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CITIES SERVICE COMPANY
ENERGY RESOURCES GROUP

BODCAU IN-SITU COMBUSTION PROJECT

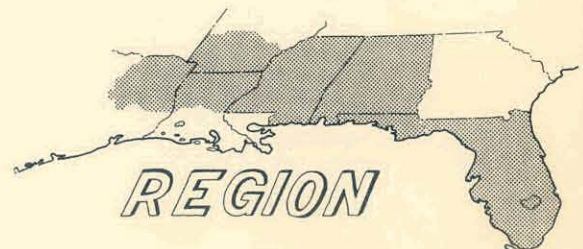
FIRST ANNUAL REPORT

SEPTEMBER, 1977

AC03-76ET12057

ERDA CONTRACT No. EY-76-C-03-1189
[Formerly E (04-3)-1189]
Improved Oil Recovery by Situ Combustion

SOUTHEAST



REGION

Leighton - 7951

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SUMMARY

The Bodcau In Situ Combustion Project is a cooperative venture between Cities Service Company and the United States Energy Research and Development Administration (ERDA). The project is governed by ERDA Contract Number EY-76-C-03-1189 {formerly E(04-3)-1189} and covers the period from June 1, 1976 through June 30, 1982. The primary objectives of the project are to demonstrate the technical efficiency and economics of the simultaneous air and water in situ combustion process. The total estimated cost for the six-year project is \$8,229,898. Of this estimated amount, ERDA will fund a maximum of \$3,102,112.

This First Annual Report covers precontract work and all work completed during the first twelve months under contract. Included are drilling, construction, ignition, operations and maintenance, laboratory and field testing, monitoring and economics.

The project is being conducted on five recently developed patterns of Cities Service Company's Bodcau Fee "B" lease in the Bellevue Field. The five patterns were a part of an eight-pattern expansion of Cities' combustion operations in the field. Twenty-nine producers and five injectors are included in the five patterns.

Three compressors with a combined output of 20 MMCFD at 250 psig provide the air for combustion.

Facilities for gathering, treating, storage and sale of production consist of tankage, a heater treater, a free water knockout, a test treater and an Automatic Custody Transfer Unit. A saltwater disposal well was drilled to 630 feet, penetrating the Lower Nacatoch Sand, for

disposal of produced water. Fresh water for cooling of downhole pumping equipment is supplied by a well drilled to a water sand at 100 feet.

Ignition of the five patterns was accomplished using a 30-kw, 440-volt, three-phase heater. Cities Service personnel operated and monitored the entire ignition process. The ignition phase began following air injectivity and falloff testing in August 1976 and was completed on September 24, 1976.

Following ignition and completion of facility construction, five temperature observation wells were drilled. These wells will be used to monitor the progress of the combustion front. One well was drilled in each pattern during December 1976.

Laboratory testing has consisted of combustion tube runs and produced oil and gas analyses. Combustion tube tests have determined the fuel deposit and air requirement for both dry burn and simultaneous air and water conditions and have investigated the ignition temperature of the Bellevue crude. Further testing will determine the optimum water-air ratio to be used in the project. Produced oil samples have been analyzed for composition, gravity and viscosity-temperature relationships. Produced gases are routinely tested for composition.

Field tests have included falloff and pulse tests. Falloff tests conducted prior to ignition indicated sufficient injectivity and overall pattern permeability for ignition and continued operations. Pulse tests were conducted to determine directional permeabilities in order to help predict combustion front movement.

Production has steadily increased from 69 BOPD in June 1976 to 420 in June 1977. Combustion has been monitored by gas analyses at producing wells.

The five injection wells were converted to simultaneous air and water injection in April 1977. Initial design rates are 150 barrels per million cubic feet of air injected per well. This ratio will be increased after a sufficient number of combustion tube tests have been conducted to determine an optimum water-air ratio.

The total expenditure for the five patterns through June 30, 1977 has been \$2,233,358. Development costs for wells and equipment have been \$1,288,777; production and research services have amounted to \$276,680; and lease operations and maintenance have been \$667,901. For the first year of the project, the total cost per barrel of oil produced has been \$10.03. This figure includes operations, maintenance, services, overhead, taxes and applicable depletion and depreciation. The most severe operations will occur during the second and third years of the project; however, this should provide an accurate measure of the unit cost of production for the simultaneous air and water in situ combustion process.

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INTRODUCTION

The Bellevue Field is located 18 miles northeast of Shreveport, Louisiana, on the eastern edge of Bossier Parish (Figure 1). The demonstration site, located in the SW/4 of Section 11-T19N-R11W, is part of Cities Service Company's Bodcau Fee "B" Lease.

The field was discovered in 1921 and is a dome-type structure covering approximately 900 productive acres. The Upper Cretaceous Nacatoch Sand is the main producing zone, being 300 to 400 feet deep. Primary production was by fluid expansion and later by gravity drainage. Many production stimulation techniques were attempted but none succeeded in increasing production of the heavy 19° API crude until Getty Oil Company successfully tested in situ combustion in the field beginning in 1966.

In 1971, Cities Service's first field test of an in situ combustion process was initiated on the Bodcau Fee "B" Lease. This test utilized dry combustion followed by waterflooding to successfully recover the viscous crude. In 1974, a similar test was begun in which dry combustion and simultaneous water and air injection were evaluated side-by-side. It was shown that the simultaneous injection method improved the efficiency of the process.

A decision was reached in 1975 to step up development of Cities' acreage in the Bellevue Field. A Request for Proposals (RFP) by the Energy Research and Development Administration (ERDA) was

responded to by Cities Service Company as plans were being carried out for further development. Wells had been drilled and construction of facilities was already in progress when ERDA Contract EY-76-C-03-1189 {formerly E(04-3)-1189} was signed. The contract calls for demonstration of the technical efficiency and economics of a commercial scale in situ combustion process.

PROJECT SITE¹

The demonstration site (Figure 2) was selected on the basis of evaluation of reservoir characteristics determined by the drilling of wells 13-3, L-1, L-2, L-3 (later numbered 15-3) and L-4. These wells were drilled through the Upper Nacatoch Sand to approximately 470 feet. Conventional Induction Electrical Surveys (Figure 3) and Compensated Formation Density Logs (Figure 4) were run. The wells were drilled during 1975 and were used to develop structure (Figure 5) and net pay (Figure 6) maps in preparation for further expansion of Cities' combustion operations in the Bellevue Field. Plans were made to develop five patterns on twenty acres directly east of Cities' 1971 pilot area.

Using the data from the evaluation well program and past experience in operating two pilot tests, the patterns were developed as elongated, inverted nine-spots with injectors located down-structure from the centers of the patterns. The dip of the Nacatoch Sand in this area is 2.5 degrees to the northeast. Locating the injectors down-structure will provide for optimum sweep as the injected air migrates more readily up-structure.

¹Little, Tracy P., Bodcau In Situ Combustion Project "Precontract Work and Plan for Project Development", Cities Service Company Topical Report.

During 1975 and early 1976, the five patterns were developed with 29 producers and five injectors. Each pattern covers approximately four acres and the total volume of reservoir contained in the project is 1039 net acre-feet. Wells 2-8, 13-5 and 16-3 were open hole logged with IES and FDC/GR logs and well 16-3 was also cored to obtain additional information for evaluations and performance prediction.

By analysis of all well logs, the average porosity was determined as 33.9% with a water saturation of 27.4%. Permeability from core analyses of several wells in the field was approximately 700 millidarcies. A typical core analysis is shown in Table 1. Net formation thickness averages 56 feet with a net/gross thickness ratio of 0.75. Gas saturation was minimal, less than 3%. These reservoir characteristics combine to give an oil in place of 1909 barrels per acre-foot, or in excess of 2,000,000 barrels for the five patterns. Previous pressure tests indicated a reservoir pressure between 25 and 40 psig. Fluid analyses showed an oil gravity of 19° API with a viscosity of 676 centipoise at the reservoir temperature of 75°F. (Viscosity vs. Temperature shown in Figure 7.)

The data gathered from the developed area was compared to ERDA's specified criteria:

1. The reservoir is relatively uniform and isolated. Faults are isolated so as to confine the combustion to one formation only.
2. Pressure tests have indicated good reservoir continuity and good reservoir control is possible from log, core and production history data.

3. The formation is a sandstone reservoir with net sand thickness greater than 10 feet. The ratio of net/gross sand thickness is higher than 0.75.
4. Reservoir porosity is higher than 20% and permeability is higher than 100 md.
5. Oil gravity is lower than 30° API.
6. The product of oil saturation times porosity is greater than 0.07 and the oil in place exceeds 540 barrels per acre-foot.
7. The reservoir does not have a gas cap or an underlying aquifer.

It is readily apparent that the project site meets all of the specifications.

DRILLING AND COMPLETIONS

Twenty-nine producers and five injectors are included in the project area. The wells were drilled to an average depth of 450 feet using skid mounted rotary equipment. Fresh water gel mud with cottonseed hulls for control of lost circulation was used. Three wells, 2-3, 2-4 and 2-5, were completed in 1970 as part of the original Cities Service pilot. These three wells are equipped with 5-1/2 inch, 14#/foot, K-55 casing. The remaining wells, both producers and injectors, have 7 inch, 23#/foot, K-55 casing. In all wells, the casing is cemented to surface. The standard cementing program for the more recent wells was to run 100 sacks of 50/50 Pozmix H cement with 40% silica flour followed by 40 sacks of Lumnite cement with 40% silica flour. The Lumnite cement across the Upper Nacatoch Sand provides greater strength under the anticipated high temperatures. Casing is centralized through the pay zone.

All wells were logged with conventional gamma ray and neutron logs (Figure 8) to provide net and gross pay (Table 2). Producers were selectively perforated at a density of two shots per foot with a 3-3/8 inch casing gun and acidized with 250 gallons of 15% hydrochloric acid. Conventional beam pumping units (16-D, 25-D and 40-D) were installed and 2-7/8 inch EUE tubing was run to the base of the pay zone. Hollow rods of 1.315 inch outside diameter and a 1-25/32 inch insert pump were run inside the tubing. Production is through

the hollow rods while the annulus between rods and tubing is used for pumping fresh water downhole to cool the pump (see Figure 9).

Injection wells were perforated at four shots per foot density in the lowermost 10 to 20 feet of net pay. A thermowell of 1.315-inch diameter pipe was run to a depth not less than 10 feet below the perforations. A type-K (chromel-alumel) thermocouple was run inside the thermowell. Air was injected down the casing for ignition and during the dry burn phase (see Figure 10).

A fresh water supply well was drilled to provide water for the downhole cooling system and to provide make-up water for injection, as needed. The well was drilled to 76 feet; 6-5/8 inch casing was run with 20 feet of stainless steel screen on bottom. The well was gravel packed and equipped with a 7-1/2 horsepower Reda pump and 3-1/2 inch tubing.

One disposal well was drilled to a depth of 630 feet. Seven inch casing was set and cemented to surface in the same manner as producers and injectors. Perforations are in the Lower Nacatoch Sand which is separated from the productive Upper Sand by a 20-foot thick shale break. A Baker AD-1 tension packer and 2-7/8 inch plastic-coated tubing were run.

Five temperature observation wells were drilled in December 1976. One well was drilled in each pattern to a depth of 450 feet and 5-1/2 inch casing was set and cemented to surface. Type K thermocouples were run inside the casing for recording profiles of temperature versus depth. These wells will monitor the combustion front progress.

FIELD FACILITIES

The equipment required for operation of the project can be separated into four distinct systems; production gathering, oil treating, water injection and air injection.

The production gathering system is composed of all flowlines through which production is transferred to the battery. Also included are five concrete-lined pits in which liquids removed from the exhaust combustion gas streams are collected. Production flowlines from wells to a central header are 2-3/8 inch diameter. Exhaust lines to the pits are 3-1/2 inch diameter. Transfer lines from the pits to the header are 2-3/8 inch. The pits, one within each of the five patterns serving five or six wells each, are 15 feet wide, 30 feet long and 6 feet deep, with one-foot thick steel reinforced concrete walls and a six-inch thick concrete base.

The oil treating system consists of the battery equipment involved in separation of the oil and water and storage and sale of the treated oil. At the header, demulsifiers are added to the production. Flow can be directed to a test treater or to the free water knockout. The test treater is a 4' x 27' vertical vessel and is used for allocation of production back to individual wells. The free water knockout is a 6' x 15' horizontal vessel which removes approximately 90% of the produced water from the production stream. The oil and remaining water are separated in the main treater, an

8' x 28' vertical vessel. The oil is then sold to pipeline through an ACT unit or diverted to tankage if it is not merchantable. Four oil tanks serve the system, all 12' x 20', 400 barrel welded steel tanks. One tank is the good oil sales tank through which the treater delivers oil to the ACT unit. The other three tanks are bad oil tanks in which additional settling time plus chemicals and heat are used to treat the oil to pipeline standards. A 500,000 BTU/Hr. steam generator circulates steam through coils in the bad oil tanks to aid the treating process.

In order to ensure smooth operation of the free water knock-out and main treater, the interface between the oil and water in these vessels must be bled off periodically. The interface holds solids which will make treating more difficult. A 20' x 60' x 6' concrete lined pit is located at the battery to allow for bleed-off of these interfaces and also for draining of tank bottoms.

The water injection system consists of two 12' x 20', 400 barrel welded steel tanks, an 8' x 45' 2000 barrel plastic lined overflow tank, a centrifugal pump for injection and disposal and the associated flowlines for the water. Also, the cooling system is included since it can be used as an alternate injection system.

Produced water is collected in the first of two 400 barrel tanks and siphoned to the second. This is done to prevent oil carry-over into the injection and disposal wells. Oil is periodically bled from the first tank for return to the treating system. A centrifugal pump delivers injection and disposal water through a trunk line and

laterals to individual wells. Fiberglass pipe is used for the injection system. Volumes are metered at the wells by use of turbine meters.

The cooling water system consists of the fresh water supply well and a system of 3-inch and 2-inch PVC line pipe which delivers water to each producing well in the project. Water from this system is also available at the injection wells and can be used for injection should the need arise.

The air injection system consists of three compressors and the trunk system for delivering the air to injection wells. A 1000 horsepower Waukesha gas engine driven Ingersoll Rand compressor was installed in 1970 for the original pilot test. This unit delivers 3000 MCFD at 250 psig discharge pressure. A new electric motor has been ordered to replace the gas engine due to shortage of fuel supply. The second compressor, a 1250 horsepower electric drive Ingersoll Rand unit, was installed in 1973. Deliverability from this compressor is 5000 MCFD at 250 psig. In November, 1975, construction began on a new 3000 horsepower electric driven Ingersoll Rand compressor which delivers 12,000 MCFD at 250 psig. The unit was completed in June, 1976. Minor problems were corrected and the unit has run smoothly since October, 1976.

The air for injection is delivered through a trunk system of 8-5/8 inch and 6-5/8 inch pipe. Three-inch laterals carry the air to individual wells for metering and injection. Injection is through casing during dry burn and through tubing during simultaneous injection of air and water (see Figures 10 and 16).

IGNITION²

The five patterns were ignited using a 30-kilowatt, 440-volt electric heater having 86 inches of heating length for each of six elements and delivering 30 watts per square inch of surface area. Power to the heater was supplied through a three conductor armored cable of 0.800 inch outside diameter. This cable was also used to position the heater in the hole as required.

Control and monitoring equipment was housed in a trailer, enabling Cities Service Company personnel to watch all aspects of the ignition process closely. Panel-mounted charts recorded air injection rates and wellhead pressures continuously. A thermostat connected to a thermocouple inside the well was used to control heater temperatures. Adjustment of the heater temperature and the air injection rate allowed control of air temperatures. Temperature profiles of the formation using the downhole thermocouple were periodically recorded.

Confirmation of ignition was by analysis of produced gases at surrounding wells. The Orsat method of analysis for oxygen, carbon dioxide and carbon monoxide was the primary means of confirming ignition. Fyrite method of analysis for oxygen and carbon dioxide was done at regular four-hour intervals and was found, generally, to

²Joseph, Conrad, Bodcau In Situ Combustion Project, "Ignition," Cities Service Company Topical Report.

compare well with Orsat analyses which were taken only once or twice each day. The injection well temperature profiles were also used as backup for confirming ignition.

Before igniting, the injection wells were cleaned out by circulating air to remove any water or oil inside the wellbore. A string of 1.315-inch diameter line pipe was run inside the well to a depth not less than ten feet below the perforations and a type K thermocouple was run inside this pipe. Air injection was begun at a rate of 200 MCFD and maintained until offset producing wells began to vent the injected air. Rates near 200 MCFD would be required during the ignition process in order to obtain air temperatures in excess of 600°F. Pressure falloff tests were conducted to determine average pattern permeability prior to ignition. Background gas analyses at producers were obtained to establish a base line prior to any heating.

Ignition equipment was then moved to the wells and set up (Figure 11). The heater was lowered through a lubricator and positioned above the perforations. The heater was turned on and the formation was first preheated to 300°F before raising the injected air temperatures to 600°F for ignition. Gas analyses and temperature profiles were taken periodically to monitor the ignition process. Ignition was indicated by drastic reductions in oxygen content and increases in carbon dioxide and carbon monoxide in the produced gases. Generally, Orsat oxygen levels of 1.0% or less were considered confirmation of ignition.

The five wells were ignited during the period August 7 through September 24, 1976. Although the actual ignitions were easily accomplished, a number of problems had to be dealt with.

At well 12-1 there was apparently some oil left in the casing. When the heater was turned on, the oil ignited within the well and temperatures of up to 1800°F were observed. The heater was pulled up to prevent damage to it and the air injection rate was cut back to reduce the temperature of the burning oil. Combustion within the wellbore ceased after about twelve hours. The heater was lowered back down to the formation and the well was easily ignited. Gas analyses at wells 2-4 and 12-2 confirmed the ignition.

Well 13-1 ignition went smoothly without incident but at well 14-1 the heater shorted out just as ignition was beginning to take place. The compressor shut down because of a faulty relay. A surface leak allowed hot gases to flow back and this melted the insulation on the heater leads and in the cable, causing the short. As the heater was pulled from the well, the cable and heater became wedged between the casing and the thermowell near the surface. Rotating and jarring the well head did not free the heater. Gas analyses indicated that the formation had ignited and was not hurt by the loss of the heater at that time. The heater was removed from the well one week later. Air injection was stopped and the pressure was bled off the well. Water was pumped in to prevent backflow of hot gases. The thermocouple was cut and allowed to drop in the hole. The heater was then pulled up into the lubricator and a patch was welded over the hole left by the thermowell. The heater was repaired and moved to well 15-1.

At well 15-1 the same problem with the compressor caused the heater to short out again because of a surface leak. No problems were encountered when the heater was pulled from the well, but the connections from cable to heater had to be completely remade in a machine shop. Although only 600,000 BTU were delivered to the formation in this well, ignition was indicated by gas analyses. A short test was conducted to confirm the ignition. The air injection rate was reduced from 180 MCFD to 90 MCFD and the temperature at the perforations was observed for 40 minutes. The temperature rose by 83°F in this time, indicating heat feedback from the formation. Routine temperature profiles several days later showed temperatures in excess of 800°F at the perforations while during the ignition process, the maximum temperature recorded was less than 500°F.

The heater was again repaired and moved to well 16-1. No problems occurred during ignition but the heater became stuck between the thermowell and casing when it was pulled up. Since this was the last well to be ignited, the heater was left in the hole for one month before retrieving it. The well was shut in and pressure was bled off. The well head was removed, the thermocouple was pulled and the heater was pulled up into the lubricator.

The ignitions of the five patterns are summarized in Table 3. Typical injection well temperature profiles and gas analyses at surrounding wells are shown in Figures 12 and 13.

OPERATIONS AND PERFORMANCE

Following ignition of the five patterns, air injection rates were steadily increased (Figure 14). During ignition 200 MCFD per well was required. Rates were increased to 1500 MCFD per well by October 18, 1976. The scheduled increases would have carried injection to 2000 MCFD per well by January 1, 1977. However, a major failure resulting in the loss of compressor #2, a 1250-hp unit, for approximately two months limited available air for increases beyond 1500 MCFD per well. Compressor #2 was virtually rebuilt at a cost of approximately \$89,000 and was back on line by December 15, 1976. The scheduled increases were postponed, however, until after conversion to simultaneous air and water injection.

The five injectors presented no problems to the injection of air at the required rates. Preignition falloff tests indicated low permeability in well #14-1. This well was treated with 250 gallons of 15% hydrochloric acid to improve its injectivity.

During April 1977, the injectors were recompleted for simultaneous air and water injection (see Figure 16). Perforations were added in the upper 10 to 12 feet of the Upper Nacatoch Sand using a 3-3/8" casing gun. A tension packer was set between the two sets of perforations and air was injected through 2-7/8" tubing below the packer while water was injected down the casing above the packer (Table 4). Simultaneous injection was begun at 150 barrels per million cubic feet of air, but high pressures caused by calcium carbonate

scale problems were encountered. Scale was severe enough in two wells that a bit and scraper were run to clean up the casing. All wells were treated with 250 gallons of 15% hydrochloric acid to clean up the perforations. Visco 950 is being added to the injection water to prevent precipitation of scale. Pressures have been higher than anticipated, probably due to high gas saturations near the wellbore and accentuated by the scale problems. A higher pressure pump may be required. See Figures 29-33 for injection wells performances through June 1977.

Oil production has steadily increased from 69 BOPD in June 1976 to 420 BOPD in June 1977 (Figure 14). Cumulative production for the five patterns has been 92,702 barrels. Production has been higher than estimated in the original proposal, as shown in Figure 15. No major treating problems have occurred as yet; however, the emulsions should become more severe as the combustion fronts approach producers in the next year. Present chemical useage at the battery is 0.05 gallons of demulsifier and 0.02 gallons of surface tension reducing chemical per barrel of oil.

Combustion front breakthrough has occurred at two wells, 12-2 and 15-2. These wells are the nearest to the injectors in their respective patterns, both due north of the injector and 165 feet away (Figure 17). Well 15-2 showed 200⁰F flowline temperatures and produced 800 MCFD of combustion gas containing 2.4% oxygen as early as February 1, 1977. Tubing was pulled on February 7 and holes were observed at depths of 380, 397, 420, 404 and 408 feet. The entire producing interval was squeeze cemented and reperforated from 386 to 396 and from 412 to 424 feet. The well was put back on production but by March 5, holes had been cut in the interval 412 -424. The well was shut in from March 5 to April 25 and squeeze

cemented again. New perforations were shot from 384 to 396 feet. By May 15 new holes had been cut in the tubing from 412 to 424 feet and the well was shut in once again.

Well 12-2 experienced combustion front breakthrough at roughly the same time as well 15-2. In this well, however, the problem was easily corrected by squeeze cementing the top of the pay zone from 367 to 380 feet where the tubing showed markings from heat and sand leaving the section from 385 to 418 feet open for production.

All wells are expected to experience failures from combustion front breakthrough and require remedial action during the next year. However, production for next year should increase as wells begin to experience a higher degree of thermal stimulation. See Figures 34 through 62 for production wells performances through June 1977.

MONITORING

Extensive monitoring of produced combustion gases and observation well temperatures for tracking combustion front advance is being carried out.

Combustion gases vented from producing wells are tested monthly for volume and content. Refer to Table 5 for typical analyses of all wells. Orsat method of analysis is being used. The purpose for monitoring these gases is threefold. First, volumes are determined for material balance. Also, the volumes produced affect the downhole operation of the wells as high rates, in excess of 400 MCFD, will carry large quantities of formation sand into the wellbore. Secondly, the content of the gas will indicate the efficiency of combustion. Thirdly, the content will indicate whether the combustion front has reached the producer. Monitoring of produced gases will continue throughout the combustion phase of the project. The method is simple and has proved to be reliable in the past.

Five wells were drilled in December 1976 for the purpose of monitoring the combustion front advance by recording downhole temperatures. One well was drilled in each pattern. The wells were each located in a different portion of the patterns so that an approximation of the movement of the combustion zone in all directions might be inferred for all patterns.

Wells were drilled to 450 feet; 5-1/2 inch casing was set and cemented using 30 sacks of Lumnite cement plus 40% silica flour on bottom and 45 sacks of Halliburton Light cement with 40% silica flour to surface.

Type K thermocouples were run inside the wells for recording downhole temperature profiles.

Profiles are taken once each month per well (Figures 18-22). Temperature is plotted against depth and a temperature of 600°F is accepted as having burned. Thus, by monitoring the temperatures at depth in all directions, an approximation of the size and configuration of the burned zone can be made. Observation well temperatures will be monitored monthly as long as heat remains in the patterns. The effect of simultaneous water injection will be noted in the profiles, as will the efficiency of the heat scavenging water injection phase.

Production wells are tested at least twice each month for oil and water production rates. These rates are used to allocate production from the total monthly volume produced. Flowline temperatures are also checked daily for indications of thermal stimulation or downhole problems. The volume of quench water used at the producers is based on the observed flowline temperatures as well as gas production rate.

The various phases of the monitoring program have indicated that the progress of the project has been very good. Efficient combustion is taking place, wells are becoming thermally stimulated and production is increasing. Monitoring will continue throughout the project to ensure efficient operation, maximum production and to provide a means of performance evaluation.

COMBUSTION TUBE TESTS³

A series of combustion tube tests are being performed at the Cities Service Research Laboratory using Bellevue core samples and produced oil. The objectives of the study are to obtain information concerning the basic in situ combustion process that might aid in understanding the performance of the Bellevue fireflood. Also being investigated are the interaction of water with the burning process to determine the water/air injection ratio that should be used in field operations. Finally, the formation ignition temperature of the field is being measured by means of laboratory oxidation tests.

The following conclusions have been determined from the combustion tube tests which are still in progress:

1. Fuel deposit and air requirement of dry combustion were determined to be 2 lb/f³ and 17 MMSCF/A-F.
2. Injecting water of 250 Bbls/MMSCF increases the efficiency of the process by decreasing fuel deposit and air requirement by approximately 25%.
3. Water rates as high as 500 Bbl/MMSCF do not extinguish the combustion reaction.
4. Temperatures near 500°F will result in ignition of the Nacatoch formation.

³Subject of Future Bodcau In Situ Combustion Project Topical Report, "Combustion Tube Tests".

A schematic of the combustion tube used in the study is shown in Figure 23. A mixture of sand, oil and water are packed in the 2.5" diameter stainless steel tube. A 0.25" diameter thermowell traverses the center of the sand pack enabling temperature measurements along the length of the tube. Four 1250 watt strip heaters are strapped to the outside of the stainless steel tube and are controlled with an automatic power unit. The entire tube assembly is placed within an insulated 6" diameter steel jacket. Tests have been performed with the system in the vertical position. Air and water are injected at the top and production is taken off the bottom. The products pass through a water-cooled separator which condenses water vapor and hydrocarbons and maintains the gas at a constant temperature. Liquids are drained from the separator while gases pass through a wet test meter, sampling valve and are then vented to the atmosphere.

A run is performed by first packing the tube with either the unconsolidated, native Bellevue core or a mixture of burned Bellevue sand and produced oil and water. The mixture is sampled for oil and water saturation determinations. The weight of mixture packed into the tube and the results from the fluid saturation measurements allow calculation of the porosity and volumetric saturations of each fluid phase. Nitrogen is flowed through the tube to establish a gas permeability and produce mobile fluids. The strip heaters are then activated raising the temperature of the system to 300°F. To initiate combustion, a heater at the inlet face increases the sand pack to over 500°F. Nitrogen injection is replaced with air and ignition is usually observed immediately. Thermocouples both in the

thermowell and attached to the ignition heater record significant increases in temperature upon ignition. Confirmation is also obtained by analyzing the effluent gas composition.

Data recorded during the run include air and water injection rates, injection pressure, produced oil, produced water and combustion gas volume. The gases produced are sampled and analyzed for oxygen, carbon dioxide and carbon monoxide using an Orsat apparatus. Oxygen is also monitored continuously with an oxygen analyzer. Thermocouples within the thermowell track the shape and movement of the combustion zone. Air flow rate is controlled using a rotometer and exit gases are monitored with a wet test meter. During simultaneous water/air injection the water rate is measured with a constant rate pump.

The air flow rate used in all runs was 0.2 SCF/Min or 435 SCF/f²-Hr. The high air flux helped to reduce heat losses and decreased run time. The exit of the tube is vented to the atmosphere and no back-pressure is held on the system. Therefore, the effective pressure at the combustion zone is controlled by the pressure drop through the sand pack. The low pressure results in a low steam temperature and often the failure of a steam zone to form ahead of the front. During tests at high water rates an obvious leveling of the temperature gradients was observed.

The results of completed combustion tube runs are summarized in Table 6. The parameters of primary interest, fuel deposit and air requirement, were determined to be 2 lb/f³ and 17 MMSCF/Ac-f for dry combustion. Increasing water/air ratios had a desirable effect on the process by decreasing both of the parameters. Fuel deposits of 1.5 lb/f³

and air requirements of 12 MMSCF/Ac-f were observed as the water rate was increased to 500 B/MMSCF. Water rates in excess of 500 B/MMSCF resulted in quenching of the combustion zone and difficulties in controlling test conditions.

Although the improved burning characteristics resulting from water injection are important in selecting the water/air ratio for field operations, the most important factor is the heat transfer properties of the entire system. The greatest heat transfer occurs at the highest water/air ratio in which no quenching was taking place. Therefore, the objective of the laboratory tests is to determine the maximum water rate without quenching. However, the selection of the optimum water/air ratio for the field requires a scale-up of laboratory conditions to those in the reservoir. Factors such as tube heat losses, formation heat losses, fluid flow behavior, heat transfer properties, sweep efficiencies and gravity segregation must be considered. These factors allow a comparison of laboratory and field water rates. At this time it is thought that because of lower heat losses in the reservoir, field design water rates will be higher than equivalent laboratory rates. As the time elapses between ignition and water injection, the burned volume increases and the effective water/air ratio in the field will be lower than that actually injected. Therefore, water should be started as soon as a stable combustion front has been established.

A small scale test was conducted to determine the ignition temperature of the formation. A small tube was packed with native Bellevue sand and produced oil and placed in an oven. Air was flowed through the sample at various temperatures and the oxygen content of the effluent gas was

monitored. Oxidation became appreciable at 300°F. As the temperature of the sand pack was increased, the concentration of oxygen in the produced gas decreased. Finally, at 500°F all of the oxygen in the injected air was reacted, indicating that the ignition temperature in the Bellevue Field is less than 500°F.

PRESSURE TRANSIENT TESTS⁴

During 1976 and 1977, extensive pressure transient testing was conducted in the five patterns of the Bodcau In Situ Combustion Project. Falloff tests were run prior to ignition and prior to conversion of the injectors to simultaneous air and water injection. Pulse tests were conducted along with the second falloff tests prior to conversion to simultaneous injection.

The purpose of the falloff tests were to determine the injection wellbore conditions prior to working on the wells and to investigate the average pattern permeabilities and flow capacities prior to ignition and after six months of continued combustion. Falloff tests involved shutting in each injection well for a period of two to five hours and recording wellhead pressures with a test gauge. A typical falloff curve is shown in Figure 24.

Before ignition the average permeability to air in the five patterns ranged from a low of 5.9 md in Pattern 14 to 32 md in Pattern 16. A second preignition test on Pattern 16 one month after the first test indicated an increase to 82 md, probably due to a high mobile water saturation in the pattern. No damage was indicated and the wells were then ignited. After six months of combustion a second set of falloff tests were run prior to converting the injectors to simultaneous air and water injection. Permeabilities from these tests ranged from 112 md to 544 md. This 15-fold increase

⁴Subject of future Bodcau In Situ Combustion Project Topical Report, "Pressure Testing."

was expected with the increased gas saturations in the patterns because of continued injection and combustion. Tables 7 and 8 summarize the two sets of falloff tests.

Pulse tests were used to determine directional permeability as an aid to predicting combustion front movement within the patterns. A pulse was created by shutting in an injector for five hours and then reinjecting at the previous rate. The response to this pulse was monitored at surrounding producing wells. Water manometers were used to monitor the change in exhaust gas flow rates at producing wells in the pattern tested. A typical response curve is shown in Figure 25. The time from the start of reinjection to the time of increasing gas rate is taken as the time lag (Δt). The directional permeability between injector and producer was calculated using this time lag value. Table 8 summarizes the results of pulse tests on each of the five patterns. The directional permeabilities towards wells in the southern half of each pattern were generally highest. However, closer examination revealed that the permeabilities were directly proportional to the square of the distance between injector and producer, as shown in Figure 26.

The characteristic time lag (Δt_1), which is a function of shut in time and measured time lag, was calculated to determine the degree of connectedness between injector and producer. These values are listed in Table 9. The calculated characteristic time lags indicate greater tendency for migration of air, and thus the combustion front, along a north-south axis with greatest movement towards the south.

RESERVOIR FLUID ANALYSES⁵

A complete analysis of combustion gases, produced oil, produced water and injected water are planned at six month intervals. Produced gas compositions reflect the efficiency of the burning process and the formation of undesirable combustion by-products. Produced oil and water analyses should indicate changes that might occur due to reservoir differences, burning characteristics or varying water/air ratios. Injection water will be analyzed to insure water quality that will not cause formation damage and loss of injectivity. In addition, special problems caused by emulsions will be studied.

Oil and water were sampled from the 29 producing wells in November, 1976. Analyses performed on the produced oils included chromatographic analysis, specific gravity and viscosity. A standard API procedure was run on the water samples. Produced combustion gases from the producing wells were analyzed on-site from January 6-12, 1977. Carbon dioxide, oxygen, and hydrocarbons were analyzed by gas chromatography. Percent water vapor was determined from a graph of air-water saturation versus temperature (Figure 27). The hydrogen sulfide concentration of the produced combustion gases was measured by the Tutweiler method. Determination of the hydrogen sulfide concentration in the ambient air are performed periodically at various locations on the lease. The Texas Air Control Board's Molybdenum Blue Method is being used and results are reported to the Louisiana Air Commission.

⁵Subject of future Bodcau In Situ Combustion Project topical report, "Reservoir Fluid Analyses."

Tables 10,11 and 12 present the results of the fluid analyses.

Some general conclusions from the results are:

1. Oils from Pattern 16 and wells 15-4, 15-5 and 15-6 have high concentrations of high boiling fractions. These oils are from the eastern edge of the field which is cooler than the other patterns.
2. Oils from wells 15-2, 15-3 and 16-3 are brown emulsions that are difficult to break.
3. The combustion gases had an average hydrogen sulfide concentration of 1302 ppm. The hydrogen sulfide concentration is lower in Pattern 16 and on the southeast part of Pattern 15 than in other parts of the project area.
4. Hydrocarbon concentrations in the produced gases average less than 1%.
5. The average oxygen concentration in the effluent gas is approximately 1.5%.

Field oil samples with excess BS and W are being used to evaluate up-flow, coarse filters for separating sand and water from Bellevue crude. Solids being used in these tests include rock salt, sand and glass beads. Preliminary results indicate that flowing the samples through a bed of rock salt improves oil-water separation. Since the specific gravity of Bellevue oil (0.92 g/cc @ 78°F) and water (1.00 g/cc @ 78°F) are not very different, gravity separation is slow. Addition of salt brine to the water to increase its gravity and accelerate oil-water separation is being investigated. According to Stokes Law, the velocity of a water sphere falling in the oil phase is proportional to the difference between the densities of the water and oil. Since the density of oil decreases with temperature faster than the water density, a temperature increase is beneficial to gravity separation. Also, the oil viscosity decreases with temperature, providing a further increase in water velocity falling in the oil phase.

DEVELOPMENT COSTS

Under the cost sharing agreement for ERDA Contract Number EY-76-C-03-1189 (formerly E(04-3)-1189), development costs are split between ERDA and Cities Service on the basis of tangible or intangible charges. The charges applicable to ERDA funding are intangible only.

The total development costs estimated in the proposal to ERDA for the contract were \$1,205,601. Of this total, the estimated tangible and intangible portions were \$704,324 and \$501,276, respectively. Actual total development cost has been \$1,288,777 with \$746,795 tangible and \$541,982 intangible. The total has thus overrun the estimate by \$83,176 or approximately 7%. This overrun has been in the costs for drilling and completions of project wells.

Tangible and intangible costs for drilling and completions of project area wells exceeded proposal estimates by 15%. Total investment was \$813,413, of which \$401,244 was tangible and \$412,169 was intangible (Table 13). Meanwhile, the investment for field facilities has run 5% under the estimates. The total invested for field facilities applicable to the project area has been \$475,364. The tangible portion has been \$345,552 while the intangible has been \$129,812 (Table 14). There are still some charges for painting of the battery equipment and compressors which should bring the totals for field facilities up to the estimated cost.

OPERATING COSTS

One of the primary objectives of the project is to demonstrate the economics of an in situ combustion operation. Costs included in the operation of such projects are research and production services, lease operations and maintenance, overhead and taxes.

The total amount estimated to be spent during the six years of the contract is \$7,024,297. During the first year to July 1, 1977, a total of \$944,581 was spent on operations. This total included \$276,680 for research and production services, \$378,030 for lease operation and maintenance, \$160,136 in overhead and \$129,736 in taxes.

Under the ERDA cost sharing agreement, ERDA will fund, within the limits of the total funding commitment, items under research services and portions of lease operations and maintenance. To July 1, 1977, items funded by ERDA have totaled \$850,105 while Cities' share has been \$1,383,253. The operating costs charged to ERDA is comprised of \$103,555 for research services and \$204,569 for operations and maintenance. The remaining portion of ERDA's share consists of intangible investments which were discussed in the previous section.

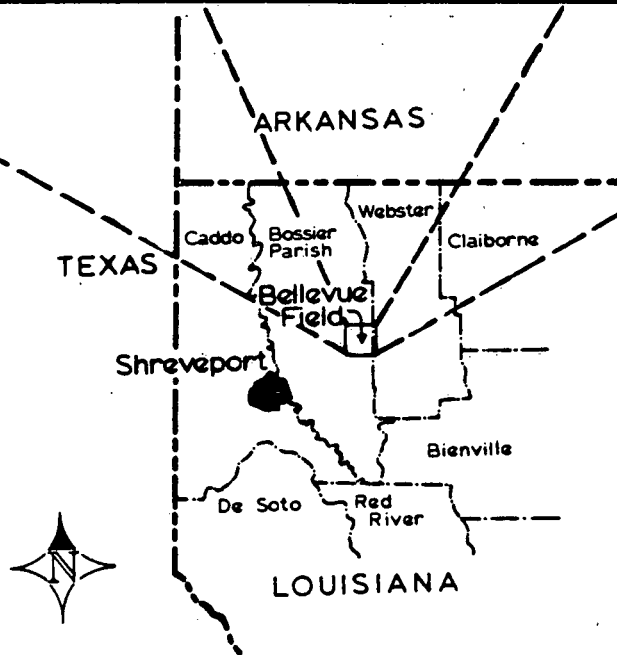
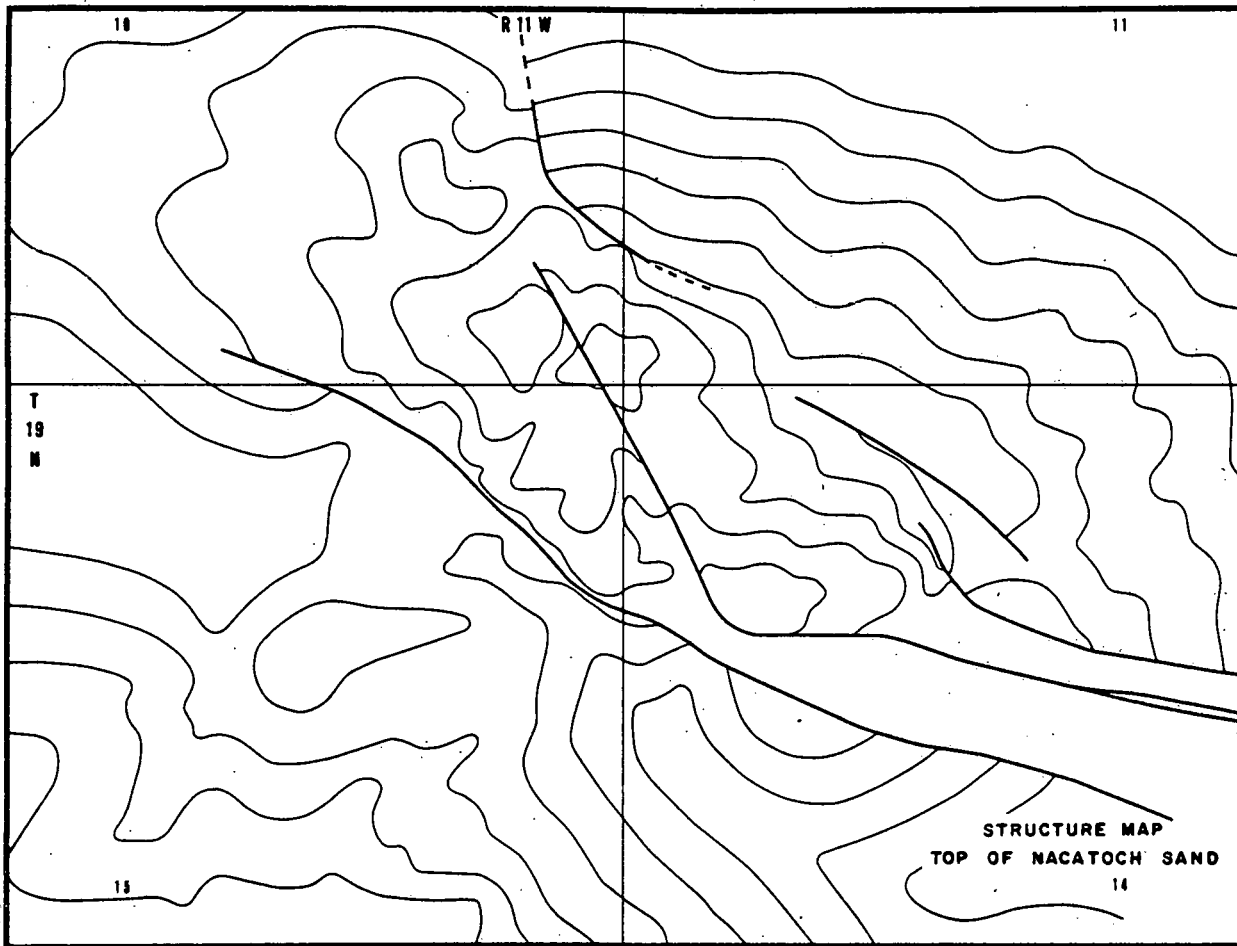
The cost of production on a unit basis is of most concern in any enhanced recovery technique. Lease operation and maintenance, overhead and taxes are the primary factors contributing to this unit cost of production. For the project to date, these items have cost \$667,902. Lease operation (Table 15), consisting of operation labor, supplies,

utilities, and chemicals, has amounted to \$70,503 or \$0.87 per net barrel of oil produced. Costs were determined on a net barrel basis, assuming a normal 1/8 royalty. Lease maintenance (Table 16), which includes replacement materials, labor, pump repair and well servicing, has cost \$118,757 or \$1.46 per barrel. Operation and maintenance of the compression facility (Table 17), including supplies, labor, utilities and materials, has cost \$188,769 or \$2.33 per barrel. The expenditure for Louisiana severance tax has been \$129,736 or \$1.60 per barrel, while Cities Service Company overhead has amounted to \$160,136 or \$1.97 per barrel (Table 18).

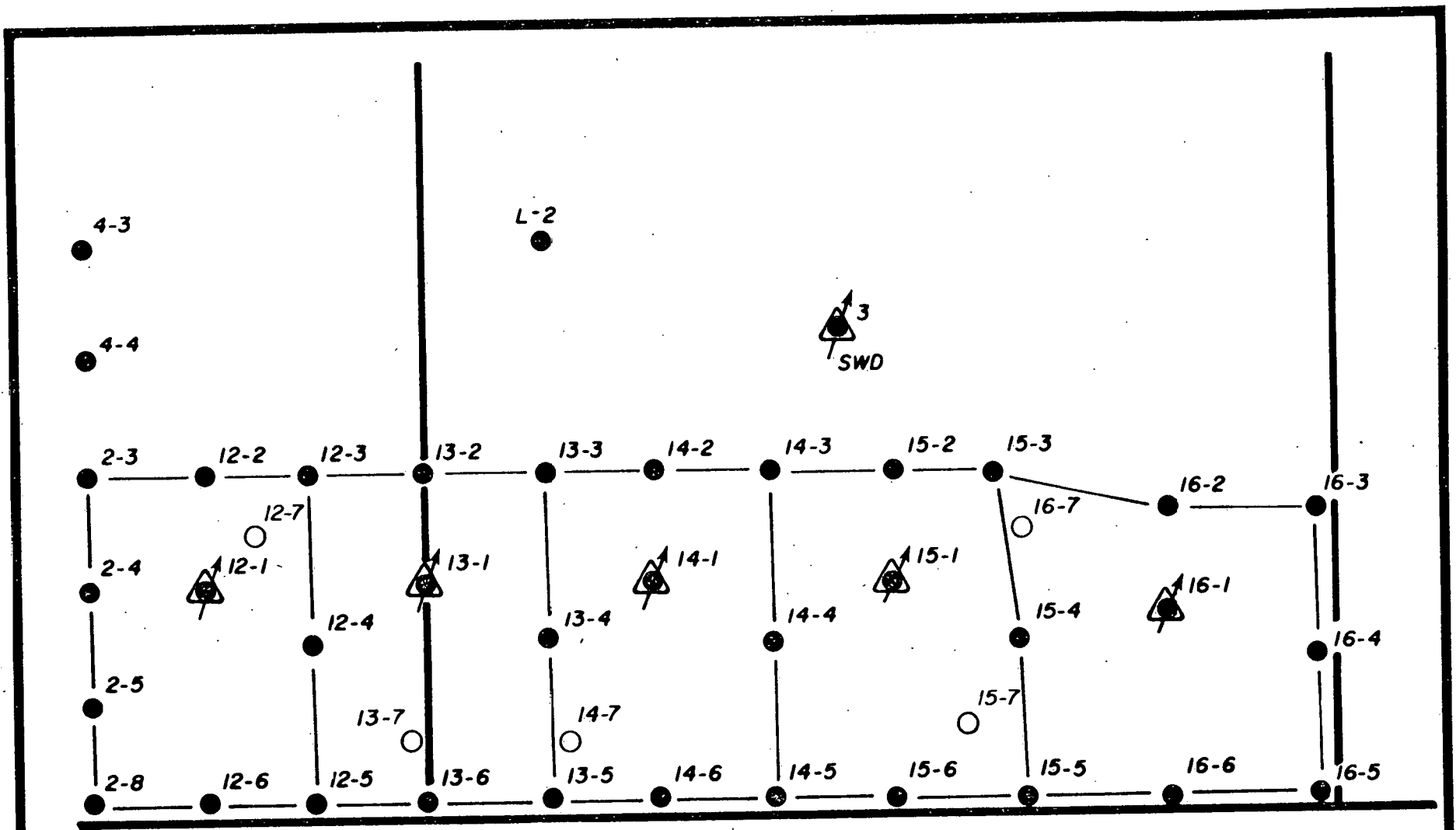
The overall cost of operations is thus \$8.23 per barrel of oil. If depletion and depreciation (investments) are considered as a cost of production, the figure becomes \$10.03 per barrel (Table 19). For the average oil price of \$13.38 during first year of the contract period, the net difference or profit was \$3.35 per barrel before federal income taxes.

Project expenditures for both operations and development have been \$2,233,358 or approximately 11% below the estimated cost for the first year. The total projected expenditure for the project was \$8,229,898. The actual total may well be reduced if present trends in operating costs are maintained or improved upon (Figure 28).

FIGURE 1



General Location Map
BELLEVUE FIELD
Bossier Parish, Louisiana



**PROJECT PATTERN MAP
BODCAU FEE FIREFLOOD**



FIGURE 2

FIGURE 3
INDUCTION - ELECTRICAL LOG
FOR
WELL 13-3

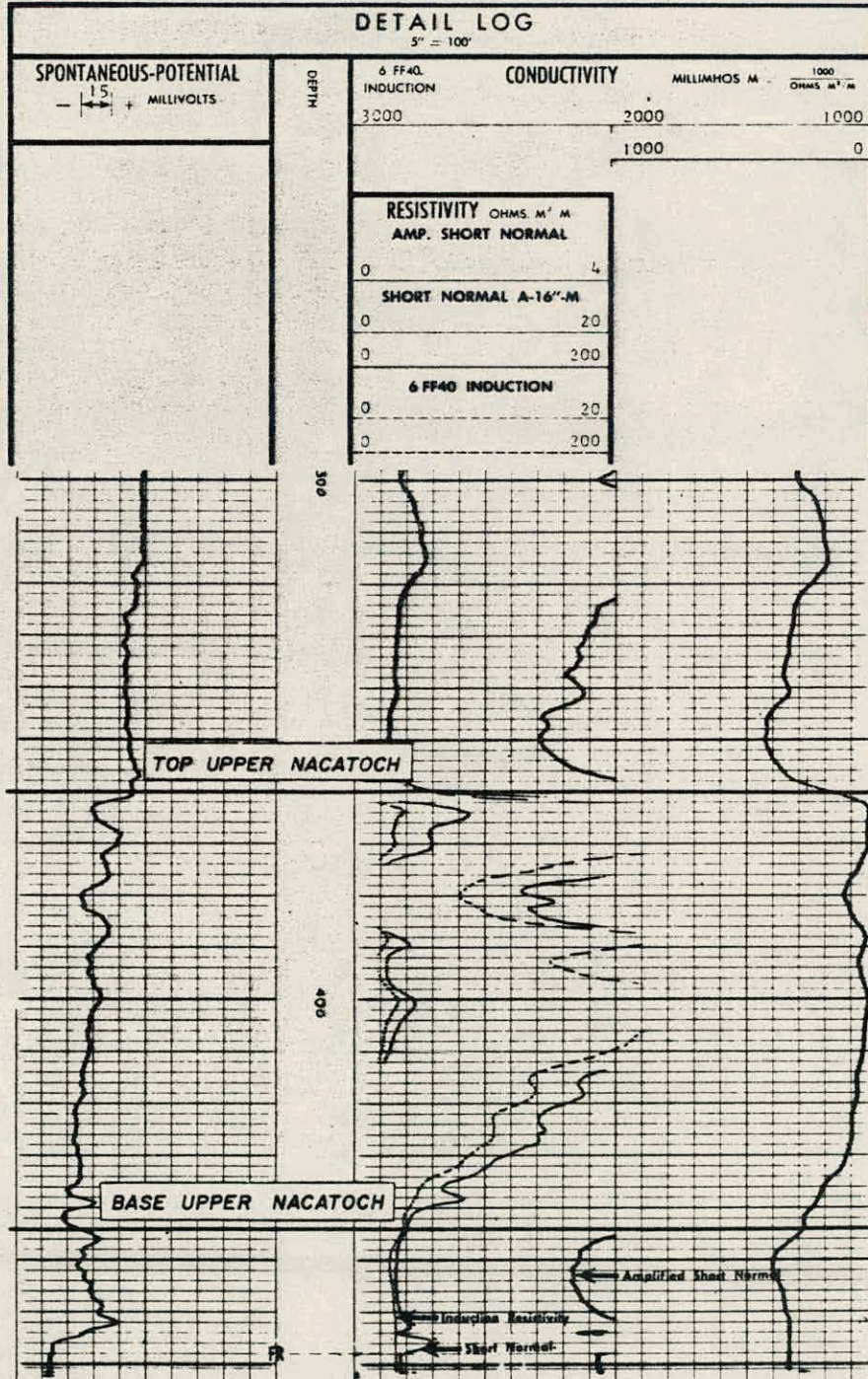
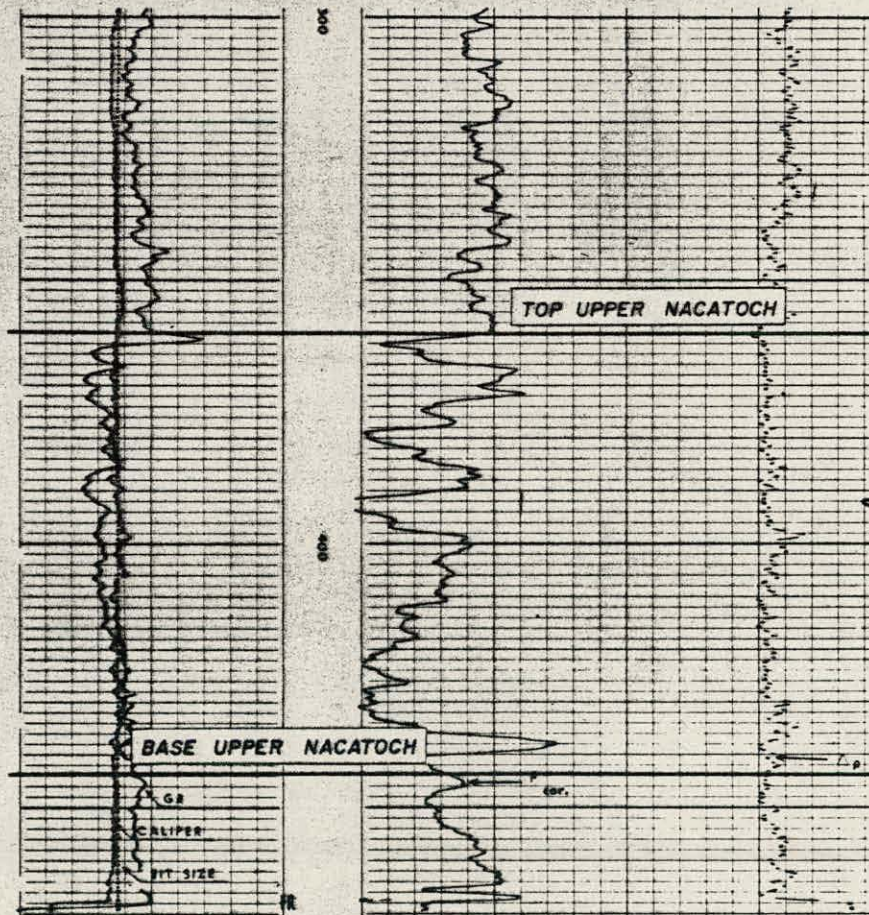
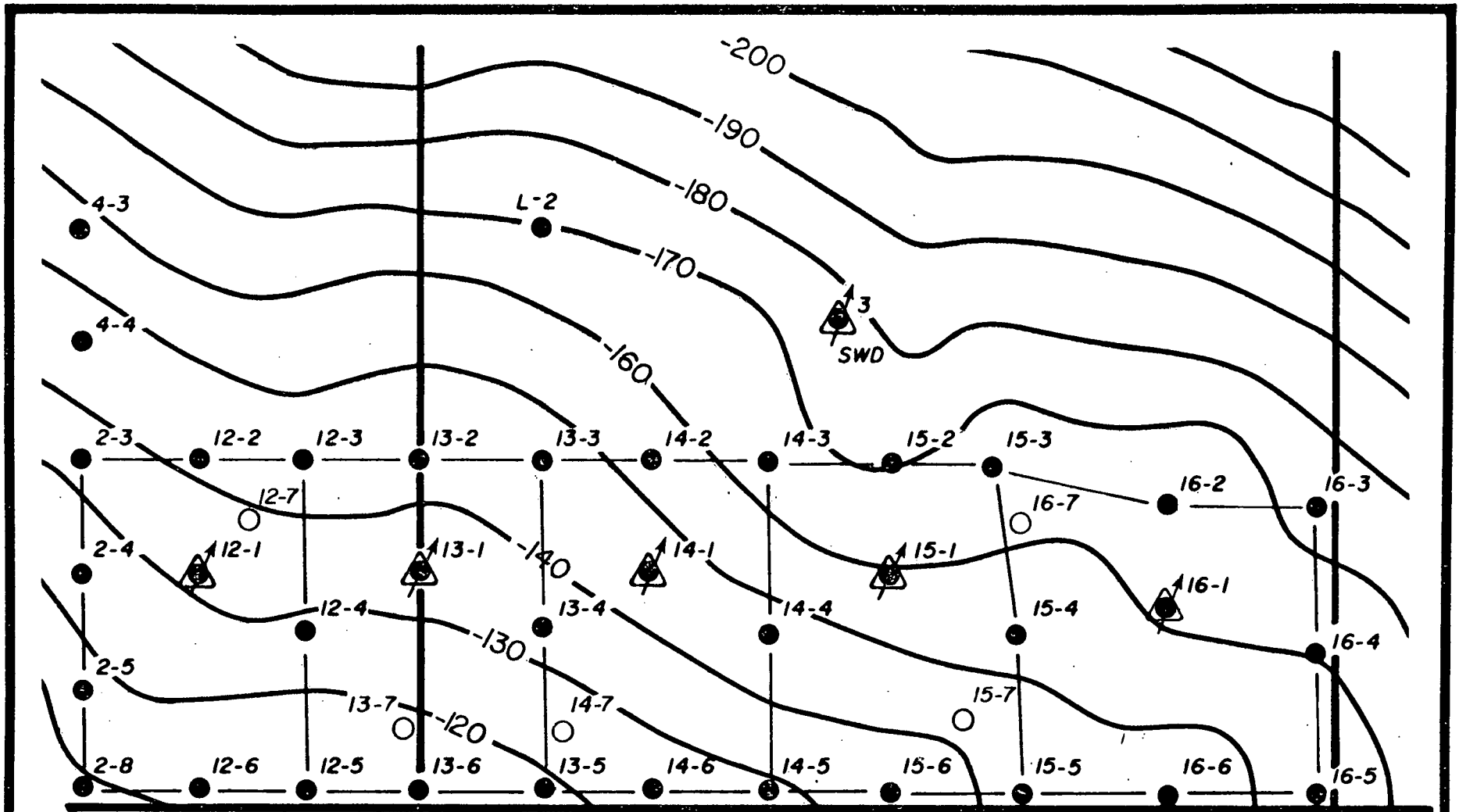


FIGURE 4
 COMPENSATED FORMATION DENSITY LOG
 FOR
 WELL 13-3

CALIPER HOLE DIAM. IN INCHES 6 ————— 16	DEPTHS	—.25 0 .25 CORRECTION GRAMS/CC.
GAMMA RAY API UNITS 0 ————— 100		BULK DENSITY GRAMS/CC. 2.0 2.5 3.0 1.0 1.5 2.0

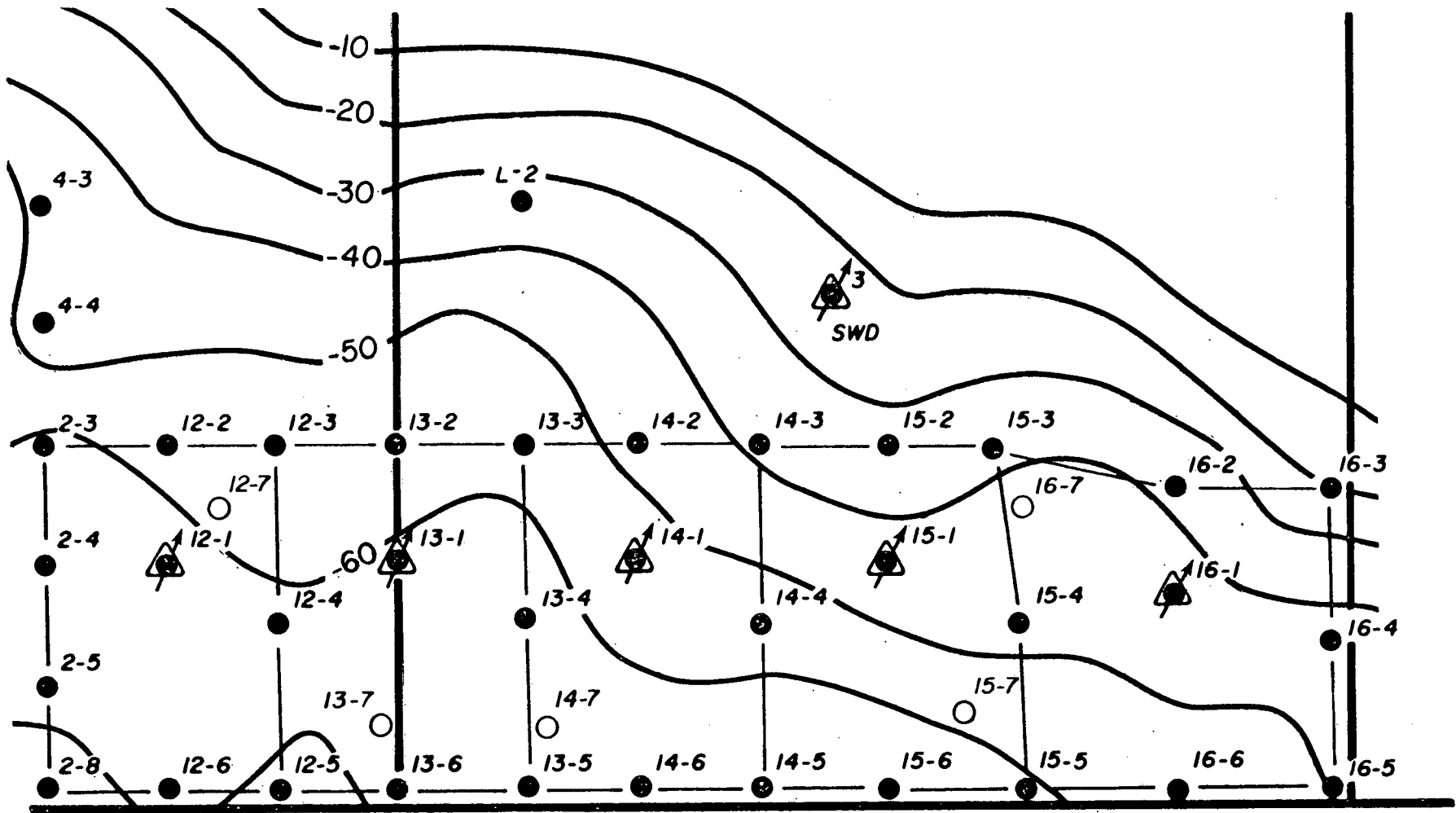




PROJECT AREA STRUCTURE MAP
BODCAU FEE FIREFLOOD



FIGURE 5



PROJECT AREA NET PAY MAP
BODCAU FEE FIREFLOOD



FIGURE 6

FIGURE 7

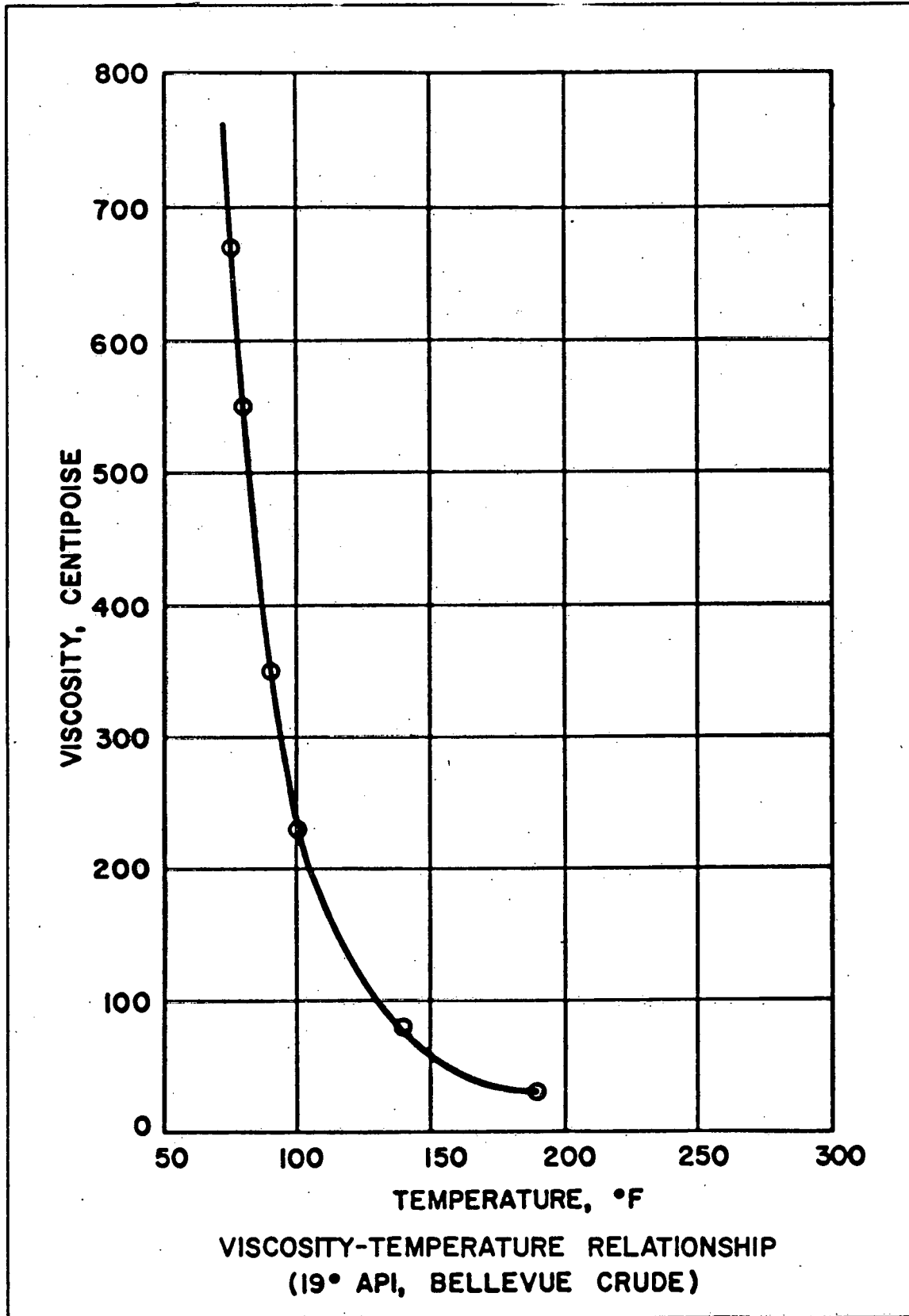


FIGURE 8

GAMMA RAY - NEUTRON LOG
FOR
WELL 2-8

RUN NO.	GENERAL		LOGGING DATA				GAMMA RAY				NEUTRON				
	DEPTHS		SPEED FT. MIN.	T.C. SEC.	SENS. SETTINGS	ZERO DIV. 1 OR 2	API G. R. UNITS PER LOG DIV.	T.C. SEC.	SENS. SETTINGS	ZERO DIV. 1 OR 2	API N. UNITS PER LOG DIV.				
	FROM	TO													
1	158	50	23	4	100/480	2 L		2	500/420	7 1/2 L					
REFERENCE LITERATURE															
REMARKS															

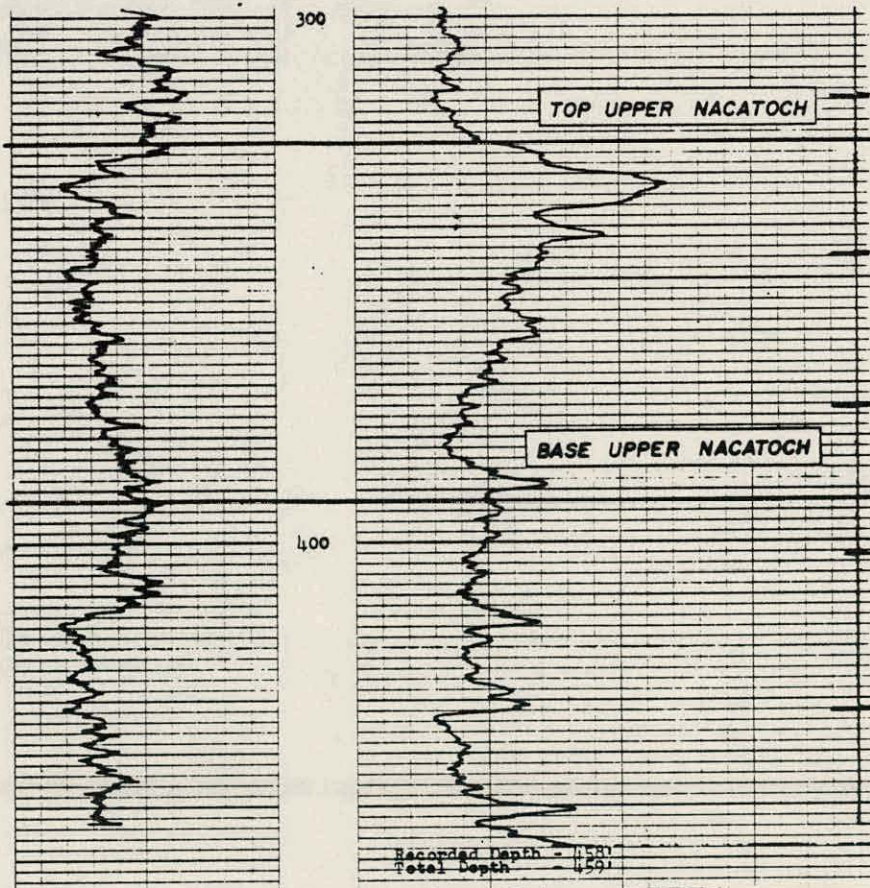


Figure 9

Production Well Schematic

Dry & Simultaneous Burning Phases

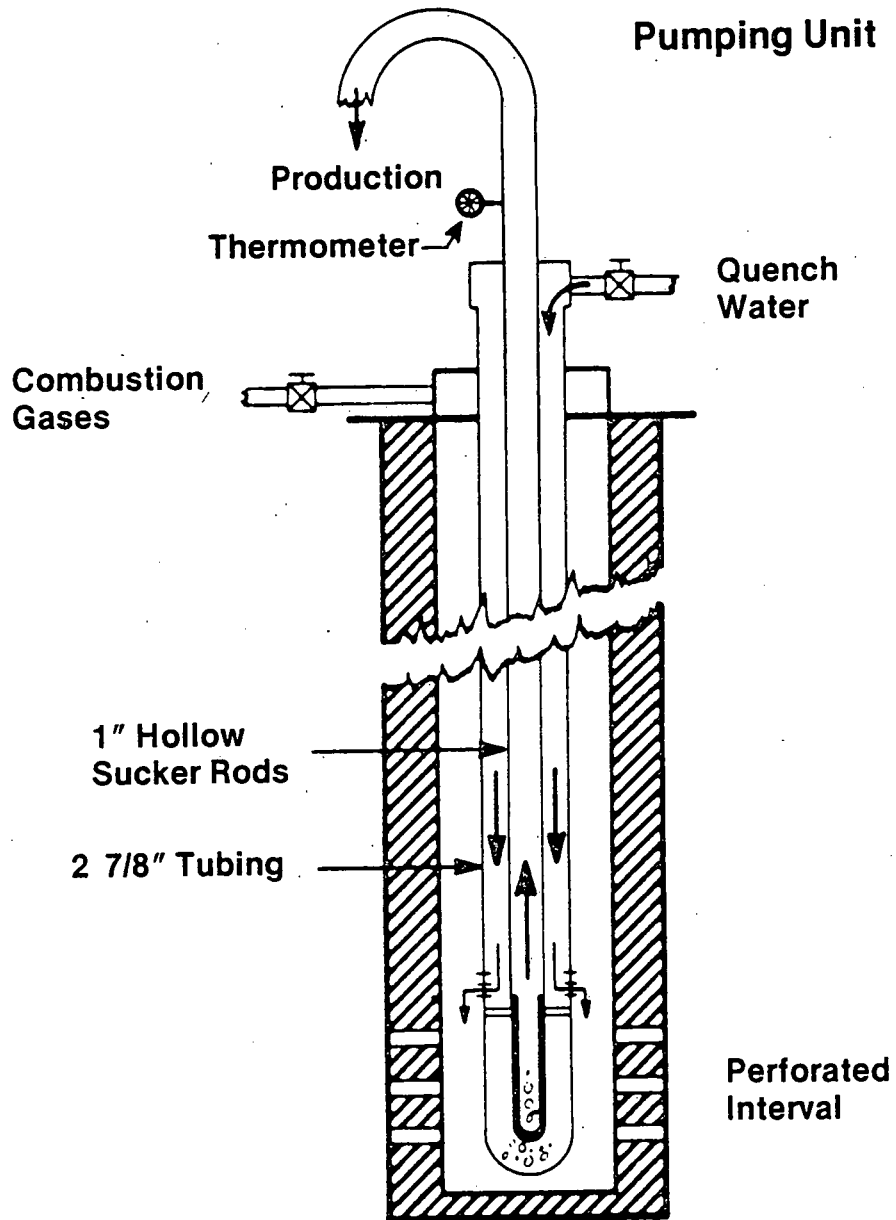


Figure 10

Injection Well Schematic

Dry Burn Phase

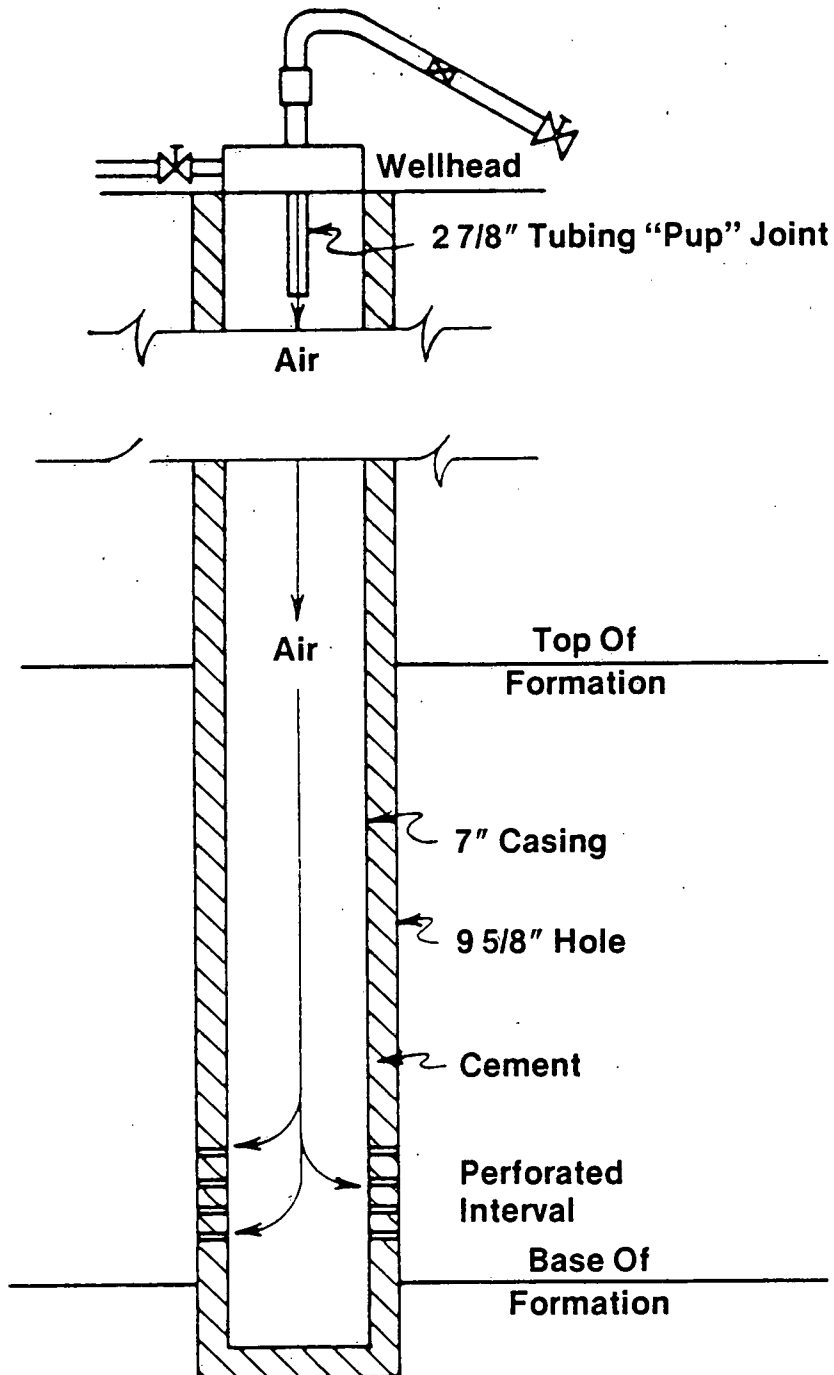


FIGURE 11
IGNITION WELL EQUIPMENT SCHEMATIC

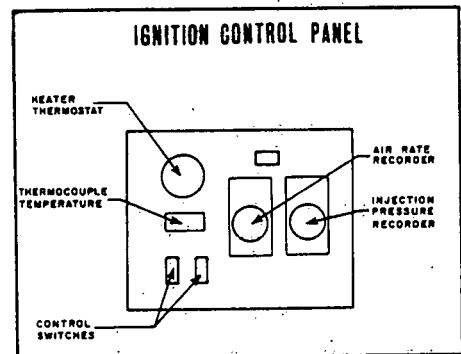
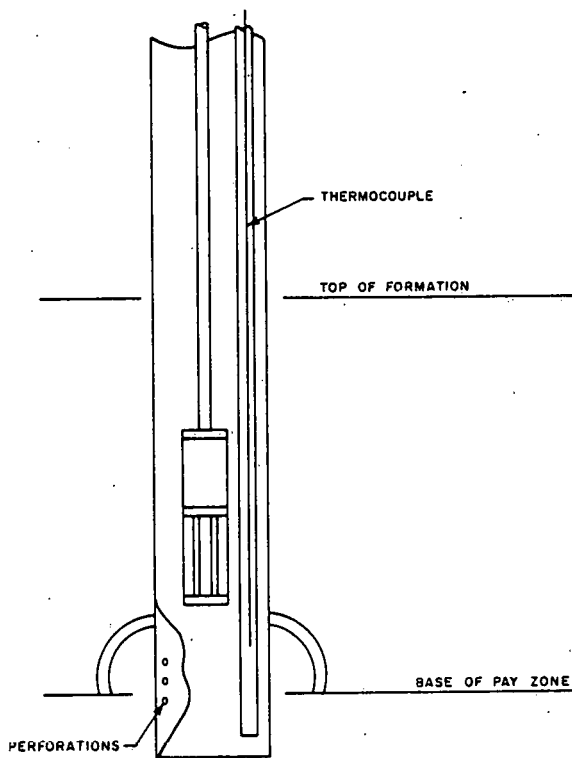
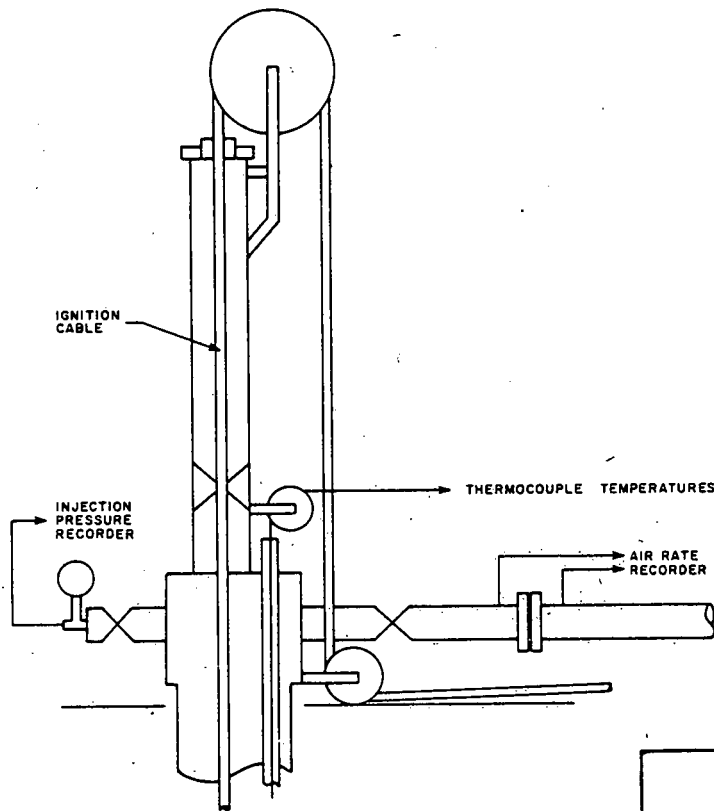


FIGURE 12

WELL #16-1 TEMPERATURE PROFILES



- - PROFILE AT 8:30 PM, 9/22/76
- - PROFILE AT 8:00 PM, 9/23/76
- ◇ - PROFILE AT 12:00 PM, 9/24/76

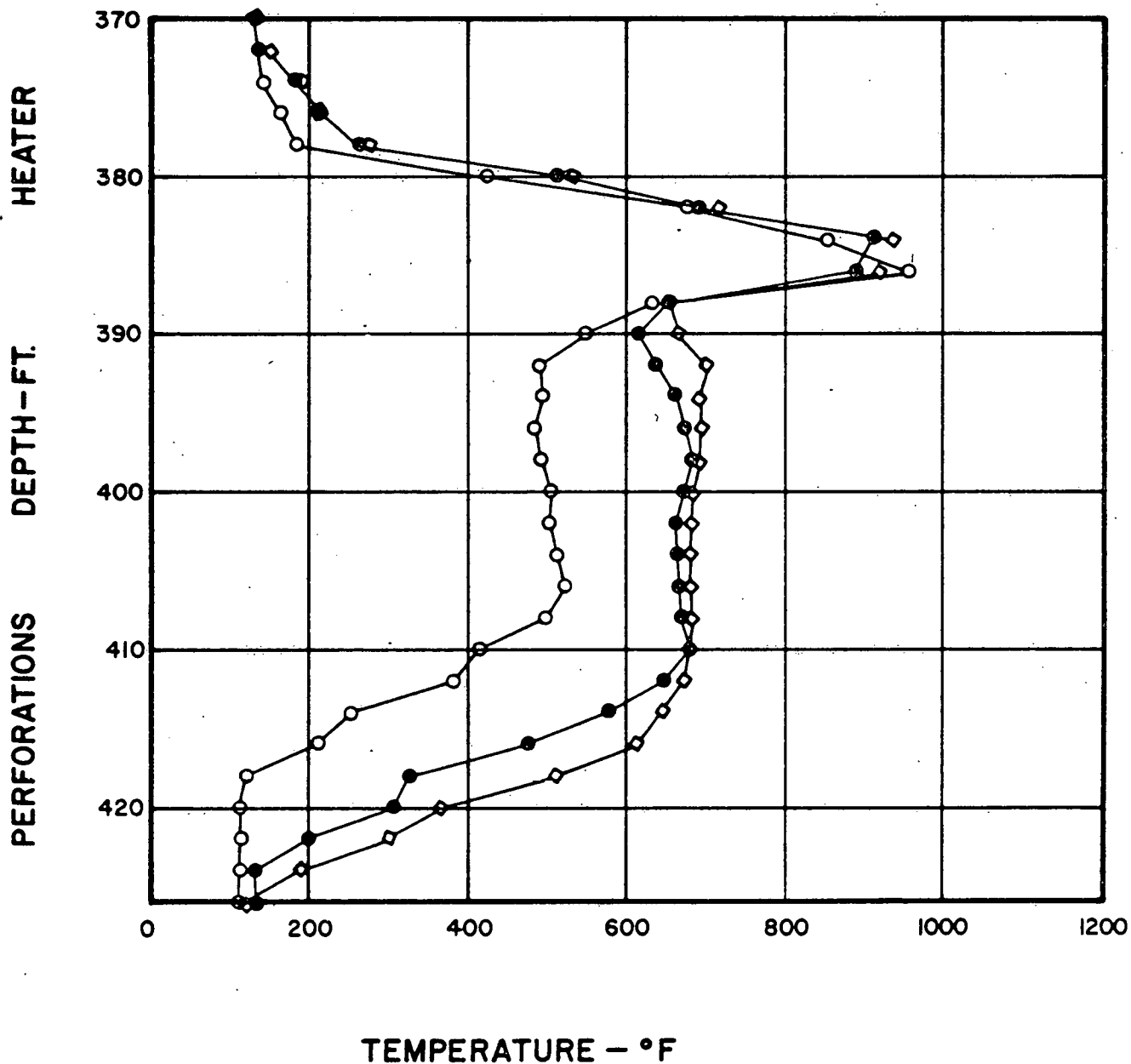


FIGURE 13

**PATTERN 16 IGNITION
ORSAT GAS ANALYSES**

- - OXYGEN
- △ - CARBON DIOXIDE
- - CARBON MONOXIDE

TIME ZERO = 9:00 AM, 9/21/76

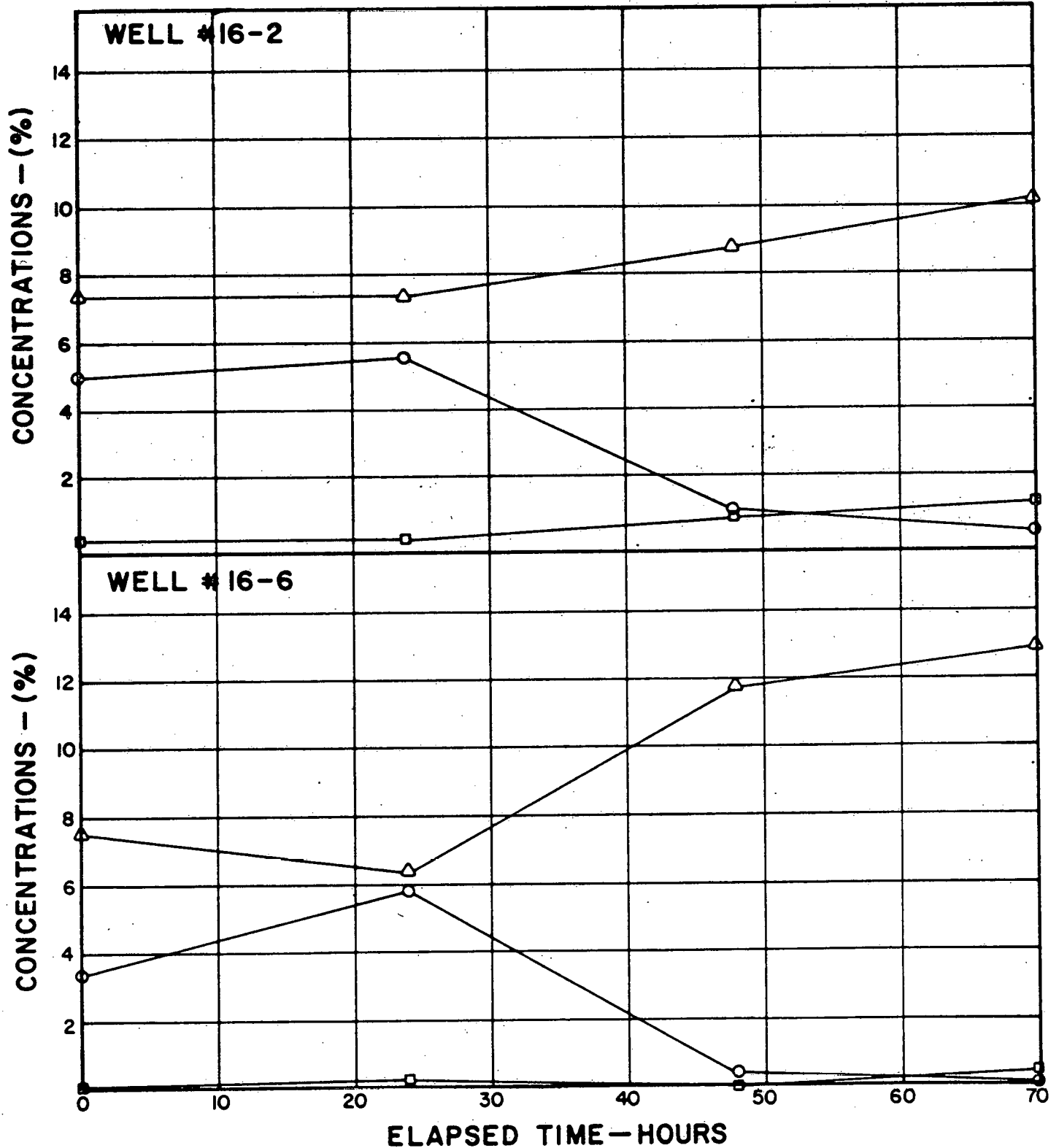
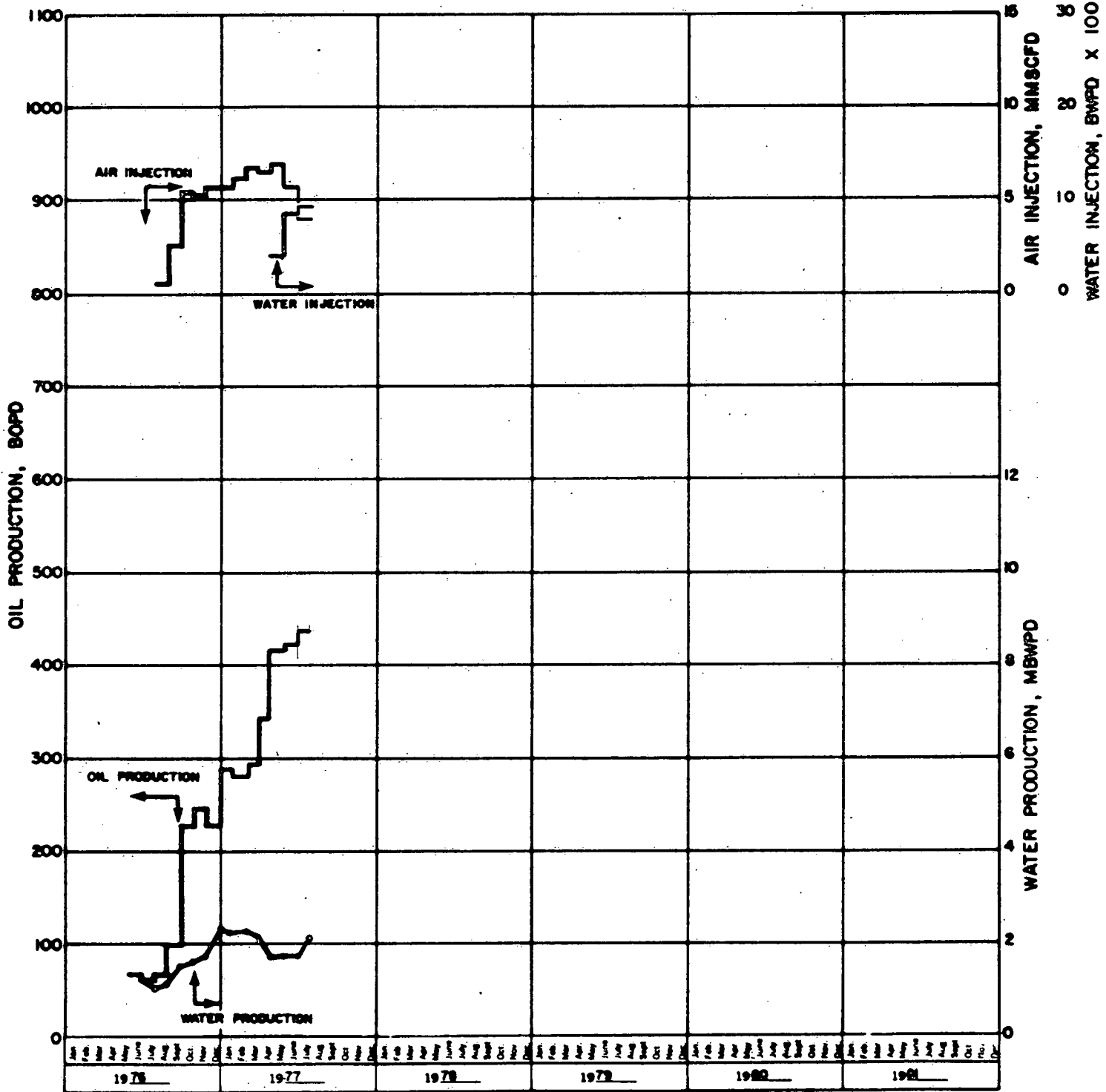


FIGURE 14

E.R.D.A. - CITIES SERVICE IN SITU COMBUSTION PROJECT
 BELLEVUE FIELD, LOUISIANA
 PRODUCTION AND INJECTION PERFORMANCE



**FIGURE 15
BODCAU IN SITU COMBUSTION PROJECT
CUMULATIVE OIL PRODUCTION**

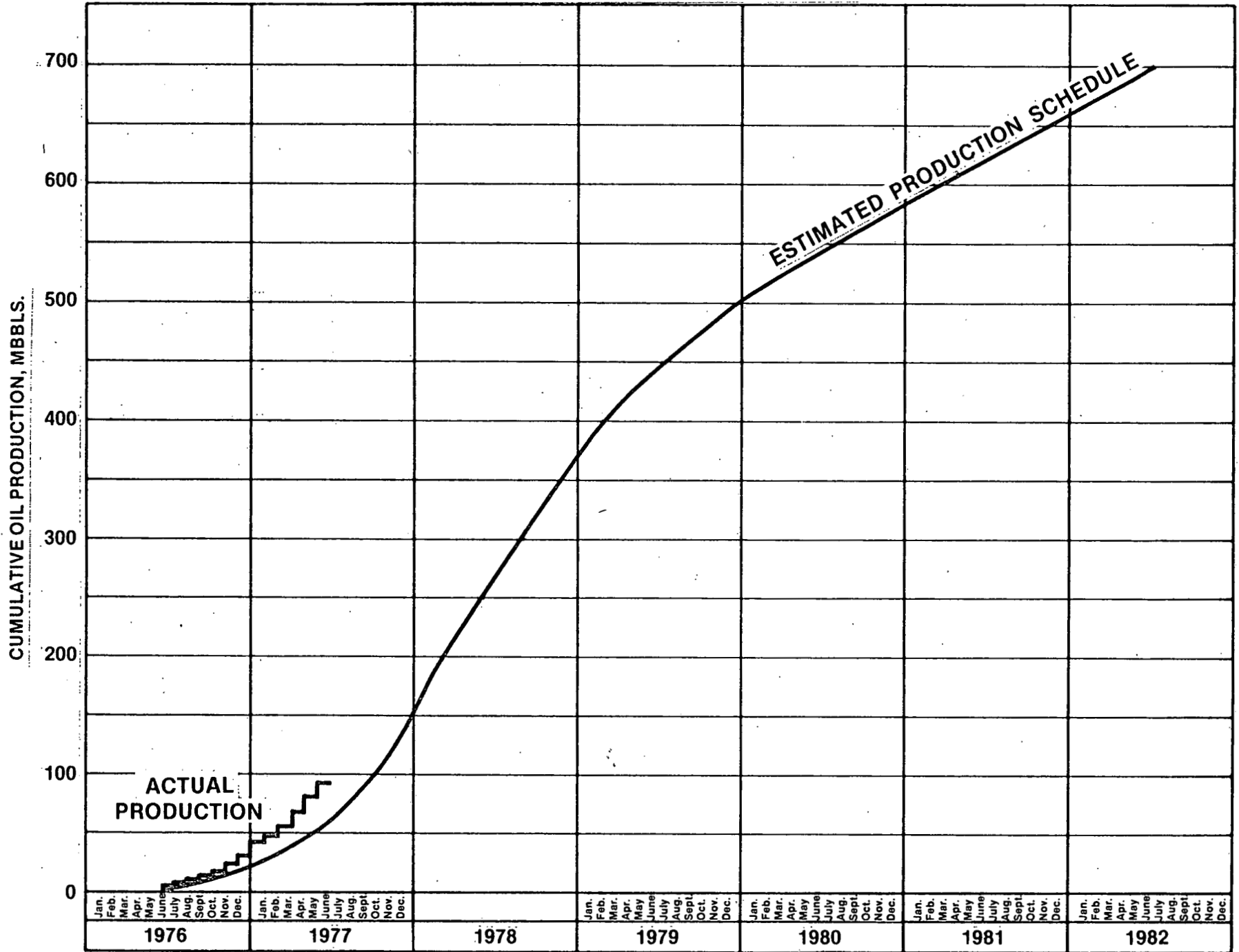
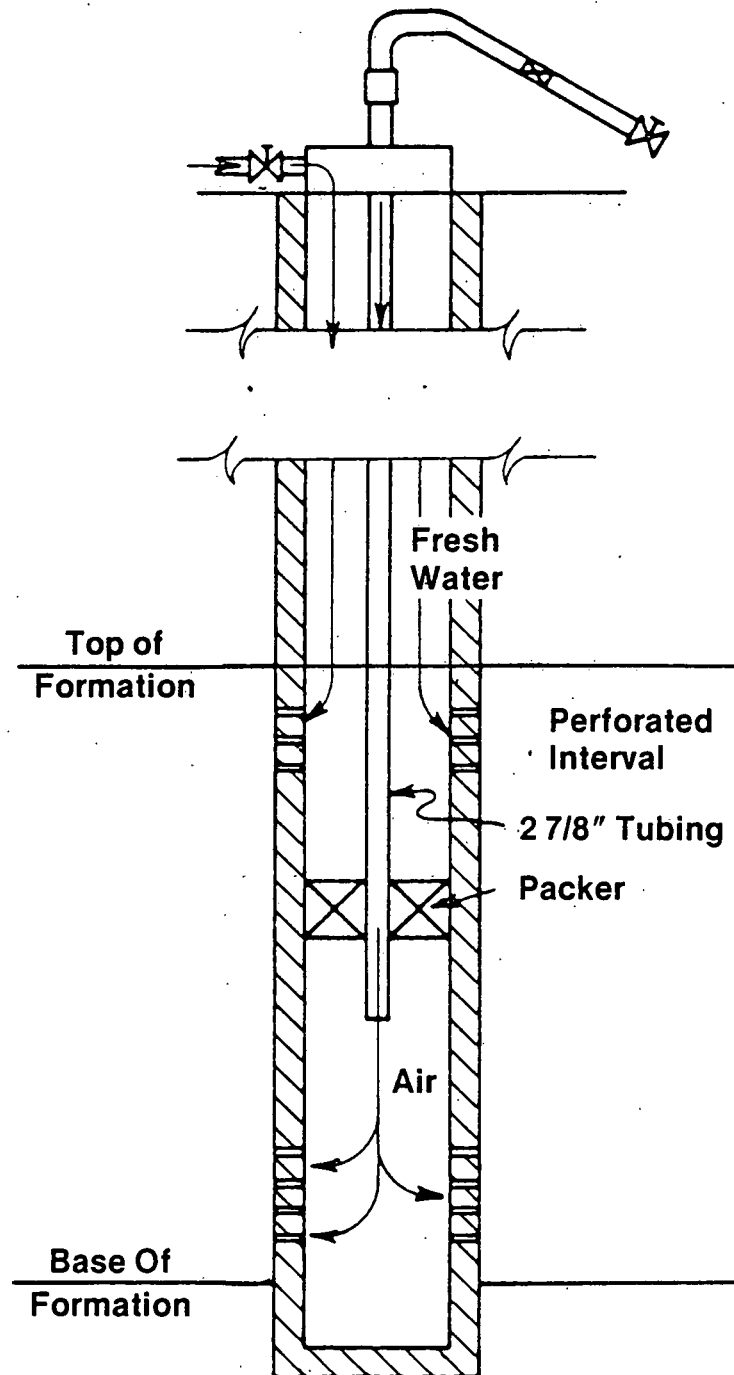
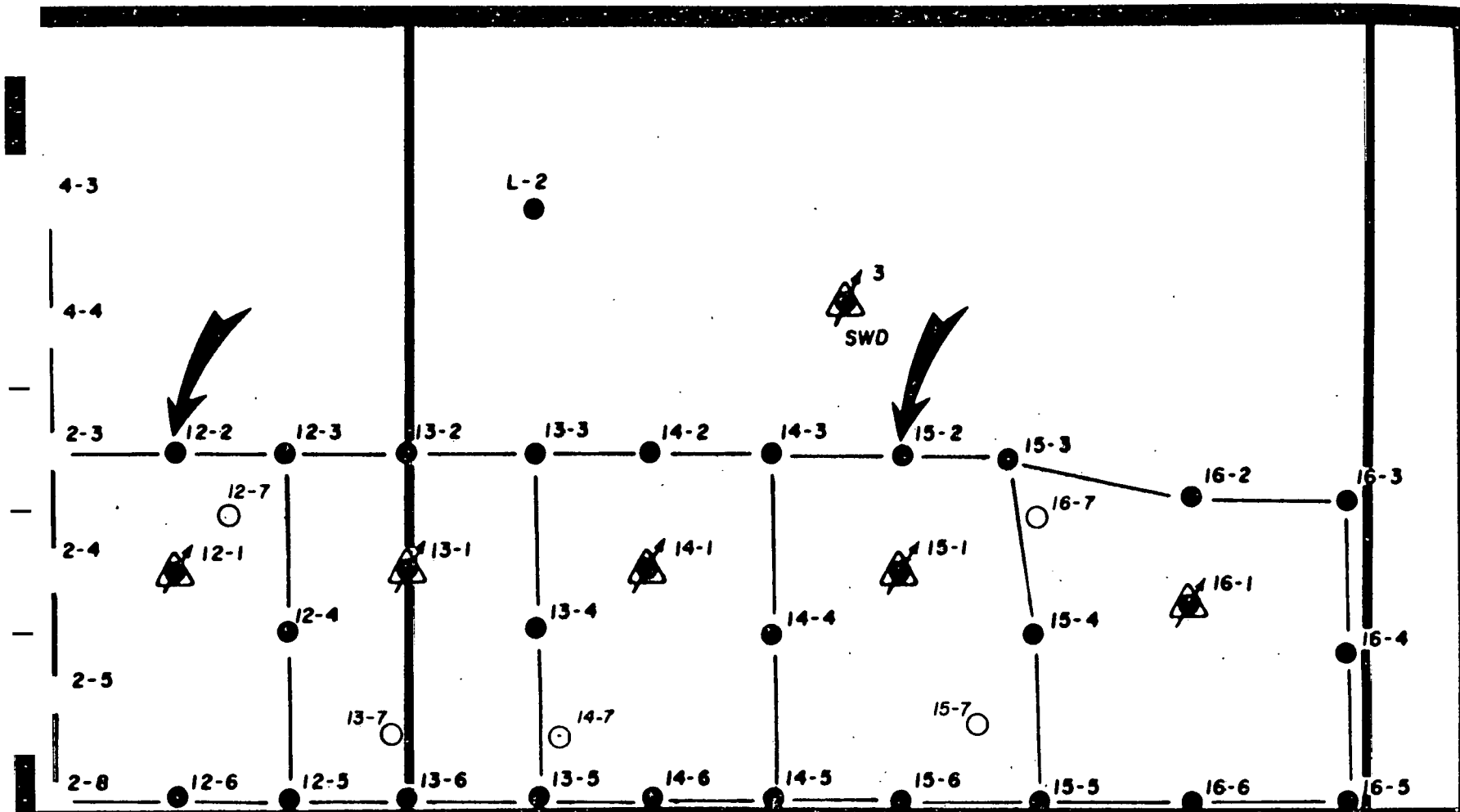


Figure 16

Injection Well Schematic

Simultaneous Injection





COMBUSTION FRONT BREAKTHROUGH

E. R. D. A.
 CITIES SERVICE COMPANY
 PROJECT PATTERN MAP
 BODCAU FEE FIREFLOOD
 SEC. II, T-19-N, R-11-W
 BOSSIER PARISH, LOUISIANA

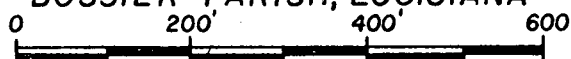


FIGURE 17

FIGURE 18

TEMPERATURE PROFILES
OBSERVATION WELL NO. 12-7

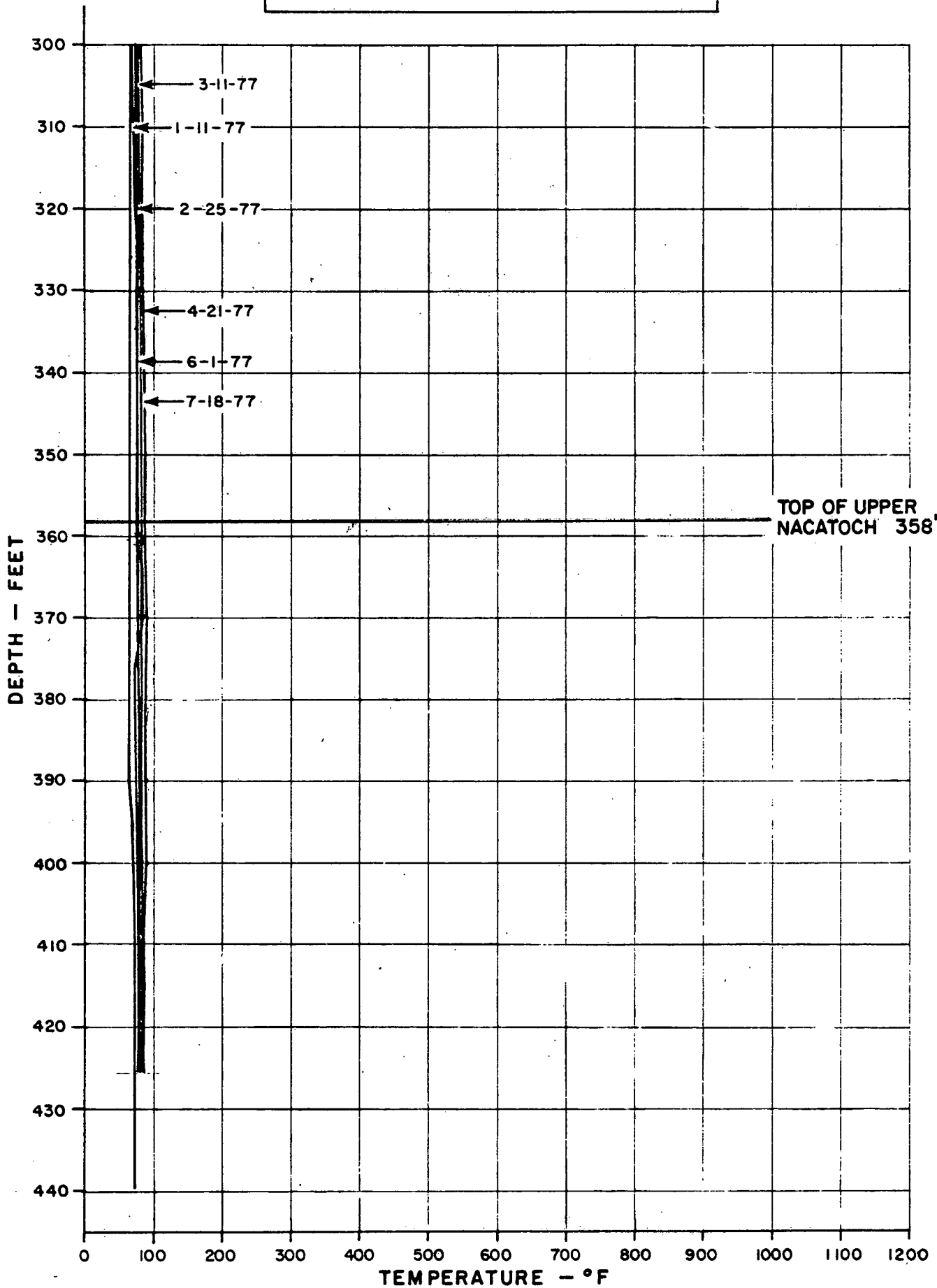


FIGURE 19

TEMPERATURE PROFILES
OBSERVATION WELL NO. 13-7

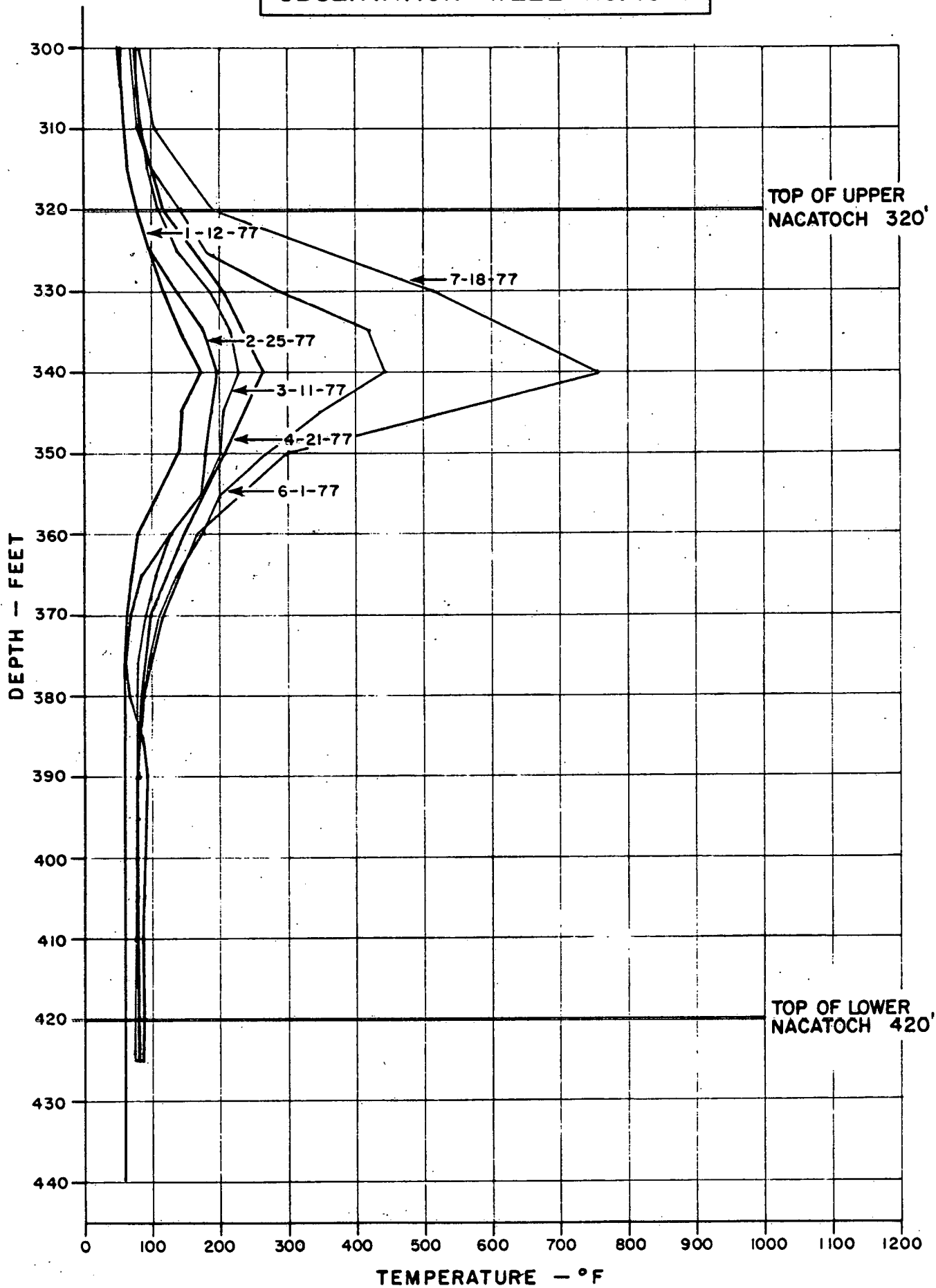


FIGURE 20

TEMPERATURE PROFILES
OBSERVATION WELL NO. 14-7

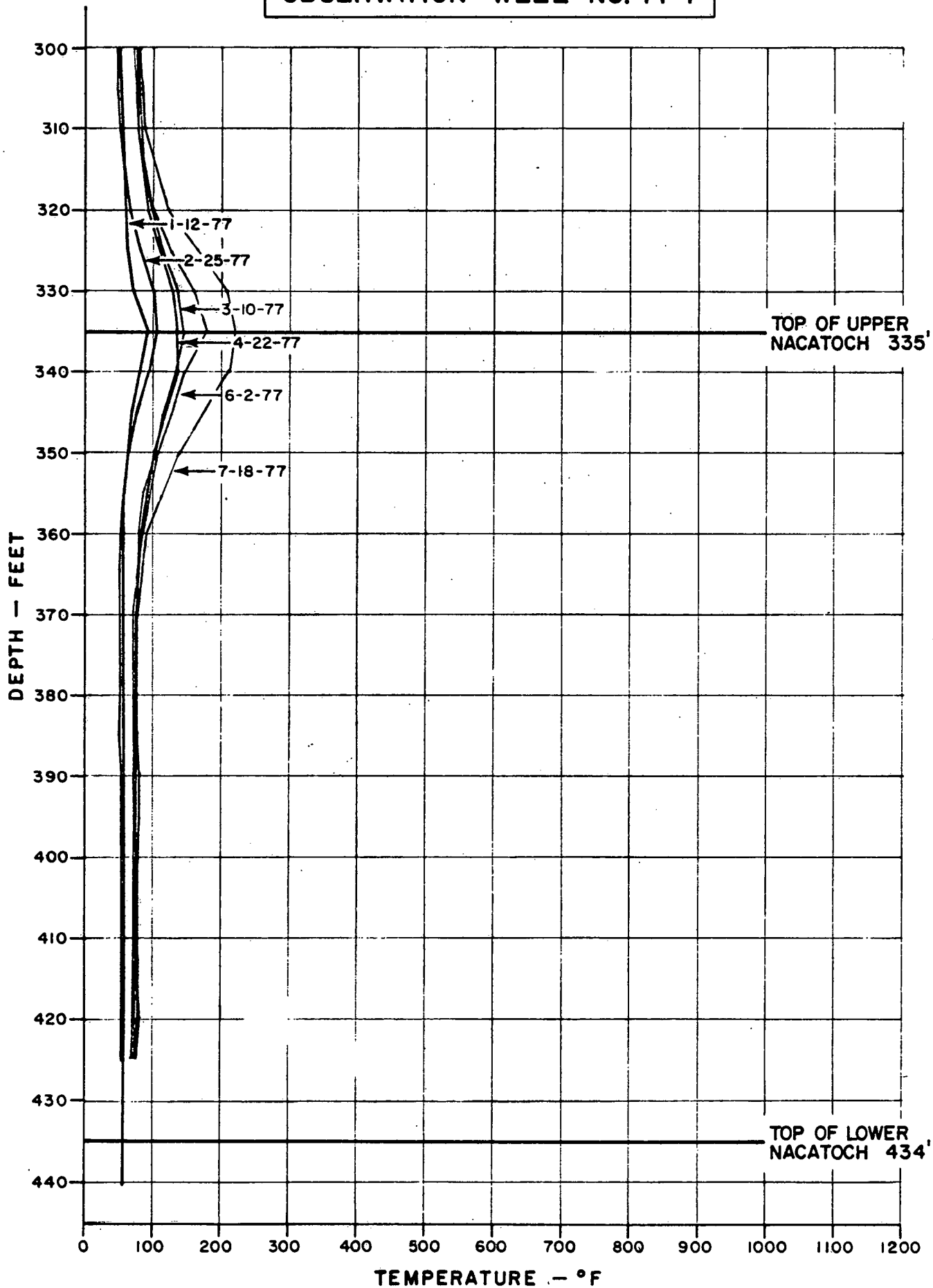


FIGURE 21

TEMPERATURE PROFILES
OBSERVATION WELL NO. 15-7

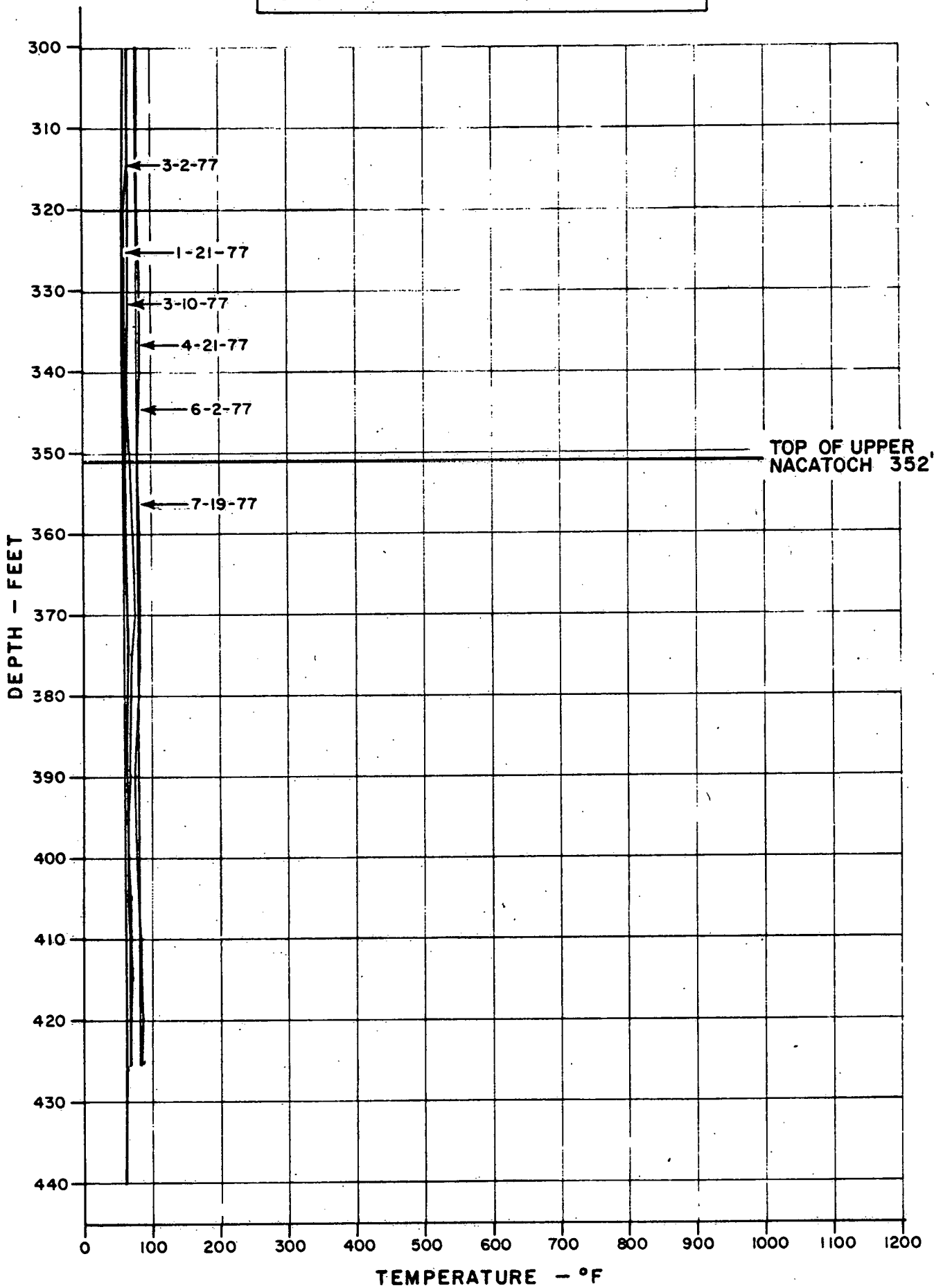


FIGURE 22

TEMPERATURE PROFILES
OBSERVATION WELL NO. 16-7

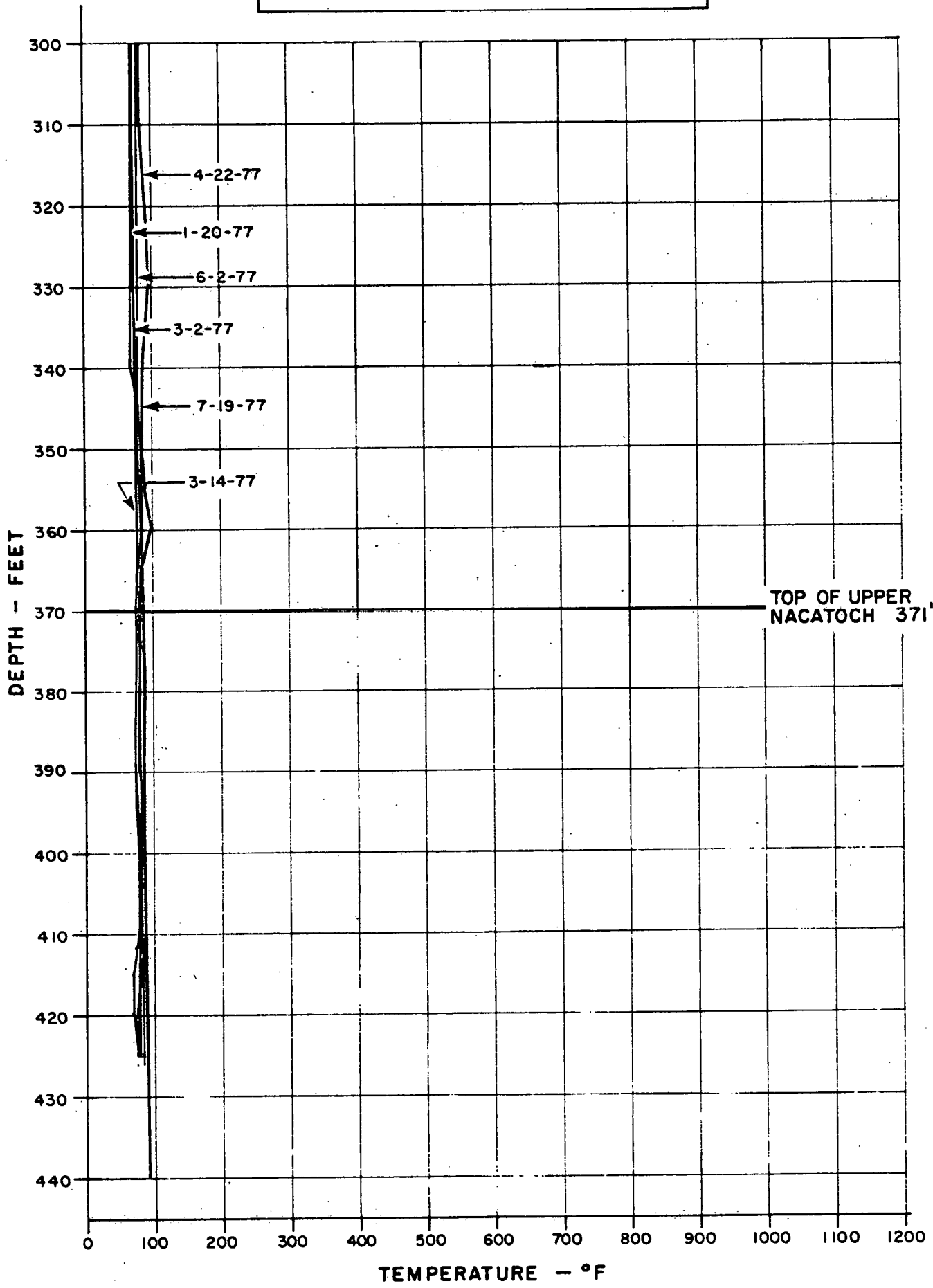
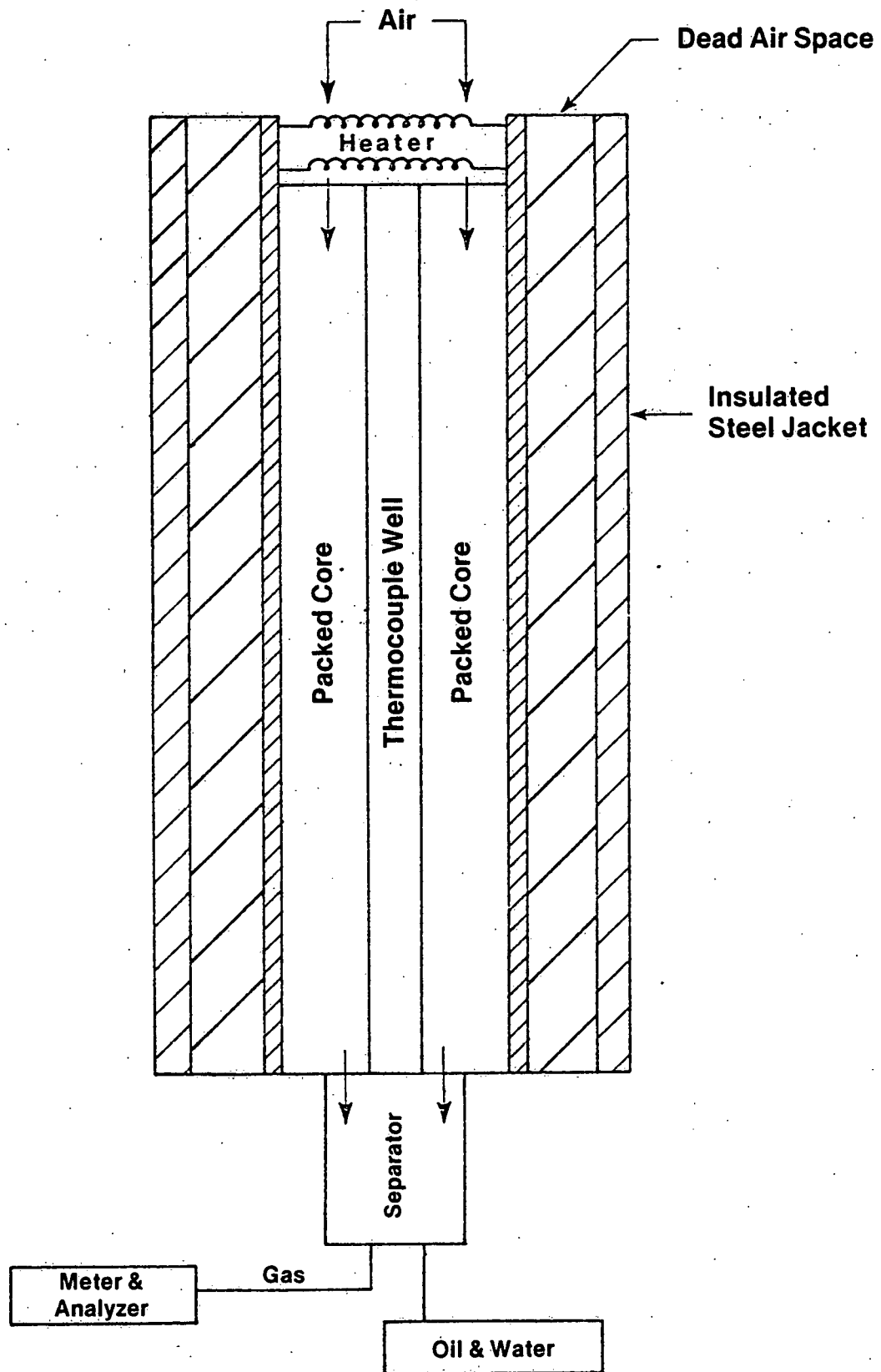


Figure 23

Laboratory Combustion Tube Schematic



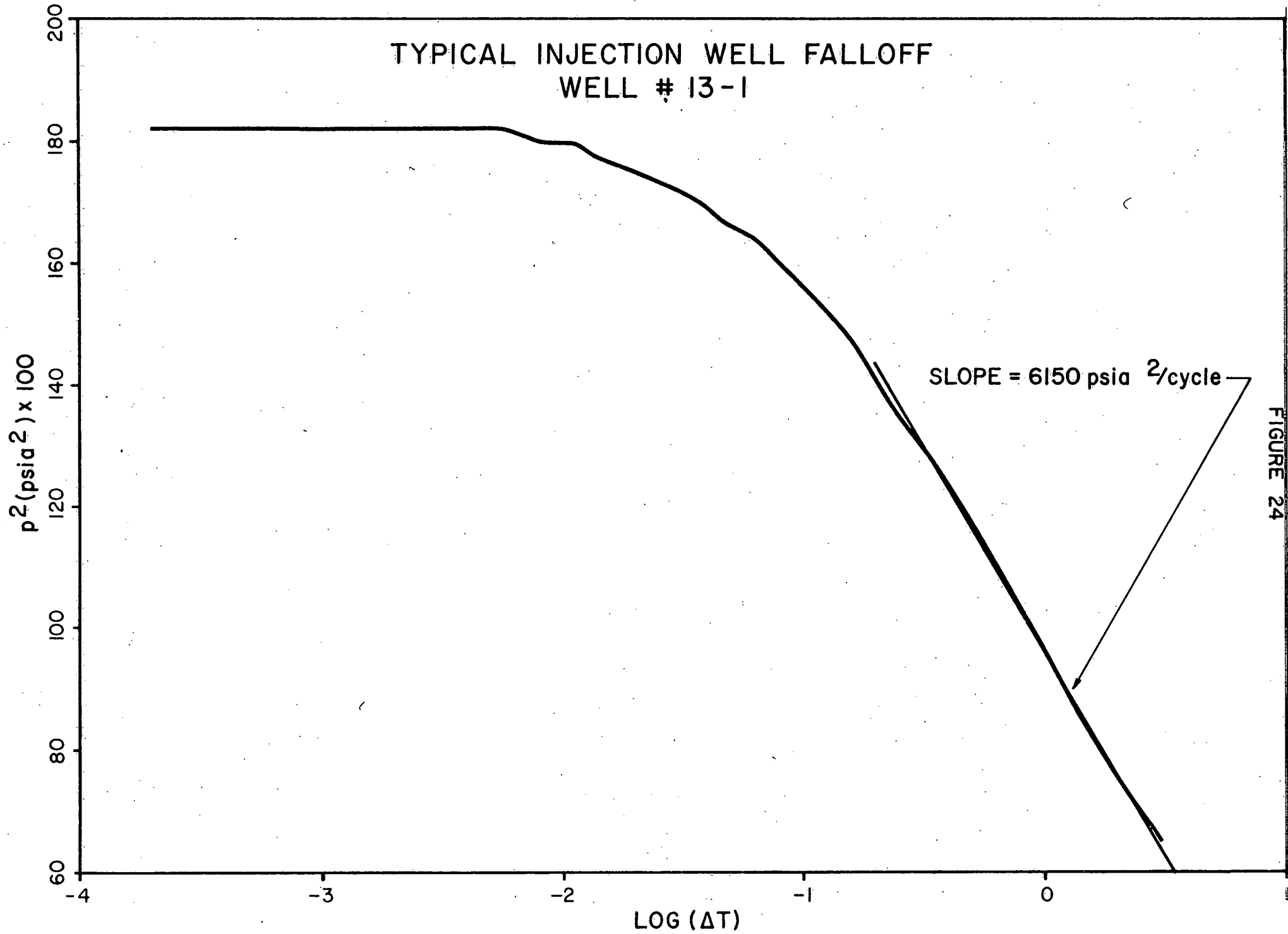
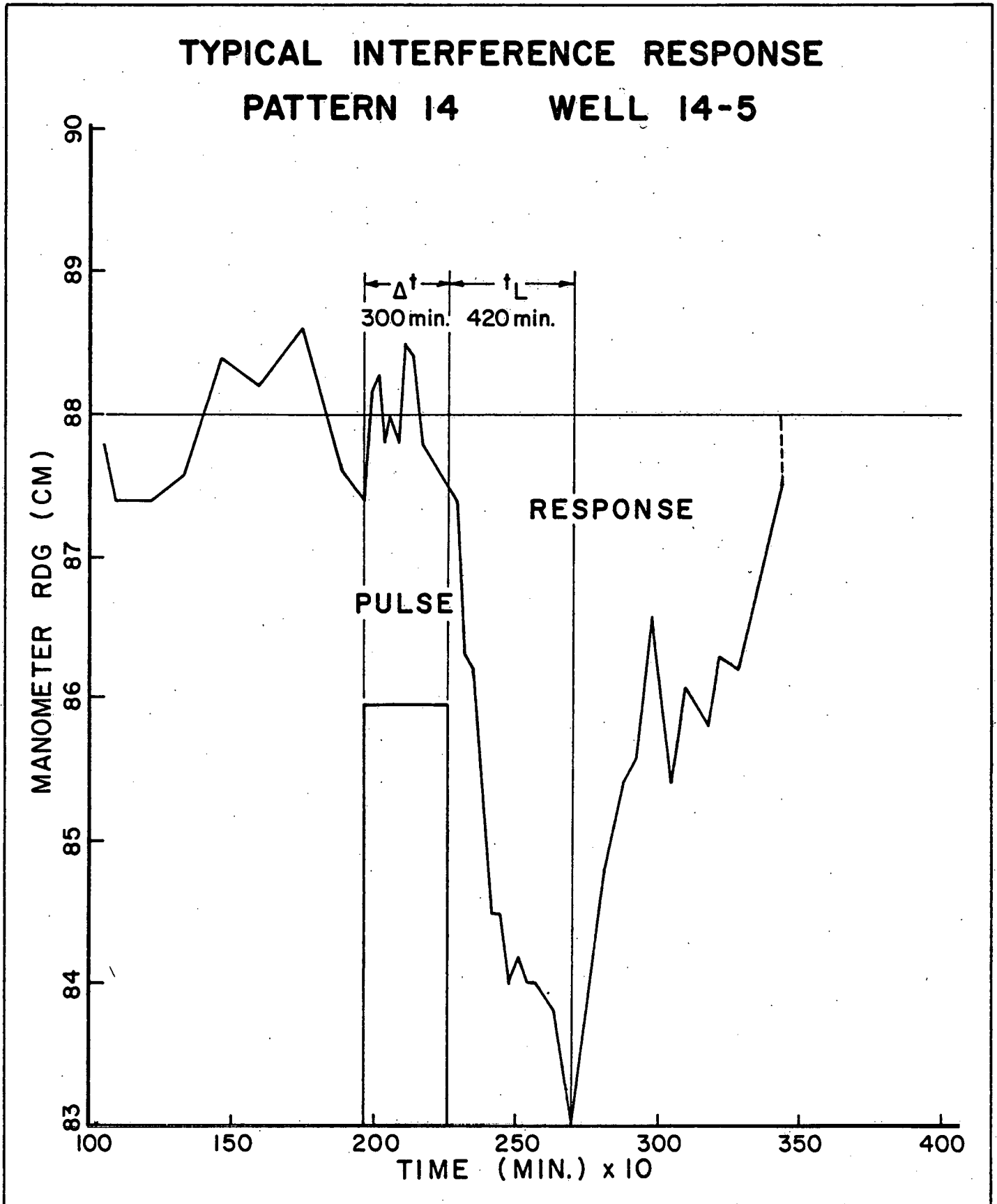


FIGURE 24

FIGURE 25

TYPICAL INTERFERENCE RESPONSE
PATTERN 14 WELL 14-5



DIRECTIONAL PERMEABILITY VS. r^2

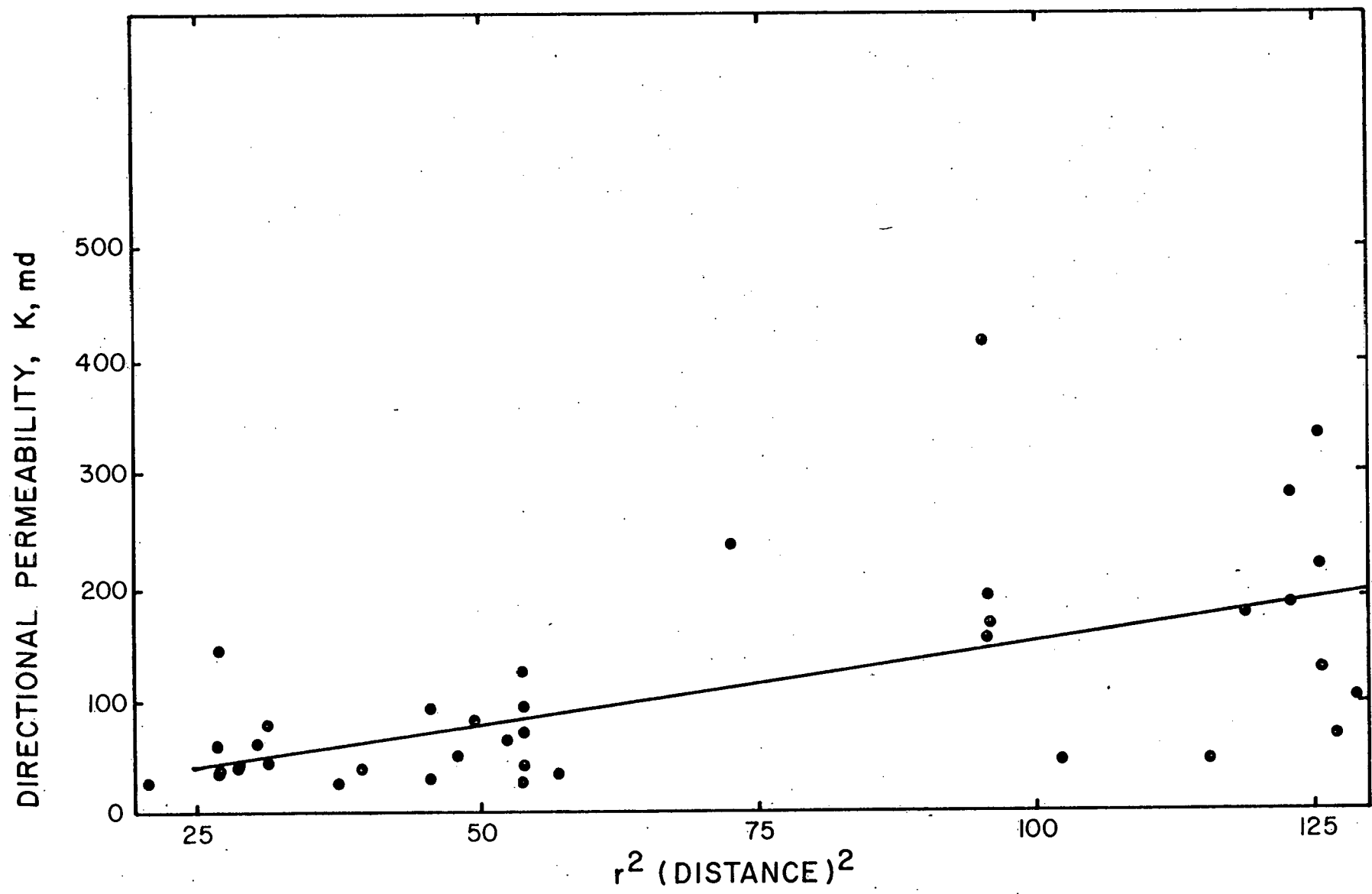


FIGURE 26

FIGURE 27

PERCENT WATER VAPOR IN AIR AT SATURATION

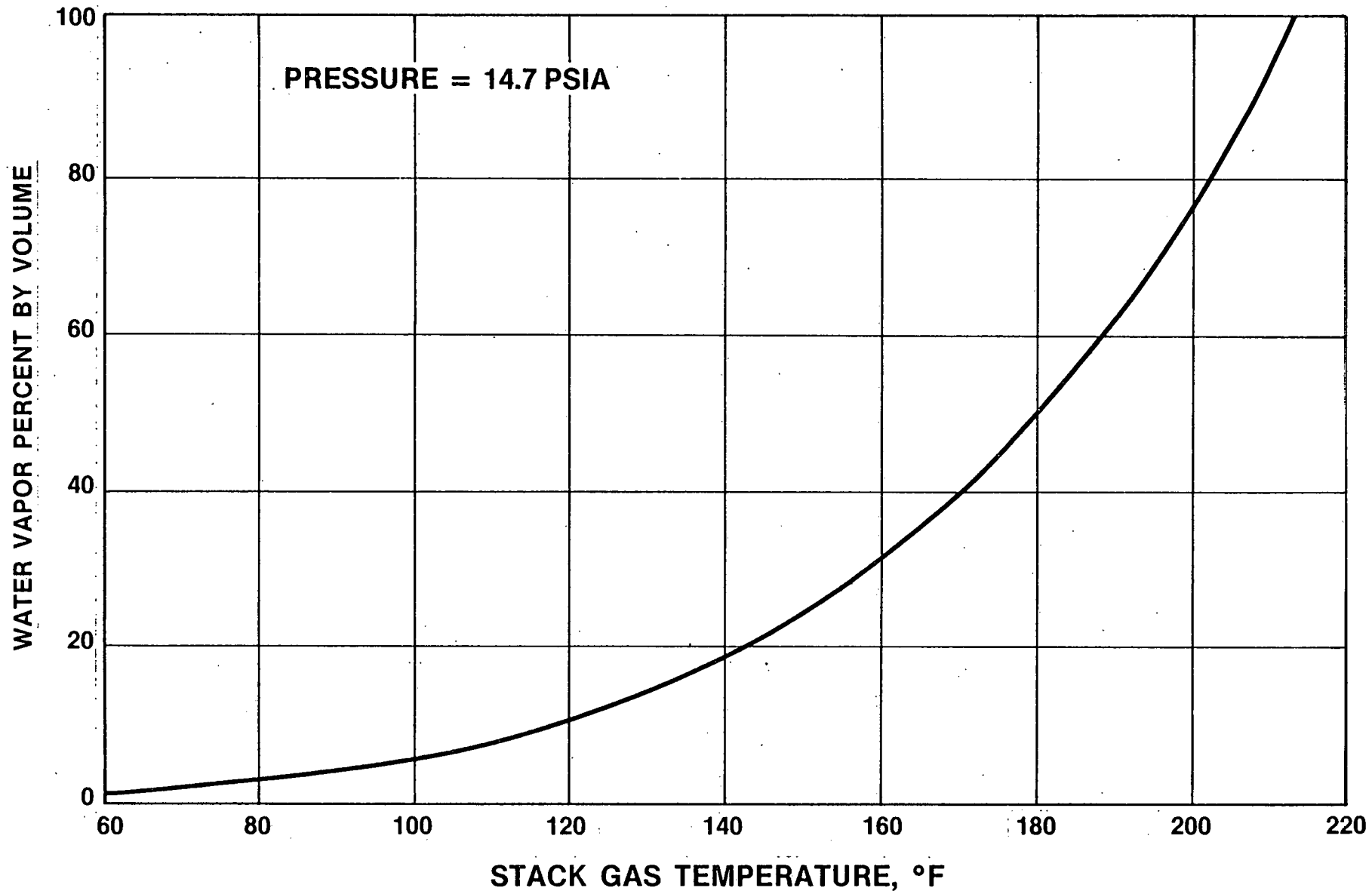


FIGURE 28

BODCAU IN SITU COMBUSTION ERDA PROJECT CUMULATIVE EXPENDITURE VS TIME

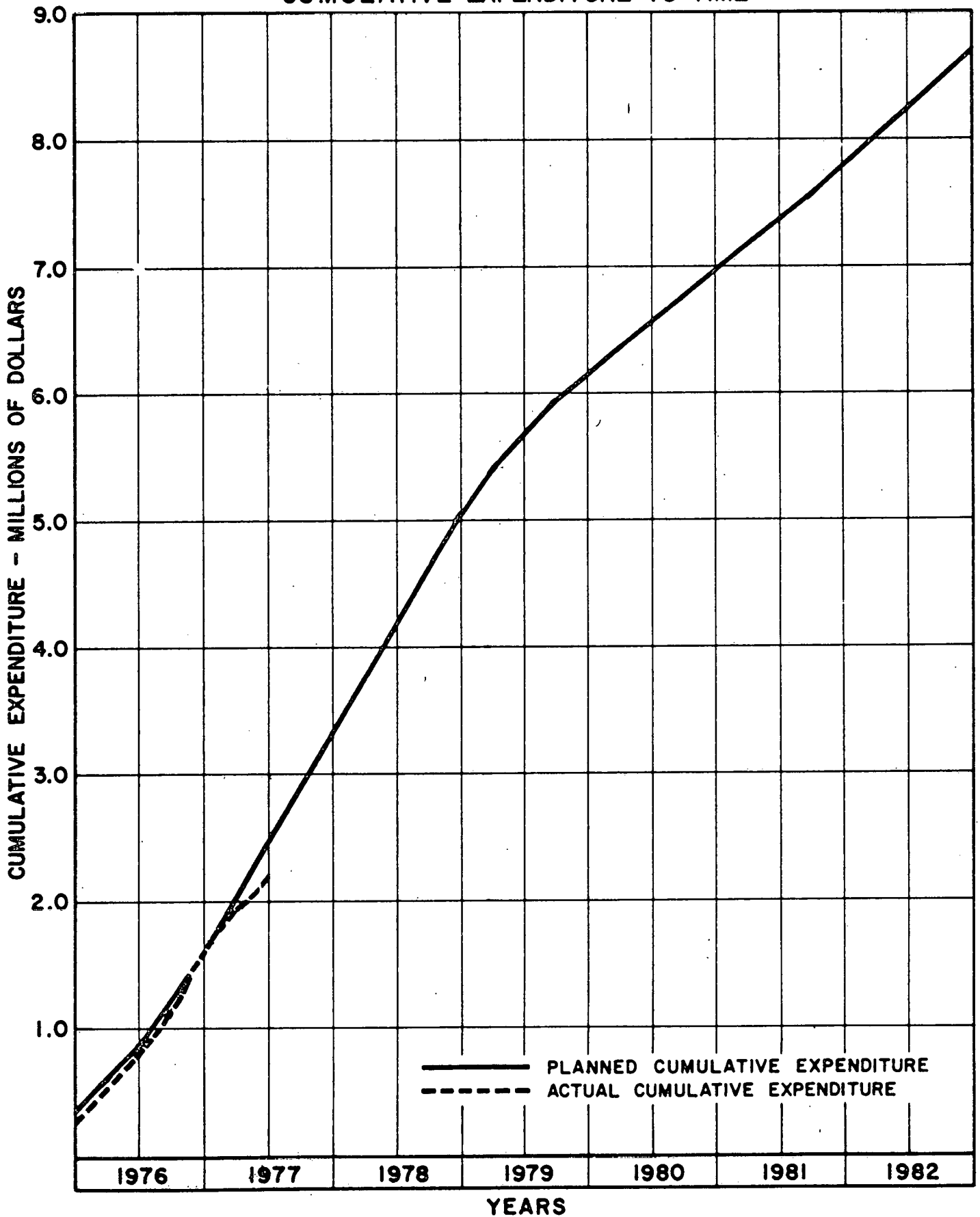


FIGURE 29

INJECTION WELL NO. 12-1 PERFORMANCE

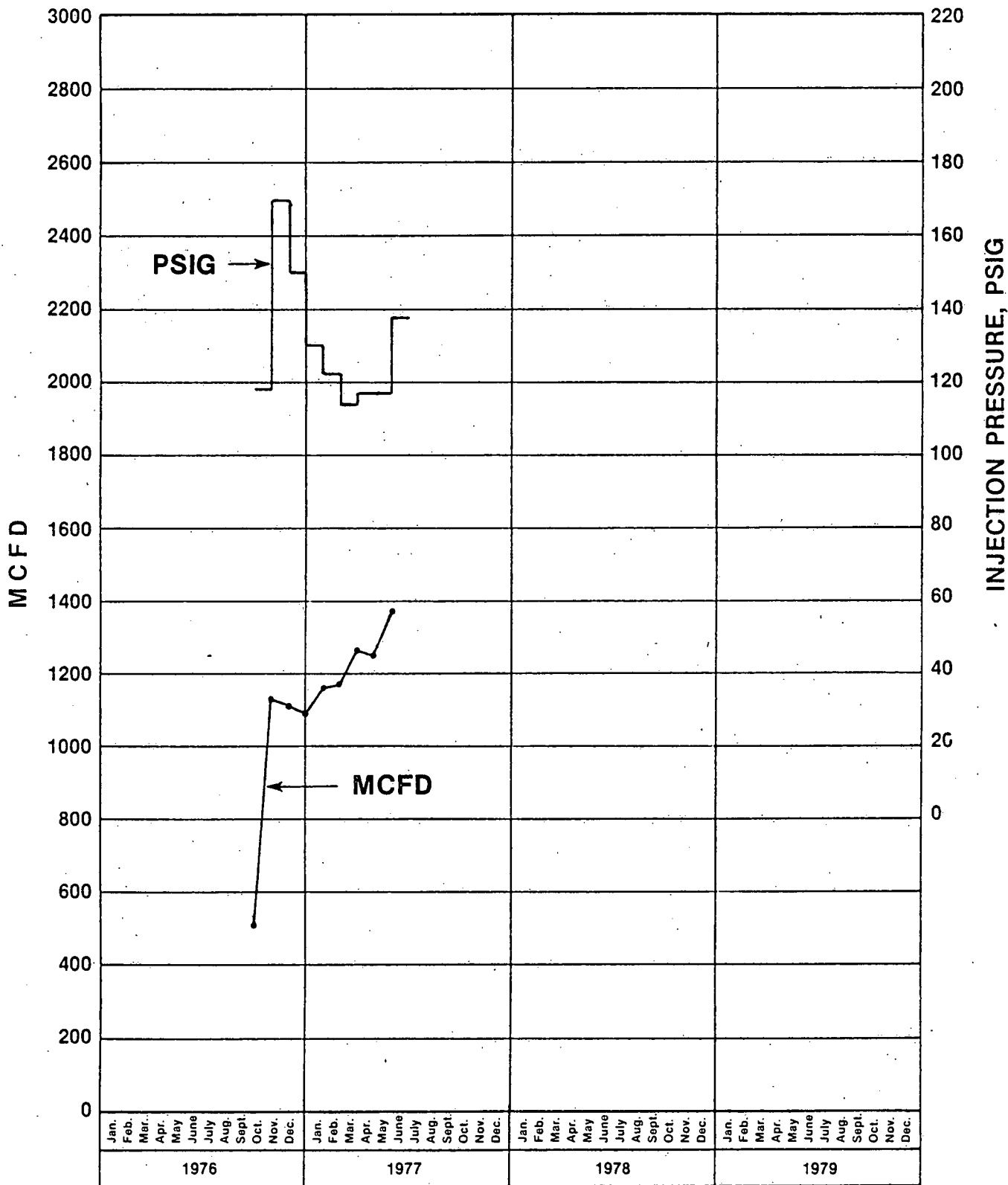


FIGURE 30

INJECTION WELL NO. 13-1 PERFORMANCE

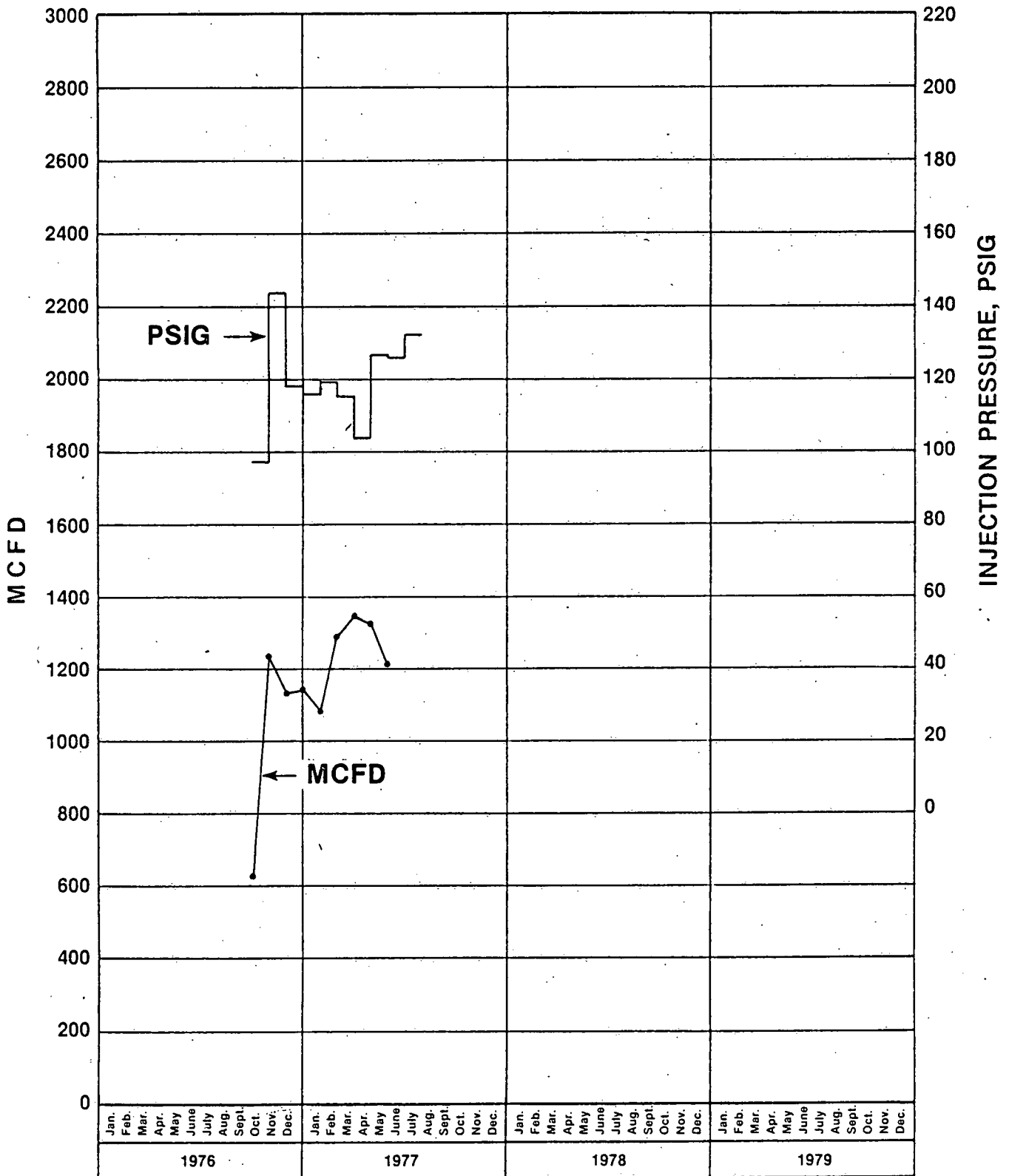


FIGURE 31

INJECTION WELL NO. 14-1 PERFORMANCE

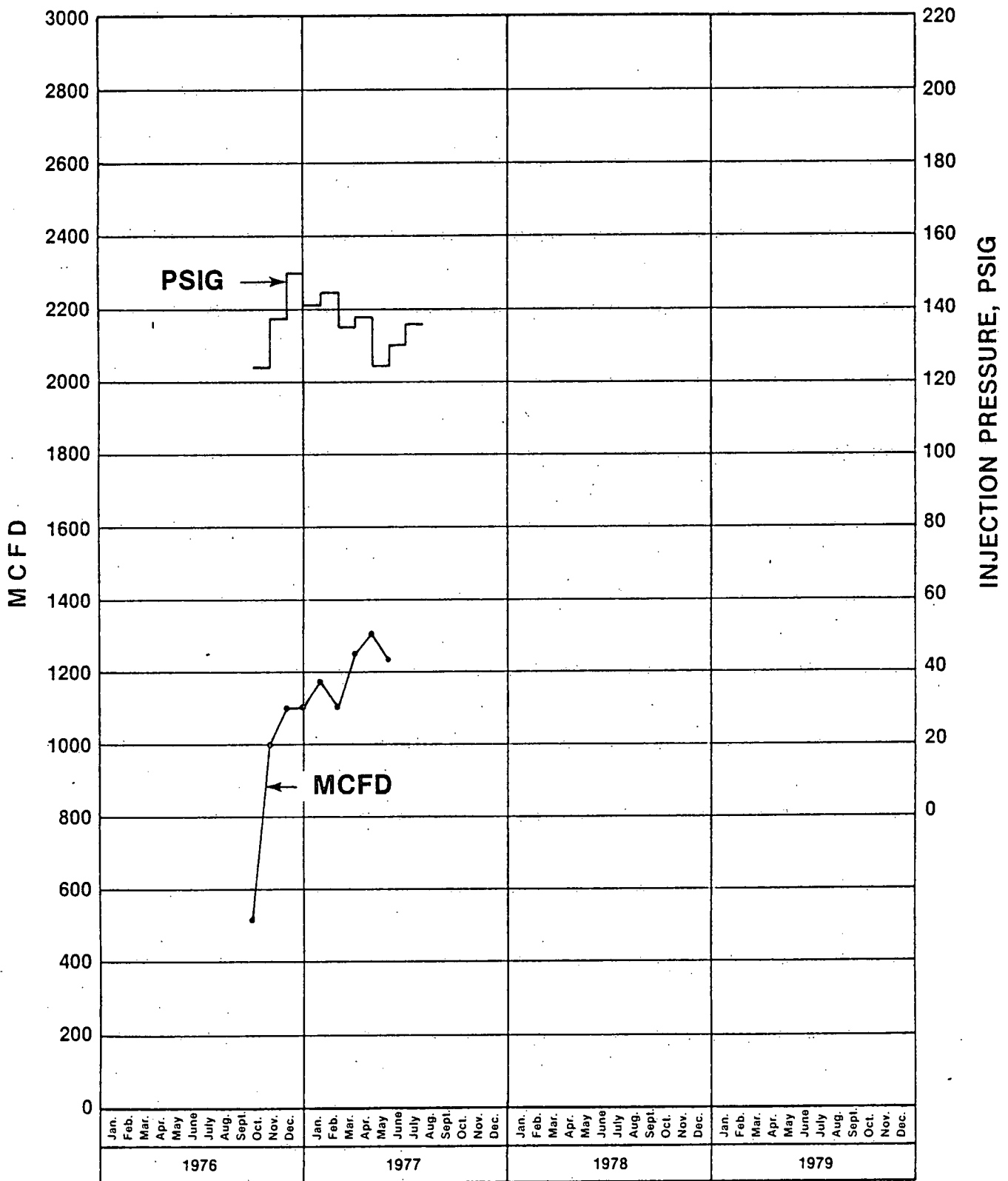


FIGURE 32

INJECTION WELL NO. 15-1 PERFORMANCE

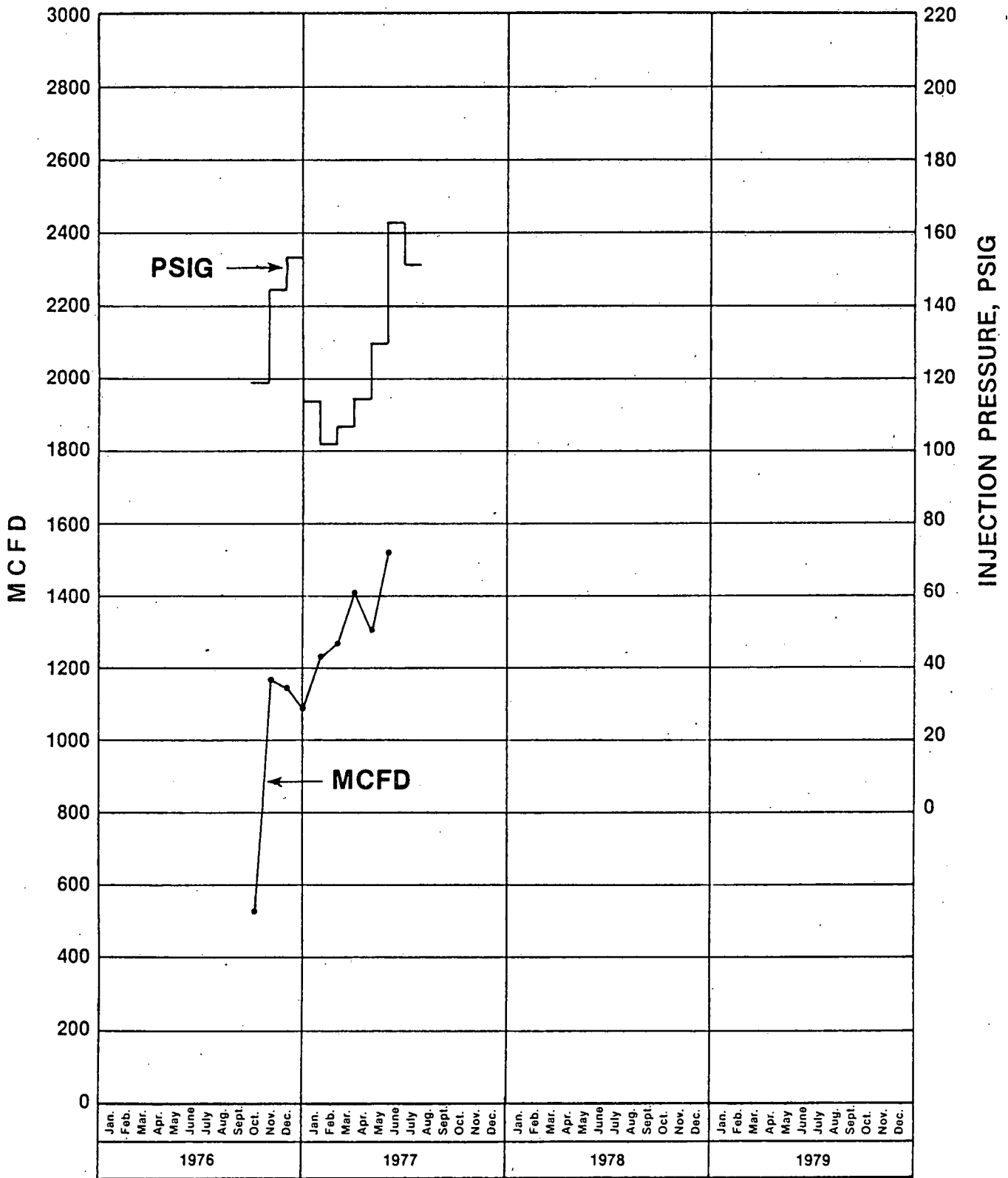


FIGURE 33

INJECTION WELL NO. 16-1 PERFORMANCE

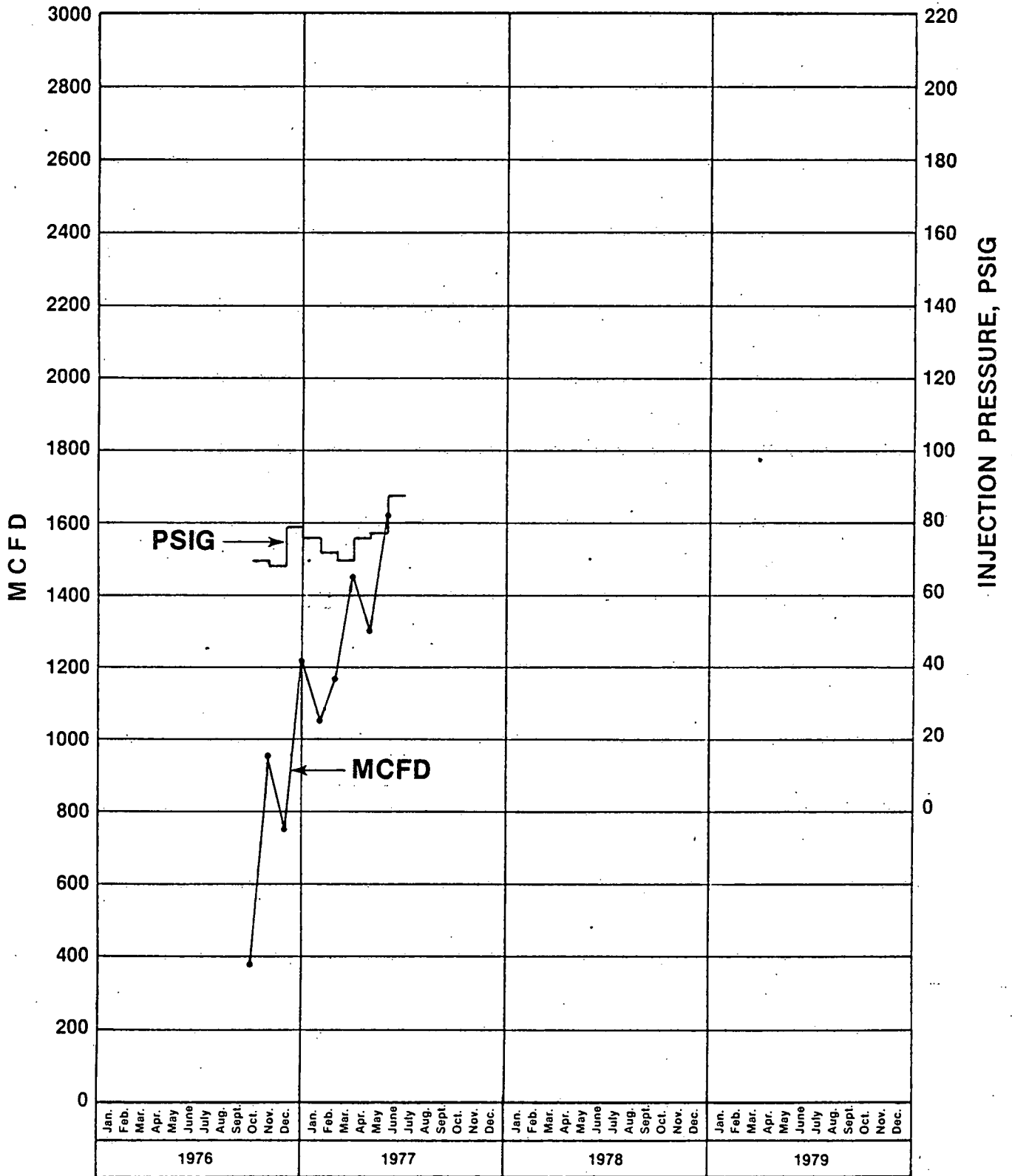


FIGURE 34

PRODUCING WELL NO. 2-3 PERFORMANCE

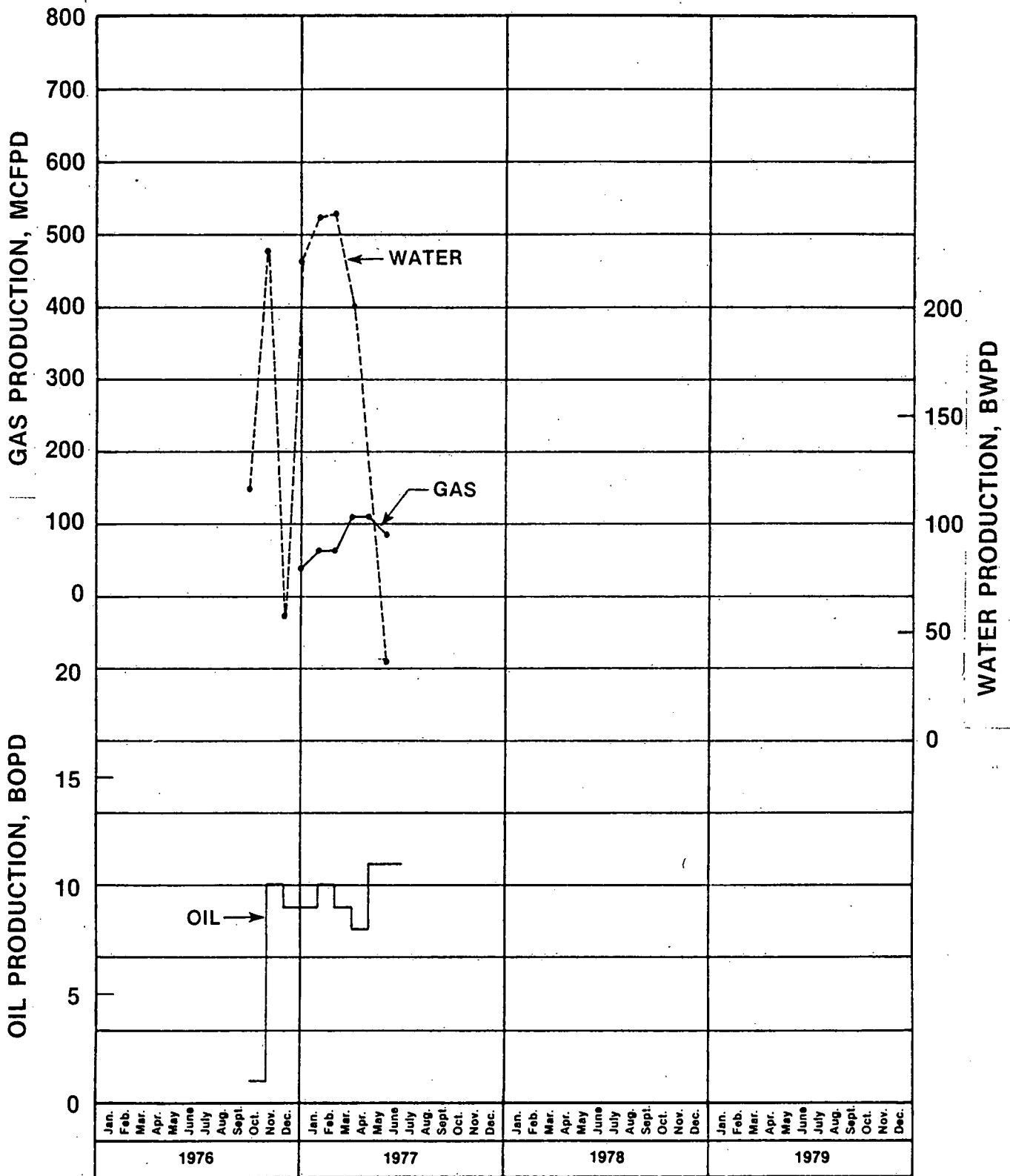


FIGURE 35

PRODUCING WELL NO. 2-4 PERFORMANCE

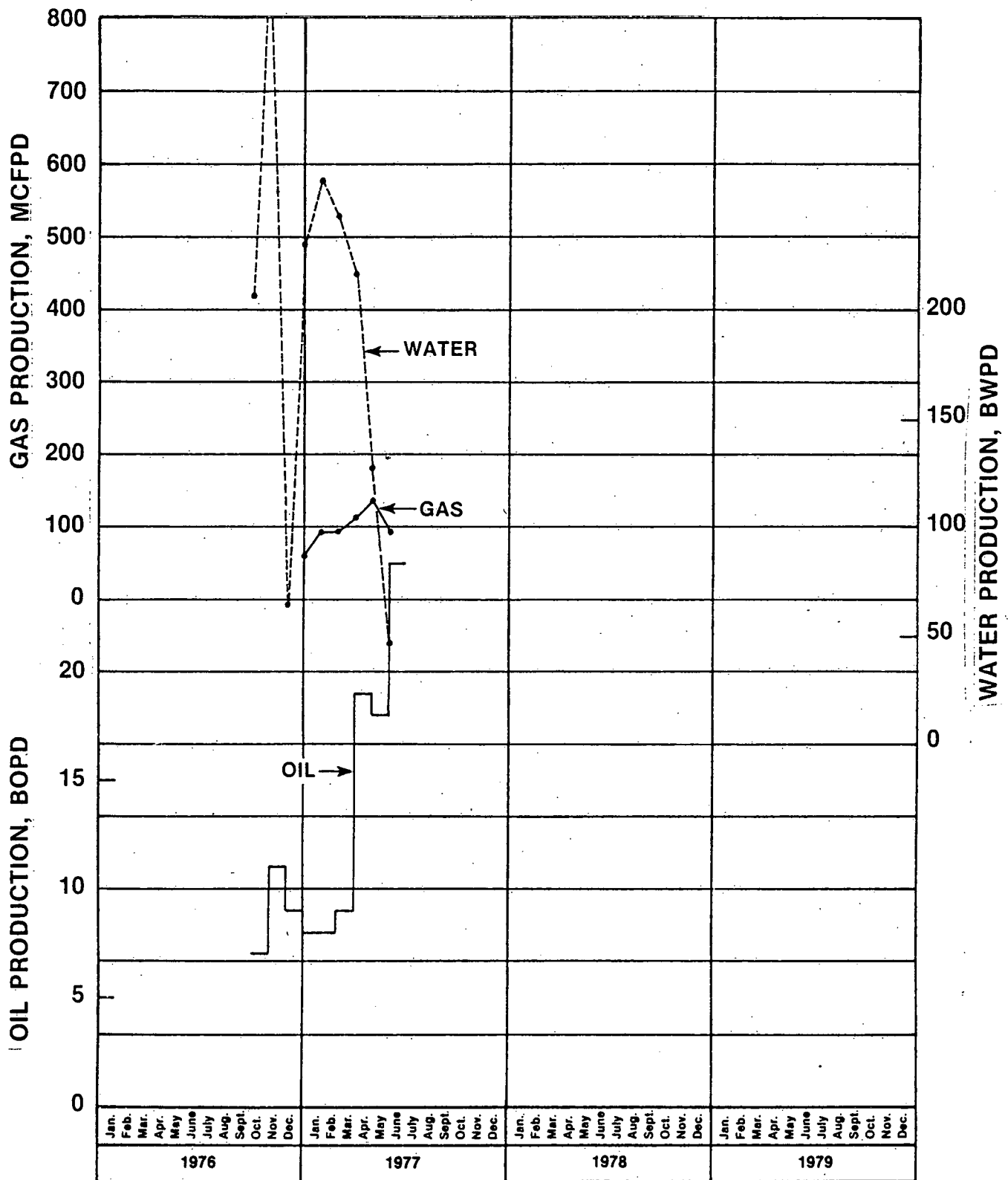


FIGURE 36

PRODUCING WELL NO. 2-5 PERFORMANCE

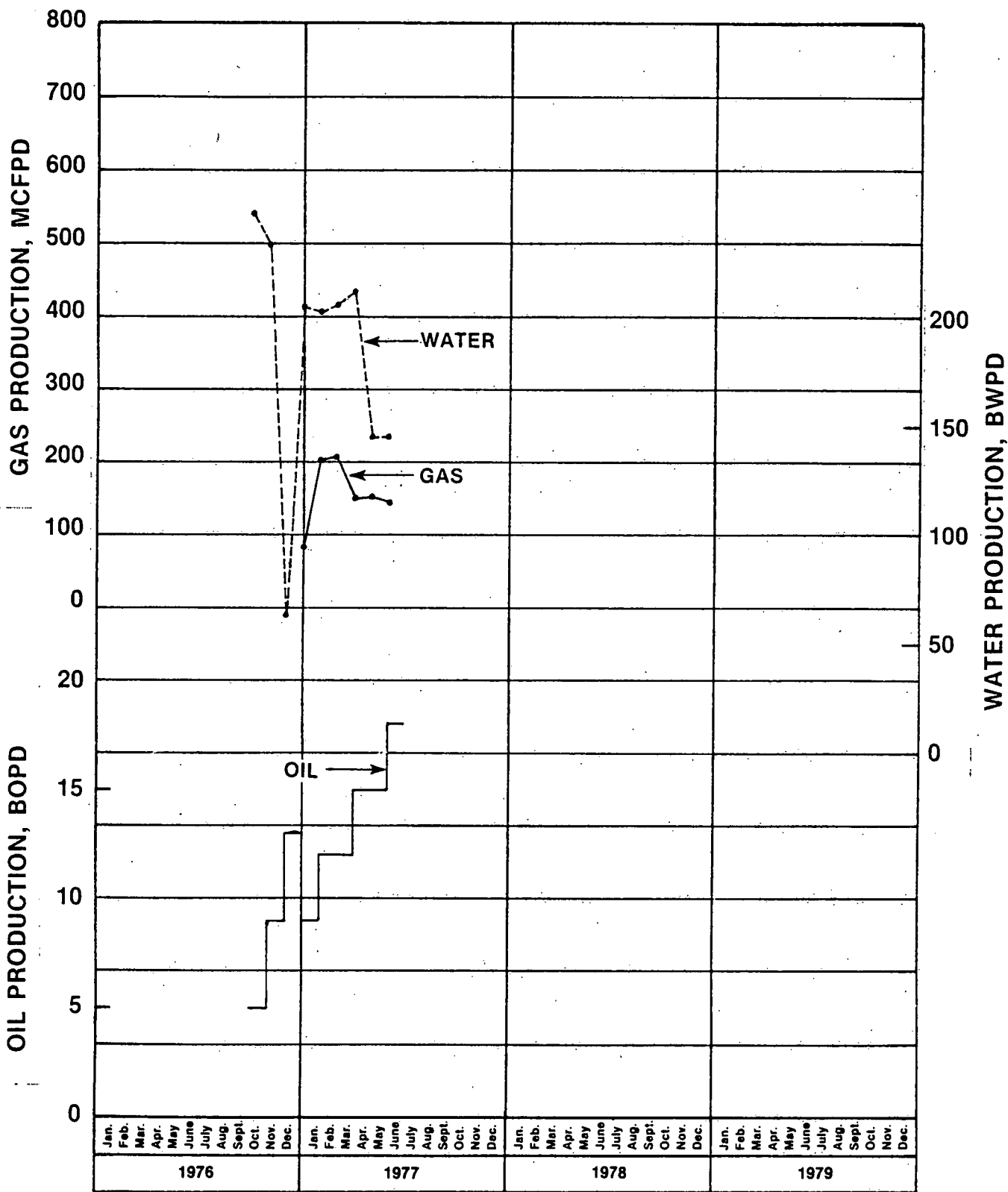


FIGURE 37

PRODUCING WELL NO. 2-8 PERFORMANCE

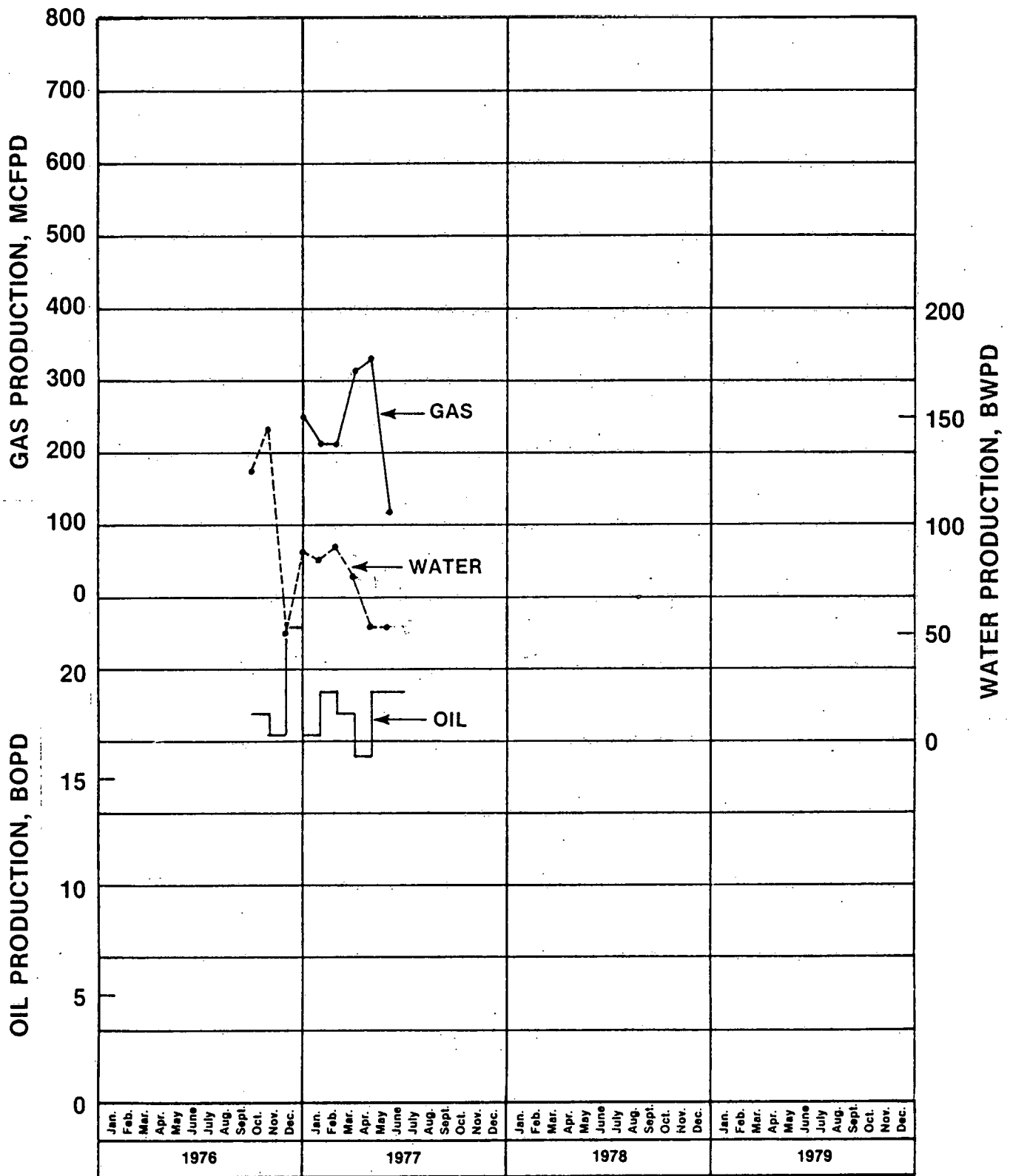


FIGURE 38

PRODUCING WELL NO. 12-2 PERFORMANCE

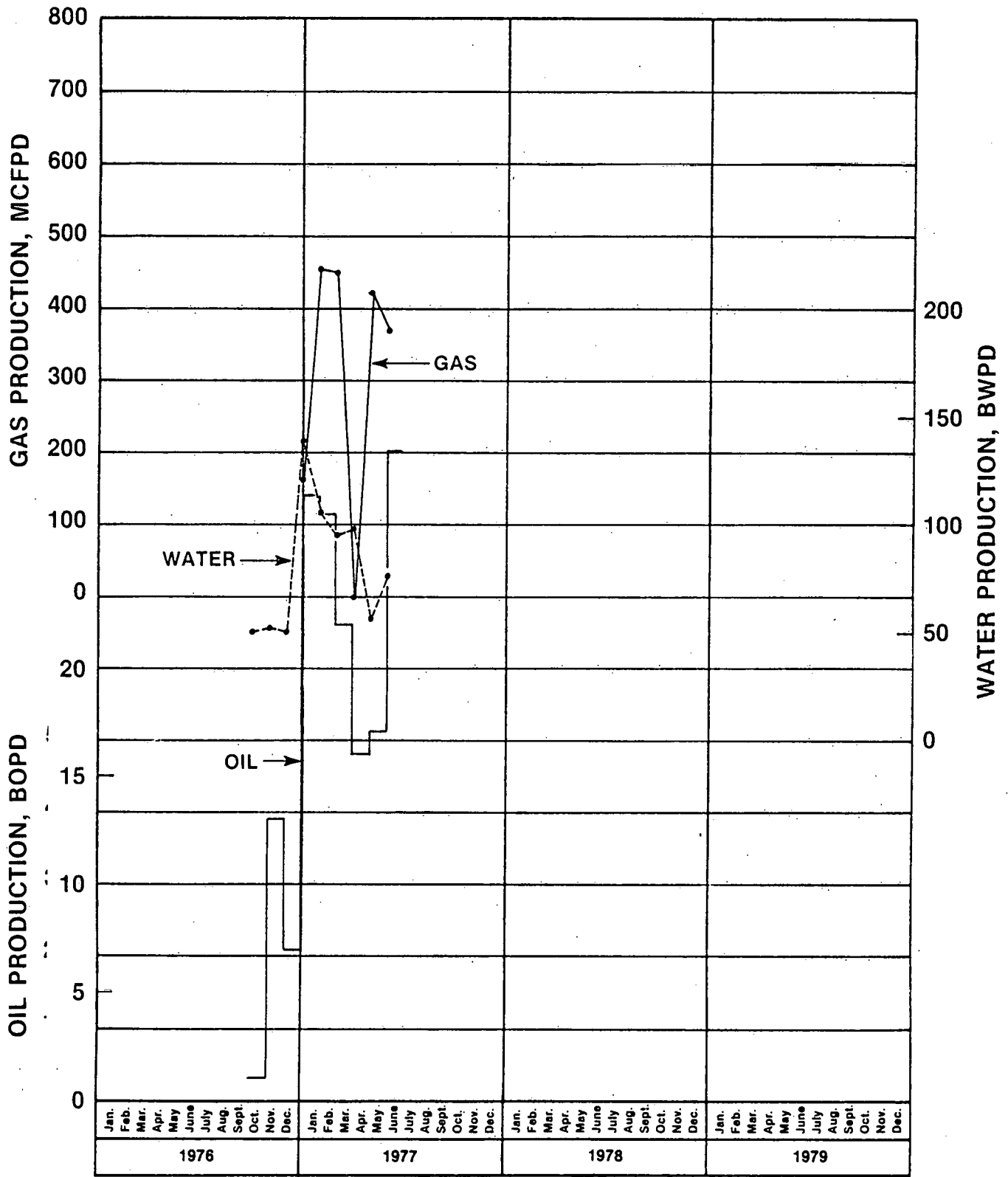


FIGURE 39

PRODUCING WELL NO. 12-3 PERFORMANCE

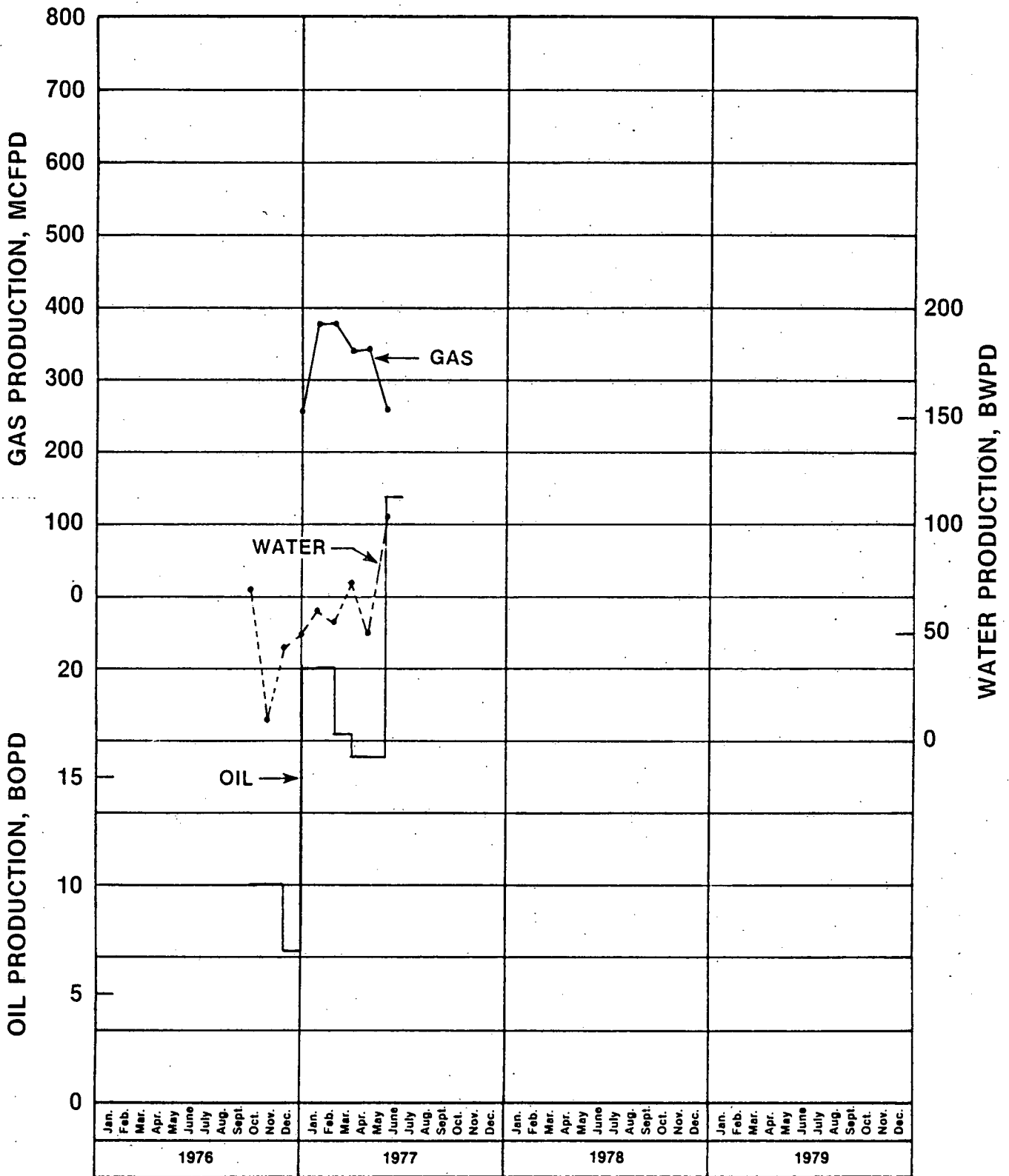


FIGURE 40

PRODUCING WELL NO. 12-4 PERFORMANCE

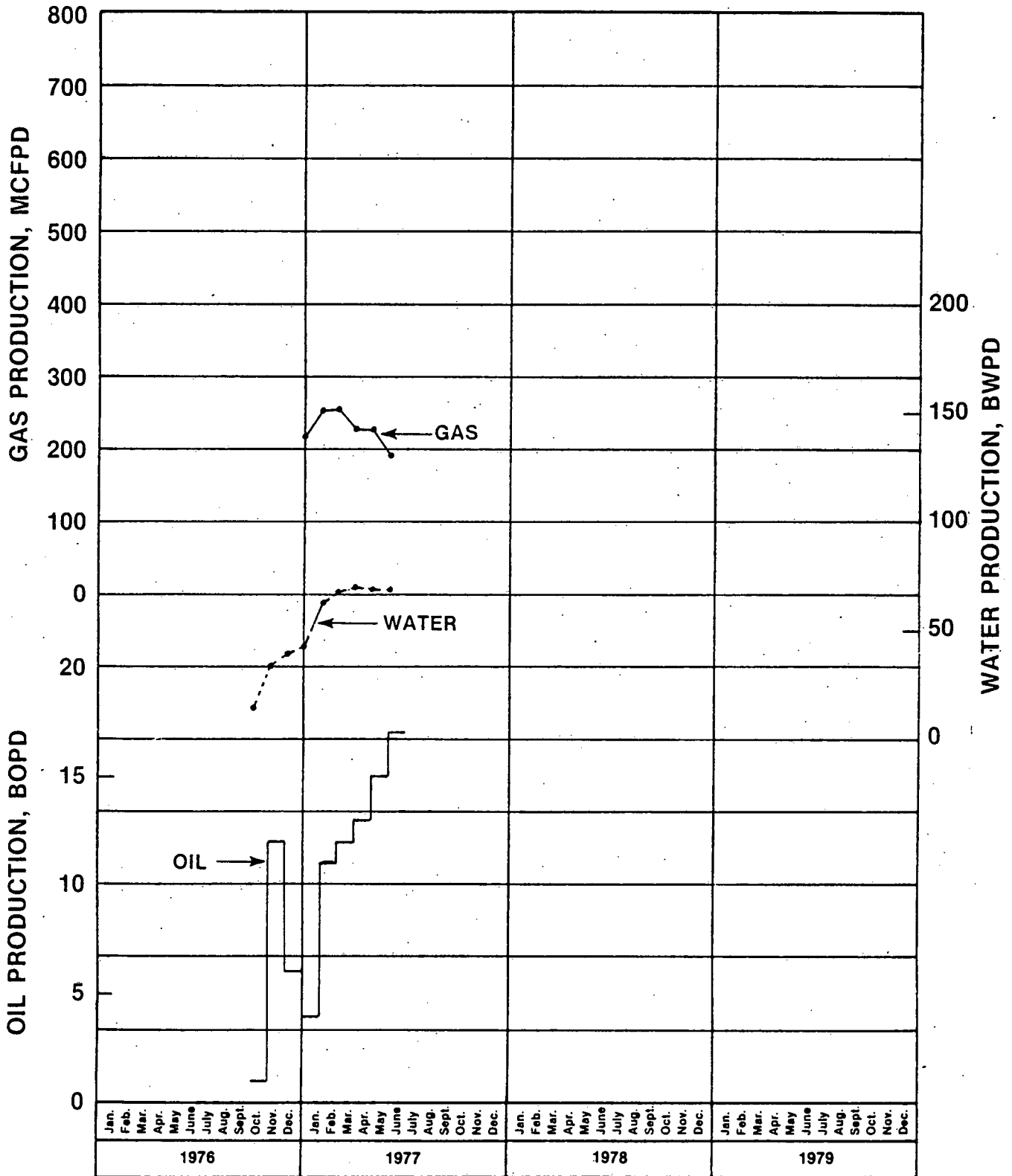


FIGURE 41

PRODUCING WELL NO. 12-5 PERFORMANCE

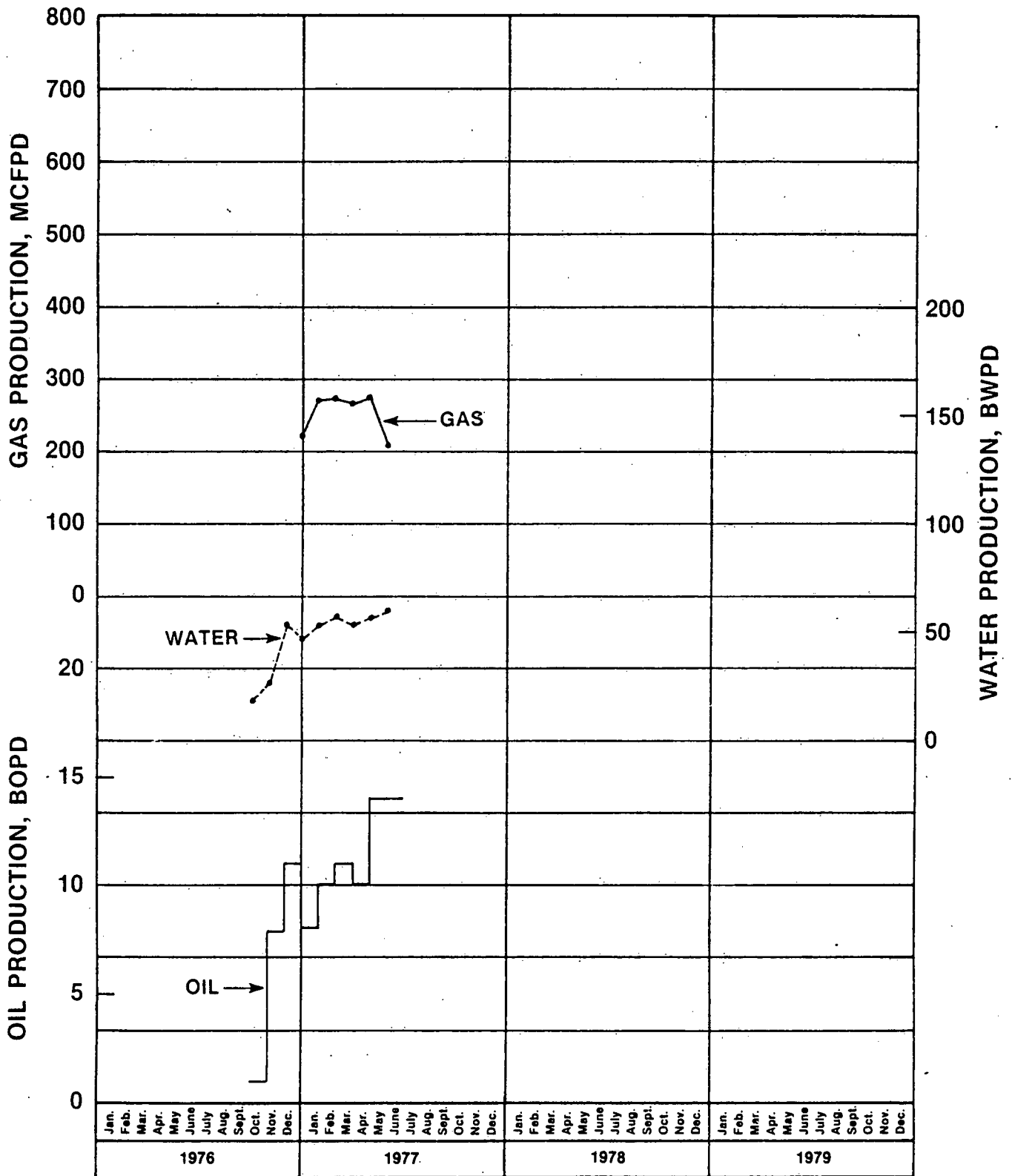


FIGURE 42

PRODUCING WELL NO. 12-6 PERFORMANCE

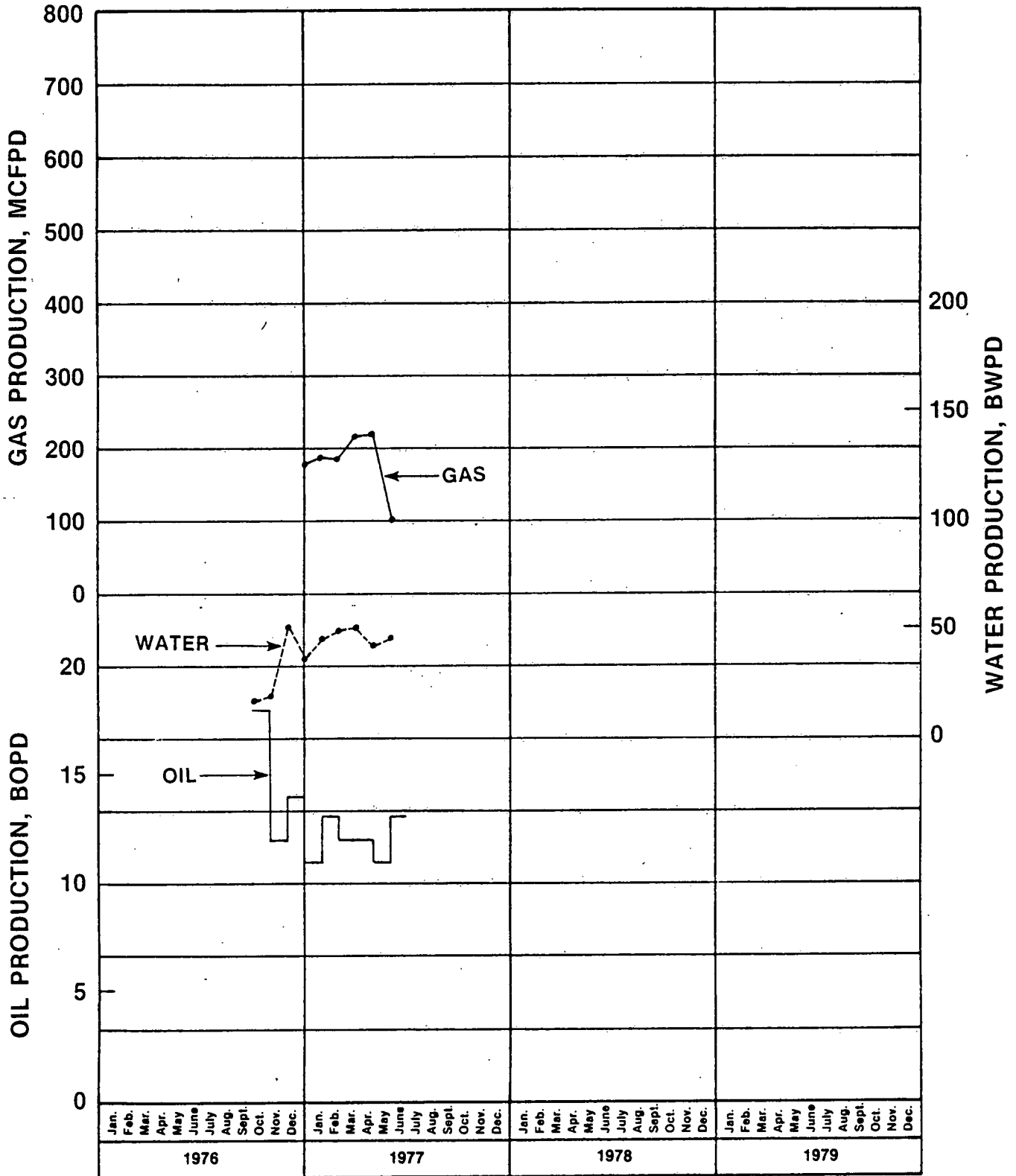


FIGURE 43

PRODUCING WELL NO. 13-2 PERFORMANCE

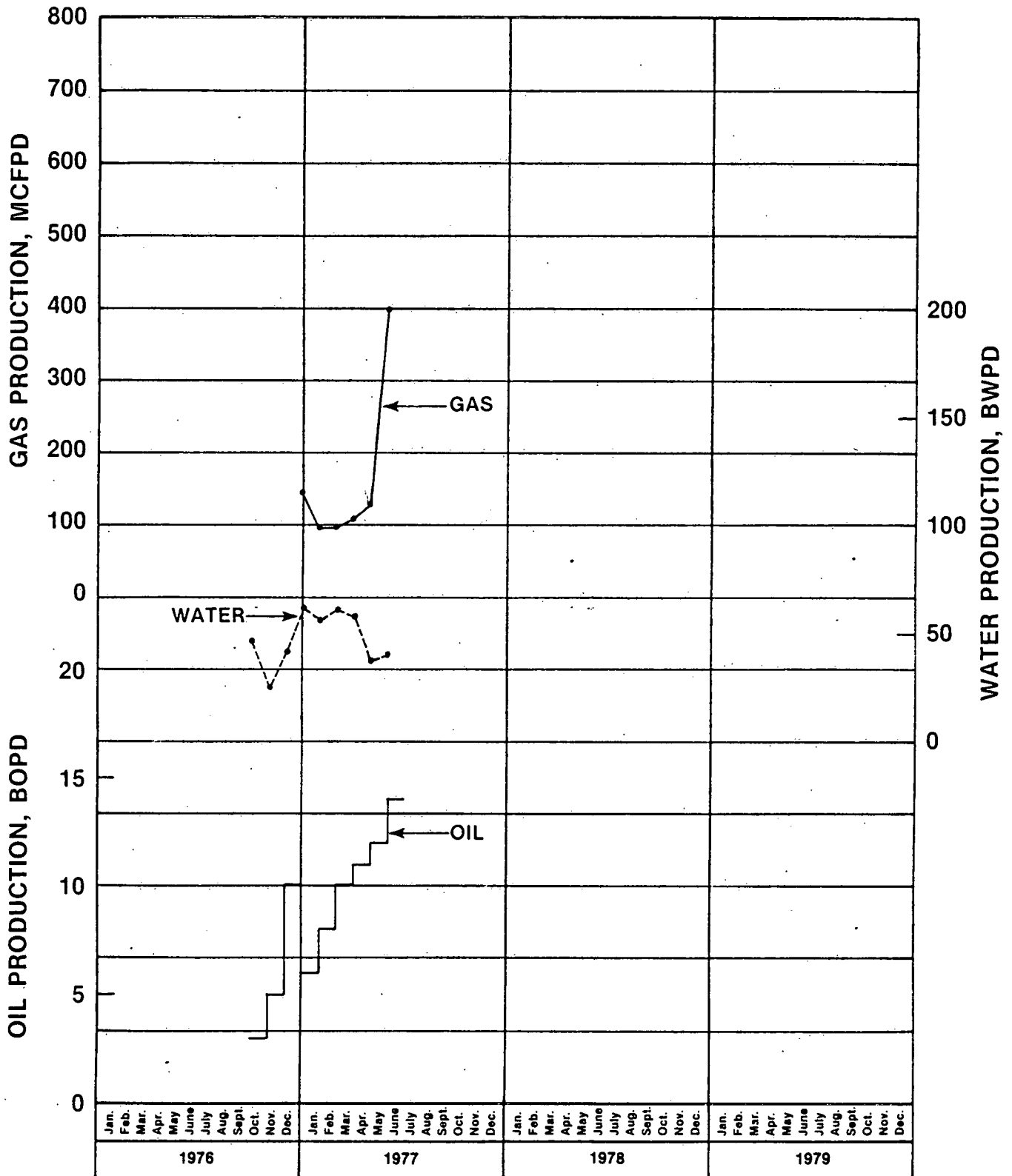


FIGURE 44

PRODUCING WELL NO. 13-3 PERFORMANCE

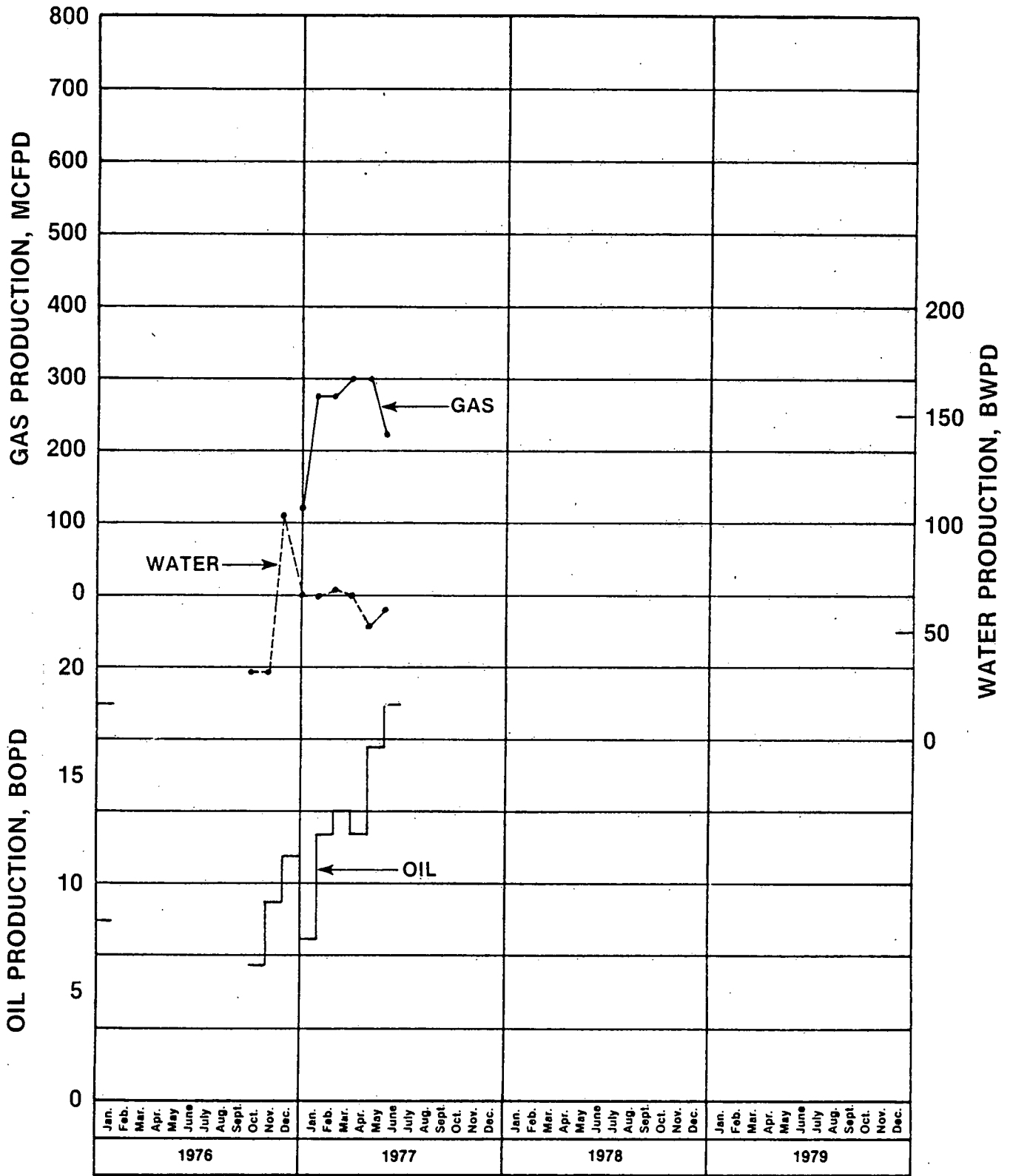


FIGURE 45

PRODUCING WELL NO. 13-4 PERFORMANCE

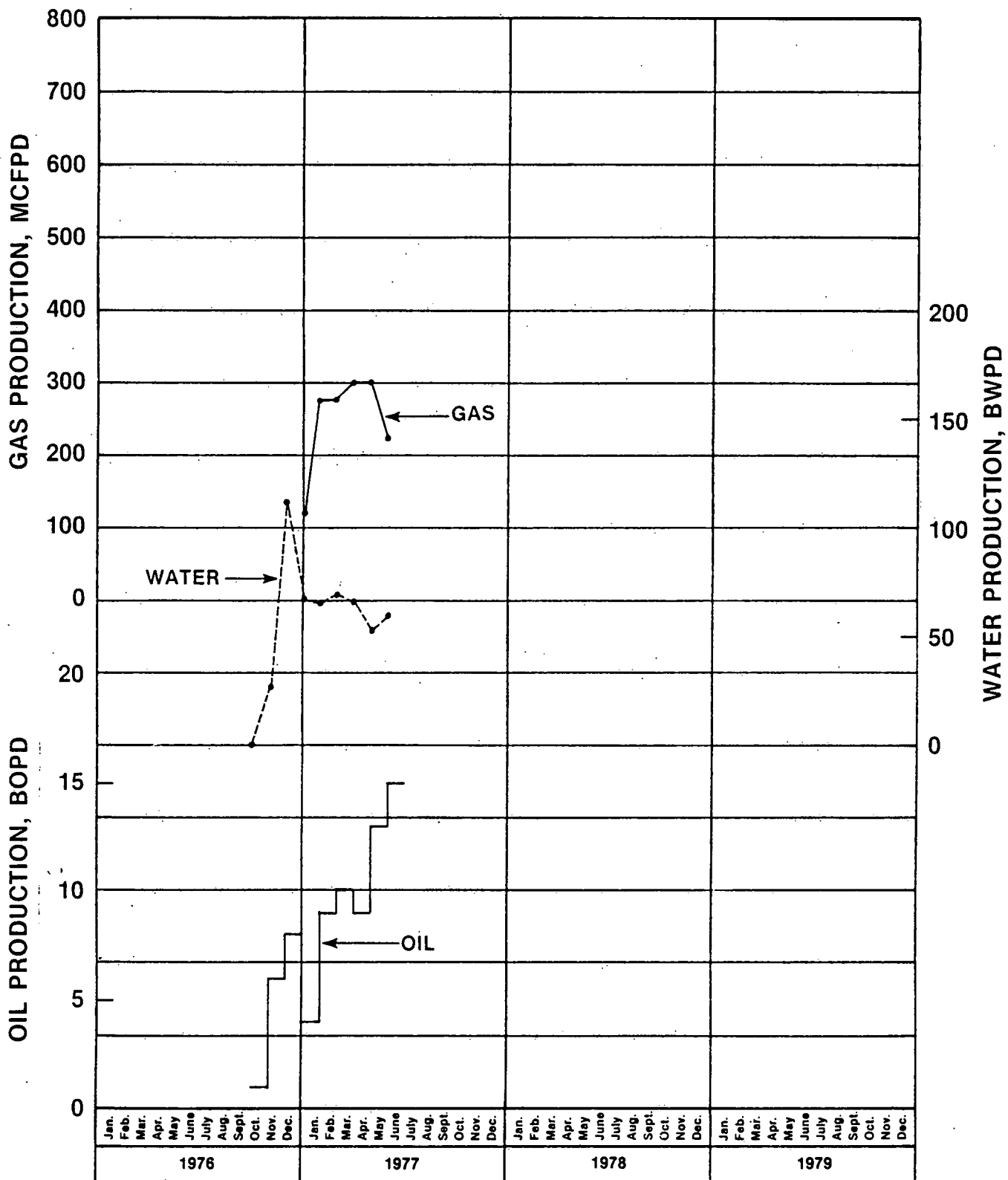


FIGURE 46

PRODUCING WELL NO. 13-5 PERFORMANCE

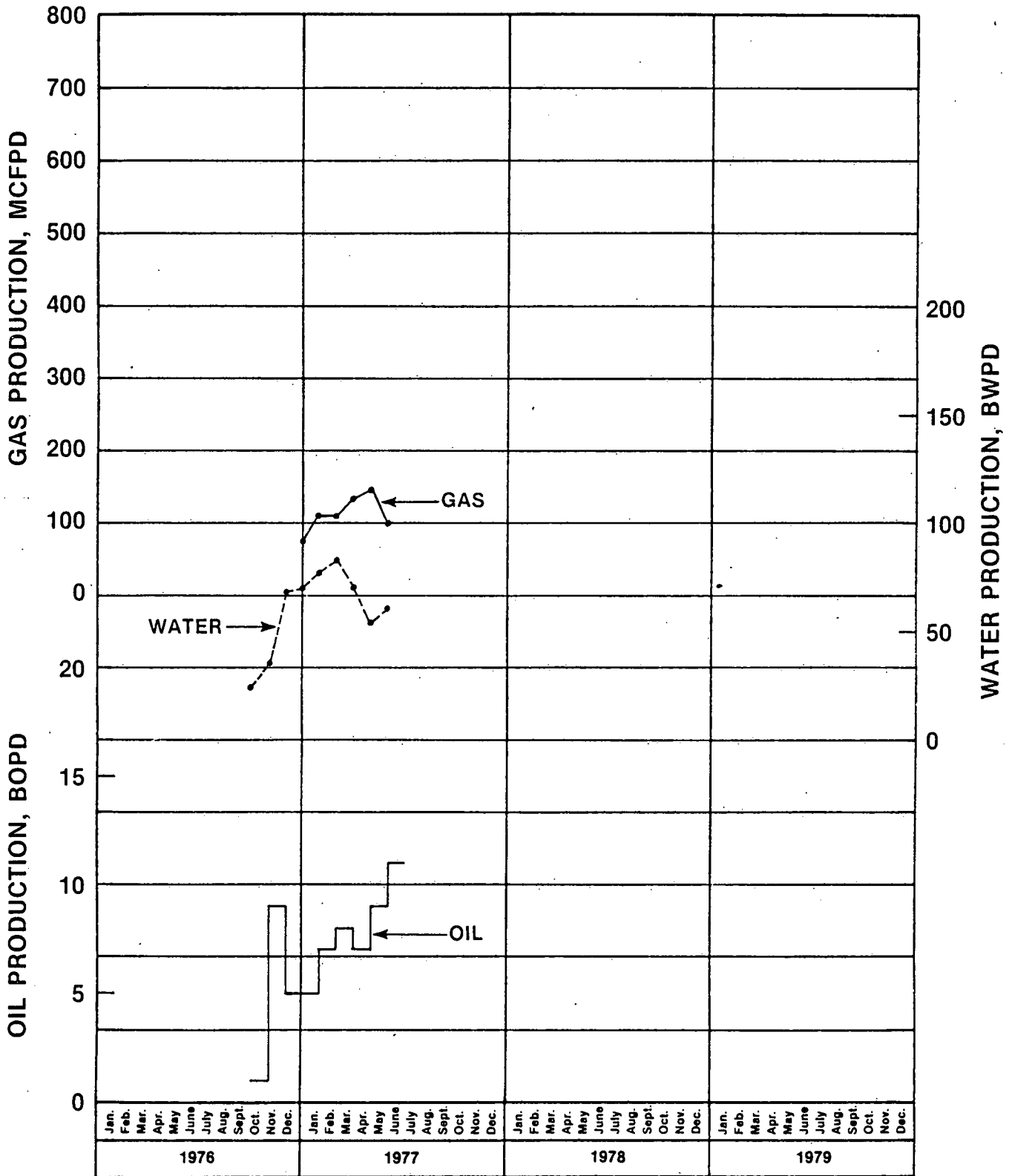


FIGURE 47

PRODUCING WELL NO. 13-6 PERFORMANCE

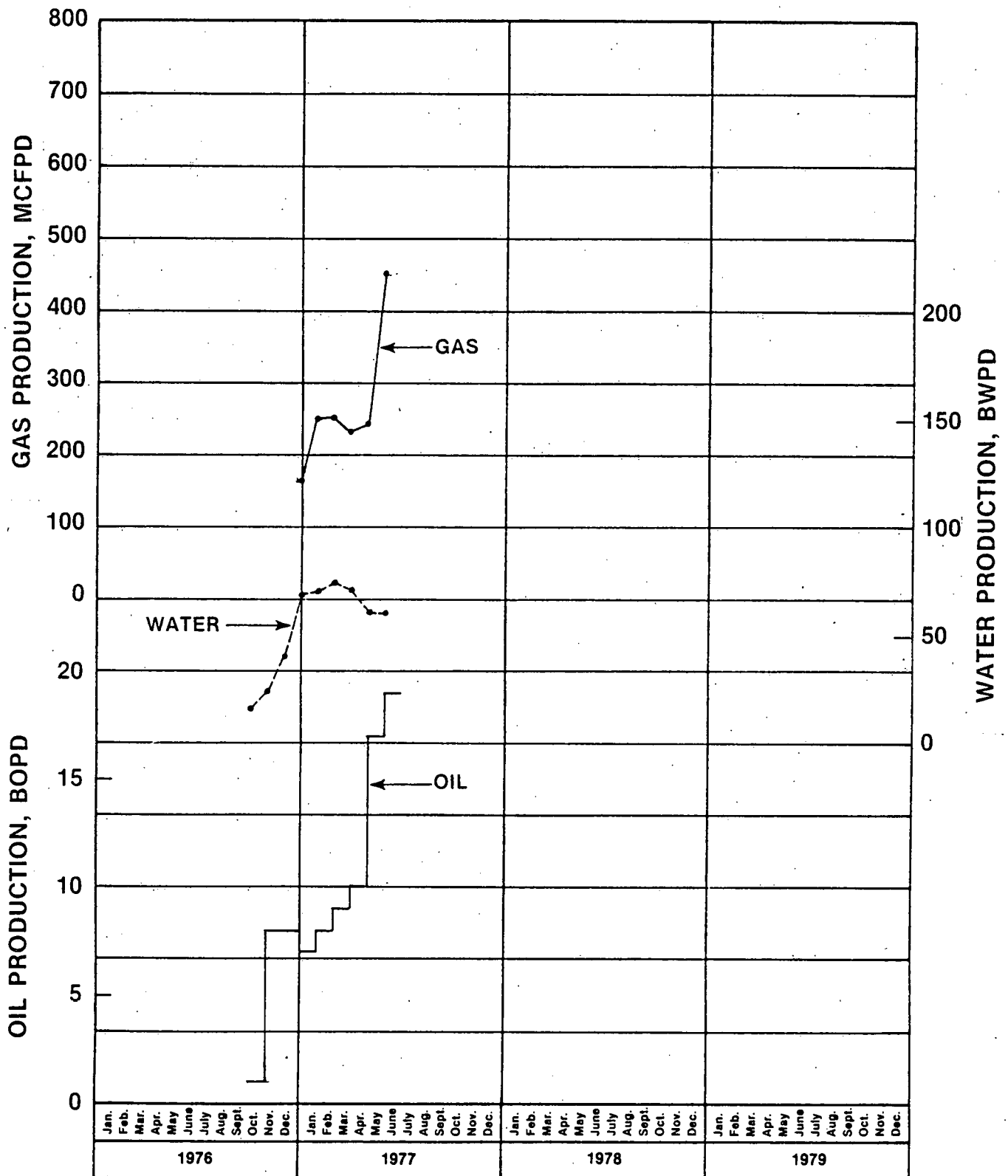


FIGURE 48

PRODUCING WELL NO. 14-2 PERFORMANCE

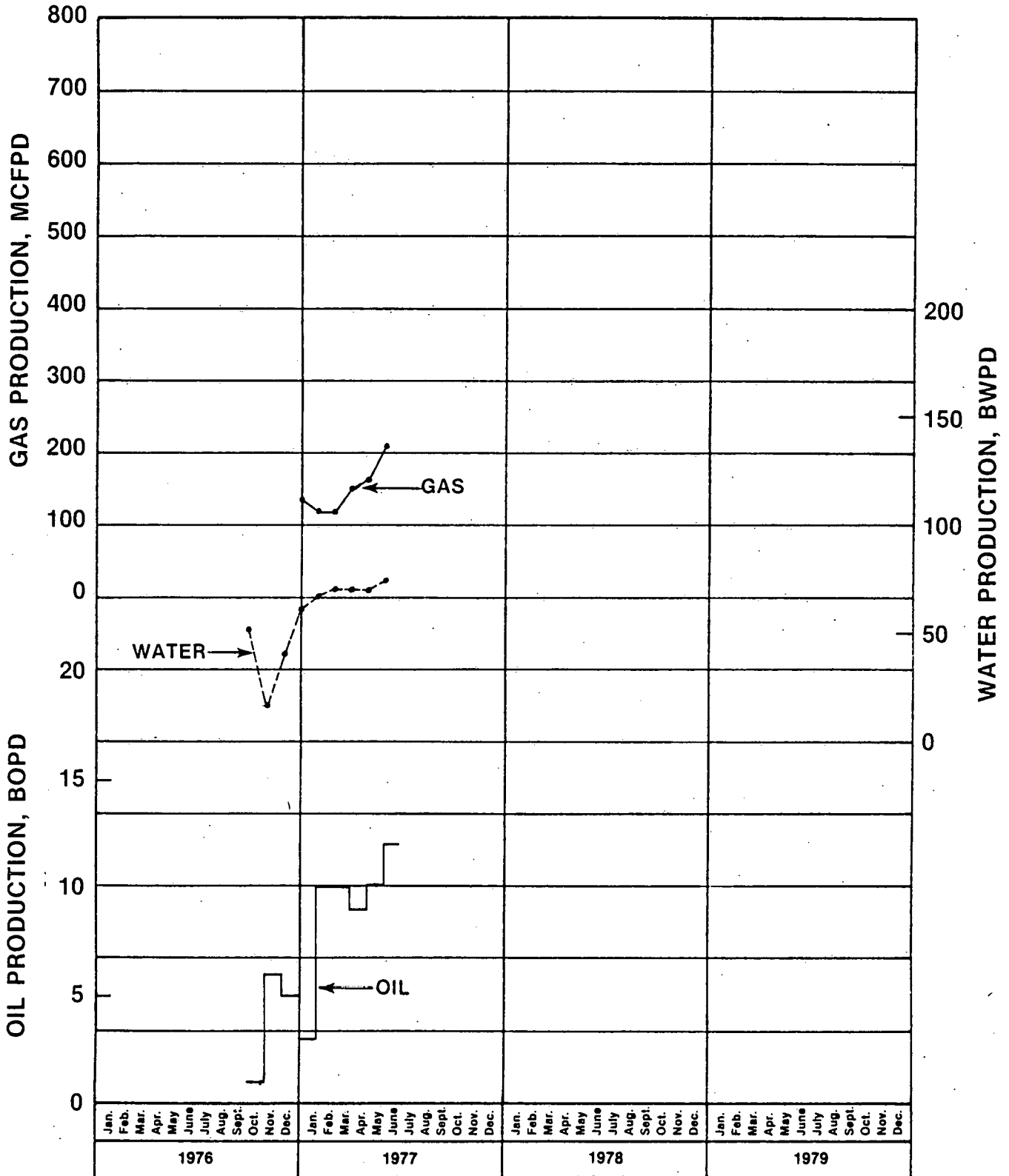


FIGURE 49

PRODUCING WELL NO. 14-3 PERFORMANCE

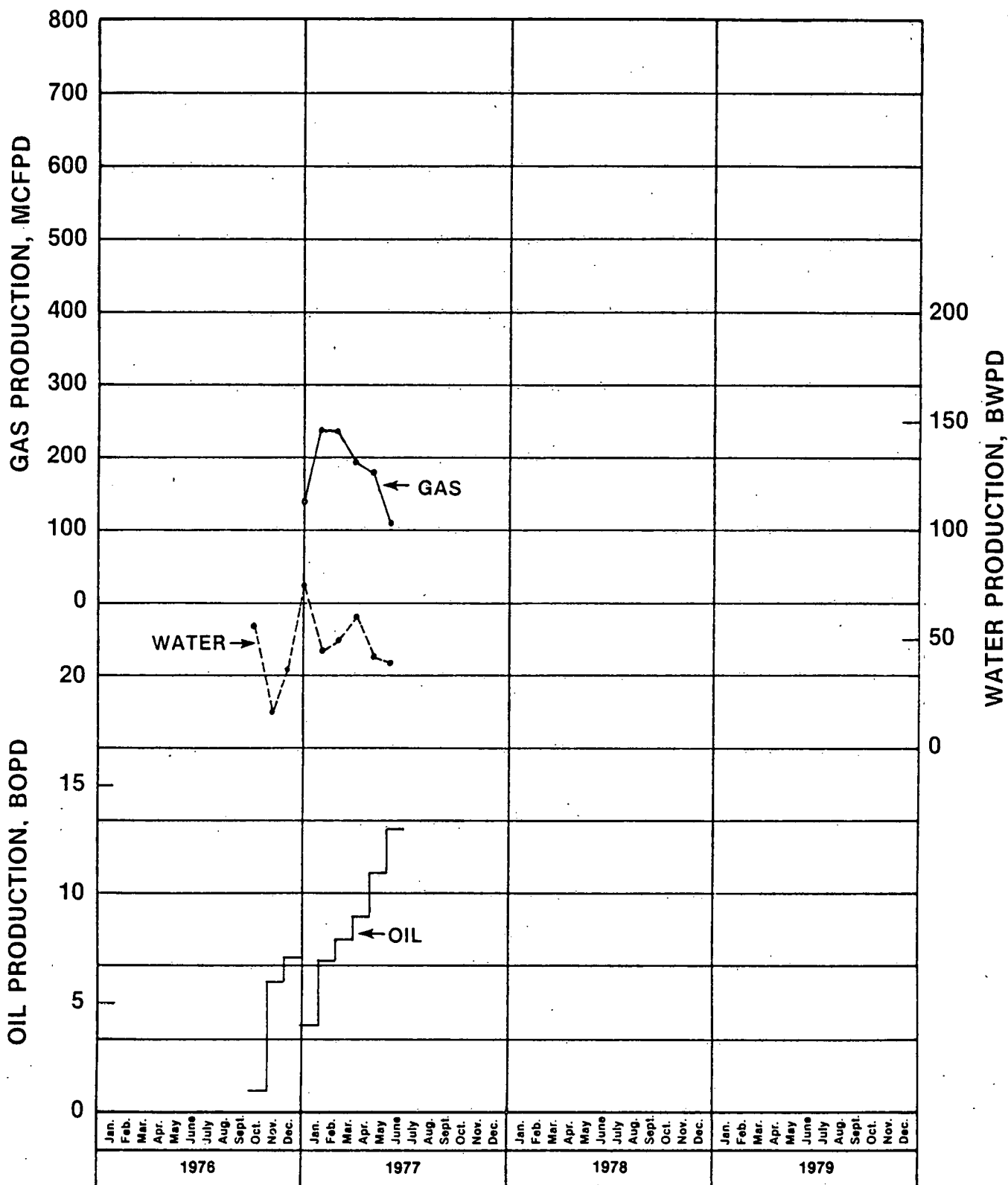


FIGURE 50

PRODUCING WELL NO. 14-4 PERFORMANCE

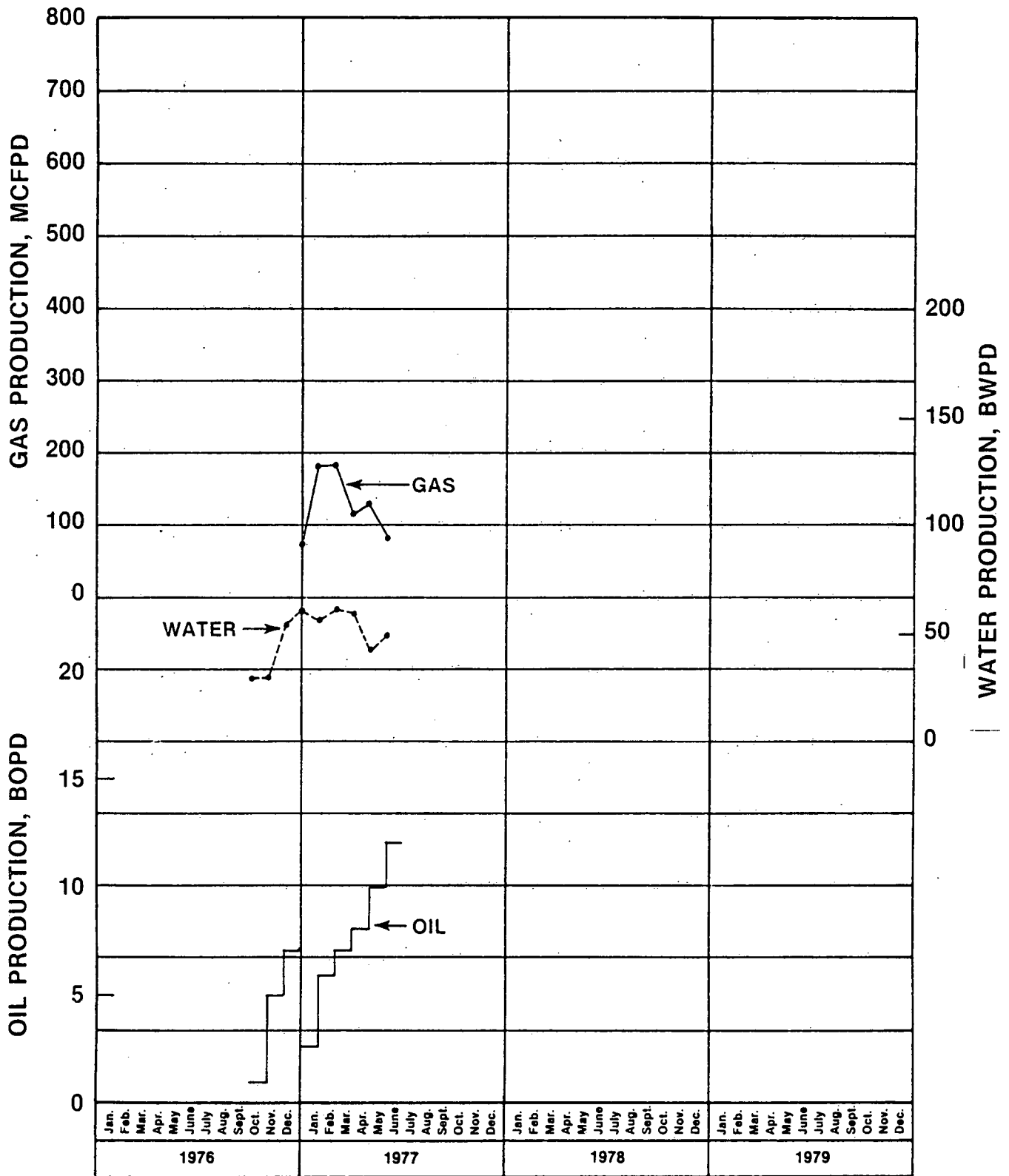


FIGURE 51

PRODUCING WELL NO. 14-5 PERFORMANCE

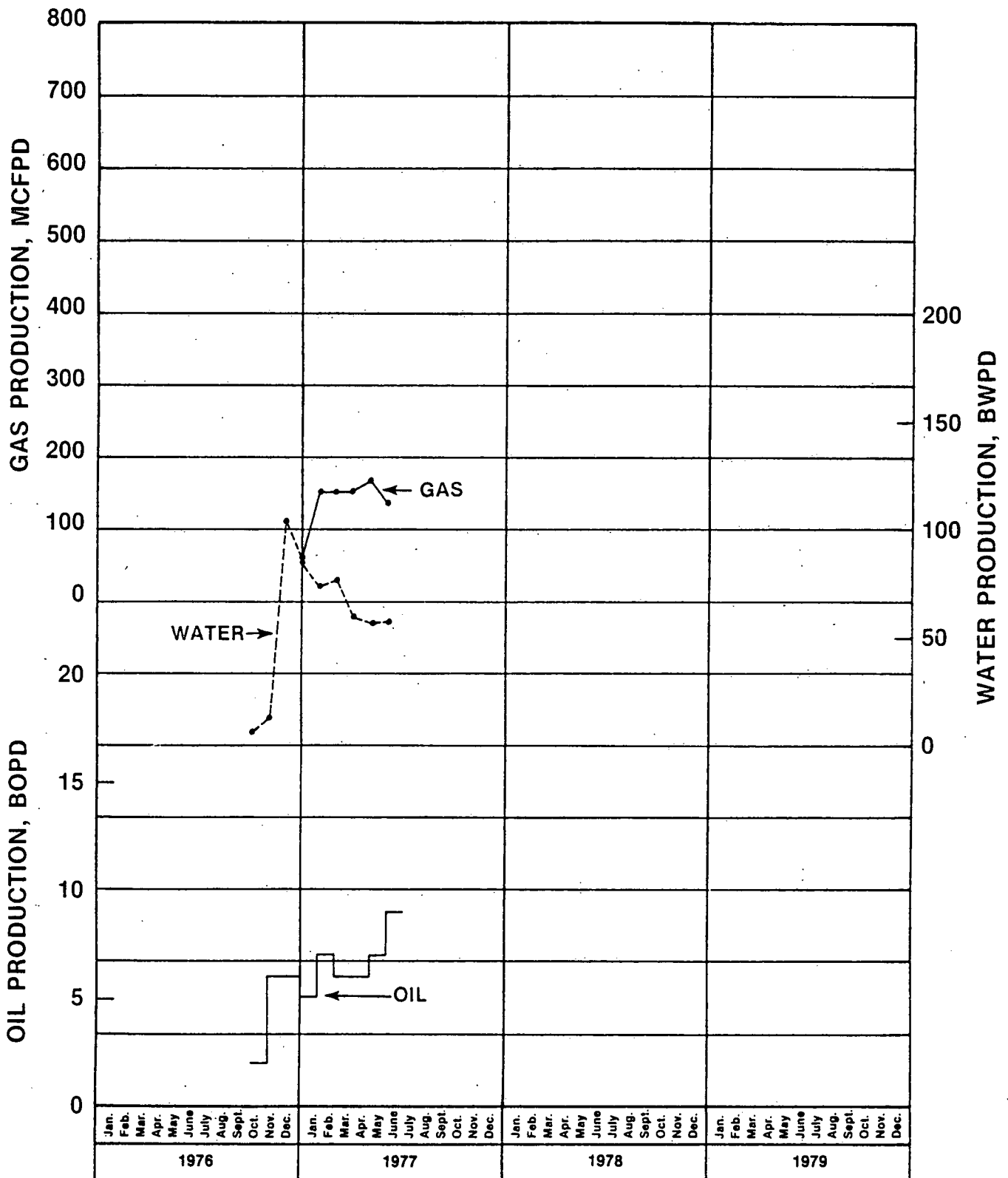


FIGURE 52

PRODUCING WELL NO. 14-6 PERFORMANCE

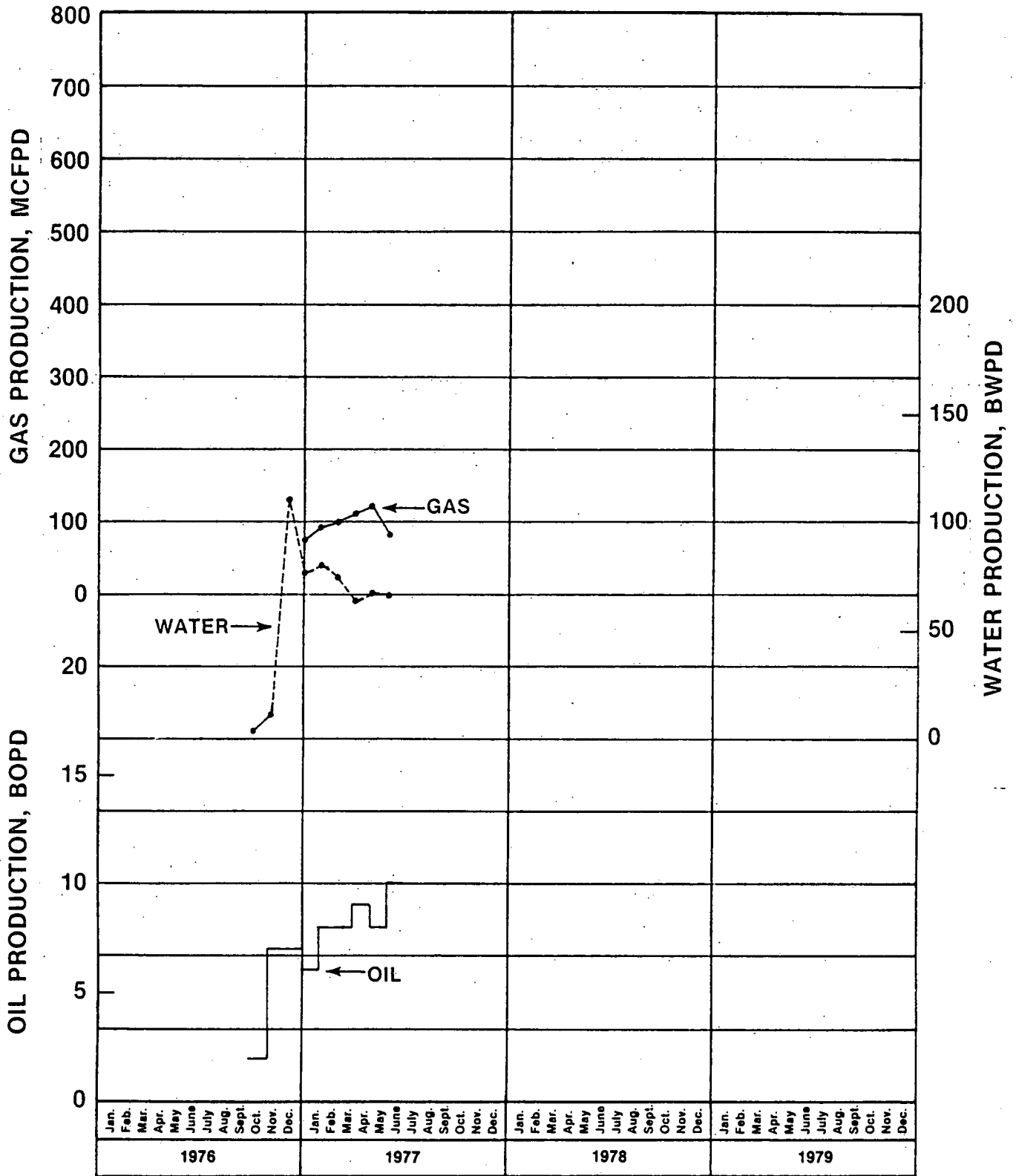


FIGURE 53

PRODUCING WELL NO. 15-2 PERFORMANCE

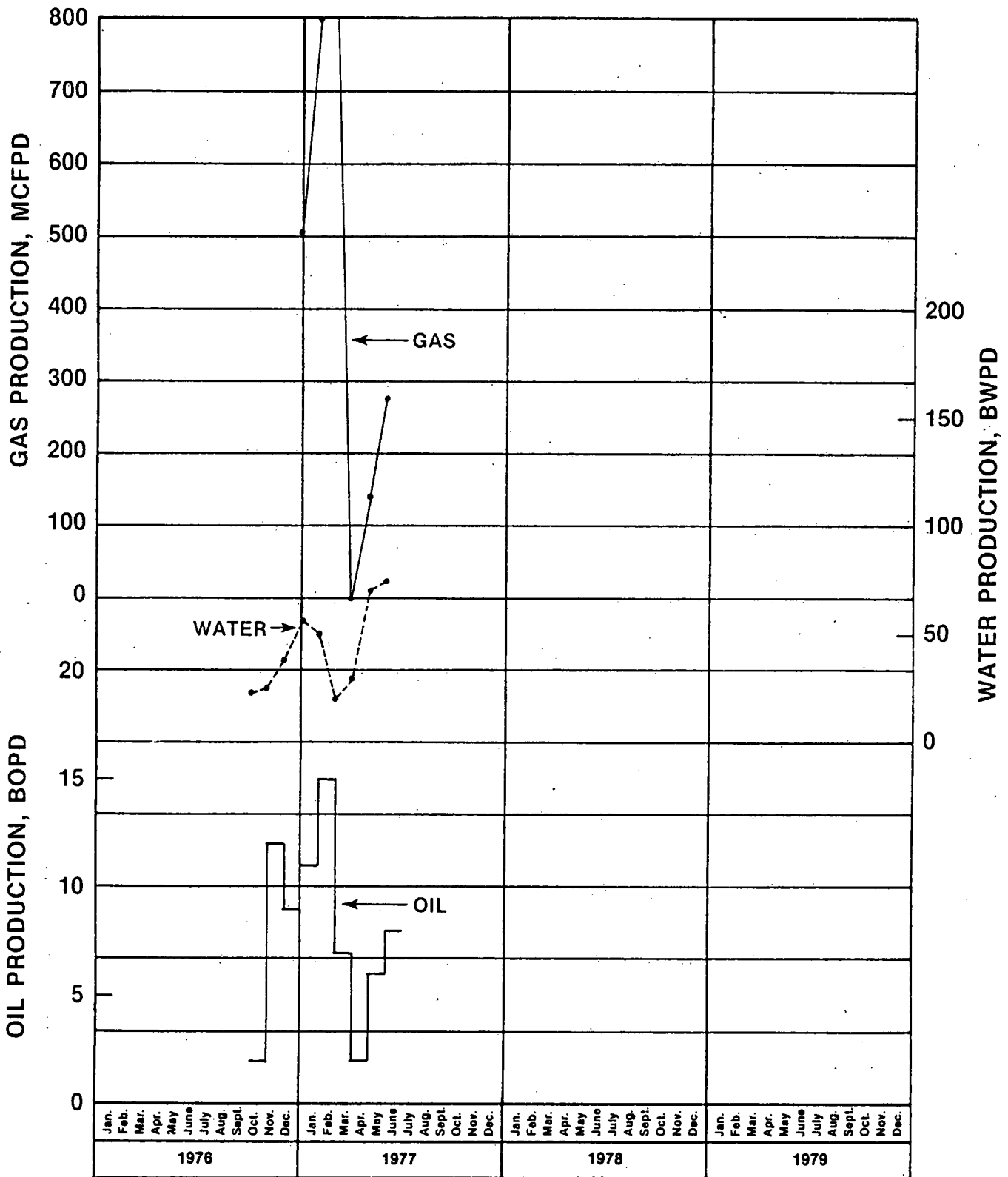


FIGURE 54

PRODUCING WELL NO. 15-3 PERFORMANCE

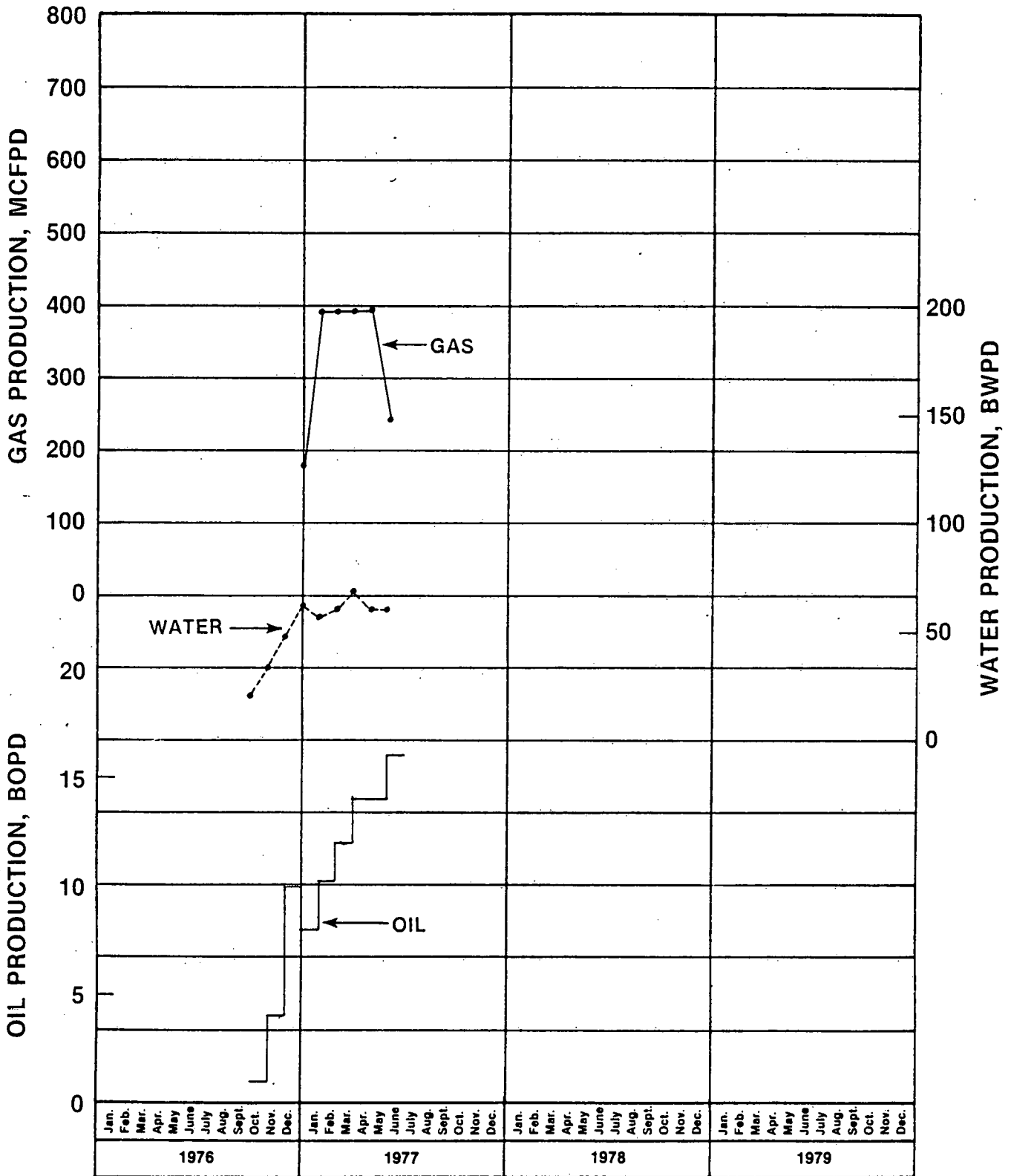


FIGURE 55

PRODUCING WELL NO. 15-4 PERFORMANCE

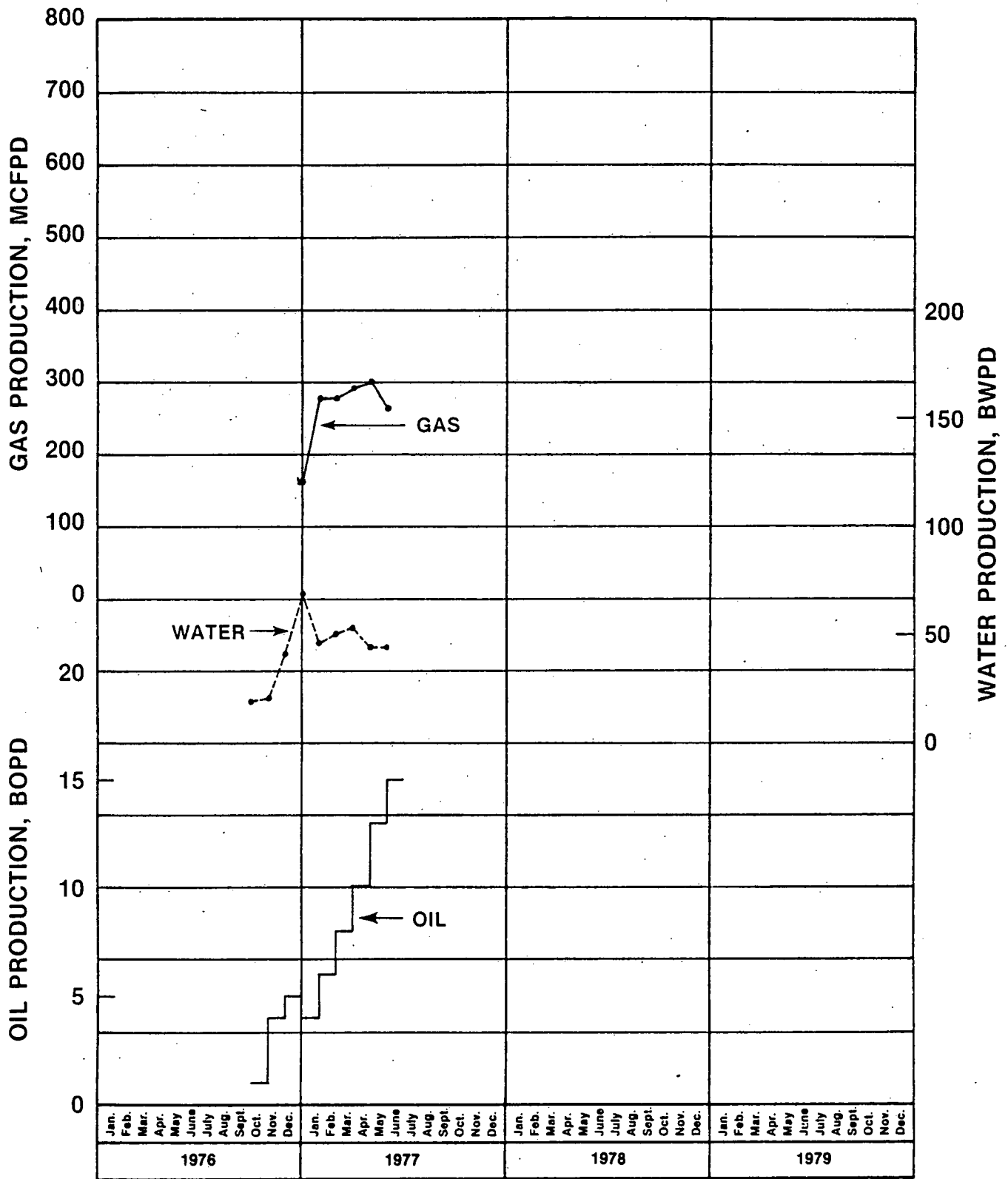


FIGURE 56

PRODUCING WELL NO. 15-5 PERFORMANCE

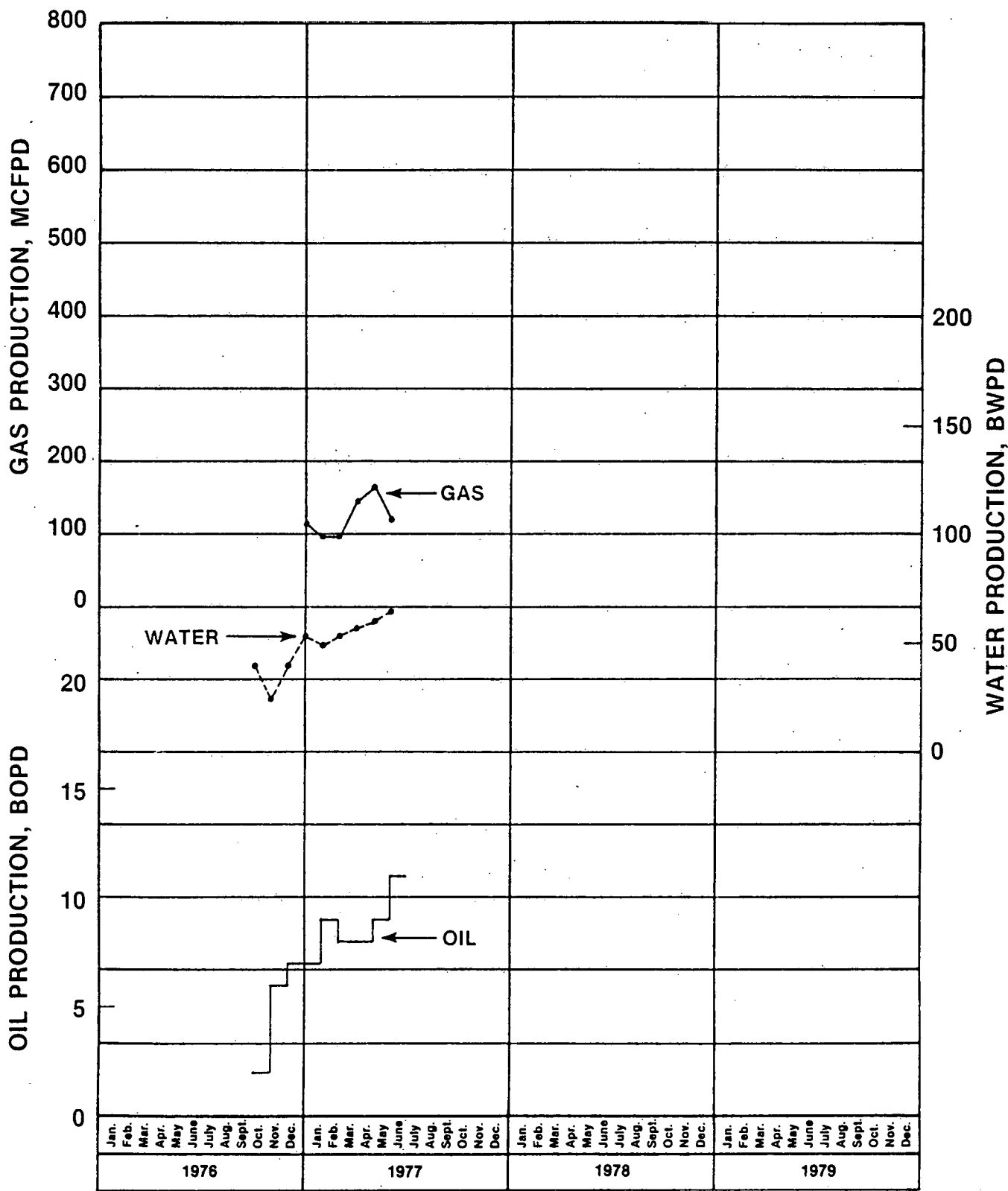


FIGURE 57

PRODUCING WELL NO. 15-6 PERFORMANCE

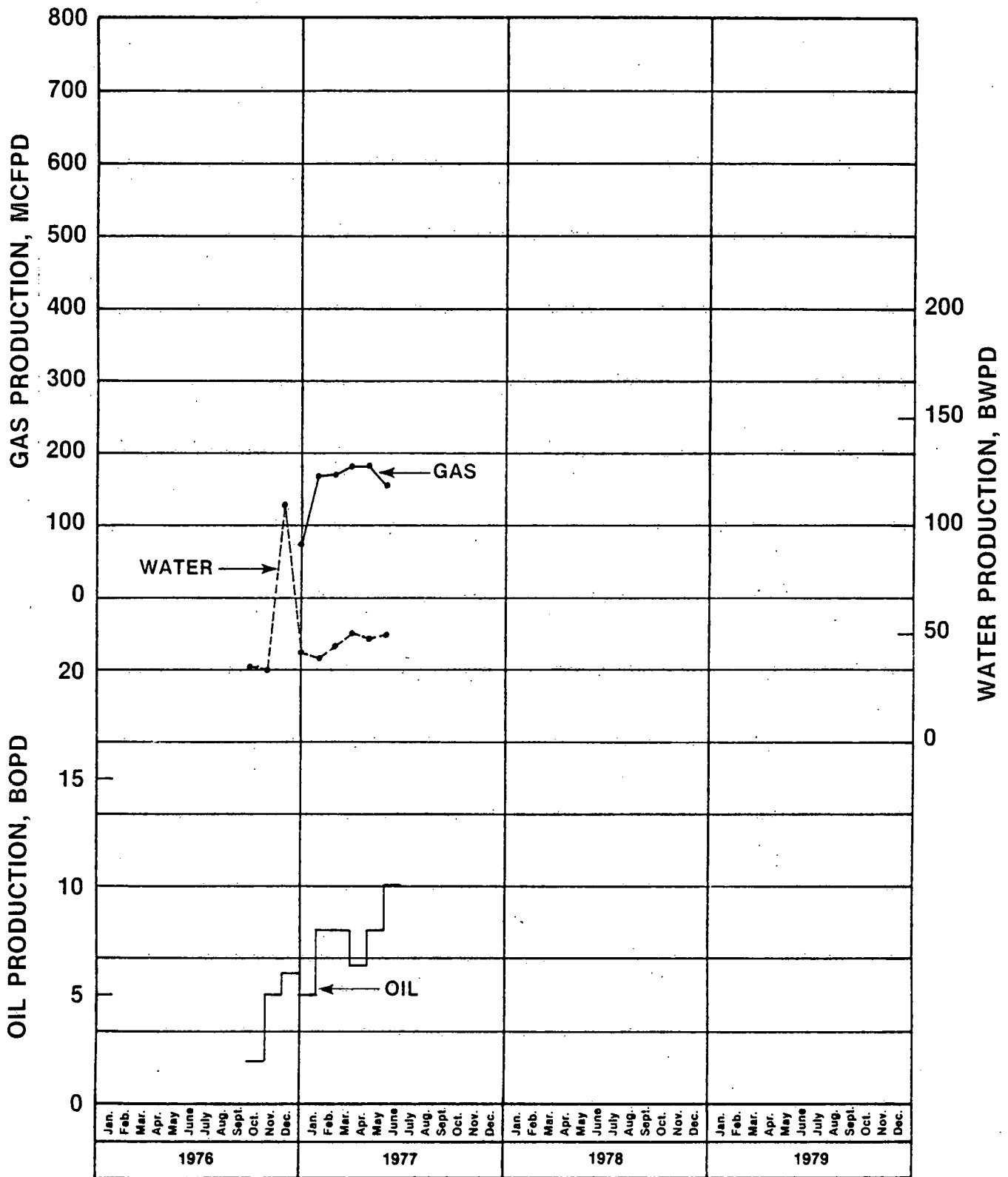


FIGURE 58

PRODUCING WELL NO. 16-2 PERFORMANCE

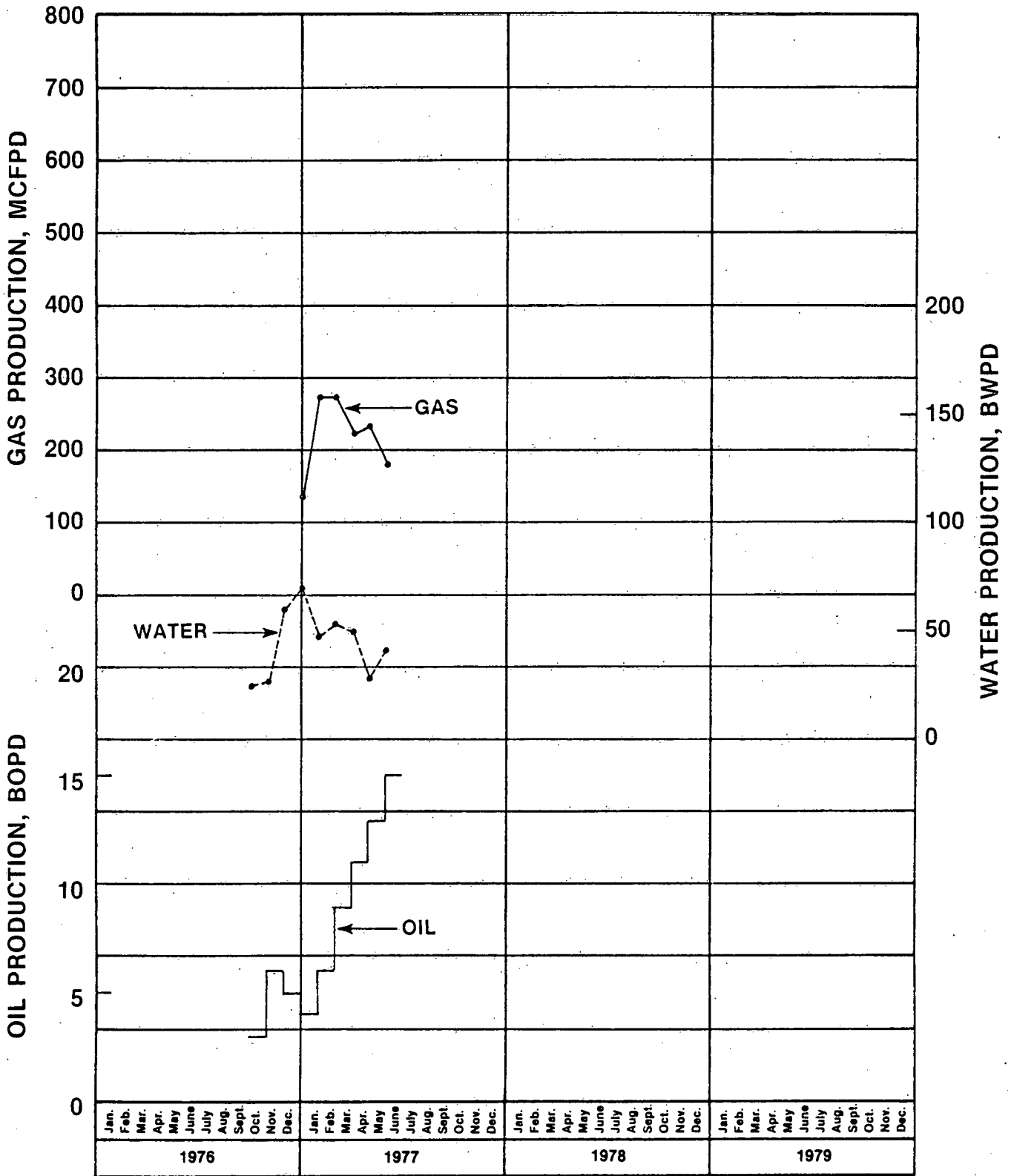


FIGURE 59

PRODUCING WELL NO. 16-3 PERFORMANCE

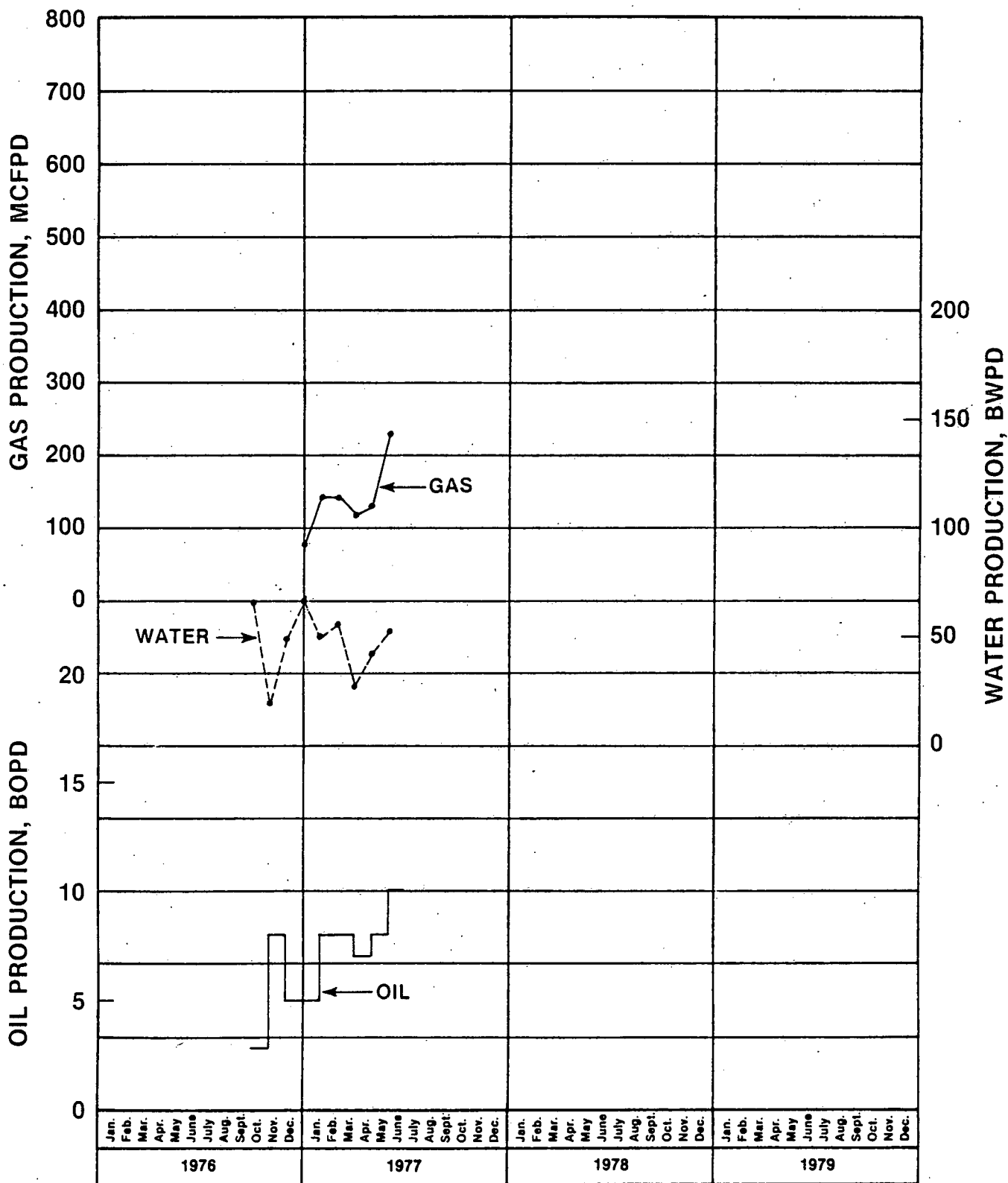


FIGURE 60

PRODUCING WELL NO. 16-4 PERFORMANCE

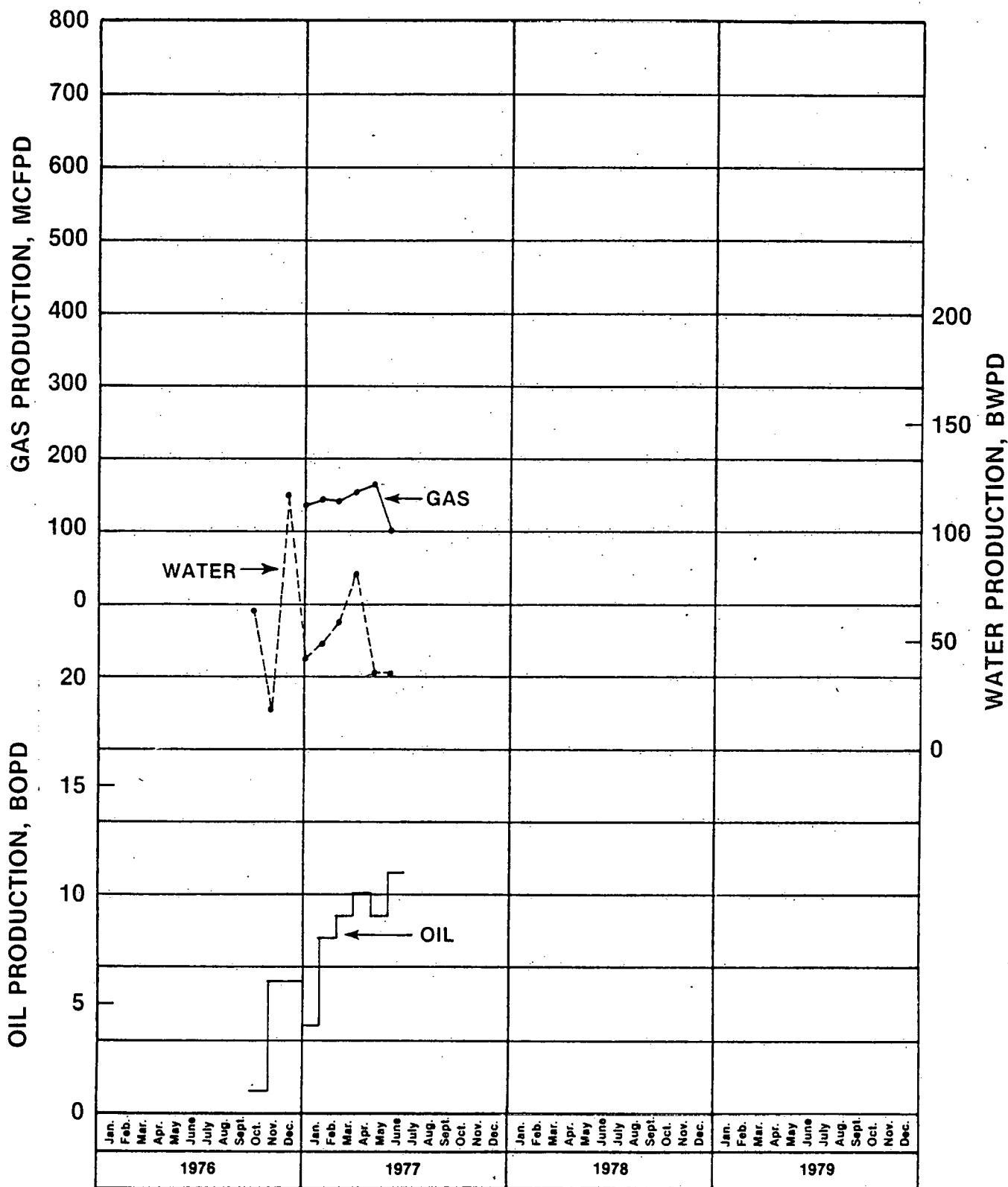


FIGURE 61

PRODUCING WELL NO. 16-5 PERFORMANCE

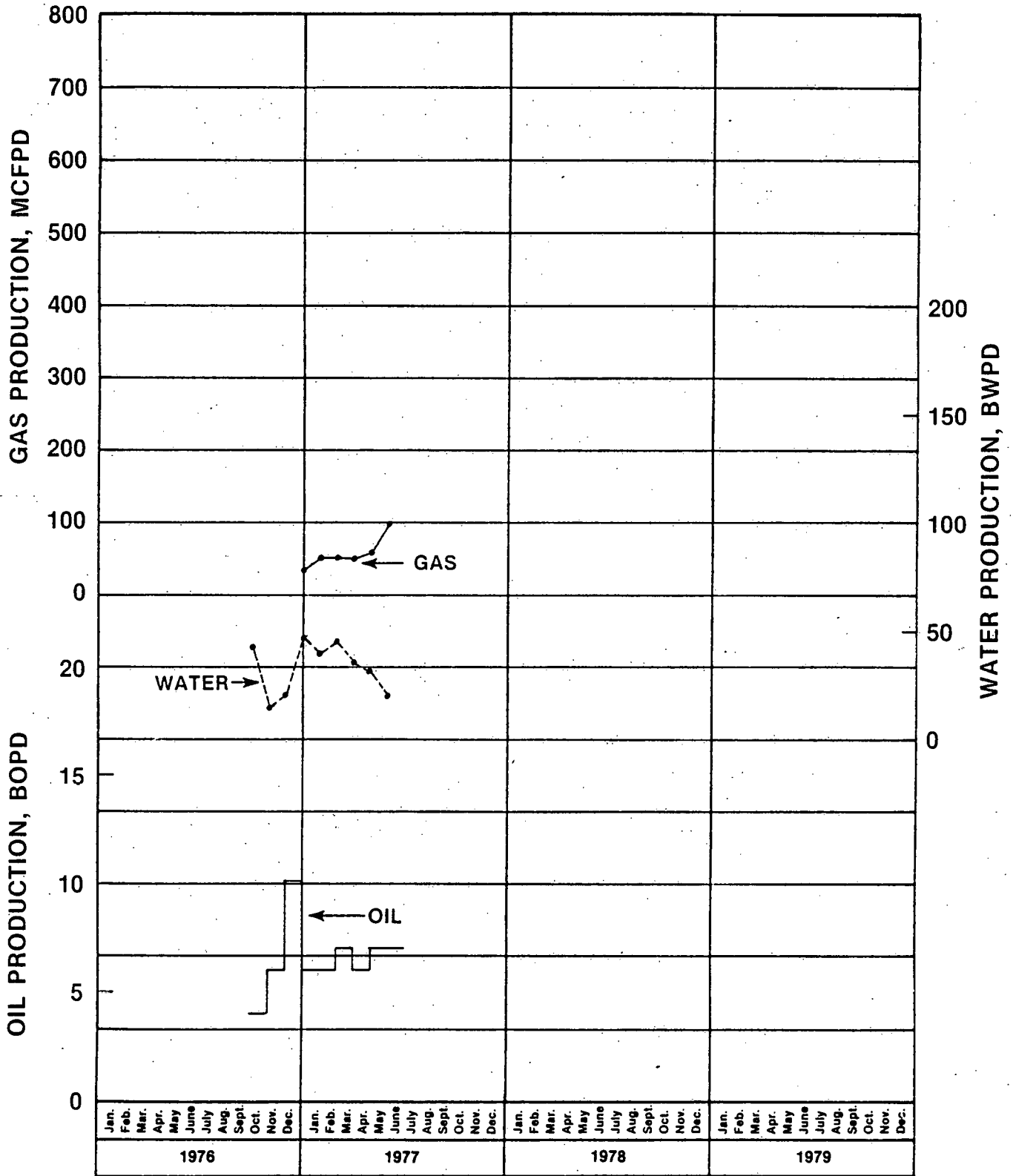


FIGURE 62

PRODUCING WELL NO. 16-6 PERFORMANCE

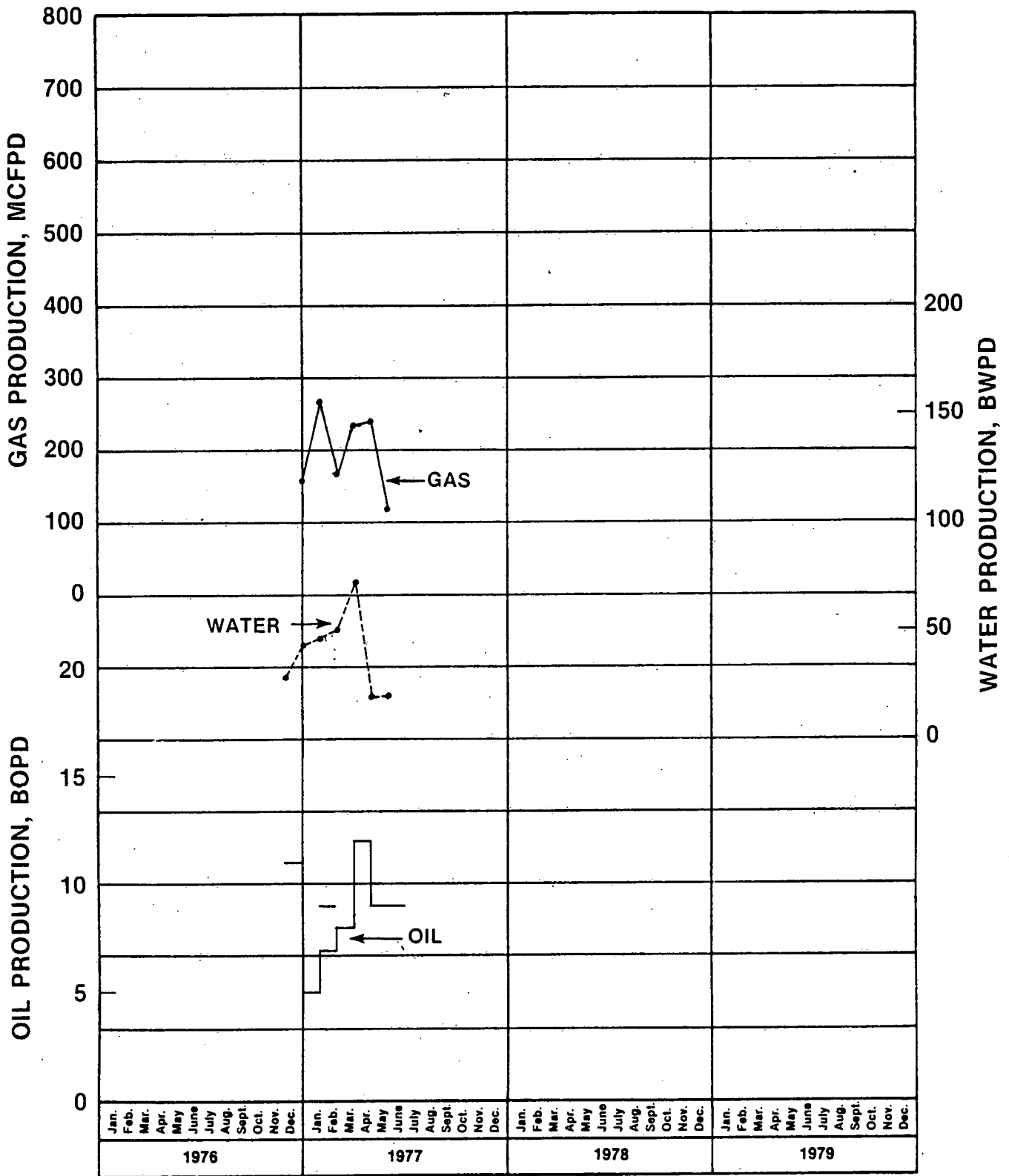


TABLE I
CORE ANALYSIS OF WELL 16-3

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CITIES SERVICE OIL COMPANY
NO. 16-3 BODCAU FIELD
BELLEVUE FIELD
BOSSIER PARISH, LOUISIANA

DATE: 2-3-75
FORMATION: NACOTCH
DRLG. FLUID: WATER BASE MUD
LOCATION:

FILE NO: 2203-3789
ANALYSTS: HK RB CW
ELEVATION:
LABORATORY: SHREVEPORT

CONVENTIONAL CORE ANALYSIS

SMP. NO.	DEPTH	PERMEABILITY MD.		% POR.	GAS VOL.	PORE SATS.		PROB PROD	DESCRIPTION
		MAXIMUM	VERT.			OIL	WTR.		
	385.0-405.0	CORE NO. 1 CUT 20 FT.			REC. 20 FT.				
	385.0-89.0								SHALE BLACK NO ANALYSIS
1	389.0-90.0	<0.1		14.6	4.5	61.5	27.5		LM FOS CHKY G ODR DUL GLD FLU
2	390.0-91.0	87		26.5	3.3	67.0	25.4		LM FOS CHKY G ODR DUL GLD FLU
3	391.0-92.0	140		33.9	2.7	75.8	17.6		LM FOS CHKY G ODR DUL GLD FLU
4	392.0-93.0	65		24.4	1.6	65.1	30.6		LM FOS CHKY G ODR DUL GLD FLU
5	393.0-94.0	16		19.2	1.9	66.8	28.3		LM FOS CHKY G ODR DUL GLD FLU
6	394.0-95.0	<0.1		5.3	1.6	35.2	54.4		LM FOS G ODR SPT GLD FLU
7	395.0-96.0	<0.1		2.3	3.2	34.5	43.9		LM FOS G ODR SPT GLD FLU
8	396.0-97.0	41		16.5	3.5	47.3	40.1		LM FOS G ODR SPT GLD FLU
9	397.0-98.0	37		11.6	4.2	59.0	28.9		LM FOS G ODR SPT GLD FLU
10	398.0-99.0	4.2		16.1	3.2	64.5	26.0		LM FOS G ODR SPT GLD FLU
11	399.0-00.0	0.6		8.2	2.8	59.4	29.7		LM FOS G ODR SPT GLD FLU
12	400.0-01.0	15		18.5	1.5	51.7	37.9		LM FOS V CHKY G ODR SPT GLD FLU
13	401.0-02.0	169		29.0	2.3	50.9	42.4		SD VFG LM FOS G ODR DUL GLD FLU
14	402.0-03.0	197		31.2	3.1	56.7	34.2		SD VFG LM FOS G ODR DUL GLD FLU
15	403.0-04.0	81		22.7	2.8	51.7	40.5		SD VFG LM FOS G ODR DUL GLD FLU
16	404.0-05.0	25		22.5	4.8	55.6	31.6		SD VFG FOS SLI SH G ODR DUL FLU
	405.0-24.0	CORE NO. 2 CUT 20 FT.			REC. 19 FT.				
17	405.0-06.0	700		39.2	2.9	53.1	39.7		SD VFG SLT SH G ODR DUL GLD FLU
18	406.0-07.0	640		40.7	2.4	56.7	37.3		SD VFG SLT SH G ODR DUL GLD FLU
19	407.0-08.0	730		40.7	2.4	49.2	45.1		SD VFG SH LAM G ODR DUL GLD FLU
20	408.0-09.0	589		32.2	1.9	49.6	45.8		SD VFG SH LAM G ODR DUL GLD FLU
21	409.0-10.0	372		30.5	2.1	51.3	43.3		SD VFG SH G ODR DUL GLD FLU
22	410.0-11.0	439		35.9	2.2	51.2	43.1		SD VFG SLI SH G ODR DUL GLD FLU

These analyses, opinions or interpretations are based on observations and materials supplied by the client to whom, and for whose exclusive and confidential use, this report is made. The interpretations or opinions expressed represent the best judgment of Core Laboratories, Inc. (all errors and omissions excepted), by Core Laboratories, Inc. and its officers and employees, assume no responsibility and make no warranty or representations, as to the productivity, proper operations, or profitability of any oil, gas or other mineral well or land in connection with which such report is used or relied upon.

TABLE I (CONT'D)
CORE ANALYSIS OF WELL 16-3

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CITIES SERVICE OIL COMPANY
NO. 16-3 BODCAU FEZ

DATE: 2-3-76
FORMATION: NACOTCH

FILE NO: 2203-3789
ANALYSTS: HK RB CW

SMP. NO.	DEPTH	PERMEABILITY MD. MAXIMUM	VERT.	% POR.	GAS VOL.	PORE SATS. OIL	WTR.	PROB PROD	DESCRIPTION
23	411.0-12.0	489		33.3	1.7	46.7	48.0		SD VFG SLI SH G ODR DUL GLD FLU
24	412.0-13.0	730		29.5	2.4	47.9	45.6		SD VFG SH G ODR DUL GLD FLU
25	413.0-14.0	<0.1		5.5	1.2	67.1	22.4		SD VFG LM HRD G ODR DUL GLD FLU
26	414.0-15.0	<0.1		7.1	3.7	33.2	50.3		SD VFG FOS HRD G ODR DUL GLD FLU
27	415.0-16.0	<0.1		3.0	2.8	34.8	52.7		SD VFG FOS HRD G ODR DUL GLD FLU
28	416.0-17.0	11		39.4	2.2	39.1	55.8		SD VFG SLT G ODR DUL GLD FLU
29	417.0-18.0	926		37.8	3.7	47.6	43.6		SD VFG SLI SH G ODR DUL GLD FLU
30	418.0-19.0	328		26.1	3.5	47.9	43.9		SD VFG SLI SH G ODR DUL GLD FLU
31	419.0-20.0	358		36.0	2.6	23.3	70.2		SD VF-FG G ODR DUL GLD FLU
32	420.0-21.0	914		39.3	3.1	15.6	75.9		SD VF-FG G ODR V DUL GLD FLU
33	421.0-22.0	439		37.2	2.8	15.6	76.8		SD VF-FG G ODR V DUL GLD FLU
34	422.0-23.0	482		38.4	3.3	14.4	77.0		SD FG SLT G ODR V DUL GLD FLU
35	423.0-24.0	804		35.4	2.7	17.5	75.0		SD FG SLT G ODR V DUL GLD FLU

(* NO INTERPRETATION MADE

NOTE: POROSITY FROM HELIUM PORISIMETER) GAS VOLUME AND PORE SATURATIONS FROM SUMMATION OF FLUIDS DATA.

TABLE 2

RESERVOIR CHARACTERISTICS BY LOG ANALYSIS

Well No.	Elevation	Top	Subsea	Base or WOC	Subsea	Net Pay	Porosity	Water Saturation	Completion Interval
2-3	222	355	-133	424	-204	61			385-419
2-4	221	344	-123	415	-194	63			372-412
2-5	213	330	-117	400	-187	67			358-405
2-8	216	324	-108	392	-176	56	34.4	28.9	336-388
12-1	218	348	-130	427	-209	62			410-425
12-2	219	362	-143	435	-216	58			367-418
12-3	217	362	-145	437	-220	55			368-420
12-4	215	343	-128	423	-208	62			351-423
12-5	213	324	-111	404	-191	56			324-404
12-6	215	328	-113	405	-190	65			328-405
13-1	215	351	-136	428	-213	61			410-426
13-2	216	358	-142	429	-213	55			358-412
13-3	213	360	-147	426	-213	58	33.6	30.9	361-398
13-4	213	346	-133	426	-213	62			346-412
13-5	211	328	-117	409	-198	67	34.4	25.4	328-402
13-6	212	324	-112	404	-192	66			324-404
14-1	212	356	-144	425	-213	54			412-425
14-2	214	368	-154	427	-213	47			369-424
14-3	215	378	-163	428	-213	39			379-416
14-4	213	357	-144	426	-213	55			357-417
14-5	211	338	-127	419	-208	68			339-419
14-6	211	336	-125	417	-206	64			336-417
15-1	210	366	-156	423	-213	44			410-423
15-2	211	378	-167	424	-213	33			380-416
15-3	212	376	-165	425	-213	38	32.4	27.0	376-414
15-4	211	362	-151	424	-213	47			364-416
15-5	211	352	-141	424	-213	61			354-415
15-6	211	342	-131	424	-213	60	34.3	22.6	344-416
16-1	210	371	-161	423	-213	42			411-421
16-2	211	375	-164	424	-213	39			375-414
16-3	213	384	-171	426	-213	19	33.5	36.6	386-411
16-4	215	374	-159	428	-213	46			376-420
16-5	216	367	-151	429	-213	49			368-421
16-6	212	355	-143	425	-213	56			355-416
L -1	224	408	-184	434	-210	19	32.0	35.0	---
L -2	215	384	-169	427	-212	33	32.4	35.0	---
L -4	217	404	-187	426	-209	11	33.6	35.0	---

Producing wells were perforated 2 shots/foot and injection wells were perforated 4 shots/ft

TABLE 3

SUMMARY OF IGNITIONS

<u>Well</u>	<u>Date Started</u>	<u>Date Confirmed</u>	<u>Cumulative BTU Input</u>	<u>Problems</u>
12-1	8/7/76	8/9/76	3,590,000	Ignited oil inside casing.
13-1	8/11/76	8/13/76	3,461,000	
14-1	8/17/76	8/18/76	1,301,000	Surface leak & compressor shut down - shorted heater; Stuck heater coming out.
15-1	9/1/76	9/3/76	608,000	Surface leak & compressor shut down. Shorted heater.
16-1	9/22/76	9/24/76	3,946,000	Stuck heater coming out.

TABLE 4
INJECTION WELL DATA

<u>WELL</u>	<u>TOP OF PAY</u>	<u>BASE OF PAY</u>	<u>PERFORATIONS</u>	<u>PERFORATIONS</u>	<u>PACKER DEPTH</u>
12-1	348	427	410-425	366-380	403
13-1	351	428	410-426	360-372	404
14-1	356	425	412-425	368-380	401
15-1	366	423	410-423	378-390	404
16-1	371	423	411-421	380-390	402

TABLE 5
 TYPICAL ORSAT GAS ANALYSIS RESULTS
 DATA FOR MAY 1977

<u>Well</u>	<u>CO₂,%</u>	<u>O₂,%</u>	<u>CO,%</u>
2-3	16.8	0.4	0.4
2-4	16.4	0.2	0.4
2-5	15.8	0.2	0.4
2-8	15.8	0.2	0.4
12-2	15.8	0.2	0.4
12-3	16.4	0.6	0.4
12-4	17.4	0.4	0.2
12-5	17.4	0.4	0.4
12-6	18.2	0.4	0.2
13-2	18.2	0.6	0.4
13-3	17.6	0.4	0.2
13-4	17.4	0.6	0.4
13-5	17.8	0.2	0.2
13-6	17.6	0.2	0.4
14-2	20.0	0.2	0.4
14-3	17.2	0.4	0.4
14-4	15.8	0.2	0.2
14-5	18.4	0.6	0.2
14-6	19.8	0.6	0.4
15-2	16.6	1.0	0.6
15-3	17.8	0.2	0.2
15-4	17.0	0.2	0.4
15-5	17.2	0.4	0.4
15-6	16.8	0.4	0.4
16-2	15.8	0.0	0.2
16-3	15.6	0.0	0.4
16-4	15.0	0.8	0.4
16-5	14.4	0.4	0.4
16-6	15.0	0.2	0.4

TABLE 6
COMBUSTION TUBE RESULTS

	<u>Run #1</u>	<u>Run #2</u>	<u>Run #3</u>	<u>Run #4</u>	<u>Run #7</u>	<u>Run #8</u>	<u>Run #9</u>
<u>Packing Conditions</u>							
Porosity, %	46	49	45	44	50	48	52
Oil Saturation, %	33	35	18	20	29	24	21
Sand Weight, grams	6963	6623	7068	7187	6493	6680	6227
Oil Weight, grams	693	780	372	399	663	534	498
Weight, % Oil	10	11	5	5	9	7	7
Native or Mixed	N	N	M	M	N	N	N
<u>Operating Conditions</u>							
Air Flux, SCF/hr/ft ²	500	583	541	458	396	417	418
Combustion Temp., °F	1053	1132	1006	957	N/R	1034	965
Burning Efficiency, %	74	83	93	90	65	86	99
Water/Air Ratio	0	0	0	0	107	267	490
<u>Results</u>							
Fuel Deposit, lb/ft ³	2.79	2.03	1.33	1.50	1.60	1.55	1.90
Air Requirement, MMCF/AF	19.9	13.4	9.6	11.1	12.1	12.0	15.4
Hydrogen/Carbon Ratio	0.11	0.06	0.12	0.14	0.14	0.14	0.16
Air/Oil Ratio, MCF/Bbl	16.1	10.0	6.7	7.8	8.7	8.6	11.4

TABLE 6 (Continued)
COMBUSTION TUBE RESULTS

	<u>Run #10</u>	<u>Run #11</u>	<u>Run #12</u>	<u>Run #13</u>	<u>Run #14</u>	<u>Run #15</u>	<u>Run #17</u>
<u>Packing Conditions</u>							
Porosity, %	51	50	52	52	50	45	41
Oil Saturation, %	22	24	24	18	32	25	57
Sand Weight, grams	6344	6403	6138	6234	6416	6976	7478
Oil Weight, grams	506	618	574	412	738	511	1051
Weight, % Oil	7	10	9	6	10	7	12
Native or Mixed	N	N	N	N	N	N	M
<u>Operating Conditions</u> ²							
Air Flux, SCF/hr/ft ²	417	417	438	427	485	436	432
Combustion Temp., °F	824	1042	906	931	823	1031	1094
Burning Efficiency, %	88	93	86	84	82	99	98
Water/Air Ratio	375	475	680	425	450	0	0
<u>Results</u>							
Fuel Deposit, lb/ft ³	1.77	1.76	1.32	1.49	2.24	1.86	2.74
Air Requirement, MMCF/AF	13.2	12.5	10.0	11.0	16.4	13.9	18.9
Hydrogen/Carbon Ratio	0.13	0.10	0.16	0.14	0.13	0.13	0.09
Air/Oil Ratio, MCF/Bbl	9.7	9.1	7.0	7.8	12.6	10.3	15.2

TABLE 7
 SUMMARY OF PREIGNITION FALLOFF TESTS
 DATE: AUGUST 1976

<u>Pattern</u>	<u>Kgh, Md-ft</u>	<u>Kg, md</u>	<u>Skin Factor, S</u>
12	897	14.5	- .3
13	761	12.5	-3.4
14	320	5.9	-2.5
15	594	13.5	-2.43
16	1338	32	- .183
16(a)	3434	82	+ .91

TABLE 8
 SUMMARY OF SECOND FALLOFF TESTS
 DATE: FEBRUARY 1977

<u>Pattern</u>	<u>Kgh, Md-ft</u>	<u>Kg, md</u>	<u>Skin Factor, S</u>
12	8418	136	-5.3
13	12828	210	2.3
14	6038	112	-1.9
15	8459	192	-4.1
16	22862	544	-3.3

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TABLE 9
RESULTS OF PULSE TEST ANALYSIS
DATE: JANUARY 31, 1977 - FEBRUARY 10, 1977

<u>Pattern</u>	<u>Well</u>	<u>q {MMSCFD}</u>	<u>r {Ft.}</u>	<u>t_L {Min.}</u> <u>Feb. 1977</u>	<u>t₁ {Min.}</u> <u>Feb. 1977</u>	<u>K_g (md)</u> <u>Feb. 1977</u>
12	12-2	0.456	165	200	1222	37
	12-3	0.379	233	730	3451	26
	12-4	0.258	175	120	842	61
	12-5	0.273	351	180	1130	182
	12-6	0.190	310	160	1036	155
	2-8	0.218	351	100	739	278
	2-5	0.208	233	100	739	122
	2-4	0.092	170	220	1312	37
	2-3	0.061	233	220	1312	69
13	12-3	0.379	233	148	979	92
	12-4	0.258	178	92	697	76
	12-5	0.273	355	148	979	215
	13-6	0.170	310	40	388	413
	13-5	0.110	355	80	632	332
	13-4	0.110	178	185	1153	46
	13-3	0.277	233	420	2173	42
	13-2	0.097	165	30	317	143
14	13-4	0.110	170	180	1129	43
	13-5	0.110	345	180	1129	176
	14-6	0.098	310	120	842	190
	14-5	0.154	360	420	2173	99
	14-4	0.183	195	480	2423	26
	14-3	0.240	230	220	1312	67
	14-2	0.120	165	180	1129	40
	13-3	0.277	215	520	2590	30

TABLE 9 - Continued

<u>Pattern</u>	<u>Well</u>	<u>q {MMSCFD}</u>	<u>R {Ft.}</u>	<u>t_L {Min.}</u> <u>Feb. 1977</u>	<u>t₁ {Min.}</u> <u>Feb. 1977</u>	<u>K_g (md)</u> <u>Feb. 1977</u>
15	14-3	0.183	240	600	2919	33
	14-4	0.129	200	320	1749	38
	14-5	0.170	355	300	1663	126
	15-6	0.183	310	140	940	170
	15-5	0.110	370	280	1577	145
	15-4	0.289	200	240	1401	48
	15-3	0.395	215	120	842	92
	15-2	0.839	160	100	739	58
16	16-2	0.273	145	220	1312	27
	16-3	0.146	260	Not Analyzable		
	16-4	0.146	225	160	1036	81
	16-5	0.051	345	Not Analyzable		
	16-6	0.269	270	60	516	235
	15-5	0.098	340	520	2672	46
	15-4	0.281	220	420	2173	49
	15-3	0.395	320	820	3818	45

TABLE 10
SUMMARY OF PRODUCED OIL & WATER ANALYSIS

Well	Viscosity, cps				API Gravity @ 60°F	Oil Specific Gravity @ 75°F	mg/l Chloride	Water Specific Gravity @ 81°F	% BS&W
	100°F	122°F	140°F	170°F					
2-3	206.9	104.2	63.2	30.0	19.0	0.9357	8130	1.0070	3.8
2-4	185.9	90.6	59.1	26.6	19.6	0.9321	8400	1.0069	0.6
2-5	162.8	80.1	49.4	24.7	19.6	0.9322	8340	1.0070	0.4
2-8	171.2	87.5	54.2	28.2	19.3	0.9338	7020	1.0040	0.8
12-2	136.3	70.4	43.7	22.3	19.6	0.9318	5650	1.0029	0.2
12-3	162.7	71.3	46.9	22.8	18.7	0.9374	7760	1.0055	3.0
12-4	193.4	100.1	58.3	30.0	18.6	0.9380	3330	0.9986	4.5
12-5	110.7	60.3	37.9	18.1	20.4	0.9268	1160	0.9965	0
12-6	152.8	76.3	47.7	24.3	19.8	0.9300	5860	1.0034	0.2
13-2	161.7	80.1	49.7	26.6	18.9	0.9362	7340	1.0048	0
13-3	211.7	104.0	63.9	30.3	19.0	0.9354	7080	1.0046	6.4
13-4	194.9	95.3	56.3	27.8	19.2	0.9340	7340	1.0052	3.4
13-5	165.3	79.8	49.6	24.4	19.6	0.9315	7340	1.0052	0
13-6	79.5	44.7	29.1	15.9	20.4	0.9267	2480	0.9982	0
14-2	192.3	94.7	56.7	26.6	18.9	0.9358	6710	1.0047	2.2
14-3	188.4	92.2	55.2	27.4	19.0	0.9351	7340	1.0059	2.3
14-4	177.8	89.1	53.2	26.3	19.6	0.9312	7080	1.0039	0
14-5	167.6	79.1	49.1	24.3	19.2	0.9340	8760	1.0062	0
14-6	150.6	73.9	46.6	22.3	20.0	0.9289	8820	1.0061	0
15-2	152.3	83.7	51.6	28.3	18.3	0.9396	2270	0.9986	24.2
15-3	225.7	-	-	-	16.3	0.9523	5390	1.0030	34.0
15-4	200.2	-	-	-	18.0	0.9412	7290	1.0060	10.4
15-5	183.7	-	-	-	18.7	0.9369	7660	1.0058	9.3
15-6	221.3	-	-	-	18.9	0.9354	6920	1.0044	2.6
16-2	226.1	-	-	-	18.1	0.9403	12090	1.0115	5.3
16-3	206.1	-	-	-	17.7	0.9434	8760	1.0070	8.4
16-4	258.5	-	-	-	16.1	0.9532	12570	1.0112	2.1
16-5	164.7	-	-	-	19.0	0.9351	8500	1.0060	1.2
16-6	172.9	-	-	-	17.8	0.9424	7340	1.0049	10.9

TABLE 11

TYPICAL CHROMATOGRAPHIC ANALYSES.
NOVEMBER 1976

Note: All Values are Accumulative Volume Percent

<u>Component</u>	<u>2-8</u>	<u>12-2</u>	<u>13-4</u>	<u>14-6</u>	<u>15-3</u>	<u>16-3</u>
C ₆	0	0	0.4	0.2	0.6	0
C ₇	0	0.1	0.4	0.2	1.0	0
C ₈	0.1	0.5	0.4	0.3	1.6	0
C ₉	1.1	2.3	1.2	2.0	3.5	0.1
C ₁₀	4.6	7.0	3.6	5.9	8.1	1.0
C ₁₁	11.3	14.3	8.8	13.0	14.9	5.4
C ₁₂	18.2	22.1	14.1	20.0	21.5	11.4
C ₁₃	26.8	30.8	21.3	28.2	29.7	19.4
C ₁₄	35.8	39.6	28.0	36.5	37.8	27.4
C ₁₅	44.4	48.2	35.4	44.9	45.6	36.3
C ₁₆	53.8	57.2	43.3	53.5	54.0	45.3
C ₁₇	58.4	61.8	48.4	58.3	58.5	50.9
C ₁₈	61.7	65.0	52.4	61.8	61.7	54.7
C ₁₉	64.7	67.9	56.1	65.0	64.4	58.4
C ₂₀	67.4	70.6	59.5	67.9	67.2	61.9
C ₂₁	70.2	73.3	63.0	70.8	70.0	65.1
C ₂₂	72.9	75.8	66.5	73.6	72.8	68.3
C ₂₃	75.7	78.3	70.0	76.4	75.5	71.6
C ₂₄	78.4	80.5	73.3	79.1	78.3	74.8
C ₂₅	81.1	82.8	76.4	81.7	81.0	77.9
C ₂₆	83.7	85.1	79.7	84.3	83.7	80.9
C ₂₇	86.4	87.6	83.1	86.9	86.3	84.1
C ₂₈	89.2	90.1	86.5	89.4	89.0	87.3
C ₂₉	92.0	92.5	89.8	92.1	91.7	90.4
C ₃₀	94.7	95.0	93.2	94.8	94.5	93.7
C ₃₁	97.4	97.5	96.6	97.5	97.2	96.8
C ₃₂ ⁺	100.0	100.0	100.0	100.0	100.0	100.0

TABLE 12
SUMMARY OF PRODUCED GAS ANALYSIS
JANUARY 6-12, 1977, REPORTED AS PERCENT OF DRY GAS

Well	H ₂ S ppm	CO ₂ Mole %	O ₂ Mole %	Methane Mole %	H ₂ O Mole %	Temp. °F	Propane Mole %	Iso-Butane Mole %	N-Butane Mole %	Pentane Plus Mole %
2-3	1468	16.3	1.4	1.6	--	--	.06	.01	.03	.19
2-4	1499	15.6	1.3	1.3	12	120	.04	.01	.01	.21
2-5	1599	15.4	1.3	1.3	<1	<50	.03	.01	.01	.12
2-8	487	15.9	1.2	0.9	--	--	.34	.01	.02	.11
12-2	1653	14.9	1.4	0.5	19	140	.04	.01	.01	.26
12-3	417	8.5	8.5	0.5	1	<50	.04	.01	.02	.08
12-4	2093	17.2	1.3	1.8	2	68	.12	.03	.05	.14
12-5	1746	12.7	1.3	1.7	3	79	.11	.02	.04	.15
12-6	502	15.0	1.4	0.8	7	112	.08	.01	.04	.52
13-2	1205	15.8	1.6	1.4	3	72	.06	.01	.02	.05
13-3	1043	15.9	1.3	4.0	--	--	.09	.01	.03	.10
13-4	1244	15.0	1.3	1.5	3	72	.05	.01	.03	.13
13-5	1784	15.5	1.3	1.6	2	69	.06	.01	.02	.19
13-6	1916	17.2	1.2	1.2	--	--	.09	.01	.03	.30
14-2	2078	14.4	1.3	1.6	2	65	.05	.02	.03	.08
14-3	2263	15.3	1.3	1.3	3	72	.05	.01	.02	.06
14-4	2287	16.4	1.4	0.2	3	74	.08	.01	.03	.04
14-5	1784	12.4	1.2	1.1	2	67	.05	.01	.02	.09
14-6	1051	14.4	1.3	1.6	3	78	.07	.01	.02	.10
15-2	3059	13.0	1.8	0.5	19	140	.06	.01	.02	.13
15-3	1622	12.9	1.0	2.0	2	68	.06	.01	.02	.07
15-4	1584	13.4	1.1	2.0	3	72	.03	.01	.02	.09
15-5	309	11.3	1.1	3.4	<1	36	.03	.01	.01	.07
15-6	688	11.8	1.4	0.8	3	74	.05	.01	.02	.07
16-2	780	12.2	1.0	1.8	2	70	.05	.01	.02	.11
16-3	587	11.8	1.1	1.1	2	71	.05	.01	.01	.05
16-4	31	12.1	1.2	0.8	<1	50	--	.01	.02	.03
16-5	39	11.3	1.1	4.1	3	73	.06	.01	.01	.05
16-6	942	12.5	1.2	1.4	3	74	.05	.01	.02	.08

TABLE 13
INVESTMENTS FOR WELLS

<u>CATEGORY</u>	<u>TANGIBLES</u>	<u>INTANGIBLES</u>	<u>TOTAL</u>	<u>COST PER WELL</u>
3 EVALUATION WELLS	\$ 10,301.81	\$ 26,457.45	\$ 36,759.26	\$ 12,253.09
29 PRODUCTION WELLS	345,135.09	287,834.57	632,969.66	21,826.54
5 INJECTION WELLS	25,692.55	59,151.10	84,843.65	16,968.73
5 OBSERVATION WELLS	14,069.16	29,235.31	43,304.47	8,660.89
1 DISPOSAL WELL	6,044.92	9,491.06	15,535.98	15,535.98
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TOTAL	\$401,243.53	\$412,169.49	\$813,413.02	

TABLE 14
INVESTMENT FOR FACILITIES

<u>CATEGORY</u>	<u>TANGIBLES</u>	<u>INTANGIBLES</u>	<u>TOTAL</u>
AIR INJECTION SYSTEM	\$ 22,339.16	\$ 12,761.58	\$ 35,100.74
WATER SYSTEMS	19,322.63	11,612.79	30,935.42
BATTERY FACILITY	151,444.13	48,748.44	200,192.57
COMPRESSION FACILITY	111,341.63	26,827.27	138,168.90
CASING EXHAUST SYSTEM	<u>41,104.24</u>	<u>29,862.08</u>	<u>70,966.33</u>
TOTAL	\$345,551.79	\$129,812.17	\$475,363.96

TABLE 15
LEASE OPERATION EXPENSES

<u>CATEGORY</u>	<u>COST TO DATE</u>	<u>COST PER BARREL¹</u>
OPERATIONS LABOR	\$21,976.05	\$0.27
SUPPLIES	743.81	0.01
UTILITIES	21,960.21	0.27
CHEMICALS	<u>25,823.25</u>	<u>0.32</u>
TOTALS	\$70,503.32	\$0.87

¹COSTS WERE DETERMINED ON A NET BARREL BASIS ASSUMING A NORMAL 1/8 ROYALTY.

TABLE 16
LEASE MAINTENANCE EXPENSES

<u>CATEGORY</u>	<u>COST TO DATE</u>	<u>COST PER BARREL¹</u>
MATERIALS	\$ 30,356.08	\$0.37
ROUSTABOUT LABOR	27,533.08	0.34
BOTTOMHOLE PUMP REPAIR	14,622.98	0.18
WELL SERVICE	30,602.94	0.38
REMEDIAL WELL SERVICE	<u>15,642.00</u>	<u>0.19</u>
TOTALS	\$118,757.08	\$1.46

¹COSTS WERE DETERMINED ON A NET BARREL BASIS ASSUMING A NORMAL 1/8 ROYALTY.

TABLE 17
COMPRESSION FACILITY EXPENSES

<u>CATEGORY</u>	<u>COST TO DATE</u>	<u>COST PER BARREL</u> ¹
OPERATIONS SUPPLIES	\$ 7,605.21	\$0.09
OPERATIONS LABOR	12,834.77	0.16
UTILITIES	116,613.21	1.44
REPLACEMENT PARTS	28,414.55	0.35
MAINTENANCE LABOR	<u>23,301.60</u>	<u>0.29</u>
TOTALS	\$188,769.34	\$2.33

¹COSTS WERE DETERMINED ON A NET BARREL BASIS ASSUMING A NORMAL 1/8 ROYALTY.

TABLE 18
OTHER LEASE EXPENSES

<u>CATEGORY</u>	<u>COST TO DATE</u>	<u>COST PER BARREL</u> ¹
LA SEVERANCE TAX	\$129,735.76	\$1.60
CSC OVERHEAD	160,136.00	1.97
DEPLETION & DEPRECIATION	<u>146,226.00</u>	<u>1.80</u>
TOTALS	\$436,097.76	\$5.37

¹COSTS WERE DETERMINED ON A NET BARREL BASIS ASSUMING A NORMAL 1/8 ROYALTY.

TABLE 19
PROJECT ECONOMIC SUMMARY

<u>CATEGORY</u>	<u>COST TO DATE</u>	<u>COST PER BARREL¹</u>
LEASE OPERATION	\$ 70,503.32	\$0.87
LEASE MAINTENANCE	118,757.08	1.46
COMPRESSION FACILITY	188,769.34	2.33
LA SEVERANCE TAX	129,735.76	1.60
CSC OVERHEAD	160,136.00	1.97
DEPLETION & DEPRECIATION	<u>146,226.00</u>	<u>1.80</u>
TOTALS	\$814,127.50	\$10.03

¹COSTS WERE DETERMINED ON A NET BARREL BASIS ASSUMING A NORMAL 1/8 ROYALTY.