DOE/BETC/RI-83/1

ECONOMICS AND ANALYSIS OF THE MISCIBLE CO_2 INJECTION PROJECT, GRANNY'S CREEK FIELD, WEST VIRGINIA

By
R. V. Smith, Royal J. Watts, and Fred W. Burtch

Date Published—April 1983

Bartlesville Energy Technology Center
Bartlesville, Oklahoma

UNITED STATES DEPARTMENT OF ENERGY

Printed in the United States of America. Available from:

National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes
Paper copy: $7.50
Microfiche copy: $4.00

DOE/BETC/RI-83/1
Distribution Category UC-92a

ECONOMICS AND ANALYSIS OF THE MISCIBLE CO_2 INJECTION PROJECT, GRANNY'S CREEK FIELD, WEST VIRGINIA

By

R. V. Smith
Royal J. Watts
Fred W. Burtch

Bartlesville Energy Technology Center
P.O. Box 1398
Bartlesville, Oklahoma 74005

Date Published—April 1983

UNITED STATES DEPARTMENT OF ENERGY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ECONOMICS AND ANALYSIS OF THE MISCIBLE CO_2 INJECTION PROJECT, GRANNY'S CREEK FIELD, WEST VIRGINIA

By

R. V. Smith,[1] Royal J. Watts,[2] and Fred W. Burtch[3]

ABSTRACT

The use of carbon dioxide (CO_2) in a tertiary oil recovery pilot in the Granny's Creek field, West Virginia, was started in 1976. At first the CO_2 was injected into the Pocono Big Injun sand at four wells at the corners of an approximately square area of 6.7 acres. The CO_2 was injected as a liquid, and the pilot portion of the reservoir was maintained at or above miscible pressure. Production was taken from a well inside the square pilot area and from eight wells outside the area. The test began with injection of water to increase reservoir pressure to more than the miscibility pressure. Injection started with CO_2 alone, then alternate slugs of CO_2 and water, then CO_2 alone, and finally water alone was injected. The additional oil recovery was 8,681 bbl for an injection total of 19.76 million lb of CO_2 for a ratio of 19,626 cu ft per bbl. A second or minipilot in which the injection was in the lower or C zone of the Big Injun sand resulted in 2,007.9 bbl of additional oil through September 1980 from the injection of 4.24 million lb of CO_2 for a ratio of 18,192 cu ft per bbl. The CO_2 spread quickly across the southern 350 acres of the field and confinement was not attained. The sales price of the oil after royalty and taxes is probably about equal to the most optimistic cost of the CO_2 per barrel of additional oil at the present time and far less than a more reasonable cost for the CO_2. Production of additional oil in each case decreased sharply after injection of CO_2 was stopped so there appeared to be no benefits over an extended period of time from the injection of CO_2.

---

[1] Petroleum Consultant, Bartlesville, Oklahoma.

[2] Project Manager, Gas Miscible Displacement, U.S. Department of Energy, Morgantown Energy Technology Center, Morgantown, West Virginia.

[3] Project Manager, Chemical Recovery, U.S. Department of Energy, Bartlesville Energy Technology Center, Bartlesville, Oklahoma.

ECONOMICS AND ANALYSIS OF THE MISCIBLE CO_2 INJECTION PROJECT, GRANNY'S CREEK FIELD, WEST VIRGINIA

By

R. V. Smith,[1] Royal J. Watts,[2] and Fred W. Burtch[3]

INTRODUCTION

The use of gases to improve oil recovery has a long history. At first, gases were injected into oil reservoirs to slow the pressure decline thereby slowing the decline in productivity of the wells. The displacement of the oil was mainly of the immiscible type. In the 1950's and 1960's, research determined the conditions and compositions at which gases could become miscible with the oil and displace the oil as a solvent. Early field trials of hydrocarbon gases have indicated the desirability of alternates to the hydrocarbon gases because of the costs relative to the amount of oil recovered. Therefore, carbon dioxide (CO_2) has been the subject of much research and several field trials for enhanced oil recovery.

Carbon dioxide is soluble in crude oil; as a gas or liquid, it can extract hydrocarbons from the oil; and under favorable conditions of pressure, temperature, and composition, the resultant mixture becomes miscible with the oil. The CO_2 that dissolves in the oil increases the volume and decreases the viscosity making the oil more mobile. These characteristics have led to field trials of CO_2 as a recovery agent under immiscible and miscible conditions. The pilot trial at the Granny's Creek field was under miscible conditions.

THE GRANNY'S CREEK PROJECT

The CO_2 injection project in the southern portion of the Granny's Creek field was a cooperative test, and costs were shared by Columbia Gas Transmission Corporation and the U.S. Department of Energy. The objective was to demonstrate the efficiency and economics of recovering oil from a shallow, low-temperature, watered-out portion of a waterflood reservoir using CO_2 and water to displace the oil for tertiary recovery. The CO_2 was injected as a liquid, and every effort was made by the operator to maintain the reservoir in the pilot area above the miscibility pressure of 1,050 psi at the reservoir temperature of 73°F. The pilot was planned as a miscible flood.

The injection of liquid CO_2 was started on June 2, 1976, into four injection wells on a 6.7-acre pilot area that had been a part of an earlier and larger

[1] Petroleum Consultant, Bartlesville, Oklahoma.

[2] Project Manager, Gas Miscible Displacement, U.S. Department of Energy, Morgantown Energy Technology Center, Morgantown, West Virginia.

[3] Project Manager, Chemical Recovery, U.S. Department of Energy, Bartlesville Energy Technology Center, Bartlesville, Oklahoma.

waterflood pilot. The earlier waterflood pilot (10.7 acres) was considered very successful as recovery was 43,750 barrels or about 4,089 barrels of gross oil per acre. The injection of liquid CO_2 continued until August 3, 1976, at which time water and liquid CO_2 was injected alternately into each well. The injection of CO_2 was stopped on January 10, 1977, because CO_2 was not available. However, water was injected until March 8, 1977, when CO_2 injection was resumed without slugs of water at the four injection wells. The injection of CO_2 was completed on June 14, 1977, after the injection of 19,759,041 lb (9,879 tons) or approximately 67,170 reservoir bbl of CO_2. Water injection was started immediately and was continued until January 8, 1980. Liquid CO_2 was then injected into well No. 20274 until August 19, 1980, at which time 4,236,000 lb (2,118 tons) or approximately 14,402 reservoir bbl of CO_2 had been injected. In February 1980, the packer was lowered in injection well No. 20274 so that further injection was into the "C" zone only. The chronology of the CO_2 injection pilot is given in Table 1.

GRANNY'S CREEK FIELD AND GEOLOGY

The Granny's Creek field is in western Clay and southeastern Roane Counties, West Virginia, and is about 25 miles northeast of the city of Charleston (see Figure 1). The field was drilled in the period from 1916 to 1944, and production has been established over an area of 2,500 to 3,000 acres (1). Well spacing on an average was 500 feet between wells, and depths to the top of the Big Injun sand were from 1,950 to 2,250 feet (3). The oil content was estimated at 6,000 bbl per acre, the total original oil content at 16,818,000 bbl, and production to November 1935 was 3,358,000 bbl (3). Maximum initial oil production per well was about 50 bbl per day (3). However, the discussion here will be confined to the southern portion of the field consisting of approximately 350 acres operated as a waterflood by Columbia Gas Transmission Corporation. This portion of the field is shown in Figure 2, and the remainder of the field extends north from the upper part of Figure 2.

The Granny's Creek field produces from the Upper Pocono Big Injun sand of Lower Mississippian Age at depths in well No. 20274 (Figure 2) of 1982 to 2,026 feet (log depths). The Granny's Creek reservoir is one of several oil reservoirs that are synclinal type traps found along the Grasslands Syncline. Bagnall (2) describes the Big Injun sand as a relatively complex stratigraphic unit ranging from a very fine-to-fine-grained argillaceous sandstone to a medium-to-coarse-grained, fairly clean sandstone at the top of the formation. The Big Injun sand has a gradational contact with the underlying Pocono shales and a sharp upper contact with the overlying Greenbrier limestone. Bagnall (2) divides the Big Injun sand into three zones, A, B, and C, on the basis of density log data and porosity development from core information. The A and B zones are in the upper, coarse-grained unit, and the C zone is in the argillaceous lower, fine-grained unit. The relationship of the three zones to the CO_2 injection pilot is shown in Figure 3 which was taken from the first monthly report for the project by Conner (4). Well Nos. 2025 and 2022 (Figure 3) were used as CO_2 injection wells and form the southeast side of the CO_2 injection pilot as shown in Figure 2. The three zones are present and open in both wells and were present and open in the other pilot wells except for well No. 2024 which was perforated in the C zone only. It is shown as an observation well on Figure 9.

Oil accumulation in the synclinal fields of West Virginia was controlled by the geological structure of the region according to Bagnall. Some of the fields are separated by minor structural highs that traverse the synclinal trend with gas occurring updip where the porosity is continuous. Other fields are separated by lithofacies changes in which the absence of porosity and permeability limits the extent of the fields. In Granny's Creek the oil accumulation was controlled by structure with gas being generally in the updip areas and oil in the lower areas. Commercial production as indicated by the drilling and development of the area depended on the presence or absence of the Big Injun sand and on its porosity and permeability.

RESERVOIR AND RESERVOIR OIL CHARACTERISTICS

The properties of the reservoir and reservoir oil in the area of the CO_2 injection pilot have been summarized in Progress Review No. 7 (5) and by Pease (6) and Goodrich (7), but the properties are outlined in Table 2 for convenience.

Oil saturation in the reservoir at the CO_2 injection pilot was estimated to be 30 percent (Table 2) after the waterflood and at the start of CO_2 injection. The average permeability was about 7 millidarcies. At a net thickness of 28 feet, porosity of 16 percent, an oil saturation of 30 percent, and a formation volume factor of 1.05, the oil content of the reservoir was about 355 bbl of stock tank oil per acre foot or 9,930 bbl per acre. Thus, the oil remaining in the pilot area after waterflooding was about 66,500 bbl of stock tank oil which was a sizable target for trial of a tertiary recovery process.

Well No. 20274 was drilled as an observation well for the CO_2 injection pilot. It was cored from a depth of 1,978 to 2,067 feet, and the cores were subjected to whole-core analyses. The results are summarized as arithmetic averages in Table 3 (see reference No. 1); however, permeabilities less than 0.1 md were not used in the averages. Well No. 20274 was drilled after the pilot area had been waterflooded. The permeability variation of the core is shown in Figure 4 where the permeabilities shown were those measured in the N-S orientation. The permeability variation is relatively large, and 50 percent of the core samples had permeabilities of 1 md or less. The permeability variations are shown for the conventional cores taken in well Nos. 2022 and 2020 in Figures 5 and 6. The permeability variations (Dykstra-Parsons k_v) are about the same for well Nos. 20274 and 2022, but the variation is larger for well No. 2020. The most permeable zone (490 md) was found in well No. 2020, yet about 14 percent of the core samples had a permeability of 0.1 md. Samples with permeabilities less than 0.1 md were not considered in Figures 4, 5, and 6. The adverse or large permeability variations found in well Nos. 20274, 2022, and 2020 indicate very strongly that high vertical sweep efficiencies were difficult to attain during the waterflood and more so in displacing the oil with liquid CO_2.

WATERFLOOD PILOT

The waterflood pilot was started in February 1964 with the injection of water into six input wells which outlined a 10.7-acre area as shown in Figure 7. It was necessary in 1966 to fracture treat the injection wells with 1,000 lb of sand to obtain an injection rate of about 50 bbl per day per well. The oil bank appeared at the producing wells in late 1966 (Figure 8). However, there had been some response observed at the producing wells in 1965. The gross oil production with time is shown on Figure 8 where a peak production rate of about 1,670 bbl per month or about 18 bbl per day per producing well was observed in October 1967. The waterflood pilot produced 43,750 bbl of gross oil for a recovery by waterflooding of 4,089 bbl per acre or about 146 bbl per acre-foot. This is considered to be very good recovery for a waterflood pilot in the Appalachian area.

FIRST CO_2 INJECTION PILOT

As a result of the good performance of the waterflood pilot, the operator started the planning of a tertiary recovery project in 1975 (8,9). Experimental work with a slim tube (75 ft long by .305 inch I.D.) packed with sand showed that miscible displacement of the Granny's Creek crude oil could be attained with pure CO_2 at about 1,050 psi and 75°F. Breakthrough with the slim tube experiment occurred at a cumulative displacement of 97.7 percent of the stock tank oil in the tube (1).

In early 1975, Columbia and the Morgantown Energy Research Center drilled and cored well No. 20274 to determine the oil saturation in the pilot area (Figure 9). Also, it was decided to conduct a miscible flood with liquid CO_2. To this end, water injection was started in August 1975 (Table 1) in the six injection wells of the waterflood pilot to raise the pressure in the pilot area above the miscibility pressure of 1,050 psi. Extensive downhole pressure surveys were made throughout the life of the CO_2 injection pilot, and there is very little doubt that the pressure in the plot area was maintained above the miscibility pressure. Construction of the CO_2 storage facilities, lines, injection equipment, and reworking of wells was started in August 1975.

On June 1, 1976, about 300 bbl of natural gasoline was injected into the pilot input wells to promote miscibility of the reservoir oil with the liquid CO_2; and on June 2, 1976, the injection of CO_2 commenced (Table 1). Injection rates for CO_2 and water from June 2, 1976, to the close of pilot operations are shown in Figure 10. Liquid CO_2 alone was injected until August 3, 1976, at which time water injection was started into the four input wells. The injection rate for CO_2 averaged 41.24 tons per day through August 3, 1976. Thereafter, water only was injected for 6 days, and from then on to December 20, 1976, slugs of water and alternating slugs of CO_2 were injected according to the planned schedule in Table 1 as shown in Figure 10. The remainder of the injection history is shown in Table 4. Generally, the injection of CO_2 and water followed four steps: (1) injection of CO_2 alone, (2) alternate injection of slugs of CO_2 and water, (3) injection of CO_2 alone, and (4) injection of water alone.

OIL PRODUCTION RESPONSE

The oil production response to the injection of CO_2 is shown on Figures 11 and 12. Figure 11 shows the rate of oil production from well No. 4254 which was the producing well inside the pilot area shown on Figure 9. Figure 12 shows the oil production rate for wells outside the pilot area and for the total pilot for the period of the pilot operation. It must be noted that Figure 12 shows total production of oil which includes the additional oil produced as a result of the CO_2 injection. The operator considered well Nos. 2021, 2024, 4254, and 20274 for reporting purposes to be inside the pattern. Well Nos. 2021, 2024, and 20274 were considered observation wells but were produced occasionally for test purposes. The small quantity of oil produced by these wells was considered as coming from inside the pilot area. Well Nos. 2047, 4049, 4591, 2043, 2044, 4090, 2046, and 2048 (see Figures 2 and 9) were considered to be outside the pattern. The additional oil resulting from the CO_2 injection was considered to be that above a base rate of 1,363 bbl per month, but when the total oil from inside and outside the pattern fell below 1,363 bbl per month, no adjustment of the additional oil was made for the deficit. On this basis, the operator calculated the total additional oil through December 31, 1979, to be 8,681 bbl as shown on Figure 12. The ratio of total CO_2 injected to additional oil was 19,759,041 ÷ 8,681 = 2,276 lb of CO_2 per barrel of additional oil. At 8.623 cu ft (14.696 psia and 60°F) per pound for CO_2 the ratio is 19,626 cu ft of CO_2 injected per barrel of additional oil.

Since the CO_2 injection pilot was a part of an old waterflood pilot that had been carried to virtual completion (see Figure 8) with a corresponding reduction in oil saturation, the remarkable result is the very high oil cuts with respect to water as shown by the upper curves on Figures 11 and 12. The oil cut at well No. 4254 was as high as 100 percent and was extremely high from July 1976 through April 1977. The oil cut for the total project, wells inside and outside the pattern (see Figure 12), was 45 percent or more for the period from June 1976 through September 1977. It must be emphasized that the period of high oil cuts with respect to water in the wells in the vicinity of the CO_2 injection wells corresponded to the period of CO_2 injection and only lasted about 2½ months after CO_2 injection was stopped. Thereafter, the oil cut decreased slowly through 1978 and 1979 (see Figure 12). Thus, it is concluded that CO_2 can be injected into a watered-out reservoir such as that in the Granny's Creek field to form a low water-cut oil bank. This is a very important consideration in the planning of future trials of CO_2 to increase recovery of oil. It would have been interesting and perhaps informative to have had CO_2 measurements at the producing wells to determine the CO_2 gas-to-oil ratio.

A comparison between Figures 10, 11, and 12 reveals a direct relationship between CO_2 injection and the production of oil as a result of the injection. There was almost no time lag between injection of CO_2 and production at well No. 4254; but after injection was stopped, oil production declined rapidly for about 5 months and then declined slowly for the next 12 months. The quick response of oil production to the injection of CO_2 could be taken as an indication of fractures. The start-up time lag was similar for the total project, but the lag after stopping the injection was longer in that the injection of water seemed to push an effective bank of CO_2 away from the injection wells (Figure 12). The principal observation here is that for this pilot at least the response to the injection of CO_2 was almost immediate as compared to waterflood operations. When the injection of CO_2 was stopped and water injection was started, oil production decreased quickly. This tends to support the thought that the oil bank generated by the CO_2 required a continuous supply of CO_2.

SPREAD OF CO_2 IN THE RESERVOIR

During the latter part of July and early August 1976, the presence of CO_2 was noted in the produced gas both inside and outside the pattern (8). On August 3, 1976, CO_2 had been found in well No. 1327 (10) which was one of the southernmost producing wells on Figure 2. Well No. 1327 is about 5,330 feet from the nearest CO_2 injection well. A summary of the gas analyses on samples taken August 3, 1976, appears in Table 5. Figure 13 shows the maximum observed CO_2 content of the gas produced at the various wells during the life of the project. Not all of the maximum CO_2 contents were observed at the same time. The maximum CO_2 content was observed for eight wells in the samples taken on January 4, 1977. Previously, five wells had maximum observed CO_2 contents on September 2, 1976, and October 29, 1976. Carbon dioxide contents were observed as high as 75.3 percent on January 4, 1977, at well No. 2047; 68.7 percent on May 4, 1977, at well No. 4591; and 75.1 percent on January 4, 1977, at well No. 2044. Such high CO_2 contents were to be expected as these wells are close to the pilot injection wells. Since many of the analyses were taken in the field with equipment not suitable for measuring CO_2 contents more than 20 percent, we only know that the CO_2 content was more than 20 percent at several wells for long periods of time. For example, well No. 2047 shows CO_2 contents more than 20 percent from September 24, 1976, to June 14, 1977. Thus, to make an accurate estimate of the amount of CO_2 produced with the oil would be difficult, if not impossible. However, Conner (11) used gas analyses and gas measurements to estimate the amount of CO_2 being produced on the dates the gas samples were taken as shown on Table 6 for the early life of the pilot. These amounts of CO_2 indicate a possible minimum amount produced and should not be construed as an estimate of the total amount of CO_2 produced on the date the samples were taken.

The movement of CO_2 was widespread over the southern portion (about 350 acres) of the Granny's Creek field. The CO_2 probably moved into the northern part of the field not shown on the map on Figure 13, but no gas analyses are available to give substance to this conjecture. Recalling that the Granny's Creek field is a synclinal accumulation of oil in the Big Injun sand with gas in the higher parts of the reservoir, significant amounts of CO_2 could have moved out of the oil bearing portion of the reservoir into the gas zones. This again is conjecture, but information on Figure 13 shows that CO_2 was found out to the edges of the oil reservoir, and Table 5 shows that the movement of CO_2 was relatively quick for a liquid-filled reservoir. A material balance of fluid injection and production could not be calculated accurately because of a lack of gas production data. However, rough estimates based on pressure distribution indicated that 6-12 percent of the CO_2 entered the pilot pattern. On the other hand, Conner (9) estimated that 3-6 percent of the CO_2 entered the pattern. After considering the spread of CO_2 over the reservoir, the possibility of migration into the gas-bearing portions of the reservoir and the difficulties of estimating the amount of CO_2 produced with the oil, it is believed accurate estimation of the amount of CO_2 that entered the pattern would be a major task. If we accept the upper limit of 12 percent and the additional oil produced inside the pattern of 4,727 bbl, the amount of CO_2 required per barrel of oil becomes (19,759,041) (0.12) ÷ 4,727 = 502 lb of CO_2 per barrel of additional oil or 4,325 cu ft of CO_2 per barrel of additional oil. The additional quantity of oil of 4,727 bbl is about 2.0 percent of the pore volume inside the pilot area, and 12 percent of the total CO_2 injected is about 3.5 percent of the pore volume under reservoir conditions. This is only 22 percent of the amount calculated previously when the overall results of the project were considered, but it should be realized that the lower ratio of CO_2 to additional oil should be viewed as a goal that might be attained in a similar reservoir with adequate confinement of the CO_2. Additional information on results of the CO_2 injection is given by Watts, Conner, Wasson, and Yost (12).

OPERATION OF PILOT AND WELLS

The mechanical problems of the CO_2 and water injection and operation of the producing wells have been described adequately by Conner (8,9), but they are summarized briefly for convenience. Care must be taken with the insulation and piping designs to prevent vapor locking the CO_2 pump. Also, pump packing and lubrication must be done properly to prevent leakage of CO_2 because the low temperature caused by a leak can freeze the packing and cause it to blow out. The original water meters were converted to CO_2 usage but proved to be inaccurate. They were replaced with turbine meters which proved more satisfactory. Although the injection system was satisfactory for the waterflood pilot, it was not satisfactory at the higher pressures required when the reservoir pressure was raised for the CO_2 pilot. No evidence of internal corrosion due to CO_2 was found.

The 12 producing wells involved in the project produced into individual tanks for each well. The original proposal called for flowing the wells, but by August 1977, it appeared that pumping was necessary to increase fluid removal from within the pattern. Rods and a pump were installed in well No. 4254 at this time. The well was treated with carbon bisulfide, reconditioned, and given a light fracture treatment to increase the producing rate. Paraffin deposition problems were found in several wells.

Otherwise, it appears that the project was relatively free of operational problems. However, in retrospect, the authors would have preferred the pumping of all the interior producing wells. Producing wells outside the pattern could have been shut in to decrease the movement of CO_2 outside the pattern. Although the reservoir in its entirety would not have been kept above the desired pressure of 1,050 psi, only small areas around the well bores would have been below the miscibility pressure. Pumping the wells probably would not have interfered with the movement of the oil to the wells.

THE SECOND PILOT OR MINIPILOT

As a result of the difficulties in interpreting the results of the first pilot, a second pilot was planned in 1978 and 1979 and was started in January 1980. For the second pilot, well No. 20274 was converted to an injection well. Well Nos. 4254 (the major producer in the first pilot) and 2024 were used as producers, and well No. 2025 was converted to a producer as shown in Figure 14. In November 1978, the rods and pump were removed from well No. 4254 in preparation for the minipilot; but after 1 month of flow, an accumulation of paraffin was found at the bottom of the tubing. The injection of CO_2 was started on January 8, 1980, in well No. 20274. There was no oil production from the pilot at that time, but almost immediately increases in water and gas production were noted in well No. 4254. There was virtually no response from well No. 2024. As a result, isotope injector and noise logs were run in injection well No. 20274. The results indicated that the CO_2 was being injected into the A and B zones, but virtually none was being injected into the C zone. Soon thereafter the logs run in well No. 4254 showed that the production of fluids was from the A and B zones. Since well No. 2024 was perforated only in the C zone, it was decided to limit injection to the C zone. Therefore, the packer in injection well No. 20274 was lowered to the top of the C zone on February 15, 1980. Subsequent indications are that all injection thereafter was into the C zone. Since injection was stopped for 9 days before the packer was lowered in the injection well, we can conclude that most of the CO_2 injection during February 1980 was into the C zone. The injection of CO_2 for the second pilot is shown in Figure 10. Well No. 2025 was used as a CO_2 injection well during the first pilot test, but it was converted to a producing well in May 1980. Oil production from the well was 35.25 bbl during May 1980. Water injection into the four surrounding injection wells continued as before in an effort to contain the CO_2 inside the pattern.

The response of the second pilot to CO_2 injection into the C zone is shown in Figure 11. Here, as in the first pilot, the oil producing rate responded almost immediately when compared to waterflooding and reached a maximum of 406.3 bbl in June 1980. The injection of CO_2 was stopped on August 19, 1980 (Table 1), after the injection of 4,236,000 lb of CO_2 (Table 4) or 15,122 reservoir bbl (about 71.7 percent of a pore volume). Water injection was started immediately into well No. 20274. Logs run during May 1980 confirmed that the production was coming from the C zone. Fluid production was obtained by flowing well Nos. 4254, 2024, and 2025. Up to 200 psi back pressure was held on the wells. Accumulated oil production for the second pilot through September 1980 was 2,007.9 bbl. Some additional oil would have been produced if allowed to decline to the base line. The oil producing rate had decreased to about 2 bbl per day (13). The ratio of CO_2 injected to additional oil was $4,236,000 \div 2,007.9 = 2,110$ lb of CO_2 per barrel of additional oil or 18,192 cu ft of CO_2 per barrel at 14.696 psia and 60°F. This was a slightly lower ratio than that for the first pilot. These ratios are summarized in Table 7. Also, the 2,007.9 bbl of additional oil was about 9.5 percent of the pore volume under the pattern.

It is our understanding that the injection of CO_2 was resumed in October 1980, stopped in May 1981, followed by water in May 1981, and CO_2 injection followed thereafter. This additional pilot operation involved techniques to control the mobility of the injected CO_2.

ECONOMICS

Table 7 contains the basis for the first and basic examination of the results of the pilots for the economics of the project. If the barrel of additional oil could not bear the cost of the CO_2 required to produce that additional barrel, then it would not bear the related costs of the pilot such as construction, equipment, operations, and engineering and management overhead expenses. Traditionally in the oil producing industry, pilot operations have not been expected to produce a profit within the accepted definitions of profit. Thus, pilots are used to prove the technical feasibility of the recovery method, but the problem remains for transforming technical feasibility into a profitable recovery method for the reservoir.

The problem of a cost of CO_2 for tertiary recovery of oil has been examined recently by Lewin and Associates, Inc. (14), and Science Applications, Inc. (15). Condensations of the Lewin report have appeared in the literature (16,17,18). The lowest delivered price for CO_2 for a quantity of 15 MMcfd from a coal-fired power plant (low sulfur) and transported 50 miles given by Science Applications, Inc. (15), was \$2.42 per Mcf (14.696 psia and 60°F). This figure gives a cost for CO_2 for each barrel of additional oil of \$2.42 x 19.357 = \$46.84 for the Granny's Creek pilots. It must be emphasized that this cost is for the CO_2 only and does not include any savings from recycling the CO_2. Also, it does not include construction, equipment, operation, or overhead. In a personal communication with the authors, Mr. E. C. Hammershaimb of Lewin and Associates, Inc., has indicated that on a field-wide basis in the Granny's Creek field about 50 percent of the total injected CO_2 would be recycled gas at a cost of \$.55 per Mcf for gathering and reinjection. On this basis of the cost of CO_2 for each additional barrel of oil would be \$28.42. The lowest cost for CO_2 for any case given by Science Applications, Inc. (15), was \$1.46 per Mcf. On the basis of the somewhat improbable premise of a demand for 75 MMcfd within 50 miles of the Granny's Creek pilot area, the cost for CO_2 if all of the injected CO_2 were purchased would be \$1.46 x 19.357 = \$29.26 per bbl. If 50 percent of the CO_2 injected were recycled gas, the cost of CO_2 for each additional barrel of oil would be decreased to \$19.45 per bbl. Kuuskraa, et al. (19), estimated the cost of CO_2 in the area to be \$2.55 per Mcf which results in a cost of CO_2 of \$49.36 per barrel of additional oil for the combined pilots. Lewin and Associates, Inc. (14) estimated the total CO_2 flooding costs for three west Texas carbonate reservoirs to be from \$26 to \$39 per gross barrel of produced oil. If the costs of the CO_2 were to be subtracted from \$26 to \$39 per gross barrel, the remaining costs would be \$14 to \$22 per barrel. In a study of five Appalachian reservoirs, Kuuskraa, et al. (19), estimated that costs per barrel of additional oil would vary from a low of \$28 for a reservoir designated as Ohio B to a high of \$45 for the Ohio A reservoir. The arithmetic average cost for the five reservoirs was \$37 with costs for the two West Virginia reservoirs being \$42 and \$36. Hammershaimb, in the private communication mentioned earlier, estimated that the cost of oil recovered by CO_2 injection in the Granny's Creek field would be \$36 per additional barrel. The \$36 per bbl included a profit of \$3.50 per bbl and a rate of return of 18 percent. However, even at the most optimistic price for CO_2 delivered to the Granny's Creek field, the total cost for the additional oil from the pilot tests exceeded the gross price for the oil except where conditions would permit recycling of 50 percent of the CO_2 at a cost of \$.55 per Mcf.

With specific reference to the Granny's Creek pilots previously, we speculated if 12 percent of the injected CO_2 had entered the first pilot pattern, the ratio of CO_2 to each barrel of additional oil would have been 4,325 cu ft per bbl, but we must consider the performance of the second pilot. Here all of the CO_2 was injected inside the pattern, but much of the CO_2 may have migrated beyond the confines of the pilot even though there may have been a better opportunity for confinement within the second pilot. Kuuskraa, et al. (19), and Hammershaimb have used computational models to estimate the average ratio of CO_2 to additional oil. The results have been summarized in Table 8 and are compared with actual results from the Granny's Creek pilots.

The differences between the CO_2/oil ratios calculated for application of the CO_2 to the entire reservoir of 6.3 Mcf per barrel and the results from the Granny's Creek pilots of 19.5 Mcf per barrel reflect the difficulties involved in computational simulation of real reservoirs and in conducting small pilots so that the results are a realistic indication of the behavior of a reservoir-wide application. Both are fraught with difficulties. The computational simulation probably did not take into account the heterogeneity of the reservoir and the effects of dispersion, viscous fingering, and channeling on the sweep efficiency of the CO_2. The performance of the pilots was influenced by the efficiency of the attempts to confine the CO_2 to the pilot areas.

SUGGESTIONS FOR IMPROVING FUTURE CO_2 PILOTS AND FIELD TRIALS

Since the pilot results have shown that liquid CO_2 under miscible conditions will displace a low water-cut oil bank from a watered-out reservoir, the principal remaining problem for pilot operation is the confinement of the CO_2. If, as we speculated, only 12 percent of the injected CO_2 entered the first pilot pattern and caused the production of 4,727 bbl of additional oil from the pattern, principally well No. 4254, the confinement of the CO_2 requires serious thought and consideration. Confinement for a pilot can be divided into two distinct problems which are (1) physical confinement within a portion of the reservoir and (2) alteration of the properties of the injected fluids to hinder the movement of CO_2 through the high permeability zones in the reservoir.

If we consider physical confinement in the specific context of the Granny's Creek reservoir in the pilot area, we must examine whether it would have been advantageous to limit injection to one zone only for both the CO_2 input well and the backup water injection wells. Otherwise, how is it known if the CO_2 is being injected into one zone and the backup water outside the pilot producers is being injected into another zone without elaborate injection and fluid entry surveys? Since the producing wells were flowed, one may question whether there was enough of a pressure sink created around the producing wells to capture as much of the oil bank as possible. The pressure sink could have been reinforced by placing the observation wells on production.

There is an alternative to the tactics mentioned in the foregoing and that would be to conduct the pilot operations in a relatively thin reservoir of limited areal extent other than Granny's Creek. Thus, the entire reservoir would be considered as the pilot, and enough CO_2 would be injected to meet the theoretical needs for the entire reservoir. The injection of water except as a mobility control agent in the CO_2 probably would not be needed. However, it is almost certain that a gathering system and recycling facilities would be needed for the produced CO_2, but the reservoir could be maintained at the miscibility pressure.

Fortunately, alteration of the properties of the injected fluids to hinder the spread of CO_2 is perhaps less controversial from an operational standpoint, but more doubt exists as to the benefits in actual practice. With the exception of alternating slugs of CO_2 and water (sometimes called the WAG process), the methods involve appreciable costs and are experimental. During pilot operations at Granny's Creek, slugs of liquid (CO_2 and water) were injected alternately by individual injection wells. There was no clear evidence of any appreciable benefit, but neither was there any indication of harm. As a result, it would be difficult to decide whether the confinement of CO_2 would have been improved by altering the frequency of alternate slugs of water and CO_2 at Granny's Creek. If a change is made in the procedure, the authors believe that the cycles should be of shorter time duration and perhaps the alternating slugs of CO_2 and water should have been started earlier in the life of the pilot. The purpose of the shorter cycles would be to achieve a more intimate mixing of the CO_2 and water so as to increase the number of interfaces between the gas and water phases. However, in considering the widespread permeability variation as shown in Figures 4, 5, and 6 for the pilot area -- for well No. 2020, 50 percent of the core samples had a permeability of less than 3 md while the maximum observed permeability was 490 md -- it is doubtful that alternating slugs of CO_2 and water were of much help in confining the CO_2. Another example of the permeability variation is to be found in the whole cores taken in well No. 20274 (details of the analyses are given in reference No. 1). The highest permeability in the N-S orientation was 31.6 md as shown on Figure 4 but with the same piece of whole core the permeability in the E-W orientation was 69.5 md. The core description indicates a horizontal crack for this piece of core. These are strong indications that something stronger than alternate slugs of CO_2 and water was needed to divert the CO_2 from the high permeability channels.

It is suggested that polymer treatments with crosslinking using either the chromium redox process (20) or the aluminum citrate process (21,22) might have been helpful. Flow experiments by Thomas (23) with polymer solutions produced physical evidence that polyacrylamides and polysaccharides reduce permeability of straight glass capillary arrays, thereby reducing the effective size of the capillary. An example of the use of these polymer treatments to remedy a thief zone in a CO_2 waterflooding project in the Lick Creek Meakin Sand Unit, Arkansas, was given by Smith and Fleming (24). The zone was calculated to have a permeability of 3,000 darcies before the treatment. In this example CO_2 injection was alternated with water injection every week. Before treatment water injection at the offending input well caused on offset producer to stop flowing within 24 hours. Since the well was not pumped, no oil production was obtained from that producer 1 week out every 2 weeks. After the treatment the oil production from the well averaged 48 bbl per day with no interruption in flow. Thus, polymer treatments are believed to merit serious consideration in planning confinement of CO_2 injection projects.

Other possibilities for altering the properties of the injected fluids have been outlined by Heller and Tabor (25) in a review of mobility control for CO_2. They discuss, in detail, the water alternated with gas (WAG), foam and thickener processes. All of these have been suggested for use with CO_2.

Results of the two tests at Granny's Creek indicate that a method to increase sweep efficiency is necessary before economic recovery of oil can be realized.

CONCLUSIONS

The results of the liquid CO_2 injection pilots in the Granny's Creek field permit the following findings and conclusions:

1. The pilots demonstrated that CO_2 can be used for tertiary recovery, and it will displace oil and form a high oil-cut bank in a watered-out reservoir.

2. Oil production response in every case was almost immediate; and after CO_2 injection was stopped and water injection was started, the oil production declined rapidly over a period of 2-3 months to very low rates.

3. Confinement of CO_2 to the pilot area was the principal problem. CO_2 spread rapidly in the liquid-filled reservoir to virtually all of the southern part of the reservoir of about 350 acres.

4. Except for weather, there were practically no operational problems. Corrosion from the CO_2 was not observed.

5. Pilot results did not demonstrate economic feasibility. The ratio of CO_2 to additional oil of 19,357 cubic feet (14.696 psia and 60°F) indicated the additional oil would not bear the probable cost of the CO_2 even under large-scale operations.

REFERENCES

1. Columbia Gas Transmission Corporation, "Technical Proposal, Tertiary Oil Recovery by Carbon Dioxide Injection," February 1976.

2. Bagnall, William D., "A Geological Investigation of the Granny's Creek Field, Clay County, West Virginia," Attachment B, Columbia Gas Transmission Corporation Proposal, February 1976 (See Reference No. 1).

3. Whieldon, Charles E., Jr., and William E. Eckard, "West Virginia Oil Fields Discovered Before 1940," Bulletin 607, U.S. Bureau of Mines, Washington, 1963.

4. Conner, William D., "Tertiary Oil Recovery by CO_2 Injection," Contract No. E(49-18)-2239, August 1976, FE 5302-1.

5. ERDA, "Contracts and Grants for Cooperative Research on Enhancement of Recovery of Oil and Gas," Progress Review No. 7, July 1976, BERC-76/3.

6. Pease, Rodney W., "Acquisition, Classification, and Evaluation of Engineering and Geological Information and Characteristics of West Virginia Petroleum Reservoirs Amenable to Enhanced Oil Recovery Technology, Particularly Carbon Dioxide Injection," Volume I: Methodology and Results, by Gruy Federal, Inc., May 1979, Contract No. DE-AC05-78MC05602.

7. Goodrich, John H., "Target Reservoirs for CO_2 Miscible Flooding -- Final Report," Volume II: Full-Scale and Pilot Field Tests by Gruy Federal, Inc., October 1980. Contract No. DE-AC21-79MC08341.

8. Conner, William D., "Granny's Creek CO_2 Injection Project, Clay County, West Virginia," Paper C-2 Presented at ERDA Symposium on Enhanced Oil, Gas Recovery, and Improved Drilling Methods, Tulsa, August 30 - September 1, 1977.

9. Conner, William D., "Granny's Creek CO_2 Injection Project, Clay County, West Virginia," Paper O-6 in Proceedings, Volume 2 -- Fifth Annual DOE Symposium -- Enhanced Oil and Gas Recovery and Improved Drilling Technology, Tulsa, August 22-24, 1979.

10. Conner, William D., "Tertiary Oil Recovery by CO_2 Injection," Contract No. EF-76-C-05-5302, November 1976, FE 5302-2.

11. Conner, William D., "Tertiary Oil Recovery by CO_2 Injection," Contract No. EF-76-C-05-5302, December 1976, FE 5302-3.

12. Watts, R. J., W. D. Conner, J. A. Wasson, and A. B. Yost, "CO_2 Injection for Tertiary Oil Recovery, Granny's Creek Field, Clay County, West

Virginia," SPE 10693 for Presentation at the Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 4-7, 1982.

13. Department of Energy, "Contracts for Field Projects and Supporting Research on Enhanced Oil Recovery and Improved Drilling Technology," Progress Review No. 24, DOE/BETC-80/4, September 30, 1980.

14. Lewin and Associates, Inc., "Economics of Enhanced Oil Recovery, Final Report," Contract No. DE-AC01-78ET12072, Fossil Energy Report No. DOE/ET/12072-2.

15. Anada, H., and Others, Science Applications, Inc., "Feasibility and Economics of By-Product CO_2 Supply for Enhanced Oil Recovery, Final Report," Contract No. DE-AM21-78MC08333, Task 36, September 1981.

16. Anonymous, "New Study Updates Economics of Five EOR Techniques," Oil and Gas Journal, May 18, 1981, p. 84.

17. Anonymous, "DOE Updates Enhanced Recovery Economics," Oil and Gas Journal, July 13, 1981, p. 43.

18. Perry, Charles W., "The Economics of Enhanced Oil Recovery and Its Position Relative to Synfuels," Journal Petroleum Technology, Volume 33, November 1981, p. 2033.

19. Kuuskraa, V. A., E. C. Hammershaimb, Frank Morra, and Donald Wicks, "Technical and Economic Potential of Enhanced Oil Recovery in Appalachia," SPE 10373, Eastern Regional Meeting, Columbus, Ohio, November 4-6, 1981.

20. Clampitt, R. L., and J. E. Hessert, "Method for Controlling Permeability," U.S. Patent No. 3,785,437, January 15, 1974.

21. Needham, R. B., C. B. Threlkeld, and J. W. Gall, "Control of Water Mobility Using Polymers and Multivalent Cations," SPE 4747, Presented at the Third Symposium on Improved Oil Recovery, Tulsa, April 22-24, 1974.

22. Gall, J. W., "Subterranean Formation Permeability Correction," U.S. Patent No. 3,762,476, October 2, 1973.

23. Thomas, C. P., "The Mechanism of Reduction of Water Mobility by Polymers in Glass Capillary Arrays," Soc. Petroleum Engineers. J., June 1976, p. 130, Trans. AIME, Volume 261.

24. Smith, R. V., and P. D. Fleming, III, "Fundamental Mechanisms Influencing Enhanced Recovery of Crude Oil," Proc. Tenth World Petroleum Congress, Volume 3, p. 291, 1980.

25. Heller, John P., and Joseph J. Tabor, "Mobility Control for CO_2 Floods -- A Literature Survey Topical Report," by New Mexico Petroleum Recovery Research Center, New Mexico Institute of Mining and Technology, Contract No. DE-AC21-79MC10683, October 1980, DOE/MC/10689-3.

TABLE 1

Chronology for the Granny's Creek CO_2 Injection Project, West Virginia

August 1975	Water injection started into the six original pilot input wells to raise the reservoir pressure to 1,000-1,100 psi.
August 1975 to June 1, 1976	Wells were reworked and CO_2 storage and injection equipment was installed.
June 1, 1976	Approximately 300 bbl of natural gasoline injected into pilot input wells to promote miscibility.
June 2, 1976	CO_2 injection began at rate of 22 tons per day (379,400 cu ft at 14.696 psia and 60°F).
August 3, 1976	CO_2 injection was stopped and water injection was started at the four pilot input wells. CO_2 injection to August 3 averaged 41.24 tons per day.
August 9, 1976	Water-CO_2 schedule as follows for each input well: 1. 800 tons CO_2, 1,000 bbl water. 2. 500 tons CO_2, 850 bbl water. 3. 400 tons CO_2, 680 bbl water. 4. 300 tons CO_2, 510 bbl water.
January 10, 1977	Injection of CO_2 stopped. Injection continued with water to maintain pressure.
March 8, 1977	CO_2 injection resumed on the four pilot input wells.
June 14, 1977	CO_2 injection was completed with total of 19,759,041 lb of liquid CO_2 injected. Immediately followed by injection of water at average rate of 49 bbl per day per well.
January 8, 1980	CO_2 injection into well No. 20274 was started for the second pilot. Oil production due to CO_2 injection prior to the mini-pilot was 8,681 bbl.
February 15, 1980	Packer was lowered in injection well No. 20274 so that all CO_2 injection was into the C zone.
May 1980	Well No. 2025 was converted to production.
August 19, 1980	CO_2 injection was stopped after injection of 2,118 tons of CO_2. CO_2 injection was followed immediately by water injection. Accumulated oil production through September 1980 was 2,007.9 bbl due to CO_2 injection.

TABLE 2

Characteristics of the Reservoir, Reservoir Oil, and Some Operating Results for the Granny's Creek CO_2 Injection Pilot

Reservoir	
Formation	Pocono Big Injun
Lithology	Sandstone
Depth, feet	2,000-2,100
Temperature, °F	73
Net effectiveness thickness, feet (pilot area)	28
Porosity, %	16
Permeability, millidarcies	7
Oil saturation after waterflood, %	30
Water saturation after waterflood, %	70
Reservoir Oil	
Type	Paraffinic
Gravity, °API	45
Viscosity at 75°F, cp	3.14
Formation volume factor after water-flood, res. bbl/stock tank bbl	1.05
Minimum miscibility pressure with CO_2, psi	1,000-1,050
Oil Recovery	
Estimated primary, bbl per acre	2,900
Estimated waterflood, bbl per acre	4,100
First Pilot	
Pattern	5-spot 3 observation wells
Size, acres	6.7
Pore volume, bbl	233,000
Second Pilot	
Pattern	4-spot
Size, acres	.85
Pore volume, bbl	21,100
Well Operation	
Injection bottom-hole pressure, psi (CO_2 and water)	1,800
Producing wells	Flowing and pumping

TABLE 3

Summary of Whole-Core Analyses on All Cores and by Zones from Well No. 20274

All Cores							
		Average Permeability, md			Porosity	Saturation %	
Zone	Depth	N-S	E-W	Vertical	%	Oil	Water
A-C	1,978-2,005	5.2	4.0	1.8	8.4	15.3	48.6
C	2,005-2,022	5.6	7.8	3.0	17.6	13.2	55.6
--	2,022-2,067	0.4	0.5	<0.1	12.7	12.2	48.9

By Zones				
Zone	Depth	Average Permeability, md	Porosity %	Oil Saturation %
A	1,980-1,986	7.2	12.2	9.4
B	1,992-1,997	6.6	8.4	19.6
C	2,002-2,022	6.5	15.8	13.7

Permeabilities less than 0.1 md not included in averages.

TABLE 4

Schedule of CO_2 and Water Injection for the Granny's Creek CO_2 Injection Pilot

Date From	Date To	CO_2 Injected, lb	Water Injected, bbl
06-02-76	08-03-76	5,195,940	-0-
08-03-76	08-09-76	-0-	733
08-09-76	12-20-76	7,056,016	6,126
12-20-76	01-03-77	-0-	613
01-03-76	01-10-77	214,460	354
01-10-77	02-28-77	-0-	2,229
02-28-77	03-08-77	80,500	510
03-08-77	06-14-77	7,212,125	-0-
06-14-77	12-31-79	-0-	136,694
	TOTAL	19,759,041	147,259
01-08-80*	08-19-80*	4,236,000	-0-
	GRAND TOTAL	23,995.041	147,259

*Second pilot or minipilot.

TABLE 5

Wells Showing Presence of CO_2 in Produced Gas on August 3, 1976

Well	Distance,* ft	Direction from Pilot	CO_2, %
1327	5,330	South	4.0
1265	3,060	South	8.0
1258	2,080	South	8.0
2040	1,080	South	3.0
2043	540	South	>20.0
4258	1,200	North	2.0
4090	770	North	9.0
2048	480	West	1.0

Note: CO_2 injection started June 2, 1976.

*Distance to closest CO_2 injection well.

TABLE 6

Production of CO_2 from Certain Producing Wells Calculated from Gas Analyses and Gas Producing Rates from Reference No. 11

Date	Total CO_2 Produced, lb per day	No. of Wells Tested	No. of Wells With CO_2
09-02-76	533	32	20
09-24-76	771	33	19
10-29-76	1,253	40	27
11-26-76	288	33	18

TABLE 7

Recovery of Additional Oil By Both CO_2 Injection Pilots in the Granny's Creek Field

Pilot	Additional Oil, bbl	CO_2 Injected, lb	CO_2/Oil, lb per bbl	CO_2/Oil, scf per bbl*
First Pilot, All Zones	8,681	19,759,041	2,276	19,626
Minipilot, Zone C	2,007.9**	4,236,000	2,110	18,192
Both Pilots	10,688.9	23,995,041	2,245	19,357

*Standard cubic feet at 14.696 psia and 60°F.
**Through September 1980.

TABLE 8

Comparison of Actual CO_2 Ratios for the Granny's Creek Pilots with Results from Computational Models for Appalachian Reservoirs

Reservoir	CO_2-Oil Ratio, Mcf/bbl
West Virginia A (19)	9.5
West Virginia B (19)	5.5
Kentucky A (19)	9.7
Ohio A (19)	7.6
Ohio B (19)	6.6
Rock Creek, WV	5.8*
Granny's Creek, WV	6.3*
Granny's Creek First Pilot (Actual)	19.6
Granny's Creek Second Pilot (Actual)	19.4

*Calculated by E. C. Hammershaimb.

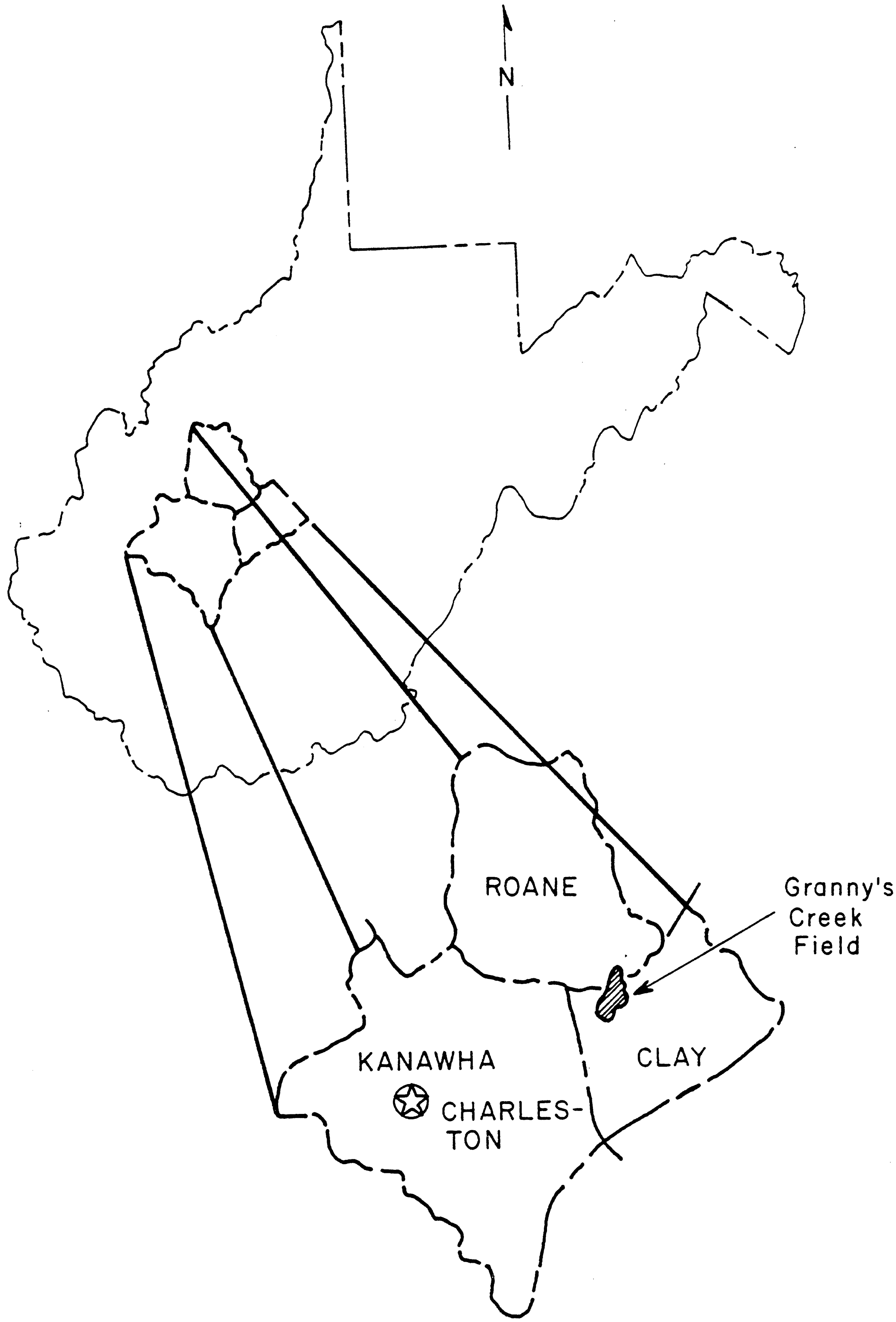

Figure 1. - Location of Granny's Creek Field in Clay County, West Virginia.

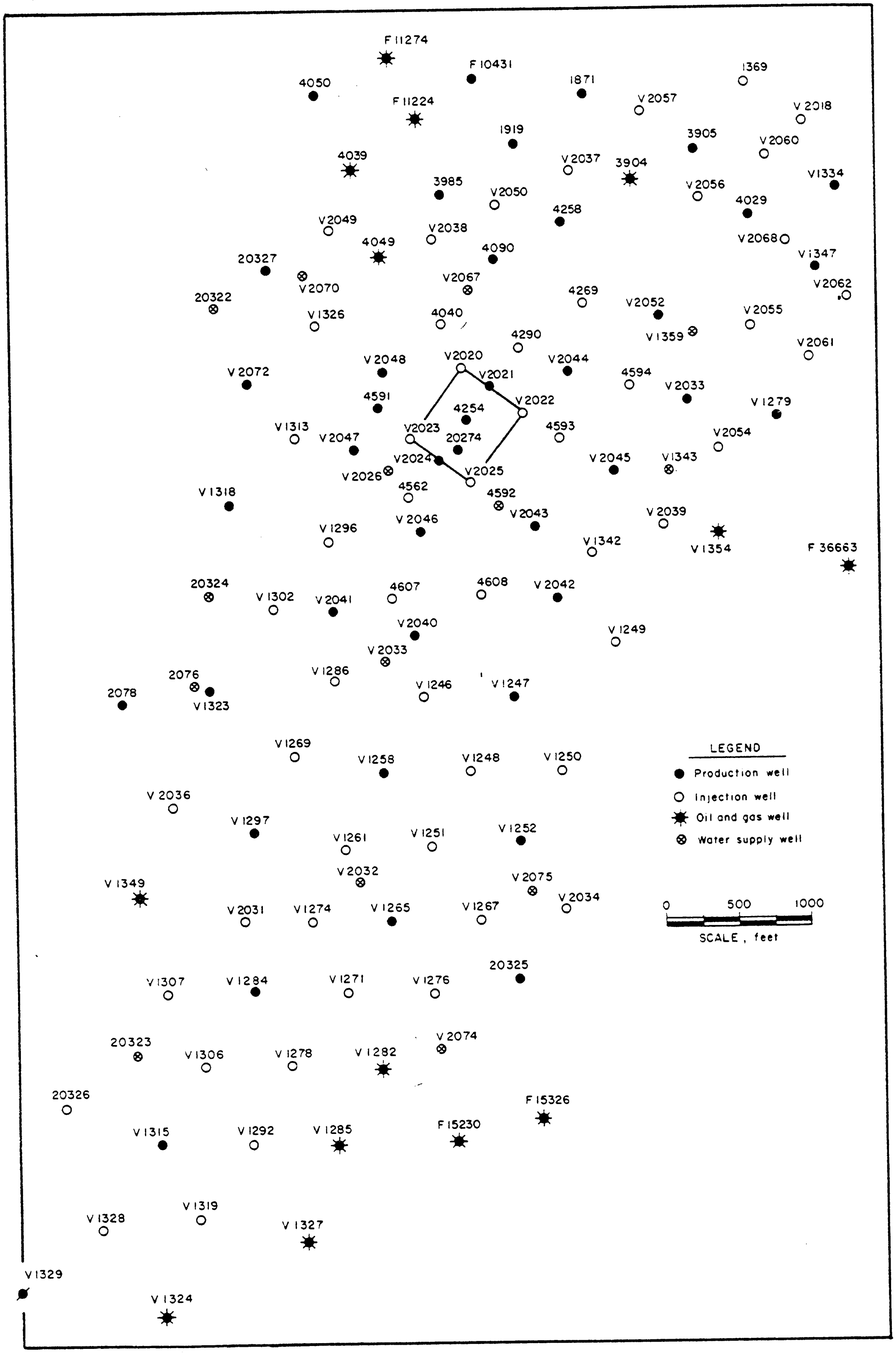

Figure 2. - South 350 acres of Granny's Creek Field, Clay County, West Virginia.

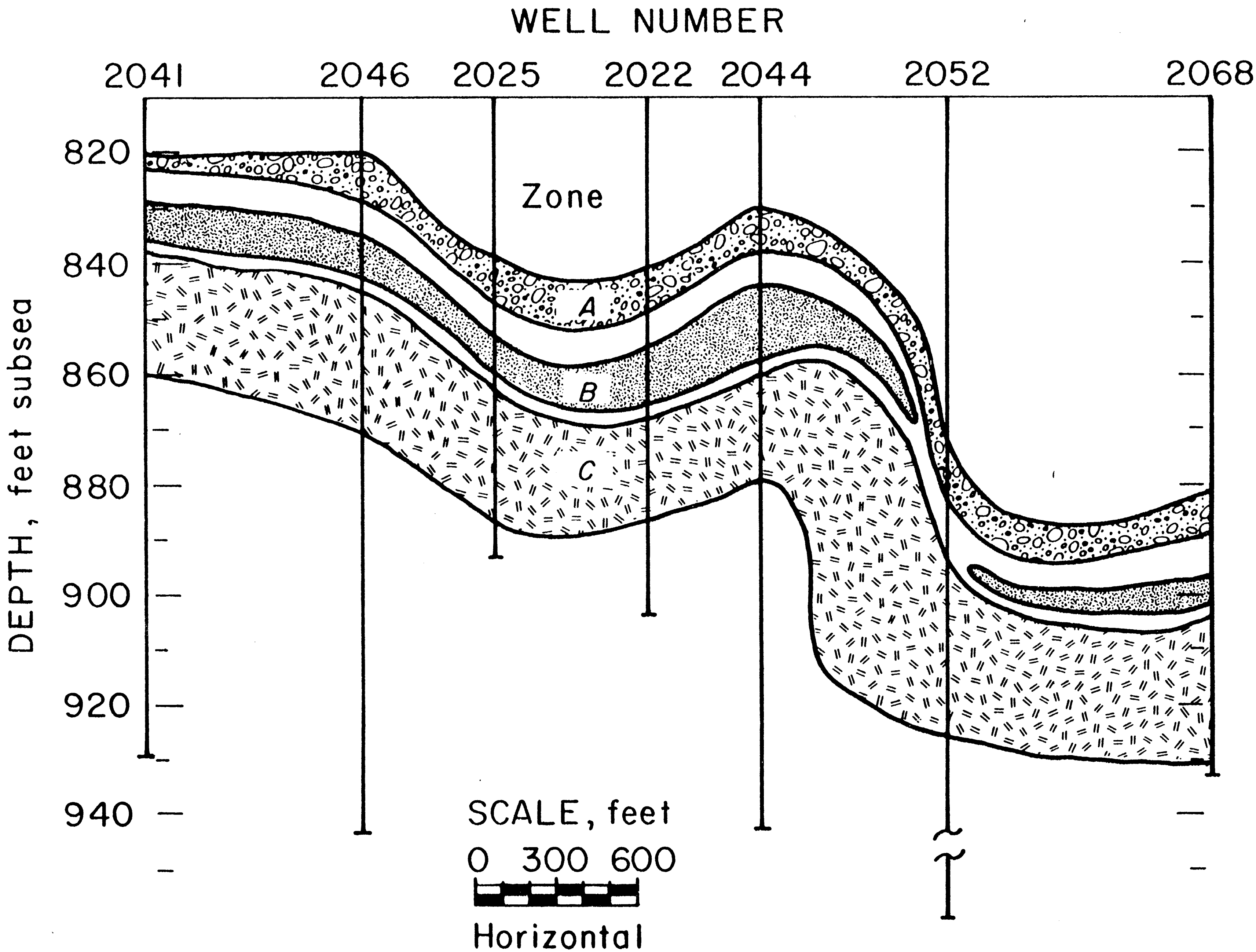

Figure 3. - Schematic cross section for Big Injun Sand in area of pilot (from reference 4).

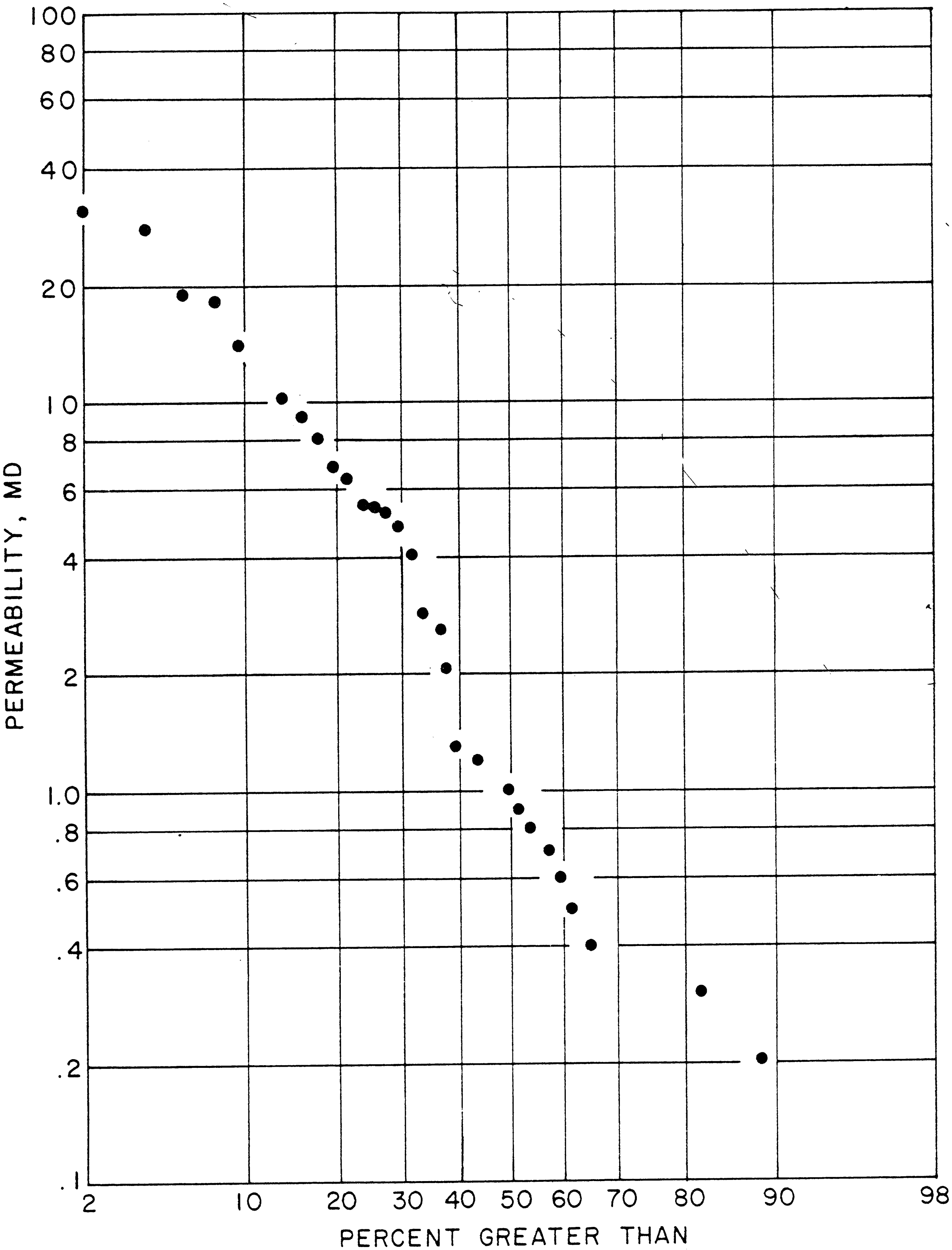

Figure 4. - Permeability variation for N-S alignment of whole cores taken from Well 20274.

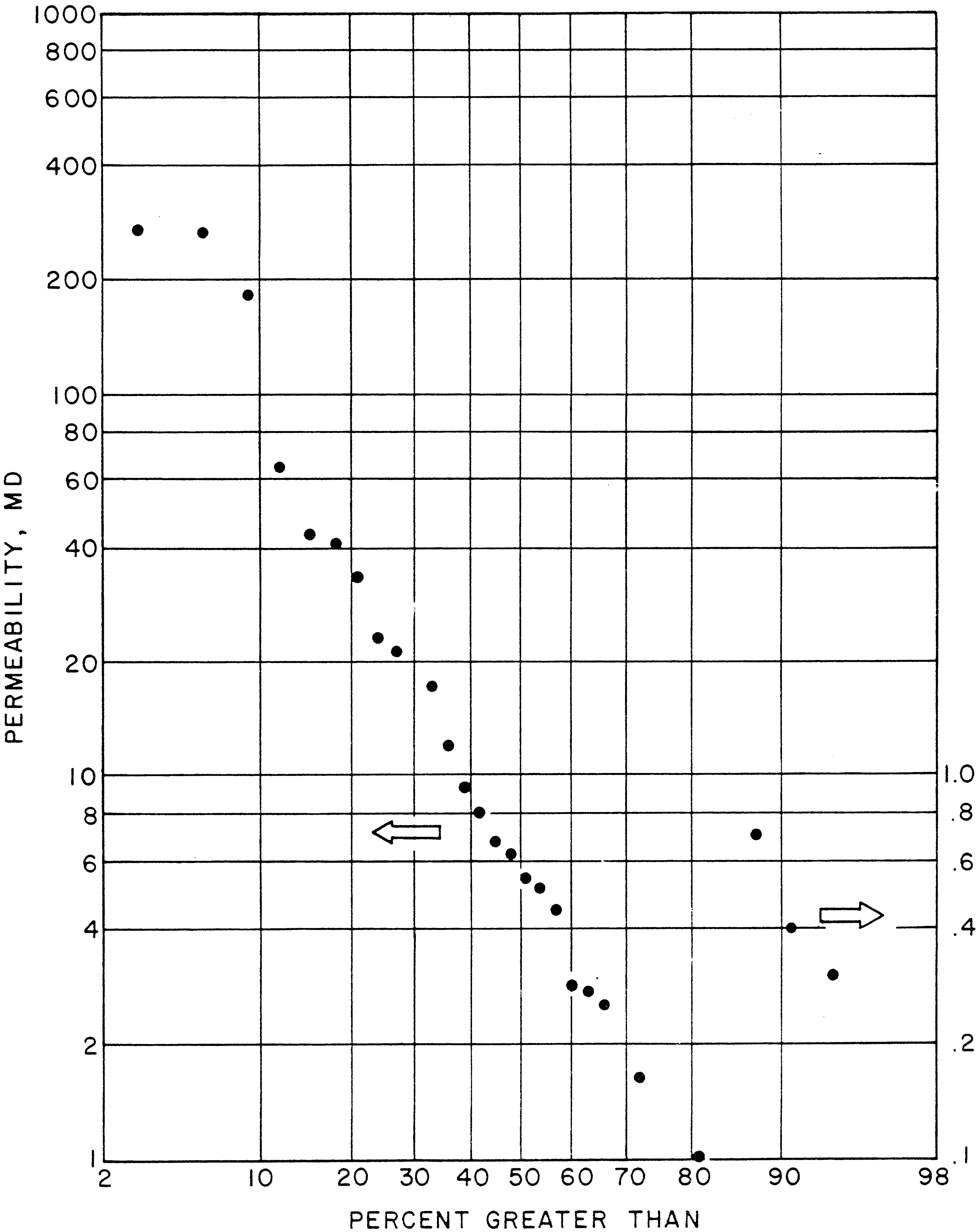

Figure 5. - Permeability variation for conventional cores from Well 2022.

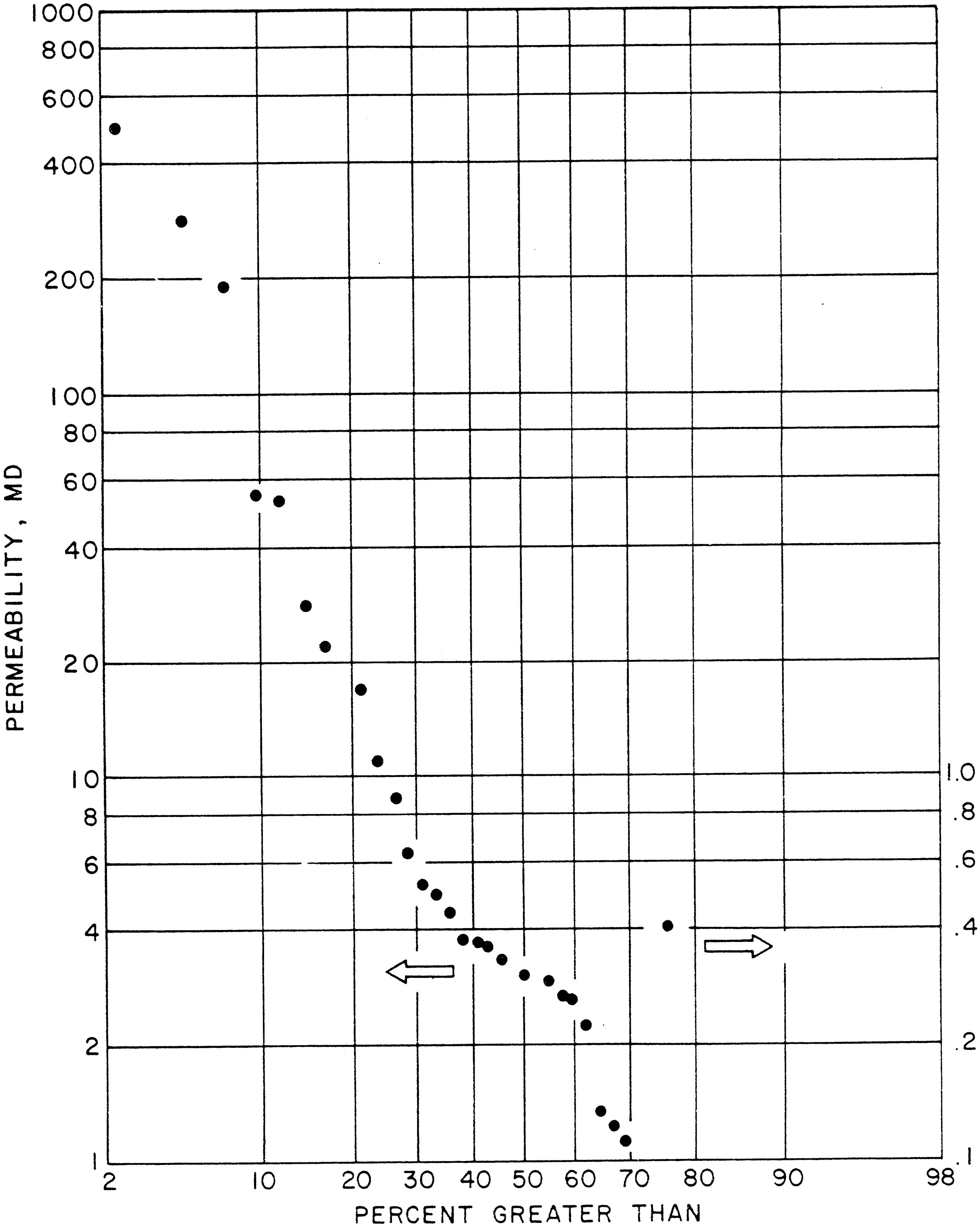

Figure 6. - Permeability variation for conventional cores from Well 2020.

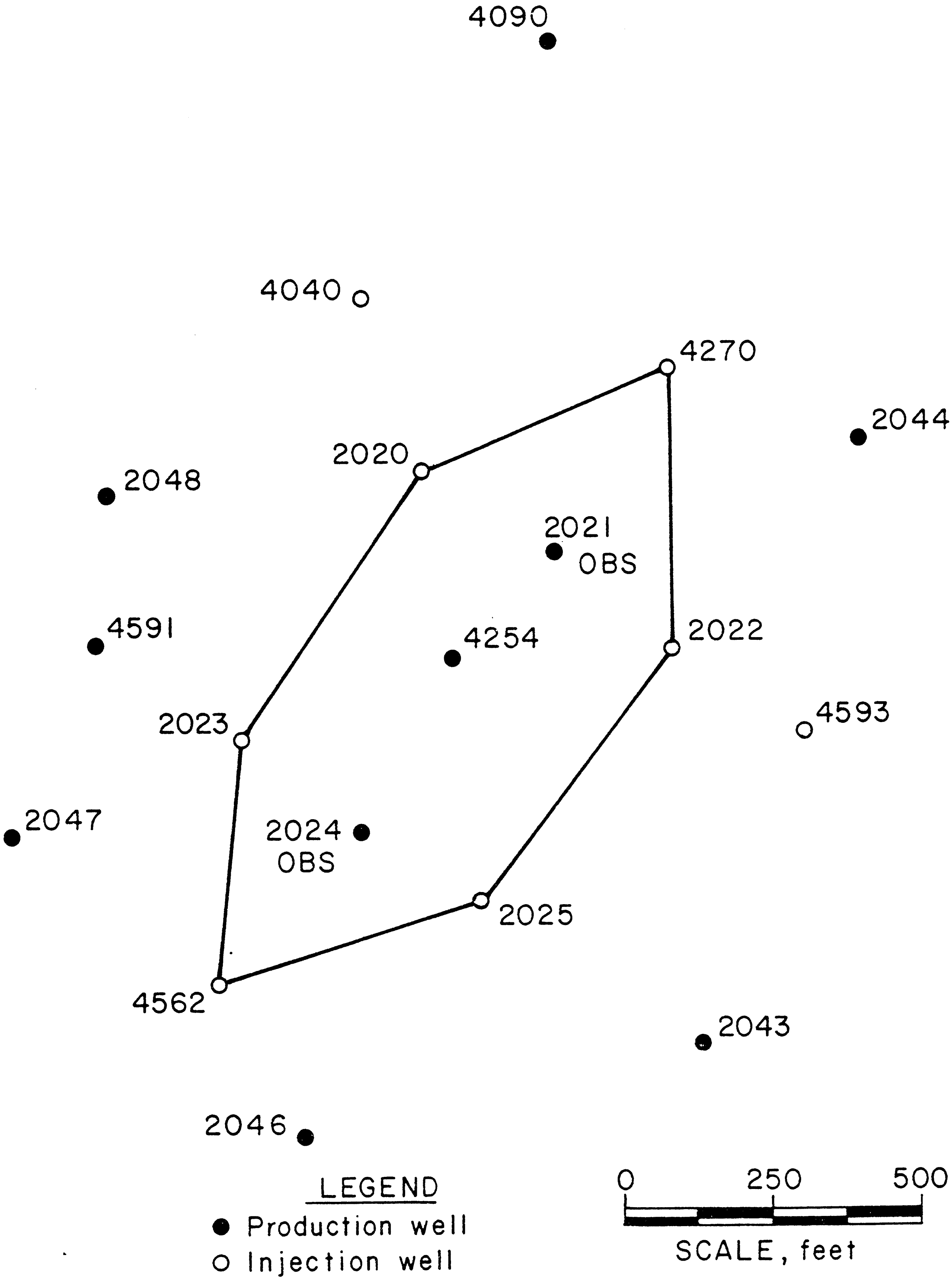

Figure 7. - Original waterflood pilot, Granny's Creek Field, Clay County, West Virginia.

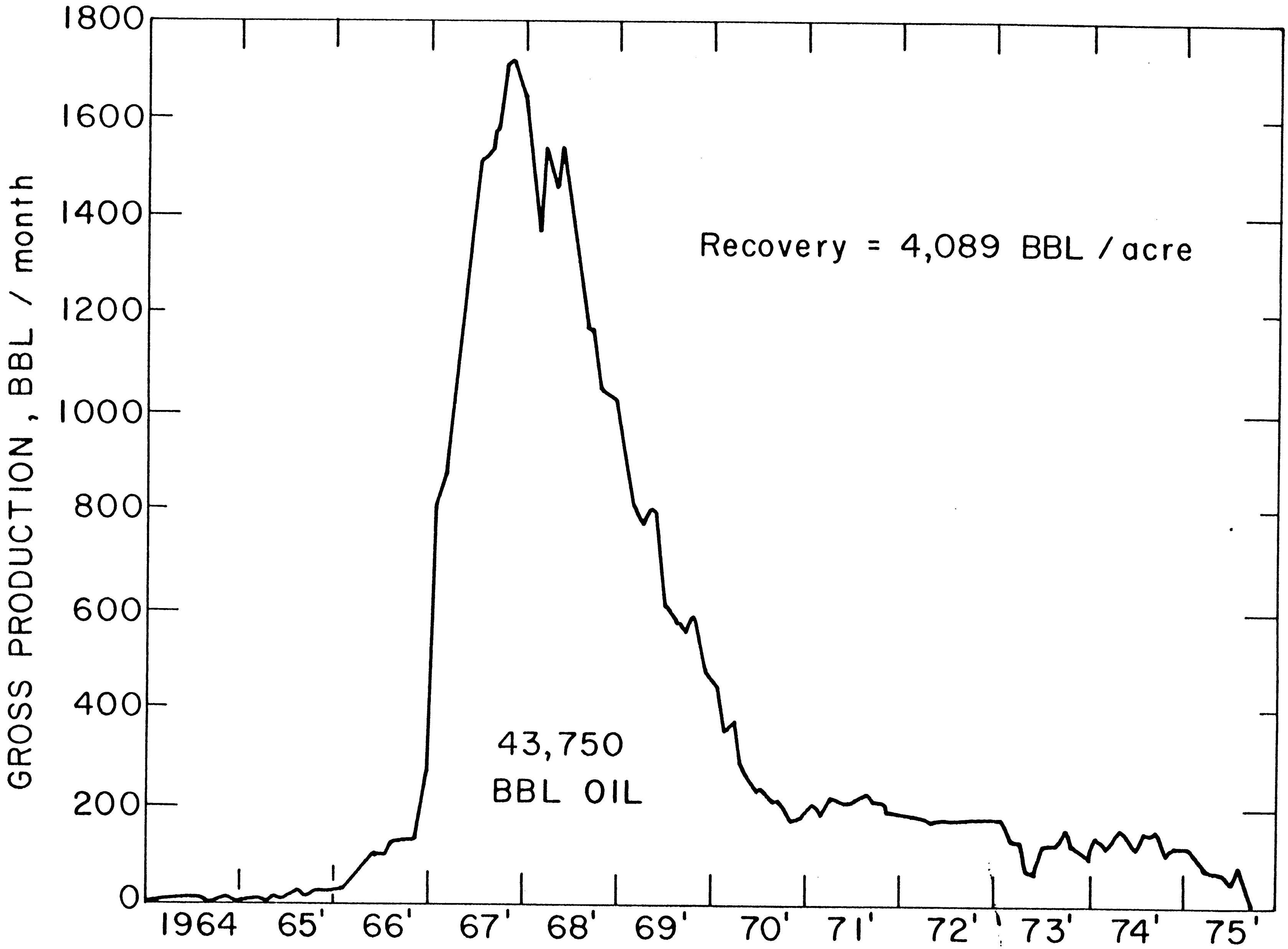

Figure 8. - Production history of waterflood pilot, Granny's Creek Field, Clay County, West Virginia.

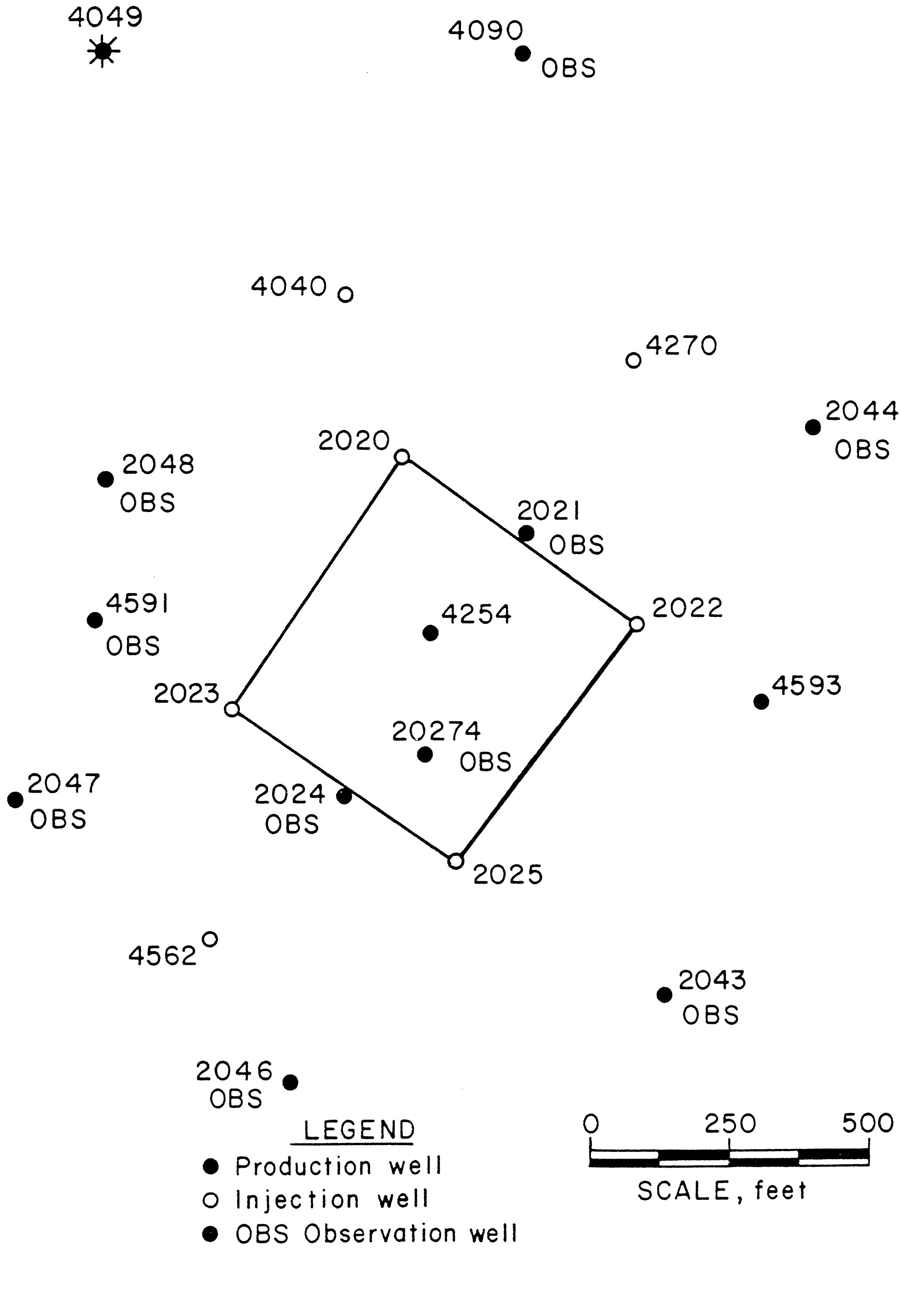

Figure 9. - First CO_2 injection pilot, Granny's Creek Field, Clay County, West Virginia.

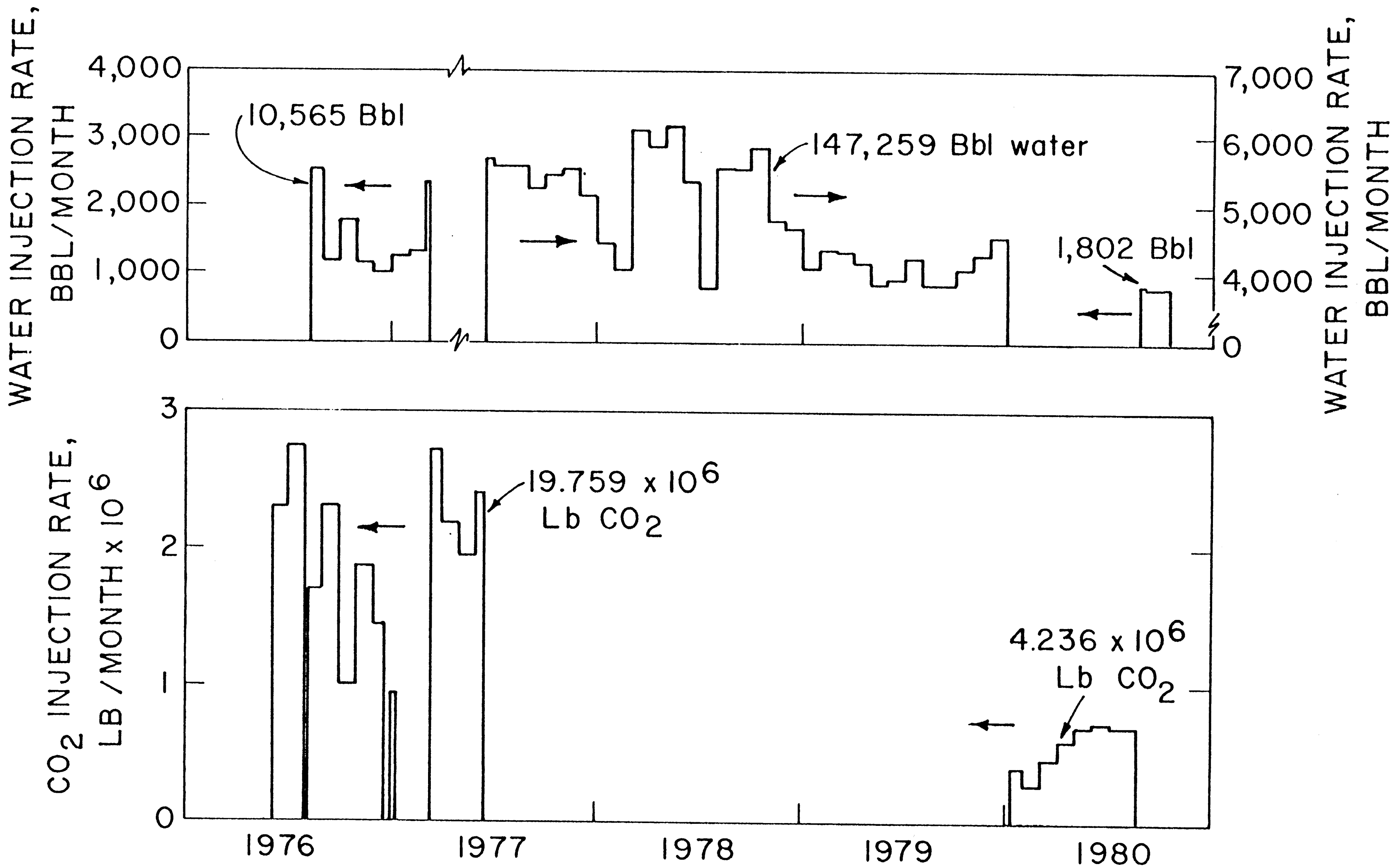

Figure 10. - Injection rates for CO_2 and water for the CO_2 injection pilots, Granny's Creek Field, Clay County, West Virginia.

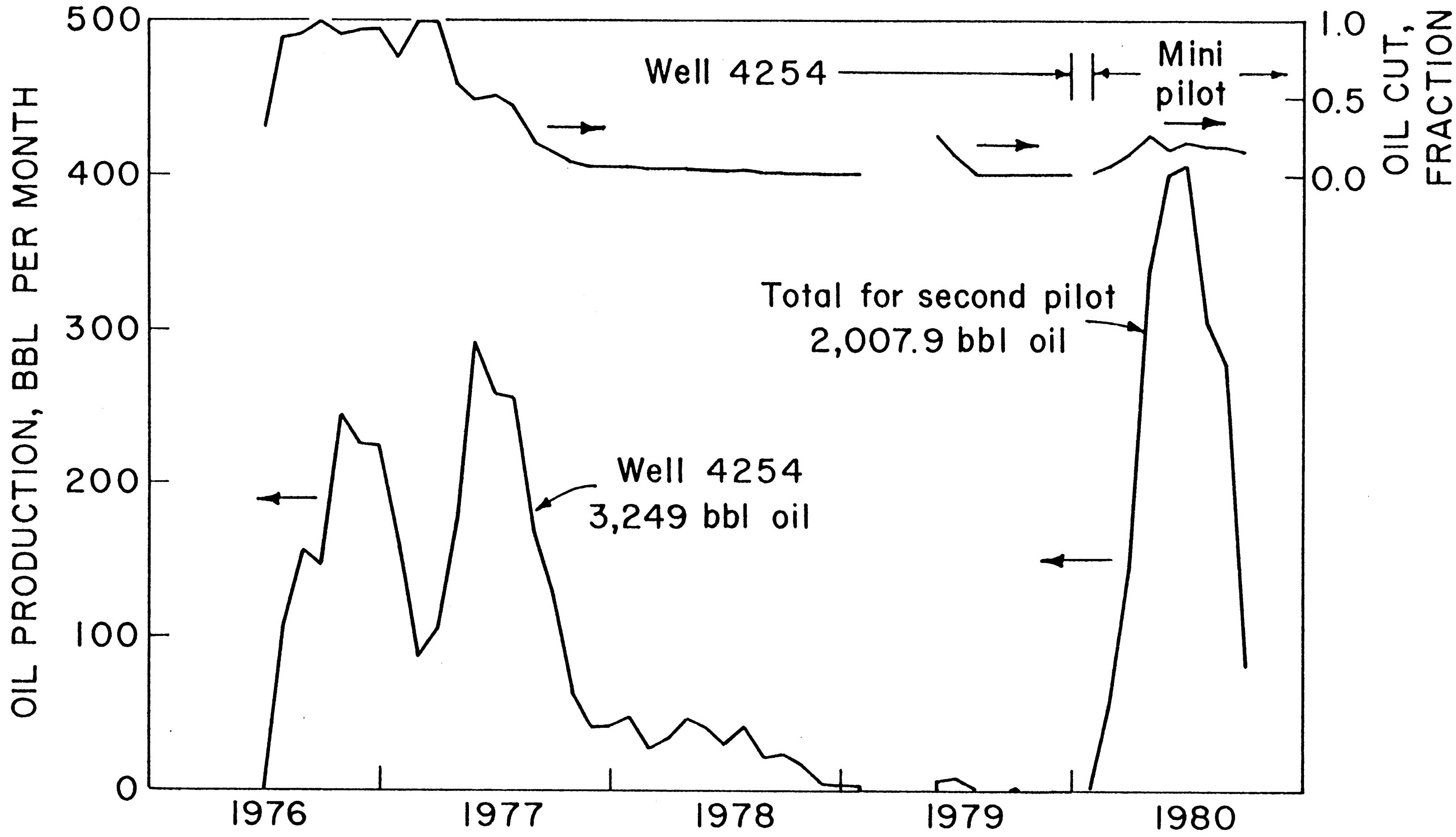

Figure 11. - Oil production response to CO_2 and water injection at Well 4254 and for the second pilot, Granny's Creek Field, Clay County, West Virginia.

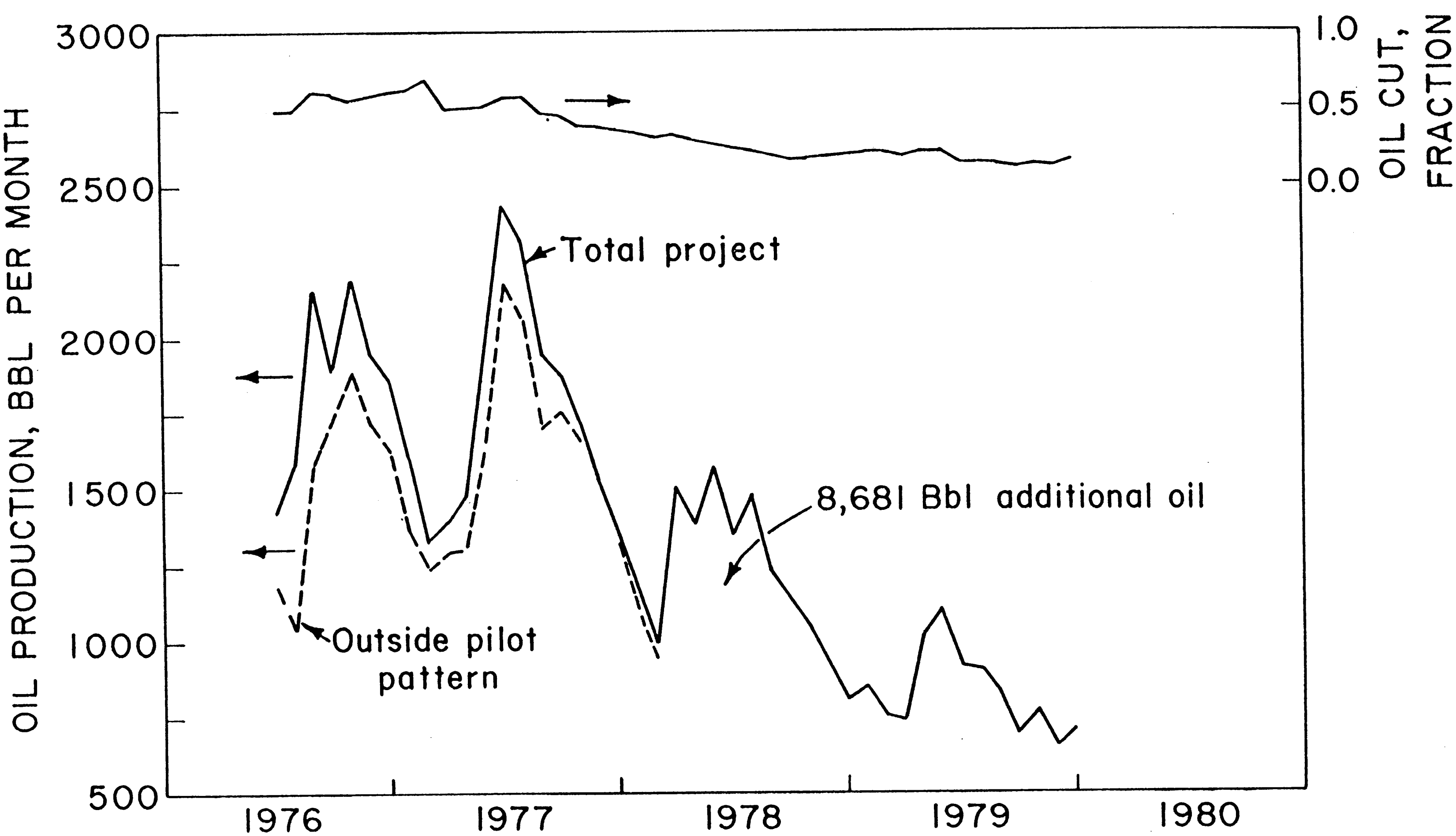

Figure 12. - Oil production response to CO_2 and water injection for the first pilot, Granny's Creek Field, Clay County, West Virginia.

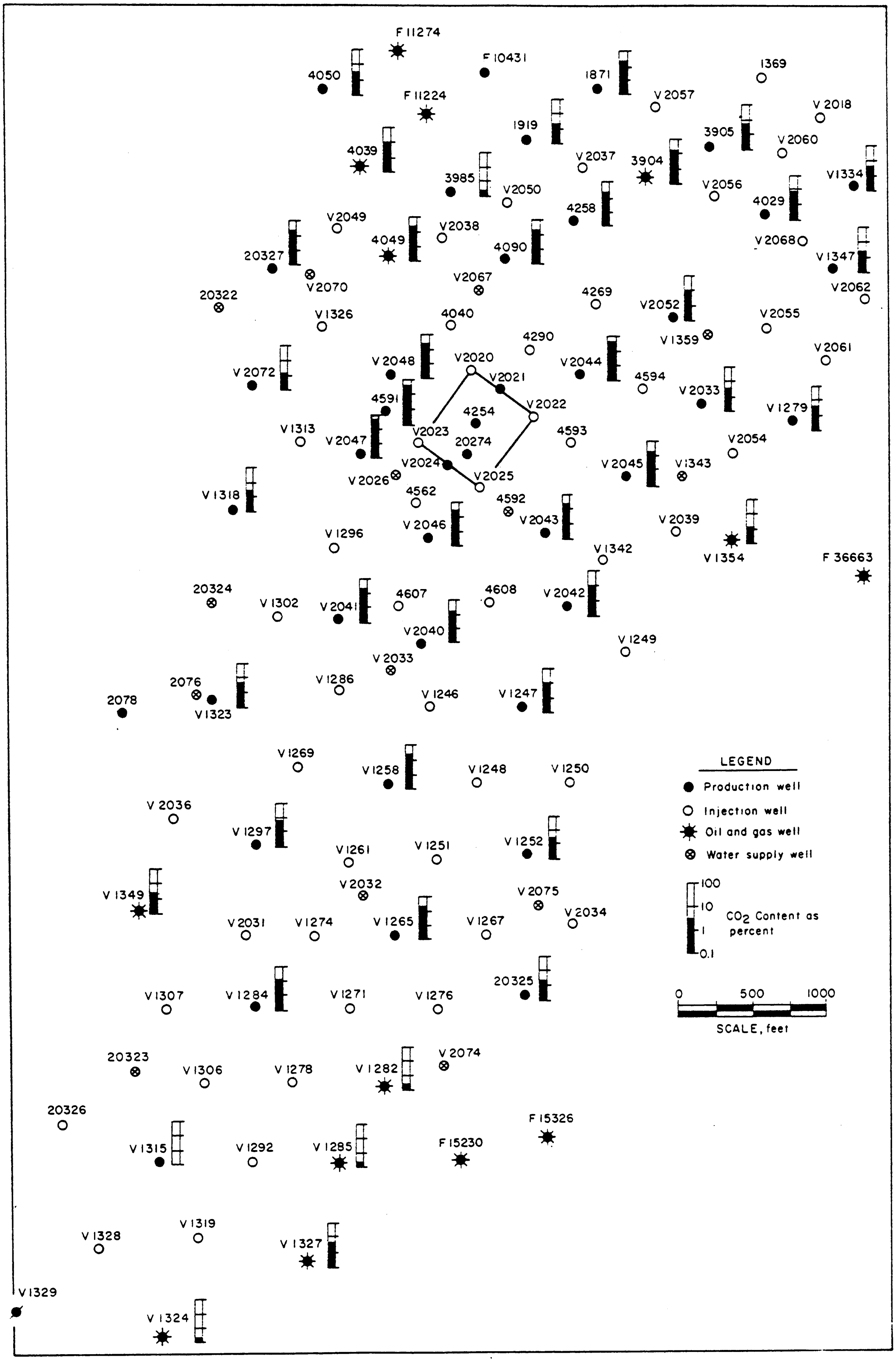

Figure 13. - Maximum CO_2 content observed by wells showing spread of CO_2 through Granny's Creek Field, Clay County, West Virginia.

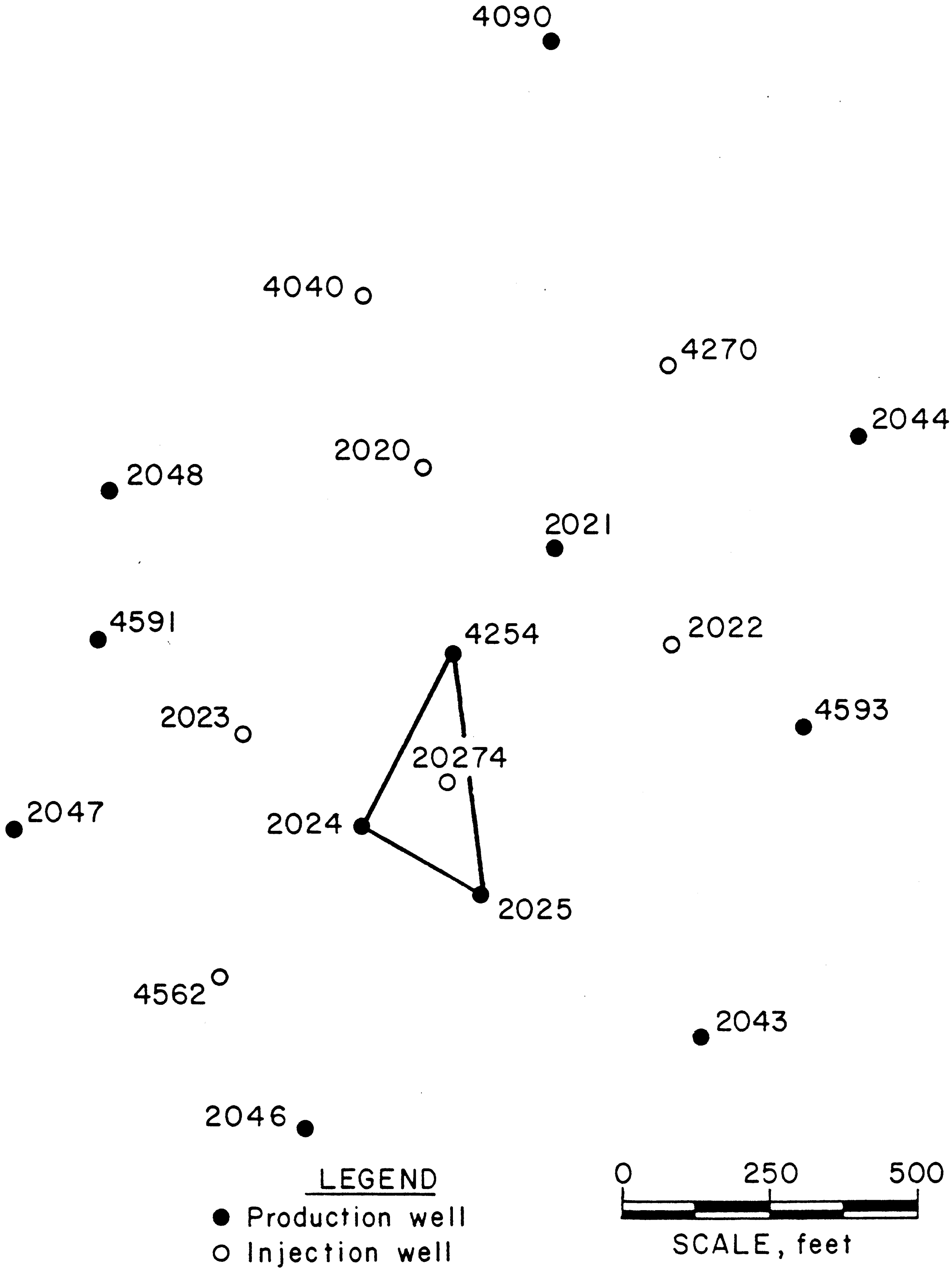

Figure 14. - Second CO_2 injection pilot, Granny's Creek Field, Clay County, West Virginia.

☆U.S. GOVERNMENT PRINTING OFFICE: 1983- 669-030/7