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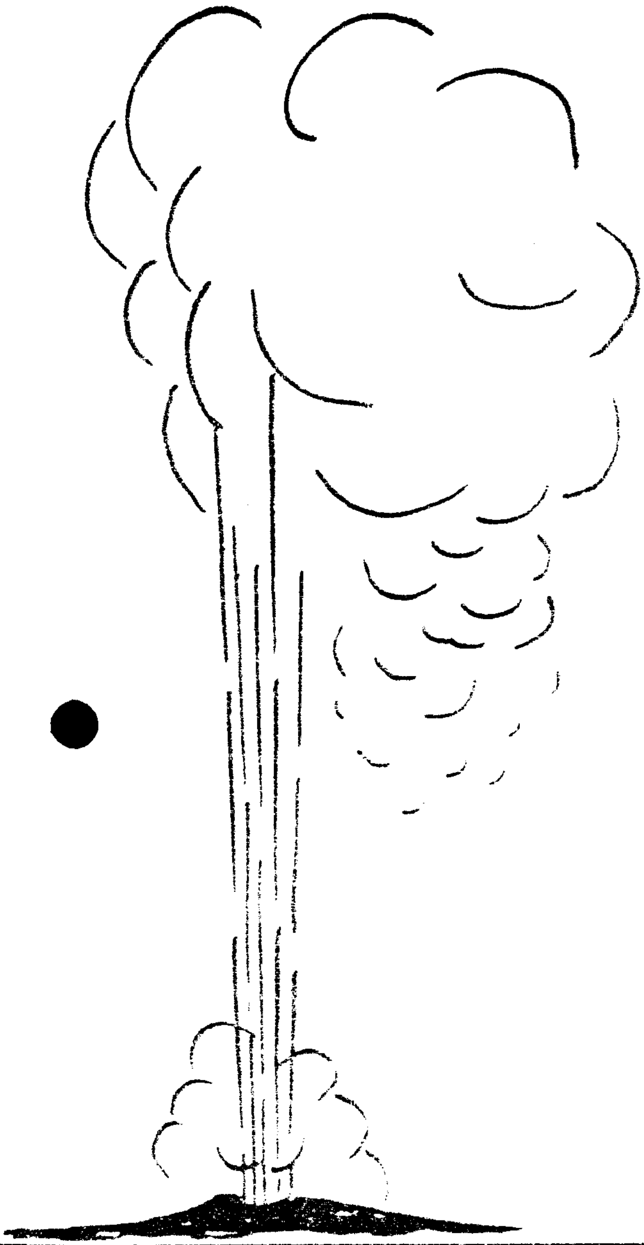

RAFT RIVER WELL STIMULATION EXPERIMENTS

Geothermal Reservoir Well Stimulation Program

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Republic Geothermal, Inc.
Santa Fe Springs, California

and

Maurer Engineering, Inc.
Houston, Texas

and

Vetter Research
Costa Mesa, California

U. S. DEPARTMENT OF ENERGY

Geothermal Energy

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SUMMARY

At the request of the U.S. Department of Energy/Division of Geothermal Energy, the Geothermal Reservoir Well Stimulation Program (GRWSP) performed two field experiments at the Raft River KGRA in 1979. Wells RRGP-4 and RRGP-5 were selected for the hydraulic fracture stimulation treatments. The well selection process, fracture treatment design, field execution, stimulation results, and pre- and post-job evaluations are presented herein.

The GRWSP is a DOE-funded program to develop stimulation techniques for geothermal producing wells. Republic Geothermal is the program manager; the active subcontractors are Vetter Research, Maurer Engineering, and Petroleum Training and Technical Services. The two-year program includes a review of the existing technology, laboratory studies, and six field experiments. The Raft River stimulation treatments were the first two field experiments in the program.

The Raft River KGRA is a low temperature hydrothermal resource of around 290°F. Wells RRGE-1 and RRGE-2 are the best producing wells in the field. These wells appear to intersect a natural fracture zone with high transmissibility, having a permeability-thickness (kh) of greater than 50 Darcy-feet. Wells RRGE-3, RRGP-4, and RRGP-5 are less productive and were all considered for stimulation. Wells RRGP-4 and RRGP-5 were chosen as the best two candidates. RRGE-3 was eliminated from further consideration because it is farther from the best producing wells and its mechanical configuration is very complex.

There are two major faults running through the field (Figure 1). The Narrows Fault lies along a line connecting Wells RRGE-1 and RRGE-2, and trends roughly east-west. Well RRGP-4 is approximately 1/2 mile south of RRGE-1 and the Narrows Fault. The Bridge Fault is on the west side of the field and trends northeast-southwest. Well RRGP-5 lies between the two faults, near their intersection.

Before stimulation, RRGP-4 was essentially non-productive. RRGP-5, however, was capable of flowing at a stabilized rate of 140 gpm and produced more than 600 gpm with a pump. This is adequate productivity, but the production came from the upper portion of the completion interval, and the produced fluid temperature of 255°F was undesirably low.

Based on the performance of the better wells in the field and the proximity of Wells RRGP-4 and RRGP-5 to the Bridge and Narrows Faults, it was considered likely that highly productive fractures existed near the wells. Hydraulic fracture treatments in the deeper intervals were chosen as the best means to connect the wells with major productive fractures and to achieve the desired produced fluid temperature of 270°F or greater. Although on the upper temperature margins of conventional oil field fracturing technology, no special techniques or materials were thought to be necessary for Raft River.

Before RRGP-4 could be stimulated effectively, a workover operation was required. The well was originally completed as a producing well with 9-5/8" casing to 3,408 feet. Leg A was directionally drilled to the north and found to be essentially non-productive. Leg B was then directionally drilled toward the west to a depth of 5,115 feet and was also non-productive. In preparation for the fracture treatment, a 7" liner was cemented in leg B leaving a 195-foot open-hole interval near the bottom of the well.

Following the recompletion, this interval was stimulated with a 7,900 bbl hydraulic fracture treatment. The technique employed was a four-stage dendritic fracture treatment. This technique is intended to generate a branched or dendritic fracture pattern. It was chosen because, if dendritic fracturing was achieved, it offered the best chance of intersecting major natural fractures. The main concern was that a single, planar fracture might only parallel and not intersect the principal natural fractures. The treatment was pumped at a high rate (50 bbl/min) and utilized a polymer gel frac fluid carrying a relatively low concentration of proppant. The treatment included 50,400 lbs of 100-mesh sand added for leak-off control and 58,000 lbs of 20-40 mesh sand proppant.

Following the treatment, the U.S. Geological Survey ran their high temperature acoustic borehole televiewer and observed that the created fracture extended the full 195-foot height of the open interval and was oriented approximately east-west, parallel to the Narrows Fault. In the post-stimulation flow test, the well produced at a stabilized rate of 60 gpm with a downhole fluid temperature of 270°F. This rate represented at least a five-fold increase over the pre-stimulation rate, but was still sub-commercial. The produced fluid temperature was significantly higher than past measurements, i.e., about 254°F before stimulation. This fact suggests that the new artificial fracture is producing fluid from a deep reservoir zone not open in the original hole. The chemical data further support this interpretation. The extent of polymer degradation determined chemically is consistent with fluid production from a higher temperature zone.

The pressure buildup data plotted as pressure vs the square root of time indicate that fracture flow effects lasted about six hours. The bottom-hole pressure reached initial reservoir pressure after about 15 hours. Conventional fracture type curve analysis (log-log plot) yields a fracture length of approximately 335 feet and a kh of 800 millidarcy-feet. The Horner plot of the same pressure buildup data has two straight line segments, one during early time (less than 15 hours) and one during later time (greater than 15 hours). These two segments give kh values of 1,070 millidarcy-feet and 85,000 millidarcy-feet, and suggest the presence of more than one permeability zone in the vicinity of the wellbore. Also, a negative skin factor (minus 6.0) indicates a stimulated zone close to the wellbore.

Well RRGP-5 was originally drilled to 4,911 feet and was plugged back with cement to 3,735 feet. The well was then completed with 9-5/8" casing to 3,408 feet and a second hole (leg B) was drilled to 4,925 feet. Leg B remained within a few feet of the original hole (leg A). The well had good productivity from the upper portion of the completion interval. The goal of the treatment for this well was a similar or higher productivity, but from a deeper, hotter interval. The well was recompleted similar to RRGP-4 in preparation for this stimulation treatment. The recompletion consisted of cementing 7" casing in leg B which excluded the existing producing interval and left a 216-foot open-hole interval near the bottom of the well.

A more conventional, large fracture treatment designed to create a single propped fracture was selected for RRGP-5. The treatment consisted of 7,620 bbl of a relatively low viscosity polymer gel with 84,000 lbs of 100-mesh sand for leak-off control and 347,000 lbs of 20-40 mesh sand proppant. Near the end of the treatment, the pumping rate was gradually reduced in an effort to sand the well out and leave the fracture well-propped near the wellbore. As the rate approached zero, the wellhead pressure dropped to zero psi indicating that communication with the reservoir had been achieved. Also, a significant pressure response was noted in RRGE-1. Following the treatment the USGS borehole televiewer showed that the created fracture spanned the upper 140 feet of the open interval. The fracture was oriented northeast-southwest, parallel to the Bridge Fault.

In the post-stimulation production test, the well stabilized very rapidly at a 200 gpm rate with a 30 psia wellhead pressure. The produced fluid temperature was unchanged from the pre-stimulation flow. Following the natural flow test, a pump was installed in the well and it produced more than 600 gpm. Chemical analysis of the produced fluid indicated a relatively low rate of polymer degradation, confirming that the frac fluid traveled upward into a cooler portion of the reservoir.

Pressure buildup and temperature data also suggest strongly that the fracture treatment went upward, perhaps through leg A to the original producing interval. A plot of the pressure buildup vs the square root of time indicates the fracture flow effect near the wellbore persists for only 38 seconds. This short linear flow period and the calculated fracture length are so small that essentially no single fracture flow exists. The Horner Plot of the pressure buildup data shows only a short transition phase between the fracture dominated period and the late time constant pressure period. Estimates of the late time formation kh were large—greater than 100 Darcy-feet. The Horner analysis indicates a very large positive skin factor. This skin factor is not due to formation damage but rather to the limited entry nature of the completion.

Both Wells RRGP-4 and RRGP-5 show a marked similarity in post-stimulation pressure response. It was possible to reproduce pressure transient data for both wells with essentially the same numerical simulation model. The model differed only in that RRGP-4 had a lower near-wellbore transmissivity. The single layer model consisted of a vertical fracture, relatively low transmissivity near the wellbore, and a constant pressure boundary (representative of communication with high transmissivity fractures). Although this is not a unique solution, it provides confirmation of the conventional pressure analysis results.

In summary, RRGP-4 and RRGP-5 were successfully recompleted and fracture treated, although the desired stimulation results were not achieved. Well RRGP-4 was stimulated from a PI of essentially 0 to 0.6 gpm per psi. Well RRGP-5 has a post-stimulation PI of 2.0 gpm per psi and no significant increase in productivity or temperature was achieved. The artificially created fracture probably intersected existing natural fractures near the wellbore and/or intersected leg A.

INTRODUCTION

The Geothermal Reservoir Well Stimulation Program (GRWSP) was initiated in February 1979 to promote industry interest in geothermal well stimulation work and to pursue technical areas directly related to geothermal well stimulation activities. Republic Geothermal, Inc. (RGI) and its principal subcontractors (Vetter Research and Maurer Engineering Inc.) formulated a development plan which would lead to the completion of six full-scale well stimulation experiments by March 1981.[1] In mid-1979 the proposed sequence of field tests was altered at the request of the U.S. Department of Energy, Division of Geothermal Energy (DOE/DGE) to include two field experiments at the Raft River KGRA. The Raft River reservoir was not considered to be the best candidate for the first field experiments for several technical reasons outlined in the GRWSP report "Proposal for Producing Well Hydraulic Fracture Stimulation - Raft River Field" of June 1979 and repeated herein. However, the Raft River project was of great importance to DOE/DGE and the geothermal industry. Therefore, well sites RRGP-4 and RRGP-5 were selected for the first two stimulation experiments. The primary factors related to the selection of these two wells and their treatments are discussed below.

The GRWSP investigation, which included the study of the reservoir data, the mechanical condition of the wells, and the production needs of the project, indicated that stimulation of the Raft River wells would have high technical and mechanical risks. The reservoir produced primarily through a complex fractured porosity system which was not totally defined nor understood. The degree of success for hydraulic fracture stimulation of this type of reservoir is very difficult to predict because the shape, size, and orientation of the artificial fracture cannot be controlled as well as in sedimentary formations.

The wells at Raft River were all open-hole completions with several having "legs" or "sidetracks" through the producing interval(s). The legs or multiple hole completions were all open to flow. This situation, along with a characteristically high degree of wellbore roughness, increased the mechanical risk because of the difficulty in achieving zonal isolation in the producing interval during the hydraulic fracturing operation. Under these conditions, it is possible to "damage" a well, either by reducing its temperature or its production rate, by any stimulation method.

The minimum production needs for the Raft River project could barely be met with the present wells. The loss of production from a current producing well would jeopardize the project electric and/or non-electric activities. Thus, there was strong motivation to select a low volume producing well for the initial test.

A disadvantage to the selection of a Raft River well was that stimulation of this low temperature reservoir (<300°F) would not make a significant contribution to improvement of the technical capability for stimulation of a wide range of geothermal wells. Oil and gas wells with higher bottom-hole temperatures have been successfully hydraulically fractured; however, even at Raft River temperatures, considerable work had to be done to arrive at fluid compositions which could do the job both technically and economically. Of particular interest were fluid evaluation and tracer test methods to be utilized for an over-all evaluation of the fracture stimulation job.

On the other hand, there were some distinct advantages to the geothermal well stimulation program in doing the first job at Raft River. First, there were no contractual problems with the operator concerning well liability. This was because both the Raft River project and GRWSP are under the jurisdiction of the U.S. Department of Energy. Second, a naturally fractured, hard rock reservoir such as Raft River is commonly encountered in geothermal development but has seldom been dealt with in petroleum operations. Thus, demonstration of successful stimulation technology in a fractured reservoir at Raft River was important to the geothermal industry.

The last major advantage of starting at Raft River was the existence of a deep well which was essentially non-productive but located within the postulated resource boundaries. This meant that production capability for this well did exist if the productive reservoir zones could be connected to the wellbore. Also, if there were problems, mechanical or technical, due to the stimulation effort, the Raft River project would not be jeopardized. Successful stimulation of this well would lower the risk of stimulating a currently adequate, producing well to enhance its production capability.

RESOURCE REVIEW

Considerable regional geology work has been done in the Raft River area by the USGS and others. It is pertinent that a brief review of the geology be included here to provide background for the discussion of the hydraulic fracture stimulation treatments. Also, the available reservoir data has been briefly reviewed below. Details may be found in the many reports from the Raft River field operator (EG&G) and the USGS.

Geology

The Raft River KGRA is located on a north trending valley which is bounded on the west by the Jim Sage and Cotterel Mountains, on the south by the Raft River Mountain range, and on the east by Black Pine and Sublett Mountain ranges. The valley, a graben, formed by down-faulting in late Tertiary times, has been filled with Tertiary and Pleistocene sediments to depths of about 5,900 feet.[2] The Jim Sage and Cotterel Mountains on the west are composed of Tertiary volcanic rocks and sediments, while the Black Pine and Sublett ranges on the east are mainly composed of Paleozoic sediments. To the south, the Raft River Mountains expose Precambrian adamellite (quartz monzonite) capped by Paleozoic sediments.[2] Two geothermal wells, RRGE-1 and RRGE-2, terminate in the adamellites, indicating that the Precambrian rocks of the Raft River Mountains form the floor of the Raft River basin.

The bulk of the sediments filling the basin belong to the Salt Lake formation of Mio-Pliocene age.[2] The Salt Lake formation comprises tuffaceous sandstone, siltstone, and conglomerate. At the bottom, the Salt Lake formation is separated from the adamellite basement by Paleozoic metamorphic rocks comprising quartzites and schists. The Salt Lake formation is overlain by Pleistocene sand, gravel, silt, and clay (Raft River formation). The Raft River formation is in turn overlain by alluvial and pluvial sediments.

The most important structural element in the vicinity of Wells RRGE-1 and RRGE-2 is the Bridge Fault, which appears to outcrop west of RRGE-1 and trends north-south and dips steeply east. RRGE-1 apparently intercepted the Bridge Fault at about 4,200 feet. Well RRGE-2 failed to indicate the presence of any pronounced fault zone. A generalized correlation section showing the relative structural relationships between all the wellbores is shown in Figure 2.

The Raft River KGRA is apparently an example of a geothermal reservoir created by near-surface geological conditions which focused fluid flow to a localized hot spot. The reservoir model for the Raft River system is, thus, a sediment-filled basin with a boundary fault and associated fractures retaining and conducting the hot fluid.[3] The fluid productivity of the reservoir is thought to be the result of fracture porosity in fault zones, such as the intersection of the Narrows and Bridge Fault zones, or from porous and permeable formations intersected by the fault zone. The interstitial rock matrix porosity and the fracture flow paths are thought to show alterations resulting from the circulation of thermal fluids.[4]

Reservoir Data

Tables 1 and 2 summarize the reservoir data obtained at Raft River from the seven deep exploration wells (RRGE-1, RRGE-2, RRGE-3, RRGP-4, RRGP-5, RRGI-6, and RRGI-7) completed since 1975. Petrophysical logs and pressure and temperature surveys are available for these wells. In addition, the USGS obtained acoustic televiewer and production logs of the wells considered for stimulation experiments. These surveys, discussed in Appendix A, provide an indication of the fluid entry zones and presence of fractures at the wellbore. It should be remembered that all the Raft River wells are open-hole completions. Cores have been taken in all seven wells at varying depth intervals; however, a complete petrophysical and physical property correlation is not available.

All seven exploration wells have been flow tested under various conditions to determine their production or injection potential.[7] These tests have included artesian flow and pumped flow tests. However, many of these production tests were too short in duration to quantify accurately the bulk reservoir parameters. Transient pressure testing of a reservoir which is dominated by heterogeneous fracture flow requires relatively long production tests to reach a semi-steady state flow condition in the reservoir. The permeability-thickness values which have been determined from production tests range from over 100 Darcy-feet to 6.7 Darcy-feet in Wells RRGE-1 and RRGE-3, respectively.[7]

A general evaluation of the Raft River wells indicates that the location of the fluid production intervals and the production capacity are dependent on the intersection of natural fractures in the wellbore. Several wells had been completed with multiple legs in an effort to increase production. Interference pressure tests have shown the reservoir to be heterogeneous with possible no-flow barriers located near the wells RRGE-1 and RRGE-2.[6] Other flow tests performed to date have not established communication between all of the existing wells. In addition, there appear to be several different aquifer zones within the hydrothermal system as indicated by the differences in the dissolved solids found in the waters. The upper aquifer has a higher total dissolved solids content than the aquifer in which the production wells are completed. At this time a viable geologic/reservoir model for this complex hydrothermal system has not been developed.

WELL SELECTION

Selection criteria for the well(s) stimulated included both the reservoir (production) considerations and the mechanical condition of the wells. Both criteria for Raft River are discussed below.

Reservoir Considerations

There are currently five deep production wells at Raft River: RRGE-1, RRGE-2, RRGE-3, RRGP-4, and RRGP-5. (The DOE/DGE geothermal well stimulation program specifically excludes the stimulation of injection wells.) All of the above wells were considered as possible stimulation candidates; however, utilizing normal hydraulic fracture criteria, the Raft River geothermal wells did not offer a high probability for a successful stimulation experiment. Fracturing a hard rock matrix is more difficult because of the high pressures required to overcome the in-situ stresses and the high fracturing fluid loss as the induced fractures intersect the natural fractures. The production problems associated with a well such as RRGP-4 appear to result from the lack of natural reservoir fractures connected to the wellbore. If the hydraulically created fracture parallels the existing natural fracture plane, the well may not produce any additional fluid. The five production wells at Raft River are spread over an area of about six square miles; therefore, the proven production wells are not in close proximity.

In general, the Raft River reservoir has not been regionally defined. The reservoir boundaries are not known although flow tests in RRGE-1 and RRGE-2 suggest that a flow barrier may exist near these wells. Well productivity is apparently dominated by heterogenous flow in the natural rock fractures and the short-term flow tests performed to date have not established communication between all of the existing production wells. The geochemistry of the produced brine indicated the possibility of more than one aquifer present within the reservoir area.

It was, therefore, extremely difficult to predict the outcome of a stimulation treatment based on the existing reservoir data.

RRGE-1 and RRGE-2 are the principal production wells in the Raft River KGRA. It is planned that these wells will provide most of the fluid for the power plant and non-electric experiments. They appear to intersect a natural fracture zone with high transmissibility (a kh greater than 50 Darcy-feet) and have shown good communication with each other. Under these conditions, a successful stimulation job would not be expected to substantially increase the production capacity of these wells.

RRGE-1 and RRGE-2 are better production wells than RRGE-3 (see Table 1). RRGE-3 was completed with three legs through the production interval to intersect more natural fractures and thus increase well productivity. These three legs reduced the probability of a successful stimulation treatment as a hydraulic fracture could easily propagate into any one of the existing legs of the well and not extend into the formation.

Well RRGP-4 was a non-commercial well, i.e., the flow tests indicated that the well could not sustain production. This well had two legs completed in the production interval, but leg A was filled with cuttings and/or was bridged. Fractures have been identified in the wellbore, but they do not appear to be connected with major natural fractures in the reservoir. This well did not offer any better chance for a successful stimulation treatment than the previous wells in terms of rock properties; however, the fact that this well was non-commercial allowed the use of several techniques which would improve the chances of stimulation success at a slight increase in risk to the well.

RRGP-5 also appeared to have potential for a well stimulation treatment. Although this well has two legs, the first leg was damaged during the drilling operation by cement pumped into the wellbore and near-wellbore natural fractures. The cement damage may have reduced the flow capacity of the well substantially since the second leg is very near the first leg. It was thought that production could be improved by hydraulically fracturing through the damaged zone and re-establishing communication with the natural reservoir fractures. If a lower zone could be stimulated, it was also thought that the produced fluid temperature could be increased.

Mechanical Considerations

In addition to the reservoir considerations, the mechanical condition of the wells was an important factor in selecting the Raft River well(s) for stimulation. Generally, the Raft River wells were not mechanically suitable for stimulation activities in their completed condition. This included not only hydraulic fracturing work, but also any other type of stimulation requiring zonal isolation for proper placement of stimulation materials.

The wells were completed open-hole and the integrity of the wellbore wall in the zones of interest (the producing zones) was very poor. This was evident from the caliper logs run with the electric logs just after completion of drilling. The wells appear to be to gauge in the hard schist and quartz monzonite sections. However, none of the major productive zones above these sections are to gauge. The original caliper logs have been verified with the borehole acoustic televiewer logs which further indicate large, irregular boreholes with many fractures. Because of the large and apparently irregular, fractured borehole, the probability of obtaining a seal with an open-hole packer was highly unlikely.

Analysis of the borehole televiewer logs generally indicated a large number of fractures in the wells. However, the logs from Well RRGP-4 indicated a much lower degree of fracturing than the other wells and many of the fractures had been sealed by secondary cementation. Appendix B contains a review of the borehole conditions in RRGP-4 and RRGP-5.

Selection

Wells RRGP-4 and RRGP-5 were selected for stimulation. The bottom open-hole sections of these wells are shown in Figures 3 and 4, respectively. As can be seen in these figures, both wells had multiple legs. The first leg in Well RRGP-5 apparently was cemented because of drilling problems and leg B was inadvertently drilled. The volume of cement used should have adequately plugged leg A for several hundred feet or more. (Details of the drilling operations on Well RRGP-5 are contained in EG&G reports.)[5] Leg B of RRGP-4 was intentionally drilled because of the low productivity of leg A; however, leg B also had extremely low productivity. A brief attempt was made to re-enter leg A just prior to moving the drilling rig off the well, but it could not be re-entered. It was concluded that leg A was filled with cuttings from drilling operations on leg B. From a mechanical point of view, the GRWSP team considered Well RRGP-5 to be preferable to Wells RRGP-4 or RRGE-3, with the mechanical risk to RRGP-4 considered to be much lower than the potential risk to RRGE-3.

There were suggestions that RRGE-3 be stimulated since it did have a higher bottom-hole temperature, and increased production would benefit the Raft River project. However, this well had three legs and the mechanical risk of preparing the well for stimulation was considered to be high. Also, if two of the legs could not be plugged and isolation obtained in the third leg, the possibility of successfully producing a long hydraulic fracture would be greatly reduced because the fracture might intersect one of the other legs and a very shallow fracture would be created. In addition, such a situation could lead to collapsed casing above the downhole pack-off.

STIMULATION TREATMENT

RRGP-4 Well Preparation

In preparation for the fracture treatment in RRGP-4, two workover operations were performed in the well. An attempt was made to re-enter and plug leg A with cement, and a 7" liner was installed through the upper part of the leg B. It was decided to plug leg A to preclude the possibility that a fracture from the deeper portion of leg B would intersect leg A. If this occurred, it was considered possible that leg B would sand out prematurely or the fracture would rise vertically in leg A to a cooler, more shallow interval.

A fracture from leg B paralleling either the Bridge Fault or the Narrows Fault would not intersect leg A. However, the risk to the success of the fracture treatment was considered sufficient to warrant at least one attempt to plug leg A. Directional drilling tools were used to attempt the re-entry, but the attempt was unsuccessful.

The 7" liner was then installed in leg B and cemented in the interval 3,307'-4,705' as originally planned. The interval from 4,705'-4,900' was left open for the fracture treatment. This 195-foot interval had been selected because it was a length that could be effectively treated, and the depth was sufficient to provide the desired produced fluid temperature. After the 7" liner was in place, it was cemented with 350 cu ft around the bottom, and an additional 300 cu ft was squeezed through the liner hanger to plug at least the upper portion of leg A with cement. The history of this operation is given in Appendix D.

Treatment Selection and Design

Petroleum industry experience has shown that results of fracture stimulation treatments in naturally fractured reservoirs are highly unpredictable. This is because the success of a treatment is entirely dependent on the intersection of the created fracture with a productive natural fracture. In any given field, earth stresses normally dictate a principal fracture orientation which is common to both the natural and created fractures. Thus there is a tendency for the created fracture to parallel, rather than intersect, the principal natural fractures. In the case of RRGP-4, the existence of the nearby Narrows Fault indicated a strong preference for an east-west fracture orientation.

Maurer Engineering (MEI) and RGI evaluated two basic fracturing processes for use in RRGP-4. The conventional fracture treatment, designed to create a single planar fracture, was considered but was rejected out of concern that the created fracture would parallel rather than intersect major natural fractures. Instead, the dendritic fracturing process was selected primarily because it appeared to offer the best opportunity of intersecting the major natural fractures in the area. The dendritic frac treatment was designed for five stages with 1,975 bbl per stage. Each stage included two pumping periods, each of which was followed by a brief flow-back period. The pumping and flow-back sequence for a typical stage is shown in Table 3. The alternating pump-in and flow-back periods are designed to stress and restress the rock, rearranging the stresses to achieve a change in fracture direction. Therefore, on the second and succeeding stages of a dendritic fracturing program, it can be expected that branched or dendritic fracturing will occur. Figure 5 is an idealized diagram of a dendritic fracturing pattern. Each stage, as shown in Table 3, included three slugs of 100-mesh sand for fluid loss control followed by four slugs of 20-40 mesh proppant sand. Each stage was designed to achieve a fracture 200 feet high by about 1,500 feet long assuming a fluid efficiency of 30%. The frac fluid was a low viscosity gel containing 10 lb of hydroxypropyl guar plus 2 lb of XC polymer per thousand gallons of water. As discussed in the following section, the treatment was terminated after four stages. A total of 7,900 bbl of frac fluid was injected with 108,400 lb of sand at an average rate of 50 bbl/min.

Treatment History

Figure 6 is a pressure-rate history of the treatment. There are three major items of interest to notice in the figure. The erratic behavior in the first two stages is a result of some unscheduled shutdowns caused by minor equipment problems and leaks. One advantage of the dendritic process is that such shutdowns do not normally have an adverse effect on the treatment results, whereas such a shutdown in an advanced stage of a conventional fracturing treatment would likely result in a sand-out and failure of the job. Stages 3 and 4 proceeded with no difficulty. As shown in Figure 6, there is little character to the pressure curve in the last two stages except for a minor decline in pressure in the final stage. It is also important to notice the trend of instantaneous shut-in pressures (ISIP's) following each pumping period. After the first stage, there is very little change in the ISIP, and that is an indication that artificial dendritic fracturing was not actually occurring but only natural fractures were being opened. In a normal dendritic fracturing job, changes in the rock stresses which result in dendritic fracturing would also be evidenced by a change in the ISIP from stage to stage. Because it appeared that no new fractures were being generated by the treatment, it was terminated after four stages. An attempt was made to inject a radioactive tracer with the frac fluid; however, equipment failure in the injection system prevented the introduction of the tracer. Native chemical tracers were used in the chemical analysis of the return fluids.

Mechanical Arrangement

The frac job was pumped through a 4-1/2" frac string with a packer set in the 7" liner. The frac string was used because of pressure limitations on the casing and liner laps above the 7" liner. Figure 7 is a schematic diagram of the surface fracturing equipment layout. B-J Hughes provided all surface fracturing equipment and treatment materials. The selection of B-J Hughes was based on competitive bids and equipment availability. Because of the large volume of the treatment, the frac fluid was mixed and pumped in a continuous process. A new 24,000 bbl, lined pond was filled with geothermal fluid from RRGP-5 prior to the job. A Model 607 45-bbl/min blender pumped water from the pond, added the two polymers and a small amount of hydrochloric acid to lower the pH of the water slightly and enhance the gelling of the polymers. This fluid then was pumped into the four

500-bbl frac tanks which provided surge capacity and residence time for gelation to occur. A Model 611 120-bbl/min blender pumped frac fluid from the tanks, added proppant sand, and fed the frac units. Sand was delivered to the blender by dump trucks. The frac units pumped through two 3" frac lines to the well. A branch line from one of these frac lines to the pit provided a means of backflowing the well between pumping stages.

The frac string was rated for a maximum burst pressure of 4,540 psig. In anticipation of fracturing pressures higher than this, a pump truck was used to pressurize the casing/frac string annulus. Pressure on the annulus provides a "backup" effectively reducing the pressure contained by the frac string and packer. However, fracturing pressures were lower than anticipated, and this truck was not actually needed.

There were four Model 133 semi-trailer frac units and four Model 139 truck-mounted frac units on location for a total of 8,000 hydraulic horsepower. Because the fracturing pressures were lower than anticipated, only 4,000 hp was actually used. B-J Hughes also provided a mobile laboratory for final checks of water chemistry and gelation. Although the polymers had been pretested in Raft River water, a final check on the location was performed. Appropriate sets of samples from all frac materials were collected for subsequent detailed chemical analyses.

RRGP-5 Well Preparation

Because RRGP-5 is near the intersection of two major faults, i.e., the Narrows and Bridge Faults, it appeared likely that a single planar fracture in the deeper portion of the well would intercept major natural fractures. The objective of the treatment was to achieve a producing rate at least comparable to the existing rate, but from a deeper, hotter interval. The recompletion consisted of cementing 7" casing in leg B to isolate a 216-foot zone near the bottom of the well (Appendix D).

Treatment Selection and Design

Maurer Engineering designed a conventional planar fracture treatment to achieve a 200-foot high by 1,000-foot long fracture with a 14% fluid efficiency. The treatment was designed for a total of 7,250 bbl as shown in the pumping schedule (Table 4). A total of 7,620 bbl of frac fluid was actually pumped because the job was restarted after some early unscheduled shutdowns. The frac fluid was a relatively low viscosity gel containing 30 lb of hydroxypropyl guar per thousand gallons of water. Eighty-four thousand pounds of 100-mesh sand were used for fluid loss control and 347,000 lb of 20-40 mesh sand were injected as proppant. This 347,000 lb of proppant included 42,000 lb of 20-40 mesh resin-coated sand which was tailed-in at the end of the job. It was intended that the resin-coated sand would bond together in the fracture near the wellbore and prevent the other proppant sand from being produced into the wellbore after the frac job. The relatively low viscosity frac fluid was designed specifically to allow settling of the sand within the fracture at a controlled rate. As the sand settles, it is believed to settle in banks, as shown in Figure 8, which props the lower portion of the fracture at nearly the full dynamic width, leaving the upper portion of the fracture open. The flow capacity of this open portion of the fracture is many times that of a sand-filled fracture.

Treatment History

Figure 9 is a pressure-rate history of the treatment. During the first 700 bbl of the treatment, there were several unscheduled shut-downs for leaks, and it was observed that the ISIP at that time was 500 psig. As the job progressed, there were substantial pressure breaks between the 800 and 1,500 bbl points, and at the time about 2,800 bbl were pumped. As the job progressed past the 5,000 bbl point, the pressure began to increase steadily. This is probably a result of leak-off into adjoining fractures and a narrowing of the fracture which resulted in a higher friction loss. At the end of the job, the rate was gradually reduced in an attempt to sand-out the well and leave a fully propped fracture at the wellbore. As the rate was reduced and finally pumping was stopped, it was noted that the ISIP was near zero. This change in ISIP from 500 psig near the beginning of the job to near zero at the end indicated that communication with major fractures had been achieved.

Ammonium nitrate was selected as a tracer to monitor fluid mixing within the reservoir and to allow interpretation of the fluid chemistry during and after the frac job. The tracer was added at a blending rate proportional to the polymer addition. Numerous samples of the injected and the subsequently produced fluids were collected for detailed chemical analyses. These analyses included monitoring separately for ammonium and nitrate ions. In addition, the solutions were analyzed for their content of polymer and polymer degradation products as described later.

Mechanical Arrangement

Figure 10 is a diagram of the well with the frac string in place. As in the case of RRGP-4, a 7" liner was installed to exclude all but the lower portion of the original completion interval. The interval below the liner, from 4,587 feet to 4,803 feet, was open at the time of the fracture treatment. A 4-1/2" frac string with a packer in the 7" liner was also used for this job. The surface equipment layout for this job was very similar to that for RRGP-4. B-J Hughes provided all surface fracturing equipment and all treatment materials except for the resin-coated proppant sand. The selection of B-J Hughes was based on competitive bid. Because of the large volume of the treatment, the frac fluid was mixed and pumped in a continuous process. A Model 608 120-bbl/min blender located at the pit added polymer, a small quantity of acid, and ammonium nitrate as a chemical tracer. The fluid was then pumped through a 10" steel line to four 500 bbl frac tanks which provided gelation time for the polymers. A Model 611 120-bbl/min blender fed by a Sand King drew frac fluid from the tanks and pumped to the frac units. The Sand King is a four-compartment field storage unit which stores up to 475,000 lb of proppant sand. It incorporates a conveyor belt delivery system to the blender. These units are especially useful where large volumes of sand and high delivery rates are required. A total of 6,000 hydraulic horsepower was on location, consisting of seven Model 139 truck-mounted frac units and one Model 133 semi-trailer frac unit. Frac fluid was pumped through two 3" lines to the well.

Following the frac job, the well produced substantial quantities of proppant sand, a common occurrence following a massive frac job. Approximately ten days of flowing and circulating were necessary before sand production diminished to a sufficiently low concentration to reinstall the electric submersible pump. Production data are given in Appendix C and E. A history of the workover and fracture stimulation is given in Appendix D.

Costs

The total cost of rig work and fracturing in RRGP-4 was $304,000. Of this amount, $64,000 was for fracturing service and materials. The remainder was spent for recompletion of the well as described above. The total cost of rig work and fracturing of RRGP-5 was $410,000. Of this total, $129,000 was for fracturing service and materials. The remainder was spent on pulling and re-running the pump and permanent packer, and recompleting the well with 7" liner. Cost details for the two jobs are given in Tables F-1 and F-2 of Appendix F. Costs incurred by EG&G Idaho, Inc. for testing the well and providing support to the rig operation are not included in the above cost figures.

PRE-STIMULATION WELL CONDITIONS

The Raft River production wells were completed within a naturally fractured zone from about 3,400 feet to 6,543 feet. The formation producing intervals are comprised primarily of siltstone, sandstone, metamorphosed quartz, quartz schist, elba quartzite, and quartz monzonite. Pre-stimulation borehole televiewer surveys (discussed in Appendix A, "Application of Acoustic Televiewer to the Characterization of Hydraulic Fractures in Geothermal Wells") indicated that both Wells RRGP-4 and RRGP-5 had natural fractures intersecting their wellbores; however, RRGP-4 showed less fracturing in the entire well (open-hole interval 3,526 feet-5,115 feet) relative to other Raft River wells, and many of the fractures had been sealed by secondary cementation. Well RRGP-5 had numerous horizontal and vertical fractures throughout the open-hole section from 3,408 feet to 4,925 feet.

After leg B of Well RRGP-4 was deepened to 5,115 feet, an attempt was made by EG&G to flow test the well. The well was found to be non-commercial and would not sustain an artesian flow rate greater than approximately 10 gpm. The maximum bottom-hole temperature was measured by geophysical logs at 254°F.

Well RRGP-5 (leg B) productivity was tested by EG&G several times after completion. The well was artesian flow tested for 72 hours at a rate of 140 gpm in November 1978. Short-term flow periods (approximately 1 hour) prior to this test obtained rates in excess of 280 gpm; however, the wellhead pressure was declining very rapidly and the well could not sustain this rate. No downhole transient pressure data were obtained during these tests with which to calculate a productivity index. A maximum bottom-hole temperature of 274°F was measured in the well. Leg B is believed to have penetrated a zone extensively damaged by cement during the workover of leg A. Sufficient volume of cement had been injected into leg A to fill the wellbore and the near-well natural fractures. Some confusion remains as to the actual productive potential of RRGP-5 after it was completed. Flow test results vary from over 1,000 gpm to 140 gpm. Several short-term production tests were attempted during the drilling operations and shortly thereafter which were not fully documented and little downhole transient pressure data were obtained. For a number of reasons, the well might achieve and/or indicate these flow rates for short periods of time. However, pressure data obtained during later tests indicated that the bottom-hole pressure must have been decreasing rapidly during these early flow tests and that the well would not have continued to sustain anywhere near the high flow rates originally ascribed to this well. None of the current Raft River wells are capable of very high artesian flow rates. The most likely sustainable maximum flow rate of Well RRGP-5 prior to the stimulation treatment was between 140 and 200 gpm.

As described above, these wells originally had long open-hole intervals. A 7" casing liner was cemented in the open-hole such that a 200-foot open-hole interval was isolated for stimulation treatment. With the liner in place, both wells were essentially non-productive as the formation natural fractures feeding the wellbore were cased-off. Therefore, no production tests were performed under these conditions prior to the fracture experiments.

POST-STIMULATION PRODUCTION TEST INSTRUMENTATION

Wells RRGP-4 and RRGP-5 were production tested several times following the fracture stimulation treatments. EG&G assisted in the test program and provided the surface equipment required to monitor the flow conditions. The general procedure was to construct a flow line from the wellhead to the nearby holding pond. The flow line was instrumented to measure rate, wellhead pressure, and temperature; and ports were provided for fluid sampling capability. The deep geothermal wells and the shallow water wells in the Raft River area were monitored continuously by EG&G for possible interference pressure data.

Downhole pressure (and temperature) instrumentation were utilized during the flow tests to obtain the transient pressure drawdown and buildup response. In most instances the downhole pressure equipment was a quartz crystal pressure gauge provided by either EG&G or Lawrence Berkeley Laboratory (LBL). However, mechanical reliability was low and several instrument failures occurred during these tests. In the case of the September 1978 flow test of Well RRGP-4, a conventional Amerada type downhole pressure gauge was used to obtain the pressure buildup data. Downhole temperature measurements were obtained to aid in the analysis of the pressure data, which could be significantly affected by a change in the fluid temperature, and to document the flowing temperature of the well.

Fluid samples were taken periodically during all post-stimulation flow tests. These samples were analyzed for fracture fluid and tracer material returns by Vetter Research. Also, the USGS ran borehole televiewer surveys in each of the wells to determine the extent of the newly created vertical fracture at the wellbore.

TEST RESULTS AND ANALYSIS

The production testing of the Wells RRGP-4 and RRGP-5 under the GRWSP will be discussed in chronological order. The pressure data were analyzed using conventional pressure analysis techniques, type curve (log-log) matching techniques, and numerical simulation methods.

RRGP-4

Well RRGP-4 was stimulated with a dendritic hydraulic fracture treatment in August 1979. A 20-hour flow test was run on August 25-26, 1979. The flow rate declined from an initial 250 gpm to about 60 gpm; however, at that point two-phase flow began to occur at the orifice meter used to measure the flow rate. The test was terminated and plans were made to re-test the well with improved flow control equipment in September. A borehole televiewer survey confirmed the existence of a 190-foot vertical propped fracture (Appendix A). The fracture was oriented in an east-west direction which parallels the Narrows Fault.

Although the August test was of short duration, the transient pressure data agree closely with the data obtained in the September test. Figure 11 summarizes the production data where the two-phase flow rate across the orifice plate is estimated. Figure 12 shows the downhole transient pressure response versus square root of time plot. Fracture flow (linear flow) is clearly evident in Figures 12 and 13 for about 6 hours. The production test and recorded pressure buildup times were too short for the late-time pressure response to reach a semi-steady condition. Table 5 summarizes the pressure data analysis. The conventional and fracture type curve analysis indicates a planar fracture length of about 400 feet; and a near wellbore formation permeability-thickness (kh) of 728 md-ft. The early-time Horner analysis (Figure 14) indicates a kh of 610 md-ft. A wellbore temperature survey obtained in November 1979 (shown in Figure 15) recorded a maximum bottom-hole static temperature of 265°F. The maximum flowing bottom-hole temperature in August was 251°F at the 3,200 foot depth.

Well RRGP-4 was retested in September 1979 with similar (to the first test) flow rates resulting in rapid downhole pressure response. Figure 16 gives the production data and Figures 17 through 20 show the pressure data plots. The downhole instrumentation failed about 8 hours into the drawdown phase. The test continued until September 12, 1979, at which point Amerada type downhole pressure and temperature instruments were utilized to obtain the reservoir buildup data. The well was flowed at a rate of about 60 gpm for 150 hours before shut-in. The fracture flow effects are indicated to last about 6 hours by the early-time pressure versus square root of time plot in Figure 18. The bottom-hole pressure apparently reached the initial reservoir pressure after approximately 15 hours of buildup time. The data show a very flat pressure curve from 15 hours to 47 hours. The significance of this is discussed later. The fracture type curve analysis (log-log plot) yields a fracture length of approximately 335 feet and a permeability-thickness (kh) of 800 md-ft. The Horner plot indicated the presence of two straight line segments; one early-time (less than 15 hours) segment and one late-time (greater than 15 hours) segment. These two data segments give kh values of 1,070 md-ft and 85,000 md-ft, respectively, and suggest the possibility of more than one permeable zone near the wellbore. Also a negative skin factor (-6.0) indicates a stimulated zone close to the wellbore. This is further confirmed by the fact that the buildup curve approaches the Horner straight line from above. Table 6 summarizes the calculations of reservoir properties derived from this test. Wellbore temperature changes were small during the reservoir buildup period and did not significantly affect the pressure data.

The maximum bottom-hole temperature recorded during the September 1979 flow test was 270°F. This temperature was significantly higher than past measurements, i.e., about 254°F before stimulation. This fact suggests that the new artificial fracture is producing fluid from a deep reservoir zone not open in the original hole. The chemical data further support this interpretation. The extent of polymer degradation determined chemically is consistent with fluid production from a higher temperature zone. This work is detailed in a later section. The detailed data from the production test are given in Appendix C.

RRGP-5

Well RRGP-5 was stimulated on November 12, 1979. The post-stimulation production test was performed November 25-26, 1979, after the well had been flowed twice to clean out sand. Figure 21 illustrates the production data obtained during the 6-hour flow period. The wellhead and downhole pressure and temperature conditions stabilized very rapidly (about 2 minutes). An average rate of about 200 gpm was maintained with a wellhead pressure of about 30 psia. The pressure drawdown of 100 psi was extremely rapid (less than 1 minute) and no early-time data were obtained. A plot of the pressure buildup data versus square root of time, shown in Figure 22, indicates the fracture flow effect near the wellbore persists for only about 38 seconds. This short linear flow period and the resulting calculated fracture length value are so small that no large single fracture appears to exist near the wellbore. The Horner plot and type curve plot of the pressure data, in Figures 23 and 24, show only a short transition phase between the fracture dominated period and the late-time constant pressure period. The results indicate a higher transmissivity than was found in RRGP-4. Estimates of the late-time formation kh were large, i.e., greater than 100,000 md-ft.

The hydraulic fracture stimulation treatment may have reopened existing natural fractures near the wellbore and/or intersected leg A which dissipated the injected frac fluid and energy. The latter condition would have limited the lateral propagation of the fracture, and cooler fluid entering from a higher zone would explain the relatively low produced fluid temperature of 264°F. The results of the fluid sample chemical analyses, performed by Vetter Research, indicate also that cooler fluid from an upper zone had entered the wellbore after the stimulation job. The details of this chemical work are given later. The borehole acoustic televiewer survey did indicate a newly created vertical fracture at the wellbore of about 140+ feet in length and oriented in a northeast-southwest direction which is parallel to the Bridge Fault (Appendix A). These reopened natural fractures did not significantly affect the already high permeability of this fractured zone. The Horner analysis indicated a very large positive skin factor; however, this skin factor was probably not due to formation damage but rather to the limited entry nature of the completion. A limited entry, theoretical skin effect calculation, yields a skin factor of the same order of magnitude as found by the Horner analysis technique. This result again suggests the fracture intersected leg A. The test data are given in Appendix C.

The maximum flowing bottom-hole temperature was measured at 264°F at the shoe of the 7" liner. Figure 25 illustrates three separate temperature surveys made in Well RRGP-5. If the hydraulic fracture intersected leg A, then relatively cool fluid could be entering the well from a shallow zone.

In March 1980, Well RRGP-5 was flow tested again by EG&G using a downhole submersible pump. The maximum rate obtained during this test was 650 gpm. The PI obtained from the November artesian flow test (2 gpm/psi) was in close agreement with the values observed during this pumped flow test. Table 7 summarizes the reservoir property calculations derived from these tests.

Pressure Interference Data

Available reservoir pressure interference data prior to the stimulation experiments did not indicate that RRGP-4 or RRGP-5 communicated with other wells in the field. During both stimulation treatments and subsequent GRWSP production tests the deep exploration wells and shallow water wells in the area were monitored for wellhead pressure changes. No interference was indicated during the RRGP-4 fracture job or its two production tests; however, the RRGP-5 fracture treatment apparently did cause a pressure spike at RRGE-1 during the injection of the frac materials. The flow tests of RRGP-5 did not cause any pressure changes at the observation wells.

Reservoir Model

Both Wells RRGP-4 and RRGP-5 show remarkably similar pressure response following the fracture treatments. Well RRGP-4 is apparently in a less fractured, tighter area of the reservoir compared to all the other production wells. The transient pressure data indicated three distinct flow response periods: (1) fracture flow; (2) early-time low flow capacity (near wellbore); and (3) late-time high flow capacity (some distance from wellbore). The late-time pressure results suggest the presence of a constant pressure boundary. It is possible to satisfy the observed pressure results of both wells with at least two types of reservoir models:

1. A reservoir with low transmissivity near the wellbore and a constant pressure boundary (or very high transmissivity some relatively short distance from the wellbore); or
2. A reservoir with high effective transmissivity but with a large skin at the wellbore.

The second model does not conform to the known reservoir physical characteristics and therefore was not considered a valid model. Numerical simulations were performed using the first reservoir model to confirm the hypothesis. It was possible to reproduce the pressure transient data for both RRGP-4 and RRGP-5 with essentially the same model (RRGP-4 was given a lower near-wellbore transmissivity). The single layer model consisted of a vertical fracture through the wellbore, a relatively low transmissivity near the wellbore, and a constant pressure boundary located along one short side of a two-to-one rectangular drainage area. Figure 26 illustrates the model geometry. Obviously, the numerical simulation approach does not yield a unique solution to the transient reservoir pressure response, but it does provide a confirmation of the conventional and type curve pressure analysis results. Tables 8 and 9 summarize the pre- and post-stimulation well characteristics.

It is interesting to note that the location of known or suspected faults in the Raft River area (relative to the stimulated wells) are close to the distances indicated in the reservoir model calculations for the constant pressure boundary. The results discussed herein suggest that the naturally fractured rock formation, at some distance from a fault, is not sufficiently permeable to support a high productivity well. The USGS estimates that the hydraulic fractures are subparallel to major faults in the area. RRGP-5 is closer to the Bridge Fault which trends slightly east of north, and RRGP-4 is closer to the Narrows structure which trends east-northeast.

CHEMICAL ANALYSES

Ultimately, the success of a stimulation job is determined by field data obtained during both injection and post-stimulation production. These data typically include pressure and temperature responses as well as intermittent and sustained flow rate data. While this information gives an indication of how successful (or unsuccessful) the stimulation was, it provides only a limited picture of what went right (or wrong). In many cases, gaps in field data can be filled by taking into account complementary data obtained by chemically analyzing the geothermal fluids before, during, and after the stimulation work. These data are used to monitor the chemical behavior of both the stimulation and produced fluids. For example, in the Raft River field experiments which used frac polymers, chemical characterization can be used to answer the following questions:

1) What are the relative amounts of makeup and formation waters at any given time in the fluids being produced during post-stimulation flow?

2) How much of the frac polymer injected is produced back and how much is retained in the formation?
3) How much of the frac polymer injected decomposes and at what rate to give water soluble degradation products which are produced back?

In order to answer these questions and others, numerous samples were collected before, during, and after the fracturing experiments at both RRGP-4 and -5 and analyzed chemically by Vetter Research.

The work reported herein includes the co-injection and monitoring of a chemical tracer (ammonium nitrate) in the RRGP-5 experiment as well as monitoring of the polymer behavior in both the RRGP-4 and RRGP-5 field experiments. In addition, comprehensive supplemental chemical data were gathered on the initial pit waters used to make up the stimulation fluids as well as the geothermal fluids being produced during the latter phases of the flow testing. The results of the chemical investigation and their significance are treated separately for each of the two field experiments in the following sections.

Chemical Aspects of Field Experiment at RRGP-4

General Description

A total of 4,032 lb of frac polymer in 7,900 bbl of water was injected over a 6-hour period on August 20, 1979. During the polymer injection, an attempt was made to co-inject approximately 4 Curies of tritiated water for use as a radioactive tracer to monitor dilution of the fracturing fluid in the reservoir. However, because of mechanical failures in the tracer injection equipment, this phase of the field experiment was abandoned. The well was subsequently flowed on three separate occasions: August 20-21 (clean-up flow only), August 25-26, and September 6-12, 1979. The cumulative production was approximately 16,200 bbl or twice the injected volume.

Sampling and Analytical Results

Samples of produced fluid were collected in plastic bottles directly from the flow line prior to entering the pond. The sampling frequency varied to some extent with more frequent sampling being done during the first two flow tests and during the early stages of the third flow test. The collected samples were analyzed for chemical characterization. These included analyses for pH, major ions, total organic carbon, and frac polymer (i.e., carbohydrate). The data are summarized in Table 10.

In addition, pit fluid samples collected prior to flow of produced fluid into the pond and the last several samples produced during the third flow test were characterized completely for their chemical constituents. The average chemical composition of each of these two groups of samples constituted the available "baseline end points" of make-up water (i.e., pit water) and formation water. These data are summarized in Tables 11-12.

Native Chemical Tracers

As mentioned above, equipment failure precluded the introduction of radioactive tracers during the frac fluid injection. In order to identify a naturally occurring chemical tracer that could be used to trace either the make-up water or formation water in the produced fluids, these two waters were characterized completely (Tables 11, 12). While major differences do exist in the sodium, potassium, and chloride content of these two waters, they are unfortunately artifacts caused by the introduction of kill fluid at the end of the first clean-up flow period. Even though there was sufficient production to theoretically remove the salt (kill fluid), fluid mixing in both the wellbore and the formation near the wellbore resulted in residual production of the kill fluid throughout the duration of the flow tests (Figure 27). The differences in concentrations of other ions were not large enough to warrant their consideration as possible native tracers; and as a result, no further work was done in this area.

Polymer Characterization of Produced Fluid

The two polymers used in the fracturing experiment (i.e., XC and HP Guar) are both derived from naturally occurring polymeric carbohydrates. The carbon content of these materials is on the order of 40% with the remainder being hydrogen and oxygen. Thus, in an aqueous solution of the polymers, the ratio of the total analyzed organic carbon (TOC) concentration to the total analytical carbohydrate (TAC) concentration will be 0.4. Since the TOC and total carbohydrate are determined by two distinct and independent methods, this ratio can also be used to check the internal consistency and validity of the analytical data.

As the polymer degrades, the total carbohydrate concentration of the solution decreases. If the decomposition product is a water soluble non-carbohydrate containing organic material, the TOC concentration of the solution will remain constant as the carbohydrate concentration decreases. This results in an increase in the total organic carbon/total carbohydrate ratio. This ratio can therefore be used to monitor frac polymer conversion to soluble decomposition products being produced back in the return fluids. Degradation to insoluble materials retained in the formation can be inferred by comparison of the total material input with that accounted for in the return fluids (i.e., material balance). These principles have been developed and tested under simulated reservoir conditions.

The results of the analyses described above are shown in Figure 28 for the produced fluids sampled during the three flow periods at RRGP-4. The left-hand ordinate gives the total organic carbon (solid line) and the right-hand ordinate, the total carbohydrate (dashed line). The cumulative production is shown on the abscissa. The three periods during which the well was produced are indicated by the dashed vertical lines.

By properly analyzing the data of Figure 28, it can be concluded that no appreciable polymer degradation occurred in the samples collected during the first flow. The production during this period was approximately 3,300 bbl or 42% of the total injected volume. Based upon an integration of the data in Figure 28, it can be shown that 22% of the polymer injected is produced back during the first flow. Unfortunately, the absence of a tracer in the fracturing fluid makes it impossible to state anything more definitive regarding dilution in or near the wellbore during this period. The lack of polymer degradation does, however, suggest that there has been little heating of the fracturing fluid by the formation during this twenty-four period immediately following injection.

By contrast, the fluid produced during the second and third periods contains appreciable amounts of degraded polymer as the injected fluid becomes exposed to the high temperatures of the formation for longer periods of time. This decomposition is indicated by the data in Figure 28 which shows a more rapid drop in carbohydrate relative to the carbon content of the waters produced during the second and third test. As discussed previously, the ratio of total organic carbon to total carbohydrate is an indicator of polymer degradation to soluble decomposition products being produced back in the return fluids with a value of 0.4 being observed for non-degraded fluids similar to those collected during the first flow test. As decomposition takes place, this ratio increases due to conversion of the polymer to non-carbohydrate materials. In the RRGP-4 experiment, by the time the well was tested a second time four days later, the average ratio had increased to 0.58 for samples collected during this test. Two weeks later, the ratio had increased markedly to 2.07 as the polymer remaining in the formation continued to degrade.

Frac Polymer Material Balance

More detailed information can be obtained by quantifying material return during each of the three periods of interest and comparing total material input to total material output. This has been done using the data shown in Figure 28. The results are summarized in Table 13.

Of the total frac polymer injected (i.e., 4,032 lb), 1,206 lb of polymer were produced back with little degradation. An additional 613 lb of the polymer were converted to soluble organic materials which were produced in the return fluids primarily during the second and third flow test. Approximately 55% or 2,213 lb of the frac polymer are not accounted for. The fate of this material is not known. While it is possible that this much polymer could have been irreversibly retained in the formation as a result of adsorption or conversion to an insoluble residue, it is not likely since it can be shown (Figure 28) that soluble organic materials were still being produced when the flow tests were terminated.

Conclusions - Chemical Aspects of the RRGP-4 Stimulation

Several analytical methods have been developed and applied to the characterization of the produced fluids from post-stimulation flow tests at RRGP-4. Stable frac fluid properties (and near wellbore cooling) are indicated by the lack of polymer degradation in samples collected during the first flow conducted soon after the injection had been completed. Significant polymer degradation was observed during later flow tests; but the products of degradation appear to be water soluble and are observed in the produced fluid. Of the frac polymer injected, only 45% can be accounted for. Some of the material as well as water soluble degradation products were still being produced back when the flow tests were terminated.

Chemical Aspects of Field Experiment at RRGP-5

General Description

A total of 9,450 lb of polymer in 8,040 bbl of fluid was injected into RRGP-5. During the fracture treatment on November 12, 1979, 7,620 bbl were injected and an additional 420 bbl were pumped into the well on November 13 to displace kill fluid from the wellbore. During the polymer injection, 1,150 lb of ammonium nitrate were co-injected for use as a chemical tracer in order to monitor dilution of the fracturing fluid in the reservoir. During the injection, pressure and temperature were monitored in the frac line as well as the return line to the pond -- the latter in the event that the well could be produced spontaneously within a reasonable time after shut-in. Because of the low shut-in pressure, the well did not flow spontaneously and the pressure transducer and thermocouple were removed. The well was later flowed on four separate occasions: November 17, November 21, November 25-27, and December 17-19, 1979. The cumulative production was 20,900 bbl or approximately 2.5 times the injected volume.

Sample Collection

Sampling was done in a manner identical to that of RRGP-4. In addition, samples of the frac fluid were collected every 30 minutes during the injection test in order to have a complete set of data that would be representative of the mixture entering the formation. These data are shown in Table 14.

The collected samples were analyzed for chemical characterization. These included analyses for total organic carbon, frac polymer, ammonium, and nitrate -- the latter two being components of the chemical tracer used to monitor dilution of the frac fluid. These data are summarized in Table 15.

In addition, pit samples collected prior to flow of produced fluid into the pond and the last several samples obtained during the fourth flow test were characterized completely for their chemical constituents. The average composition of each of these two groups of samples constituted the available "baseline end points" of make-up water (i.e., pit water) and formation water. These data are summarized in Tables 16 and 17.

Chemical Characterization of Stimulation Fluid

The ammonium and nitrate concentrations of the frac line samples and all return fluids were analyzed by two separate and independent analytical methods. These data, along with two other independent analyses for total organic carbon and carbohydrate, provided four independent checks on the internal consistency of the analytical data.

As discussed above, a total of 9,450 lb of HP Guar was to have been injected during the field experiment. This amount of polymer would correspond to an average frac line composition of 3,356 ppm carbohydrate (i.e., polymer). The several frac line samples collected during the job, however, only had an average composition of 1,721 ppm (Table 14). Significantly, this is 50% of the expected level. While it may be argued that there could be an error in the carbohydrate analyses, independent analyses for TOC substantiate this conclusion. As previously discussed, carbohydrates, the basic structural unit of HP Guar, typically contain on the order of 40% carbon. As a result, the ratio of total organic carbon to carbohydrate should be approximately 0.4 if both sets of data are internally consistent. The analyzed TOC values and the ratios TOC/carbohydrate, summarized in Table 14, are approximately the anticipated value of 0.4.

The validity of the carbohydrate and TOC data is further confirmed by the characterization of the frac line samples for ammonium and nitrate ions by several independent methods. A total of 1,150 lb of ammonium nitrate was added into 8,040 bbl of the frac fluid. The average concentration of ammonium and nitrate ions in the stimulation fluid should have been 92 ppm and 317 ppm, respectively. These values are in agreement with the average analyzed values of 85 ppm and 300 ppm for the ammonium and nitrate ions (Table 14). Based upon this interpretation of the chemical data, it is concluded that 4,844 lb of HP Guar were injected. This is substantially less than the 9,450 lb which were to have been injected.

In the course of normal quality control procedures on location, there was a count of the number of sacks of polymer added at the blender, and a sample of frac fluid was taken by MEI for a viscosity check. The sack count confirmed that 9,450 lb of polymer were used and the viscosity of MEI's sample was as high or higher than the design viscosity.

The data indicate that nearly half of the polymer was lost between the first blender and the well. The only apparent explanation is that some polymer settled in the frac tanks. By the time the discrepancy was discovered, however, the frac tanks had been emptied, and confirmation of this was impossible.

Chemical Characterization of Produced Fluid

Samples of the produced fluids were analyzed for TOC and carbohydrate as described previously for the RRGP-4 well. In addition, all samples collected were also analyzed for ammonium and nitrate ions. Table 15 contains the numerical data. The results for the TOC and carbohydrate analyses are shown graphically in Figure 29. Ammonium and nitrate data are shown in Figure 30.

Although the polymer remained in the formation for five days prior to the first flow, little degradation was observed in samples collected during this flow test. The average ratio of TOC/carbohydrate in the initial stimulation fluid was 0.39 (Table 14) whereas the average ratio increased only slightly to 0.43 in samples collected during the first flow. The significance of this ratio as it relates to polymer degradation has been discussed. One would expect this ratio to increase as the stimulation fluid thermally equilibrated with the temperature of the formation. Significantly, this was not the case in RRGP-5. The ratio increased only slightly to 0.49 in samples collected four days later during the second flow period. There was no appreciable change in the ratio during the third and fourth flow periods (i.e., 0.50 and 0.47, respectively). The fact that this ratio remains relatively constant, even a month after the injection, strongly indicates that the stimulation fluid has entered a cool portion of the reservoir where it has not experienced the high temperature environment of the producing interval. This is further confirmed when the chemical tracer data are used to monitor the relative amounts of formation water and frac fluid in the produced fluids.

Frac Polymer and Chemical Tracer Material Balance

The frac polymer and its degradation products are produced in the same ratio with respect to the chemical tracer as they entered the formation. Everything originally dissolved was produced back and there was no evidence of the following:

1) Irreversible retention of the polymer in the formation, or
2) Degradation of the polymer to insoluble products retained in the formation.

Evidence for this conclusion is based on comparisons of ammonium ion, nitrate ion, and TOC content of the fluids produced during each of the four flow periods. These are shown in Table 18 where the integrated total return for each constituent is shown as a percent of the amount originally injected. The value for the average tracer is a straight arithmetic average of the ammonium and nitrate data (45.1%). The difference between the total percent TOC return (46.1%) and carbohydrate return (39.6%) is a measure of the amount of polymer that was converted via degradation to water soluble organic products.

Substantial amounts (54%) of the material initially injected are retained in the formation after the fourth flow period. As previously discussed, the chemical evidence is consistent with 4,844 lb of HP Guar being injected. Of this amount, 1,918 lb or 40% are produced back with little degradation. An additional 315 lb (6% of that injected) are converted to water soluble materials that are also produced in the return fluids. This leaves a total of 2,919 lb or 54% that remains in the reservoir at the end of the fourth flow test. Thus, a total of

2,233 lb of HP Guar can be accounted for in the return fluids as either undegraded or degraded polymer. This is 46% of the frac fluid originally injected (Table 19 and Figure 29).

The conclusions regarding ammonium nitrate return closely parallel those of the organic material return. About 1,150 lb of tracer were injected and 510 lb or 45% were accounted for in the produced fluids collected and analyzed during the four flow periods (Table 18 and Figure 30).

Formation Water Content of Produced Fluids

The analytical data on the chemical tracer have been used to monitor the loss of frac polymer to the formation. It was concluded that none had occurred, although the results were not quantitative. Additional evidence for this was obtained by using the chemical tracer to monitor the relative amounts of formation water and stimulation fluid in the produced fluid.

Figure 31 is a plot of the fraction of formation water in the produced fluid as a function of cumulative production. Ideally, this fraction would remain low until the injected volume (7,600 bbl in this case) had been produced back along with the polymer or its degradation products. Instead, as early as the beginning of the second flow period, substantial amounts of formation water appear in the produced fluids. At this point in the production, only 25% of the frac fluid had been produced back (Table 18 and Figure 29). The fraction of formation fluid continued to increase until at the end of the fourth flow period when the produced fluid contained approximately 95% formation water (Figure 31). At this time, only 45% of the original stimulation fluid had been produced.

Conclusions - Chemical Aspects of the RRGP-5 Stimulation

Several analytical methods have been developed and applied to the characterization of the fluids produced from post-stimulation flow at RRGP-5. These included, as for RRGP-4, analyses for TOC and carbohydrate. In addition, a chemical tracer, ammonium nitrate, was co-injected and analyzed for during the flow tests. Based upon the chemical work done, it can be estimated that approximately 50% less polymer [i.e., HP Guar] was injected into RRGP-5 than originally thought. Part of this polymer may have been retained in the surface equipment. A major portion of the frac fluid entered a cold zone of limited productivity. This conclusion is based on two facts: (1) there is little thermal degradation of the polymer after a one-month period in the reservoir; and (2) less than 50% of either the polymer or tracer is produced back even after a cumulative volume of 2.5 times the injected volume had been produced from the well. During these production tests, significant volumes of formation water were obtained.

CONCLUSIONS

Well RRGP-4 was successfully stimulated using the dendritic fracture treatment method. The PI was increased from essentially zero to 0.6 gpm/psi, and the produced fluid temperature increased approximately 15°F.

Well RRGP-5 was successfully stimulated using a conventional large hydraulic fracture treatment technique; however, the artificially created fracture probably re-opened existing natural fractures near the wellbore and/or intersected leg A. The latter condition would have limited the lateral propagation of the fracture and may explain the low fluid temperature. No significant increase in productivity was achieved. The post-stimulation PI was 2.0 gpm/psi.

Borehole televiewer surveys indicate that the artificially created fractures in the wells paralleled the nearby fault lines. The 190-foot vertical fracture in RRGP-4 was oriented in an east-west direction which parallels the Narrows Fault, and the 140-foot vertical fracture in RRGP-5 was oriented in a northeast-southwest direction which is parallel to the Bridge Fault.

The results suggest that the naturally fractured rock formation, at some distance from a fault, may not be sufficiently permeable to support a high productivity well. Future wells should probably be drilled to intersect the fault zones.

Mechanically, the stimulation zones were successfully isolated by cementing blank liners into the open-hole sections.

With the exception of low material return in both field experiments, there are no striking similarities between the chemical behavior of the post-stimulation fluids produced at RRGP-4 and RRGP-5. The frac fluid injected at RRGP-4 entered a much hotter zone than that at RRGP-5. While the temperature at the top of the producing interval at RRGP-4 is slightly warmer than that at RRGP-5 (i.e., 270°F vs 264°F, respectively), this temperature difference is not large enough to account for the extensive differences in polymer degradation that were observed. With further work under controlled laboratory conditions, the extent of polymer degradation (as indicated by the measured ratio of TOC/carbohydrate) may become useful in future field experiments as a temperature indicator of fracture environment.

The Raft River experiments provided the first field experience for the GRWSP group and service companies in geothermal well fracturing treatments. The unique environment of geothermal wells causes problems not present in normal petroleum industry field work. This experience will be valuable in later high temperature reservoir experiments.

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TABLE 1

RAFT RIVER WELL DATA

WELL NAME	RRGE-1	RRGE-2
Total Depth	4989'	6543'
Prod. Interval	Open Hole 3623'-4989'	Open Hole 4227'-6543'
Casing Configuration	20" 0-901' 13 3/8" 0-3623'	20" 0-904' 13 3/8" 0-4227'
Max. Temperature	296° F	294° F
Pressure, psig	150 wellhead	150 wellhead
Tests	Flow, Core P, T, Logs	Flow, P, T, Logs, Cores
Flow Rate	800 gpm	540 gpm
Water TDS (Principle Consultants)	1560 ppm ($Cl-Na-SIO_3$)	1267 ppm ($Cl-Na-SIO_3$)
Geological Data	820'-4595' Salt Lake FM. 4595'-4708' Metamorphosed Zone 4708'-4928' Elba Quartz 4928'-TD Quartz Monzonite	1050'-4664' Salt Lake 4664'-4752' Metamorphosed Zone 4752'-4988' Elba Quartz 4988'-TD Quartz Monzonite
Average Porosoity	.30	.17
Avg. Permeability -thickness	>100 D - ft. k=25 - 165 md	49 D - ft. k=25 md
Core Data	Φ= .162 k=5 md @ 4506' Tuffaceous Siltstone	Φ=.155 k=.04 md @ 4227' k=.0022 md @ 4372' (Shale)

TABLE 1 (continued)

WELL NAME	RRGE-3	RRGP-4
Total Depth	5900' Approx.	5099'
Prod. Interval	Open Hole (3 legs)	Open Hole 3526'-5115' (leg B)
Casing Configuration	20" 0-120' 13 3/8 " 0-1386' 9 5/8" 1188'-4241' 3 legs all open hole to 5900' approx.	20" 0-400' 13 3/8" 0-1901' 9 5/8" 1512'-3526'
Max. Temperature	298° F	240° F @ 2900' approx.
Pressure, psig	112 @ wellhead	120 @ wellhead
Tests	Logs, P, T, Flow	Cores, Logs, P, T, Flow
Flow Rate	540 gal/min	Non-commercial
Water TDS (Principle Consultants)	4130 ppm (Cl-Na)	< 2,000 ppm (Cl-Na)
Geological Data	Slight variations on legs 2 & 3 1270'-5300' Metamorphosed Zone 5300'-5780' Elba Quartzite, 5780'-5842' Quartz Monzonite	4600'-5099' Quartz, Schist, Elba Quartzite, Quartz Monzonite, w/Fractures
Avg. Porosity	-	-
Avg. Permeability -thickness	6.7 D- ft.	26 D - ft. @ 2840 ft. (RRGI-4)
Core Data	Φ=.228 k=.04 md @ 3366' Tuff k= ~ 100 md @ 3365' Tuff	Φ=.245 k=60 md @ 1900' (water)
Peculiarities	Three legs open to production	Leg A filled with cuttings or bridged.

TABLE 1 (continued)

WELL NAME	RRGP-5B	RRGI-6
Total Depth	4925'	3858'
Prod. Interval	Open Hole 3408'-4925'	Injection Well Open Hole 1698'
Casing Configuration	20" 0-1500' 13-3/8" 0-1510' 9-5/8" 1284 - 3408' first leg cemented second leg open hole to 4925'	20" 0-120' 13-3/8" 0-1698'
Max. Temperature	274° F	209° F
Pressure, psig	-	-
Tests	Logs,Cores, P, T, Flow	Cores, logs, P, T, Flow
Flow Rate	(1095 gpm leg A) 700 gpm leg B (damaged)	1500 gpm injection
Water TDS (Principle Consultants)	1618 ppm ($Cl-SIO_3$)	6286 ppm (Cl-Na)
Geological Data	Siltstone, Quartzite Schist, Elba Quartzite, Quartz Monozonite	-
Avg. Porosity	.17-.30	
Avg. Permeability	25-165 md	
Peculiarities	Leg A cemented, leg B near wellbore may be cemented in fractures	Skin damage suspected

TABLE 1 (continued)

WELL NAME	RRGI-7
Total Depth	3888'
Prod. Interval	Injection Well Open Hole 2044'-3888'
Casing Configuration	20" 0-150' 13 3/8" 0-2044'
Max. Temperature	-
Pressure, psig	65 @ wellhead
Tests	Logs, Core P, T, Flow
Flow Rate	840 gpm injection
Water TDS (Principle Consultants)	< 2,000 ppm (Cl-Na-Ca)
Geological Data	Fractured Metamorphics above Elba Quartzite
Avg. Porosity	.17-.30
Avg. Permeability	25-165 md
Core Data	-

TABLE 2

Available Chemical Analyses of Raft River Geothermal Water
(in mg/l unless otherwise noted)

	RRGE-1	RRGE-2	RRGE-3	RRGP-4	RRGP-5	RRGI-6	RRGI-7
Ca	53.5	35.3	193	150	40	157	315
K	31.3	33.4	97.2	28	--	--	--
Li	1.5	1.2	3.1	3.1	--	--	--
Mg	2.4	0.6	0.6	0.2	--	--	1.6
Na	445	416	1185	1525	--	--	2,100
Si	57	61	74	51	67	--	39
Sr	1.6	1.0	6.7	6.5	--	--	--
Cl	776	708	2170	2575	900	3,150	4,085
F	6.3	8.3	4.6	4.5	8.4	8.5	5.0
HCO_3	64	41	44	24	--	37	26
NO3	<0.2	<0.2	<0.2	--	--	--	--
$S^=$	--	0.3	--	--	--	--	--
$SO^=_4$	60	54	53	61	--	--	64
pH	8.4	7.6	7.3	7.4	8.1	7.3	--
Conductivity (umhos/cm)	3370	2740	9530	7280	2150	10,500	12,000
TDS	1560	1270	4130	4470	--	--	--

TABLE 3

Pumping Schedule for One Stage of Frac, RRGP-4

Event No.	Fluid Volume (bbl) Incr.	Fluid Volume (bbl) Cum.	Sand lb/gal	Sand Size	Fluid
1	200	200			10 lb H.P. Guar + 2 lb XC polymer per 1,000 gal
2	25	225	4	80/100	"
3	200	425			"
4	25	450	4	80/100	"
5	200	650			"
6	25	675	4	80/100	"
7	200	875			"
8	25	900	2	20/40	"
9	200	1,100			"
10	25	1,125	4	20/40	"
11	200	1,325			
12	25	1,350	4	20/40	"
13	200	1,550			"
14	25	1,575	4	20/40	"
15	200	1,775			"
16	Shut down and flow back				"
17	200	1,975			"
18	Shut down and flow back; ready for next stage.				

TABLE 4

RRGP-5 Fracture Treatment
Pumping Schedule

Time (min)	Fluid Volume (bbl) Incr.	Cum.	Sand lb/gal	Size	Comments
0-10	500	500			Pad Stabilize rate and measure ISIP during pad.
10-50	2,000	2,500	1	100	
50-80	1,500	4,000	1	20/40	
80-140	3,000	7,000	2	20/40	
140-145	250	7,250	4	20/40 Supersand	Slow rate if possible at the end. Displace Supersand to below liner and stop. Measure ISIP.

TABLE 5

RAFT RIVER RRGP-4 TEST SUMMARY

TEST 1 - AUGUST 25-26, 1979

Flow Rate = 60 gpm

Production Time = 20 hrs

Maximum Bottom-hole Temperature = 251°F

BUILDUP DATA(1)

A. Fracture Type Curve Analysis

L_f = 400 ft

KH = 728 md-ft

B. Horner Plot Analysis

KH = 610 md-ft (Early Time)

(1) No Late Time Data, T > 15.4 hrs

TABLE 6

RAFT RIVER RRGP-4 TEST SUMMARY

TEST 2 - SEPTEMBER 6-14, 1979

Flow Rate = 60 gpm

Production Time = 150 hrs

Maximum Bottom-hole Temperature = 274°F

BUILDUP DATA

A. Fracture Type Curve Analysis

L_f = 335 ft
KH = 800 md-ft

B. Horner Plot Analysis

KH = 1,070 md-ft (Early Time)
KH = 85,000 md-ft (Late Time)[1]
S = -6.0

(1) Constant Pressure Boundary Effect

TABLE 7

RAFT RIVER RRGP-5 TEST SUMMARY

TEST 1 - NOVEMBER 25-26, 1979

Flow Rate = 200 gpm

Production Time = 6 hrs

Maximum Bottom-hole Temperature = 264°F

BUILDUP DATA

A. Horner Plot Analysis

KH > 100,000 md-ft (Late Time)(1)

TEST 2 - EG&G: USING DOWNHOLE REDA PUMP (MARCH 1980)

Flow Rate = 650 gpm

Production Time = 61.3 hrs

Productivity Index = 2.05 gpm/psi

Maximum Temperature = 257°F (Wellhead)

(1) Constant pressure boundary effect

TABLE 8

RAFT RIVER RRGP-4 WELL DATA SUMMARY

PRE-STIMULATION WELL CONDITION:

Open-hole Interval 3526'-5115'

Maximum Bottom-hole Temperature = 254°F (Geophysical Log)

Flow Rate = Well Would Not Sustain Flow

Natural Fractures in Wellbore

POST-STIMULATION WELL CONDITION:

Open-hole Interval 4705'-4900'

Vertical Fracture in Wellbore (190+ ft height)

Flow Rate = 60 gpm (artesian)

Maximum Bottom-hole Temperature = 270°F (at 3,200')

Fracture Effects Show L_f = 335'

Near Wellbore Effective KH = 800-1,000 md-ft

Constant Pressure Boundary with High Effective KH > 100,000 md-ft

Communicates with natural fractures or matrix permeability in area. Did not communicate effectively with major source of reservoir fluids.

TABLE 9

RAFT RIVER RRGP-5 WELL DATA SUMMARY

PRE-STIMULATION WELL CONDITION:

Open-hole Interval 3408'-4925'

Maximum Bottom-hole Temperature = 274°F

Flow Rate ≈ 140 gpm (artesian)

Near Wellbore Cement Damage

Natural Fractures in Wellbore

POST-STIMULATION WELL CONDITION:

Open-hole Interval 4587'-4803'

Maximum Bottom-hole Temperature = 264°F @ 4,600'

Flow Rate = 200 gpm (artesian)

Near Wellbore Effective KH > 100,000 md-ft with Limited Entry

Constant Pressure Boundary with High Effective KH > 100,000 md-ft

Vertical Fracture in Wellbore (140+ ft height)

Communicates with natural fractures or matrix permeability in area. Did not communicate effectively with major source of reservoir fluids

Appears to have limited pressure communication with RRGE-1

TABLE 10

COMPOSITION OF RRGP-4 PRODUCED FLUIDS DURING FLOW TESTS[a]

DATE	TIME	SODIUM	POTASSIUM	CALCIUM	MAGNESIUM	CHLORIDE	SULFATE	TOC[b]	CARBOHYDRATE	pH
					First Flow Test (August 20-21, 1979)					
8/20/79	1440	620	51	83	3.59	951	63	357.4	1260	3.23
8/20/79	1500	550	56	70	4.73	1200	153	384.4	1100	2.78
8/20/79	1600	620	88	120	5.32	1260	174	407.4	1180	3.50
8/20/79	1718	540	56	66	3.98	1080	82	384.9	1100	2.81
8/20/79	1917	460	48	51	2.39	827	72	-	920	6.22
8/20/79	.924	420	48	48	2.36	802	59	319.3	934	6.45
8/20/79	2010	500	48	58	2.35	833	43	405.0	608	6.60
8/20/79	2023	480	50	53	2.45	774	41	197.7	491	6.55
8/20/79	2104	490	54	61	2.71	821	64	355.0	1040	6.58
8/20/79	2220	440	52	46	1.99	852	44	324.0	905	6.07
8/20/79	2330	430	53	56	1.83	882	53	267.0	772	6.20
8/21/79	0030	560	52	88	1.71	871	69	329.0	926	6.43
8/21/79	0115	480	54	71	1.63	871	77	273.6	788	6.46
8/21/79	0230	460	56	72	1.64	852	70	283.6	488	6.67
					Second Flow Test (August 25-26, 1979)					
8/25/79	initial	980	64	107	1.08	1510	79	133.0	376	6.90
8/25/79	1420	4000	92	130	1.11	4770	77	149.0	334	7.15
8/25/79	1520	4000	96	137	0.78	4560	76	145.0	360	7.06
8/25/79	1920	3300	92	128	1.08	3930	73	139.0	358	7.11
8/25/79	1726	2900	89	123	1.28	3470	75	146.0	360	6.93
8/25/79	1800	2450	91	125	1.36	3730	80	166.0	351	7.17
8/25/79	2020	2800	78.6	136	0.97	4290	70	207.7	287	7.51
8/25/79	2120	2800	94.7	139	1.05	4290	67	207.3	276	7.35
8/25/79	2220	2750	91.2	140	1.03	4850	82	202.7	285	7.35
8/25/79	2320	2700	93.1	140	0.97	4330	74	179.3	252	7.27
8/26/79	0120	2600	92.2	134	0.92	4100	82	168.8	271	7.32
8/26/79	0220	2700	92.4	144	0.93	4200	88	175.4	273	7.26
8/26/79	0320	2400	93.4	124	0.95	4660	68	187.0	262	7.23
8/26/79	0420	2500	92	135	0.93	4380	49	177.0	287	7.23
8/26/79	0520	2200	96	115	0.97	4570	68	109.3	305	7.25
8/26/79	0520	2700	94	142	0.90	4600	71	170.4	298	7.00
8/26/79	0620	2500	89	134	1.04	4730	67	162.5	273	7.10
8/26/79	0820	2600	92	137	0.91	4500	59	-	285	7.03
8/26/79	0920	2600	90	145	0.94	5090	52	123.0	317	6.88
8/26/79	1026	2600	86	156	0.89	4730	65	118.6	259	7.05
					Third Flow Test (September 2-12, 1979)					
9/2/79	1800	1150	65	89	0.72	1500	58	74.0	85	7.00
9/6/79	0833	1510	74	100	4.94	2270	73	87.0	235	7.01
9/6/79	0954	2000	91	123	0.63	3420	69	116.0	261	7.30
9/6/79	1052	2100	87	108	0.14	3420	80	117.0	177	7.23
9/6/79	1200	870	77	101	0.71	1460	64	110.0	139	7.22
9/6/79	1350	1250	69	102	0.84	1910	63	94.0	71	7.38
9/6/79	1500	1330	72	105	0.84	2030	41	79.0	77	7.12
9/6/79	1600	1300	73	94	0.81	2030	62	81.0	75	7.24
9/6/79	1700	1150	60	84	0.65	1700	44	61.0	72	6.88
9/6/79	1900	1070	68	89	0.71	1880	62	73.0	74	7.28
9/6/79	2000	1140	52	66	0.58	1510	45	67.0	51	7.00
9/6/79	2100	840	71	88	0.69	2000	62	69.0	74	7.12
9/6/79	2200	1140	74	97	0.72	2080	64	71.0	72	7.28
9/6/79	2300	1100	75	90	0.72	1950	64	78.0	73	7.10
9/6/79	2400	1040	63	82	0.61	1820	70	68.0	53	6.92
9/7/79	0600	1300	77	105	0.78	2240	59	81.0	67	7.20
9/7/79	1200	1350	79	104	0.68	2310	83	66.0	57	7.26
9/7/79	1800	1570	78	122	0.65	2560	75	73.0	57	6.84
9/8/79	0600	1500	77	114	0.89	2530	76	71.5	47	6.88
9/8/79	1800	1450	71	116	0.55	2280	77	65.1	39	6.63
9/8/79	2400	1250	73	103	0.53	2440	63	81.2	50	6.58
9/9/79	0600	1300	48	107	0.28	1310	59	95.1	22	6.24
9/9/79	1800	753	72	60	0.39	2080	59	66.5	32	7.28
9/9/79	2400	1200	71	95	0.39	2010	60	62.2	37	6.91
9/9/79	2400	1200	77	95	0.48	2370	59	67.2	42	6.98
9/10/79	0600	1175	67	92	0.39	1770	60	54.9	34	6.95
9/10/79	0600	1030	66	82	0.40	1770	44	50.4	27	6.83
9/10/79	1815	950	66	75	0.33	1700	30	55.1	24	6.48
9/11/79	1900	950	65	74	0.87	1700	48	50.7	18	6.84
9/10/79	2400	880	64	70	0.33	1700	63	50.6	28	6.82
9/11/79	2400	930	64	74	0.29	1570	59	45.6	14	6.96
9/12/79	-	906	63	73	0.30	1480	62.5	39.2	12	7.11
9/12/79	1300	860	40.5	92.7	0.37	1525	25.4	43.1	14	7.2

a. Results expressed as mg/l. b. TOC = Total Organic Carbon

TABLE 11

AVERAGE COMPOSITION OF RRGP-4 PIT WATER (AUGUST 20, 1979)

COMPONENT	mg/l
Sodium	502.00
Potassium	26.00
Lithium	3.53
Calcium	66.00
Magnesium	1.98
Barium	< 0.03
Strontium	1.30
Manganese	< 0.001
Boron	0.36
Silica	143.00
Carbonate	31.40
Bicarbonate	29.50
Chloride	771.00
Fluoride	8.40
Bromide	0.52
Sulfate	65.00
Total Organic Carbon	2.00
Carbohydrate	1.10
pH	9.00

Elements not listed were below the following detection limits: Ag 0.003, Al 0.03, As 0.1, Au 0.009, Be 0.001, Cd 0.007, Ce 0.001, Co 0.009, Cr 0.01, Cu 0.002, Fe 0.003, Ga 0.07, Ge 0.08, Hg 0.03, La 0.003, Mo 0.08, Ni 0.04, Pb 0.05, PO_4 0.1, Sb 0.04, Se 0.1, Sn 0.1, Ti 0.002, V 0.003, Zn 0.007, Zr 0.005

TABLE 12

AVERAGE COMPOSITION OF RRGP-4
PRODUCED FLUIDS (SEPTEMBER 10-12, 1979)

COMPONENT	mg/l
Sodium	913.00
Potassium	63.00
Lithium	3.18
Calcium	73.00
Magnesium	0.35
Barium	0.08
Strontium	1.94
Manganese	0.038
Boron	0.25
Silica	122.00
Carbonate	0.00
Bicarbonate	25.40
Chloride	1613.00
Fluoride	6.40
Bromide	0.07
Sulfate	48.00
Total Organic Carbon	47.40
Carbohydrate	18.00
pH	6.90

Elements not listed were below the following detection limits:

Ag 0.003, Al 0.03, As 0.1, Au 0.009, Be 0.001, Cd 0.007, Ce 0.001, Co 0.009, Cr 0.01, Cu 0.002, Fe 0.003, Ga 0.07, Ge 0.08, Hg 0.03, La 0.003, Mo 0.08, Ni 0.04, Pb 0.05, PO_4 0.1, Sb 0.04, Se 0.1, Sn 0.1, Ti 0.002, V 0.003, Zn 0.007, Zr 0.005

TABLE 13

MATERIAL BALANCE FOR RRGP-4 FRAC POLYMER STIMULATION

POLYMER

Total weight of polymer injected:		2044 lbs.
Total weight of polymer returned:		
First flow:	899 lbs.	
Second flow:	184 lbs.	
Third flow:	123 lbs.	
Cumulative weight (%):	1206 lbs. (59%)	
Total weight of polymer converted to soluble products (%):	613 lbs. (30%)	
Therefore, total weight polymer not accounted for (%):	225 lbs. (11%)	

ORGANIC CARBON

Total weight organic carbon injected:		818 lbs.
Total weight organic carbon returned:		
First flow:	368 lbs.	
Second flow:	106 lbs.	
Third flow:	254 lbs.	
Cumulative weight (%):	728 lbs. (89%)	

TABLE 14

FRAC FLUID SAMPLES FROM RRGP-5
DURING INJECTION (NOVEMBER 12, 1979)

		COMPONENT[a]				
TIME	pH	AMMONIUM	NITRATE	TOC[b]	CARBOHYDRATE	TOC/CARBOHYDRA
initial make-up	6.4	66.0	236	697	1700	.41
11:40	6.4	101.0	347	740	1940	.38
12:00	6.5	102.0	346	778	2040	.38
12:32	6.5	102.0	349	758	1970	.38
13:02	6.6	80.5	278	641	1560	.41
13:27	6.6	82.1	299	625	1560	.40
14:01	6.8	77.4	290	626	1590	.39
14:22	6.4	69.8	252	632	1610	.39

AVERAGE COMPOSITION OF FRAC FLUID:

Ammonium:	85.1 mg/l
Nitrate:	300 mg/l
TOC:	695 mg/l
Carbohydrate:	1721 mg/l
Average % C:	39%

a. Results expressed as mg/l.

b. TOC = Total Organic Carbon

TABLE 15

COMPOSITION OF RRGP-5 PRODUCED FLUIDS DURING FLOW TESTS[a]

DATE	TIME	AMMONIUM	NITRATE	TOC[b]	CARBOHYDRATE
		First Flow Test (November 17, 1979)			
11/17/79	12:15	33.6	135	315	664
11/17/79	13:15	27.5	106	248	587
11/17/79	14:15	36.3	117	270	593
11/17/79	15:15	37.4	118	272	606
11/17/79	16:15	38.7	114	257	590
11/17/79	17:15	32.2	111	247	560
11/17/79	18:15	31.9	106	235	548
11/17/79	19:15	30.5	101	225	579
11/17/79	20:15	28.0	93	205	492
11/17/79	21:15	28.3	93	200	458
		Second Flow Test (November 20-21, 1979)			
11/20/79	10:30	9.1	42.5	94.	246
11/21/79	6:45	0.9	6.1	9.4	46
11/21/79	9:05	7.6	40.1	67	214
11/21/79	10:00	14.9	52.3	105	327
11/21/79	10:05	15.6	54.6	105	313
11/21/79	11:05	11.3	40.7	81	252
11/21/79	12:05	12.3	46.3	78	269
11/21/79	13:05	17.0	57.7	105	302
11/21/79	14:05	13.3	50.5	95	275
		Third Flow Test (November 25-27, 1979)			
11/25/79	15:00	7.1	27.4	50	141
11/25/79	19:00	7.6	26.4	41	128
11/25/79	19:30	7.7	25.5	40	124
11/25/79	20:00	2.4	13.2	45	67
11/25/79	21:00	10.5	30.3	57	145
11/25/79	22:00	11.7	29.0	55	137
11/25/79	23:00	8.0	30.0	62	143
11/25/79	24:00	8.0	29.3	62	144
11/27/79	9:30	4.5	16.7	37	84
11/27/79	13:40	4.4	14.8	25	70
11/27/79	14:30	6.6	13.0	24	68
11/27/79	15:00	4.1	14.0	23	73

a. Results expressed as mg/l.

b. TOC = Total Organic Carbon.

TABLE 15 (continued)

COMPOSITION OF RRGP-5 PRODUCED

FLUIDS DURING FLOW TESTS[a]

DATE	TIME	AMMONIUM	NITRATE	TOC[b]	CARBOHYDRATE
Fourth Flow Test (December 17-19, 1979)					
12/17/79	16:45	4.1	6.7	91	16
12/17/79	18:00	1.9	7.6	21	32
12/17/79	19:00	2.0	8.1	12	38
12/17/79	20:00	1.8	6.8	8	29
12/17/79	21:00	2.6	9.1	15	40
12/17/79	22:00	2.8	9.6	22	55
12/17/79	23:00		7.6	24	36
12/17/79	24:00	4.6	9.6	15	39
12/18/79	01:15	5.8	9.0	12	36
12/18/79	02:00	3.8	8.6	23	35
12/18/79	03:00	2.8	9.7	13	34
12/18/79	04:00	2.8	9.7	11	37
12/18/79	05:00	3.7	8.6	24	32
12/18/79	06:00	2.8	9.6	11	34
12/18/79	07:00	3.8	9.6	17	52
12/18/79	08:00	3.7	8.7	10	36
12/18/79	09:00	2.9	7.9	22	32
12/18/79	10:00	2.3	8.8	14	37
12/18/79	11:30	3.1	10.4	15	40
12/18/79	17:00	4.2	13.7	22	49
12/19/79	03:00	3.3	8.7	20	37

a. Results expressed as mg/l.

b. TOC = Total Organic Carbon.

TABLE 16

AVERAGE COMPOSITION OF RRGP-5

PIT WATER (NOVEMBER 11,12, 1979)

COMPONENT	mg/l
Sodium	855.00
Potassium	59.1
Lithium	5.52
Calcium	86.30
Magnesium	0.74
Strontium	1.90
Iron	0.10
Manganese	0.07
Zinc	0.017
Boron	0.25
Silica	134.00
Carbonate	0.00
Bicarbonate	98.70
Sulfate	101.00
Chloride	1399.00
Fluoride	1.10
Bromide	0.80
Ammonium	1.30
Nitrate	<0.10
Total Organic Carbon	25.90
Carbohydrate	16.00
pH	7.64

Elements not listed were below the following detection limits:

Ag 0.003, Al 0.03, As 0.1, Au 0.009, Be 0.001, Cd 0.007, Ce 0.001, Co 0.009, Cr 0.01, Cu 0.002, Fe 0.003, Ga 0.07, Ge 0.08, Hg 0.03, La 0.003, Mo 0.08, Ni 0.04, Pb 0.05, PO_4 0.1, Sb 0.04, Se 0.1, Sn 0.1, Ti 0.002, V 0.003, Zn 0.007, Zr 0.005

TABLE 17

AVERAGE COMPOSITION OF RRGP-5
PRODUCED FLUIDS (DECEMBER 18-19, 1979)

COMPONENT	mg/l
Sodium	1450.00
Potassium	57.00
Lithium	1.72
Calcium	88.00
Magnesium	0.25
Barium	0.58
Strontium	2.16
Manganese	0.024
Zinc	0.13
Boron	0.041
Silica	113.00
Bicarbonate	68.90
Chloride	2360.00
Fluoride	7.50
Bromide	0.10
Sulfate	72.00
Total Organic Carbon	17.20
Carbohydrate	39.00
pH	7.46

Elements not listed were below the following detection limits:

Ag 0.003, Al 0.03, As 0.1, Au 0.009, Be 0.001, Cd 0.007, Ce 0.001, Co 0.009, Cr 0.01, Cu 0.002, Fe 0.003, Ga 0.07, Ge 0.08, Hg 0.03, La 0.003, Mo 0.08, Ni 0.04, PO_4 0.1, Sb 0.04, Se 0.1, Sn 0.1, Ti 0.002, V 0.003, Zr 0.005, Pb 0.05

TABLE 18

PERCENT RETURN OF INJECTED MATERIAL AT RRGP-5

COMPONENT	PERCENT OF TOTAL INJECTED: FLOW 1	FLOW 2	FLOW 3	FLOW 4	TOTAL RETURN
AMMONIUM ION	26.1	4.8	9.0	4.4	44.3
NITRATE ION	26.4	6.9	9.5	2.8	45.6
AMMONIUM NITRATE (AVERAGE)	26.3	5.9	9.3	3.6	45.1
TOTAL ORGANIC CARBON	25.9	6.2	11.0	3.0	46.1
CARBOHYLRATE	23.7	4.9	8.5	2.5	39.6

TABLE 19

MATERIAL BALANCE FOR RRGP-5
FRAC POLYMER STIMULATION

POLYMER

Total weight of polymer injected:		4844 lbs.
Total weight of polymer returned:		
First flow:	1148 lbs.	
Second flow:	237 lbs.	
Third flow:	412 lbs.	
Fourth flow:	121 lbs.	
Cumulative weight (%):	1918 lbs. (40%)	
Total weight of polymer converted to soluble products (%):	315 lbs. (6%)	
Therefore, total weight polymer not accounted for (%):	2919 lbs. (54%)	

ORGANIC CARBON

Total weight organic carbon injected:		1889 lbs.
Total weight organic carbon returned:		
First flow:	489 lbs.	
Second flow:	117 lbs.	
Third flow:	208 lbs.	
Fourth flow:	57 lbs.	
Cumulative weight (%):	871 lbs. (46%)	

FIGURE 1

RAFT RIVER FACILITY WITH GEOLOGIC STRUCTURE AND WELL LOCATIONS

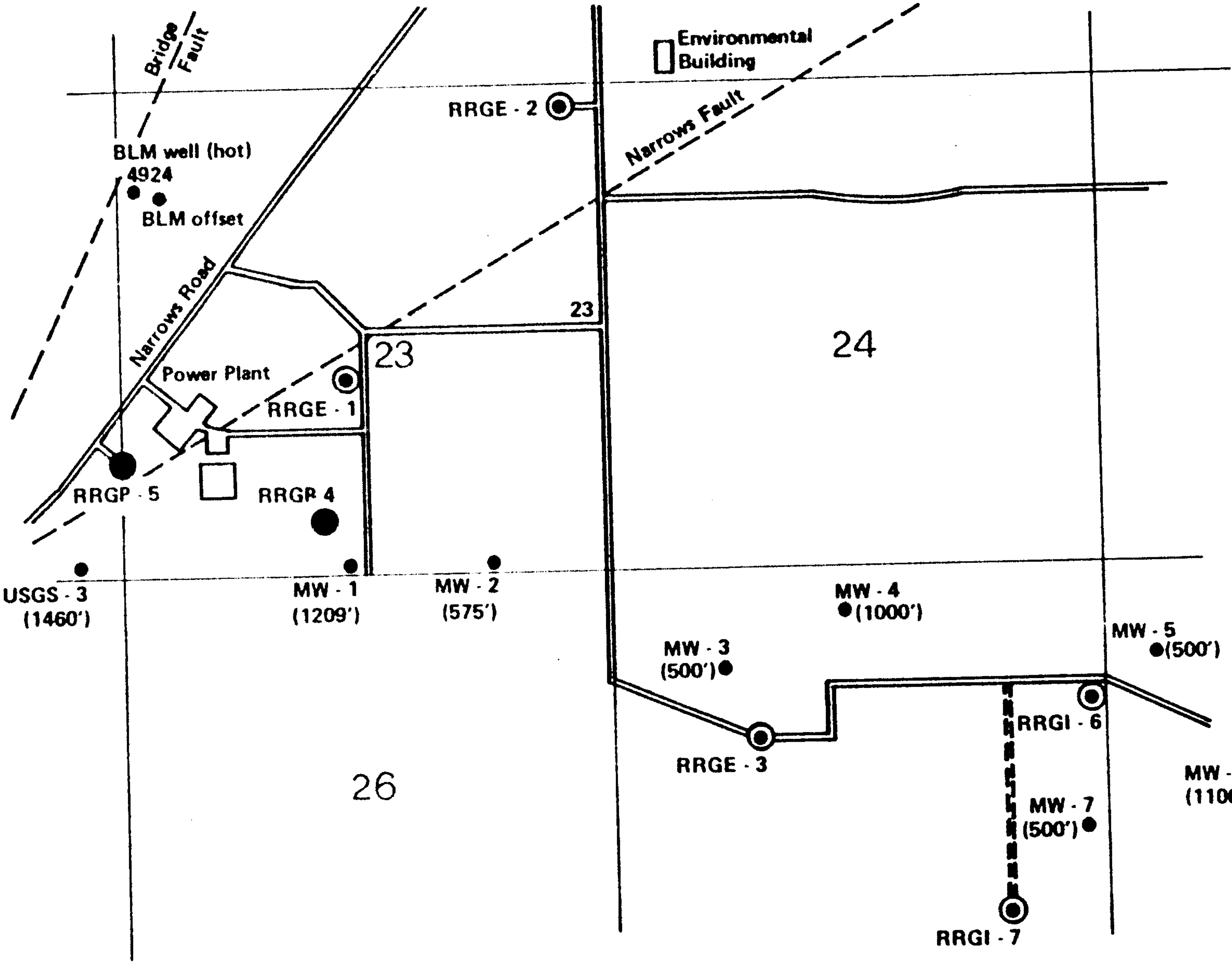

FIGURE 2

RAFT RIVER WELL SYSTEM
JANUARY 1979

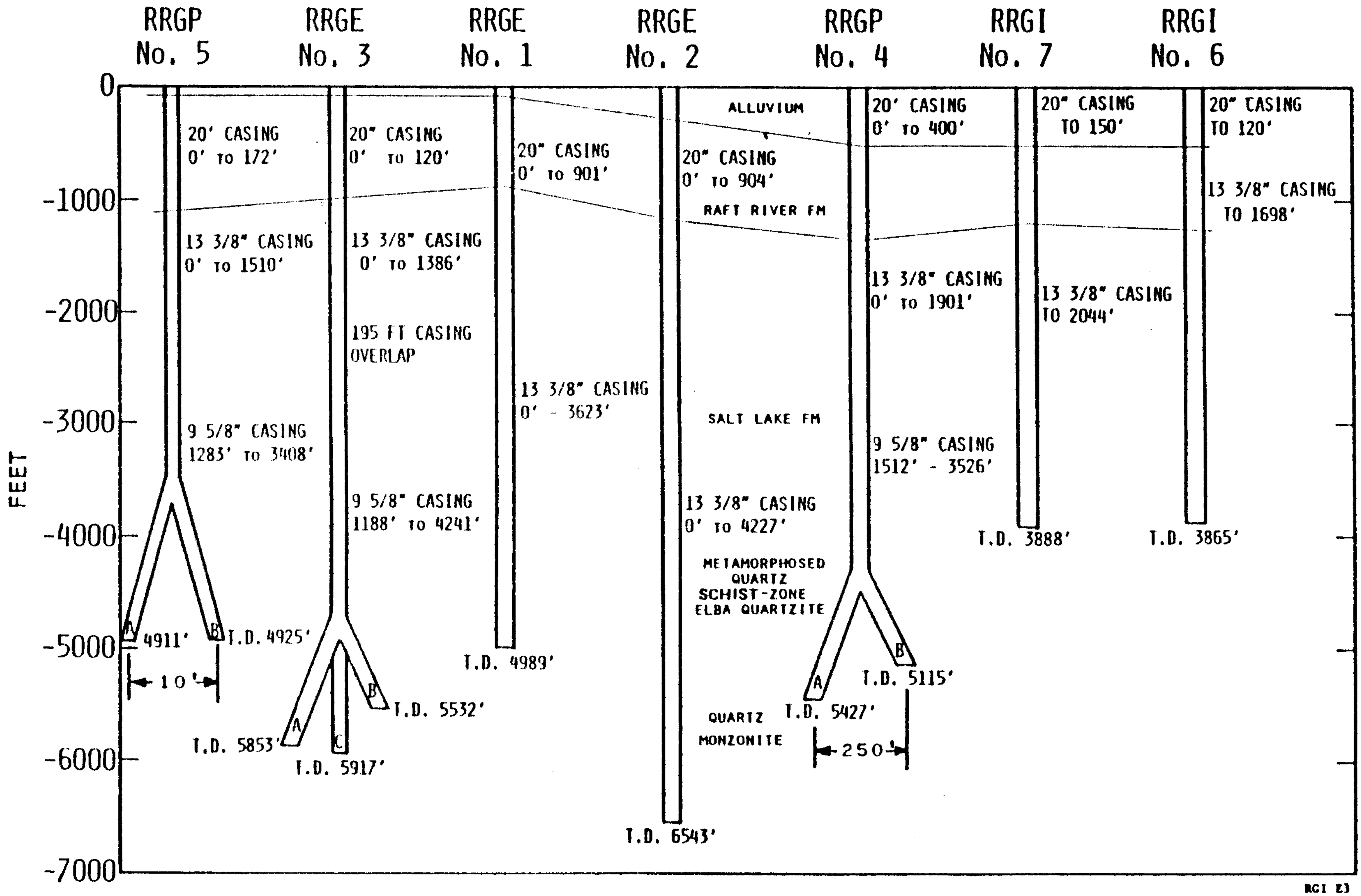

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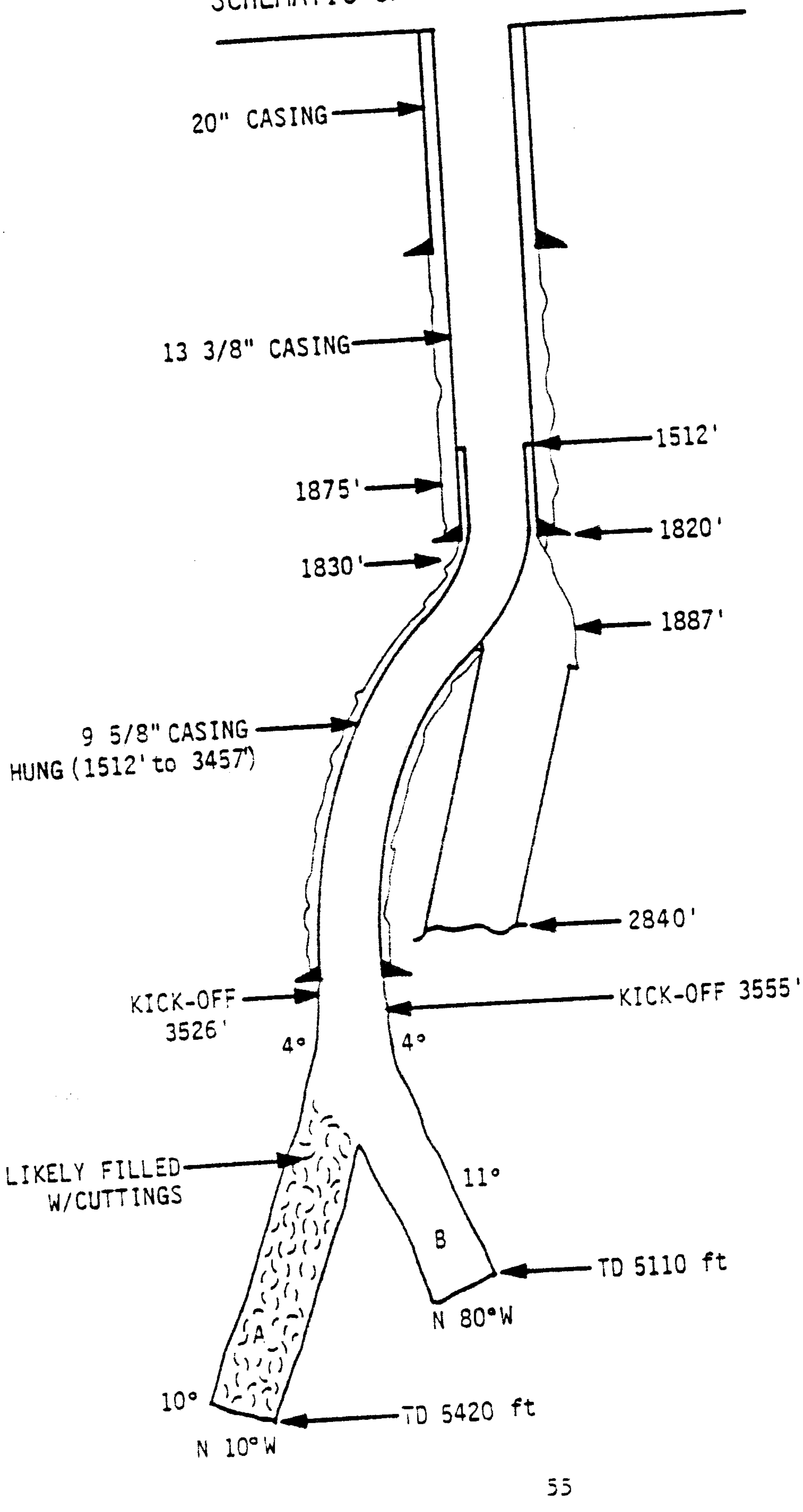
FIGURE 3

SCHEMATIC OF RAFT RIVER RRGP-4



RGI E137

FIGURE 4

SCHEMATIC OF RAFT RIVER WELL RRGP-5

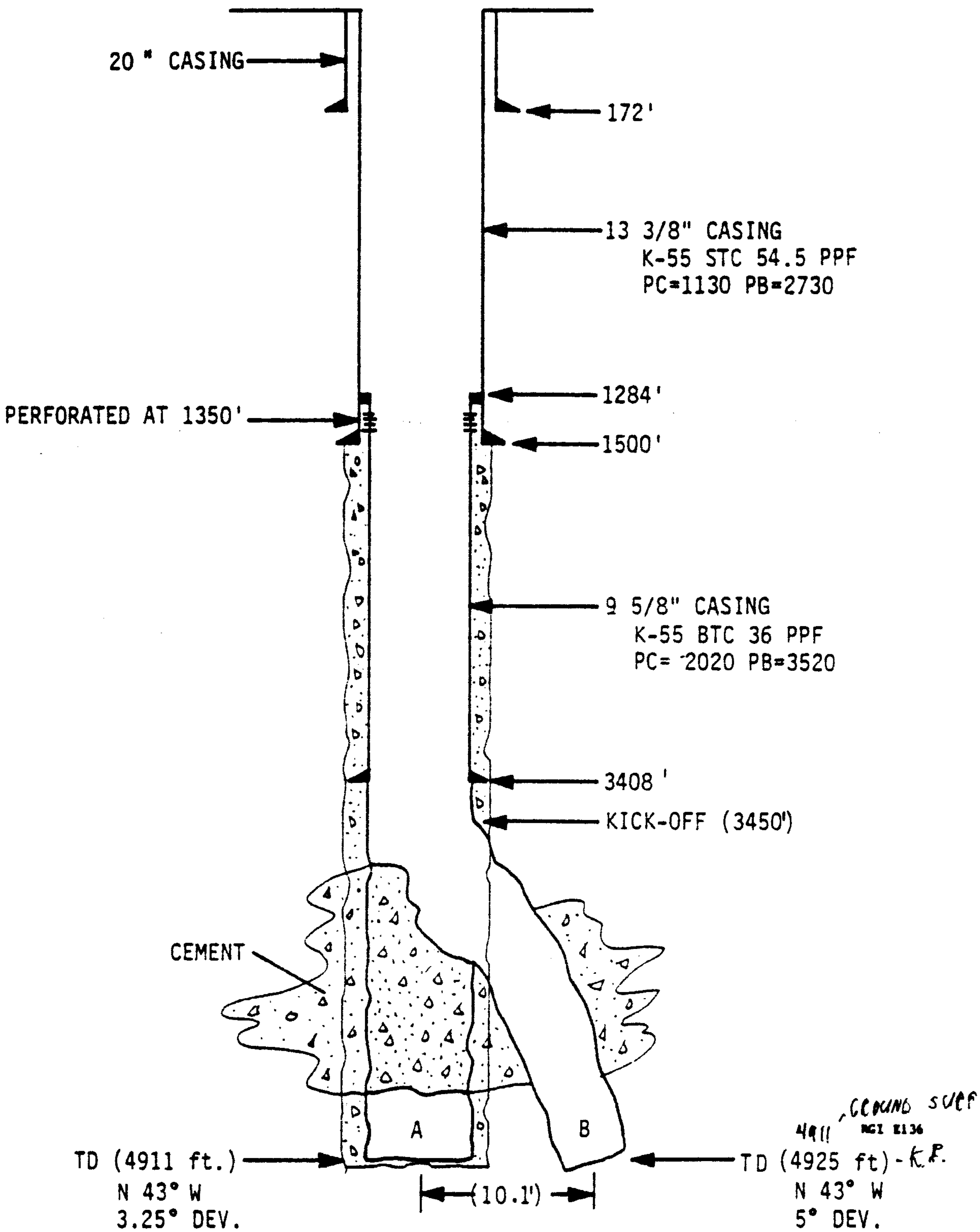
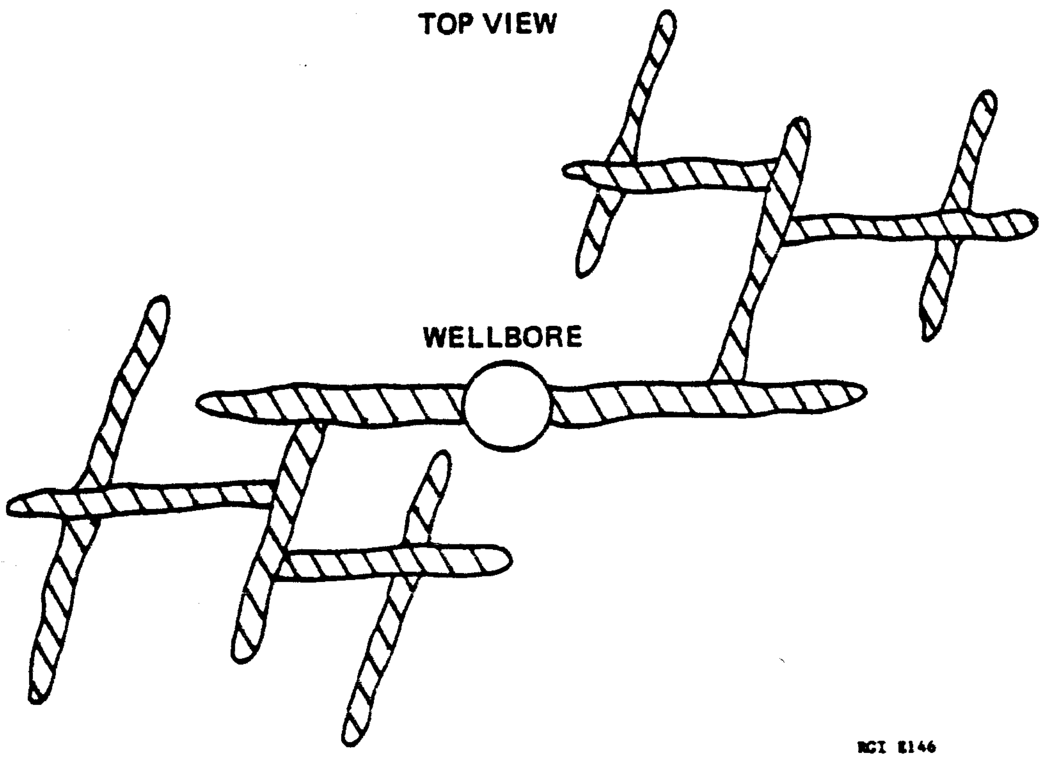


FIGURE 5

SCHEMATIC OF A DENDRITIC FRACTURE



RCI E146

FIGURE 6
PRESSURE-RATE HISTORY
RRGP-4 FRAC JOB

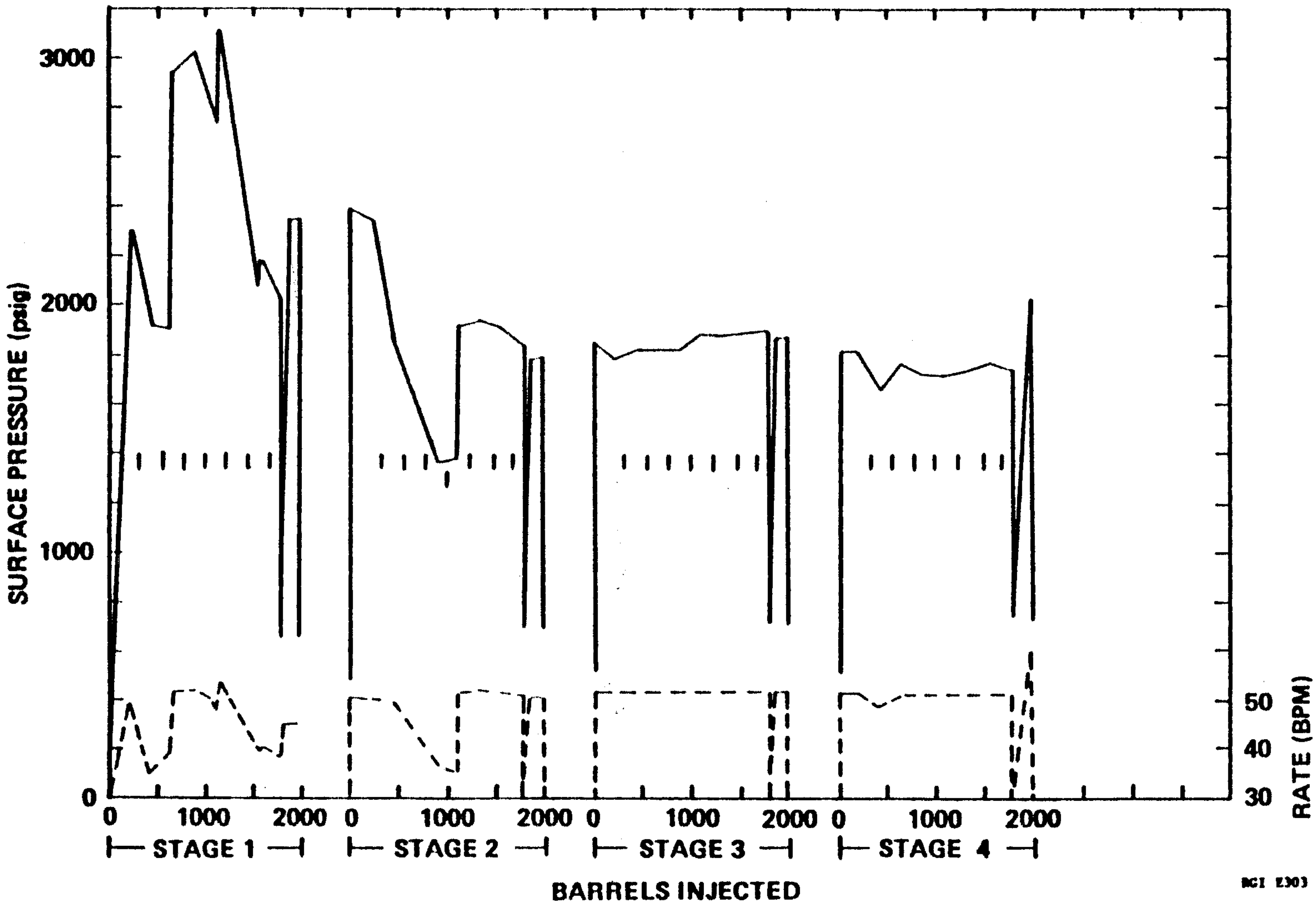


FIGURE 7
EQUIPMENT LAYOUT FOR RRGP-4 FRAC TREATMENT

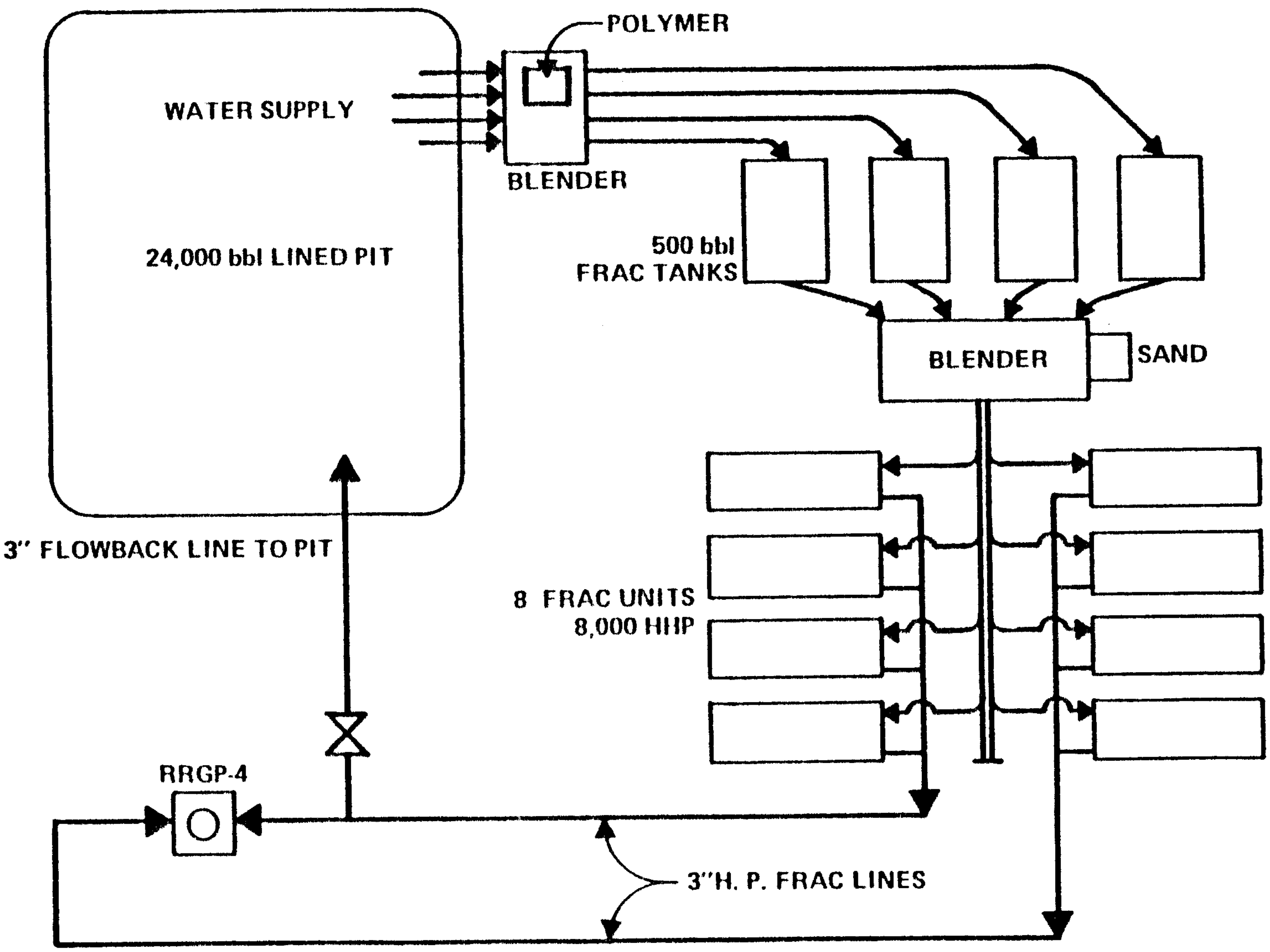
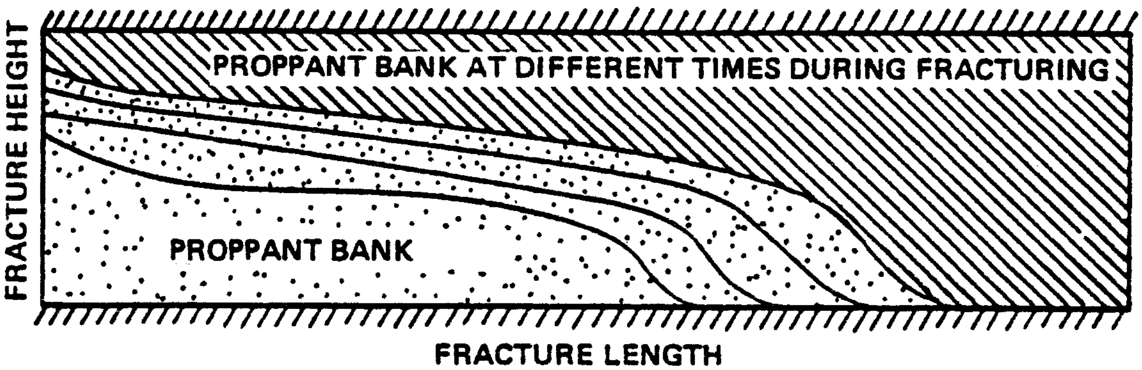


FIGURE 8
SCHEMATIC SIDEVIEW OF PLANNER FRACTURE
SHOWING SAND SETTLING IN LAYERS



EQUILIBRIUM SAND BANK IS FORMED WHEN PROPPANT SETTLES THRU FLUID

MCI E145

FIGURE 9
PRESSURE-RATE HISTORY
RRGP-5 FRAC JOB

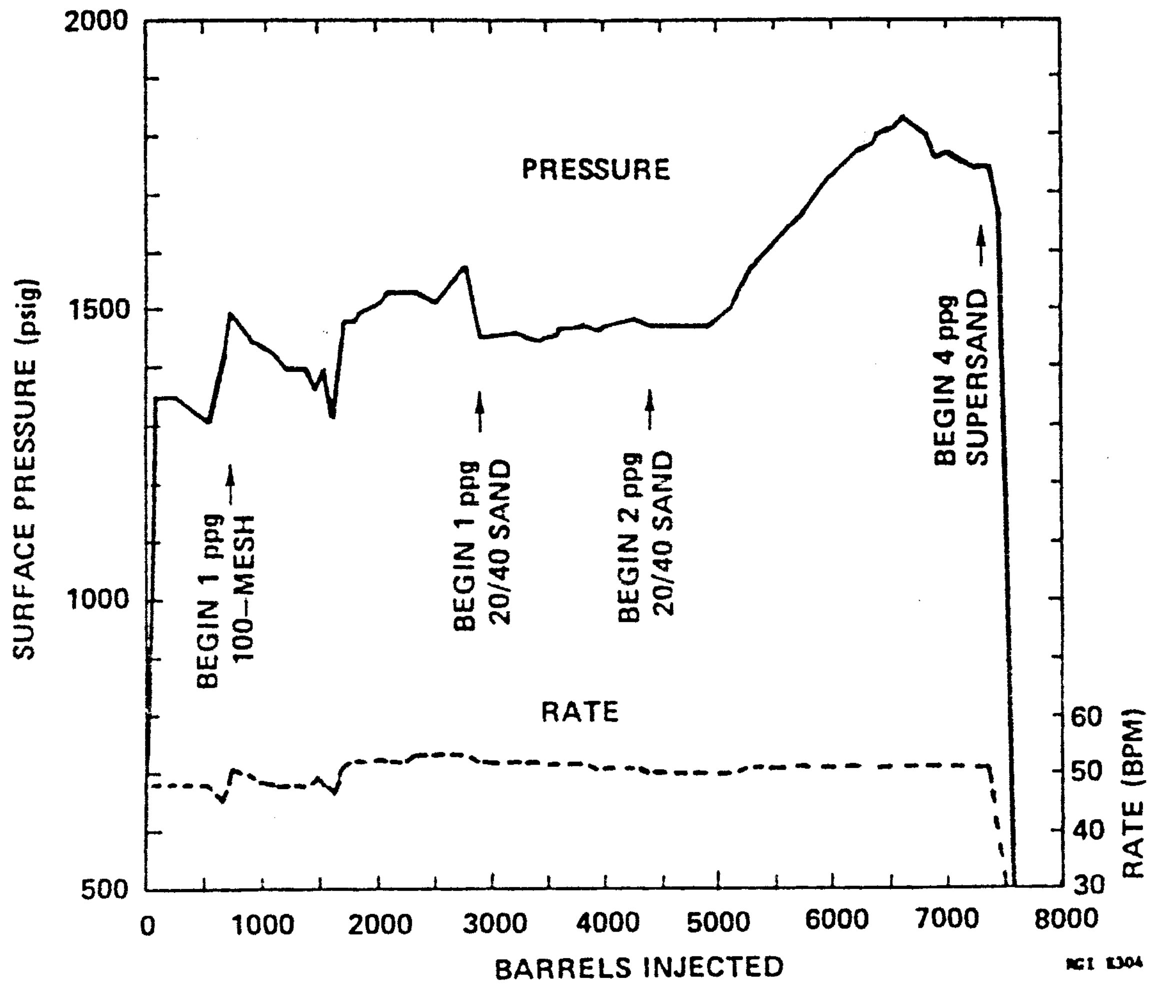


FIGURE 10

SCHEMATIC OF RAFT RIVER WELL RRGP-5
WITH LINER AND FRAC STRING IN PLACE

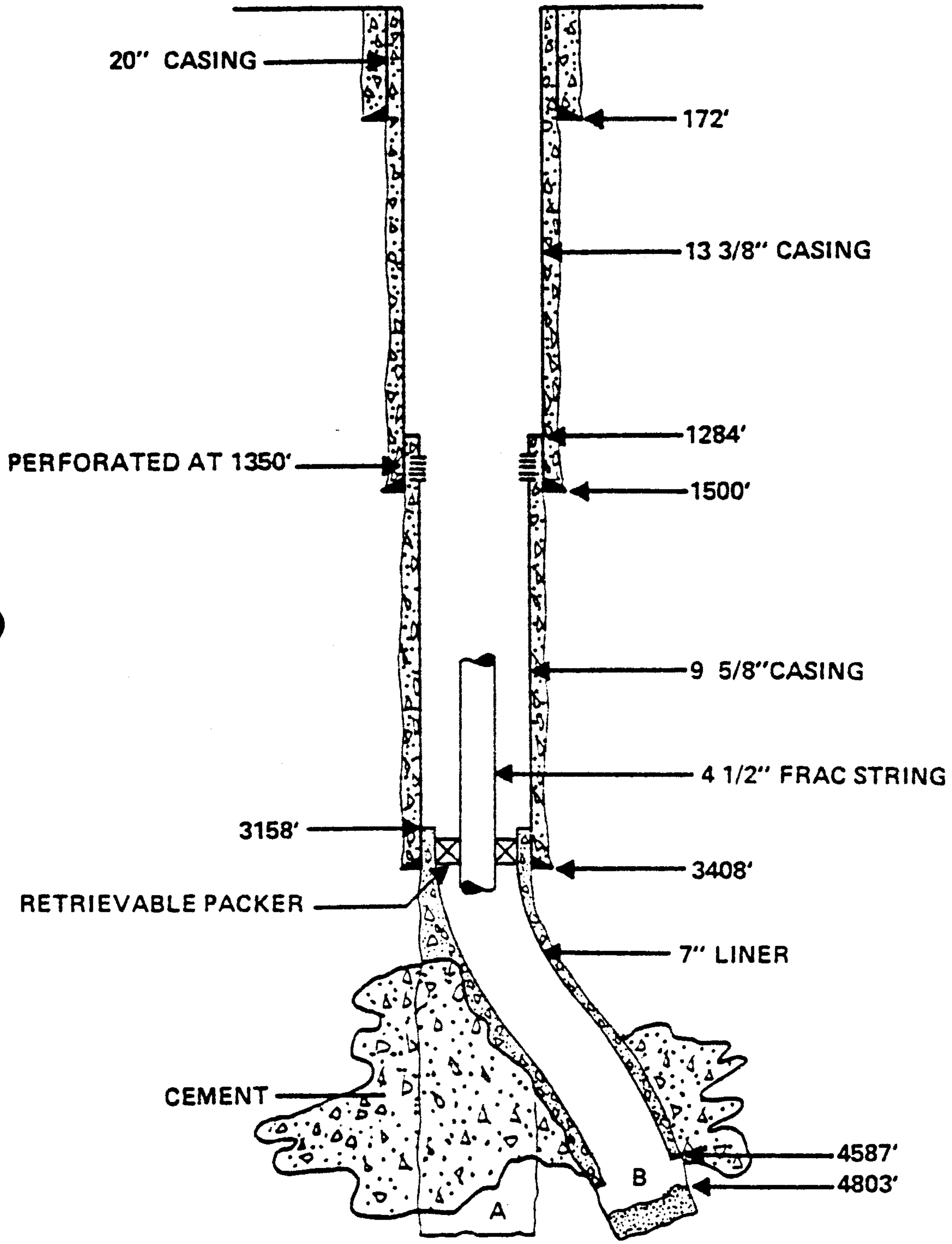


FIGURE 11

RRGP -4 PRODUCTION DATA

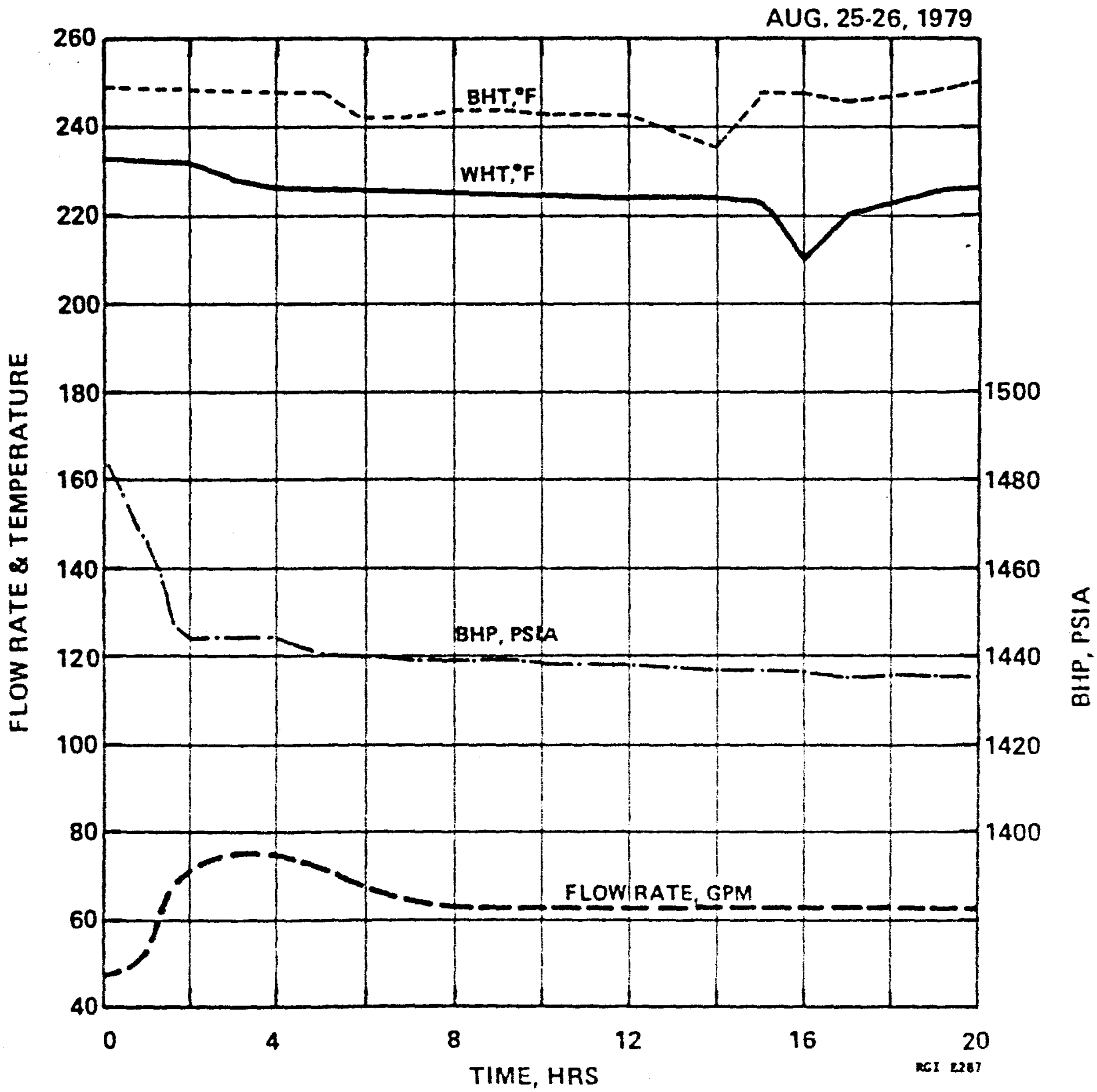


FIGURE 12

RRGP-4 BUILDUP DATA

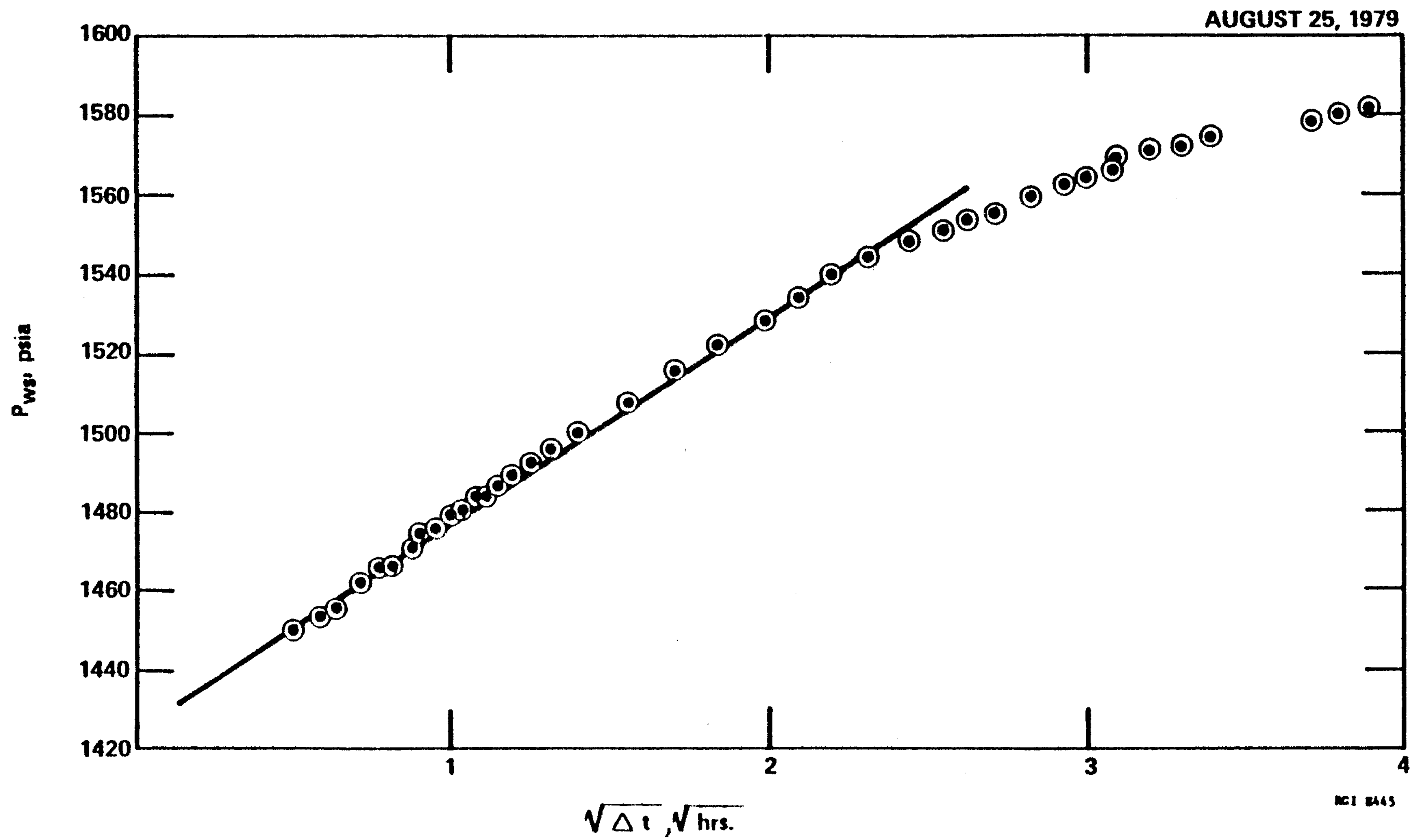


FIGURE 13
RRGP-4 BUILDUP DATA

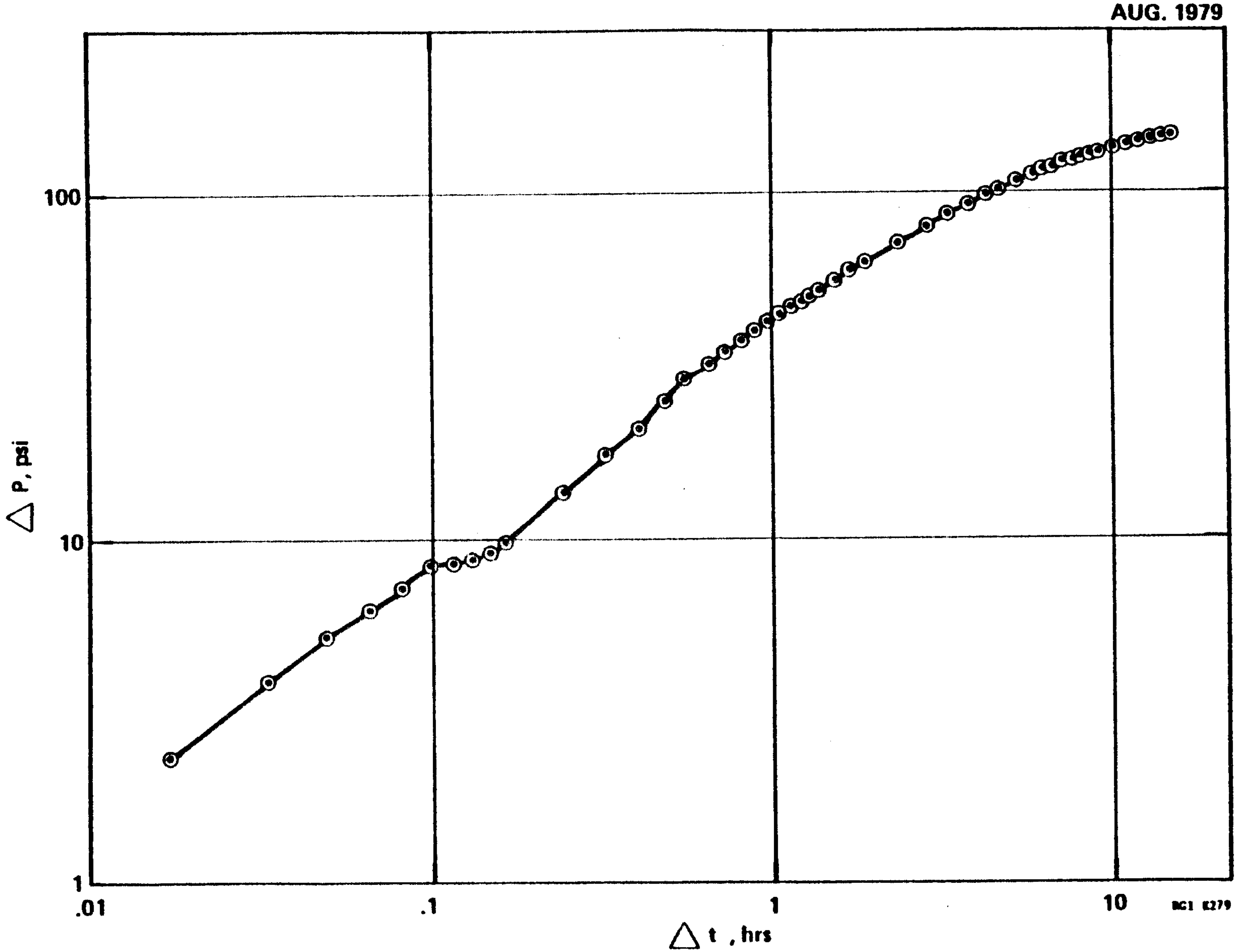


FIGURE 14
RRGP-4 BUILDUP DATA

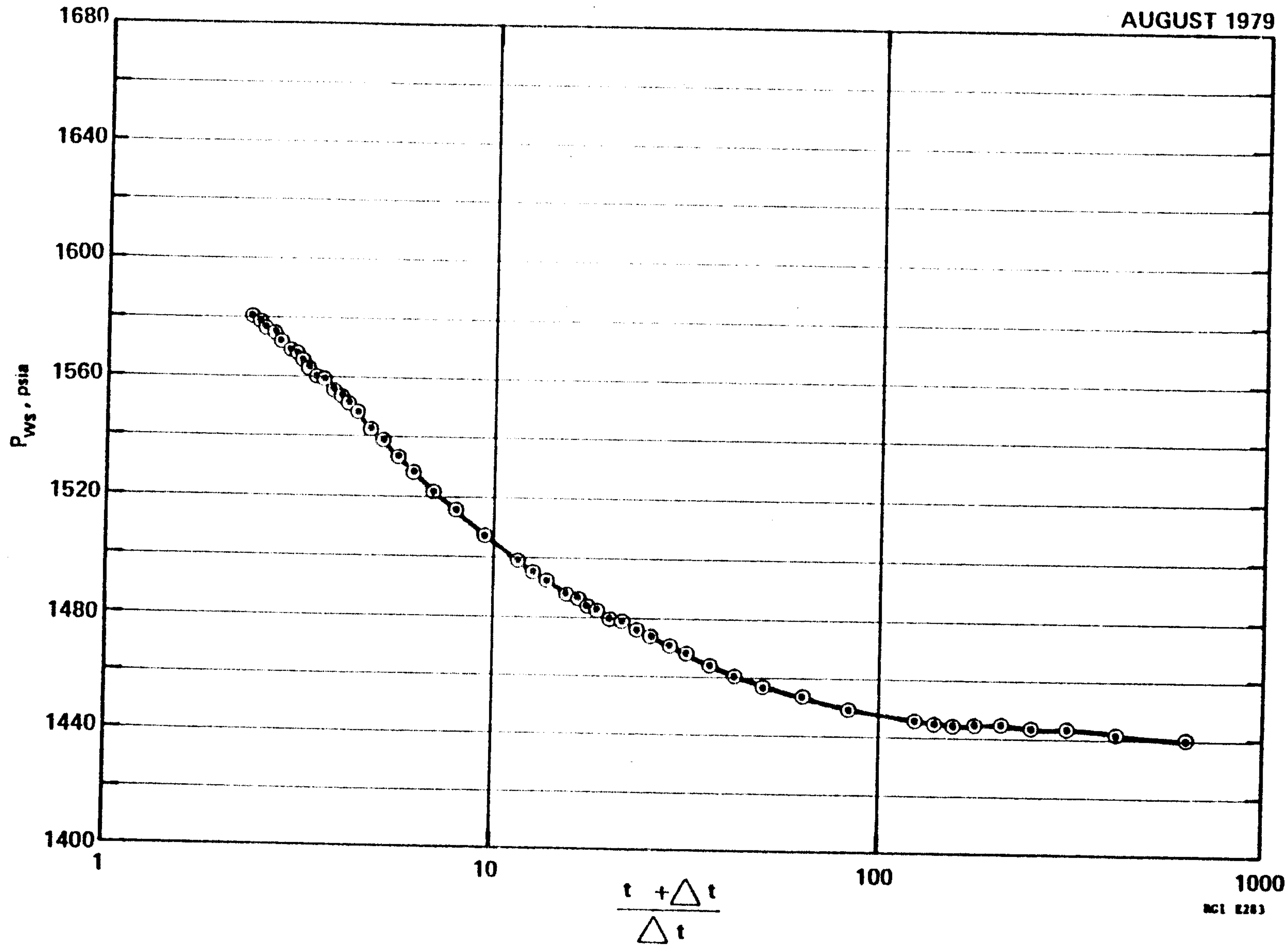


FIGURE 15
STATIC TEMPERATURE SURVEY RRGP-4
RAFT RIVER, IDAHO

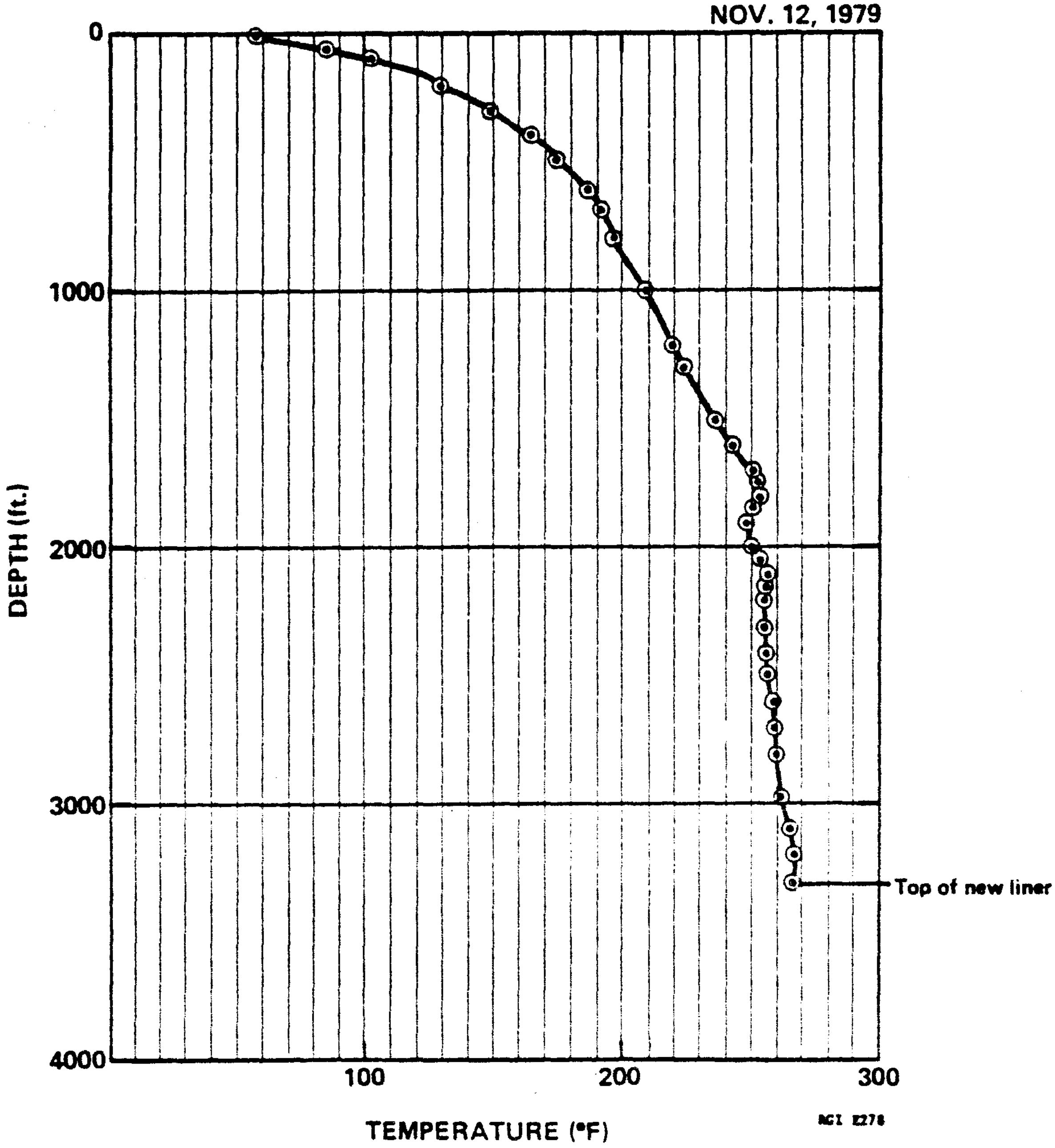


FIGURE 16

RRGP-4 PRODUCTION DATA

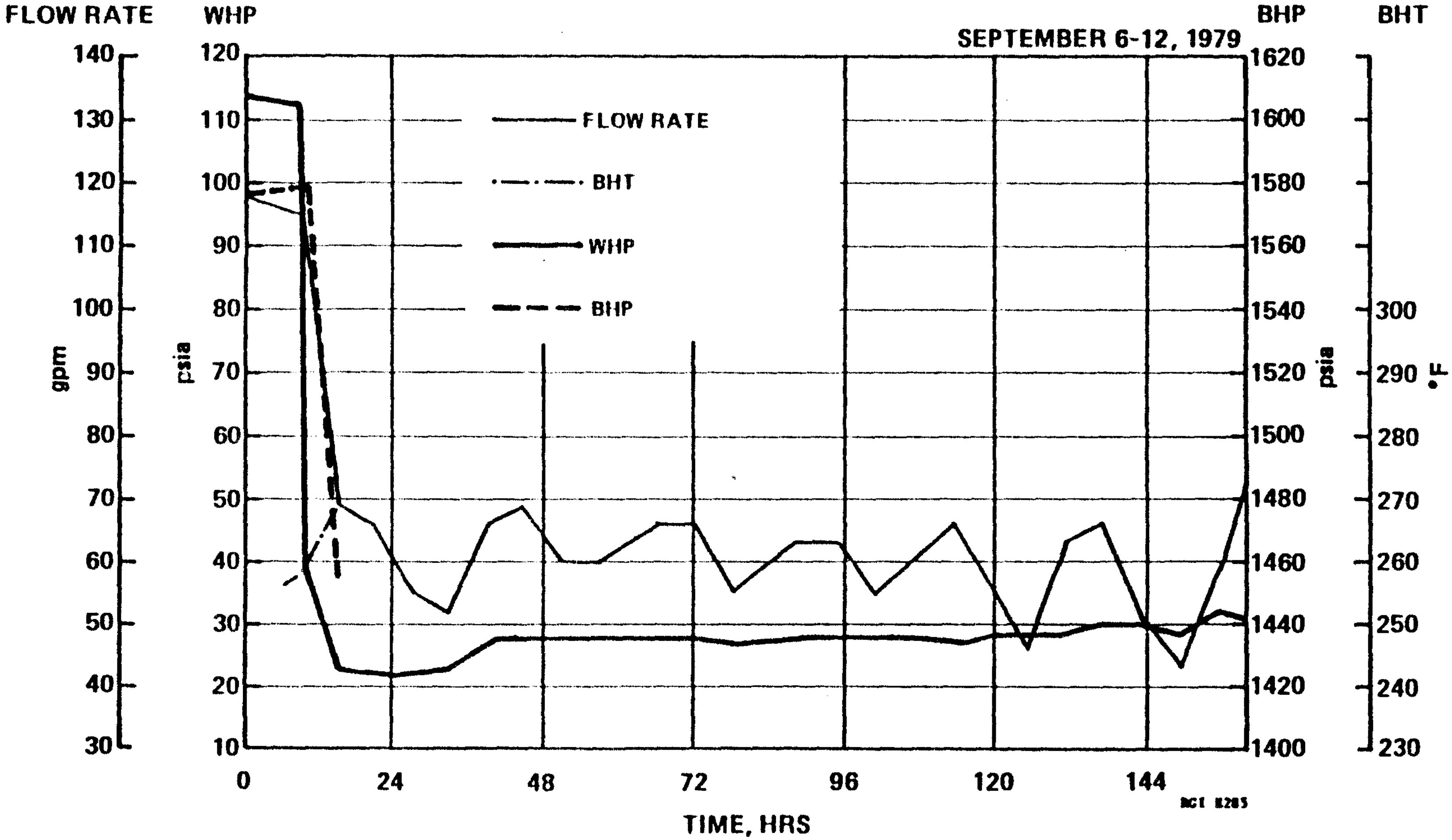


FIGURE 17
RAFT RIVER RRGP - 4
BOTTOM-HOLE DATA

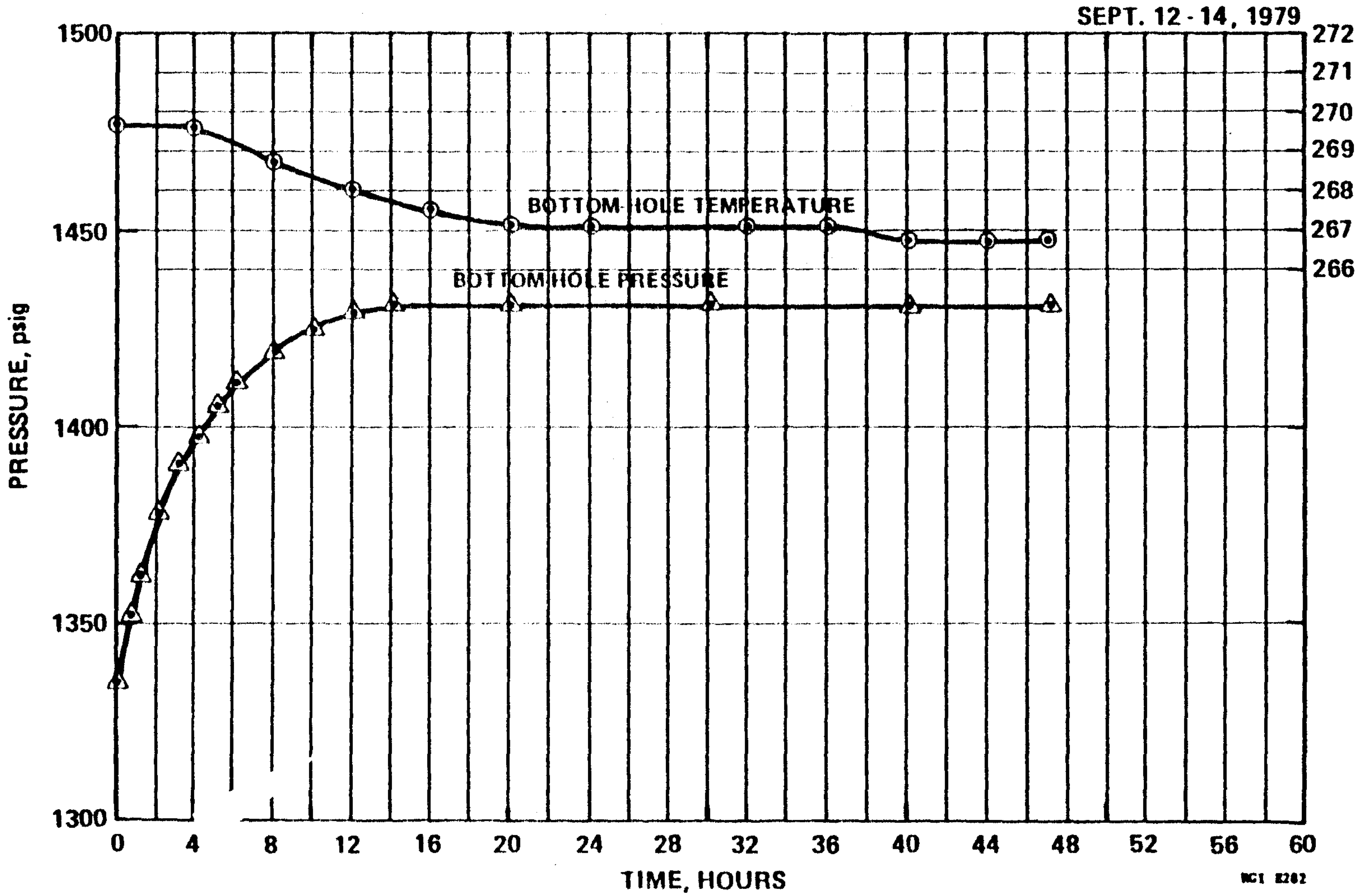


FIGURE 18

RRGP–4 BUILDUP DATA

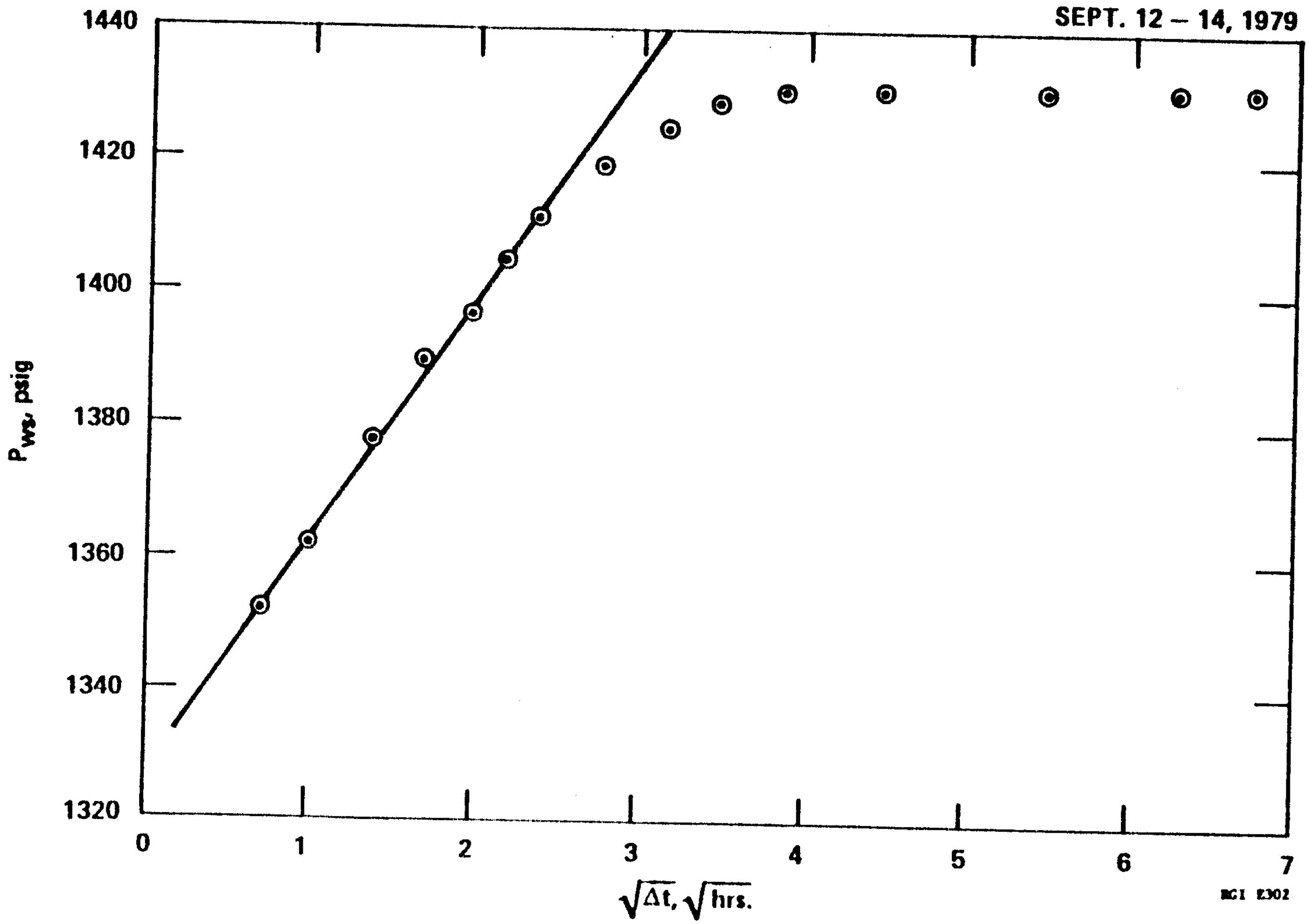


FIGURE 19
RRGP–4 BUILDUP DATA

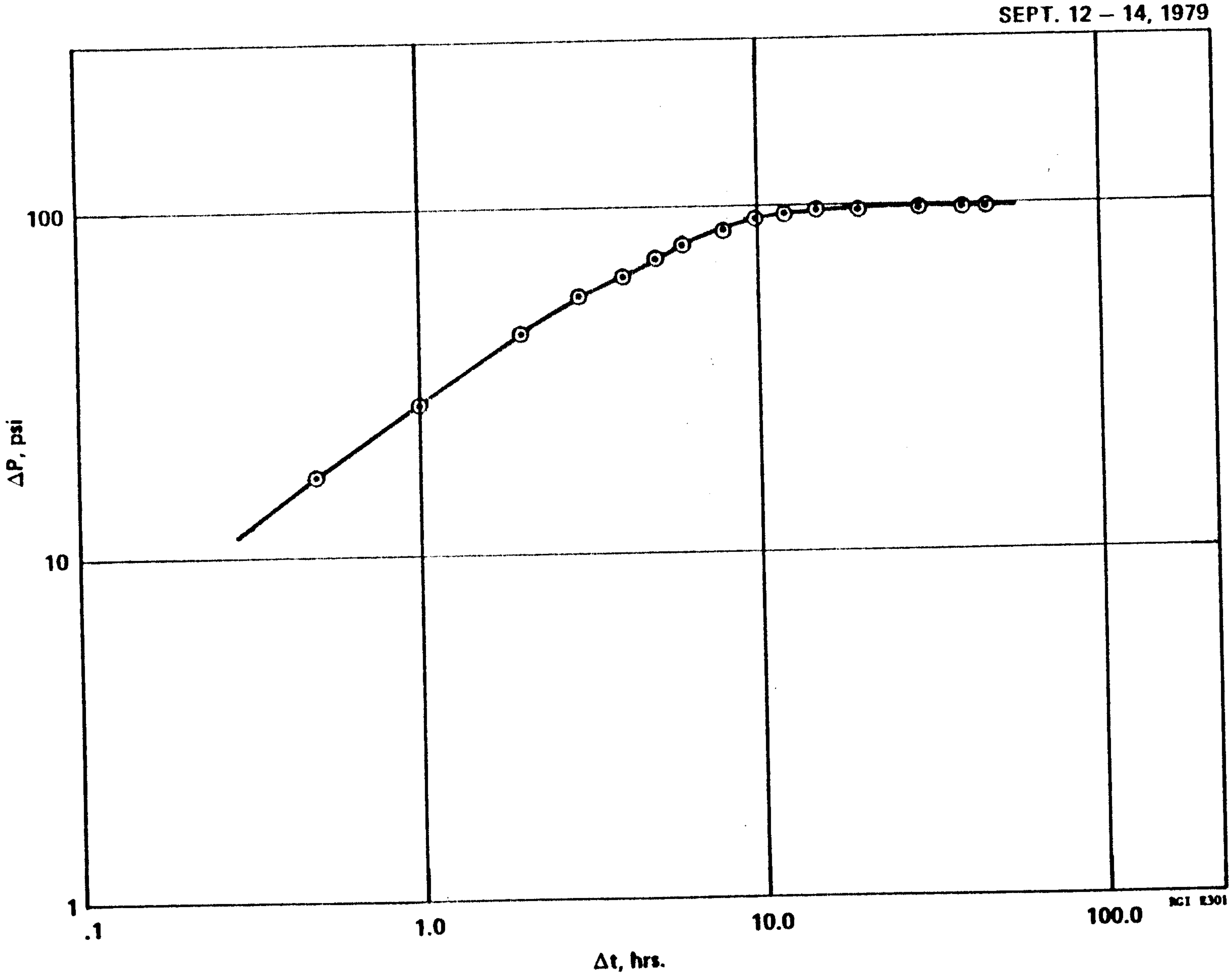


FIGURE 20

RRGP-4 BUILDUP DATA

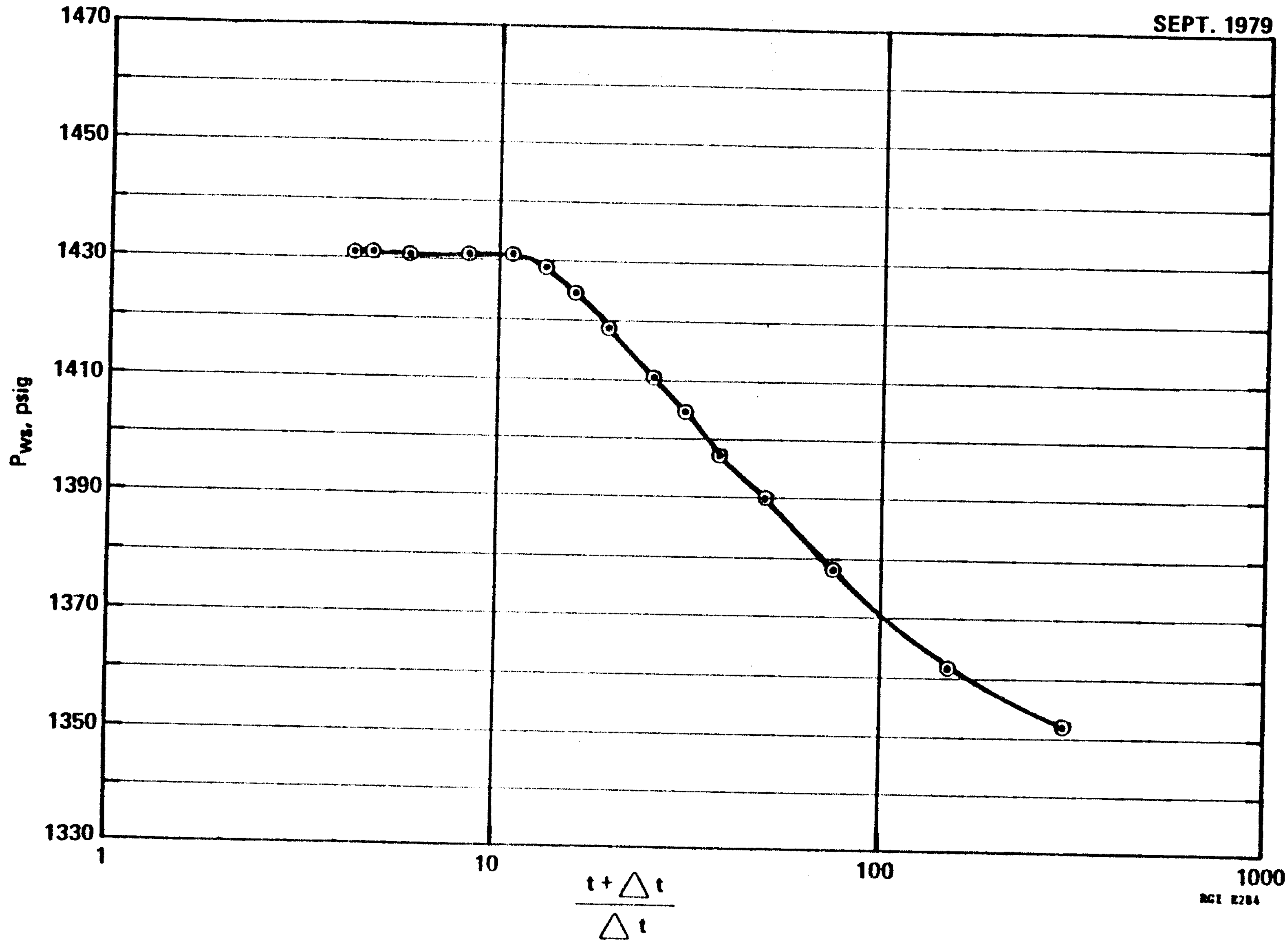


FIGURE 21

RRGP- 5 PRODUCTION DATA

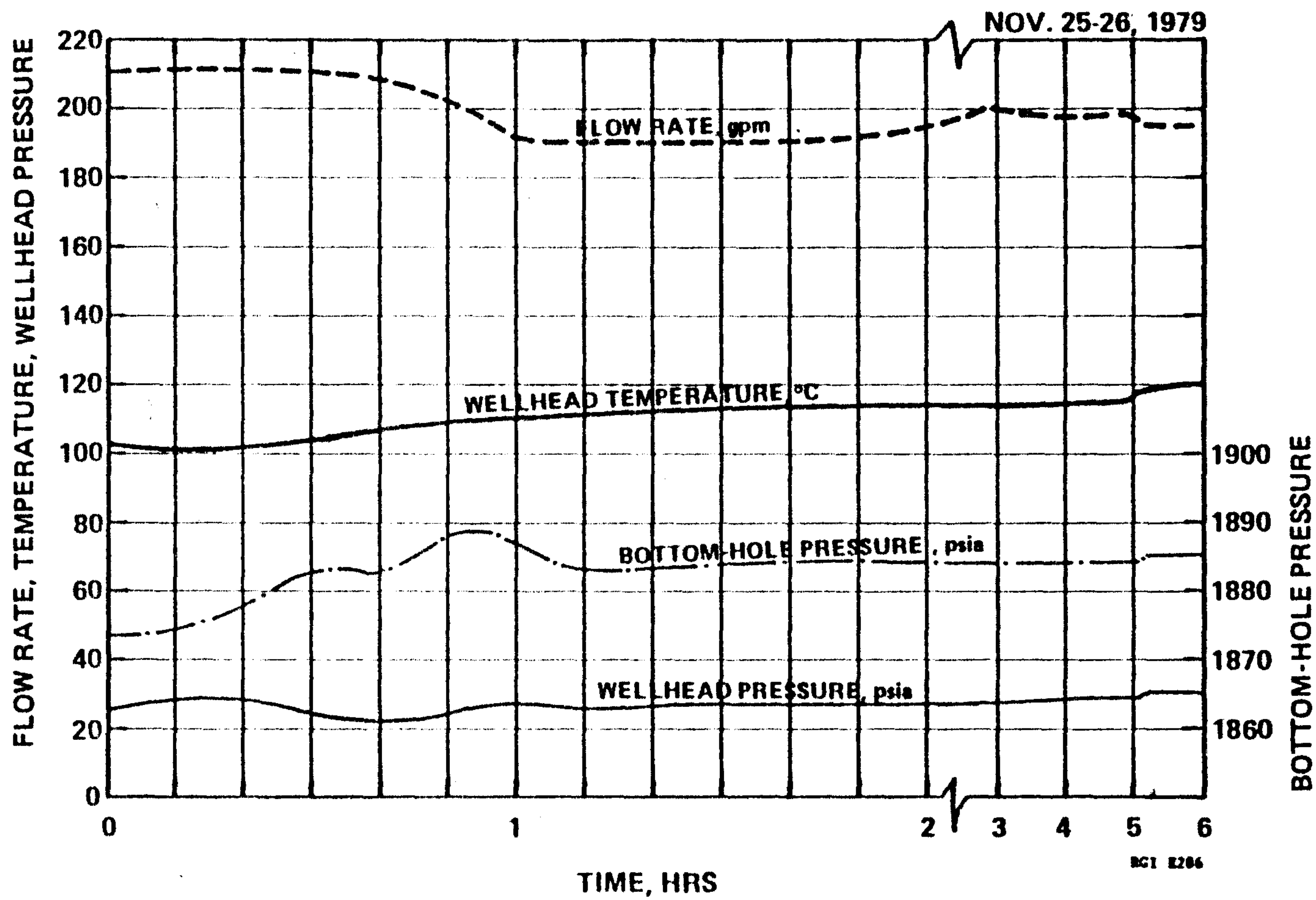


FIGURE 22

RRGP–5 BUILDUP DATA

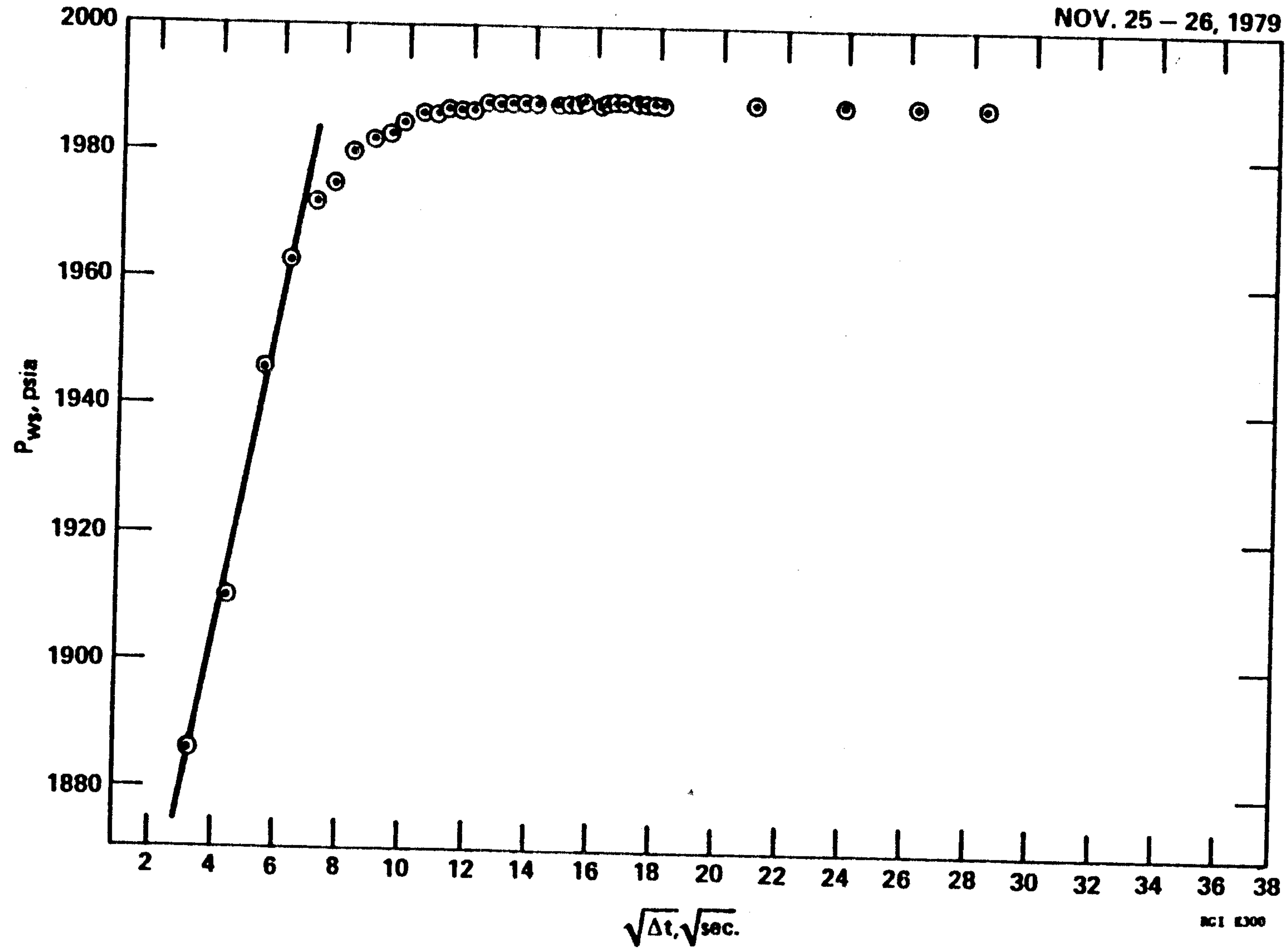


FIGURE 23

RRGP-5 BUILDUP DATA

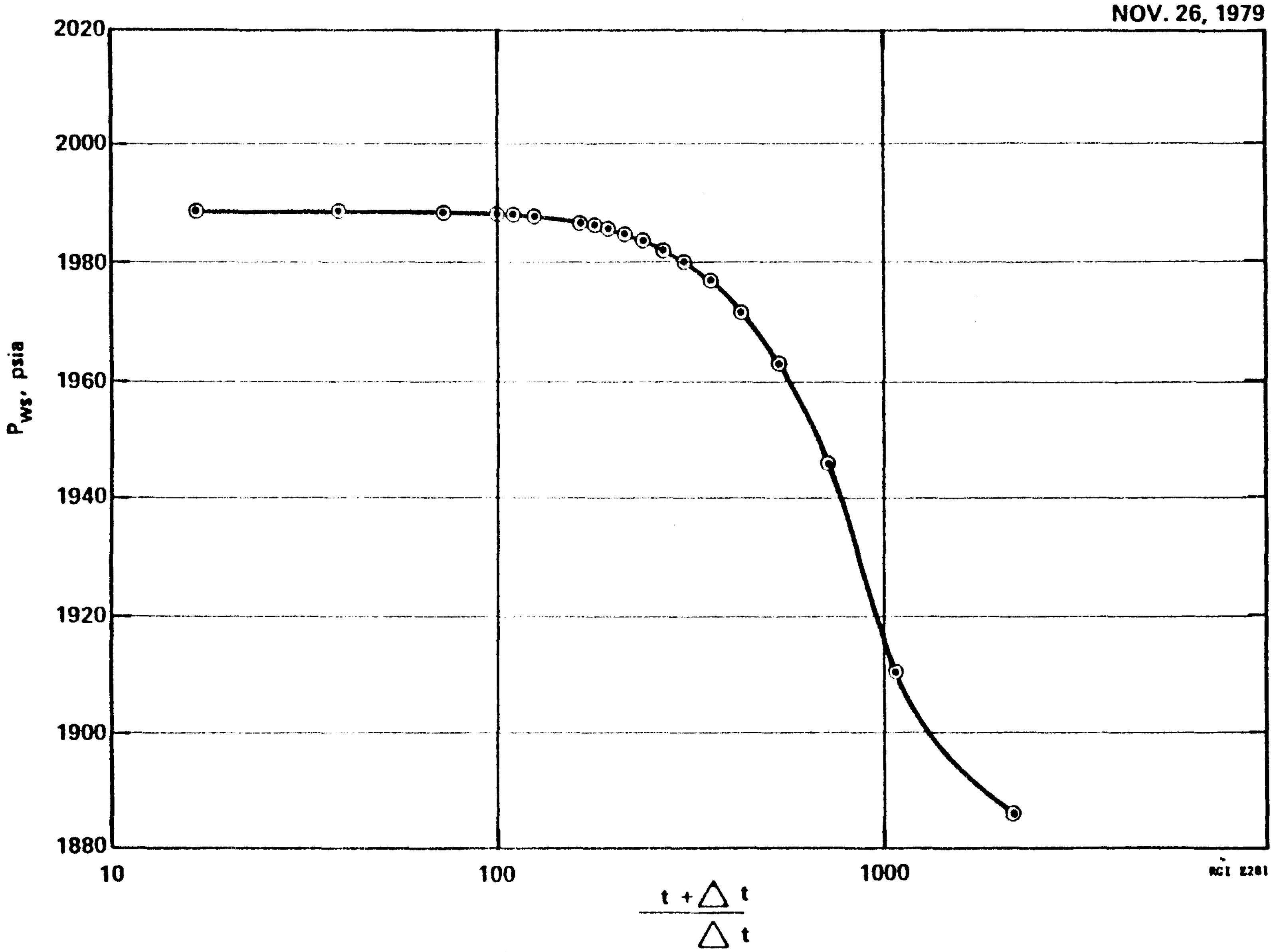


FIGURE 24
RRGP-5 BUILDUP DATA

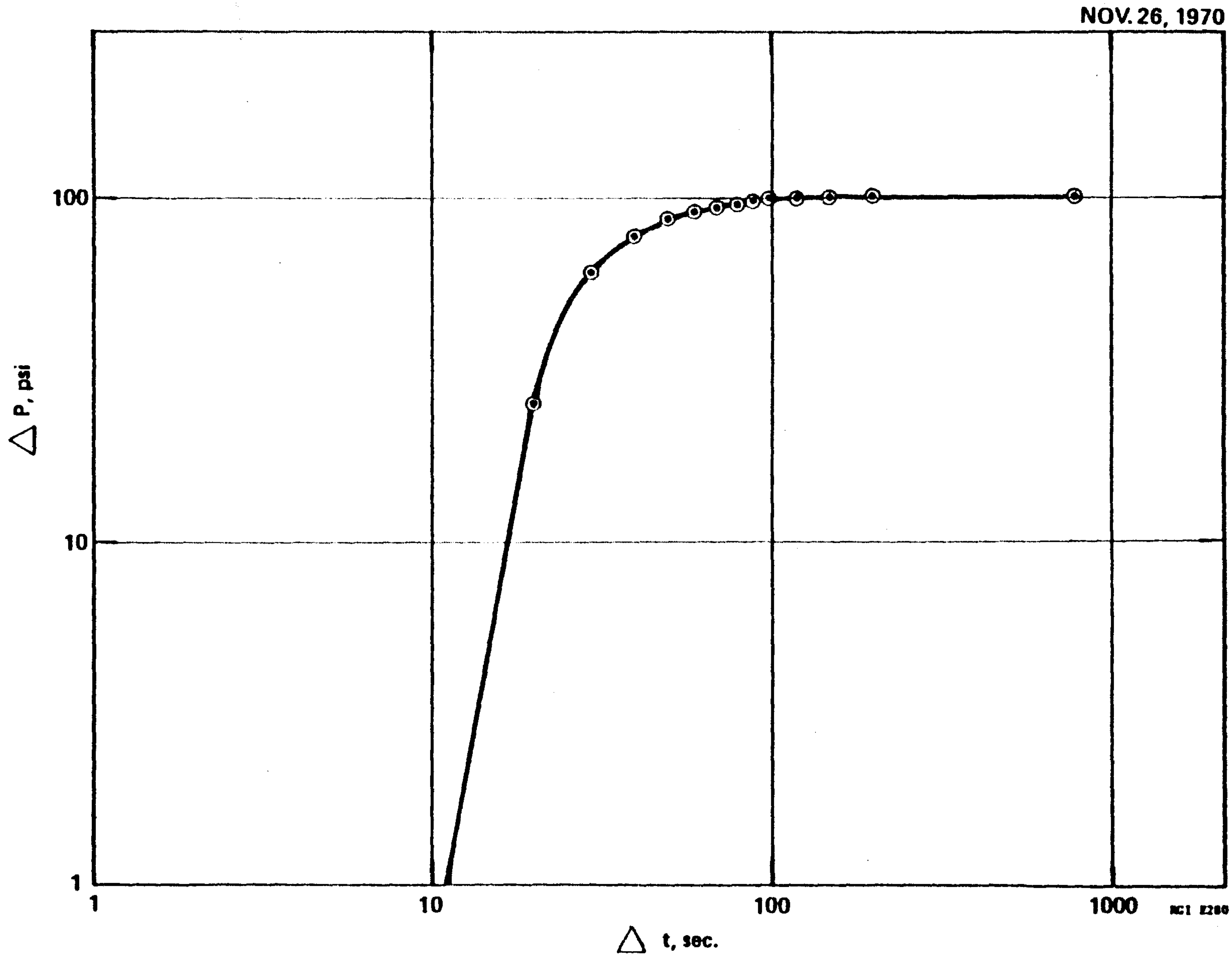


FIGURE 25
TEMPERATURE SURVEYS
RAFT RIVER, IDAHO
RRGP-5

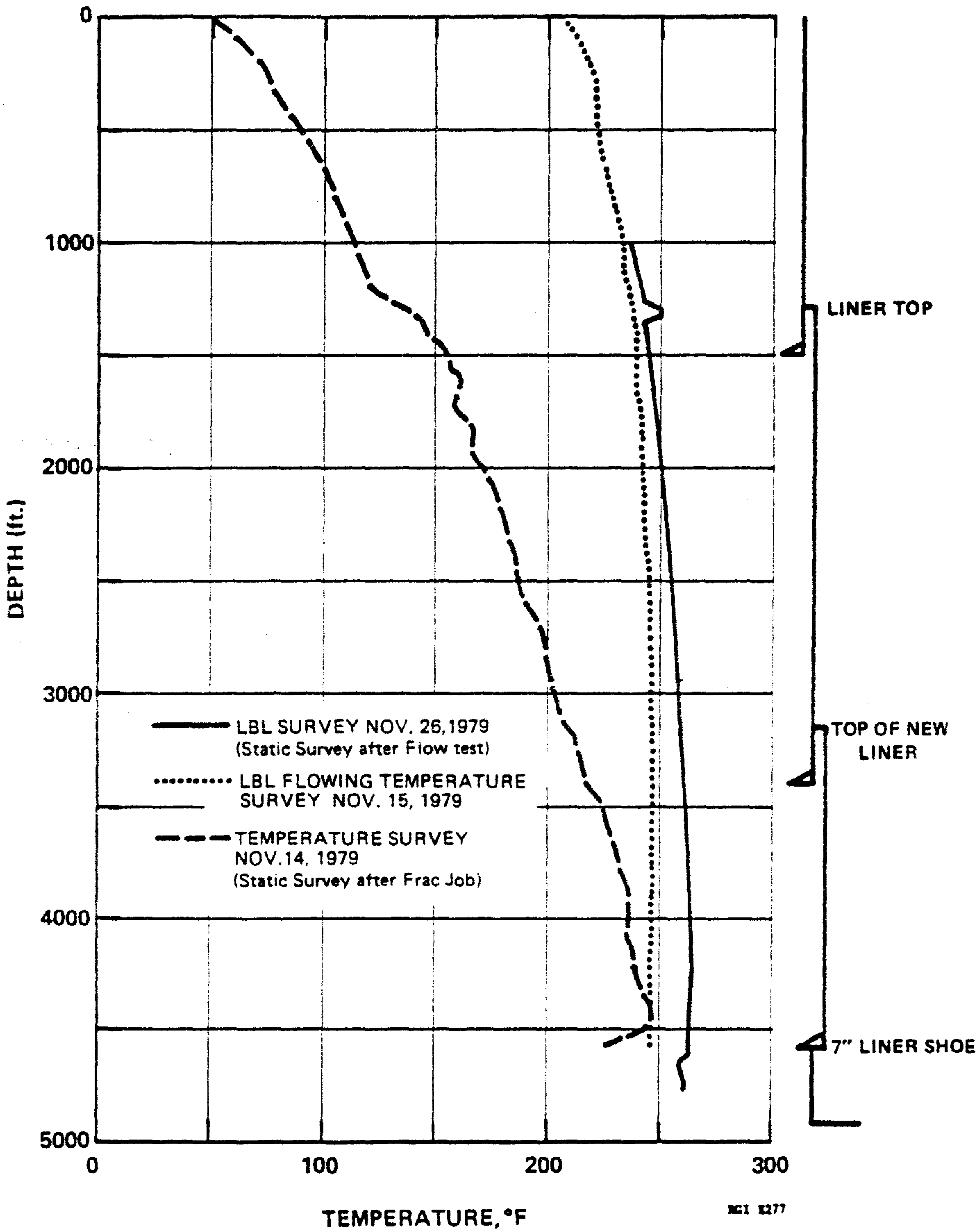


FIGURE 26
RESERVOIR SIMULATION MODEL

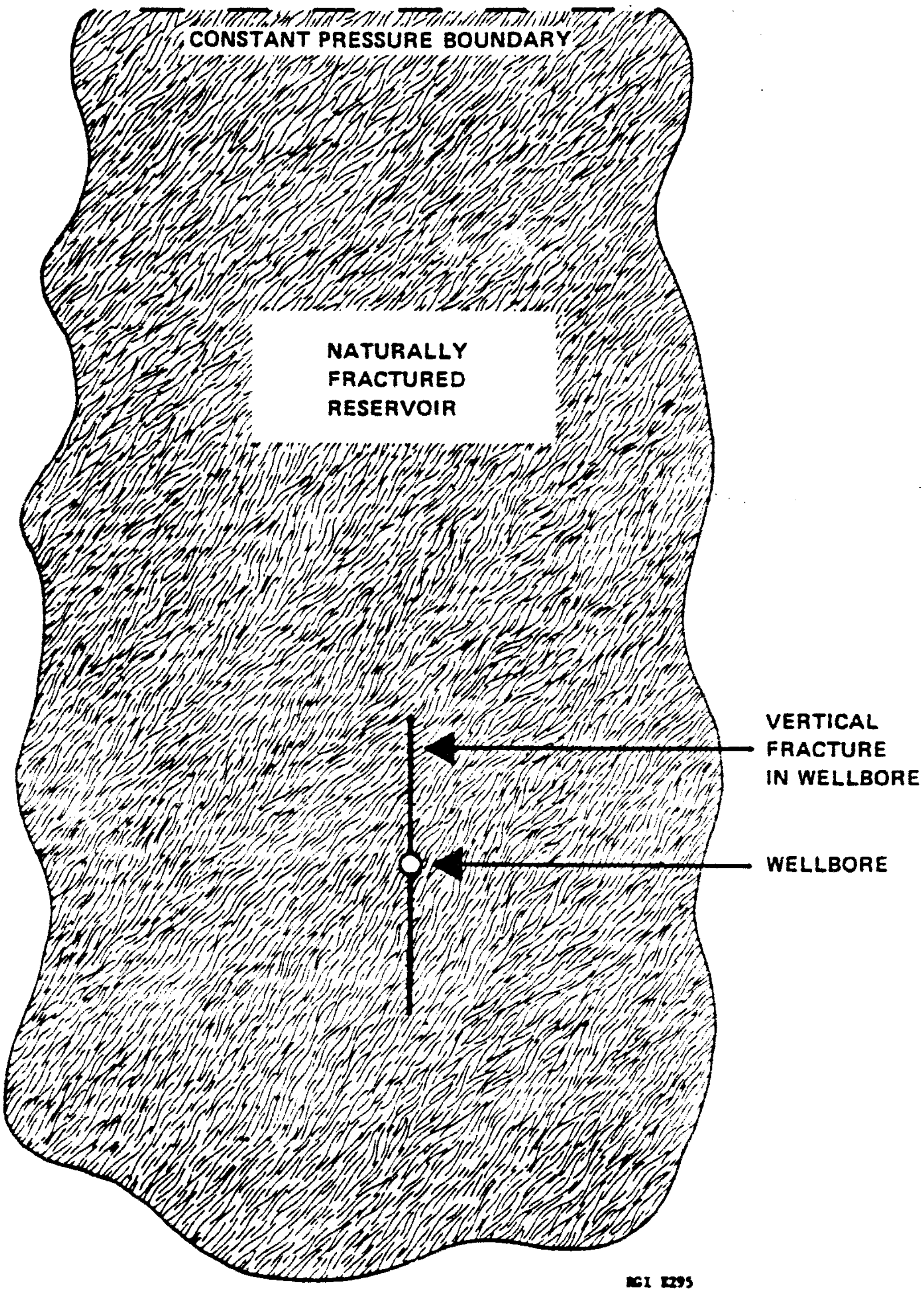


FIGURE 27
SODIUM AND CHLORIDE CONCENTRATIONS
OF RRGP-4 PRODUCED FLUIDS

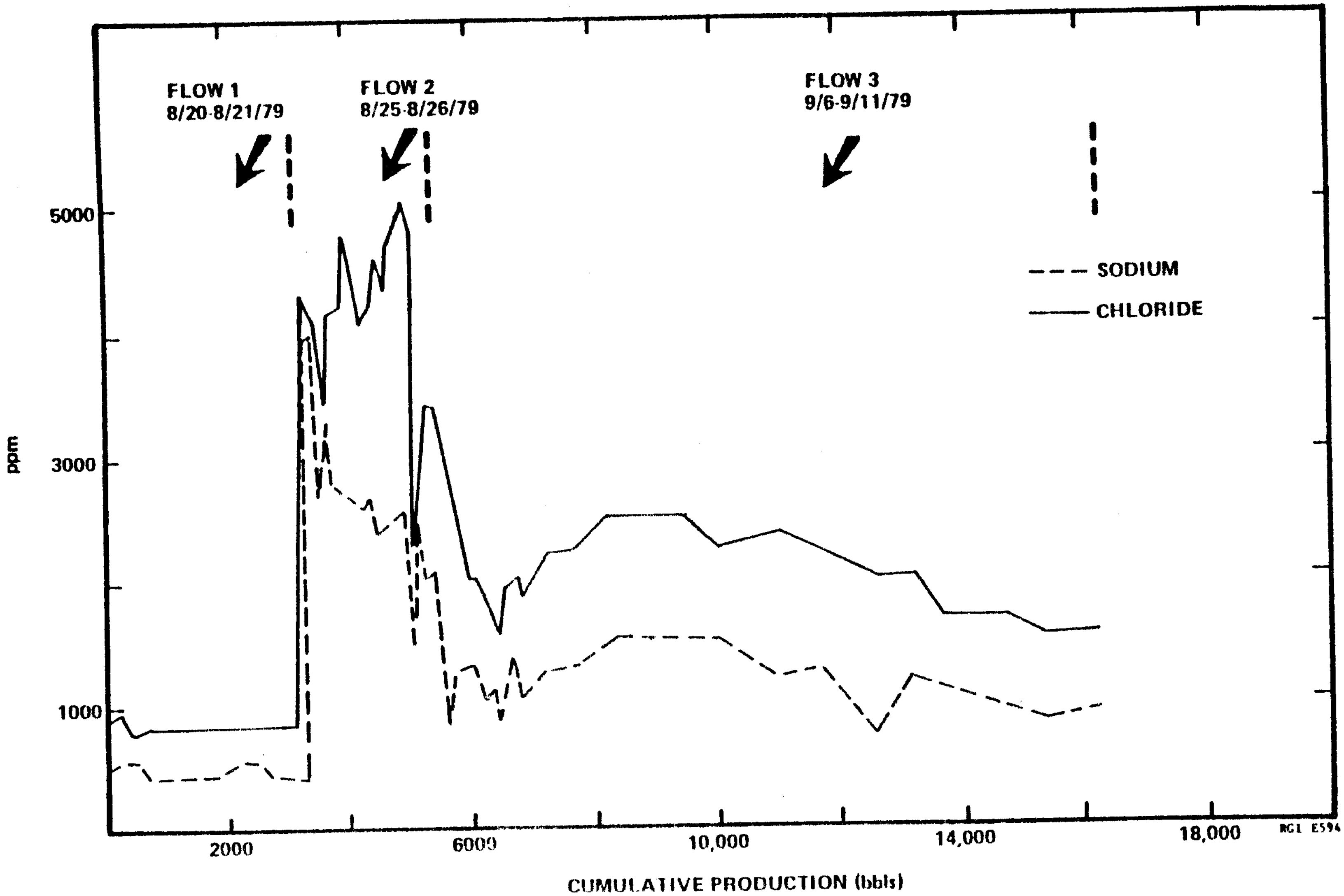


FIGURE 28
TOTAL ORGANIC CARBON AND CARBOHYDRATE
CONCENTRATION OF RRGP-4 PRODUCED FLUID

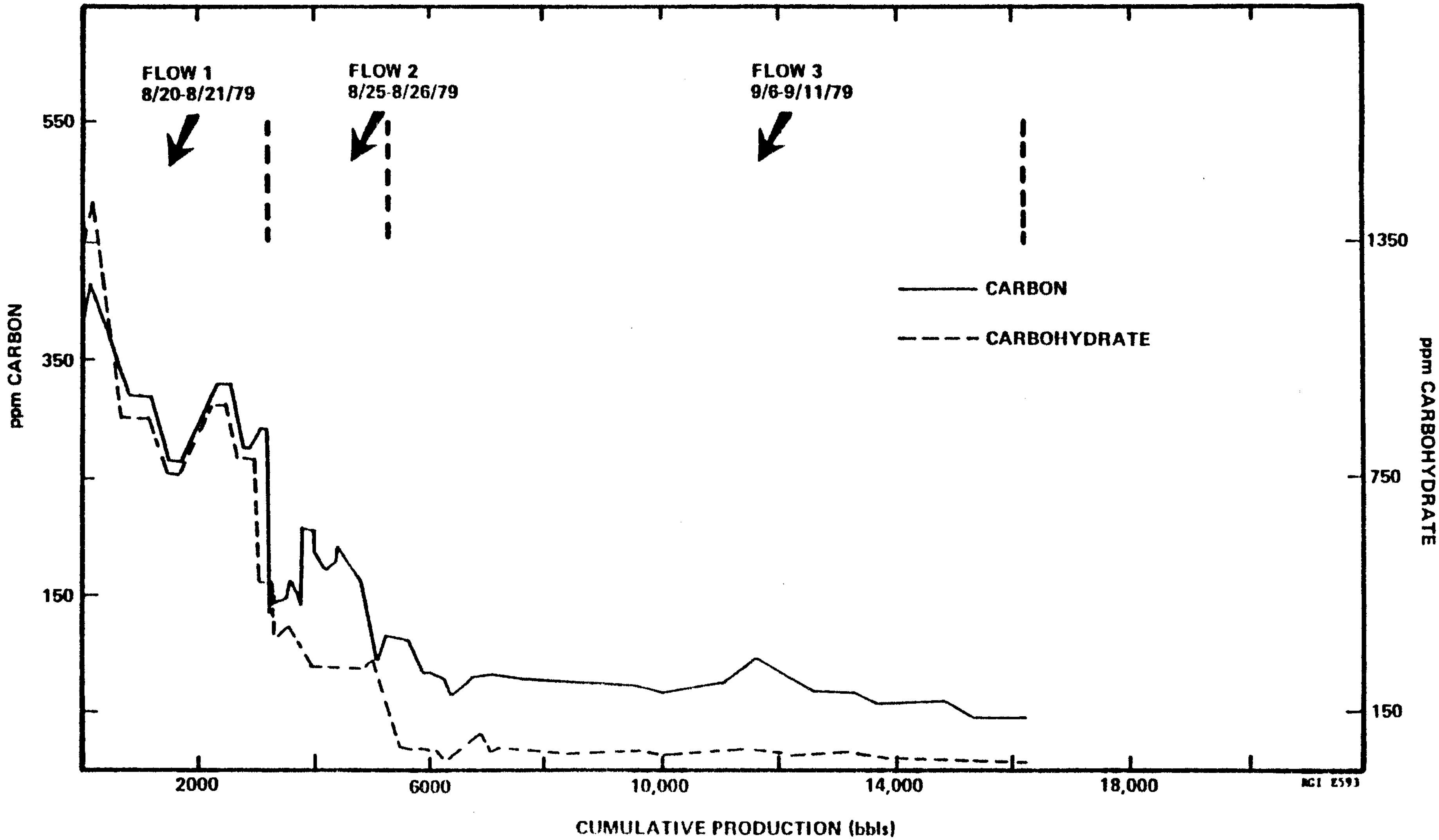


TABLE F-2

ACTUAL DIRECT COSTS FOR
WORKOVER AND STIMULATION*
RRGP-5

Rig mobilization/demobilization	$ 24,401
Rig daywork and standby	92,426
Casing, related equipment, and services	31,263
Cementing	11,827
Fracturing materials and service	128,998
Tool and equipment rentals	34,399
Miscellaneous services	35,586
Expendables	18,172
Transportation	17,198
Consultant for wellsite supervision	15,648
TOTAL	$409,918

* Exlcudes RGI and subcontractor labor

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FIGURE 29
TOTAL ORGANIC CARBON AND CARBOHYDRATE
CONCENTRATION OF RRGP-5 PRODUCED FLUID

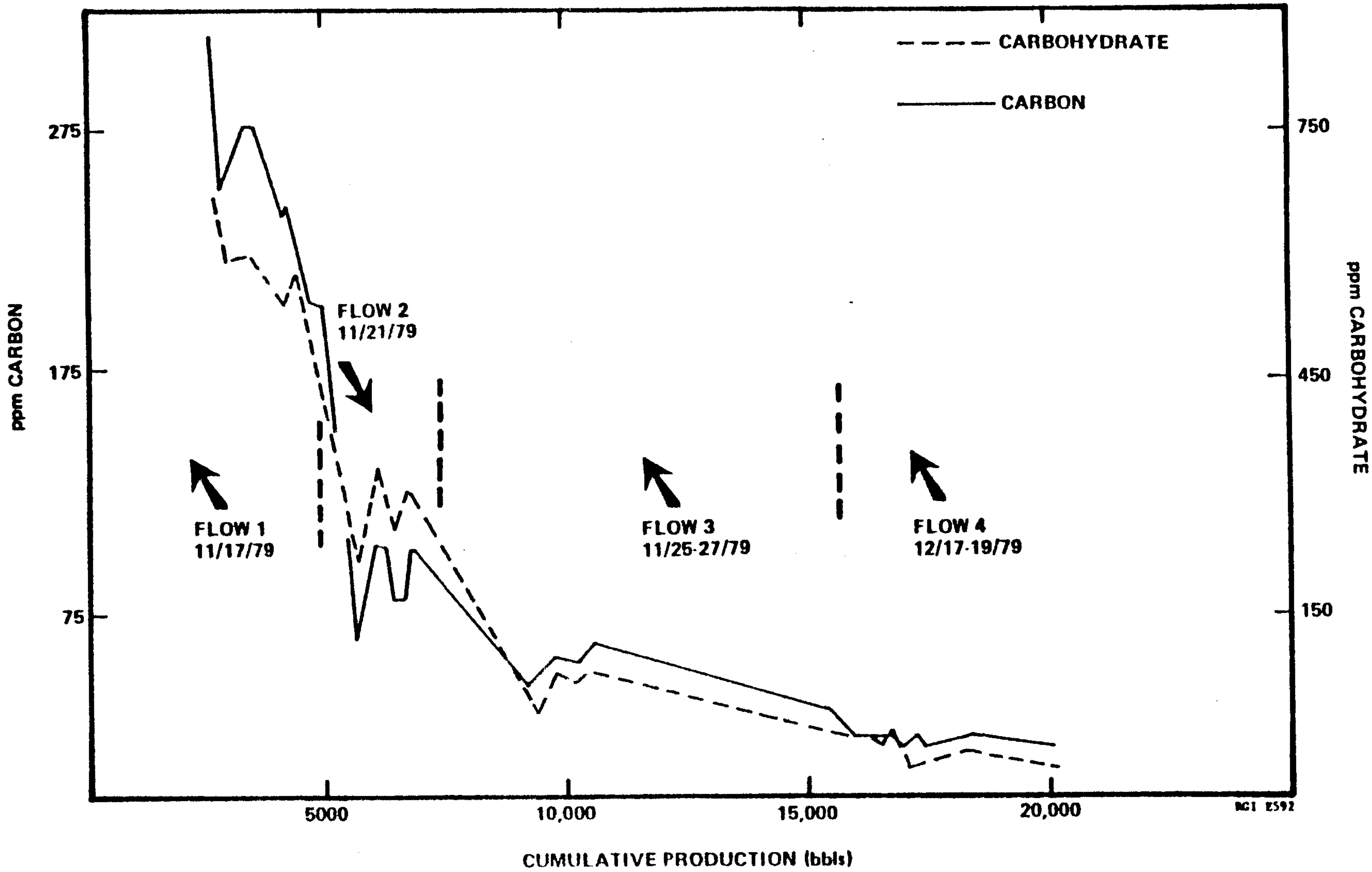


FIGURE 30
AMMONIUM AND NITRATE TRACER
CONCENTRATION IN RRGP-5 PRODUCED FLUID

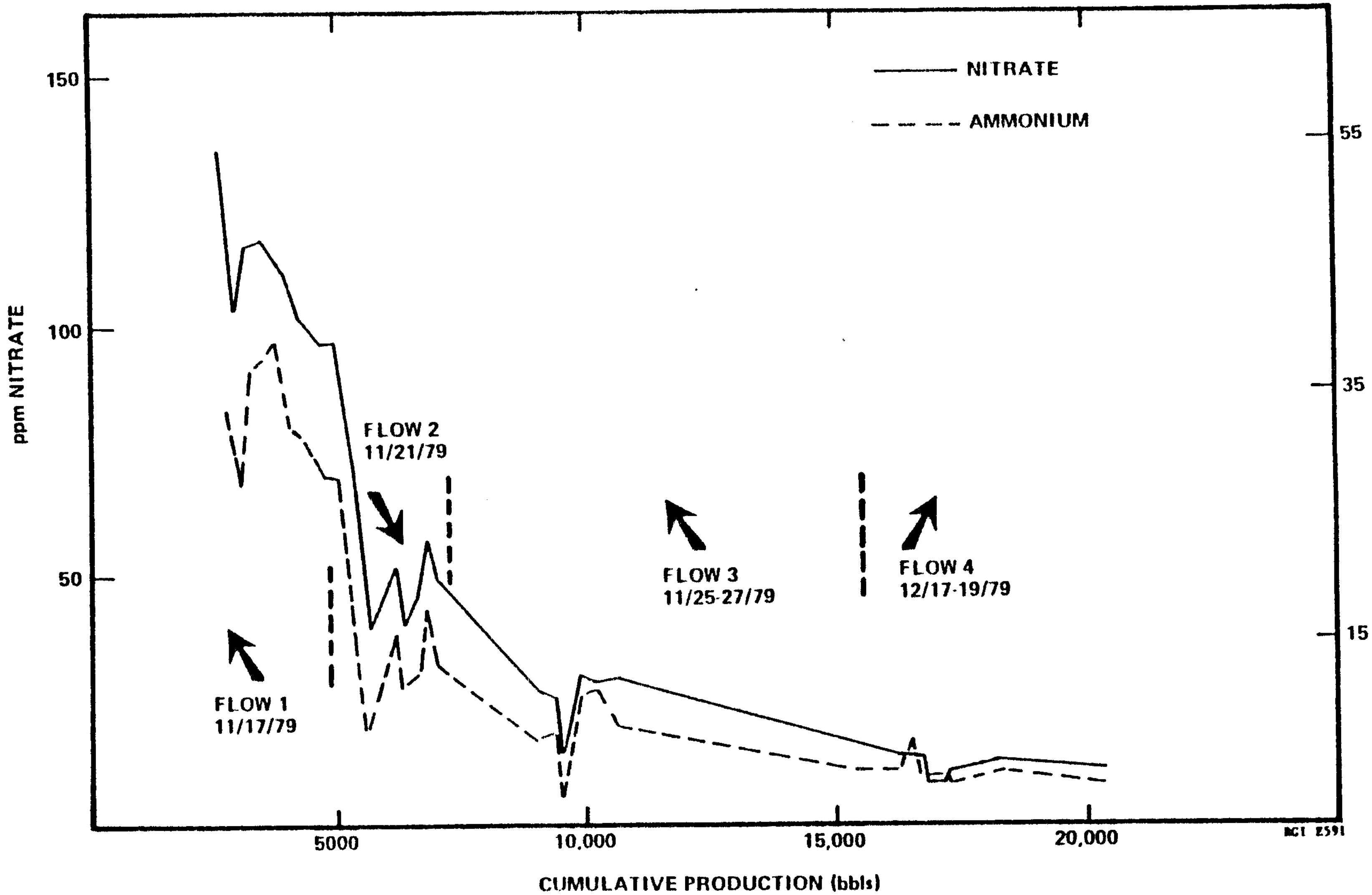
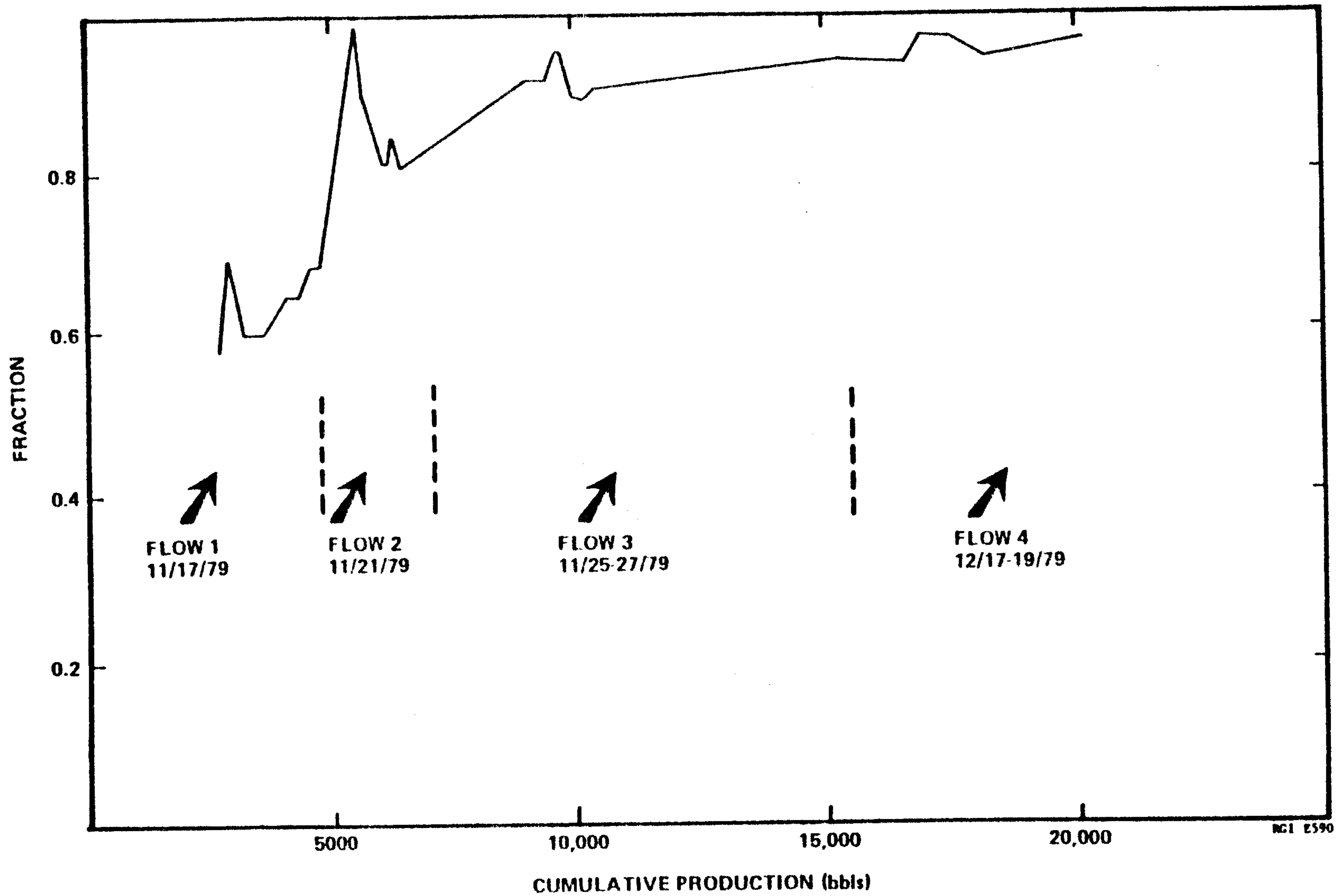


FIGURE 31
FORMATION WATER CONTENT OF
RRGP-5 PRODUCED FLUIDS



APPENDIX A

THE APPLICATION OF THE ACOUSTIC TELEVIEWER TO THE CHARACTERIZATION OF HYDRAULIC FRACTURES IN GEOTHERMAL WELLS

by

W. Scott Keys

U.S. Geological Survey