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\# 40

GEOTHERMAL RESERVOIR EVALUATION OF THE REDONDO CREEK AREA, SANDOVAL COUNTY, NEW MEXICO

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TABLE OF CONTENTS

INTRODUCTION

The Valles Caldera is located in north central New Mexico in the Jemez Mountains about 55 miles north of Albuquerque and 40 miles northwest of Sante Fe (see Figure 1). Interest in the geothermal potential of the Valles Caldera began accelerating in the 1960's with the drilling of several exploratory wells in the Sulphur Creek and Redondo Creek areas in the caldera.

Union Oil Company leased approximately 100,000 acres of the Baca ranch in April, 1971, and began active exploration by drilling Baca #5 in the Redondo Creek area in July, 1971. Since then, Union has drilled 10 additional wells in the Redondo Creek area. Various tests have been performed on these wells to evaluate the production and reservoir characteristics and the chemistry of the produced fluids.

The purpose of this report is to evaluate the geothermal potential of the Redondo Creek area based on the existing geologic and reservoir data. The findings and conclusions of this report should form the basis for a feasibility study to determine if geothermal energy for electrical generation can be economically extracted. Recommendations are presented for the future work needed to establish initial geothermal development and eventually achieve the full potential of the Redondo Creek area and Valles Caldera.

CONCLUSIONS

Engineering and geologic studies of the Redondo Creek area wells have indicated the existence of an extensive, high temperature hydrothermal system. The following conclusions are derived from the studies completed to date.

1. Total water in place determined from depletion calculations is at least 4.6×10^{12} lbs of hot water. The estimated average reservoir temperature is 600°F.

2. Estimates of the potential generating capacity range from 494 to 1236 MW's. Operation of a 55 MW pilot facility will give us additional data to design optimum generating capacity in the Valles Caldera.

3. Interference testing indicates reservoir communication between Baca 6, 10, 11, 12, 13 and 14.
   a. Average reservoir kh is approximately 6000 md ft.
   b. Average reservoir øh is approximately 90 feet.
   c. Geochemical data suggest produced fluids are from a common aquifer of about 624°F.

4. Production tests indicate that no measureable reservoir depletion is evident to date. Total production from the reservoir has been $4,935 \times 10^6$ lbs total mass; total injection has been $2,340 \times 10^6$ lbs resulting in a net withdrawal of $2,595 \times 10^6$ lbs total mass.

5. Deliverability of an average well is on the order of 200,000 #/hr total mass with a 35% steam fraction.
   a. Sixteen wells would be required for initial development of a 55 MW generating facility.
   b. Initial development would require drilling 11 additional wells and redrilling 2 wells.

6. Productivity is a result of fracturing in the Bandelier Tuff which is connected to a deeper, more extensive hot water aquifer.

7. Fracture system extent and orientation are indeterminate at this time. Success of future wells depends on locating fracture permeability.

8. No primary or secondary steam cap is associated with the liquid phase reservoir at this time.

9. An isolated, low-pressure steam zone appears to exist in the Redondo Creek area, but its extent and size are undetermined at this time.

10. No evidence exists to prove or disprove active recharge of the hot water reservoir in the Valles Caldera.

11. Scale deposition, primarily calcium carbonate and silica, has been observed and might affect the production and injection facilities. In the period of observation, remedial measures have proven to restore the productivity of the affected wells.

RECOMMENDATIONS

Potential generating capacity of the reservoir is 494 to 1236 MW's, based on water in place from reservoir depletion calculations. The following are preliminary recommendations based on reservoir engineering and geologic evidence developed at this time.

1. Proceed with plans to install 55 MW of generating capacity initially in the Redondo Creek area.
   a. Detailed economic feasibility studies will be required to determine price and investment parameters.
   b. Perform preliminary reservoir model studies to predict reservoir performance in the Redondo Creek area. The studies should be updated with production history and any additional reservoir data acquired during development.
   c. Model studies should be initiated to learn more about the performance of the reservoir as a whole unit (rock, fluid and heat). Important considerations are the effects of cooling due to liquid reinjection, heat transfer from the rock to the fluid, and the lowering of the saturation temperature due to pressure depletion. This needs to be done to design the optimum generating capacity to be derived from energy stored in the rock and the fluid.

2. More detailed geologic studies are needed to identify and predict where permeable fracture systems are located in the Redondo Creek area and elsewhere in the Valles Caldera. This is necessary to fully exploit the indicated water in place. An equally important benefit will be to enhance the success ratio of future wells.

3. Additional exploratory drilling will be required to test those additional productive regions within the caldera that may be identified from geologic studies.

4. Methods of artificial stimulation of the reservoir fracture system, either by chemical, mechanical or explosive means, need to be studied in order to improve the productivity of the wells.

5. Optimum well design and well spacing should be determined. At this time, it appears that productivity is limited by reservoir conditions rather than well design. Spacing will be a function of the fracture system orientation and extent.

6. Methods of economically handling or preventing scale deposition will need to be studied and developed.

GEOLOGY

REGIONAL GEOLOGY

The Valles Caldera is located in the Jemez Mountains, a complex volcanic highland of Pliocene and Pleistocene age. Two major geologic features intersect in this area as shown on Figure 1. One is the southeastern rim of the Colorado Plateau, along which a number of volcanic fields developed: White Mountains, Datil, Mt. Taylor, Jemez and San Juan volcanic fields. The other regional geologic feature is the Rio Grande Depression, a down-dropped block or graben that extends several hundred miles north-northeasterly through New Mexico into Colorado. Geophysical work has shown that the Pre-Cambrian rocks in the central down-dropped block are about 19,000 feet lower in elevation than those in the uplifted blocks to the east and west of the graben.

The western border fault of the Rio Grande Graben is located near the western edge of the Valles Caldera. West of the fault, a thin veneer of volcanics lies directly upon Mesozoic, Paleozoic or Pre-Cambrian rocks. East of the fault, in the Jemez Mountains, a very thick volcanic pile overlies late Tertiary sediments which fill the Rio Grande Graben. Almost all of the volcanic activity in the Jemez Mountains occurred on the east side of the border fault, within the graben; this was probably due to the formation of magma under the graben and the easy access to the surface afforded by the border fault and associated faults in the graben.

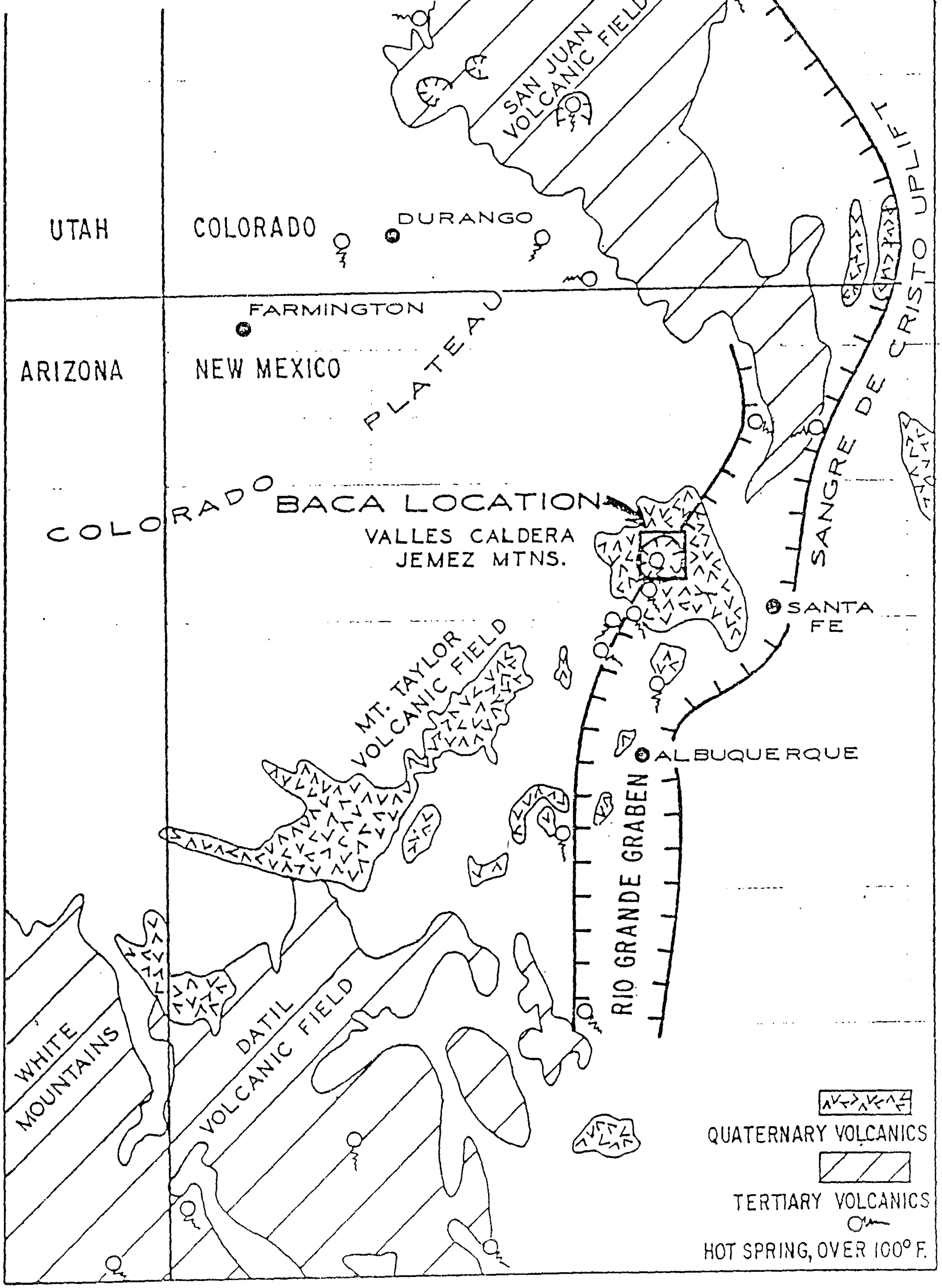

FIGURE 1. REGIONAL GEOLOGIC SETTING OF VALLES CALDERA, JEMEZ MOUNTAINS, NEW MEXICO.

0 25 50 75 100 Miles

VALLES CALDERA

The Valles Caldera is a subcircular, volcanic depression 12 to 15 miles in diameter, with its walls rising from a few hundred to more than 2000 feet above the floor. A central structural dome, Redondo Peak, near the center of the caldera has a relief of nearly 3000 feet and is bisected by a northeasterly-trending central graben. Over ten large rhyolite volcanic domes are located on or close to a ring fracture zone circling the central dome; caldera collapse occurred along this fracture (Figure 2).

The caldera represents the latest stage of a volcanic sequence which began in late Miocene or early Pliocene time with the eruption of several basalt-rhyolite sequences, and climaxed in Mid-Pleistocene time with two huge pyroclastic eruptions which produced the Bandelier Tuff and the Toledo and Valles calderas. About 100 cubic miles of rhyolite ash and pumice were ejected, mainly as ash flows; this was closely followed by caldera collapse into the partially evacuated magma chamber.

The sequence of events in the formation of the Valles Caldera was described by Smith and Bailey[1] in 1968 and is summarized as follows:

1. Regional doming of the Jemez volcanic highland occurred with the formation of a ring-fracture system over the Valles magma chamber.

2. Two gigantic eruptions from the ring-fracture system about one million years ago, ejected about 100 cubic miles of ash and pumice which deposited as ash flows and made up the Bandelier Tuff. The older Toledo Caldera was formed before the second eruption.

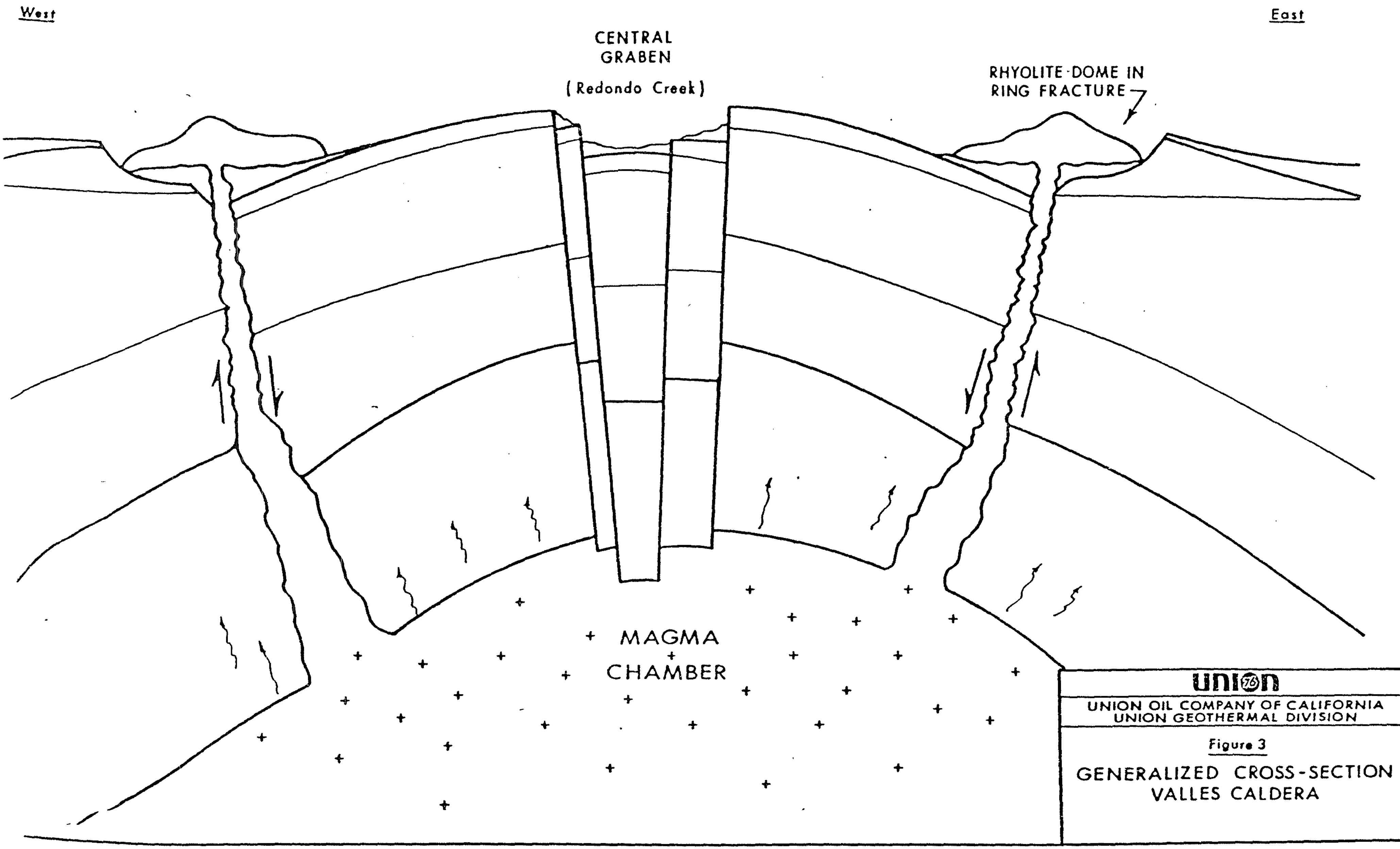

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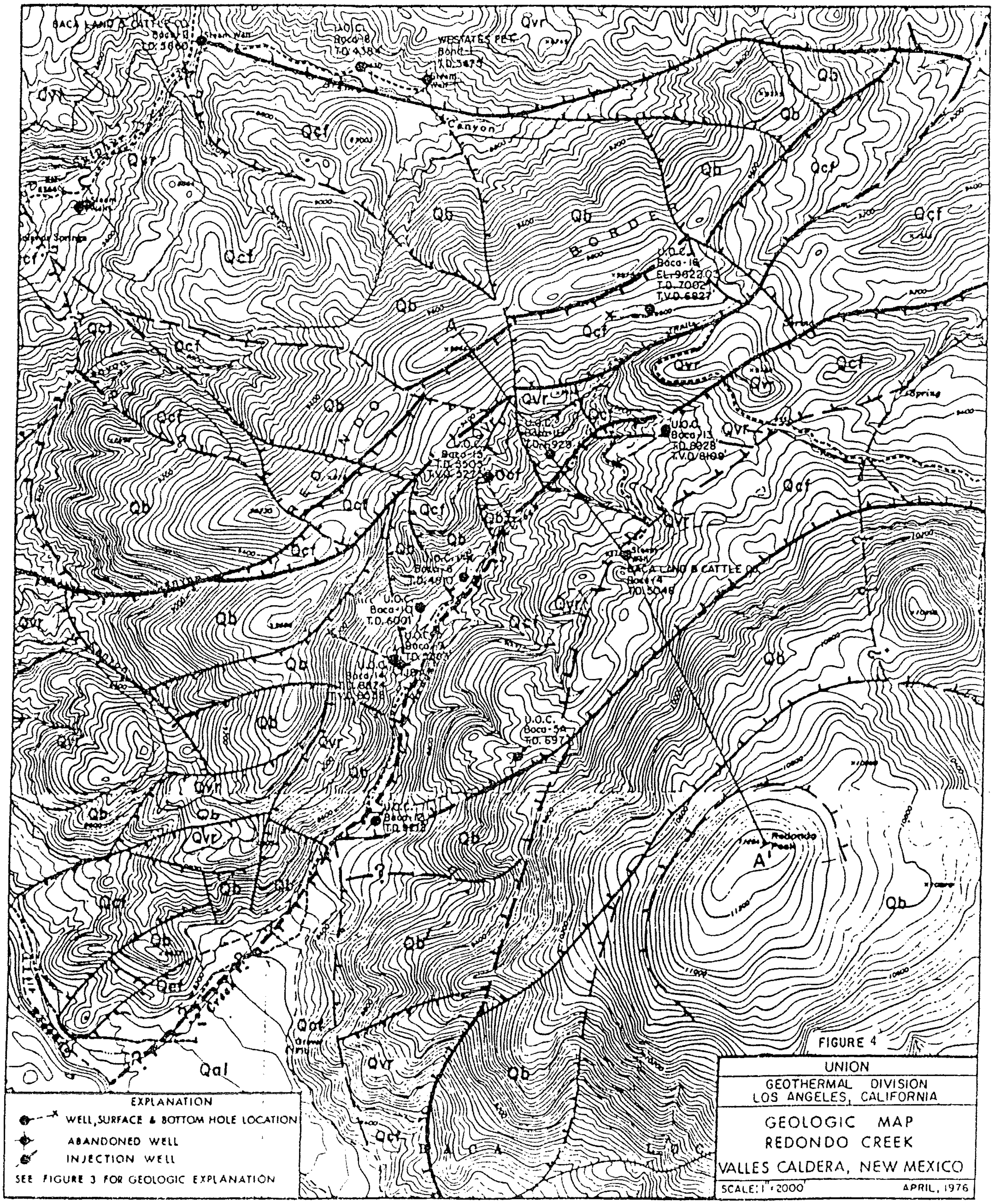
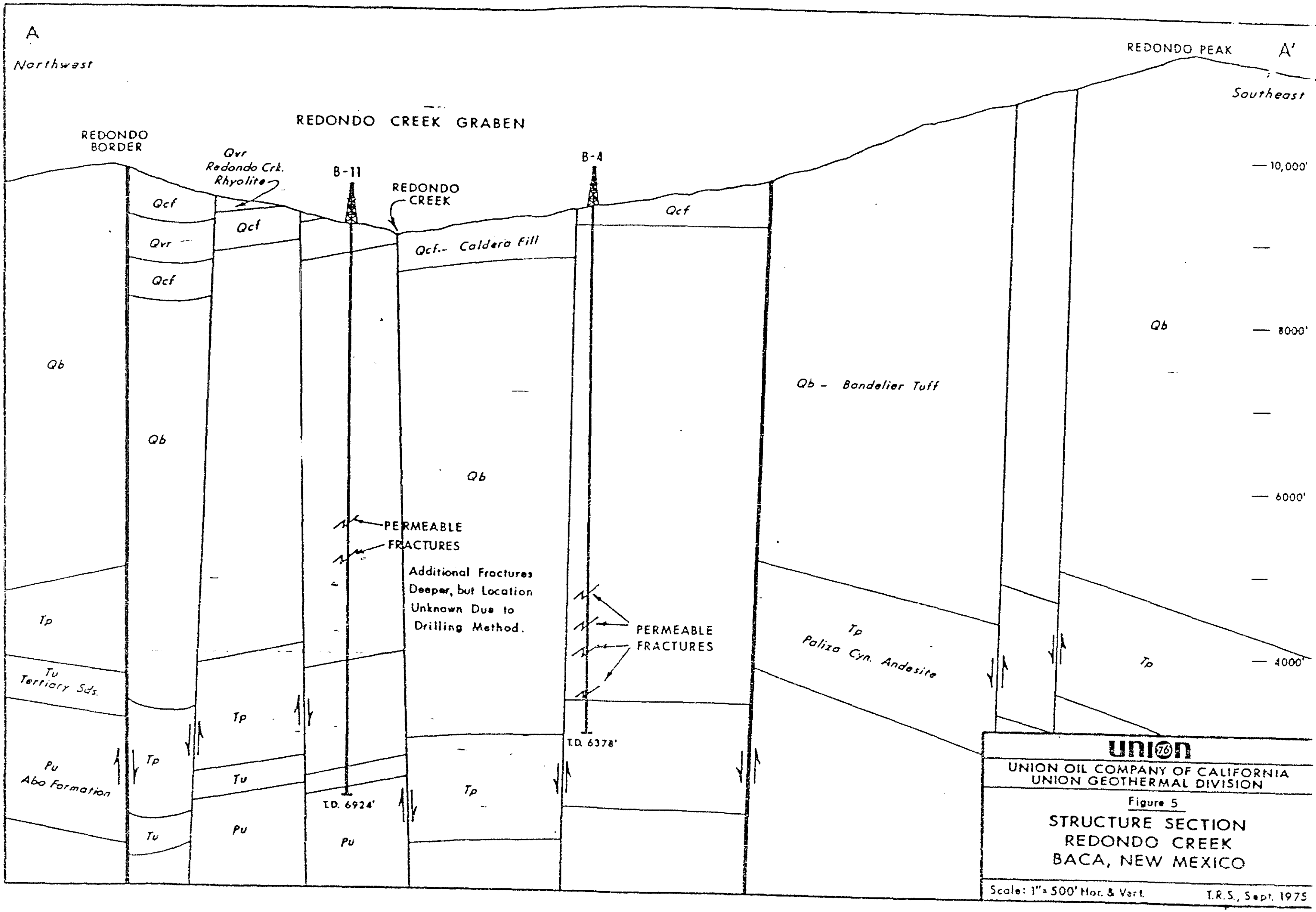
Figure 3

GENERALIZED CROSS-SECTION
VALLES CALDERA


EXPLANATION
WELL, SURFACE & BOTTOM HOLE LOCATION
ABANDONED WELL
INJECTION WELL
SEE FIGURE 3 FOR GEOLOGIC EXPLANATION
FIGURE 4
UNION
GEOTHERMAL DIVISION
LOS ANGELES, CALIFORNIA
GEOLOGIC MAP
REDONDO CREEK
VALLES CALDERA, NEW MEXICO
SCALE: 1" = 2000'
APRIL, 1976
BACA LAND & CATTLE CO.
Baca-11
T.D. 5860
U.O.C.
Baca-8
T.D. 4384
WESTATES PET.
Baca-1
T.D. 5479
U.O.C.
Baca-16
EL: 9622.03
T.D. 7082
T.V.D. 6927
U.O.C.
Baca-13
T.D. 8028
T.V.D. 8109
U.O.C.
Baca-15
T.D. 3505
T.V.D. 3272
U.O.C.
Baca-6
T.D. 4810
BACA LAND & CATTLE CO.
Baca-4
T.D. 5046
U.O.C.
Baca-10
T.D. 6001
U.O.C.
Baca-14
U.O.C.
Baca-5A
T.D. 6973
U.O.C.
Baca-12
Redondo Peak
A
A'
Canyon
Qvr
Qb
Qcf
Qal



A
Northwest
REDONDO PEAK
A'
Southeast
REDONDO CREEK GRABEN
REDONDO BORDER
Qvr
Redondo Crk. Rhyolite
B-11
REDONDO CREEK
B-4
10,000'
Qcf
Qcf
Qcf
Qcf.- Caldera Fill
Qvr
Qcf
Qb
Qb
8000'
Qb - Bandelier Tuff
Qb
Qb
6000'
PERMEABLE FRACTURES
Additional Fractures Deeper, but Location Unknown Due to Drilling Method.
PERMEABLE FRACTURES
Tp
Tp
Paliza Cyn. Andesite
Tp
4000'
Tu
Tertiary Sds.
Tp
Tp
Pu
Abo Formation
Tu
Tp
T.D. 6378'
T.D. 6924'
Tu
Pu
Pu
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Figure 5
STRUCTURE SECTION
REDONDO CREEK
BACA, NEW MEXICO
Scale: 1" = 500' Hor. & Vert.
T.R.S., Sept. 1975

3. Simultaneously with the eruptions, the roof of the Valles magma chamber collapsed along a ring fracture zone eight to ten miles in diameter and down-dropped a very thick pile of Bandelier Tuff.

4. A caldera lake formed and deposition of about 2000 feet of landslide debris and lacustrine sediments occurred in the caldera.

5. Rising magma again caused uplift and doming in the center of the caldera. This was accompanied by radial fracturing, rhyolite eruptions and the concomitant formation of a longitudinal graben (Redondo and Jaramillo creeks) on the rising dome (Redondo Peak). See Figures 3, 4 and 5.

6. Along the ring fracture zone around the central dome, eruption of rhyolite resulted in the formation of a series of domes and flows. The youngest eruption is about 100,000 years old; the oldest about one million years, only slightly younger than the Bandelier Tuff.

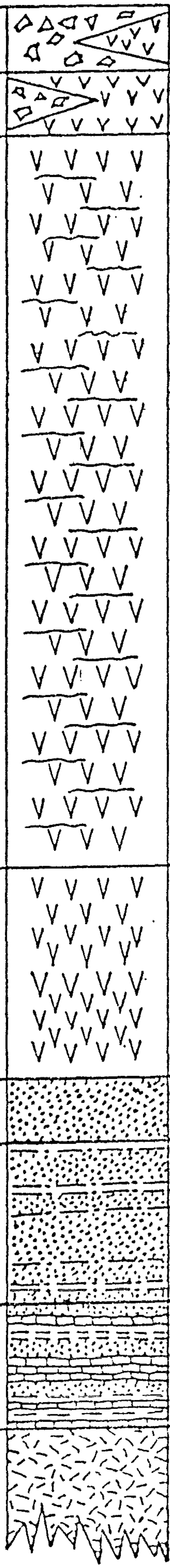
7. The final step in the sequence is the hot spring and solfataric activity in the western half of the caldera, which persists to the present.

STRATIGRAPHY

Pre-Tertiary

In the area of Redondo Creek, the oldest unit encountered in the wells is the Abo Formation of Permian age (Figure 6). It is comprised of more than 1600 feet of well consolidated, calcareous and argillaceous sandstones and siltstones. The four wells

REDONDO CREEK, BACA, NEW MEXICO



SECTION & MAP SYMBOL	DESCRIPTION	THICKNESS	AGE
Qcf	CALDERA FILL. Mainly landslide deposits. Coarse breccia, gravel and silt.	0-500'	QUATERNARY
Qvrc	REDONDO CREEK RHYOLITE. Rhyolite flows, biotitic, amygdular. (DEER CANYON RHYOLITE. Outcrops in South Redondo Creek. (Qvdc))	0-500'	QUATERNARY
Qb	BANDELIER TUFF. Welded to non-welded rhyolite ashflows and pumice.	4500'-6300'	QUATERNARY
Tpa	PALIZA CYN. ANDESITE. Andesite, dacite flows and tuffs.	300' - 2400'	PLIOCENE
Tu	TERTIARY SANDS UNDIFFERENTIATED. Poorly consolidated, very fine sands, occasionally tuffaceous.	200' - 500'	MIO-PLIOCENE
Pa	ABO FORMATION. Well consolidated, calc, fine, red and purple arkosic sandstone and siltstone.	1600'+	PERMIAN
Cm	MAGDALENA GROUP. Gray to black limestone and shale and arkosic sandstone.	800'+	CARBONIFEROUS
p€	GRANITE. Dense, microcline granite.		PRECAMBRIAN

(Baca 11, 12, 13 and 14) encountering this unit found little or no permeability in it. Regionally, this unit is underlain by more than 800 feet of a Carboniferous shale-limestone-sandstone sequence which comprises the Magdalena Group; it rests upon Pre-Cambrian granite.

Tertiary

Overlying the Abo Formation are 200 to 500 feet of undifferentiated Tertiary sands, some of which are considered to represent the Santa Fe Formation. Usually the sands are poorly consolidated, very fine, and occasionally tuffaceous. They are probably equivalent to the Mio-Pliocene sediments in the central portion of the Rio Grande Graben. These sands oridinarily have very good to excellent permeability. The absence of these sands in B-13 may be due to localized erosion or faulting, suggested by the unusually thick Paliza Canyon sequence in this well.

The only volcanic unit of Tertiary age in the Redondo Creek area is the Paliza Canyon Formation of Pliocene age. It is composed of 300 to 2400 feet of andesite flows with subordinate amounts of tuff and dacite flows. This unit is usually pervasively altered in the subsurface.

Quaternary

The Bandelier Tuff of Mid-Pleistocene age is the oldest unit exposed in the Redondo Creek area and is about 4500 to 6300 feet thick. It is composed of rhyolite ash and pumice which was deposited over a very large area, mainly as ash flows. It varies from being nonwelded to very densely welded. Although primary permeabilities are generally low in this unit, its denseness and brittleness have made it particularly susceptible to the formation of fractures, along which geothermal fluids may migrate.

The Caldera Fill of Pleistocene age overlies the Bandelier Tuff. Erosion has completely removed much of the Caldera Fill in Redondo Creek, but it is as much as 500 feet thick on the east side of the creek. The unit is composed of coarse breccia, gravel, sand, silt and lacustrine deposits. Blocks of Bandelier Tuff and Tertiary volcanics from the walls of the caldera were interspersed in the sediments by landslides during their deposition.

Eruption of the Redondo Creek Rhyolite was contemporaneous with the deposition of the Caldera Fill and rhyolite flows may be found at the base of, or within, the Caldera Fill. The thickest section encountered was at the northern end of Redondo Creek where it is about 500 feet thick. Only a few erosional remnants of this unit remain. The rhyolite is usually biotitic and amygdaloidal with abundant small geodes.

HYDROTHERMAL GEOLOGY

GENERAL

The Valles Caldera is favorably situated in space, time and type of volcanism for development of a large hydrothermal system. The Jemez volcanic field covers an area of more than 700 square miles and has been active, more or less continuously, for the last 10 million years.

The geologic history of the caldèra, during the last 1.5 million years, consisted of: doming-rhyolite eruption-collapse-resurgent doming-rhyolite eruption. This sequence indicates the caldera is directly over the most active and shallowest portion of the magma chamber which supplied the volcanics to the Jemez volcanic field (Smith and Bailey, 1968). The association of large hydrothermal systems with acidic extrusive and intrusive rocks is well known (Salton Sea and Long Valley in California, Yellowstone National Park, and Wairakei, New Zealand). This association is ascribed to the probability that rhyolite (acidic) magma chambers are large shallow sources, whereas basalt (basic) sources are too deep to generate large thermal anomalies close to the earth's surface.

SURFACE HYDROTHERMAL ACTIVITY

Many hot springs occur along the western boundary fault zone of the Rio Grande Graben, but are most numerous around the Jemez Mountains (Figure 2). The many chloride-bearing hot springs along the Jemez River and within and around the Valles Caldera are an expression of an extensive, deep, hot water-dominated geothermal system. At Sulphur Springs in the western part of the caldera, there are hot springs which are gaseous, acidic (ph of 2), and have a negligible chloride content. Surrounding the springs is a large area of active hydrothermal alteration. The combination of hot, chloride-free springs and alteration activity are indications of the presence of a vapor-dominated hydrothermal system. Extensive rock alteration in the Redondo Creek area and Alamo Canyon area (north of Redondo Creek) probably indicate that a leaking vapor-dominated system has been sealed off by the rock alteration and mineral deposition in these areas.

SUBSURFACE HYDROTHERMAL ACTIVITY

Since 1971, most of the exploratory drilling has been concentrated in the Redondo Creek area in the southern half of the Valles Caldera. The following interpretation is derived from the analysis of the drilling, surveying and testing of the eleven wells drilled in that area, and from surface geologic mapping.

The Bandelier Tuff is 4500 to 6300 feet thick in the Redondo Creek area. Nearly all of the production in the Redondo Creek wells has come from fractures in the tuff. Cores of the Bandelier Tuff from Baca 13 show interstitial permeability is negligible (<1 md) and porosity is in the order of 4% - 10%. The upper portion of the tuff is densely welded and forms the caprock on the hot water reservoir. Most of the hot fluid entries into the wellbores have occurred in the bottom half of the Bandelier Tuff (see Figures 8 and 9). The occurrence of pumice is restricted to the lower portion of the Bandelier Tuff.

A saturated steam zone has been penetrated by Baca 4, 11 and 15 (see Figure 4), and it is located structurally higher in the Bandelier formation than the higher pressured hot water entries. As will be shown later in this report, this steam zone is not in pressure communication with the deeper hot water. It has been isolated by fracture mineralization and reduced in pressure by fumarolic activity. It is reasonable to assume that the hot spring and hydrothermal activity in the Sulphur Creek area is related to this steam zone.

The deeper, higher pressured water production from the Bandelier Tuff is most likely connected with a more extensive reservoir, the location and nature of which has not yet been determined. Below the Bandelier Tuff, the Redondo Creek wells have penetrated as much as 2400 feet of the Paliza Canyon Andesite. The andesite contains some fractures, but there is considerable alteration to clay and very little productivity has been encountered. Cores of the andesite from Baca 13 show porosities of 6% to 16%, but very low permeabilities (0.1 to 1.5 md).

Baca 10, 11 and 16 encountered Tertiary sands beneath the andesite. These sands are very fine grained and largely unconsolidated, which may inhibit sustained productivity. Since none of the wells have completely penetrated the Tertiary sands, the thickness and areal extent of this potential reservoir is unknown. The absence of the Tertiary sands in Baca 13 may be due to localized erosion prior to deposition of the andesite.

The Tertiary sands probably extend under Redondo Border to Sulphur Creek since they were penetrated below 2400' in the Baca 2 well in the Sulphur Creek area. East of Redondo Creek, the sands are assumed to thicken as the unit is several thousand feet thick in the center of the Rio Grande Graben.

Baca 12 and 13 penetrated the top of the Permian Redbeds, which consist of interbedded, compact sands and shales. Little is known of its potential as a reservoir rock. Based on the stratigraphy in the Sulphur Creek area, a Pennsylvanian limestone-shale-sandstone unit occurs below the Permian Redbeds before reaching Pre-Cambrian granite.

From the reservoir engineering portion of this report, it was concluded that the Redondo Creek wells are connected to an extensive hot water reservoir. However, the extent of this reservoir has not been determined from the wells drilled to date.

The most promising productivity appears to be in wells located in the most fractured portions of the Bandelier Tuff. This fracturing is primarily associated with the collapse faulting running longitudinal northeast to southwest.

The structural characteristics of the Redondo Creek area are illustrated on the generalized structure map on the base of the Bandelier Tuff in Figure 7, and on the cross-sections in Figures 8 and 9.

SUBSURFACE TEMPERATURE

The subsurface temperatures measured in the Redondo Creek wells appear to be controlled by the permeability of the rocks penetrated by the wellbores. Typical static temperature profiles for each of the wells are shown in Appendix A. Characteristic of each profile is a rapid temperature increase with depth through the impermeable caprock until the top of the geothermal reservoir is encountered, then the temperature increases more slowly. This is due to temperature equalization by convection of the geothermal fluids within the contained reservoir. The change in the slope of the temperature profile occurs at the base of the impermeable reservoir caprock. A contour map of the base of the caprock is shown on Figure 10. This map was constructed using the temperature profiles in Appendix A.

Using the temperature profiles, a series of temperature distribution maps are shown in Figures 11-13 for elevations of 7000', 5000', and 3000' above sea level. It is apparent from these maps that the geothermal reservoir in the Redondo Creek area trends to the northwest toward Sulphur Creek. Baca 5A indicates significant cooling in the vicinity of Redondo Peak. This is interpreted to be the result of a lack of pressure communication with the deep reservoir.

Also significant is the abrupt increase in temperature at the bottom of Baca 11 and 16. This occurs in both of these wells in the Tertiary sand interval. On Figure 13, the Baca 16 temperature of 580°F at 3000' elevation is obviously anomalous on the isothermal map. The large increase in Baca 11 occurs below 3000' elevation, but it extends to 627°F, higher than any other well.

Geochemical data can be used to estimate the equilibrium temperature of the rock and fluid within the reservoir. An empirical relationship developed by Fournier and Truesdell[2] was used to calculate reservoir temperatures using ionic ratios of sodium, potassium and calcium. The calculated values are shown in Table 1. The average of all of these values is 619°F with a range of 515°F to 789°F. If the one extremely high value of 789°F and the five extremely low values of 515°F to 579°F are disregarded as sampling or analytical errors, the remaining 33 values average 624°F with a range of 590°F to 643°F. If the temperature of the deep-seated reservoir is on the order of 624°F, it is probable that the Tertiary sands and underlying rocks make up the bulk of this primary reservoir, since the temperature of these sands in Baca 11 is approximately 627°F.

In summary, the Redondo Creek area is underlain by a hydrothermal system, with temperatures in excess of 600°F, situated in a thick section of fractured volcanic tuff and porous sedimentary rocks.

TABLE 1

Na-K-Ca Geothermometer Indicated Temperatures

Well	Date	Concentrations (ppm) Na	K	Ca	Indicated Temperature (°F)
Baca 4	9/18/73	1580	300	7.0	615
	9/21/73	1500	305	6.8	626
	9/24/73	1500	307	6.7	627
	9/28/73	1500	307	6.6	628
	10/01/73	1525	310	6.4	628
	10/05/73	1525	310	7.0	626
	10/08/73	1500	307	6.4	629
	10/12/73	950	198	4.1	632
	10/15/73	1525	311	6.4	629
	10/19/73	1450	307	6.2	635
	10/22/73	1525	310	6.3	629
	10/26/73	1525	305	6.2	626
	10/29/73	1525	311	6.4	629
	11/02/73	1550	310	6.4	626
	11/05/73	1550	311	6.4	626
	11/09/73	1330	292	5.4	643
Baca 5	8/24/71	1832	210	19.2	515
Baca 6	10/11/72	1640	370	0.1	789
	11/09/72	259	25	1.0	515
	10/27/72	1770	319	11	597
	11/07/72	1780	331	11	602
	6/13/75	1900	363	17	596
	11/09/75	1700	300	12	590
Baca 11	12/22/73	1920	360	32	577
	12/22/73	1930	340	32	567
	9/16/74	1900	483	23	636
	9/20/74	1900	483	25	634
	11/08/75	2200	550	46	618
	1/12/76	2000	463	27	617
	2/24/76	1810	430	17	632
	4/08/76	2010	541	36	635
Baca 13	12/07/74	2000	278	5	579
	12/07/74	2030	394	11	613
	12/07/74	1890	377	11	616
	10/15/75	1570	317	5	635
	11/07/75	1500	305	5	635
	1/11/76	1700	338	6	629
	2/26/76	1620	328	6	631
	4/07/76	1550	296	5	625

SUMMARY OF DRILLING OPERATIONS

Active exploration for geothermal resources in the Redondo Creek area of the Baca Ranch began in September, 1970 with the drilling of Baca 4 by Baca Land & Cattle Company. Union Oil Company began its operation in the area in July, 1971, when drilling began on Baca 5. Since that time, ten additional wells have been drilled in the Redondo Creek area. Two wells have been plugged and abandoned due to severe hole problems: Baca 5 and 9. Of the ten wells completed, five have proven to be productive: Baca 4, 6, 11, 13 and 15; one is marginally productive: Baca 10 (it may have been damaged during drilling and completion); four are non-productive: Baca 5A, 12, 14 and 16.

Drilling wells in the Redondo Creek area has presented some serious problems. Formations penetrated by the wells are considerably under-pressured with respect to normal cold water hydrostatic pressure. Using mud as a circulation medium often caused severe lost circulation due to the large pressure differential with the formation fluids. Drilling with air caused sloughing of the formations into the wellbore resulting in greater risk of losing a well. Baca 11 was drilled to 3650' using mud, then from 3650' to total depth, the well was drilled using an aerated water system with good success. Subsequent wells have been drilled using this method. Introducing air to the drilling system has caused corrosion problems in the drill string. Various inhibitors were tried to combat the corrosion; the use of ammonia has yielded the best results though it is expensive. The following is a summary of the drilling histories and remedial work on each well in the Redondo Creek area. Mechanical diagrams of the wells are included in Appendix B.

BACA #4

Elevation G. L.	Date Drilled	T.D.	Casing Record
9318'	9/11/70-10/12/70	5048'	13-3/8" 1441' - 0' 9-5/8" 3182' - 0'

This well was drilled with mud to 1442' then with air to T.D. Water chemistry and steam flow indicates vapor-dominated zones from 2625' - 3177'. Dry steam zones were encountered from 3468' - 4991', which flowed at a rate of 100,000 #/hr. Water and steam entries were encountered on the bottom and further drilling was halted.

Deepened	6/07/73-6/28/73	6378'	7" 6276' - 3031' (Slotted Liner)

The well was deepened with air. Drilling was halted at 6378' because of excessive drill pipe drag. This well was flow tested through a separator in 1973. After 50 days (9/10-10/28/73), the flow rate stabilized at 47,500 #/hr steam and 125,000 #/hr water with a wellhead pressure of 120 psig and a separator pressure of 113 psig.

Remedial	9/20/76-10/21/76		7" 2985' - 0'

A caliper log was run in the well and indicated worn and damaged casing at 2697', 2680', 2200', 2195', 1325', and 1050'. The damaged intervals were cemented. A string of 7" casing was run from 2985' to the surface and cemented in place.

BACA #5

Elevation G. L.	Date Drilled	T.D.	Casing Record
9290'	7/18/71-8/11/71	2878'	20" 390' - 0'

This well was drilled with mud to 2878'. Bad sloughing occurred from 290' - 480' and after lengthy fishing operations, the well was plugged and abandoned, leaving 2459' of drill pipe in the hole. The drilling log indicated steam and water entires, but no tests were done. After abandonment, the rig was skidded over to drill Baca 5A on the same location.

BACA #5A

Elevation G.L.	Date Drilled	T.D.	Casing Record
9290'	8/13/71-9/20/71	6973'	20" 676' - 0' 13-3/8" 2828' - 0' 9-5/8" 4400' - 2692'

This well was drilled with air. Large amounts of hot water were encountered towards the bottom, but due to a temperature reversal up the hole, the well would not flow. The well is now being used as a disposal well for produced water.

BACA #6

Elevation G. L.	Date Drilled	T.D.	Casing Record
8726'	7/08/72-7/23/72	3715'	13-3/8" 36' - 0' 9-5/8" 795' - 0' 7" 3700' - 692' (Slotted Liner)

The well was drilled with mud to 795' then with air to T.D. At T.D., the stripper rubbers and the pipe rams kept cutting out, preventing further drilling. In 1972, the well was flow tested through a separator. The flow rate stabilized at 45,400 #/hr steam and 102,300 #/hr water at 50 psig wellhead pressure after 91 days total flow time during three test from 10/8/72 through 1/16/73.

Deepened	3/01/75-4/14/75	4810'	Add 7" 2585' - 0'

The 7" slotted liner was pulled and the hole deepened to 4810' T.D. and completed open hole from 2585'-4810'. The liner was inspected and light scale noted on the bottom 15 joints, light corrosion on the bottom 10 joints and about 30% of the slots were plugged with a clay powder material. While deepening, a possible steam increase was noted at 3717' - 3737' and a drilling break from 4743' - 4759'. The well was flowed through the separator for 24 days, 7/25 through 8/17/75. Final separator rates were 38,500 #/hr steam and 136,500 #/hr water at a wellhead pressure of 108 psig. Later attempts to run a slotted liner over the production interval failed and the well was left as an open hole completion.

BACA #9 & BACA #9 REDRILL

Elevation G. L.	Date Drilled	T.D.	Casing Record	
8605'	9/15-10/13/73	Orig. 3518'	13-3/8"	805' - 0'
	10/13-11/21/73	Redrill 5303'	9-5/8"	3599' - 385'
			P&A Plug	2590' - 2795'
			Plug	468' - 0'

This well was drilled with mud to 805' then air to 3518'. Bad sloughing was encountered from 3000' - 3500'. After extensive fishing operations, the hole was sidetracked at 2433'. After being sidetracked, the well was drilled with air to T.D. The well was plugged and abandoned due to inability to recover approximately 250' of stuck pipe and the hazardous conditions created by worn and damaged casing.

BACA #10

Elevation G. L.	Date Drilled	T.D.	Casing Record
8735'	7/05/73-9/18/73	6001'	20" 653' - 0' 13-3/8" 2794' - 0' 9-5/8" 4418' - 2480' 9-5/8" Tieback 2480'-0' 7" 6000' - 4278' (Slotted Liner)

This well was drilled with mud to 658' then with air to T.D. The well was planned for 7500', but the wellbore started sloughing and drilling was halted. During fishing operations, approximately 2,500 bbls of fluid was lost to the formation close to the bottom of the hole. The well flowed before running the liner, but has not flowed since.

In January, 1975, the well was treated with 2000 lbs of caustic (ph ≈ 13.5 to 14) mixed in 500 bbls water in an attempt to remedy the damaged production interval. In May, 1975, an attempt was made to flow the well. It unloaded about 300 bbls of water and died. Flowing pressure was 72 psig at 5959'. In August, 1975, the well was perforated at intervals from 3075' to 4195' (4 holes per foot, 220 feet total). A subsequent two-phase flow test indicated flow rates of 44,000 #/hr steam and 81,000 #/hr water at 16 psig wellhead pressure.

BACA #11

Elevation G. L.	Date Drilled	T.D.	Casing Record	
9065'	9/19/73-11/13/73	6931'	20"	207' - 0'
			13-3/8"	1336' - 0'
			9-5/8"	3380' - 1219'
			Tieback	1219' - 0'
			7" (Slotted Liner)	6926' - 3320'

This well was drilled with aerated water. The well blew in at 3960' - 3970', but further steam entries could not be detected because of the aerated water system used. Drilling was stopped at T.D. because of sloughing Redbeds. The well was flow tested through a separator. The flow rate stabilized at 160,000 #/hr water and 116,000 #/hr steam at 130 psig wellhead pressure after four tests which totaled 51 days during the period 1/8/74 through 2/24/74.

Remedial 9/26/74-10/13/74

During flow test #5, 6/1/74 through 9/25/74, the well began exhibiting erratic and restricted production behavior. Sinker bar runs indicated restrictions in the wellbore at ±3209'. A service rig cleaned out the well and encountered scale buildup from ±3068' to ±3937'. Samples of the scale indicated it was made up of calcium carbonate with some silica. Upon completion of the cleanout, the well was tested again from 11/8/74 through 11/17/74. Prior to shut-in, rates were 119,300 #/hr steam and 186,600 #/hr water at 120 psig wellhead pressure and 101 psig separator pressure.

Remedial 8/23/76-9/11/76

During the last month of the interference test (3/15-4/19/76) production rates began declining severely. A sinker bar run in the well stopped at ±3200' and scale deposition was suspected. The scale was drilled out from 1565' to 4179'. The wellbore was apparently clean from 4179' to 6609' ETD.

BACA #12

Elevation G. L.	Date Drilled	T.D.	Casing Record	
8430'	6/19/74-8/19/74	9212'	20"	247' - 0'
			13-3/8"	1453' - 0'
			9-5/8"	3540' - 1269'
			9-5/8"	1270' - 0'
			7"	9211' - 3343'
				(Slotted Liner)

This well was drilled with mud to 250', then water to 6900' and aerated water to 9212' T.D. Upon completion, attempts were made to flow the well. For several days it blew with the assistance of an air compressor at wellhead pressures of 2 to 48 psig. Without a compressor it flowed through an 8-1/2" orifice at 0-12 psig wellhead pressure. After running a 7" slotted liner, the well was again flowed for a short time but died. The well has been used for water disposal from various other well tests.

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BACA #13

Elevation G. L.	Date Drilled	T.D.	Casing Record	
9292'	8/23/74-10/27/74	8228'	30"	12' - 0'
			20"	211' - 0'
			13-3/8"	1469' - 0'
			9-5/8"	3499' - 1270'
			9-5/8" (Tieback)	1270' - 0'
			7" (Slotted Liner)	8200' - 3340'

This well was drilled with mud to 2607' and aerated water to 8228' T.D. Cores were cut at intervals: #1 - 5084' to 5095' (4' rec.); #2 - 5074' to 5081' (no rec., difference due to pipe stretch); #3 - 5097' (unable to drill); #4 - 5286' to 5300' (6' rec.); and #5 - 6292' to 6308' (9-1/2' rec.). Logs run in the hole included temperature log, CDL, DIL and sonic log. The well was tested with an 8-1/2" orifice at rates of 475,000 #/hr to 330,000 #/hr (two-phase estimates) at pressures of 65 psig to 38 psig prior to moving the rig off location. Initial separator tests on the well indicated total mass flow of 275,000 #/hr to 300,000 #/hr at pressures of 129 to 124 psig and 24 to 25% flash (flow rates and pressures fluctuated during separator tests).

During drilling Baca #13, an extensive corrosion control program was undertaken to keep the rate under two pounds per square foot per year. Careful application of COAT 777, Unisteam and caustic soda maintained the design rate from surface to 4854'. Below that depth the corrosion rate increased due to inability to circulate continuously.

BACA #14

Elevation G. L.	Date Drilled	T.D.	Casing Record	
8605'	11/16/74-2/24/75	Orig. 6824'	30"	10' - 0'
		Plugged 5780'	20"	193' - 0'
			13-3/8"	1452' - 0'
			9-5/8"	3074' - 1371'

This well was drilled with mud to 3075' then with water to T.D. Several attempts were made to flow the well with the assistance of an air compressor; without assistance the well would die. Additional attempts were made to flow the well with open end drill pipe hung at 5583' and later with open end tubing hung at 5314', 5665', and 5757'. Again, the well would die without the assistance of an air compressor. The well was plugged back to 5780' due to sloughing problems and completed as an injector. Again, corrosion coupons were used as an integral part of a corrosion control program undertaken on this well. Corrosion rates were maintained within design limits of 2 lbs/ft^2/yr except during fishing operations or when chemical pumps failed.

BACA #15

Elevation G. L.	Date Drilled	T.D.	Casing Record	
9117'	4/29/75-6/12/75	5505'	20"	210' - 0'
			13-3/8"	1273' - 0'
			9-5/8"	2509' - 0'

This well was drilled with mud to 2519' and aerated water to 5505' T.D. It was rig tested at rates in excess of 500,000 #/hr (two-phase estimate) at 84 psig and assumed flash of ±30%. Later a flowing survey and two-phase flow test indicated rates on the order of ±170,000 #/hr at 65 psig with flash estimated at 70%.

Recompletion	9/13/76-9/19/76	7" 5503' - 2371' (Slotted Liner)

Baca 15 was originally completed open hole without a liner. To prepare for production testing, a 7" blank and slotted liner was run from 5503' and hung at 2371'. A 2-3/8" tubing string was also run from 5472' to surface. The tubing will facilitate gathering flowing pressure and temperature data during subsequent production testing.

BACA #16

Elevation G. L.	Date Drilled	T.D.	Casing Record	
9622'	6/19/75-8/21/75	7002'	20"	193' - 0'
			13-3/8"	1215' - 0'
			9-5/8"	2905' - 1100'

This well was drilled with mud to 1216', water to 4160' and aerated water to 7002' T.D. The well would not sustain flow during tests at 6203' and 7002'. A flowing survey indicated a flowing pressure of about 124 psig at 6200' with an estimated rate of 44,000 #/hr total mass. An injectivity test (7000 bbls injected at 9 bpm, vacuum at wellhead) indicated water exiting the wellbore at ±3600' and ±5400'. The fractures encountered by the well were altered and mineralized to the point of making the well nonproductive.

SUMMARY OF WELL TESTS

The following wells completed in the Redondo Creek area are capable of steam and hot water production, Baca 4, 6, 10, 11, 13 and 15. Various tests have been performed on these wells to evaluate the production and reservoir characteristics and the chemistry of produced fluids. Tests performed were two-phase tests, separator tests, pressure buildup and drawdown tests, and chemical analyses of produced water, steam condensate and noncondensible gases. This discussion will cover testing programs up to the start of the interference test in October, 1975.

A tabulation of all production tests (two-phase and separator) is presented in Table 2 on the next page. Graphs for individual well test performance are included in Appendix C.

TWO-PHASE TESTS

The purpose of two-phase tests is to establish that a well is productive and provide an estimate of its flow rate. All wells drilled were two-phase tested while the rig was on the well and several had longer two-phase tests after the rig was moved.

The test method consisted of flowing the well to the reserve pit and measuring the pressure drop across an orifice. This provided an estimate of the flow rate, and steam flash was assumed. Rates determined by this method are subject to error and can only be considered approximate. Other factors affecting two-phase tests during rig operations would be the tendency of

TABLE 2

WELL TEST SUMMARY THROUGH SEPTEMBER, 1975

WELL	DATE	FLOW TIME HRS	WELLHEAD PRESSURE PSIG	SEPARATOR PRESSURE PSIG	STEAM FRACTION	TOTAL MASS FLOW #/HR	TOTAL FLUID ENTHALPY BTU/LB	RESERVOIR TEMPERATURE BASED ON ENTHALPY, °F	
B-4-1	8/13-22/73	228	204	175	26.0	145,800	569.5 516-569	566 523-566	@ 228 hrs range
B-4-2	9/10-11/13/73	1538	120	113	27.5	172,500	556.1 526-566	556 532-563	@ 1538 hrs range
B-6-1	10/08-15/72	166	137	92	24.4	153,500	517 513-534	524 521-538	@ 165 hrs range
B-6-2	10/25-11/4/72	190	92	69.5	27.6	146,900	530.9 527-538	536 532-541	@ 189 hrs range
B-6-3	11/6/72-1/16/73	1700	51.5	37.75	30.7	147,700	532.2 518-581	536 525-574	@ 1700 hrs range
B-6-4	6/5-24/75	428	58	--	30.0 (est.)	248,000 (est.)	--	--	2-phase test
B-6-5	7/3-21/75	428	53	--	30.3 (est.)	240,000 (est.)	--	--	2-phase test
B-6-6	7/25-8/19/75	584	107.5	100.5	22.0	175,000	500.9 493-513	510 504-521	@ 584 hrs range
B-10-1	8/26-9/3/75	215	31	--	34.1 (est.)	126,000	--	--	2-phase test
B-11-1	1/8-9/74	24	--	140	33.4	480,500	619.9 619-664	602 602-631	@ 24 hours

TABLE 2
WELL TEST SUMMARY THROUGH SEPTEMBER 1975
Page 2

WELL	DATE	FLOW TIME HRS	WELLHEAD PRESSURE PSIG	SEPARATOR PRESSURE PSIG	STEAM FRACTION	TOTAL MASS FLOW #/HR	TOTAL FLUID ENTHALPY BTU/LB	RESERVOIR TEMPERATURE BASED ON ENTHALPY, °F	
B-11-2*	1/11-25/74	311	121	105	49.6	205,000	746.6	676	@ 310 hrs
							744-806	674-696	range
B-11-3	1/29-30/74	27	143			No Data			
B-11-4	2/01-24/74	546	131	115	41.1	271,400	675.9	638	@ 546 hrs
							668-734	634-669	range
B-11-5	6/26-9/25/74	2182	138	126.5	35.6	267,100	633.1	611	@ 745 hrs
			127	114	32.9	252,000	604	591	@ 1440 hrs
			129	124	26.9	164,300	556.4	556	@ 2182 hrs
							526-671	532-635	range
B-11-6	11/8-17/74	243	120	101	39.0	305,900	651	623	@ 217 hrs
B-13-1	11/30/74 - 1/06/75	792	62	--	29.6 (est.)	300,000	--	--	2-phase test
B-13-2	1/10-2/25/75	1103	124	115	25.4	303,700	537.8	541	@ 1100 hrs
							522-561	533-559	range
B-13-3	5/14-6/6/75	471	110	92.5	31.6	257,200	581	575	@ 471 hrs
							549-588	550-580	range
B-13-4	6/13-20/75	163	110	87	27.0	273,200	537	540	@ 115 hrs
							536-539	539-542	range
	2nd rate		190	33	20.5	161,000	432	453	@ 159 hrs
B-15-1	6/27-7/14/75	429	63	--	70.0 (est.)	169,400	--	--	2-phase test

*Sand buildup in water line makes H_2O data suspect.

a well to unload the wellbore fluids and nearby fracture system during the early portion of a test giving rise to high estimates of flow under unstable conditions.

Nonproductive wells presented the problem of whether lack of productivity was due to formation damage or lack of permeability. In the case of nonproductive wells, Baca 5A, 12, 14 and 16, further attempts had to be made to induce flow. Usually air was pumped through drill pipe or tubing to lighten the liquid column and help the well kick off. If the well started flowing with assistance, the air was turned off. If the well would not sustain production after several attempts, operations were suspended and the rig was moved. Three nonproductive wells (Baca 5A, 12 and 14) have been used as water disposal wells during subsequent production operations. Baca 16 was used as an observation well during the recent interference test.

Longer two-phase tests were done on Baca 6, 10, 13 and 15. In the case of Baca 6 and 13, they were done to clean up the wells prior to separator tests. Baca 10 and 15 were produced two-phase in lieu of separator tests when timing or other plans did not allow a full separator test. Baca 15 will have its first separator test this fall upon completion of the interference test.

SEPARATOR TESTS

Separator tests provide a means of evaluating a well's flow capacity with respect to producing pressure and time, steam fraction, reservoir fluid enthalpy, and composition of produced fluids. Wells tested with separators were Baca 4, 6, 11 and 13. Several tests were conducted on each well and average test conditions are summarized in Table 2.

A typical separator test consisted of flowing the well to a separator vessel and measuring steam and water phases individually. Continuous recording meters were used to keep a record of the flowing pressures and pressure drops used to make flow rate calculations. Steam enthalpy and quality were measured using throttling calorimeters. Samples of steam condensate, water and noncondensible gases were taken for chemical analyses. Schematics of typical production systems are shown in Figures 14 through 16.

Productivity of Redondo Creek area wells has been relatively low. The measured flow capacity at stable conditions ranged from 147,700 #/hr (Baca 6, test 3) to 303,700 #/hr (Baca 13, test 2). Productivity indices, PI, were calculated by the relationship $PI = \frac{q_{sc}}{p_e - p_{wf}}$, $\frac{\text{\#/hr at surface conditions}}{\text{psi drawdown in the wellbore}}$.

These calculations indicated PI ranged from about 221 to 400 lbs/hr/psi drawdown in the wellbore. The calculations were made at stabilized flow rates when the wells were being separator tested.

When pressure in the formation drops below saturation pressure, flashing will occur introducing two-phase relative permeability effects to the formation flow regime. Calculations of bottom-hole flowing pressures indicate this is happening in all of the wells. Whether boiling occurs near or far from the wellbore cannot easily be determined, but the rapid expansion of the steam as pressure declines may cause a flow restriction in the fracture system and limit the productivity.

To illustrate this, fluid mobility ratios, $\frac{kh}{\mu}$, were calculated from the productivity index data. They were generally much lower than those derived from pressure buildup calculations. The reason for this is that during pressure buildup in a well only one phase, water, is present in the reservoir. During production tests two-phases, steam and water, are present and flowing simultaneously in the reservoir. The fluid mobility ratio is calculated as follows:

$$\frac{kh}{\mu} = \frac{q\beta \ln r_e/r_w}{(7.08\text{x}10^{-3})(p_e-p_w)}, \quad \frac{\text{md ft}}{\text{cp}}$$

Total mass flow rate measured at the surface is converted to volumetric flow rate at reservoir conditions in the term $q\beta$, (p_e-p_w) is the difference between reservoir pressure and calculated bottomhole flowing pressure, and $\ln r_e/r_w$ is the natural log of the ratio of the well's drainage radius to wellbore radius. Drainage radius, r_e, is assumed to be 745', the radius of a 40 acre circular drainage area. Since r_e enters the equation as a log term, doubling the radius increases the calculated mobility value by only 10%. Table 3 tabulates the mobility values calculated from productivity data and pressure buildup data.

With the exception of Baca 11 and 13, as noted, fluid mobility ratios appear to be higher when only a single phase is present in the reservoir (pressure buildup tests) than when two phases are present (productivity tests). When a well is shut in for pressure buildup, steam within the fracture system condenses very rapidly resulting in a majority of the buildup being recorded while only water is present in the fracture system.

TABLE 3

Mobility Values From Productivity and Pressure Buildup Data

WELL	TEST NUMBER	PI lbs/hr/psi	PI MOBILITY $\frac{kh}{\mu}$, $\frac{md\ ft}{cp}$	PRESSURE BUILDUP MOBILITY $\frac{kh}{\mu}$, $\frac{md\ ft}{cp}$
Baca 4	2	263	22,400	42,100
Baca 6	1	274	24,900	48,500
Baca 6	2	241	21,900	46,400
Baca 6	3	221	20,300	46,700
Baca 6	6	316	29,100	64,000
Baca 11	4	318	29,300	No Buildup
Baca 11	6	400*	36,800*	34,600
Baca 13	2	427**	39,300**	26,400
Baca 13	3	329**	30,300**	No Buildup
Baca 13	Interference Test	243**	22,400**	20,300

* Well may not have been stable.

**Baca 13 rates and pressures fluctuate; therefore, PI's may not be representative of stabilized conditions.

Production decline was usually high during the first several days of a test due to wellbore and fracture system unloading. After that, decline was about 10% for the duration of the extended flow tests (45 to 90 days). Baca 11 declined severely during Test #5 (after 60 days) due to $CaCO_3$ scale deposition in the wellbore. The well has also unloaded sand periodically, which distorted flow rates during Test #2. Baca 13 exhibited continually cyclic production rates and pressures during all flow tests. Cause of this behavior may be steam flashing in the fracture system or possible permeability restriction which could lead to alternating slugs of steam and water. Magnitude of the cycles is about 10-15 psig and rates varied by about 10%.

The steam fraction varied considerably in the wells and ranged from 22% at Baca 6 to nearly 50% in Baca 11. Steam fraction is related to the reservoir fluid temperature and operating pressure at the separator. Lowering or raising separator pressure will cause corresponding increase or decrease in steam fraction. The effect of separator pressure on steam fraction is illustrated in Figure 17. It is evident that given constant reservoir fluid temperature, the steam fraction should vary only 11% over the indicated range of separator pressures.

Possible reasons for the wide range of steam fraction could be: 1) wells are producing reservoir fluids that originate at different reservoir temperatures; 2) heat is being lost or gained by the two-phase mixture as it is produced; 3) additional steam is being produced at a well that comes from an isolated steam zone; or 4) steam is being lost due to migration or segregation as the two-phase mixture flows through the fractures toward the well. Of these possibilities, the first is evident from temperature measurements made in the wells where maximums ranged from 536°F at Baca 6 to 627°F at Baca 11. Geochemical evidence indicates reservoir fluid temperature is on the order of 590°F to 643°F, and all producers sampled (Baca 4, 6, 11 and 13) seem to fall into this range. This point was discussed earlier but to reiterate, calculated reservoir fluid temperatures appear to be relatively constant for all producing wells. Therefore, low steam fraction is probably due to a loss of heat from the reservoir fluid or loss of steam by migration and segregation in the case of wells producing low steam fraction. High steam fraction may be due to the production of additional steam from an isolated steam zone as in the case of Baca 11.

Effective produced fluid enthalpy provides evidence for both of the above arguments. This is determined from the enthalpy of steam and water at separator pressure multiplied by their respective mass fractions and adding as such, i.e.:

$$h_{eff} = x(h_s) + (1-x)(h_w).$$

By assuming adiabatic flash of reservoir liquid to surface conditions, the h_{eff} should be equal to the enthalpy at reservoir fluid temperature.

At the maximum observed temperature, 627°F, the corresponding liquid enthalpy is 658 btu/lb. This is the upper limit of expected effective enthalpy of produced fluids. The range of effective enthalpies was 500 to 588 btu/lb for wells Baca 4, 6 and 13. Effective enthalpy at Baca 11 has ranged from 600 to 844 btu/lb for various well tests including the interference test. However, Baca 11 penetrated a zone at 3959' where lost circulation occurred and the well blew in. Temperature of this zone appears to be about 530°F, which has a saturation pressure of 875 psig. A plot of flowing pressure at 4000' versus effective enthalpy, Figure 18, shows that as pressure drops below 700 psig at 4000', effective enthalpy increases rapidly because steam can flow from the zone into the well. This is a cause of high steam fraction at Baca 11.

Evidence of steam migration or segregation occurred during the interference test. An energy balance calculation was done to determine the effective enthalpy of all produced fluids during the test. Table 4 shows each well's cumulative mass and energy production.

TABLE 4

Cumulative Production From Interference Test

Well	Cumulative Mass Production, 10^6 lbs	Cumulative Energy Production, 10^9 btu's	Average Fluid Enthalpy btu/lb
Baca 6	256	133	520
Baca 11	899	665	740
Baca 13	1089	608	558
TOTAL	2244	1406	626

$$h_{eff} = \frac{1406 \times 10^9 \text{ btu's}}{2244 \times 10^6 \text{ lbs}} = 626 \text{ btu/lb}$$

Fluid temperature corresponding to 626 btu/lb is 606°F. This appears to agree within the limits of previous indications of maximum reservoir fluid temperature, but more important it supports the idea that Baca 6 and 13 are losing steam by migration or segregation. Baca 11 could be gaining some of the migratory steam, but the reservoir pressure measured in the observation wells during the interference test are well above saturation pressure. Thus, it seems likely that the migratory steam condenses before it has traveled very far in the fracture system. The isolated steam zone production appears to be the best explanation of the higher effective enthalpy in Baca 11.

PRESSURE BUILDUP TESTS

Transient pressure testing provides quantitative information necessary to understand the rock-fluid flow relationship in the reservoir. It also gives some qualitative information regarding reservoir geometry, flow boundaries or barriers and mechanical condition of a well. The most popular methods of transient pressure testing are the shut-in pressure buildup test and the pressure drawdown test.

Pressure buildup tests were performed on six of the wells in the Redondo Creek area with varying degrees of success. The buildup is performed by shutting a well in at the surface after production testing, lowering a pressure instrument into the well, and measuring the pressure recovery versus shut-in time. Pressures are plotted on a semi-log graph (called a Horner graph) versus the log of dimensionless time, $\frac{t+\Delta t}{\Delta t}$. From this plot we can determine the reservoir permeability-thickness product (kh), the wellbore skin effect, and the static reservoir pressure.

The equations used to analyze pressure buildup tests have been adapted from methods developed in the oil and gas industry.

Derivations of these equations are in SPE Monograph 1[3]. The basic equation for pressure buildup analysis is:

$$p_{ws} = p_i - \frac{162.6\ q\mu\beta}{kh} \log \left(\frac{t+\Delta t}{\Delta t}\right)$$

p_{ws} = Well pressure after shut-in, psig.

p_i = Initial well pressure, psig.

q = Volumetric flow rate, Stock Tank Barrels/Day.

β = Reservoir volume factor, Reservoir Barrels/Stock Tank Barrel.

μ = Viscosity, centipoise.

k = Formation permeability, millidarcies.

h = Formation thickness, feet.

t = Total flow time, hours.

Δt = Shut-in time, hours.

From this equation it is evident that a plot of p_{ws} vs. $\log\frac{t+\Delta t}{\Delta t}$ will be a straight line with a slope of $m = \frac{162.6\ q\mu\beta}{kh}$. From this equation the formation permeability, k, can be calculated. In fractured reservoir systems it is difficult to determine h, reservoir thickness, so generally the equation takes the form:

$$kh = \frac{162.6\ q\mu\beta}{m} \text{ millidarcy feet.}$$

Thus, the product kh is used to determine reservoir fracture system capacity to transmit fluid. The kh calculated from any individual well pressure buildup test will be representative of the reservoir in the vicinity of that particular wellbore. If all the wells penetrate the same fracture system, the kh values should reflect whether or not the system is homogeneous.

The skin effect is an indicator of near wellbore permeability impairment (positive skin) or improvement (negative skin). The equation used to calculate the skin effect is:

$$S = 1.151 \left[\frac{p_{1hr} - p_{wf}}{m} - \log \frac{k}{\phi \mu c r_w^2} + 3.23 \right]$$

p_{1hr} = Extrapolated well pressure one hour after shut-in, psig.

p_{wf} = Well flowing pressure prior to shut-in, psig.

k = Reservoir permeability, millidarcies.

ϕ = Reservoir porosity, fraction.

μ = Viscosity, centipoise.

c = Compressibility, vol/vol/psi.

r_w = Wellbore radius, feet.

S = Skin factor, dimensionless (positive or negative).

In the log term of the above equation, we generally substitute the products kh and ϕh for the terms k and ϕ. This is done because both k and ϕ are not easily determined in a fracture system. We can calculate kh from the pressure buildup, so if a reasonable estimate of ϕh can be made, skin effect can be calculated. Since ϕh enters the equation in a log term, large errors in ϕh will have only a small effect on the calculated skin effect. Positive skin effect means permeability impairment which can be caused by invasion of drilling fluids into the fracture system, scale deposition in the formation fracture system, partial penetration, flashing of steam in the formation fracture system, or high steam saturation near the wellbore. The effect is a reduction of flow capacity because more pressure drop is required to move the same amount of fluid across the impaired area. Permeability improvement (negative skin effect) is due to fractures or enlarged wellbore radius in the producing interval and less pressure drop is necessary to move the fluid to the wellbore.

Static formation pressures are measured in each well prior to any significant testing or withdrawals. After completion of any production and pressure buildup testing, static formation pressure is measured to determine whether there has been any measureable change due to withdrawal of reservoir fluids. If the static formation pressure drops then reservoir depletion is evident and reservoir size can be calculated. If there is no measureable drop in formation pressure, then there are two possible explanations: 1) reservoir size is very large and withdrawals were not enough to cause depletion; or 2) the reservoir is being recharged at a rate sufficient to sustain formation pressure.

Results of the pressure buildup tests done on Baca 4, 6, 10, 11, 13 and 15 are tabulated in Table 5. Horner graphs of the pressure buildup test data are included in Appendix D.

Calculated values of kh varied throughout the field but their order of magnitude indicates some degree of fracture system homogeneity. Average kh from all tests excluding Baca 15 was 4310 md ft. Baca 15 was excluded from the average because only a short two-phase production test had been done and there were not enough data to conclude it was a representative pressure buildup test. The calculated kh values were mapped and Figure 19 is an iso kh map of the data. The contours on the iso kh map show some correlation to isothermal trends mapped within the

TABLE 5

Results of Pressure Buildup Tests

Well	Test Number	Date	kh md ft		Skin S	Final Static Buildup Press., psig	Measured Depth ft
Baca 4	2	11/13/73	4207		+14.7	1686	6350
Baca 6	1	10/15/72	4849		+ 7.9	959	3690
Baca 6	2	11/03/72	4641		+ 8.0	984	3690
Baca 6	3	1/16/73	4666		+ 8.8	985	3690
Baca 6	6 (After Deepening)	8/19/75	6401		+ 9.7	1004	3830
Baca 10	1 (Two-phase Test)	9/03/75	5151		+42.9	1761	5959
Baca 11	6	11/17/74	3457		- 3.9	1811	6630
Baca 13	2	2/25/75	2638	2332	- 1.9	2310	8176
Baca 13	Interference Test	4/19/76	2025	Avg.	+ 4.3	2288	8100
Baca 15	1 (Two-phase Test)	7/14/75	8630*		- 2.9	911	5500

Average of all tests (except Baca 15) 4310 md ft (using average for B-13 and value from B-6 test 6)

* Assumes drainage area contains steam only.

field (refer to Figures 11-13). This appears to confirm the relationship between productivity, fractures and high temperature. High temperatures are a result of hot fluid convection within the fracture system and the fractures are the main source of reservoir permeability and resultant productivity. Lack of productivity or permeability in nonproductive wells does not necessarily indicate lack of fractures, but may be due to secondary mineralization and thermal alteration within the fracture system.

Skin effects calculated from pressure buildup data ranged from +42.9 to -3.9 with most values being positive. This indicates that permeability impairment exists which may be caused primarily by flashing in the fracture system and steam saturation near the wellbore, but other factors, as noted earlier, could also have an effect. Negative skin values are probably a result of a higher degree of fracturing in that particular well.

Log-log type curves, Horner type curves and plots of pressure versus $\sqrt{\Delta t}$ were used to qualitatively identify wellbore effects, drainage area boundaries and type of fluid flow. Log-log type curve analysis indicated that early portions of all pressure buildups were controlled by wellbore storage and skin effects.

Late portions of pressure buildups were often controlled by heat transfer and two-phase flow effects which tend to mask boundary effects. Horner type curves, though no true matches were achieved, indicated the drainage areas of wells to be bounded by combinations of closed and constant pressure boundaries. Pressure versus $\sqrt{\Delta t}$ plots indicated flow through fractures where pressures fell on a straight line.. Fracture flow was not indicated on log-log fracture type curves due to masking by wellbore storage effects in most cases.

Static pressures at the end of the buildup tests returned to original levels within the accuracy of pressure measurement tools ($\pm$10 psi). Table 6 on the next page lists initial static pressures at a +3000 ASL datum for all the wells. Also listed are the final static buildup pressures at the same datum in the wells that were production tested.

The conclusions from these observations are that no measureable pressure depletion has occurred due to production. A reservoir size estimate will be made based on these data later in this report. At this time there is no data to indicate whether there is pressure support or recharge from outside the reservoir. It would be necessary to produce from the reservoir for an extended period of time in order to determine whether the reservoir is a closed system or is being recharged. Monitoring the chemistry of produced fluids could also give some clues regarding reservoir recharge.

A map with initial pressures plotted at the +3000' ASL datum, Figure 20, shows the anomalous pressure observations in B-15. Figure 21 shows the pressure profiles of Baca 13 and 15 to compare pressure observations at datums common to both wells. Baca 15 appears to be completed in a saturated steam region which may be completely separated from the deeper liquid phase

TABLE 6

Static Pressure at +3000' Above Sea Level

Well	Test Number	Initial Pressure psig	Final Press. After Buildup psig	Cumulative Production At End of Test MMlbs	Comments
Baca 4	2	1684	1676	301.3	
Baca 5	-	1701	--	--	
Baca 6	1	1694	1648	24.6	Final static press. at Δt=221 hrs, well may not have been completely built up.
Baca 6	2	1694	1674	54.1	
Baca 6	3	1694	1674	299.9	About 15 months after well was shut-in.
Baca 6	6	1665*	1648*	646.5*	*After deepening the well in 4/75.
Baca 10	1 (Two-phase Test)	1678	1688	37.9	-
Baca 11	6	1678	1653	791.8	Well pressure fluctuating.
Baca 12	-	1664	--	--	
Baca 13	2	1710	1720	629.4	
Baca 13	Interference Test	1710	1700	1919.5	
Baca 14	-	1688	--	--	
Baca 15	1 (Two-phase Test)	1245	1188	82.7	No liquid level in well, assumed .33 gradient in extrapolation to +3000' datum.
Baca 16	-	1711	--	--	

reservoir. This does not preclude communication with some of the wells, possibly through an isolated steam zone that may be cased off in the other wells. Baca 11 may be in communication with Baca 15, but no data exists at present to prove this. More will be learned about the reservoir and production characteristics of Baca 15 when it is separator tested later this fall.

DRAWDOWN TESTS

Pressure drawdown tests are also conducted during production operations. Basically, the test consists of measuring the flowing bottomhole pressure and plotting it versus producing time, Δt. Information gained from this type of test is the permeability-thickness product and skin effects. In geothermal wells, flowing pressures are not easily measured and had to be calculated using a computer program. This limited the utility of the tests because the calculations of flowing pressure have not proven to match all of the available flowing pressures measured in wells. Because of this limitation, drawdown test analysis is used only for comparison to results obtained by pressure buildup tests. Good agreement was achieved in some cases and this method will become more valuable if confidence can be placed in calculated flowing pressures. Plots of pressure drawdown tests are included in Appendix D.

CHEMICAL COMPOSITION, CORROSION & SCALE DEPOSITION

Samples of produced fluids were gathered from the wells during various production tests. Samples of produced water, steam condensate and noncondensible gases were analyzed for their chemical composition and quantity relative to total mass production. Summaries of the chemical analyses are included in Appendix E.

Table 7, on the next page, summarizes the average concentrations of total dissolved solids in produced water and condensate, silica concentration, noncondensible gas concentration and hydrogen sulphide concentrations.

The dissolved solids in the produced water consist primarily of sodium, potassium, calcium, silica, and chlorides. The significance of these components are their contributions to scale formation in the reservoir and surface facilities and their corrosive properties. Steam condensate generally had small amounts of dissolved solids. This can be attributed to carryover of entrained water into the steam line.

Scaling has been observed in wellbore casing, surface production equipment and injection facilities to varying degrees. Scale deposition first occurred in Baca 11 during Test #5 (6/26/74 to 9/25/74). In the wellbore, light scale was noted from 3068' to 3194' where bridging had occurred. Heavy scale was noted from 3194' to 3813' grading to light scale at 3937'. The wellbore was apparently clean from that point to 6605' ETD.

TABLE 7

Well	Avg. TDS In Brine	Avg. TDS In Condensate	Silica (ppm) In Brine	Noncondensible Gas % by Wt. of Steam Phase	H_2S Concentration (ppm)		Average	
					Noncondensible	Total Steam	Flash %	Flowrate lbs/hr Total
Baca 4	5100	28	302 (167-701)	3.16	165 (150-180)	165 (117-213)	26.8	171,400
Baca 6	6018 (5800-6230)	23 (3-65)	453 (160-600)	1.33 (1.27-1.38)	61 (60-61)	99 (69-257)	27.8	163,700
Baca 11	6895 (6056-7593)	59 (7-105)	740 (640-835)	3.76 (2.30-5.94)	365 (222-564)	477 (290-867)	39.7	227,100
Baca 13	6477 (5500-8684)	13 (7-25)	786 (556-963)	2.93 (1.93-3.94)	81 (57-96)	149 (86.3-205)	28.4	284,600

NOTE: 1. Some samples from Baca 4 were diluted prior to analysis. The results from these analyses are not included in the above.

2. Left out values obtained from low rate of two-rate test on Baca 13.

The depth where scale was last noted coincides roughly with the suspected isolated steam zone in Baca 11 and this could have a bearing on the scale deposition. Analysis indicated the scale was primarily $CaCO_3$. Additional scaling occurred in the separator and flow lines which was primarily silica.

During the interference test an attempt was made to install a downhole scale inhibitor injection system in Baca 11. The objective was to prevent scale from forming in the wellbore and related surface equipment. Mechanical problems with downhole backpressure valves and leaks in the tubing rendered the system unworkable.

After 132 days of production (about 3/15/76), rate and pressure declined severely until the well was shut in on 4/19/76. Sinker bars run into the well stopped at 3200' and scale deposition was evident. A caliper log run in the well indicated scale buildup from ±1575' (about 1/16") to ±3170' (about 3/4") where the caliper tool stopped. The scale was drilled out from ±1565' to ±4179' where the scale apparently stopped. There were no indications of scale from 4179' to 6609' ETD. Some samples of the scale were gathered and preliminary analysis indicate it was primarily $CaCO_3$.

Inspection of all surface production equipment at the end of the interference test indicated pipe and separators were essentially clean except for some slight deposition of metal sulfides and silica. Samples of pipe from production and injection wells were sent to Union Research for corrosion inspection.

Injection facilities were also inspected and showed that scale had formed in cooling ponds and in the injection lines near orifices and wellheads. Bridges were found in Baca 12 at 3614' and in Baca 14 at 3984' with wireline tools. Cleanout operations in Baca 12 found scale buildup from 550' to a bridge at 3614' in the 7" liner. Scraping operations continued to a bridge at 5100' and 5628'. Below 5628', pipe was apparently clean to 8454' where bridging (or formation fill) was noted. The operation was halted at 8454' due to inability to rotate and maintain circulation with the rig pumps.

Cleanout operations were also performed on Baca 14. Scale was noted at ±1248' where a small bridge was located. The scale was scraped and drilled from 1248' to 3074' (shoe of 9-5/8" casing). Below the casing in the 8-3/4" open hole, bridges were noted at various intervals from 3779' to 5488'. The operation was suspended at 5488' due to high torque when rotating and problems with sticking pipe.

Samples of the scale from both wellbores and surface injection lines were sent to Union Research for analyses. The scale is believed to be predominantly silica. Though the scaling was pronounced in Baca 12 and 14 both wells remained in service throughout the entire interference test. Presently, both wells are shut-in to allow them to heat up. Later this fall, attempts will be made to backflow the wells to determine if productivity may have been enhanced due to injecting the low pH water into the wells. Additional injectivity tests will need to be done on Baca 12 and 14 to determine whether the injection capacity of each well has been impaired due to scaling which was observed.

Baca 4, 6 and 13 do not appear to have significant scale problems at the present time. Some minor scale was noted in the 7" production liner pulled out of Baca 6 in April, 1975. Thickness of the scale was about 1 mm (.039") and was made up of silica and iron. No scale has been detected in Baca 13 at this time. A caliper log will be run in the well to verify this later. This is significant in that Baca 13 has produced about 1919 x 10^6 lbs total mass compared to 1691 x 10^6 lbs total mass for Baca 11.

Conclusions from observations to date are that calcium carbonate scaling will be a problem in wellbore casing in some of the wells and possibly the reservoir fracture system. It appears that scaling was severe where steam zone production in Baca 11 commingled with the two-phase mixture from the deep reservoir. Other producing wells do not appear to have the same scaling tendencies as Baca 11 at this time.

Problems with silica scaling generally occurred after the produced water had flashed to atmospheric pressure and cooled. Water injection facilities will need to be designed to prevent cooling of the residual water to minimize scale deposition or methods of straining the water to remove scale particles before they get to the injection wells may have to be used.

The noncondensible gases consist primarily of carbon dioxide (about 99+%) with small amounts of hydrogen sulphide, nitrogen, hydrogen, methane and ethane. The noncondensible gases also present problems due to their corrosive properties, contribute to scaling and require special handling in the condensers of generating units. Weighted average noncondensible gas was about 3% (based on total steam production). Baca 11 appeared to have higher concentrations as evidenced by its average and range of measurements on Table 7. Baca 6 appears to have low concentrations. These extreme values could be due to steam zone production in Baca 11 and steam migration or segregation in the case of Baca 6. The CO_2 dissolved in the reservoir fluid has a marked effect on $CaCO_3$ solubility and $CaCO_3$ can be deposited when CO_2 comes out of solution, but other factors also affect this reaction which are not fully understood yet.

Corrosion tests have been performed on various metal alloys in conjunction with heat exchanger tests at Baca 11. Corrosion rates were measured in three environments; clean steam, dirty steam, and brine. Carbon steel showed significant corrosion in all three environments. Copper based alloys also suffered measureable corrosion, but was not considered severe. Titanium, Carpenter 20, Incoloy 825, Inconel 600, Carpenter 7 Mo and 316 stainless steel suffered no corrosion in all three environments.

The 7" production liner was pulled from Baca 6 in April, 1975. The liner had been in place about 3-1/2 years and the well produced about 85 days during the period (cumulative production was 324 x 10^6 lbs total mass). Wall thickness measurements were within mill specifications for all joints indicating no serious corrosion had occurred during this period. Some scale deposition was noted in the liner with major elements being silica and iron and minor amounts of aluminum and sodium. Thickness of scale was generally less than 1 mm (.039").

Several wireline failures were attributed to corrosion. High temperature hydrogen attack was suspected in failures of plow steel wireline. Stainless steel wireline used to replace the plow steel failed due to chloride stress corrosion cracking. The stainless steel had been in service for 61 surveys prior to the failure. Carpenter 20 wireline has been recommended for future use due to its resistance to chloride stress corrosion. Stainless steel tubing is being used in the Sperry Sun Pressure Monitor System installed in Baca 10. The system has been in service for 6 months with no apparent problems.

Union Research has conducted two long-term pilot plant heat exchanger tests at Baca 11. The first test was undertaken in August and September, 1974 (38 days) and the second test was from November, 1975 through January, 1976 (50 days). Objectives of the heat exchanger tests were to study heat transfer coefficients of steam and hot water, degree of fouling or scale deposition on heat transfer surfaces, corrosiveness of steam and hot water on various metals and characteristics of steam under dynamic conditions.

Overall heat transfer coefficients on the steam exchangers ranged from 450 - 550 Btu/hr-ft^2-°F. The coefficients declined during the tests with some flattening noted at the end of the run. There was no visible scale deposition on the steam side of the exchanger but on the cooling water side there was considerable fouling due to clay and rust deposition which contributed greatly to the decline in coefficients. Also noted was an increase in noncondensible gases (from 3.1% to 6.2%) during the last test and it is felt this also contributed to the decline in the overall heat transfer coefficients.

Dissolved solids in the steam varied during the tests. Total dissolved solids in the steam from the wellhead separator varied from 35 to several hundred parts per million and in the steam to the exchangers, they ranged from 8 to several hundred parts per million, indicating that brine entrainment was related to liquid level in the wellhead separator. A demister used to remove entrained brine and solids proved to be more effective at high levels of entrainment than at the lower levels.

Heat transfer coefficients for the brine exchangers ranged from 475 to 920 Btu/hr-ft^2-°F initially, but showed significant decline during the run with decline leveling off as the test continued. Decline was due to silica scaling with the change in the rate of decline attributed to changing rate of silica deposition. Two exchangers were thermally shocked several times a day in efforts to remove scale deposits but this proved to be only slightly beneficial. The cooling water side of the brine exchangers also showed fouling from clay and rust, but they were not cleaned during the test and no assessment of this effect was made. It is believed that fouling of the cooling water side also contributed to the decline of brine heat transfer coefficients.

Results of the heat exchanger tests indicate that the steam could be utilized in a binary cycle or directly in a steam turbine. Scale deposition or fouling caused by the steam are problems that can be solved through steam cleanup, separator design and control of wellhead separator levels.

Additional heat recovery from brine heat transfer does not appear to be practical in light of the scale problems encountered during the heat exchanger tests.

INTERFERENCE TEST

METHOD

Interference tests are performed to determine reservoir properties, such as permeability and porosity, and to establish whether inter-well communication exists. The general method of conducting an interference test is to produce or inject into a well and measure the pressure disturbance caused in a nearby observation well. A test can be expanded to include several producers, injectors and observation wells depending on field and operational conditions. Interference tests have been used by ground water hydrologists and petroleum engineers in water and oil and gas reservoirs for many years. Very few interference tests have been performed in geothermal reservoirs to the present time.

The test performed on the Redondo Creek wells had a three-fold purpose; to determine reservoir and fracture system porosity-thickness product, permeability-thickness product, and continuity of the reservoir fracture system. The aforementioned reservoir characteristics are necessary parameters to determine recoverable reserves and to make reservoir performance predictions.

Production had been established in the Redondo Creek area by the drilling of Baca 4, 6, 10, 11, 13 and 15, but nonproductive wells, Baca 5A, 12, 14 and 16 compounded the problem of defining the areal extent of the field and whether the reservoir was continuous or large enough to support commercial energy extraction.

The test was designed to provide as much withdrawal from the reservoir as possible and use observation wells that were known to penetrate fractures. Producers chosen were Baca 6, 11 and 13 because of their proven productivity. Observation wells chosen were Baca 4, 10, 15 and 16. Baca 5, 12 and 14 were used as water disposal wells during the test. See Figure 22 for location of producers, injectors and observation wells. Prior to the test, calculations were done to predict pressure drops at the observation wells by assuming a range of values for kh, permeability-thickness product, and ϕh, porosity-thickness product, and average production rates. From these calculations it appeared that 90 days would be enough producing time to create measureable pressure drops. Later the test was extended an additional 90 days due to lack of definite pressure response and mechanical problems. The mechanical problems occurred at Baca 6 when wellbore sloughing caused the well to plug off several times. Mainly, this affected only the rate of withdrawals during the remainder of the test. The analysis of the interference test was in no way affected because the calculation method was designed to handle varying production rates including times when there was no flow from a well.

PRODUCTION PERFORMANCE

The test began 10/3/75 when Baca 6 and 13 were put on production. Production from Baca 11 was delayed until 10/28/75 because of problems encountered while installing a downhole scale inhibitor injection system. Graphs of each well's production performance are presented in Appendix F. The following is a summary of production performance of each well.

Baca 6

Initial rates were 180,000 #/hr total mass at wellhead pressure of 110 psig, 44,000 #/hr steam, 24% steam fraction at 102 psig separator pressure. The final rates were 156,000 #/hr total mass at wellhead pressure of 95 psig, 38,000 #/hr steam, 24.5% steam fraction at 90 psig separator pressure. Calorimeter measurements of steam quality ranged from 98.8% to 99.8% during the test. Baca 6 produced only 63 days. On three occasions, sloughing of the formation caused plugging of the wellbore and surface equipment to the extent that the well died. Twice it came back on production and was put in the bypass to clean up. The third time on 12/5/75, the well plugged off and would not come back on production. A service rig was moved in to clean the well out and run a liner, but efforts were unsuccessful and the well was left shut-in for the remainder of the test.

Baca 11

Initial rates were 260,000 #/hr total mass at wellhead pressure of 154 psig, 130,000 #/hr steam, 50% steam fraction at 118 psig separator pressure. The final rates were 113,000 #/hr total mass at wellhead pressure of 108 psig, 44,000 #/hr steam, 38.8% steam fraction at 98 psig separator pressure. Steam quality ranged from 99.4% to 99.6% as measured with a calorimeter. Baca 11 produced a total of 170 days. Problems were encountered with the downhole scale inhibitor injection system and the well had to be shut-in from 11/21/75 to 11/25/75 in an attempt to repair the system. The well then produced for the remainder of the test without scale inhibition. For a period of time, 12/1/75 to 1/2/76, the production rate declined steadily from 260,000 #/hr to 180,000 #/hr total mass, and the steam fraction increased to nearly 60% until 1/2/76 when the well surged and unloaded sand from the wellbore. The production rate increased to 252,000 #/hr total mass and the steam fraction returned to about 50%. From 1/2/76 to 3/11/76, the production rate declined gradually from 252,000 #/hr, 50% steam fraction to 210,000 #/hr, 43% steam fraction, but the wellhead pressure increased from 145 to 190 psig.

Also during this time, noncondensible gas increased from about 4% (1/12/76) to nearly 6% (2/24/76). From 3/11/76 to the time the well was shut-in on 4/19/76, production rate declined from 210,000 #/hr, 43% steam fraction, to 112,000 #/hr, 38.5% steam fraction. Subsequent sinker bar runs into the well encountered restrictions at ±3200' confirming scale deposition in the wellbore which caused the severe production rate decline during the final month of testing. The well was cleaned out to determine the extent and depth of scale deposition. A summary of the cleanout operation is in the previous section of this report on page 49.

<u>Baca 13</u>

Initial rates were 270,000 #/hr total mass at wellhead pressure of 120 psig, 75,000 #/hr steam, 28% steam fraction at 100 psig separator pressure. The final rates were 205,000 #/hr total mass at wellhead pressure of 90 psig, 56,000 #/hr steam, 27.5% steam fraction at 74 psig separator pressure. Steam quality measured by calorimeter ranged from 99.3% to 99.6%. The well produced a total of 207 days during the test. An important feature of Baca 13's production characteristic is that the flow rates and pressures fluctuated continually during the entire test. Ranges of fluctuation were on the order of 10 to 15 psig and rates fluctuated about 10% during a cycle. Cycles lasted about two hours from peak to peak and were very regular during the entire test. The surging is probably caused by permeability restriction of a fractured zone. When pressure drops in the zone, flashing occurs. The rapid expansion of steam probably causes ejection of steam and water into the wellbore. The sudden addition of steam and water to the wellbore causes the flowing gradient to increase momentarily. As the pressure increases opposite the zone, flashing ceases until the pressure gradient equalizes and flowing pressure drops below the saturation pressure of the zone until flashing begins again, starting another cycle. This process is probably comparable to the geysering effects that occur in natural geysers. To accomodate the surging pressures, the separator at Baca 13 was elevated about 10 feet above ground level. This was done to keep a positive hydrostatic head over the water metering orifice and prevent flashing of steam in the water line.

Total production from all wells during the test was 2244 x 10^6 lbs total mass and of this amount about 1214 x 10^6 lbs were reinjected into the reservoir. Net withdrawals from the reservoir were about 1030 x 10^6 lbs total mass. Listed on Table 8 on the next page, are production and injection data for each well during the interference test.

TABLE 8

Production

Well	Days on Prod.	Total Mass x 10^6 lbs	Total Steam x 10^6 lbs	Average Rates, mlbs/hr Total Mass	Steam
B-6	63	256	66	170	44
B-11	170	899	425	220	104
B-13	207	1089	302	219	61
TOTAL		2244	793	609	209

Injection

Well	Total Mass x 10^6 lbs
B-5	140
B-12	575
B-14	499
TOTAL	1214

The average rate of steam produced from the three wells represents about 20% of the total theoretical requirement for a 55 MW generator.

Injected fluid is about 54% of the total mass production. Injectivity tests indicate water was entering the Bandelier Tuff in all of the injection wells. Scale buildup was noted in both Baca 12 and 14. Both wells have been cleaned out to determine the extent of the scale problem and identify its composition.

Decline of production rate with time was noticeable in all the wells. At Baca 13, decline was about 17% in the first 40 days and then averaged about 10% over the last 167 days of testing. Decline at Baca 6 was about 18% during the 63 days it produced, but wellbore sloughing and the extended cleanup periods in the bypass make the decline data less indicative of reservoir conditions in this case. Production rates from Baca 11 declined also, but sand plugging, increased wellhead pressures, and scale formation in the wellbore contributed to the decline. Therefore, no useful rate decline information can be extracted from Baca 11.

Production rate decline data is important in forecasting future performance of a well or group of wells. Factors affecting decline are reservoir fracture system permeability-thickness, fluid saturations and their relative permeability effects, scaling in the fracture system, and reservoir pressure depletion.

Productivity of the Redondo Creek wells depends primarily on encountering fractures in the brittle Bandelier Tuff. Below the Bandelier Tuff are the andesite and Tertiary sands. The Tertiary sands may be the primary reservoir. Few fractures exist in the andesite which has been highly altered to clay, and little productivity has been found in this unit. The Tertiary sands are very fine grained and mostly unconsolidated which could inhibit their sustained productivity. Therefore, production decline could result from permeability restrictions in the Tertiary sands or the andesite could act as a choke due to its alteration. Under these conditions, production decline would occur until steady-state conditions are established between the primary reservoir and the fracture system.

Productivity index calculations showed that steam flashing in the reservoir fracture system could limit productivity. This could be a result of the above mentioned permeability restrictions between the primary reservoir and the fracture system.

Scale deposition in the fracture system would also cause production rate decline. Scaling has been noted in the wellbore at Baca 11 but other producers do not appear to have the same problem at this time. There is no evidence at present to indicate scale deposition is occuring in the fractures. Methods need to be developed to predict where scale will precipitate and production methods designed to minimize or eliminate conditions which may lead to scaling.

Depletion of reservoir pressure in response to fluid withdrawals will also affect the production rate in the well. We cannot attribute any of the observed production decline to reservoir pressure depletion. The time required to reach final static pressure after a well has been produced and shut-in is on the order of 1000-2000 hours for the Redondo Creek area wells. This could be further evidence of permeability restrictions between the primary reservoir and the fracture system. Pressure buildup tests were done on both Baca 11 and 13 at the conclusion of the interference test. Due to scale deposition in Baca 11, the pressures had to be measured at 3000'. During most of the buildup the fluid level in the well was below 3000' so no interpretative data was obtained and no estimate of bottomhole static pressure could be made. Pressure in Baca 13 built up to 2288 psig at 8100' 1558 hours after shut-in. This compares with an initial pressure of 2281 psig at the same depth. Total production since Baca 13 was completed is on the order of 1919 x 10^6 lbs total mass. Static pressure measured in Baca 6 in June, 1976, was 991 psig at 3690', which also compares favorably with initial pressure of 968 psig (the increase is probably due to tool accuracy). Total production from Baca 6 has been 902 x 10^6 lbs. This agrees with observations in the other wells that measureable pressure depletion has not occurred in the reservoir. A reservoir size estimate was made from these data and will be discussed in the next section of this report.

PRESSURE PERFORMANCE IN OBSERVATION WELLS

To monitor pressure disturbances in the reservoir during the interference test, four wells were used as observation wells. (See location map, Figure 22.) Of the four, three had proven productivity, Baca 4, 10 and 15. Baca 16, though not a productive well, was monitored to determine if the well penetrated the reservoir but was nonproductive due to localized reduced permeability.

Pressure and temperature measurements were done on a weekly basis in the wells. Two datum points were chosen, one near T.D. and the other at the nearest 1000' depth above T.D. To insure tool response was fully equilized with formation pressure, stops at datum points generally lasted from one-half to one hour. Tools used were the conventional Kuster wireline pressure and temperature instruments. These tools are designed and modified for high temperature environments, but some problems have occurred with data reproducibility. Experience indicates the accuracy of the instruments to be about 20 psi for an individual tool and two instruments may not agree within 10-20 psi. Nearly all pressure measurements made in the observation wells were done with one instrument to eliminate this problem. Design considerations prior to the test took into account tool accuracy. Pressure change of 20 psi or greater would be necessary to confirm communication within the reservoir.

Measurements in the wells did fluctuate within instrumental accuracy during the entire test. Baca 4, 15 and 16 exhibited no distinct trends of measureable pressure change during the test or after the production and injection wells were shut-in. Baca 10 did exhibit a considerable pressure response during the test as shown on Figure 23. Pressure gradually increased from 1614 psig on 10/1/75 to 1627 psig at about the end of October followed by a gradual decrease to 1595 psig in late December. The pressure began increasing again and leveled off in February at 1627 to 1633 psig. The trends were distinct and both datums exhibited the same general trends.

In March, a Sperry Sun "Pressure Monitor System" was installed in Baca 10. This system utilizes a .094" O.D. capillary tubing from which a 10' x 1.75" expansion chamber is suspended. The tubing and chamber are hung in the well and charged with nitrogen. A surface recorder is used to measure the surface nitrogen pressure and automatically convert it to bottomhole pressure. The Sperry Sun method of correcting pressures utilized a single wellbore average temperature used to calculate the nitrogen gradient and correct to bottomhole pressure. Pressures determined in this manner did not agree well with Kuster tool measurements, so a new method had to be developed. The new method utilized the actual temperature gradient in the well to correct to bottomhole pressure. Corrections done in this manner agreed within 3 psi of Kuster tool measurements. Pressures were measured daily with the Sperry Sun system from March 25 through September. The system performed well with good reproducibility and accuracy.

From the end of March until the end of April, pressures at B-10 remained in the range of 1623 to 1634 psig. After injection and production operations ceased on 4/27/76, pressure steadily declined to around 1605 psig in early August. This response is quite noticeable and figures prominently in the interference calculations, which are discussed in the next section.

Results of the interference test indicate that pressure at B-10 was affected by both production and injection operations. This was evidenced by the pressure increases and drops as noted earlier, proving that the wells are communicating within the reservoir.

Calculations to match pressure observations at Baca 10 indicate that Baca 6, 11 and 13 (producers) and Baca 12 and 14 (injectors) all have an effect on the pressure response at Baca 10.

Lack of measureable response at Baca 4, 15 and 16 may confirm that lateral permeability barriers exist in the field. Geologic data show that extensive faulting has occurred and that there is associated fracturing. Faults can act either as permeability barriers or as communication pathways. Where there is associated fracturing, the chances of reservoir communication are greatly enhanced.

In hydrothermal systems, there is a self-sealing tendency caused by thermal alteration of the rock and mineral deposition in the pores and fractures with changing conditions of pressure and temperature. Baca 16 had very little permeability, and this was attributed to rock alteration and mineralization of the fractures the well penetrated. Baca 4 was productive and though no measureable pressure response was recorded, similarities in geochemical and temperature data indicate it may be connected to the same reservoir at depth as the rest of the Redondo Creek wells are. Baca 15 is completed in what appears to be a saturated steam region which is separated from the deeper liquid reservoir.

At this time, it appears that Baca 6, 10, 11, 12, 13 and 14 are directly connected within the reservoir and fracture system. Some evidence exists that indicates Baca 4 may be separated laterally from the rest of the wells but could be connected to the same reservoir at depth. Baca 15 is yet to be tested, but presently appears to be completed in a steam cap that is separated from the rest of the Redondo Creek wells.

RESERVOIR SIZE ESTIMATION

Two tests were used to evaluate the size of the Redondo Creek area reservoir. They were: (1) production tests, and (2) an interference test. Most of the production and all of the interference observations occurred during October 1, 1975 to July 1, 1976. The production and interference tests are discussed separately.

PRODUCTION TESTS

All of the prior production from the Baca wells has been for well testing purposes only. Thus, the production/injection activity has been sporadic until the initiation of a field-wide test on October 1, 1975, when sustained production from three wells (Baca 6, 11 and 13) was planned for four months. Unfortunately, Baca 6 was lost due to mechanical problems about halfway during this test period and Baca 11 was shut-in at various times for maintenance purposes. Baca 13 gave good sustained production during this period.

Production Has Not Reduced Reservoir Pressure

As of July, 1976, we have produced 4.9×10^9 lbs of total fluids and injected 2.3×10^9 lbs of water in Baca wells. Yet, despite a net withdrawal of 2.6×10^9 lbs of fluid, there has been no discernible decline in the static reservoir pressure. All of the pressure fluctuations observed are within the accuracy of the pressure sensing instruments (± 10 psi).

Figures in Appendix G show: (1) the stable shut-in pressures; (2) the cumulative field production; and (3) the cumulative well production of all the wells as a function of time. The status of a well, i.e., whether it is producing or shut-in can be inferred from the slope of the cumulative well production curve; a horizontal well production curve means shut-in conditions. The flow rates of (1) steam, (2) water, and (3) steam plus water as a function of time are shown in Appendices C and F.

Is Production the Result of Fluid Expansion?

If we make the assumption that all of the fluid produced is the result of fluid expansion only, then we can estimate the amount of fluid in place. A pressure decline is always associated with fluid production by expansion or depletion. Even though we have not observed a pressure decline anywhere in the system, we will assume here that the reservoir pressure has in fact declined and that the decline is within the instrument accuracy. Using the assumption of pressure decline, we will attempt to estimate the reservoir size.

In order to calculate the reservoir size by the depletion equation, we have to satisfy two conditions: (1) the reservoir is confined; and (2) there is no associated steam cap with water; i.e., there is no steam-water interface in the reservoir.

A system is confined if the free water surface lies above the upper confining boundary of the aquifer as in Figure 24(A). Free water surface or the piezometric head is the hypothetical water level which the water will rise to if we penetrated a pipe into the aquifer. The hot water may or may not have a steam cap in communication with it. If the free water surface is below the upper confining boundary, as in Figure 24(B), it is an unconfined aquifer. Thus, the space between the free water surface and the cap rock will be occupied by steam at saturation pressure relative to the reservoir temperature.

We have to answer two questions in order to determine whether the Baca reservoir is confined or unconfined: (1) is there a cap rock; and (2) is the free water surface above the bottom of the cap rock? If the answer to both the questions is yes, then it is a confined aquifer.

Is There a Cap Rock in the Baca Reservoir?

For geothermal fluids to stay in place through geologic times it is necessary that a lid, namely a cap rock, be firmly placed on the pot or reservoir. Otherwise all the water would boil and disappear as steam.

As discussed in the Geology section of this report, evidence from drilling, geologic and static temperature records indicate that there is an impermeable stratum or cap rock persisting in all the wells. The bottom of this cap rock lies between 5000 and 7300 feet above sea level in all of the wells.

Is the Free Water Surface Above the Cap Rock?

Figure 25 shows the elevation of the free water surface in each of the Baca wells. This surface has been determined by extrapolating the static pressure in each well, using a hydrostatic gradient of 0.32 psi/ft (550°F water). The free water surface ranges from 8200' to 8347' which is more than 900' above the bottom of the cap rock. Thus, we satisfy the conditions of a confined aquifer. Figure 25 does not show the free water surface of Baca 15. This well has an anomalous pressure and is not considered in hydrologic communication with the rest of the wells.

Does the Water Have an Associated Steam Cap?

Evidence of whether there is an associated steam cap must come from two sources of information: (1) the static temperature and pressure surveys; and (2) the production records. If steam exists in the reservoir and is associated with any water, the reservoir pressure must be the saturation pressure corresponding to the measured temperature. At any higher pressure, the steam will condense into water. The static pressure profiles for wells Baca 4, 6, 10, 11, 13 and 15 are shown in Appendix H. Also plotted on these profiles are the saturation pressures which correspond to the temperature profiles in Appendix A. It is evident from the static pressure profiles that Baca 6, 10 and 13 have pressures well above the saturation pressure. Baca 11 is also over-pressured at depths below 4000' in the well. Above 4000', the pressures are at or less than saturation pressure, which would signal the potential existence of steam. The combination of both a steam zone and an over-pressured hot water zone in the same well cannot be explained in any way other than that there are two distinctly separate reservoirs penetrated by this well. If the two zones were pressure connected, the pressure in the water zone would be relieved by the steam zone until either the pressure was close to saturation pressure or the steam zone was condensed to hot water.

The pressure profile in Baca 4 represents this last type of condition. Over-pressuring is essentially non-existent. Considerable steam entries were observed during the drilling of Baca 4. The flow testing of the well indicated that the combined fluid enthalpy is consistent with the observed temperature for the well. It is concluded then that Baca 4 contains primarily hot water at basically saturation conditions. There could be a minor amount of a pressure connected steam cap in the well, but it would be located behind the 9-5/8" casing.

Since the geochemical data from Baca 4 is similar to the other wells producing from the over-pressured water reservoir, it has been interpreted that this well is connected to the same reservoir. However, the lack of over-pressuring and the lack of pressure response during the interference test tend to indicate that the connection is at some distance away from the Baca 4 wellbore and that the connection may not be very permeable.

The pressure profile in Baca 15 is a classic example of a steam zone which is just under saturated conditions. The pressures in this well are distinctly lower than the other nearby wells which produce from the over-pressured water reservoir. The well has had only limited two-phase testing and will soon be flow tested through a separator to accurately determine the fluids and their flow rates. Baca 11 will be monitored during the testing of Baca 15 to investigate pressure communication of the steam zone in both of these wells.

Another method of determining the existence of a steam zone is by comparing the enthalpy of the produced steam-water mixture with the enthalpy of the fluid at measured reservoir temperature. If the reservoir fluid is all water, and no steam, the enthalpy of the produced steam-water mixture is approximately the same as the enthalpy of the reservoir liquid. However, if steam from a steam cap is produced along with hot water below it, the enthalpy of the produced mixture will greatly exceed the enthalpy of water at reservoir temperature. Table 9 lists these comparisons for the various Baca wells.

TABLE 9

Well	Enthalpy Produced Steam-Water Btu/lb	Temperature Based on Prod. Enth.	Maximum Measured Well Temp.	Enthalpy Based on Well Temp. Btu/lb
B-4	556	556°F	585°F	596
B-6	532	536°F	536°F	532
B-11	740	672°F	627°F	658
B-13	558	556°F	588°F	600
B-15	(N.A.)	---	530°F	524

The table indicates that Baca 6 is producing solely from the hot water reservoir. In Baca 4 and 13, we are producing less enthalpy from the reservoir than our maximum temperatures would indicate. This means that both of these wells are producing from only a hot water reservoir and that most likely we are flashing in the formation and losing some of the steam by vertical migration.

The produced enthalpy of Baca 11 is certainly higher than its reservoir fluid enthalpy. A closer look at the Baca 11 production characteristics reveals an interesting phenomenon. On Figure 18 is a plot of the produced enthalpy of Baca 11 as a function of the wellbore flowing pressure at a depth of 4000'. When the flowing pressure is above the steam zone pressure, the produced fluid enthalpy is the same as the reservoir fluid enthalpy, indicating no steam production. However, when the flowing pressure at 4000' falls below 700 psig, sufficient to exert a drawdown on the steam zone, the produced enthalpy reflects the increase due to production of steam in addition to the hot water reservoir fluids. As stated previously, this steam cannot exist in pressure communication with the hotter and higher pressured hot water without a much higher temperature and correspondingly higher pressure in the zone.

In summary, we conclude that Baca 6, 10 and 13 are producing from an over-pressured hot water reservoir. Baca 11 is producing from the same hot water reservoir and also from a separate steam zone, and not from an associated steam cap. Baca 4 is producing from a hot water reservoir which is close to saturation pressure. And finally, Baca 15 most likely is completed in a saturated steam zone, which is definitely not connected to the higher pressured water reservoir.

An Under-Saturated Reservoir Produced by Depletion

The hot water reservoir in Baca meets all the conditions of an under-saturated reservoir producing by fluid expansion. It is a confined reservoir with no primary or secondary steam cap.

It will continue to perform as an under-saturated reservoir until the pressure under the cap rock declines to saturation pressure. For such a system, we can write the following equation from material balance considerations:

$$\frac{Wp}{W} = \frac{v - vi}{v}$$

where: Wp = Net total mass produced.

W = Original total mass in the reservoir.

vi = Initial specific volume (before depletion).

v = Specific volume when Wp has been produced (after depletion).

The pressure change does not figure explicitly in the above equation, but both v and vi are dependent on the pressures. Temperature is considered constant, which is a reasonable assumption so long as the pressure does not fall below the saturation pressure.

Calculation of Reservoir Size by Depletion Equation

Although we have not observed any decline of the static reservoir pressure, the accuracy of our pressure tools is around 20 psi. Thus, in order to calculate the minimum reservoir size, we are assuming that the reservoir pressure dropped from 2000 to 1980 psia at a constant temperature of 600°F. Our cumulative production so far is 4.935×10^9 lbs and cumulative injection is 2.34×10^9 lbs. Thus, the net production is 2.595×10^9 lbs. Specific volume at 2000 psia and 600°F is 0.023320 cft/lb and specific volume at 1980 psia is 0.023333 cft/lb. Substituting these values in the above equation:

$$\frac{2.595 \times 10^9}{W} = \frac{0.023333 - 0.023320}{0.023333}$$

from which W = 4.6 x 10^{12} lbs. The assumptions used in this estimate are: (1) the reservoir is confined; (2) there is no steam cap on top of the water (a separate steam zone is not ruled out); (3) the pressure has declined by 20 psi; (4) under static conditions, after this withdrawal, we have no steam cap; and (5) the production and injection came from a common aquifer.

INTERFERENCE TEST

An interference test was planned to start on October 1, 1975, with three production wells, three intermittent injection wells, and four observation wells. The production wells are Baca 6, 11 and 13. The injection wells are Baca 5, 12 and 14, and the observation wells are Baca 4, 10, 15 and 16. The production histories of the wells are given in a separate section in this report.

Pressures in the observation wells were measured periodically with conventional Amerada type Kuster wireline tools. On March 25, 1976, a Sperry Sun Pressure Monitor System was installed in Baca 10 to provide greater accuracy and reproducibility over the Kuster measurements. After three months use, the Sperry Sun tool calibration changed 0.8 psi on a 0-5000 psig shop test.

Pressure Changes Observed In Baca 10

Wells Baca 4, 15 and 16 did not show any interference or response due to production or injection, but Baca 10 did show an interference in spite of the limitations of the Kuster tool. The pressure changes observed in Baca 10 are shown on Figure 26.

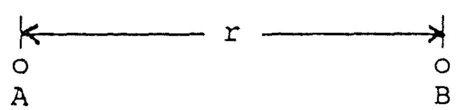
The pressure changes on Figure 26 were measured at 5500'. The well depth is 5959'. Positive pressure change means that the pressure increased with respect to the reference pressure and the negative pressure change means that the pressure declined.

The reference pressure used to calculate the pressure changes is 1614 psig. This pressure was measured on 9/12/75 at 5500' depth. Because we are examining pressure changes rather than the absolute pressures, the actual pressure on 10/1/75 (corresponding to t = 0 days on Figure 26) is not a critical parameter.

The observed pressures show several unmistakeable trends. The values up to time period of 175 days are measured with the Kuster tool and after that with the Sperry Sun Tool. The trends in observed pressure changes are helpful in seeking a match with the calculated pressure changes. We will be attempting to match two parameters: (1) observed pressure changes, and (2) the trends of pressure changes. The second parameter becomes more important when there is uncertainty in the observed pressure changes.

Calculation of Pressure Changes

Consider two wells A and B. Well A produces at a rate of



q STB/day and B is an observation well. The wells are r feet apart. After a time of t hours since flowing A, the pressure change, Δp, at B is given by:

$$\Delta p = \frac{70.6\ q\mu\beta}{kh}\ Ei\left(-\frac{\phi h\ \mu c r^2}{0.00105\ kht}\right)$$

where: μ is viscosity of fluid, cp

β is formation volume factor, res. bbl/STB

ϕ is porosity, fraction

k is permeability, md

h is thickness, ft

We have a computer program to calculate the pressure changes for a given set of kh and ϕh values. The program essentially uses the above equation and has the following features:

1. It allows for more than one production/injection well and observation well.

2. It allows for different starting times of the production/injection wells.

3. It allows for fluctuating production/injection rates.

4. It allows the previous production/injection histories of the wells (including the observation wells) to be incorporated.

External to the program, we can generate the boundaries, either closed or constant pressure, by imaging technique and feed it into the program.

The program assumes that the reservoir contains single fluid (water only). Even though the interference observations started 10/1/75, the program takes into consideration the production/injection history of all the wells (including the observation wells) since 10/1/74. The fluctuations in the production/injection rates (including zero rates) are also considered. The production/injection rates are given on a monthly basis from 10/1/74 to 8/1/75 and on a weekly basis from 8/1/75 to 4/26/76 in 50 steps. The reservoir fluid is considered at a uniform temperature of 600°F.

kh Values From Earlier Buildups

To calculate the pressure change at an observation well, at a particular time interval, we need to know two parameters, among others. They are kh and øh, neither of which are known ahead of time. We have one equation with two unknowns, kh and øh. We are attempting to find a set of kh and øh values which will give a calculated Δp similar to the observed Δp.

Fortunately, we can establish a range of values for kh from the pressure buildup analysis. This helps us in narrowing down our search for the set of kh and øh values that will give us a close match.

The kh values (permeability-thickness products) obtained from the various buildup tests on the Baca wells are summarized in the well test section of this report. The average kh for the field is in the order of 4300 md ft. This is an average value in the vicinity of the wellbores. The kh observed from the interference test should be not too far from the well test derived kh value, particularly when the production duration is small. Thus, with the help of our well test derived values, we can set an upper and a lower limit on the interference derived kh values. We can reasonably say that the kh value should lie between 1000 and 10,000 md ft.

The Best Match

The best match obtained between the calculated and the observed pressures at Baca 10 is shown in Figure 27. The calculations assume an infinite aquifer with kh = 6000 md ft and ϕh = 90 ft. Using a porosity of 5% (which would be a reasonable value for a fractured reservoir), this ϕh corresponds to a reservoir thickness of 1800 feet.

It could be argued that all the active wells, namely Baca 6, 11, 13, 12 and 14 may not have had a contribution in the observed pressure changes at Baca 10. We tried various combinations of the wells which could give us a reasonable match. The best match was obtained when contributions from all these wells were considered.

The Calculated Pressure Changes Are Not Very Sensitive to ϕh

Figure 28 shows the calculated pressure changes for kh = 6000 md ft and for ϕh = 80, 90 and 100 feet. Although ϕh = 90 feet gives the best fit, particularly in the range where Sperry Sun observations are available, the calculated change of Δp by only ± 2 psi represents ± 10 feet change in ϕh. This error in Δp is within the accuracy range of the instrument. Thus, we conclude that the calculated ϕh from the comparison between the calculated and observed Δp's could be between 80 and 100 feet. This variation still does not change our conclusions drastically.

The Calculated Pressure Changes Are Sensitive to kh

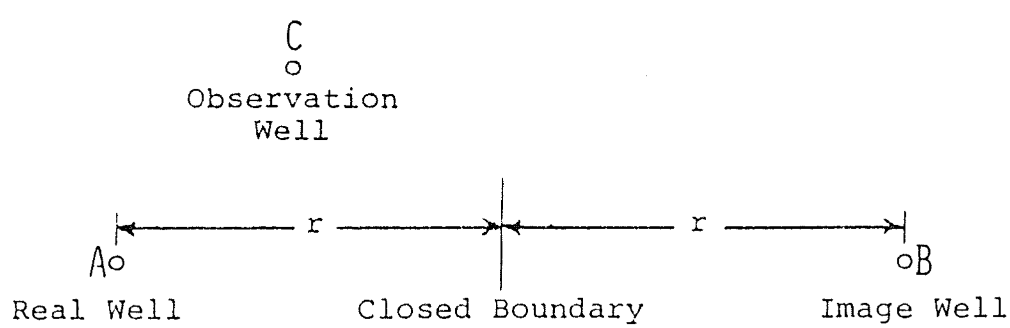
Figure 30 shows the effect of kh on the calculated pressure response for ϕh = 90 feet. The kh values used are 5000, 6000 and 7000 md ft. It is observed from the figure that the pressure response with a 1000 md ft change in kh is greater than the response with a 10 foot change in øh. We estimate from this figure that the calculated kh is 6000 ±500 md ft.

Reservoir Size From the Interference Calculations

The pressure response at an observation well is influenced by the shape and the nature of the reservoir boundary. This pressure response can be calculated under different boundary conditions. By obtaining a match between the observed and the calculated pressure changes, it is possible to determine the size and the nature of boundaries of the reservoir. This particular application of an interference test is rather new and was reported for the first time in literature in Reference 4.

As mentioned earlier, the best match between the observed and the calculated pressure responses assumes an infinite reservoir, but a mathematically infinite aquifer does not mean literally that the actual aquifer is infinite. The model will consider an aquifer infinite if during the calculation time period, the observation well did not feel the effect of the boundaries. This statement permits us to fix a lower limit on the reservoir size.

Mathematically, a reservoir boundary is generated by imaging technique. If a closed boundary is located r feet away from



well A, the effect of this boundary can be created by locating an image well B at a distance of 2r feet from well A. The pressure response at observation well C will be a cumulative response due to wells A and B. The Δp contribution of the image well B at C is a function of the distance between B and C; the greater the distance, the lesser will be the Δp contribution. As the closed boundary is moved farther and farther away (or if r is increased), the contribution of B at C keeps on decreasing. At some value of r, the contribution of the image well B at C becomes negligible. At that point, the boundary stops playing any role and the reservoir acts as an infinite reservoir even though a boundary exists.

We generated boundaries in the form of a rectangle enclosing wells 6, 10, 11, 12, 13 and 14 by imaging technique. The smallest reasonable rectangle that can be created is shown on Figure 31. This is a 1:3 rectangle having an area of 1100 acres. We studied the pressure performance at Baca 10 using this rectangle with various boundary conditions. We will discuss these results in the next section.

Then we started to increase the dimensions of this rectangle until such time as the effect of the boundaries was rendered negligible. This occurred when the size of the rectangle was made 20,000 ft × 60,000 ft occupying an areal extent of 27,500 acres (43 square miles). A reservoir of this size behaves as an infinite reservoir for the calculation of pressure changes at Baca 10 in the period of observation, even though physically, it is a finite system. Any reservoir greater than this size will also behave as an infinite reservoir; so this is the <u>smallest</u> size that satisfies the conditions of an infinite reservoir.

<u>Attempts to Define the Aquifer Boundaries are Inconclusive</u>

Given the facts that: (1) Baca 4 and 16 did not show definite interference effects; and (2) Baca 5 was used only rarely for injection purposes and hence its contribution to the pressure change in Baca 10 is minor, we can assume some possible areal boundaries of the aquifer as shown on Figure 31, and test whether these assumed boundaries are realistic.

Our first assumption was that the boundary is closed. We generated closed boundaries by an imaging technique and calculated the pressure response shown on Figure 32 using kh = 6000 md ft and ϕh = 90 feet. It is clear that no match between the observed and the calculated pressures can be obtained under closed boundary assumption.

It could be argued that the areal extent of the aquifer may be limited to the 1100 acres contained in the assumed rectangle shown on Figure 31 and the 4.6×10^{12} lbs of fluid in place are distributed vertically below this rectangle. This system would have a ϕh of 2160 feet. The calculated pressure profile for such a system is shown in Figure 33. It is clear that the calculated pressure changes do not match the observed changes at Baca 10. Thus, the reserves are distributed areally rather than vertically down below the wells involved in the interference test.

Figure 34 shows the pressure profile for south boundary at constant pressure, the remaining being closed, for kh = 6000 md ft and øh = 90 feet. As in the previous case, there is no possibility of a match.

Figure 35 shows the pressure profile when the east boundary is held at constant pressure, the remaining being closed for kh = 6000 md ft and øh = 90 feet. The pressure profile cannot be matched against the observed pressure changes.

Figure 36 shows the pressure profile when south and east boundaries are held at constant pressure and the remaining are closed. The match is poor.

Figure 37 shows the pressure profile when the west boundary is closed and all the rest are held at constant pressure. The match is poor.

Figure 38 shows the pressure profile when all the boundaries are held at constant pressure. The match is poor.

It is observed from the above pressure profiles that an infinite reservoir gives the best match between the observed and the calculated pressure profiles at Baca 10.

Reservoir Size From Interference vs. Depletion Calculations

The depletion calculations show reserves of 4.6×10^{12} lbs. From the interference test interpretation, the minimum areal extent of the aquifer is 43 square miles. Using øh = 90 feet, this area will occupy reserves of 5.4×10^{12} lbs. The two values are reasonably close together.

The depletion calculations do not distinguish between the areal and the vertical spread of the reservoir, but the interference calculations indicate that the reservoir has an areal spread of a minimum of 43 square miles. We believe that the wells are in communication with a large aquifer. It is difficult to conclude from our calculation procedures the direction in which the aquifer might extend.

Matching the Pressure Behavior at the Other Observation Wells

The observed and calculated pressure responses at the remaining observation wells (Baca 4, 15 and 16) are shown on Figure 39 to 41. We did not anticipate much interference at Baca 15 and 16 based on their production performance. Baca 15 shows an anomalous datum pressure behavior, as shown on Figure 20. This well does not appear to be in hydrological communication with the rest of the wells. Well Baca 16 is a poor producer, although the datum pressure map shows it in communication with the rest of the wells. The well is located in a tight spot. It might have been in hydrological communication with the rest of the wells over geological time periods, but it is not likely to be in communication with the rest of the wells over real time periods. It is clear from the observed and calculated pressure profiles that both Baca 15 and 16 are not in communication with the rest of the wells. The calculated profiles used kh = 6000 md ft and ϕh = 90 feet.

Baca 4 is a good producer and has a datum pressure similar to the other wells. But the observed and calculated pressures are significantly different. The well is probably completed in a fault system which is different from the fault system of Baca 6, 10, 11, 12, 13 and 14.

CONCLUSIONS FROM THE PRODUCTION AND THE INTERFERENCE TESTS

In summary, the tests tell us the following:

1. The original total mass in the reservoir is at least 4.6×10^{12} lbs.

2. The reservoir has a kh of 6000 md ft and øh of 90 feet.

3. The reservoir is "infinite" in extent, i.e., the boundaries are a considerable distance from the test area.

4. The reservoir fluid is distributed areally (covering an area of approximately 43 square miles) rather than vertically downwards.

It is good to keep in mind the limitations and assumptions involved in the analysis. Listed below are the assumptions and the reasons why the assumptions are reasonable:

1. The reservoir fluid exists in single phase. This assumption is reasonable because the reservoir pressure is greater than the saturation pressure corresponding to the reservoir temperature for all wells that played a part in the analysis.

2. The reservoir fluid is contained in a confined aquifer. This is reasonable because the free water surface is above the bottom of the cap rock.

3. There is no steam-water interface in the reservoir. One would be tempted to suspect steam-water interface in Baca 11 because of the high steam-water mixture enthalpy, but the excess steam is contributed by a separate steam zone in Baca 11. It produces only when the flowing pressure opposite this zone falls below the steam zone pressure.

4. The equations used assume a horizontal, isotropic and porous reservoir. Recent work on flow of fluids through fractured media suggests that radial equations might in fact define the flow in fractured systems subject to certain conditions. The calculated kh and øh are not meant to be the reservoir parameters microscopically. These values should be looked at macroscopically. These are a set of parameters which define the flow in the system for the duration of the observation. They have been obtained by history matching and are not considered unique. The analysis indicated that the øh is 90 ±10 feet and the kh is 6000 ±500 md ft.

The total mass in place has been calculated using the production tests. They have not been contradicted by the interference analysis. The interference test confirms that the areal extent of the reservoir is much greater than 1100 acres, but the efforts to determine the nature of the boundaries have been inconclusive. All we can say from the interference test is that the reservoir is at least 25 times the area of the rectangle shown on Figure 31 (43 square miles). The areal extent from depletion calculations is 37 square miles. Thus we get similar numbers from two different approaches.

It is interesting to point out here that the areal extent of the aquifer calculated from the production and interference tests (37 and 43 square miles, respectively) is similar to the area calculated by R. F. Dondanville. He calculated an areal extent of 40 square miles based on the shallow hole drilling, geological and geophysical surveys. The reservoir size estimated in this report is completely independent of Dondanville's data.

We have to emphasize a weakness in the calculation of the total mass by production tests. The reservoir size has been calculated by pressure observations. While the pressures can be transmitted over large distances, and hence can be extrapolated, temperatures are local features. They cannot be extrapolated. When we say that the total mass in place is calculated to be 4.6×10^{12} lbs, we cannot say with great certainty that all the total mass is at 600°F. All we can say at present is that there is no evidence to support communication of hot water with a cold water aquifer. The reservoir engineering calculations cannot rule out such a possibility, but if the water in place is contained entirely within the caldera, it is most likely that the temperature will be uniformly about 600°F, based on the geological data.

GENERATING CAPACITY

Water in place calculated from pressure depletion and interference calculations is 4.6×10^{12} lbs at about 600°F. These two parameters provide a basis for determining the commercial potential of the reservoir. The generating capacity of the field will depend on various factors some of which are: (1) development scheme selected; (2) the production mechanism; and (3) fracture intensity. A brief discussion of these factors is given below.

1. Development scheme: The reservoir may be produced with or without reinjection. The performance of the field will depend upon the fraction of the produced water injected into the field and the temperature of injection water.

2. Production mechanism: The reservoir may produce under depletion drive or water drive. The drive is governed by the nature of reservoir boundaries. If the boundaries are closed, the reservoir will produce under depletion drive. If the boundaries are actively recharged, water drive will dominate. The production performance of the reservoir will depend on the dominating drive.

3. Fracture intensity: Fracture intensity will influence the generating capacity in two ways: (a) the amount of heat released by the rock increases if the fracture intensity increases, and (b) the injected brine may arrive at the producing well earlier than expected if the fracture

intensity is small. It is difficult to quantify the fracture intensity of a reservoir which is yet to be developed. The reservoir performance will be studied under limiting conditions: (a) zero fracture intensity, i.e., just one big fracture containing all the hot water, and (b) full fracture intensity which can be considered analogous to a porous system.

If the reservoir produces under active recharge, our effective reserves will be increased. But we cannot calculate the extent of recharge unless we produce the field for long periods. Thus, in order to be conservative in our calculations, we will assume that the reservoir boundaries are closed.

Recoverable Reserves vs. Fluids in Place

In oil and gas reservoirs, the recoverable reserves are less than the fluids in place. The reserves are defined in units of mass or volume only. In geothermal reservoirs, on the other hand, we are interested in both the mass and energy level of the reserves. Our real resource is heat energy recovered from the fluid.

Initially, the fluid and the rock exist at the same temperature. Thus the heat energy is contained not only in the fluid but also in the rock. If we can recover some of the heat from the rock, then, we have a potential of recovering more heat from the reservoir than is initially contained in the fluid. The rock will release a part of its heat if we can reduce the fluid temperature. The amount of heat released by the hot rock depends on two parameters: (1) the temperature difference between the rock and the surrounding fluid, and (2) the amount of surface area of the rock exposed to the fluid, which is controlled by the grain size or the fracture intensity of the rock.

Calculation of the Generating Capacity

It will be shown later in this chapter that a recovery factor of 1 is quite conservative in a hot water geothermal reservoir. Recovery factor (R.F.) is defined as:

$$\text{R.F.} = \frac{\text{Amount of heat recovered to an economic temperature}}{\text{Amount of heat initially in the fluid in place}}$$

The economic fluid temperature will be specified when discussing reservoir performance and recovery factor under different cases.

We will calculate the generating capacity using R.F. = 1. The following additional assumptions are also made:

1. Turbine inlet pressure is 100 psig.
2. Steam requirement is 20,000 lbs/hr-MWH.
3. Steam fraction at the turbine inlet is 35.3%.
4. Amortization period is 30 years.
5. Generating unit capacity factor is 75%.

$$\text{Generating Capacity} = \frac{(4.6\text{x}10^{12})(0.353)\ \text{lbs}}{(20{,}000\ \text{lbs/hr-MWH})(8760\ \text{hrs/yr})(30\ \text{yrs})(0.75)}$$

$$= 412\ \text{MW}$$

Thus if we are able to recover the heat energy from just the fluid initially in place (R.F.=1), the generating capacity is 412 MW. If R.F. is doubled, either the generating capacity or the life of the project will be doubled.

We will calculate recovery factors under three different cases. In all the cases, the reservoir is considered to have closed boundaries. A material-energy balance equation is used to study all the cases. Derivation of the equation, the assumptions involved, and its solution procedures, are discussed in Appendix I. The equation is used to calculate the reservoir pressure, temperature, steam quality, and the enthalpy in terms of cumulative fractional production.

The three cases studied are described below:

Case I:

None of the fluid produced is reinjected. The reservoir is a porous system with 5% porosity. The reservoir fluid is at 2000 psia and 600°F. Figures 42 to 44 present the production performance of the reservoir. Figure 42 shows the pressure and temperature as a function of cumulative production. The reservoir pressure declines from 2000 to 1543 psia with only 1.4% of the production. This production occurs under volumetric expansion only. There is no temperature decline during this period. Three things happen with any subsequent withdrawal of the fluid: (1) a part of the fluid vaporizes to steam; (2) temperature drops and heat is released from the rock to maintain thermal equilibrium; and (3) the pressure drops to the saturation pressure corresponding to the prevailing temperature.

The temperature of the system does not drop significantly. With 90% production, the temperature has dropped from 600°F to 593°F. This is due to the fact that the rock is a big source of heat. The amount of heat in the rock will decline with increase in porosity, but the effect on temperature is minor for any reasonable value of porosity.

Figure 43 shows the reservoir fluid quality and Figure 44 shows the fluid enthalpy. Enthalpy of the produced fluid is assumed the same as the reservoir fluid enthalpy. With 90% production, the quality has gone up from 0 to 0.84 and enthalpy from 617 to 1140 Btu/lb.

Total heat recovered in this case was determined by planimetering the area under the curve on Figure 44. With 90% fluid production, we recover 740 Btu's as opposed to 617 Btu's initially in place for every pound of fluid. The recovery factor in this case is 740/617 = 1.2. Thus, under this production mechanism, the generating capacity is 1.2 x 412 = 494 MW's.

<u>Case II:</u>

75% of the fluid produced, by mass, is reinjected at 273°F into the same reservoir. The injected fluid mixes with the reservoir fluid, causes the temperature to drop which, in turn, causes the rock to release its heat. The reservoir is considered a porous system with porosity of: (1) 5%; and (2) 18%. The initial conditions are identical to Case I.

The production performance is shown on Figures 45 to 48. All the figures show a cumulative fluid production of 3. This means that three times as much fluid has been produced as was initially in place. Theoretically, we could produce 4 times the fluid initially in place, with 75% reinjection, but the fluid produced after cumulative production of 3 is considered below economic limit.

Figure 45 shows the reservoir pressure under two different porosities, 5% and 18%. With larger porosity, we have less rock volume per unit fluid volume and consequently less heat content. Thus, the temperature will drop more with 18% porosity than with 5% porosity. Temperatures are shown on Figure 46. With 18% porosity (worse of the two cases), temperature is still 460°F at a cumulative production of 3. This means that the reservoir could keep on producing, if 460°F is acceptable. The corresponding temperature with 5% porosity is 551°F.

Figure 47 shows the reservoir fluid qualities. At a production of 3, the qualities are 17.5% with 5% porosity and 7.5% with 18% porosity. Figure 48 shows the fluid enthalpies. The total heat produced was calculated by planimetering. With 5% porosity, we recovery 1863 Btu's, and with 18% porosity, we recovery 1638 Btu's. The values give us recovery factors of 3 for porosity of 5% and 2.65 for porosity of 18%. The generating capacities for the two cases are 1236 MW for 5% porosity and 1092 MW for 18% porosity.

Case III:

All the fluid is contained in one big fracture. There is no porous system and thus no heat is available from the rock. Mathematically, this case is analogous to a porous system with porosity = 1. Just as in Case II, 75% of the fluid produced is reinjected at 273°F. Initial conditions are 2000 psia and 600°F. The reservoir has closed boundaries.

The production performance is shown on Figures 49 and 50. We can produce twice what was initially in place. At abandonment, the reservoir temperature is 415°F. Figure 50 shows the enthalpy of the fluid. Up to a cumulative production of 2, we recover 880 Btu's which gives a recovery factor of 1.4.

The generating capacity under this case is 577 MW.

The above calculations assume that an adequate number of initial and makeup wells will be available to produce enough fluid for the installed generating capacity for 30 years.

The cases show the importance of fracture intensity and reservoir communication for adequate mixing and recovery of heat from the reservoir. Recovery factor in the cases studied varies from 1.2 to 3. The best case assumes that mixing between the hot reservoir and cold injected water occurs uniformly and instantaneously over the entire field. If we can design our injection facilities such that the injected water is heated by the time it reaches production wells, then we can localize the mixing to occur near our injection wells. In this situation, the field performance will depend on the well location, reservoir thickness, reservoir porosity and the injection rates. The calculation procedures will be discussed, using one set of conditions, in the following chapter.

The calculated generating capacity for different cases is summarized below:

Table 10

Case	Description	Generating Capacity, MW
I	Closed system, no reinjection, 5% porosity.	494
II	Closed system, 75% of fluid produced is reinjected at 273°F	
	(a) 5% porosity	1236
	(b) 18% porosity	1092
III	Closed system, 75% of fluid produced is reinjected at 273°F one big fracture. (Porosity = 100%)	577

PROPOSED INITIAL DEVELOPMENT

The generating capacity in the Redondo Creek area has been calculated to be in excess of 400 MW. The calculations are based on several assumptions, some of which need to be verified. Over the last few years, we have gathered a substantial amount of information about the geology of the field, and production and injection characteristics of the wells. We would like to know certain aspects of the field in greater detail to develop the field to its full potential. The aspects are discussed below:

1. The fracture pattern and the fracture intensity influence the field performance in two ways: (1) drilling successful production wells, and (2) recovering heat from the rock. Thus, we would like to study both the fracture pattern and the fracture intensity in greater detail.

2. The extent of natural ground water recharge will control the performance of the wells over the production life of the field. If there is little or no ground water recharge, the steam quality of the produced fluid will increase with time. In that case, any decline in the mass flow rate of a well should be offset by an increase in the steam quality of the produced fluid which in turn means that we may not need any makeup wells. If there is a complete recharge, either by aquifer flow or by complete reinjection, the steam quality of the produced fluid will stay constant as a function of time, but the producing capacity will be increased.

3. The flow pattern and the heating efficiency of the injected water will influence the performance of the field. If the injected water reaches a production well sooner than expected, that well might start producing cold water. Design of the injection wells is also tied up with the fracture pattern and the fracture intensity of the reservoir.

It is proposed that we install a 55 MW plant initially. This small scale development will give us an opportunity to understand and evaluate the above mentioned aspects of the field and build our confidence in planning an optimum future development.

Wells Needed for a 55 MW Plant

The wells in Redondo Creek have shown an average deliverability of 200,000 lbs/hr total mass with 35% steam fraction at a separator pressure of 100 psig. Thus the average steam production per well is 70,000 lbs/hr. A 55 MW power plant would require 1,100,000 lbs/hr steam based on 20,000 lbs/MW hr. Sixteen production wells will be adequate to supply the steam for a 55 MW plant.

Present flow capacity of the Redondo Creek wells is about 988,000 lbs/hr total mass and 361,000 lbs/hr steam. Table 11 shows predicted deliverability for each well.

No estimate was made for Baca 10 because there have been no reliable production tests on the well. The current test on Baca 15 will give a better indication of its potential.

The Baca interference test gave a ϕh (porosity-thickness product) of 90 feet. The test does not tell us the porosity and thickness separately. The porosity used in ϕh from the interference test may be partly in the fractures and partly in the rock matrix. This differentiation of porosity is important for heat transfer calculations, and not for the interference test calculations. If the porosity is derived from the intergranular pore spaces, then the assumptions of thermal equilibrium and instantaneous heat transfer are justifiable. The assumptions are not justified if the porosity is derived from a few fractures. The calculation procedure discussed in Appendix J assumes that the porosity is derived from intergranular pore spaces.

Temperature behavior of the production wells over a 30-year period has been studied in two different cases. All the wells are assumed to be producing and injecting in the same aquifer. 80% of the produced fluid is reinjected. Total production from the field is 3,200,000 lbs/hr and injection is 2,560,000 lbs/hr. Each of the 16 wells produces 200,000 lbs/hr mass flow and each of the three injection wells injects 853,000 lbs/hr. The reservoir fluid is assumed to be in the liquid phase all the time. In reality, we are producing more than what we are injecting, but to satisfy the steady-state assumption of the calculations, the production rate is the same as the injection rate. This is not a bad assumption knowing that we are attempting to trace the movement of injection water only.

Table 12

Well	Hydrodynamic Breakthrough Time, Years	Temperature Breakthrough Time, Years	
		Case I	Case II
B-10	1.5	25 - 30	7 - 9
D-1	4.4	>30	21 - 25
D-2	12.2	>30	>30
B-6	7.9	>30	>30
D-3	7.5	>30	>30
B-15	8.6	>30	>30
D-4	15.6	>30	>30
D-5	>30	>30	>30
D-6	7.4	>30	>30
D-7	10.2	>30	>30
D-8	13.3	>30	>30
B-11	23.4	>30	>30
D-10	19.9	>30	>30
D-11	>30	>30	>30
B-13	>30	>30	>30
D-9	>30	>30	>30

Twelve of the sixteen production wells will experience a hydrodynamic front breakthrough in the 30-year period. Those which will not are D-5, D-11, B-13, and D-9. The first one to have broken through is B-10 (after 1.5 years). But the interesting information comes from the cold temperature breakthrough times. Although the hydrodynamic front arrives in 1.5 years in B-10, the cold water front arrives between 25 and 30 years in Case I and between 7 and 9 years in Case II. The times here are given in ranges because the production temperature is computed at specified time periods. There is a long delay between the arrival of hydrodynamic and low temperature fronts. When a low temperature front hits a production well, the temperature does not drop to the injection temperature. For example, in B-10, the temperature is 493°F after 30 years in Case I and 494°F after 9 years in Case II. The injection temperature is 273°F and the reservoir fluid temperature is 600°F. At abandonment (30 years), the temperature at the same well is 433°F. B-10 is the only well in Case I showing a slight temperature decline before abandonment. In Case II, there is another well, D-1, in addition to B-10, that shows temperature decline.

It is observed from Table 12 that the effect of porosity, up to 18%, is not overwhelming. All the calculations do assume that the reservoir can be considered as a porous medium. From an overall field consideration, we can assume that fluid is produced at approximately the same temperature throughout the life of the field.

Another important observation from the two cases is that the injection water should be monitored by tracer surveys. Arrival of a hydrodynamic front can be detected from the tracer survey. If the hydrodynamic front arrives much sooner than expected, there is still considerable time to take corrective measures. Even shutting an injection well might improve the situation by heating the injected water. Thus tracer surveys are expected to be an integral part of a hot water geothermal development.

We can certainly rule out the worst case of immediate cold water breakthrough in Baca. During the interference test, brine was injected in Baca 12 and 14 over a six-month period. No cooling effect was observed in any of the production wells.

A small-scale initial development of a 55 MW unit will give a much needed opportunity to learn about the fracture pattern, fracture intensity and thermodynamic characteristics of the rocks. The small unit can be considered as a large pilot test and will help us in engineering large-scale development of the Valles Caldera.

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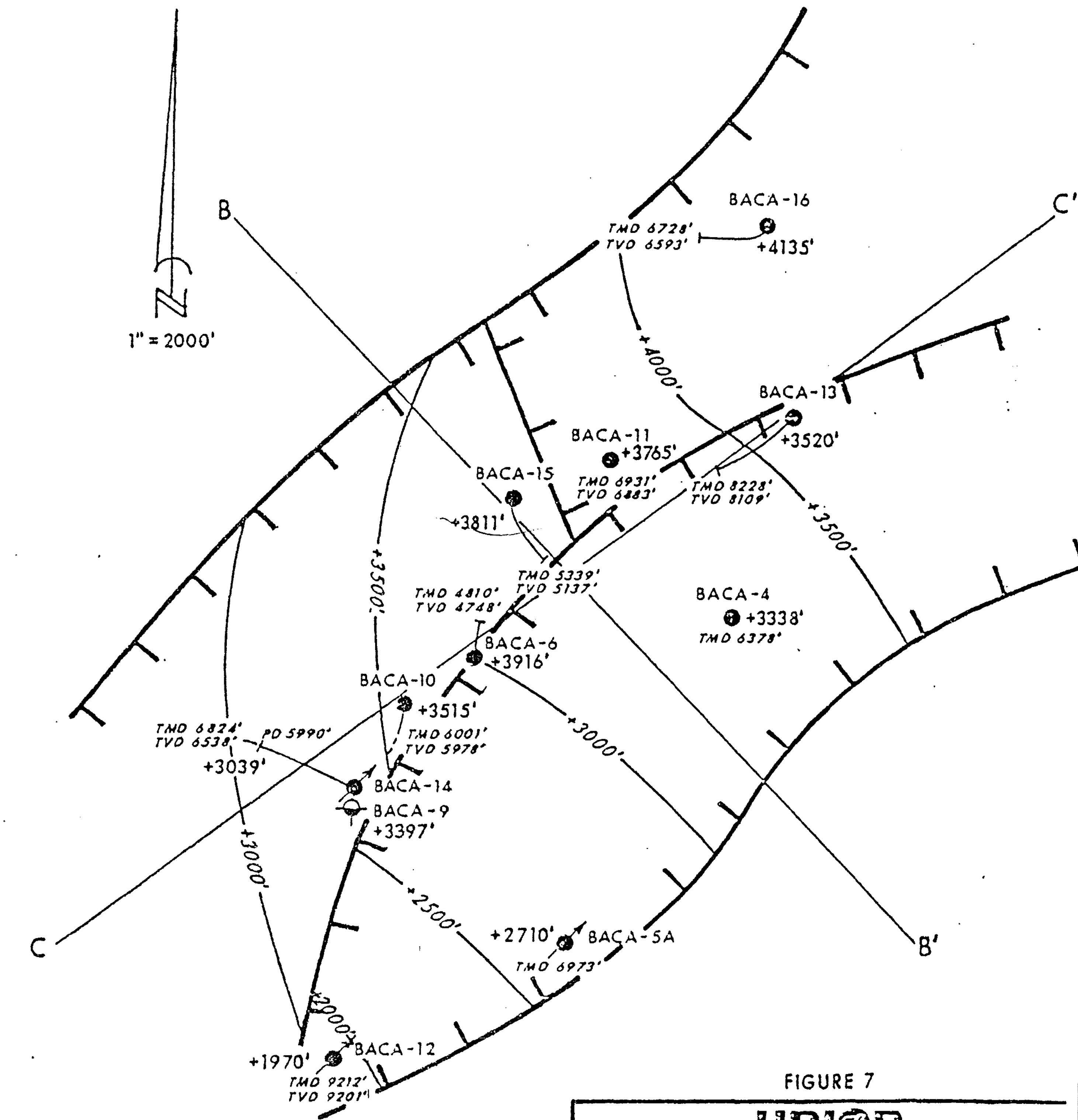


CONTOUR DATUM: SEA LEVEL

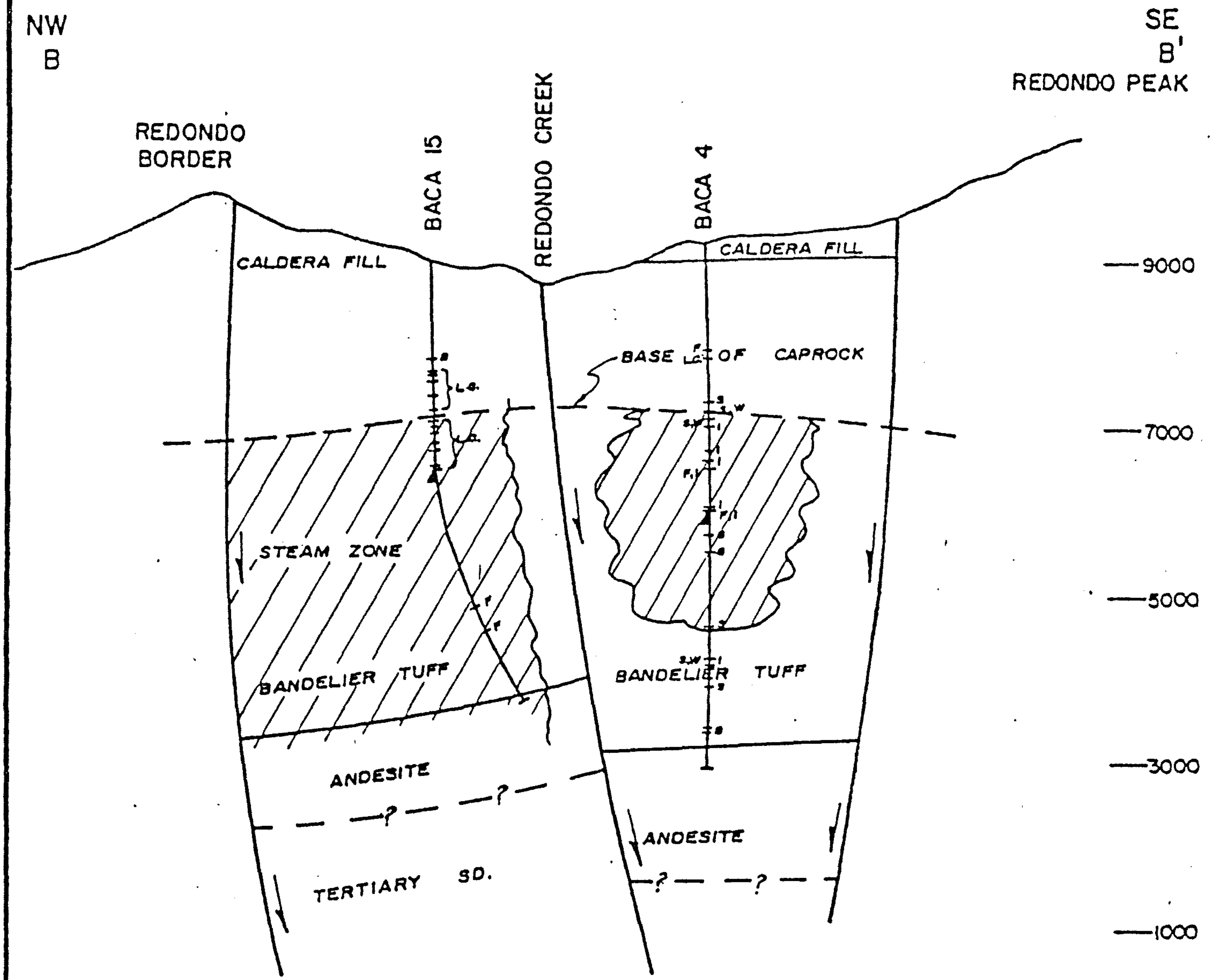
FIGURE 7

UNION 76

UNION OIL COMPANY OF CALIFORNIA
UNION GEOTHERMAL DIVISION

STRUCTURE MAP
BASE OF BANDELIER TUFF

BACA PROJECT – BACA, NEW MEXICO



B DRILLING BREAK
F FRACTURES
I FLOW INCREASE
S STEAM
W WATER
L.C. LOST CIRCULATION
CASING SHOE

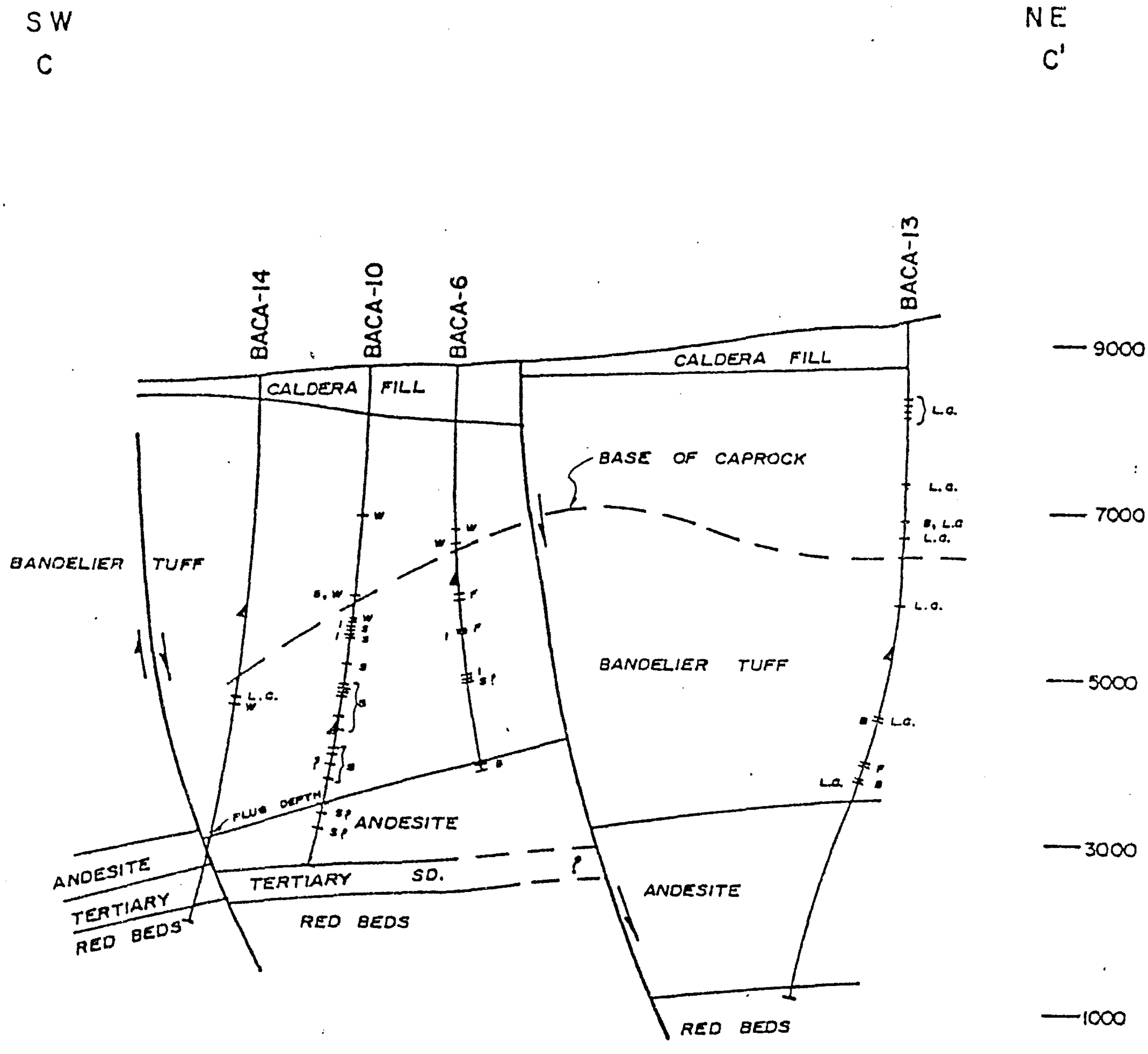
NOTE: SEE FIGURE 7 FOR TRACE OF CROSS SECTION

FIGURE 8

UNION OIL COMPANY OF CALIF.
GEOTHERMAL DIVISION

N W-SE CROSS SECTION THROUGH THE REDONDO CREEK AREA

SCALE 1" = 2000'



B - DRILLING BREAK
F - FRACTURES
I - FLOW INCREASE
S - STEAM
W - WATER
L.C.- LOST CIRCULATION
-CASING SHOE

NOTE: SEE FIGURE 7 FOR TRACE OF CROSS SECTION

FIGURE 9

UNION 76

UNION OIL COMPANY OF CALIF.
GEOTHERMAL DIVISION

SW-NE CROSS SECTION THROUGH THE REDONDO CREEK AREA

SCALE 1" = 2000'

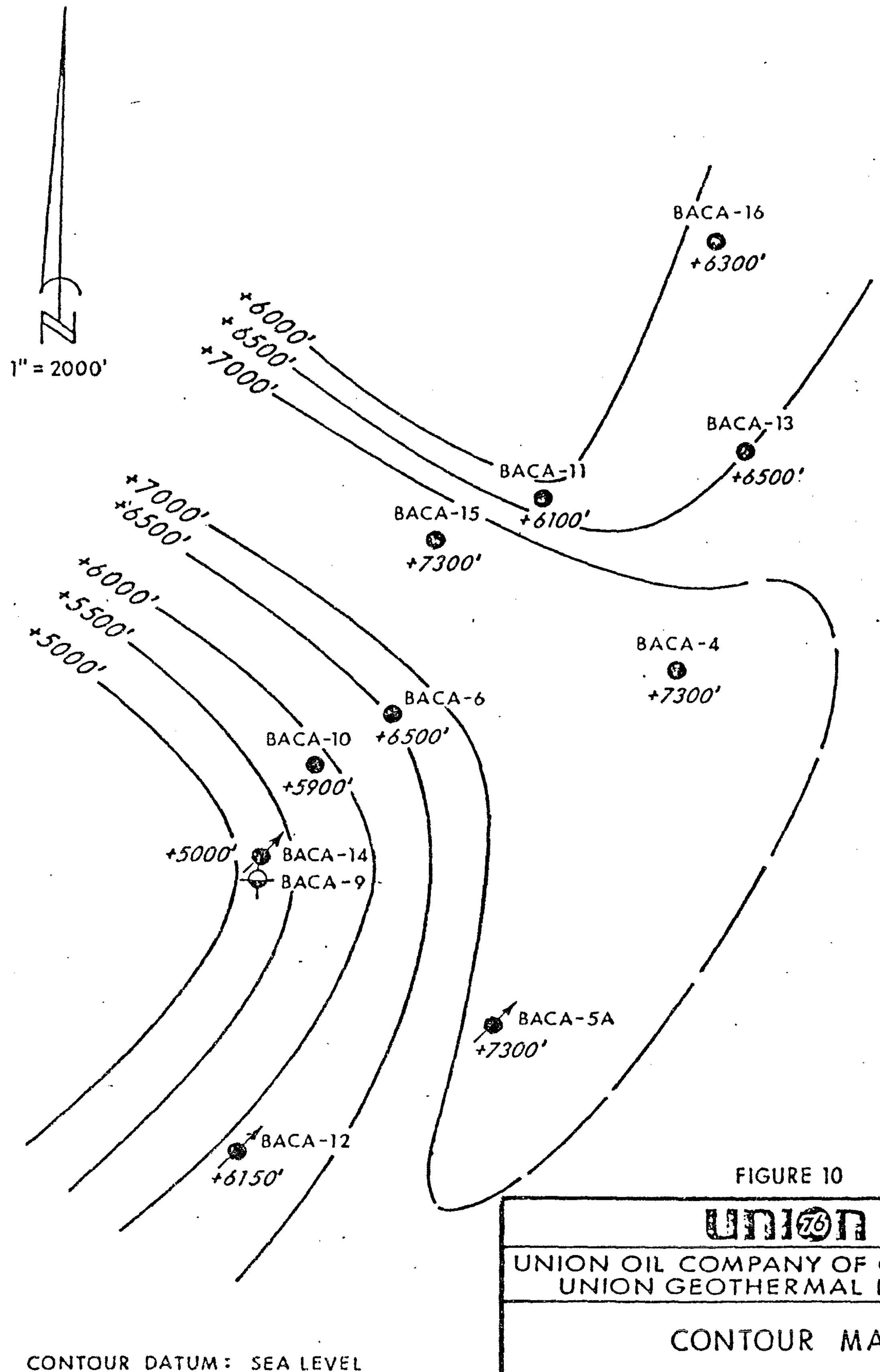


FIGURE 10

UNION OIL COMPANY OF CALIFORNIA
UNION GEOTHERMAL DIVISION

CONTOUR MAP
BASE OF CAPROCK

BACA PROJECT – BACA, NEW MEXICO

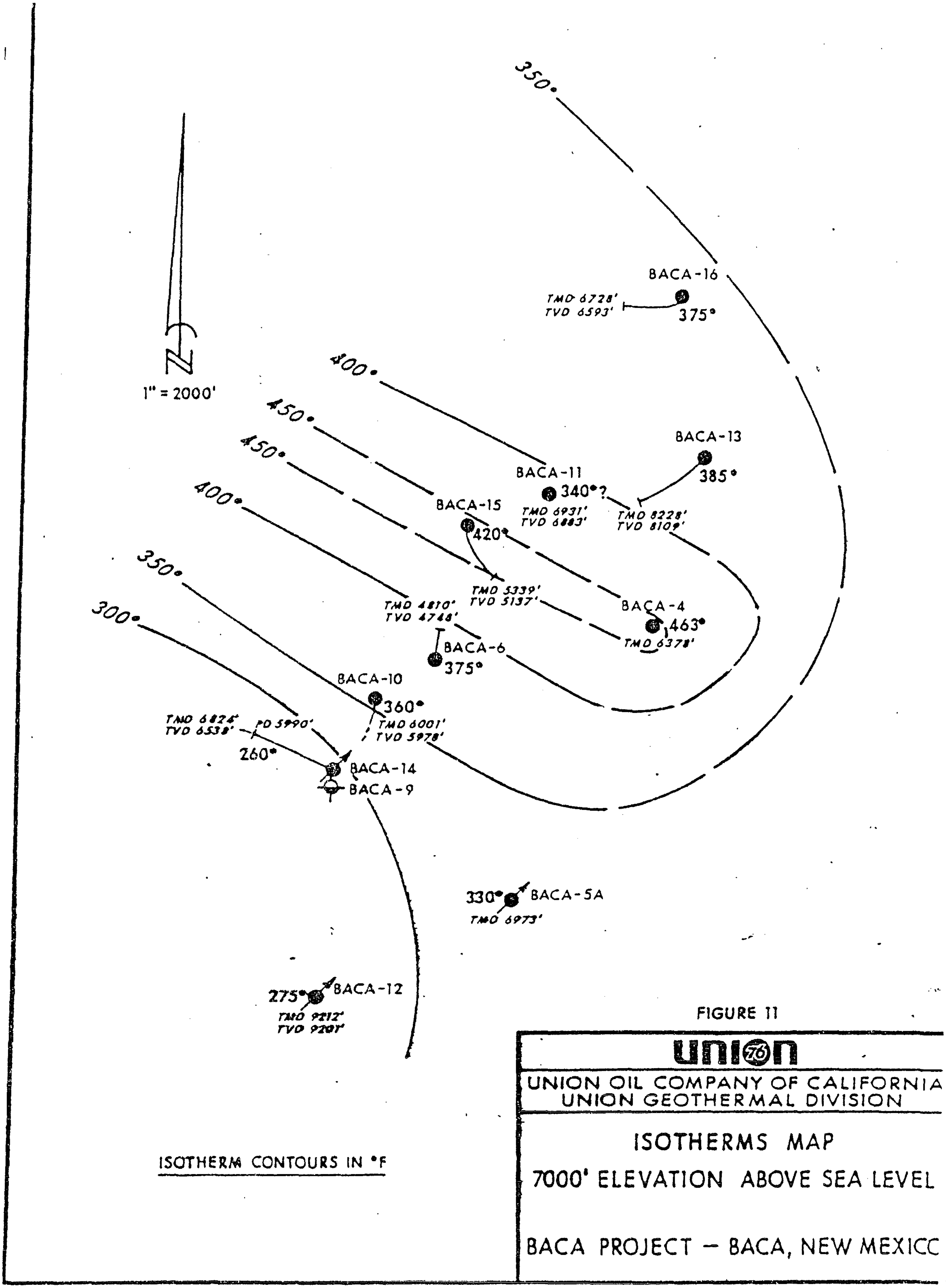


FIGURE 11

UNION

UNION OIL COMPANY OF CALIFORNIA
UNION GEOTHERMAL DIVISION

ISOTHERMS MAP

7000' ELEVATION ABOVE SEA LEVEL

BACA PROJECT — BACA, NEW MEXICO

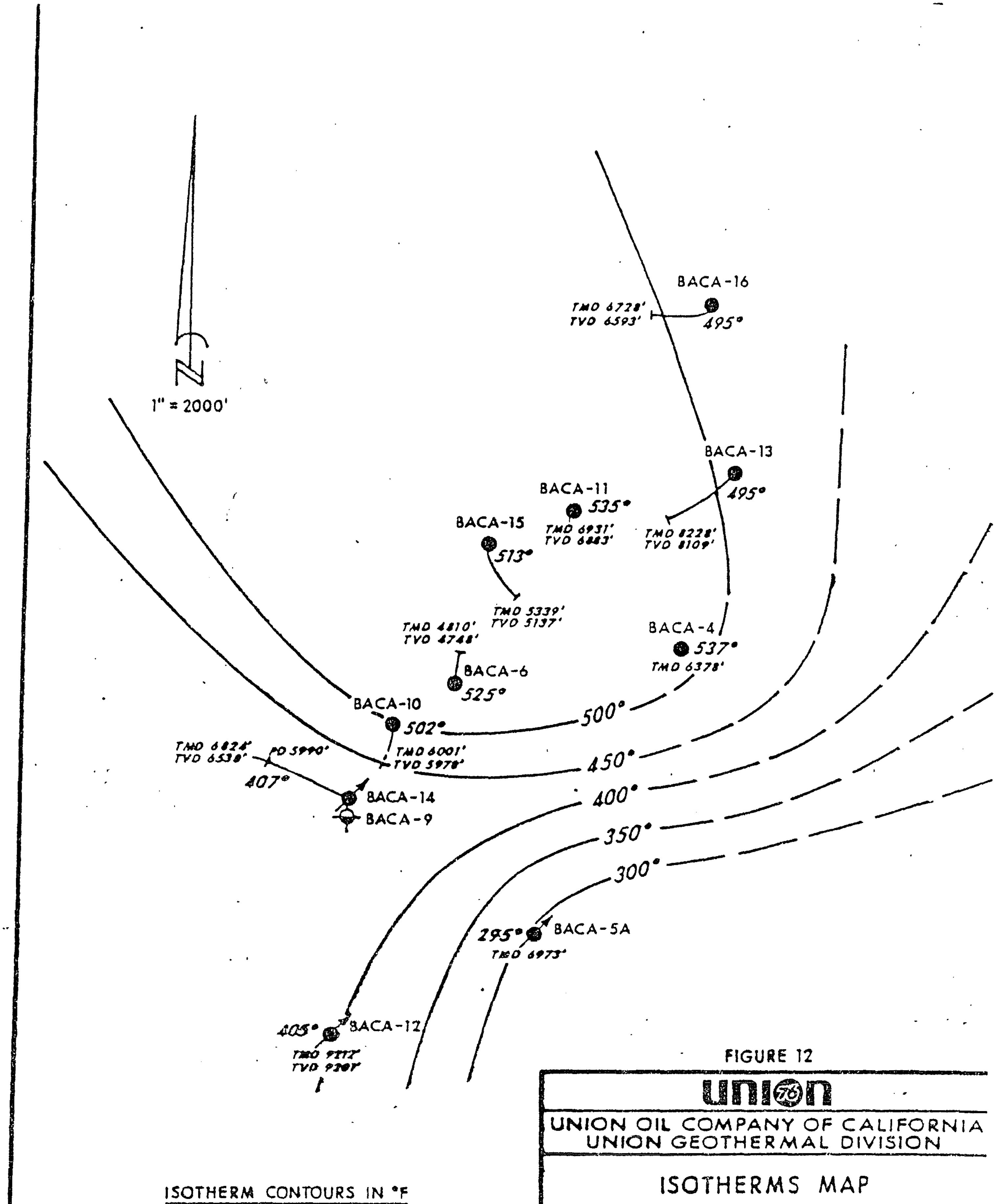


FIGURE 12

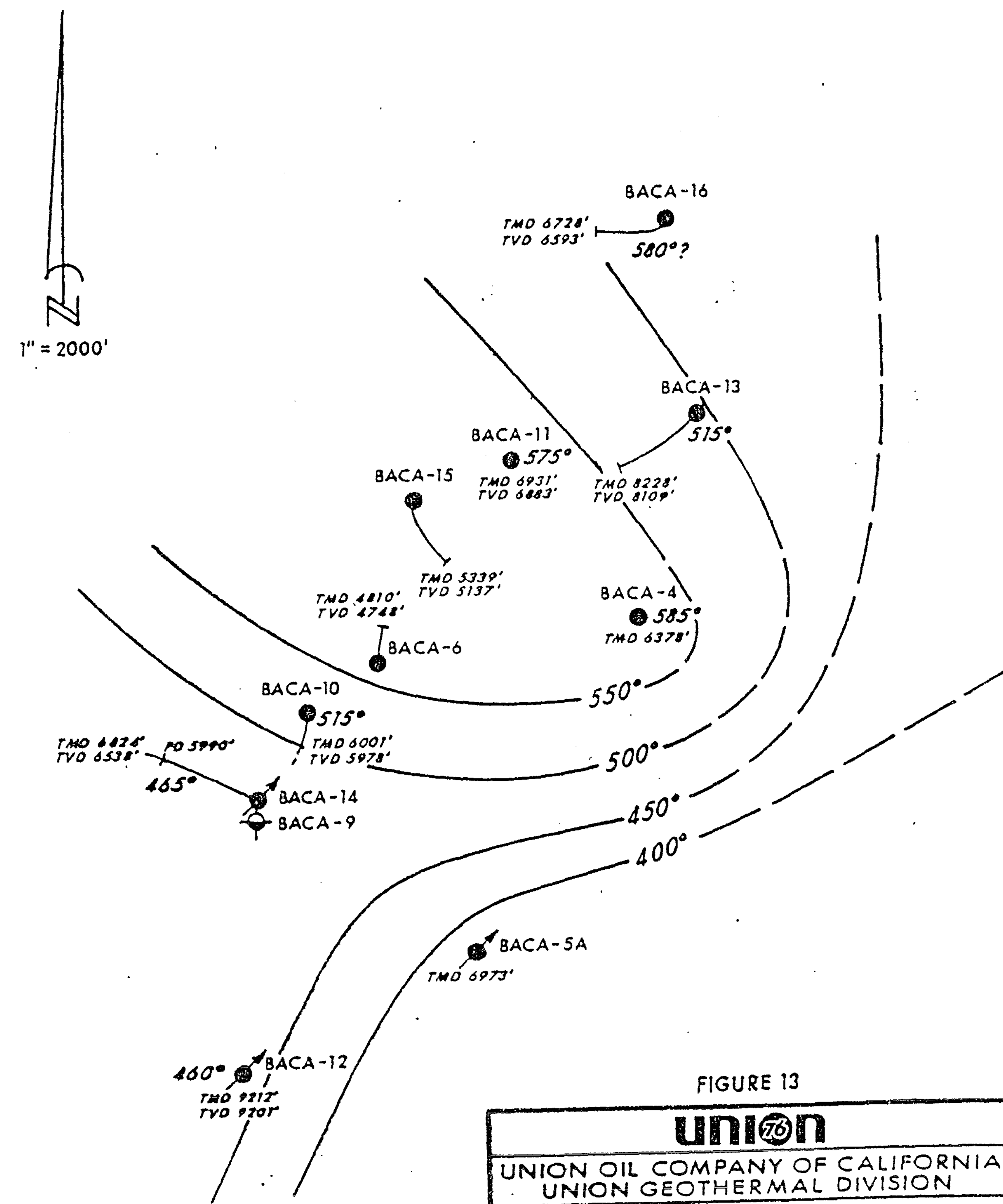
UNION

UNION OIL COMPANY OF CALIFORNIA
UNION GEOTHERMAL DIVISION

ISOTHERMS MAP

5000' ELEVATION ABOVE SEA LEVEL

BACA PROJECT – BACA, NEW MEXICO



ISOTHERM CONTOURS IN °F

FIGURE 13

UNION OIL COMPANY OF CALIFORNIA
UNION GEOTHERMAL DIVISION

ISOTHERMS MAP

3000' ELEVATION ABOVE SEA LEVEL

BACA PROJECT – BACA, NEW MEXICO

MATERIAL

1. Valve 10", 600#, Wing
2. " 4", 150#, Ball
3. " 12", 150#, Butterfly
4. " 10", 300#
5. Orifice 6", 2-12", 300# Flanges
6. H_2O Orifice 6", 2-12", 300# Flanges
7. 2 ϕ Flow, 8.5" Orifice, 2-12", 300# "

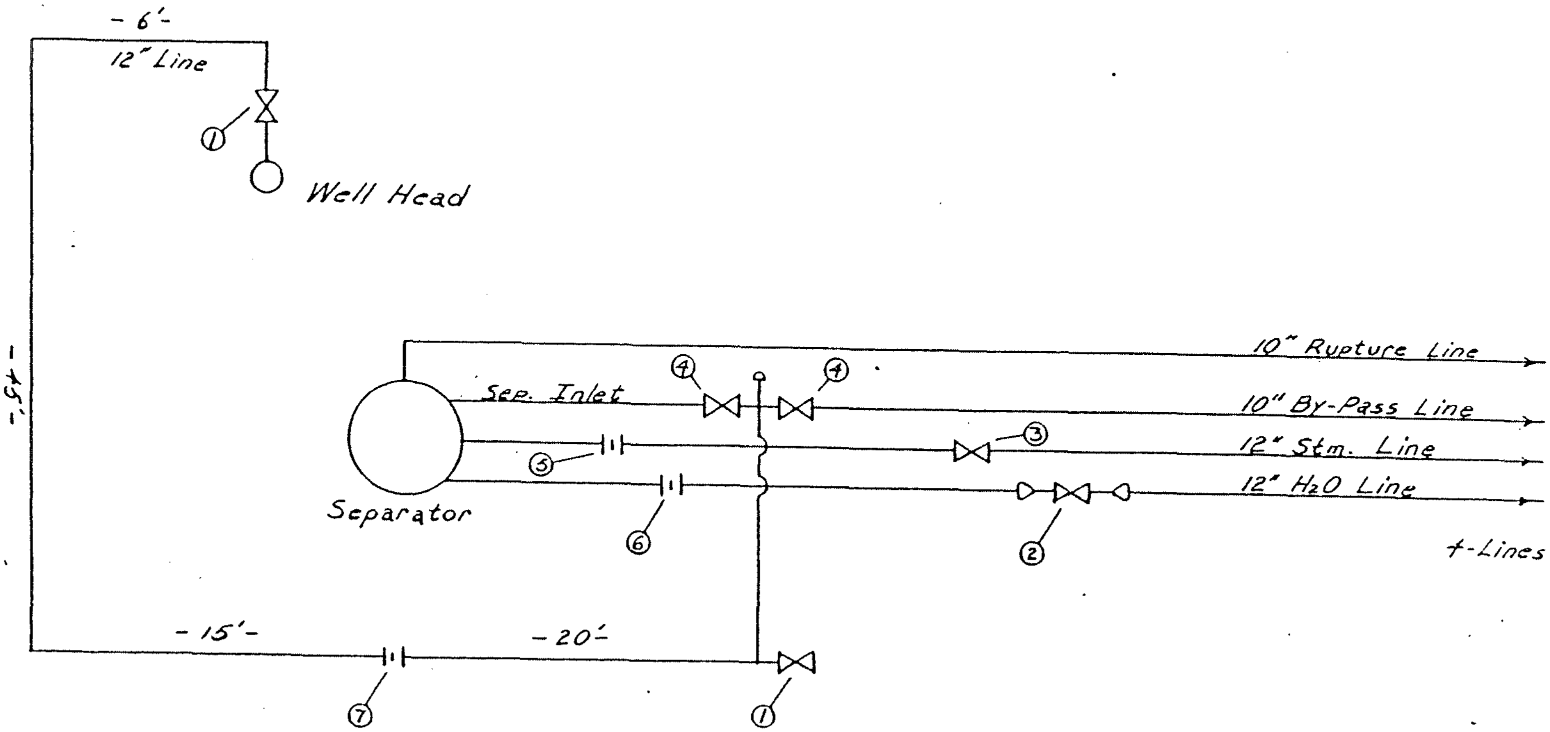


FIGURE 14

REVISED

DATE

union 76

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA #6 GENERAL LAYOUT
BACA, NEW MEXICO

DRAWN
FOR:
BY:
DATE:
SCALE: NONE
DRAWING NUMBER

MATERIAL

1. Valve 12", WKM, 300#
2. " 8" " "
3. " 8" Butterfly
4. " 4" 150#, Ball
5. Stm. Orifice, 8", 2-12", 300# Flang
6. H_2O " 6", " ", "
7. 2 Ø Flow, 7.5" Orifice, 2-10", 300#

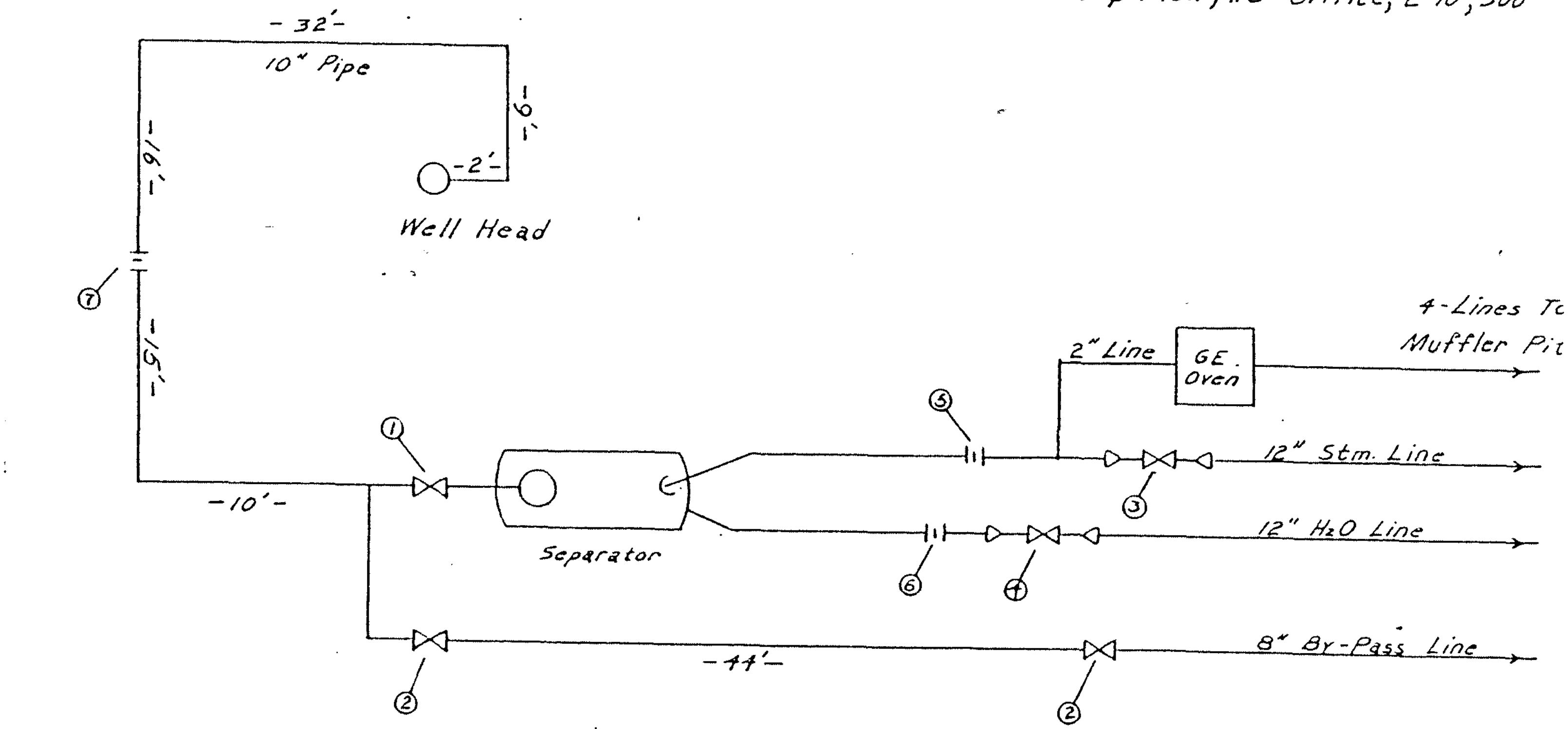


FIGURE 15

REVISED | DATE

UNION

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA #11 GENERAL LAYOUT
BACA, NEW MEXICO

DRAWN
FOR:
BY:
DATE:
SCALE: NONE
DRAWING NUMBER

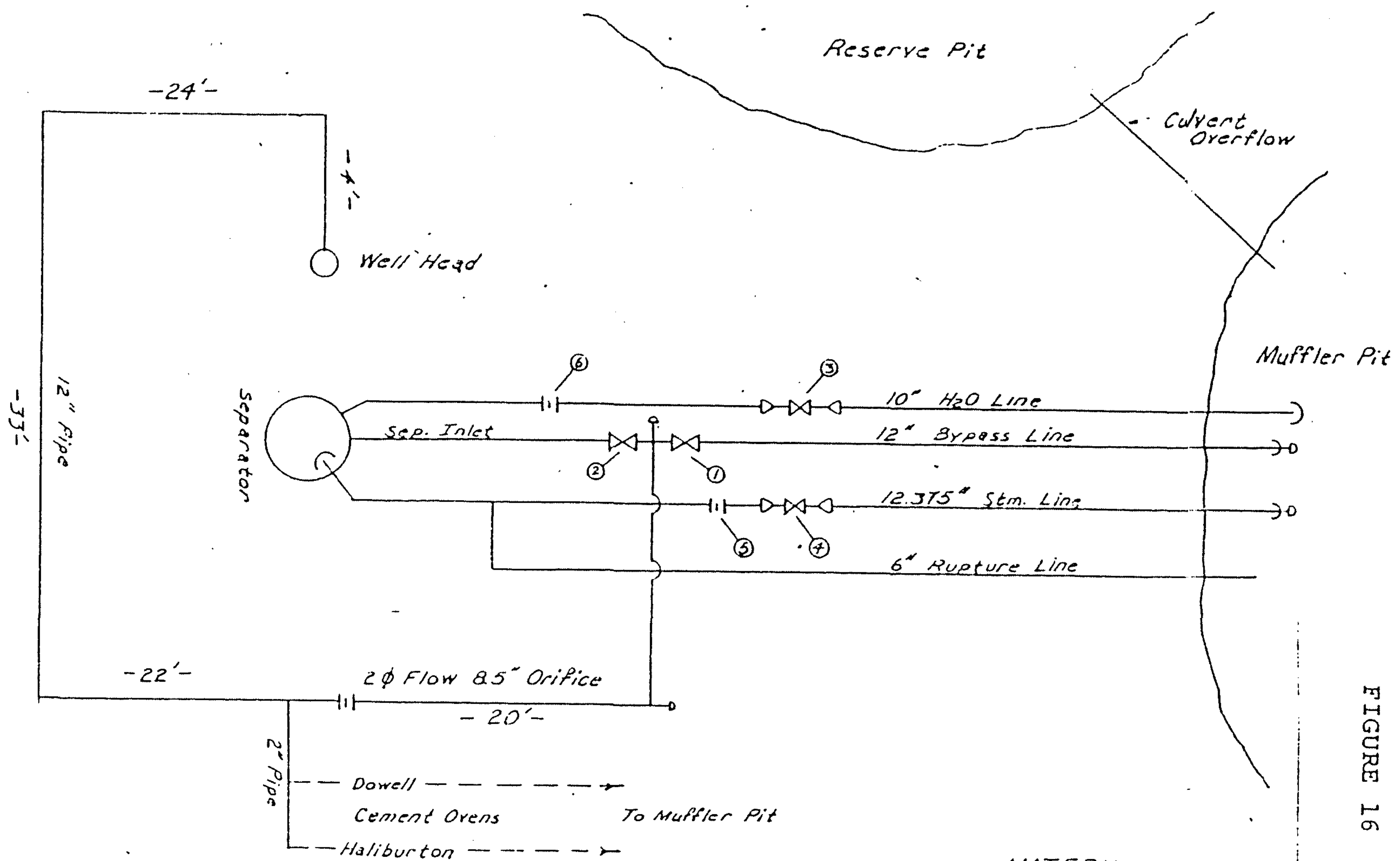


FIGURE 16

MATERIAL

1. Valve 12", WKM, 400#
2. " 12" 400#
3. " 7" 300#
4. " 8" 150# Butterfly
6. Stm. Orifice 6", i 12", 300# Flanges
6. H_2O " " " " " "

REVISED | DATE

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

UNION 76

BACA #13 GENERAL LAYOUT
BACA, NEW MEXICO

DRAWN
FOR:
BY:
DATE:
SCALE: NONE
DRAWING NUMBER

STEAM FRACTION AS A FUNCTION OF SEPARATOR PRESSURE AT RESERVOIR TEMPERATURES OF 525°F AND 600°F

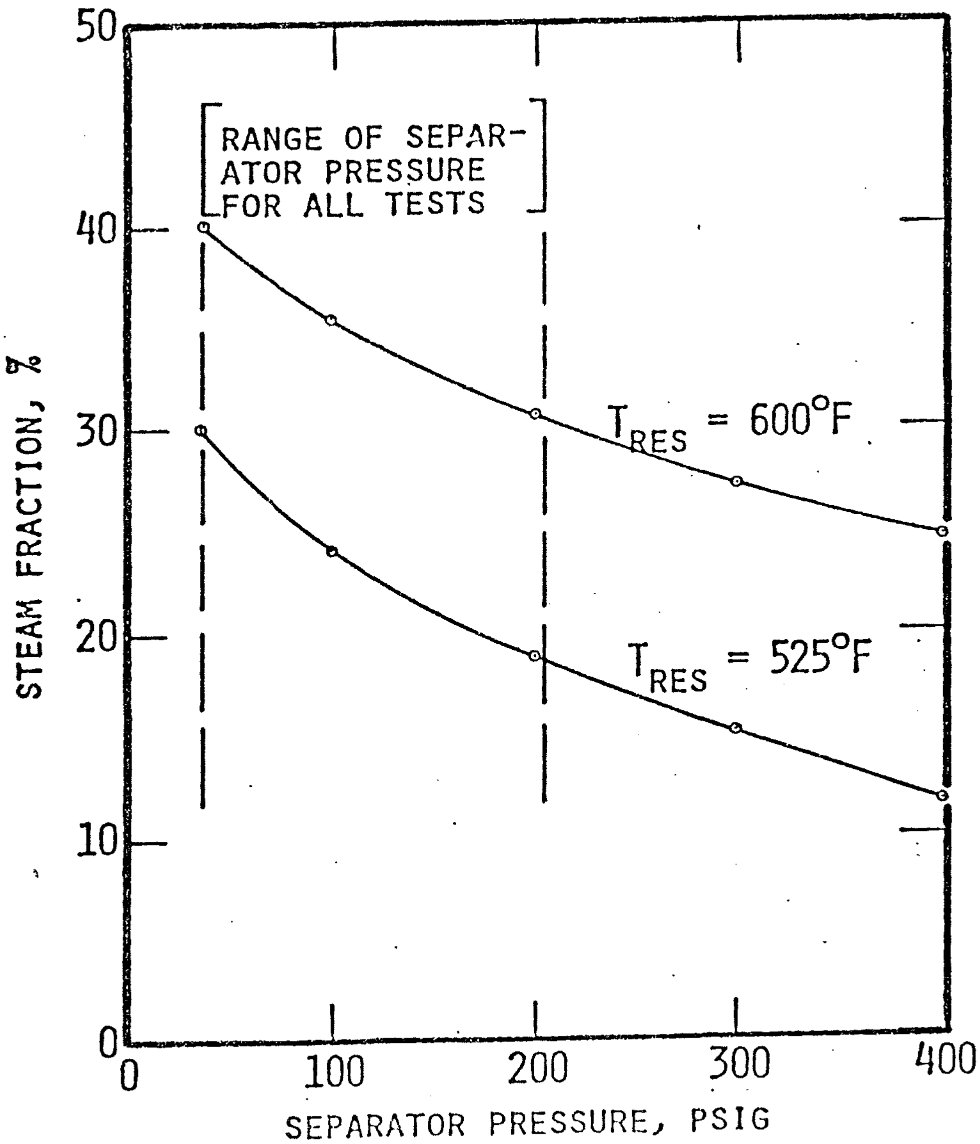
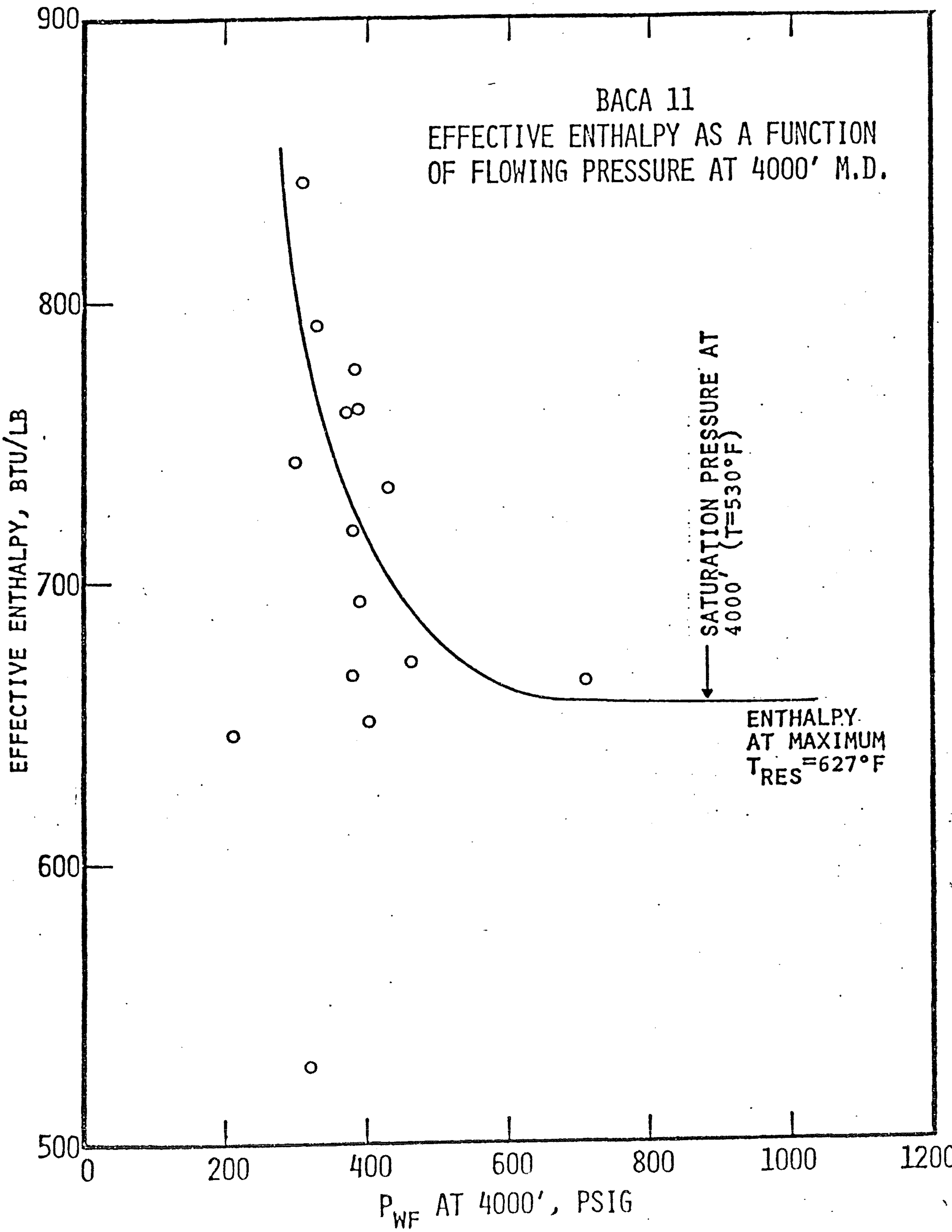
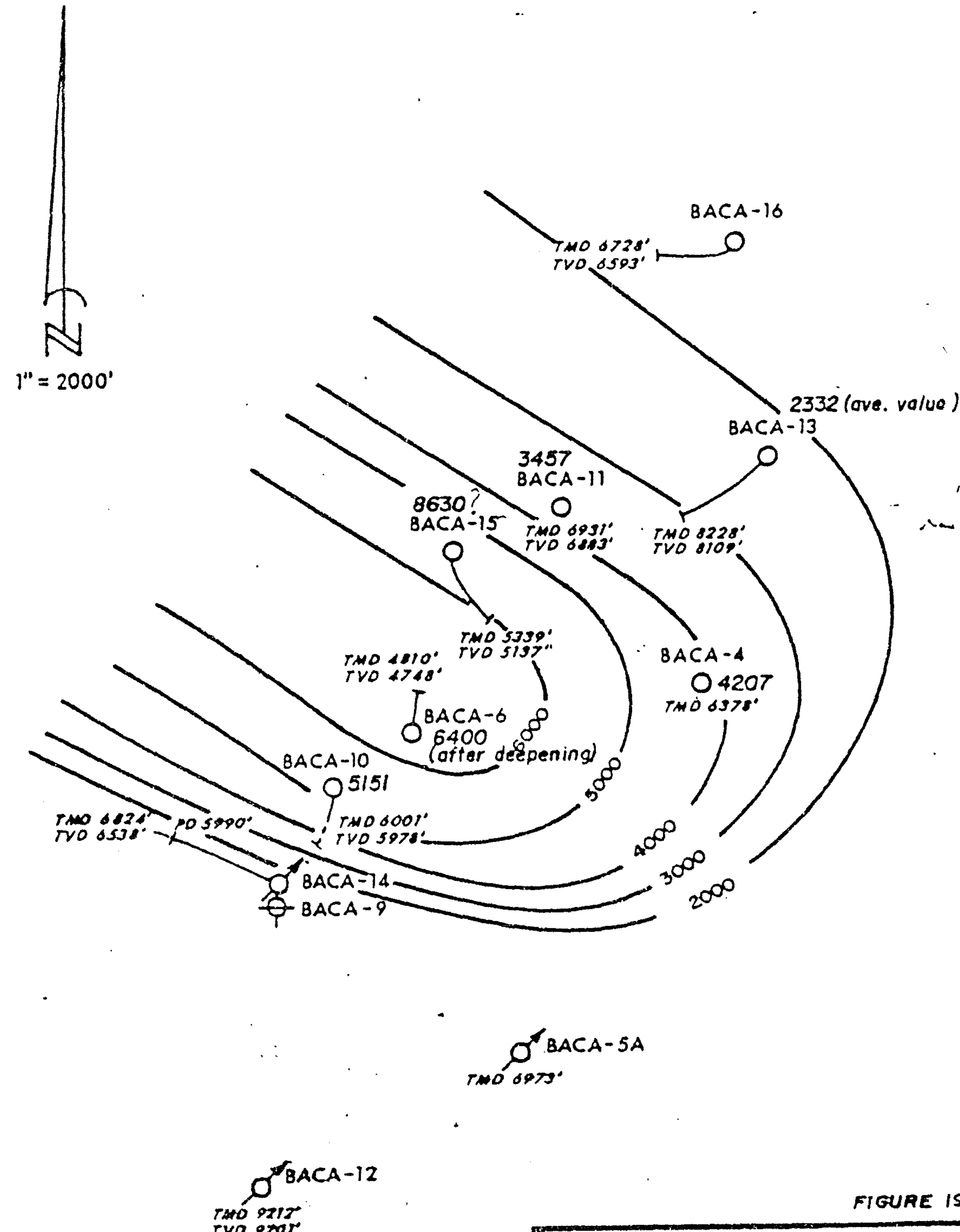


FIGURE 18


BACA 11
EFFECTIVE ENTHALPY AS A FUNCTION
OF FLOWING PRESSURE AT 4000' M.D.
SATURATION PRESSURE AT
4000' (T=530°F)
ENTHALPY
AT MAXIMUM
T RES =627°F
EFFECTIVE ENTHALPY, BTU/LB
900
800
700
600
500
0
200
400
600
800
1000
1200
P WF AT 4000', PSIG



DATA FROM PRESSURE BUILDUP ANALYSIS
CONTOURS IN MILLIDARCY FEET

FIGURE 19

UNION OIL COMPANY OF CALIFORNIA
UNION GEOTHERMAL DIVISION

ISOPERMEABILITY

THICKNESS MAP

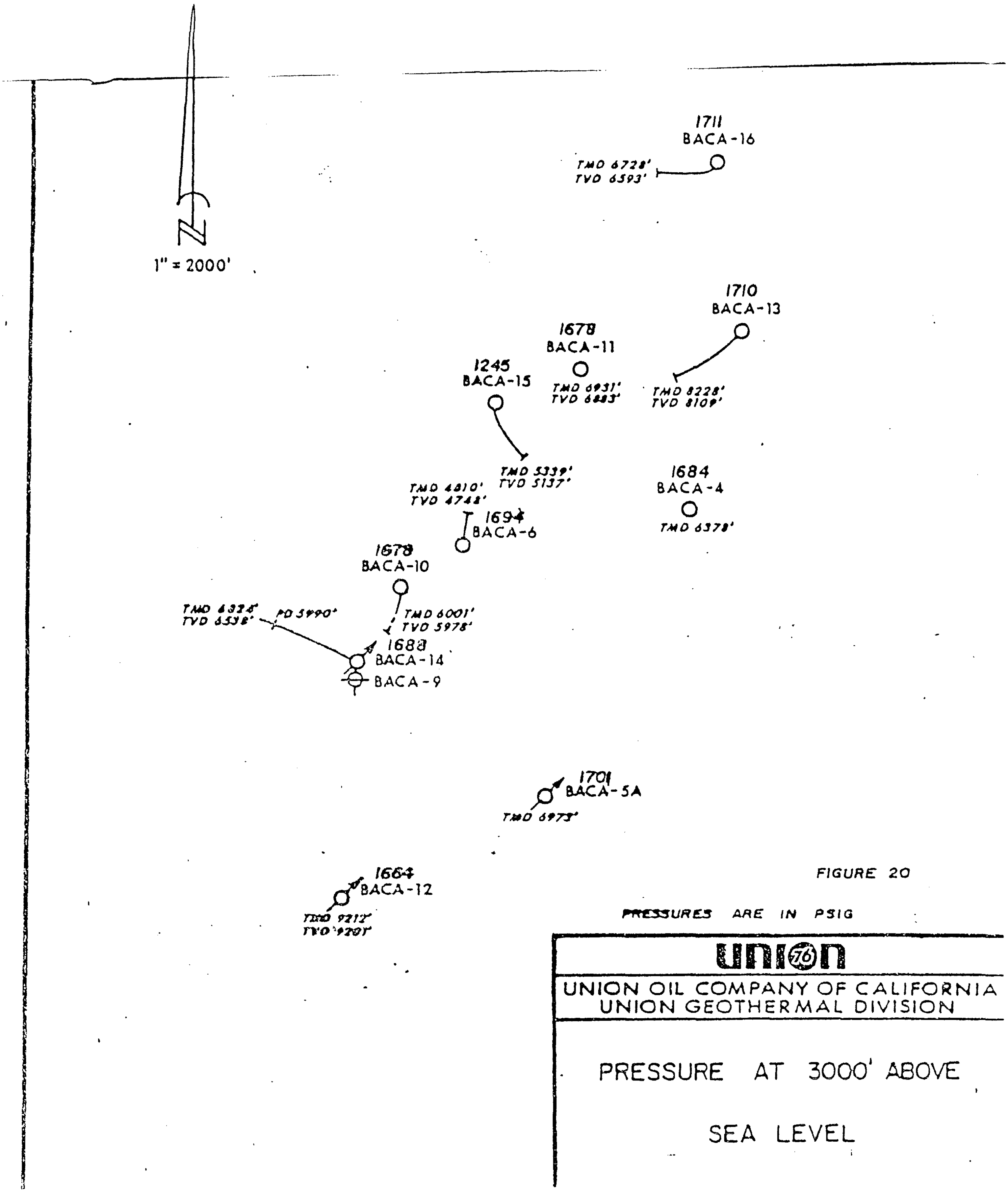


FIGURE 20

PRESSURES ARE IN PSIG

UNION

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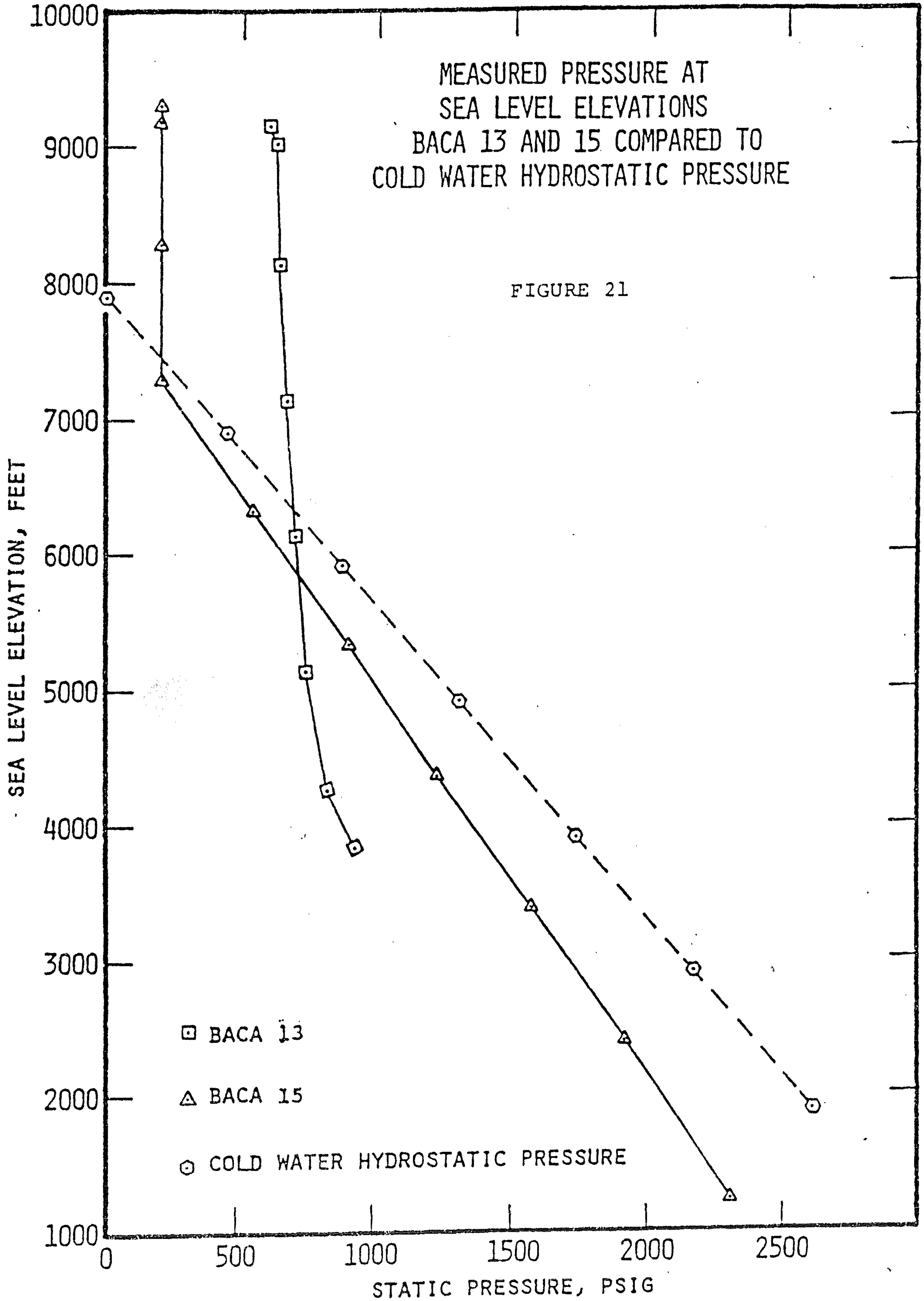
UNION GEOTHERMAL DIVISION

PRESSURE AT 3000' ABOVE SEA LEVEL


MEASURED PRESSURE AT
SEA LEVEL ELEVATIONS
BACA 13 AND 15 COMPARED TO
COLD WATER HYDROSTATIC PRESSURE
FIGURE 21
SEA LEVEL ELEVATION, FEET
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
500
1000
1500
2000
2500
STATIC PRESSURE, PSIG
BACA 13
BACA 15
COLD WATER HYDROSTATIC PRESSURE

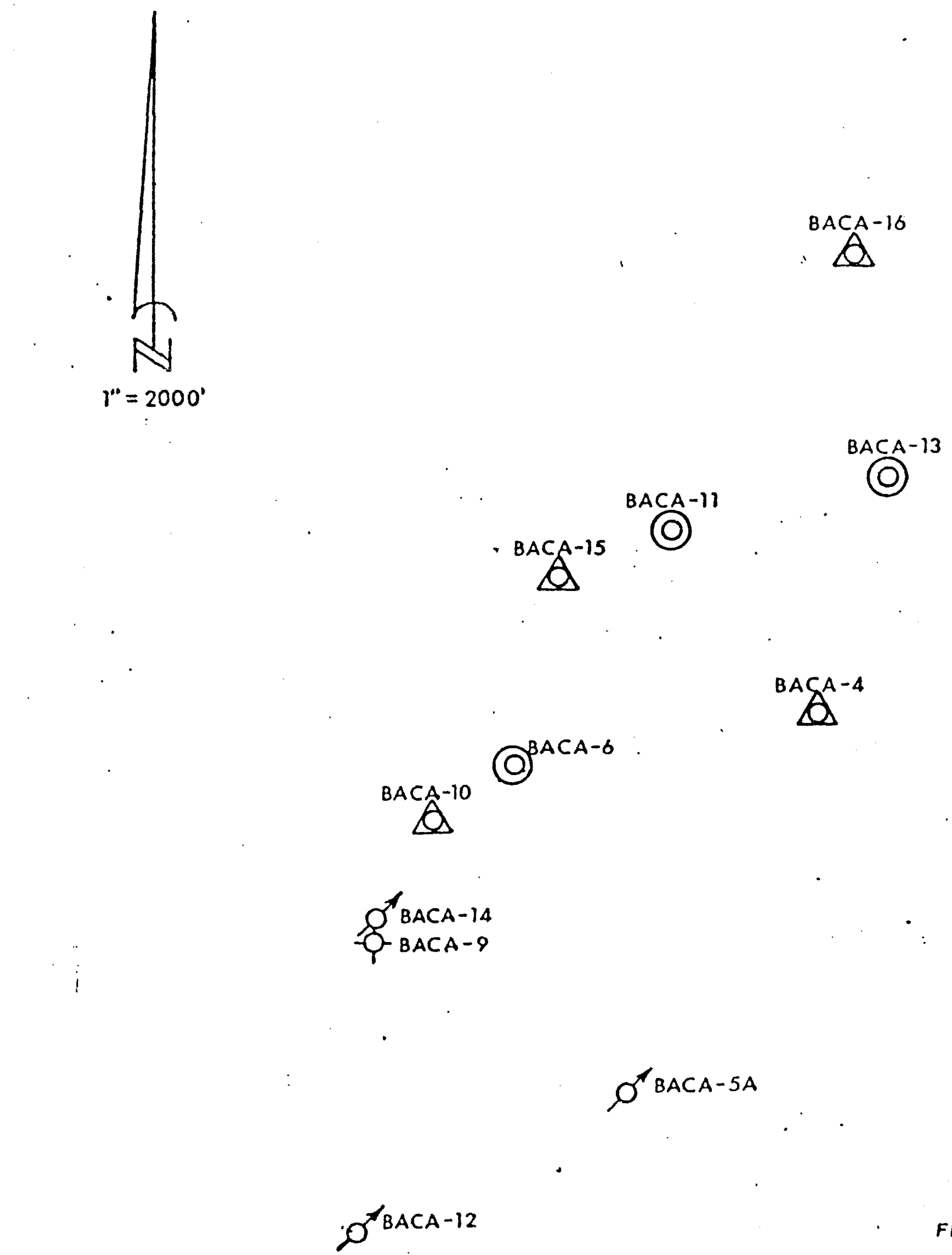
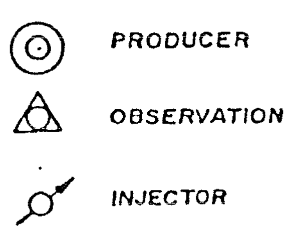


FIGURE 22



UNION

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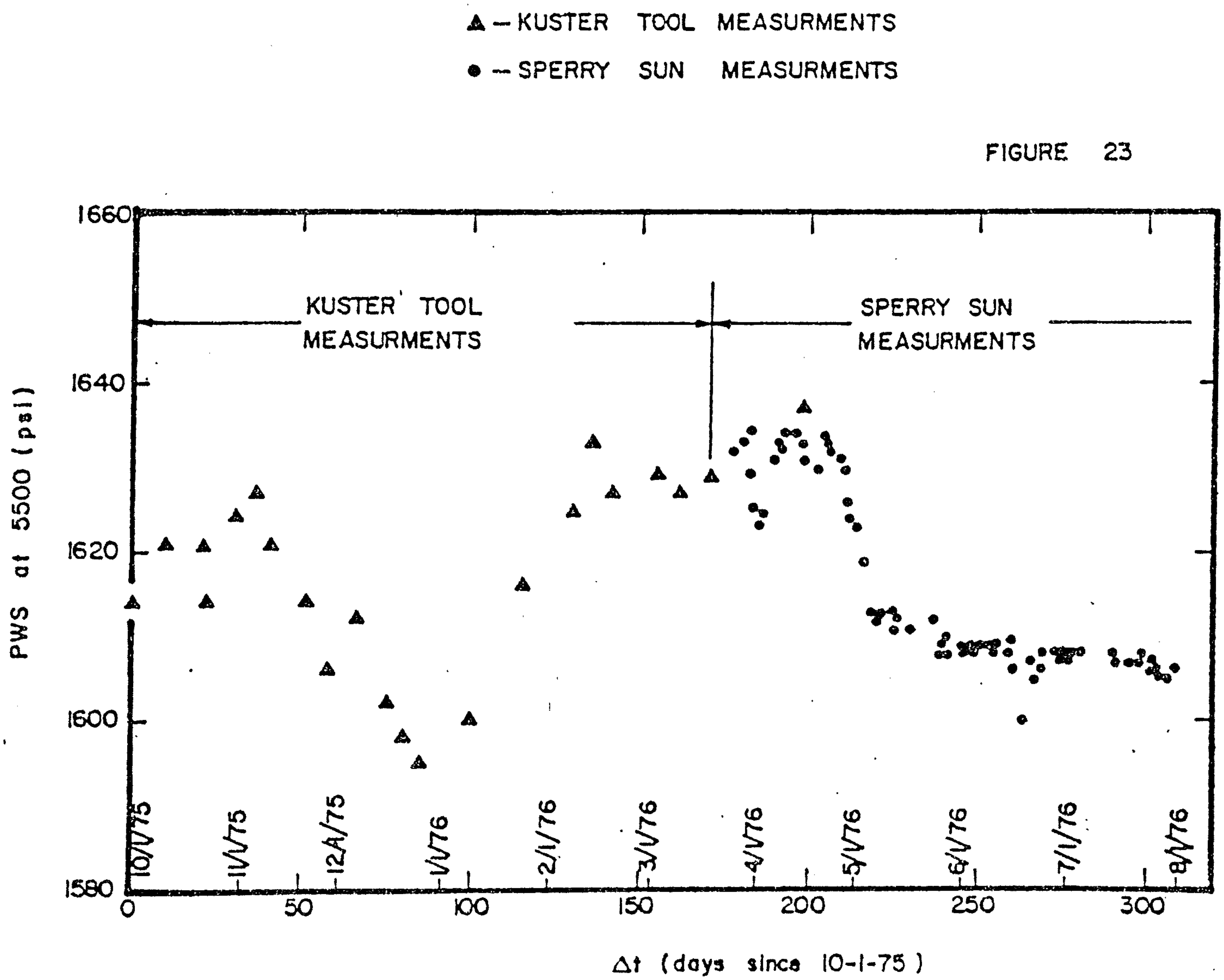
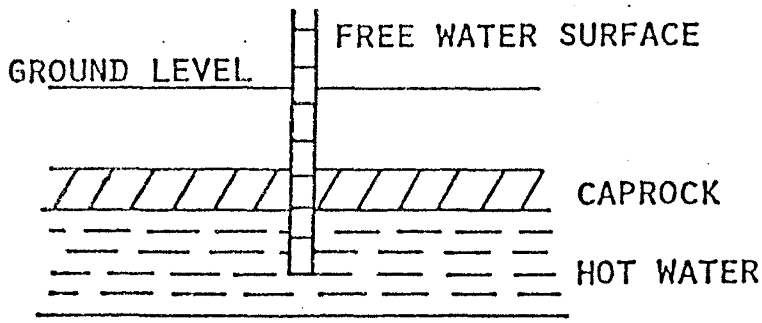
INTERFERENCE TEST

LOCATION OF PRODUCERS, INJECTORS, & OBSERVATION WELLS

BACA 10 MEASURED PRESSURE AT 5000' MD 10-1-75 — 8-1-76

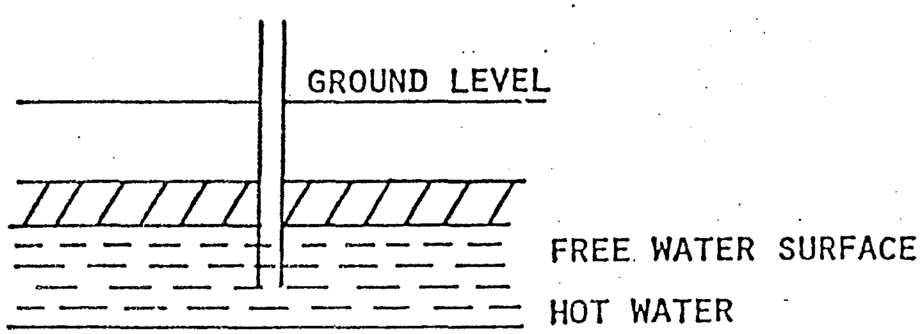


SCHEMATIC DIAGRAM OF CONFINED AND UNCONFINED RESERVOIRS



(A)

CONFINED AQUIFER



(B)

UNCONFINED AQUIFER

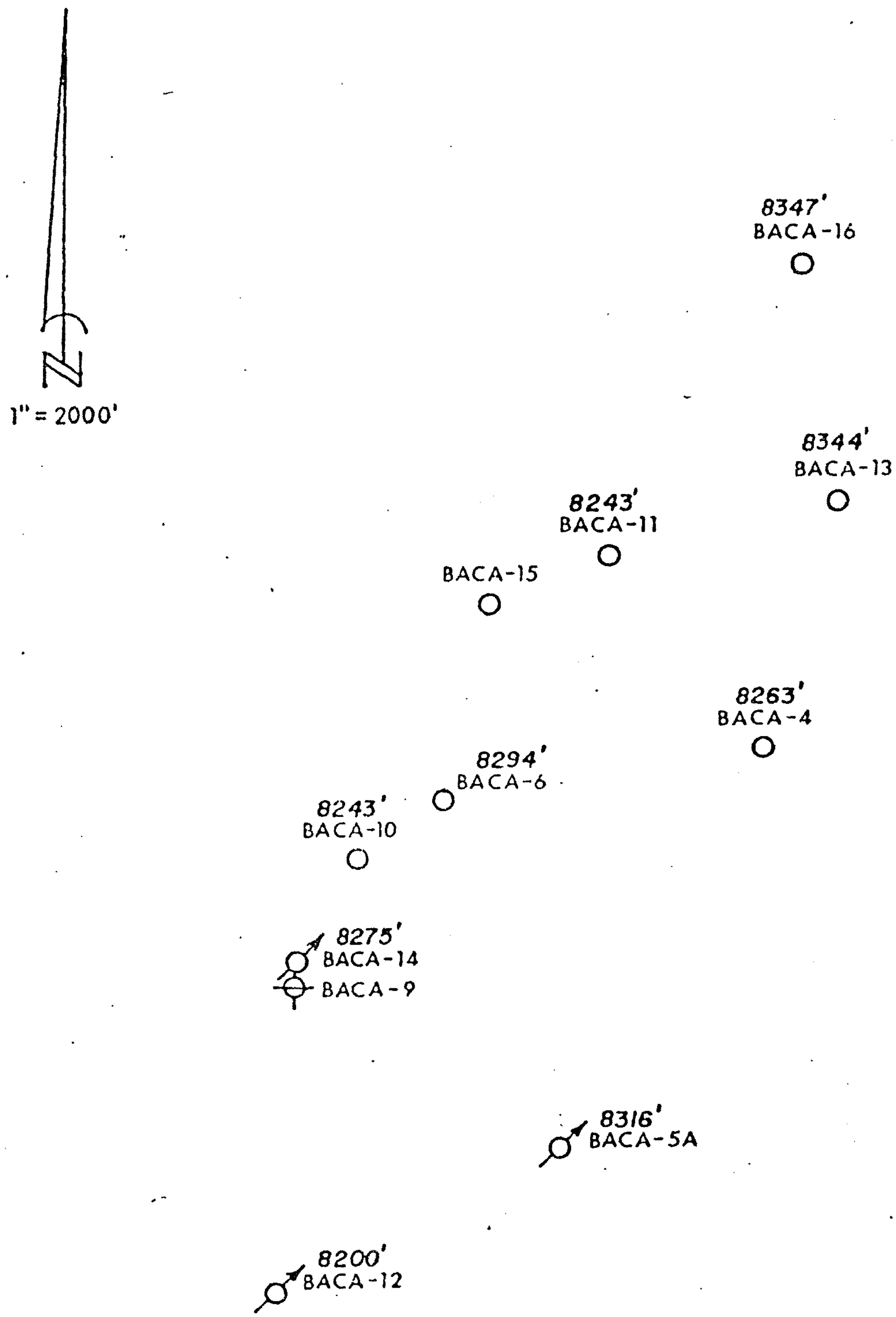


FIGURE 25

UNION 76

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UNION GEOTHERMAL DIVISION

ELEVATION OF
FREE WATER SURFACES

BACA INTERFERENCE TEST
OBSERVED PRESSURE CHANGES AT BACA-10

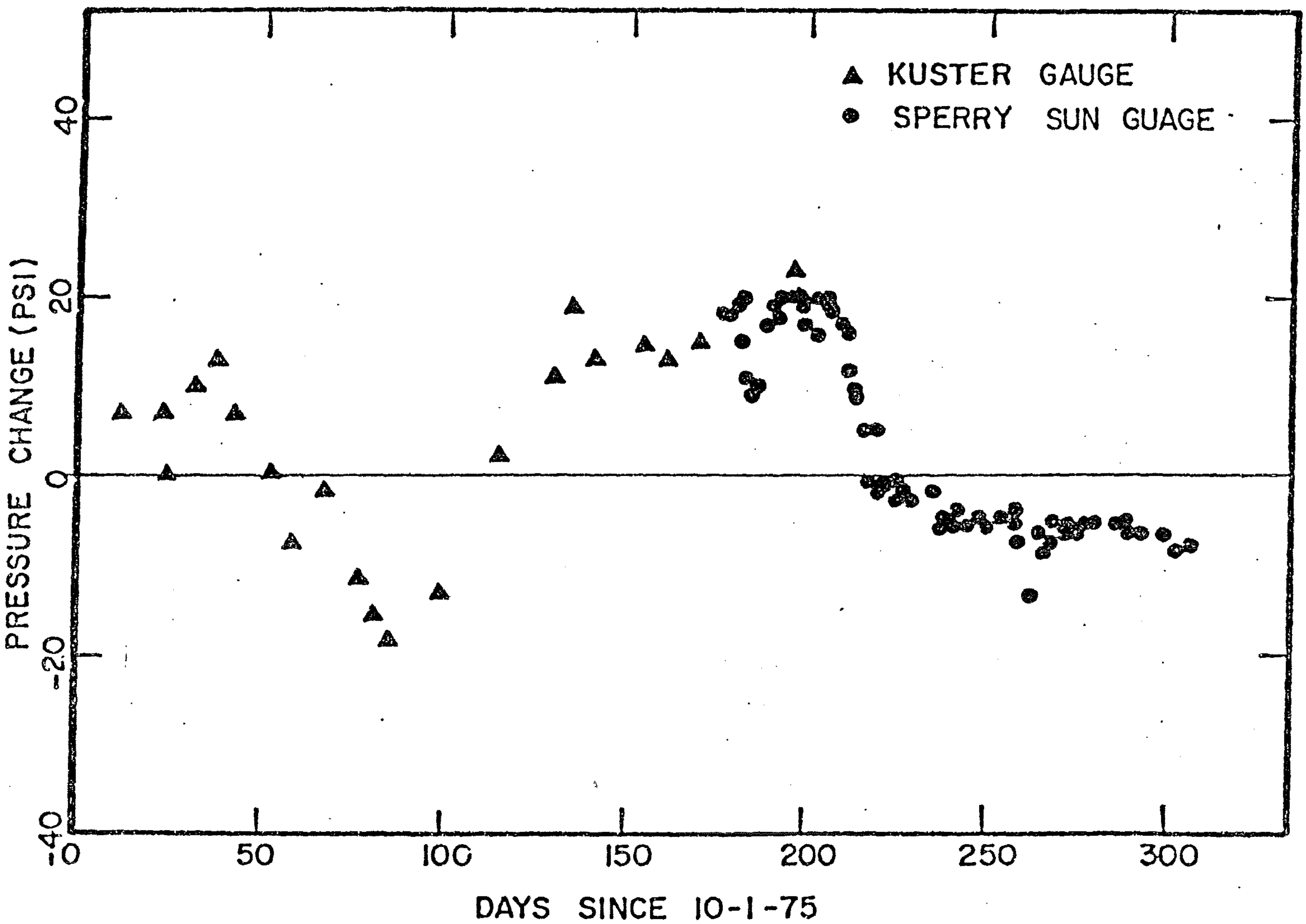
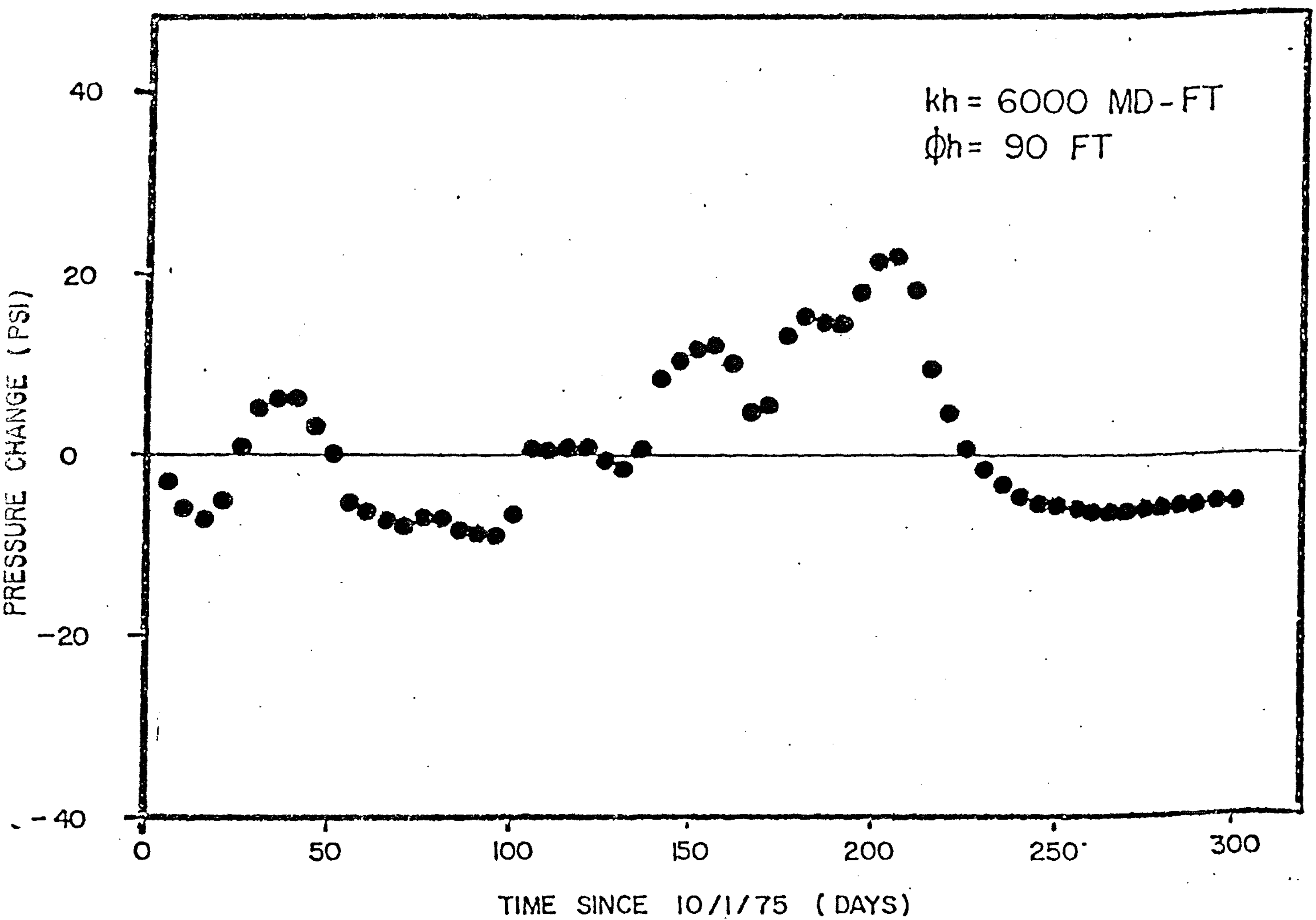
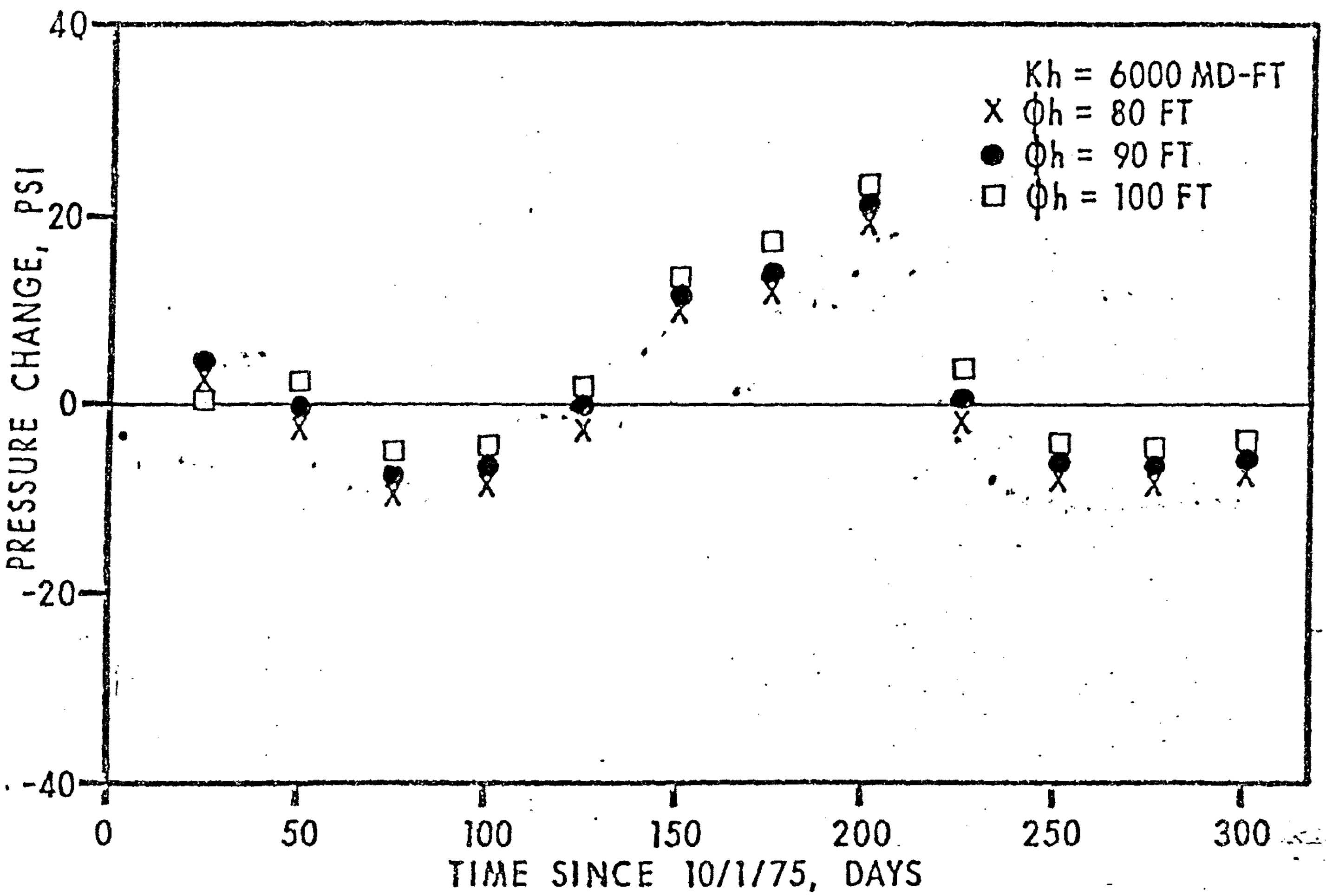


FIGURE 27



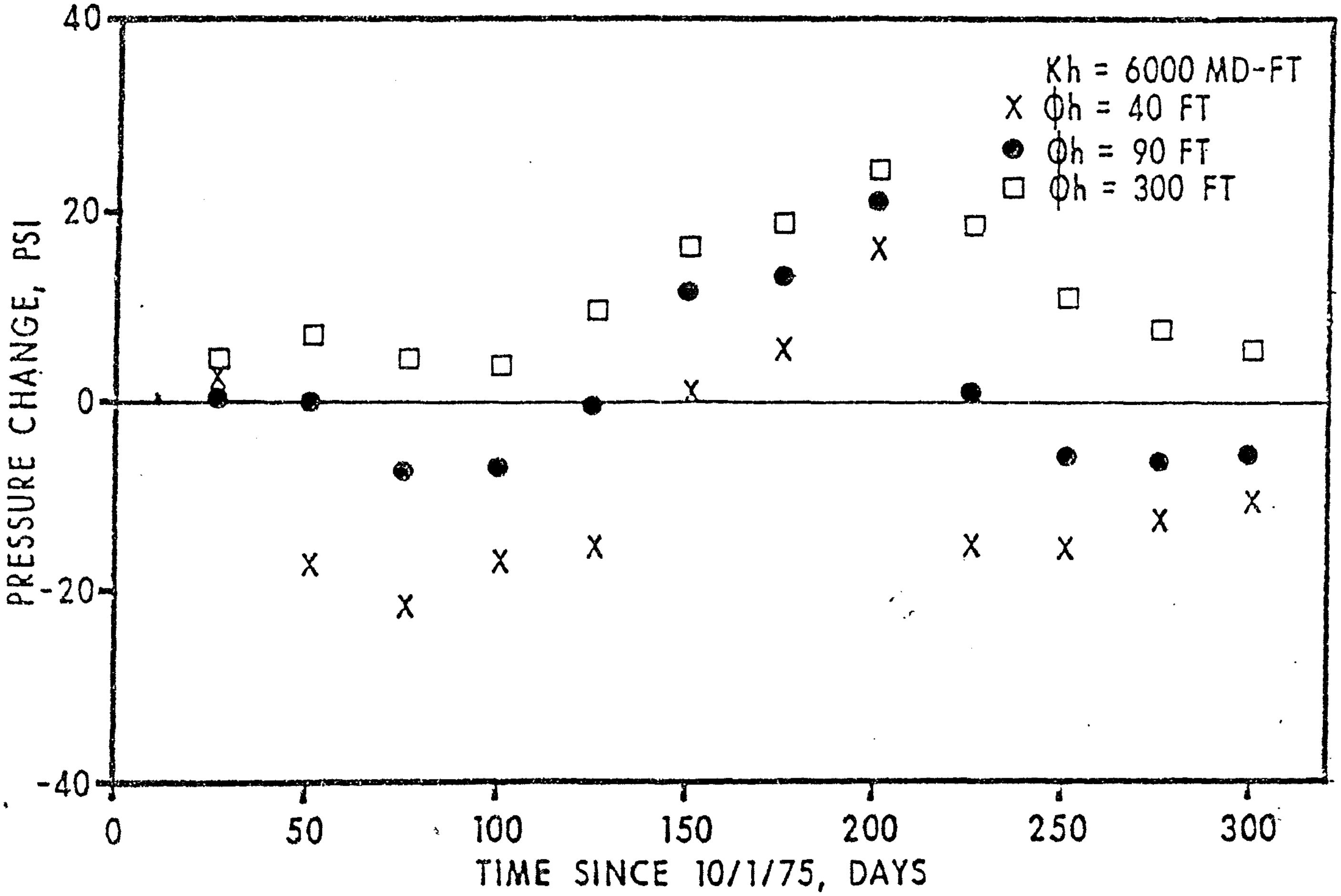
THE CALCULATED PRESSURE RESPONSE
USING INFINITE AQUIFER

FIGURE 28



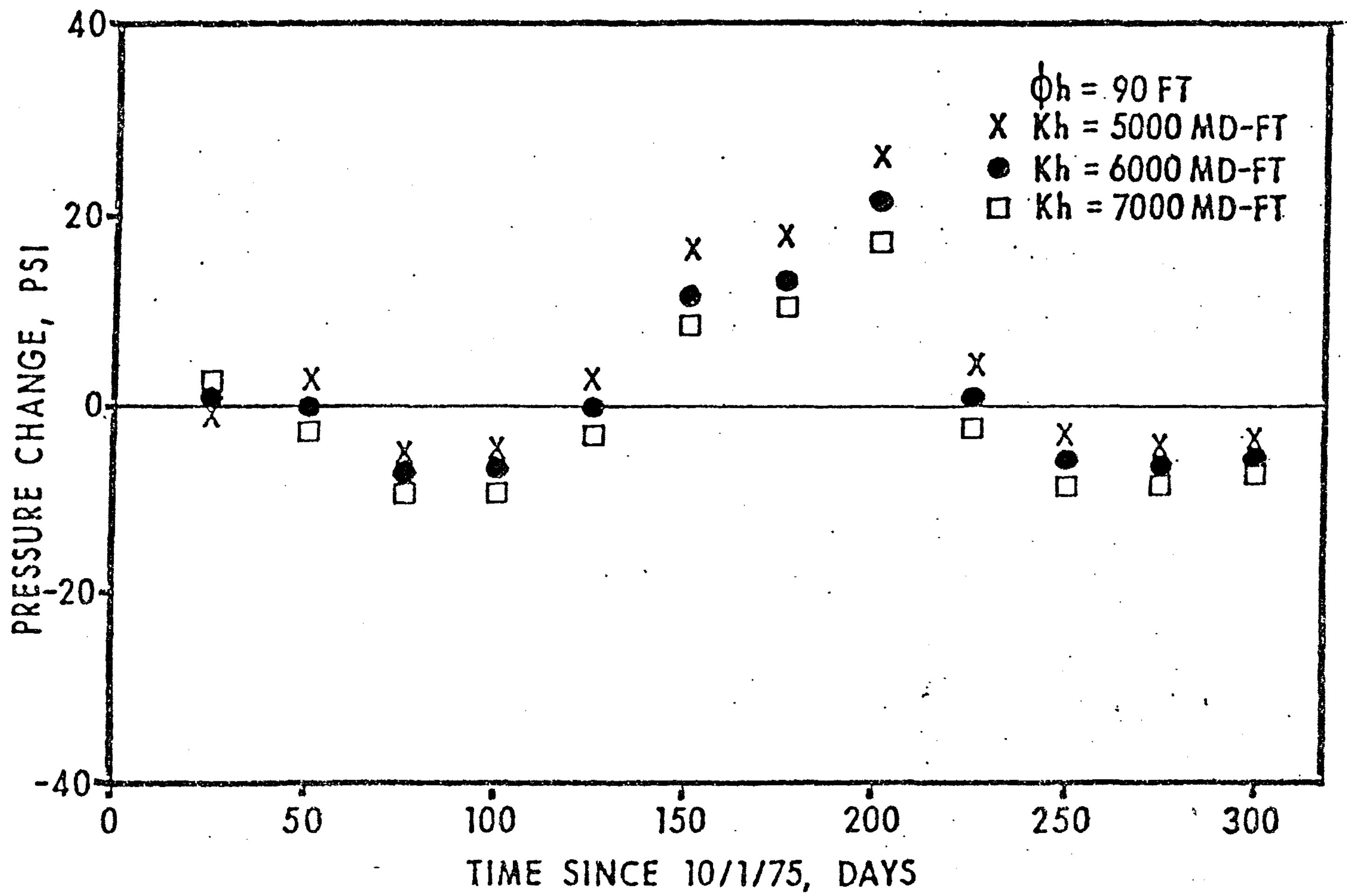
EFFECT OF ϕh ON THE CALCULATED PRESSURE RESPONSE

FIGURE 29



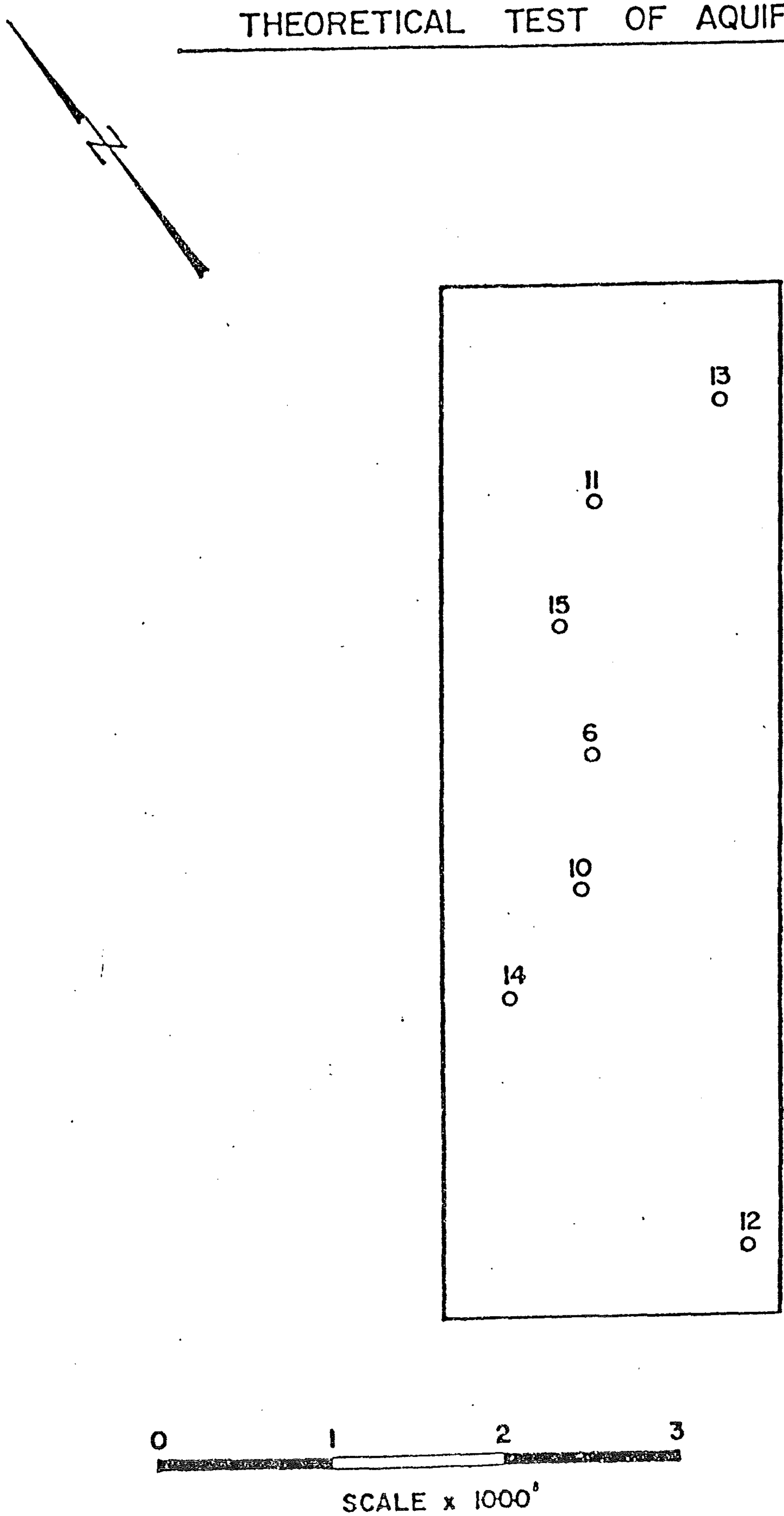
EFFECT OF ϕh ON THE CALCULATED PRESSURE RESPONSE

FIGURE 30



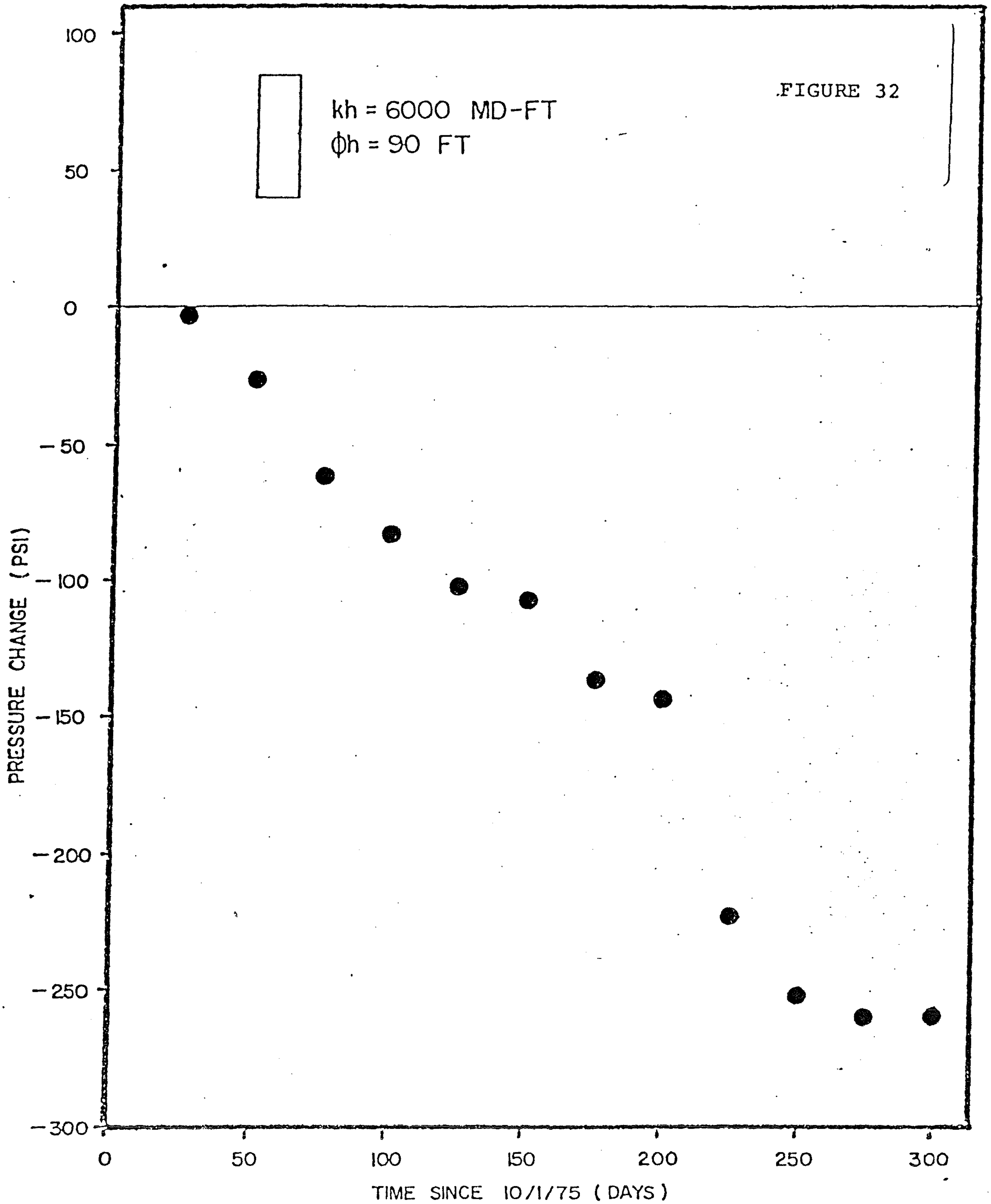
EFFECT OF Kh ON THE CALCULATED PRESSURE RESPONSE

THEORETICAL TEST OF AQUIFER SHAPE

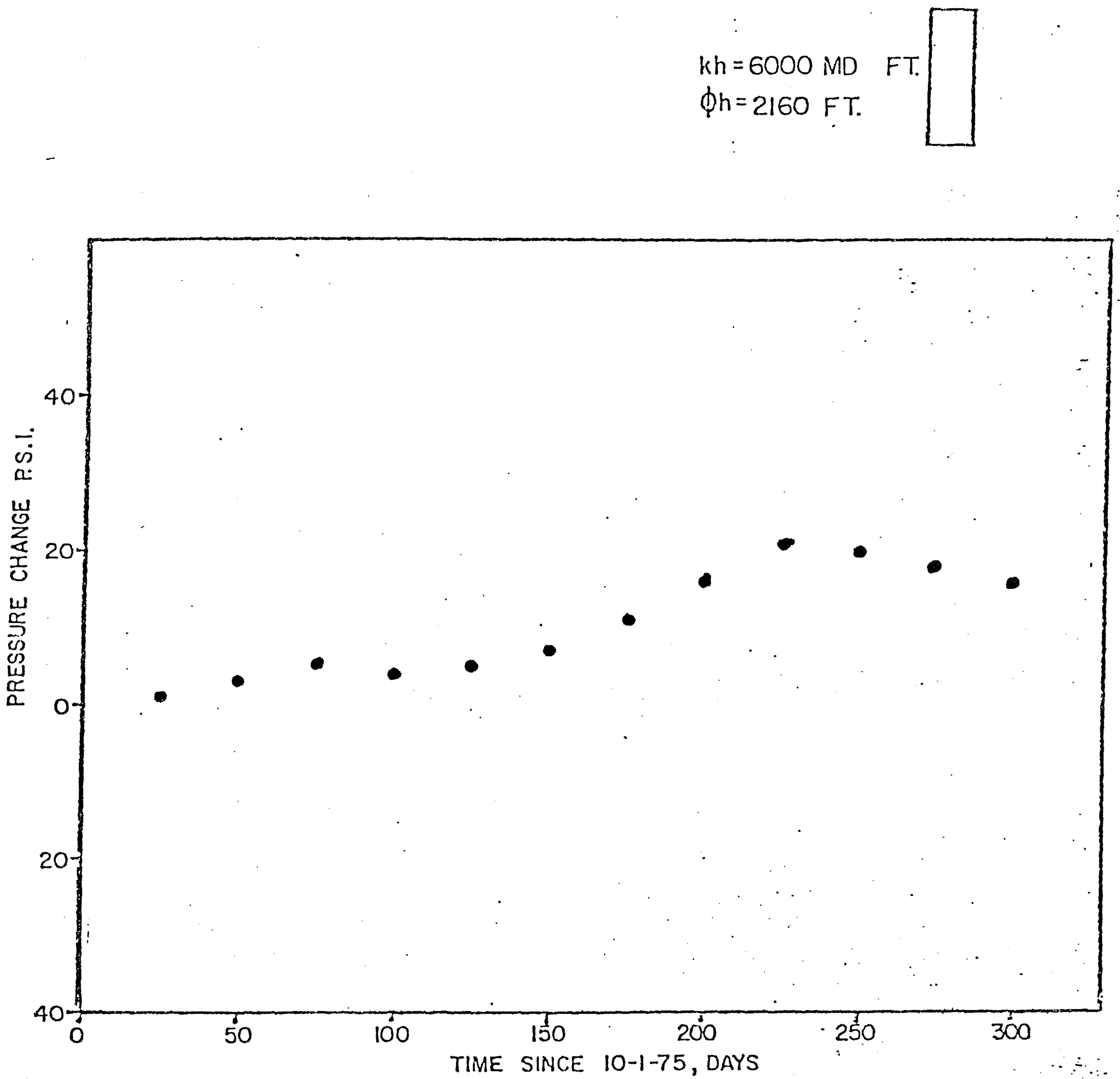


WELL SPOTS AT APPROX. MIDPOINT OF PRODUCTIVE INTERVAL

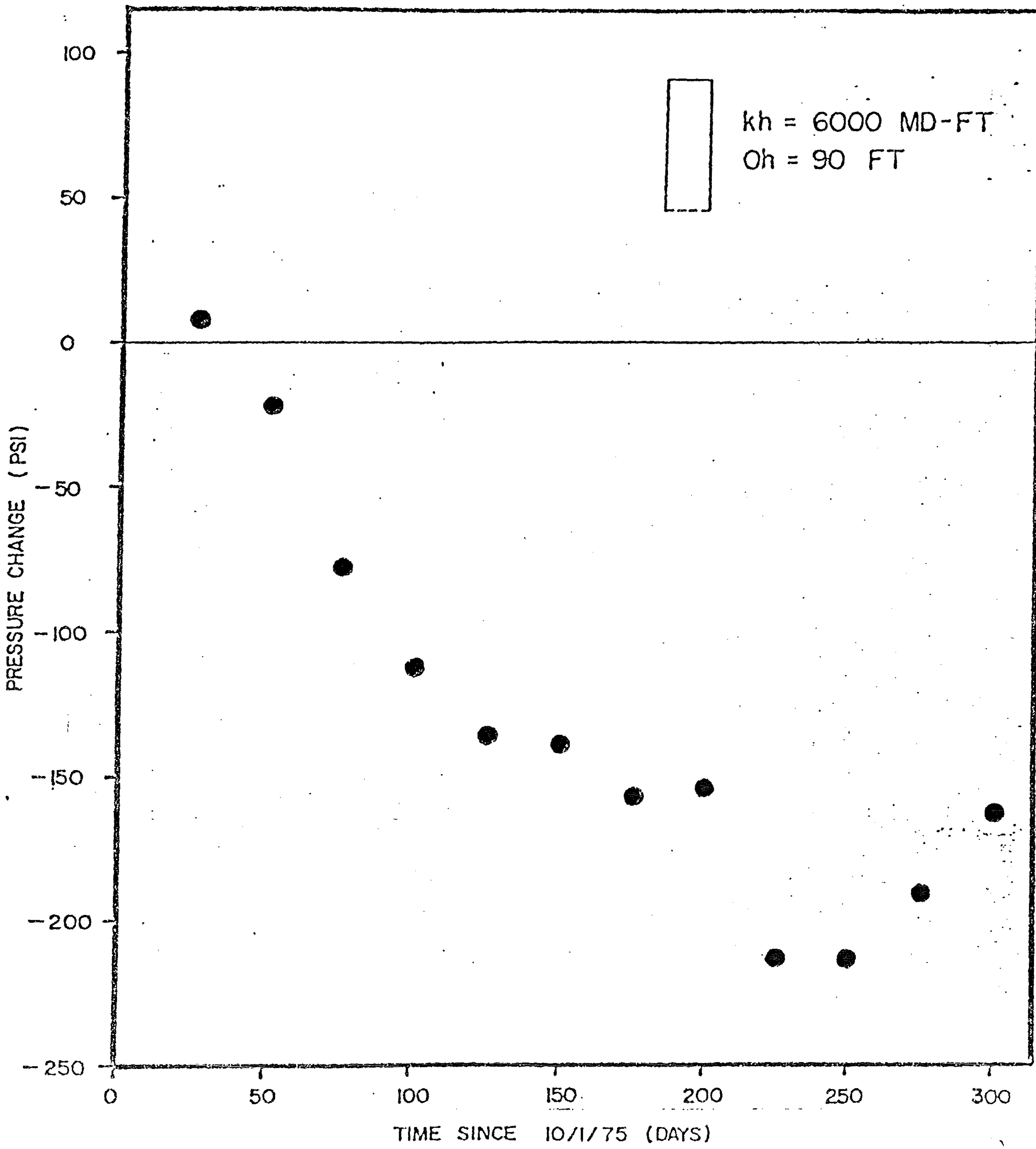
FIGURE 32



PRESSURE PROFILE WITH ALL BOUNDARIES CLOSED

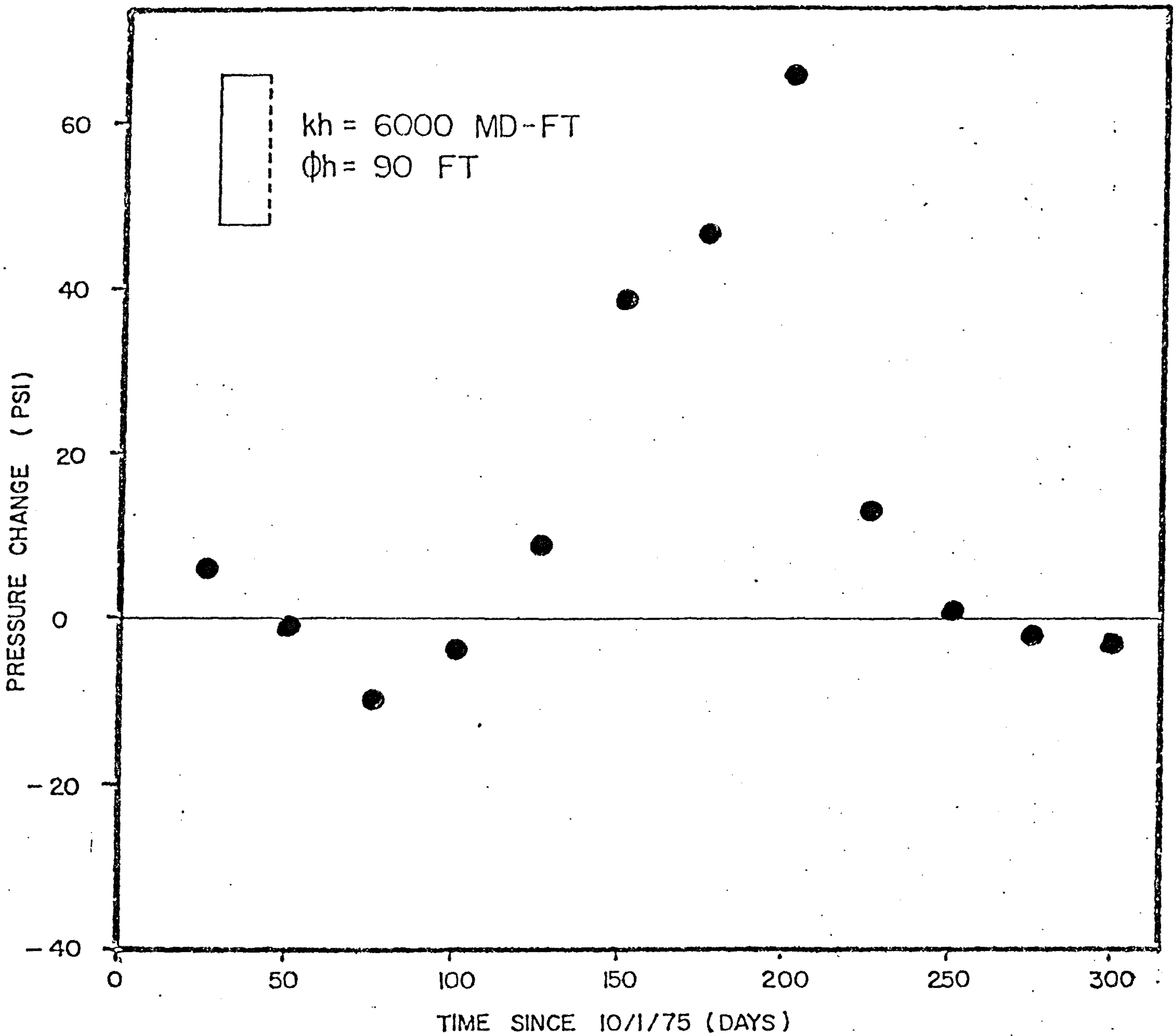


CALCULATED PRESSURE PROFILE IN A CLOSED RECTANGLE WITH ϕh = 2160'



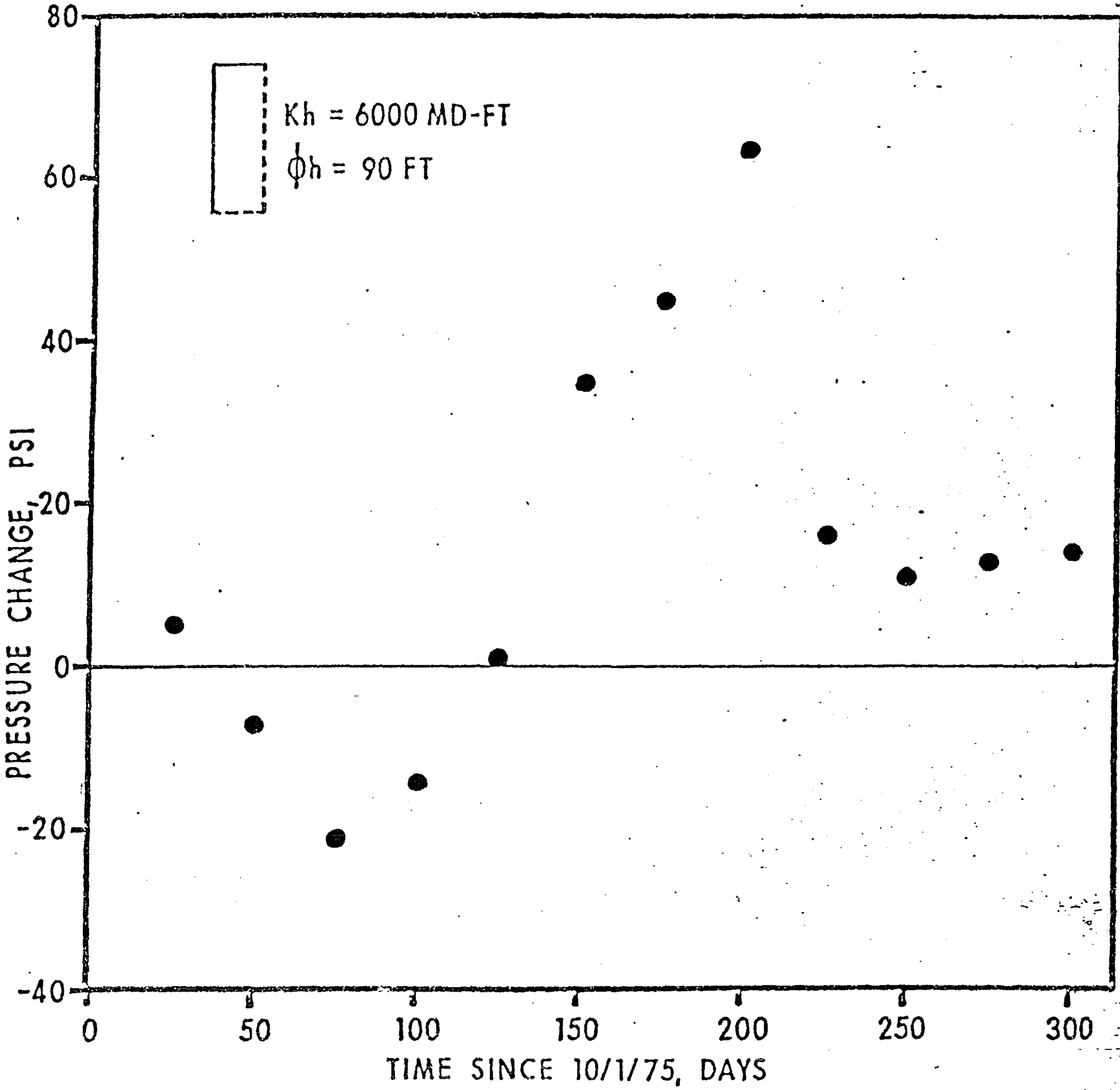
PRESSURE PROFILE WITH SOUTH BOUNDARY AT CONSTANT PRESSURE

FIGURE 35

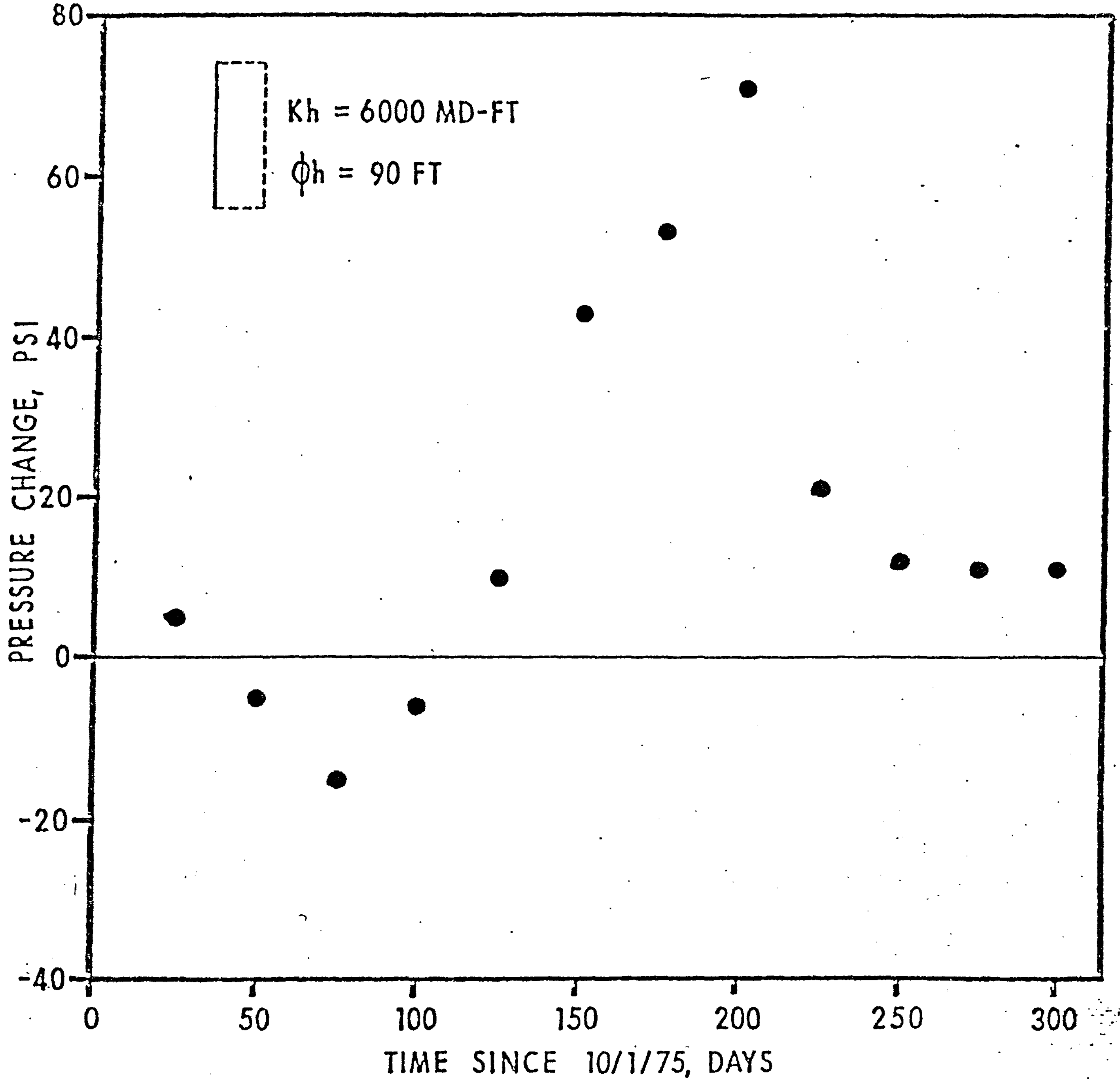


PRESSURE PROFILE WITH EAST BOUNDARY
AT CONSTANT PRESSURE

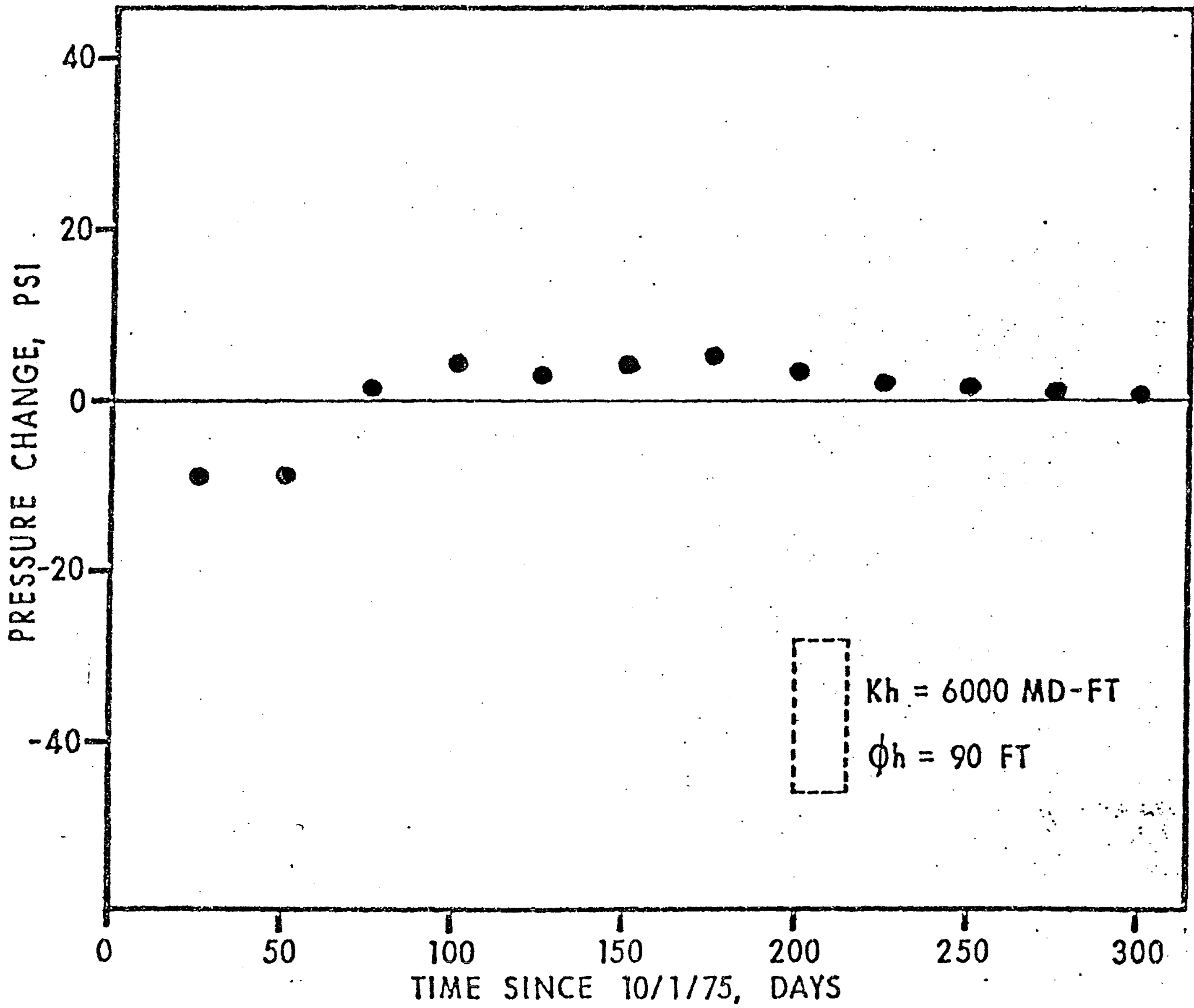
FIGURE 36



PRESSURE PROFILE WITH SOUTH AND EAST BOUNDARIES
AT CONSTANT PRESSURE

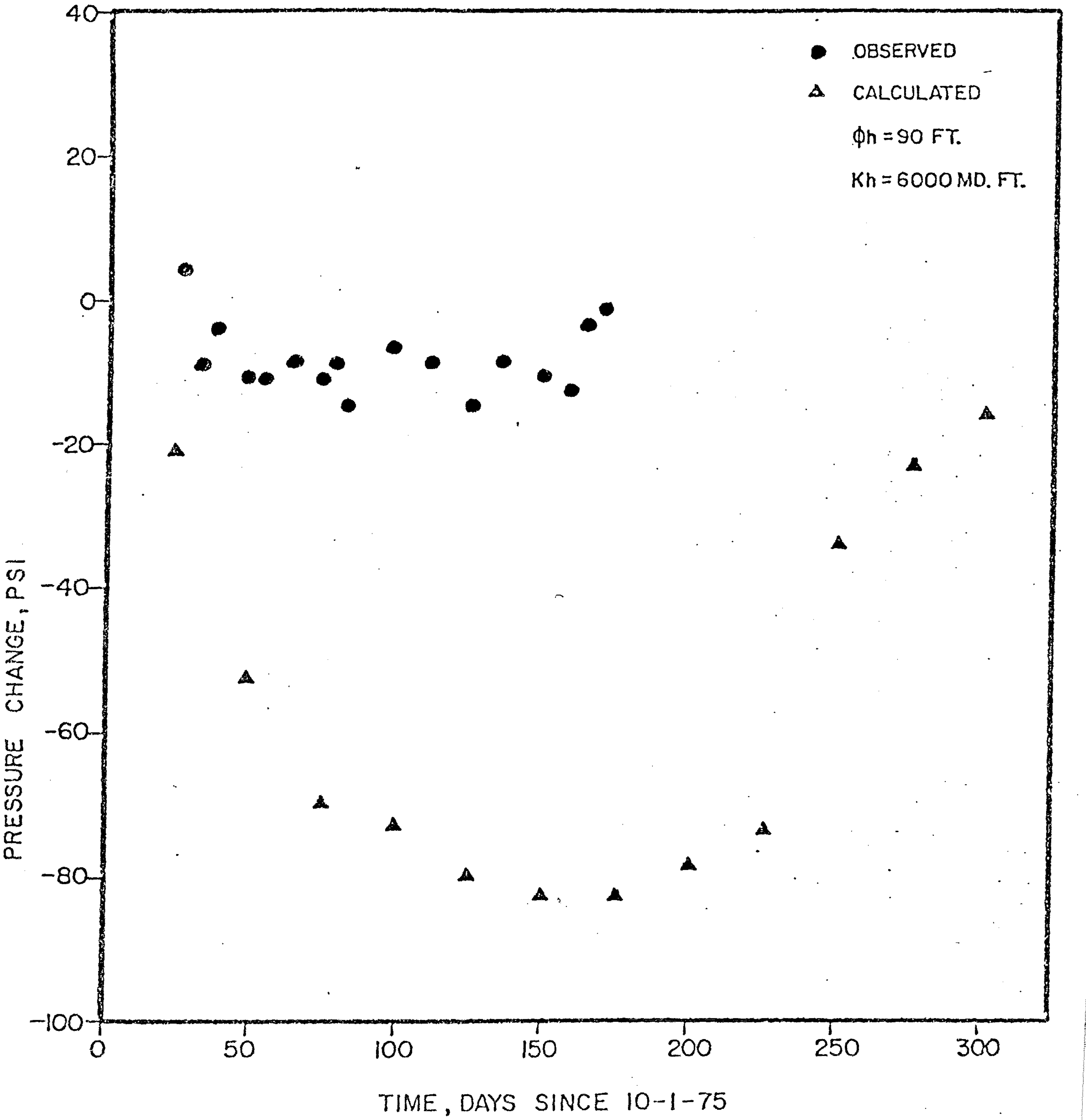


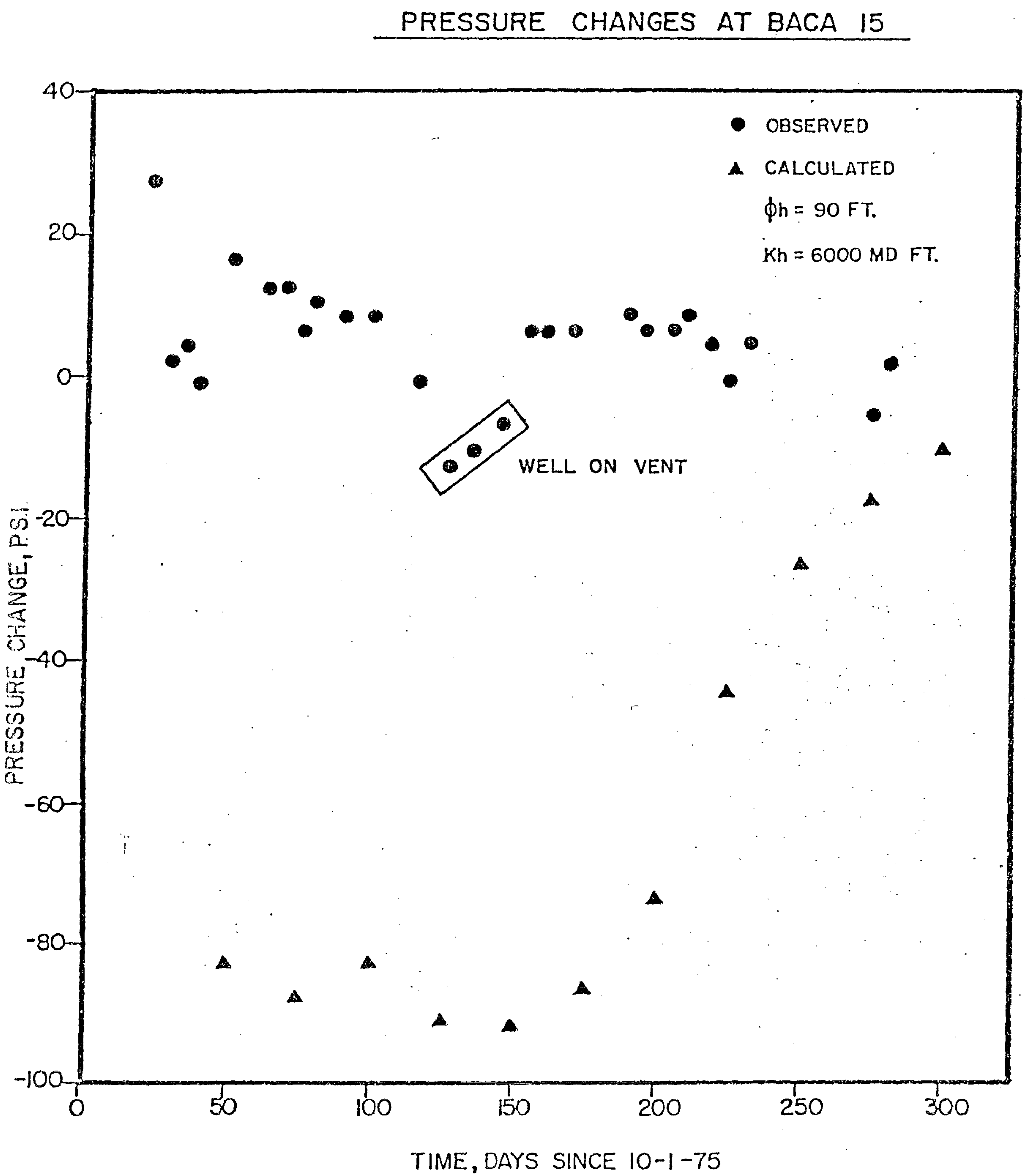
PRESSURE PROFILE WITH NORTH, EAST AND SOUTH BOUNDARIES AT CONSTANT PRESSURE

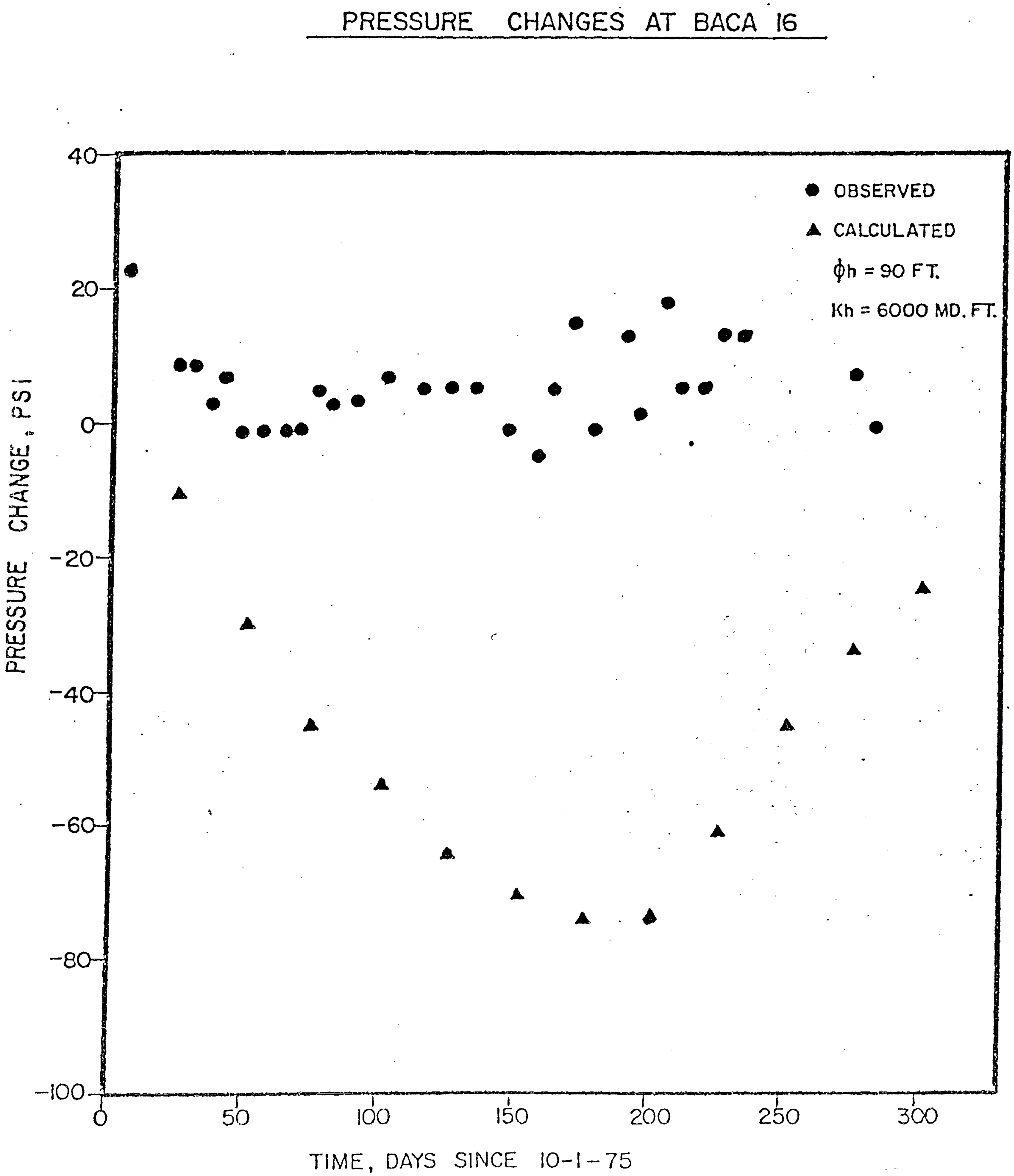


PRESSURE PROFILE WITH ALL BOUNDARIES
AT CONSTANT PRESSURE

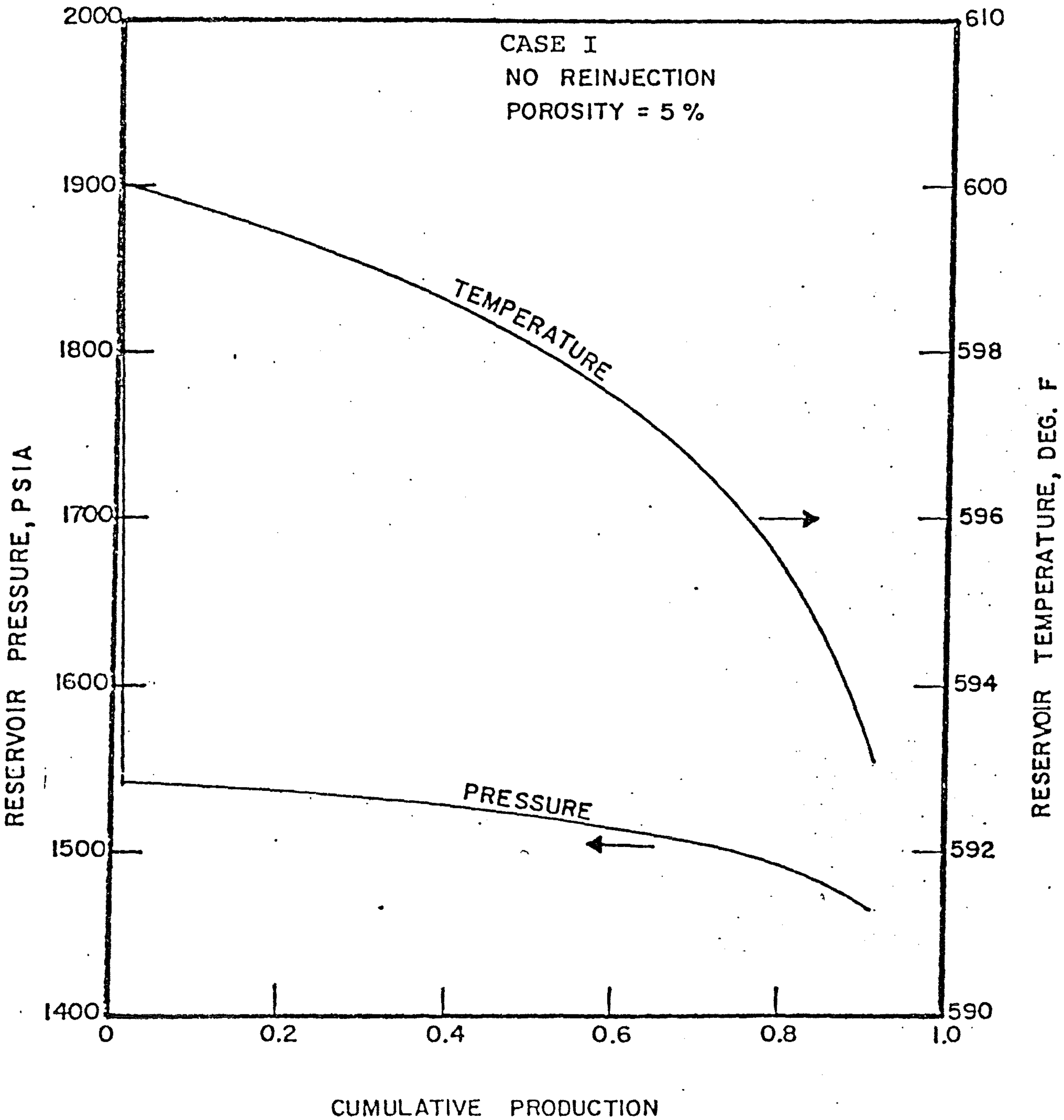
PRESSURE CHANGES AT BACA 4




PRESSURE CHANGES AT BACA 15
OBSERVED
CALCULATED
ϕh = 90 FT.
Kh = 6000 MD FT.
WELL ON VENT
PRESSURE CHANGE, PSI
40
20
0
-20
-40
-60
-80
-100
0
50
100
150
200
250
300
TIME, DAYS SINCE 10-1-75


PRESSURE CHANGES AT BACA 16
OBSERVED
CALCULATED
ϕh = 90 FT.
Kh = 6000 MD. FT.
PRESSURE CHANGE, PSI
40
20
0
-20
-40
-60
-80
-100
0
50
100
150
200
250
300
TIME, DAYS SINCE 10-1-75

GEOTHERMAL RESERVOIR PERFORMANCE



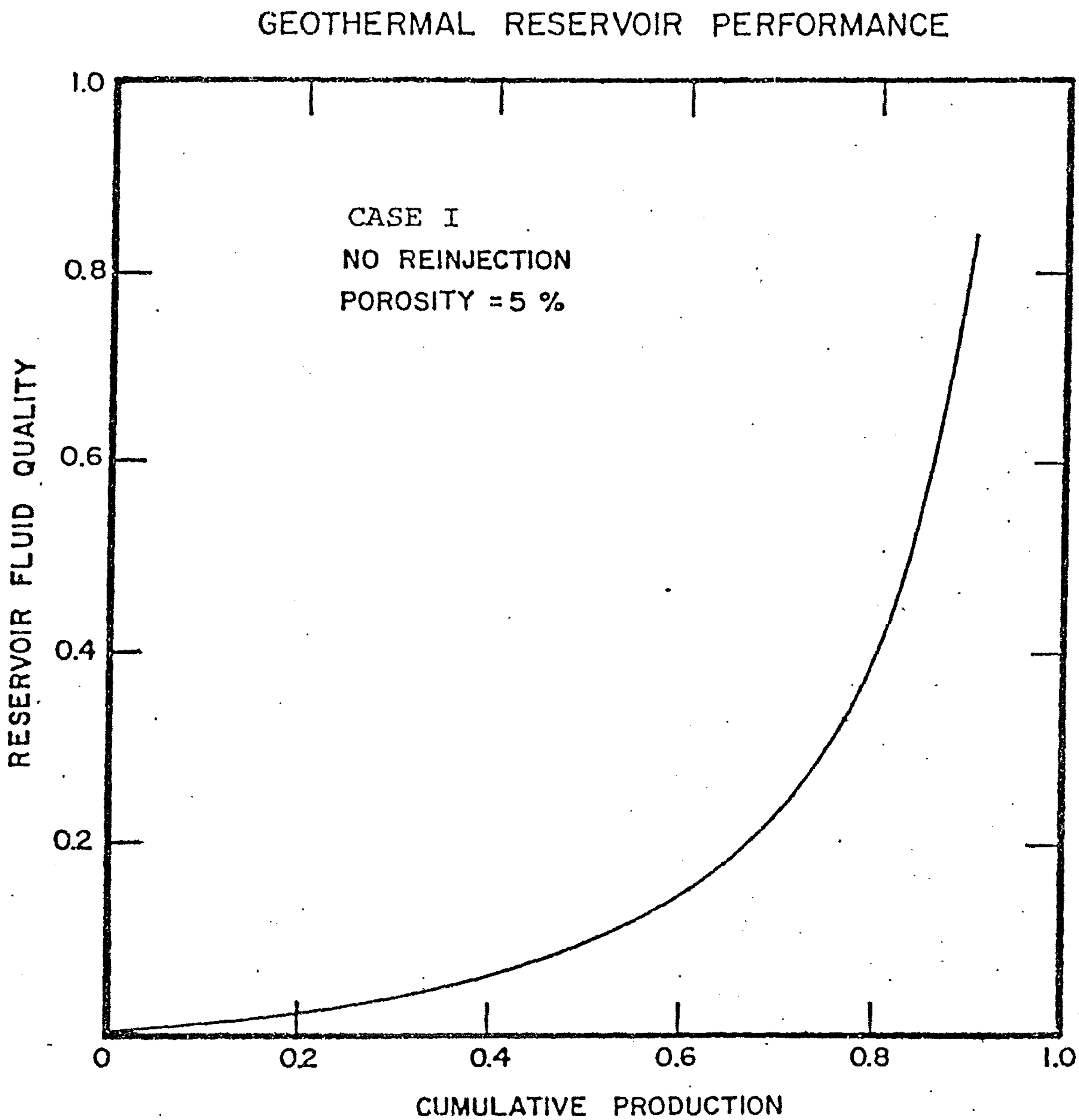
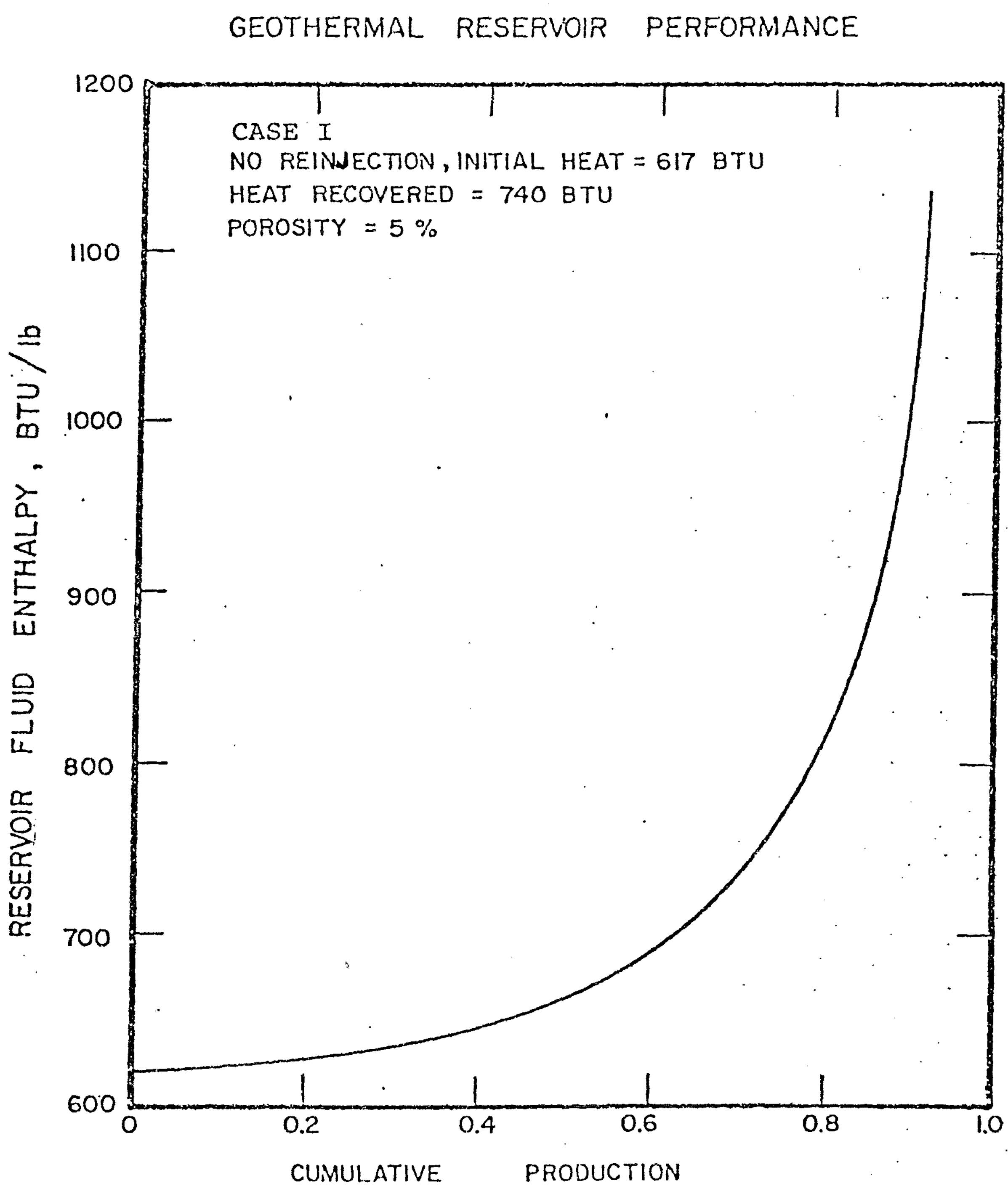
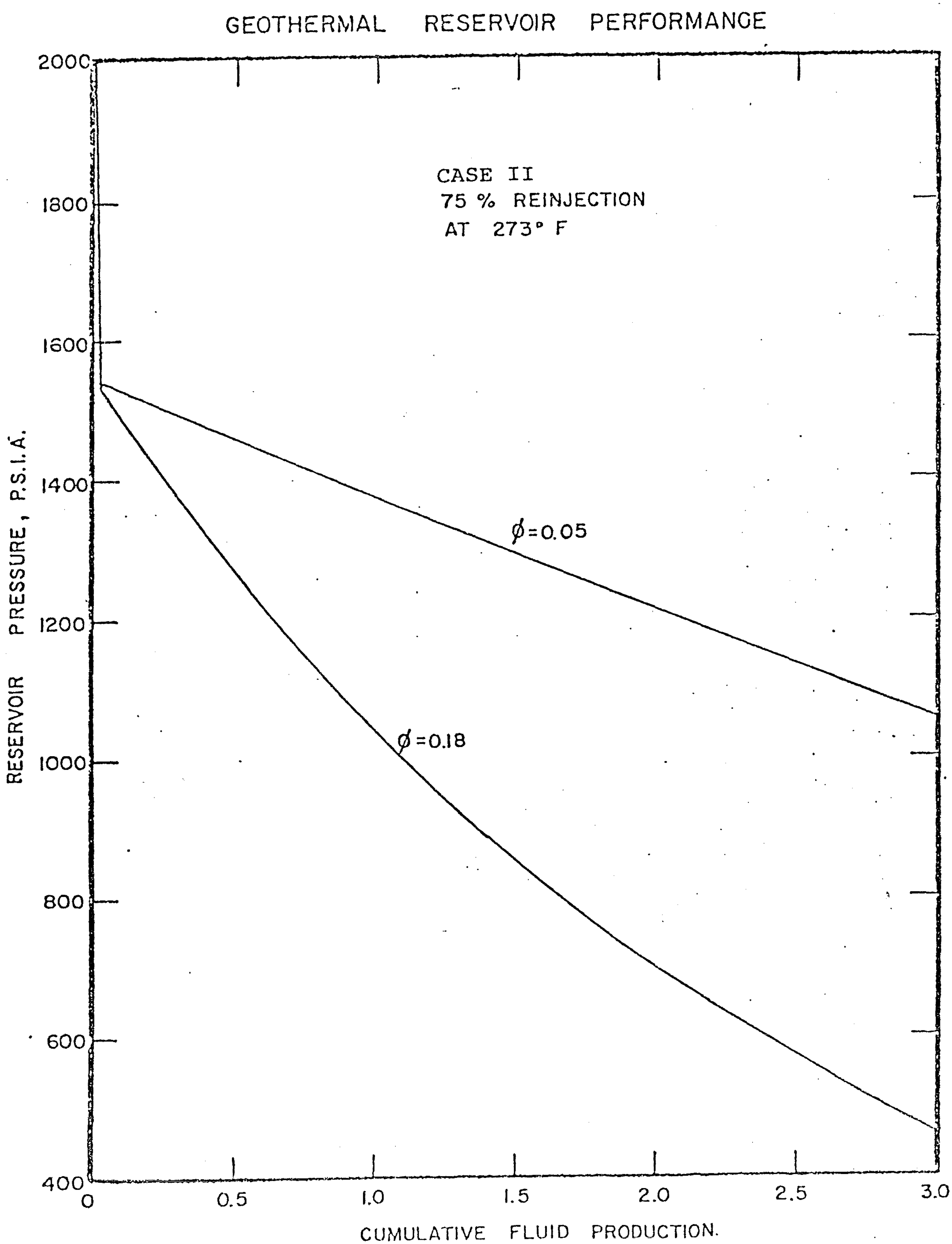

GEOTHERMAL RESERVOIR PERFORMANCE
CASE I
NO REINJECTION
POROSITY = 5 %
RESERVOIR FLUID QUALITY
CUMULATIVE PRODUCTION
0
0.2
0.4
0.6
0.8
1.0

FIGURE 44


GEOTHERMAL RESERVOIR PERFORMANCE
CASE I
NO REINJECTION, INITIAL HEAT = 617 BTU
HEAT RECOVERED = 740 BTU
POROSITY = 5 %
RESERVOIR FLUID ENTHALPY, BTU/lb
1200
1100
1000
900
800
700
600
0
0.2
0.4
0.6
0.8
1.0
CUMULATIVE PRODUCTION


GEOTHERMAL RESERVOIR PERFORMANCE
CASE II
75 % REINJECTION
AT 273° F
ϕ=0.05
ϕ=0.18
RESERVOIR PRESSURE, P.S.I.A.
2000
1800
1600
1400
1200
1000
800
600
400
0
0.5
1.0
1.5
2.0
2.5
3.0
CUMULATIVE FLUID PRODUCTION.

GEOTHERMAL RESERVOIR PERFORMANCE

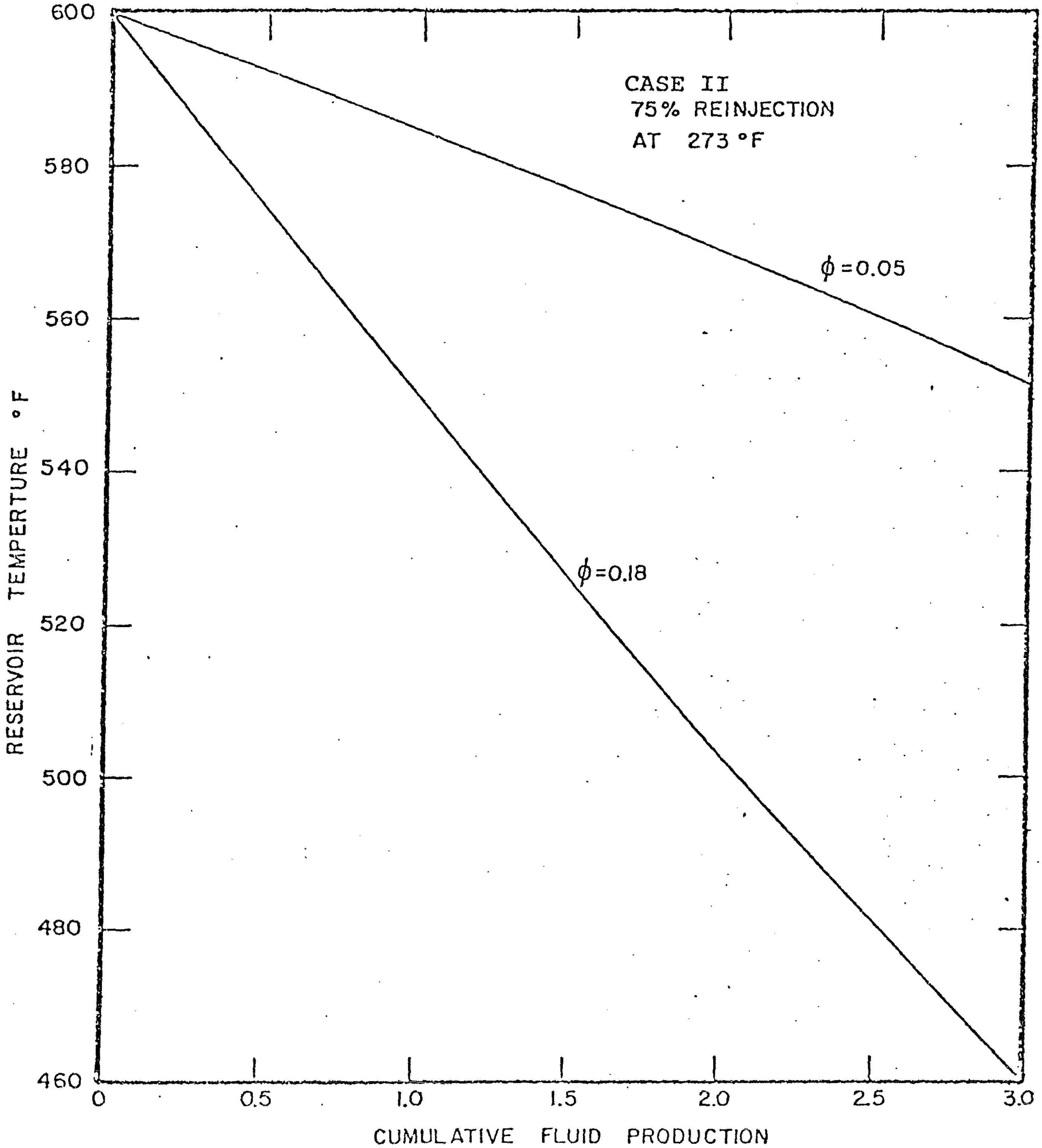
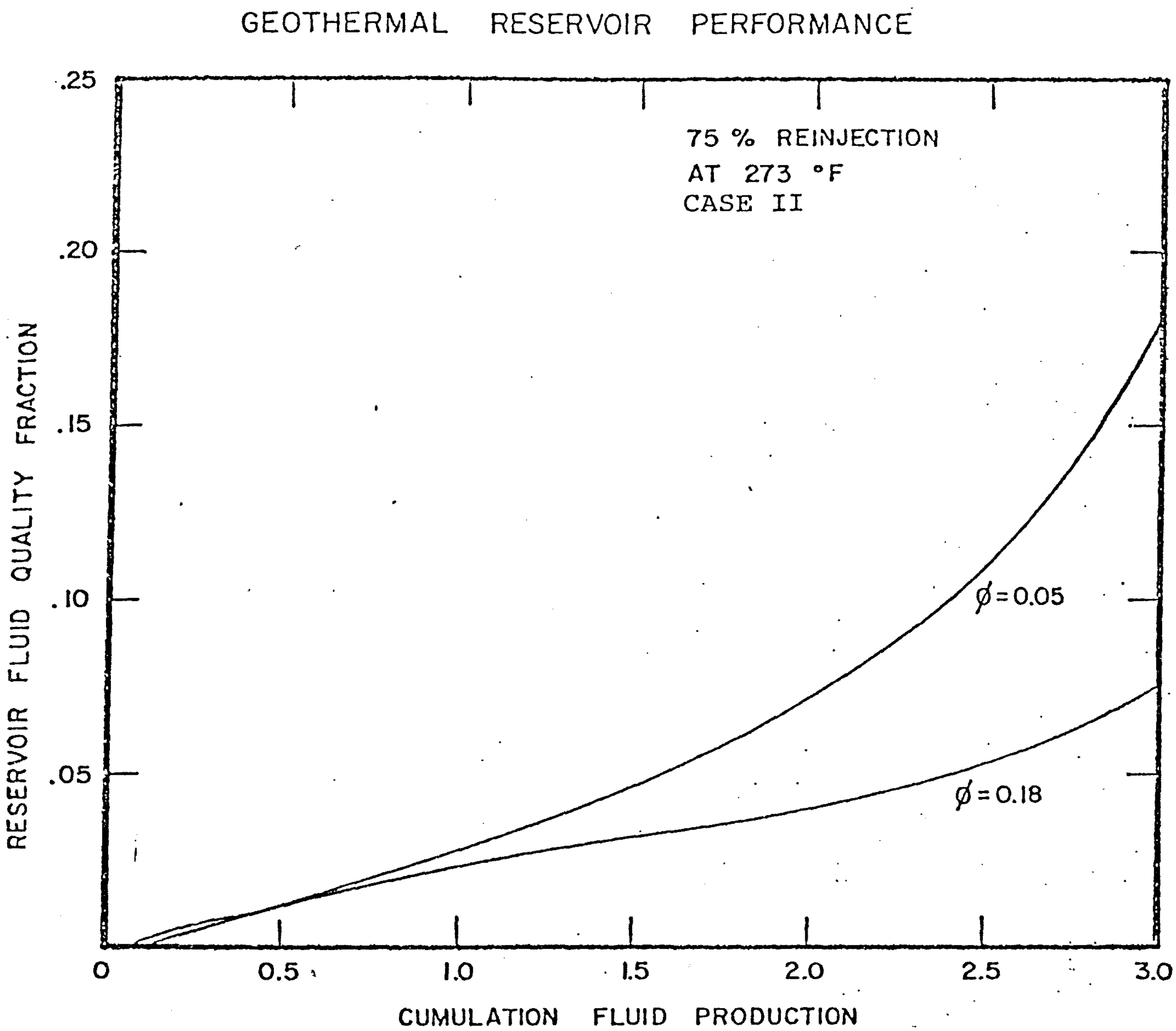
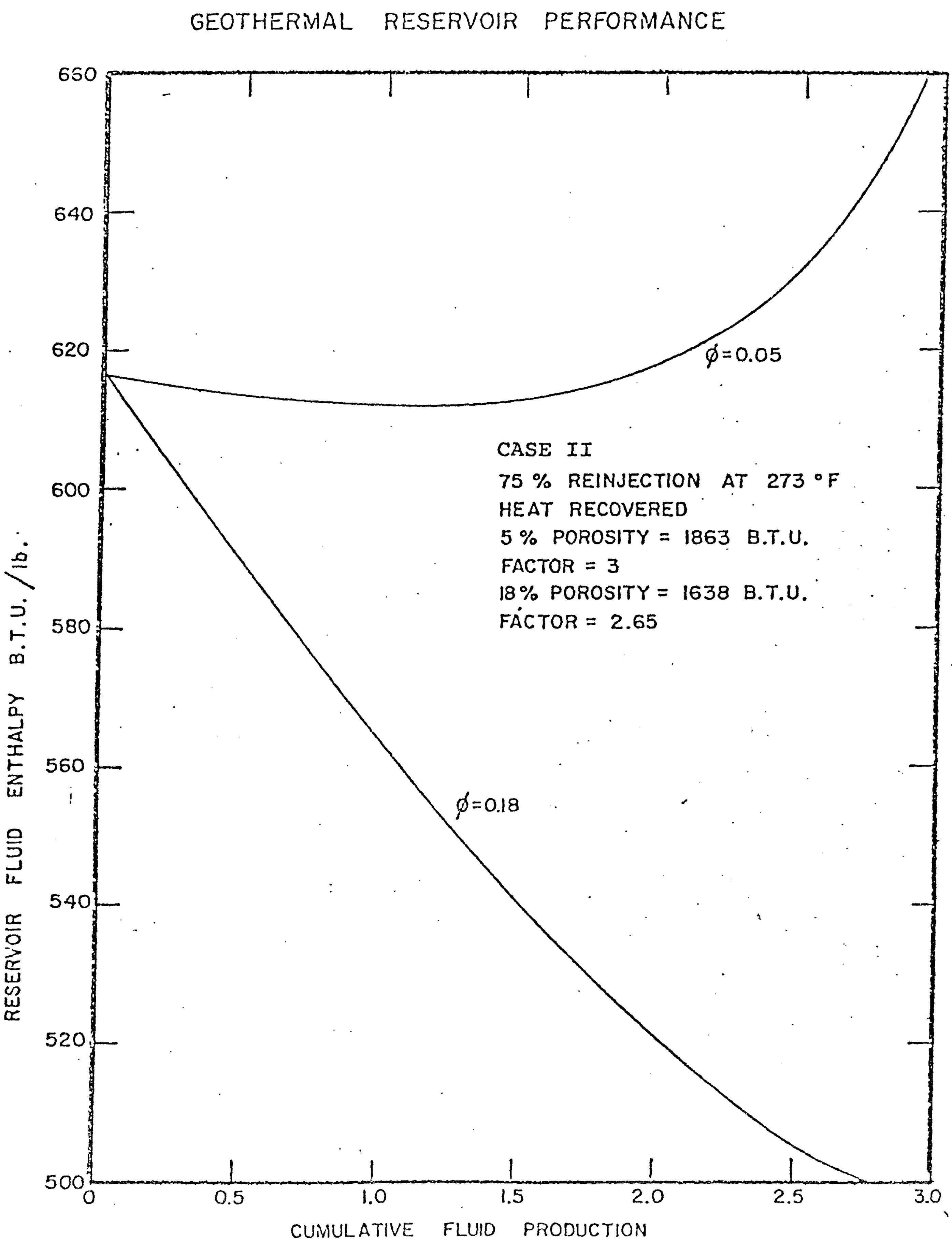
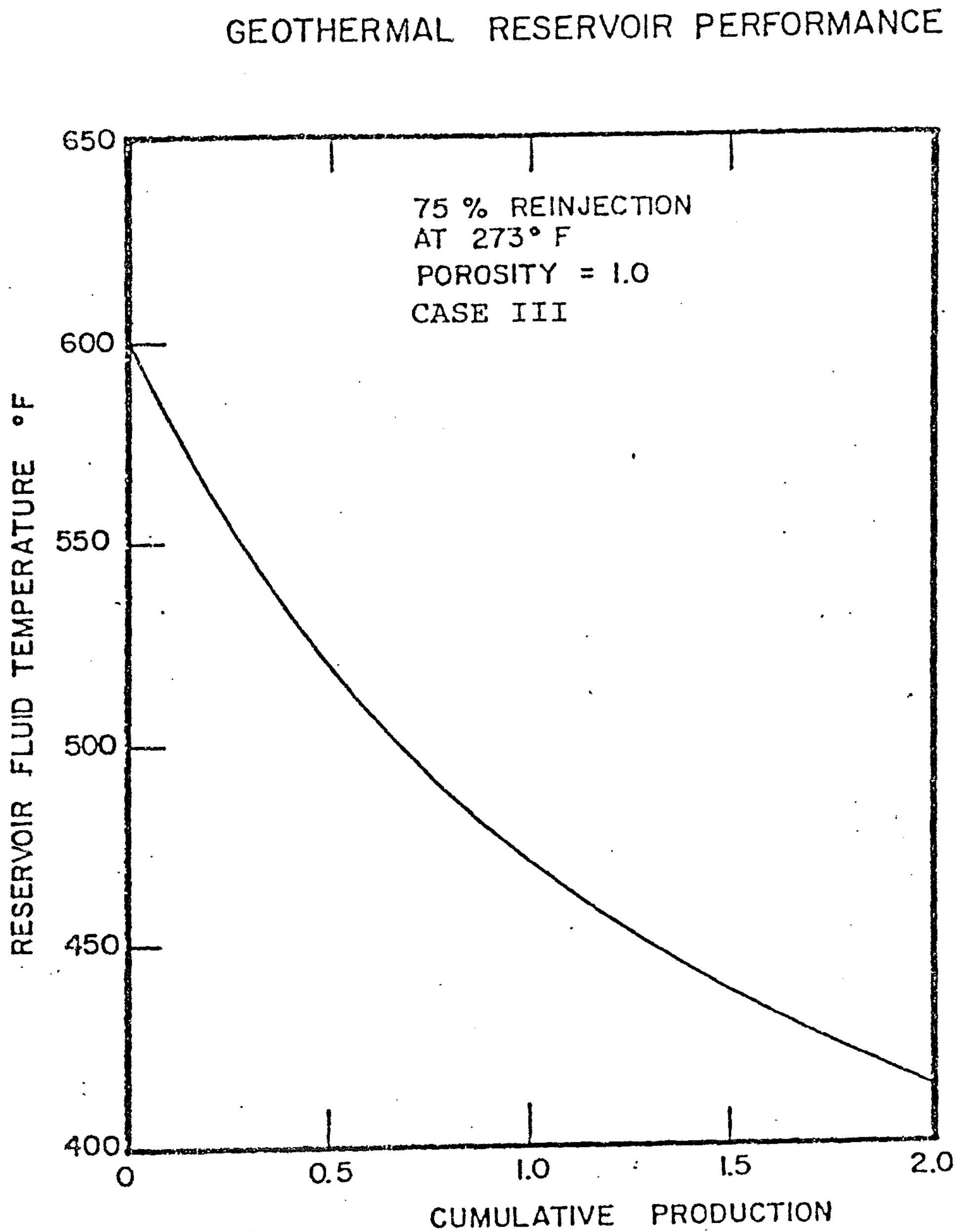


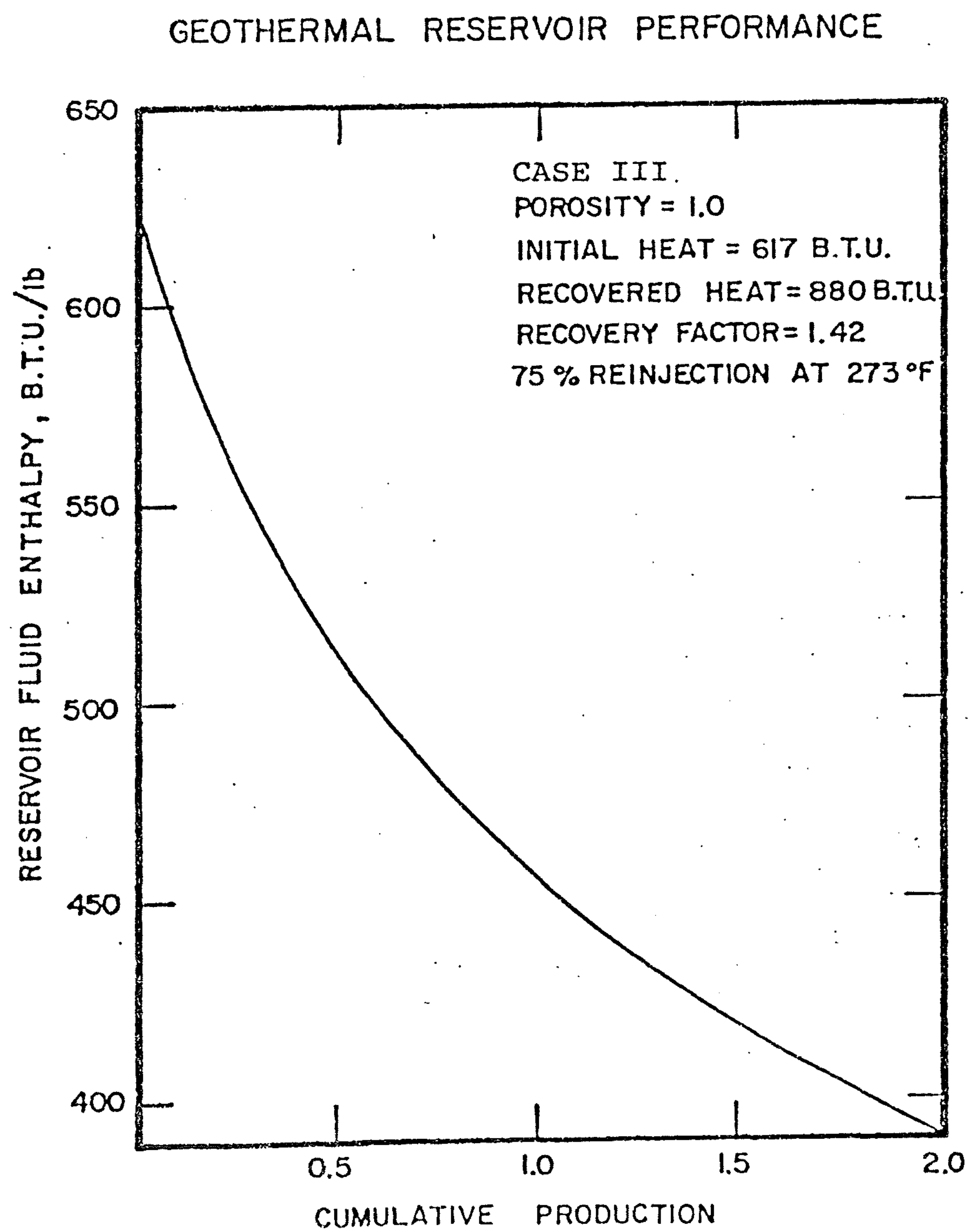
FIGURE 47

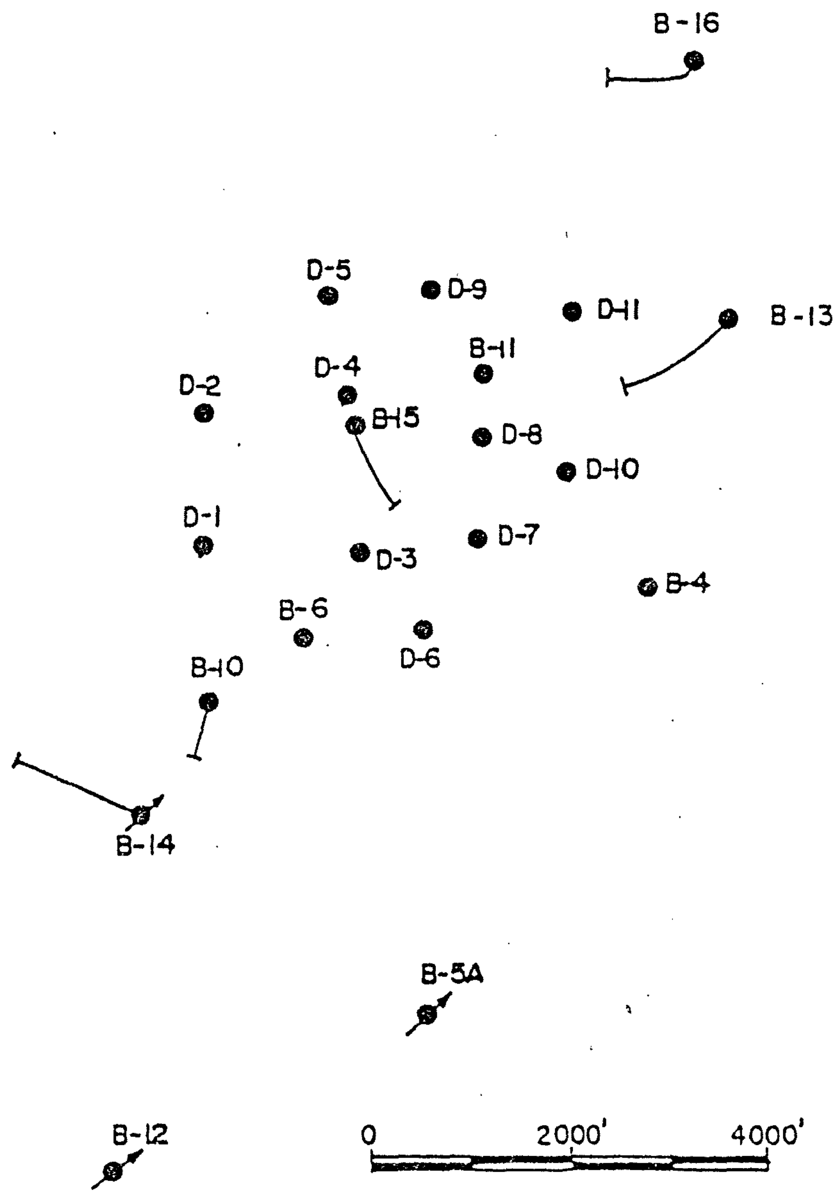


GEOTHERMAL RESERVOIR PERFORMANCE
75 % REINJECTION
AT 273 °F
CASE II
RESERVOIR FLUID QUALITY FRACTION
.25
.20
.15
.10
.05
0
0.5
1.0
1.5
2.0
2.5
3.0
CUMULATION FLUID PRODUCTION
Ø = 0.05
Ø = 0.18


GEOTHERMAL RESERVOIR PERFORMANCE
650
640
620
600
580
560
540
520
500
0
0.5
1.0
1.5
2.0
2.5
3.0
RESERVOIR FLUID ENTHALPY B.T.U. /lb.
CUMULATIVE FLUID PRODUCTION
ø=0.05
ø=0.18
CASE II
75 % REINJECTION AT 273 °F
HEAT RECOVERED
5 % POROSITY = 1863 B.T.U.
FACTOR = 3
18 % POROSITY = 1638 B.T.U.
FACTOR = 2.65


GEOTHERMAL RESERVOIR PERFORMANCE
75 % REINJECTION
AT 273° F
POROSITY = 1.0
CASE III
RESERVOIR FLUID TEMPERATURE °F
650
600
550
500
450
400
0
0.5
1.0
1.5
2.0
CUMULATIVE PRODUCTION

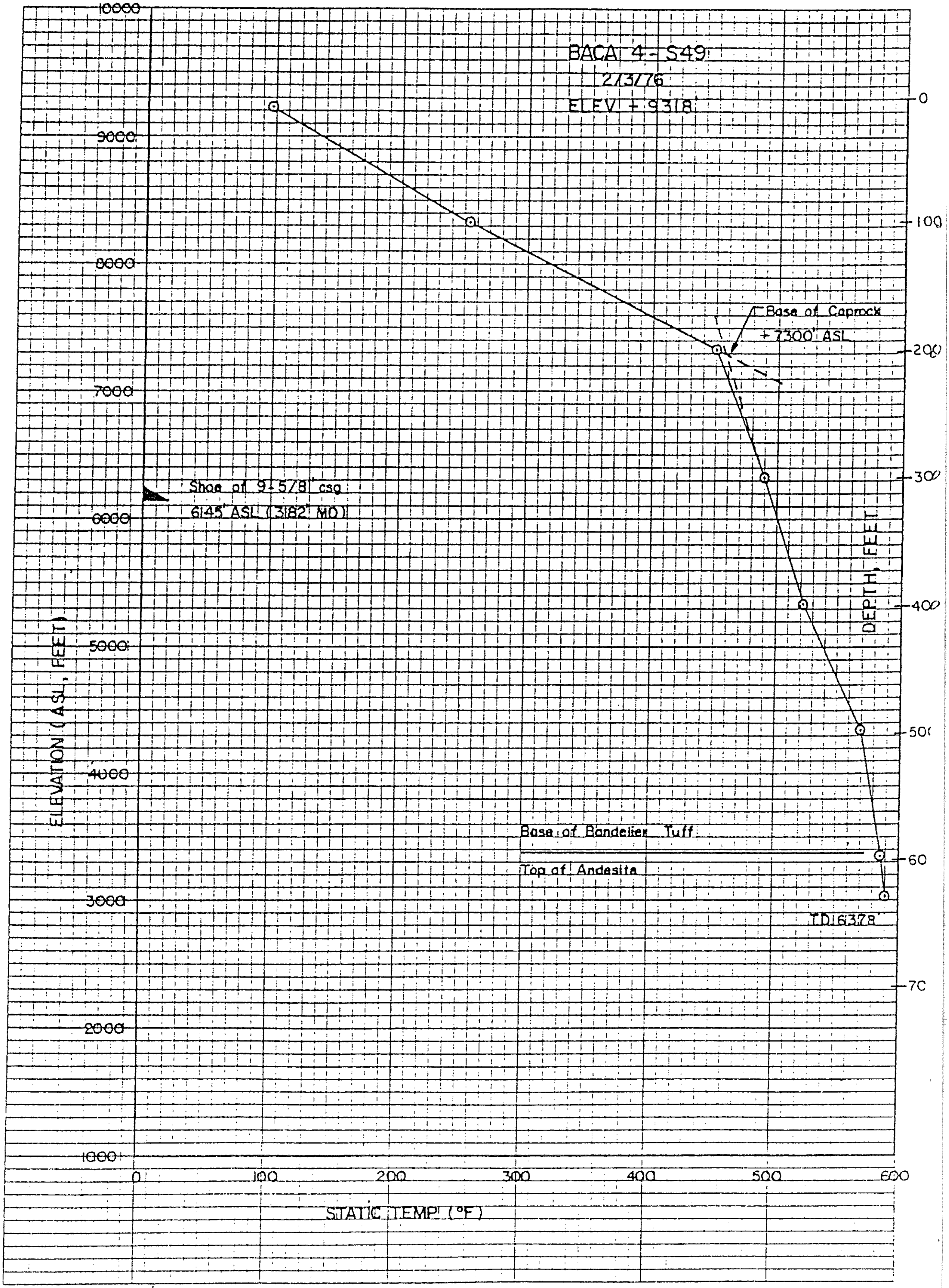

GEOTHERMAL RESERVOIR PERFORMANCE
CASE III.
POROSITY = 1.0
INITIAL HEAT = 617 B.T.U.
RECOVERED HEAT = 880 B.T.U.
RECOVERY FACTOR = 1.42
75 % REINJECTION AT 273 °F
RESERVOIR FLUID ENTHALPY, B.T.U./lb
650
600
550
500
450
400
0.5
1.0
1.5
2.0
CUMULATIVE PRODUCTION

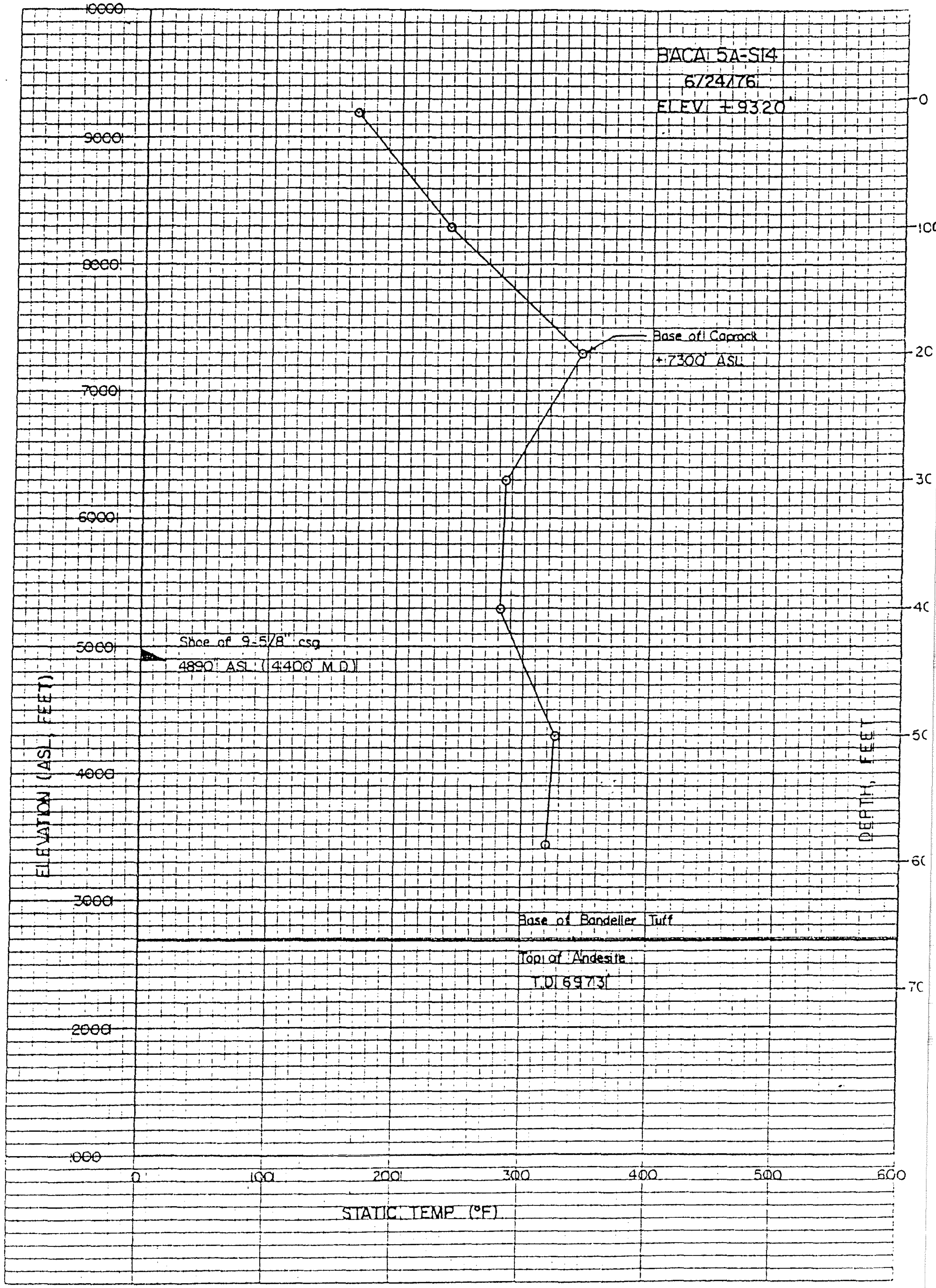


PRODUCTION-INJECTION PATTERN
PROPOSED DEVELOPMENT SCHEME
REDONDO CREEK AREA, BACA, NEW MEXICO

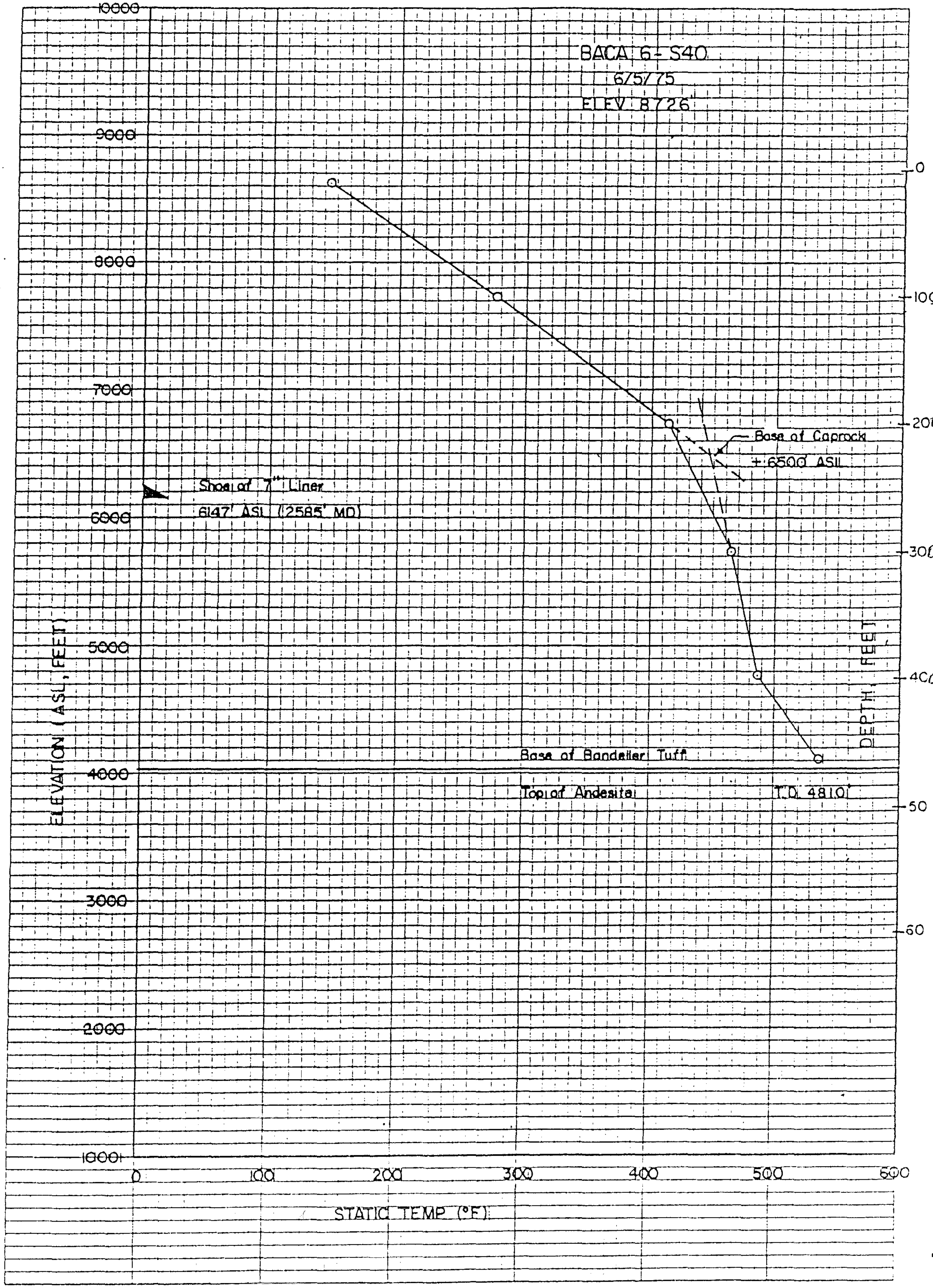
APPENDIX A

STATIC TEMPERATURE PROFILES
OF THE REDONDO CREEK AREA WELLS

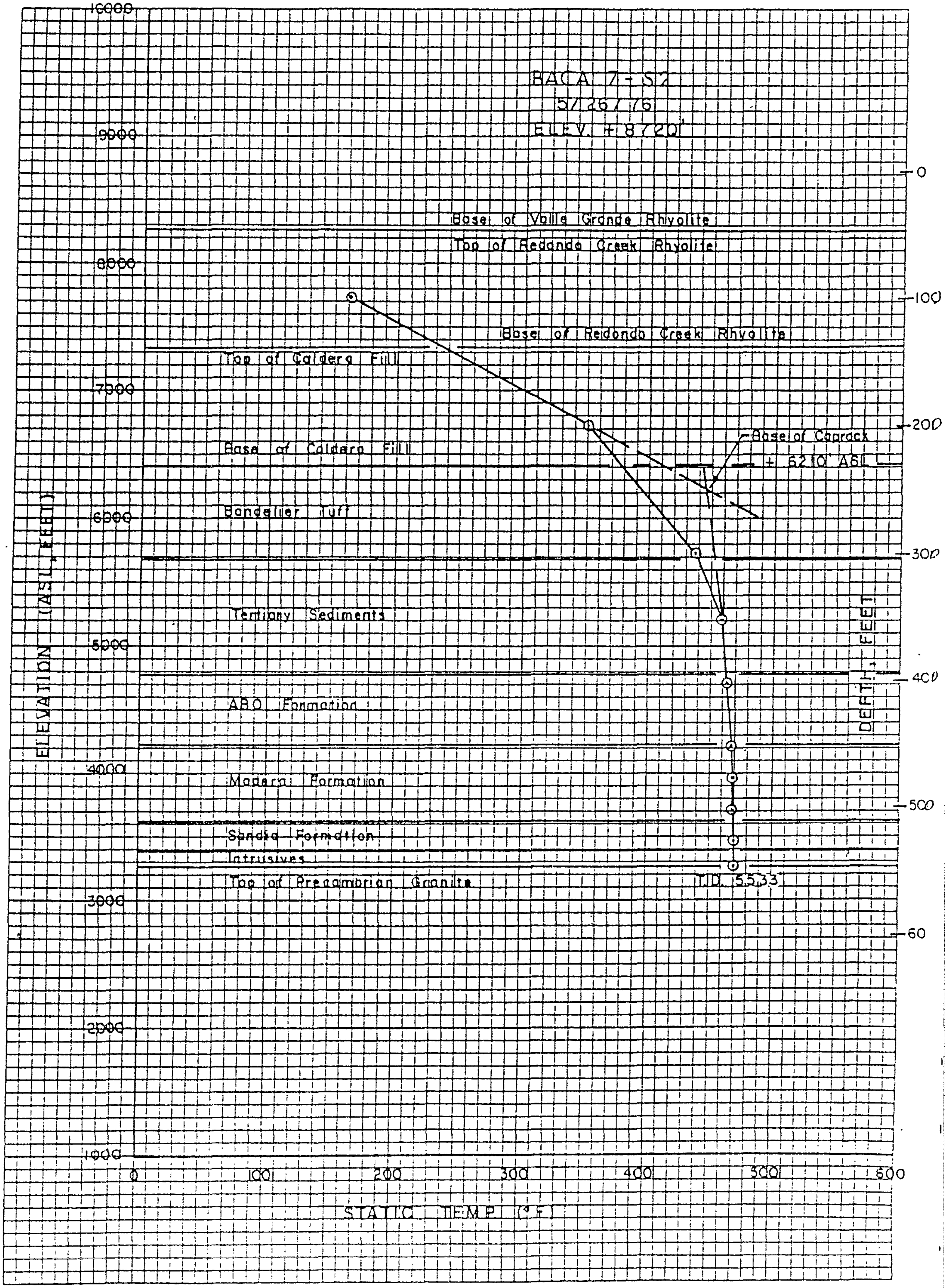

BACA 4 - S49
2/3/76
ELEV + 9318
Base of Caprock
+ 7300' ASL
Shoe of 9-5/8" csg
6145' ASL (3182' MD)
Base of Bandelier Tuff
Top of Andesite
TD 6378
ELEVATION (ASL, FEET)
DEPTH, FEET
STATIC TEMP (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
200
300
400
500
600

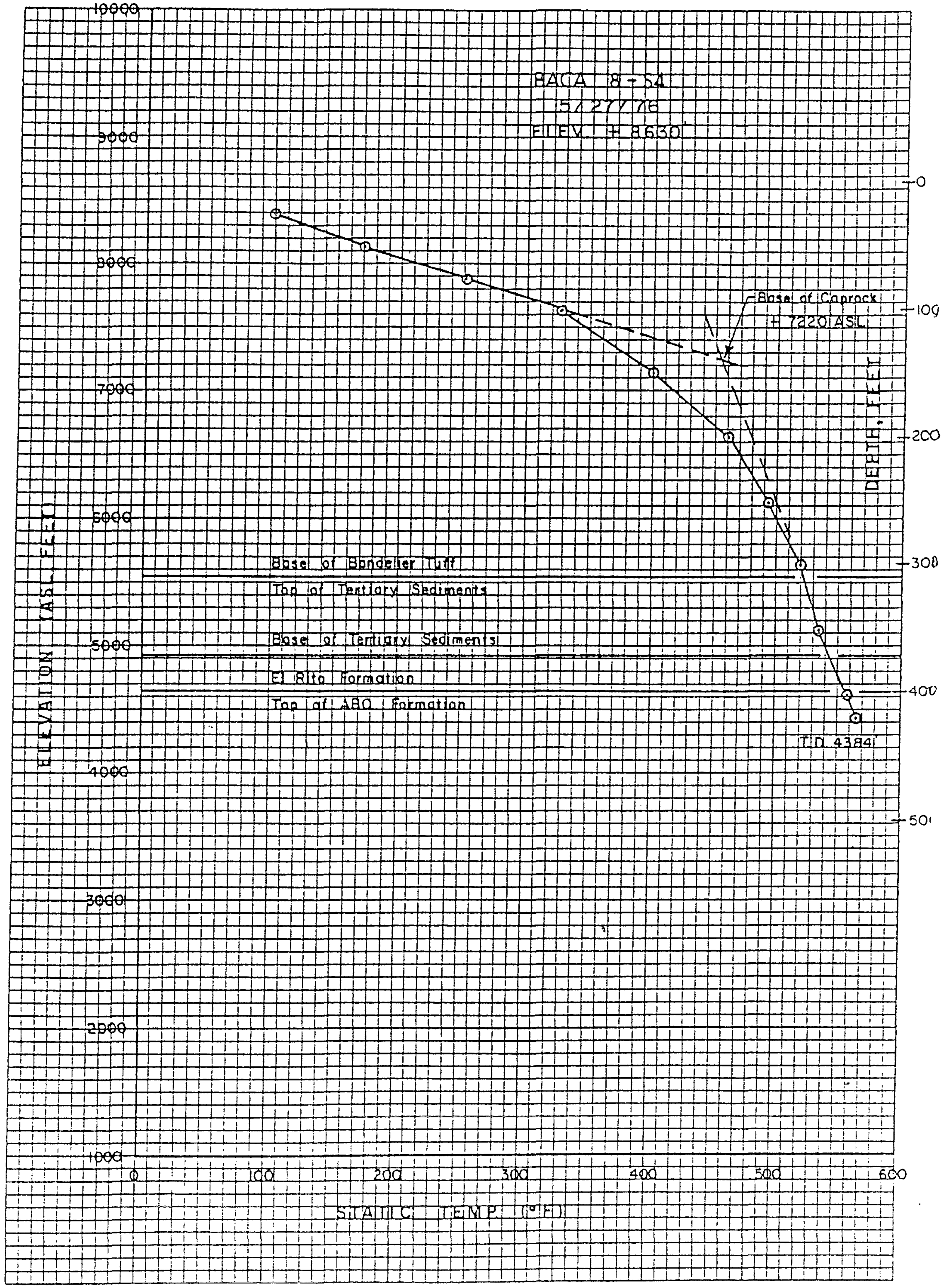


BACA 5A-ST4
6/24/76
ELEV +9320'
Base of Caprock
+7300' ASL
Shoe of 9-5/8" csg
4890' ASL (4400' M.D.)
Base of Bandelier Tuff
Top of Andesite
T.D. 6973'
ELEVATION (ASL, FEET)
DEPTH, FEET
STATIC TEMP (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
200
300
400
500
600

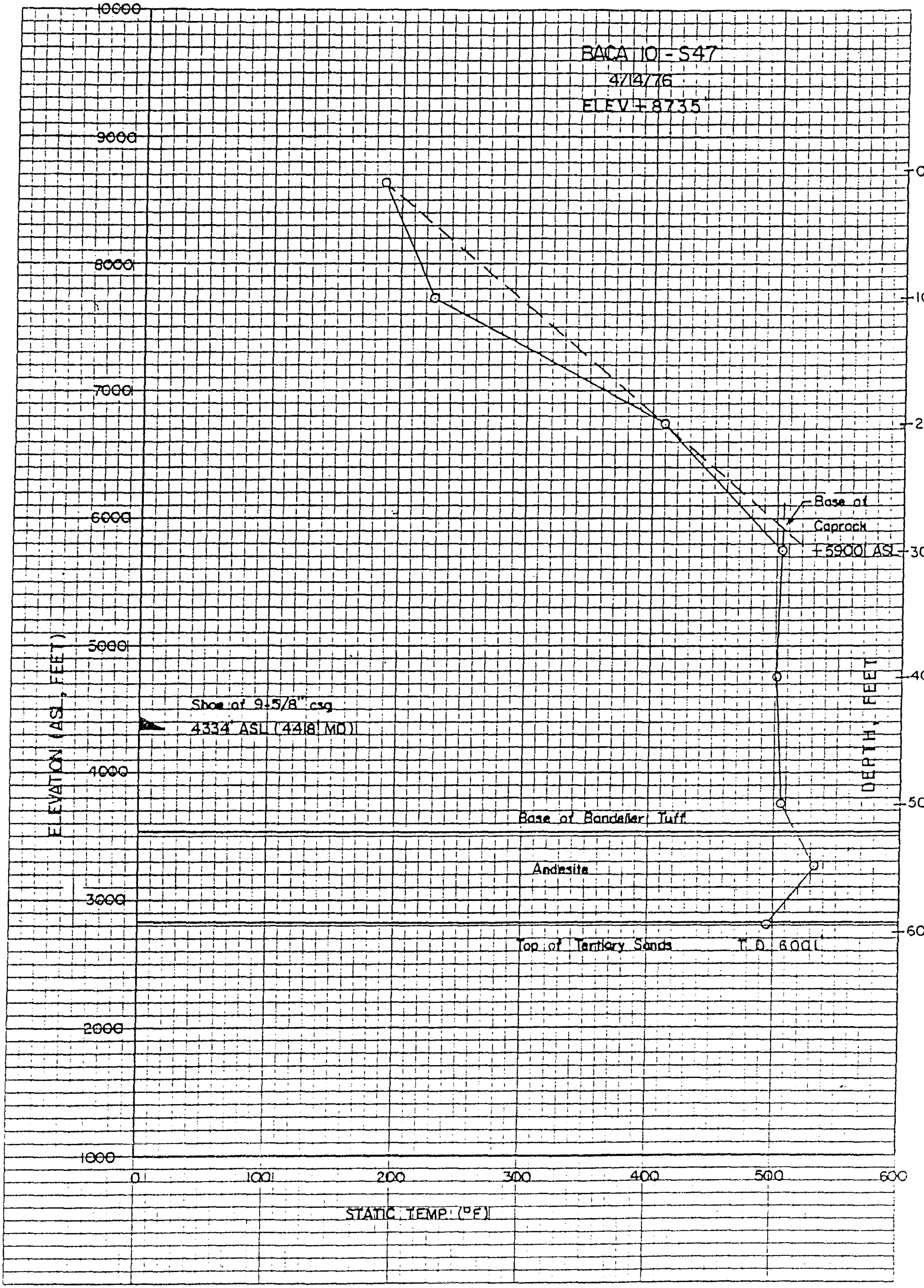


BACA 6-S40
6/5/75
ELEV 8726
Base of Caprock
+6500 ASL
Shoe of 7" Liner
6147' ASL (2585' MD)
Base of Bandelier Tuff
Top of Andesite
T.D. 4810'
ELEVATION (ASL, FEET)
DEPTH FEET
STATIC TEMP (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
200
300
400
500
600

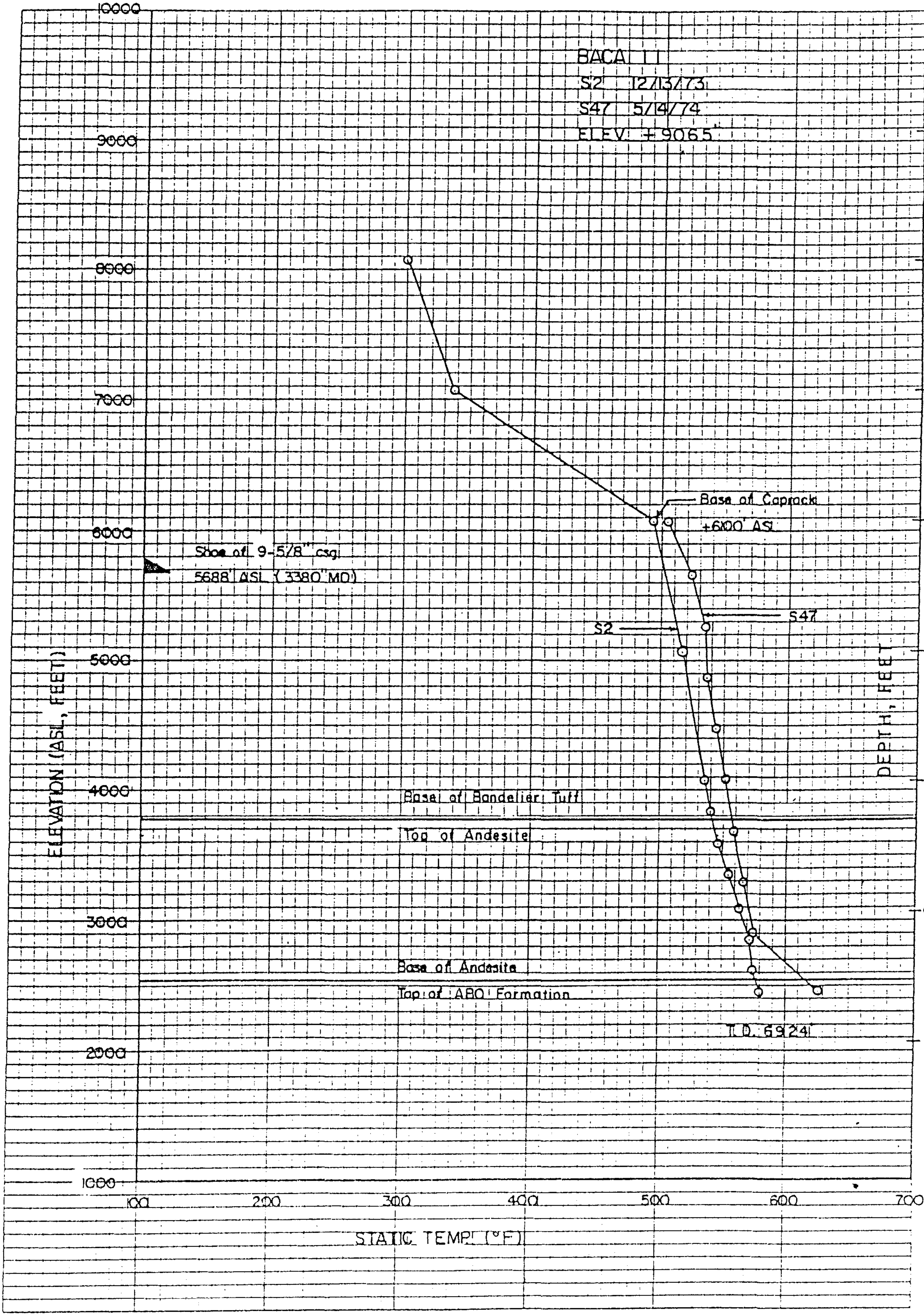

BACA 7-S2
5/26/76
ELEV. + 8720'
Base of Valle Grande Rhyolite
Top of Redondo Creek Rhyolite
Base of Redondo Creek Rhyolite
Top of Caldera Fill
Base of Caldera Fill
Base of Caprock
+ 6210' ASL
Bandelier Tuff
Tertiary Sediments
ABO Formation
Madera Formation
Sandia Formation
Intrusives
Top of Precambrian Granite
T.D. 5533'
ELEVATION (ASL, FEET)
DEPTH, FEET
STATIC TEMP (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
200
300
400
500
600

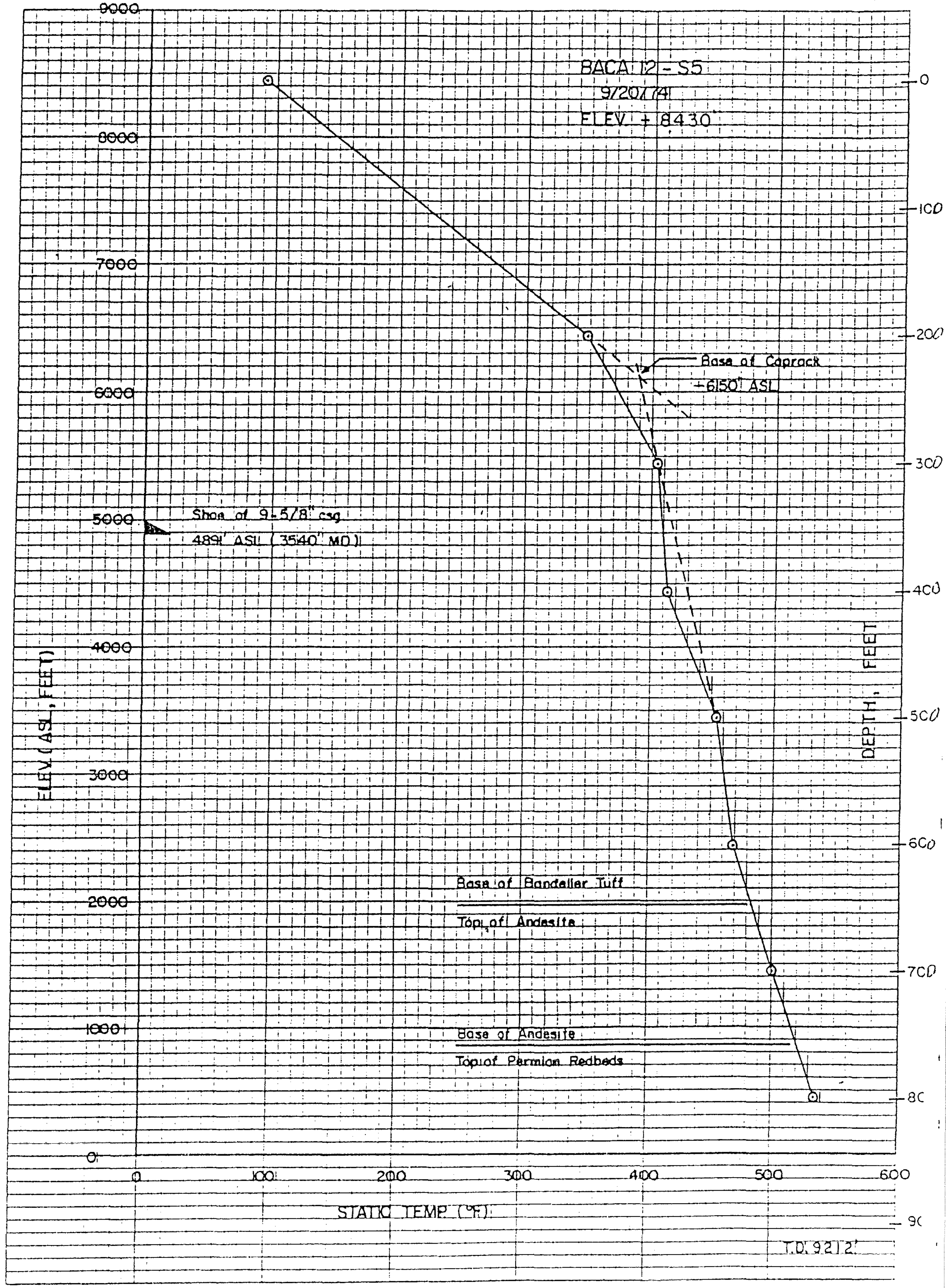


BACA 8-54
5/27/76
ELEV. + 8630'
Base of Caprock
+ 7220 ASL
Base of Bandelier Tuff
Top of Tertiary Sediments
Base of Tertiary Sediments
El Rito Formation
Top of ABO Formation
T.D. 4384'
ELEVATION (ASL FEET)
DEPTH, FEET
STATIC TEMP (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
200
300
400
500
600

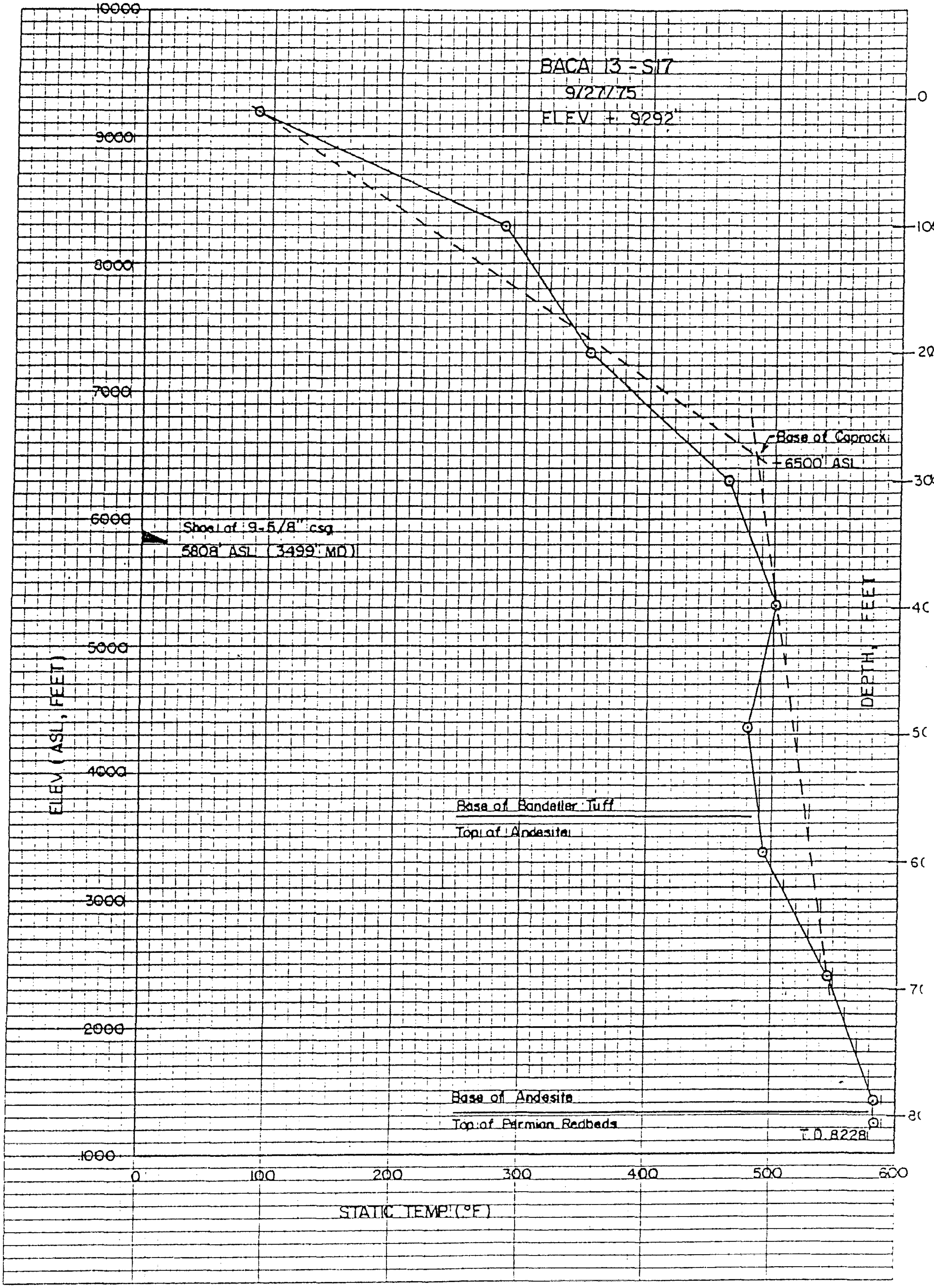


BACA 10 - S47
4/14/76
ELEV + 8735'
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
ELEVATION (ASL, FEET)
0
1000
2000
3000
4000
5000
6000
DEPTH, FEET
0
100
200
300
400
500
600
STATIC TEMP (°F)
Base of Caprock
+5900' ASL
Shoe of 9-5/8" csg
4334' ASL (4418' MD)
Base of Bandelier Tuff
Andesite
Top of Tertiary Sands
T.D. 6001'

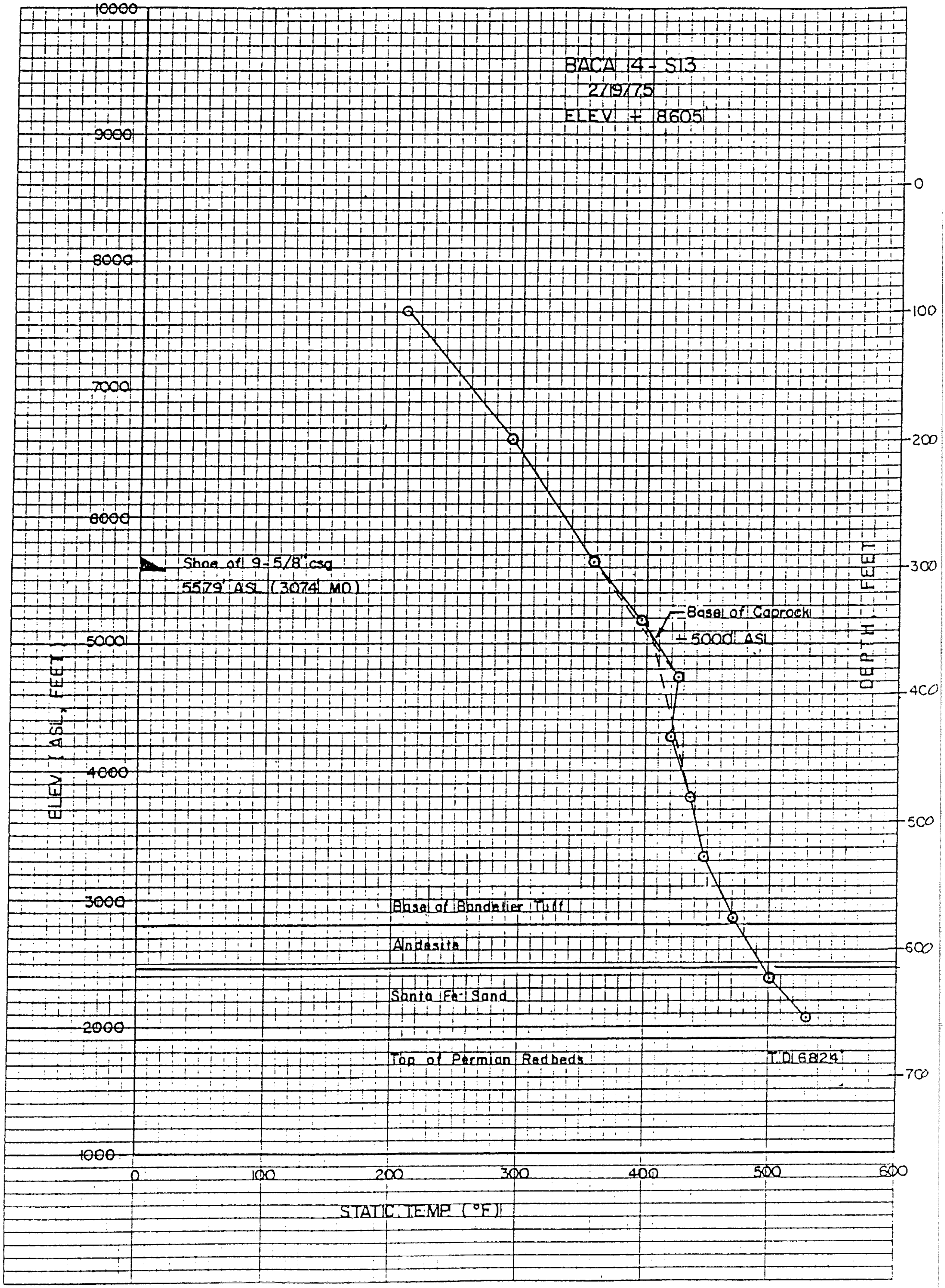

BACA 11
S2 12/13/73
S47 5/14/74
ELEV +9065
Base of Caprock
+6100 ASL
Shoe of 9-5/8" csg
5688 ASL (3380 MD)
S47
S2
Base of Bandelier Tuff
Top of Andesite
Base of Andesite
Top of ABO Formation
T.D. 6924
ELEVATION (ASL, FEET)
DEPTH, FEET
STATIC TEMP (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
100
200
300
400
500
600
700
0
1000
2000
3000
4000
5000
6000
7000



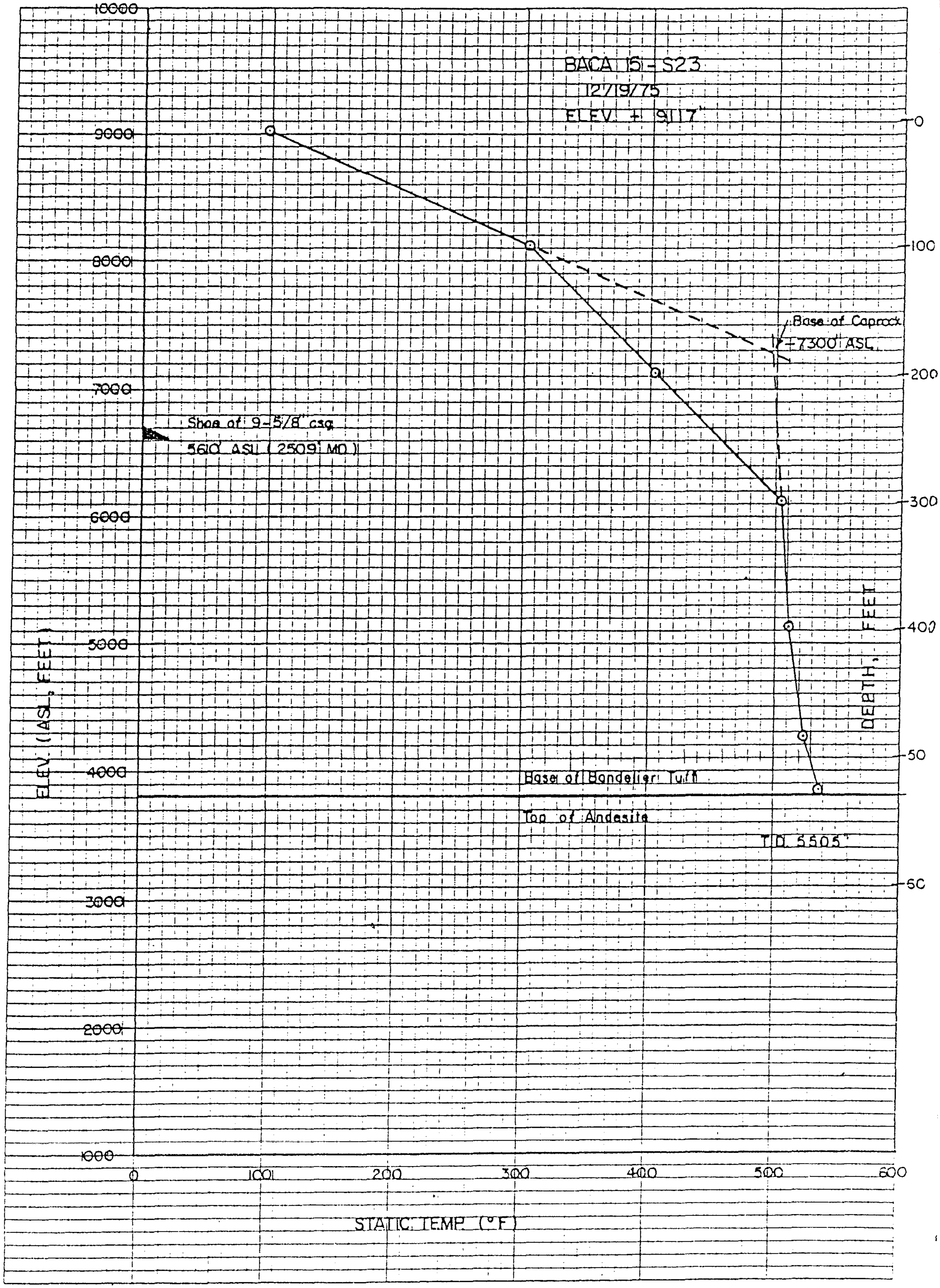
BACA 12 - S5
9/20/74
ELEV. + 8430'
Base of Caprock
+6150' ASL
Shoe of 9-5/8" csg
4891' ASL (3540' MD)
Base of Bandelier Tuff
Top of Andesite
Base of Andesite
Top of Permian Redbeds
ELEV. (ASL, FEET)
DEPTH, FEET
STATIC TEMP. (°F)
T.D. 9212'

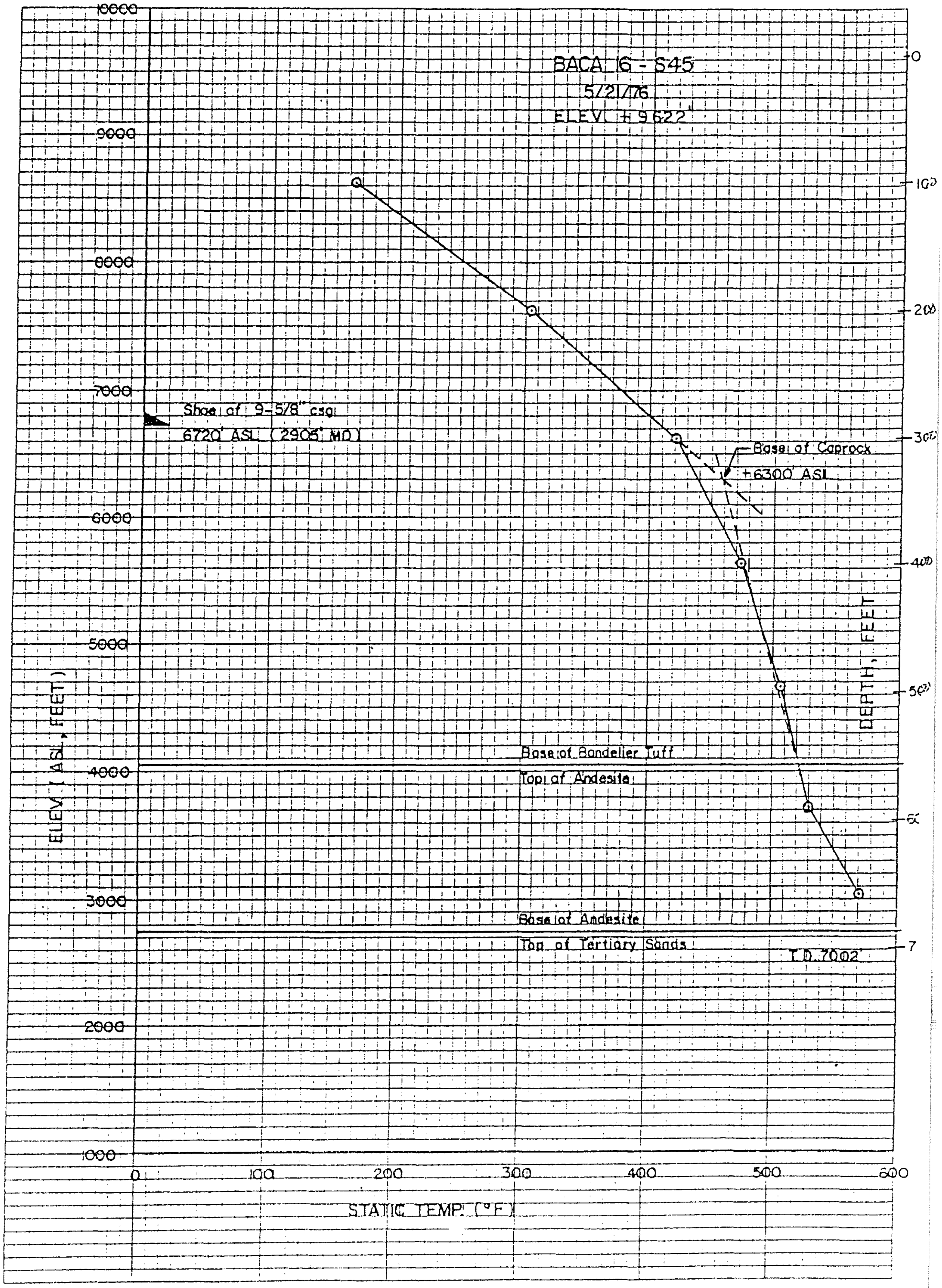


BACA 13 - S17
9/27/75
ELEV + 9292'
Base of Caprock
6500' ASL
Shoe of 9-5/8" csg
5808' ASL (3499' MD)
Base of Bandelier Tuff
Top of Andesite
Base of Andesite
Top of Permian Redbeds
T.D. 8228'
ELEV (ASL, FEET)
DEPTH, FEET
STATIC TEMP (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
200
300
400
500
600



BACA 14 - S13
2/19/75
ELEV ± 8605'
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
ELEV (ASL, FEET)
0
100
200
300
400
500
600
700
DEPTH, FEET
Shoe of 9-5/8" csg
5579' ASL (3074' MD)
Base of Caprock
± 5000' ASL
Base of Bandelier Tuff
Andesite
Santa Fe Sand
Top of Permian Redbeds
T.D. 6824'
0
100
200
300
400
500
600
STATIC TEMP (°F)


BACA 15 - S23
12/19/75
ELEV. ± 9117'
Base of Caprock
±7300' ASL
Shoe of 9-5/8" csg
5610' ASL (2509' MD)
Base of Bandelier Tuff
Top of Andesite
T.D. 5505'
ELEV. (ASL, FEET)
DEPTH, FEET
STATIC TEMP. (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
200
300
400
500
600

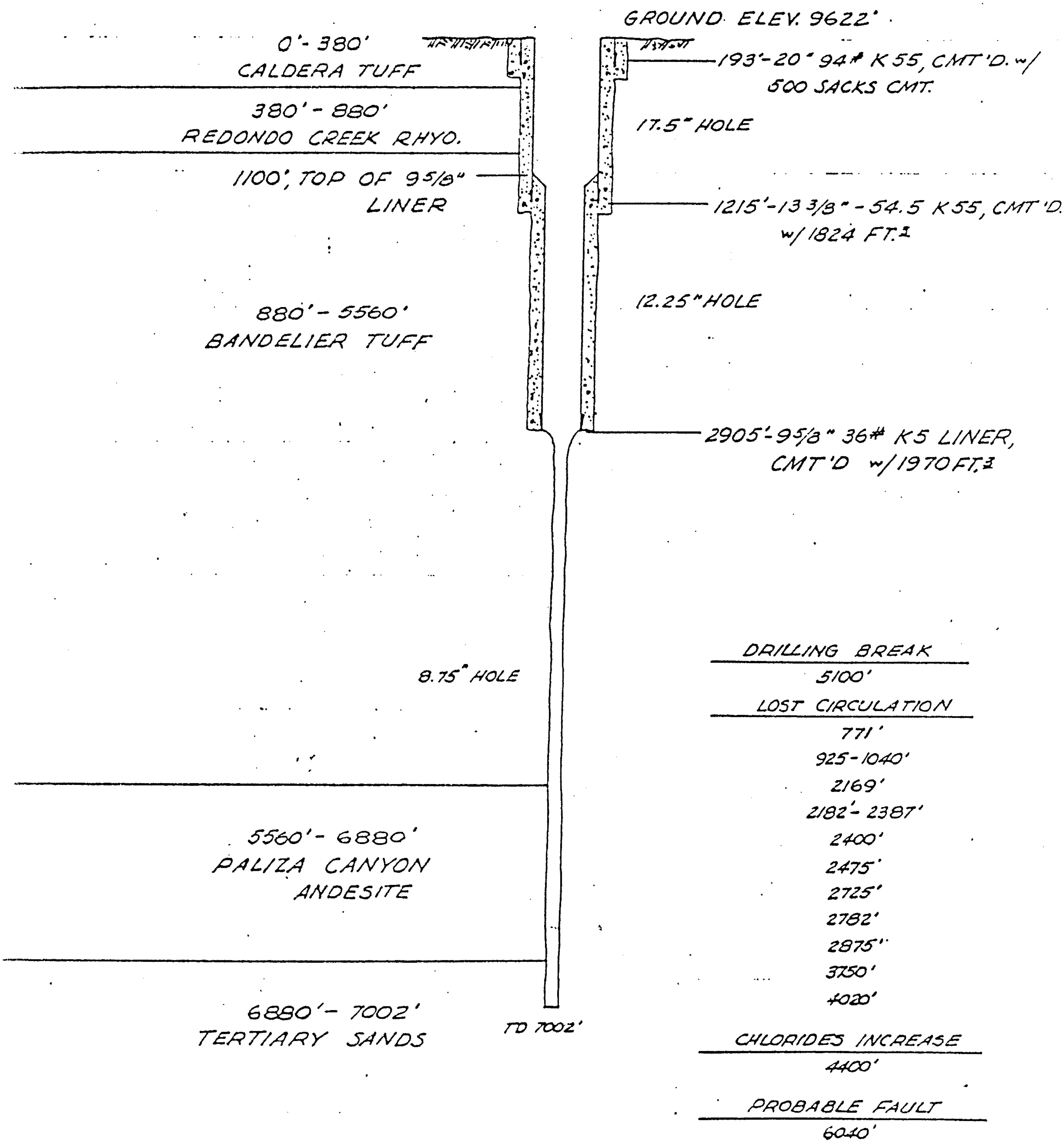


BACA 16 - S45
5/21/76
ELEV. +9622'
Shoe of 9-5/8" csg.
6720' ASL (2905' MD)
Base of Caprock
+6300' ASL
Base of Bandelier Tuff
Top of Andesite
Base of Andesite
Top of Tertiary Sands
T.D. 7002'
ELEV. (ASL, FEET)
DEPTH, FEET
STATIC TEMP. (°F)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
200
300
400
500
600

APPENDIX B

MECHANICAL DIAGRAMS
OF THE REDONDO CREEK AREA WELLS

FIRST COMPLETED 8-21-75



REVISED	DATE

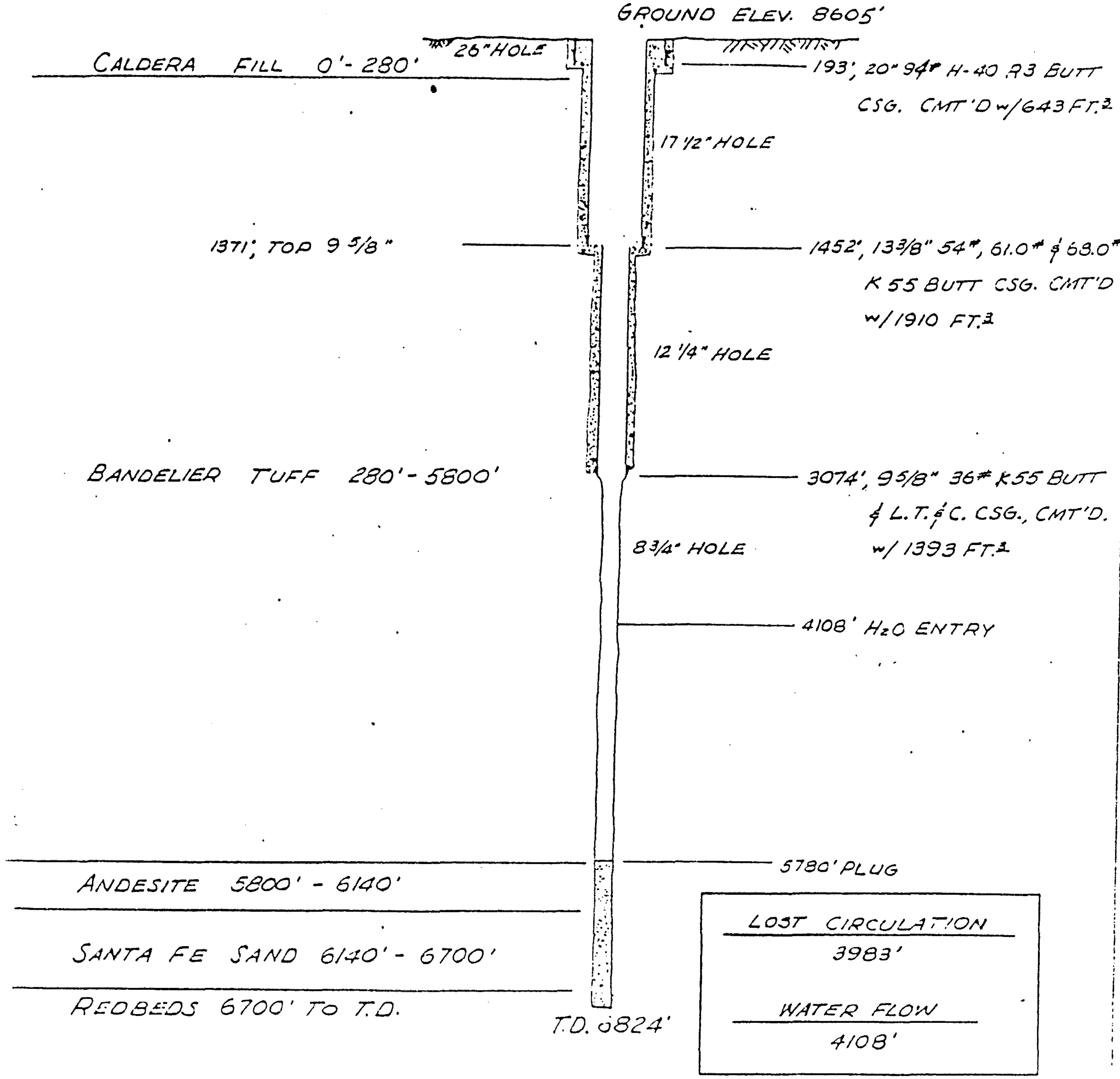
UNION 76

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

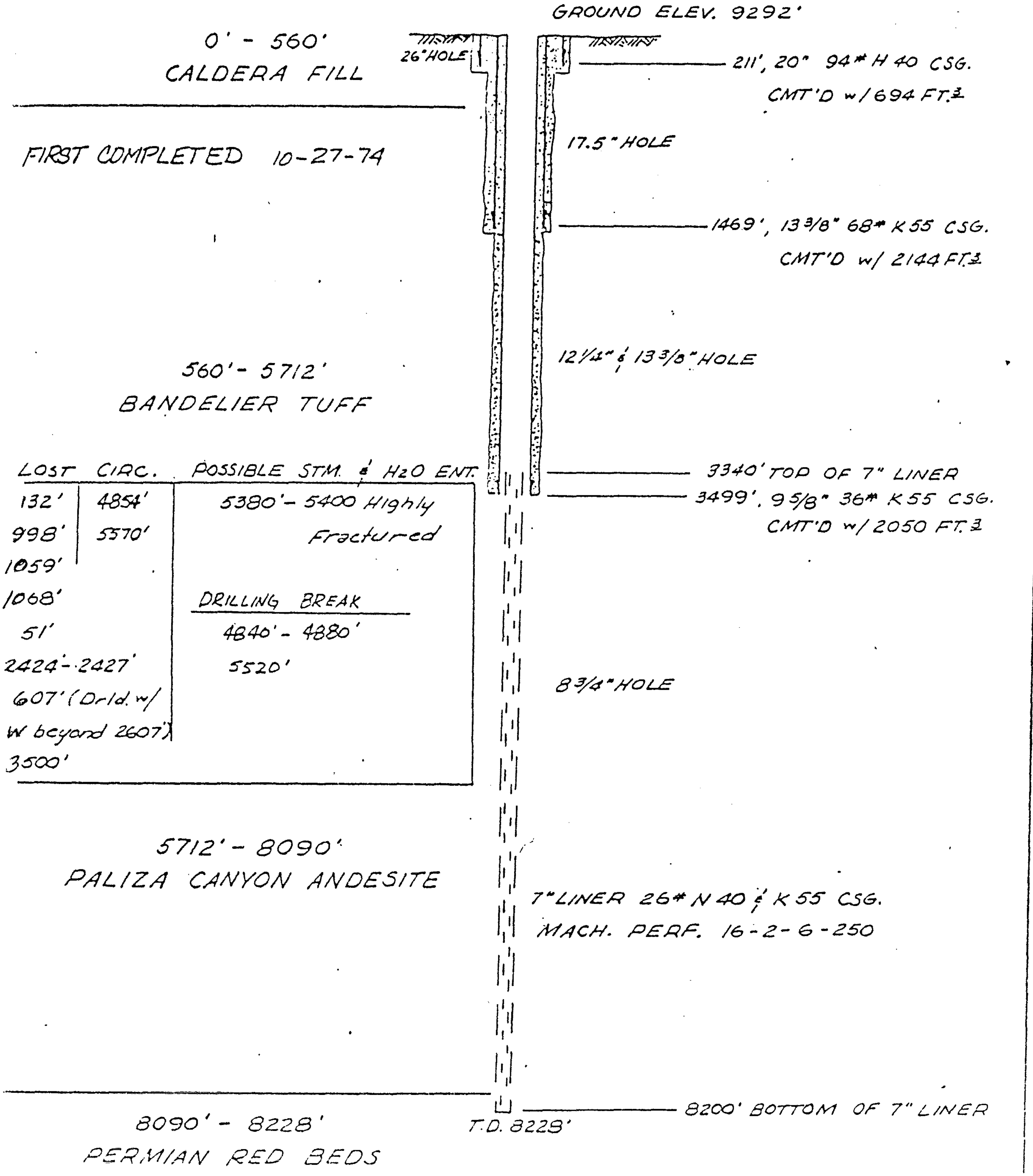
BACA 16 CASING SCHEMATIC

DRAWN
FOR:
BY: L.D.C.
DATE: 11-12-75
SCALE: 1"=1000'
DRAWING NUMBER

FIRST COMPLETED 2-24-75



REVISED	DATE	UNION 76	DRAWN
		UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION	FOR:
			BY:
			DATE:
		BACA 14 CASING SCHEMATIC	SCALE:
			DRAWING NUMBER

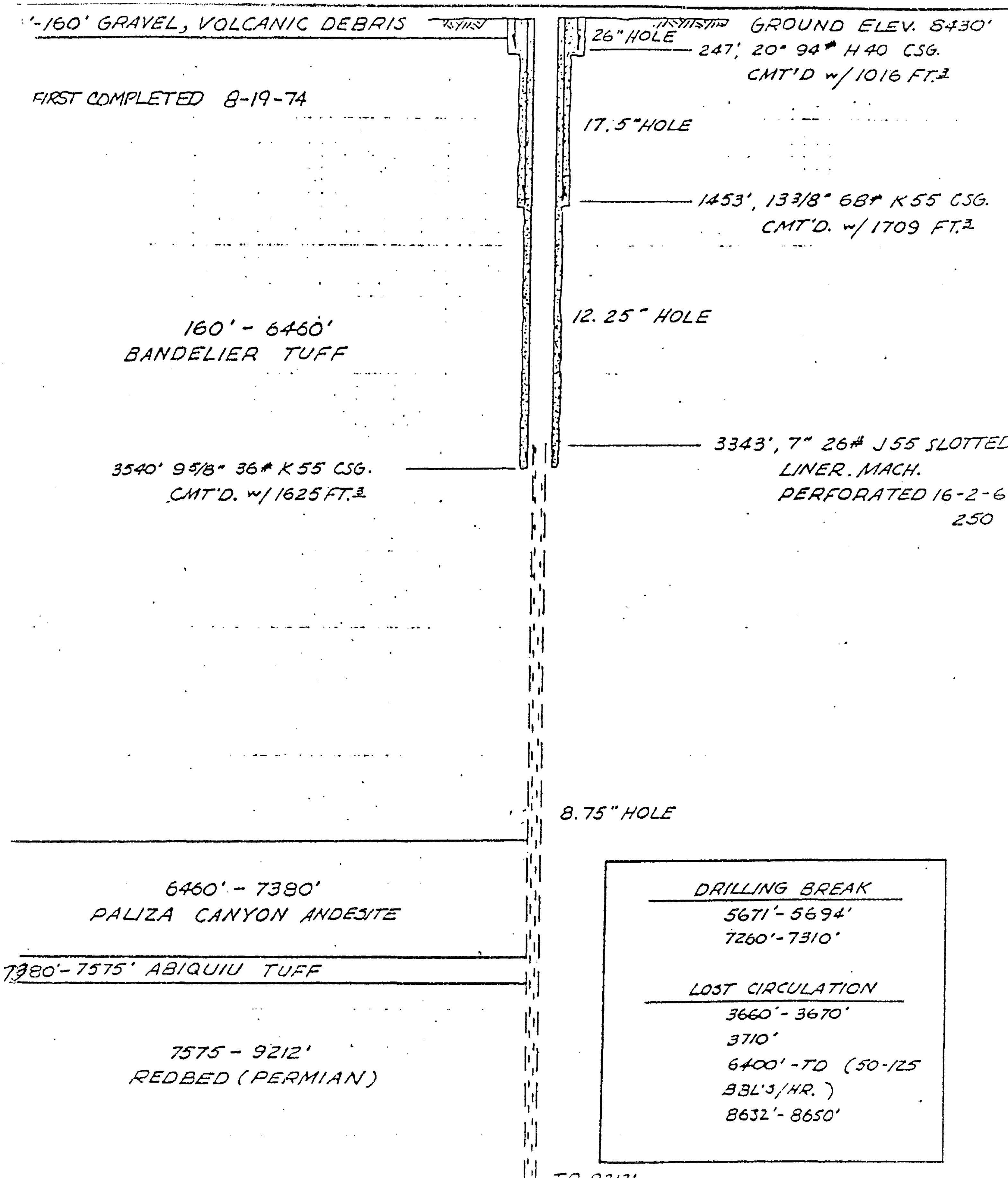


VISED	DATE

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA 13 CASING SCHEMATIC

DRAWN
FOR:
BY:
DATE:
SCALE:
DRAWING NUMBER



REVISED	DATE

UNION 76

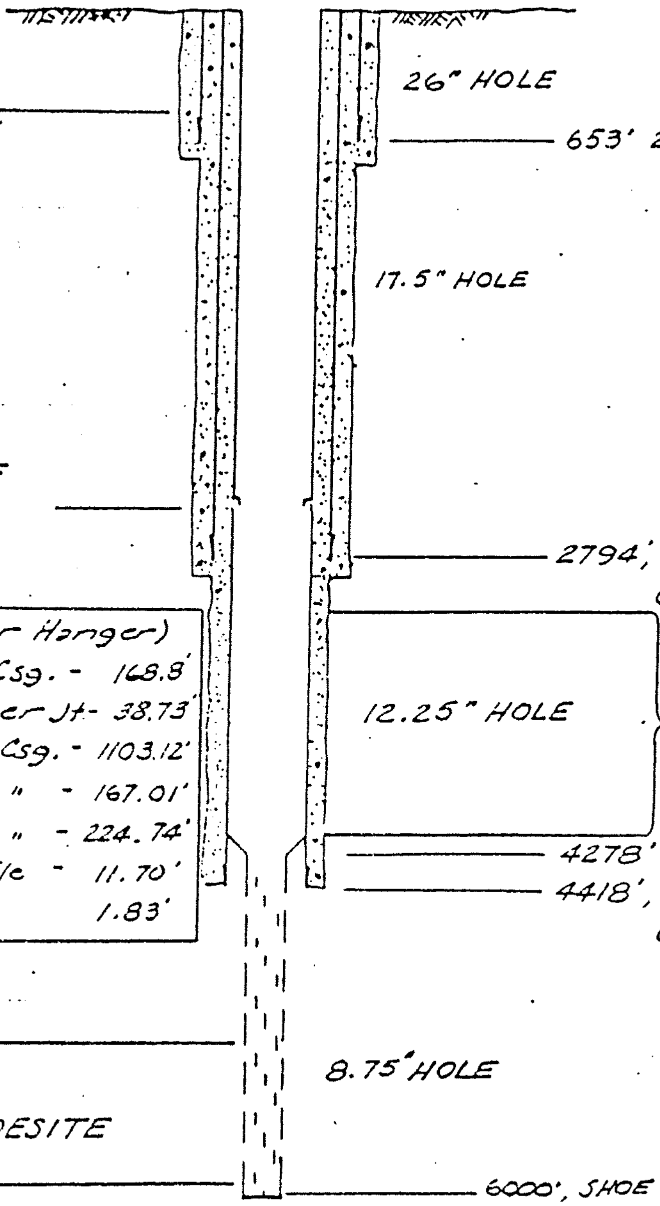
UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA 12 CASING SCHEMATIC

DRAWN
FOR:
BY: . . C.
DATE: 1-12-75
SCALE: 1" = 1000'
DRAWING NUMBER

STEAM ENTRIES		POSSIBLE STEAM ENTRIES	WATER ENTRIES
1720'	3800'	4500'	2622'
2622'	3907'	4595'	2960'
2700'	4149'	4742'	3030'
3103'	4316'	4760'	3200'
3370'	4500'	5290'	
3560'	4595'	5310'	
3713'	4886'	5480'	
3725'			

GROUND ELEV. 8735'



0' - 520'
CALDERA FILL

26" HOLE

653' 20", 94# CSG. CMT'D w/ 2150 FT.³

17.5" HOLE

520' - 5220'
BANDELIER TUFF

480', 9 5/8" CSG. (TIE BACK) CMT'D w/ 1965 FT³

2794', 13 3/8" 54.5# & 61# CSG. CMT'D w/ 2441 FT.³

LINER DETAIL (Burns Liner Hanger)

3 Jts. 7" 23# Blank L.T.&C. Csg.	-	168.8'
1 " " 26# 40 Mesh X-Over Jt.	-	38.73'
26 " " 23# 180 " ST&C Csg.	-	1103.12'
4 " " " Blank L.T.&C "	-	167.01'
6 " " 26# 40 Mesh " "	-	224.74'
1 " " Blank Csg. w/ Baffle	-	11.70'
" S.O.W. Float Shoe		1.83'

12.25" HOLE

PERFORATED INTERVAL
SEE DETAIL BELOW

4278' TOP OF 7" LINER

4418', 9 5/8" 36# & 40# CSG. CMT'D w/ 100 FT.³

8.75" HOLE

5220' - 5930'
PALIZA CANYON ANDESITE

6000', SHOE 7" LINER (12 Slots/Ft.)

T.D. 6001'

5930' - T.D.
TERTIARY SEDIMENTS

TEST COMPLETED 9-18-75

PERFORATION DETAIL : 4 - 1/2" HPF

3075 - 3085	3345 - 3355	3535 - 3545	4035 - 4045
3095 - 3105	3365 - 3375	3555 - 3565	4125 - 4135
3115 - 3125	3385 - 3395	3575 - 3585	4145 - 4155
3135 - 3145	3405 - 3415	3595 - 3605	4165 - 4175
	3675 - 3735	3955 - 3965	4185 - 4195

REVISED	DATE

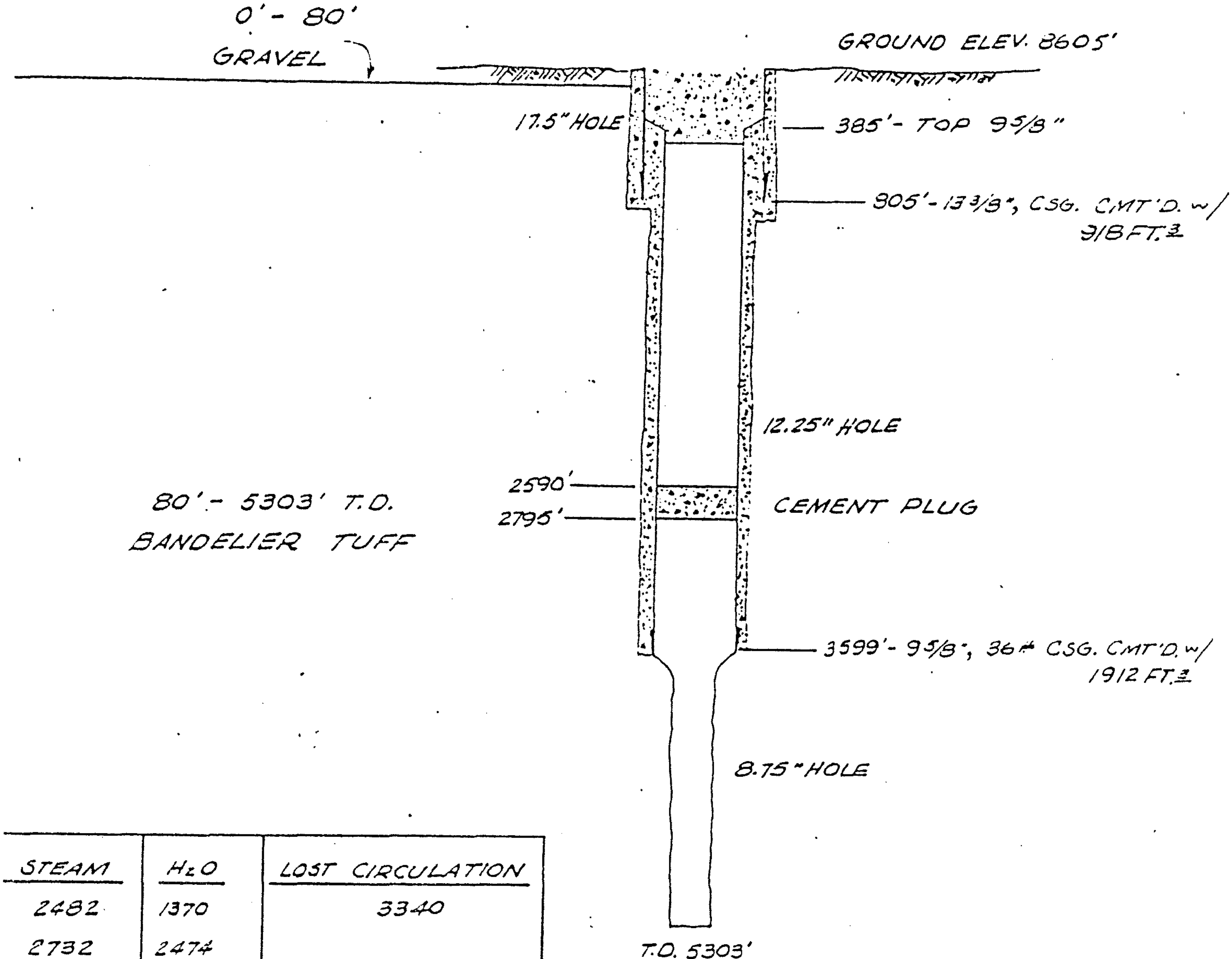
UNION 76

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA 10 CASING SCHEMATIC

DRAWN
FOR:
BY: L.D.C.
DATE: 11-12-75
SCALE: 1" = 1000'
DRAWING NUMBER

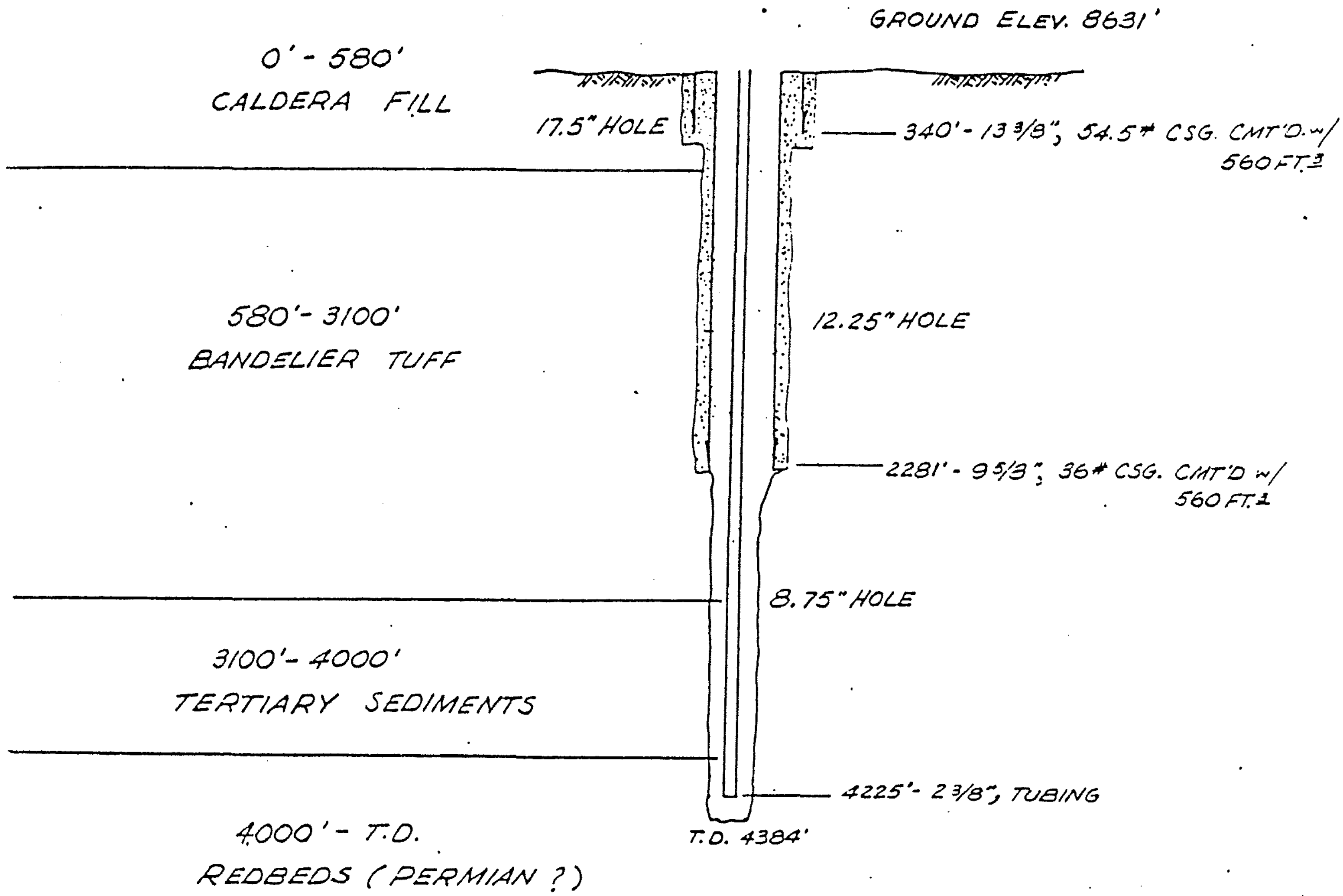
FIRST COMPLETED 11-22-72



STEAM	H_2O	LOST CIRCULATION
2482	1370	3340
2732	2474	
3702	2482	
4077	2732	
5000		

REVISED	DATE	UNION 76	DRAWN
		UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION	FOR:
			BY:
		BACA - 9 CASING SCHEMATIC	DATE:
			SCALE:
			DRAWING NUMBER

FIRST COMPLETED 9-13-72

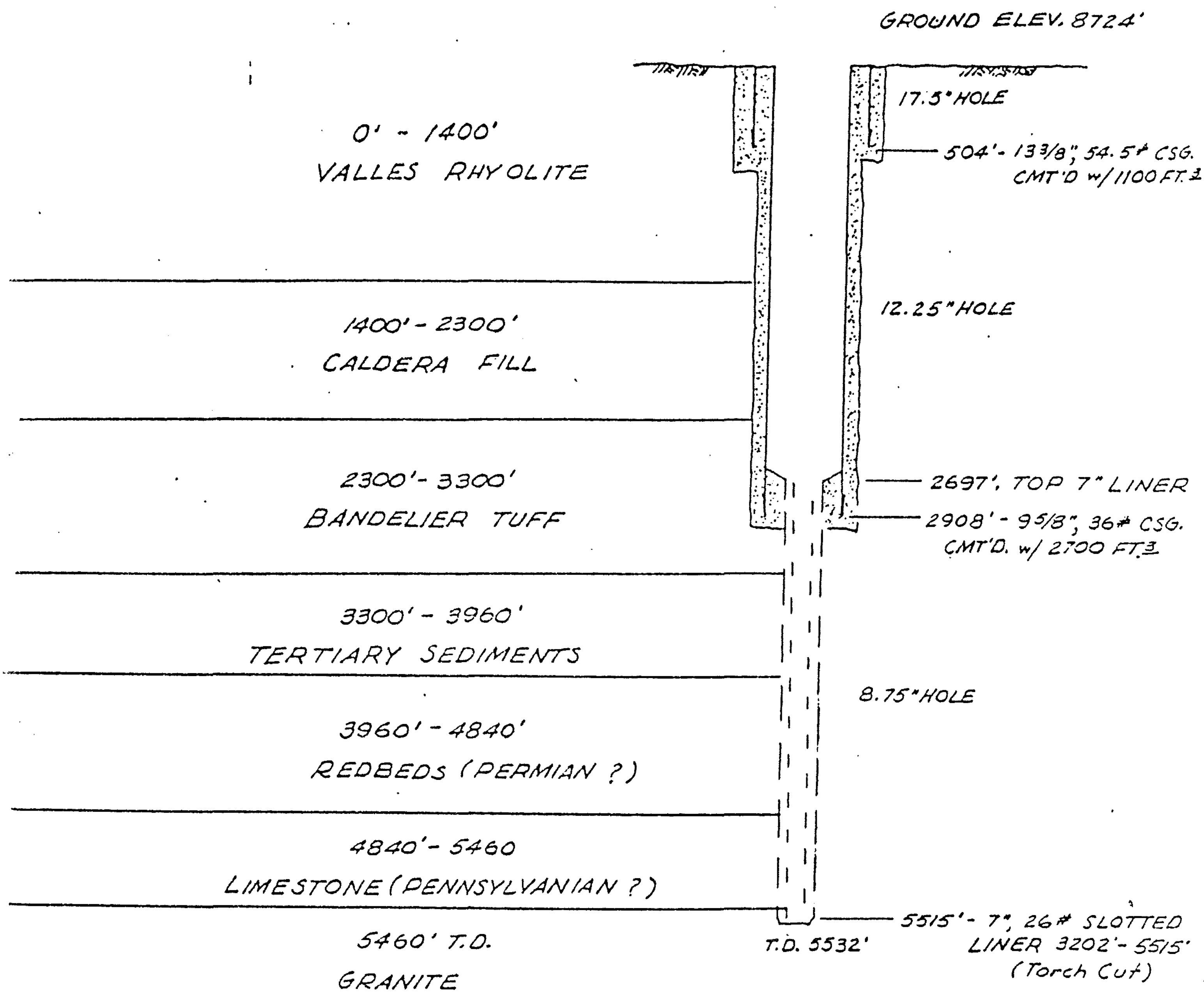


STEAM & WATER ENTRIES

2375' - 2400'

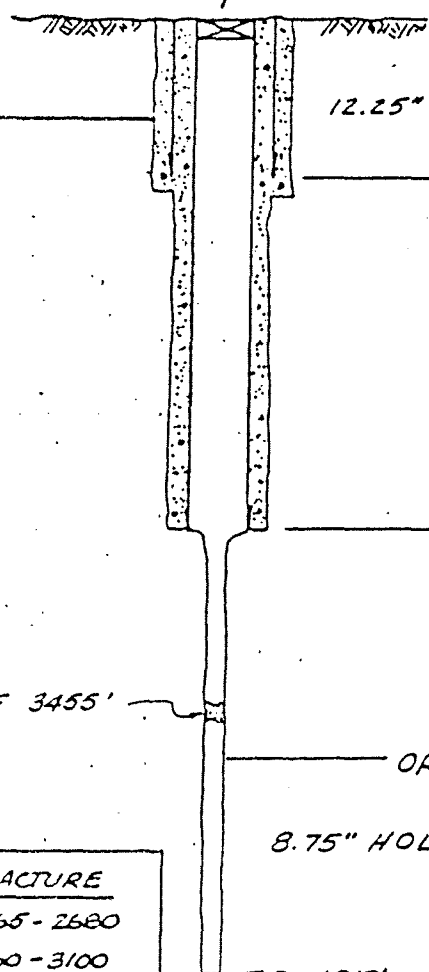
VISED	DATE	UNION	DRAWN
		UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION	FOR:
			BY:
		BACA - 8 CASING SCHEMATIC	DATE:
			SCALE:
			DRAWING NUMBER

FIRST COMPLETED 8-5-72



REVISED	DATE	UNION 76 — UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION	DRAWN
		BACA 7 CASING SCHEMATIC	FOR:
		BACA PROJECT NEW MEXICO	BY:
			DATE:
			SCALE:
			DRAWING NUMBER

FIRST COMPLETED 7-23-72
REMEDIAL WORK 4-14-75
CLOSED IN 1-15-76



) & STEAM	DRLG. BREAK	FRACTURE
1880	4743 - 4759	2665 - 2680
2050		3060 - 3100
25 - 3150		2670 - 2688
1591 - 3650		
17 - 3737		

PERF. 4 HOLES @ 565', 750', 843' & 1175'
PERF. 1 HOLE @ 427', 443' & 504'

VISED	DATE
H.	1-9-76
. S.	6-10-76

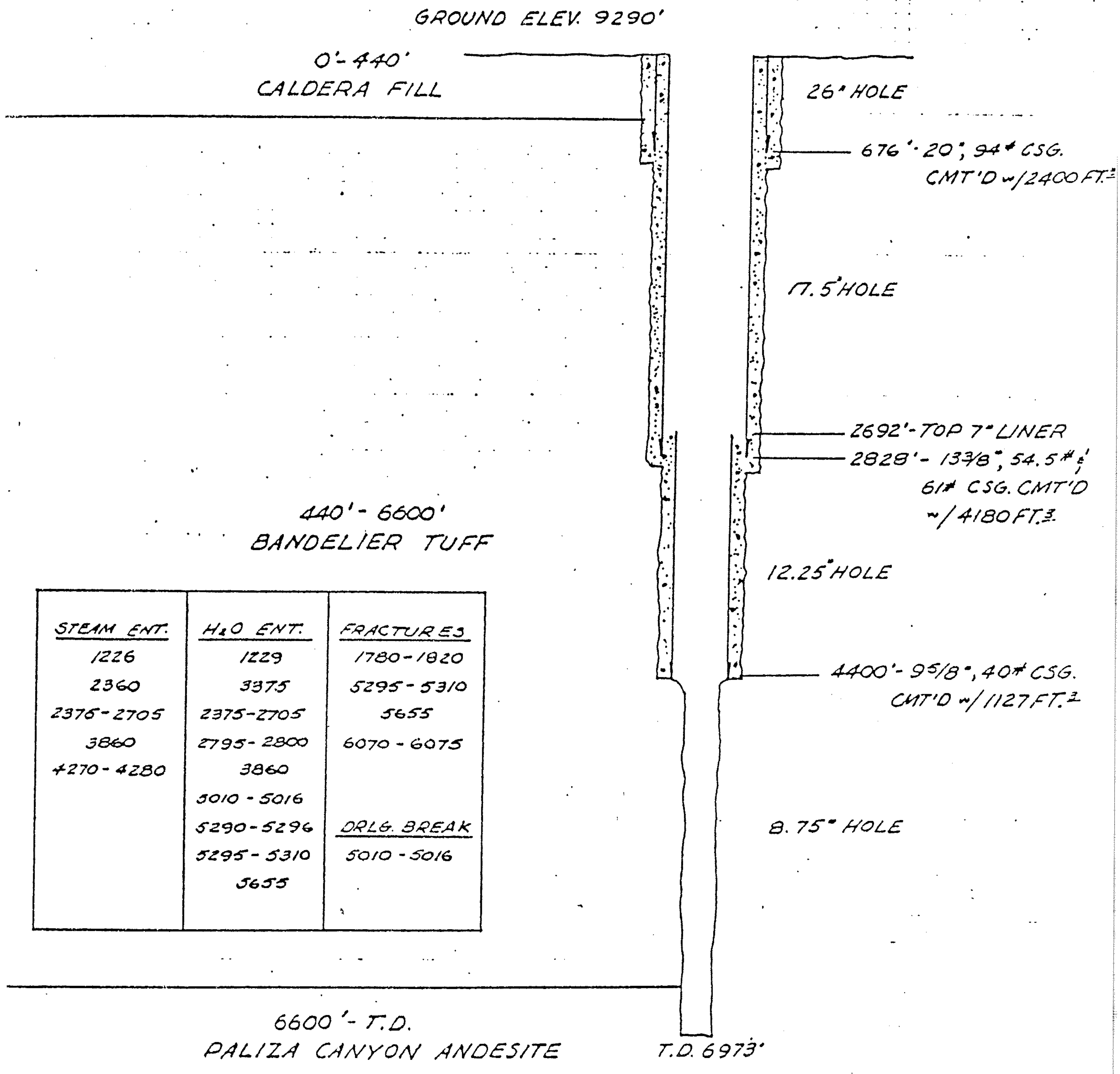
UNION (76)

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA 6 CASING SCHEMATIC

DRAWN
FOR:
BY:
DATE:
SCALE:
DRAWING NUMBER

FIRST COMPLETED 9-20-71



STEAM ENT.	H_2O ENT.	FRACTURES
1226	1229	1780-1820
2360	3375	5295-5310
2376-2705	2375-2705	5655
3860	2795-2800	6070-6075
4270-4280	3860	
	5010-5016	
	5290-5296	DRLG. BREAK
	5295-5310	5010-5016
	5655	

REVISED	DATE

UNION 76

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA 5 CASING SCHEMATIC

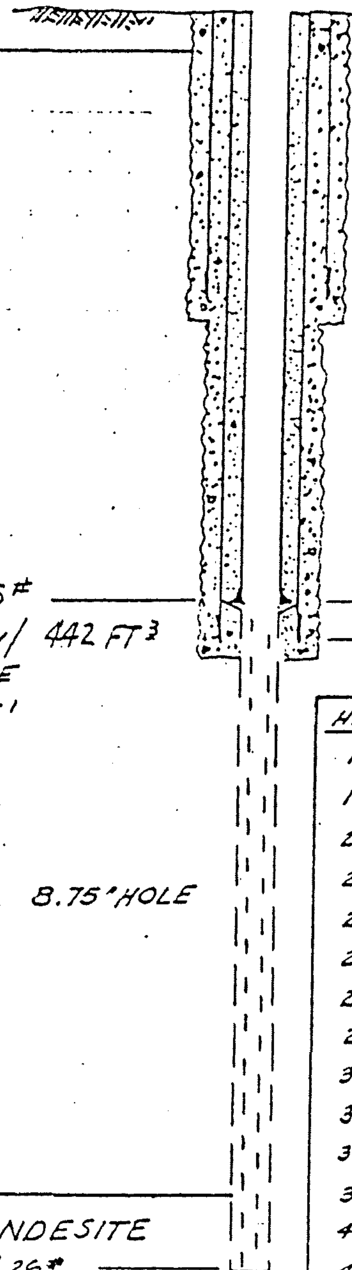
BACA PROJECT NEW MEXICO

DRAWN
FOR:
BY: L.D.C.
DATE: 11-12-75
SCALE: 1"=1000'
DRAWING NUMBER
1097

FIRST COMPLETED 10-12-70
REMEDIAL WORK 6-28-73

GROUND ELEV. 9318'

0'-200'
CALDERA FILL



200'-5980'
BANDELIER TUFF

2985'; 7" 26#
CSG, CMT'D w/ 442 FT³
TOP - SURFACE
SHOE - 2985'

5980 - T.D. PALIZA CANYON ANDESITE

6376'; 7", 23# & 26#
SLOTTED LINER
SLOTS 3036'-6375'
(6-12-24-250)

H_2O & STEAM	FRACTURES
1887	1286-1294
1988	1988-2000
2000	2220
2115	
2200	LOST CIR.
2490	1400
2591	
2625	
3120	DRLG. BREAK
3150-3177	5814-5823
3468	
3710	
4300-4400	
4610-4618	
4975	
4991-5000	
5291	
5866	

REVISED	DATE
[illegible]	[illegible]

UNION 76

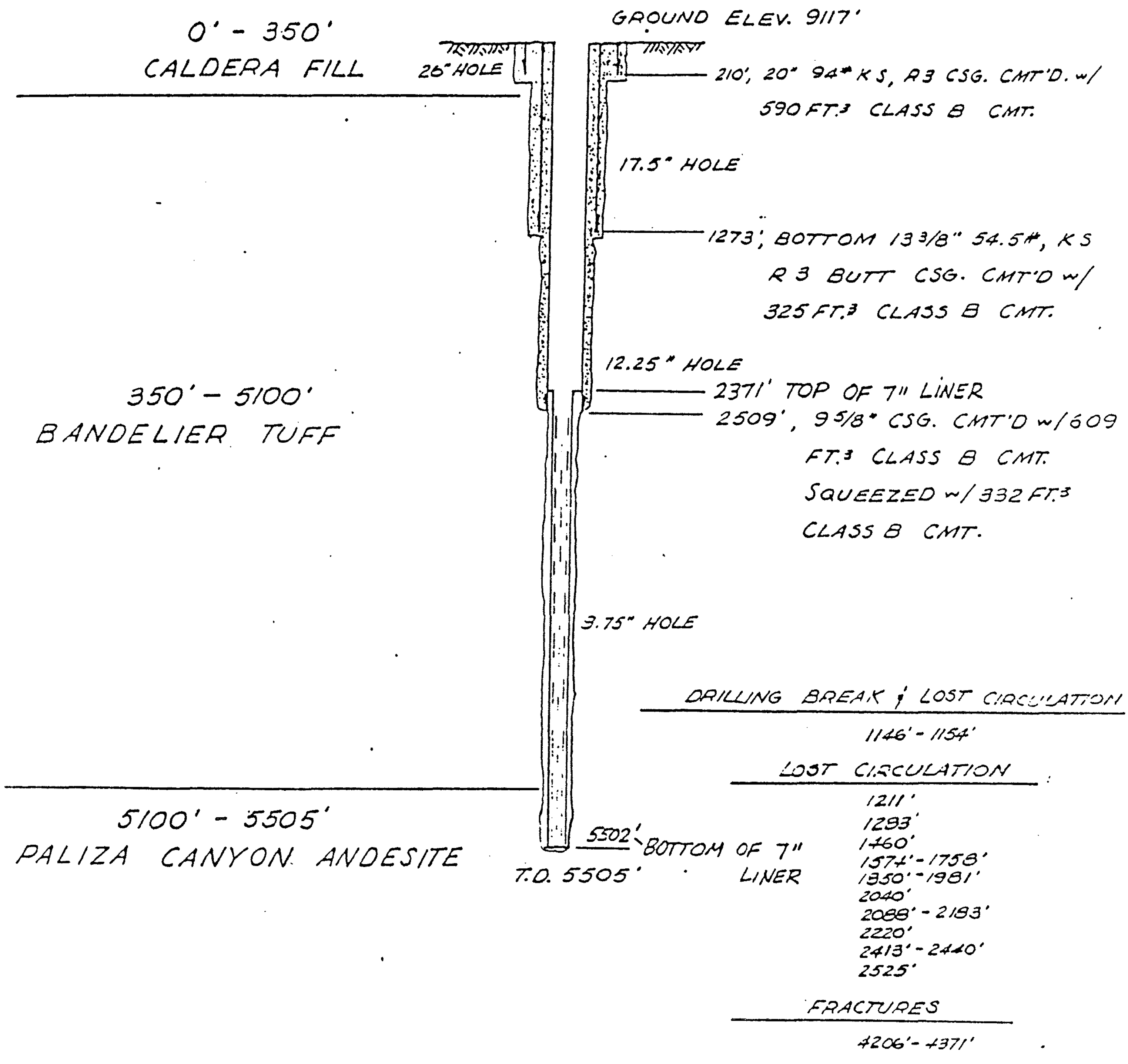
UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA 4 CASING SCHEMATIC

BACA PROJECT NEW MEXICO

DRAWN
FOR:
BY: [illegible]
DATE: 11-12-75
SCALE: [illegible]
DRAWING NUMBER
[illegible]

HKST COMPLETED 6-13-75



REVISED	DATE

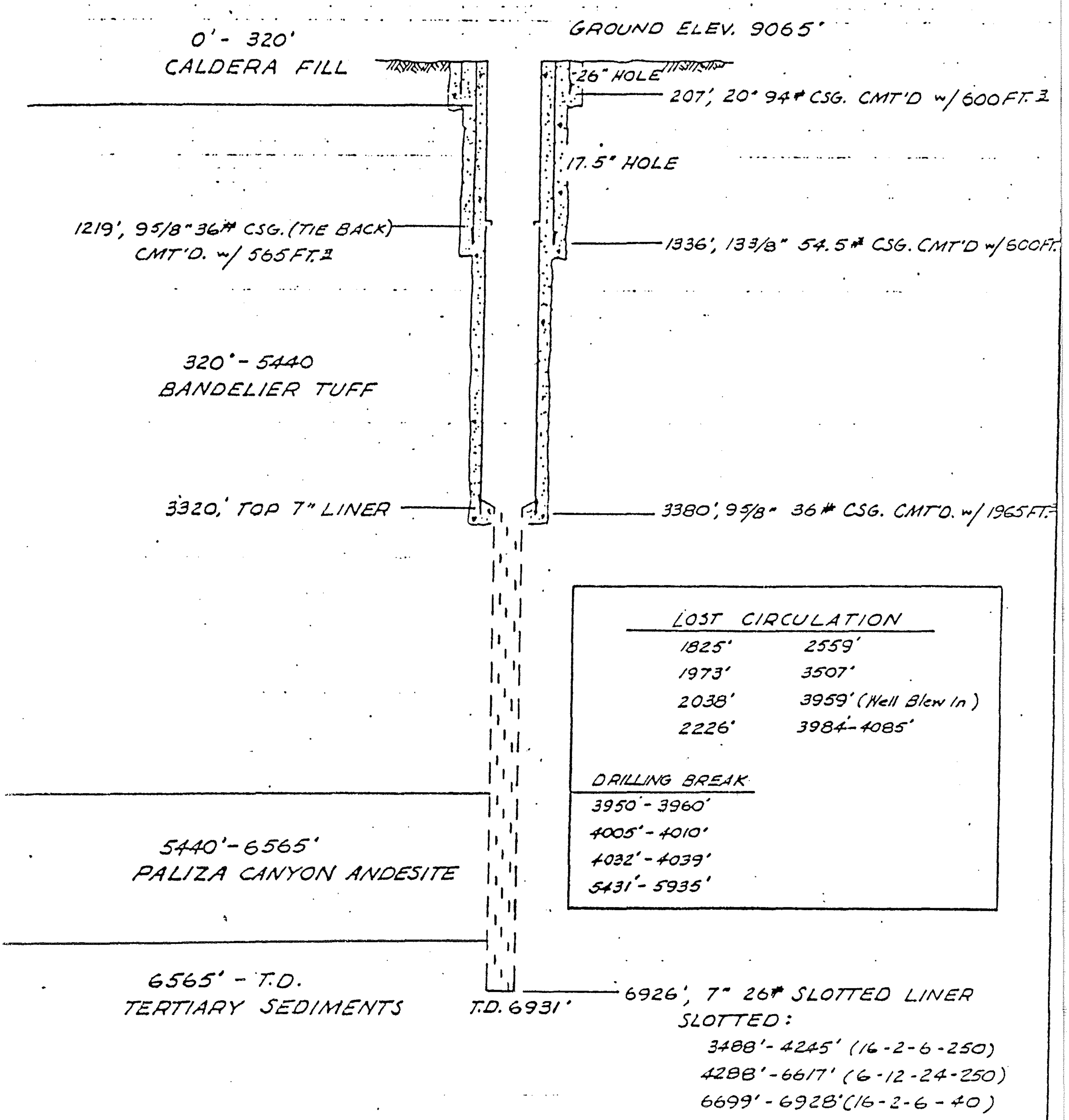
UNION 76

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA 15 CASING SCHEMATIC

DRAWN
FOR:
BY:
DATE:
SCALE:
DRAWING NUMBER

FIRST COMPLETED 11-16-73



REVISED	DATE

UNION 76

UNION OIL COMPANY OF CALIFORNIA - GEOTHERMAL DIVISION

BACA-11 CASING SCHEMATIC

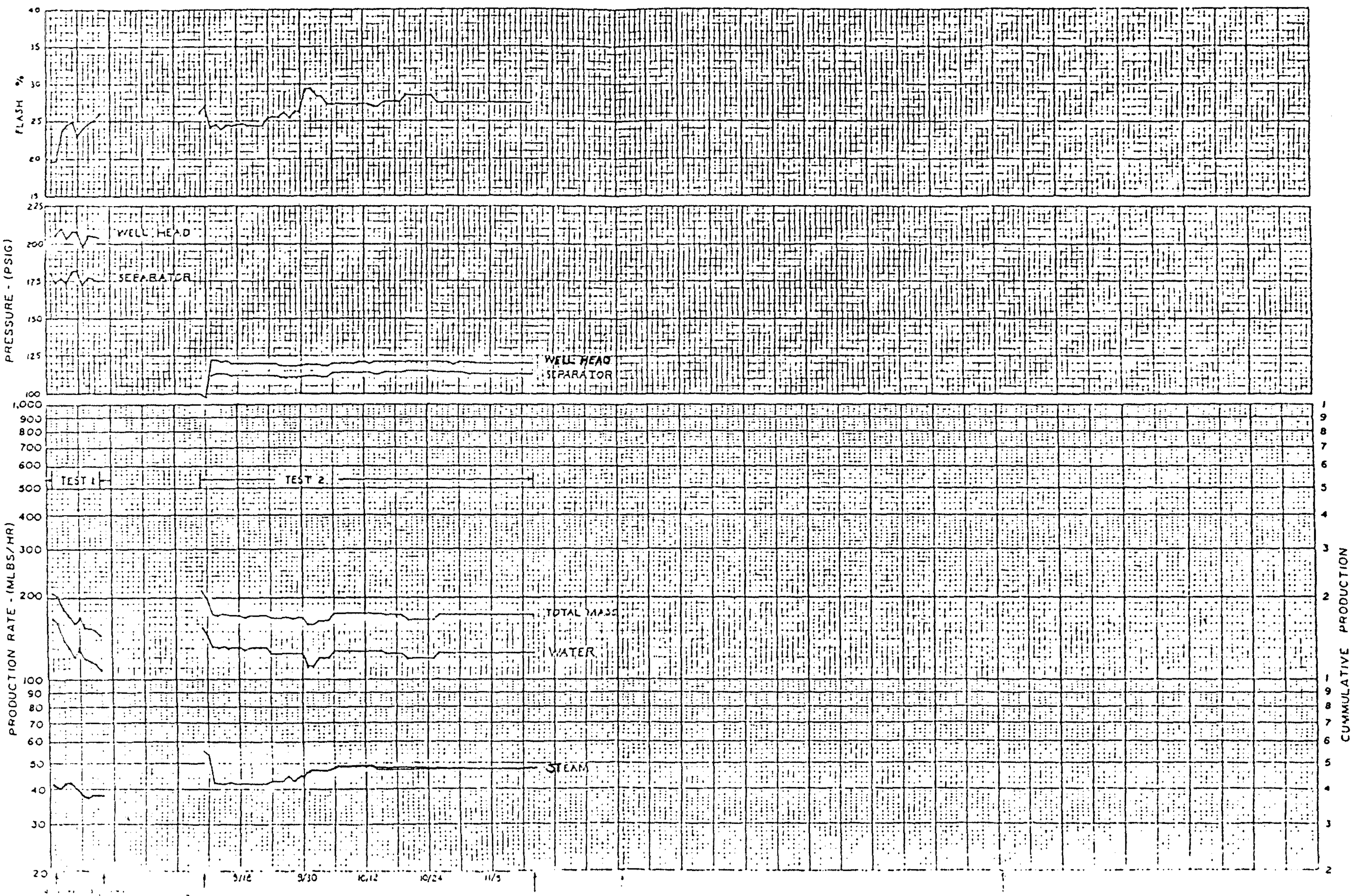
BACA PROJECT — NEW MEXICO

DRAWN
FOR:
BY: L.O.C.
DATE: 11-12-75
SCALE: 1" = 1000'
DRAWING NUMBER
1102

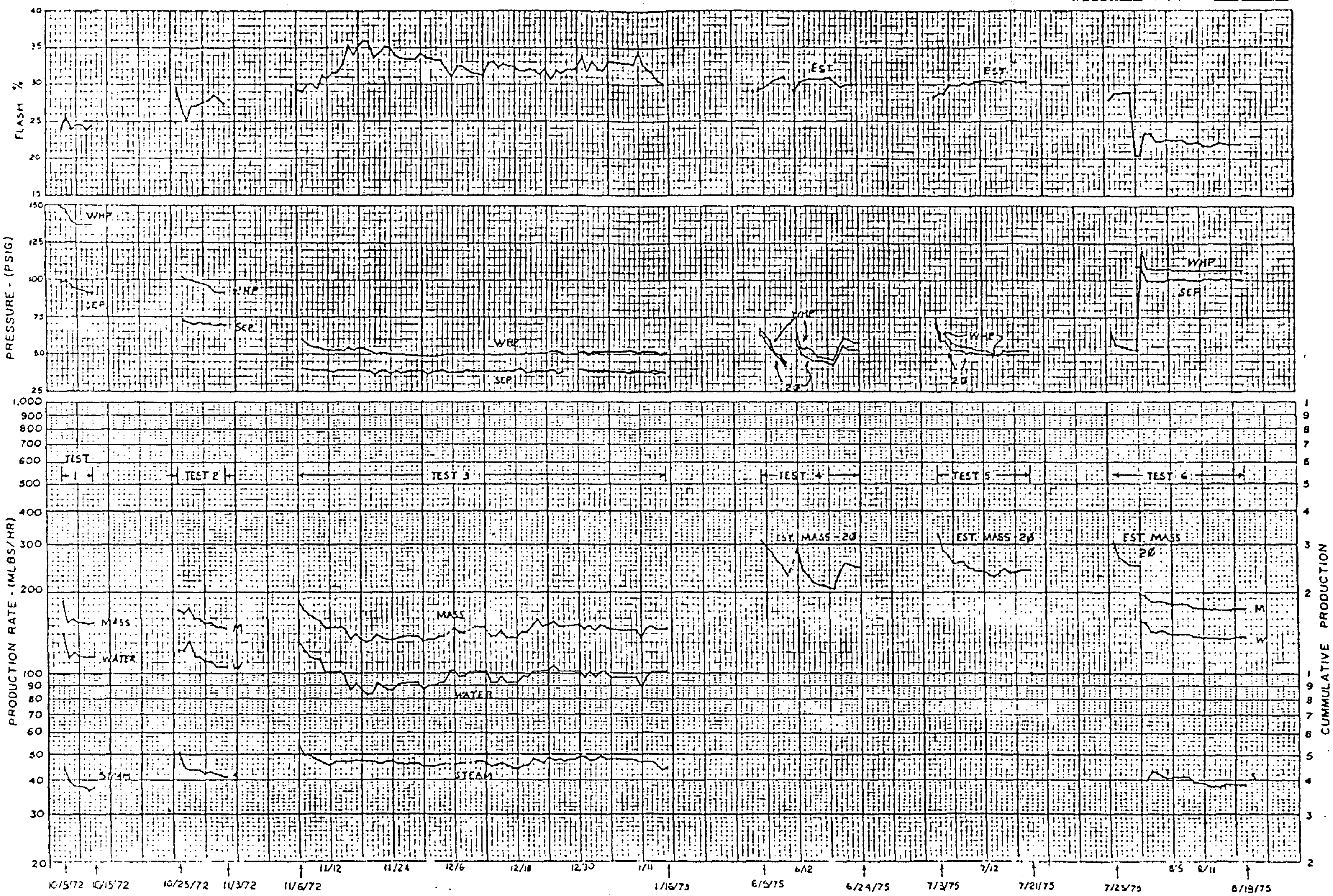
APPENDIX C

PRODUCTION PERFORMANCE OF THE REDONDO CREEK AREA WELLS PRIOR TO THE INTERFERENCE TEST

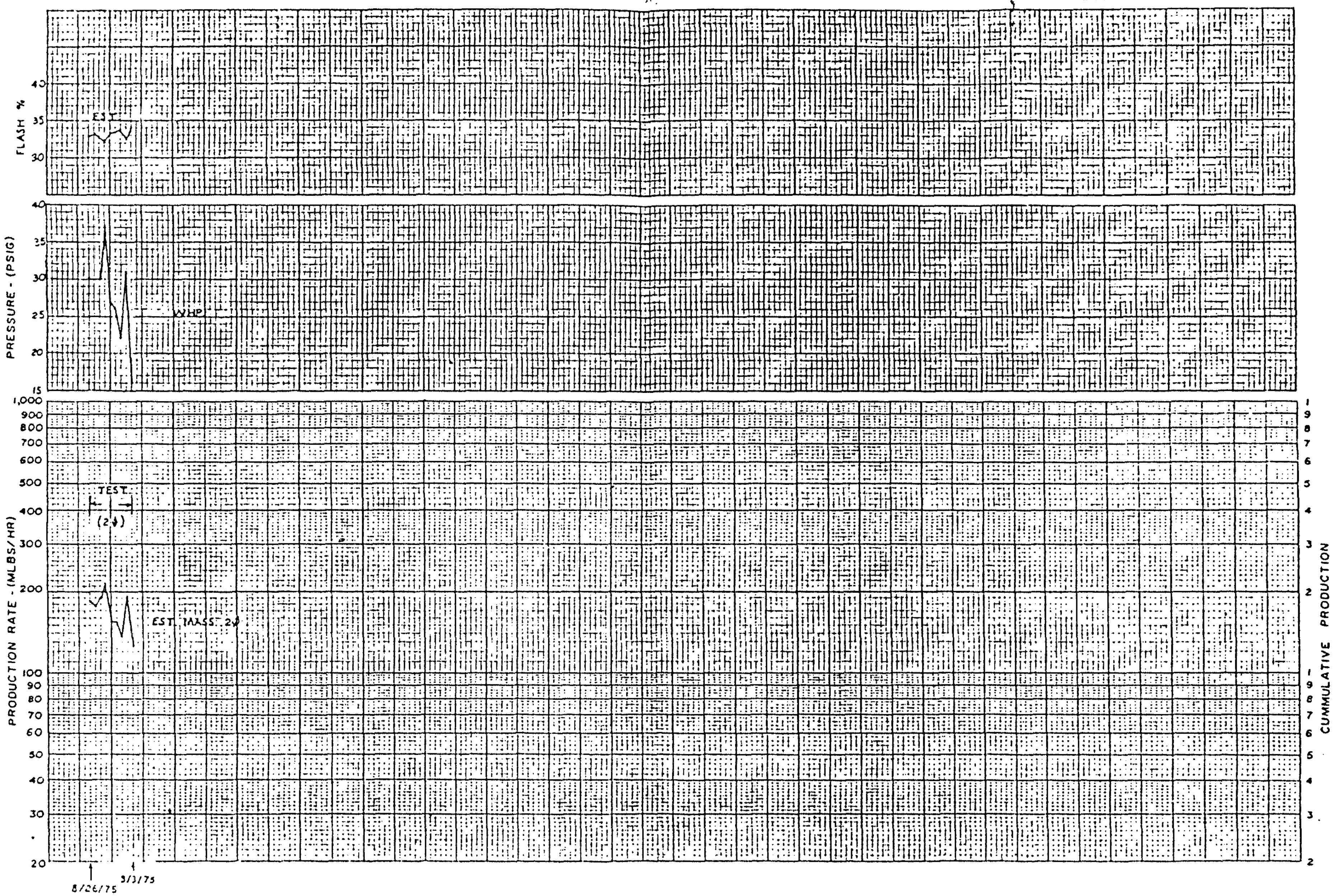
AREA REDONDO CREEK
WELL BACA # 4



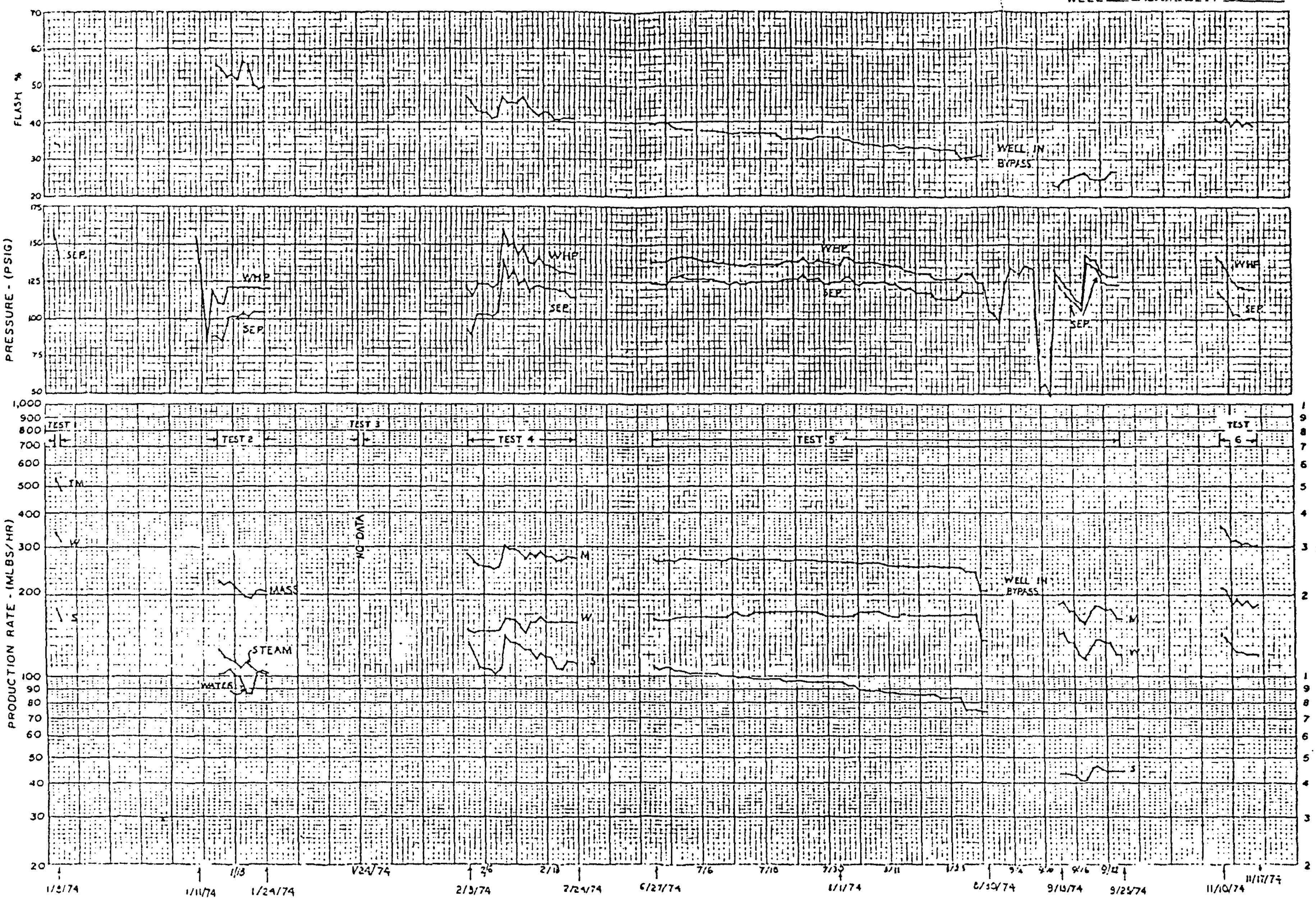
AREA REDONDO CREEK
WELL BACA # 6



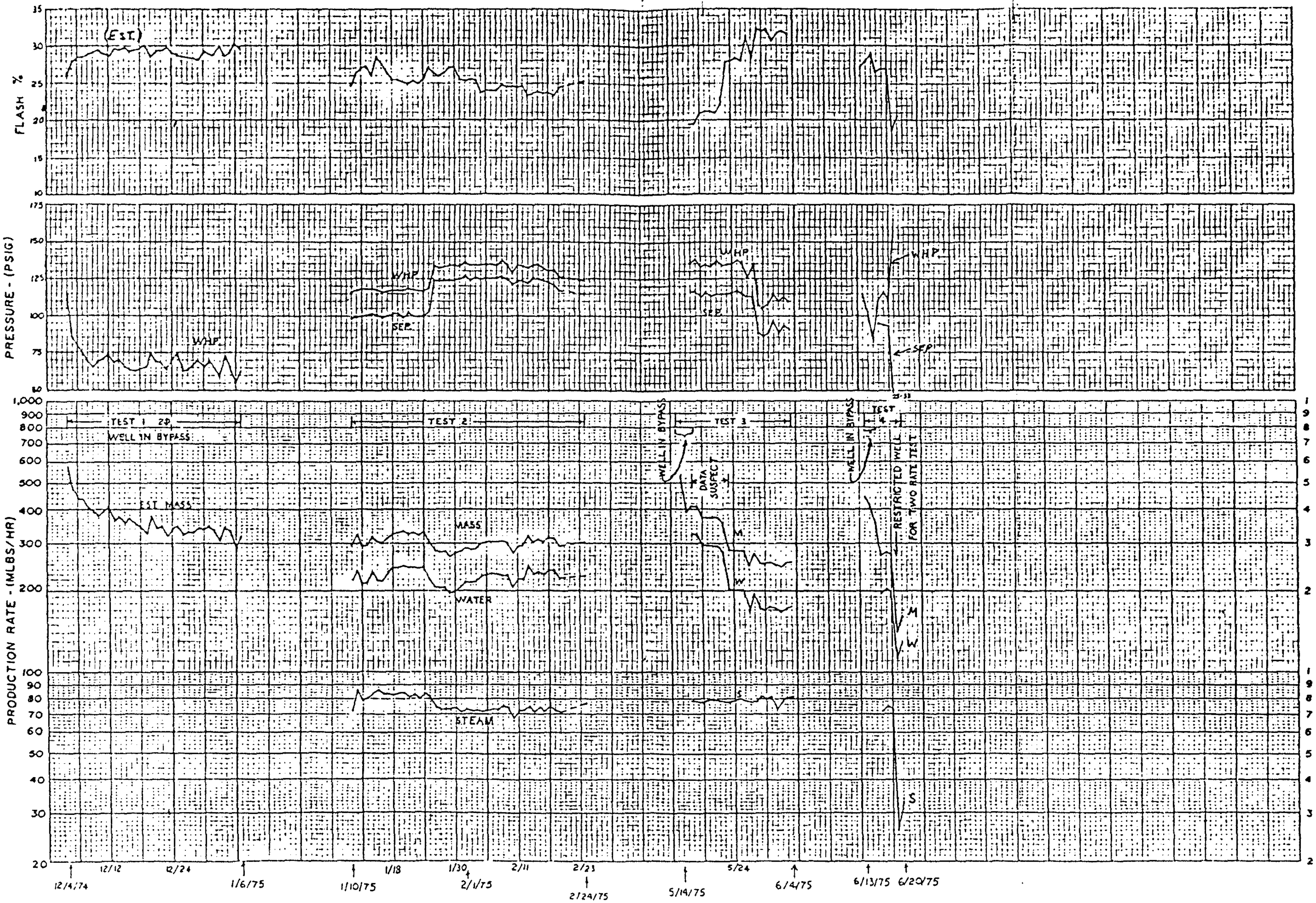
AREA RECONDO CREEK
WELL BACA # 10

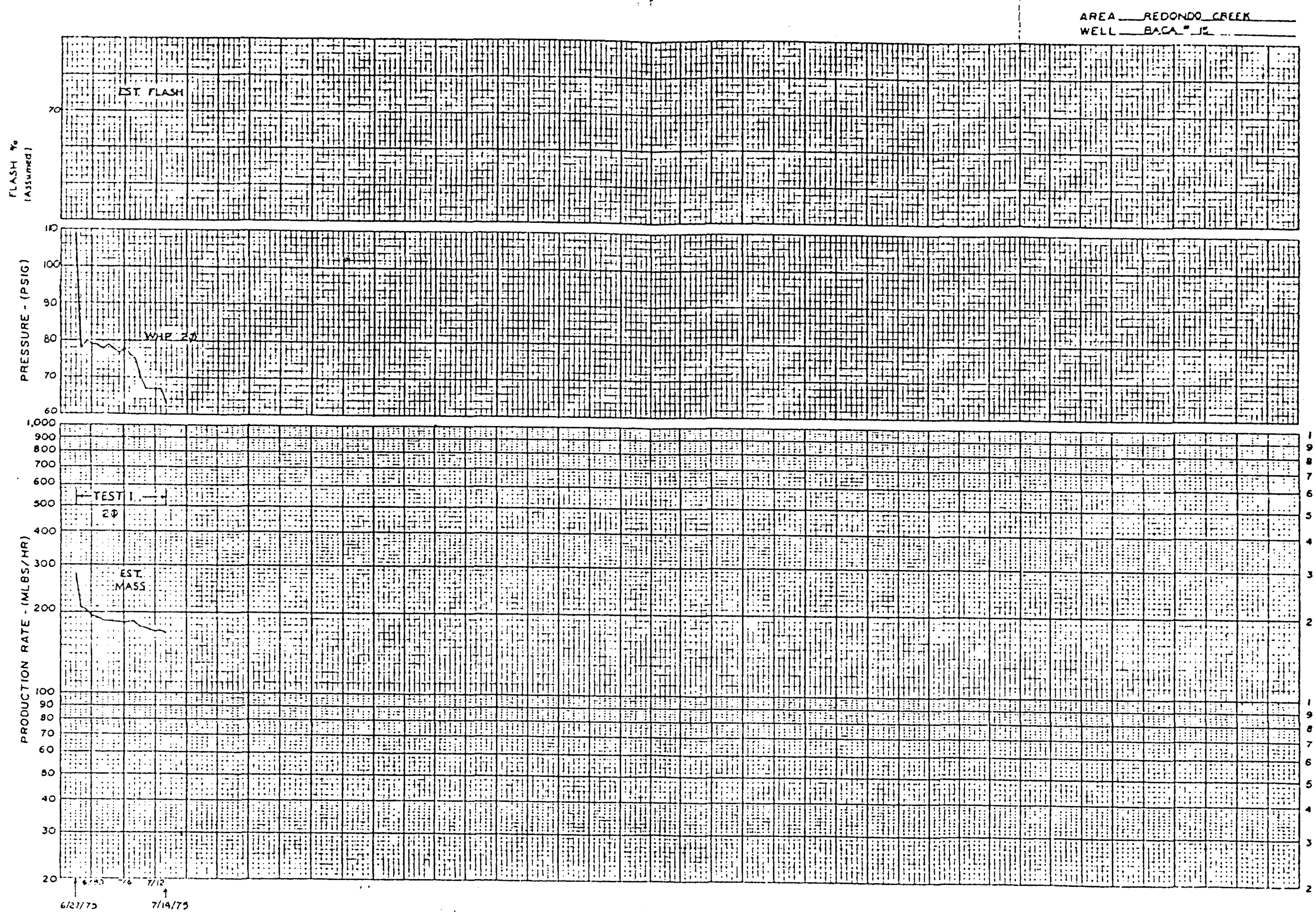


AREA — REDONDO CREEK
WELL — BACA # 11



AREA REDONDO CREEK
WELL BACA # 12

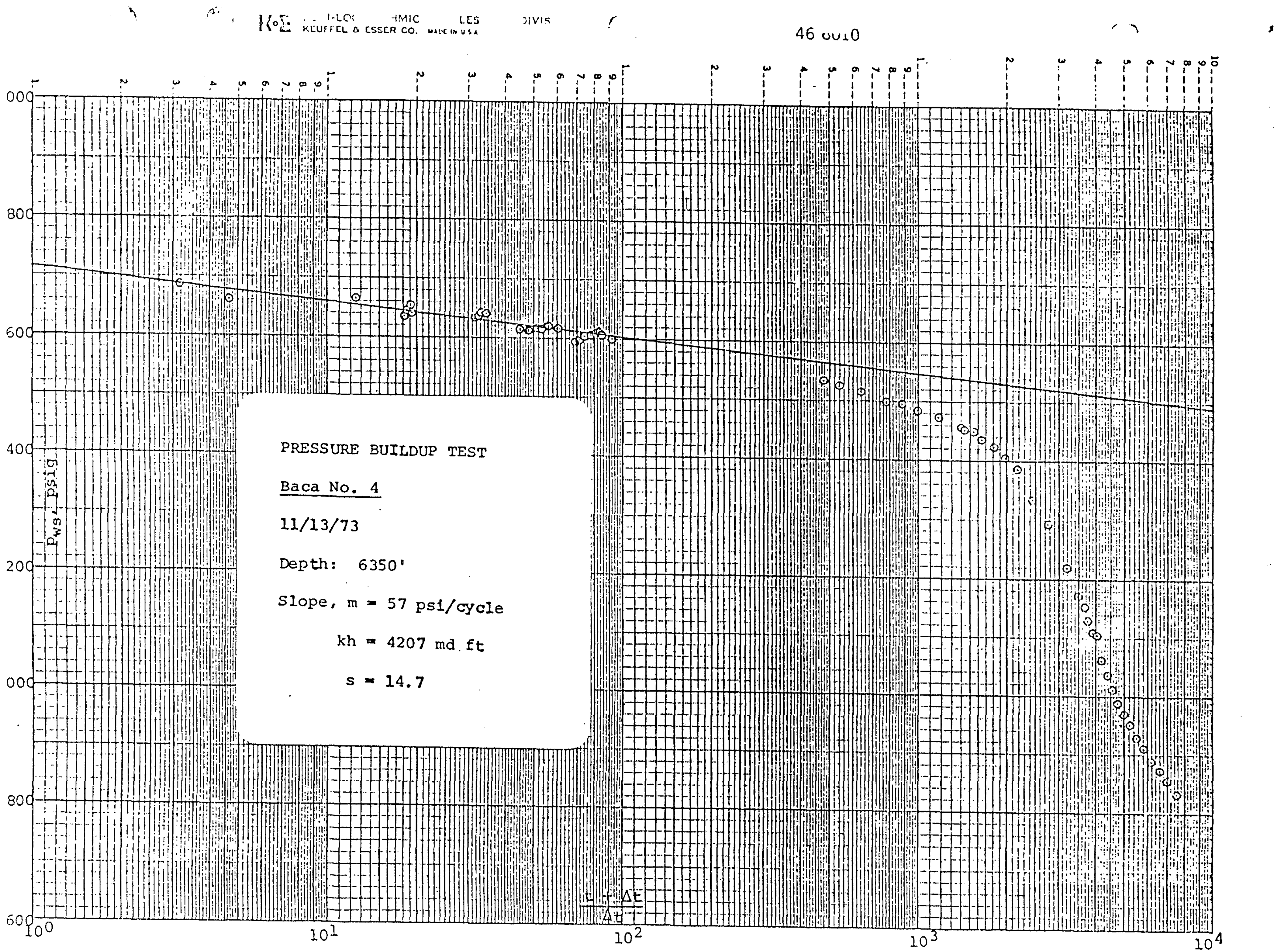




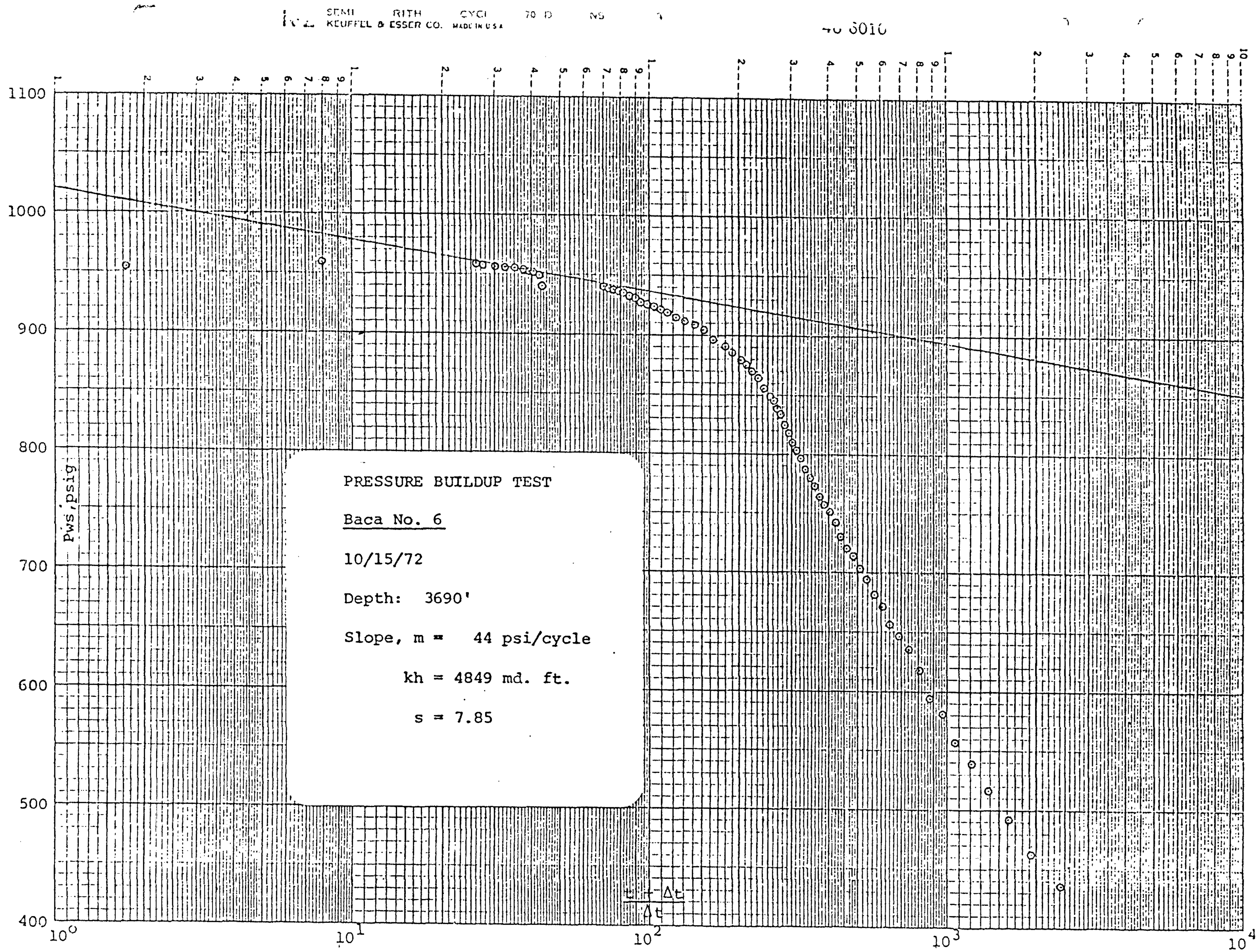
AREA REDONDO CREEK
WELL BACA #12
FLASH % (Assumed)
EST. FLASH
70
PRESSURE - (PSIG)
110
100
90
80
70
60
WHP 2Φ
PRODUCTION RATE - (MLBS/HR)
1,000
900
800
700
600
500
400
300
200
100
90
80
70
60
50
40
30
20
TEST 1.
2Φ
EST. MASS
CUMMULATIVE PRODUCTION
6/27/75
7/12
7/14/75

APPENDIX D

HORNER GRAPHS OF PRESSURE BUILDUP TESTS AND PRESSURE DRAWDOWN TESTS



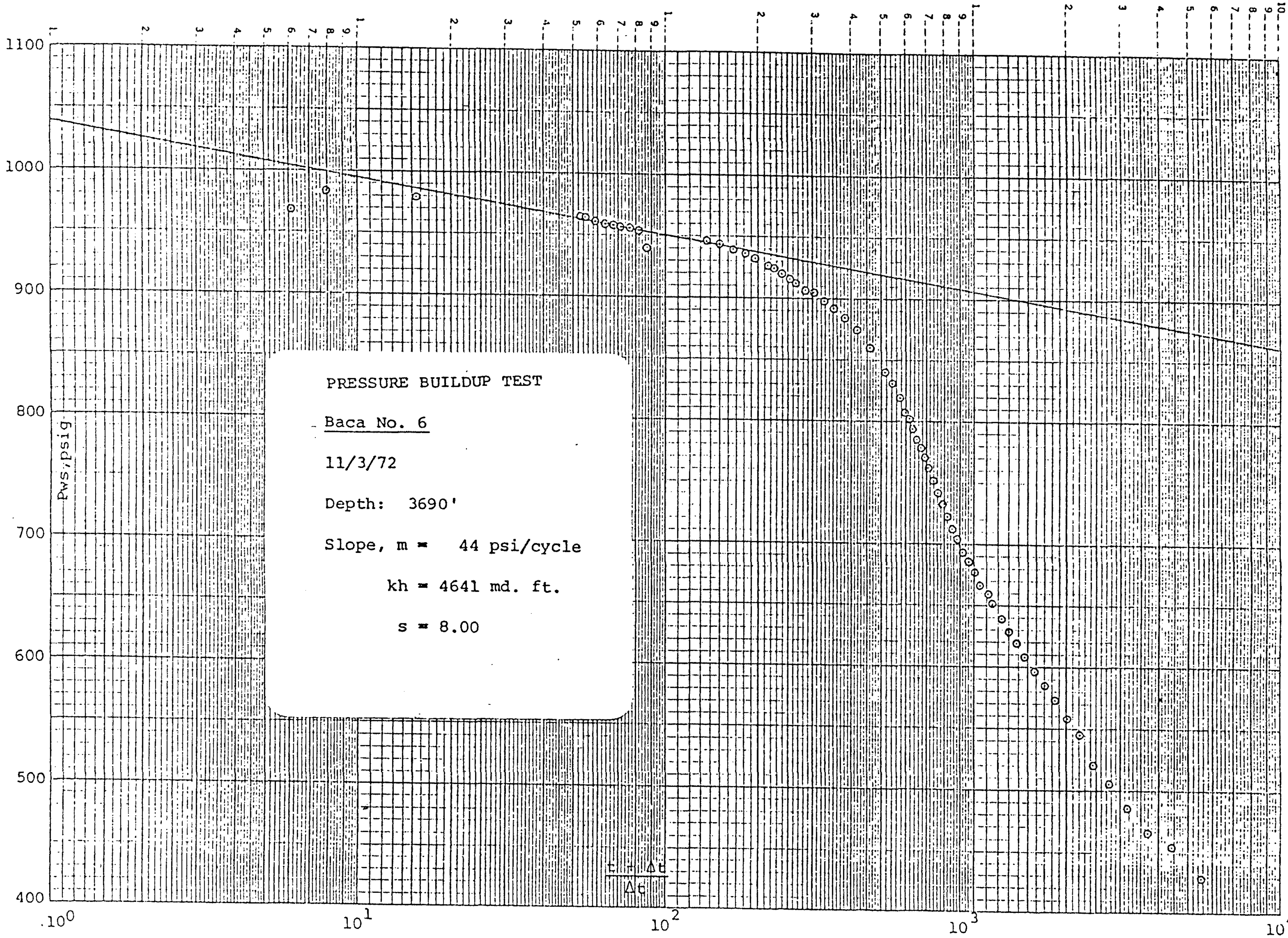
KΣ KEUFFEL & ESSER CO. MADE IN U.S.A.
46 0010
PRESSURE BUILDUP TEST
Baca No. 4
11/13/73
Depth: 6350'
Slope, m = 57 psi/cycle
kh = 4207 md ft
s = 14.7
P_{ws}, psig
$\frac{t + \Delta t}{\Delta t}$
000
800
600
400
200
000
800
600
10^0
10^1
10^2
10^3
10^4

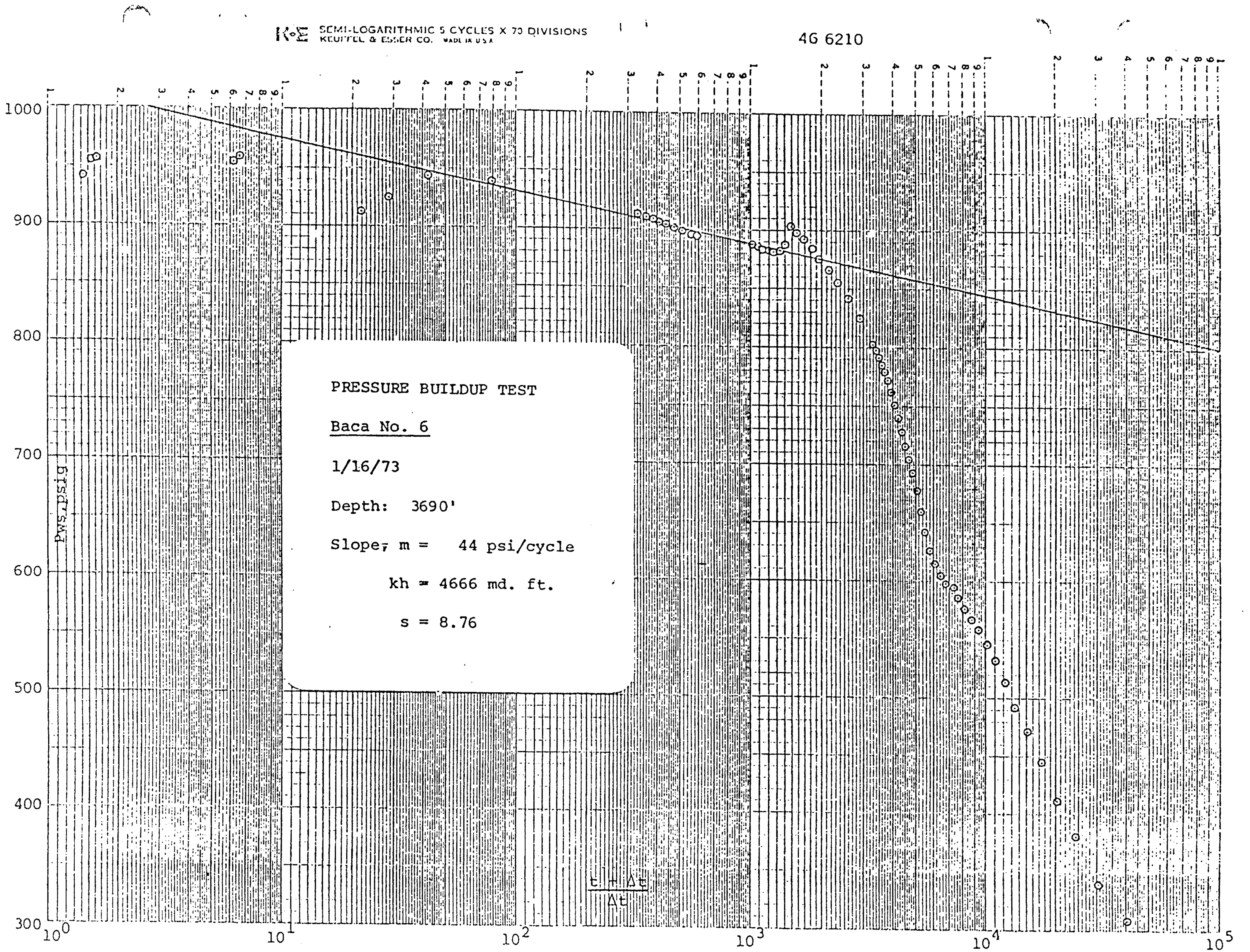


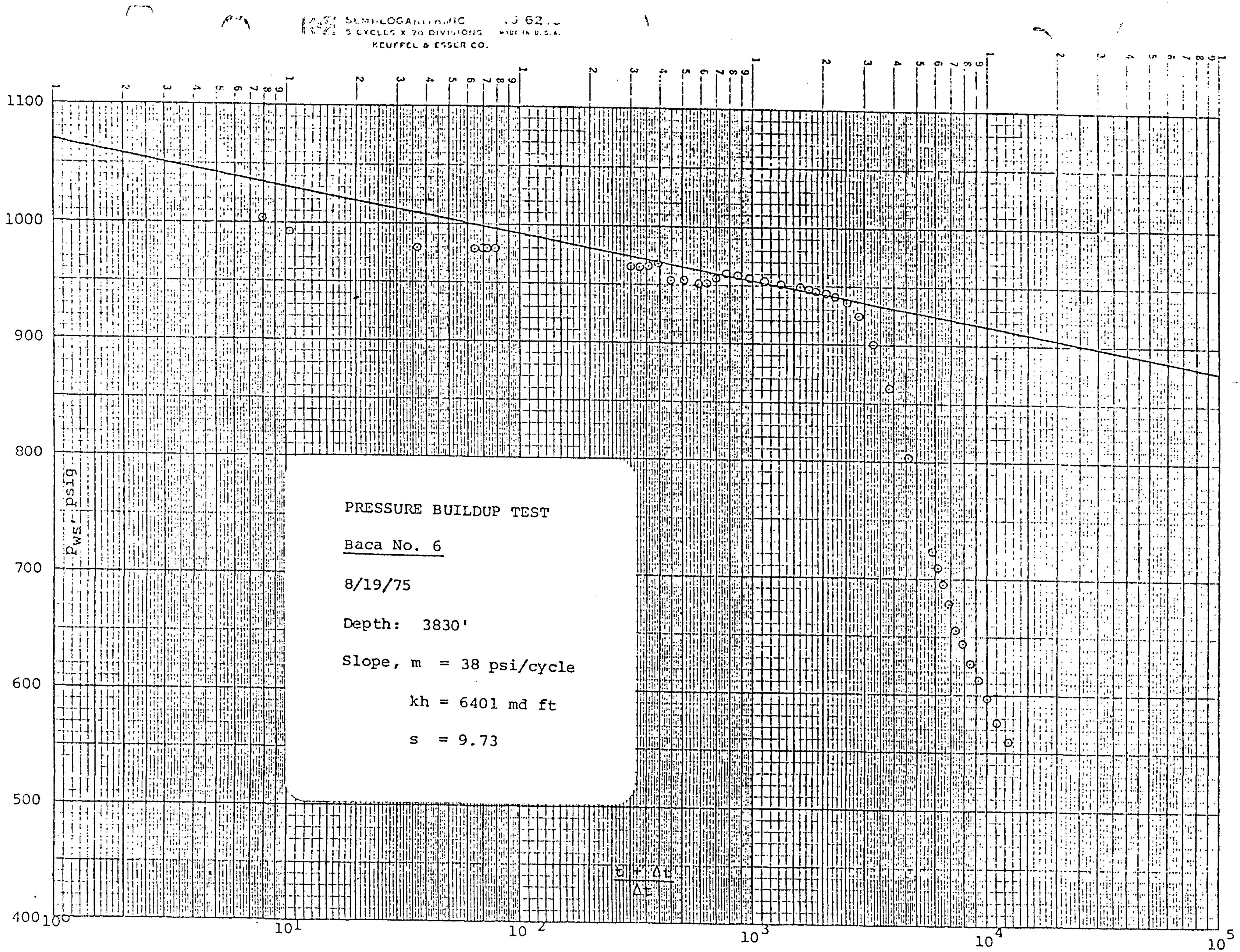
SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6010
PRESSURE BUILDUP TEST
Baca No. 6
10/15/72
Depth: 3690'
Slope, m = 44 psi/cycle
kh = 4849 md. ft.
s = 7.85
Pws, psig
t + Δt
Δt
1100
1000
900
800
700
600
500
400
10^0
10^1
10^2
10^3
10^4

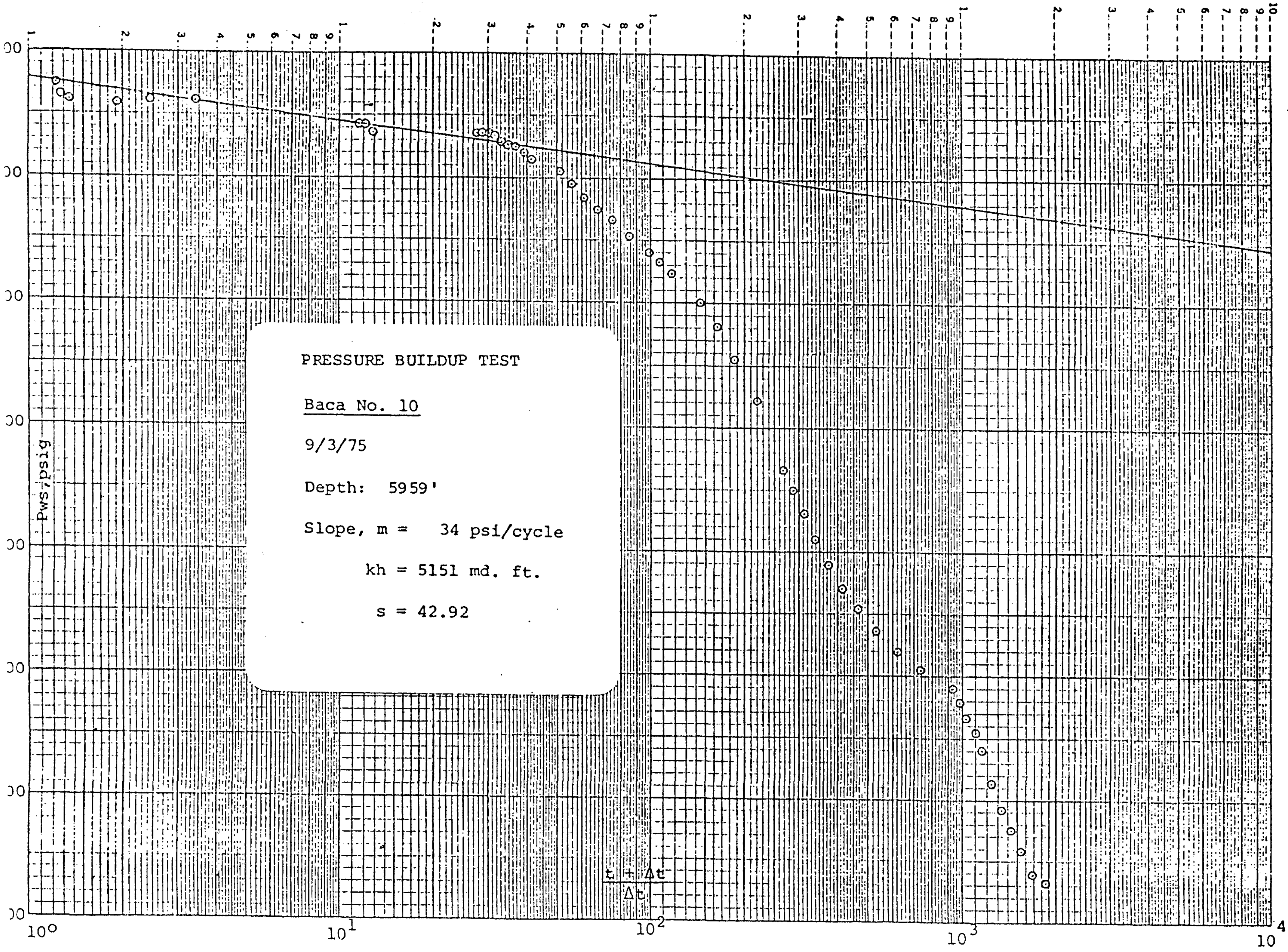
KEUFFEL & ESSER CO. MADE IN U.S.A.

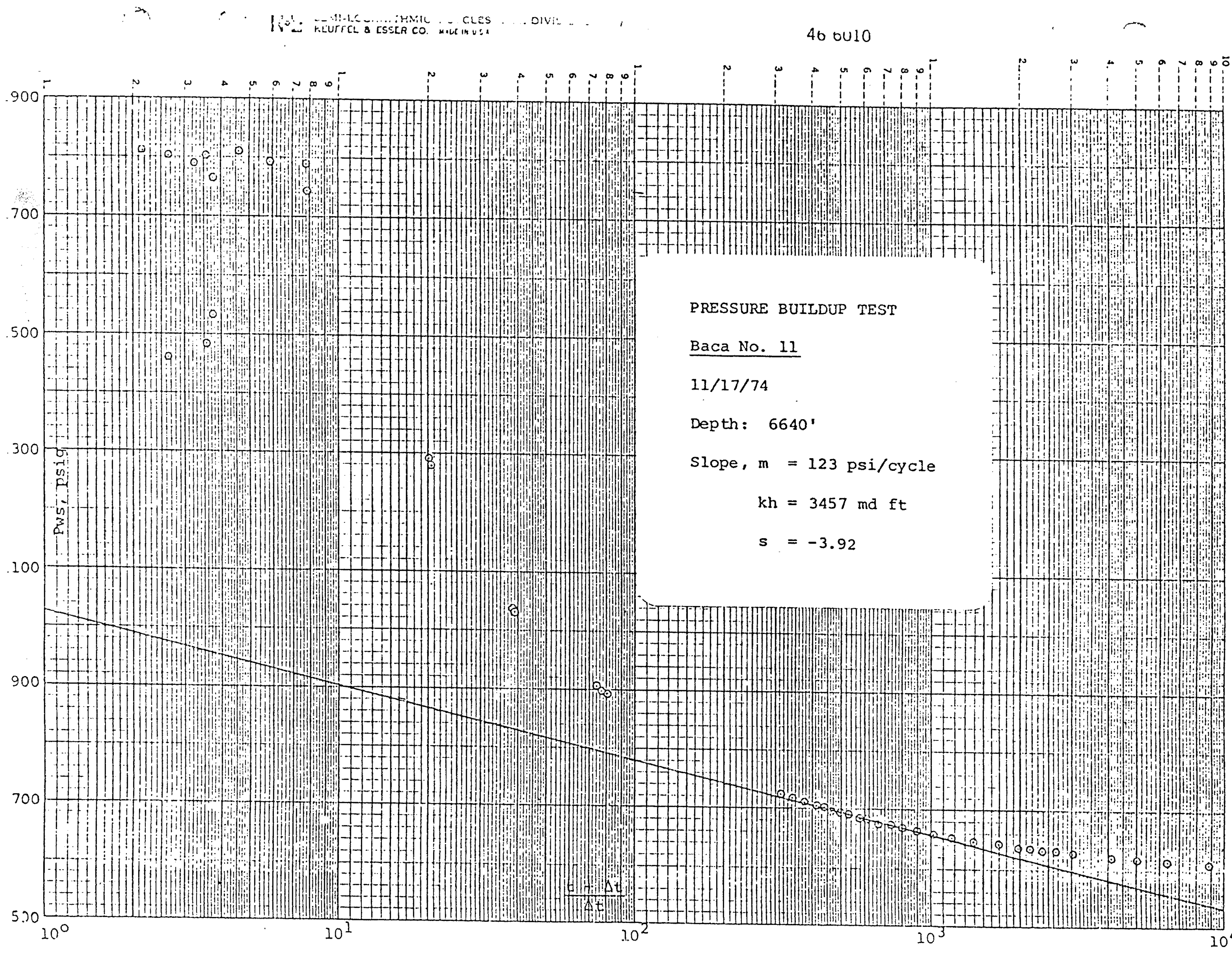
46 6010

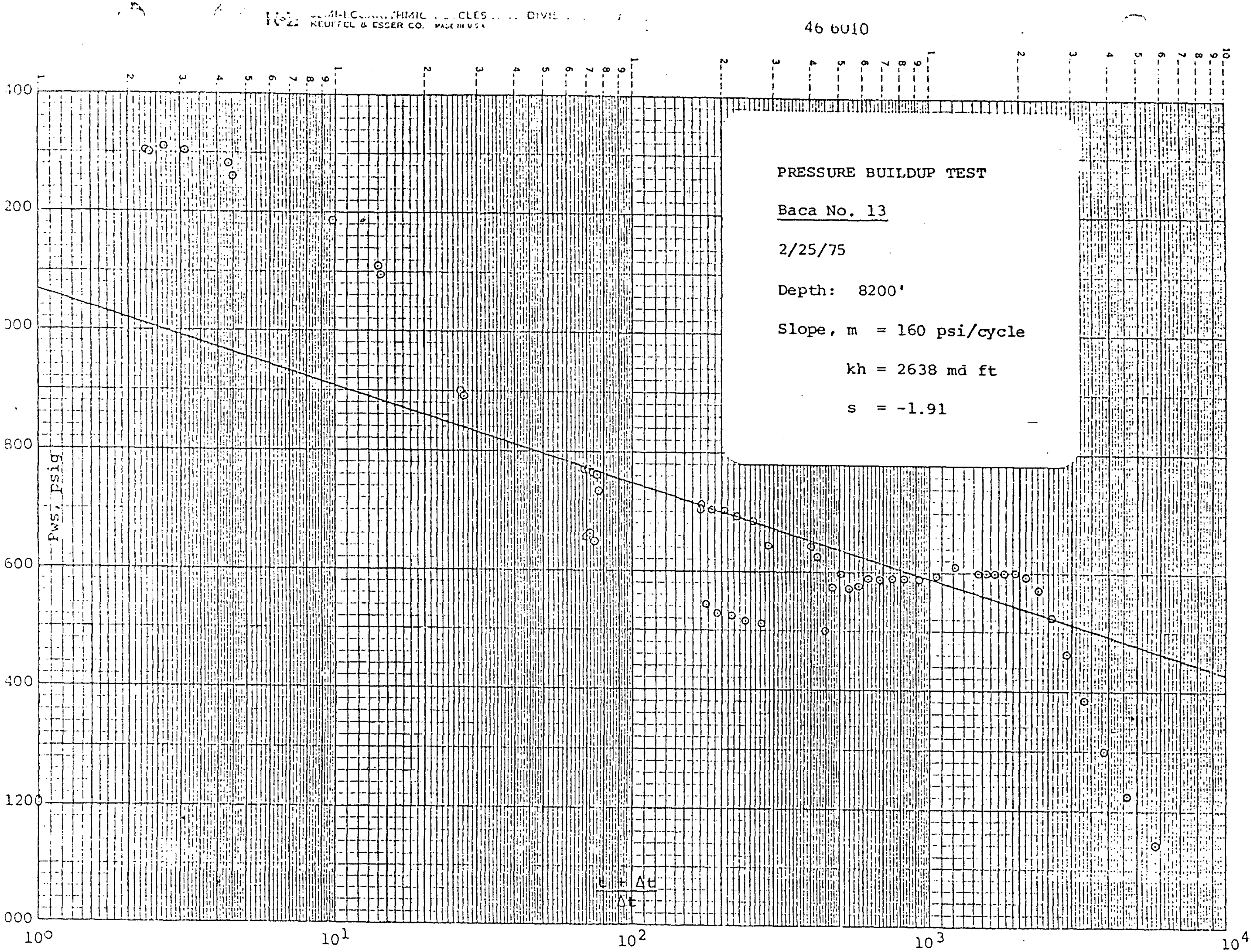



K&E SEMI-LOGARITHMIC 5 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6210
PRESSURE BUILDUP TEST
Baca No. 6
1/16/73
Depth: 3690'
Slope, m = 44 psi/cycle
kh = 4666 md. ft.
s = 8.76
Pws, psig
(t + Δt)/Δt
1000
900
800
700
600
500
400
300
10^0
10^1
10^2
10^3
10^4
10^5

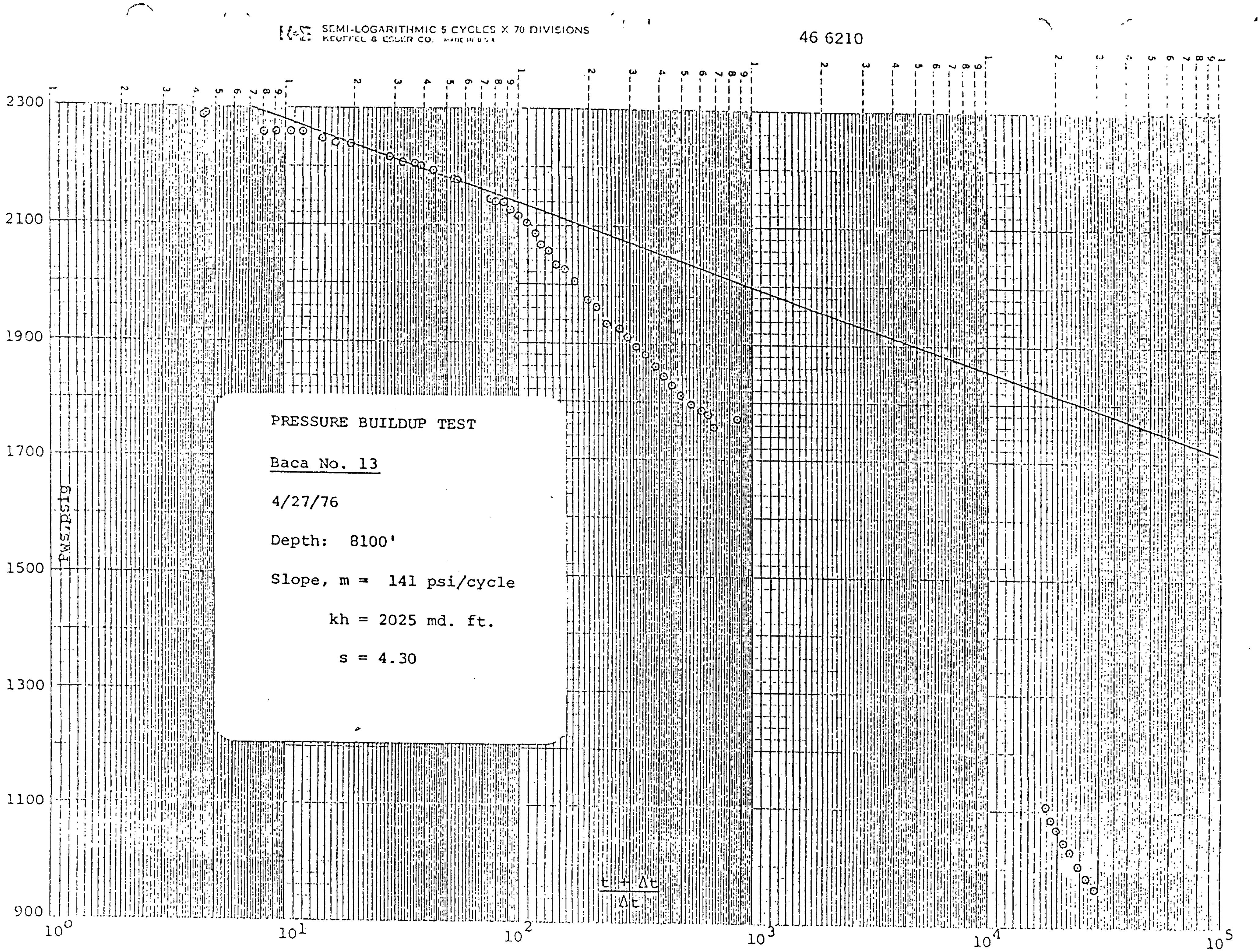

KEUFFEL & ESSER CO.
1100
1000
900
800
700
600
500
400
P_{ws}, psig
10^0
10^1
10^2
10^3
10^4
10^5
$\frac{t + \Delta t}{\Delta t}$
PRESSURE BUILDUP TEST
Baca No. 6
8/19/75
Depth: 3830'
Slope, m = 38 psi/cycle
kh = 6401 md ft
s = 9.73


SEMI-LOGARITHMIC 4 CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.
PRESSURE BUILDUP TEST
Baca No. 10
9/3/75
Depth: 5959'
Slope, m = 34 psi/cycle
kh = 5151 md. ft.
s = 42.92
Pws, psig
$\frac{t + \Delta t}{\Delta t}$
10^0
10^1
10^2
10^3
10^4

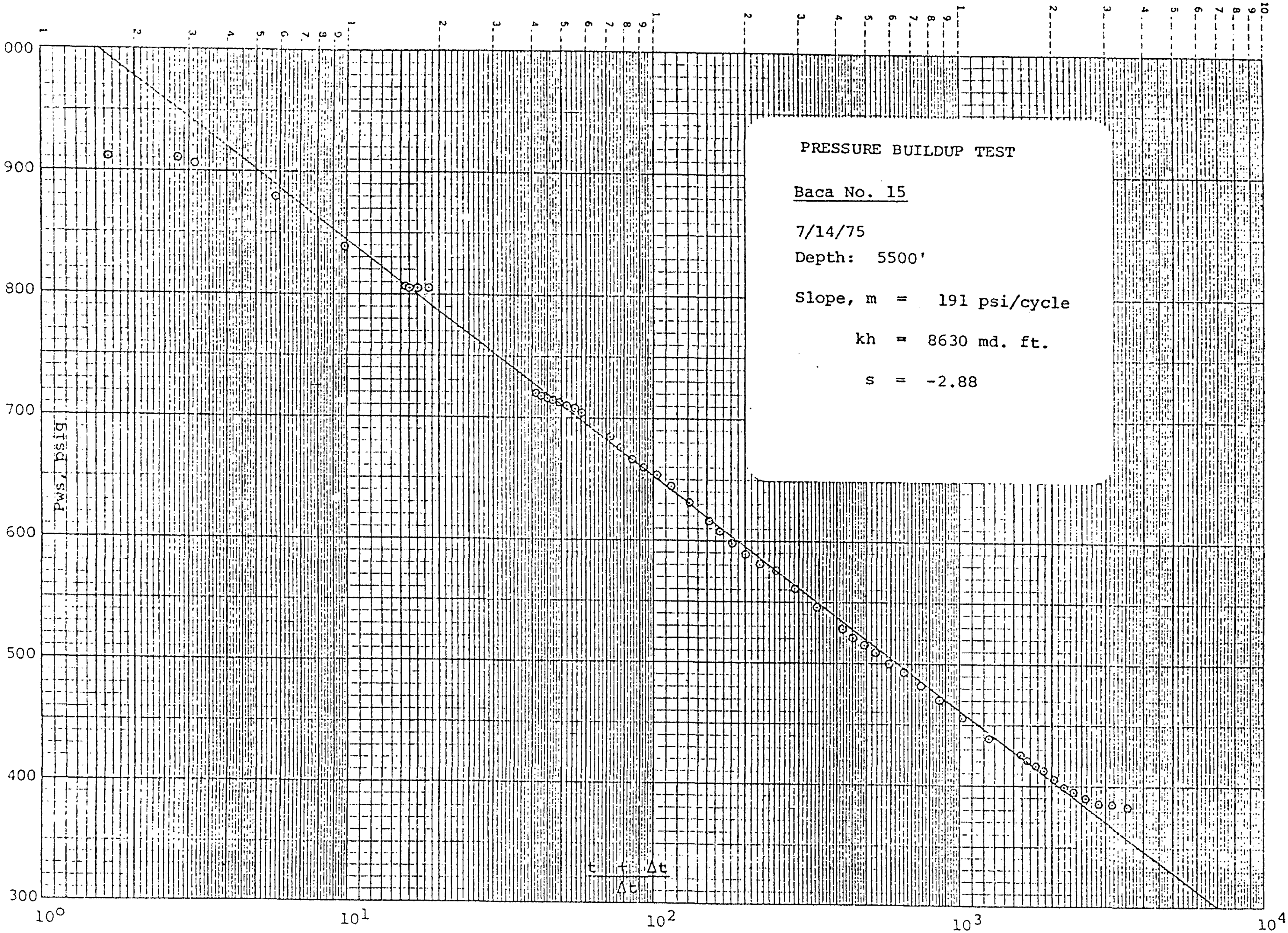

KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6010
PRESSURE BUILDUP TEST
Baca No. 11
11/17/74
Depth: 6640'
Slope, m = 123 psi/cycle
kh = 3457 md ft
s = -3.92
Pws, psig
.900
.700
.500
.300
.100
900
700
500
$\frac{t + \Delta t}{\Delta t}$
10^0
10^1
10^2
10^3
10^4



PRESSURE BUILDUP TEST
Baca No. 13
2/25/75
Depth: 8200'
Slope, m = 160 psi/cycle
kh = 2638 md ft
s = -1.91
Pws, psig
$\frac{t + \Delta t}{\Delta t}$
10^0
10^1
10^2
10^3
10^4
400
200
000
800
600
400
1200
000
46 6010
KEUFFEL & ESSER CO.

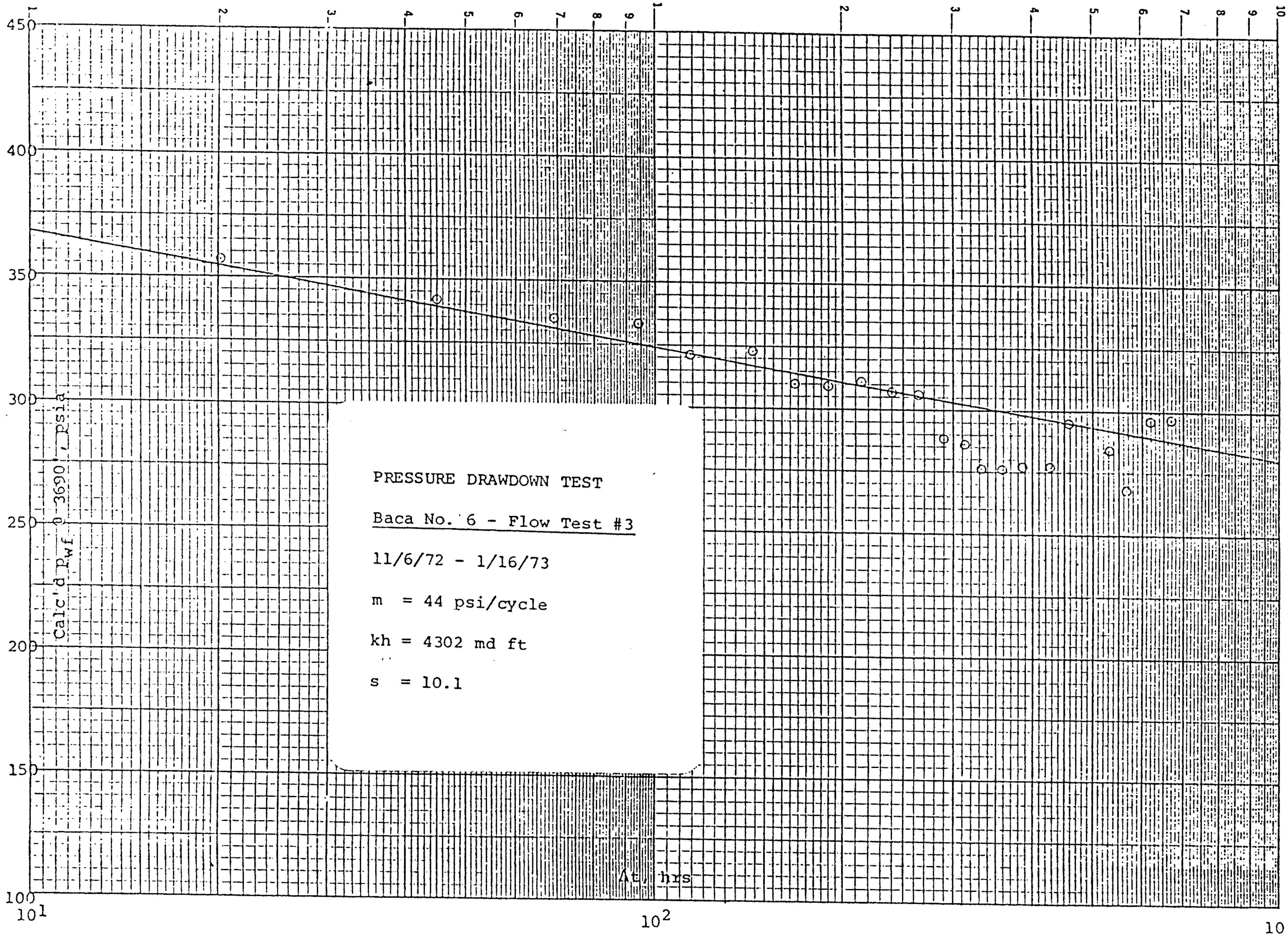


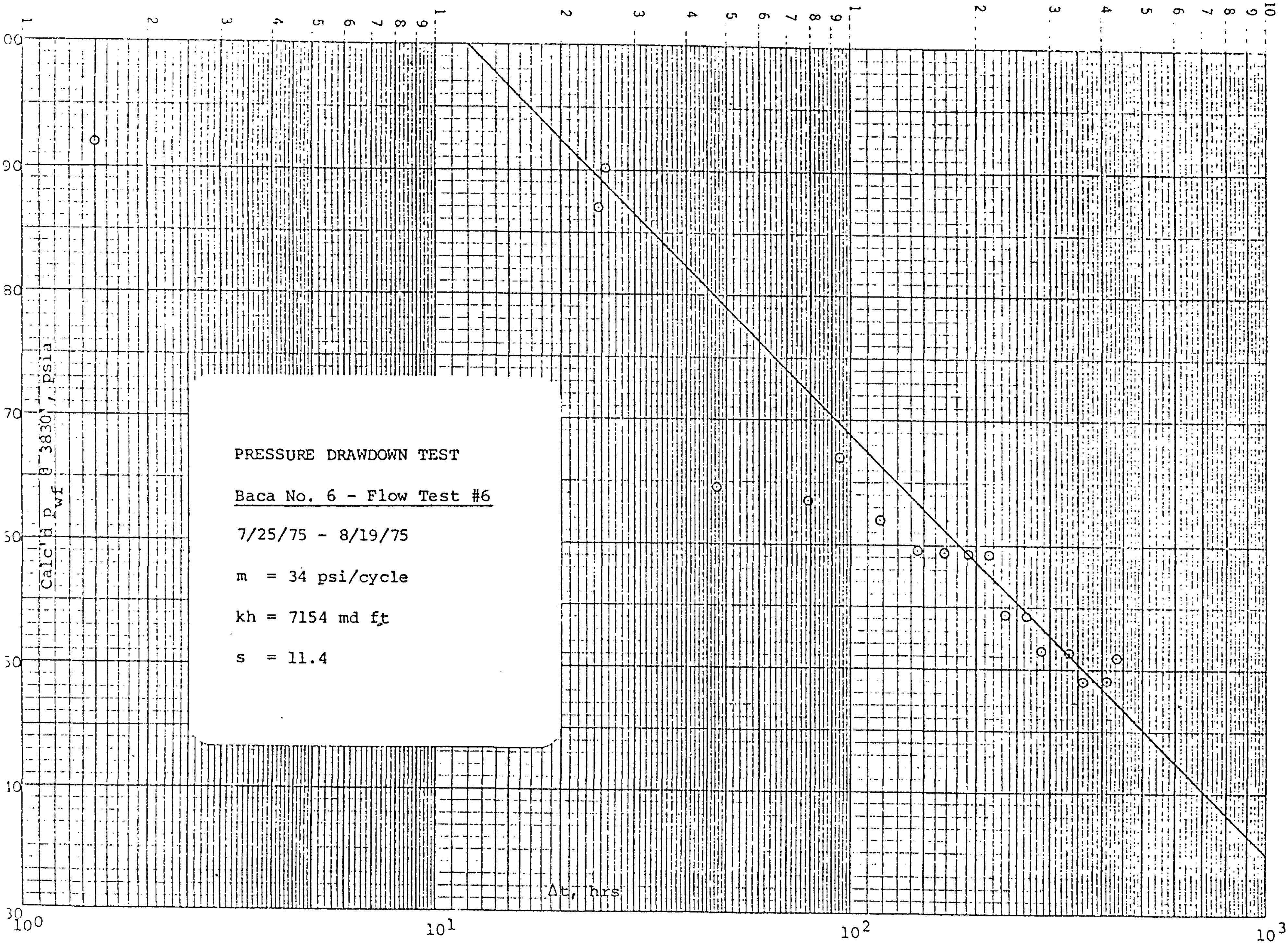
K&E SEMI-LOGARITHMIC 5 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 6210
PRESSURE BUILDUP TEST
Baca No. 13
4/27/76
Depth: 8100'
Slope, m = 141 psi/cycle
kh = 2025 md. ft.
s = 4.30
Pws, psig
2300
2100
1900
1700
1500
1300
1100
900
$\frac{t + \Delta t}{\Delta t}$
10^0
10^1
10^2
10^3
10^4
10^5

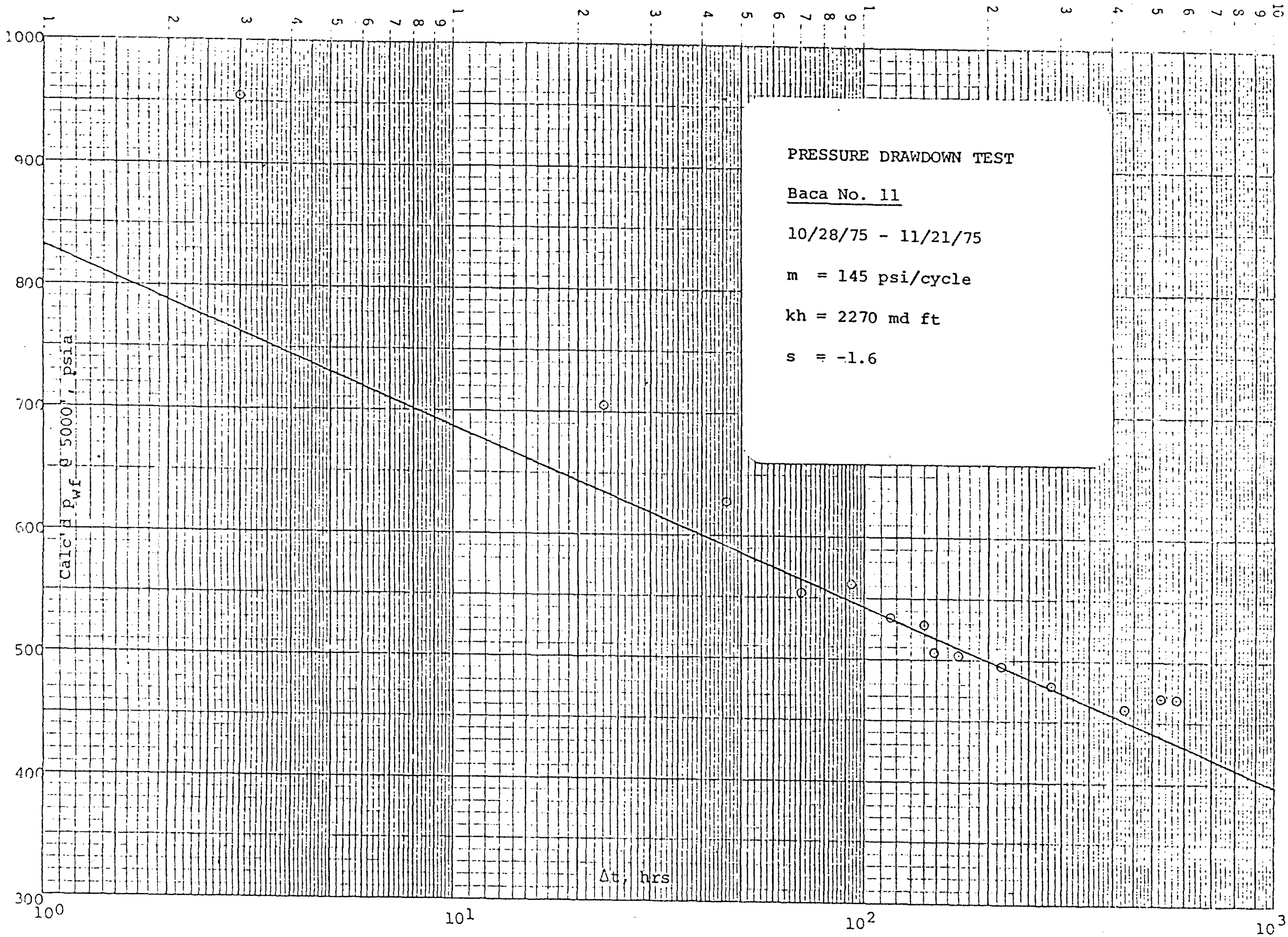


PRESSURE BUILDUP TEST
Baca No. 15
7/14/75
Depth: 5500'
Slope, m = 191 psi/cycle
kh = 8630 md. ft.
s = -2.88
Pws, psig
$\frac{t + \Delta t}{\Delta t}$
1000
900
800
700
600
500
400
300
10^0
10^1
10^2
10^3
10^4

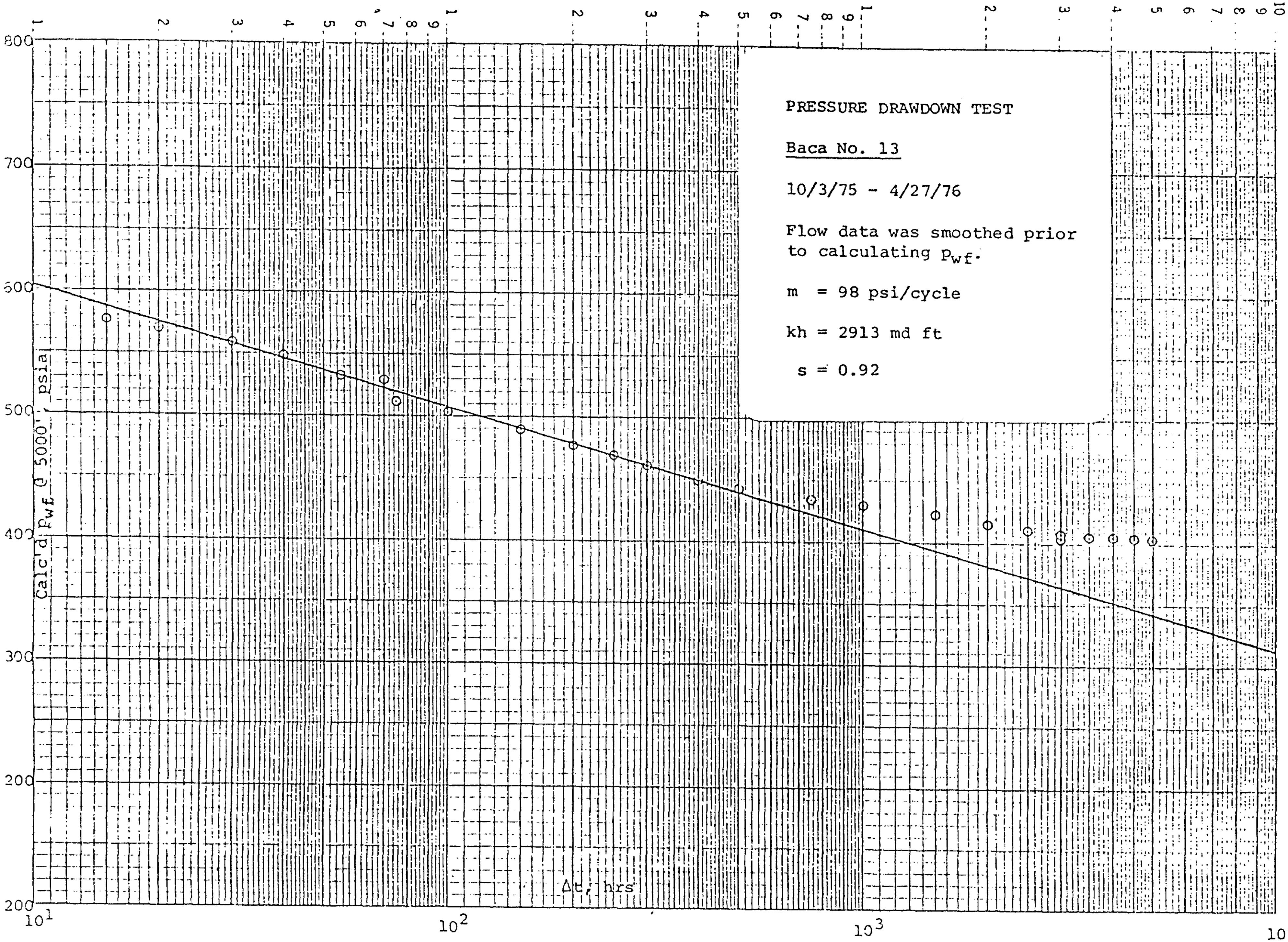
KEUFFEL & ESSER CO.




PRESSURE DRAWDOWN TEST
Baca No. 6 - Flow Test #6
7/25/75 - 8/19/75
m = 34 psi/cycle
kh = 7154 md ft
s = 11.4
Calc'd p_{wf} @ 3830', psia
Δt, hrs
10^0
10^1
10^2
10^3
00
90
80
70
60
50
10
30



PRESSURE DRAWDOWN TEST
Baca No. 11
10/28/75 - 11/21/75
m = 145 psi/cycle
kh = 2270 md ft
s = -1.6
Calc'd p_wf @ 5000', psia
Δt, hrs


PRESSURE DRAWDOWN TEST
Baca No. 13
10/3/75 - 4/27/76
Flow data was smoothed prior to calculating p_{wf}.
m = 98 psi/cycle
kh = 2913 md ft
s = 0.92
Calc'd p_{wf} @ 5000' psia
Δt, hrs
800
700
600
500
400
300
200
200
10^1
10^2
10^3
10^4

APPENDIX E

SUMMARY OF CHEMICAL ANALYSES

FLUID CHEMISTRY SUMMARY

Well BACA NO. 4

	BRINE Avg. Conc.	Range	No. of Samples
pH	6.7	6.5-7.2	3
Suspended Solids, mg/l			0
Total Dissolved Solids, mg/l	5100		1
SiO_2 mg/l	302	167-701	15
$CO_3^=$ "	0		2
HCO_3^- "	182	175-188	2
S^- "			0
$SO_4^=$ "	42	30-53	2
Cl^- "	2495	1560-2660	15
Na "	1473	950-1580	16
K "	300	198-311	16
Ca "	6.3	4.1-7.0	16
Mg "	0.3		1
Ba "			0
B "	20	19-21	2
F "	<0.02		1
Total Mass Flow, #/hr	171,400	160,300-176,100	
Steam Fraction, %	26.8	24.4-29.4	
Pressure, psig	119.7	111-173.5	

NONCONDENSIBLE GASES

% by wt. 3.16 Avg. ______ Range 1 No. of Samples

% by Vol. ______ Avg. ______ Range 0 No. of Samples

	ppm by weight Avg.	ppm by weight Range	ppm by volume Avg.	ppm by volume Range	No. of Samples
CO_2	30,390		12,430		1
H_2S	165	117-213	87	62-112	2
N_2	0		0		2
H_2	1.4		12.5		2
CH_4	2.8	2.2-3.4	3.2	2.5-3.8	2

NOTE: Left out values obtained from diluted samples. CO_2 and H_2S concentrations are from total steam samples.

FLUID CHEMISTRY SUMMARY

Well BACA NO. 6

	BRINE Avg. Conc.	Range	No. of Samples
pH	7.4		1
Suspended Solids, mg/l	26		1
Total Dissolved Solids, mg/l	6018	5800-6230	5
SiO_2 mg/l	453	160-600	3
$CO_3^=$ "	58	0 -93	3
HCO_3^- "	84	68.8-99	2
S^- "	1		1
$SO_4^=$ "	30	29-32	4
Cl^- "	3082	2860-3400	6
Na "	1721	1640-1780	5
K "	322	290-370	5
Ca "	8.5	0.1-12	4
Mg "	0.08		1
Ba "			0
B "	20	17-21	3
F "	6.7		1
Total Mass Flow, #/hr	163,700	148,500-181,600	
Steam Fraction, %	27.8	23.7-31.5	
Pressure, psig	60.4	38 - 96	

NONCONDENSIBLE GASES

	Avg.	Range	No. of Samples
% by wt.	1.33	1.27-1.38	2
% by Vol.	0.78	0.52-1.06	5

	ppm by weight Avg.	ppm by weight Range	ppm by volume Avg.	ppm by volume Range	No. of Samples
CO_2	11,140	9,000-15,775	6450	(1 sample)	7
H_2S	99	69-257	136	(1 sample)	7
N_2	2.5	0-5	1.5	0 - 3	2
H_2	0.5	0.4-0.6	4.5	3.7-5.2	2
CH_4	0		0		2

NOTE: CO_2 and H_2S concentrations are from total steam samples.

FLUID CHEMISTRY SUMMARY

Well BACA NO. 11

	BRINE		
	Avg. Conc.	Range	No. of Samples
pH	7.2	6.6-8.4	8
Suspended Solids, mg/l	616	522-688	3
Total Dissolved Solids, mg/l	6895	6056-7593	4
SiO_2 mg/l	740	640-835	7
$CO_3^=$ "	11	0 - 48	8
HCO_3^- "	99	24-150	8
S^- "	4.1	1.5-6.5	4
$SO_4^=$ "	68	50-84	6
Cl^- "	3453	2590-4400	8
Na "	1959	1810-2200	8
K "	456	340-550	8
Ca "	30	17-46	8
Mg "	0.14	0.07-0.2	7
Ba "			0
B "	28	24-35	7
F "	6.6	5-7.6	3
Total Mass Flow, #/hr	227,100	122,700-347,400	
Steam Fraction, %	39.7	24.2-50.3	
Pressure, psig	123.7	96-171	

NONCONDENSIBLE GASES

	Avg.	Range	No. of Samples
% by wt.	3.76	2.30-5.94	8
% by Vol.	1.60	0.96-2.54	7

	ppm by weight		ppm by volume		
	Avg.	Range	Avg.	Range	No. of Samples
CO_2	49,250	33,700-89,100	20,220	13,775-36,450	6
H_2S	477	290-867	255	153-474	7
N_2	132	0-381	86	0-245	8
H_2	3.8	1.4-7.4	34.5	13-69	8
CH_4	1.2	0-5.8	1.4	0-6.6	8

NOTE: CO_2 and H_2S concentrations are from total steam samples.

FLUID CHEMISTRY SUMMARY

Well BACA NO. 13

	BRINE		
	Avg. Conc.	Range	No. of Samples
pH	7.6	6.9-8.5	8
Suspended Solids, mg/l	360	5.5-734	3
Total Dissolved Solids, mg/l	6477	5500-8684	8
SiO_2 mg/l	786	556-963	10
$CO_3^=$ "	28	0-97	8
HCO_3^- "	214	163-281	8
S^- "	2.2	1-4	5
$SO_4^=$ "	164	50-344	7
Cl^- "	2783	2320-3300	8
Na "	1733	1500-2030	8
K "	329	278-394	8
Ca "	6.8	5-11	8
Mg "	0.49	0.04-1.5	6
Ba "			0
B "	22	19-24	8
F "	10.2	8-11.6	7
Total Mass Flow, #/hr	284,600	195,500-507,000	
Steam Fraction, %	28.4	26.8-30.2	
Pressure, psig	89.4	64-118	

NONCONDENSIBLE GASES

% by wt. 2.93 Avg. 1.93-3.94 Range 12 No. of Samples

% by Vol. 1.23 Avg. 0.80-1.64 Range 12 No. of Samples

	ppm by weight		ppm by volume		
	Avg.	Range	Avg.	Range	No. of Samples
CO_2	38,520	30,040-45,200	15,830	12,300-18,900	5
H_2S	149	86.3-205	79	45.6-108	6
N_2	33	0-122	24	0-114	14
H_2	0.22	0-0.9	2.1	0-8.4	10
CH_4	1.7	0-10	1.9	0-11	9

NOTE: CO_2 and H_2S concentrations are from total steam samples.

Left out values obtained from low rate of two-rate test.

FLUID CHEMISTRY SUMMARY

Well BACA 12 - REINJECTION WATER

	BRINE		
	Avg. Conc.	Range	No. of Samples
pH	7.6	6.85-7.9	3
Suspended Solids, mg/l	434	18-1216	3
Total Dissolved Solids, mg/l	7203	6770-7690	3
SiO_2 mg/l	828	621-1027	3
$CO_3^=$ "	25	20-31	3
HCO_3^- "	144	127-175	3
S^- "	0.5	0.3-0.6	2
$SO_4^=$ "	93	81-104	3
Cl^- "	3627	3350-3800	3
Na "	2152	2100-2180	3
K "	443	400-480	3
Ca "	16	14-18	3
Mg "	0.15	0.06-0.3	3
Ba "	0.08	0.07-0.08	3
B "	27	23-30	3
F "	11.5	10.4-12.4	3
Total Mass Flow, #/hr			
Steam Fraction, %			
Pressure, psig			

NONCONDENSIBLE GASES

% by wt. ________ Avg. ________ Range ________ No. of Samples

% by Vol. ________ Avg. ________ Range ________ No. of Samples

	ppm by weight		ppm by volume		
	Avg.	Range	Avg.	Range	No. of Samples
CO_2					
H_2S					
N_2					
H_2					
CH_4					

FLUID CHEMISTRY SUMMARY

Well BACA 14 - REINJECTION WATER

	BRINE Avg. Conc.	BRINE Range	BRINE No. of Samples
pH	7.4	6.8-7.9	3
Suspended Solids, mg/l	458	23-1300	3
Total Dissolved Solids, mg/l	7533	6550-8420	3
SiO_2 mg/l	778	621-877	3
$CO_3^{=}$ "	21	1.5-33	3
HCO_3^- "	112	82-128	3
S^- "	0.3		2
$SO_4^{=}$ "	107	83-120	3
Cl^- "	3828	3480-4435	3
Na "	2123	2040-2200	3
K "	538	475-575	3
Ca "	22	16-31	3
Mg "	0.1	0.05-0.2	3
Ba "	0.12	0.08-0.2	3
B "	31	30-32	3
F "	10.7	8.6-11.8	3
Total Mass Flow, #/hr			
Steam Fraction, %			
Pressure, psig			

NONCONDENSIBLE GASES

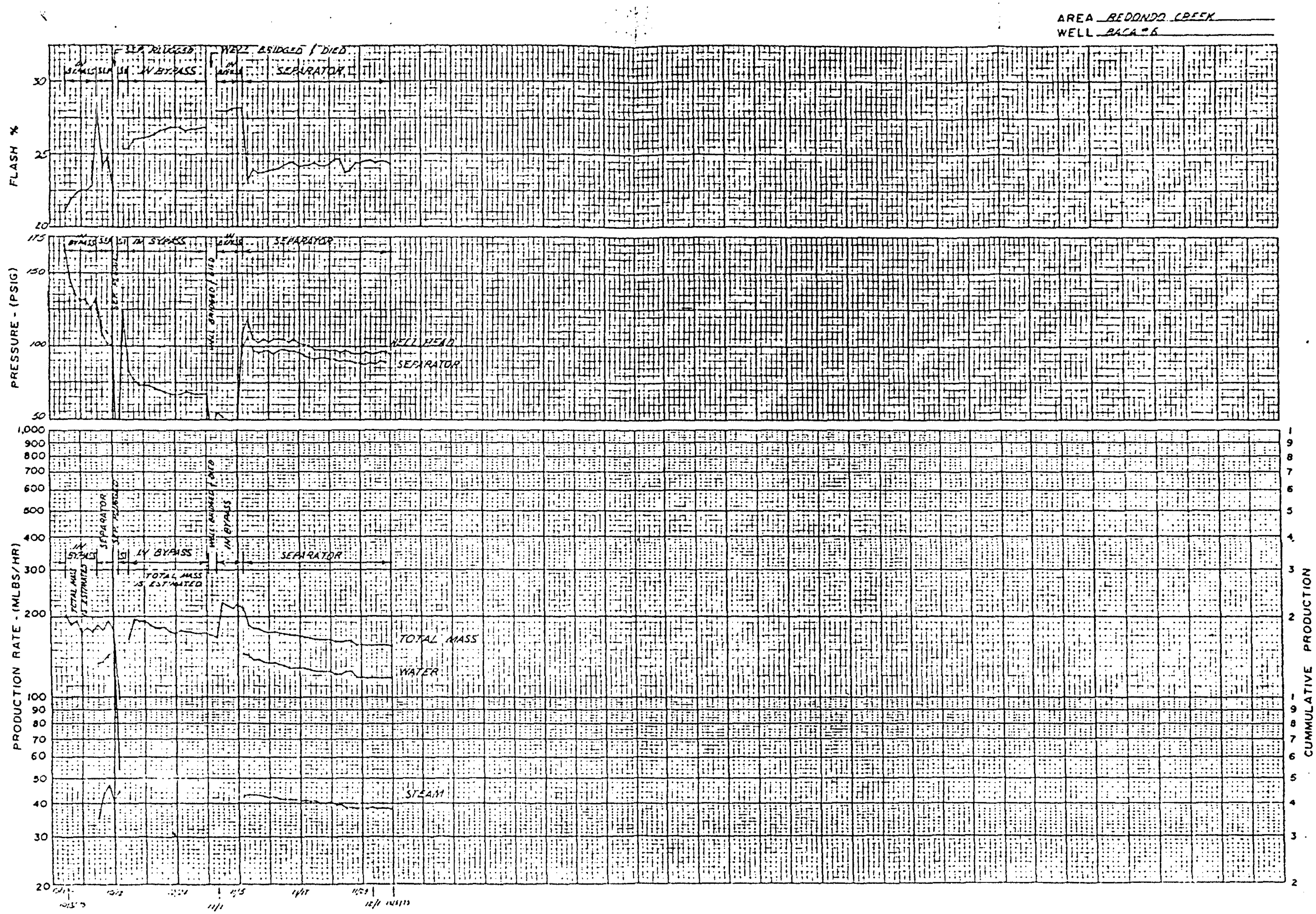
% by wt. ______ Avg. ______ Range ______ No. of Samples

% by Vol. ______ Avg. ______ Range ______ No. of Samples

	ppm by weight Avg.	ppm by weight Range	ppm by volume Avg.	ppm by volume Range	No. of Samples
CO_2					
H_2S					
N_2					
H_2					
CH_4					

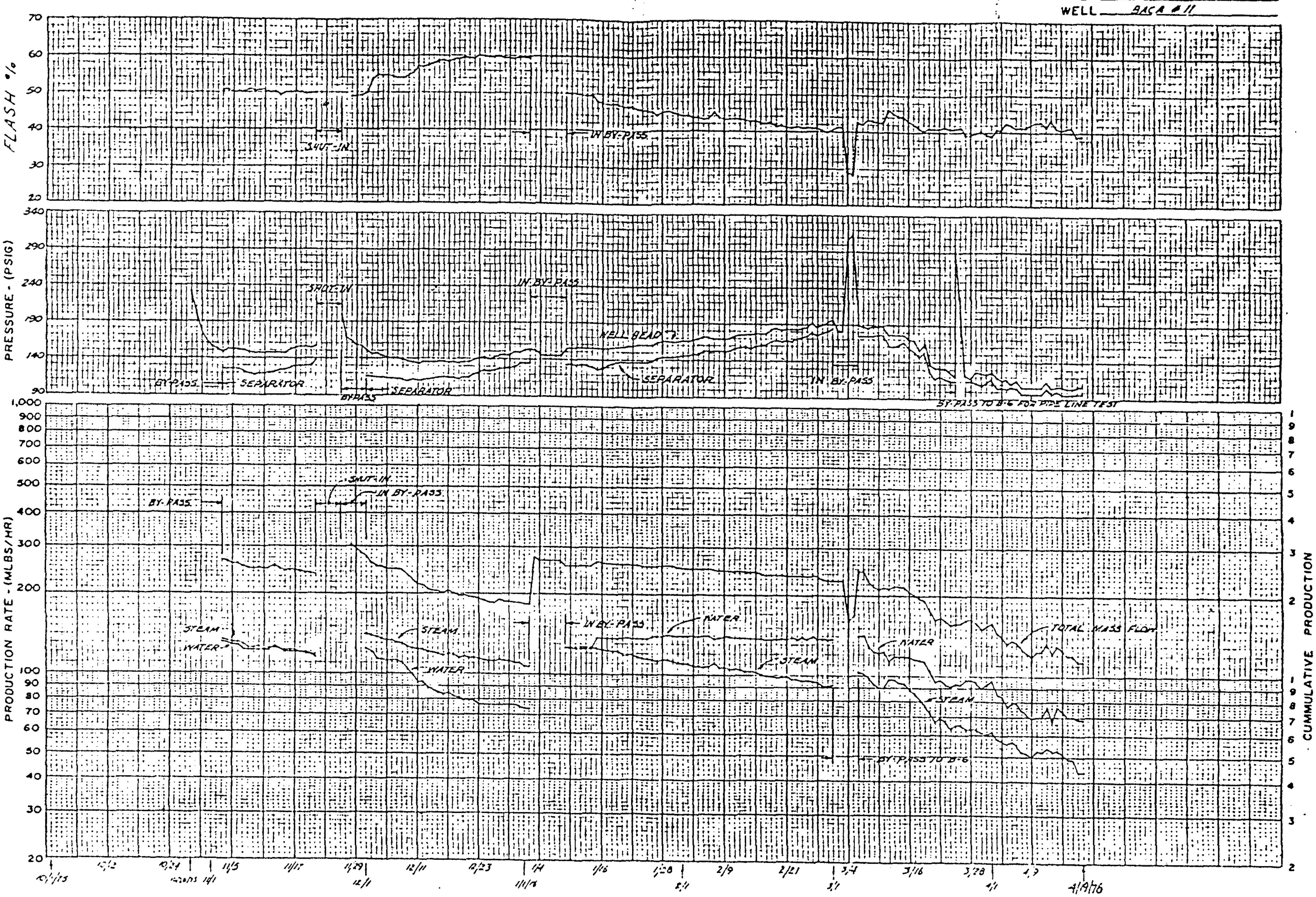
APPENDIX F

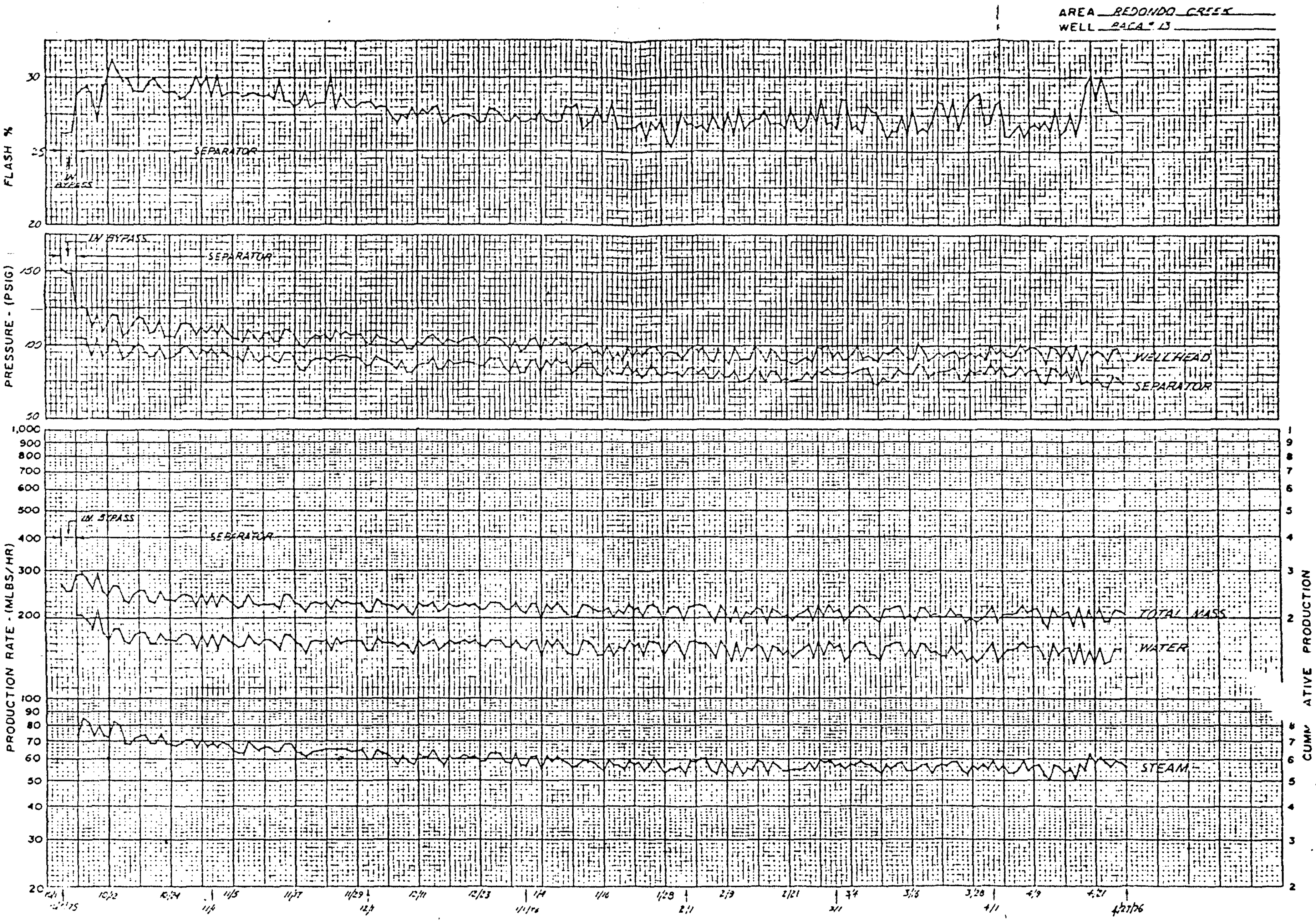
PRODUCTION PERFORMANCE OF
WELLS B-6, 11 & 13 DURING THE
INTERFERENCE TEST
10/1/75 THROUGH 4/27/76



AREA REDONDO CREEK
WELL BACA #6
FLASH %
PRESSURE - (PSIG)
PRODUCTION RATE - (MLBS/HR)
CUMMULATIVE PRODUCTION
WELL BRIDGED / DIED
SEPARATOR
IN BYPASS
WELL HEAD
TOTAL MASS
WATER
STEAM
TOTAL MASS IS ESTIMATED

AREA REDONDO CREEK
WELL BACA # 11

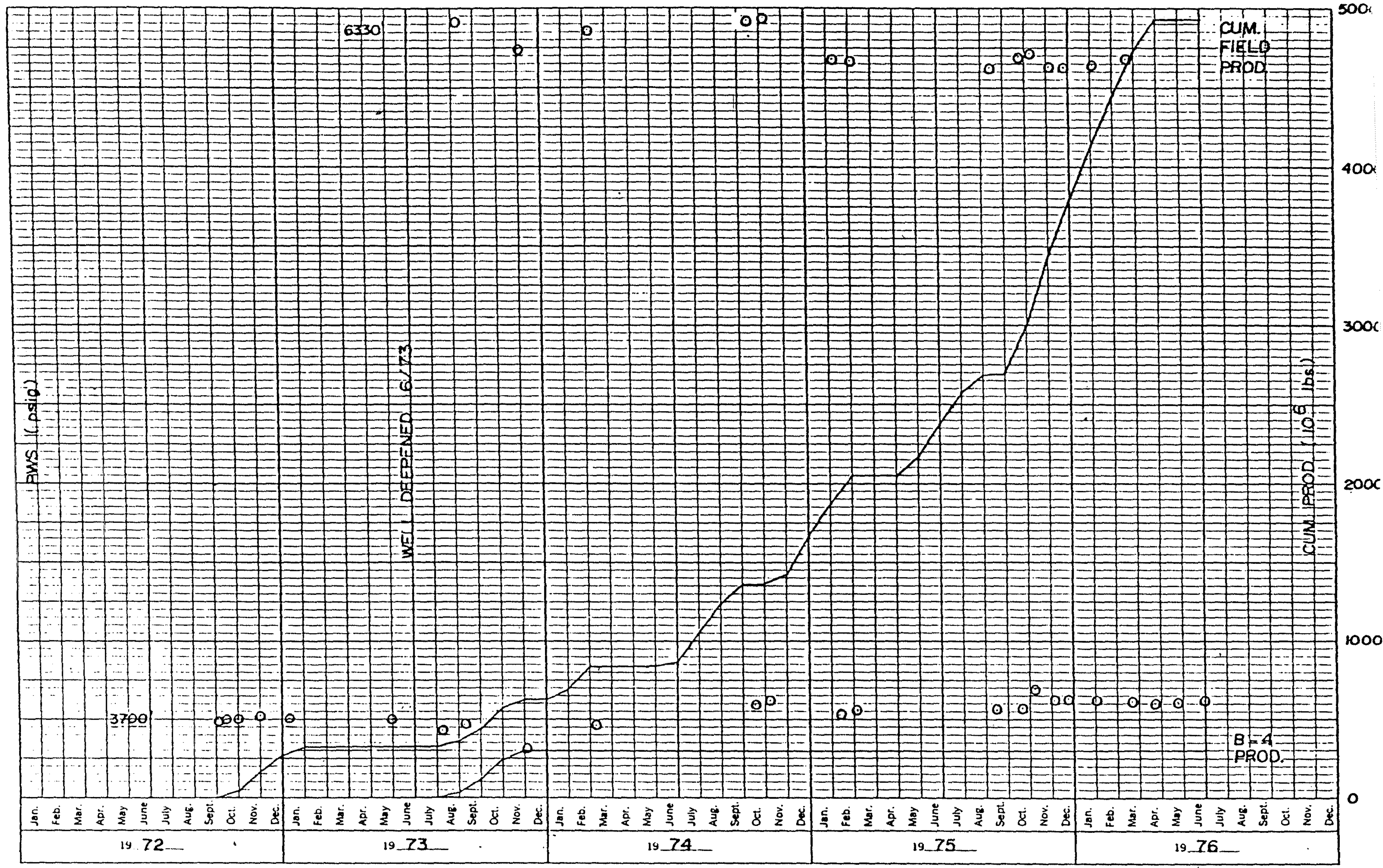




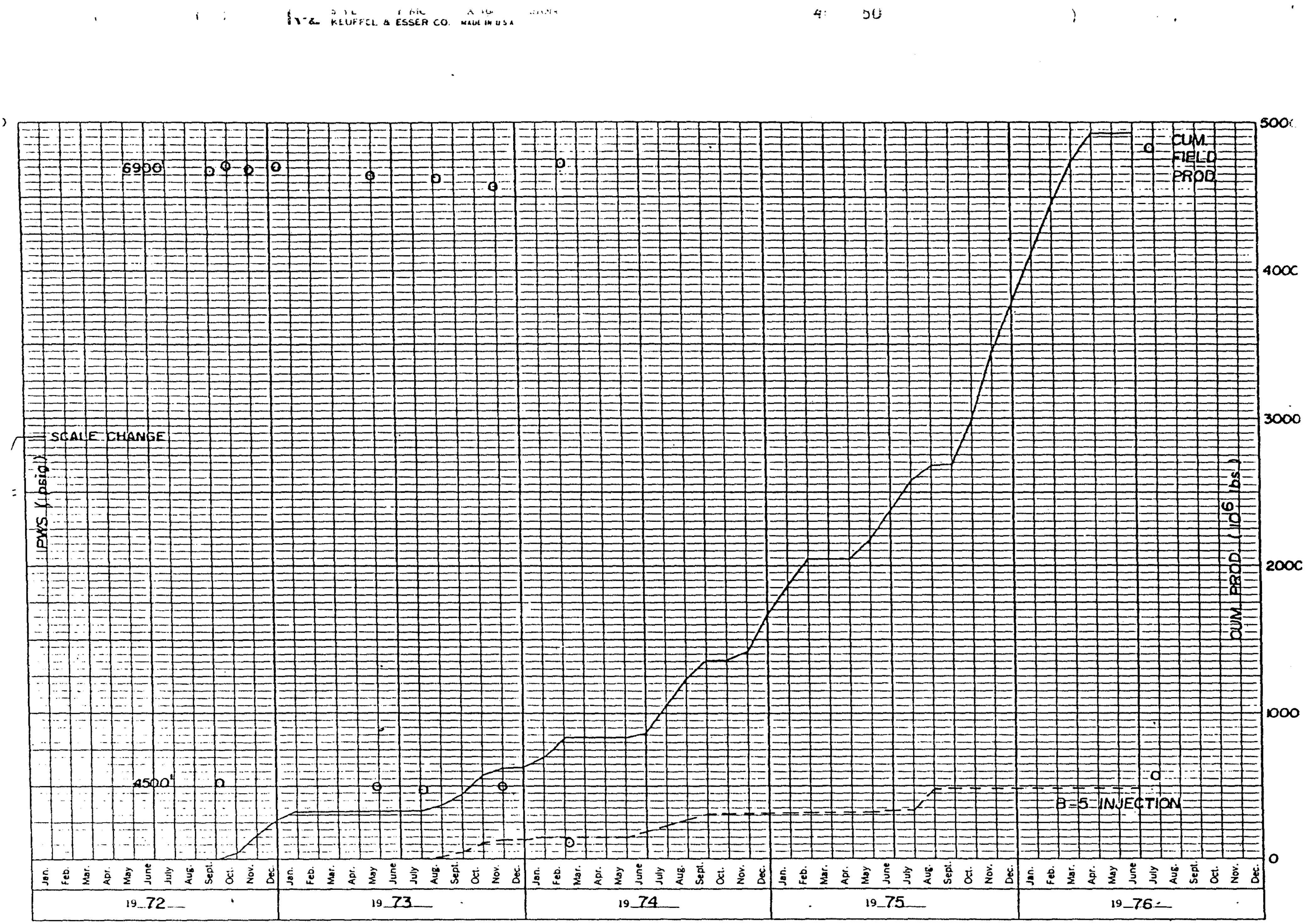
AREA REDONDO CREEK
WELL BACA # 13
FLASH %
30
25
20
SEPARATOR
LW BYPASS
PRESSURE - (PSIG)
150
100
50
WELLHEAD
SEPARATOR
PRODUCTION RATE - (MLBS/HR)
1,000
900
800
700
600
500
400
300
200
100
90
80
70
60
50
40
30
20
TOTAL MASS
WATER
STEAM
CUMMULATIVE PRODUCTION
10/2
10/24
11/4
11/5
11/17
11/29
12/1
12/11
12/23
1/1/76
1/4
1/16
1/28
2/1
2/9
2/21
3/1
3/4
3/16
3/28
4/1
4/9
4/21
4/27/76

APPENDIX G

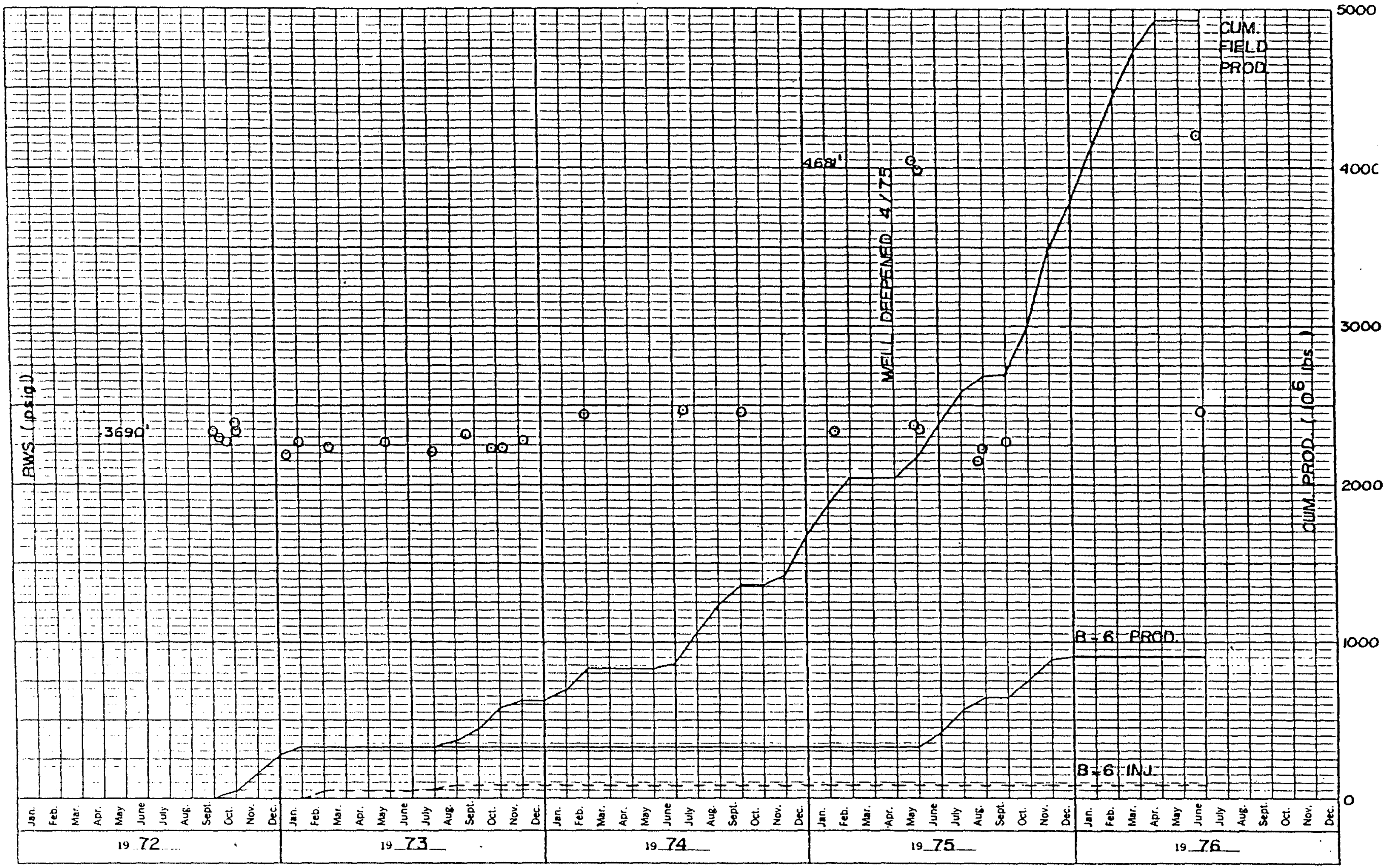
PRODUCTION AND PRESSURE HISTORY OF THE REDONDO CREEK AREA WELLS



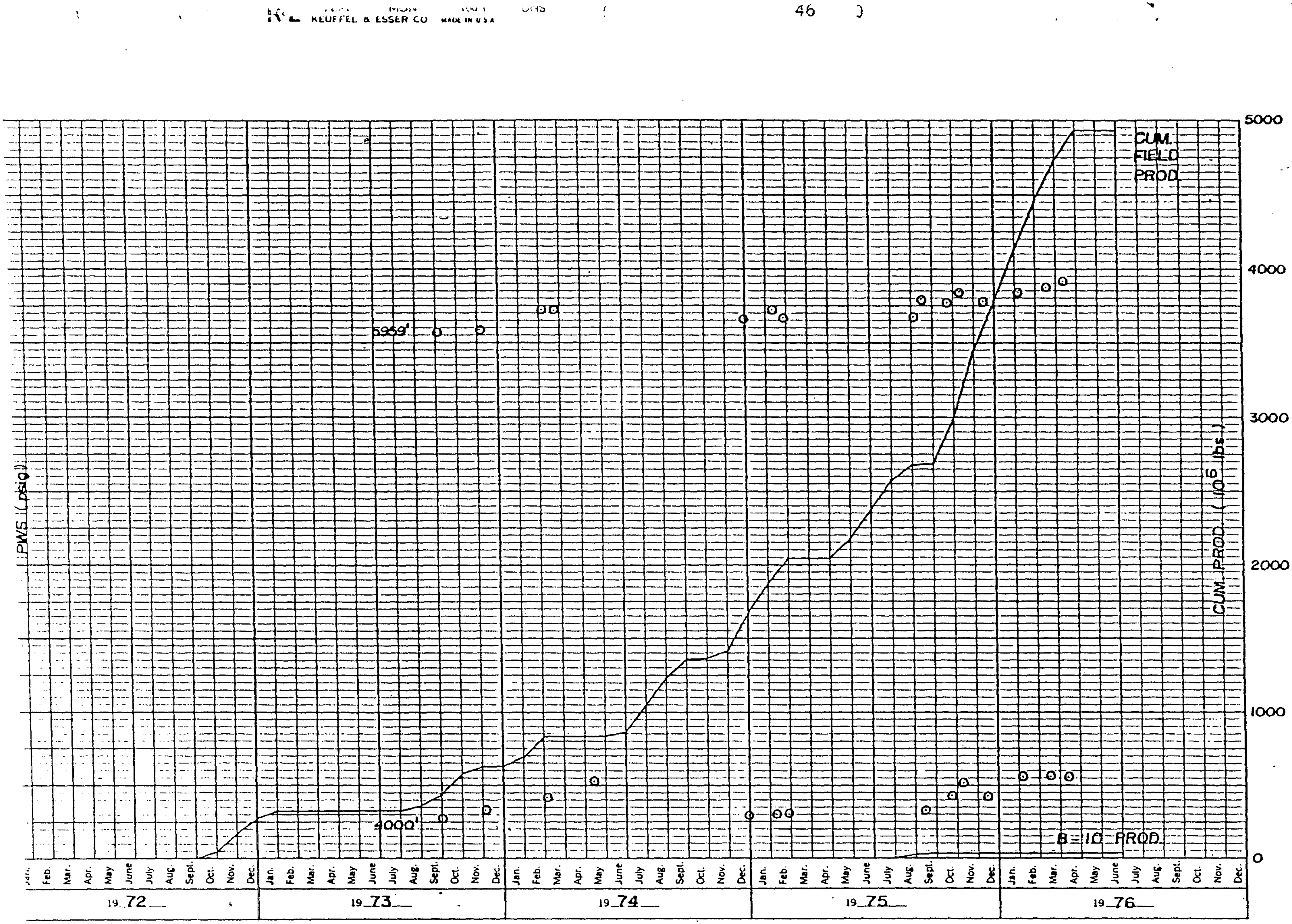
PRODUCTION AND PRESSURE HISTORY - BACA 4



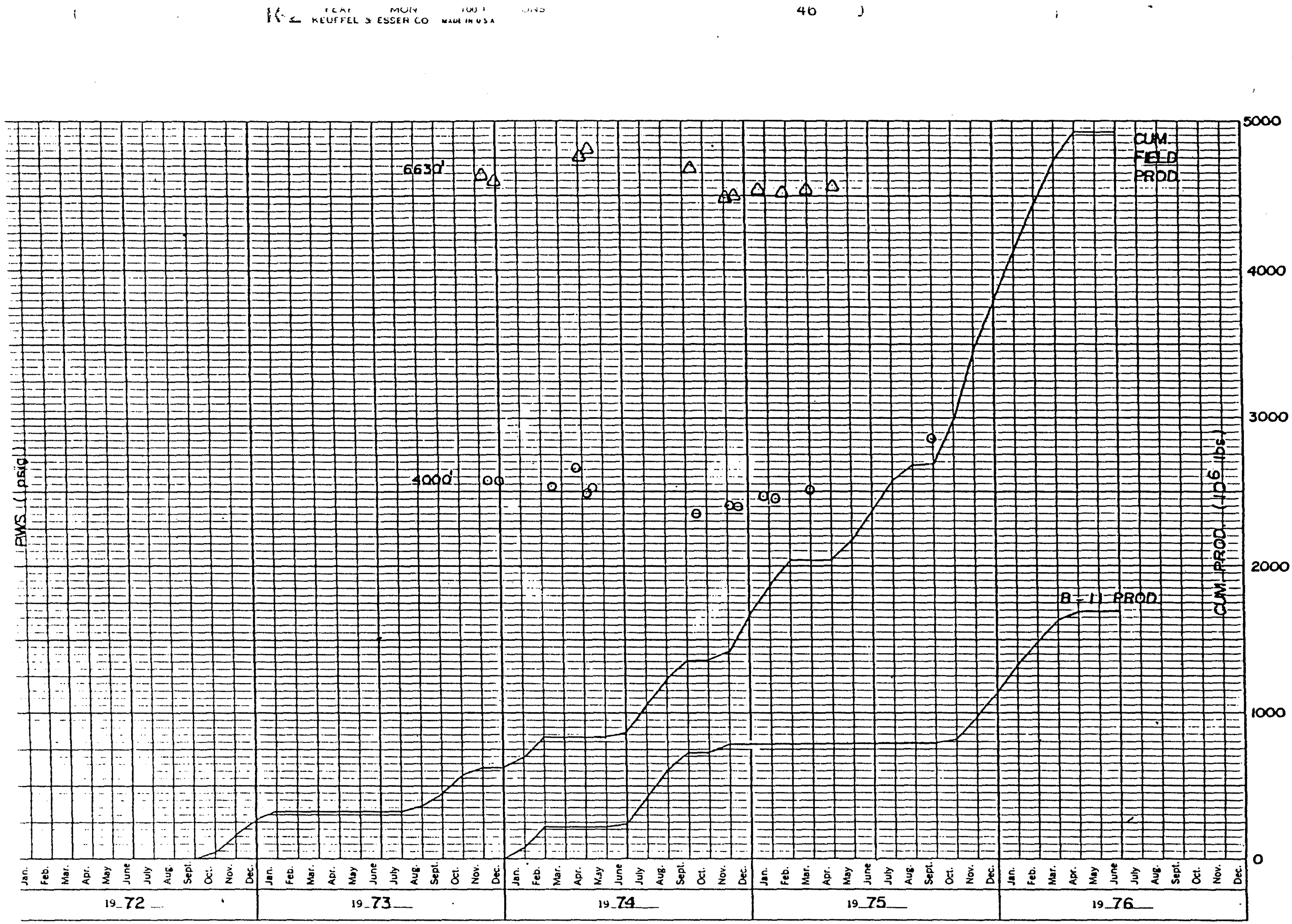
INJECTION AND PRESSURE HISTORY - BACA 5



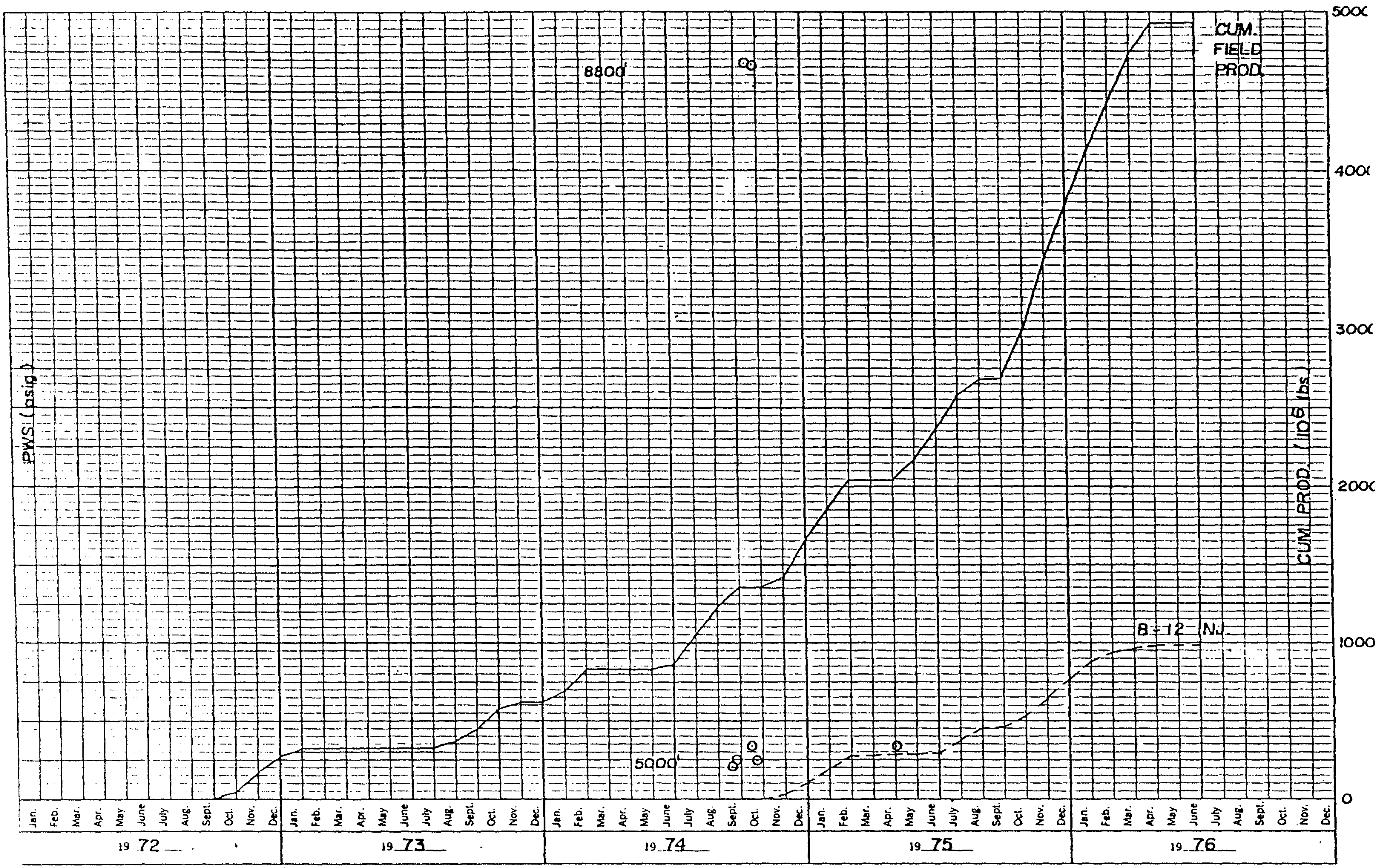
PRODUCTION, INJECTION, AND PRESSURE HISTORY - BACA 6



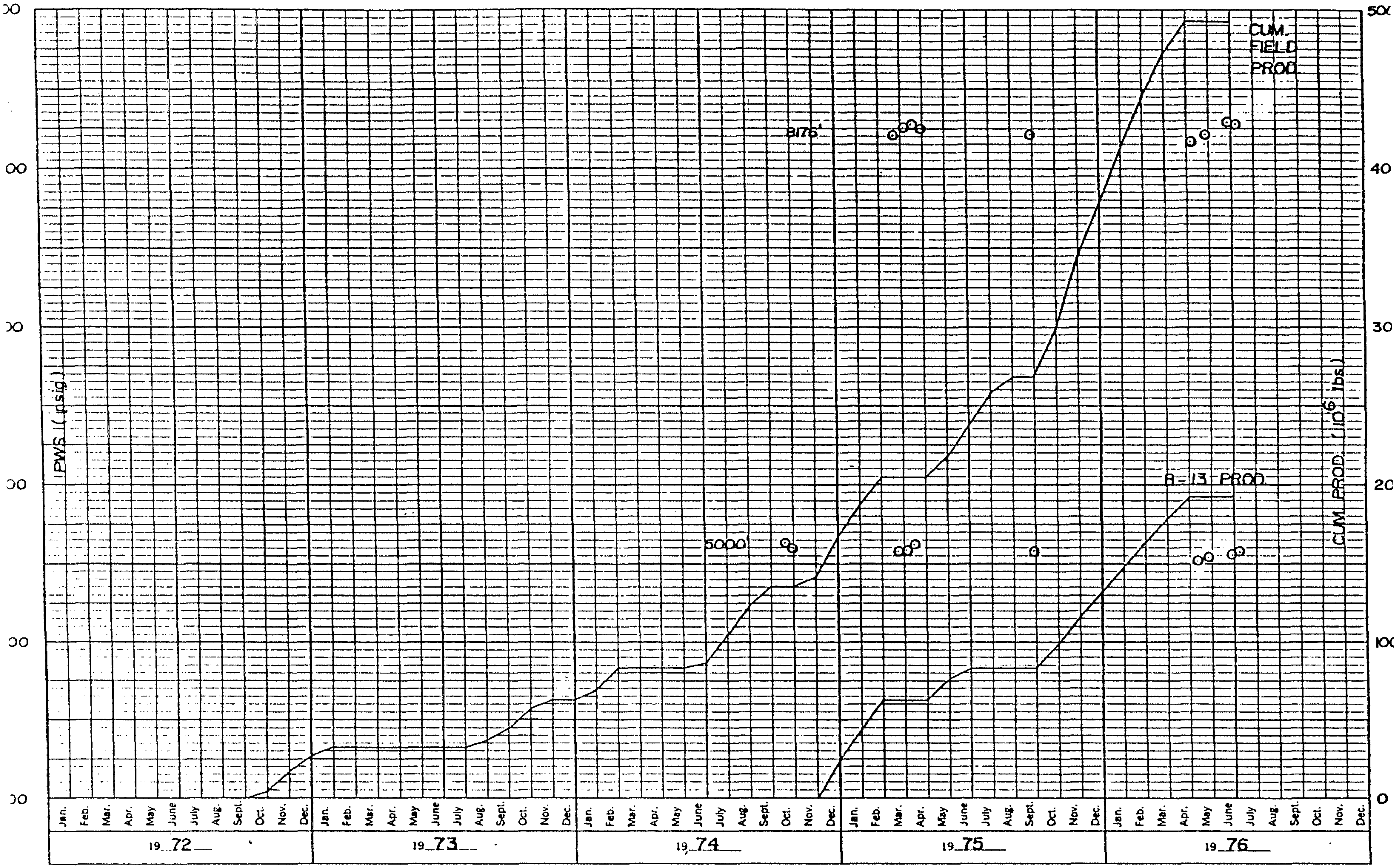
PRODUCTION AND PRESSURE HISTORY - BACA 10



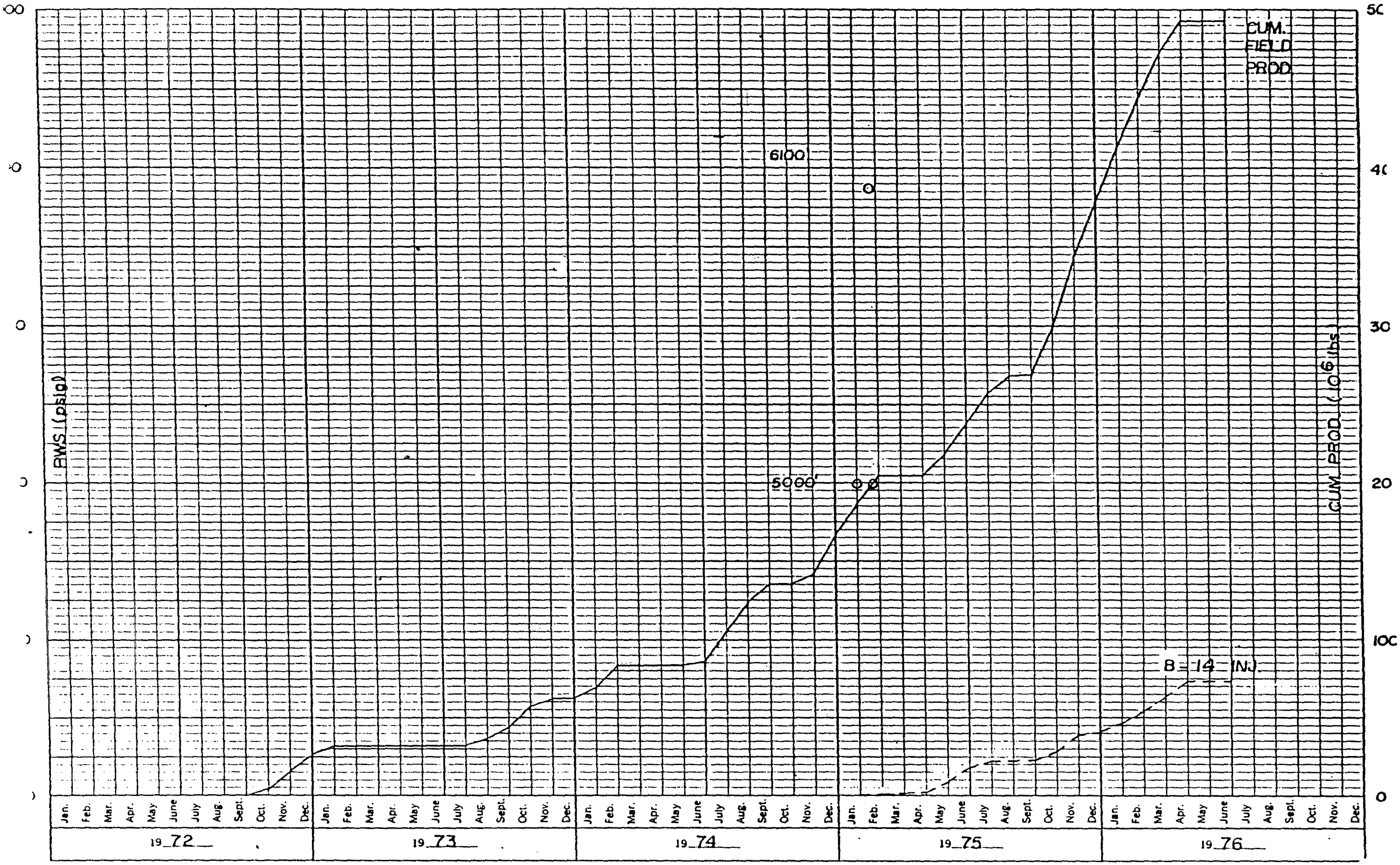
PRODUCTION AND PRESSURE HISTORY - BACA 11



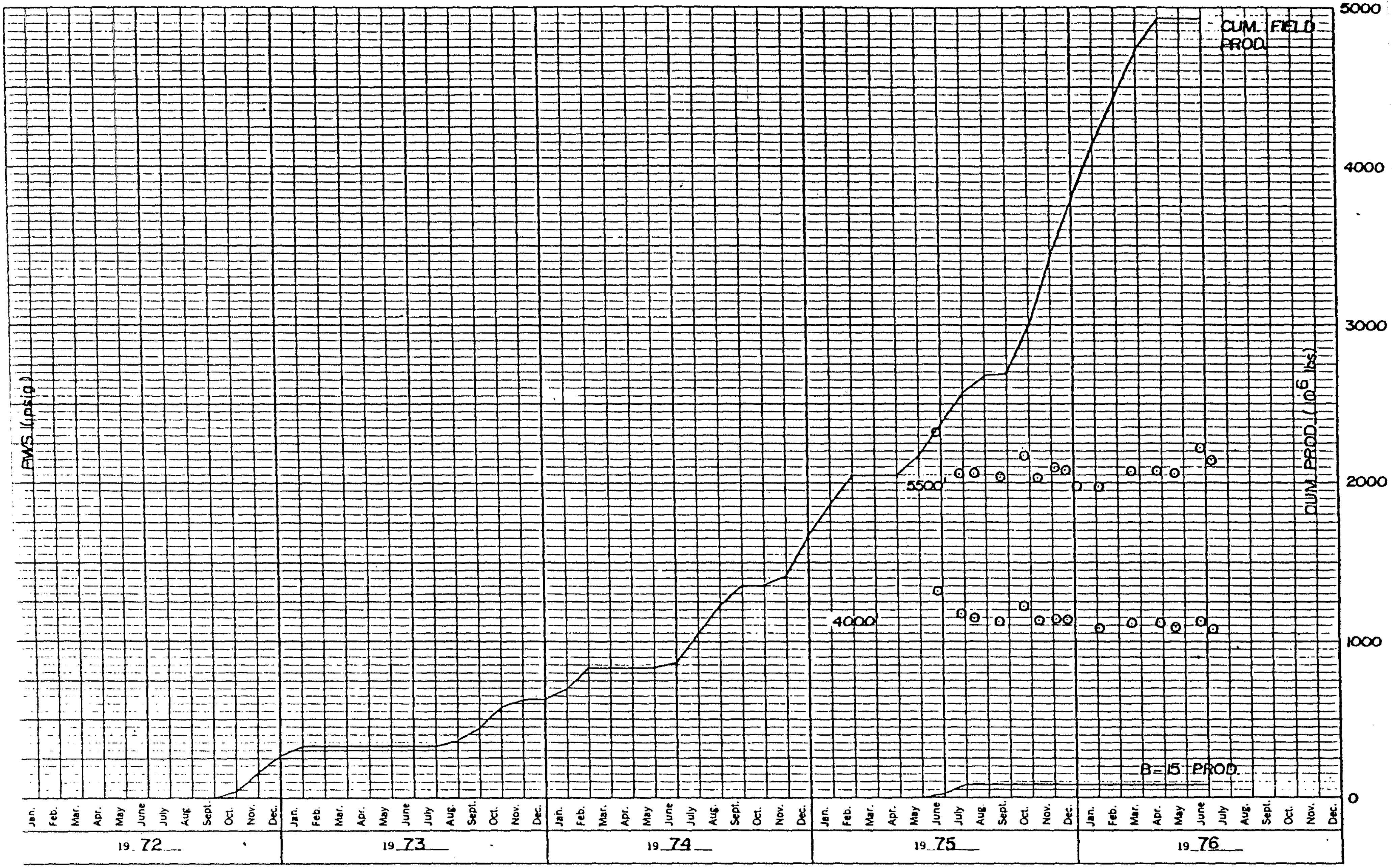
INJECTION AND PRESSURE HISTORY - BACA 12



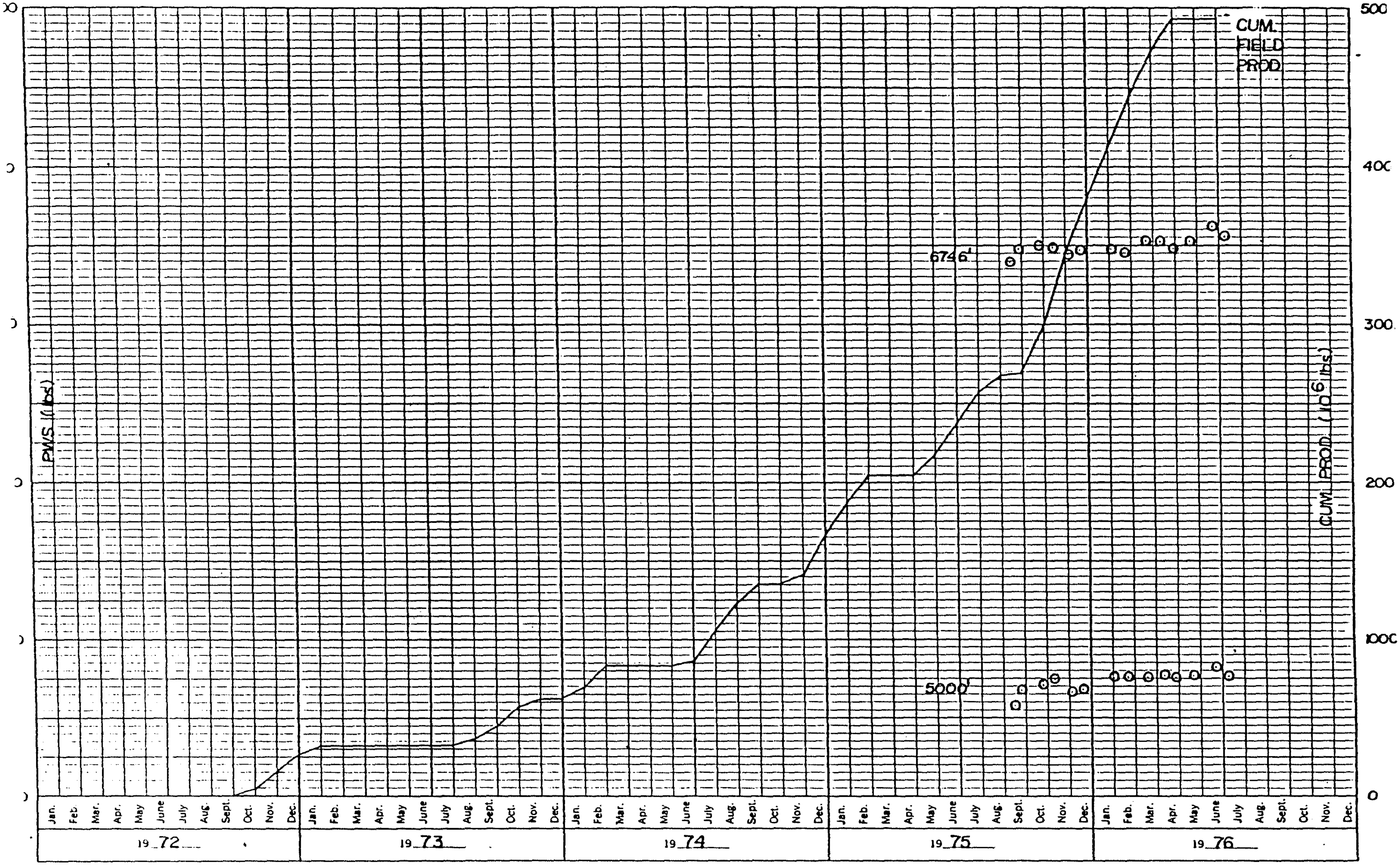
PRODUCTION AND PRESSURE HISTORY - BACA 13



INJECTION AND PRESSURE HISTORY - BACA 14



PRODUCTION AND PRESSURE HISTORY - BACA 15



PRODUCTION AND PRESSURE HISTORY - BACA 16

APPENDIX H

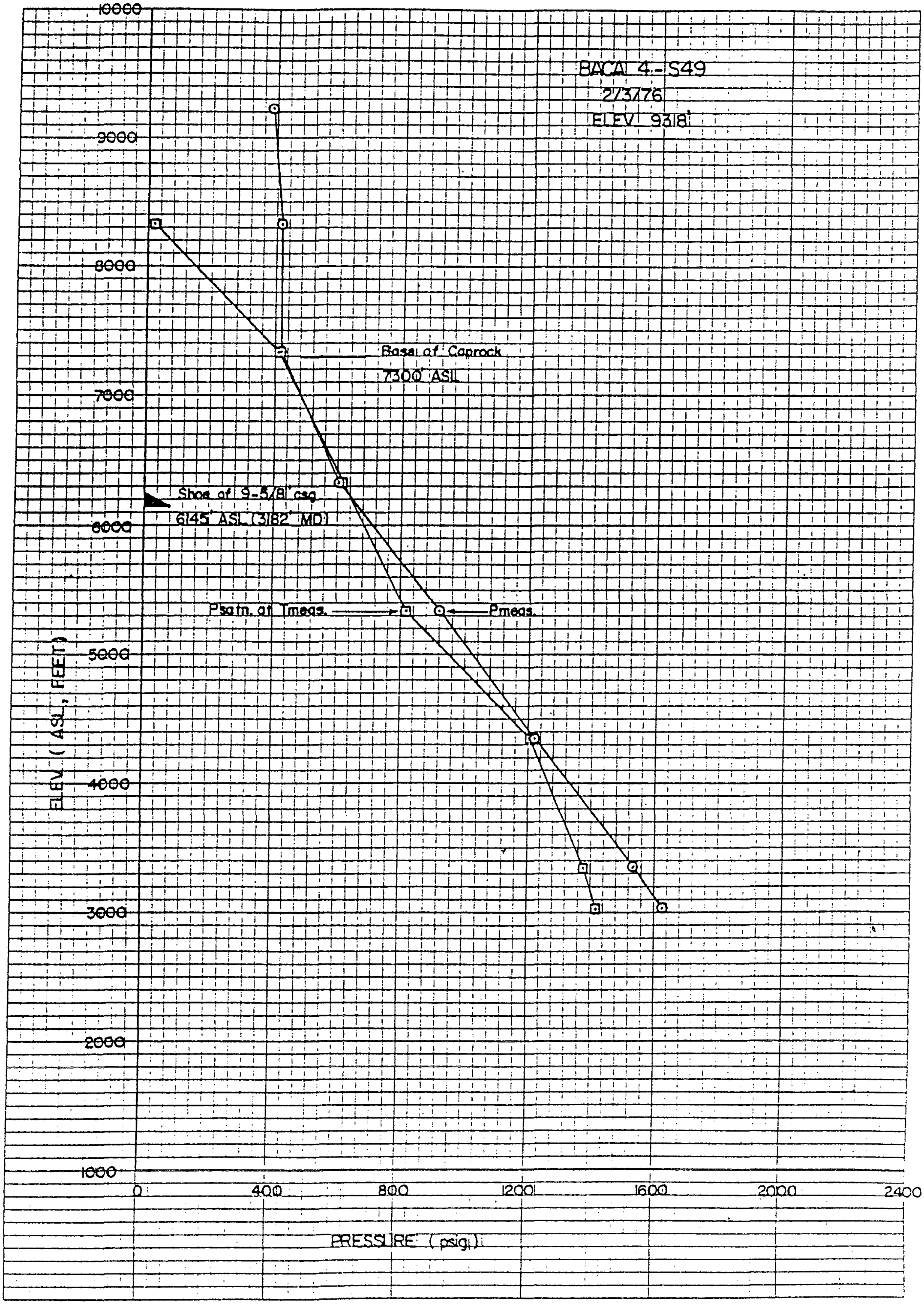
STATIC PRESSURE PROFILES

BACA 4, 6, 10, 11, 13 AND 15

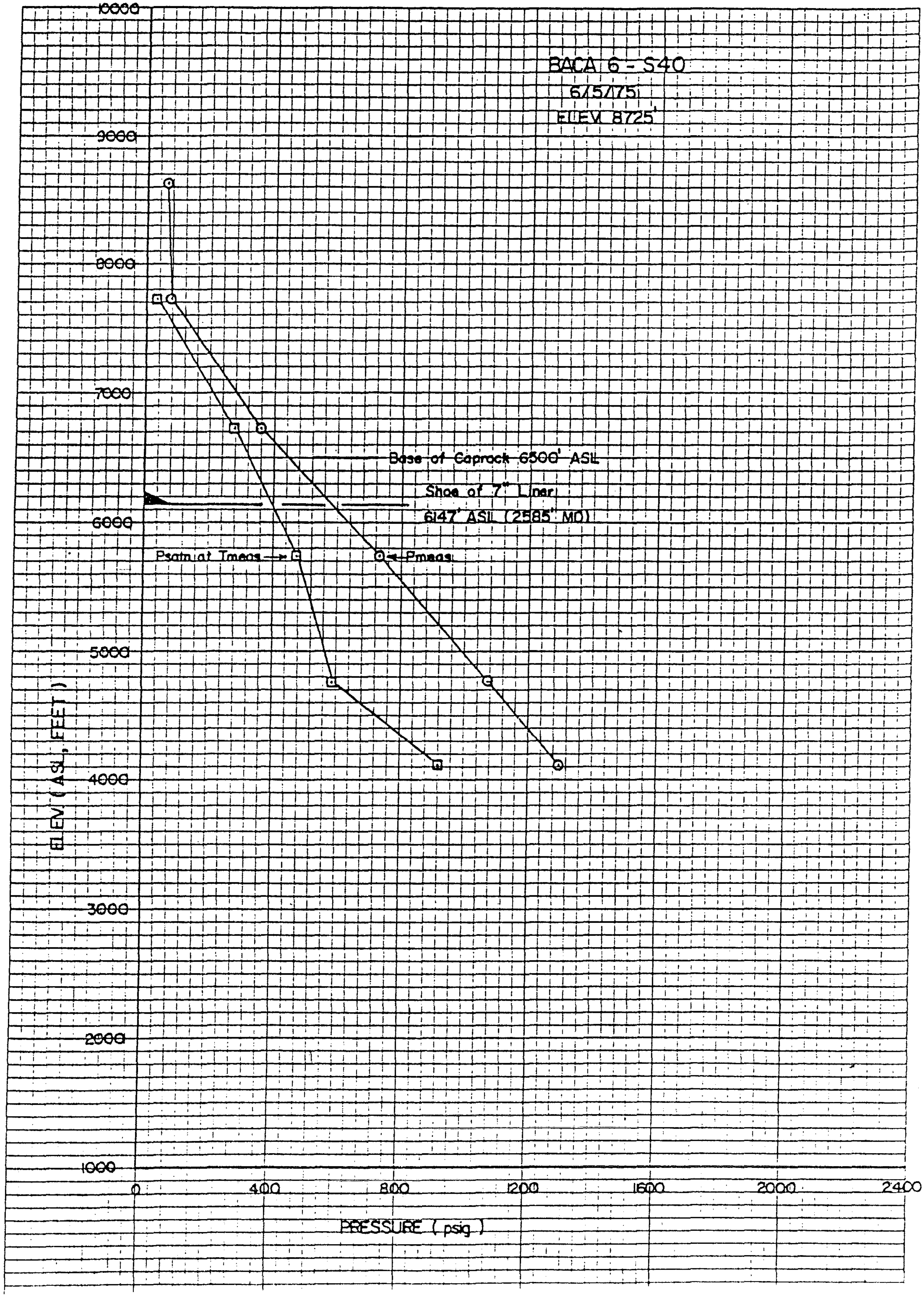
COMPARISON OF MEASURED PRESSURE

TO SATURATION PRESSURE AS DETERMINED FROM

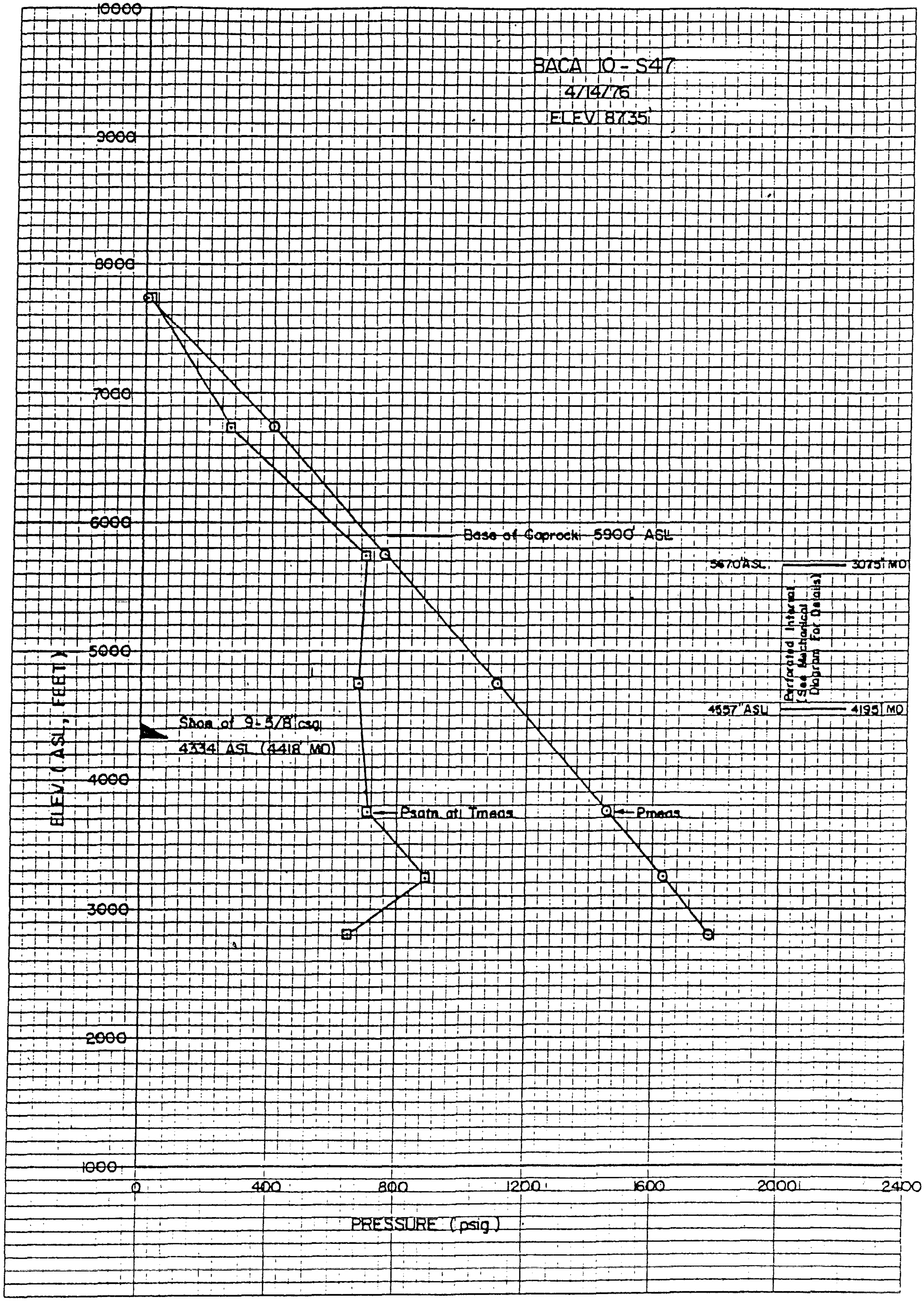
THE MEASURED TEMPERATURE IN EACH WELL

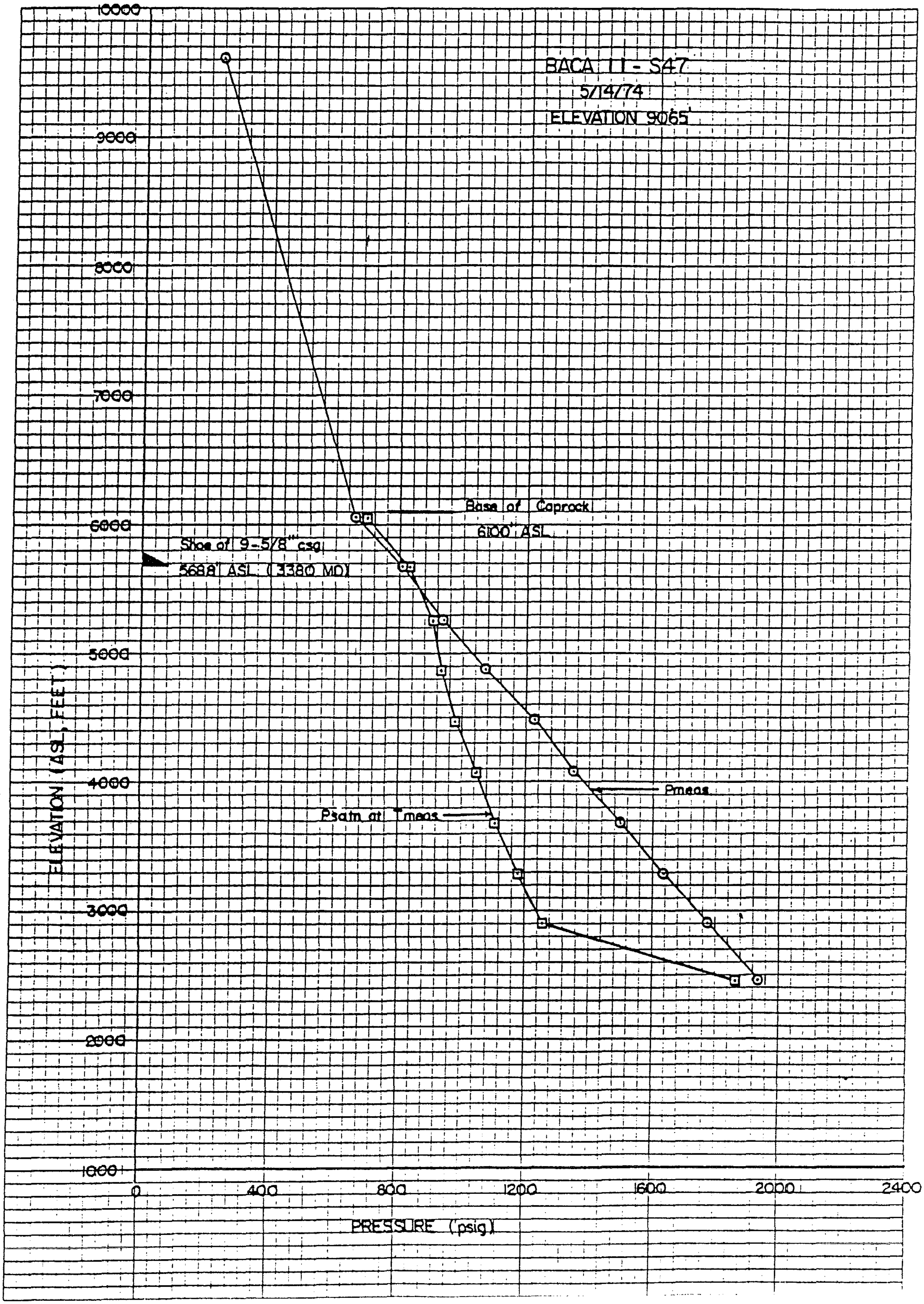


BACA 4 - S49
2/3/76
ELEV. 9318'
Basal of Caprock
7300' ASL
Shoe of 9-5/8" csg.
6145' ASL (3182' MD)
Psatn. at Tmeas.
Pmeas.
ELEV. (ASL, FEET)
PRESSURE (psig)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
400
800
1200
1600
2000
2400

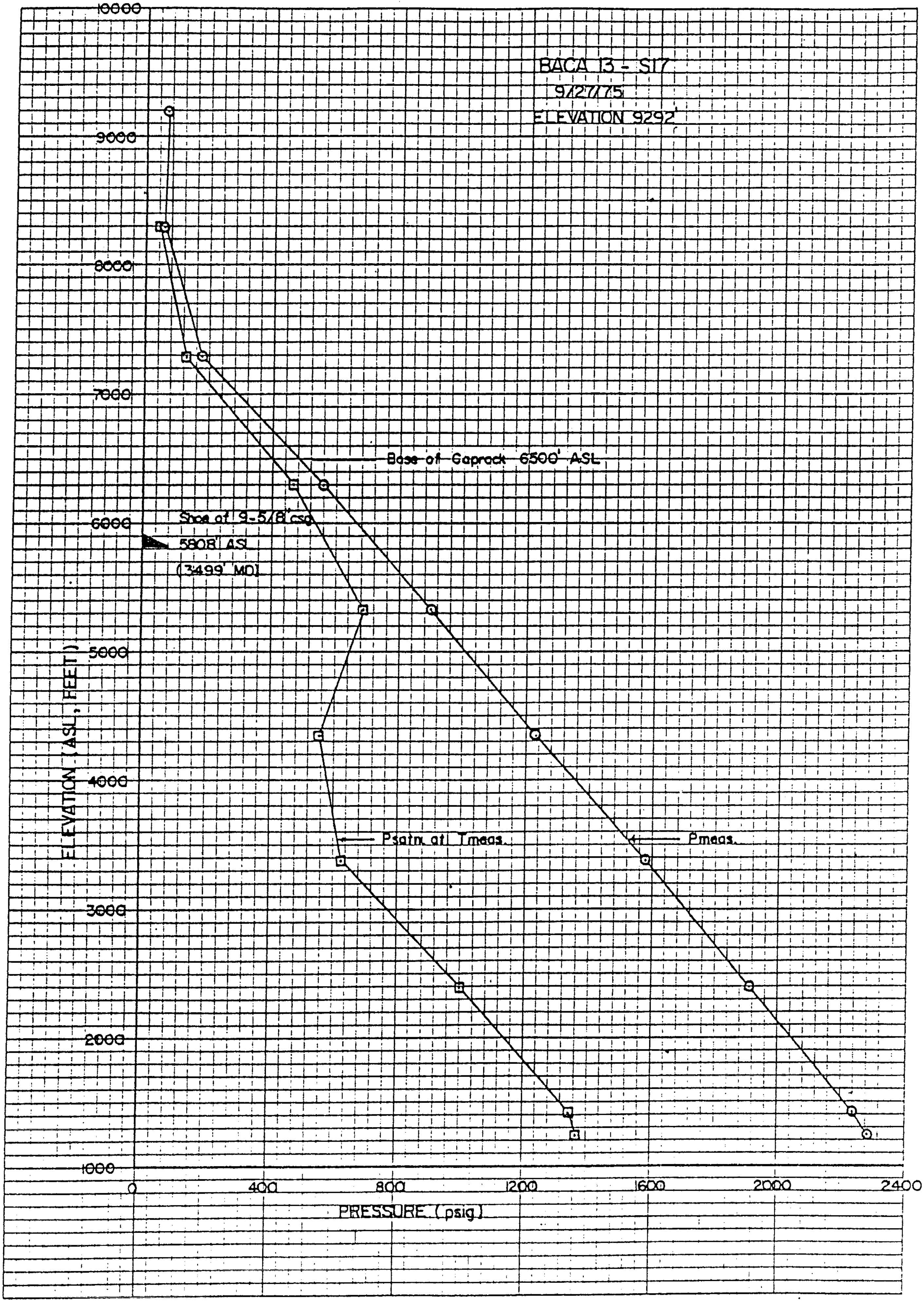


BACA 6 - S40
6/5/75
ELEV 8725'
Base of Caprock 6500' ASL
Shoe of 7" Liner
6147' ASL (2585' MD)
Psatn at Tmeas
Pmeas
ELEV (ASL, FEET)
PRESSURE (psig)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
400
800
1200
1600
2000
2400

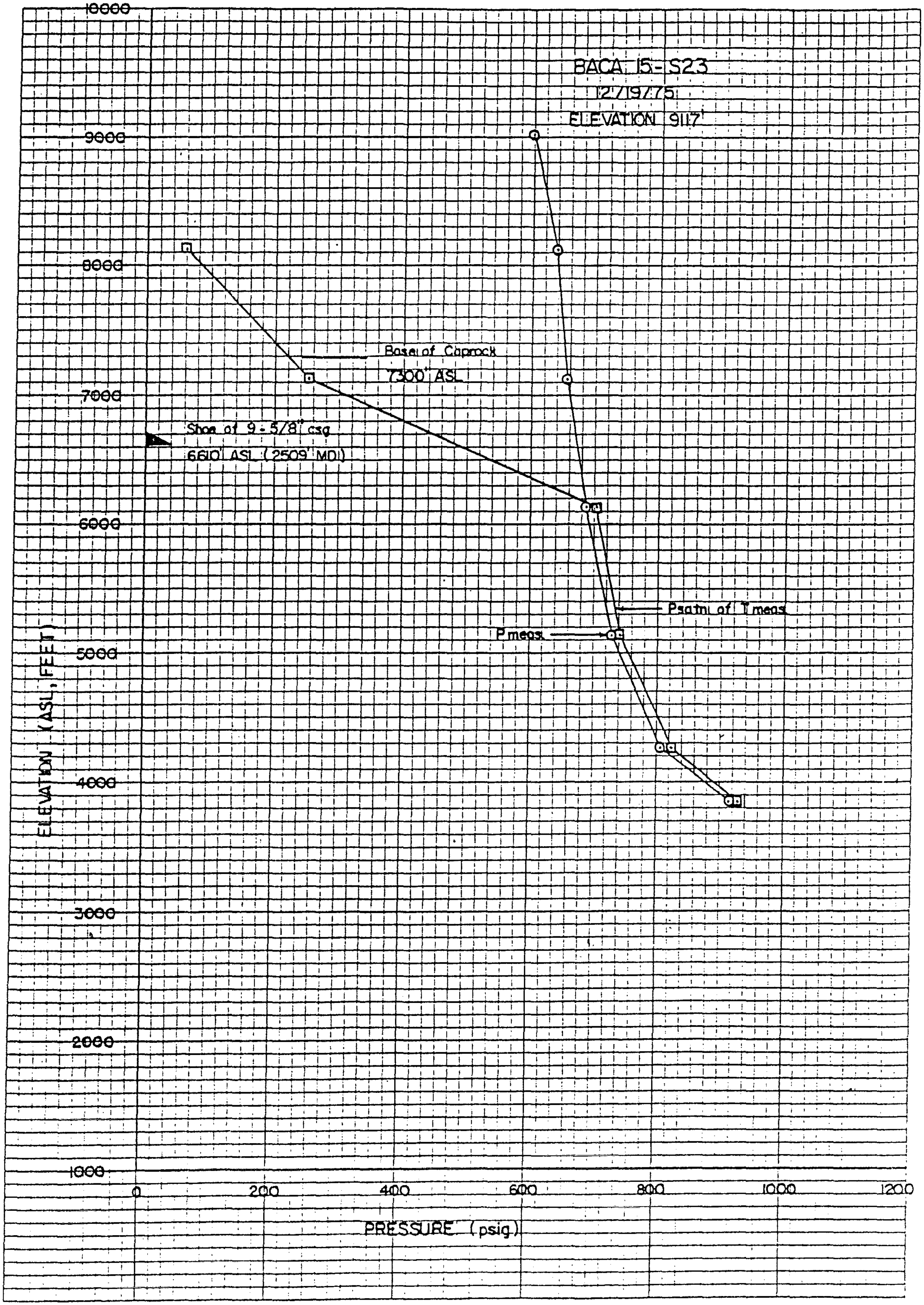

BACA 10 - S47
4/14/76
ELEV 8735'
Base of Caprock 5900' ASL
5670' ASL
3075' MD
Perforated Interval (See Mechanical Diagram For Details)
4557' ASL
4195' MD
Shoe of 9-5/8" csg
4334' ASL (4418' MD)
Psatn at Tmeas
Pmeas
ELEV (ASL, FEET)
PRESSURE (psig)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
400
800
1200
1600
2000
2400



BACA 11 - S47
5/14/74
ELEVATION 9065'
Base of Caprock
6100' ASL
Shoe of 9-5/8" csg
5688' ASL (3380 MD)
Pmeas
Psatn at Tmeas
ELEVATION (ASL FEET)
PRESSURE (psig)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
400
800
1200
1600
2000
2400



BACA 13 - S17
9/27/75
ELEVATION 9292'
Base of Caprock 6500' ASL
Shoe of 9-5/8" csg
5808' ASL
(3499' MD)
Psatn at Tmeas.
Pmeas.
ELEVATION (ASL, FEET)
PRESSURE (psig)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
400
800
1200
1600
2000
2400



BACA 15-S23
12/19/75
ELEVATION 9117'
Base of Caprock
7300' ASL
Shoe of 9-5/8" csg
6610' ASL (2509' MD)
Psat of T meas
P meas
ELEVATION (ASL, FEET)
PRESSURE (psig)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
200
400
600
800
1000
1200

700

APPENDIX I

MATERIAL ENERGY BALANCE CALCULATIONS

A tank-model (zero dimension) approach is used in these calculations. Thermal equilibrium exists between the fluid and the rock at all times. When steam is formed, it is distributed uniformly in the reservoir. Any temperature difference between the rock and the fluid causes the heat to transfer instantaneously.

Derivation of Equations

1 Pound of fluid at pressure, p_i and temperature, T_i

Consider 1 pound of geothermal fluid contained in an insulated porous system of known porosity (ϕ) and heat capacity ($\rho_r C_r$). Before production, the fluid exists at pressure, p_i, and temperature, T_i. No heat or fluid is gained or lost from the system except through the production or injection wells.

Let us define the following variables:

- H = Enthalpy, Btu/lb
- X = Steam quality, fraction of total fluid
- T = Temperature, °F
- p = Pressure, psia
- W_p = Fluid produced, fraction of original fluid
- $\rho_r C_r$ = Heat capacity of the rock, Btu/cu ft-°F

F_r = Fraction of the produced fluid injected

H_{inj} = Enthalpy of the produced fluid injected, Btu/lb

H_p = Enthalpy of the produced fluid, Btu/lb

v = Specific volume

ϕ = Porosity, fraction

Initial conditions:

p_i, T_i, X_i, H_i, v_i

Current conditions:

p, T, X, H, v

Using the conservation of energy principle:

$$\text{Energy produced} = \text{Initial energy} - \text{Remaining energy} + \text{Energy reinjected} \quad (1)$$

Examining the individual terms:

$$\text{Initial energy} = \text{Energy in the fluid} + \text{Energy in the rock}$$
$$= H_i + v_i \frac{(1-\phi)}{\phi} \rho_r C_r (T_i)$$

$$\text{Remaining energy} = H(1 - W_p + F_r W_p) + v_i \frac{(1-\phi)}{\phi} \rho_r C_r (T)$$

$$\text{Energy produced} = W_p H_p$$

$$\text{Energy reinjected} = F_r W_p H_{inj}$$

Substituting in Equation 1 and transposing:

$$H = \frac{H_i + v_i \frac{(1-\phi)}{\phi} \rho_r C_r (T_i - T) - W_p H_p + F_r W_p H_{inj}}{(1 - W_p + F_r W_p)} \quad (2)$$

Equation 2 describes the tank-type model.

In addition to Equation 2, the following relations are also known:

$$v_i = X_i v_g + (1 - X_i)\ v_f \tag{3}$$

$$H_i = X_i H_g + (1 - X_i)\ H_f \tag{4}$$

The thermodynamic properties of the fluid are known.

Known parameters are:

$p_i,\ T_i,\ v_i,\ \phi,\ \rho_r,\ C_r,\ X_i,\ H_i,\ W_p,\ H_p,\ F_r,\ H_{inj}$

Unknown parameters are:

p, T, X and H for a given W_p

Solution of Material Energy Balance Equation

(A) A procedure used for the solution of Equation 2 in a liquid-dominated system is described below:

1. Fix produced fluid, W_p.

2. Assume temperature, T.

3. Solve for reservoir fluid enthalpy, H, using Equation 2.

4. Calculate specific volume of the remaining reservoir fluid, $v = v_i/(1 - W_p + F_r W_p) = X\ v_g + (1 - X)\ v_f$

5. Find $v_g(T)$ and $v_f(T)$ from steam tables.

6. Solve for quality, $X = \dfrac{v - v_f}{v_g - v_f}$

7. Find $H_g(T)$ and $H_f(T)$ from steam tables.

8. Calculate enthalpy of the fluid, $H = X\ H_g + (1 - X)\ H_f$

9. Does H from Step 8 agree with H from Step 3? If yes, then we know T from Step 2, p from steam tables, v from Step 4, X from Step 6, and H from Step 8. If no, assume a different T and go to Step 3.

(B) A procedure used for the solution of Equation 2 in a vapor-dominated system is described below:

1. Fix produced fluid, W_p.

2. Assume temperature, T.

3. Solve for reservoir enthalpy, H, using Equation 2.

4. Calculate specific volume, $v = v_i/(1 - W_p + F_r W_p)$

5. Knowing T and v, find pressure, p, by trial from steam tables.

6. Find reservoir fluid enthalpy, H (p,T) from steam tables.

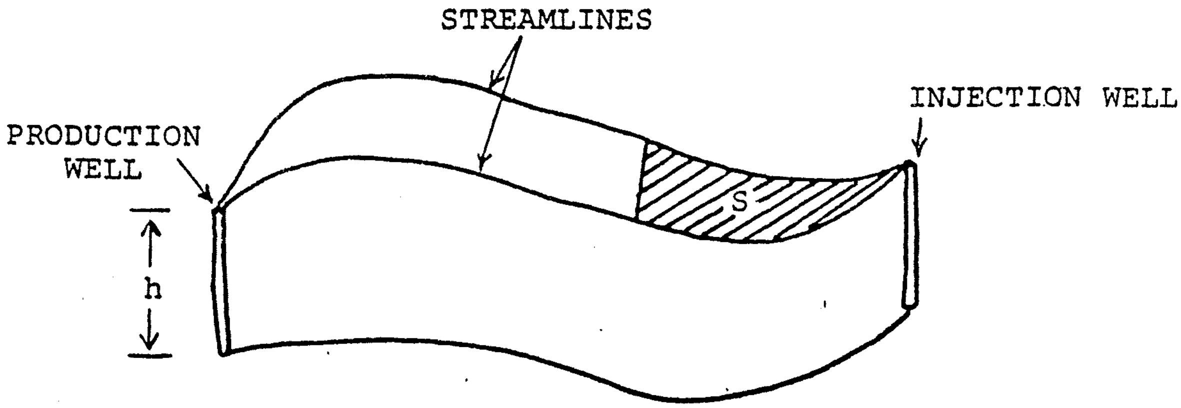
7. Does H from Step 6 agree with H from Step 3? If yes, we have the answer. If no, assume a different T and go to Step 3.

A computer program was written to solve Equation 2 for both the liquid-dominated and vapor-dominated systems. Results are discussed in the text.

APPENDIX J

TEMPERATURE DISTRIBUTION AT A PRODUCTION WELL

IN A HOT WATER SYSTEM WITH BRINE DISPOSAL WELLS



Fluid from an injection well to a production well can be considered to flow along streamlines. Two adjacent streamlines will form a stream-channel. The above figure represents a stream-channel. Injection fluid has moved through an area "S" in the stream-channel.

Our objective is to calculate temperature of the produced fluid as a function of time. Some simplifying assumptions to handle the problem are given below:

1. The aquifer is horizontal, of uniform thickness, "h", and of infinite extent in the horizontal directions. The caprock and the bedrock, above and below the aquifer are impermeable to flow and of infinite extent in the vertical direction.

2. Flow is assumed steady, since the duration of the transient flow period is small compared to the time required to reach thermal equilibrium. The total

injection rate, "Q", is constant and is equal to the production rate. All wells fully penetrate the aquifer.

3. Initially, the water and the rock in the aquifer, and cap and bed rocks are at same temperature, T_o. At time t=0, the temperature of the injected water is set equal to T_i, and maintained constant thereafter. Thermal equilibrium is supposed to take place instantaneously between the water and the rock in the aquifer.

4. There is no heat transfer by radiation, nor by conduction in the horizontal directions. All heat transport is by vertical conduction above and below the aquifer and forced convection in the horizontal direction within the aquifer.

5. Differences in viscosity between injected and native water are neglected. Piston-like displacement is assumed in the aquifer.

For a given stream channel, the temperature distribution is given by the following equation as derived by Lauwerier[1]:

$$\frac{T_o - T_w\ (S,t)}{T_o - T_i} = \text{Erfc}\left[\frac{(\rho_w C_w)^2}{K_r \rho_r C_r}\left(\frac{q}{S}\right)^2\left(t - \frac{\rho_a C_a}{\rho_w C_w}\frac{hS}{q}\right)\right]^{-\frac{1}{2}} \qquad \text{(J-1)}$$

where: T_o = Initial temperature in the aquifer.

T_i = Injection temperature.

$T_w(S,t)$ = Temperature at the hydrodynamic front.

S = Area covered by the hydrodynamic front in the stream channel from the injection well.

t = Time since injection.

ρ = Density

C = Specific heat.

q = Injection rate into the stream channel

Subscript w = Water.

Subscript r = Rock.

$\rho_a C_a = \phi \rho_w C_w + (1 - \phi) \rho_r C_r$: Aquifer heat capacity.

K_r = Thermal conductivity of rock.

ϕ = Aquifer porosity.

A computer program has been written to calculate the temperature profile at one or more production wells due to one or more injection wells. The wells can be located arbitrarily. The program is in two parts:

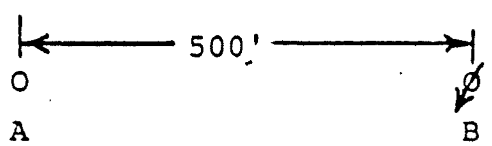
(1) The first part of the program calculates the flow channels from all the injection wells to all the production wells. The fluid carrying capacity of all the channels is the same. If the fluid moves along 50 stream channels for a particular injection rate (say 500,000 lbs/hr.), the fluid will need only 25 stream channels for a well whose injection rate is 250,000 lbs/hr. The lengths of the stream channels varies over the field. The number of maximum stream channels assigned to the largest injector in the field is an arbitrary number. The accuracy of the calculations increases as this number is made larger. In our studies, we have used 29 stream channels.

(2) The second part of the program calculates the temperature of the fluid at a production well through each stream

channel, using Eq. (J-1). The temperature is calculated only after a channel has been broken through. For a given production well, the heat content of the water produced through all the channels combined, over a given time interval, is determined. Then the temperature of the fluid produced is determined from the steam tables. This procedure is repeated for all the production wells and for all the time periods.

<u>Example of Temperature Calculations</u>

As an illustration, we consider an isolated two-well system, shown below:



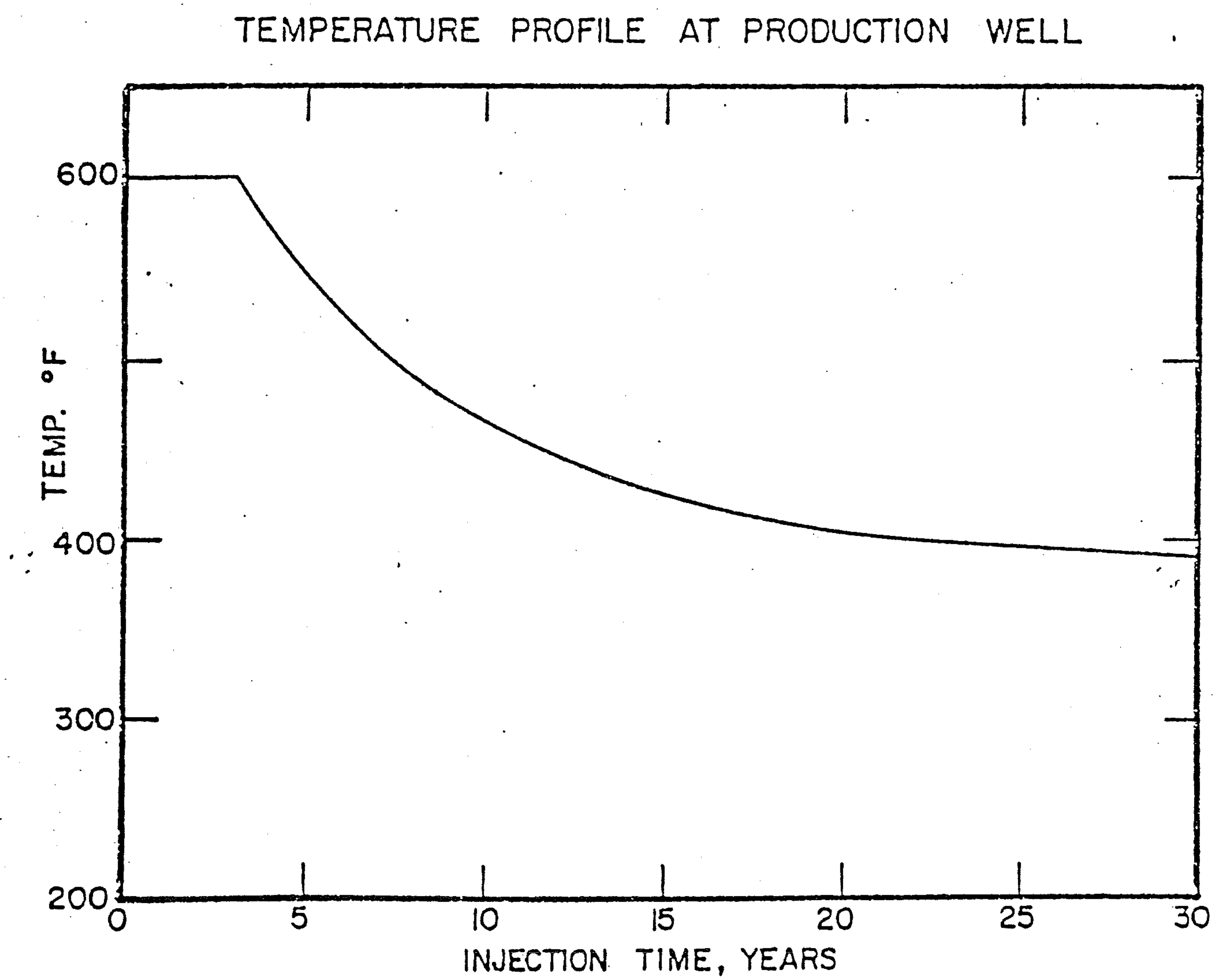
A produces at the rate of 200,000 lbs/hr and B injects at the rate of 200,000 lbs/hr. The wells are 500 ft. apart. Other pertinent data are described below:

Thickness	=	500 feet
Porosity	=	18%
Initial Temperature	=	600°F
Injection Temperature	=	273°F
Density of Water	=	42.32 lbs/cft
Sp. Heat of Water	=	1 Btu/lb°F
Thermal Conductivity of Rock	=	2.5 Btu/hr-ft-°F
Density of Rock	=	162.5 lbs/cft.
Sp. Heat of Rock	=	0.2 Btu/lb-°F

Figure J-1 shows the temperature profile at Well A. The hydrodynamic front arrives at Well A after 0.67 years but the cold temperature breakthrough occurs after 3 years. The production temperature drops gradually. The reason is that the fluid is moving through various stream channels of different shapes and at different velocities. When one channel is bringing in cold water, the other channels might still be producing hot water. This difference in the stream channel breakthroughs does two things: (1) the temperature declines gradually, and (2) it will take an infinitely long time for produced temperature to become equal to the injection temperature. Even after 30 years of production, the temperature is 387°F, whereas the injection temperature is 273°F.

Reference:

Lauwerier, H.A.: "The Transport of Heat in an Oil Layer Caused by the Injection of Hot Fluid", Applied Science Research, Sec. A, V. 5, P. 145, 1955.



TEMPERATURE PROFILE AT PRODUCTION WELL
TEMP. °F
600
400
300
200
0
5
10
15
20
25
30
INJECTION TIME, YEARS

FIGURE J-1