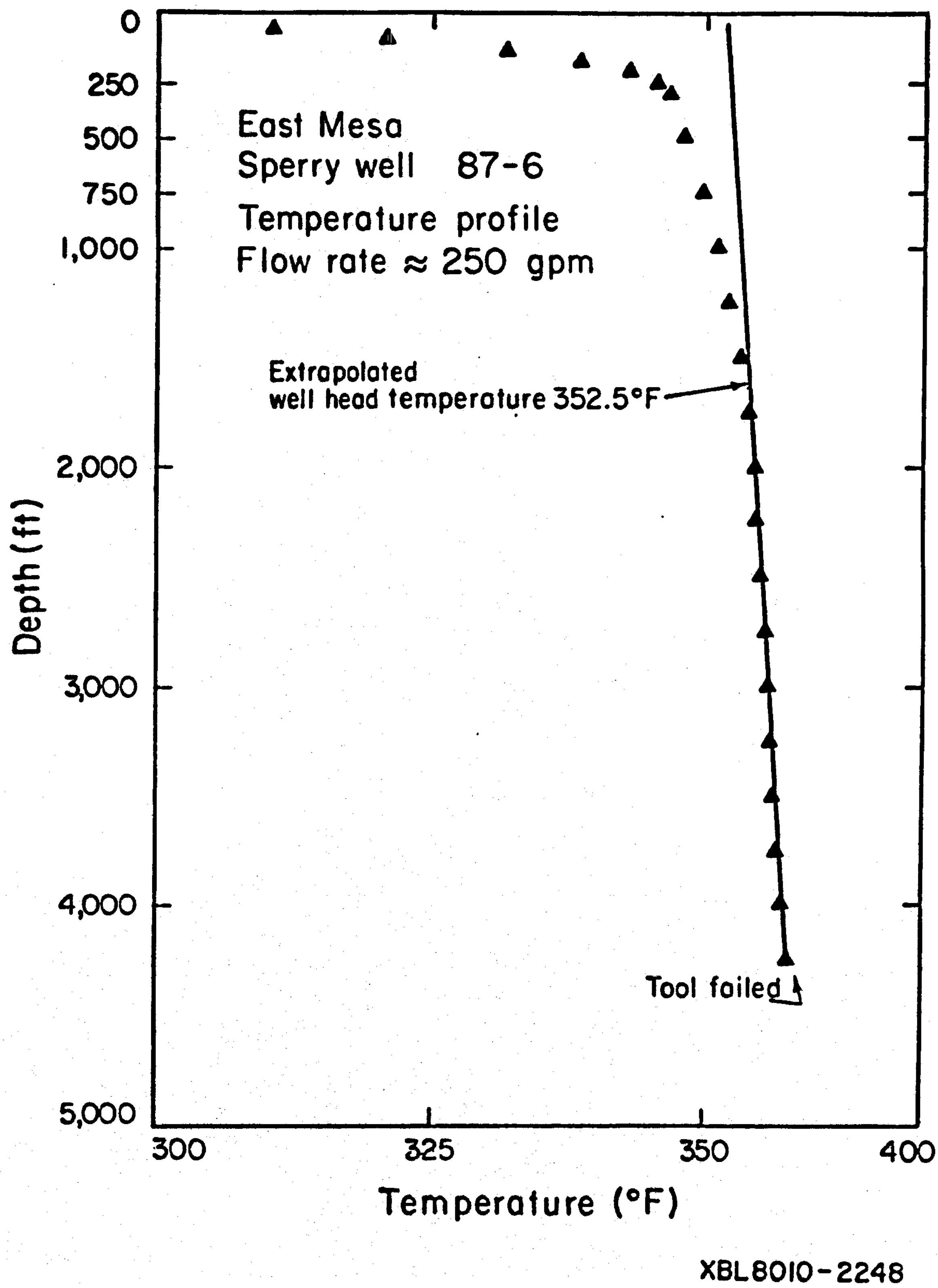


FIGURE 2: Flowing Wellbore Temperature Survey.

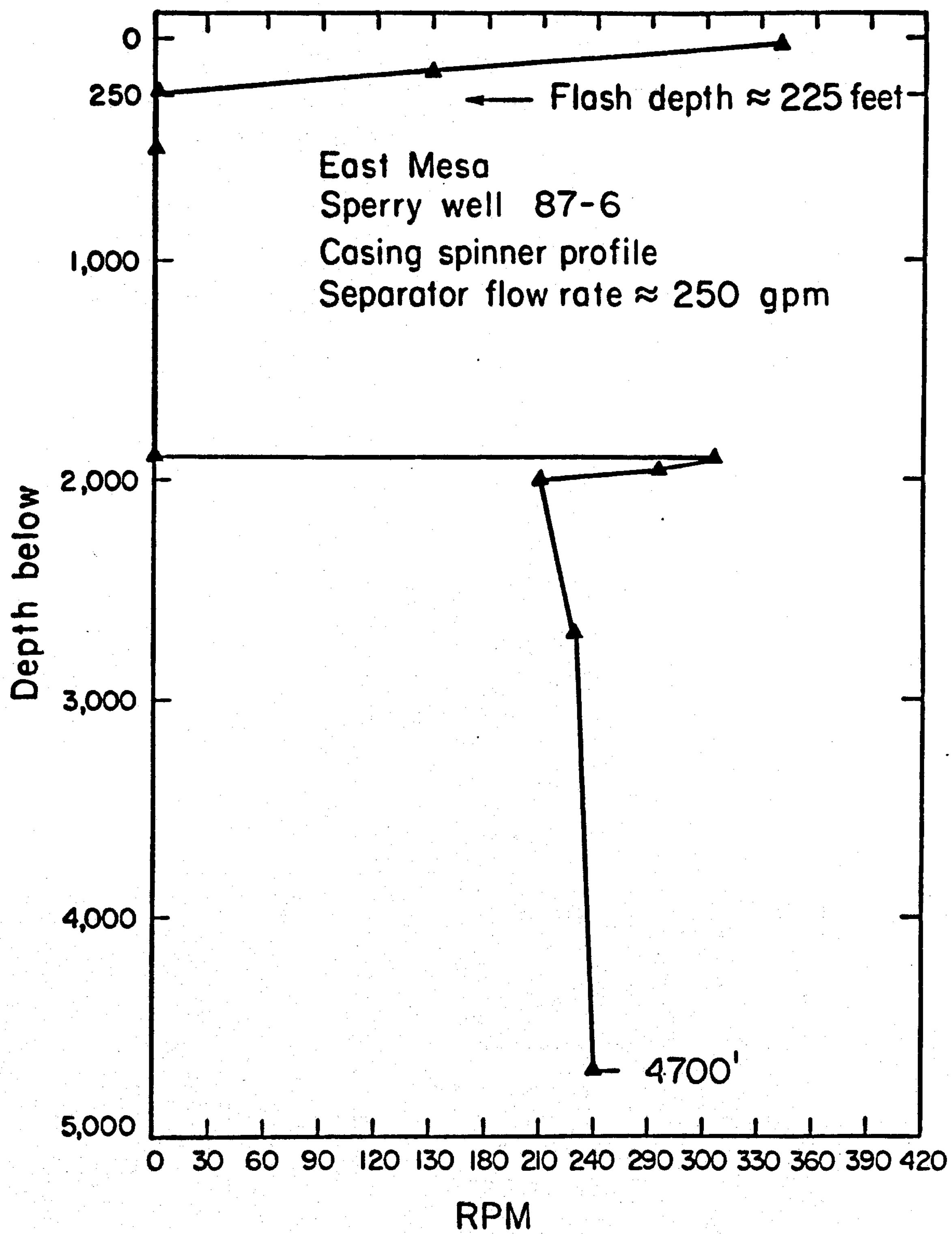


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FIGURE 3: Spinner Profile through Casing.
(Production Interval Begins at 4700 ft.)

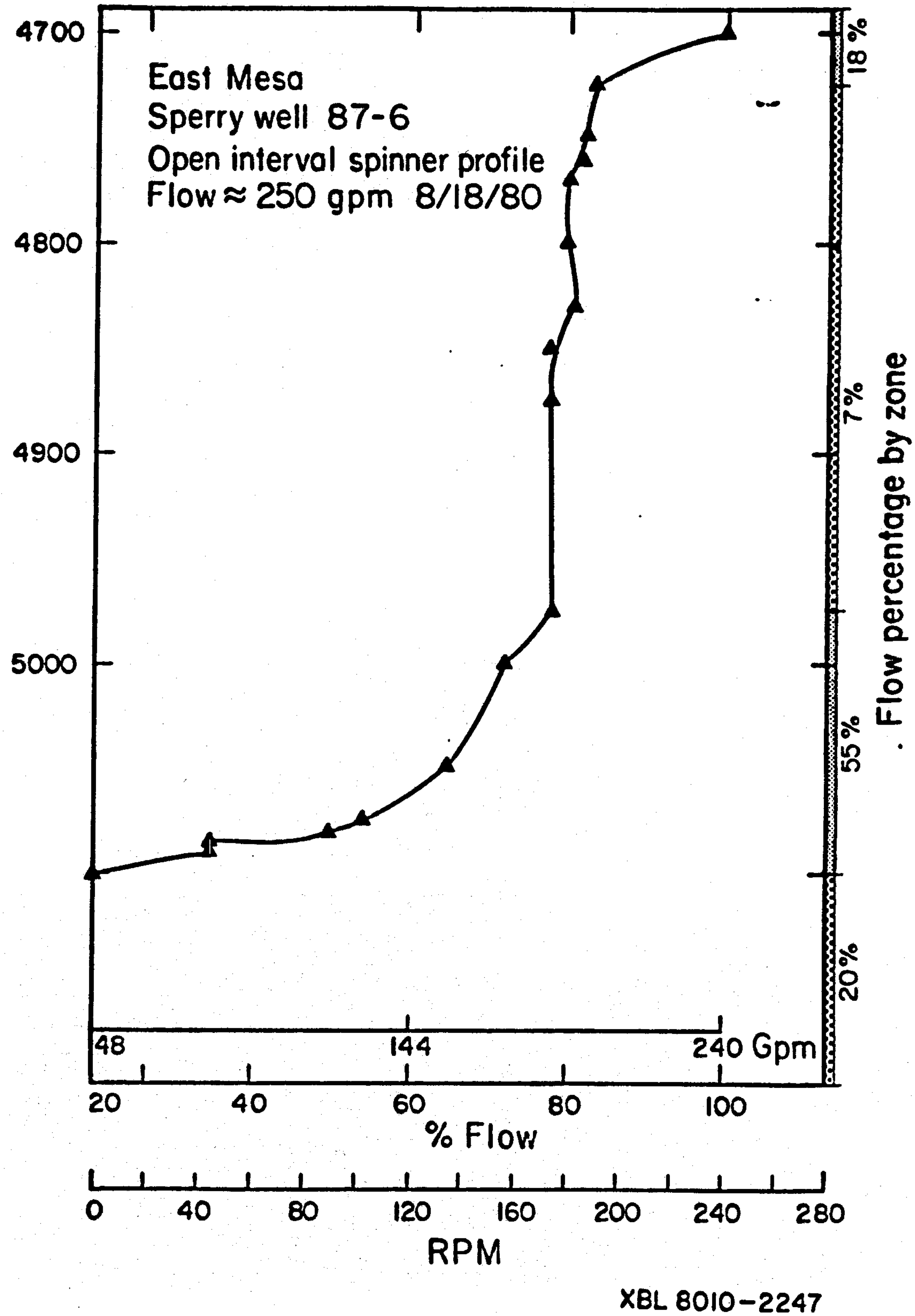

FIGURE 4: Open Interval Spinner Profile.

$$\text{PRESSURE} = \text{FSP} \times \frac{10}{\text{EP}} \times \frac{\text{PP}}{\text{FSMV} + \frac{\text{SENSV}}{100} \times \text{FSMV}\ (\text{T}-80°\text{F})} - \frac{\text{ZEROS}}{100} \times \text{FSP}\ (\text{T}-80°\text{F})$$

FSP	Pressure Range
PP	MV Signal Out
EP	Excitation Voltage
FSMV	Full Scale MV Output
SENSV	Full Scale Sensitivity Shift Per Degree F.
ZEROS	Zero Shift Per Degree F.

FIGURE 5: Equation Used in Correcting Pressure Calculations for Temperature Changes.

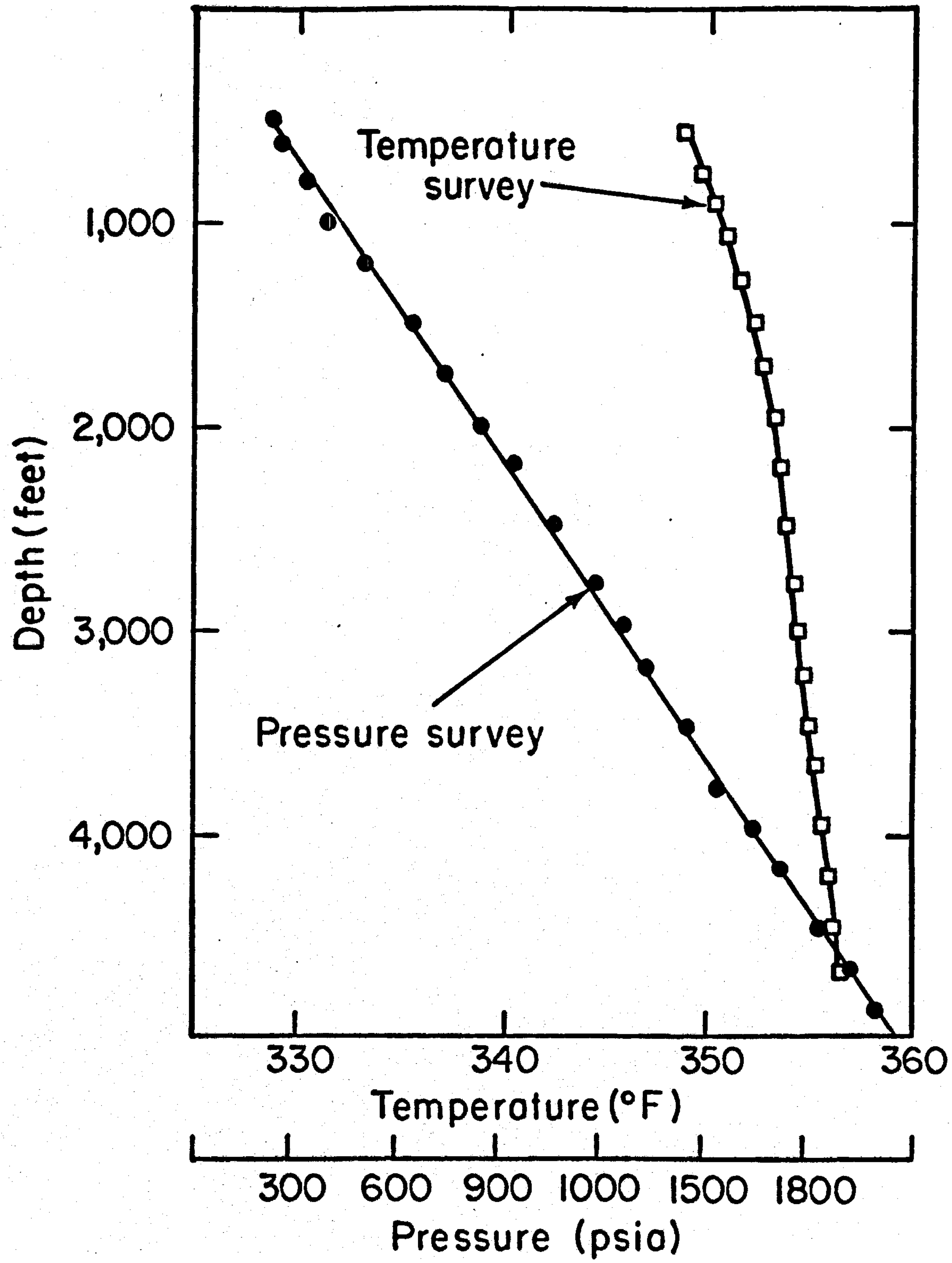

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FIGURE 6: Graph of Flowing Pressure and Temperature Distributions in the Wellbore.