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IN SITU COMBUSTION PROJECT AT BARTLETT, KANSAS

Final Report

By
John S. Miller
Kenneth L. Spence

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Bartlesville Energy Technology Center
Bartlesville, Oklahoma

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IN SITU COMBUSTION PROJECT AT BARTLETT, KANSAS, FINAL REPORT

by

John S. Miller[1] and Kenneth L. Spence[1]

ABSTRACT

As part of an ongoing research program for enhanced oil recovery, the Bartlesville (Okla.) Energy Technology Center, U. S. Department of Energy, is in the process of developing petroleum-recovery techniques for shallow, low-productivity, heavy-oil deposits in southeastern Kansas, southwestern Missouri and northeastern Oklahoma.

Personnel at BETC designed and conducted an *in situ* combustion experiment on the Link Lease in Labette County, near Bartlett, Kansas. The Nelson-McNeil calculation method was used to calculate oil recovery and predict production time for a 1.25 acre inverted five-spot.

Two attempts to ignite the formation are described. The well completion methods, hydraulic fracturing, injection of air, workovers, production techniques, and well-monitoring methods of the process are described. Production results are shown for both combustion attempts.

The progression of the burn and the final extent of the burn front were evaluated by the following methods: (1) controlled source audio-frequency magnetotelluric technique (CSAMT), (2) thermogravimetric analysis (TGA), (3) burn-front model, (4) geophysical log analysis, and (5) computer model study.

[1]Petroleum engineer

INTRODUCTION

Heavy oil reserves have received much attention in recent years because of (1) increases in heavy oil production from thermal-recovery operations, (2) the existence of more than 2,000 known heavy-oil reservoirs, and (3) the fact that these reservoirs contain a high percentage of the oil originally in place.

The technology for increasing the recovery of viscous crude oils by raising the temperature through *in situ* combustion methods is presently available (1-7). However, reservoir characteristics and economics have limited general use of *in situ* combustion methods of recovery. Significant improvements in technology or economic conditions could result in increased profitability in the use of *in situ* combustion recovery methods.

One difficulty in applying *in situ* combustion to some reservoirs in the Mid-Continent area is the low effective permeability to injected air which is caused by a combination of the low permeability of the rock and the high viscosity of the oil in place. To effectively burn a pattern, communication must be established between the injection well and the producing well. One way to accomplish this in a tight sand is to fracture the formation, either hydraulically or with chemical explosives (8).

The Bartlesville (Okla.) Energy Technology Center, U. S. Department of Energy, is evaluating petroleum-recovery techniques for shallow, low-productivity heavy-oil deposits in southeastern Kansas, southwestern Missouri and northeastern Oklahoma. One program actively under evaluation, an *in situ* combustion project, consisted of a laboratory testing phase which has been followed with a small field test. The laboratory work was done to acquire baseline data on the effects of *in situ* combustion in heavy-oil field cores with and without hydraulic fractures. The cores were obtained from the heavy oil reservoirs near Bartlett, Kansas.

The *in situ* combustion laboratory experiments used cores taken from wells on the Link Lease near Bartlett, Kansas. The results of a series of eleven *in situ* combustion experiments were used to establish a relationship between volume percent of core burned and the fracture width. The results showed propagation of the burn front in the cores if the propped fracture width was no greater than $\sim$ .012 inches (0.3 mm) wide with as much as 90 percent of the core being consumed (6).

Concurrently with the laboratory testing, a field test site was selected and developed to determine the technical feasibility of recovering heavy oil by the *in situ* combustion process from reservoirs which are shallow and contain no production energy.

In December 1976, a well was drilled on the R. L. Link Lease located in sec. 21, T. 34S, R. 20E to a depth of 420 ft (Fig 1). Log and core analysis indicated a 12-ft section (350-362 ft) of Bartlesville sand with an average oil saturation of 43 percent, an average porosity of 22 percent, and an average permeability of 177 md.

In September of 1978 the first attempt to ignite the formation was made and proved to be successful for a relatively short period of time. Data obtained from the production wells indicated that the fire had died and the burn front was not moving. Excessive periods of compressor shut-down and by-passing of injected air to surrounding unplugged wells around the test pattern starved the fire, causing it to slowly go out.

A remedial program to fracture the production wells and rework the injection well so that a new attempt could be made to ignite the formation at a lower depth was accomplished.

In January of 1980 a second attempt was made to ignite the formation at a lower interval. A burn was initiated and was monitored by obtaining data from the production wells. Again compressor problems and by-passed air created a low intensity burn which was caused by insufficient air reaching the burn front.

The progress of this burn was monitored several times by the (CAMST) or resistivity logging method. A post-burn site evaluation was made by drilling and coring three evaluation wells. Well logs were obtained and a thermogravimetric and mass loss analysis were run on core samples. A mathematical model study was also made to further evaluate the combustion zone.

RESERVOIR CHARACTERISTICS FROM CORES AND LOGS

The Bartlesville sand in this area was deposited as a system of deltaic to shoestring sands of slightly different age, bordering the coast of a shallow sea which occupied much of eastern Kansas and northeastern Oklahoma in Cherokee (Pennsylvanian) time. The specific reservoir description for the Link Lease near Bartlett, Kansas was developed using cores from the injection well and logs from the production wells. Standard logs run in all wells were: compensated density, gamma-ray neutron correlation and dual induction focused logs.

The porosity from the density log generally agreed with core porosities and appeared to be the proper log for use in porosity determination. The gamma log and neutron log indicated a relatively shaly sand as shown in Table 1. Temperature measurements on produced water indicated the reservoir to be about 55°F.

Cores taken from the Link 1 well were sent to a commercial core laboratory for analysis. Table 2 lists the results of the analysis. Thin section analysis (Fig 2), X-ray diffraction mineralogy, and cation exchange capacity measurements, all indicate this part of the Bartlesville sand to be relatively shaly, as shown in Table 3.

The analysis of logs and cores has shown the upper portion of the Bartlesville sand at approximately 274 ft, but the effective porosity capable of production starts from 300-308 ft and extends downward to 360-364 ft. This zone across the five-spot contains disseminated shale with some laminar shale breaks (see Table 1). The core analysis showed the zone to have an average k_{air} of 177 md, an average porosity of 22 percent with an average oil saturation of 43.0 percent. The oil is 15° API gravity, having a specific gravity of 0.966, and a viscosity of 1270 cp at 100°F.

PROJECT DESIGN

The laboratory and field data shown in Table 4 were utilized to calculate oil recovery and to predict production time for the 1.25 acre inverted five-spot test pattern at the Link Lease. Using the Nelson-McNeil (12) method of calculation, a recovery of 4,410 bbl could be expected in a period of 409 days with an average net pay of 12.0 ft of sand as shown in Table 5. However, because of reservoir anomalies, such as permeability differences, fracturing of the formation, clay content, excessive water and non-uniform burning of the formation, predictions from these calculations were adversely affected.

SITE DRILLING AND COMPLETION

The drilling of the center well of the five-spot was started in December 1976 (Fig 3). Well 1 was drilled with a 9-in. bit to 265 ft and cored with a 4-in. core barrel to 365 ft. The hole was then reamed and drilled with a 9-in. bit to 423 ft. The well was completed with 423 ft of 5½-in. casing, respectively, with 1¼-in. tubing welded to the casing. All wells were cemented from top to bottom with high temperature Luminite cement with 40 percent silica flour. Well 1 was directionally perforated from 355 to 36/ ft with 2 shots per ft. Wells 2,3,4, and 5 were perforated between the intervals of 351 to 367 ft, 351 to 366 ft, 345 to 365 ft and 342 to 366 ft, respectively, with 6 shots per ft. Directional shots were used to keep from damaging the 1¼ in. tubing which shielded the thermocouple.

Air was injected into the center well of the five-spot to determine the extent of air flow to the four producing wells. Pressure-testing results indicated no communication existed between the wells. An acid treatment to Well 1, at approximately 1,100 psi pressure, created communication by fracturing the formation between the injection well and the four producers.

PRODUCTION FACILITIES

The site area for the experimentation encompassed a five acre plot (Fig 4). Three buildings were located on the site: a trailer used as an office and sleeping facility, a combined office-storage building and an electrical distribution building.

Tank Battery and Water Disposal

Two tanks, shown in the lower-center of Figure 4, were for salt water disposal storage tanks. The produced water was dumped from the heater-treaters to the forward tank. When the water reached a predetermined level in the second tank (due to water not being disposed of) a shutdown system stopped all pumping units on the lease.

A pump, located at the water storage tanks, was used to circulate water back to the casing production tank at the production wells. The pumps at the individual wells had the capability to circulate water down hole and cool the production equipment when the fire front is near or at the well bore.

The oil tank battery, shown at lower left of Figure 4, consisted of three tanks, tied in series, with both the test and production heater-treaters. All tanks were connected to the waste heat system so that the produced heavy oil can be pumped in cold weather.

Two heater-treater units were installed in the production system. The small treater, a 4 ft diameter x 20 ft high tank was installed as a test unit and it has the capacity to handle an oil rate of 100 bbls/day with a 30 percent water-cut. This unit was used to test the oil and water production for a single well on a daily basis. The large treater, a 10 ft diameter x 20 ft long electrostatic oil processing unit, had capacity to process 400 bbls/day of oil with a 30 percent water-cut. It was installed to handle the total production of the lease.

The main diesel-oil storage tank supplied fuel to the primary compressors. The booster compressors were supplied fuel from the propane storage tank. Both storage tanks were located near the compressors as shown in Figure 4.

Injection Facilities

The airflow equipment consisted of two primary compressors (Fig. 4) capable of developing 500 Mcfd each at 350 psi. These compressors were located on a covered cement pad. A waste heat recovery system, installed adjacent to the compressor, utilizes the heat from the compressor's exhaust system to heat the water used in the storage building and oil tank battery. Two booster compressors capable of delivering 1 MMcfd each at pressures exceeding 600 psi were located on cement pads adjacent to the primary compressors. If one compressor becomes inoperative, the second unit can be put in service to maintain continuous air injection to the fire flood. Dual injection lines were laid from the booster units to the injection header with switching valves to control flow into a single 2-in. line to the injection well. A 2-in. orifice meter was installed in the line with appropriate meter equipment to control and obtain data necessary to calculate the flow rate. The 2-in. line was connected to a side gate on the 5-in. casing head of the injection well.

Production Equipment

The four producing wells were equipped with the same surface wellhead equipment, pumping equipment and auxillary equipment needed to produce fluids or inject cooling water down the well to control heat from combustion.

The 5½-in. well heads were made to accommodate 2 3/8-in. tubing with pressure-tight rubber pack-off. Two 3-in. side ports were required--one to make tests or inject into the wells, the other to flow gas or fluids to a concrete pit. One inch hollow sucker rods were connected by high pressure hose to the production line. Fluid could be produced directly to the separator or to a concrete pit beside the well. When the production from the well filled the pit to a designated level a float valve started a pump which injected the fluid either to the separator or down hole as a coolant.

A Cook 4-D-13 electric pumping unit with a 30 inch stroke was installed on each well. The units were controlled by electric timers set at predetermined pump-off times for the individual wells. The units were also connected to an automatic shutdown system controlled by the water level in the salt water storage tanks.

All wells produced through a production header with a dual set of valves for each of the four wells. One set of four valves directs flow to the large production heater treater; the other set of valves directs the flow to the test heater treater. The design of the production header allowed the testing of one well per day for its production capacity through the test heater-treater; the other production was directed through the production heater-treater.

FORMATION IGNITION

First Burn Attempt

Two attempts were made to ignite the 15° API gravity oil in the Bartlesville sand.

The first burn was initiated on September 14, 1978. The center injection well of the inverted five-spot was equipped to accept a heater and related ignition equipment through the lubricator on top of the casinghead. The air from a booster compressor was injected downhole through a sideport on the casing string.

The initial ignition attempt was made with air being injected past a downhole electric heater powered from a diesel generator. The heater was run downhole on an armored cable to approximately three feet above the perforated interval at 352 ft. The generator supplied the heater with 410 volts and 44 amps which resulted in an ignition temperature of 1,042°F. The heater was left in place for 6 days to insure ignition. Ignition was achieved and verified by analysis of combustion gases from the production wells. The average daily air injection rate during the ignition period was 149 Mcfd.

Combustion Analysis - First Burn

The data to determine ignition and progress of the burn in the formation were obtained from temperature logs from the injection well and the four production wells and gas analyses for the O_2 and CO_2 content from the production wells. The temperature logs and CO_2 and O_2 readings were obtained on a daily basis.

Temperature Logs

The temperature log data from Wells 2, 3, 4, and 5 were obtained from the month of September 1978 through February 1979. The data are plotted in figures 5, 6, 7, and 8. The data plotted from March 1980 to May 1981, pertains to the second burn with the broken line being the interim time between burns. Well 3 shows only the first burn because the 1½-in. tubing which was used to house the temperature probe on the casing was damaged; the thermocouple was pulled and subsequently could not be replaced

A temperature high of 73°F, obtained from Well 4, does not indicate a fire in the formation for the first burn.

Temperature readings were deleted from the data determinations after February 1979, because no appreciable rise of temperature was obtained from the four production wells during the first 6 months of operation.

Gas Analysis

The O_2 - CO_2 data plotted versus time from September 1978 through December 1979 at three day intervals are shown in Figures 9, 10, 11, and 12.

The data from Wells 2, 3, and 4, shown in Figures 9, 10, and 11, indicated spasmodic burn intervals where the CO_2 - O_2 readings start to approach each other. Figure 9 (Well 2) indicates the presence of a burn condition in October 1978; March and April 1979, and June and August 1979. Figure 10, (Well 3) indicates a burn condition during the early stages of the test, October and November 1978 and in August 1979. Figure 11 (Well 4) indicates the presence of a burn from November 1978 to February 1979 and in August of 1979. Figure 12 (Well 5) indicates the presence of a burn from November 1978 to February 1979, with the exception of the month of April 1979. These data indicate that a low grade type of combustion was taking place within the formation resulting in low temperature readings, low CO_2 readings, and high O_2 readings being observed at each production well.

Fluid Injection and Production

Figure 13 reflects the overall performance of the first attempt to ignite the formation and identifies some problems encountered to that time. After ignition the fluid production decreased for the first two months. The water production continued to decrease to 18 bbls/month and the oil production rose to 16 bbls for the month. The water production increased for the next 9 months while the oil production was very erratic. The air injection, shown in Figure 13, was at an average rate of 425 Mcfd which was close to the rate required by the Nelson-McNeil method. The rates were erratic due to compressor problems during crucial times of the life of the burn. The erratic air injection rates were considered to have the most serious effect on the fire and to be the cause of the low grade combustion in the formations.

Reconditioning Production Wells

In the spring of 1979 (March, April, and May) the producing wells were hydraulically fractured to establish better communication with the injection well. Each producing well received a frac treatment consisting of 3,000 gal of frac fluid as a pad, 3,000 gal of frac fluid with 1 pound/gal of 20/40 mesh sand, and 2,000 gal fluid in sequence.

The rise in water production during this period can be attributed to the frac treatments of these wells.

In June and August of 1979 the four producing wells were chemically stimulated to clean up the well bores and the formation adjacent to the perforations. The first stimulation treatment in June, consisted of 500 gal of diesel oil with 15 gal of Flow Master chemical to clean the perforations and formation to improve the flow to the well bore. This treatment was performed in Wells 1 and 4. The second treatment was done in August to stimulate Wells 2, 3, 4, and 5. The treatment consisted of 500 gal of diesel with 15 gal of chemical followed by a flush treatment of 2-3 bbls of salt water.

These two treatments, when produced back, added to the oil production as can be evidenced on Figure 13.

Reconditioning Injection Well

Injection tests performed after the fracture and stimulation treatments indicated a higher air flow rate from the production wells. A spinner survey was run on the injection well to determine where the major flow of air was entering the perforated zone. The survey indicated that air was entering through the top perforations of the interval at a high rate, indicating air was flowing through a fracture system to a shale zone above. Injected air was evidenced in eleven old unplugged wells surrounding the site. Eight of these wells were located north of the east-west section line with the majority of the injected air being produced from a well approximately ¼-mile north of the project. Thus the amount of injected air to reach the fire front was inadequate to support the in situ combustion fire as the front progressed away from the injection well, consequently the fire died.

An engineering study was made to determine if a second attempt could be made to ignite the formation after squeezing off the existing perforations with cement and reperforating the formation at a lower depth.

In August 1979, a squeeze job was performed by injecting 1,000 gal of Injectrol, followed with 35 sacks of cement, and tailed with 380 gal of water. The cement plug was drilled out and an oriented tool was used to perforate the zone between 361-367 ft, with four shots per ft. The perforated interval would not take air, so in September 1979, a hydrojet tool with two jets spaced 90° to each other was run with the jets oriented away from the 1¼-in. thermocouple tubing. The hydrojet perforations, which penetrated the casing and formation to approximately 16 in., were made at 362 and 366 ft. After washing down the hole, 450 gal of 7½-percent HCl acid was spotted on the perforations for 45 min. Air injectivity was started and communication to all four production wells was established.

Second Burn Attempt

An attempt was made in September 1979 to re-ignite the formation. The electric heater burned out during the first hours of the attempt. A new heater was installed and a second attempt was made to ignite the formation on January 10, 1980. The downhole electric heater was placed above the formation with the electric generator set to furnish a temperature of 950°F to the injected air. The heater was left in place for approximately 10 days until combustion was verified by an analysis of the gaseous products from the combustion wells. Routine injection began in January 1980, averaging 486 Mcfd for the first four months. The air injection history for the project is shown in Figure 13.

Combustion Analysis-Second Burn

Temperature Logs

The temperature profiles for Wells 2, 4, and 5 at three different depths, 350, 360, and 370 ft, are shown in Figures 5, 7, and 8 for the second burn. The temperature profiles show that from March to August of 1980 the temperatures were decreasing, indicating that insufficient air was being injected to maintain the fire. In July the air rates were increased and the temperature profiles increased to a high value of 109°, 89°, 97°F in Wells 2, 4, and 5, respectively. Temperature decreases after this period again indicate that insufficient air was being supplied to the combustion zone and that the fire was slowly going out.

Gas Analysis

The propagation of the combustion front was monitored by an analysis of the effluent gases (O_2 and CO_2) from each production well. The analysis started on January 1, 1980 and concluded on May 25, 1981. The heater was placed in the injection well on January 24, 1980, and was withdrawn on February 3, 1980, when, by analysis, the CO_2 started to rise and the O_2 started to decrease. This indicated a successful ignition of a burn in the formation from Wells 2, 3, and 4, Figures 14, 15, and 16. Well 5 (Fig 17) had O_2-CO_2 readings, indicating a burn situation that was a holdover from the previous burn.

The combustion data analyzed from the production wells indicate conclusively that a low temperature combustion was in progress in the formation. Wells 3 and 5 showed this trend through the injection period while Wells 2 and 4 showed a steady decline of the combustion process. An effort was made to increase the injection rate during April and May, but due to continued compressor problems the calculated increase of rate could not be obtained. A new compressor was installed and the increase in rate can be observed from the combustion data during July. It can be concluded that the rate increase gave a kick to the oxygen-starved combustion process. Even with the increased rate of injection, too much air was being lost through fractures, leaking beyond the combustion zone.

Fluid Injection and Production

The net oil production profile, shown in Figure 13, reflects the over-all performance of the project and identifies some problems encountered. After ignition the fluid production fell off sharply for the first month. During a steep increase in the fluid production rate for the next four months, the net oil production increased to approximately 70 bbls per month. Lower oil production and total fluid production for the next three months is attributed to air injection difficulties.

The average air injection profile, shown in Figure 13, generally corresponds to that calculated by the Nelson-McNeil method. After reaching the maximum air injection rate in the prescribed program, the compressors began to fail. After numerous repairs, new compressors were obtained and the injection rates continued.

At this point, the total fluid production increased sharply, but the net oil production decreased significantly. After several well treatments, the water production decreased and the net oil production increased to 28 bbls per month. The oil production then dropped off with the water production increasing to the end of the project. The fluid production corresponds to the decreases of temperatures and the O_2 - CO_2 readings indicating the fire was quenching and ultimately going out.

Table 6 is a summary of the well treatments after the reignition of the second combustion front.

COMBUSTION EVALUATION METHODS

Introduction

The *in situ* combustion experiment conducted near Bartlett, Kansas, has presented an opportunity to combine a variety of techniques in an effort to map the progress of an underground thermal process. The mapping of an *in situ* combustion process can be useful for improved reservoir stimulation. In particular, knowledge of the location of the thermal process could allow the field operator to make corrections to injection rates and production rates from the appropriate wells in order to avoid early breakthrough. This section describes the combined application of controlled source audio-frequency magneto-telluric (CSAMT), conventional geophysical logging, thermal gravimetric analysis (TGA and DTG), and modeling of the fireflood. Details of these methods are described in a paper by Wayland and Bartel (16), of Sandia Labs.

Methods

Drilling and Coring (E-1, E-2, and E-3)

Three evaluation wells were drilled and cored in and around the northern half of the five spot pattern. The drill sites of these wells were chosen from data interpretation of the CSAMT methods shown in Figure 18 performed by personnel from Sandia Labs.

The data indicated the position of the suspected fire front, the combustion zone ahead of the front, and the unburned area ahead of the combustion zone.

Well E-1 was drilled into the burned zone; Well E-2 was drilled into the combustion zone ahead of the burned zone, and Well E-3 was drilled into the unburned portion of the formation according to the CSAMT data. These wells were triangulated and located from existing wells in the five spot pattern and are shown in Figure 18.

Wells E-1, E-2, and E-3 were drilled with a 10-in. bit to 20 ft and a 15 ft piece of 8 5/8-in. casing was set for surface pipe. The wells were then drilled with a 7 7/8-in. bit to 260 ft, 315 ft, and 318 ft respectively. The wells were then cored from these depths with a $6\frac{1}{4}$-in. core bit to 376 ft, 374 ft, and 380 ft. Approximately 116 ft, 50 ft, and 62 ft of core were obtained from E-1, E-2, and E-3 respectively. The wells were then drilled to 390 ft with a 10-15 ft "rat hole" to accomodate logging tools for the geophysical logging program.

The 2 5/8-in. cores were examined on site, boxed and sent to a commercial lab where core plugs were cut and analyzed.

The cores after being pulled and laid out were visually observed to determine changes or abnormalities in the cores through the zone of interest. The changes that were observed in the cores were a bleeding core section, noted as Zone I; a sand section that had no visual oil present, noted as Zone II; and a sand section that visually looked clean, noted as Zone III. No indication of fractures were noted in the visual examination of the cores.

A summary of the zone depths, oil saturation, water saturation, mobility, API gravity and fracture zones is given in Table 8.

The oil saturation data obtained from laboratory analysis did not agree with the visual observance. Zone I, where the bleeding of oil from the core occurred, showed an oil saturation of 31.2 percent in the pretest oil saturation analysis; whereas the oil saturation decreased in Well E-1 to 28.8 percent but increased to 39.6 and 50.7 percent in evaluation Wells E-2 and E-3 respectively. This would indicate that a burn occurred in the zone of E-1 and a bank of oil was moving through the zone to E-2 and 3. The evaluation of oil saturation data in Zone II indicates that a burn was not evidenced in this zone since the oil saturations remained approximately at the pretest level of 39.3 percent . The evaluation of oil saturation data in Zone III shows a pretest value of 48.4 percent in Link 1 Well. No data were obtained from Well E-1 while values of 12.7 and 27.4 percent were obtained for evaluation wells E-2 and E-3, respectively. This would indicate that a burn occurred in the zone, and the oil was pushed from the zone toward the producing wells.

Fracture identification logs were run on the three evaluation wells. This was an attempt to determine, if possible, that fractures existed above the zone of interest, and if there was a pattern to the existing fractures.

After examining the fracture identification logs, the following fracture zones were obtained and were noted on Table 8 with the exception of a large fracture zone located at 257-258 ft in a shale zone at the top of the Bartlesville sand. The remaining fractures shown in Table 8 do not follow a pattern. A fractured zone located at 350 to 361 ft in Well E-1 did not extend to any of the other wells. A lower fractured zone 372 to 374 ft is evidenced in Wells E-2 and E-3.

The large amount of injected air that was lost to surrounding wells was most likely lost through the fracture system located at 257-258 ft.

Thirty-three plugs were obtained from the cores from E-1 and E-2, and 32 plugs were obtained from E-3. The data for permeability, porosity, water saturation, and oil saturation are shown in Table 7. The data from the three evaluation wells are compared to Well 1, the first well drilled on the site, for comparison of pre- and post-data of the fire flood. The permeability of the three evaluation wells were higher than the precombustion well and these permeabilities increased as the distance increased from the injection well. The permeability of E-3 was the highest in value being located in a cross fractured zone between the hydraulically fractured Wells 2 and 5. The porosity of Wells 1, E-1 and E-2 is of a constant value; the porosity of Well E-3 is somewhat higher. The oil saturation of Well 1 and E-1 are of comparable value with the oil saturation of E-2 and E-3 being higher. The water saturation in Well E-1 is higher than in Wells E-2 and E-3. The increased permeability, porosity and oil saturation in the outer two Wells, E-2 and E-3 indicate that a bank of oil was present ahead of the fire front. This agrees to some other evaluation methods and interpretation of data made by Sandia Labs.

CSAMT Technique

The Controlled Source Audio frequency Magnetotelluric (CSAMT) technique (1,6,10,13,14) is an electromagnetic sensing method that allows one to estimate subsurface resistivities from measurements made at the surface. Basically an electromagnetic field (EMF) is generated using a current source that drives a grounded antenna. The interaction of this generated EMF with the formation is determined by measuring the components of the scattered EMF at points above the zone being integrated. The basic assumption is that an *in situ* combustion process will change the resistivity of the burn zone and the surface measurements will indicate this.

Field Application. The CSAMT antenna used at the *in situ* combustion site at Bartlett, Kansas was a long (~ 200 m, 610 ft) dipole laid out on the surface of the earth and grounded at both ends. A transmitter operating at selected frequencies (32-2048 Hz) was located at the center of the dipole. The transmitting antenna and a magnetometer were used to measure the magnetic field perpendicular to the transmitting antenna and in the plane of the earth.

Measurements of the electric and magnetic fields are made at each frequency and at various locations over the area to be interrogated. These measurements can be used to infer an apparent resistivity of the subsurface structure. The resistivities of the various formations as a function of depth can be inferred by constructing a model that gives the measured apparent resistivities as a function of frequency. This inference can be drawn since the depth interrogated by an electromagnetic (EM) wave as it penetrates a material depends upon the frequency; the lower the frequency the deeper the penetration of the EM wave.

In the field application a series of three surveyed lines were established as the base stations. These are indicated by the lines A, B, and C shown in Figure 19. From the measurements taken along these lines, a determination was made of areas where additional measurements were needed. These determined sampling stations are indicated by the points off of the lines A, B, and C in the figure. Note that where possible the additional stations are located on radial lines originating from the injection Well No. 1. The data stations were used in all surveys. In addition, in establishing the location of post operation coring of Wells E-1, E-2, and E-3, a more finely spaced grid was used.

CSAMT Modeling

Calculations of the apparent resistivity as a function of frequency at different locations above a buried object indicate the type of response to be expected in field measurements. If a shallowly buried object is a conductor relative to the surrounding media, the model indicates there will be noticeable reductions in the surface measured apparent inference of the location of the object. Laboratory measurements have shown that the resistivity of an oil- bearing formation increases dramatically after the fire front has passed through the region. Further, calculations for an interior region of high resistivity surrounded by an outer region of lower resistivity, all buried in a uniform half space, indicate that for shallow objects the center region (the region affected by the fire front) can be detected. The model also suggests that the outer edges of the high resistivity region are characterized by apparent resistivity readings above background.

In each of the models where there is a conducting body burned in a homogeneous half space of higher resistivity, the surface apparent resistivities are always lower than the half space resistivity. If the buried body has a resistivity higher than the homogeneous half space, the surface measured apparent resistivities will show values equal to or higher than background. As will be shown below there should be a zone of high resistivity where the firefront has passed.

Results. For the first survey performed in August 1980, a plan view contour plot for constant measured apparent resistivity at 1024 Hz is shown in Figure 20. For lines A, B, and C, indicated in Figure 20, apparent resistivities as a function of frequency are shown in Figure 21. The anticipated resistivity highs due to the zone behind the fire front are not apparent for the survey taken in August.

Two additional resistivity measurements were made in October 1980 and February 1981. The results for 1024 Hz in October 1980 are shown in Figure 22. As in Figures 20 and 21, Figure 22 again shows lower than background (32 to 34 ohm-m) apparent for the survey taken in August.

Two additional resistivity measurements were made in October 1980 and February 1981. The results for 1024 Hz in October 1980 are shown in Figure 22. As in Figures 20 and 21, Figure 22 again shows lower than background (32 to 34 ohm-m) apparent resistivities within the five-spot pattern.

Because of the complexity of this fireflood experiment and the fact that pretest data over the process area was not obtained, the resistivity values taken in February were normalized to those taken in August. A value of 1.0 indicates areas with no change in the resistivity, a value less than one indicates areas which are less resistive (more conductive), and a value greater than one indicates areas which are more resistive (less conductive) than the August survey. Plan-view values of normalized resistivity pseudosections for lines A, B, and C are shown in Figure 24.

The higher normalized resistivity around the injection well No. 1, especially at the higher frequencies (512 and 1024 Hz), suggests the presence of the burn zone of the fireflood. Care should be used in making this interpretation, however, as the entire zone within the five spot pattern bounded by Wells 2, 3, 4, and 5 is considerably below the background apparent resistivity whereas regions both to the extreme east and northwest of the pattern show higher than background values. Recall that from the model calculations a lower than background apparent resistivity is a signature for a buried conducting object. Similarly, a body more resistive than the background produces in the model an apparent resistivity above background. The appearance of a conducting body within the production pattern could result from the intrusion of subsurface water of high conductivity into that region.

A study of the CSAMT data was made to help locate three post-test evaluation boreholes as discussed in the section under drilling and coring.

Thermal Gravimetric Analysis Technique

Thermal gravimetric analysis (TGA) is a technique whereby a small sample of a substance is continuously weighed as its temperature is increased at a linear rate. By careful analysis of the resulting weight change as a function of temperature, one can extract information concerning the thermal stability and composition of the original samples, the composition and thermal stability of intermediate compounds, and the composition of the residue. Since the temperature is increased at a constant rate, the weight, W, as a function of temperature, T., or time can be easily determined. For conventional differential thermogravimetric analysis (DTG) the differential dW/dT is calculated. The negative of dW/dT is then plotted on the same graph as the weight loss vs temperature.

TGA and DTG Results. The TGA and DTG measurements on core samples taken from the post-test holes and from a core from a burn-tube test present strong evidence as to the location of the burn front and presence of low temperature oxidation (LTO). In both pre- and post-test sample materials from unaffected zones, there are distinct DTG mass loss peaks at 200 - 350°C and at 400 - 550°C. These correspond to oxidation reactions in the unburned core. In the burn tube samples which were taken from an unburned section of core ahead of the firefront, evidence of considerable low-temperature oxidation (LTO) was observed. The closer to the firefront the greater was the reduction of both peaks in the DTG, suggesting some amount of LTO and limited combustion had occurred. After the firefront has passed, there is no longer a hydrocarbon weight loss because the hydrocarbon has been completely consumed, leaving a clean sand.

The plugs taken from the cores in the post-experiment coring of Wells E-1, E-2, and E-3 have five overlapping zones for which TGA and DTG measurements were made. The air was injected into an interval between 335 - 372 ft. The TGA and DTG measurements on the core from the interval 368-369 ft of Well E-1 were identical to those in the burned zone of the combustion tube tests, indicating a complete burn in this interval. The measurements from the 360-361 ft interval were quite variable with a typical result shown in Figure 25. These curves indicate a substantial burn has already occurred, as reflected by the suppressed peak near 400 to 550°C. An examination of this plug shows areas of both burned and unburned sandstone. In the 354-355 ft interval the same signature of reduced oxidation components in the low temperature (200-300°C) region is observed. In both the burn-tube core and this core from the field, the implication is that this is LTO caused by blowby gases. Similar results are also observed in the samples from the 339-340 ft interval with the appearance of this plug suggesting the development of firefront fingering. For the upper interval of the field core at 334-335 ft, the 200-350°C oxidation peak has disappeared indicating just LTO and the passage of a burning front. Similar results were found for this interval in samples from Wells E-2 and E-3 with evidence of decreasing LTO as one proceeds away from the injection well. A summary of the TGA and DTG measurements are given in Table 9. Thus, it appears that the burn front was in fact very near Well E-1 in the injection interval (355-372 ft) with perhaps some bypass into the 330-340 ft interval. This bypass probably continued out to Wells E-2 and E-3, decreasing in effect with distance.

Geophysical Well Log Analysis

Standard logs of the post-test Wells E-1, E-2, and E-3 were obtained using conventional field procedures. The following analysis, which was suggested by the Schlumberger Co., includes determination of the porosity, cycle skipping in the transit times on sonic logs, resistivities for 40 and 60 cm spacing for inferred magnitude of permeability, and the water saturation.

Geophysical Well Log Results. The primary data obtained from the well log analyses are related to the water saturation of materials in the pay zones of the three post-test wells. Generally, water saturations of materials taken from Well E-3, thought to be ahead of the burn front, were found to be higher than those for Well E-1, conceded to be behind the burnfront. Further, the water saturation in Well E-1 is also relatively high, at least compared to what one might expect for a dry combustion process. Resistivity logs indicate a low permeability to water flow in the pay zone for Well E-3 and fracturing is less evident in Well E-3 than in Well E-1. The combination of less fracturing and lower water permeability at Well E-3 could help to explain the observed results of higher measured CSAMT apparent resistivities nearer Well E-3 than Well E-1. The log determined resistivity gives an overall average of approximately 20-30 ohm-m for the three evaluation boreholes, a value which is considerably higher than the CSAMT inferred resistivities. Measurements of oil and water saturations in the core materials from the post-test holes indicate a loss of oil or water from the natural state.

Burnfront Model Analysis

The analysis of a fireflood can be as simple as a linear one dimensional model all of the way to a complex multicomponent three-dimensional reservoir model. Fortunately many of the results from simpler models can be used to characterize the general features of an *in situ* combustion project. It is with this in mind that a simple series of models are presented to help in understanding this project and perhaps to indicate a possible explanation of the observed phenomena.

Burn-front Model Results. From the model it was found that the pay zone was within the range one normally expects except that the air requirements were excessive and the combustion temperature was high (1280°F). As expected, the *in situ* combustion model indicates that when the radius is small and/or when large quantities of air can get to the firefront, the rate of advance is greatest. Thus the burning rate can obviously be controlled by the injection rate. For a burning zone of height h, the radius increases as 1/ h and the velocity as 1/h. However, as larger surfaces are exposed, heat losses increase and the temperature of the front decreases. Eventually, the front progresses to where the temperature is below that necessary to maintain combustion and the burn terminates. Assuming a critical combustion temperature of 500-600°F, the front should have progressed to approximately 160-180 ft from the injection well. However, based on a resistivity (normalized) contour of 2.0 from Figure 23 as an indication of the extent of the burn, the front extended to about 80 ft (radius of a circle of area equal to the irregular "burned"zone) where the fire went out. One possible explanation for this difference is that some or most of the air bypassed (see above discussion on TGA) the fire zone. As a qualitative indication of this, air leakage was observed in a number of unplugged oil wells in the immediate neighborhood of the test site. A set of calculations that might indicate the air flow into the burning zone is given in Figure 26. A balance between the methods given above and the field experience suggest that the firefront was receiving only a few percent of the injected air.

Finally, it should be noted that the interpretations placed on the data accumulated from the various sources are not unique. These techniques do not provide conclusive evidence as to the extent and/or nature of the *in situ* combustion process. It is significant to note, however, that this experiment offered an opportunity to integrate several new techniques into a systematic study of a difficult problem. Perhaps the largest single factor in the uncertainty was the lack of any CSAMT field measurements prior to the start of the initial *in situ* combustion process in this field.

SUMMARY AND CONCLUSIONS

Two attempts were made to perform an _in situ_ combustion experiment on the Link lease. The first attempt to start a burn in the Bartlesville sand was made in a perforated interval between 342 to 367 ft. An acid treatment of the injection well at approximately 1,100 psi pressure created communication between the injection well and the four producing wells.

Some conclusions from the first burn attempt are:

1. The ignition of the formation was successful according to the O_2 and CO_2 data observations.

2. The burn front advanced in a west to northwest direction. The strongest advance of burn was to the northwest, and the indication of the burn was evidenced for one year.

3. Remedial treatments stimulated the wells and gave indications that a low temperature burn was in progress.

4. Sufficient volumes of air were not reaching the fire front to sustain the burn. This was caused by compressor failure and air migrating to and leaking from unplugged wells surrounding the test site. One well north northwest of the site was leaking large amounts of air. There was no way to measure the air loss because the casing was either broken off below ground level or there was no surface casing installed.

5. The temperature readings showed no indication of a burn front nearing the producing wells.

The following conclusions were reached for the second burn attempt:

6. The O_2 - CO_2 data indicate that a low temperature combustion was achieved in the formation.

7. Compressor problems resulting in the loss of air injection during crucial periods of time and excessive leaking of air from unplugged wells contributed to the low temperature burn.

8. The temperature in Wells 2, 4, and 5 increased indicating that a burn was in progress and had fingered out to these wells.

9. The original acid treatment not only fractured the formation from the injection well to the producing wells, but also into a permeable zone above. This zone connected the test site to surrounding unplugged wells through which large amounts of air escaped.

The following conclusions were reached from the analysis of the evaluation attempts:

10. The burn front cannot be explicitly defined. Results from the CSAMT measurements, together with the TGA analysis of core material from

Wells E-1, E-2, or E-3, indicate the approximate burn front location in one area. Extension to other areas can then be inferred.

11. Fingering of the combustion front was indicated at 340 ft in Well E-1.

12. Low temperature oxidation was observed at a depth of 335 ft in Well E-2.

13. No evidence was found by the evaluation methods that the combustion front had reached Well E-3.

14. The location of Wells E-1, E-2, and E-3 were close to the fire front including both burned and unburned portions of the reservoir.

15. The model study coupled with the CSAMT data helped to establish geometrics of the combustion process.

16. The model study confirmed that an excessive amount of injected air had bypassed the combustion front.

17. The decreased CSAMT resistivity indicates water intrusion into the burned zone.

18. These results further confirm that a total systems approach, utilizing all data and information available and obtaining data in a coordinated fashion, is necessary to offer a high probability of success.

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TABLE 1 - Average reservoir properties from log analysis of five wells at the Link Lease, Bartlett, Kansas

Well No.	Net Interval, feet	Average Porosity, percent	Water Saturation, percent	Volume-Shale, percent	Comments
Link 1	349-368	20.7	48	15	Shaly
Link 2	352-367	23.0	50	20	Disseminated Shale
Link 3	350-366	25.0	49	10	Disseminated Shale
Link 4	342-364	21.0	50	10	Disseminated Shale
Link 5	340-364	22.0	48	25	Disseminated Shale 6 feet laminated

TABLE 2 - Summary of core analysis from Link 1 well Labette County, Kansas

Depth, feet	Perm. to Air millidarcies	Porosity, percent	Saturation Oil percent	Saturation Water percent	Grain Density g/cm^3	Comments
275-279	1.1	10.9	15.8	60.6	2.71	Oil
279-287	1.0	11.2	3.6	80.2	2.74	Non Prod.
287-289	1.3	11.5	26.1	57.6	2.74	Oil
290-295	6.2	12.7	30.0	48.5	2.70	Oil
295-302	1.3	10.7	7.5	71.4	2.71	Oil
302-313	32.0	15.8	37.4	39.4	2.66	Oil
332-342	9.4	13.4	30.3	48.5	2.67	Oil
344-353	99.0	21.3	28.8	44.6	2.67	Oil
353-363	186.0	21.4	49.0	30.3	2.69	Oil

TABLE 3 - X-Ray diffraction mineral percentages from Bartlett test site core samples

Core Depth, feet,	Quartz, Percent	Feldspar, Percent	Kaolinite, Percent	Chlorite, Percent	Illite, Percent	Siderite, Percent
350	78	8	6	4	4	-
353	69	12	9	5	5	-
355	68	13	9	4	5	1
360	46	9	15	12	18	-

TABLE 4 - Laboratory and field data used to calculate and design the in situ combustion project

LABORATORY DATA

I. D. of combustion tube, feet		0.24
Length of pack burned, feet		0.89
Porosity, percent		25.88
Volume of produced gas (dry basis), scf		23.60
Composition of injected air:	Component	Volume, percent
	N_2	71
	O_2	21
Composition of produced gas:	Component	Volume, percent
	N_2	81.38
	O_2	6.41
	CO_2	10.26
	CO	1.95

FIELD DATA

Pattern area, acres	1.25
Distance between injection and production wells, feet	165.00
Formation thickness, feet	12.00
Formation temperature, °F	55.00
Production-well bottom-hole pressure psia	14.70
Porosity, percent	22.00
Permeability, md	177.00
Oil saturation, percent	43.00
Water saturation, percent	35.30
Production-well radius, feet	0.46

TABLE 5 - Results of Link lease evaluation by Nelson-McNeil method

Total oil recovery, barrels	4,410
Total water recovery, barrels	4,860
Total time, years	1.12
Maximum required air injection, MMSCF/D	0.772
Total air injection, MMSCF	267
Reservoir efficiency, percent	400

TABLE 6 - History of well treatments to maintain productivity

Date	Wells	Type of Treatment
1-28-80	1	New heater in the hole.
1-30-80	1	New generator. Heater back in hole 2-2-80. Pulled out after ignition 2-12-80.
6-09-80	Compressor	Installed larger booster compressor.
6-26-80	2, 3, 4, 5	Stimulated producing wells: 250 gallons water with 12.5 gal detergent. 250 gal 15 percent HCL, spaced with 210 gal lease water, 420 gal water with 55 gal scale inhibitor, displaced with 840 gal water mixed with 12 gal corrosion inhibitor.
7-15-80	Compressor	Replaced booster compressor.
7-22-80	Compressor	Set an additional primary compressor.
8-06-80	5	Cleaned well with sand pump.
8-18-80	2, 3, 4, 5	Stimulated producing wells: 250 gal diesel with 55 gal paraffin solvent, 2½ gal Flow Master, chased with 420 gal lease water. Shut in 24 hrs.
10-27-80	5	Cleaned well with sand pump.
11-18-80	5	Cleaned well with sand pump and swabbed.
11-24-80	2, 3, 4, 5	Stimulated producing wells: 250 gal diesel with 55 gal paraffin solvent, 2½ gal Flow Master, chased with 420 gal lease water. Shut in 24 hrs.
1-19-81	5	Hydrojeted well: Cut 2 slits in casing at 373-374 and 362-363. Acidized with 500 gal 15 percent HC, chased with 420 gal lease water.
1-29-81	2, 3, 4, 5	Stimulated producing wells: 250 gal diesel with 55 gal paraffin solvent, 2½ gal Flow Master, chased with 420 gal lease water. Shut in 24 hrs.

All producing wells were initially treated with 30 quarts of corrosion inhibitor and continued on a rate of 1 quart/day. Biocide treatment was started 4-03-80 at the rate of 5 gallons/well every two weeks.

TABLE 7 - Comparison of core analysis from Link No. 1 Well and three evaluation wells, Bartlett site

Link No. 1					Evaluation No. 1				Evaluation No. 2				Evaluation No. 3			
Depth ft	Perm	Poro-sity	Oil Sat, Percent	Water Sat, Percent	Perm md	Poro-sity	Oil Sat, Percent	Water Sat, Percent	Perm md	Poro-sity	Oil Sat, Percent	Water Sat, Percent	Perm md	Poro-sity	Oil Sat, Percent	Water Sat, Percent
350	100.0	23.6	23.8	49.2	222.0	20.4	42.8	39.0	240.0	24.0	26.8	41.1				
351	163.0	23.1	22.2	50.3	186.0	20.8	47.2	34.4	169.0	22.6	25.1	45.7	141.0	22.5	26.1	45.6
352	164.0	22.9	18.6	53.7	183.0	23.4	34.3	37.0	79.0	20.4	49.6	29.3				
353	170.0	22.6	49.3	24.4	181.0	23.0	29.3	41.6	188.0	22.4	51.2	27.6				
354	35.0	15.0	46.1	35.4	155.0	11.3	11.4	83.4	182.0	22.3	30.0	31.6				
355	151.0	21.9	53.3	29.7	224.0	23.1	34.3	39.4	182.0	22.2	34.1	36.5				
356	258.0	23.6	50.7	28.3	168.0	22.6	44.3	37.0	195.0	22.3	34.2	33.0	264.0	25.2	34.8	36.6
357	242.0	23.5	45.6	31.9	194.0	22.7	55.7	27.5	802.0	24.0	61.0	22.2	761.0	24.4	51.7	27.2
358	207.0	22.3	41.1	34.7	219.0	23.2	54.0	29.0	240.0	22.7	58.0	22.0	730.0	22.2	58.0	28.5
359	222.0	22.0	56.1	26.5	266.0	20.5	61.0	12.0	251.0	22.8	64.1	18.0	361.0	24.2	59.0	26.2
360	228.0	21.8	53.5	28.4	142.0	22.3	44.4	32.0	391.0	23.5	55.3	26.0	523.0	25.1	59.5	21.3
361	208.0	21.4	50.3	29.7					424.0	23.8	56.5	25.2				
362	136.0	19.5	43.5	34.3												
363																
364																
365																
Ave of all points	176.0	21.8	42.6	35.1	195.0	21.2	41.7	28.5	279.0	22.8	46.3	29.9	463.0	23.9	48.2	30.9
Ave Points 365-360 ft	231.0	22.6	49.4	39.8	198.0	22.3	51.9	29.7	376.0	23.1	54.5	24.2	528.0	24.2	52.8	28.0

TABLE 8 - Summary of the TGA and DTG Measurements

Well Depth	E-1	E-2	E-3
334-335 ft	LTO	Little LTO	Slight LTO
339-340 ft	LTO with burn front fingering		
354-355 ft	LTO[(a)]	Virgin core	Virgin core
360-361 ft	Half burn w/some hi temp coke left		
368-369 ft	Completely burned		

[(a)]Probably caused by blowby gases

FIGURE 1. Map of Kansas shows site location.

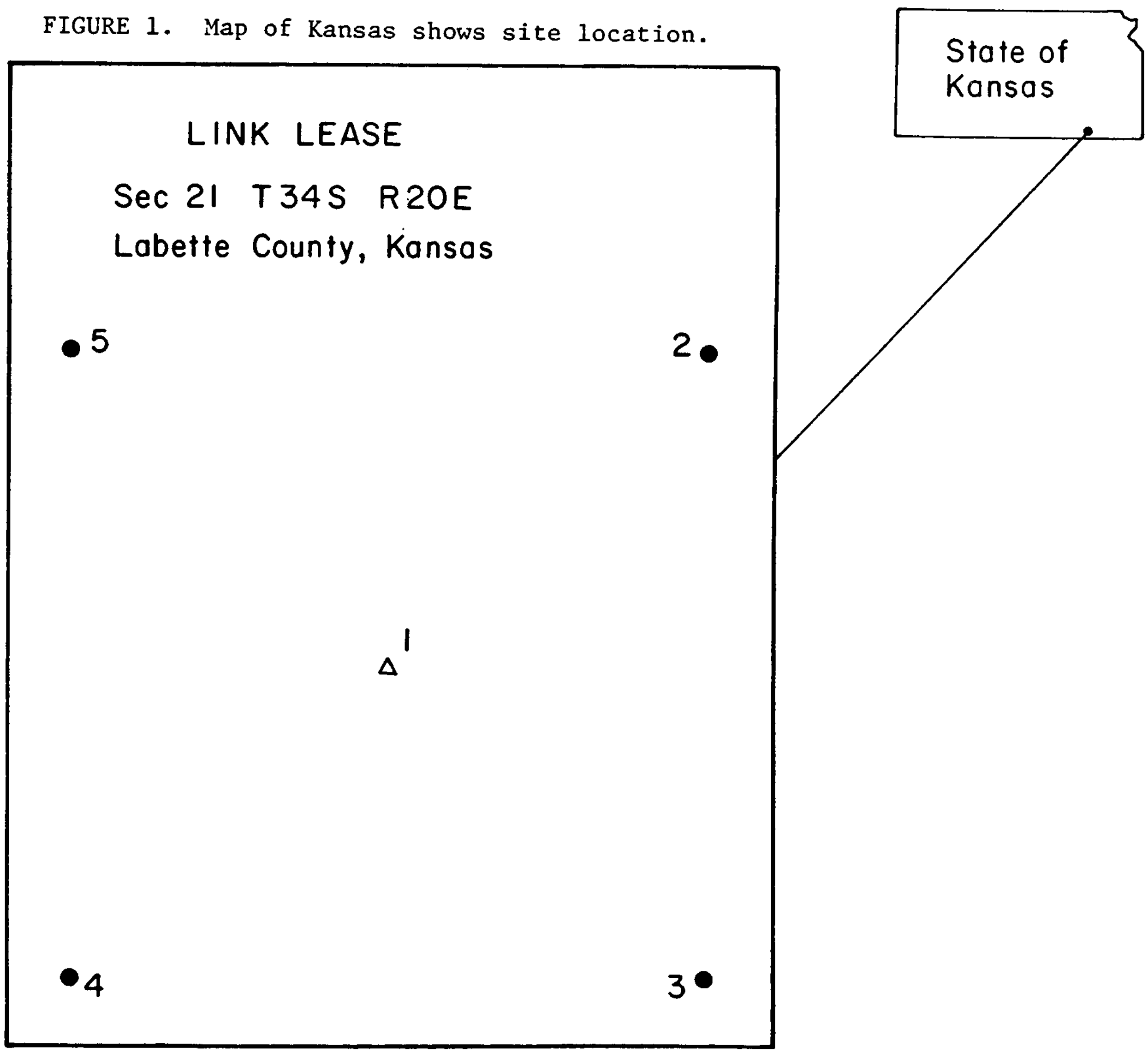

FIGURE 2. Thin Section Photograph, Bartlesville Sand

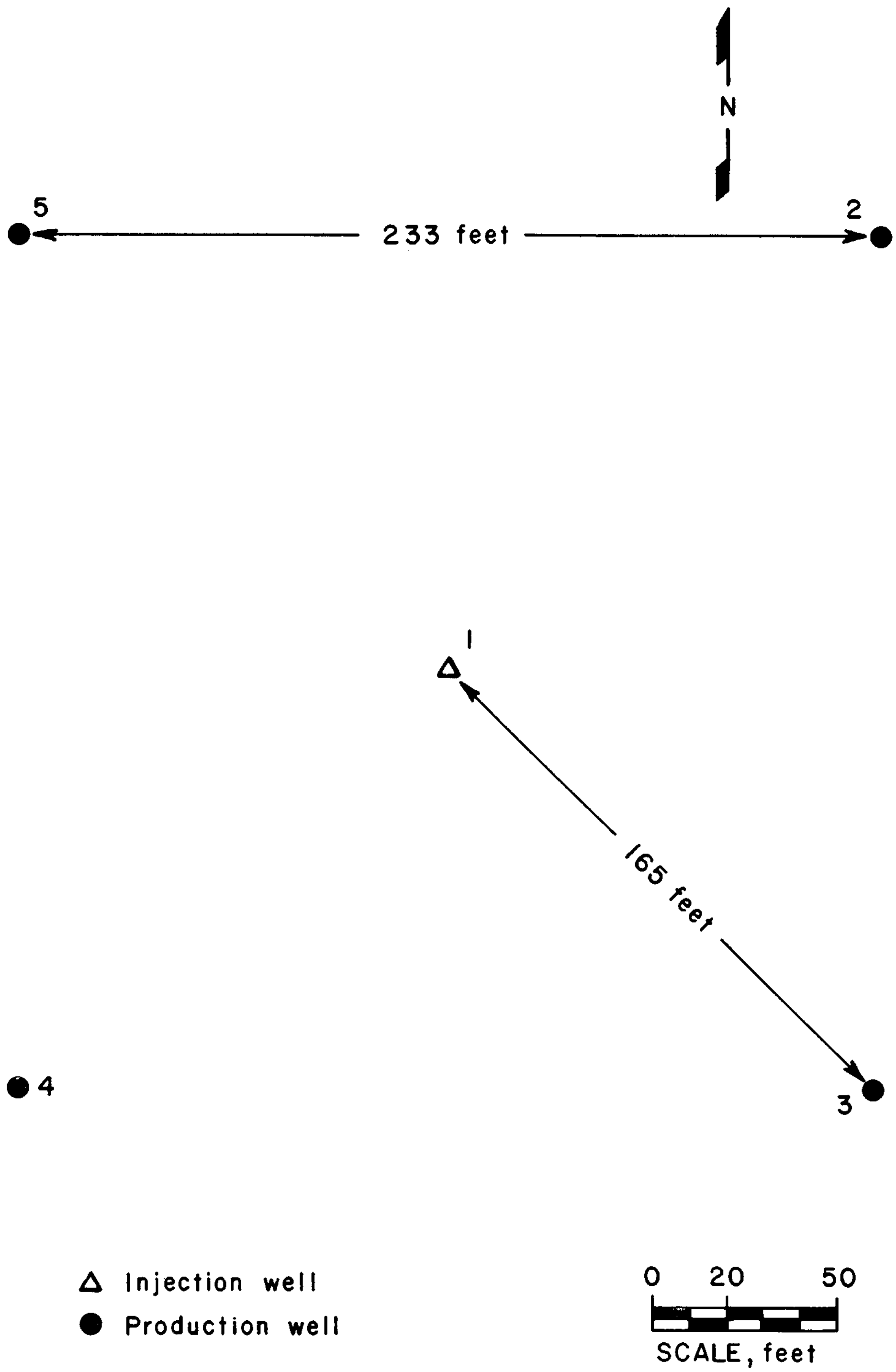

FIGURE 3. Well Patterns, Bartlett Site

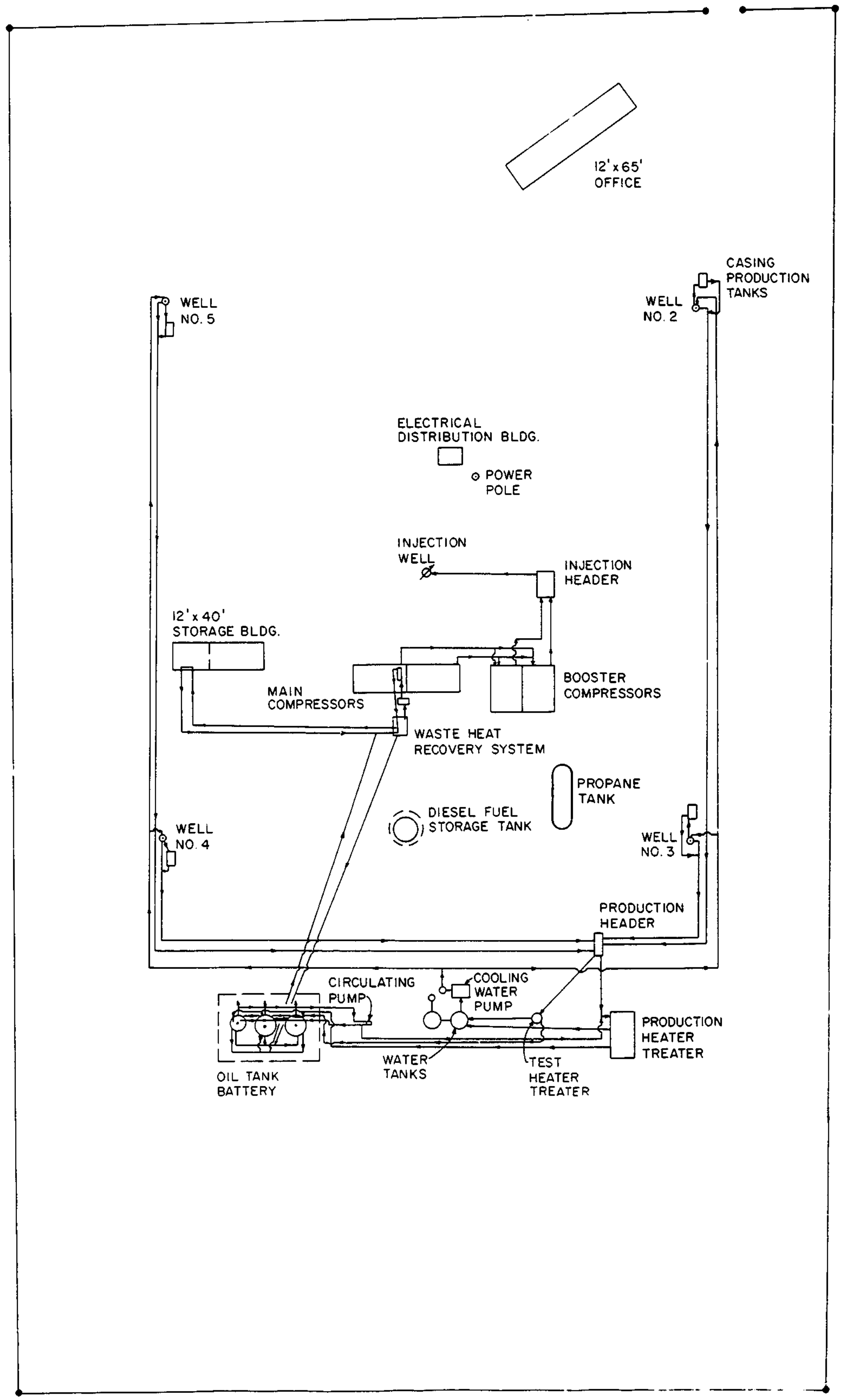

FIGURE 4. Equipment Location, Bartlett Site

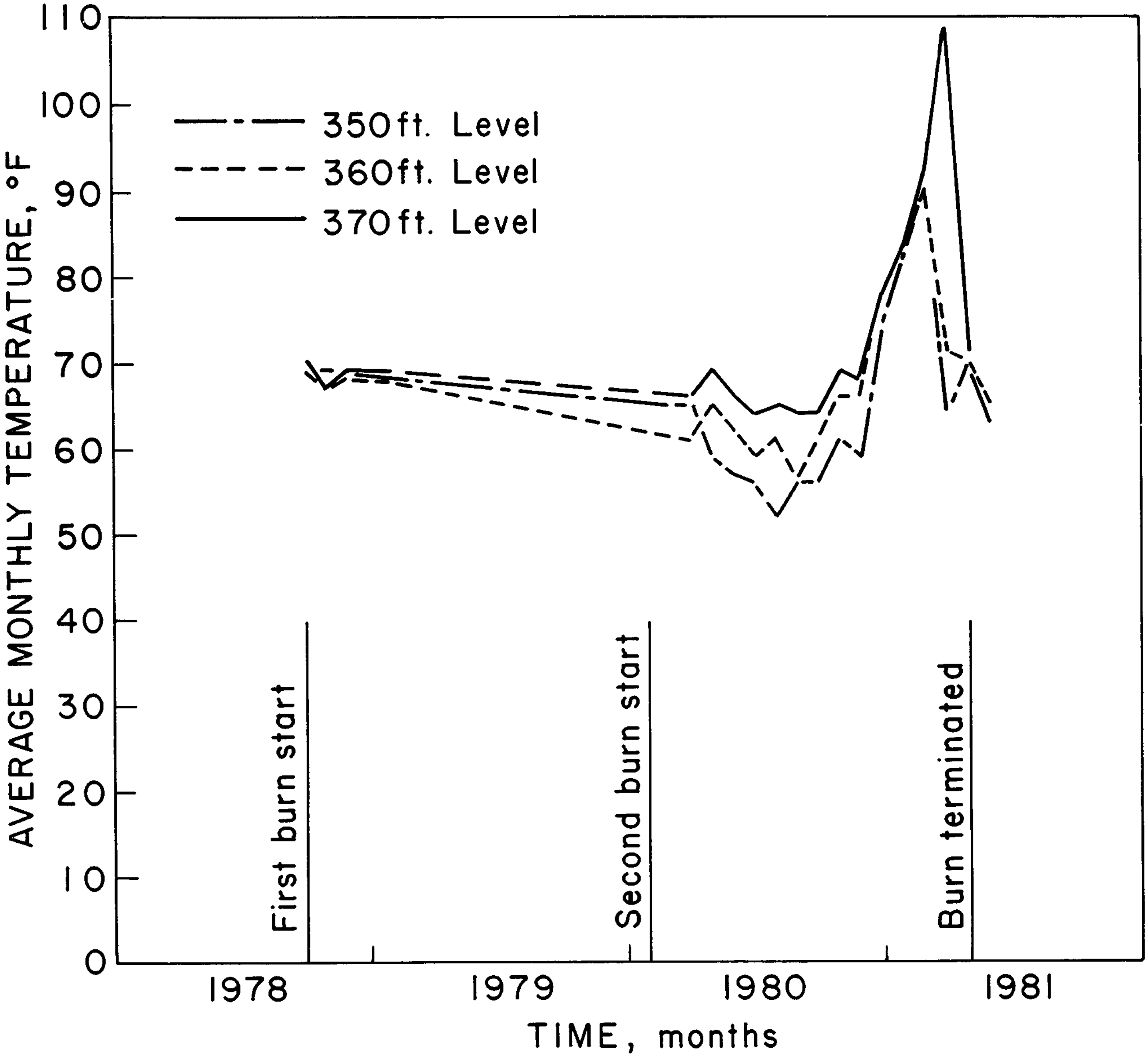

FIGURE 5. Formation Temperature Log, Burns 1 and 2, Well 2

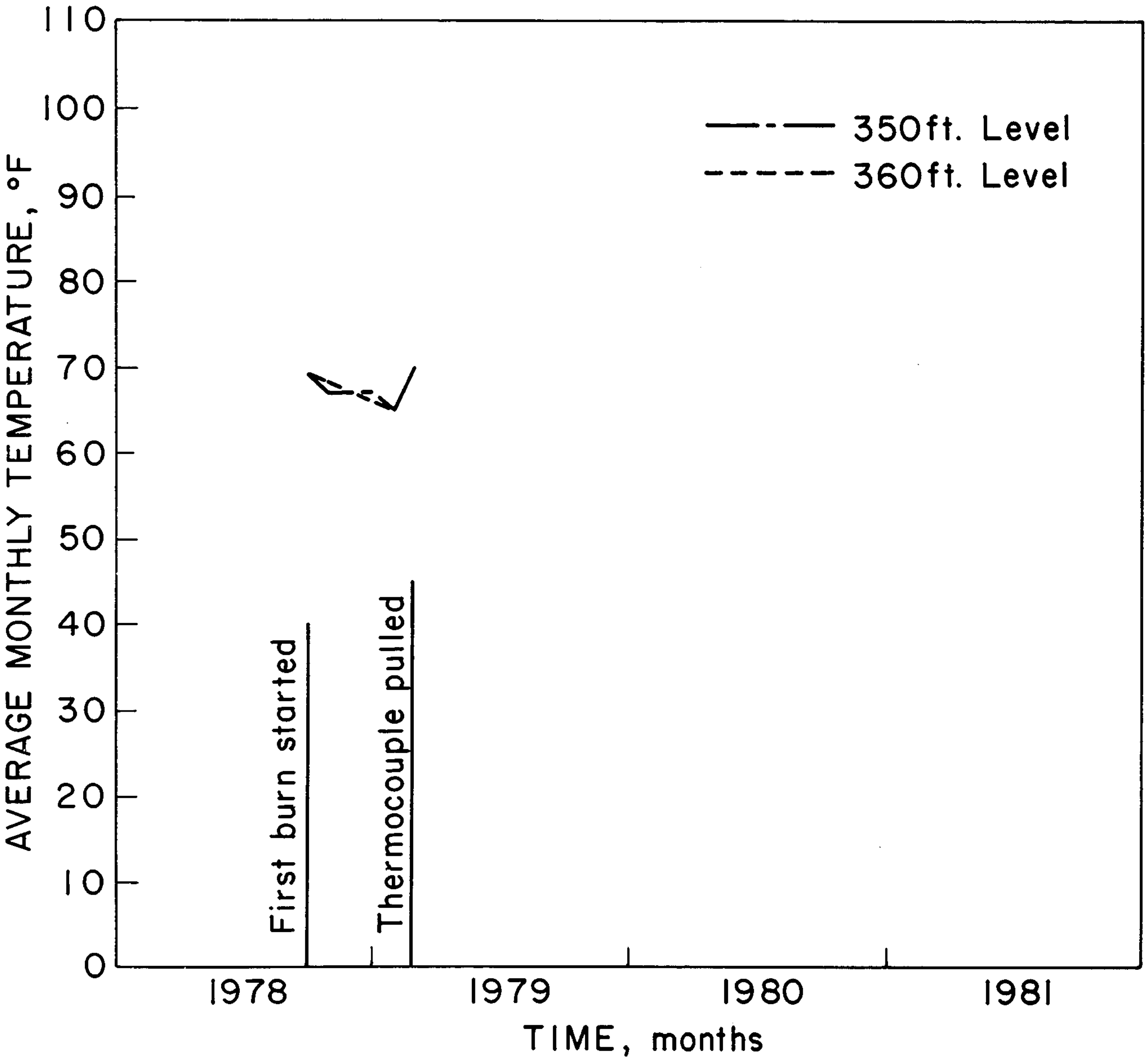

FIGURE 6. Formation Temperature Log Burn 1, Well 3

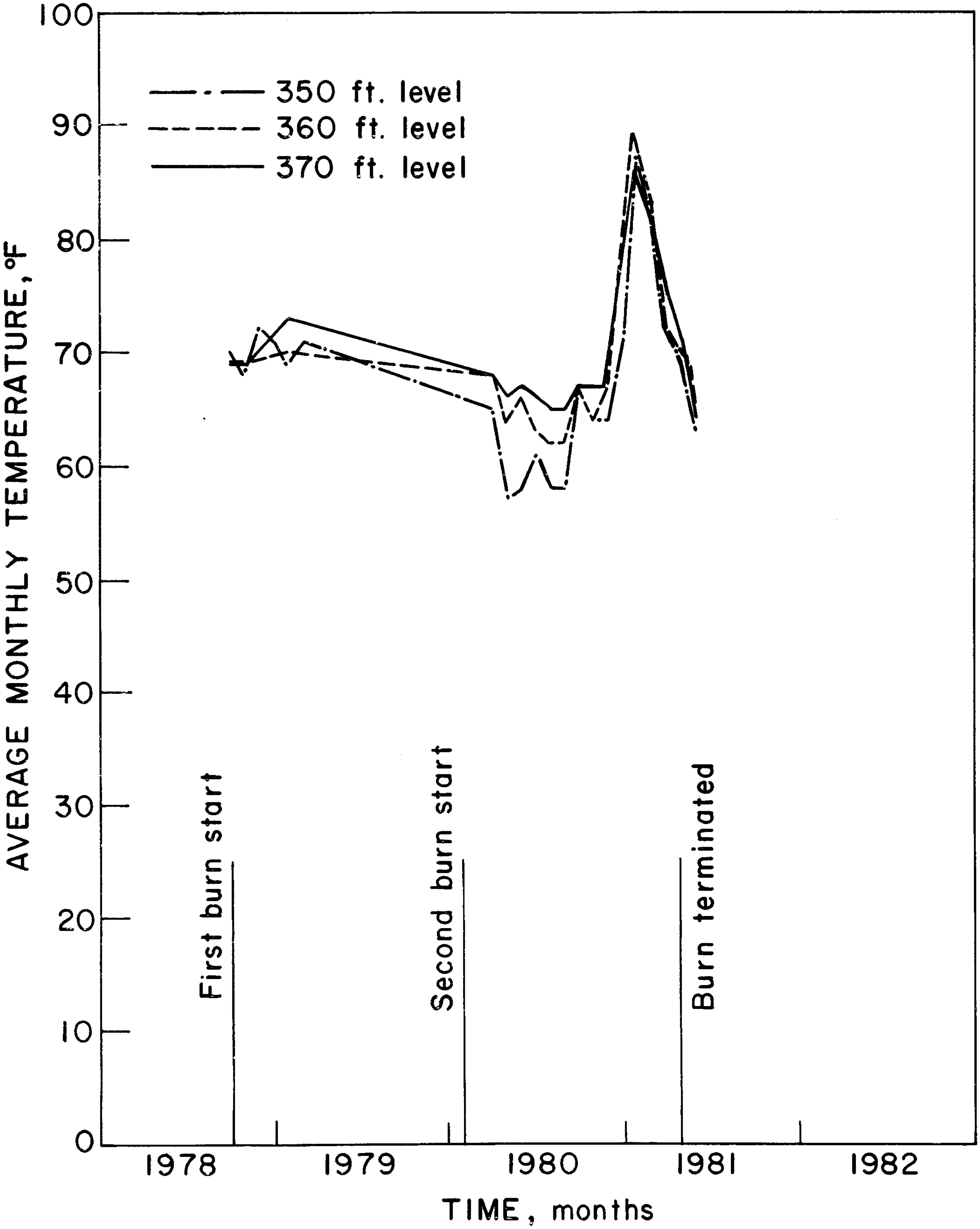

FIGURE 7. Formation Temperature Log Burns 1 and 2, Well 4

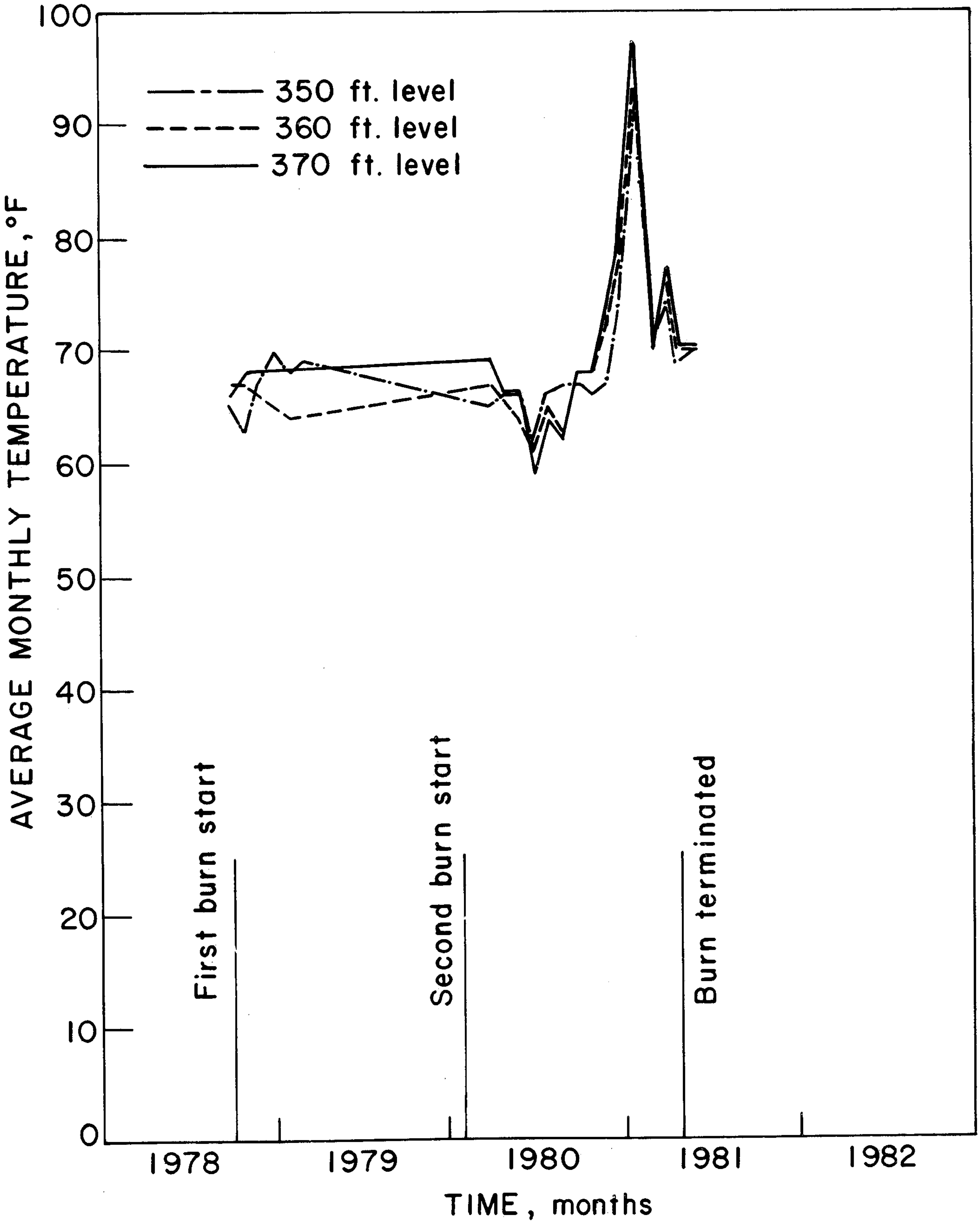

FIGURE 8. Formation Temperature Log Burns 1 and 2, Well 5

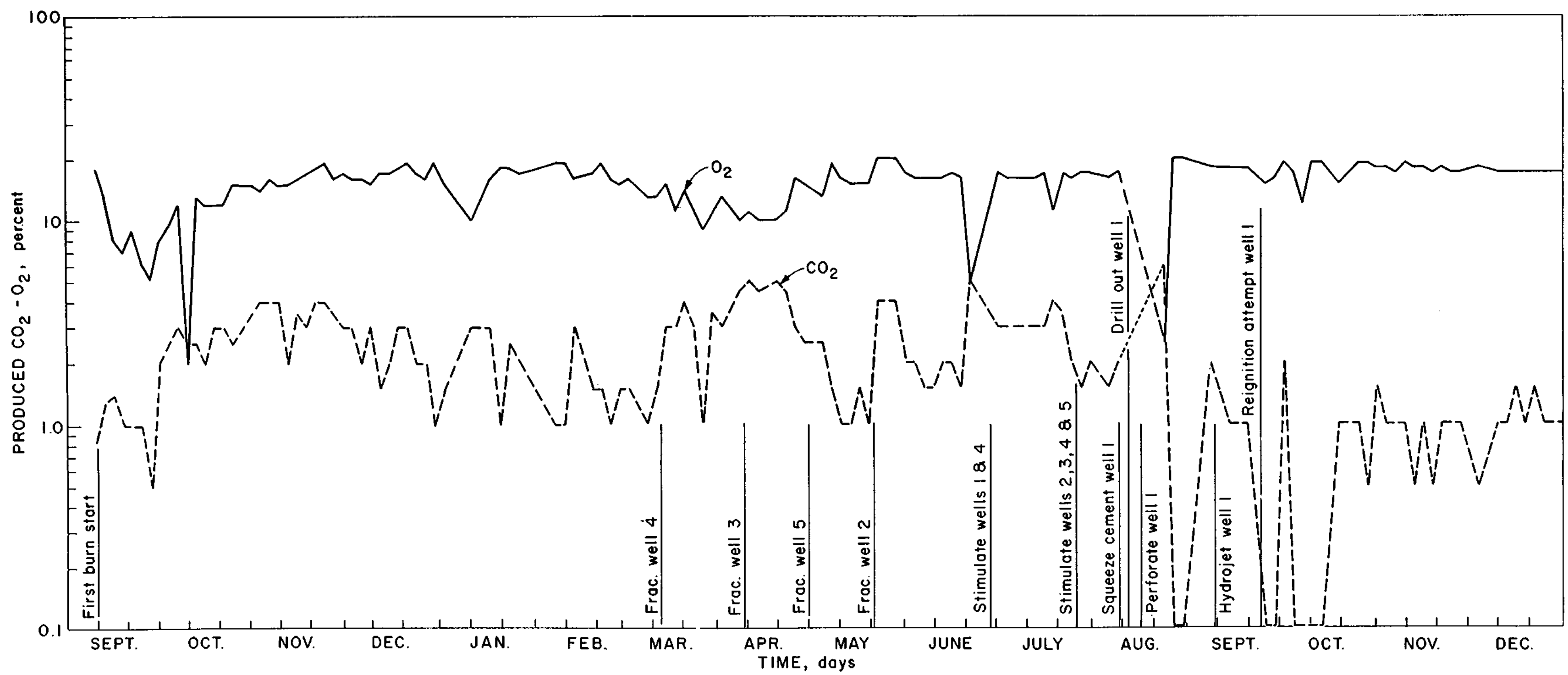

FIGURE 9. Plot of O_2 and CO_2 from Combustion Gases, Burn 1, Well 2

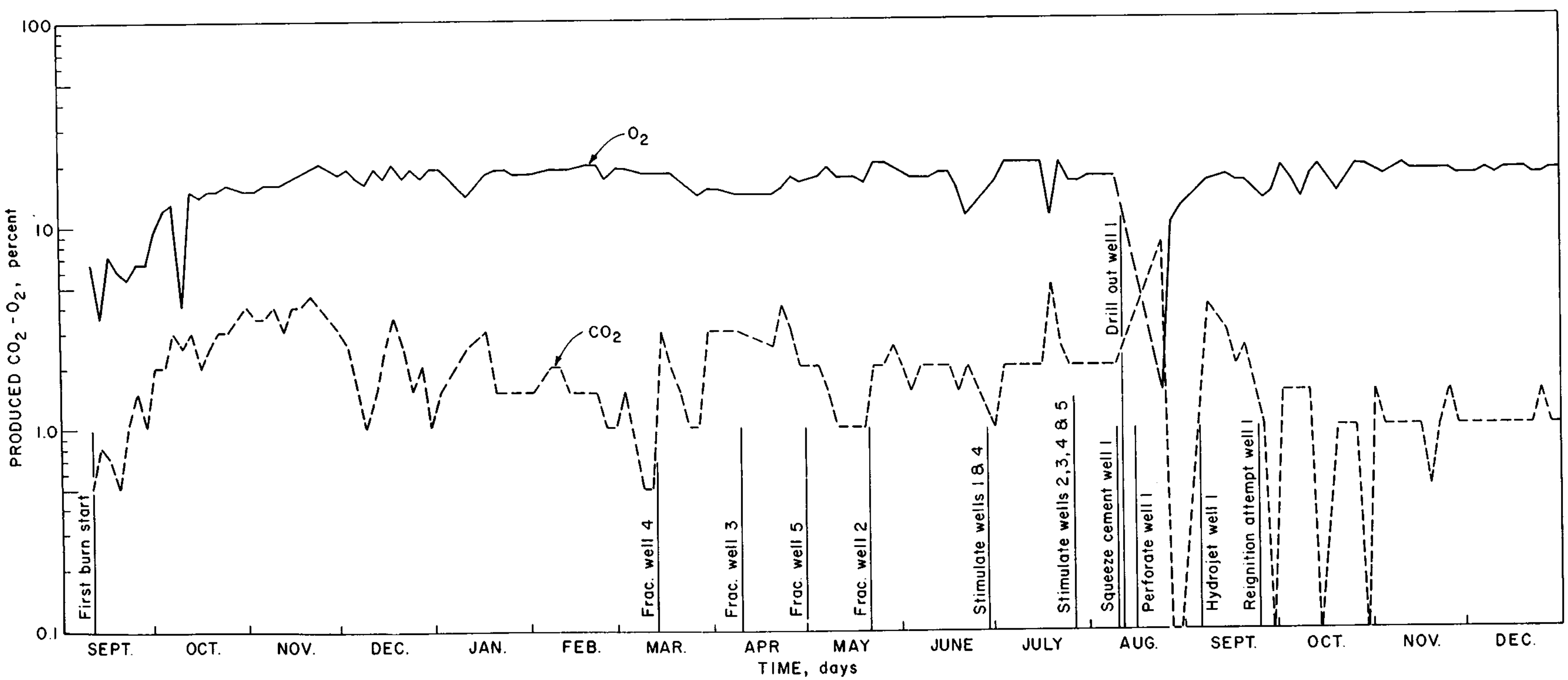

FIGURE 10. Plot of O_2 and CO_2 from Combustion Gases Burn 1, Well 3

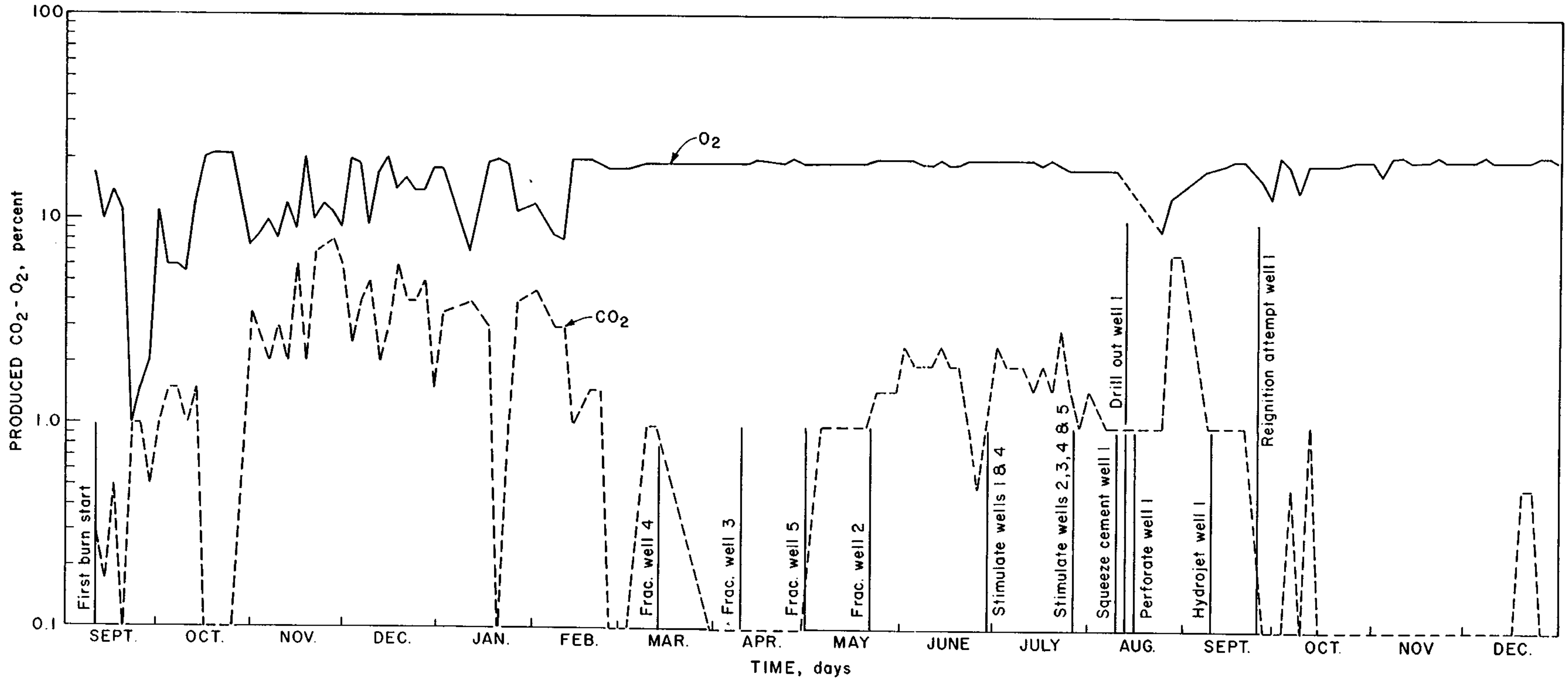

FIGURE 11. Plot of O_2 and CO_2 from Combustion Gases Burn 1, Well 4

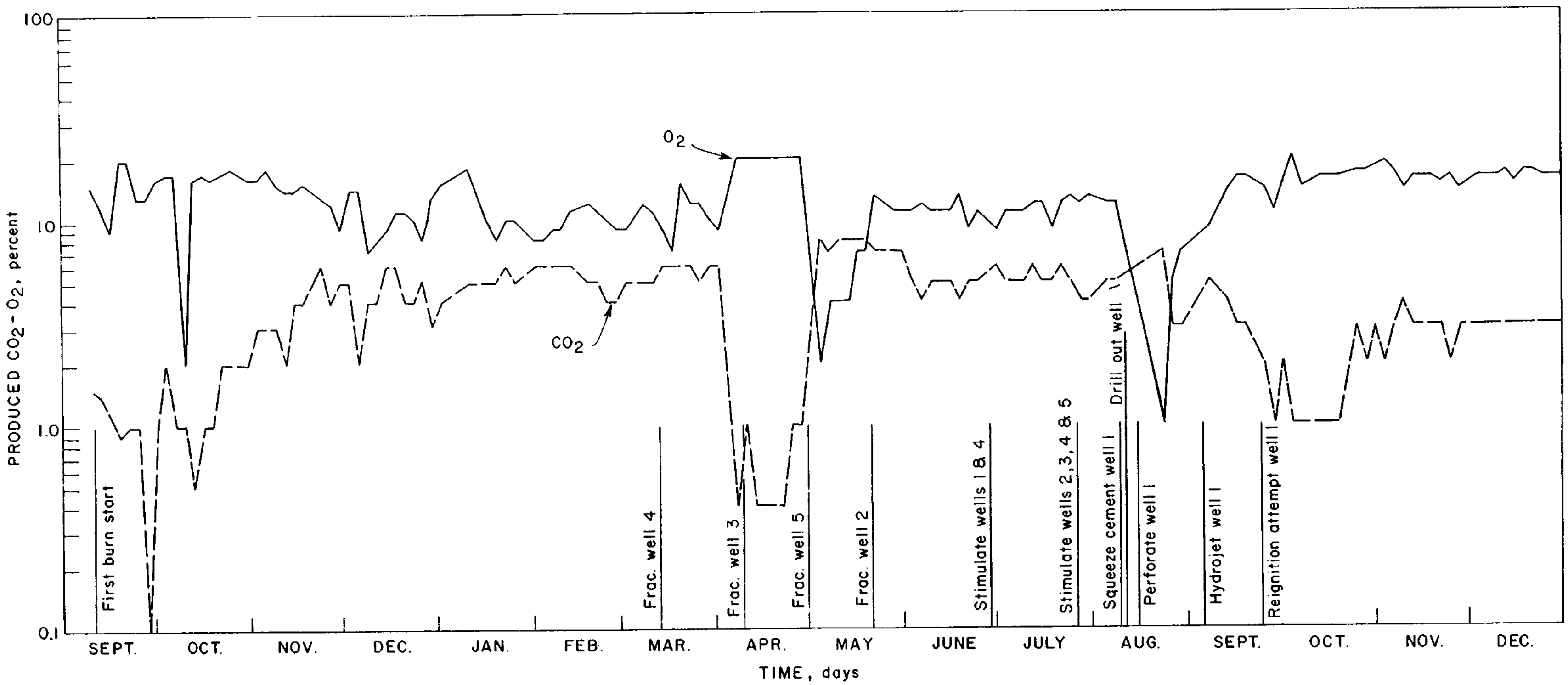

FIGURE 12. Plot of O_2 and CO_2 from Combustion Gases Burn 1, Well 5

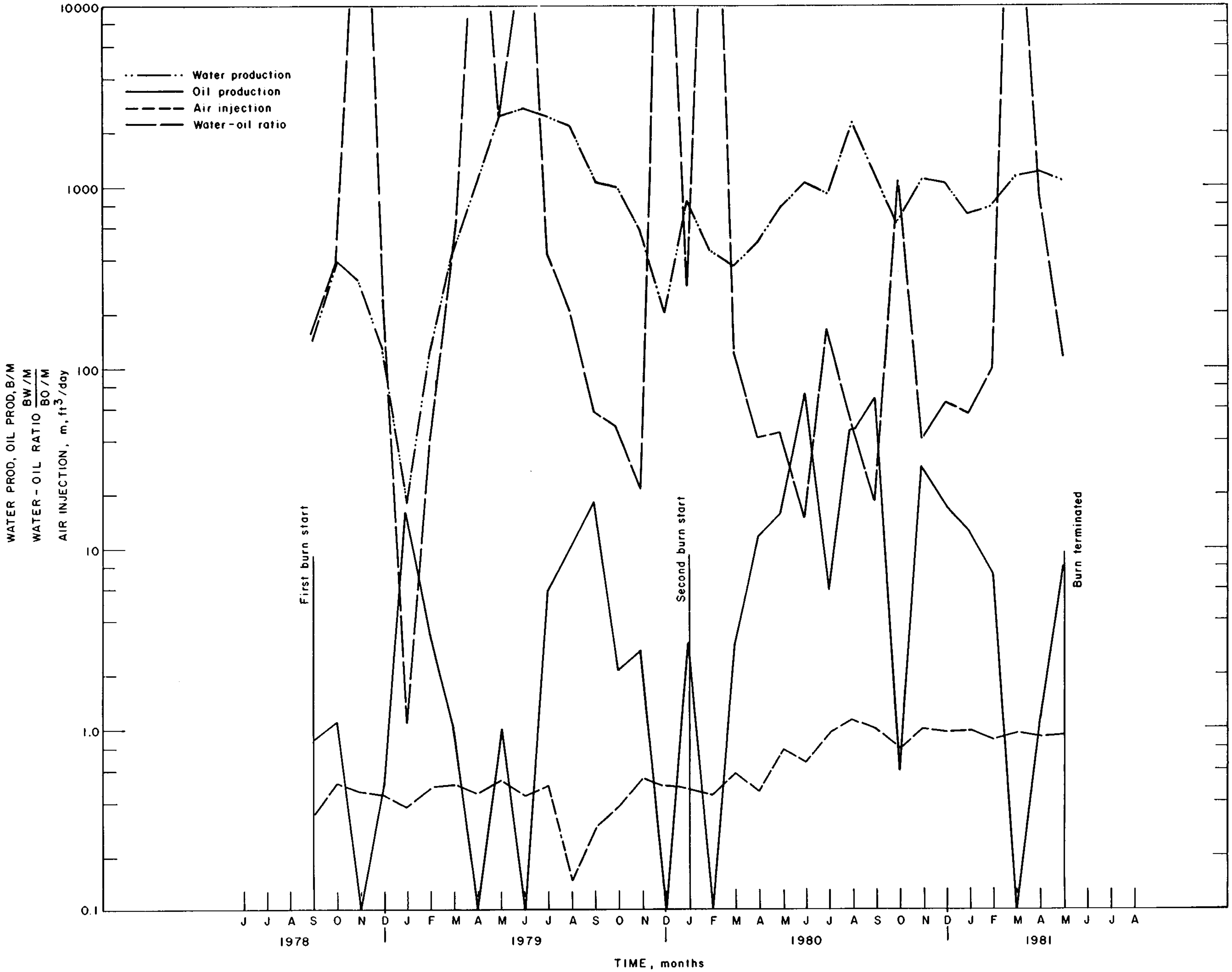

FIGURE 13. Fluid Production and Air Injection Burns 1 and 2, Bartlett Site

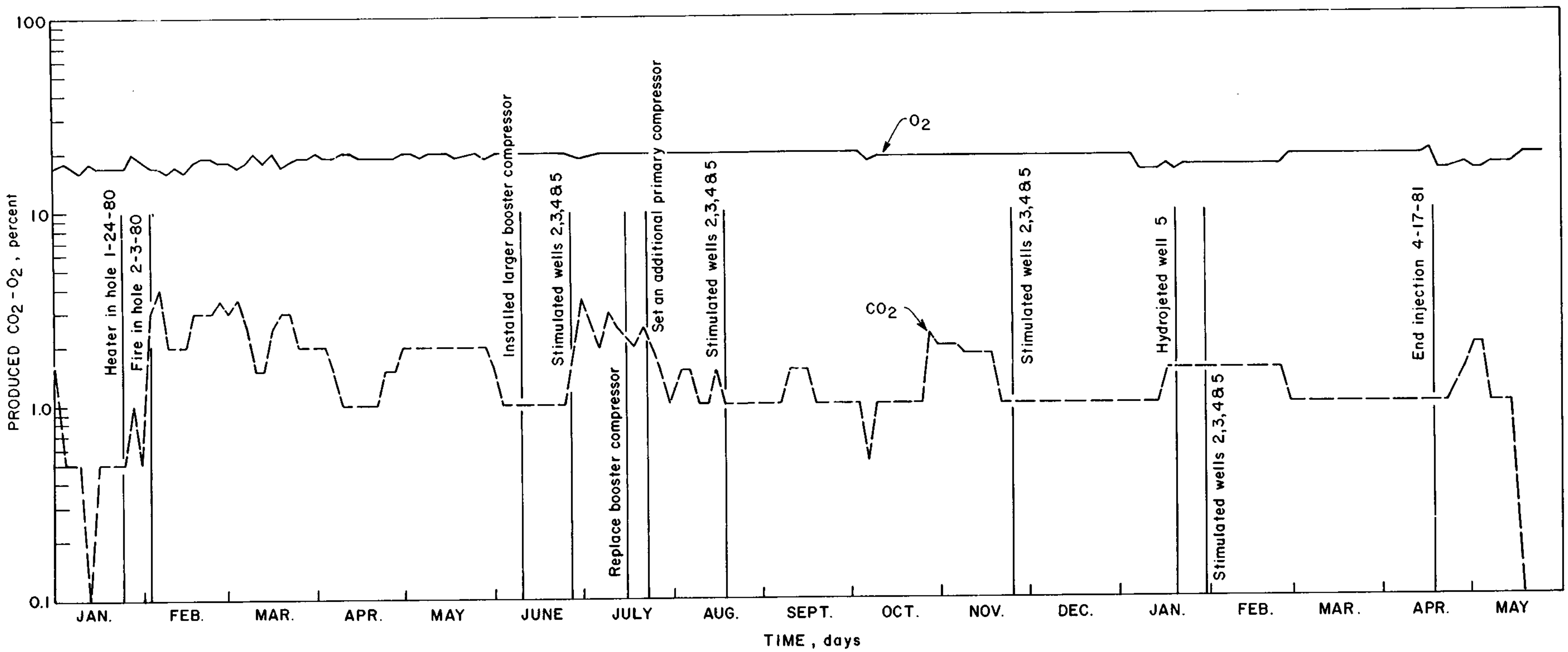

FIGURE 14. Plot of O_2 and CO_2 from Combustion Gases Burn 2, Well 2

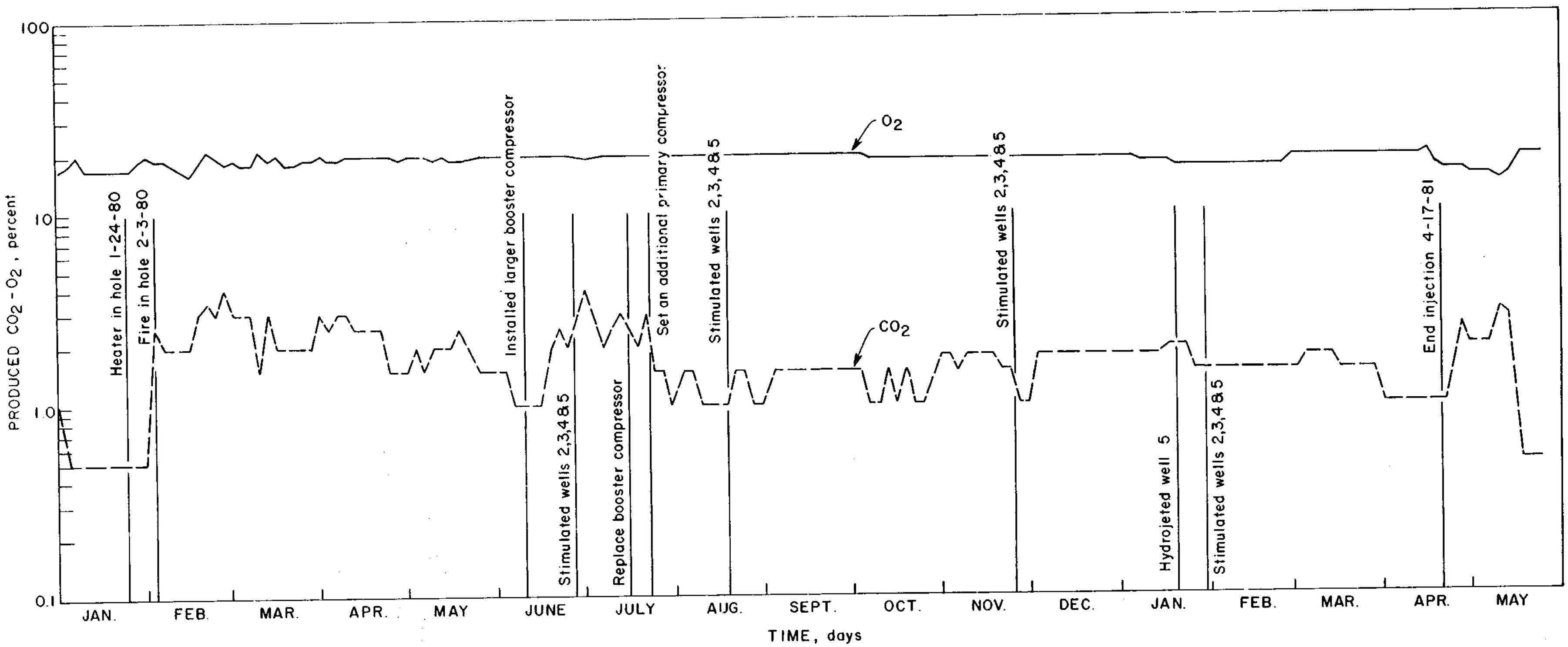

FIGURE 15. Plot of O_2 and CO_2 from Combustion Gases Burn 2, Well 3

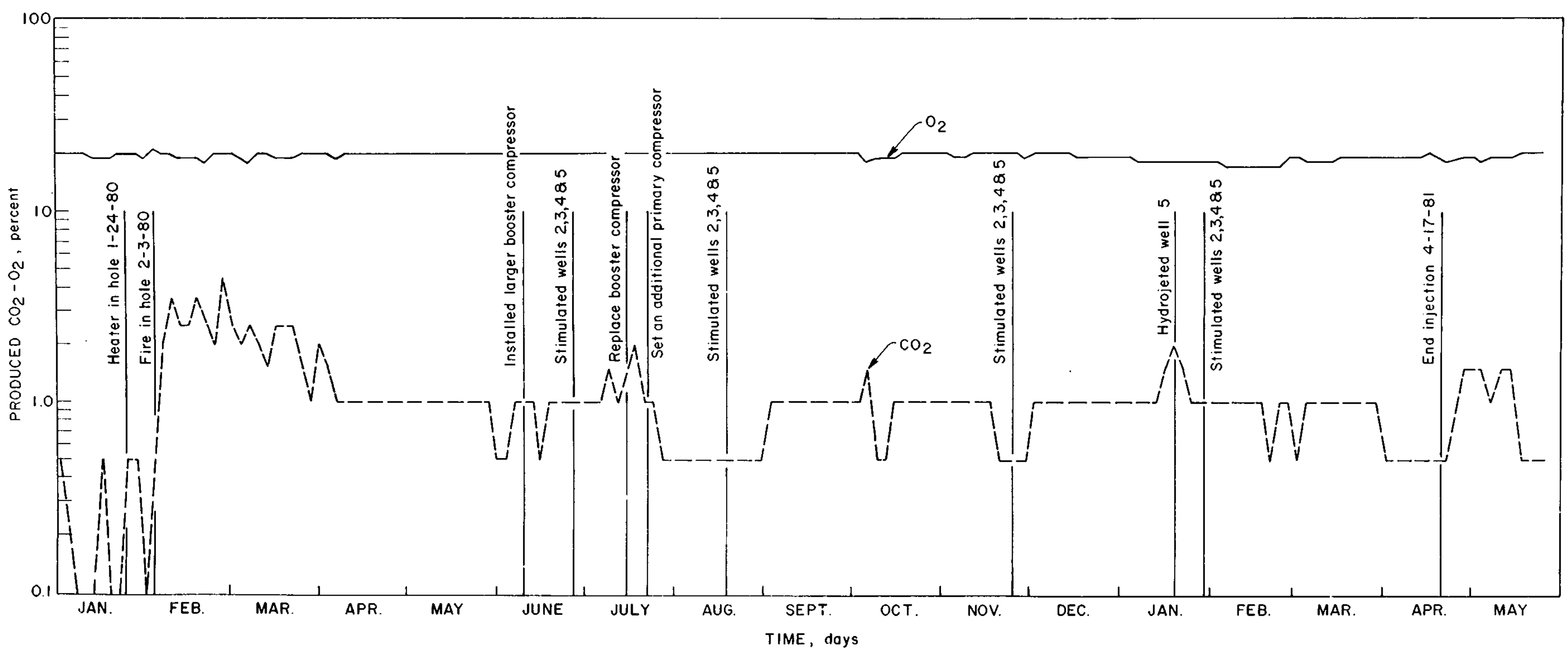

FIGURE 16. Plot of O_2 and CO_2 from Combustion Gases Burn 2, Well 4

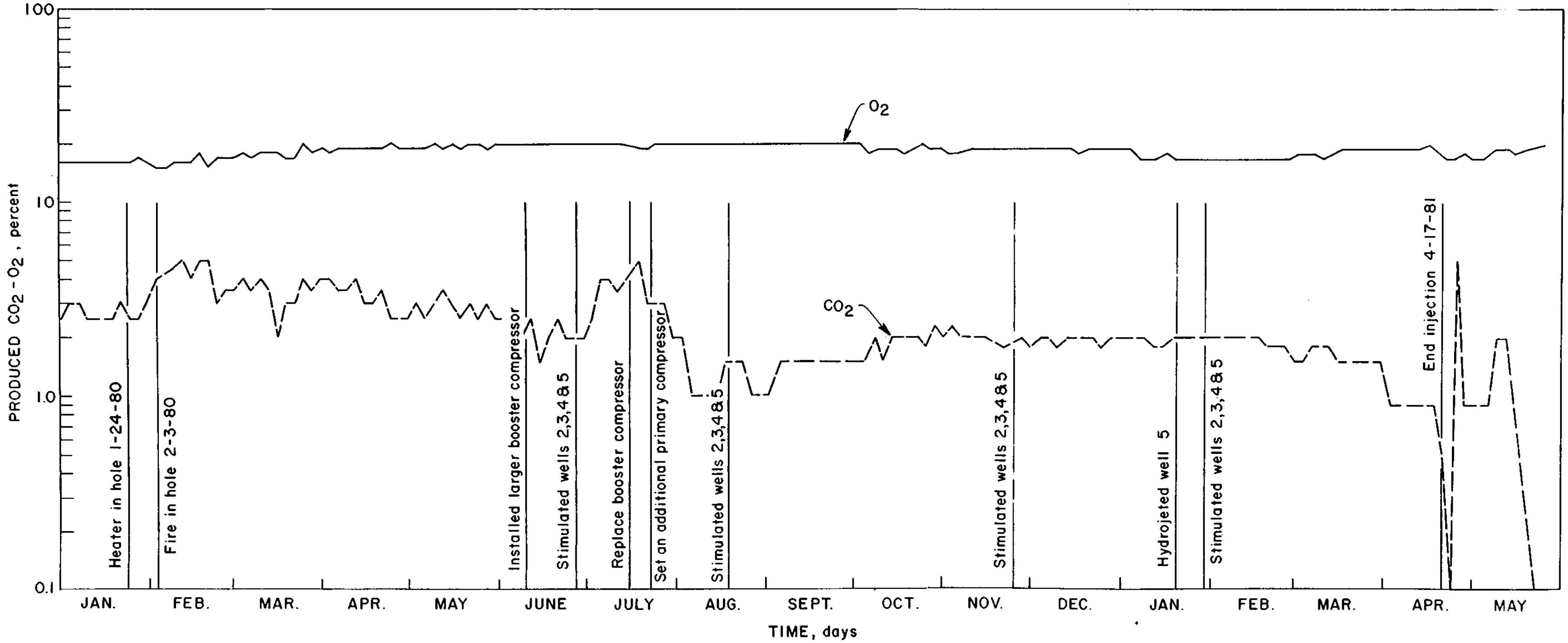

FIGURE 17. Plot of O_2 and CO_2 from Combustion Gases Burn 2, Well 5

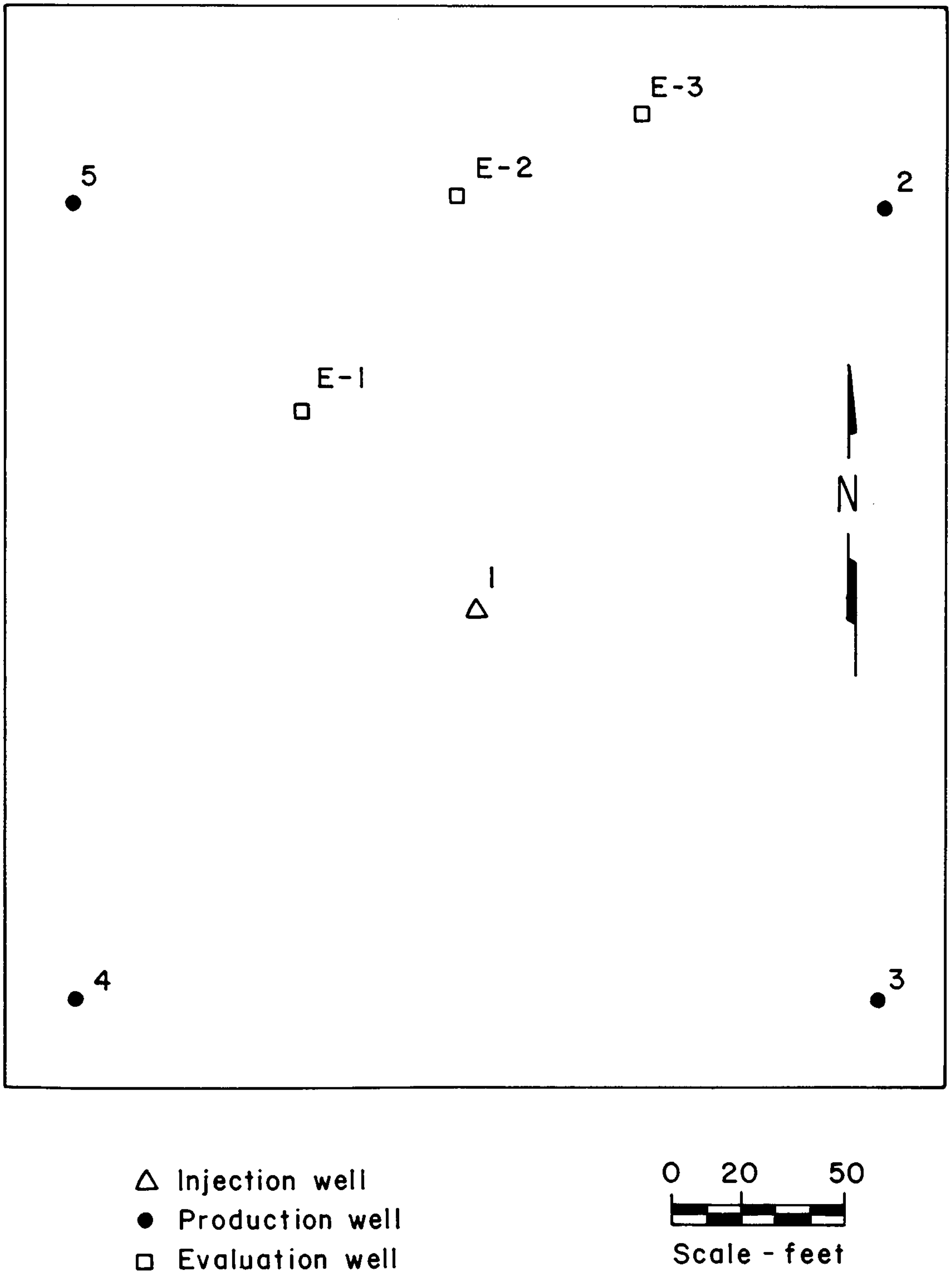

FIGURE 18. Evaluation Well Pattern, Bartlett Site

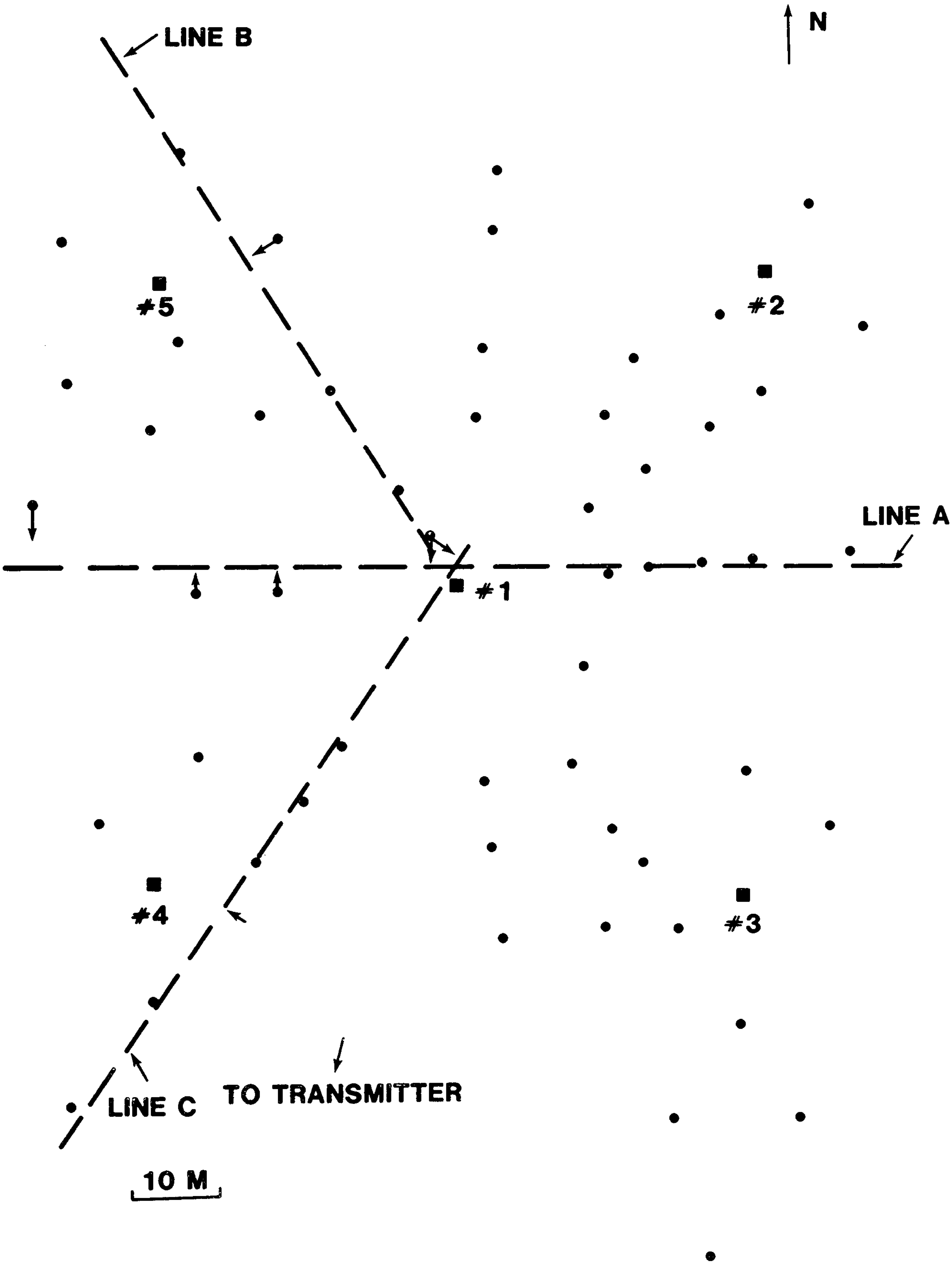

FIGURE 19. Location of Base Lines and Measuring Stations for CSAMT Tests

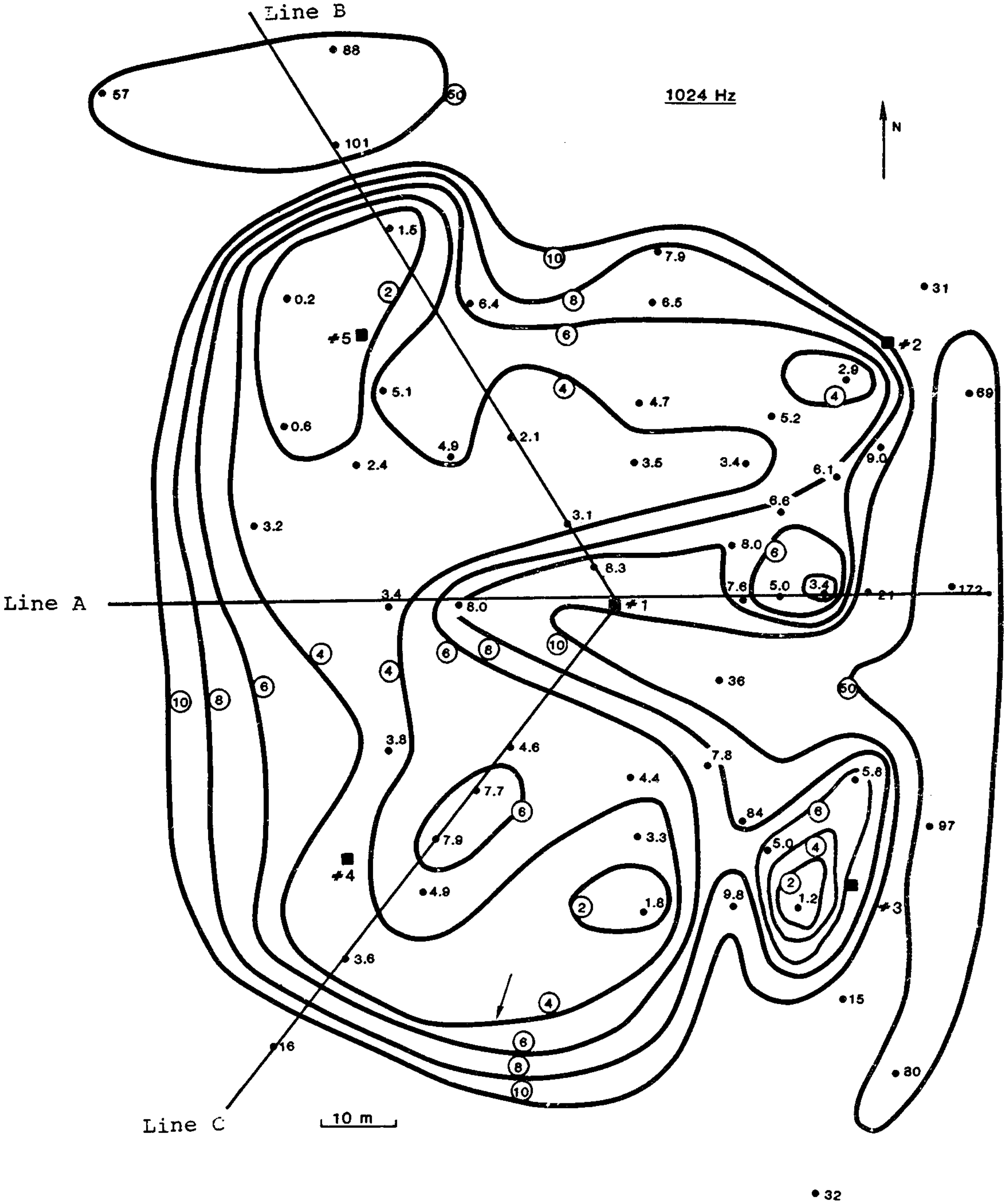

Figure 20 Constant apparent CSAMT resistivity contours (in ohm-m) at 1024 Hz, August 1980. The approximate sampling depth is 400 ft. Note that the fire front zone, as determined by the injection interval, should be between 335 and 372 ft. The background apparent resistivity is approximately 32 ohm-m.

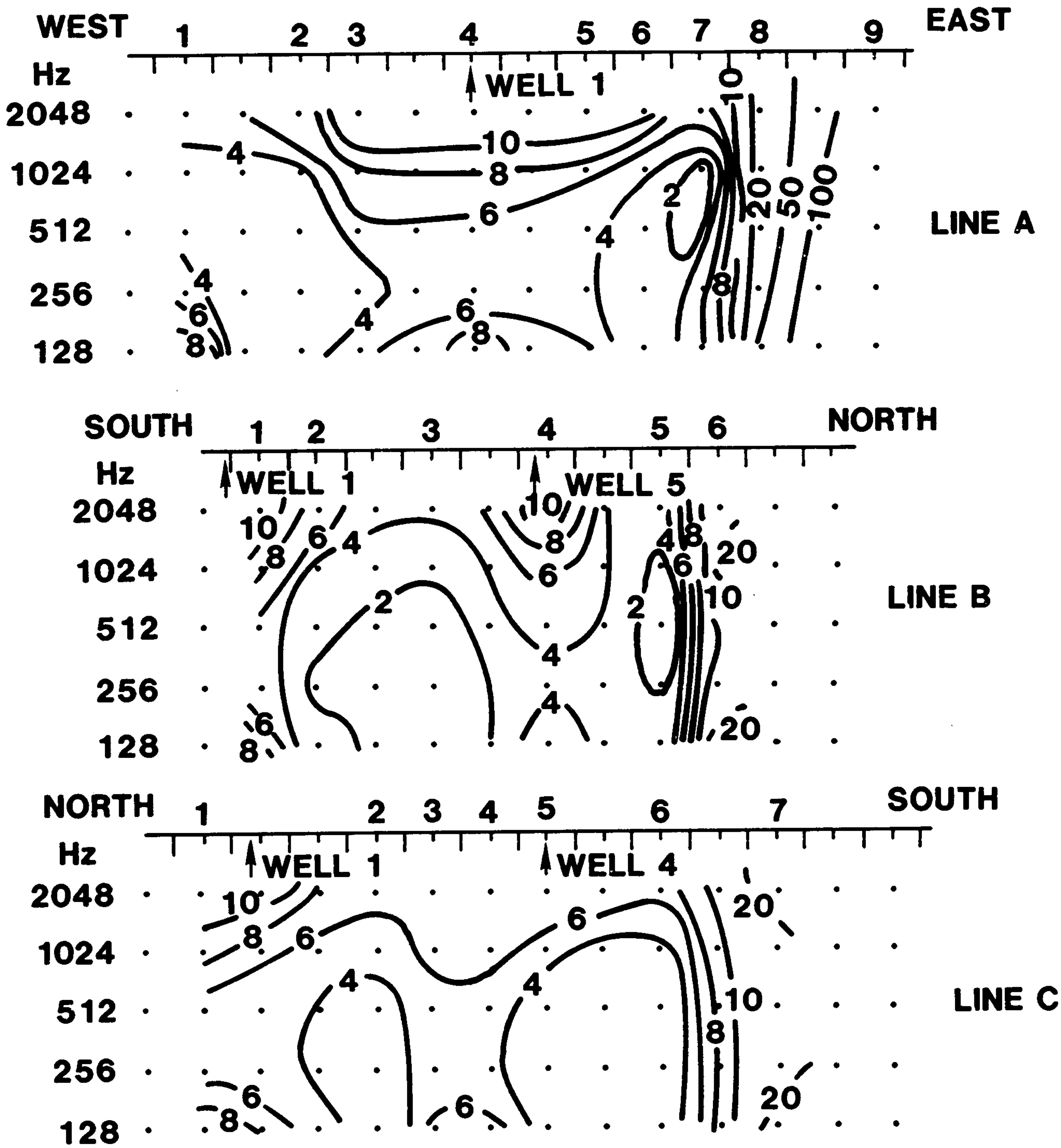

FIGURE 21. Constant Apparent Resistivity Contours vs Frequency at Positions Along Lines, A, B, and C

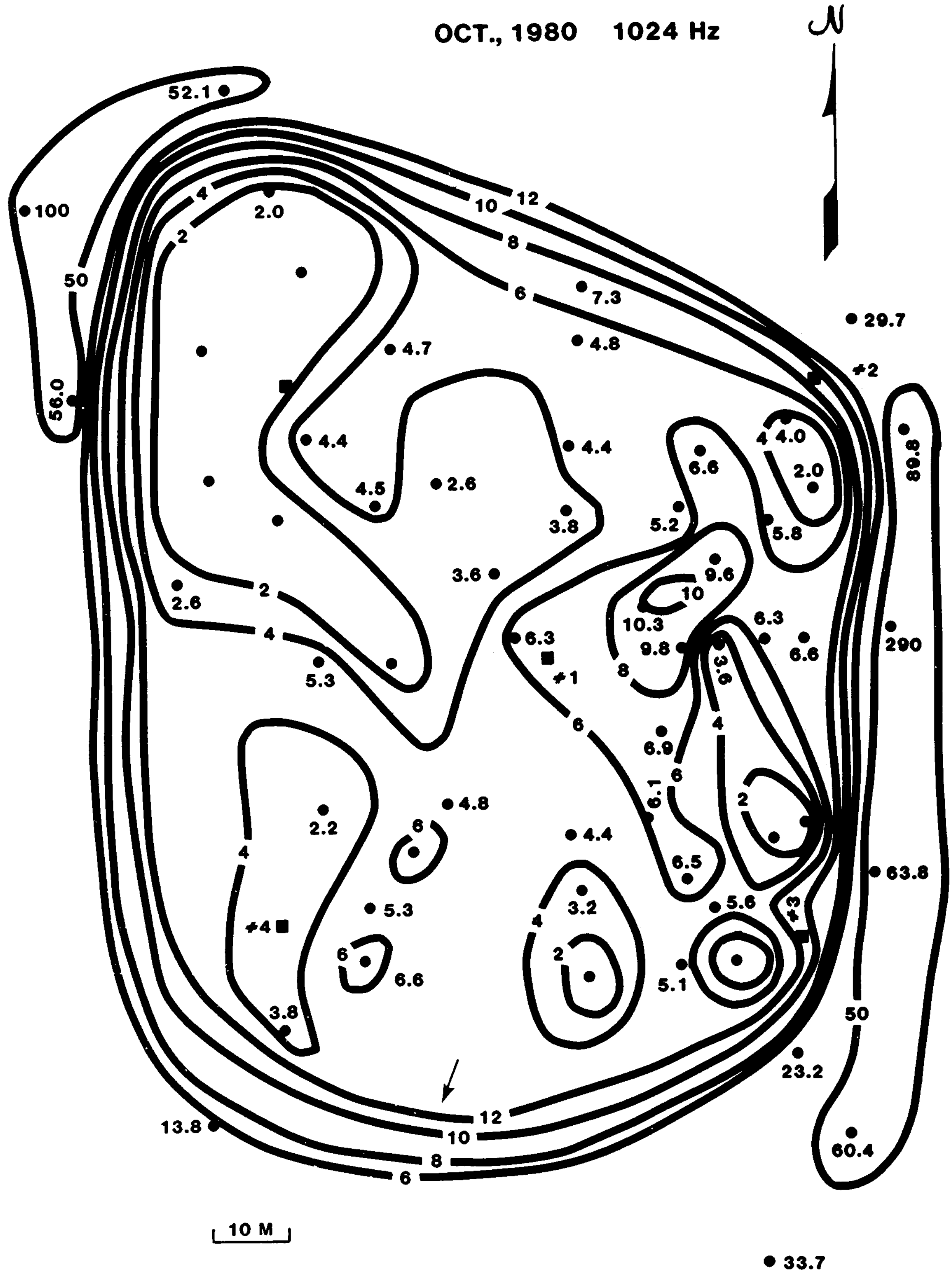

FIGURE 22. Apparent CSAMT Resistivity Contours at 1,024 Hz October 1980

FIGURE 23. Constant Apparent Normalized Resistivity Contours at 1,024 Hz, February 1981

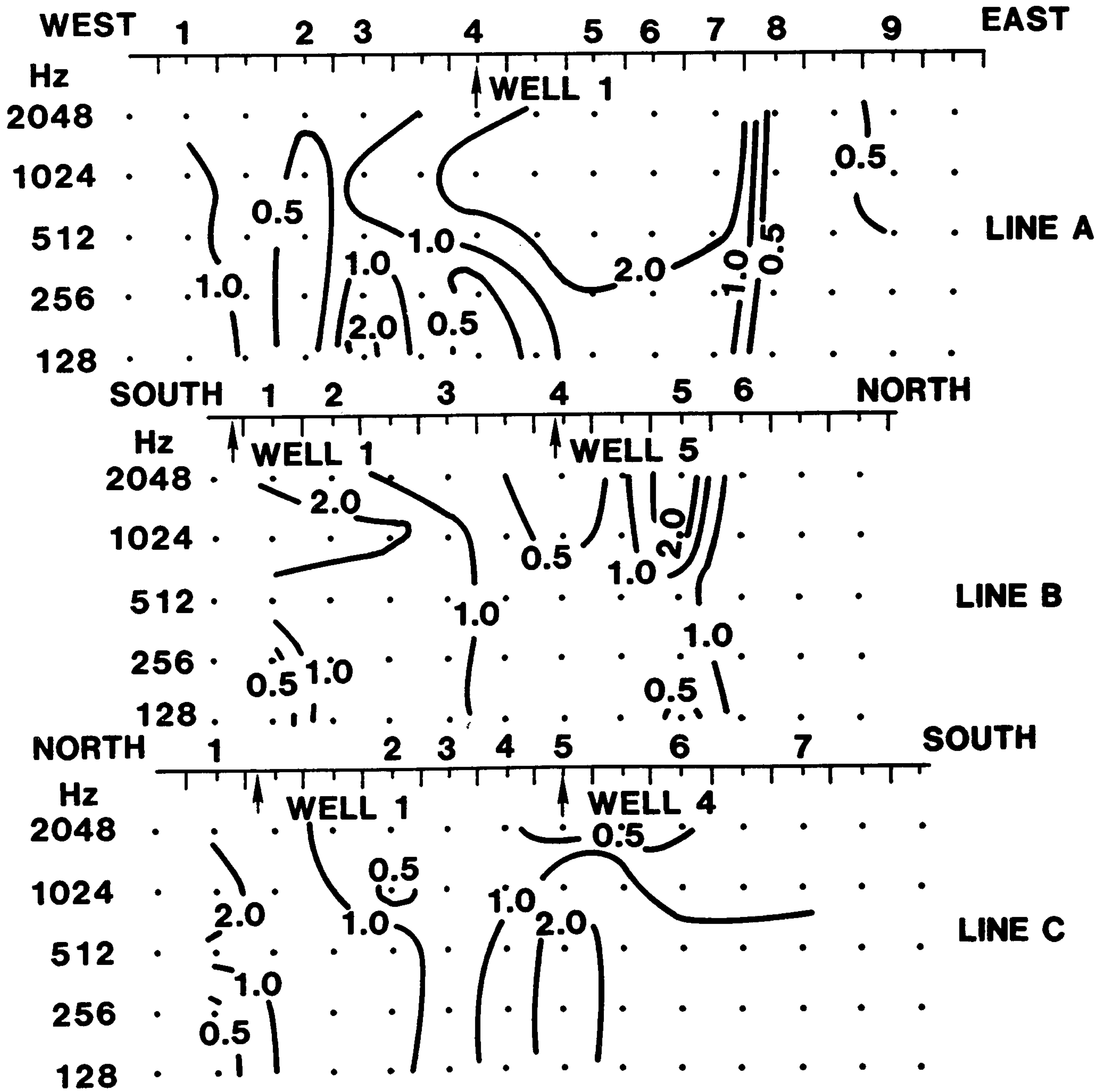

FIGURE 24. Constant Normalized Apparent Resistivity Contours vs Frequency at Positions Along Lines A, B, and C, February 1981

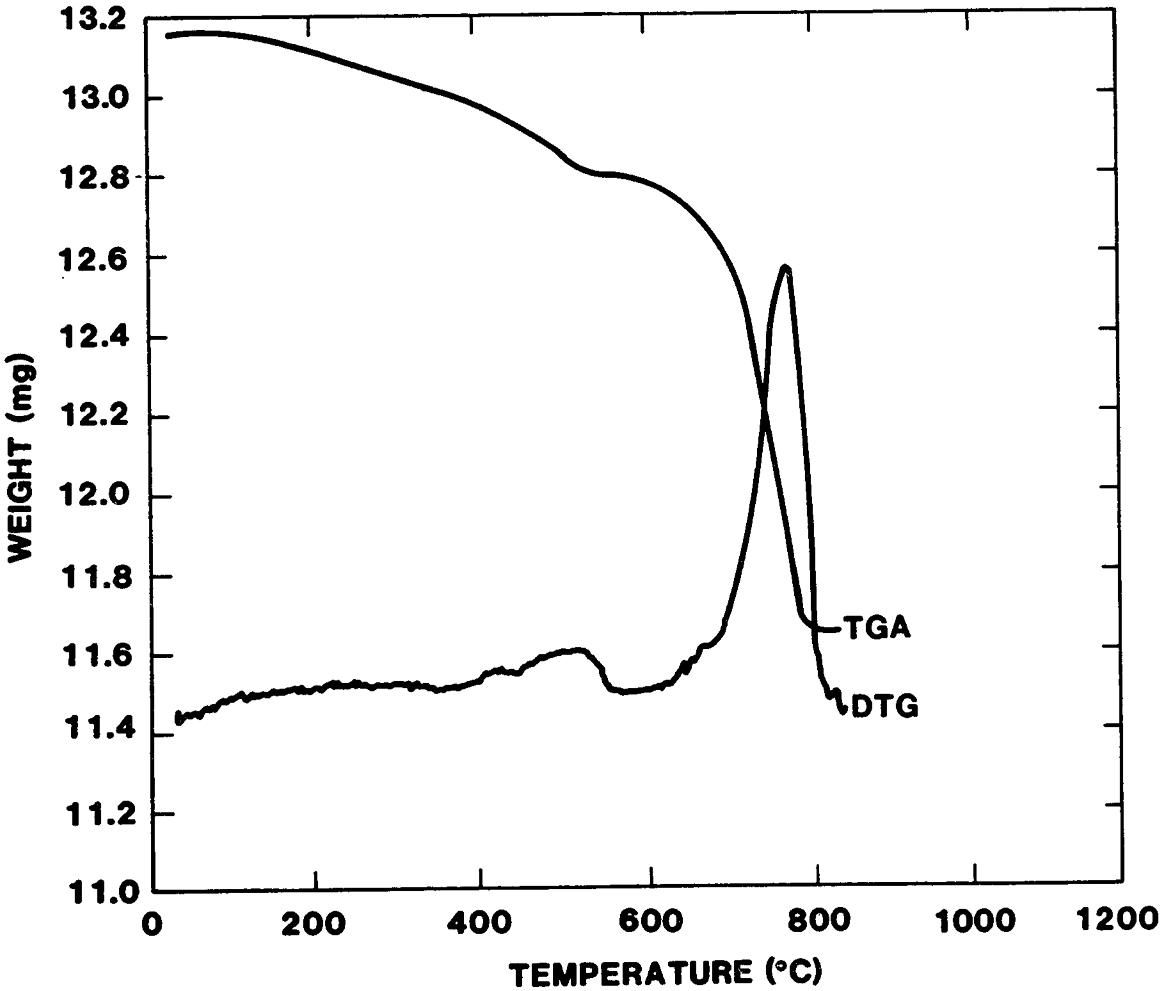

FIGURE 25. TGA and DTG Results, Interval 360-361 ft, Indicating LTO not Complete Combustion of High Temperature Components

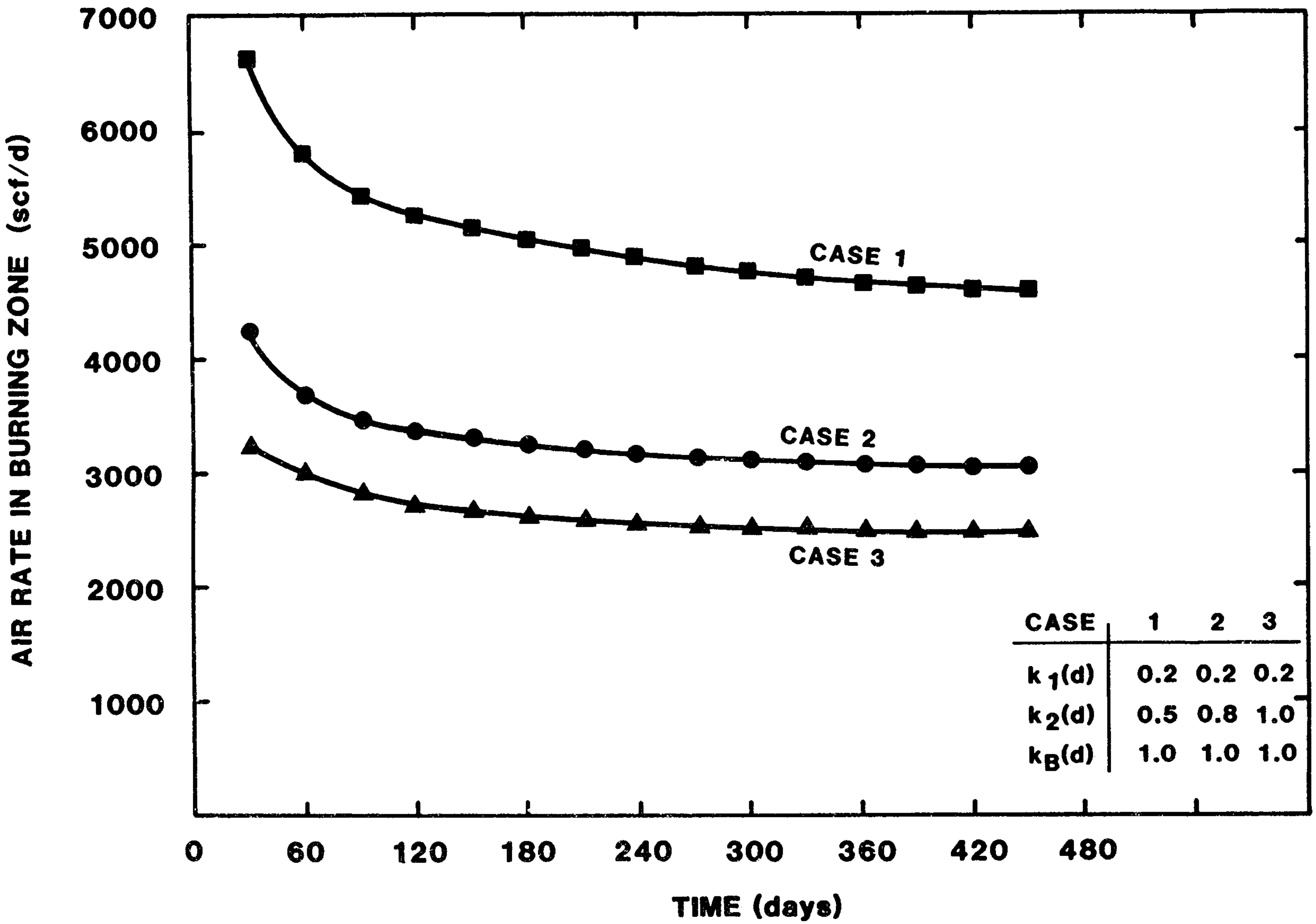

FIGURE 26. Air Flow through Burned Zone vs Time for Assumed Permeabilities

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