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1957

SYMPOSIUM ON WATERFLOODING

Held at Urbana, Illinois
October 28-30, 1956

Paul A. Witherspoon
Chairman

BULLETIN 80

ILLINOIS STATE GEOLOGICAL SURVEY
JOHN C. FRYE, *Chief*
URBANA, ILLINOIS

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Topographic Mapping in Cooperation with the United States Geological Survey

FOREWORD

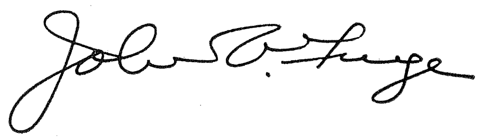
The Illinois State Geological Survey, since it was established fifty years ago, has been charged with the responsibility of research and service in the fields of basic geology, development of mineral resources, and utilization of both raw minerals and their products.

For more than fifteen years Illinois has been the leading oil producing state east of the Mississippi River, but in recent years primary production has fallen far below the peak production attained during the early 1940's. For that reason the importance of secondary methods of oil recovery—particularly waterflooding—has been recognized and the number of waterflood operations has increased rapidly. The expansion of the relatively new technique in Illinois oil fields has created a pressing need for a quick exchange of ideas, experience, and information.

As part of the Survey's service program for the oil industry and citizens of the State, we decided two years ago to begin a series of biennial conferences on problems and techniques of secondary recovery. The second such conference for petroleum engineers was held in Urbana on October 28-30, 1956, and this bulletin contains the reports that were presented.

Because the conference was a cooperative effort by industry and other agencies as well as the Geological Survey, the affiliation of the author of each paper is indicated and we extend our thanks to all those who took part in this venture. The Geological Survey, of course, can take credit and responsibility for only those contribuutions by its staff members.

We are publishing this bulletin at the request of members of the oil industry in the hope that the industry at large may benefit from the values of the conference.



CONTENTS

INTRODUCTORY REMARKS

PAUL A. WITHERSPOON

Illinois State Geological Survey
Urbana, Illinois

Waterflooding, as an effective means of increasing crude oil production, has become increasingly important to the oil industry of the Illinois basin. A glance at the record of annual oil production for the State of Illinois (fig. 1) shows the significant increases in production that have been attained, especially in the past few years. It is important to note that crude oil production has increased by amounts that have grown steadily each year. The net effect has been to bring the industry back to a level of production comparable to that of 1943, a time when Illinois production was declining rapidly from the peak year of 1940. It is quite apparent, however, that the present waterflood increases have resulted in a much more stable oil production than that during the flush period of the early 1940's.

It is also apparent (fig. 1) that the magnitude of waterflood oil recovery has now reached substantial proportions. In 1955, a total of 81,131,000 barrels of oil were produced in Illinois of which almost 26,600,000 barrels, or 33 percent, were produced by waterflooding. On the basis of records for the first eight months it is estimated that Illinois will produce 83,000,000 barrels of oil in 1956, and that waterflooding will account for about 33,000,000 barrels, or 40 percent.

The time is not far away when this method of secondary oil recovery will be contributing the major portion of the State's total oil production. Indeed, waterflood oil reserves are conservatively estimated to be at least 1.5 billion barrels, whereas proved primary reserves are only of the order of 500 million barrels. From the standpoint of past performance, Illinois had produced 1.8 billion barrels of oil at the end of 1955, of which only 100 million barrels were due to waterflooding. It is apparent that the results of this method of secondary recovery have just recently become statistically important to the oil industry of the state.

The Illinois State Geological Survey early recognized the possibilities of waterflooding as an effective and economical means of stimulating oil production. One need only mention the pioneer work of the late Dr. Frederick Squires who, as the first petroleum engineer on the Survey staff, recognized the potentialities of waterflooding in the early 1930's and labored with unceasing effort to publicize this method of increasing oil recoveries. It was a long slow process of education, and it is fitting that Dr. Squires lived to witness the gratifying effect of waterflooding on oil production all over the State prior to his death in August 1956.

As the application of waterflooding methods has spread among all operators, from major oil companies to small independents, the need for a better understanding of the fundamental factors involved and the most desirable field techniques has become apparent. Consequently, the Illinois State Geological Survey, as part of its petroleum engineering activities, has undertaken a series of biennial conferences on various aspects of waterflooding.

The first of this series was held in Urbana on February 10 and 11, 1955, with Professor Holbrook G. Botset, Head of the Department of Petroleum Engineering at the University of Pittsburgh, as guest lecturer. Professor Botset laid the groundwork for future conferences by a very fine presentation of fundamental concepts regarding the production of fluids from reservoir rock and the special conditions that affect the success of waterflood operations. Some 258 persons attended the conference despite discouraging weather conditions. The enthusiasm with which Professor Botset's lectures were received was an adequate indication of the great interest and need for this kind of technical meeting.

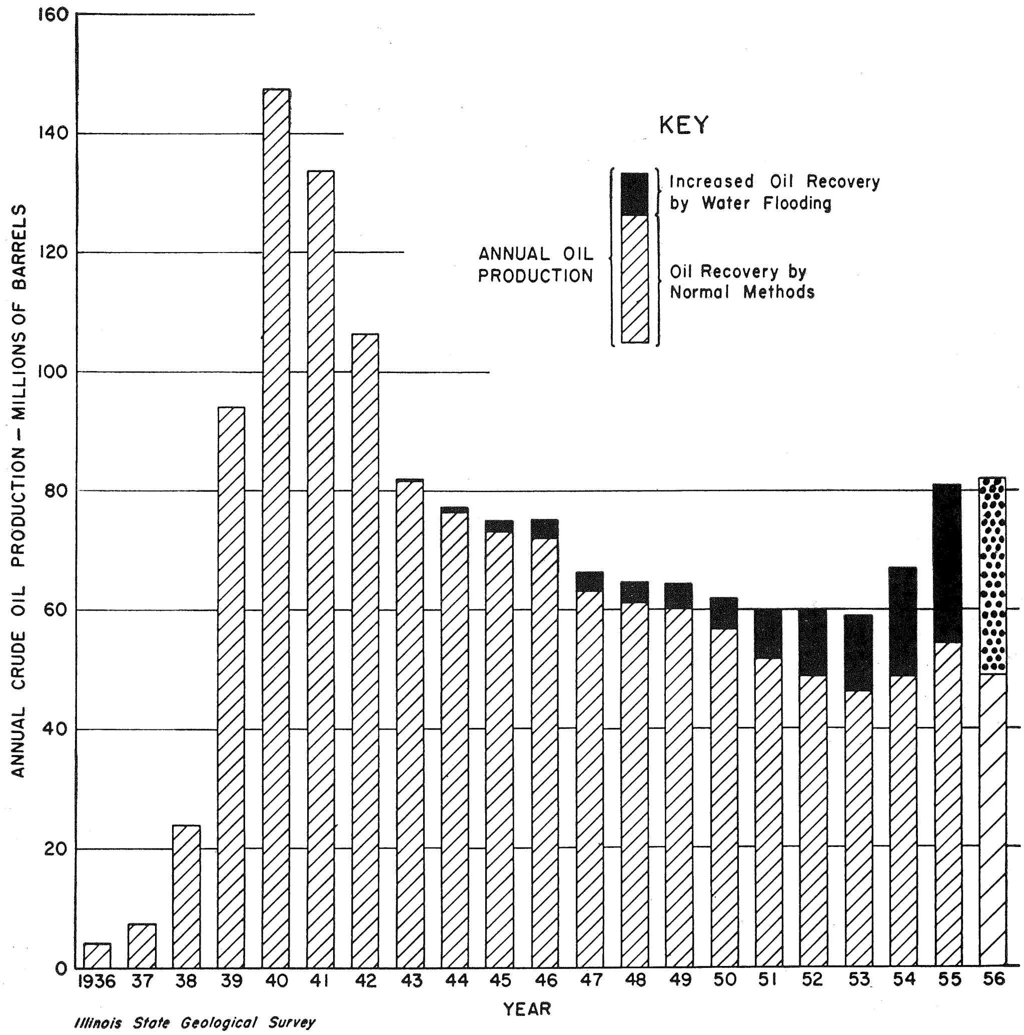


FIG. 1.—Annual crude oil production in Illinois. (Waterflood production estimated for 1956.)

In February 1956, at a meeting of the Illinois Basin Chapter of AIME in Fairfield, Illinois, a number of persons asked me when the Survey was going to sponsor another waterflood conference. When I replied to the effect that tentative plans were being made for April 1957, there was an immediate request for a much earlier date. As a result of this request and a later poll of the AIME membership, October 28-30, 1956, was chosen for the second conference on waterflooding.

Because of the great interest expressed by the AIME chapter, I asked George H. Link, who was then working for the Carter Oil Company in Mattoon, Illinois, and was in charge of the technical program for AIME meetings, to become chairman of the Technical Program committee for the second waterflood conference. His committee included the following: E. A. Milz of Shell Oil Company, Centralia, Illinois; Walter D. Rose of the University of Illinois, Urbana; A. T. Sayre of the Pure Oil Company, Crystal Lake, Illinois; and myself. Later when Mr. Link was transferred from Illinois, I turned to the President of the local AIME chapter, Mr. B. P. Walker, who is with the

Gulf Refining Company, Evansville, Indiana, and he kindly consented to complete Chairman Link's job. The excellence of the eleven technical papers of this symposium attests to the fine work of the Technical Program committee.

In the process of organizing the first waterflood conference in 1955, the Survey received much help from an advisory committee composed of representatives from all of the oil and gas associations and technical societies of the Illinois basin. A second advisory committee was therefore formed of the following persons: Paul A. Witherspoon, chairman, Illinois State Geological Survey; J. R. Atkinson, Indiana Oil and Gas Association; J. P. Bassett, Illinois Basin Chapter API; A. H. Bell, Illinois State Geological Survey and Illinois Secondary Recovery and Pressure Maintenance Study Committee of Interstate Oil Compact Commission; C. E. Brehm, Independent Oil Producers and Land Owners Association, Tri-State Inc.; George D. Ellison, Kentucky Oil and Gas Association; Harry J. Langley, Tri-State Association of Petroleum Engineers; Carl F. Pampe, Illinois Geological Society; Walter D. Rose, University of Illinois; David R. Stewart, Illinois Oil and Gas Association; J. R. Vaughan, Illinois-Indiana-Kentucky Section, API Eastern District Study Committee on Secondary Recovery; B. P. Walker, Illinois Basin Chapter, AIME; and Roscoe E. Wise, Indiana-Kentucky Geological Society. This advisory committee began an intensive campaign of publicizing the conference all over the Illinois basin and in adjacent states as well, with the result that a record crowd of 355 persons attended the meetings.

To provide entertainment for the informal dinner on the first night of the conference, I asked Daniel M. Moon, Schlumberger Well Surveying Corporation, Mt. Vernon, Illinois, if he would be chairman of an entertainment committee. Mr. Moon kindly consented and organized the following committee: Charles Clark, Lane Wells Company, Olney, Illinois; John Crane, Dowell, Inc., Salem, Illinois; Stanley Flynn, Bird Well Surveys, Robinson, Illinois; Jack Holtz, McCullough Tool Company of Mt. Vernon, Illinois; E. C. Lawrence, Halliburton Oil Well Cementing Company, Evansville, Indiana; and Joseph Williams, Independent Oil Well Cementing Company, Fairfield, Illinois. This committee provided a most enjoyable social hour prior to the dinner that was a highlight of the conference.

It is evident from the foregoing that the success of the 1956 waterflood conference is due largely to the combined efforts of a great many people from a large number of organizations of the oil industry of the Illinois basin. The authors of the eleven technical papers, of course, deserve the most praise for they have provided the real substance of the meeting. The various committees that have functioned so effectively also deserve credit for a job well done, and of course the conference would have been seriously hampered if it had not received such enthusiastic support and such a thorough campaign of publicity from all segments of the industry. The Illinois State Geological Survey is extremely pleased by the wholehearted cooperation everywhere evident and it is honored to be able to sponsor technical conferences of this kind. We firmly believe that such meetings are of great importance to the intelligent development of one of the State's most important mineral resources.

INPUT WELL COMPLETION PRACTICES IN THE ILLINOIS BASIN

RAY R. VINCENT

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Evansville, Indiana

ABSTRACT

The increase of waterflooding in the Illinois basin has caused operators to focus their attention on well-completion practices. The presence of numerous sand and lime producing horizons (often separated by only a few feet) has compelled the operators to plan and engineer their completion programs carefully.

To meet the needs of the operators, industry has introduced a wide selection of production tools, cements, and drilling muds.

Completion practices have been divided into three depth categories: shallow (0-1000 feet); intermediate (1000-2500 feet); and deep (2500 to 4500 feet). These categories have been selected as a basis for discussion of the completion methods and equipment in use in the Illinois basin.

INTRODUCTION

The stimulus needed by operators to consider their oil reservoirs for potential waterfloods was provided in 1942 when Forest Oil Company inaugurated the first successful waterflood. The success of this flood created such an impact in the Tri-State area that input well completions have increased from 107 in 1942 to approximately 1600 in 1955.

The use of the waterflood method involved not only input completion problems but also the consideration of a number of other factors, including depth of the pay, thickness and characteristics of the formation, and well spacing. These factors controlled the flood's economics and affected decisions on the conversion of existing oil wells to inputs, or determined the number of new wells that could be drilled. In either case, one essential requirement is a cement job adjacent to the potential pay zones, and the cementing problems increase if multiple completions are involved. An injection well also requires provision for a mechanical installation to separate and control the injection media into each zone.

The answer to these problems did not come overnight. It required years of experimenting and the knowledge and skill of the entire petroleum industry to produce today's practices, tools, and techniques.

The question arises, "How do these statements pertain to input well completion practices?" The answer originates in the "second oil boom" and the inception of rotary drilling in the Tri-State area.

A review of events during this time provides background for present day operations.

CEMENTS AND CEMENTING PRACTICES

The first cementing failures were encountered in southern Illinois where frequently the interval between pay zones was more than 700 feet (Wells, 1948). To help insure a successful primary cement job one operator started the practice of spudding or reciprocating the casing. The method reduced the number of cementing failures, and they were further decreased with the addition of reciprocating-type wall cleaners. During the year 1945, rotary-type cleaners were developed, and by 1947 most operators used casing centralizers.

The contractor began better mud programs, and as drilling technology advanced the holes were drilled faster, straighter, and cheaper. Common cement with two percent calcium chloride was used to cement surface

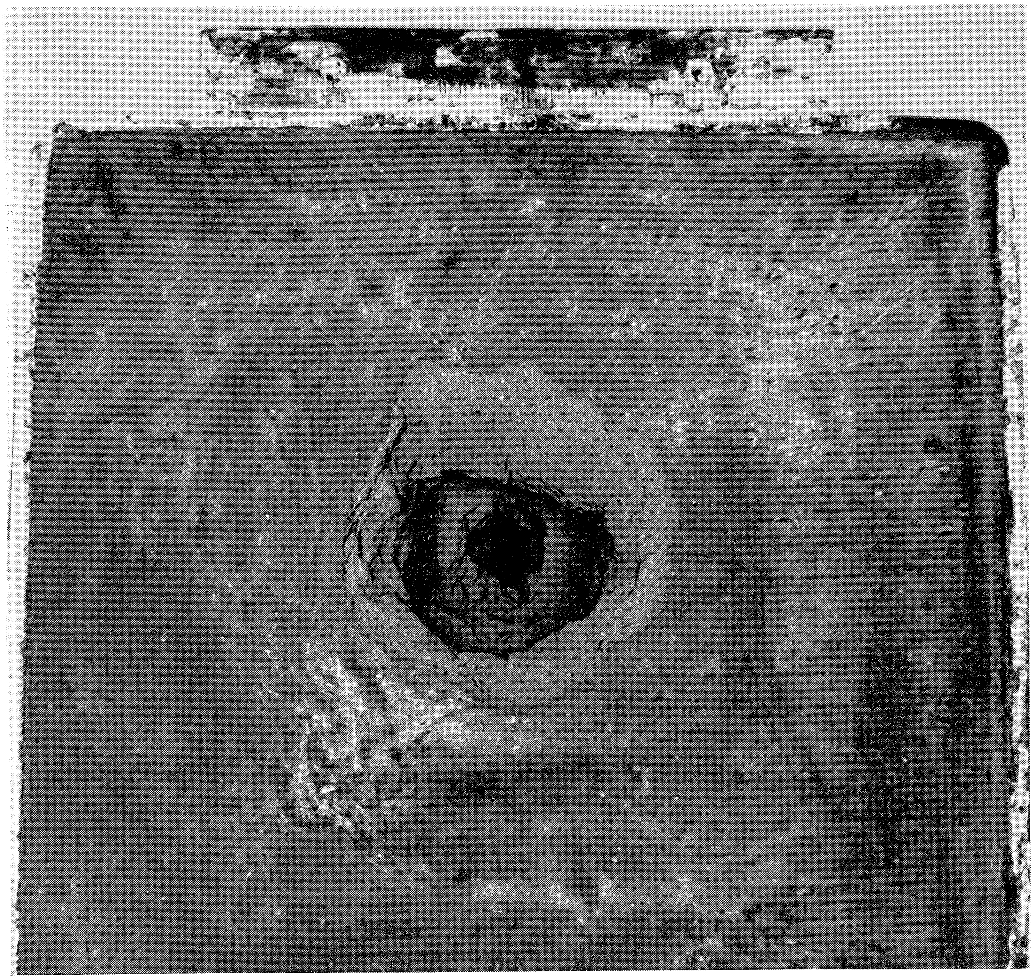

FIG. 1.—Perforation test on type Pozmix A cement, 50 percent Pozmix and 50 percent cement by absolute volume, cured three days at 100° F. *Courtesy of Halliburton Oil Well Cementing Company.*

pipe, but two to three percent of bentonite was added to the cement for the long strings. Because the characteristics of Hi-Early type cements reduced waiting time, their use was quickly adopted during World War II by both operators and contractors.

Experimental work near Salem, Illinois, in 1950 proved the cementing merits of pozzolanic cements, and their popularity has increased until today this cement is used on 40 and 70 percent, respectively, of all surface and long-string cementing jobs. These cements possess excellent oil well cementing and gun-perforating characteristics, and on a volume basis cost less than Hi-Early cement (fig. 1).

TOOL TECHNOLOGY

An effort to simplify the difficulties of many completion problems brought a demand for new and better tools. The challenge was met by the tool and service companies with improvement of existing tools and the development of many new ones.

Many of the tools were first conceived for use in oil well completions. However, their construction made them easily adaptable for use in injection wells. One can choose from a variety of tools to help him with his problems, and today we find in wide usage such tools as the hook-wall and upside down packers; parallel flow and cross-over tubes; retrievable and permanent type bridge plugs; mine cementing baskets; and multiple-stage cementing equipment.

The design and operation of this equipment is not discussed here except for comment on the fact that these tools have simplified many of the completion problems of multiple zone work.

DRILLING FLUIDS

Use of crude oil and its various components in certain drilling operations dates back many years, but it was not until relatively recent years that an oil-base drilling fluid capable of holding suspended solids was devised. The mud did not gain acceptance in the Tri-State area, but in the last five years an adaptation of oil-base mud (oil-emulsion mud) has increased in popularity for the drilling of input wells. The low water-loss property of this mud makes it suitable for low-pressure reservoir work, and because it is conductive, logs can be made with regular electrodes.

It is important to state that this mud has not replaced the bentonitic muds, as some 98 percent of all wells drilled in the area still use a straight water bentonitic type of mud.

MULTIPLE ZONE COMPLETION

In normal production practice, the operator is not usually concerned with the separation of production from multiple pay zones; but in waterflooding, experience has proved that it is usually more prudent to inject into each zone separately. Therefore, in a multiple zone injection well, not only must the pay zones be exposed, but some method must be provided to separate the injection into each zone.

Several methods can be used to expose an upper pay zone. Probably one of the first was to rip and shoot out the pipe with liquid nitroglycerin opposite the desired section. The method is effective, but creates the hazard of damaging the casing to such an extent that it might be impossible to work over or produce lower zones.

To alleviate some of these hazards, the practice of installing removable casing windows was inaugurated, with the first window of this type run in September, 1938 (Wells, 1948). Windows facilitated completion on an upper zone, as they could be removed prior to shooting by a number of ways: milling; acidizing; or a solution of caustic soda. The pay section could then be shot with less risk of damaging the casing and obstructing completion of a lower zone. The actual shooting and tamping procedure will be elaborated in the discussion of intermediate zone completion work.

This review has been presented to provide background material for present day input completion practices. Some of the procedures and materials used in shallow zone work (0-1000 feet) follow.

SHALLOW ZONE (0-1000 FEET) COMPLETION

By far the greatest number of the shallow wells have been drilled with cable tools. After setting drive pipe (usually 8⅝-inch) through the glacial drift, the well is carried to a depth 10 to 20 feet above the expected top of the pay zone, with a hole diameter large enough to run either 6¼ or 7-inch casing. The well is then cased, and a bailer test made to insure that a tight seal has been obtained to prevent the entry of water into the well. Drilling is then resumed and the well deepened a few feet at a time until the top of the sand is reached, at which point a Baker core barrel is run in and the entire pay zone cored. After securing the core a visual examination is made to determine the shooting program and to pick the proper casing or packer setting depth.

The majority of wells are shot selectively with one to three quarts of nitroglycerin per foot of sand thickness, with the average shot containing 50 to 75 quarts. Before placing the shot the casing is raised from 20 to 40 feet above the top of the shot to avoid damage to the casing.

The shot is fired by means of a mechanical time bomb placed inside of a cave catcher, and to confine the force of the shot it is tamped by placing 2 to 4 feet of pea gravel on top of the bomb and cave catcher, followed by 2 feet of sand and six to eight sacks of calseal. Some operators prefer 100 to 150 feet of sand on top of the gravel and fill the remainder of the hole with water. Following detonation, the bridge is removed; the casing again lowered; the well cleaned out; and the injection string run.

Injection strings vary in size from 1 to 4 inches in diameter, and as the depth of the pay zone approaches 1000 feet, it is preferable to run either 4-inch line pipe or casing.

In completing a well with either 1-inch or $1\frac{1}{2}$-inch pipe, a 2-inch perforated stinger is placed on the bottom with the perforations starting some 2 feet below the top of the pay with an unperforated section of 2 or 3 feet above the top of the pay. The annulus between the perforated stinger and sand face is filled with enough gravel to reach the top of the pay at which point 2 feet of sand is added. The injection pipe is cemented into place by a 1-inch cementing string run alongside of the injection string and spotting 10 to 15 sacks of cement on top of the sand. In this type of completion rag packers are unnecessary, and after cementing the string either the $6\frac{1}{4}$-inch or 7-inch casing and the 1-inch cementing string are pulled.

Rag packers are used on many installations. The packer consists of a 4-inch metal disc welded a foot or two from the bottom of a joint. Burlap cloth about three feet wide is then wrapped around the joint of tubing and securely wired to the ring and the tubing until it is flush with the 4-inch metal disc. All of the burlap above the point of attachment is then slashed to form long ribbons. The packer is then run ring first and sufficient tubing added to place the packer two to three feet below the selected packer setting depth. Crushed rock is added and the tubing raised two or three feet to where it wedges and cannot be pulled higher. The tubing is then clamped, and six to ten sacks of cement spotted on top of the packer through a 1-inch cementing string. Drilling and shooting procedures are essentially the same as heretofore described.

Any number of minor variations of these methods are practiced, but basically these programs cover most of the shallow zone completion procedures.

One interesting cementing technique employed (where 4-inch casing was run into the injection wells) was to follow the common cement with four to five sacks of 50-50 mix of cement and calcium chloride. This enabled the operator to resume completion work on the well in two or three hours. The operator has encountered no cementing failures to date using this procedure.

INTERMEDIATE ZONE (1000-2500 FEET) COMPLETION

Drilling costs constitute a major part of the developmental expense in a flood installation if the program calls for the drilling of a number of new wells. Therefore, to reduce developmental costs, it has become common practice to select patterns where existing wells could be used for inputs.

Where conversion involves a single zone, the preparation necessary to place it on injection requires a minimum of work and expense. Often the only work done is to measure the well's present depth, as a check on extensive cavings in the hole, and if it is found relatively free from debris, it is then connected to the injection system and injection started down the casing. Although some operators prefer a short workover period (two to three days) to swab the well as insurance against future cavings, very little reshooting or acidizing work is done on this type of completion.

Where it is necessary to protect the casing, the wells can be completed with a tubing and packer installation. Installations of this type are employed under three different circumstances: 1) where the injection fluid tends to be very corrosive; 2) where a weakened casing string is suspected; 3) where workable coal beds are present above an oil or gas reservoir. As additional insurance against corrosion, the casing-tubing annulus is sometimes filled with a light oil or inhibited water.

To complete multiple-zone wells where casing has been set on top of the lower zone and where the upper zone has been blanked off by a window, it is necessary to first complete the lower zone which is shot in the conventional manner, cleaned out, and an in-

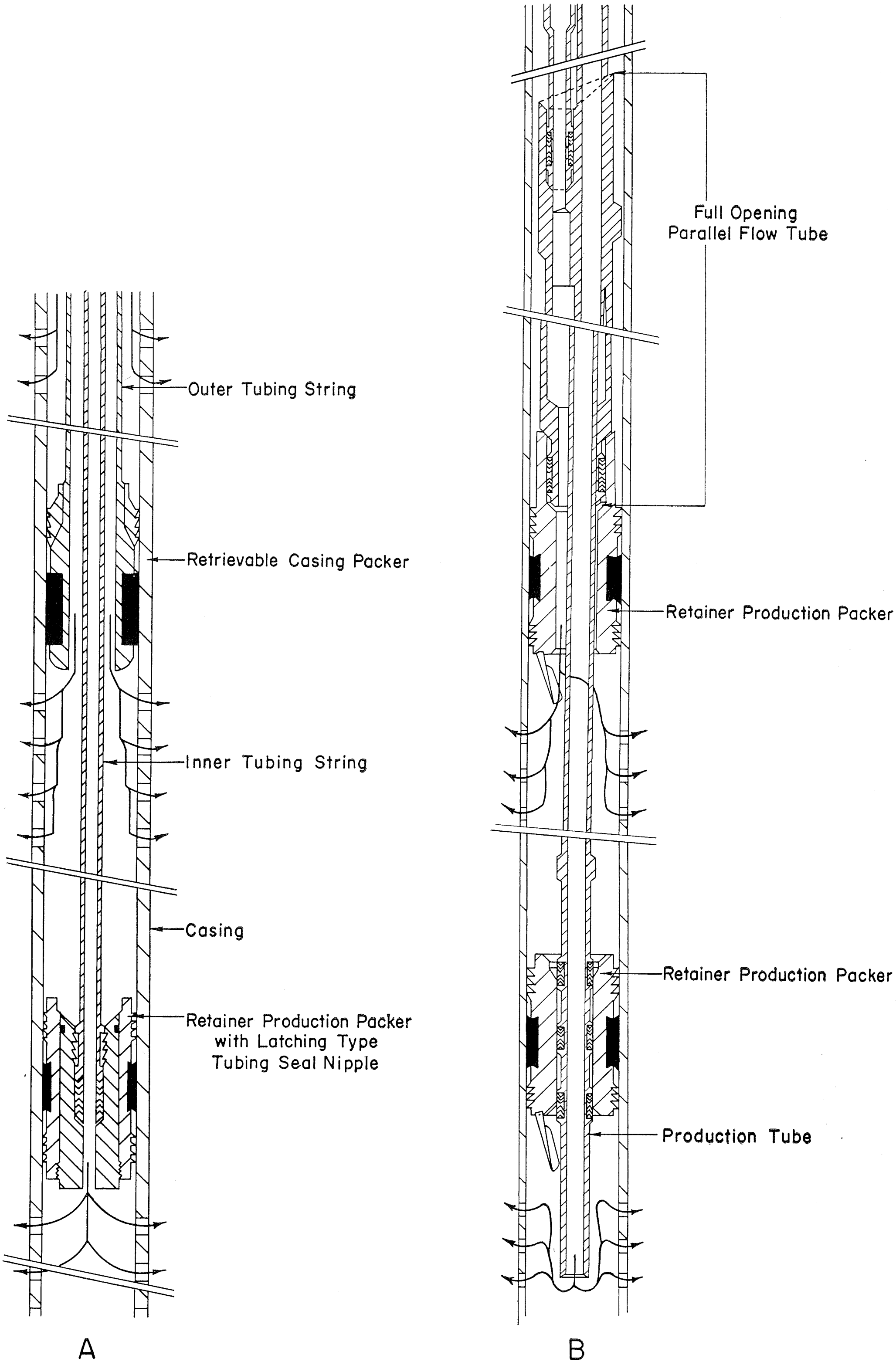

FIG. 2.—Diagrams showing selective waterflood hook-ups.
A—three-zone hook-up.
B—two-zone hook-up.

jectivity test run. To expose an upper zone blanked off by a window, a bridging plug is set 20 to 40 feet below the window and calseal is spotted on top of the plug. The window is then removed with caustic, acid, or by perforating and shooting. After the window has been removed or perforated but before shooting, a natural injectivity test may be run. The shot procedure is as follows:

1) Approximately 5 feet of pea gravel is dumped into the hole to bring the base of the shot to the bottom of the sand.

2) The shot with a bomb and cave catcher is run into the hole opposite the desired section.

3) Two feet of pea gravel is dumped on top of the cave catcher.

4) About 40 to 80 feet of calseal is run on top of the gravel.

In shooting a window it is preferable to place the shot at least five feet away from each of the window's casing shoes. This procedure is repeated for any additional windows to be opened.

Figures 2A and 2B show two systems by which isolation of the injection media can be accomplished and the equipment used for each. The method shown in figure 2A is flexible and can be adapted very easily for either two- or three-zone injection. Figure 2B covers a method for two-zone injection using a parallel flow tube and two retainer production packers. Hydraulic fracturing (currently coming into use as a method of completing injection wells) is used mainly on an upper pay zone that is relatively thin (six to ten feet).

This method not only accelerates the completion of a well, but also eliminates the hazard of damaging the casing caused by shooting a relatively thin pay zone where it is difficult to secure a good tamp near the window's casing shoes.

The procedure followed is to leave an open hole opposite the lower zone by setting the casing on or near the top of the pay. The shot is run into the hole, tamped in the conventional manner, and the remainder of the casing filled with water. After the shot fires, part of the water tamp is removed, the desired interval is perforated (usually four bullets per foot or a combination of bullets and kone-shots) and hydraulically fractured. The fractured section is then swabbed, cleaned out, and tested. The remainder of the lower tamp and bridge are drilled out; the section sand-pumped and cleaned out. Tubing and packer are installed with the packer set in the bottom casing joint to separate the injection media.

DEEP ZONE (2500-4500 FEET) COMPLETION

Because the methods and equipment already described apply to deeper zones, only the completion of wells where lime producing pays are present will be considered. The majority of limestone wells produce from a single zone, but in areas where the Ste. Genevieve is productive there are as many as two or three closely spaced productive zones. Completion of a single zone is usually by the open hole method, but if two or three zones are present, it is common practice to set casing through the zones and expose them by gun perforating. Since most lime producing zones were acidized when completed as oil wells, few of them are reacidized when converted to injection wells.

Prior to converting either a single- or a multiple-zone well it is customary to measure the total depth of the well. Many operators run a radioactive log to verify the extent of the porous zones and to make sure all of the sections have been exposed. This is especially true on older wells where electric logs are not available.

It would be well to point out at this time that the majority of these wells were first utilized in dump flooding operations where the injection was usually down the casing. In this type of completion some 20 to 30 feet of an upper water-bearing formation (usually Cypress) are perforated with one shot per foot and the water forced into the formation by the available hydrostatic head.

Although this type of completion is effective, the only means available to control the water injection rate is to limit the number of shots per foot and the length of section perforated. Where more positive control over the injection rate in a dump flood well is desired, several methods are available:

1) The two zones are separated by a packer-tubing arrangement with an orifice plate seated below a perforated section of the tubing at the time it is made up and run into the well. Depending on the hydrostatic head of the column of water above the formation to be flooded and the size of the opening in the orifice plate, the rate of injection into the formation can be either increased or decreased.

2) A Sperry-Sun teleflood meter, tubing, and packer are run into the well, and the packer is seated between the flood zone and the formation supplying the water. Direct reading surface equipment can be added, thereby providing a daily check on the well's injection rate (Patterson et al., 1949).

These two methods of control have been employed on operations commonly called "controlled dump floods."

In addition to the dump flood operations there are many surface controlled limestone floods, which are handled in many respects like any single zone completion. Injection may be either down the casing or through a tubing and packer arrangement if it is advisable to prevent contact of water with the casing.

Where a sand producing formation is present above porous lime zones and where it is desired to convert and flood both zones simultaneously, one has several alternatives, depending upon the original completion methods. If a window has been set opposite the sand it can be removed as previously described, the sand shot and cleaned out, and tubing and packer set to separate the injection. In the absence of a window, the section may be perforated and shot and the same procedure regarding clean-out and a tubing-packer arrangement followed. As previously discussed, if the desired sections of the lime zones are exposed they are not reacidized or worked over. Where the upper sand zone has been perforated, hydraulic fracturing has been employed to a limited extent as a method of completion.

Calseal, plastic, hydromite, and resin cements are used today where it is necessary to plug off bottom water or lower zones. Because calseal is not considered a permanent-type plugging material, it is advisable to cap it with 2 to 4 feet of either plastic, hydromite, or resin cement.

In retrospect we find that it is to the credit of all phases of the oil industry that they have met the challenge of the past by providing the answers to completion problems, and we can be assured that their resourcefulness and competitive spirit will be our most valuable assets in solving the problems of the future.

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INCREASING THE INTAKE RATE OF INPUT WELLS IN WATERFLOODING

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ABSTRACT

The purpose of this paper is to discuss the causes and corrective measures for undesirably low intake rates in waterflood input wells and to explore the possible means of determining whether attempts to increase intake rates are likely to succeed. In considering this problem, three questions must be asked: 1) Is it desirable to increase intake rates? 2) Is it possible to do so? 3) Would it be sufficiently profitable? For the purposes of this paper it is assumed that it is desirable. The second question cannot be affirmatively assumed, and a large part of this paper is devoted to finding answers to this question. The answer to the third question is intimately involved with the second.

The principal sources of information in attacking this problem are injectivity curves and pressure fall-off curves. The proper analysis of this information will indicate whether the impediment to a desired rate of water input is within a very short distance from the well bore (that is, a "skin" effect) or is the result of a more general condition existing over significantly larger distances from the point of injection. Methods of analysis and interpretation are discussed.

The methods of increasing intake rates that are discussed in this paper involve: 1) reducing the skin effect, 2) solvent extraction of residual oil, 3) use of surface active chemicals, 4) heating injection water, and 5) in situ combustion.

INTRODUCTION

Contrary to the title, this paper will not discuss the results of using various materials, chemicals, and agents for the purpose of increasing the intake rate of input wells. The object of this paper is rather to explore the possible means of determining whether attempts to increase intake rates are likely to succeed, to explore by various tests and manipulation of data the location and character of the impediment to higher injection rates, and the extent of the problem of increasing rates where low permeabilities exist. Brought together are several ways of conducting tests to throw light upon underground conditions.

NATURE OF THE PROBLEM

In considering the problem of increasing input rates, three questions must be asked: 1) Is it desirable to do so? 2) Is it possible to do so? and 3) Would it be sufficiently profitable? For the purpose of this paper it is assumed that it is desirable. The second cannot be affirmatively assumed, and a large part of this paper is devoted to finding answers to the question. The answer to the third question is intimately involved with the second.

The determination of the nature and location of the impediments to satisfactory injection rates would seem to be the most logical approach to the problem of improving them. These may be those brought about by completion practice or by conditions of injection (dirty water), or they may be indigenous to the sand, as for example, low permeability to water due to various causes.

SOURCES OF INFORMATION

Injectivity Curves

The nature of the problem forces the use of indirect evidence in attempting to diagnose the underground condition. The earliest method probably was the use of injectivity tests in which rates of injection at various pressures (or pressures required for various rates) were determined. Early publications describing these were by Dickey and Andresen (1945), Yuster and Calhoun (1945), and Grandone and Holleyman (1949).

Plotting the pressure vs. input rate data on rectangular coordinate paper frequently results in a straight line. The slope of the straight line is the "localized injectivity index" of the well, expressed in barrels per day per pound of injection pressure (either well head or sand face). Dividing by the sand thickness gives the "specific injectivity index" for the well. The localized injectivity index is a useful tool for comparing the behavior of an individual well before and after treatment, etc. The specific index would be required for comparing the behavior of different wells where thickness is not constant. Since the slope of the line (and hence the injectivity index) flattens with time, these tests are not useful for comparisons if the tests are made at long time intervals. Inherent in the method also is the requirement that the test involves only small increments of injected water in order that the pressured radius is not extended appreciably by the small quantity of water injected during the test.

According to Grandone (1949), these curves are useable in detecting the presence of thief zones, and reflect the effect of shooting. Dickey and Andresen (1950) point out that such curves can be used to distinguish between the decrease in intake rate due to plugging from that due to fill-up of the reservoir.

It is frequently found that an abrupt change in slope occurs at some fairly reproducible condition of pressure and rate. This change in slope is interpreted generally as indicating the pressure at which the formation is broken down or parted, resulting in a considerable increase in rate for small increases in pressure. The pressure at which this change in slope occurs is referred to as the critical pressure for the well or the lease, and normally should not be exceeded. However, Grandone (1949, p. 11 and table 2) shows that many operators are deliberately operating at pressures well above this point.

Directions for making this kind of test are contained in the papers by Dickey and Andresen (1945, 1950) and in the report by Grandone and Holleyman (1949). The reason for discussing these is in relation to the problem of increasing input rates by normal permeable flow into the sand exposed in the well. If the well is being operated at pressures below the critical, presumably the influx into the sand is in relation to the permeabilities of the various sand layers in the producing formation (as these may have been affected by shooting or by accumulations at the inlet faces). In wells, which by the injectivity tests are known to be operating at pressures above a break in the curve, disproportionate quantities of water are entering a crevice, fracture, or opened joint. Remedial efforts in such a case would be limited to the removal of clogging or obstructing material, and such efforts easily could result in increasing the disparity in the amounts of water entering the various parts of the sand body. The chief use then of injectivity curves is to furnish some evidence of underground conditions and of the chances of success of remedial efforts.

Pressure Fall-off Curves

The injectivity curves have not been explored nor elaborated mathematically to the same extent as have the so-called pressure fall-off curves. These have been discussed by a number of writers, in the form of pressure build-up curves in primary production practice and in the form of pressure fall-off curves in waterflooding, and it has been shown by these writers that the mathematics of the build-up curves and the fall-off curves is intrinsically the same. Among those who have applied these curves to problems of water injection are Joers and Smith (1954) and, more recently, Groeneman and Wright (1956). Joers and Smith discussed the determination of the extent of the impediment at the intake surface of the sand, the "skin effect," and the means of determining a numerical value of the permeability to water of the sand at some distance from the well bore. Groeneman and Wright give somewhat simplified equations applicable to gas injection wells as well as water injection wells.

In making such a test, the well is operated at steady rates and pressures for a sufficient time to eliminate local pressure and rate transients. It is then shut in completely, and the pressure drop against time is recorded, usually with a recording pressure gauge. The data, when plotted with the pressure as the ordinate and the logarithm of time as the abscissa, result in a curve in which the early portion may be concave up or down and the later portion is a straight line with a negative slope.

The "skin effect" is indicated by a number, the sign of which is positive if the permeability of the sand in the near vicinity of the well bore is less than that of the sand more remote from the well bore. The value of the "skin effect" is zero when there is no impediment to flow, and the sign of the numerical value is minus when the permeability in the vicinity of the well bore is greater than that of the sand some distance away. The former case would result from a blocking of the sand face. The latter condition (negative skin effect) would result from shooting or acidizing the well so as to increase the permeability locally. The square of the radius of the well bore enters in the denominator of a logarithmic term, and the numerical value depends for its accuracy upon the use of the true well radius. Since this in the form of a true effective radius would be very difficult to obtain, it is customary to use the drilled diameter or the calipered diameter of the well, even though the well has been shot or acidized. This results in relatively large negative values of "skin effect" for such wells. The mere fact of a negative skin effect does not mean that the well has not suffered damage. A progressive damage to the well would be indicated by a progressively decreasing value of a negative figure, and a successful corrective operation would result in an increase in the magnitude of the negative "skin effect." The equations as used by Groeneman and Wright (1956) are as follows:*

$$K_w = \frac{162.5\ Q_w\ \mu_w\ \beta}{m\ h}$$

$$\text{Skin Effect (S.E.)} = 1.151\ \frac{P_{1hr} - P_w}{m} -$$

$$1.151 \log \frac{Q_w\ \beta}{10.4\ m\ h\ \phi\ c\ r_w^2}$$

In the paper by Joers and Smith (1954), means of converting the skin effect to pounds of pressure loss or gain due to the skin effect are disclosed. However, since the numerical value is in question due to uncertainty as to the correct value of the well radius, only the numerical value as derived above is computed. This is sufficient for comparative purposes. In cases where the value of sand thickness (h) is uncertain or unknown, a value for $k_w h$ may be derived for purposes of comparison on the same well. One requirement stressed by the various authors in considering the usefulness of these equations for this purpose is that enough water must have been injected before the test to insure that the pressure drop as reflected will occur entirely within the water phase, and that the liquid saturation should be high enough to preclude the existence of a continuous gas phase within the pressured area. Their application is thus limited to wells into which a considerable quantity of water has been injected.

The pressure fall-off curve therefore furnishes data from which a diagnosis of well condition can be made, furnishes a means of comparing the effect of treatments on a "before and after" basis, and, by providing the value of the permeability to water in the area remote from the well bore, it furnishes a basis for determining whether the chief impediment to satisfactory injection rates is local to the sand face, or is indigenous to the sand itself.

A paper by Dunning and others (1956) contains numerous references to the use of these curves on a "before and after" basis, to measure the effect of the use of detergent solutions to increase input rates. This subject will be discussed in a following part of this paper.

Yuster's Method

Another method of securing some indication of the permeability of the oil-bearing sand to water at some distance from the well bore is by application of a method devised by Yuster (1945). In this method, only one set of data can be taken. The data required include core analysis data, total water injected as a function of time, and the injection pressure. It is desirable to have daily meter read-

*See nomenclature at end of paper.

ings at the beginning of injection but the time interval may be increased as the total amount of water injected increases. From the cumulative volume readings as a function of time it is possible to calculate average daily rates. Considerable care in determining the correct pressure and daily rate is required.

With this method, the logarithm of the cumulative volume injected is plotted as the ordinate and the reciprocal of the rate, or the difference between the formation pressure and the sand face pressure divided by the rate, is plotted as the abscissa. Plotted in this manner there frequently results a straight line from the slope of which it is possible to compute the average permeability to water (and also the effective well radius). The value of k_w may be obtained by setting the slope of the straight line equal to the expression

$$\frac{.00617\ k_w h\ (P_w - P_f)}{\mu_w}.$$

In case there has been a pressure variation and this has been accounted for by plotting $\frac{P_w - P_f}{Q_w}$ instead of $\frac{1}{Q_w}$, the pressure term $(P_w - P_f)$ in the above equation is eliminated. In case h is unknown, the value of $k_w h$ may be solved for, for the purpose of comparing behavior of a well. As mentioned above, the method is applicable only in the very early life of the well, when the flow outward from the well bore is still radial, and no interference from neighboring wells has occurred. In fact, under favorable conditions it might be possible by use of this method to determine the point at which interference first occurs. This approach provides a method for securing a value of k_w before this value can be determined by the method of pressure fall-off. In questionable areas, and in pilot plant operation, the taking of the data required for this method would be amply justified.

The apparent permeability to water measured by this method is probably the average of several permeabilities in series extending from the wall of the well bore and including in the average any sediment or plugging material (producing the "skin effect") near the well bore. In a comparison of k_w values for the same wells (unshot Bradford Second Sand) derived from pressure fall-off data and by Yuster's method, the values of k_w by Yuster's method were found to be smaller by a factor of 1/3 to 1/5 than those determined by the pressure fall-off method. This fact was construed to indicate a completion damage or an early plugging of the sand face.

METHODS OF INCREASING THE INTAKE RATES

Reducing the Skin Effect

It should be possible to determine the permeability of the "skin" by assuming a reasonable value for its thickness and using the over-all permeability value determined by the pressure fall-off method and the value of r_w as derived from Yuster's equation. One method would involve the equation for averaging permeabilities in series (Calhoun, 1953). This method is suggested here as a further means of securing information as to the nature and magnitude of the impediments to satisfactory injection rates. Certain precautions should be observed. A curvature of the plotted line, or a change in slope resulting in a decreasing effective permeability to water could possibly be construed as resulting from progressive plugging. This, however, would be difficult to distinguish from the results of well interference. A large variation in permeability in the beds composing the sand body will introduce serious errors into the computation of k_w. The chief utility of the method, as mentioned previously, is in providing a clue to the nature of the impediment to higher injection rates.

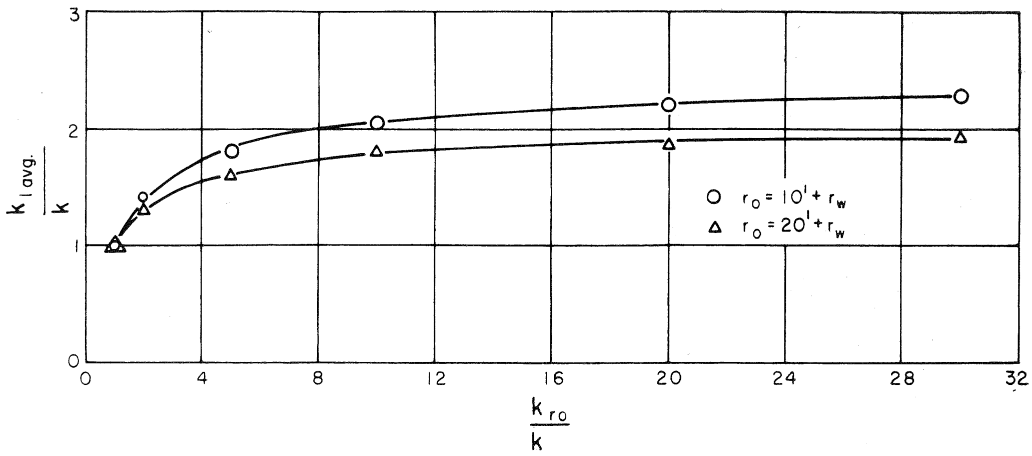
If a "skin effect" has been demonstrated to exist, attempts to reduce its harmful effect would consist of treatments dependent upon the nature of the skin. Muskat (1937) shows that very large increases in percentage are possible by the removing, at the inner surfaces of a well, relatively thin layers of obstructing material that are less permeable than the formation. The effect, however, is limited to an improvement up to the capacity of the unobstructed formation. Accumulations of bacteria, algae, or other organic material would best be attacked by oxidizing agents that will result in soluble compounds. The most suitable, of course, is chlorine, since very many chloride compounds are water soluble. If the skin is composed of corrosion products (these are usually hydrated oxides, carbonates, and sulfides), then hydrochloric acid would be indicated, again in an effort to put these into a water-soluble form. In case silt, clays, rock flour and other mineral substances are believed to be present, then hydrofluoric or some of the proprietory mud acids would be indicated. Emulsions present might be attacked with surface active agents such as emulsion breakers. This is a subject requiring very specific knowledge, and indiscriminate use of these in high concentration could result in additional damage.

If the conclusion from the data secured is that the unsatisfactory input rate is indigenous to the sand, this knowledge must be broken down into several categories. If the specific permeability is very low, of the order of only a few millidarcys, it seems obvious that measures should be taken during the development program to offset this. This might consist of shooting or fracturing, and would not properly come under this discussion.

If the permeability to water is grossly lower than the specific permeability, a first assumption would be that this can be attributed to high residual oil saturation. The reduction of this residual oil saturation in even a limited area around the well may be quite beneficial in increasing the permeability to water. In a paper by Bossler and MacFarlane (1955), graphs were given showing that improvements in through-put rates in linear cores of more than 20-fold could be obtained by reduction of oil saturation from 38 percent to 10 percent in one case and from 38 percent to 15 percent in another case. The reduction in saturation was accomplished by extraction of the residual oil with volatile solvents, and removal of the solvents by vaporization with natural gas. These reductions, when applied to a limited zone about the input well in a purely radial system, indicated that for a system having a well radius of 0.25 feet, an external radius of 250 feet, and a permeability to water of 5 md., a 20-fold increase in the permeability to water in a 10-foot zone around the well would result in an increase of about 100 percent in intake rate. Applied to a well which had been shot, the increases in input rate attainable by this method were very much smaller (of the order of 35 percent in the example used in the paper).

Since most waterfloods are developed as 5-spot patterns, an examination was made to see how much benefit could be expected from predictable improvements in local permeability to water, when a zone or area of improvement is considered as a part of a 5-spot pattern. For this purpose, a quadrant of a 5-spot pattern was considered to consist of 3 resistances in series, one the radial region around the input well, and similarly around the producing well, and a 5-spot region between these in which the flow was considered to follow the 5-spot flow equation. The investigation consisted in varying the average permeability of the input radial region by varying the permeability of a ring around the input well. Radii of improvement of 10 and 20 feet were considered. The effect of improvements in permeability to water of 2- to 30-fold within these rings, first upon the average permeability of the radial region, and second upon the conductivity of the entire 5-spot, were determined.

Figure 1 shows the relation between the ratio of the average permeability of the radial region to the permeability without improvement, and the ratio of improvement within the ring of improvement. It is seen that after a 10- or 12-fold improvement in a 10-foot ring is made, further improvement in permeability has small effect upon the entire region. Increasing the width of the ring to 20 feet makes only about a 14 percent improvement over that of the 10-foot ring. Figure 2 shows the effect of the improvement in average permeability of the input radial region (whether brought about by improving the conductivity greatly over a small area or by a lesser amount over a larger area) upon the conductivity of the 5-spot patterns. The improvement is expressed as a percentage improvement, and it is evident that doubling



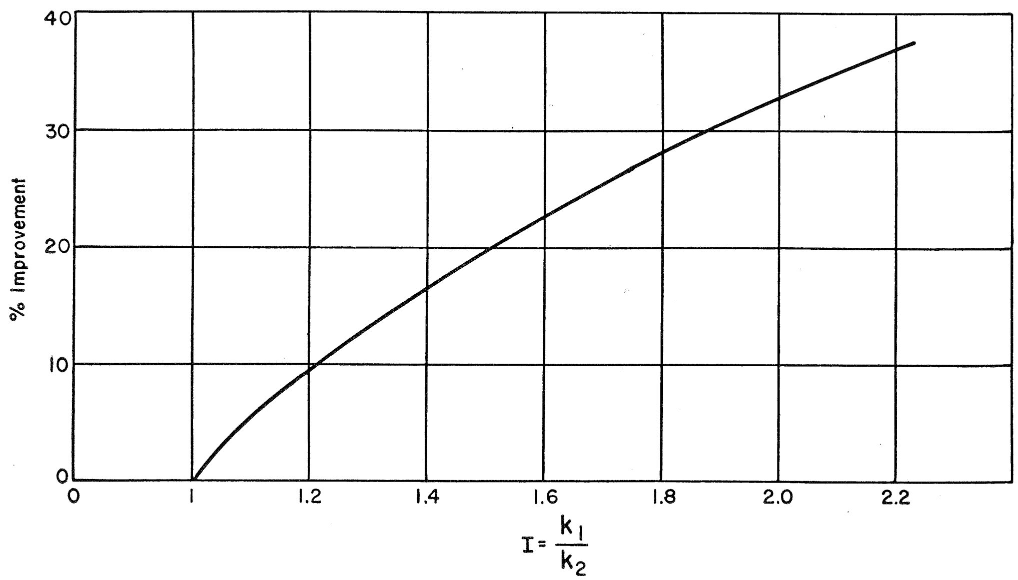


FIG. 1 (Above).—Permeability of a 5-spot pattern with increase in permeability of a ring about an input well.

$$\frac{k_1 \text{ avg. permeability of the radial region (including the improved area.)}}{k \text{ permeability without improvement}}$$

$$\frac{k_{ro} \text{ permeability of ring of improvement}}{k \text{ permeability of the radial region beyond the ring of improvement}}$$

FIG. 2 (Below).—Percentage improvement in conductivity of a 5-spot pattern with improvement in average permeability in the radial region about an input well.

the permeability to water in the entire input radial region ($\frac{k_1}{k_2} = 2$) will produce only about a 33 percent improvement in total 5-spot conductivity. However, when it is considered that a 20 percent increase in water input would, if maintained, shorten the life of a 5-spot operation by 20 percent, improvements of this magnitude are of great importance.

As stated previously, if the low permeability to water can be attributed to high residual oil saturation, there exists the possibility of increasing the intake rate by lowering the oil saturation. Figures 1 and 2 give clues to the extent of improvement possible. Means of bringing about the improvement would include solvent extraction by means of LPG or other available products, as demonstrated in the work cited.

Surface Active Chemicals

Other possibilities for reducing residual oil saturations include the use of surface active chemicals. Much work has been done on this subject from the standpoint of increased oil recovery. The cost of recovering oil by use of such chemicals (because they may be adsorbed from solution upon the reservoir rock) has been presented as an insuperable obstacle. However, their application for a limited objective (such as improving the permeability locally around a well), could come within the range of economic possibility. In addition, Johansen, Dunning, and Beatty (1955) point out that recent developments on the application of chromatographic theories to petroleum production indicate that adsorption remains an important, but not necessarily insurmountable, difficulty. They cite articles showing that the adsorbed reagent may be moved ahead by a process of desorption at the trailing edge and adsorption at the leading edge of a moving band of material. Such a process involves the passage of many pore volumes of water through the sand undergoing this process. This condition is nicely fulfilled in the vicinity of the input well.

In a recent paper Torrey (1955) shows a reduction of oil saturation in a core by use of a 50 ppm solution of non-ionic surface active agents of 8 percent of pore space below that obtainable by water alone. This reduction required the passage of about 8 pore volumes of solution, a condition which would exist within the region at a short distance from the well bore. It is quite conceivable that a considerable reduction in oil saturation over a zone wider than the core width, could have been made by use of the same volume of chemical, resulting in a permeability increase over a larger area, had the core been large in diameter.

A paper by Dunning and others (1956) describes a field experiment using detergents for the purpose of increasing injectivity. The statement is not made that the increases in permeability to water are credited to decreases in residual oil saturation, but this position is strongly inferred.

Input rates may be increased in the presence of residual oil saturation without necessarily reducing the oil saturation. This would involve the reduction of interfacial tension between the injected water and the residual oil. The increase in water conductivity of cores without removal of appreciable quantities of oil has been observed by Johansen, Dunning, and Beatty (1955), cited above, and by workers at the Pennsylvania Grade Production Research Laboratory (1955). Among the reasons suggested for this phenomenon are: movement of oil to regions where it offers less hindrance to flow, changes in capillary pressure due to changes in wetness (increasing oil wetness), reaction of clay minerals, solubilization of the oil or core components otherwise insoluble in the untreated injection water, and a decrease in the film-forming tendency as the oil is squeezed through pore openings. To these reasons may be added the very simple explanation that the reduction of interfacial tension reduces the energy required to deform the oil or to subdivide it into fine droplets small enough to be moved through the pore channels. Such a reduction in interfacial tension is caused by many surface-active compounds, and the subject is discussed by both Torrey (1955) and Johansen, et al., cited above.

Torrey shows numerous examples in which

relatively large increases in water through-put were produced in cores by use of surface-active chemicals. The exact mechanism causing the increase is not specifically stated, but the inference in the paper is that the increases are related to the reduction in interfacial tension.

Heating Injection Water

Investigations at the Bradford Laboratory of the Pennsylvania Grade Crude Oil Association of effect of heat upon the permeability of cores to water indicated that considerable increases were possible, and in these tests it is reported that no significant quantities of oil were produced during the test. Field tests involving the heating of the injection water have been reported on recently by Breston and Pearman (1956). The mechanism of the improvement is considerably in doubt. The procedure as a remedial effort is expensive and difficult and its application will probably have to await development of a practical field method.

In Situ Combustion

A suggestion as follows was presented to the Pennsylvania Grade Crude Oil Production Research by the author during his employment at the Bradford Laboratory. Although it has little merit as a remedial effort in normal flooding operations, it may have merit as a preparatory treatment in the same way that shooting, cleaning out, or acidizing are used before injection is begun. This treatment would consist of firing the hole after the manner described by Grant and Szasz (1954) in Sinclair's in situ combustion process. This company has reduced the firing of holes to a relatively simple procedure. Such a firing would remove all liquids from a predeterminable area immediately around the well bore, and would make available for water conduction the entire pore area. In fact, the permeability within the fired area may be greater than the specific permeability of the unfired sand.

Clay Swelling

The causes of unsatisfactory input rates discussed above are largely indigenous to the sand, or occur at the sand face. An additional cause sometimes arises or is induced by the reaction of the injected water and certain components in the reservoir sand. This is frequently referred to as clay swelling and has been discussed by Johnston and Beeson (1945) and Hughes (1947) and more recently, Torrey (1955). The diagnosis of this condition probably could not be made by any of the test or observational techniques suggested herein, except possibly the Yuster method. Laboratory testing of cores of the producing formation may detect the existence of conditions such that clay swelling will occur. In this case prevention, rather than cure would be indicated.

CONCLUSIONS

To sum up, the major purpose of this paper has been to explore ways and means of finding the nature, location, and extent of the causes of unsatisfactory water injection rates as a preliminary to efforts to improve them. The problem has been considered mostly from the standpoint of a flood already in operation. Examination of the subjects discussed (except possibly the reduction of residual oil saturation for the improvement of the permeability to water) would indicate that obstructive conditions could best be prevented rather than cured. Possibility of obstruction due to faulty completion or to dirty or corrosive water should be recognized in advance, and proper measures taken. If surface-active chemicals are to be used for interfacial tension reduction, or prevention of clay swelling, these obviously would be best applied at the outset of the waterflood.

Although some of the causes of unsatisfactory injection rates may be removed after the flood is started, prevention or removal of as many causes as possible at the outset still appears to be the most desirable procedure.

NOMENCLATURE

β formation volume factor, volume per volume, equal to unity for water.

C equal to $C_wS_w + C_oS_o + C_r$ where C_w, C_o, and C_r are the compressibility of water, oil, and the reservoir rock, vol/vol/psi, and S_w and S_o are the saturations of water and oil.

h equals the net effective sand thickness, feet.

k_w effective formation permeability to water, millidarcys.

m slope of the straight line section of pressure fall-off curve in psi per $\log_{10}$ cycle. Sign negative (Groeneman and Wright).

μ_w viscosity of injected water, centipoise.

P_f formation pressure, psia.

P_w wellhead pressure psig (Groeneman and Wright) sand face pressure (Yuster).

P_{1hr} pressure on straight line of slope m at 1 hour (60 minutes) shut-in time, psig.

ϕ porosity of effective formations, fraction.

Q_w rate of water input barrels per day (sign negative when used in Groeneman and Wright equation).

r_w radius of well bore, feet.

S.E. dimensionless term proportional to pressure drop caused by additional resistance concentrated around the well bore.

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WATER-INJECTION-WELL FRACTURE TREATMENTS BENTON FIELD, FRANKLIN COUNTY, ILLINOIS

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ABSTRACT

Maintenance of desirable water-injection rates has been a problem at Benton and is a problem common to many waterflooding projects. Inability to maintain desirable injection rates is generally the result of plugging by precipitates in the injected water, skin effects incurred during completion, and limited reservoir capacity. Several methods have been used to alleviate this problem in the Benton field, and one of the most successful has been hydraulic fracture treatment.

Data from 29 fracture treatments of 26 injection wells at Benton show that water-injection rates have been substantially increased. Although the behavior of other injection wells mask the effects of increased injection rates in treated wells, total liquid production has been increased in surrounding producing wells without adversely affecting produced water-oil ratios.

Fracture treatments have been varied, but an optimum treatment has not been conclusively indicated. However, results of water-base treating liquids compare favorably with the results obtained from the use of more expensive acid-base and/or oil-base liquids.

The physical nature of the fractures has been investigated by several different injection profiling methods. Pronounced profile changes have not been observed. It appears that existing zones of weakness in the formation have been extended and that a single vertical or horizontal fracture plane has not occurred.

INTRODUCTION

Maintenance of desirable water-injection rates has been a problem at Benton since the start of waterflood operations in November 1949. The Benton waterflood is not unique in this respect, as the problem of maintaining water-injection rates is common to many waterflood operations. Considerable effort has been expended to solve this problem because of its importance to the success of any waterflood project. Inadequate water-injection rates create unbalanced flood conditions that reduce flood efficiency, and cause flood life to be extended.

With the exception of inadequate injection facilities and insufficient water supply, inability to maintain desirable water-injection rates is generally the result of formation plugging by precipitates or solids from the injected water, skin effects incurred during well completion, and limited reservoir capacity. At Benton several methods have been used to improve water-injection performance: 1) Injection pressures have been increased; 2) water-treating methods have been modified to improve the quality of injection water; 3) hydrochloric acid has been used extensively to remove acid-soluble plugging agents; 4) surfactant chemicals have been utilized; 5) the formation has been shot with nitroglycerin; and (6) the injection wells have been subjected to hydraulic fracture treatments. Each method has had varying success; in many cases, injection rates showed initial improvement, then declined rapidly. This has been the result not only of the remedial treatment method but also of the continued plugging effect caused by the injected water.

In December 1954, water-injection facilities at Benton were modified to provide a closed-system of water treatment for all produced water while continuing to use the open-system facilities for make-up water. In this manner the problem of continued plugging by the injected water was effectively minimized.

The first hydraulic fracture treatments were performed during 1953 and a general program was continued through 1954 and 1955. The fracture treatment program has successfully increased water-injection rates, and, in conjunction with the modified water-treating facilities, the increases have been sustained.

FIELD HISTORY

The Benton field, an anticlinal structure with a north-south axial trend, is located in Franklin County, Illinois, and covers approximately 2200 productive acres. The field discovery well was completed during 1941 with production from the Tar Springs sandstone of Mississippian age at a depth of 2100 feet. Ultimately about 250 wells were drilled in the field, approximately 230 having been completed during the first year of development. In general, spacing density was ten acres per well, but there are irregularities because of drilling on small roadway tracts and the necessity of deviating from the established pattern because of coal mining operations at a depth of 600 feet.

Initial production rates varied from a few barrels to 900 barrels of oil per day per well and averaged about 300 barrels per day per well. A peak field production rate of one million barrels of oil per month occurred during 1941, but by mid-1949 oil production had declined to about 50,000 barrels per month. Although some water encroachment has been observed, the reservoir produced essentially under a solution-gas drive mechanism during its primary phase.

Net pay thicknesses encountered range from less than ten feet to 70 feet, averaging about 35 feet. The sandstone is fine- to medium-grained with some shale partings that are not considered to be a major characteristic. From core data, permeability averages about 75 millidarcys and porosity averages about 19 percent.

Unitized waterflooding operations were put into effect at Benton during November 1949. Alternate producing wells were converted to water-injection wells to develop a 20-acre, 5-spot flood pattern except in those areas where variable well density necessitated irregular patterns.

FRACTURE TREATMENTS

The techniques used to hydraulically fracture-treat water-injection wells at Benton have been essentially the same as those used throughout the industry. It has been necessary, however, to limit the flexibility of the treatments due to the presence of coal mining operations. A maximum safe treatment pressure has been established, and it has been necessary to use tubing-packer assemblies during all treatments.

Fracture treatment volumes have ranged from 500 to 5000 gallons, averaging 1480 gallons of fracture fluid per treatment. Based on the thickness of interval treated, treatment volumes have averaged 43 gallons per foot with a range from 14 to 154 gallons per foot. The amount of sand used has averaged 1580 pounds per treatment, ranging from zero to 1.8 pounds per gallon of fracture fluid, with both round, medium (20- to 40-mesh) and subangular, coarse (10- to 20-mesh) types having been used. Rates of injection during treatment have varied from 1.5 to 5.9 barrels per minute, depending upon treatment conditions.

The types of fracture fluids have been varied. The first treatment performed utilized a gelled refined oil, and subsequently eleven treatments were performed with a viscous acid-kerosene emulsion, sixteen with a gelled water-base fracture fluid, and one with a gelled-acid fracture fluid.

Five multiple-fracture treatments have been performed, one with acid-kerosene gel, three with water-base gel, and one with acid-base gel. One of the treatments performed with water-base gel involved an attempt to completely plug the sand face prior to treatment so that when the fracturing pressure was applied, a vertical fracture would be created. The sand face could not be completely plugged and the fracture did not occur in the theorized manner. Other multiple-fracture treatments have been performed in the conventional manner by using a temporary plugging material to block fractures created by the first stage of the treatment, causing the fracture fluid of the second stage to create new or multiple fractures.

Figure 1 depicts the locations of the 26 fracture-treated water-injection wells and table 1 presents a summary of fracture treatment data.

WATER-INJECTION RATE INCREASES

Of the 29 hydraulic fracture treatments performed, only two have failed to result in increased water-injection rates. Severe sand screen-outs have occurred during four treatments, including the two failures.

TABLE 1.—HYDRAULIC FRACTURE TREATMENT DATA, WATER INJECTION WELLS, BENTON FLOOD UNIT

Well No.	Thickness treated (ft.)	Date treated	Fracture treatment data								Water injection data						
			Fracture fluid			Sand		Pressure		Treatment rate bpm	Recom. rate bpd	Rate before treatment		Rate after treatment		Current rate as of 7-1-56	
			Type[a]	Gallons	Gallons per ft.	Pounds	Size[b]	Max. psig	Final psig			bpd	%[c]	bpd	%[c]	bpd	%[c]
3-W	18	3-10-55	IV (M)	2,400	133	—	—	2500	100	3.1	310	24	8	1,195	385	433	140
7-W	47	4-24-55	II	1,000	21	1,000	Med.	2200	1900	2.8	435	36	8	98	23	34	8
9-W	59	1- 5-55	II	1,000	17	1,000	Med.	2100	2100	3.0	365	38	10	82	22	115	32
15-W	54	1-14-54	I	1,000	19	1000/500	Med/Cor	2000	1500	4.0	625	47	8	356	57	416	67
17-W	49	8-24-54	II	5,000	102	5,000	Med.	2200	2200	4.0	300	35	12	142	47	83	28
18-W	25	1-18-54	I	2,000	80	2000/1000	Med/Cor	2900	2150	2.0	275	51	19	484	176	261	95
26-W	63	3-15-55	II (M)	1,500	24	1,500	Med.	2200	1450	3.0	480	120	25	252	53	209	44
59-W	50	1-26-55	II (M)	2,500	50	2,500	Med.	1800	1800	6.3	510	302	59	710	139	569[d]	112
67-W	13	8- 3-53	I	2,000	154	2,000	Med.	2500	1700	2.0	235	7	3	56	24	—	—
	13	12-23-54	II	1,000	77	1,000	Med.	2800	2500	2.9	235	21	9	50	21	62	26
89-W	38	12-28-54	II	1,000	26	1,000	Med.	2650	2200	4.8	380	38	10	436	115	392[d]	103
103-W	19	1-24-55	II	500	26	500	Med.	2900	2600	3.1	100	60	60	132	132	41	41
111-W	27	1-21-54	I (M)	2,000	74	3,000	Med.	1900	1100	4.5	325	8	2	1,409	434	369[d]	114
140-W	33	12-21-53	I	1,000	30	1300/200	Med/Cor	2700	2200	4.0	325	187	58	675	208	457[d]	141
142-W	23	1-18-54	I	2,000	87	2000/1000	Med/Cor	2900	2500	3.5	220	10	5	154	70	42	19
146-W	39	4- 1-54	II (M)	1,500	38	1,500	Med.	4000	4000	3.5	360	99	28	516	143	449[d]	125
161-W	35	10-28-54	II	500	14	500	Med.	1500	1100	2.0	280	48	17	185	66	258	92
165-W	14	7- 7-53	I	2,000	143	2,000	Med.	2200	1700	3.0	115	5	4	172	150	50	43
167-W	40	6-25-54	II	1,000	25	1,000	Med.	2600	2475	4.0	310	197	64	638	206	356	115
185-W	24	6- 8-54	II	1,000	42	1,000	Med.	1900	1900	4.0	235	47	20	280	119	90	38
186-W	22	1- 4-55	II	1,000	45	1,000	Med.	1550	1550	5.9	225	25	11	61	27	55	24
188-W	23	1- 4-55	II	1,000	43	1,000	Med.	1200	1200	4.4	230	37	16	563	245	401[d]	174
196-W	41	3-29-54	II	1,000	24	1,000	Med.	2850	2700	2.5	335	171	51	446	133	373[d]	111
198-W	30	12-18-53	I	1,000	33	1000/500	Med/Cor	2400	2000	4.0	190	11	6	333	175	196[d]	103
221-W	14	6-26-53	III	2,000	143	1,500	Med.	4000	4000	1.5	100	3	3	1	1	—	—
	14	7-22-53	I	2,000	143	2,000	Med.	2600	2100	3.5	100	1	1	48	48	41	41
225-W	35	3-30-54	II	1,000	29	1,000	Med.	1900	1900	3.5	450	72	16	435	97	340	76
237-W	25	12-18-53	I	1,000	40	1000/500	Med/Cor	3600	2700	3.0	200	27	14	52	26	—	—
	25	1-12-54	I	1,000	40	1,800	Med.	4000	4000	2.0	200	40	20	—	—	33	17
Total	993			42,900		45,800					7,915	1,767		9,961		6,125	
Average	34			1,480	43	1,580		2502	2114	3.4	304	61	20	340	112	236	78

(a) Type I: Acid-kerosene gel
Type II: Water-base gel
Type III: Oil-base gel
Type IV: Acid-base gel
(M): Denotes plugging material used for multiple fracture.

(b) Med: 20-40 Mesh (medium)
Cor: 10-20 Mesh (coarse)
(c) %: Injection as percent of recommended rate.
(d) Injection rate restricted.

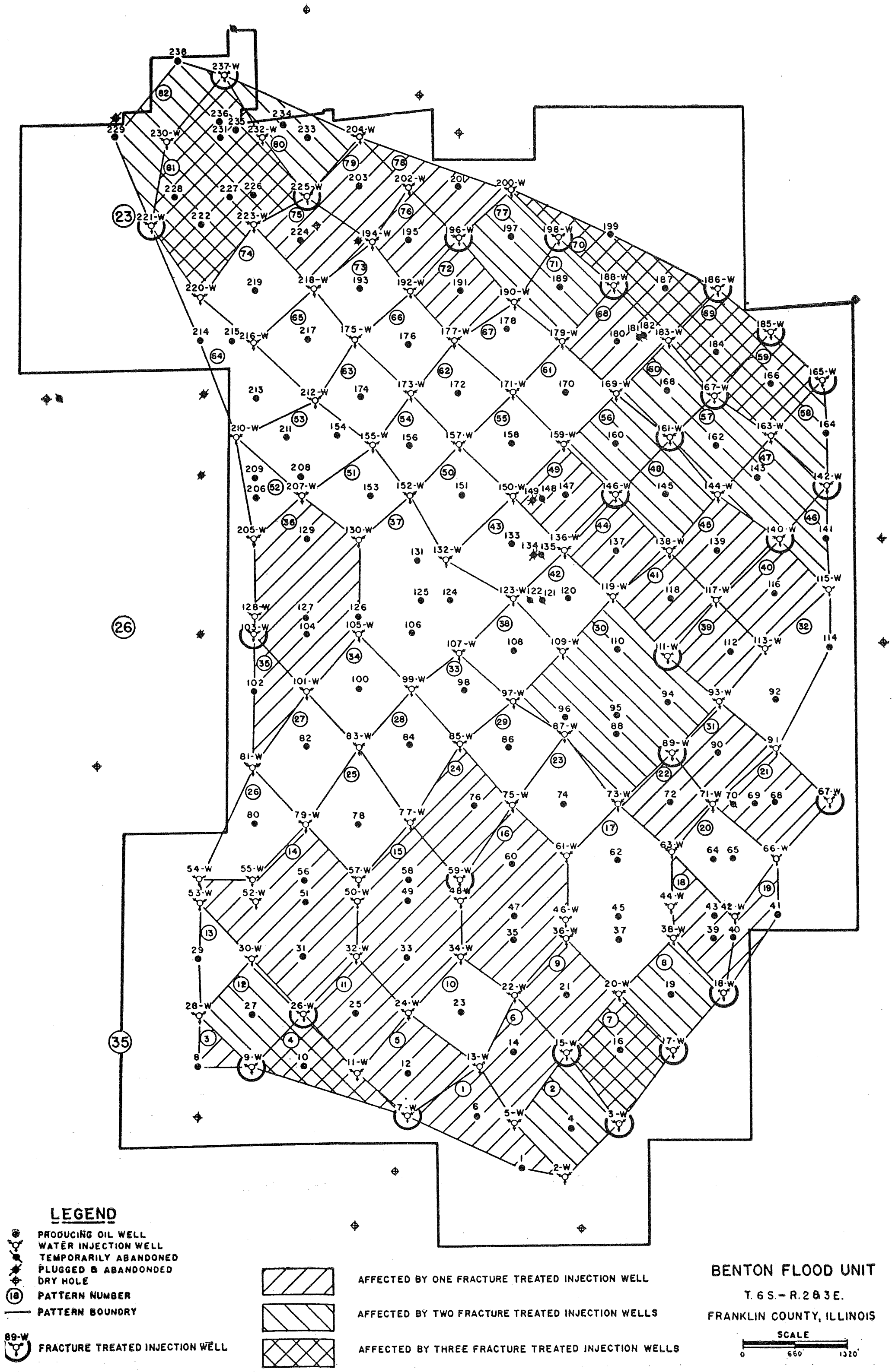

Fig. 1.—Producing areas affected by fracture-treated water-injection wells.

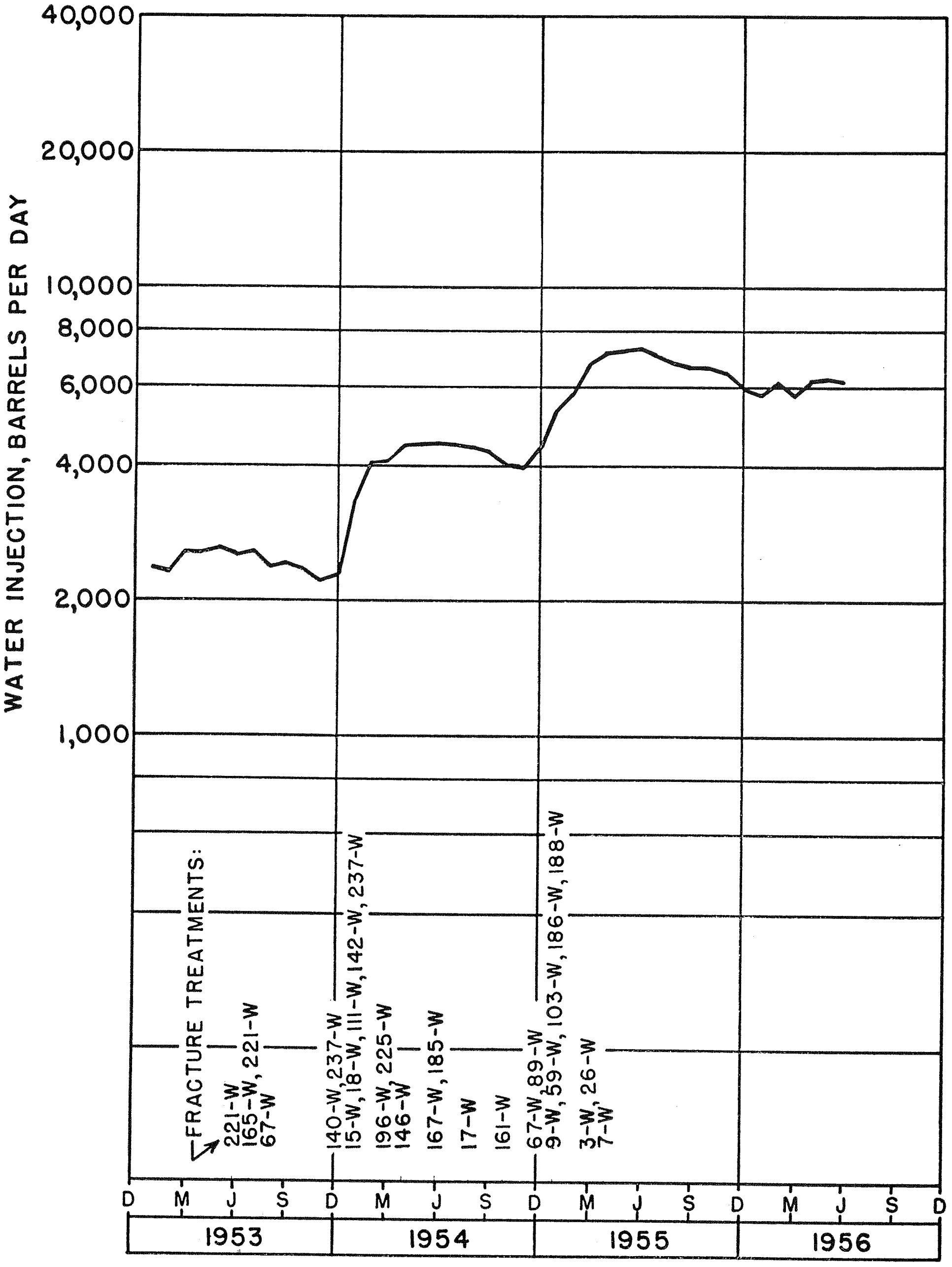

FIG. 2.—Total injection for all fracture-treated wells.

The first attempt to fracture-treat well No. 221-W with a refined-oil gel containing 0.75 pound of sand per gallon resulted in a sand screen-out and did not improve injection performance. Following clean-out, the well was successfully fracture treated with an acid-kerosene gel containing one pound of sand per gallon.

Two attempts to fracture-treat well No. 237-W with an acid-kerosene gel resulted in sand screen-outs. The first treatment increased the water-injection rate, but it was necessary to perform additional remedial work before the well could be returned to injection after the second treatment.

A multiple-fracture treatment using a water-base gel resulted in a sand screen-out in well No. 146-W. However, the water-injection rate was increased from 99 to 516 barrels per day and the treatment was considered successful.

Including failures, the 29 fracture treatments of 26 injection wells have resulted in a per treatment average increase of water injection from 61 barrels per day, or 20 percent of the recommended rate, before fracture treatment to 340 barrels per day, or 112 percent of the recommended rate, immediately after fracture treatment. This represents an average water-injection rate increase of 457 percent due to fracture treating. As of July 1, 1956, the average injection rate for the 26 wells amounted to 236 barrels per day, or 78 percent of the recommended rate.

All injection wells at Benton have been assigned recommended daily water-injection rates in an effort to achieve uniform advance of flood fronts in producing areas. These rates are based upon floodable reservoir volumes and afford a basis for comparing injection rates which is related to flood balance.

Excepting the northwest portion of the field where three fracture-treatment failures have occurred, reservoir conditions are similar for the producing areas influenced by the fracture-treated injection wells. It appears that the principal effect of the fracture treatments has been to improve injection performance by reducing flow restrictions at the injection well. This has been evidenced by the results of small treatments that could have done no more than reduce flow restrictions in the immediate vicinity of the well bore, yet substantial injection-rate increases have been obtained.

Before the fracture-treating program was started in 1953, daily average water injection into the group of subsequently treated wells totaled 2500 barrels per day. A maximum rate of 7300 barrels per day was reached during June 1955, which represents an increase in injection of 4800 barrels per day over the former rate. Present injection into this group of wells is about 6000 barrels per day. The trend of total field daily average water injection follows closely the trend of the fracture-treated injection wells, thus reflecting the increased injection rates.

It should be noted that during this period injection facilities were modified so that the majority of injection wells were receiving water from the closed treating system which was operating at a pressure higher than that of the existing open system. Performance indicates that injection rates were increased from 10 to 15 percent as a result of the closed system conversion and a similar increase was indicated for 24 of the fracture-treated injection wells, all of which received water from the closed system. Two of the fracture-treated injection wells receive water from the open system facilities. Figure 2 presents a composite graph of water–injection rate versus time for the group of fracture-treated injection wells.

To determine more accurately the effect of fracture treatments on injection and production rates, it is necessary to consider the behavior of injection wells offsetting fracture-treated wells. It appears that a change in the injection rate of one well often causes counteracting changes in the offset injection wells. This can be illustrated by figure 3 which depicts the injection for well No. 111-W, a fracture-treated well, and two injection offsets, wells Nos. 93-W and 119-W. Injection into the two offsets is inversely proportional to the injection into well No. 111-W. The other offset injection well, No. 117-W, has maintained its rate throughout this period, but the injection pressure is proportional to injection into well No. 111-W. This is the most pronounced example of interference between injection wells in the field; but nevertheless, the injection rate increases due to fracture treating must be carefully examined to determine the net increases affecting producing areas.

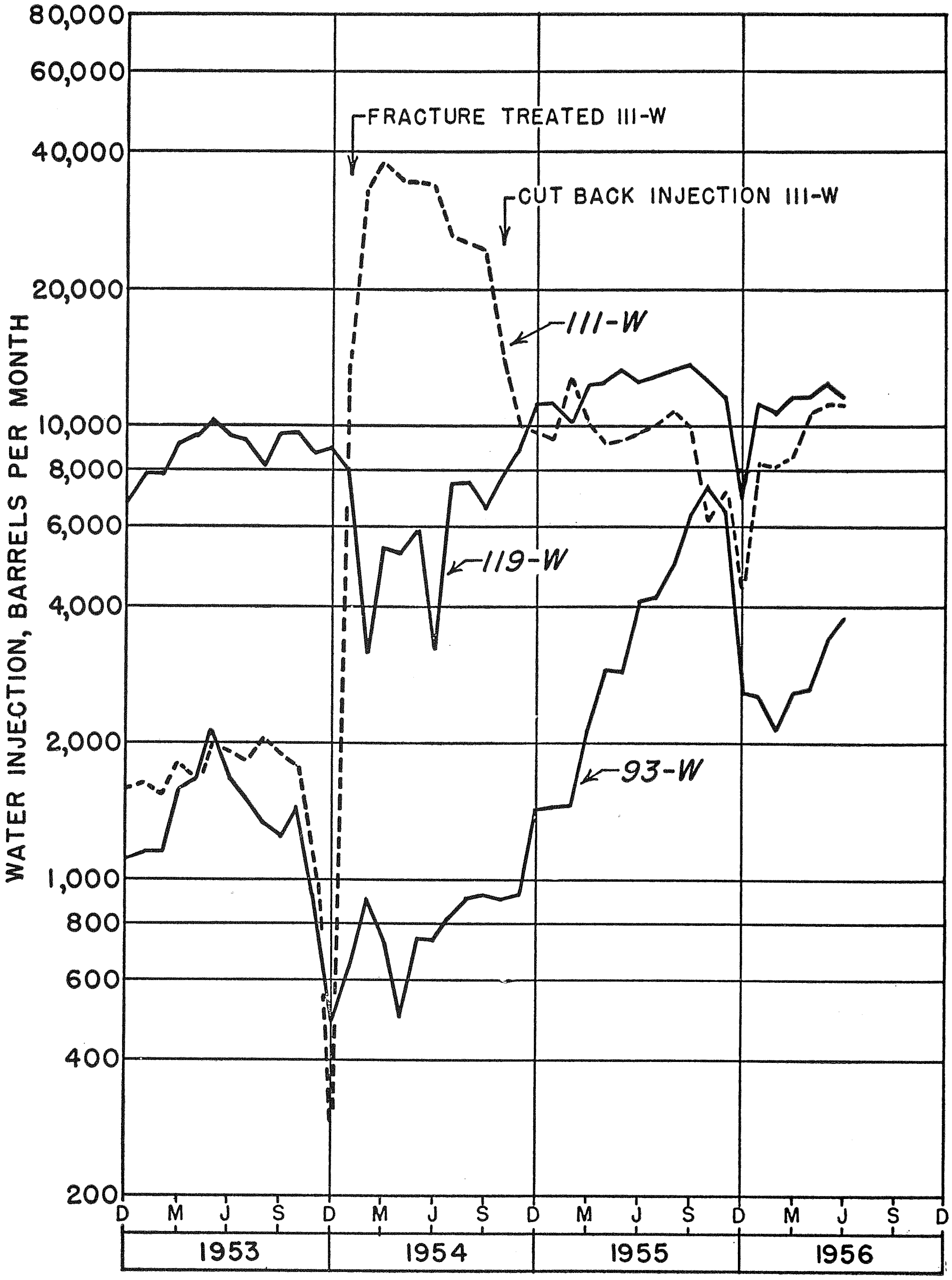

FIG. 3.—Water injection for wells 93-W, 111-W, 119-W.

EFFECTS ON PRODUCTION

At Benton, producing areas have been separated into 82 patterns, the outlines of which are formed by lines connecting water-injection wells. Fifty of the pattern areas have been affected by fracture-treated injection wells. Of these, six have been affected by three fracture treatments, 15 by two fracture treatments, and 29 by one fracture treatment. These pattern areas are identified in figure 1.

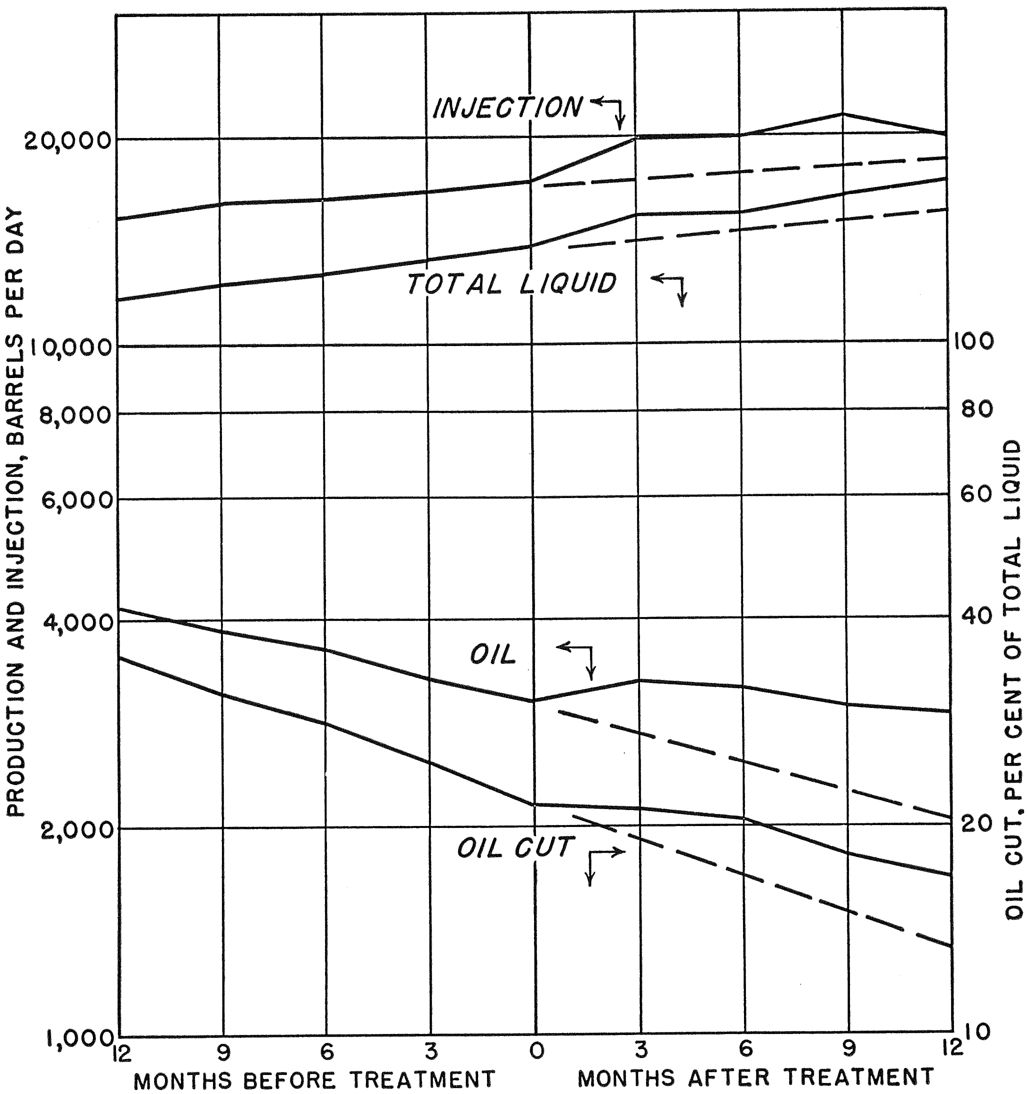

FIG. 4.—Composite performance data for all affected producing patterns, before and after fracture treatment.

To determine how increased water-injection rates (brought about by hydraulic-fracture treatments) affect oil production, it has been necessary to consider the performance of all injection wells that affect the producing area under consideration. To accomplish this, a proportionate share of the water injected into any particular well has been allocated to surrounding producing areas. The allocation has been related to the geometric configuration of the pattern, being based on the angle formed at the injection well by the pattern boundary. No attempt has been made to take into consideration the effects of variables such as close-spaced wells, field-edge losses, pay thicknesses, permeabilities, pressures, et cetera, which influence the distribution of injected water.

Figure 4 depicts composite water injection, total liquid production, oil production, and oil-cut performance data for the producing areas affected by fracture-treated injection wells. The data have been separated to show performance before and after fracture treat-

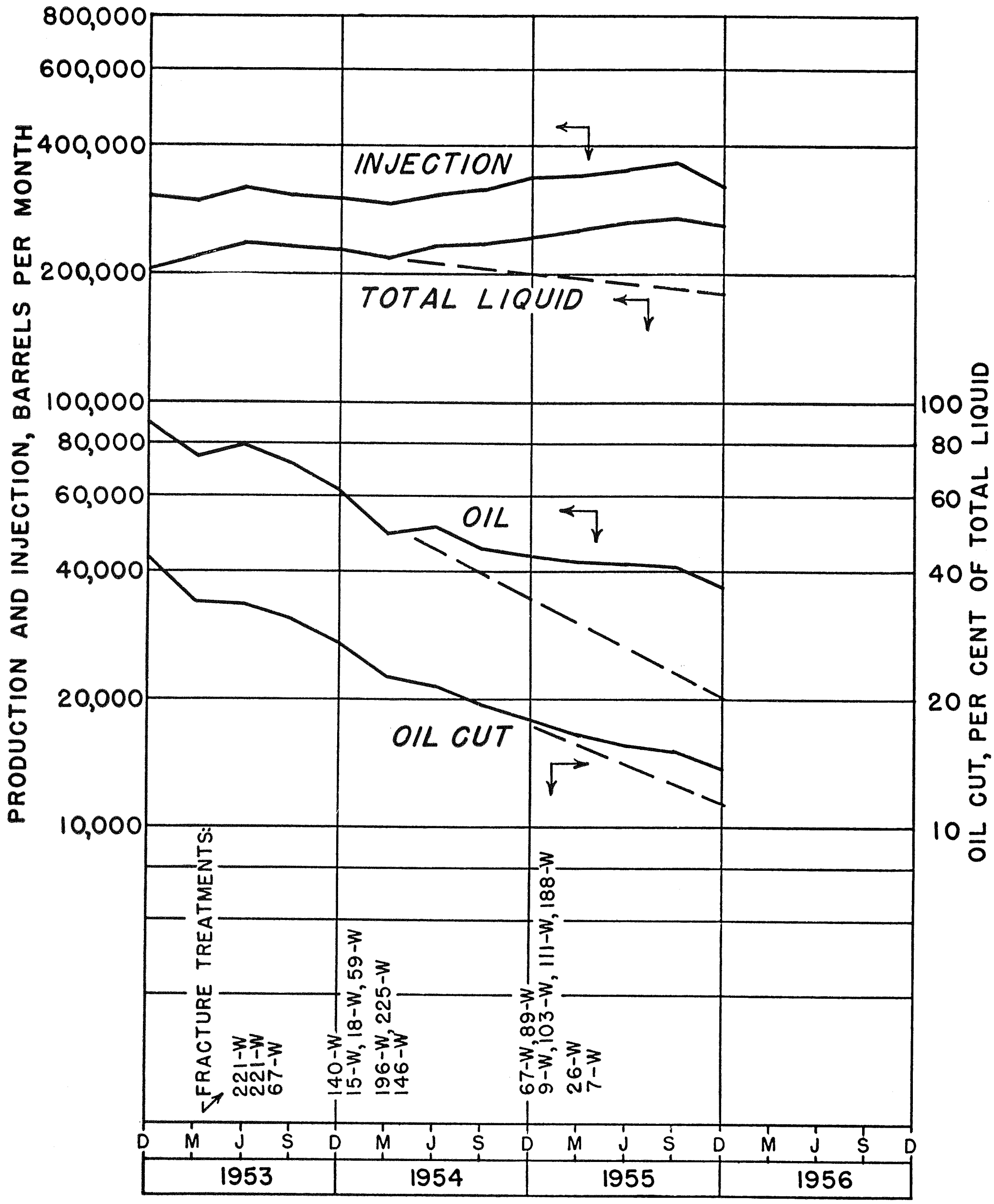

FIG. 5.—Composite performance data, for producing patterns affected by one fracture treatment.

ment. For areas that are affected by more than one fractured injection well, the date of first treatment has been used to separate the data.

Extrapolations of trends before treatment indicate that increased water-injection rates have resulted in corresponding increases in total liquid production. During the 12-month period following the treatments, net water injection was increased 870,000 barrels and total liquid production was increased 470,000 barrels over the prevailing trend.

Inasmuch as the total increase in injection is more than the total increase in production, it appears that portions of the reservoir not being flooded effectively under previous con-

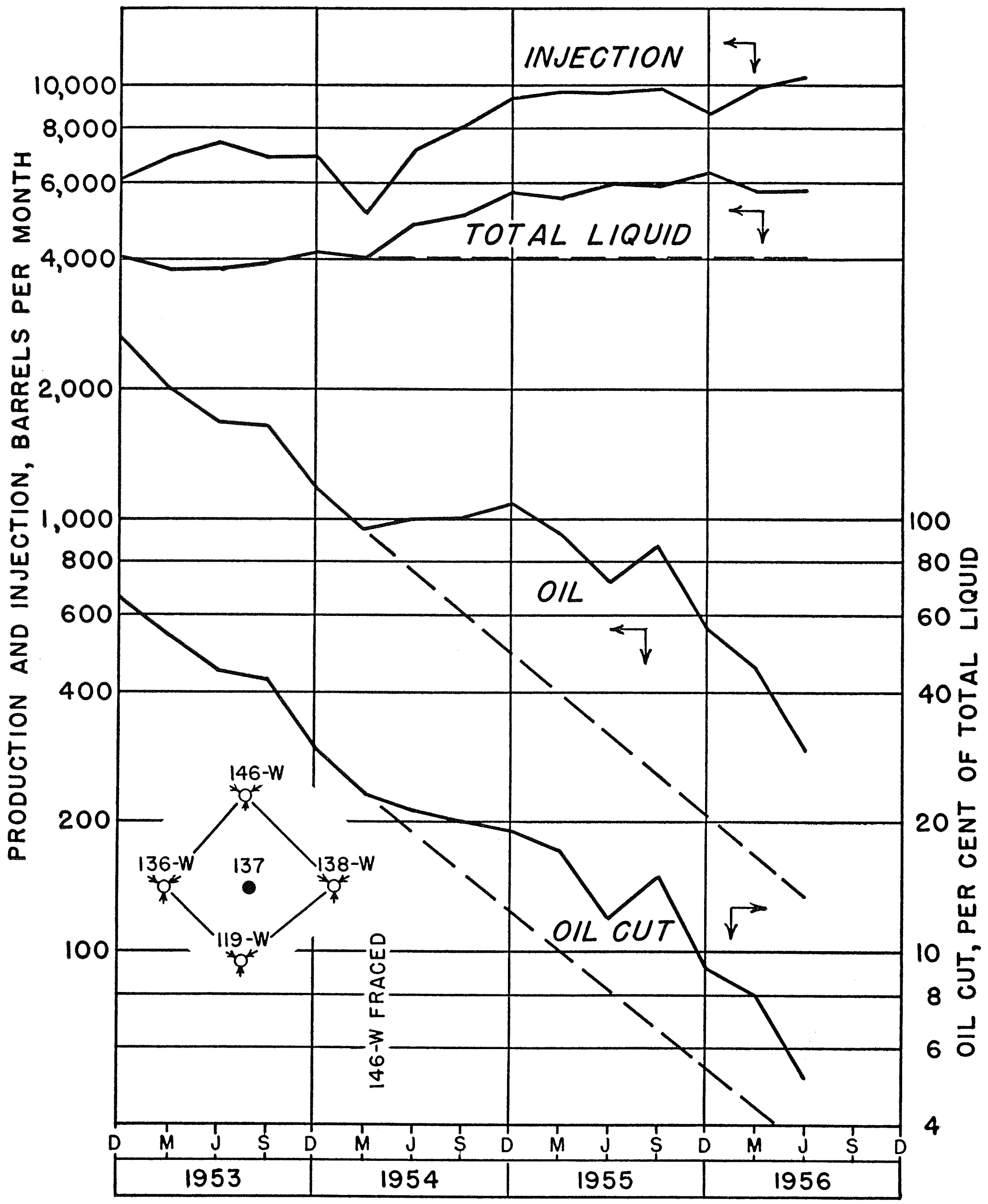

FIG. 6.—Performance of producing pattern No. 44.

ditions are now being flooded. This contention is supported by the apparent improvement in oil-cut trend. Although the observed oil-cut supports the possibility that an increase in ultimate oil recovery may be realized, the data are not considered sufficiently conclusive to indicate an increased ultimate recovery. However, a definite improvement in the oil production rate has been achieved. Based on the extrapolated trend, an additional 270,000 barrels of oil were produced during the 12 months following fracture treatment. It should be noted that the extrapolation of the oil-production curve is con-

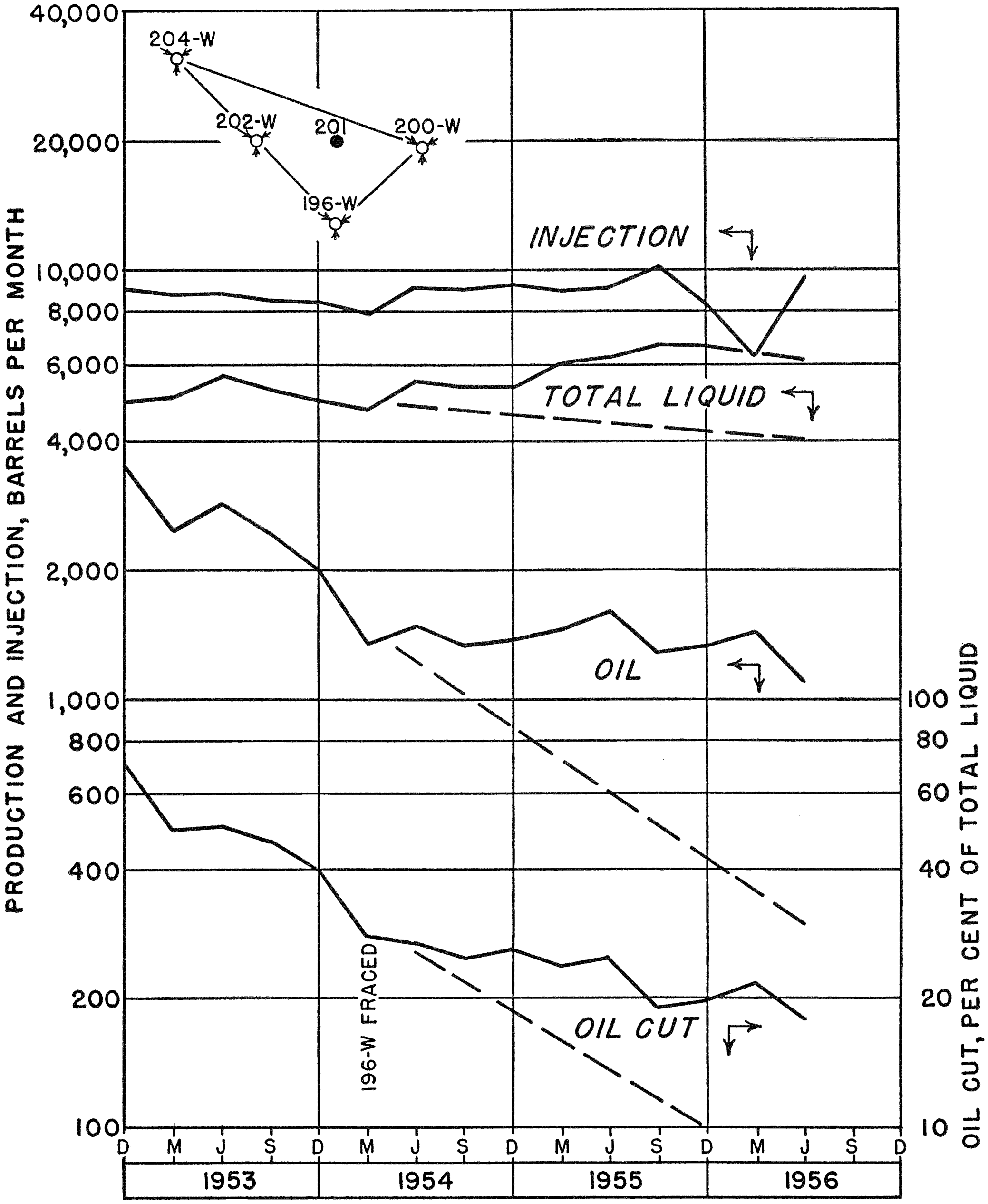

FIG. 7.—Performance of producing pattern No. 78.

trolled by the extrapolations of the total liquid production and oil-cut curves.

Figure 5 presents composite water injection, total liquid production, oil production, and oil-cut curves for producing areas affected by one fracture-treated water-injection well. The curves indicate that increased water-injection rates have resulted in improved production performance. Although the trend of the oil-cut curve has not been significantly affected, total liquid production has increased and the oil production curve has flattened. Examples of production and injection data for individual producing areas

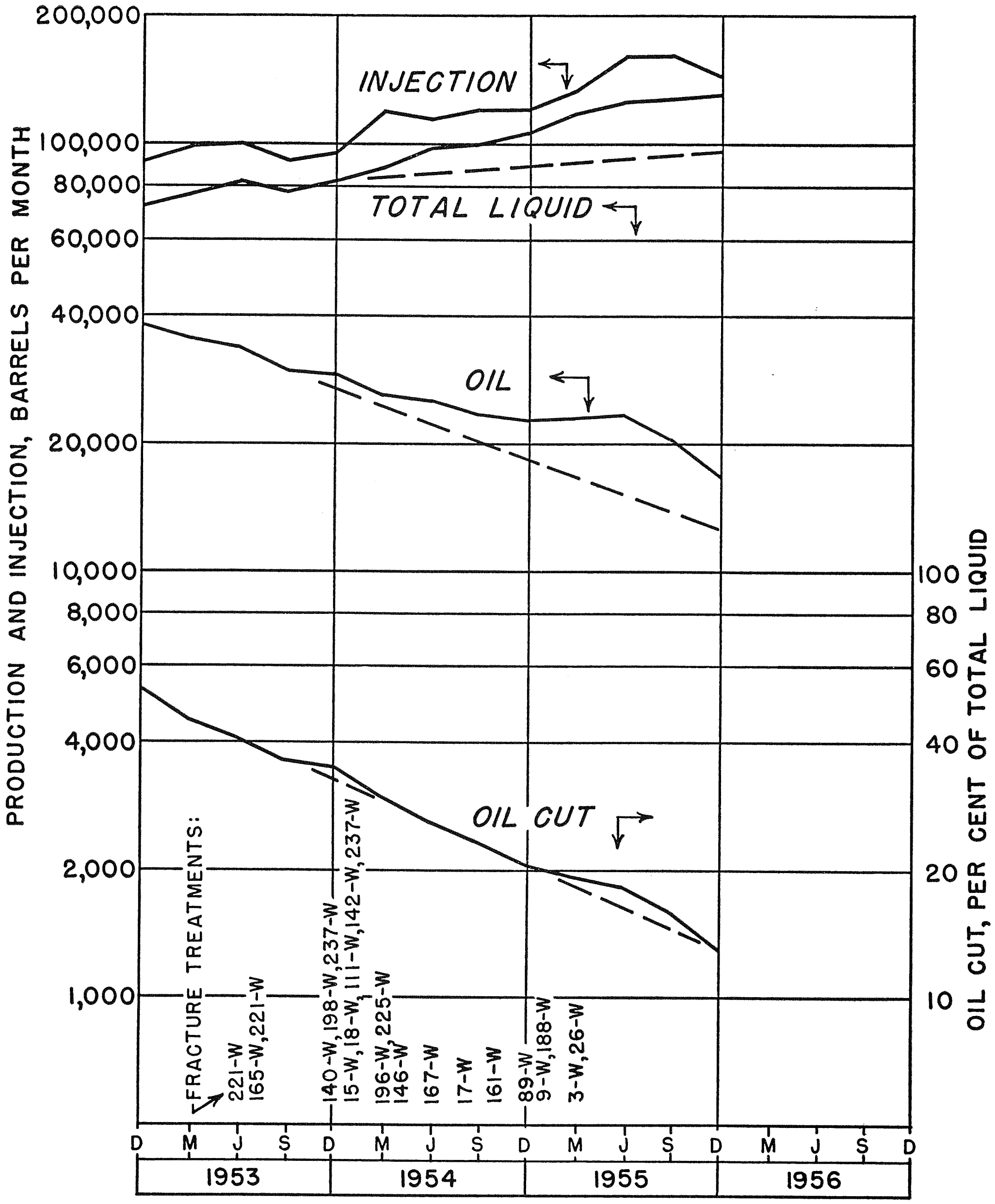

FIG. 8.—Composite performance data for producing patterns affected by two fracture treatments.

affected by one fracture-treated injection well are shown in figures 6 and 7. These examples indicate definite flattening of the oil production curves, which has been the result of improved total liquid production and oil-cut trends.

Composite water injection, total liquid production, oil production, and oil-cut data for producing areas affected by two fracture-treated injection wells are shown in figure 8. The trend of the oil-cut curve has not been changed appreciably and a flattening of the oil production curve has occurred as a result of increased total liquid production.

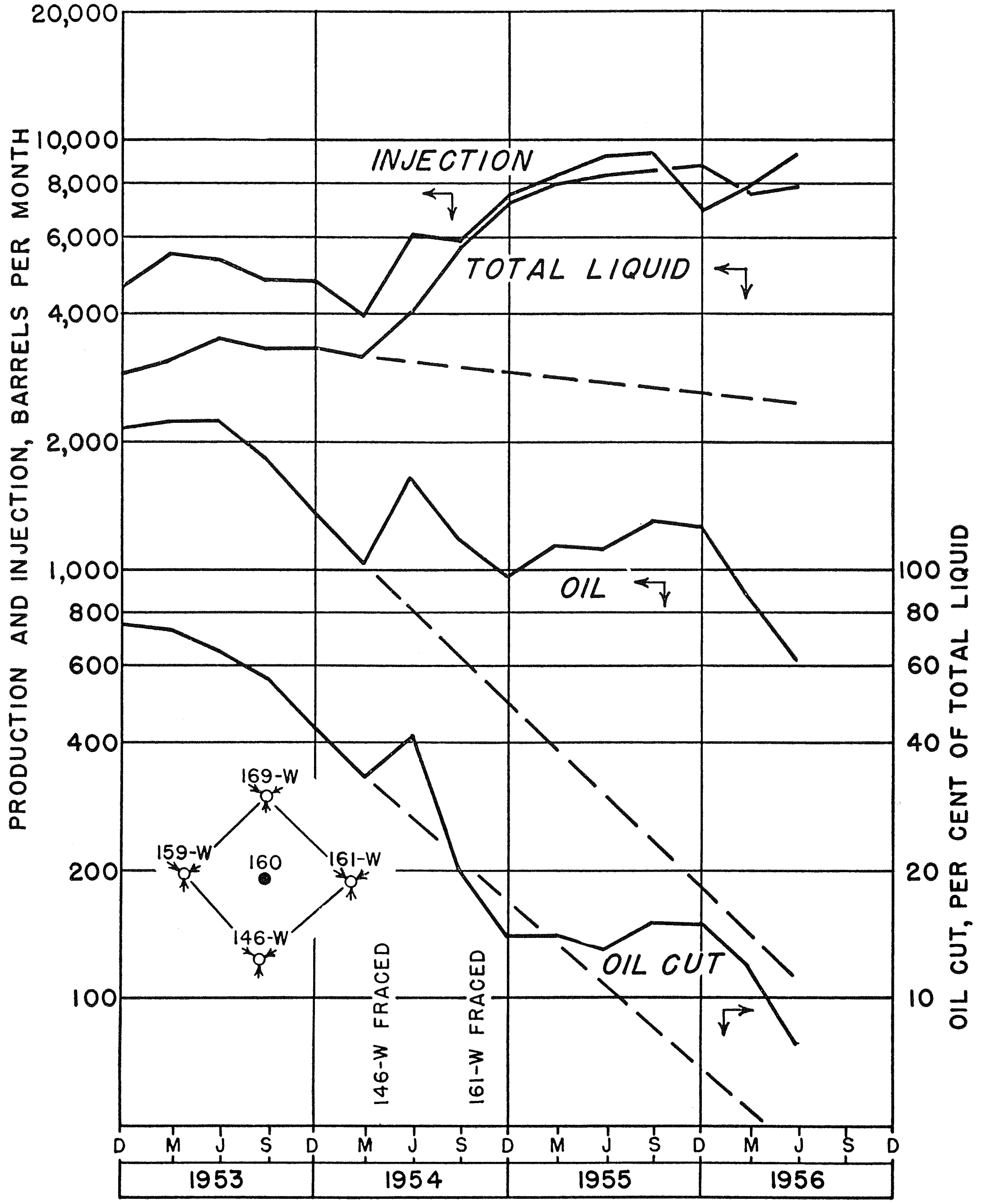

FIG. 9.—Performance of producing pattern No. 56.

Figures 9 and 10 are examples of production and injection data for individual producing areas affected by two fracture-treated injection wells. In figure 9, the oil-cut trend has been improved and, combined with the increased total liquid production, the oil production rate has been benefited. The curves depicted in figure 10 are difficult to interpret because peak production under flood had not been attained, and the total liquid and oil production curves were increasing when the fracture treatments were performed. How-

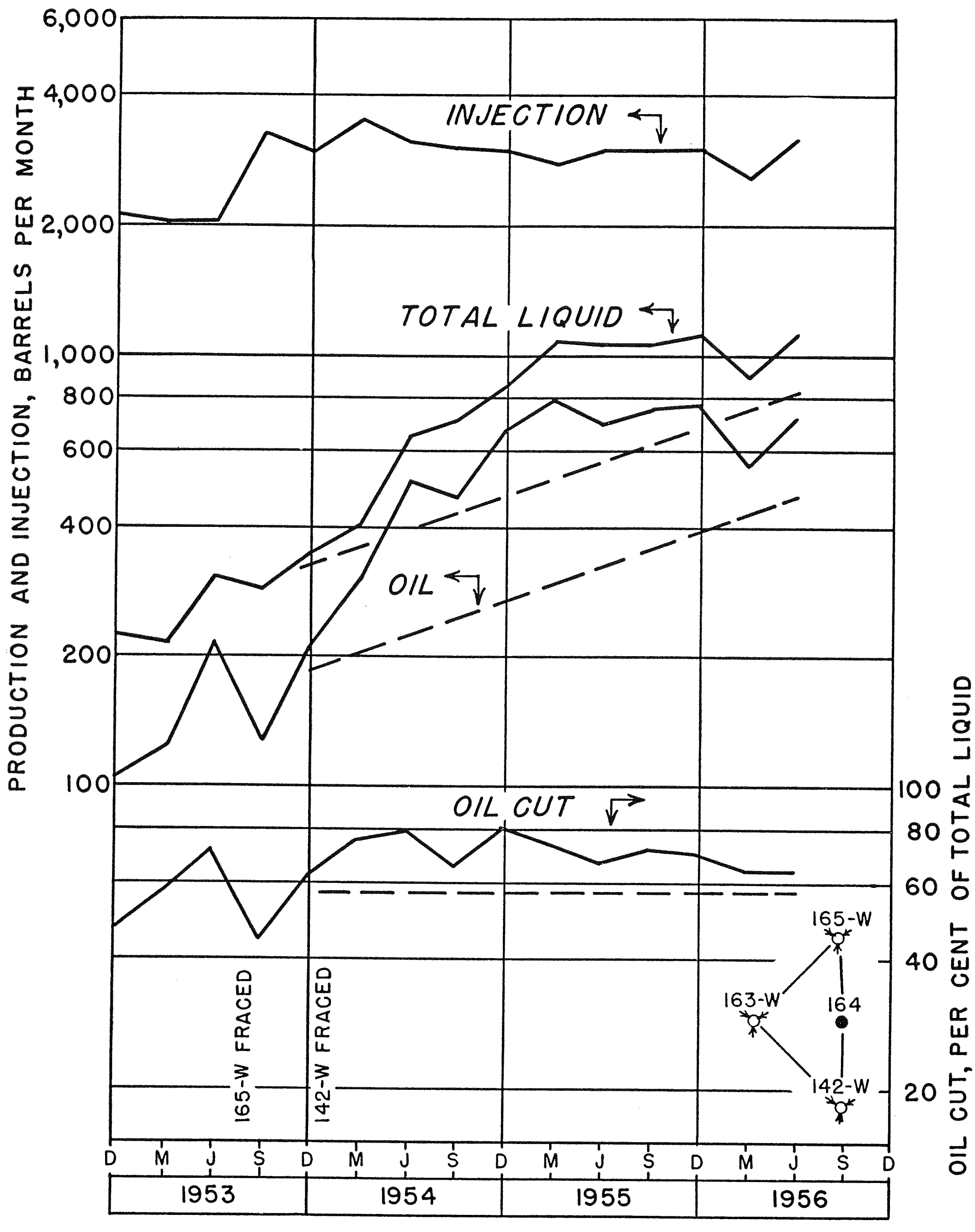

FIG. 10.—Performance of producing pattern No. 58.

ever, it appears that the performance of this edge pattern has been improved by the increased water-injection rates.

Composite water injection, total liquid production, oil production, and oil-cut data for the producing areas affected by three fracture-treated water-injection wells are shown in figure 11. Increased water-injection rates have increased total liquid production without accelerating the decline of the oil-cut curve, and an improved oil production rate is indicated. Figures 12 and 13 are examples

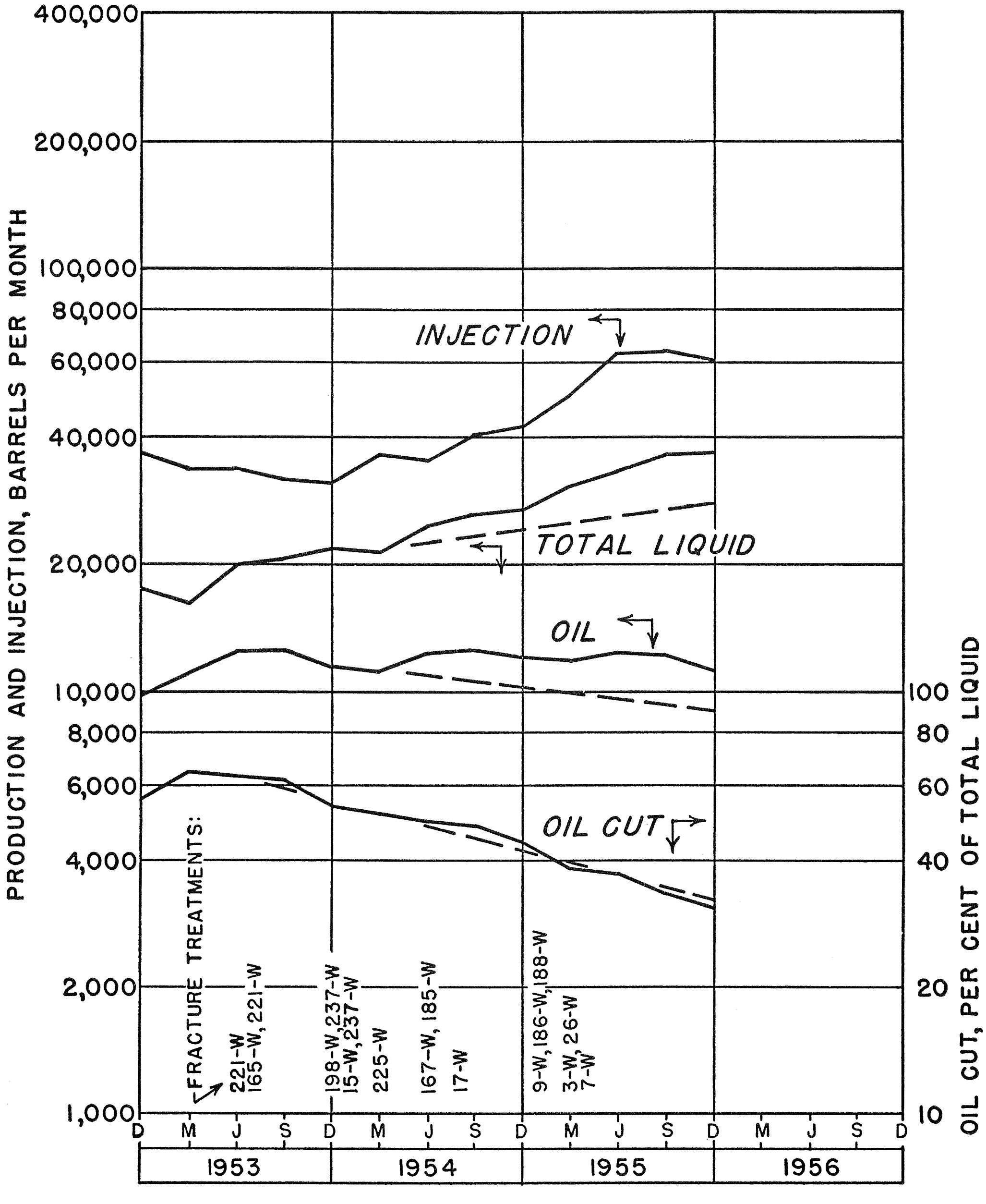

FIG. 11.—Composite performance data for producing patterns affected by three fracture treatments.

of production and injection data for individual producing areas affected by three fracture-treated injection wells. Definite improvements in the oil production rates have accompanied the increased total liquid production rates and improved oil-cut trends.

As indicated by a comparison of the composite data and the data for individual producing areas, the examples presented are not entirely representative of production and injection trends for all affected areas. Data for many of the areas are much more difficult to interpret, for there are no discernible changes in the production trends. The many uncon-

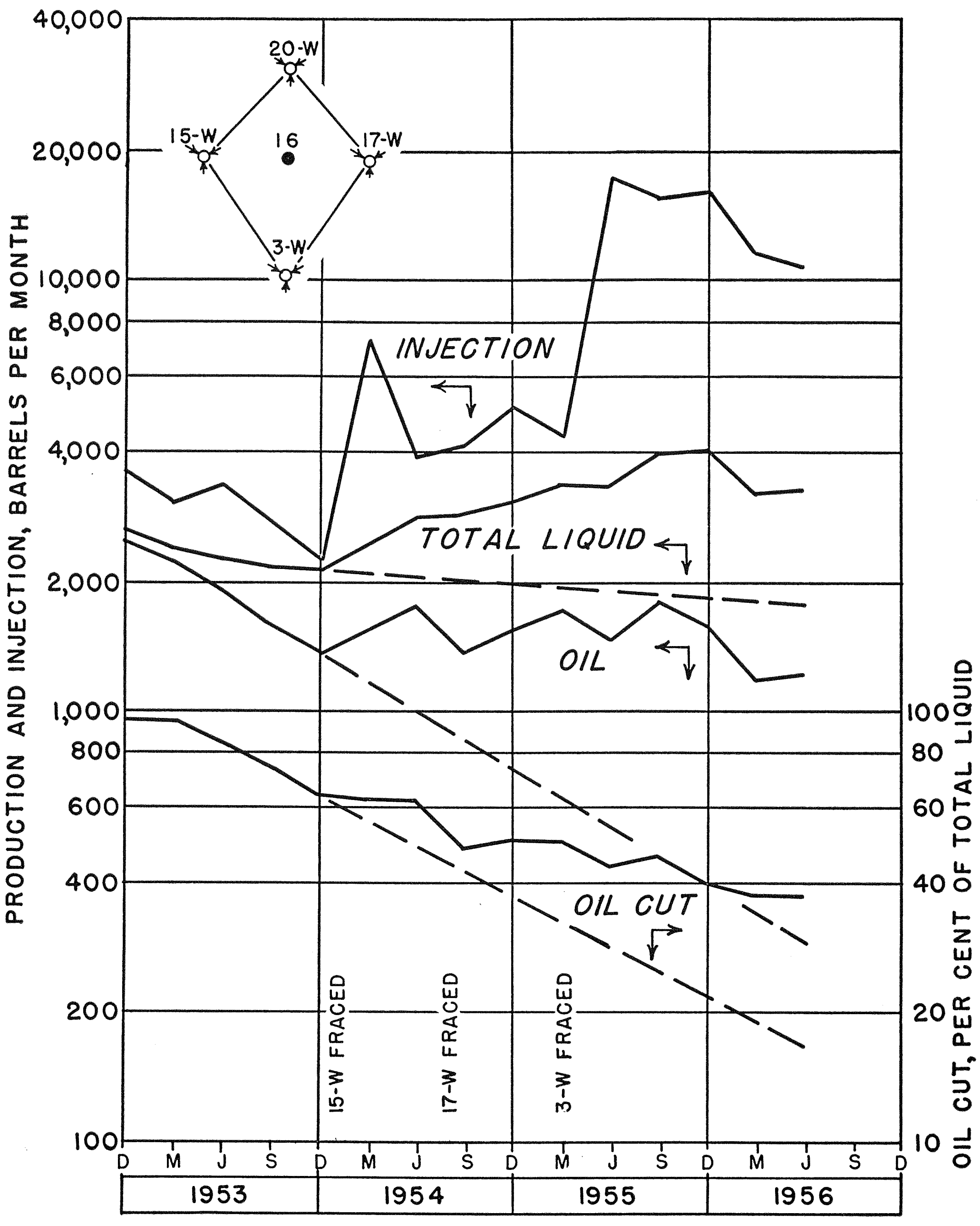

FIG. 12.—Performance of producing pattern No. 7.

trollable factors that affect a comparison of water-injection and production rates for individual producing areas are such that it is not possible to make a conclusive determination for every area studied. The data indicate, however, that increased oil production rates have occurred as a result of increasing water-injection rates by hydraulic fracture treatments.

Water-injection wells at Benton have been fracture-treated in an effort to achieve balanced flood conditions and assure maximum

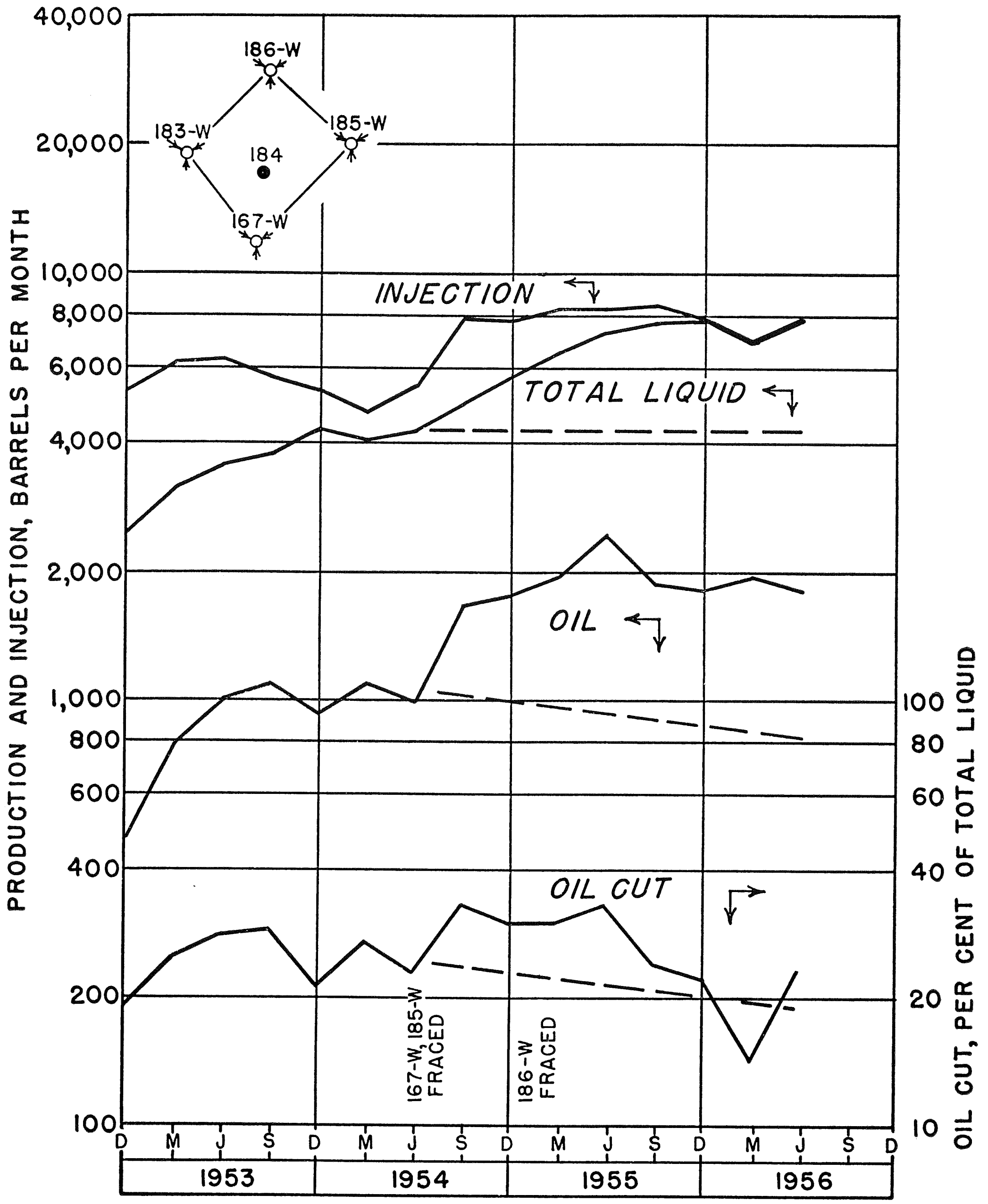

FIG. 13.—Performance of producing pattern No. 69.

oil recovery. The criteria for determining the success of the program is production performance. Even though an increased ultimate oil recovery may not be conclusively indicated, there has been no indication that ultimate oil recovery has been reduced. If it is assumed that ultimate oil recovery has not been changed and that for a given ultimate recovery the same ultimate water injection is required, regardless of the rate, then increased injection rates will effectively reduce the flood life of the affected producing areas.

TABLE 2.—COMPARISON OF FRACTURE TREATMENT TYPE AND METHOD

Treatment type	No. of treatments	Water injection after treatment percent of recommended rate			
		Initial	6 Months	12 Months	Current (7-1-56)
Straight Treatments					
Acid-kerosene	7	120	67	65	79
Water-base	13	91	80	71	67
Total	20	101	76	69	71
Multiple Treatments					
Acid-kerosene	1	433	272	92	114
Water-base	3	109	96	92	91
Total	4	172	130	92	95
Straight and Multiple Treatments					
Acid-kerosene	8	167	98	69	84
Water-base	16	96	84	76	73

Note: Data exclude both treatments of well No. 237-W and first treatment of well No. 67-W.

OPTIMUM FRACTURE TREATMENT

To determine the optimum fracture treatment at Benton, several parameters have been used to compare data for the various treatments. Parameters of treatment size, type, and method appear most significant. Comparisons based on pumping rates during treatment and the amounts of sand employed have been inconclusive because of the narrow range of variations encountered.

Eleven fracture treatments have been performed with acid-kerosene gels, sixteen with water-base gels, one with a refined-oil gel, and one with an acid-base gel. The refined-oil treatment was performed on well No. 221-W and failed to give satisfactory results. The acid-base gel treatment was performed on well No. 3-W, and although excellent results were obtained, no sand was used due to the mechanical condition of the well. Therefore, comparisons of fracture fluid types have been confined to acid-kerosene and water-base gel treatments. The acid-base gel treatment has been considered, however, when comparing treatment sizes. Treatment methods considered in the comparisons are multiple-fracture treatments that utilize temporary plugging materials and straight-fracture treatments that do not utilize temporary plugging materials.

As indicated in table 2 under the comparison of straight treatments, the acid-kerosene gels have given better initial results than have the water-base gels. However, the initial injection-rate increases have declined rapidly and the differences in current injection are such that the water-base gels compare favorably. They also offer the significant advantage of lower cost.

In table 2 under the comparison of multiple treatments, there are insufficient data to indicate conclusively a superior fracture fluid for multiple treatments. However, the water-base treatments have resulted in substantial injection rate increases. There is a marked difference in the number of treatments compared, but the data indicated that multiple treatments have been more success-

TABLE 3.—COMPARISON OF FRACTURE TREATMENT SIZE

Treatment size gal./ft.	No. of treatments	Water injection after treatment percent of recommended rate			
		Initial	6 Months	12 Months	Current (7-1-56)
<26	7	77	69	66	66
26 – 50	10	138	99	96	100
51 – 100	4	199	127	62	71
>100	4	189	108	92	74

Note: Data exclude both treatments of well No. 237-W and first treatments of wells Nos. 67-W and 221-W.

ful than straight treatments. Initial results have been superior and the injection-rate increases have been sustained at higher levels. It appears that multiple treatments can be expected to give better results than straight treatments, regardless of the type of fracture fluid.

Under the comparison of fracture treatment sizes in table 3, treatments have been considered on the basis of gallons of fracture fluid per foot of sand thickness treated. Although the data are somewhat inconclusive, it appears that the treatments involving 26 to 50 gallons of fracture fluid per foot of sand have resulted in more sustained injection increases. Treatments in this category have given acceptable initial increases, although lower than those of larger treatments, and the increased injection rates have been maintained at approximately recommended values.

In the foregoing comparisons of fracture-treatment data, injection pressures have been disregarded and data have been included for wells that have had injection rates restricted in an effort to maintain waterflood balance. To account for these factors, comparisons of fracture treatment data have been made on the basis of injection capacity expressed as the ratio of injection rate to injection pressure at the sand face. Expressed in this manner, the data reflect comparable capacities for restricted and unrestricted injection conditions. As indicated by table 4, the results of comparing treatment sizes on this basis substantiate the results of the comparisons that neglected pressure variations and embodied restricted injection data.

Superficially it appears that the data supporting the size comparisons contradict the generally accepted hypothesis that, within limits, the results of fracture treating are proportional to treatment size. It should be noted, however, that the treatments at Benton have been much smaller than those normally employed when fracture-treating producing wells operating under primary production mechanisms. Undoubtedly, much larger treatments would substantially increase water-injection rates. However, they would seriously increase the risk of reducing waterflood efficiency and oil recovery. Waterflood balance can be harmed by excessive water-injection rates as well as by inadequate rates. Consequently, it is necessary to confine water injection within close limits to assure flood balance, and under theses conditions, there is a practical limit to desired or required water-injection rate increases.

Considering effect on injection, magnitude of desired results, and treatment cost, the comparisons of fracture-treatment data indicate that multiple, water-base gel treatments in the amount of 50 gallons of fracture fluid per foot of sand thickness treated are optimum fracture treatments for water injection wells at Benton.

WATER-INJECTION PROFILES

To determine the effects of fracture treatments on water-injection profiles, three surveying methods have been used to determine profiles before and after treatment. Eleven fracture-treated injection wells have been sur-

Table 4.—Comparison of Fracture Treatment Size

Treatment size gal./ft.	No. of treatments	Water injection after treatment Barrels per day per psi at sand face*			
		Initial	6 Months	12 Months	Current (7-1-56)
< 26	7	.20	.19	.19	.18
26 – 50	10	.30	.19	.20	.21
50 – 100	4	.39	.23	.12	.08
>100	4	.29	.14	.13	.11

Note: Data exclude both treatments of well No. 237-W and first treatments of wells Nos. 67-W and 221-W.
*Surface pressure plus hydrostatic column.

veyed in this manner, three of which have been surveyed by each of the three types of surveys to compare the results of the different methods.

Five fracture-treated wells were surveyed before and after treatment by a dyed-water—clear-water interface method. The method involves locating the interface in the well bore with a photo-electric cell while injecting water at a constant rate, and determining the velocity with which the interface moves toward the bottom of the hole. The interface velocities are combined with hole-volume data to determine the amount of injected water leaving the well bore at various intervals. Inasmuch as Benton injection wells are completed in heavily shot open-hole intervals, these surveys are often difficult to interpret, and accuracy is generally limited to three- or four-foot intervals.

An example of an injection profile determined by the dyed-water—clear-water interface method is shown in figure 14 for well No. 198-W. Considering the accuracy of the survey, no significant change in the injection profile has occurred as a result of the fracture treatment. Although the example shown is not completely representative, as other profiles exhibit more diversified injection distribution, it nevertheless illustrates the minor effects that fracture treatments have had on injection profiles. An exception has been the multiple-fracture treatment of well No. 111-W. The injection profile survey after treatment indicated that a one-foot interval was receiving 40 percent of the total injection, whereas the survey before treatment had indicated 10 percent injection into this interval.

Three wells have been surveyed, before and after fracture-treating, by the radioactive tracer method of determining injection profiles. In addition, the method has been used to survey three wells that were first surveyed by the dyed-water—clear-water interface method. The radioactive tracer method consists of running a base radioactivity log; dispersing 30- to 50-mesh radioactive charcoal in the injected water; and running a series of radioactivity logs while the charcoal is being deposited on the sand face. Logs are run until no significant changes are observed and a comparison of the final log with the base radioactivity log indicates the intervals of water injection in qualitative manner.

An example of an injection profile determined by the radioactive tracer method is shown in figure 14 for well No. 225-W. Intervals accepting appreciable amounts of injection water are clearly discernible, being indicated by the displacement of the induced radioactivity from the natural radioactivity. Zones receptive before treatment correspond to zones receptive after treatment, and it is concluded that the fracture treatment did not change significantly the injection profile. It should be noted that the logs can be compared only within a single survey and that the difference in radioactivity between surveys is not indicative of increased receptivity. Rather, the difference is the result of differ-

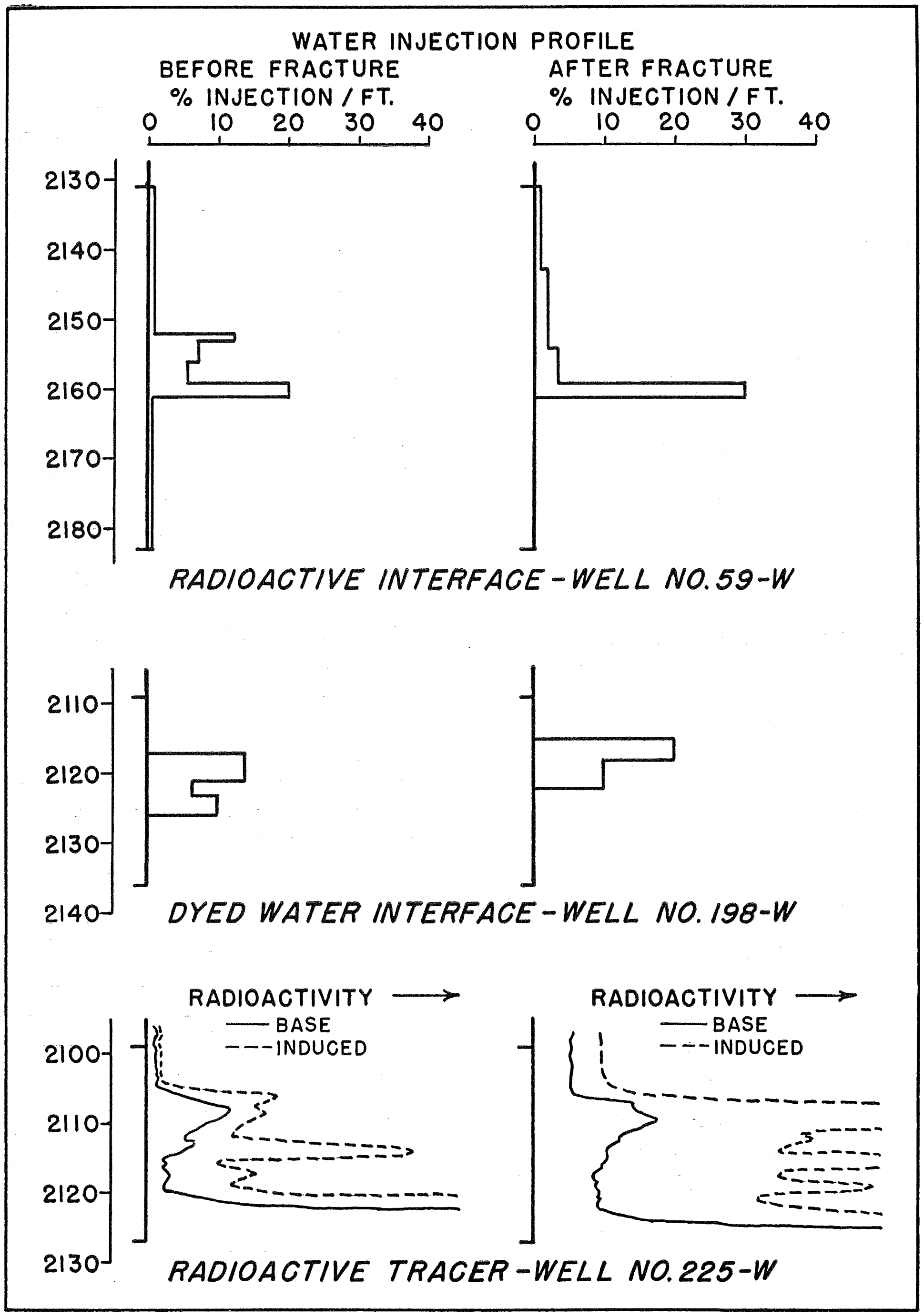

FIG. 14.—Water-injection profiles for wells 59-W, 198-W, 225-W.

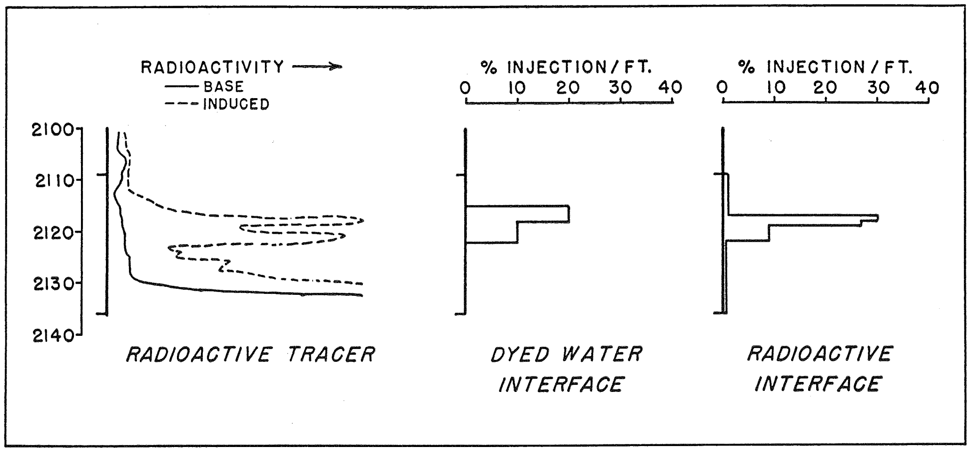

FIG. 15.—Comparison of water-injection profiles for well 198-W.

ent logging sensitivity and radiation intensity of the charcoal.

The survey method used most extensively at Benton has been that of locating a radioactive interface. Open-end tubing is run to the bottom of the hole, and metered water is injected separately into the tubing and tubing-casing annulus. A soluble radioactive material is introduced into the tubing injection and an interface is established in the annular space between tubing and bore hole. Water injected into the tubing-casing annulus enters the formation above the interface, and water injected into the tubing enters below the interface. The interface is located by a gamma ray counter run inside the tubing, and by progressively increasing the percentage of total injection entering the tubing, the interface is moved vertically upward. The injection profile is determined by relating the vertical movement of the interface with the change in tubing injection.

Seventeen wells have been surveyed by the radioactive interface method, three of which were surveyed both before and after fracture treatment. Three of the surveys were on fracture-treated wells that had been surveyed previously by the dyed-water—clear-water interface and radioactive tracer methods.

An example of an injection profile determined by the radioactive interface method is shown in figure 14 for well No. 59-W. No significant change in the injection profile is indicated. What appears to be a change in the distribution of injection is the result of surveying technique more than the result of fracture treating. The zone of highest receptivity before fracture treating remains the zone of highest receptivity after fracture treating.

A comparison of dyed-water—clear-water interface, radioactive tracer, and radioactive interface injection profiling methods is shown in figure 15 for well No. 198-W. With the exception of the zone of injection at the bottom of the hole, indicated by the radioactive tracer survey, the surveys indicate within reasonable accuracy identical injection profiles. Other comparison surveys have given similar results, each indicating substantially the same profile. The injection zone at the bottom of the hole indicated by radioactive tracer surveys has been considered an anomally because it cannot be substantiated by other profiling methods.

Considering the relative advantages and disadvantages of the three profiling procedures, the radioactive interface surveys have been superior to other surveys. However, it should be emphasized that the results obtained at Benton cannot be applied indiscriminately to other fields where injection rates, well completion methods, and other conditions are decidedly different.

Based on the results of surveying eleven water-injection wells before and after fracture treating, injection profiles observed at the well bore have not been changed appreciably by hydraulic fracture treatments. Possibly fracturing has extended existing zones of weakness that are present due to natural fractures, high permeability intervals, shale parting, damage during drilling and completion, or some other reason. Thus the injection profile, which is undoubtedly controlled by these factors prior to fracture treating, remains essentially unchanged. It is apparent, however, that the observed injection profiles are applicable only to a study of conditions at the well bore. Should the profiles be representative of conditions existing throughout the reservoir, severe water channeling could be observed and production rates could not be explained. It appears that the increased injection rates resulting from fracture treatments have afforded a more beneficial distribution of injection water, causing the flood to extend into portions of the reservoir not being flooded effectively under previous pressure conditions.

CONCLUSIONS

Data available for 29 hydraulic fracture treatments of 26 water-injection wells at Benton indicate that water-injection rates have been increased initially an average of 457 percent per treatment and that the increases have been sustained, current injection rates being 287 percent more than those prior to treatment. The average treatment size has been 1480 gallons of fracture fluid containing 1580 pounds of sand. Based on the thickness of injection interval treated, treatment size has averaged 43 gallons per foot.

Fracture treating techniques have been varied. Refined-oil, acid-kerosene, water-base, and acid-base fracture fluids have been employed with both straight- and multiple-fracture treating methods being used. Although somewhat inconclusive, comparisons of fracture treatment data indicate that the optimum treatment is a multiple-type, water-base gel treatment in the amount of 50 gallons of fracture fluid per foot of sand thickness to be treated.

Increased water-injection rates due to fracture treating have improved the performance of affected producing areas without adversely affecting produced oil-water ratios. There are no conclusive indications that ultimate oil recovery has been affected by the increased injection and production rates. It is possible that the only effect of increased water-injection rates will be to reduce the flood life of affected producing areas.

Composite performance data from 50 affected producing areas indicate that during a 12-month period following injection-well fracture-treatments, net water injection was increased 870,000 barrels and oil production was increased 270,000 barrels over that which would have been realized during the period.

With one exception, injection profiles determined before and after eleven fracture treatments indicate that hydraulic fracture treatments at Benton have not changed appreciably the injection profiles observed in the well bore. It appears that existing zones of weakness have been extended and that increased injection into these zones has promoted a more beneficial distribution of injection water, causing the flood to extend into portions of the reservoir not being flooded effectively under previous conditions.

The radioactive interface method of determining water injection profiles appears to be superior to other methods utilized at Benton.

SOURCES OF GROUNDWATER FOR WATERFLOODING IN ILLINOIS

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ABSTRACT

Groundwater reservoirs, containing both fresh and saline waters, are the most important source of injection fluids for waterflood operations in Illinois. More than 288 million barrels a year are now used for this purpose, an amount that is less than one percent of the groundwater used in Illinois for all purposes.

The sources of large quantities of fresh groundwater in southeastern Illinois are the sand and gravel deposits associated with buried or partially buried preglacial valleys. Small quantities of water, both fresh and saline, can be obtained from the Pennsylvanian and Chester sandstone aquifers. Production of large quantities of water from these sandstones is limited by low permeabilities and low water levels.

The source, movement, and occurrence of groundwater is discussed briefly and the geology and water-yielding characteristics of the various aquifers in southeastern Illinois are described. Geophysical, test drilling, and well-development methods are suggested to aid in obtaining water supplies from water-yielding sand and gravel deposits.

INTRODUCTION

Secondary recovery of oil by water-flooding is a rapidly increasing practice in the Illinois basin in the south half of Illinois. Increased need for both fresh and saline water for this purpose has prompted many requests to the Illinois Geological Survey for information regarding the availability of groundwater supplies. The requests have come from many parts of an area where the availability of even moderate amounts of fresh groundwater is limited and occurrence of sand and gravel and sandstone formations, the chief sources of fresh water, is sporadic. Occurrence of formations from which saline waters are available is also limited, primarily because such formations differ widely in thickness, depth, and permeability.

This paper describes, within the limitations of the available information, the source, movement, and occurrence of groundwater that might be developed for waterflooding purposes within the area shown in figure 1.

Several investigators have described, in part, water supply for waterflooding in Illinois. Reports by Squires, Bell, and Cohee (1942), Squires and Bell (1943), Witherspoon (1952), and the summaries of waterflooding operations in Illinois for 1949 through 1954 (joint surveys by the State of Illinois and the Interstate Oil Compact Commission and published by the Illinois State Geological Survey as Circulars 165, 173, 176, 182, 185, 193 and Illinois Petroleum Series 73) contain considerable information on the source, occurrence, and use of groundwater for waterflooding. Swann (1951) and Foley (1953) briefly describe sources of fresh water and brines for waterflooding.

The operators of the Illinois waterflood projects and the drillers in the oil fields furnished most of the basic information on which this report is based. The staff of the Illinois State Geological Survey edited the report and offered many valuable suggestions.

SOURCE, MOVEMENT, AND OCCURRENCE OF GROUNDWATER

The surface material and underlying bedrock formations that constitute the crust of the earth are saturated with water from near the surface to depths of thousands of feet. This water, called *groundwater,* usually occurs in the pores, joints, and solution channels in the rocks. It is nearly all derived from the small fraction of the precipitation that penetrates the soil-moisture zone. The top of the zone of saturation is called the *water*

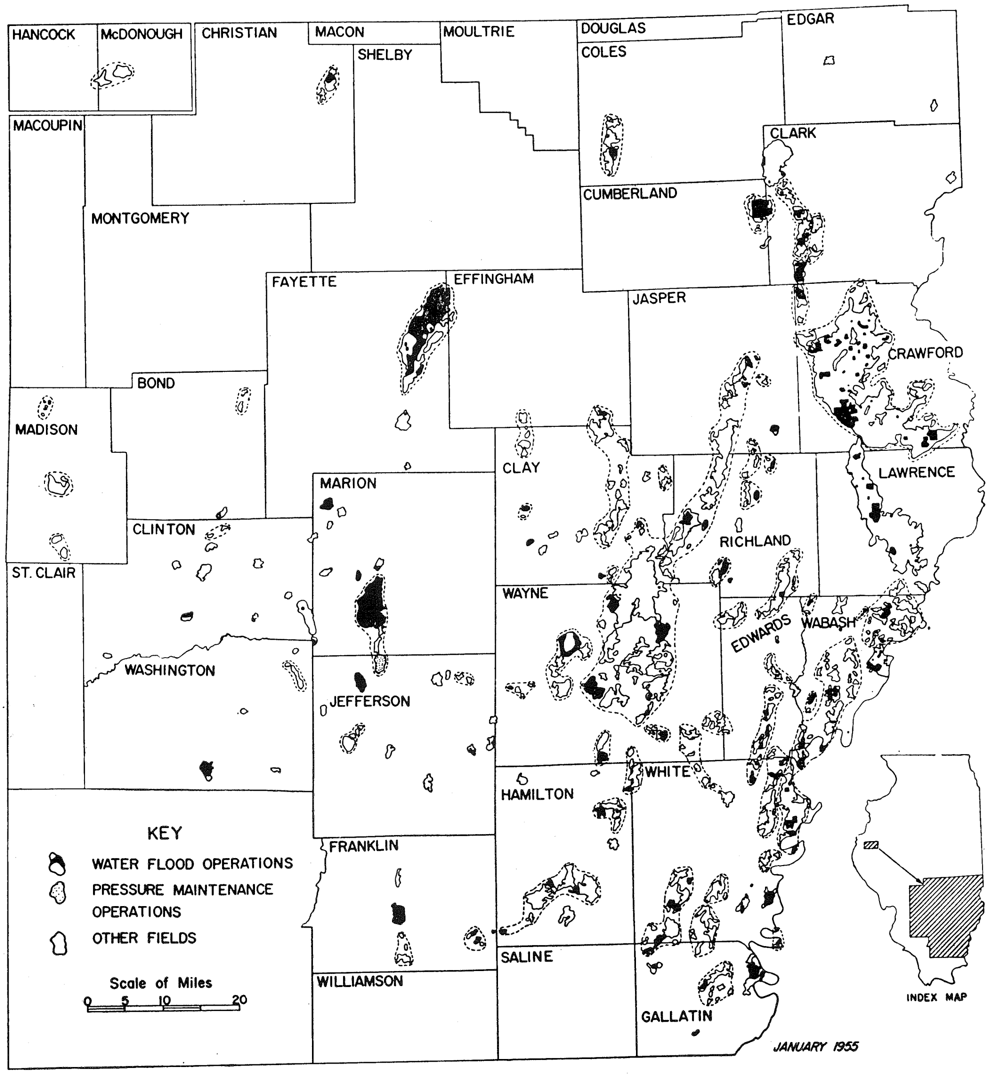

FIG. 1.—Area described in this report, and oilfields of Illinois.

table. It is not level but roughly corresponds to the configuration of the land surface and fluctuates in response to changes in precipitation. The water in the saturated zone is often called *unconfined* or "water table" water.

If groundwater is trapped in a permeable formation (*aquifer*) between two less permeable formations or beneath a less permeable layer it is called *confined water.* If it is under pressure so that it rises above the top of the aquifer when the impermeable layer is pierced or broken, the water is under artesian conditions.

Groundwater moves under the force of gravity, or occasionally in response to some other pressure differential, toward the point of lowest hydraulic head which is usually a point of discharge. Thus, in relatively low areas where the water table or an aquifer intersects the land surface, groundwater is discharged as springs into streams, lakes, and swamps. Confined water often escapes along faults or other permeable zones and discharges at the land surface. The movement of groundwater through rock materials is slow because of friction with the pore and channel walls.

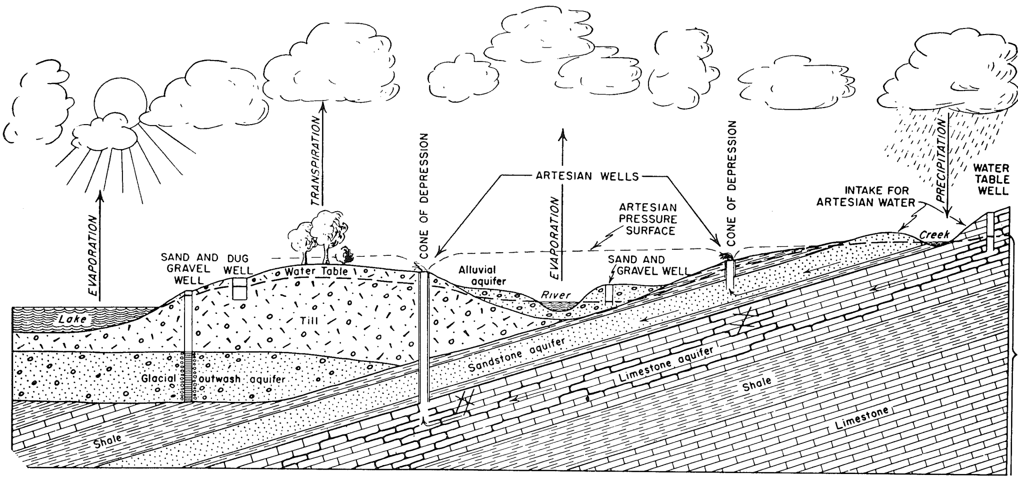

FIG. 2.—Source, movement, and occurrence of groundwater.

Because recharge results from precipitation, groundwater is a renewable resource and is said to be "mined" only when the quantity removed from the zone of saturation exceeds the replenishment. This normally happens only as a result of pumping or other activities by man. The place of groundwater in the hydrologic cycle is shown in figure 2.

The capacity of rock materials to absorb, store, and yield water—that is, their porosity and permeability—depends upon the abundance, size and shape, and degree of interconnection of the openings. Sand, gravel, and clean sandstone are permeable and may be productive aquifers, whereas shale and clay may be more porous but are relatively impermeable because the openings are small and water does not readily pass through them. The over-all water-yielding potential of an aquifer, or transmissibility (unit permeability multiplied by saturated thickness), depends in part on the sorting of grains of various sizes and composition or upon the distribution of cracks and solution openings in the rock.

For example, a formation may consist of thin alternating layers of clean sand and shale or shaly sand. The sand layers may be highly permeable but thin. The shale is relatively impermeable. Thus an expression of unit permeability of one or the other material or any combination is essentially meaningless as far as quantitatively expressing the potential yield of the formation whereas the transmissibility accurately expresses this potential. A method of determining transmissibility is briefly described below.

When groundwater is removed from an unconfined aquifer by pumping a well, the hydrostatic head in the vicinity of the well is lowered. The local gradient of the water table is changed and water moves toward the cone of pumping depression from adjacent parts of the aquifer. The gradient of the sides of the cone, and therefore the quantity and rate of flow of water toward the well, will depend upon the distance that the water level is lowered at the well and the transmissibility of the aquifer. Highly transmissible formations yield relatively large quantities of water with small drawdown whereas aquifers of low transmissibility yield only small quantities of water with relatively large drawdown.

In groundwater studies laboratory determinations of permeability have not proved especially valuable, but field determinations based on either the Thiem formula (Thiem, 1906; Wenzel, 1942) or the Theis formula (Theis, 1935; Wenzel, 1942) have proved to be reliable and useful in many investigations. The Thiem formula or some variation of it is often used to determine permeability. For problems involving unconfined water it expresses permeability in gallons of water as measured at 60° F. per day per foot of cross-section at unit gradient. Thus

$$P = \frac{527.7\ q \log \frac{r_2}{r_1}}{m\ (s_1 - s_2)} \qquad (1)$$

where P=permeability in units described above, q is the rate of pumping in gallons per minute, r_1 is the distance of nearby observation well from the pumping well, r_2 is the distance of an observation well farther away from the pumping well, s_1 and s_2 are the drawdowns in feet at the respective observation wells, m is the average thickness in feet of the saturated part of the aquifer at the observation wells. Transmissibility equals P multiplied by m. In oilfield terminology this is often called permeability capacity.

Field determinations in which the Thiem and Theis (see below) formulas are applied are based on carefully conducted pumping tests. During these tests the water levels in both the pumping well and in nearby observation wells are measured continuously or periodically. Both the levels and the time are recorded. Also, the discharge of the pumping well, which should be constant throughout the test, is measured periodically. Thus the values for q (Q in the Theis formula), r_1, r_2 (r in the Theis formula), s_1, s_2 (s in the Theis formula), and t (in the Theis formula) are determined in the field. The saturated thickness of the aquifer, m, is determined from the log of the well and from water-level measurements in the wells. When the Thiem formula is used, the pumping test is run until it is believed that the discharge from the well and the gradient of the water table are in equilibrium, that is, until the water levels in the wells stop declining. With the Theis formula this is not necessary.

The Theis nonequilibrium formula for problems involving unconfined water has been the most commonly used basis for analyzing groundwater problems in recent years. Most hydrologists prefer this formula because the pumping test does not have to be run until a state of equilibrium between discharge and gradient is reached. Also by special application T and S can be determined by pumping only one well (Brown, 1953, p. 861-864).

In absolute form the equation is:

$$s = \frac{Q}{4\pi T} \int_{\frac{r^2 S}{4\,Tt}}^{\infty} \frac{e^{-u}}{u}\,du \qquad (2)$$

in which $u = \frac{r^2\,S}{4\,Tt}$; s is the drawdown at any point in the vicinity of a discharging well; Q is the rate of discharge of the well; T is the coefficient of transmissibility of the aquifer; S is the coefficient of storage or the specific yield of the aquifer; r is the distance of the point from the discharging well at which s is measured; t is the elapsed time since the discharge began.

Expressed in English units with Q in gallons a minute, T in gallons a day per foot, r in feet, and t in days, the equation reads:

$$s = \frac{114.6\ Q}{T} \int_{\frac{1.87\,r^2\,S}{Tt}}^{\infty} \frac{e^{-u}}{u}\,du \qquad (3)$$

Direct solution of this equation is not possible but by various graphic methods (Wenzel, 1942; Brown, 1953; Bruin and Hudson, 1955) T and S can be determined.

When confined water is removed from an aquifer the hydrostatic head is depressed in the vicinity of the well and a cone of pumping depression is formed in the artesian pressure surface. The aquifer is not dewatered, as it is when unconfined, but water is withdrawn from storage. Dewatering occurs when the cone of depression invades the aquifer. In general, the equations described above apply to analysis of problems involving confined water except that the storage coefficient does not equal the specific yield of the confined aquifer as long as the aquifer is saturated. Rather the storage coefficient (S) expresses the cubic feet of water obtained from storage by the compression of a column of the aquifer whose height equals its thickness and whose base is one foot square as the water level falls one foot.

Application of these equations presupposes that the aquifer is homogeneous and isotropic and of infinite extent. It is also assumed that the wells observed during experimental work fully penetrate the aquifer. Departures from such ideal conditions are tolerable to some extent or can be allowed for in part (Jacob, 1940; Brown, 1953; Wenzel, 1942; Theis, 1935) by applied corrections. With due allowances for these limitations, results of analysis by the equations are invaluable in studies to determine the source, movement, and amount of groundwater and to forecast certain possible groundwater conditions.

GROUNDWATER GEOLOGY

The rocks in the south half of Illinois may be classified into two distinctly different types (fig. 3): 1) the unconsolidated deposits, chiefly glacial and alluvial materials which range from a feather edge to 200 feet in thickness, and which overlie 2) the indurated sediments or bedrock and crystalline basement rocks that extend from the surface to depths of thousands of feet. Conditions of groundwater occurrence in these two classes of rocks contrast greatly. The unconsolidated rocks often are more permeable, more accessible for development, and contain a quality of water generally suitable for all purposes, even domestic use. The bedrock formations are usually low in permeability and only the shallower formations (surface to 500 feet) yield water that is not highly mineralized. In the Illinois basin it is well known that nearly all kinds of water are useful for purposes of waterflooding.

The stratigraphy, lithology, water-yielding characteristics, location and distribution of both classes of rocks are discussed in the following paragraphs.

Unconsolidated Deposits

The unconsolidated deposits occur throughout the area chiefly as a thin veneer of clay and silt with minor local lenses and stringers of sand and gravel. Only in the preglacial, glacial, and present drainage systems where sizable river valleys have been cut and partly or wholly filled are thick unconsolidated deposits found. These deposits contain varying amounts of sand and gravel and usually the thicker the deposits, the greater the probability of presence of sand and gravel beds. Although the sand and gravel deposits may, in a few instances, occur in widespread layers, they are chiefly interbedded lenses and stringers interfingering with thicker and more continuous silt and clay deposits. The more or less sporadic distribution of these deposits is shown in part in figure 4. Almost all of the sand and gravel in the valley deposits is glacial outwash.

Most of the unconsolidated deposits in this area, as well as in the northern part of Illinois, were deposited as a result of glaciation. During the Pleistocene epoch large masses of ice formed in Canada and spread into the central part of the United States southward as far as the Ohio River. Four distinct stages of ice advance are recognized, only two of which left appreciable deposits in southern Illinois. These are the Illinoian and the Wisconsin stages. The Illinoian deposits include most of the silt and clay veneer on the uplands north of the latitude of Harrisburg (fig. 4) and underlie the silt, clay, sand and gravel deposited by the Wisconsin ice sheet north of Shelbyville and east of Peoria. Outwash deposited by meltwater from the ice comprises most of the sand and gravel deposits in the valleys many miles south of the ice fronts. Actually, most of the sand and gravel in the area was deposited in this manner.

The sand and gravel deposits are the best sources of large quantities of fresh groundwater in southern Illinois. They are highly to moderately permeable, are structurally uncomplicated, and lie within a short distance (0 to 200 feet) of the land surface. They are readily accessible to annual recharge of considerable amounts from both direct precipitation and infiltration from streams that cut through or directly overlie them.

Bedrock

Figure 3 is a generalized geologic column showing the formations that underlie the unconsolidated deposits or crop out at the land surface. These formations are composed of shale, limestone, coal, and sandstone which range in age from Cambrian to Pennsylvanian and which lie on the crystalline base-

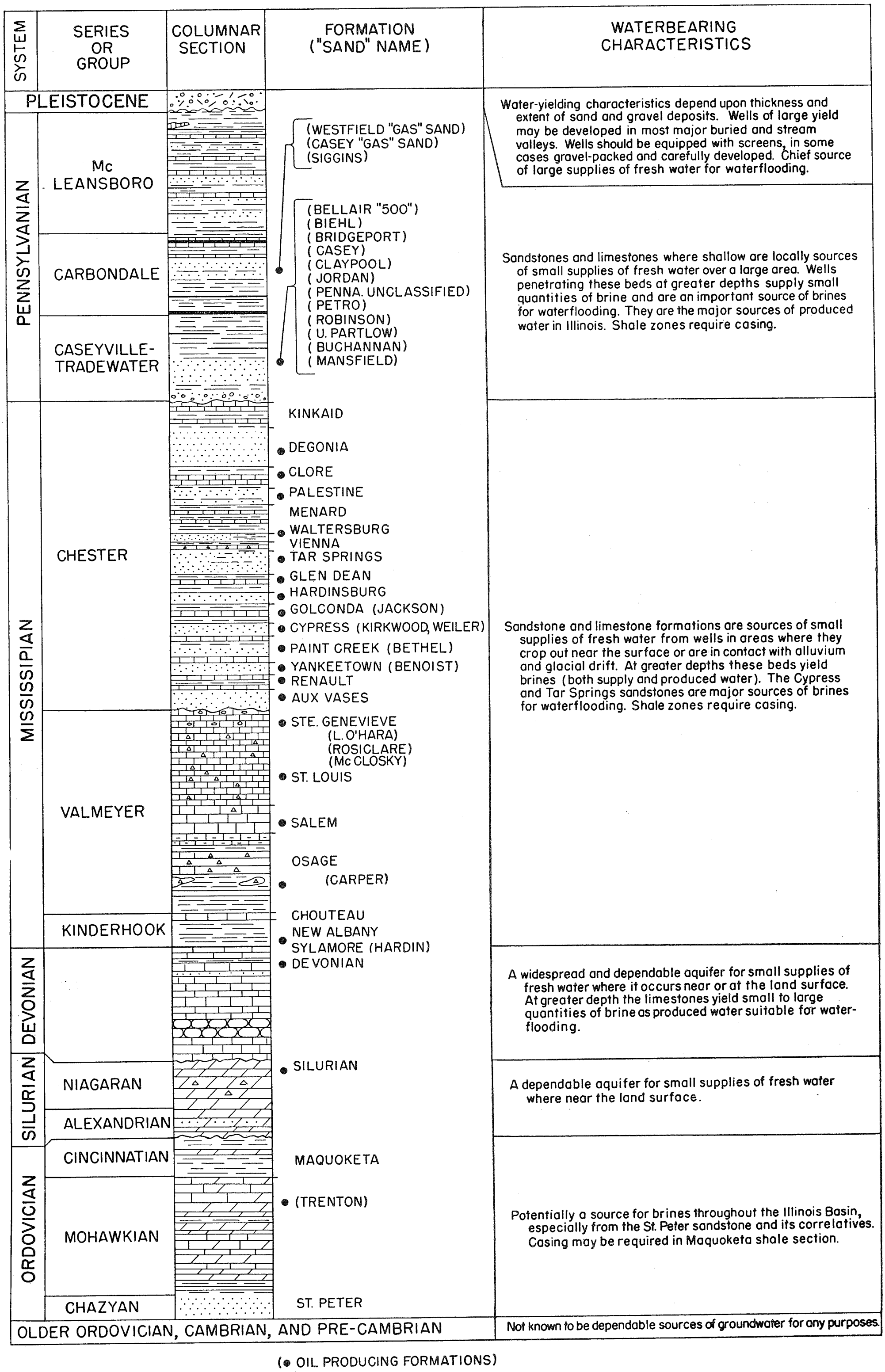

FIG. 3.—Generalized geologic column for the Illinois basin.

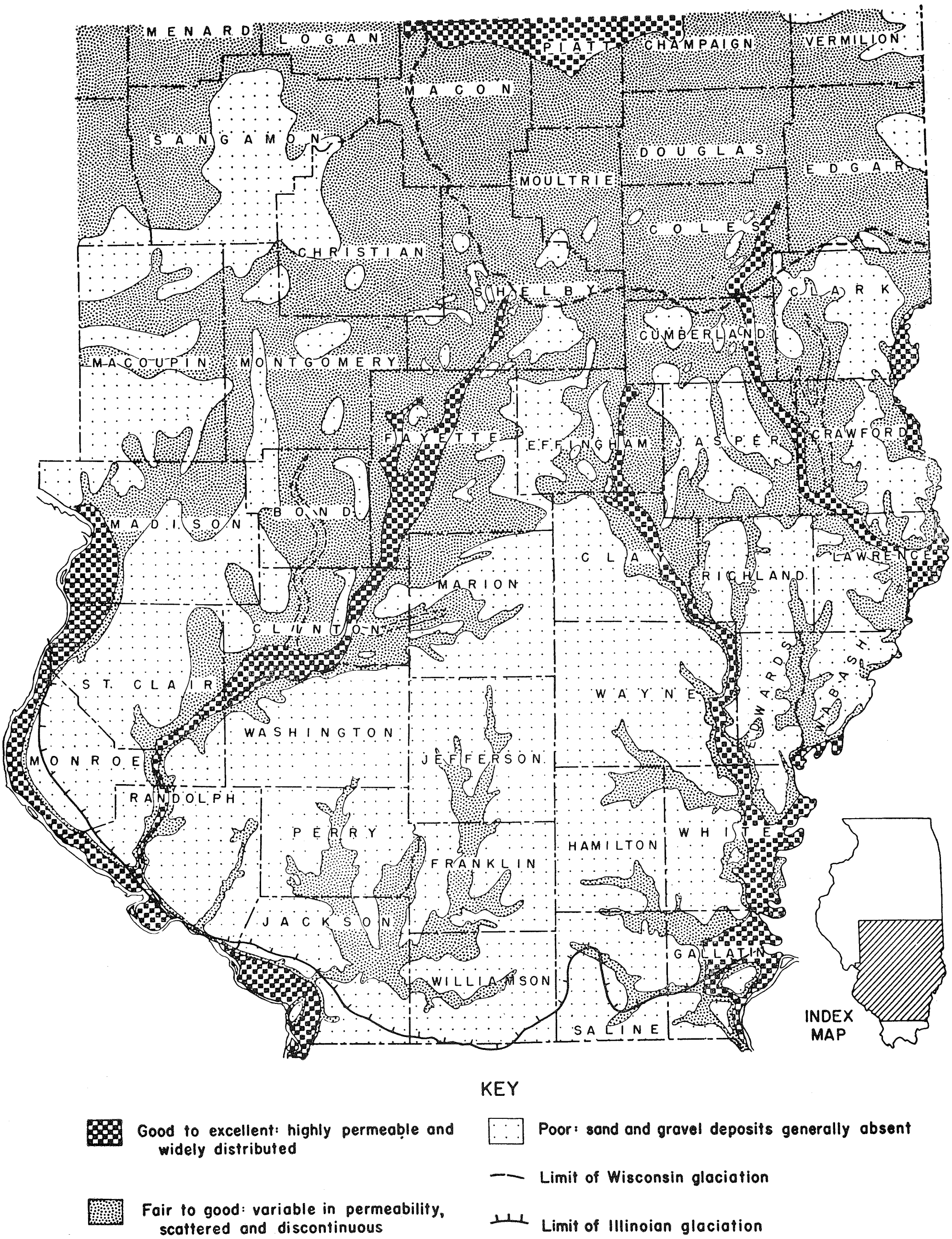

FIG. 4.—Probability of occurrence and distribution of sand and gravel deposits.

ment rocks. In general, each formation is present throughout the area but some of them differ in thickness areally and thin out or have been removed by erosion locally. These sedimentary strata form a structural basin with its deepest part in southeast Illinois near Carmi where the rocks are about 12,000 feet thick. Within this basin there are several outstanding structural features including the LaSalle anticline along the eastern margin and the Duquoin monocline along the western margin. In extreme southern Illinois and along the Wabash Valley the bedrock formations have been faulted as well as tilted and folded. Many smaller anticlines and faults occur throughout the basin.

PRE-CAMBRIAN

The Pre-Cambrian basement rocks do not crop out in Illinois. Information concerning them has been taken from several drill holes in the western and northwestern part of the State and from outcrop areas in Missouri and Wisconsin. This information indicates that the basement is composed of granites and granitic gneisses. These rocks are deeply buried in the south half of Illinois and are not a source of groundwater.

CAMBRIAN

The Cambrian rocks, which overlie the basement crystallines, are widespread and are found throughout Illinois. In northern Illinois they are composed of thick beds of sandstone, dolomite, and limestone with minor amounts of shale. The sandstone formations are the prolific aquifers. In the south the thickness and lithology of Cambrian rocks are unknown. Their depth and the poor quality of water they might contain would prohibit their ordinary use as sources of groundwater.

ORDOVICIAN

The Ordovician rocks, which occur throughout most of Illinois, may exceed 2500 feet in thickness in southern Illinois. They are predominantly limestone and dolomite with some thick beds of sandstone.

The lowermost Ordovician rocks are dense dolomite with a few interlayered sandstone beds. The sandstones may be permeable and contain highly mineralized water but are not recognized as important aquifers in the area.

The St. Peter sandstone, which ranges from a thin layer to about 200 feet in thickness, overlies the dolomites and sandstones. It is one of the best-known aquifers in the State. Fresh water in relatively small quantities is obtained from it near the outcrop area in northern and western Illinois. Highly mineralized water is available from it throughout the central part of the Illinois basin.

The "Trenton" limestone overlies the St. Peter sandstone. It is tapped by wells for water supply where it is near the surface and may locally yield large supplies. In some areas the limestone yields some water with oil but it is not a widely used aquifer. It is overlain by the thick, relatively impermeable Maquoketa shale which comprises the upper part of the Ordovician section.

SILURIAN

The Silurian rocks overlie the Maquoketa shale or its equivalents. They are chiefly limestone and dolomite with minor amounts of interbedded shale and are 200 to 1,000 feet thick. Water is available from crevices and solution channels but these formations are not important aquifers. It is not likely that brines in usable quantities can be obtained from them in the central part of the basin.

DEVONIAN

The Devonian rocks, as much as 1400 feet thick, overlie the Silurian formations and are primarily composed of limestone and dolomite with some bedded cherts. In extreme southwestern Illinois where these rocks are near the surface they are permeable and yield relatively large amounts of water from crevices and solution channels. Production water from Devonian oil wells is used for injection in several waterflooding projects but there is no record of make-up water being pumped from wells.

MISSISSIPPIAN

The Mississippian rocks have wide distribution throughout Illinois and are the most important sources of oil. They have a maximum thickness of about 2300 feet and are divided into three series, the Kinderhook, Valmeyer, and Chester.

The Kinderhook is the lowest series and is predominantly shale with a maximum thickness of about 400 feet. It is not considered as a feasible source of groundwater for flooding purposes.

The Valmeyer series overlies the Kinderhook and is divided into the Burlington-Keokuk, Salem-Warsaw, St. Louis–Ste. Genevieve formations. The Valmeyer series, composed chiefly of limestone and siltstone, attains thicknesses of 1,000 to 2,000 feet. The limestones yield water from cracks, solution channels, and the permeable oolitic zones of the Ste. Genevieve formation. The more permeable zones of the Ste. Genevieve appear to be the only aquifers in the Valmeyer series that presently yield large quantities of water for injection purposes.

The Chester series overlying the Valmeyer beds has a maximum thickness of about 1400 feet. This series is an alternating sequence of shale, sandstone, and limestone. The various sandstone formations of the Chester series yield water at many places. Yields vary greatly because the sandstones differ widely in composition, sorting, lateral extent, and thickness. The most important aquifers in the Chester series are the Palestine sandstone, Waltersburg sandstone, Tar Springs sandstone, Cypress sandstone, Bethel sandstone, and Aux Vases sandstone. Of these formations the Tar Springs and Cypress are the most common sources of brines for waterflooding. Both have wide distribution and are relatively thick throughout the deeper parts of the Illinois basin. The distribution and thickness of the Tar Springs and Cypress formations are shown in figures 5 and 6.

PENNSYLVANIAN

The Pennsylvanian rocks are the uppermost formations in most of Illinois. They range from a feather edge to 2700 feet in thickness. They are overlain by Pleistocene deposits and alluvium in most places and lie unconformably upon older rocks. This unconformity is angular and the Pennsylvanian sediments rest on progressively older formations toward the north margin of the basin.

In Illinois the Pennsylvanian system is divided into the Caseyville, Tradewater, Carbondale, and McLeansboro groups. These groups are characterized by cyclically arranged, alternating beds of shale, siltstone, coal, limestone, and sandstone. The sandstone formations are the most important aquifers in the Pennsylvanian system and range widely in distribution, thickness, composition and sorting, and permeability. Locally, there are some well defined pre-Pennsylvanian drainage channels superimposed on the older Mississippian surface (Siever, 1951). The thicker and more permeable basal Pennsylvanian sandstones were deposited in these channels. The lenticular sandstone formations of the lower Pennsylvanian system (Caseyville and Tradewater groups) are characterized by clean, coarse, quartzose sandstones. The lenticular sandstone bodies of the Carbondale and McLeansboro groups are generally fine-grained and contain considerable amounts of clay, silt, and mica. Thus the permeability of the lower sandstones is generally greater than that of the upper groups, although both laterally and vertically the permeability is highly variable.

SUMMARY

Large quantities of fresh groundwater in the Illinois oil fields are obtained from the sand and gravel outwash deposits in present or buried ancient stream valleys. Smaller fresh groundwater supplies are taken from scattered sand and gravel lenses in the alluvial and glacial deposits that are spread as a veneer across the uplands between these valleys, but most supplies developed in these deposits are too small and scattered to be of value in waterflooding operations.

Fresh groundwater supplies, in most instances adequate for waterflooding projects, are found in the Devonian and Mississippian rocks where they are near the surface in southern Illinois and along the margins of the Illinois basin (fig. 7). Also, Pennsylvanian sandstones, close to the land surface or directly beneath glacial and alluvial deposits, are locally useful as a water source for injection.

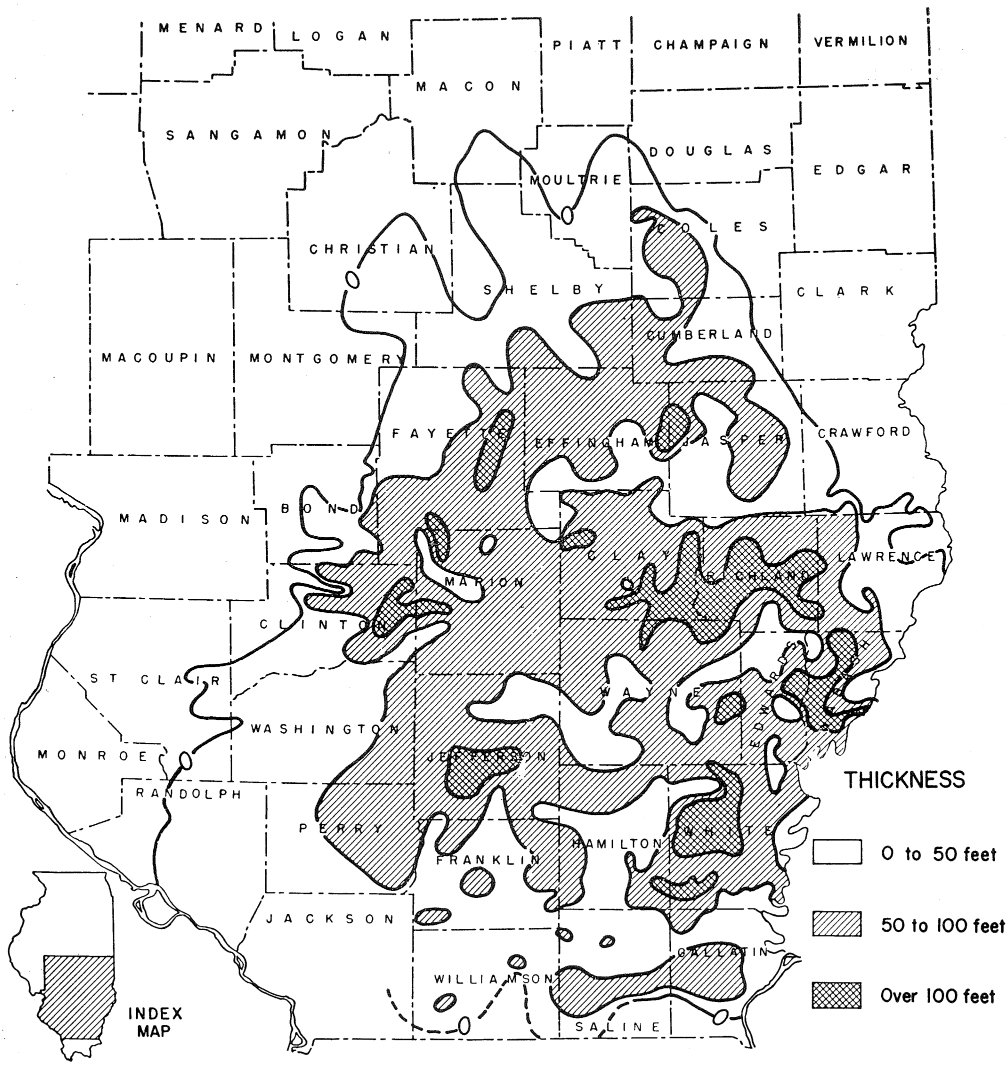

FIG. 5.—Approximate cumulative thickness of sandstone in the Tar Springs formation.

Brines are available from many formations throughout the basin. The most common sources for brines at present are the Tar Springs and the Cypress sandstones of Mississippian age. Other important sources are the Devonian limestone and dolomite, the Ste. Genevieve formation, the Palestine, Waltersburg, Bethel, and Aux Vases sandstones, and some Pennsylvanian sandstones. Much water is now taken from most of these formations in the course of oil production and much of this water is injected for waterflooding projects. Potential water sources are further discussed in the section of this report on "Availability of Water for Future Development."

WATERFLOOD PROJECTS IN ILLINOIS

Intentional waterflooding as a means of secondary recovery of oil in Illinois is known to have been practiced as early as 1924 (Squires and Bell, 1943). Prior to that, several accidental waterfloods resulting from

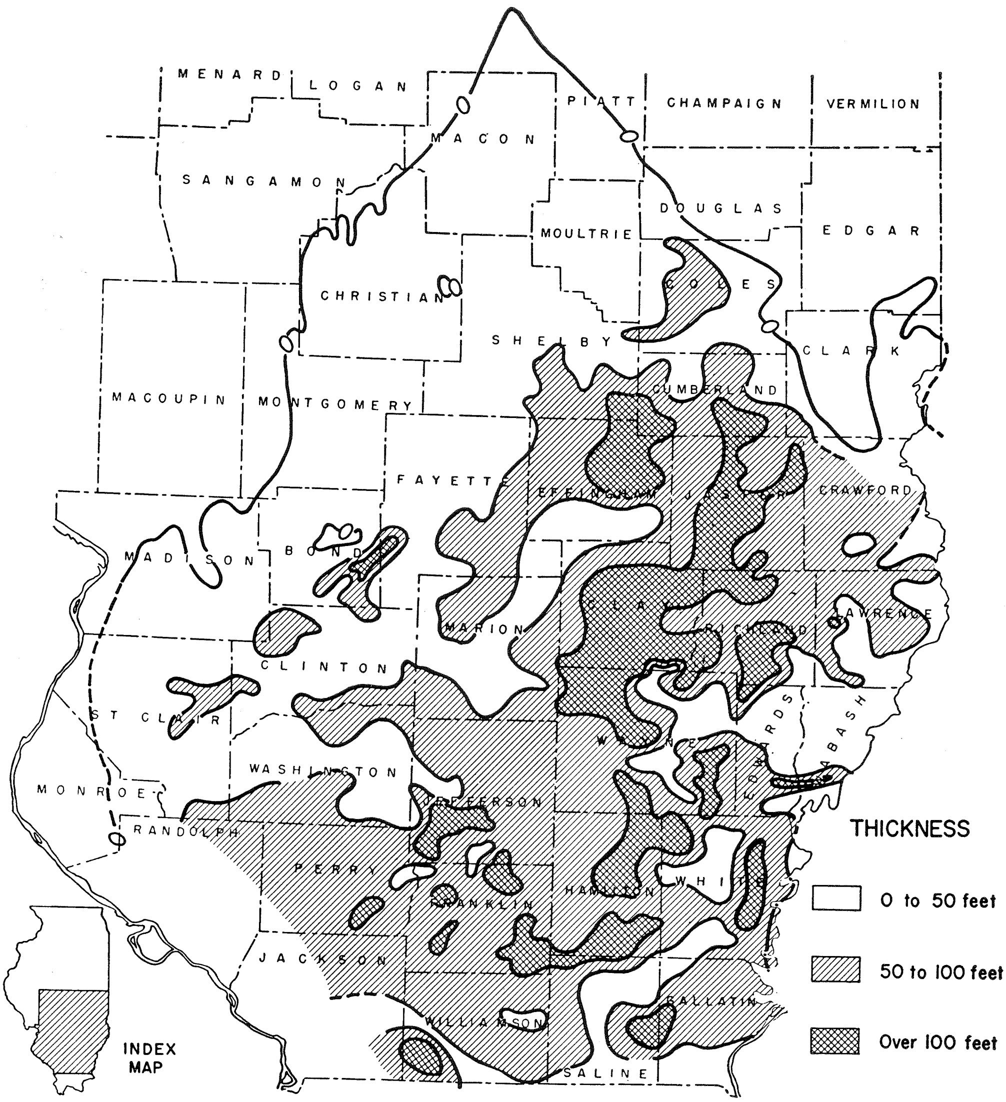

FIG. 6.—Approximate cumulative thickness of sandstone in the Cypress formation.

waters invading oil sands through leaky casings had been reported (Squires and Bell, 1943; Witherspoon, 1952). However, these operations did not involve large quantities of deliberately pumped groundwater (make-up or supply water) nor are they known to have been responsible for appreciably increased oil production. Between 1924 and 1933, it is reported that only produced water was injected in one project in Illinois.

On June 8, 1933, the State recognized the necessity of and approved regulations for intentional waterflooding. Soon after, a water injection project utilizing fresh well water and produced brine was begun in Crawford County; however, it was not until 1942 that appreciable quantities of water were used for waterflooding. Reliable records of amounts of water used for this purpose are not available prior to the later part of 1943, by which

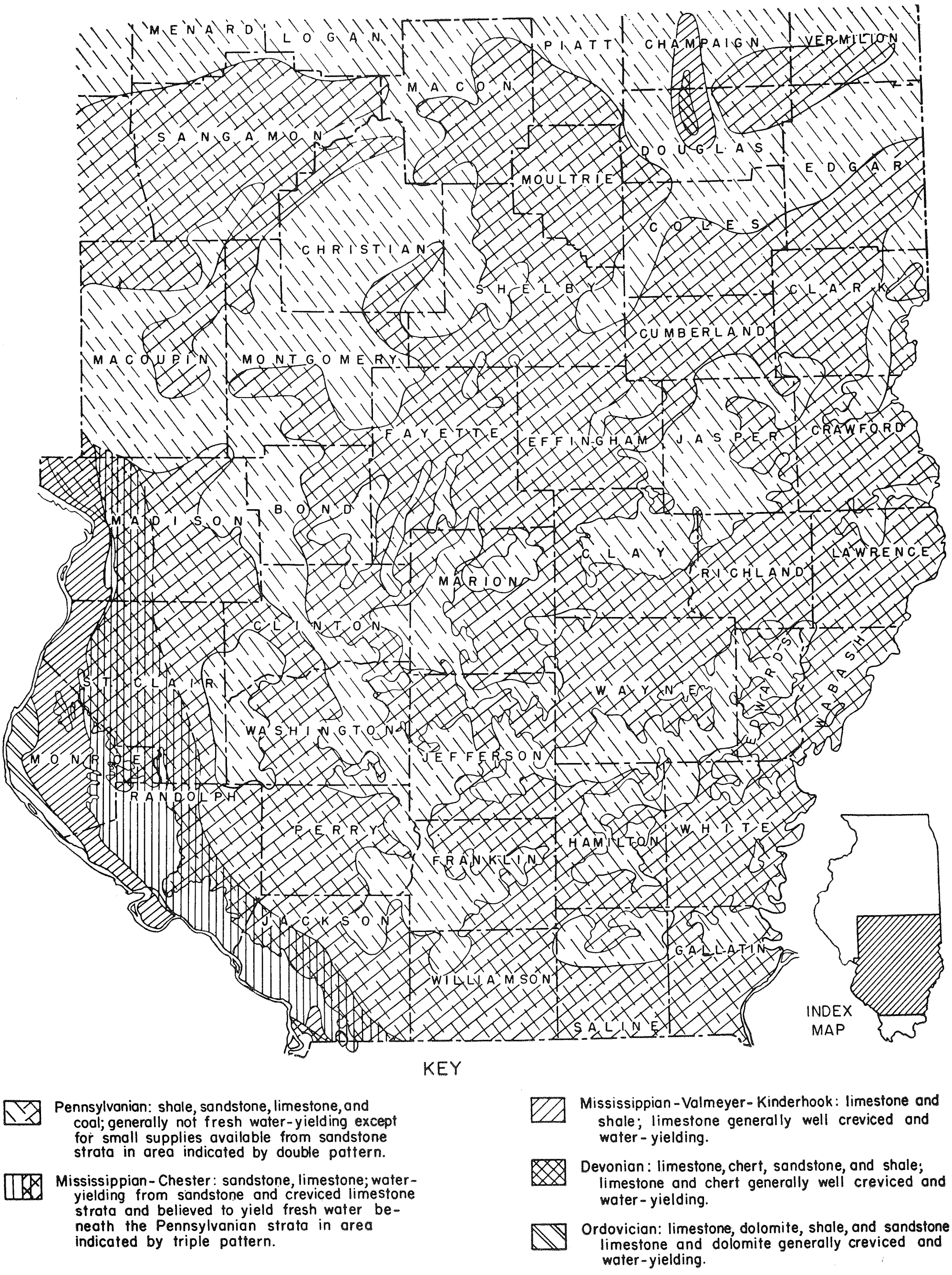

FIG. 7.—Areal distribution, type, and water-yielding character of upper bedrock formations.

time a few more waterflood projects had been started.

Figure 8 shows the development of waterflooding in Illinois from 1943 to 1955 by illustrating the number of waterflood projects for each year, the amount of water injected and produced, and the oil production. The amount of "make-up" or supply water may

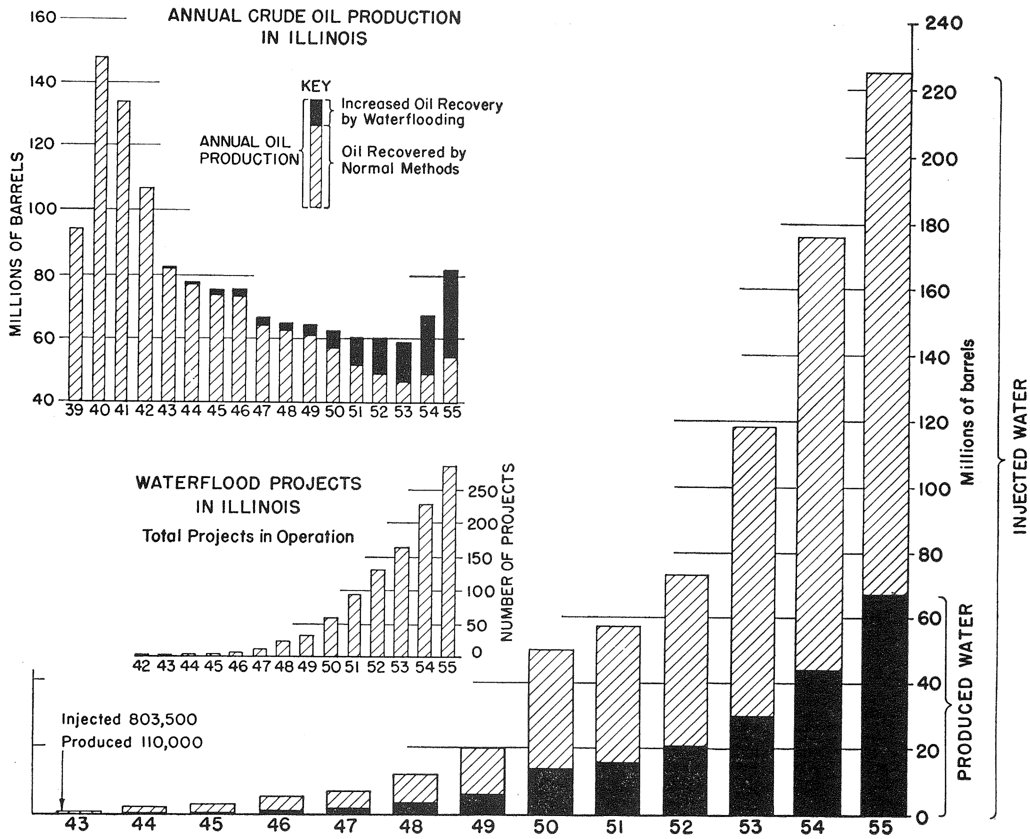

FIG. 8.—Development of waterflooding in Illinois, 1943 to 1955.

be roughly estimated by subtracting the produced water from that injected. Although oil production declined from year to year between 1943 and 1953, the amount of oil produced by secondary flooding consistently increased, and in the years 1954 and 1955 the increase in total oil production was primarily the result of increased production from waterflooding activities. Before 1943 less than 10 million barrels of oil had been produced by this method in Illinois but by 1955 cumulative production totaled 81,131,000 barrels. In 1955 alone 26,563,000 barrels or 32.7 percent of total oil production resulted from waterflooding. In 1943 only 3 projects were reported in operation, by 1947 there were 16 projects, and in 1955 there were 284 projects in operation.

The early waterflood projects used only produced water and it was not until 1933 that fresh make-up water was injected. By 1943 about 693,000 barrels of make-up water a year were mixed with 110,000 barrels of produced water for injection; by 1947 more than 5 million barrels of make-up water and 2 million barrels of produced water were injected; and in 1955 nearly 158 million barrels of make-up water were mixed with about 67 million barrels of produced water for injection. The increase in use of make-up water was relatively small until 1950, but in the years 1953 and 1954 it nearly doubled. Increase in use of produced water has grown steadily since 1950 but at a lower rate than make-up water until 1955 when much of the increase in injection water was produced water.

Intentional waterflooding operations up to 1946 utilized fresh make-up water from sand and gravel aquifers in Crawford County and

TABLE 1.—ESTIMATED AMOUNTS OF WATER USED FOR WATERFLOODING IN 1956, BY AQUIFERS
In thousands of barrels

Source or formation	Total water	Supply or make-up water		Produced water
		Fresh	Brine	
Alluvial Sand and Gravel	84,548	84,548	0	0
Tar Springs	61,720	0	47,717	14,003
Lower Pennsylvanian	51,610	954	15,971	34,685
Benoist	17,074	0	347	16,727
Surface Water	16,662	16,662	0	0
Devonian	13,986	0	0	13,986
Cypress	11,911	0	8,246	3,665
McClosky	11,328	0	2,464	8,864
Upper Pennsylvanian	4,589	2,107	2,409	73
Waltersburg	3,728	0	657	3,071
Aux Vases	2,792	0	91	2,701
Rosiclare	2,662	0	19	2,643
Renault	2,055	0	0	2,055
Palestine	1,727	0	0	1,727
Bethel	1,396	0	538	858
Hardinsburg	883	0	0	883
Ohara	183	0	0	183
Degonia	72	0	72	0
Clore	55	0	0	55
Total	288,981	104,271	78,531	106,179

in the Siggins and Parker pools in Cumberland and Clark counties, brine for make-up from the Tar Springs formation in the Patoka field in Marion County, and Devonian brines at Sandoval field. In the Carlyle oil field in Clinton County water from unreported sources, perhaps chiefly produced water, was used. Probably in all of these places produced water was used in varying quantities either mixed with fresh water or injected into the older part of the flooded area.

In addition to these sources, make-up water supplies were developed between 1946 and 1956 from surface streams and lakes, upper and lower Pennsylvanian sandstones, Cypress sandstone, Benoist sandstone, McClosky limestone, Waltersburg sandstone, Aux Vases sandstone, Rosiclare limestone, Renault limestone, Palestine sandstone, Clore formation, Degonia sandstone, and Bethel (Paint Creek) sandstone. The Hardinsburg sandstone and Ohara limestone furnished only produced water. Produced water was, of course, taken from all other oil producing formations in the normal course of operations.

Table 1 shows the quantities of fresh, salt, and produced water to be derived from these sources in 1956, estimated from an inventory made during the summer of 1956. As shown by the table considerably more than one-third of the total is produced water, somewhat more than one-fourth is brine supply water, and the remainder is fresh water. The largest single source of water is the alluvial sand and gravel and the second largest source is the Tar Springs sandstone. Together these two aquifers produce about half of all the water used for injection.

Table 2 shows the quantities of fresh, salt, and produced water estimated to be used in the oil fields during 1956. The three greatest users are the Louden, Salem Consolidated, and Main Consolidated fields which inject well over one-half of all waters used for waterflooding in Illinois. Although Lou-

TABLE 2.—ESTIMATED AMOUNTS OF WATER USED FOR WATERFLOODING IN 1956, BY OIL FIELDS
In thousands of barrels

Field	Total water	Supply		Produced
		Fresh	Brine	
Louden	58,996	0	42,609	16,387
Salem Cons.	45,564	29,200	566	15,798
Main Cons.	35,891	15,447	11,144	9,300
Lawrence	23,928	13,732	256	9,940
New Harmony Cons.	12,998	8,286	461	4,251
Benton	11,936	2,592	0	9,344
Clay City Cons.	11,828	1,755	7,000	3,073
Johnson South	8,775	1,825	0	6,950
Boyd	7,569	4,672	0	2,897
Allendale	6,343	2,976	82	3,285
Siggins	5,721	2,246	239	3,236
Bellair	5,201	5,201	0	0
Inman East Cons.	4,652	3,607	0	1,045
Patoka	4,550	0	1,461	3,089
Roland Cons.	4,087	0	2,766	1,321
Johnsonville Cons.	3,724	0	2,373	1,351
Johnson North	2,989	2,102	0	887
Albion Cons.	2,679	1,137	91	1,451
Storms Cons.	2,190	2,190	0	0
Maunie South	2,081	511	0	1,570
Kenner West	1,935	0	1,935	0
Mt. Carmel	1,719	1,394	137	188
Mattoon	1,693	913	0	780
Aden Cons.	1,388	0	584	804
Dale Cons.	1,274	55	329	890
Thompsonville North	1,223	730	438	55
Sailor Springs Cons.	1,213	420	499	294
Assumption Cons.	1,158	779	0	379
Bartelso	1,059	0	657	402
Phillipstown Cons.	1,034	128	350	556
Cordes	986	0	0	986
Barnhill	840	0	183	657
Oskaloosa	840	0	548	292
Casey	735	370	0	365
Bungay Cons.	715	0	167	548
Stanford South	644	0	378	266
Parkersburg	606	0	551	55
Calhoun Cons.	585	0	110	475
Dundas East	572	0	389	183
Browns East	559	0	150	409
Centerville	548	0	511	37
Odin	529	0	91	438
Inman West Cons.	508	0	503	5
Concord	462	131	218	113
Wamac	417	417	0	0
Seminary	355	0	245	110
Keensville	347	318	0	29
Mill Shoals	328	328	0	0
Markham City West	299	0	191	108
Olney Cons.	293	183	0	110

TABLE 2.—(Continued)

Field	Total water	Supply		Produced
		Fresh	Brine	
Junction	210	210	0	0
Bone Gap Cons.	197	0	0	197
Stringtown	183	0	44	139
St. James	180	0	0	180
New Haven	170	170	0	0
Westfield	164	91	0	73
Omaha	157	0	0	157
Bone Gap South	155	0	0	155
Thompsonville East	128	0	82	46
Divide East	98	0	0	98
Golden Gate	89	0	89	0
Keensburg South	86	86	0	0
Samsville North	80	0	0	80
Maple Grove Cons.	73	0	0	73
Tonti South	73	0	0	73
Woburn Cons.	73	0	0	73
Friendsville North	71	0	51	20
Centerville East	54	27	0	27
York	43	0	0	43
Concord North	42	42	0	0
Lancaster South	29	0	29	0
Herald Cons.	24	0	24	0
Livingston	24	0	0	24
Beaver Creek	8	0	0	8
Carlyle North	4	0	0	4
Total	288,981	104,271	78,531	106,179

den, the largest user, injects no fresh water, the other two fields use nearly one-half of all injected fresh water that is obtained from wells in alluvial and glacial gravels and from surface sources. More than one-half of all brine make-up water is injected in Louden field and about one-fourth of all produced water is injected in the Louden and Salem Consolidated fields.

Other users of large quantities of fresh water include the Lawrence, New Harmony Consolidated, Bellair, and Boyd fields. Users of large quantities of brine make-up water include Main Consolidated, Clay City Consolidated, Johnsonville Consolidated, and Roland Consolidated fields; and users of large quantities of produced water include Lawrence, Benton, Main Consolidated, Johnson South, New Harmony Consolidated, Siggins, Allendale, Patoka, and Clay City Consolidated fields.

Table 3 shows the amount and type of water taken from each of the aquifers and from surface sources by oil fields. Thus it combines the information presented by Tables 1 and 2 and shows which localities are heavy users of water. Further the information summarized in these tables is a reliable guide for location of potential sources of water for waterflooding.

QUALITY OF THE WATER

Considerable study has been made of the quality of brines from most of the aquifers now being used as sources of supply water in Illinois and the results can be consulted in Meents et al. (1952). The known approximate range of total parts per million of solids in the waters are tabulated below:

Source	Total solids (ppm)
Fresh	
Alluvial and glacial beds	Less than 1,000
Upper Pennsylvanian	200 to Brine
Lower Pennsylvanian	200 to Brine
Surface Water	Less than 1,000
Brine	
Upper Pennsylvanian	Fresh to 50,000 +
Lower Pennsylvanian	Fresh to 50,000 +
Degonia	50,000 to 60,000 +
Palestine	60,000 ±
Waltersburg	60,000 + to 100,000 −
Tar Springs	40,000 + to 127,000 +
Hardinsburg	60,000 − to 127,000 −
Cypress	10,000 + to 145,000 +
"Benoist"—Bethel	13,000 − to 140,000 −
Renault	127,000 ±
Aux Vases	91,000 + to 160,000 +
Ste. Genevieve: Ohara, Rosiclare, McCloskey	24,000 + to 163,000 +
Devonian-Silurian	2,100 + to 170,000 −

In general, as in nearly all brines, the predominating constituents are sodium and chlorine which together comprise more than three-fourths of the total dissolved solids in all the brines of which we have proper analyses. Calcium, magnesium, bicarbonate, and sulfate ions are also present but in much smaller and more variable quantities. Ammonia, silica, iron, alumina, manganese, and nitrate occur commonly but in comparatively small proportions.

The ranges of total solids for water from formations below the Pennsylvanian given in the table above apply only where the rocks are deeply buried. In most places where the formations crop out or are overlain directly by glacial or alluvial deposits, the water withdrawn from them may be fresh and may contain less than 1000 parts per million of total solids. In general, the mineral content of the water increases with depth for all formations.

Further studies of water quality and its effects in waterflooding operations are not within the scope of this report.

EXPLORATION FOR GROUNDWATER SUPPLIES

An exploration program is as necessary and valuable for locating groundwater supplies as it is for locating oil. Many of the techniques used in exploration for water-bearing beds are similar to those used in finding oil, but because the occurrence of water differs in some respects from that of oil, exploration methods also differ. Normally, oil exploration techniques are most useful in locating water-yielding beds in the bedrock, whereas other techniques have been developed in Illinois to locate aquifers in the unconsolidated glacial drift and alluvium.

In and near the oil fields, the sources of large supplies of fresh groundwater are the sand and gravel beds in the glacial drift and alluvial deposits. Therefore, the first step in any exploration program in search of fresh water should be a geological study of the area to determine both the lateral and vertical distribution of these deposits. Usually this can best be accomplished by study of all available well logs, supplemented with careful areal mapping. In many areas a successful test-well drilling program can be conducted on the basis of information obtained from a geological study. In other areas adequate well data, surface outcrops, and other data may be lacking. Then it may be advisable to conduct geophysical surveys to supplement the geological data as a guide for location of drilling sites.

The electrical earth-resistivity survey generally is the most economical and successful tool for locating shallow (250±feet) sand and gravel deposits. Resistivity of water-saturated clay, shale, and other fine-grained materials is usually low whereas the resistivity of saturated sand and gravel deposits is normally high. By passing an electrical current through the earth at various depths the approximate boundaries and position of the different lithologic types can be determined. The general method used by the Illinois State Geological Survey is described by Buhle (1953). Careful geologic study should always precede, and be used as a guide for, resistivity surveys. Often it is desirable to conduct geologic study, test drilling, and resistivity work concurrently.

Geophysicists have also used seismic refraction methods (Johnson, 1954). Although most of the work with this method in Illinois is considered experimental, it has proved useful in some instances to determine the thickness of unconsolidated materials and to locate sand and gravel deposits.

TABLE 3.—AMOUNT, TYPE, AND SOURCE OF WATER USED
In thousands

Field	Surface Water	Alluvial Sand and Gravel	Upper Pennsylvanian			Lower Pennsylvanian			Degonia	Clore	Palestine	Waltersburg	
			Fresh	Make-up brine	Produced	Fresh	Make-up brine	Produced	Brine	Produced	Produced	Make-up brine	Produced
Aden Cons.	—	—	—	—	—	—	584	—	—	—	—	—	—
Albion Cons.	954	183	—	—	—	—	91	850	—	—	—	—	91
Allendale	—	1,852	175	82	—	949	—	3,285	—	—	—	—	—
Assumption Cons.	779	—	—	—	—	—	—	—	—	—	—	—	—
Barnhill	—	—	—	—	—	—	—	—	—	—	—	—	—
Bartelso	—	—	—	—	—	—	—	—	—	—	—	146	—
Beaver Creek	—	—	—	—	—	—	—	—	—	—	—	—	—
Bellair	—	5,201	—	—	—	—	—	—	—	—	—	—	—
Benton	2,592	—	—	—	—	—	—	—	—	—	—	—	—
Boyd	4,672	—	—	—	—	—	—	—	—	—	—	—	—
Bone Gap Cons.	—	—	—	—	—	—	—	—	—	—	—	—	197
Bone Gap South	—	—	—	—	—	—	—	—	—	—	—	—	155
Browns East	—	—	—	146	—	—	—	—	—	—	—	—	—
Bungay Cons.	—	—	—	—	—	—	167	—	—	—	—	—	—
Calhoun Cons.	—	—	—	—	—	—	—	—	—	—	—	—	—
Casey	—	365	—	—	—	5	—	365	—	—	—	—	—
Carlyle North	—	—	—	—	—	—	—	—	—	—	—	—	—
Centerville	—	—	—	—	—	—	—	—	—	—	—	511	—
Centerville East	—	27	—	—	—	—	—	—	—	—	—	—	—
Clay City Cons.	551	219	985	468	—	—	1,862	—	—	—	—	—	—
Concord	—	131	—	—	—	—	—	—	—	—	—	—	—
Concord North	—	42	—	—	—	—	—	—	—	—	—	—	—
Cordes	—	—	—	—	—	—	—	—	—	—	—	—	—
Dale Cons.	—	55	—	—	—	—	256	—	—	—	—	—	—
Divide East	—	—	—	—	—	—	—	—	—	—	—	—	—
Dundas East	—	—	—	—	—	—	—	—	—	—	—	—	—
Friendsville North	—	—	—	51	—	—	—	20	—	—	—	—	—
Golden Gate	—	—	—	89	—	—	—	—	—	—	—	—	—
Herald Cons.	—	—	—	—	—	—	24	—	—	—	—	—	—
Inman East Cons.	14	3,593	—	—	—	—	—	—	—	—	—	—	—
Inman West Cons.	—	—	—	—	—	—	503	—	—	—	—	—	—
Johnson North	657	1,445	—	—	—	—	—	887	—	—	—	—	—
Johnson South	—	1,825	—	—	—	—	—	6,950	—	—	—	—	—
Johnsonville Cons.	—	—	—	—	—	—	—	—	—	—	—	—	—
Junction	—	210	—	—	—	—	—	—	—	—	—	—	—
Keensburg South	—	86	—	—	—	—	—	—	—	—	—	—	—
Keensville	—	318	—	—	—	—	—	—	—	—	—	—	—
Kenner West	—	—	—	—	—	—	1,241	—	—	—	—	—	—
Lancaster South	—	—	—	—	—	—	—	—	—	—	—	—	—
Lawrence	—	13,732	—	110	—	—	146	9,226	—	—	—	—	—
Livingston	—	—	—	—	—	—	—	—	—	—	—	—	—
Louden	—	—	—	—	—	—	—	—	—	—	—	—	—
Main Cons.	1,519	13,826	102	444	—	—	7,771	9,300	—	—	—	—	—
Maple Grove Cons.	—	—	—	—	—	—	—	—	—	—	—	—	—
Markham City West	—	—	—	—	—	—	—	—	—	—	—	—	—
Mattoon	913	—	—	—	—	—	—	—	—	—	—	—	—
Maunie South	—	511	—	—	—	—	—	—	—	—	1,570	—	—
Mill Shoals	—	328	—	—	—	—	—	—	—	—	—	—	—
Mt. Carmel	128	1,160	106	—	—	—	137	74	—	—	—	—	—
New Harmony Cons.	235	7,915	136	310	—	—	—	—	—	—	—	—	2,190

for Waterflooding in 1956 by Oil Field
of barrels

Tar Springs		Hardinsburg	Cypress		Bethel		Benoist		Renault	Aux Vases		Ohara	Rosiclare		McClosky		Devonian
Brine	Produced	Produced	Make-up brine	Produced	Brine	Produced	Make-up brine	Produced	Produced	Make-up brine	Produced	Produced	Make-up brine	Produced	Make-up brine	Produced	Produced
—	—	—	—	—	—	—	—	—	—	—	402	—	—	—	—	402	—
—	42	—	—	256	—	—	—	—	—	—	—	—	—	—	—	212	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	369	—	—	—	—	—	—	—	9	—	—	1
—	—	—	183	—	—	—	—	—	—	—	—	—	—	—	—	657	—
—	—	—	73	402	438	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	8	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	9,344	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	2,373	—	—	524	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
4	—	—	—	409	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	274	—	—	—	—	274	—
—	—	—	110	—	—	—	—	—	—	—	—	—	—	—	—	475	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	4	—	—	—	—	—	—	—	—	—
—	—	—	—	37	—	—	—	—	—	—	—	—	—	—	—	—	—
—	27	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
16	—	—	4,654	—	—	—	—	—	—	—	234	—	—	2,012	—	827	—
51	—	—	110	—	—	—	—	—	—	19	—	—	19	11	19	102	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	986	—	—	—	—	—	—	—	—	—
—	—	—	73	—	—	—	—	183	—	—	707	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	98	—	—	—
—	—	—	389	—	—	—	—	—	—	—	—	183	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	986	—	—	59	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	5	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	2,373	1,351	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	29	—	—	—	—	—	—
—	—	—	347	—	—	—	347	—	—	—	—	—	—	—	—	—	—
29	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	255	—	—	—	459	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	24	—	—	—	—	—	—	—	—	—
42,609	3,249	—	—	271	—	110	—	—	—	—	—	—	—	—	—	—	12,757
1,898	—	—	1,031	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	73	—
—	—	—	191	—	—	—	—	—	—	—	54	—	—	—	—	54	—
—	—	—	—	365	—	—	—	—	—	—	—	—	—	415	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	99	—	—	15	—	—	—	—	—	—	—	—	—	—	—	—	—
51	256	—	—	621	100	379	—	748	—	—	57	—	—	—	—	—	—

TABLE 3.—

Field	Surface Water	Alluvial Sand and Gravel	Upper Pennsylvanian			Lower Pennsylvanian			Degonia	Clore	Palestine	Waltersburg	
			Fresh	Make-up brine	Produced	Fresh	Make-up brine	Produced	Brine	Produced	Produced	Make-up brine	Produced
New Haven	—	170	—	—	—	—	—	—	—	—	157	—	—
Omaha	—	—	—	—	—	—	—	—	—	—	—	—	—
Odin	—	—	—	—	—	—	—	—	—	—	—	—	—
Olney Cons.	—	—	183	—	—	—	—	—	—	—	—	—	—
Oskaloosa	—	—	—	548	—	—	—	—	—	—	—	—	—
Parkersburg	—	—	—	—	—	—	—	—	—	—	—	—	—
Patoka	—	—	—	—	—	—	—	—	—	—	—	—	—
Phillipstown Cons.	—	128	—	40	—	—	72	449	72	55	—	—	—
Roland Cons.	—	—	—	—	—	—	2,500	—	—	—	—	—	438
St. James	—	—	—	—	—	—	—	—	—	—	—	—	—
Sailor Springs Cons.	—	—	420	121	—	—	—	—	—	—	—	—	—
Salem Cons.	—	29,200	—	—	—	—	—	—	—	—	—	—	—
Samsville North	—	—	—	—	—	—	—	—	—	—	—	—	—
Seminary	—	—	—	—	—	—	—	—	—	—	—	—	—
Siggins	238	2,008	—	—	—	—	239	3,236	—	—	—	—	—
Stanford South	—	—	—	—	—	—	378	—	—	—	—	—	—
Storms Cons.	2,190	—	—	—	—	—	—	—	—	—	—	—	—
Stringtown	—	—	—	—	—	—	—	—	—	—	—	—	—
Thompsonville East	—	—	—	—	—	—	—	—	—	—	—	—	—
Thompsonville North	730	—	—	—	—	—	—	—	—	—	—	—	—
Tonti South	—	—	—	—	—	—	—	—	—	—	—	—	—
Wamac	417	—	—	—	—	—	—	—	—	—	—	—	—
Westfield	73	18	—	—	73	—	—	—	—	—	—	—	—
Woburn Cons.	—	—	—	—	—	—	—	—	—	—	—	—	—
York	—	—	—	—	—	—	—	43	—	—	—	—	—

The results from the geologic and geophysical studies described above are used to indicate the most promising areas for test-well drilling. Usually they do not contain enough detailed information to indicate the best site for a finished supply well. In other words, these studies should be regarded as guides for test-well drilling, and the test-well drilling regarded as a necessary step toward final location of the most promising site for the supply well.

Test-well drilling should result in accurate determination of the thickness, depth, and lithologic character of the aquifer and the position of the water table or piezometric surface. Proper pumping tests should be conducted to determine the specific capacity of the well and the coefficient of storage and the transmissibility of the aquifer. This information is necessary for the proper placement and for the most efficient construction and development of supply wells.

Test wells are usually small diameter holes and normally are not developed or finished as elaborately as supply wells. The driller's records and carefully conducted testing procedures are an important part of the test-well program. The driller should record an accurate log and save samples of formations penetrated; during drilling he should record static water levels and changes of water levels; drilling time for intervals of individual formations; weight, viscosity, and loss of drilling fluid; and depth at which fluid was lost. Carefully conducted test-well drilling programs usually permit selection of a satisfactory site and efficient construction and development of a well.

In exploration for supplies of fresh water or brines in the various bedrock aquifers, a careful study of electrical resistivity and driller's logs will assist in location, determination of the thickness, and lateral extent of the aquifers. Test wells should be drilled

Continued

Tar Springs		Hardinsburg	Cypress		Bethel		Benoist		Renault	Aux Vases		Ohara	Rosiclare		McClosky		Devonian
Brine	Produced	Produced	Make-up brine	Produced	Brine	Produced	Make-up brine	Produced	Produced	Make-up brine	Produced	Produced	Make-up brine	Produced	Make-up brine	Produced	Produced
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
91	—	—	—	438	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	110	—
—	—	—	—	—	—	—	—	292	—	—	—	—	—	—	—	—	—
551	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	55	—
1,461	—	—	—	128	—	—	—	2,961	—	—	—	—	—	—	—	—	—
22	—	—	—	52	—	—	—	—	—	72	—	—	—	—	72	—	—
266	—	883	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	180	—	—	—	—	—	—	—	—	—	—	—	—	—
102	—	—	276	172	—	—	—	—	—	—	53	—	—	58	—	11	—
566	—	—	—	—	—	—	—	8,463	2,055	—	—	—	—	40	—	4,012	1,228
—	—	—	—	—	—	—	—	80	—	—	—	—	—	—	—	—	—
—	—	—	245	—	—	—	—	—	—	—	—	—	—	—	—	110	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	266	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	44	—	—	—	—	—	—	—	—	—	—	—	—	139	—
—	—	—	82	—	—	—	—	—	—	—	46	—	—	—	—	—	—
—	—	—	438	—	—	—	—	—	—	—	55	—	—	—	—	—	—
—	—	—	—	—	—	—	—	73	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	73	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

if this information is not adequate for construction of successful wells. Logs of existing water wells in and near the area, in conjunction with production data, may indicate the approximate magnitude of the transmissibility of the aquifer and of expectable well yield.

WELL CONSTRUCTION AND DEVELOPMENT

Water well construction and development in the bedrock are similar to those of oil wells but differ considerably in the unconsolidated alluvial and glacial drift deposits. The efficiency of water wells in unconsolidated materials depends in large part upon proper construction which should include placement of well screens and gravel packs or envelopes opposite the water-yielding beds. The screen and gravel pack allow freer and slower flow of water into the well. They also prevent the movement of fine materials into the well after proper development. The size of the screen openings should be carefully chosen, the choice being determined by the particle sizes of aquifer materials and the gravel pack.

Unconsolidated deposits contain considerable amounts of clay, silt, and fine sand, removal of which increases the transmissibility of the aquifer in the vicinity of the well. Much of this fine material can be removed by developing the well, that is by pumping and surging during and after the gravel pack and screen are installed. Successful development results in a graded filter which allows easy entrance of the water but retards movement of fine materials into the well during periods of normal pumping.

More detailed descriptions of construction and development of wells in unconsolidated sediments are available in Smith (1954), Bennison (1947, p. 219-282), and other sources quoted by them.

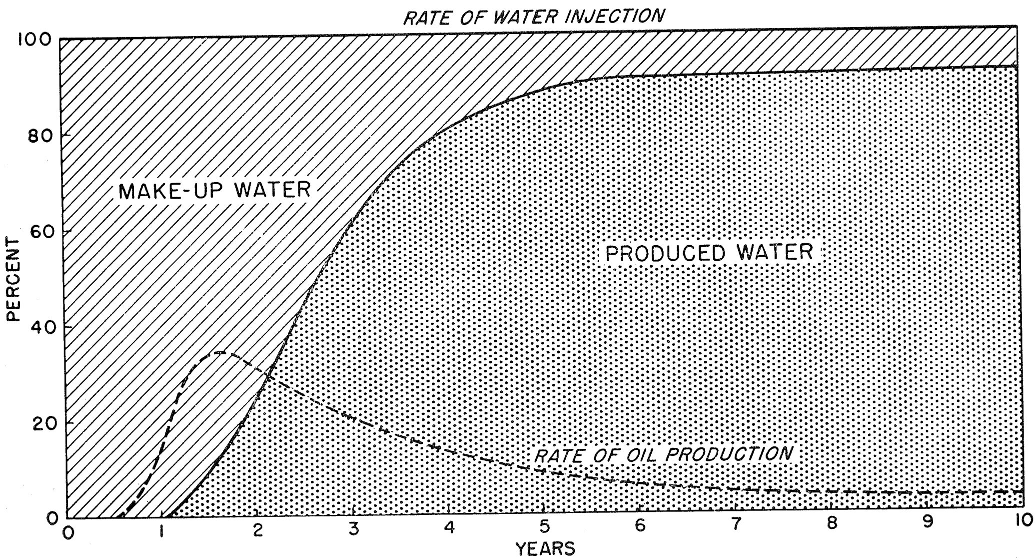

FIG. 9.—Relations between make-up water, produced water, and oil production in a typical waterflood project.

AVAILABILITY OF WATER FOR FUTURE DEVELOPMENT

The water that is used in secondary recovery projects comprises less than one percent of the water used for all purposes in Illinois. Further, only about one-third of the waterflooding supply is fresh water withdrawn from aquifers from which water for other uses is taken. Thus, the chief restrictions upon increasing development of water supplies for waterflooding arise from natural conditions. Restrictions imposed by competitive exploitation of water sources are only locally applicable to the surface water, the alluvial and glacial drift aquifers, and fresh water from the Pennsylvanian sandstones.

Water supply problems in secondary recovery projects differ in several respects from those in the usual water supply project. The quantities of water needed for such projects range widely from only a few hundred barrels a day to several hundred thousand. The quality of water needed is not nearly so restrictive as in most water-supply projects. It is usually immaterial in Illinois whether water is fresh or salty, thus allowing use of both water produced with the oil and water from any one of several aquifers directly underlying the project. Further, as shown in figure 9, for any given project, the quantity of make-up water needed is largest at the beginning of the operation and decreases to about 10 percent of the original amount within 6 or 7 years. This means that waterflood operators need not be as concerned about recharge as most other water users, because the demand decreases rather than increases during the life of the project. Care must be taken to determine that there is enough water available to last through the life of the project but in most instances, especially with brines, determination of recharge to the aquifers is not always necessary. As in all water supply projects, when storage capacity is determined the proper well spacing should be determined so there will be no future well interference and so a maximum quantity of water can be withdrawn at minimum expense.

Most of the potential water sources for waterflooding have already been tapped at one place or another but only a few are being pumped heavily in any of the fields. Therefore, the most likely sources of water for future development will be from these aquifers and from surface-water bodies.

Fresh Water

Most of the fresh water used for waterflooding comes from the alluvial sand and gravel aquifers in the areas shown as "Good to Excellent" in figure 4. These are limited and at some places water for flooding is piped a considerable distance from supply wells. These aquifers constitute an excellent potential source of fresh water and large but unknown quantities may still be developed for waterflood projects.

In many areas these aquifers have not been tapped; in others continued use from them with resultant depression of water levels along the stream courses will undoubtedly result in increased recharge to wells. However, in areas where existing wells are withdrawing water from the sand and gravel, considerable caution should be exercised to avoid interference between wells too closely spaced or other overdevelopment of the aquifers.

Many waterflood projects do not require quantities of water as large as those which can be developed in the "Good to Excellent" areas; they might be considerable distances from these areas. Such projects might successfully develop fresh water supplies in the areas labeled "Fair to Good." This is especially true in the elongate buried valleys indicated by dashed lines on figure 4 where the glacial and alluvial materials are thick but, because of lack of information, the number and occurrence of sand and gravel lenses is unknown. Throughout the "Fair to Good" areas a careful exploratory and testing program should be conducted to determine suitable well sites. In any case, a single well in these beds probably may not be adequate, even for modest demands, but a few or several wells properly spaced to avoid interference may suffice for the fresh-water needs of smaller flooding projects.

Little if any water can be developed from sand and gravel aquifers in the areas labeled "Poor" on figure 4, and it is doubtful, even with the most careful exploration and development, that adequate quantities of water for waterflooding can be taken from the thin alluvial and glacial drift deposits that characterize them.

About one-seventh of the fresh water used for secondary recovery comes from surface water sources, that is streams, lakes, and ponds. Most of the surface water is used in Boyd, Benton, Main Consolidated, and Storms Consolidated oil fields. Undoubtedly much more water for waterflooding can be obtained from these sources but data on which to base accurate estimates are not available. Probably the major streams and lakes in the Illinois basin can supply some of the oil fields with part or all of the fresh water needed for waterflooding. However, development of supplies from these sources requires careful planning which should take into account 1) the availability of water not used for other purposes, especially during low flow, 2) treatment of the water which changes considerably in chemical quality and in content of suspended material during the year, 3) cost of pumping and piping the water from the source to the place of use, and 4) the cost of impounding this water. In most instances it will probably prove more desirable to use water from other sources, especially from aquifers that are not sources of supply for other uses.

Limited quantities of fresh water, normally large enough for the small flooding project or to supplement supplies from other sources for larger projects, can be developed in the Pennsylvanian sandstones where they lie at shallow depths ranging from near the surface to about 500 feet. Wells into the upper Pennsylvanian sandstones now supply about two million barrels a year and those in the lower Pennsylvanian supply about one million barrels a year for waterflooding.

Specific capacities reported by the operators of 17 wells drilled into Pennsylvanian rocks for water supplies in 10 different oil fields range from 1.2 to .02 gallons a minute per foot of drawdown and average about 0.43. These wells are limited to small yields because they have such low specific capacities and are shallow. Although most of the reported wells produce brine it is likely that fresh-water wells have similar characteristics.

The areas believed to be underlain by fresh-water yielding Pennsylvanian sandstones are shown in figure 7. Although the distribution of these areas is sporadic and somewhat discontinuous, one or more are closely adjacent to any Illinois oil field. Therefore the sandstones are a potential source for small quantities of fresh water throughout the Illinois basin.

The precautions outlined for the development of water supplies from other fresh-water sources apply even more strictly to development from these sandstones. Wells should be carefully spaced so that they do not interfere with existing wells or with each other. The recharge is probably limited and most wells will probably withdraw water from storage in the aquifers. Therefore, the amount of water in storage should be determined as accurately as possible in order to estimate whether an adequate amount of water will be economically available for any given flooding project. With large withdrawals in some areas salt water may encroach from adjacent parts of the aquifer or from other aquifers, resulting in considerable increase in total solids concentration in the pumped aquifer. In most instances more than one well, perhaps several wells, will be needed to supply adequate quantities of water for a flooding project.

Small to large fresh-water supplies may be developed locally from the Pennsylvanian formations in the Illinois basin where included permeable sandstones are shallow. Figure 7 shows the approximate areas of outcrops of these formations and further discussion of their water-bearing characteristics may be found in the section in "Groundwater Geology."

One possible source of large quantities of water for waterflooding are the abandoned coal mines and strip pits in Christian, Coles, Madison, Macoupin, Clinton, Marion, Randolph, Jackson, Franklin, and Saline counties. These waters usually do not contain a large proportion of total solids but some may be expected to be highly corrosive because of low pH, especially the water in underground workings. Much of this water is now unused for any other purpose.

Brines

In Illinois waterflood projects brines, both pumped with oil (produced water) and pumped for make-up (supply water), comprise approximately two-thirds of all water injected. The sources of this water include aquifers in the Pennsylvanian, Mississippian, and Devonian systems which are everywhere available at depth in the oil fields. Potential sources, not yet tapped by waterflood supply wells, include aquifers in the Lower Mississippian, Devonian, and the Ordovician systems and possibly in the Silurian and Cambrian.

Little if any of the brine is used for any purpose other than waterflooding and only a small proportion of the total available brine is presently exploited. Because there is little use for this water other than for waterflooding and because of the relatively short life of waterflooding projects, "mining" the water, that is, pumping it from storage, is not considered objectionable.

Nearly 52 million barrels of brine a year are pumped from the Pennsylvanian sandstones in the eastern oil fields for injection. About two-thirds of this brine is produced water and one-third is supply water. Except locally, it appears that much more brine can be developed throughout the oil fields at various horizons in the Pennsylvanian rocks, especially in oil fields where they are not now pumped.

Most of the wells to the Pennsylvanian aquifers are pumped for brine and it appears that small to moderate yields, ranging from 10 gallons a minute to more than 100 gallons a minute, are common. Usually the brine wells are deeper than fresh water wells in the same aquifers; therefore larger drawdowns may be developed with resultant larger yields for the brine wells, assuming similar specific capacities. In general the precautions discussed in regard to development of fresh-water wells in these sandstones apply for brine wells.

More brines for injection are pumped from the Chester sandstones than from any other aquifers in the oil fields. The quantity of brine comprises nearly one-half of all water pumped for secondary recovery projects. The Tar Springs sandstone in the Louden field, in an area of about two townships, alone yields more than half of this brine. Other important Chester aquifers include the Cypress sandstone, a source common throughout the oil fields but with largest yields in the eastern half of the area; and the Benoist (Yankeetown) sandstone which yields mostly produced water, over half of which comes from wells in the Salem Consolidated oil field and the remainder from various other widely separated fields. Less used aquifers include the Waltersburg, Aux Vases, Palestine, Bethel, Hardinsburg, and Degonia sandstones, and the Renault and Clore limestones.

The transmissibility of the Chester sandstones increases with increased thickness. Therefore wells of larger yield may be expected where the sandstones are thicker. Figures 5 and 6 show the thickness of the two most important sources of brine in the Illinois oil fields, the Tar Springs and Cypress sandstones. It is believed that satisfactory and large supplies of brine can be obtained from the sandstones where they are 100 feet thick or more; that moderately large, probably satisfactory supplies can be pumped where the sandstones are 50 to 100 feet thick; and that only small supplies, probably not satisfactory for waterflooding, are available from thicknesses of less than 50 feet.

Reported specific capacities for the Bethel (Paint Creek) and the Tar Springs sandstones are small but the allowable drawdowns are large and yields of wells range from 12 to 52 gallons a minute (400 to 1800 barrels a day).

All of the Chester aquifers are potential sources for brine for waterflooding, but locally, as in the Louden and Salem Consolidated fields, where large quantities are pumped in a relatively small area, continued expansion may result in well interference and excessive depression of the water levels.

The Ste. Genevieve formation is tapped by oil wells in several oil fields throughout the area and brines are produced with the oil in most of these fields. The chief water-yielding rocks are the McClosky, Rosiclare, and Ohara zones. Only small quantities of brine are pumped for make-up water from these beds. These aquifers can undoubtedly supply much more water than is now pumped but adequately permeable zones are limited to the oolitic facies that occur erratically throughout the oil fields.

Brines may be produced from the Valmeyer formations where they are creviced or where extensive solution channels have developed. No production of water for flooding from these formations has been reported and their permeability and other aquifer characteristics are poorly known. Careful examination of oil-well drilling records may yield information concerning the transmissibility of these beds in specific areas.

Considerable quantities of produced water are pumped from the upper part of the Devonian rocks in Louden and Salem Consolidated oil fields. On the basis of the performance and yield of existing wells it appears that relatively large quantities of brine are generally available from these rocks throughout the oil field area.

Aquifers below the Devonian and probable availability of water supplies from them are described in the section on "Groundwater Geology."

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USE OF SEWAGE EFFLUENT AS A WATERFLOOD MEDIUM, MATTOON POOL, ILLINOIS*

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ABSTRACT

The Mattoon waterflood, located in south-central Illinois, encompasses 450 acres and includes 28 injection and 32 producing wells. A pilot flood utilizing Pennsylvanian age brine proved the feasibility of flooding the Mississippian age formations in the Mattoon pool. However, since usable subsurface brines were limited in availability, an expansion of the project could be achieved only after another source of compatible water was found. One such source was the effluent from the municipal sewage disposal system of the city of Mattoon. This effluent carries considerable suspended matter in addition to aerobic and anaerobic bacteria. Following a series of tests, a satisfactory treating method was developed, consisting of chlorination, settling, and filtration. A contract was negotiated with the city of Mattoon to purchase the sewage effluent and injection began in May, 1954.

During the summer of 1955, additional tests revealed that produced water from the oil wells could be mixed with the effluent without additional treating and, during September, 1955, the produced water was introduced into the injection system. Currently, some three million barrels of sewage effluent have been injected with no permanent plugging of input wells being evidenced. Phosphates, principally of iron, resulting from the presence of detergent soaps in the sewage effluent, continue to form after filtration but are readily removed by periodic acid treatments of the well-bores. Although the cost per barrel of water injected is greater than for similar floods using subsurface brines, and considerable time is required to control quality, sewage effluent has proved to be a satisfactory injection water.

INTRODUCTION

The Mattoon pool, located along the west side of Mattoon, Illinois, was discovered in June, 1940. Development of the pool proceeded at a moderate pace and was not essentially completed until 1948. Final development included approximately 420 producers and 90 dry holes drilled on 10-acre spacing. The principal producing horizons are the Cypress and Rosiclare sands of the Mississippian Chester series.

During May, 1952, a 70-acre pilot waterflood was initiated to evaluate the feasibility of flooding the Cypress and Rosiclare sands. Production increases were realized in November, 1952, and by late 1953, results of the pilot indicated that large-scale flooding would be economically attractive. Water requirements for the proposed expansion of the project were in excess of that available from the Pennsylvanian brine used in the pilot. The only other subsurface water source was the Devonian limestone, found at a depth of approximately 3,000 feet. However, because the Devonian brine was sour, its use would be accompanied by relatively high lifting and treating costs, and its availability in sufficient quantities to meet ultimate requirements was uncertain. The continued agricultural and industrial growth envisioned for this area of Illinois will require the bulk of the potable surface water available; consequently, the oil operators in the Mattoon pool were reluctant to place their needs for injection water on this supply.

One source of surface water readily available in adequate quantities was the effluent from the municipal sewage disposal system of the city of Mattoon. Although it was known that this water carries considerable suspended matter along with bacteria, a series of laboratory tests indicated that by utilizing a rather simple treating method, the sewage effluent could be used.

This paper presents a brief resume of the Mattoon reservoir characteristics and flood performance and describes in detail the problems encountered and methods devised to make the sewage effluent a satisfactory flood medium.

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TABLE 1.—RESERVOIR AND FLUID ANALYSES, MATTOON WATERFLOOD

	Cypress	Rosiclare
Core Analysis		
Porosity—percent	20.1	14.1
Permeability—md	54	97
Estimate connate water—percent	35	30
Fluid Analysis		
Original reservoir pressure—psig @ subsea datum	707 @ 1,037′	780 @ 1,200′
Saturation pressure—psig	707	450
Reservoir temperature—°F	85	90
Solution gas-oil ratio—cu. ft. per bbl.	322	196
Formation volume factor	1.209	1.130
Viscosity @ original reservoir conditions—cp	1.63	2.00
Viscosity @ atm. press. and reservoir temp.—cp	4.32	5.06
Oil gravity—°A.P.I.	39	39

RESERVOIR AND FLUID CHARACTERISTICS

The Mattoon pool lies on a northward trending anticline at the northern edge of the Illinois basin. The Cypress and Rosiclare sands, found at subsurface depths of approximately 1,750 feet and 1,950 feet respectively, are the principal producing horizons and are the only sands being waterflooded. The Cypress sand occurs in four distinct breaks separated by continuous shale barriers, over a gross interval of approximately 80 feet. The Rosiclare sand occurs as two erratically developed productive zones. Table 1 presents pertinent average rock and fluid data for the two sands. The primary producing mechanism for both sands has been a solution-gas drive.

FLOOD DEVELOPMENT

The pilot project, started in May of 1952, consisted of four producing wells converted to input duty on a 20-acre, 5-spot pattern, and eight producing wells. Because of sand discontinuity, only 70 surface acres were effectively placed under flood. Flood water was obtained from a Pennsylvanian sand found at a depth of approximately 1,500 feet. This brine was produced by a conventional beam pumping unit and the water was filtered through a pressure-type anthracite filter prior to injection. Injection averaged approximately 850 barrels per day, with surface pressures of 550 psig. First gains appeared six months after initial injection, or during November, 1952, and first expansion to the project occurred in May, 1954.

DETERMINATION OF SUITABILITY OF SEWAGE EFFLUENT AS A FLOOD MEDIUM

Prior to the first expansion, an additional source of injection water was needed. After exploring and discarding the possibility of using sour Devonian brine, the city of Mattoon was contacted regarding the use of effluent from the municipal sewage disposal plant. Mattoon is a city of some 18,000 persons and has a sewage through-put averaging 54,000 barrels per day. The plant uses an activated-sludge-type treatment with primary and final clarification, which yields an effluent carrying considerable suspended matter and is heavily loaded with aerobic and anaerobic bacteria. Samples of the water were obtained and complete chemical and bacteriological analyses were made.

The tests indicated that prior to using the sewage effluent, methods must be devised for: 1) removing the suspended matter; 2) destroying the living organisms; 3) reducing the corrosive tendencies of the water; and 4) removing any residual suspended solids. For ease of operation and optimum use of existing personnel, it was determined that the most efficient method of handling the water would be to confine the treating facilities to the injection plant site and, as a consequence, transport the raw sewage effluent through 3½ miles of pipeline. To prevent the suspended solids from settling in the line, a diameter was selected to insure turbulent flow and yet be large enough to avoid excessive pressure and attendant high power costs. It was determined that an 8-inch ID pipeline would meet these requirements at the design throughput rate of 8,000 barrels per day.

Filtration tests were conducted to determine settling and filtration requirements. It was found that 24-hour settling followed by filtration resulted in a water with plugging qualities no worse than those of tap water. Furthermore, 90 percent of the suspended matter settled out in four to six hours, resulting in a water that would not overload a conventional pressure-type filter. Thus, the bulk of the suspended matter could be removed by providing a pit of 10,000-barrel capacity which, at an injection rate of 8,000 barrels per day, would result in a nominal settling time of some 30 hours.

Bacteriological counts showed that aerobes averaged 1,150,000 per cc and anaerobes 22 per cc, none of which were sulfate reducers. Tests with various bactericides revealed that chlorine was the most suitable. Dosages of 8 ppm or less chlorine were found to have little effect on the bacterial count. However, 20 ppm resulted in a reduction from the 1,150,000 aerobes per cc to less than 10 per cc. On the basis of these results, a dosage of 20 ppm chlorine to achieve initial kill was recommended. Additional studies were undertaken to determine the residual chlorine content and the number of bacteria remaining in the water as a function of time following a dosage of 20 ppm. It was found that of the 20 ppm chlorine added, 16 ppm were removed within 10 minutes, presumably by the oxidation of H_2S and/or organic matter. It was also determined that following an initial dosage of 20 ppm the water remained effectively sterile if a residual chlorine content of 2 ppm were maintained.

Corrosive tendencies of the water were found to be approximately 10 milligrams per square decimeter per day (mdd) or less than 0.002 inch per year (ipy) and, as a consequence, use of corrosion inhibitor was deemed unnecessary.

Filtration to remove the residual suspended solids could be accomplished by the use of two pressure-type filters utilizing anthracite media at a filtration rate of less than 3 gallons per minute per square foot of filter area.

SYSTEM DESIGN

Based on the foregoing field and laboratory tests, an injection water system was installed. As shown in figure 1, it is composed of three major parts: a supply system, a treating and pumping station, and a distribution system. The sewage effluent is obtained from a sump following sludge treatment by the City and is pumped through approximately 3½ miles of 8-inch steel line to the waterflood treating plant. In addition to maintaining turbulent flow, to combat the build-up of suspended solids, scraper traps were installed, and line clean-out with a flexible wire brush-type of scraper is performed every three months. The supply pump at the City plant is operated through a time clock, regulated to avoid pumping at times the City plant experiences flash industrial loads that result in a poor quality effluent. The time clock is adjusted to meet major changes in water requirements such as those occurring when the flood is expanded.

Treating, settling, and pumping are done at the plant site centrally located in the Mattoon pool. Sewage effluent arriving at the plant passes through the chlorinator building into the settling pit. Two semi-automatic chlorinators, using gaseous chlorine obtained in 150-lb. cylinders, are used for chlorination prior to and following settling. Pre-settling chlorination is at the rate of 20 ppm chlorine and is sufficient to destroy the bacteria. Following the removal of suspended solids by settling in the pit, the water is again treated with chlorine to insure a residual chlorine content of 2 ppm. Since chlorine hydrate forms at temperatures below 49° F., which would cause interruption of the chlorine operation, the chlorinator building is insulated and heated during cold weather to maintain a temperature of 60° F. As a safety precaution, gas masks are readily available and exhaust fans controlled from outside the building have been installed.

The 10,000-barrel settling pit, with dimensions of 113 feet x 113 feet x 7 feet, was constructed with 2½-inch thick 'Gunite'-type cement reinforced with 4 inch x 4 inch steel mesh. A concrete pit was selected rather

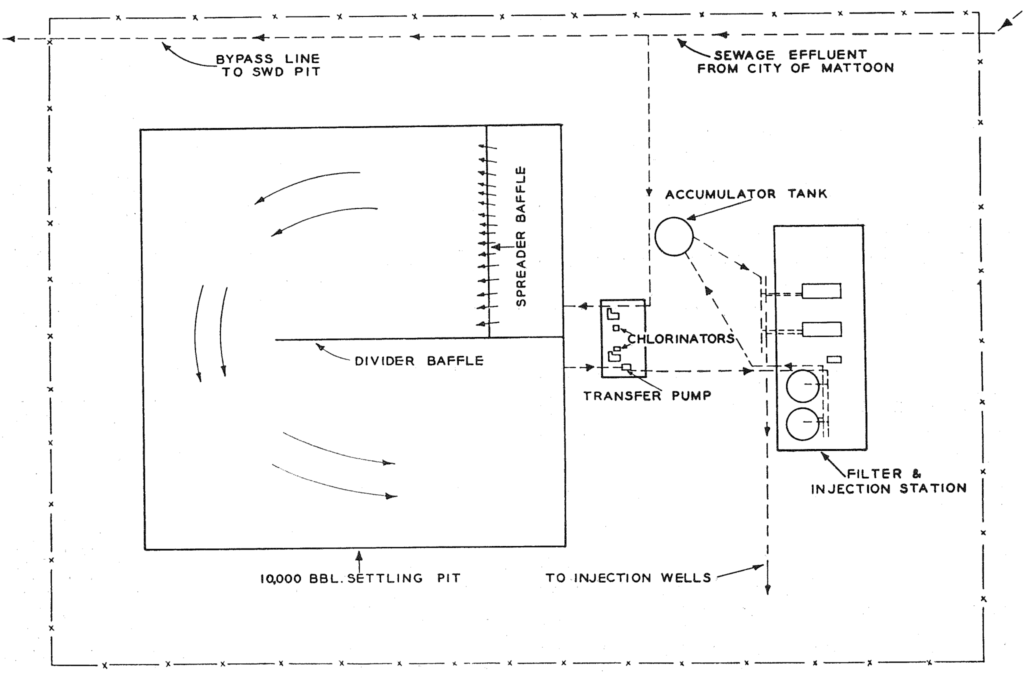

FIG. 1.—Flow diagram, Mattoon waterflood plant, Mattoon pool, Illinois.

than an earthen sump to avoid contamination of the water with silt. A baffle of cypress wood extends two-thirds of the length of the pit, resulting in the water's traveling approximately twice the length of the pit before it is pumped into the filters. In addition, the entrance section of the pit is divided by a spreader weir which encourages diffusion of the incoming water and provides a sediment trap. Selected views of the treating system are shown in figure 2.

Following post-chlorination, the effluent passes through two rapid sand filters that contain graded anthracite filter media, a master meter, and into the clearwell tank. The treated effluent from the clearwell flows by gravity into a suction supply header for two horizontal triplex pumps whose operation is automatically controlled by electrodes suspended in the clearwell tank. A pressure-type regulator provides a by-pass to the suction header and thereby controls discharge pressures. In addition, safety relief valves prevent exceeding rated pressures. To prevent freezing in the pump and header building, temperature is maintained above 40° F.

The distribution system is constructed of a cement-lined steel pipe buried at a depth of 30 inches to avoid freezing. Further freeze protection is provided at the input wellheads by the use of insulation-filled wooden boxes containing all the above-ground connections.

OPERATION

Quality Control

Following the start of sewage effluent injection, a program of sampling and testing the water was set up to assure satisfactory water quality. Basically, tests are required to determine: 1) sediment content; 2) residual chlorine content; 3) bacterial content; and 4) corrosiveness.

Sediment concentration is determined by use of a squeeze-type test filter using preweighed filter papers. Test samples are obtained at the following locations: a) sewage effluent entering pit following pre-chlorination; b) settled water entering filters following post-chlorination; c) filtered water entering clearwell; d) injection water leav-

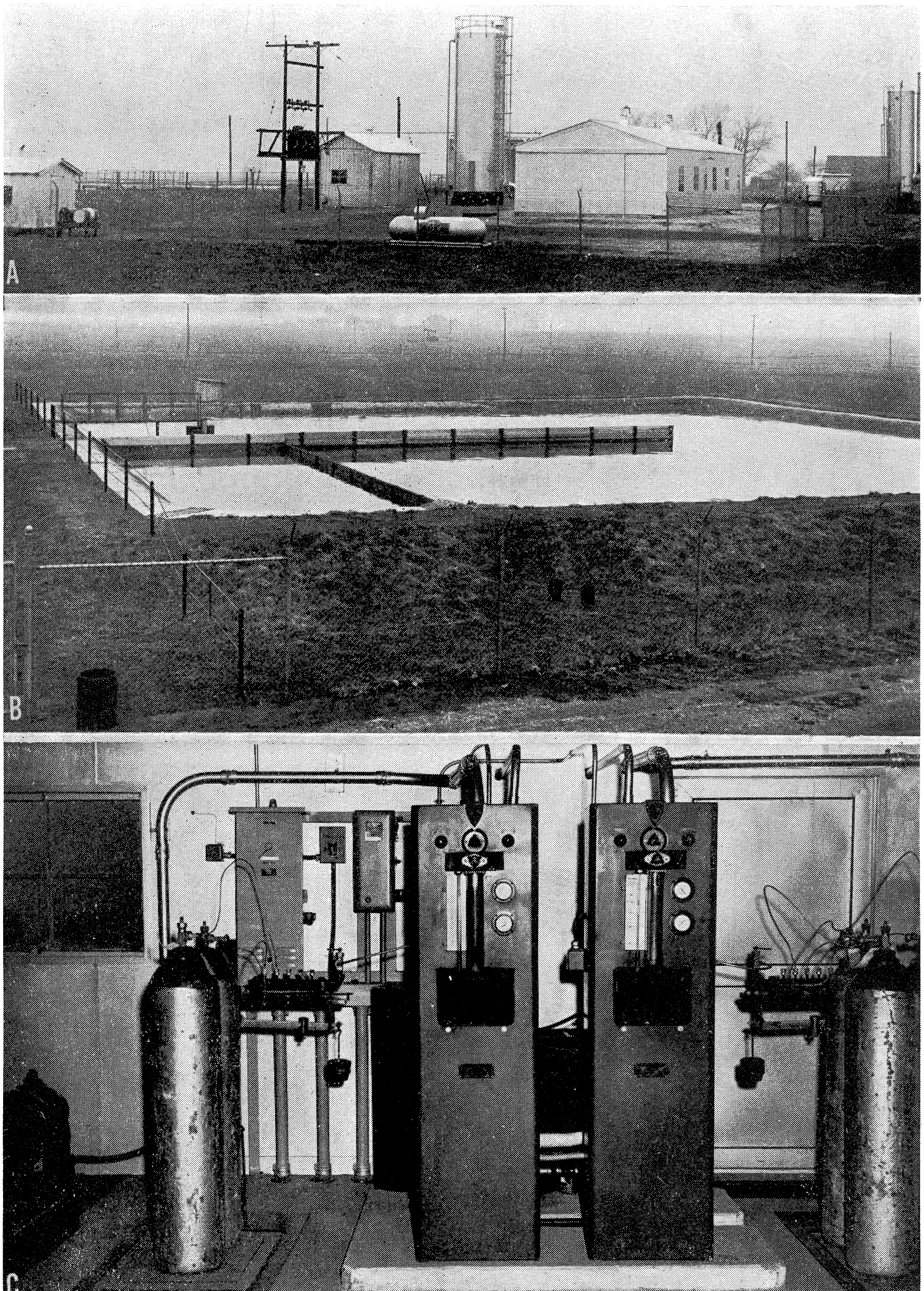

FIG. 2.—Mattoon waterflood plant, Mattoon, Illinois.
A—Over-all plant installation.
B—10,000-barrel settling pit.
C—Chlorinators.

ing station; e) injection water at the wellheads of two key inputs.

In addition, periodic checks have been made with a standard turbidimeter. This instrument measures the diffusion of light through the water sample, calibrating the answer in terms of the equivalent diffusion of SiO_2 in distilled water. The turbidity of the sewage effluent ranges from 21 to 56 ppm SiO_2 equivalent, and averages 30 ppm of SiO_2 equivalent. The filtered water, after treatment, has turbidity ranging from 8 to 20 ppm SiO_2 equivalent, with a maximum of 20 ppm SiO_2 equivalent having been found to be the minimum quality acceptable. Should unsatisfactory water be encountered, the system is shut down and the pit cleaned. Cleaning the pit each spring has been found adequate. The eight-inch line is cleaned every three months by pumping a scraper from the treating end back to the sewage plant and allowing this water to enter the City disposal system. Residues obtained on the pre-weighed filter papers, using the squeeze-test filter, are occasionally sent to a laboratory for qualitative and quantitative analyses. Solids are reduced from an average of 50 pounds per 1,000 barrels in the untreated water to less than 5 pounds per 1,000 barrels in the injection stream.

Chlorine content is determined by use of a residual chlorine comparator which determines chlorine concentration by a visual color inspection. Water is sampled daily from the following locations: a) downstream from pre-chlorinator (minimum 20 ppm); b) upstream from post-chlorinator; c) downstream from post-chlorinator (minimum 2 ppm); d) at the wellhead farthest from plant (minimum 2 ppm).

If the water is found to be below the standards set, the rate of chlorine injection is increased. This occurs when the effluent delivered by the City suffers a decrease in quality, which is fairly frequent in the summer months. During warm weather, optimum conditions for bacteria growth occur and, furthermore, the City plant experiences increased throughput.

Bacteriological tests are conducted every three months to determine if any strains of bacteria are building up an immunity to the chlorine treatment. Samples are obtained and tested for aerobic, anaerobic, and sulfate-reducing bacteria at the following locations: a) after pre-chlorination; b) after post-chlorination; c) at several key injection wells.

To date, no decrease in the effectiveness of chlorine gas as a bactericide has been found.

Corrosion rates are determined by weighing standard 1¼-in. x 5-in. mild steel coupons exposed in the system at the following locations: a) ahead of the pre-chlorinator; b) leaving the station; c) at the wellhead of various key inputs); d) down the hole in the key inputs.

These tests were conducted every three months, initially. Since no significant change in corrosion rates has been found, and all are below 10 mdd, no corrosion inhibitor is used and the frequency of testing has been reduced to semi-annually.

At only one time has the water quality fallen below the prescribed standards. This was in June, 1954, when the City treating plant was overloaded and essentially raw sewer water was delivered for several days. The chlorinator capacity could not meet the increased demand, and residual chlorine content dropped from 2 ppm to zero. To avoid a recurrence and to sterilize the eight-inch pipe-line, which had probably become a bacteria breeding ground, a chemical pump to inject sodium hypochlorite into the supply line was installed at the City sump. Hypochlorite is injected at this point whenever the tests at the injection station indicate that water quality is falling and chlorine demand will exceed the ability of the chlorinators to restore sterility.

Formation of Precipitates Within the Injection System

Use of the sewage effluent began during May, 1954. Within one month, a soft deposit of fine yellow-colored material was found in the discharge of one of the pressure-type filters. Chemical analysis revealed that it was primarily iron oxide, aluminum oxide, and iron phosphate. It was 95 percent soluble in dilute (19 percent) hydrochloric acid. Deposits of similar material have been, and are now being, found throughout the entire system, including input well tubing and in water backflowed from input well sand faces. A representative analysis of this material is shown in table 2. The phosphates are thought to be a result of detergent soaps used in both home and commercial laundries. Tests of additional filtration using a diatomaceous earth type filter-aid did not appreciably reduce the amount of this very fine precipitate. The problem has been accepted as one best controlled by periodic acid treatment of the input wells.

Beginning in August 1955, a program of input well testing was initiated to determine if permeability impairment was occurring near the well bore. Using concepts developed by the Carter Research Laboratory, (A. F. Van Everdingen (1953) and S. T. Yuster (1945)), relating to analysis of pressure fall-off data and well injection histories, it has been determined that no permanent plugging of the sand faces is occurring.

Addition of Produced Water to Sewage Effluent

During the summer of 1955, another series of tests was conducted to determine if the produced Cypress and Rosiclare brines could be mixed with treated sewage effluent for re-injection. Produced water had been handled by segregated injection into a limited number of waterflood input wells, with the excess being eliminated by surface evaporation and injection into a salt water disposal well. However, water-producing rates were approaching the capacity of existing facilities. The principal problem in returning the two waters to a common injection system was the control of calcium carbonate precipitation. The calcium-bicarbonate ratio is high in the combined produced water, tending to result in super-saturation of calcium carbonate. However, the sewage effluent is high in bicarbonates and it was postulated that a mixture of at least eight parts sewage water to two parts produced water would help prevent super-saturation of calcium carbonate and its eventual precipitation in the injection system.

Table 2.—Typical Analysis of Precipitates Formed After Water Treatment, Mattoon Waterflood

Constituent	*Weight Percent*
Iron phosphate	21
Iron oxide	31
Aluminum oxide	17
Calcium oxide	2
Calcium carbonate	2
Calcium chloride	3
Calcium sulfate	2
Silica	1
Acid-soluble organic compounds and water of hydration	21
Total	100

Field tests were conducted using a scale model of the settling and treating system. Water quality was determined by observing plugging tendencies of the water in alundum cores having permeabilities representative of the horizons being flooded; that is, from 50 to 100 md. Several tests of various mixtures, ranging from 10 percent brine and 90 percent effluent to 50 percent brine and 50 percent effluent, were run. Further tests with various brine-effluent mixtures, treated with alum in concentrations of 12 to 24 pounds per 1,000 barrels of water were made. A final series of tests were performed on alum-treated mixtures that had been given additional filtration through a diatomaceous earth filter.

Results of the testing indicated that mixtures consisting of up to 20 percent produced water had equal or slightly lower plugging tendencies than 100 percent sewage effluent. Both the addition of alum and further filtration through diatomaceous earth reduced plugging tendencies only slightly. Since the improvement in water quality is so slight, the additional investment for enlarged treating facilities is not justified.

By October 1, 1956, a total of 3,940,000 barrels of water had been injected, of which approximately 2,900,000 barrels were sewage effluent. Current injection averages 4,000 barrels per day with surface injection pressures of up to 880 psig. Accumulated oil gains exceed 475,000 barrels with September 1956 production averaging 1,000 barrels per day, of which 900 barrels per day is the increase over normal primary.

Costs

The cost of injection water at Mattoon has ranged from \$0.035 to \$0.055 per barrel of water, including depreciation. Currently, water is being injected at a cost of approximately \$.04 per barrel, which is 30 to 40 percent more than the cost of water at floods of similar size in the area using subsurface brine. The sewage effluent cost is greater because of treating expense, including depreciation of the additional investment in treating facilities, and because the operating problems accompanying its use require considerably more time of engineering and operating personnel. However, by devoting the necessary time and money to achieve and maintain proper water quality, it has been possible to utilize the sewage effluent as a satisfactory waterflood medium.

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RECENT TRENDS IN TREATING WATERS FOR INJECTION INTO OIL-PRODUCTIVE FORMATIONS

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ABSTRACT

The earliest procedures used to analyze and treat brines and fresh waters injected into oil-productive formations to stimulate oil production were outgrowths and adaptations of municipal water-treating practices. It soon became apparent that the characteristics of the waters available for injection differed considerably from those of potable and other industrial waters and that the purposes of treating water for injection were entirely different from those of treating water for household and industrial uses.

As a consequence, revised analytical and treating procedures gradually were adapted to the specific problems common to waters handled in waterflooding and pressure-maintenance injection plants of petroleum fields. Increased emphasis on petroleum technology during the past several years has been responsible for the development of treating procedures for injection waters that are entirely foreign to some of those originally employed or those used for other industrial waters.

Recent developments in methods of treating injection waters include increased emphasis on more complete separation of oil from the accompanying produced water and on the use of closed injection systems when waters have characteristics that permit their use. New methods for removing dissolved acidic gases from waters include controlled aeration, "scrubbing" with combustion gases or natural gas in packed columns, the use of submerged burners, and chlorination. Numerous organic treating chemicals have been made available during the past few years and have been finding extensive experimental application as biocides, corrosion inhibitors and wetting agents. The use of various sequestering agents has been increased, specific complexing additives being used to sequester or chelate some of the more troublesome metallic ions.

New and improved chemical feeders and sedimentation tanks and ponds have been designed. Changes in filtration procedures are seen in the development of corrosion-resistant element-type filters and the increased use of diatomaceous-earth filtration. Non-corrodible plastic and cement-asbestos materials and corrosion-resistant metallic alloys have been improved and are used more extensively for many purposes. Automatic controls have been utilized to a greater extent.

The use of water analyses in designing plants and controlling treating processes has received recent emphasis and much attention is being given to detecting, evaluating, and controlling microorganisms in injection waters. Although good progress has been made toward solving many injection-water treating problems, the available information pertinent to many other problems is scanty and incomplete and much additional research work is justifiable to attain optimum treating procedures.

INTRODUCTION

Methods used to condition waters for injection into oil reservoirs to stimulate oil production have been discussed in detail in numerous earlier publications by authors from many petroleum-research organizations (Andresen and Gardner, 1950; Bernard, 1950; Blair, 1951; Breston, 1950; Gregory et al., 1950; Torrey, 1955; Voss and Nordell, 1950; Watkins et al., 1950 and 1952). As petroleum technology becomes a more advanced and familiar science, experimental methods of water treating tend to become established practices, and newly developed methods often are eagerly accepted for testing in field trials under a variety of conditions. Some of the trends in treating brines and surface waters for subsurface injection that have been employed during the past several years are discussed in this paper. Problems upon which additional research is justified are pointed out. It is concluded that much additional work upon adequate, simple, economically practicable methods of conditioning injection waters can and should be done. The treating of brines for subsurface injection is becoming a technology in itself, as distinct from being an outgrowth and adaptation of municipal water-treating practices.

Oil-Water Separation

The incomplete separation of oil from water has serious adverse effects on water-conditioning systems. The presence of even minute quantities of oil in raw water causes fouling of lines, treaters, and pond or tank walls. Even more troublesome is the removal of oil films by filter media, thereby necessitating recharging of filters or replacing elements. Oil in any quantity may be incompatible with some treating chemicals; for example, quaternary-ammonium compounds are soluble in crude oil.

Increasing use is being made of emulsion treaters, commonly called "heater-treaters," for effecting more complete separation of free and emulsified water from oil by the use of heat and demulsifying chemicals.

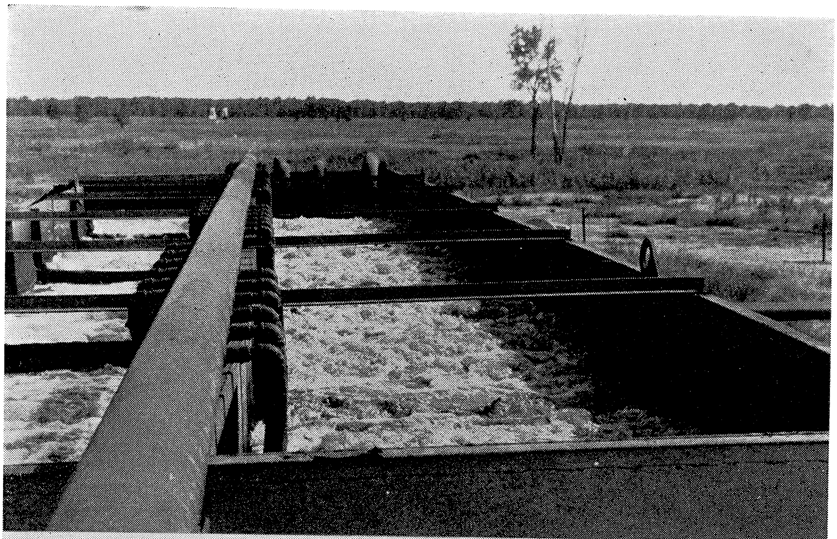
Oil-skimming compartments frequently are used, either as separate ponds or as compartments in aeration or primary settling ponds, isolated by baffles installed and adjusted to permit flow of water under the baffles while retaining oil floating on top of the water. Even two such stages often will not remove all oil from the water. An expedient used by at least one operator has been to flow produced brine countercurrent to kerosene in a tower to remove traces of crude oil. Stormont (1956) described the use of countercurrent flow of gas in a "flotation cell" for the same purpose.

CLOSED SYSTEMS

The economic advantages of closed treating systems, where the constituents of the waters treated permit their use, have been discussed elsewhere (Amstutz, 1956; Watkins, 1955). Many closed systems now are being used to inject waters having low or negligible concentrations of dissolved hydrogen sulfide and iron, although such waters may contain comparatively high amounts of dissolved free carbon dioxide. In a few plants, waters containing considerable dissolved hydrogen sulfide or ferrous iron are injected through closed systems. However, this procedure often is not practicable. Where the permeability of the injection formation is high enough that some precipitation of iron or carbonate compounds is not deleterious, gradual plugging of sand pores may be ignored until reductions in injection rates force the cleaning-out of wells. Corrosion caused by dissolved hydrogen sulfide also may be written off, if not too serious, as normal depreciation of waterflood equipment, amortized over a period of several years. The most critical operational consideration in any closed system is maintaining the system completely airtight. Corrosion and precipitation are demonstrably increased if any air is introduced into the system. There has been a definitely noticeable trend toward the use of closed systems for handling injection water during the past several years.

DISSOLVED-GAS REMOVAL

A large part of all corrosion in water plants and systems is caused by the common dissolved gases—oxygen, free carbon dioxide, and hydrogen sulfide (Watkins and Wright, 1953). It follows that, if the dissolved gases are removed, the magnitude of corrosion should be materially lessened. Many methods have been used for removing dissolved gases, particularly the acidic gases usually found in subsurface waters. The most common method used has been aeration. One of the principal disadvantages of aeration is that the extent of aeration necessary to remove dissolved acidic gases is so great and the control of the degree of aeration so dependent upon the basic design of aeration facilities and atmospheric conditions that such systems often are overdesigned. This results in undesirable solution of atmospheric oxygen in the water. Dissolved oxygen may be partly removed by vaccum deaeration in packed columns. However, disadvantages of this practice are found. For instance, one additional step is introduced into the treating process, vacuum deaeration is expensive, the mechanical removal of dissolved oxygen to a residual concentration less than 1 ppm is quite difficult, and the removal of dissolved oxygen usually is accompanied by the removal of some free carbon dioxide, thereby changing the carbon-dioxide-bicarbonate-carbonate balance and promoting precipitation of metal carbonates in the column. For these reasons,



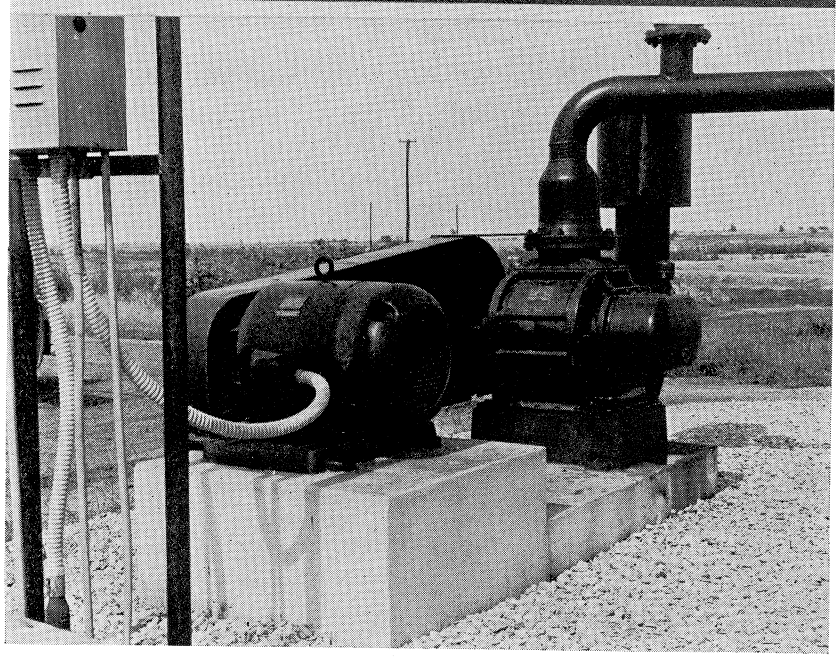


FIG. 1 (Above).—Top view of air-diffusion degasifier tank.

FIG. 2 (Below).—Blower used as air supply for air-diffusion degasifier.

vacuum deaeration has largely been discontinued in many plants where it formerly was used.

One recent development in dissolved-gas removal has been the replacement of aeration by other methods. One new method is the use of either synthetic or natural combustion-exhaust gases to remove hydrogen sulfide and oxygen from water by countercurrent scrubbing in a packed tower. One application of this method has been described by Doscher and Tuttle (1954); the principles involved have been discussed elsewhere by Crawford (1955). Similar degasification operations have been conducted by using a submerged burner, as discussed by Hart and

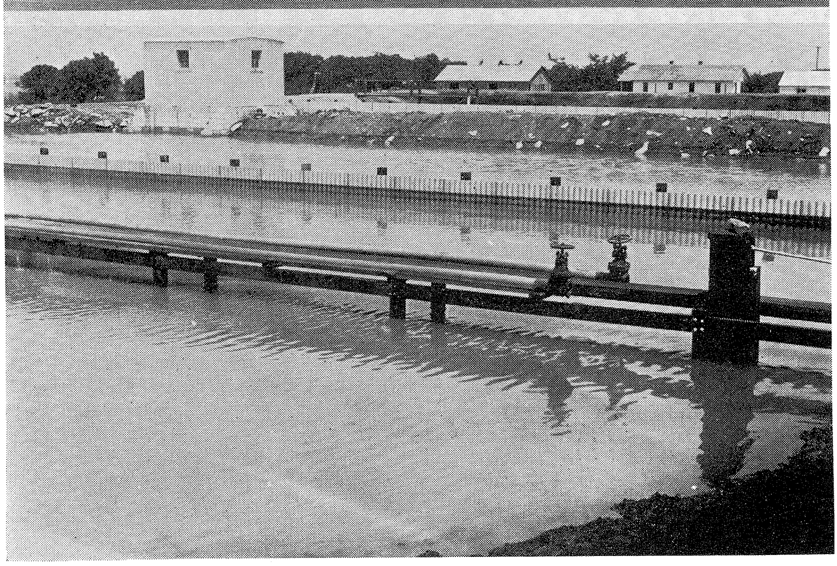


FIG. 3 (Above).—Spray aerators and aeration pond.

FIG. 4 (Below).—Plastic spray aerators and aeration pond.

Wingate (1955). A method for the deaeration of water by scrubbing with natural gas has been described by Brewster et al. (1955).

Changes in aeration procedures also are evident. Many forced-draft blowers now are used with tray-type aerators. One recent innovation has been the use of a submerged diffusion manifold for controlled aeration of brines, as illustrated in figure 1.

The diffusion aerator or degasifier pictured here is housed in a rectangular steel tank 10 feet wide by 36 feet long by 6 feet deep, with a working capacity of about 425 barrels and a daily throughput capacity of 10,000 barrels. Air is discharged from the central manifold through x-shaped slits in 1-inch Tygon tubing loops under the surface. A mixture of about 25 percent of produced brine containing 30+ ppm of iron, and about 75 percent of Arbuckle supply water containing 140+ ppm of dissolved hydrogen sulfide at pH 6.7 at the inlet is discharged from the unit with about 8 ppm of dissolved iron and no dissolved hydrogen sulfide at pH 8.0. The concentration of free carbon dioxide also is proportionately reduced, from about 200 ppm to less than 20 ppm. Air is supplied from a 10 by 15-inch blower, pictured in figure 2, powered by a 40-hp motor. The blower has a capacity of 1,360 cubic feet per minute at 4 psig pressure.

The use of spray nozzles for water aeration is becoming more widespread. Frequently the nozzles are fabricated from plastics or other non-metallic materials to prevent corrosion and minimize plugging of orifices by precipitated solids.

In figure 3 nozzles that spray the water upward are pictured. Figure 4 is a photograph of a plastic aeration system in which the spray is directed downward into the pond to minimize the loss of water vapor. The electrical switch of a float-actuated control system is visible in the right foreground.

Chlorine is used in more plants to oxidize traces of hydrogen sulfide than it was a few years ago. However, in most instances, chlorine is used as an oxidant only to supplement, rather than replace, aeration because of the high cost and great potential corrosivity of chlorine. Few efforts have been made to use reducing agents, such as sodium sulfite, in concentrated brines because of their tendencies to combine with metals through chemical exchange to form insoluble compounds.

CHEMICAL TREATMENT

Lime is still the principal alkaline agent used for pH control because of its low cost, ready availability, and ease of handling. In many treating plants there has been an observable trend away from the use of aluminum sulfate as a coagulant toward the use of others, such as ferric sulfate and ferric chloride. Probably the most notable change in treating procedures in the last several years has been the increased use of organic treating compounds, such as biocides, corrosion inhibitors, and wetting agents.

Biocides

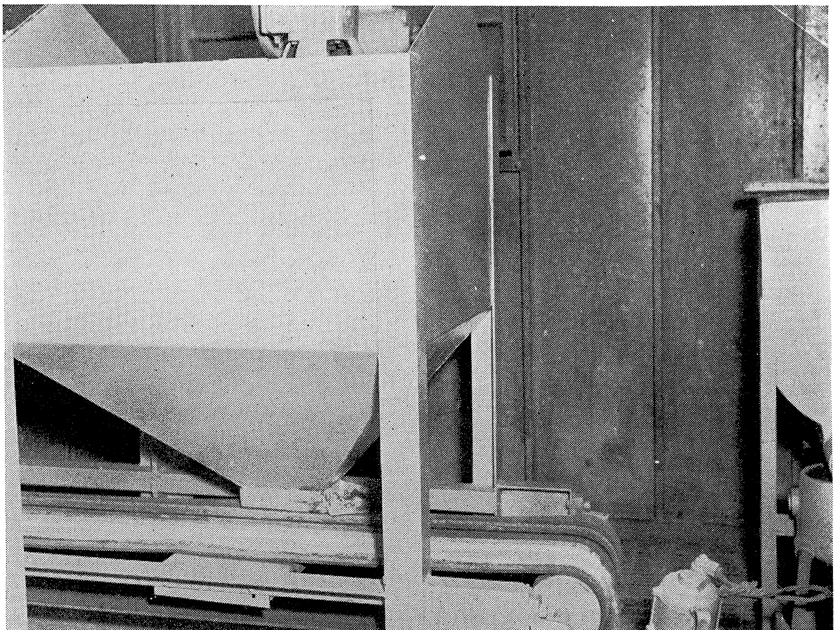
Although it has been known for many years that numerous kinds of organisms, including several strains of bacteria, were prevalent in both brines and fresh waters, there has been a growing awareness in recent years of the deleterious effects that may be caused by such organisms, as discussed by Allred (1954) and Williams (1953). Particular attention has been given to the presence and effects of sulfate-reducing bacteria (Allred et al., 1951; Anderson and Liegey, 1956). The increased interest of oil producers in microbiology has been the combined result of increased emphasis on technology in waterflooding, the availability of organic biocides, and the fact that operational difficulties caused by microorganisms, either in the nature of plugging or corrosion, are by nature cumulative rather than immediate. Microorganisms often contaminate an injection system to the point that stringent remedial measures are necessary. More attention is being given to early and periodic examinations to detect microorganisms, to bacteristatic control, rather than attempting to achieve a complete kill, and to the standardization of microbiological test methods (Anderson, 1956).

Common biocides now in use include the quarternary-ammonium compounds (Barton and Moss, 1952; Breston, 1949; Heck et al., 1949; Williams et al., 1952), mercuric and phenolic compounds, fatty and rosin amines, and old standbys such as chlorine, formaldehyde, and copper sulfate. Most biocides have both advantages and disadvantages, influenced by the types or strains of organisms present, compatibility with other substances used for treating or naturally present as dissolved salts in the injection waters, and cost.

Corrosion Inhibitors

Whenever the common metallic alloys are in contact with water, some corrosion may be expected. This especially is true of ferrous alloys. The usual indeterminate factors are the severity of corrosion and the extent to which corrosion may be minimized. The adverse effects of severe corrosion are immediate, usually visible, and of economic concern, as opposed to the effects of microorganisms, which may be concealed for longer periods. Secondary effects of corrosion, such as plugging of meter screens and porous rock formations by corrosion products, are less costly than leaks from corroded systems, although they are equally troublesome.

Thus it is easier for the operator of a water-injection plant to recognize that cor-



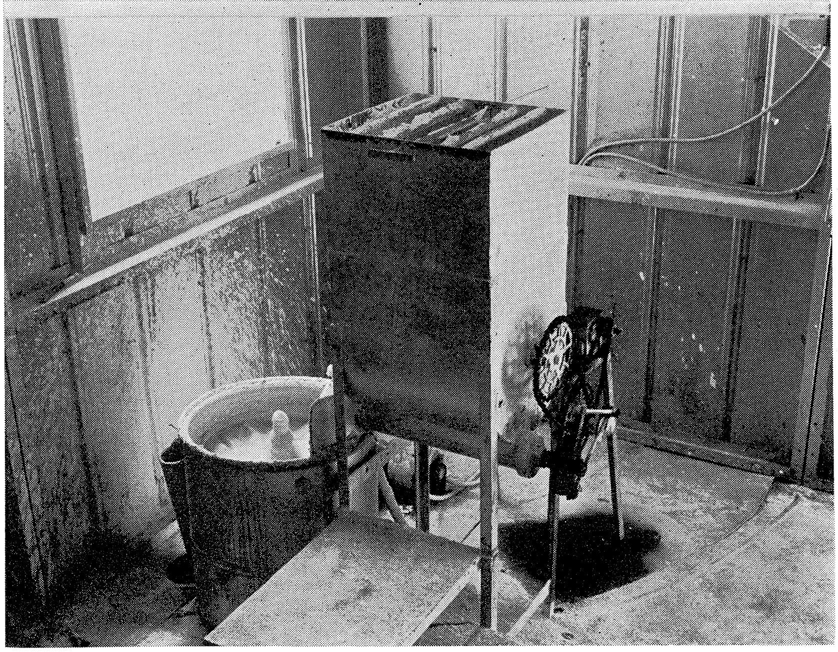


FIG. 5 (Above).—Dry chemical feeder with variable-speed conveyor belt.

FIG. 6 (Below).—Washing machine used for mixing and solution of chemicals proportioned from dry feeder.

rosion-protective measures are necessary than to accept the fact that a serious microorganic problem may exist.

Corrosion-prevention measures may be divided generally into the following categories, listed in order of the current trend of emphasis on their importance: 1) Chemical inhibition; 2) Removal of dissolved gas; 3) Use of non-corrodible materials; 4) Use of corrosion-resistant alloys, and 5) stabilization of injection waters.

Although chemical inhibition, removal of dissolved gases, and water stabilization all may be considered chemical-treating methods, they have been arbitrarily separated here because each represents a separate and distinct step toward corrosion control.

The current interest in chemical inhibition is largely a result of the availability of organic treating compounds that possess both corrosion-inhibiting and biocidal properties. Field and laboratory tests made with organic inhibitors such as the quaternary, rosin, and fatty amine compounds, reportedly have indicated favorable results in minimizing the corrosion caused by dissolved acidic gases (Breston, 1949; Heck et al., 1949; Robinson, 1956). The results of attempts to inhibit oxygen corrosion apparently have been less successful.

The new experimental methods of dissolved-gas removal discussed previously have been developed primarily to combat corrosion. Additional work, both in the laboratory and field, on improved methods of dissolved-gas removal, is desirable.

The availability of improved non-metallic materials, chiefly plastics, for fabricating tubular goods and other production equipment, has promoted wider use of non-corrodible materials. Cement-asbestos and plastic pipe now are used extensively in brine-gathering lines and low-pressure water-distribution lines. Plastic pipe has been used to a limited extent as tubing in water-supply wells and shallow input wells. The use of plastic-lined and cement-lined pipe strings in water-input wells has become common. Porcelain plungers are commonly used to good advantage in positive-displacement injection pumps. Plastic spray nozzles have been used in aerators instead of steel ones; in at least one instance, plastic trays have been used successfully in aerating towers. The trend toward the use of plastic and other non-metallic equipment is likely to continue.

Although some metallic alloys afford good corrosion resistance in certain environments, their use has not been widespread. This is due partly to the higher cost of the corrosion-resistant alloys compared with that of carbon steel and to the fact that alloys which are resistant to corrosion in an oxidizing environment often are corroded badly in a reducing one.

The practice of adjusting the pH and carbonate supersaturation of water to values that will promote precipitation of a carbonate film on metal surfaces, a long-accepted practice in treating potable waters, is not now used extensively with brines in injection systems. The reasons for this are that the protection afforded is neither good nor uniform, and any precipitation of solids in input wells is undesirable.

Sequestering and Chelating Agents

In most brine-injection systems a primary water supply from some source other than the oil-productive formation is required. It also is expedient in most instances to dispose of produced brines by injecting them into the oil-productive formation through wells in the flood pattern. Therefore, the chemical compatibilities of two or more waters from different sources, mixed either in the treating system or, less likely, mingling in the formation, becomes important. The significance of water incompatibilities has been discussed from different points of view by Headlee (1950) and Bernard (1955). When one water contains a soluble compound such as barium chloride and another a compound with an incompatible ion, such as a sulfate, mixing of the waters might be expected to form insoluble barium sulfate. Rather than go to the expense of removing one ion to a tolerable concentration, it usually is considered more economical and expedient to complex the metallic ion by adding a sequestering or chelating agent. The complex phosphates are used extensively for this purpose (Burcik,

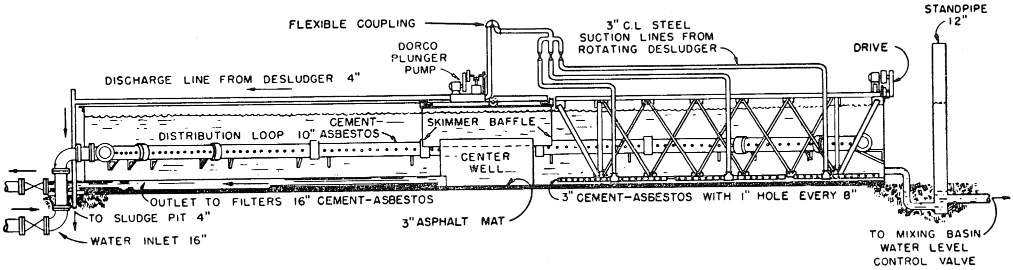


FIG. 7.—Sectional view of coagulation tank with rotating desludger.

1954). Recently there has been a trend toward the use of organic chelating agents, such as citric and acetic-acid derivatives, especially various salts of ethylenediamine tetraacetic acid (Torrey, 1955). Complex phosphates usually are employed for preventing the precipitation of carbonates and the sequestration of barium to prevent formation of barium sulfate when two waters are mixed. The citric- and acetic-acid compounds are used more commonly to chelate ferrous iron.

Despite the common use of sequestering and chelating agents, there is a distinct lack of published laboratory and field data on the comparative efficiencies of such agents in complexing specific metallic ions in waters of varied composition. Research on this problem now is in progress at the Bartlesville Station of the Bureau of Mines.

DETERGENTS

Much interest has been evidenced during the past several years in the use of wetting and surface-active agents for increasing the injectivity characteristics of water and improving the efficiency of oil displacement. Many reports have been published in the technical literature describing the results of laboratory and field tests with various detergents (Breston and Johnson, 1951; Calhoun et al., 1951; Dunning et al., 1953 and 1956; Torrey, 1955). The consensus regarding the utility of detergents as floodwater additives may be summed up as follows:

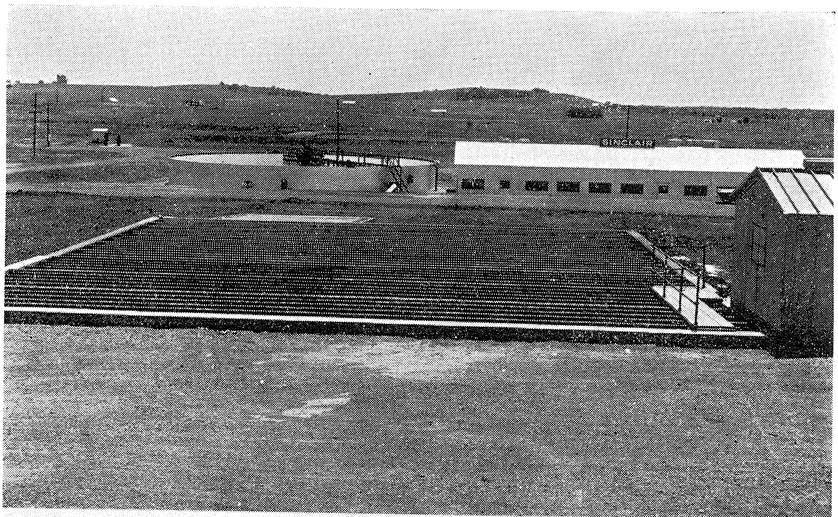
1) Detergents improve water injectivity markedly in the laboratory under controlled conditions.
2) The efficiency of oil displacement by water in laboratory tests is enhanced by the addition of detergent solutions.
3) The efficiency of oil displacement by detergent solutions varies with the kind of detergent with "built" nonionics, pure nonionics, anionics, and cationics in general descending order.
4) Field results have not been as encouraging as those obtained in laboratory tests. It has been demonstrated that improvements in injectivity or oil production may be obtained by the use of detergent solutions under specific circumstances. Whether general increases in injectivity and oil production can be obtained by detergent injection is a question not yet answered.

The complex phosphates, which possess detergent properties, as well as sequestering ones, sometimes are used successfully as "builders" for synthetic organic detergents.

CHEMICAL FEEDING

For the most part, chemical feeders in use still are of the dry, proportioning type which utilize a hopper, stirrer, and adjustable orifice. One notable modification of this type of feeder is shown in figure 5. The feeder pictured here discharges lime and a coagulant from separate hoppers onto a variable-speed conveyor belt. Coagulant is discharged onto the belt through a fixed orifice; the amount added is regulated by varying the speed of the belt. The amount of lime added is regulated by means of an adjustable orifice.

One common difficulty in the addition of dry chemicals is incomplete solution of the



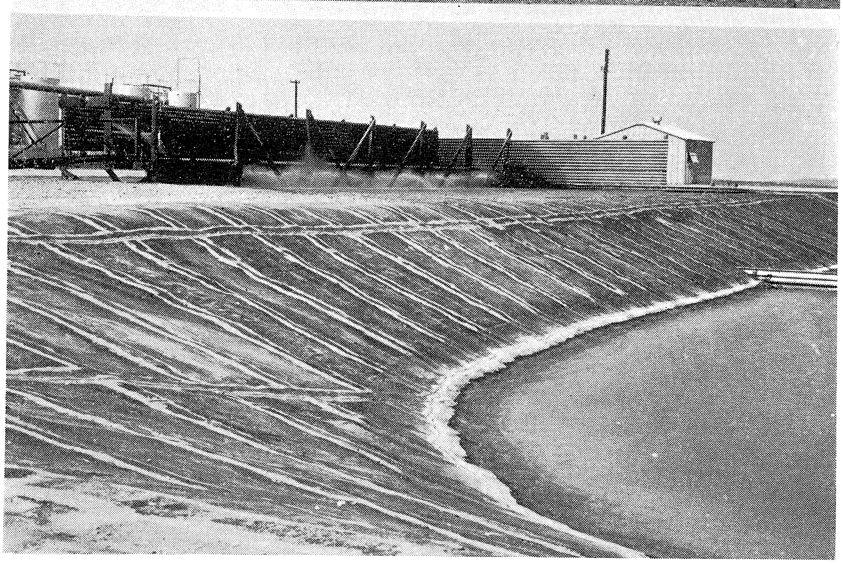


FIG. 8 (Above).—Mixing and flocculation basin, showing arrangement of "end-around" baffles.

FIG. 9 (Below).—Corner of sedimentation pond, showing method in which asphaltic lining has been applied.

salt, which causes a loss of treating agents. Various methods are employed to insure complete solution of the chemical, including mixing with water jets and the use of mechanical agitators. One novel apparatus used for this purpose is a conventional washing machine with an oscillating agitator, as shown in figure 6. The cost of the apparatus is nominal and the efficiency of mixing and solution are high.

SEDIMENTATION

A definite trend toward the use of sedimentation tanks has been noticed. Such devices are manufactured by several commercial organizations and are identified by a variety of names. Usually a series of concentric baffles, a large-diameter, slowly rotating agitator, and sludge-drawoff facilities are provided. Regardless of mechanical construc-

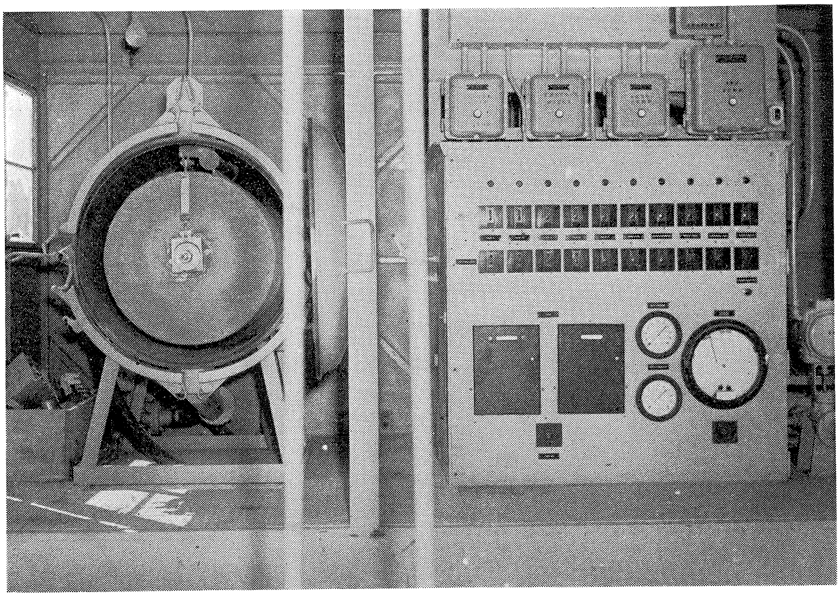


FIG. 10.—Diatomaceous-earth filter and electrical control panel, mounted on portable base.

tion and operation, the purpose of such units is to introduce raw water at one point and discharge treated water, essentially free from suspended matter, at another point. Although most such treating and sedimentation tanks in use are of standard commercial design, some are especially designed and fabricated for specific installations. One such unit is diagrammed in figure 7. In this unit, treated water is distributed around the periphery of the tank through a perforated cement-asbestos loop, goes under one baffle, and over another into a center well from which the water flows to the filters. One unique feature of this unit is the desludging mechanism. A 3-line, oscillating "vacuum cleaner" rotates to about 300° of the circumference of the tank in about a 2-hour period before automatically reversing the direction of rotation. The sludge drawn from the bottom of the tank is discharged continuously into a sludge pit.

In figure 8 the sedimentation tank described may be seen in the background of the photograph. In the foreground is a unique mixing and flocculation basin. The stream of water containing treating chemicals enters the basin at the near, right corner and passes around the ends of the numerous baffles before being discharged at the far end to flow into the sedimentation tank.

By no means all sedimentation facilities are tanks; earthen ponds still are used extensively. One weak point remaining in the construction of many sedimentation ponds is the arrangement of baffles. A sedimentation pond may have a displacement time of 12 to 24 hours; the actual detention time may be less than 1 hour. Such a situation defeats the primary purpose of using a large pond—that of providing adequate detention time for complete flocculation and sedimentation. Further study of optimum baffle design and arrangement is warranted.

One noticeable trend in construction of earthen sedimentation ponds is the practice of lining the sides and walls of such pools with asphaltic, membranous materials (Powell, 1956). A pond so treated is pictured in figure 9. The asphaltic material is applied in sheets, and the cracks between the sides and ends of the sheets are filled with asphalt. The resultant surface is water proof, resilient, and abrasion resistant. Data on the durability and current comparative cost of this type of surface are not available.

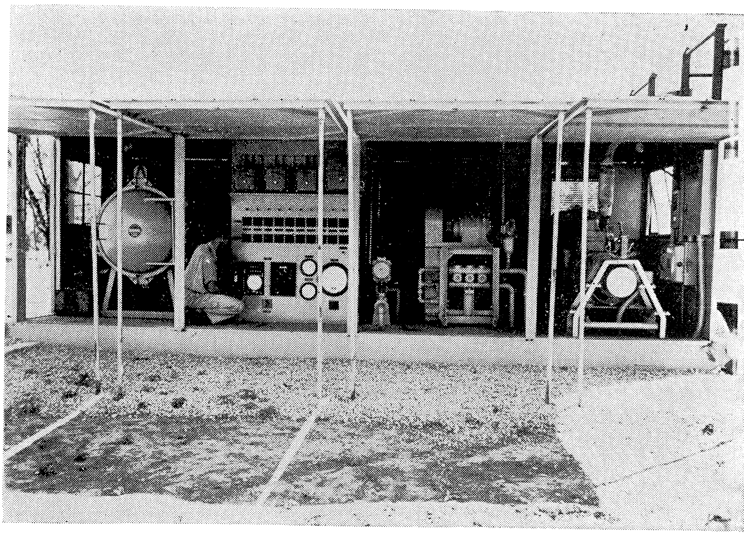


FIG. 11.—Complete portable pilot-flood treating and injection plant.

FILTRATION

Filtration still is largely accomplished by the use of pressure sand filters. Variations of this procedure are the use of open gravity filters and the use of crushed anthracite as a filter medium. Slow sand filters remain in use in a very few plants; there is a decrease rather than an increase in their use. The most noticeable trend in filtration procedures is the increased use of diatomaceous-earth filters (Alciatore et al., 1955). This increased use is not of great magnitude but is a definite and interesting trend. Several filter manufacturers now market precoat and slurry-feed element filters suitable for the use of diatomaceous earth as a medium and embodying non-metallic or corrosion-resistant metallic-alloy parts.

Figure 10 is a photograph of one type of diatomaceous-earth filter, mounted on a common base with all other treating and injection units required for a pilot-flood installation. The filter has a Monel shell and employs plastic-cloth covered Fibreglas filter leaves. The filter has 75 square feet of area and a rated capacity of 2,500 barrels daily, equivalent to 1.0 gallon per minute per square foot. A slurry of diatomaceous earth and asbestos fiber is continuously injected to form a filter cake. Backwashing and precoating of the leaves are accomplished in place. The control panel shown with this unit is electrically operated and automatically regulates the flow of influent and slurry, as well as backwashing operations.

This unit, complete with the injection pump and other facilities, is shown in figure 11 in place for operation on a pilot flood in Washington County, Okla., before injection had been started. The portable treating and injection plant shown here includes, from left to right, the filter, automatic-control panel, filter-slurry mixing and feed tanks and pump (behind control panel), horizontal triplex injection pump with variable-speed drive, and a 37.5 kv.-a., gas-powered, 220-volt generating plant. The two 130-barrel capacity steel tanks at the right rear of the photograph also have pipe skids mounted parallel to the long axes of the tanks so that they also may be loaded onto truck beds. One tank is used for raw-water storage; the other is used for storage of filtered water. A laboratory and office building, approximately the same size as, and mounted similarly to the treating plant, completes the pilot-plant equipment, all of which may be transported by four large trucks. A similar but larger diatomaceous-earth filter, in use by the same company in Nowata County, Okla., now is being used for daily filtration of 1,500 barrels of water to yield an effluent with zero turbidity by conventional optical methods of analysis.

OTHER TRENDS

Other trends of noteworthy interest in water-conditioning systems are the increased use of automatic controls in injection plants (Guldner, 1954), use of meters with isolated working parts, increased emphasis on routine testing of waters, use of analytical methods in predicting chemical and physical reactions in injection systems (Stiff and Davis, 1952), and closer control of treating equipment and procedures.

One new test to determine the quality of injection water, from the standpoint of its potential plugging tendencies, has been developed during the past few years. This test measures the reduction in flow as the water passes through a core, filter, or other permeable medium. One apparatus for making this determination with Whatman No. 50 filter paper is pictured in figure 12. Another apparatus, employing a "Millipore" membrane filter with an average pore diameter of 0.45 micron, has been adopted as a standard by the American Petroleum Institute Southern District Study Committee on Water Treatment.

It is observed that the treating of brines for subsurface injection is beginning to emerge as a technology of its own, rather than being the outgrowth of older and less suitable methods of municipal water analysis and conditioning. This technology still is in its infancy. Much additional experimental work on new and improved methods of water conditioning is warranted and no doubt will be performed during the next several years.

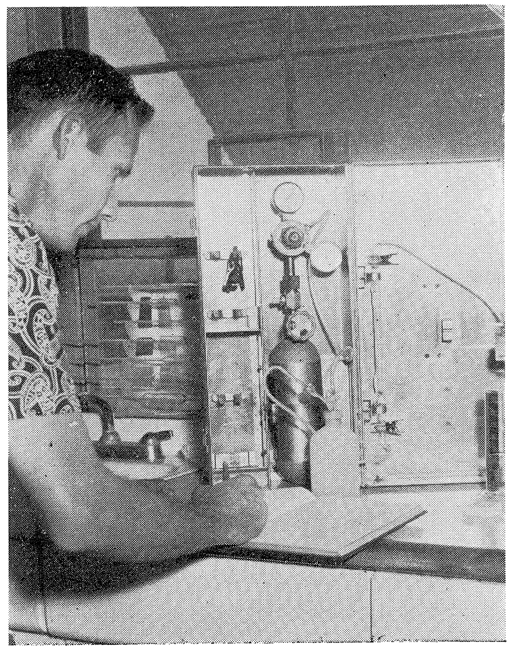


FIG. 12.—Apparatus for test of injection quality of water.

ACKNOWLEDGMENTS

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EFFECT OF REACTIONS BETWEEN INTERSTITIAL AND INJECTED WATERS ON PERMEABILITY OF RESERVOIR ROCKS

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ABSTRACT

In laboratory experiments, various waters were injected into Berea sandstone that were incompatible with the interstitial waters used to saturate the sandstone. Injection waters and interstitial waters containing the following combinations of reacting constituents were used: 1) barium and sulfate ions, 2) calcium and sulfate ions, 3) ferrous ion and hydrogen sulfide, 4) ferrous ion and oxygen, 5) ferric ion and ammonium hydroxide, 6) magnesium ion and ammonium hydroxide.

In no case was a decrease in permeability of the rock observed with solutions whose concentrations were comparable with those normally encountered in oil field practice.

A questionnaire was prepared requesting information concerning field experience with injection waters that were incompatible with interstitial waters, during waterflooding of oil reservoirs. This was sent to fifty persons who had had considerable experience with all phases of waterflooding. Three waterfloods were reported in which incompatible waters had been used without any injurious effects. Thus far, no case has been reported in which the use of incompatible waters had a deleterious effect.

It is concluded that there is little danger of plugging a reservoir rock by injecting into it a water that is incompatible with the reservoir interstitial water.

INTRODUCTION

This is a continuation and enlargement of a paper previously published on this subject (Bernard, 1955). Many of the data presented here are taken from the previous paper.

Interstitial and injection waters usually contain a number of inorganic salts in solution. The salts are mostly chlorides, sulfates and bicarbonates of sodium, calcium, magnesium, potassium, strontium, and barium. Many other ions are often present in small concentrations.

The literature contains numerous references to the danger of plugging a reservoir by the injection of water that is incompatible with the interstitial water in the reservoir (see references at end of paper). Following are some typical reactions that may occur between a flood water and interstitial water. (The symbol $\downarrow$ indicates a precipitate.)

$$CaCl_2 + Na_2SO_4 = CaSO_4 \downarrow + 2\,NaCl$$
$$BaCl_2 + Na_2SO_4 = BaSO_4 \downarrow + 2\,NaCl$$
$$SrCl_2 + Na_2SO_4 = SrSO_4 \downarrow + 2\,NaCl$$
$$12\,Fe\,(HCO_3)_2 + 3O_2 + 6H_2O = 12\,Fe\,(OH)_3 \downarrow + 24CO_2$$
$$Fe\,(HCO_3)_2 + H_2S = FeS \downarrow + 2H_2CO_3$$
$$Mn\,(HCO_3)_2 + H_2S = MnS \downarrow + 2H_2CO_3$$
$$O_2 + 2H_2S = 2H_2O + S \downarrow$$

It is common practice, before starting a secondary recovery project, to test the compatibility of the injection and interstitial waters. The test is carried out by mixing the two waters in a glass container and observing if a precipitate forms. If it is found that the two waters react to form a precipitate, it is concluded that they are incompatible and therefore that particular injection water should not be used in flooding the given reservoir. The results of our work show that this conclusion is questionable.

EXPERIMENTAL PROCEDURE

The experimental procedure was designed to reproduce as nearly as possible conditions existing during a waterflood that used incompatible waters. In each experiment a pair of incompatible waters was used. The core was first saturated with one water, then a second water that was incompatible with the first water was passed into the core. The permeability of the core to the injected water was measured during the displacement test.

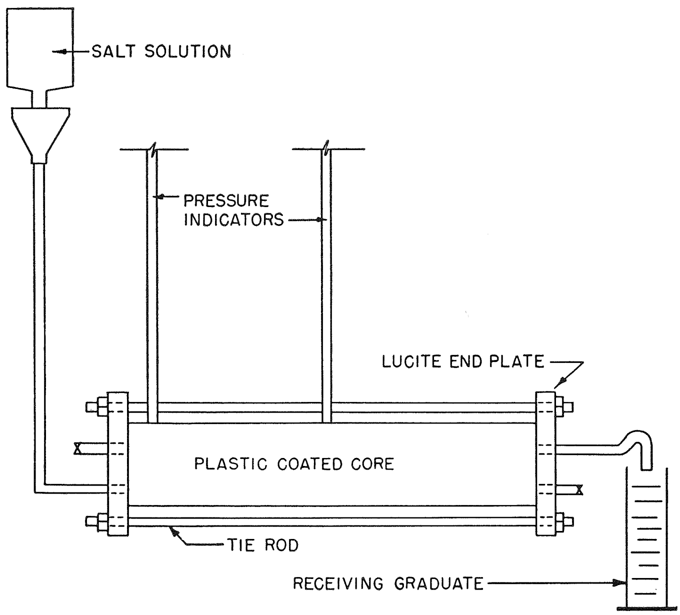


FIG. 1.—Apparatus for flooding core.

The results of these experiments are shown in figures 2 to 22.

Core Mounting

The cores used in these experiments were Berea sandstone, obtained from the Cleveland Quarries Co., and cut to the following dimensions: 3.8 x 5.1 x 28 cm and 3.8 x 5.0 x 88 cm.

Each core was covered with 3 M Scotchcast Resin No. 2, and cured overnight at room temperature. This procedure gave a penetration of the resin into the core of approximately 1/8 inch. After the resin had set, about one-half inch was cut from each end of the core. This procedure gave a core with fresh sandstone faces at each end.

Each core was equipped with 2 to 3 pressure taps. To make a pressure tap, a 1/8-inch hole was drilled about 1/4-inch into the core. A 1/4-inch I.D. by 1/2-inch long glass tube was cemented to the opening with Scotchcast resin. A plastic tube was then connected from the pressure tap to a manometer.

A gasket was cemented to each end of the core, then lucite end plates were fastened by means of four tie-rods (fig. 1). The core was then ready for the displacement tests.

Method of Injecting Solutions Into Cores

A glass funnel was suspended 100-250 cm above the core. By means of a plastic tube the funnel was connected to the core inlet. The funnel was equipped with a filter paper, so that all solutions entering a core had previously been filtered. Above the glass funnel, an inverted gallon glass jug containing the salt solution was suspended. The neck of the jug was about one inch below the rim of the funnel. In this manner, solutions were fed into the core at a constant pressure.

Flow Experiments

1. $BaCl_2$, $CaCl_2$, and Na_2SO_4 solutions

The core was evacuated and saturated with the $BaCl_2$ solution. Next, the $BaCl_2$ solution was passed through the core till the effluent contained the same concentration of barium as the injected water. This procedure was necessary to satisfy the cation exchange capacity of the core.

After the cation exchange capacity of the core was satisfied, a Na_2SO_4 solution was passed through the core. The permeability of the core was measured and plotted as the experiment progressed (figs. 2 to 8).

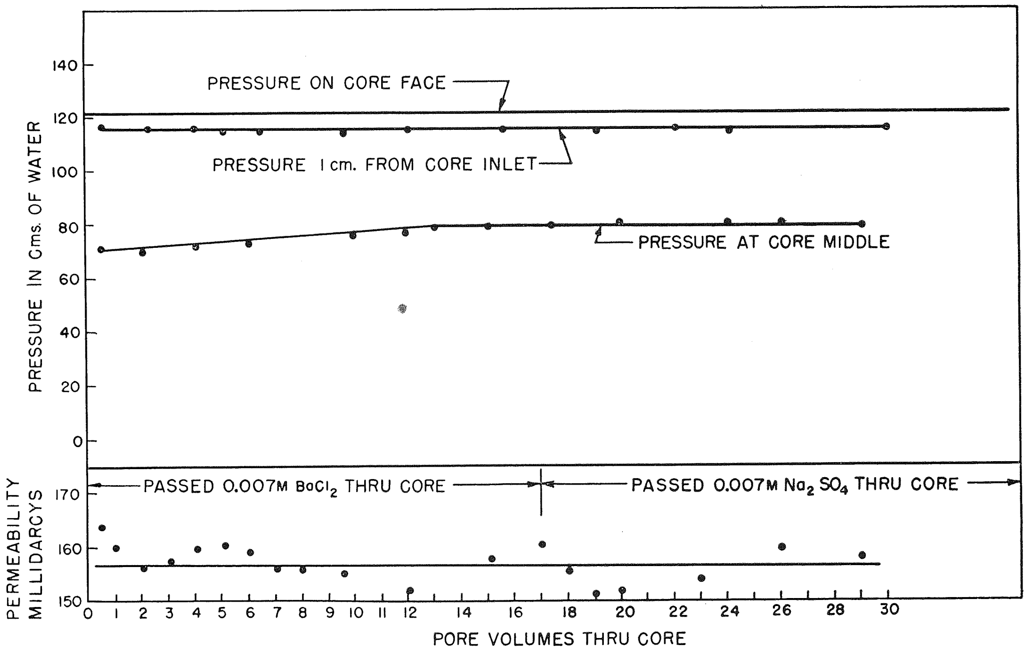


FIG. 2.—Effect of consecutive passage of $BaCl_2$ and Na_2SO_4 solutions through a Berea core 28 cm. long.

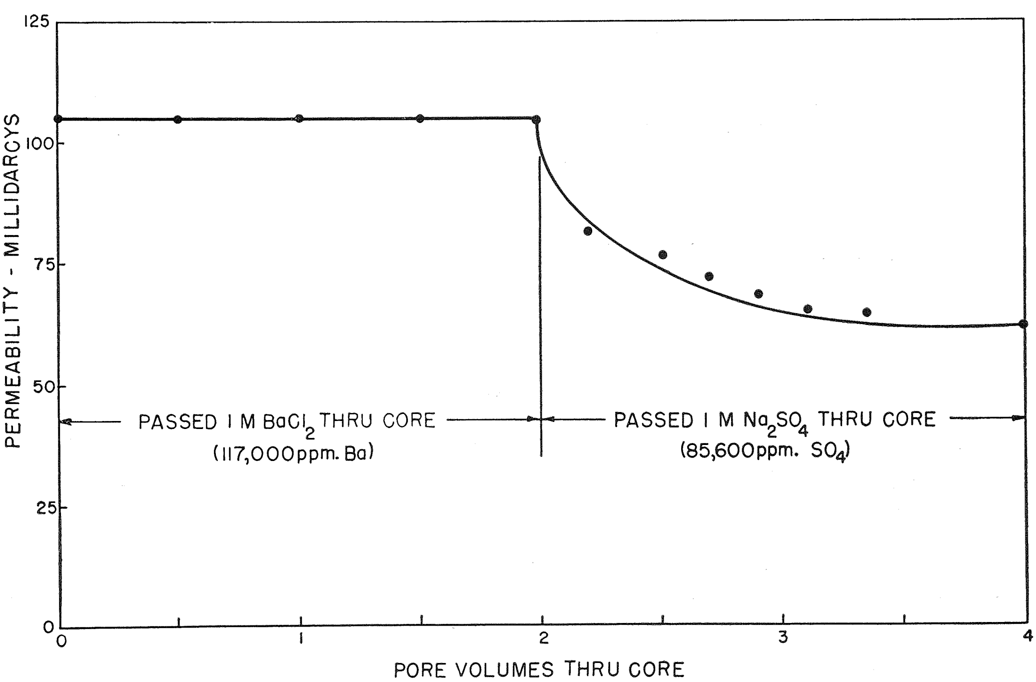
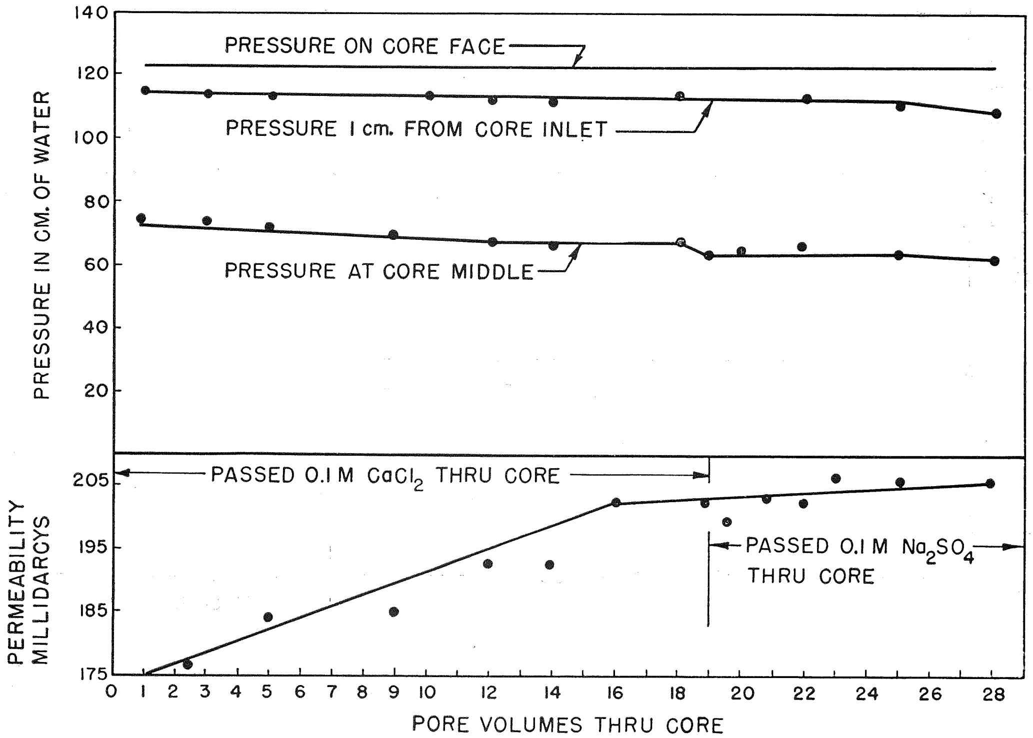


FIG. 3.—Effect of consecutive passage of $BaCl_2$ and Na_2SO_4 solutions through a Berea core 28 cm. long.



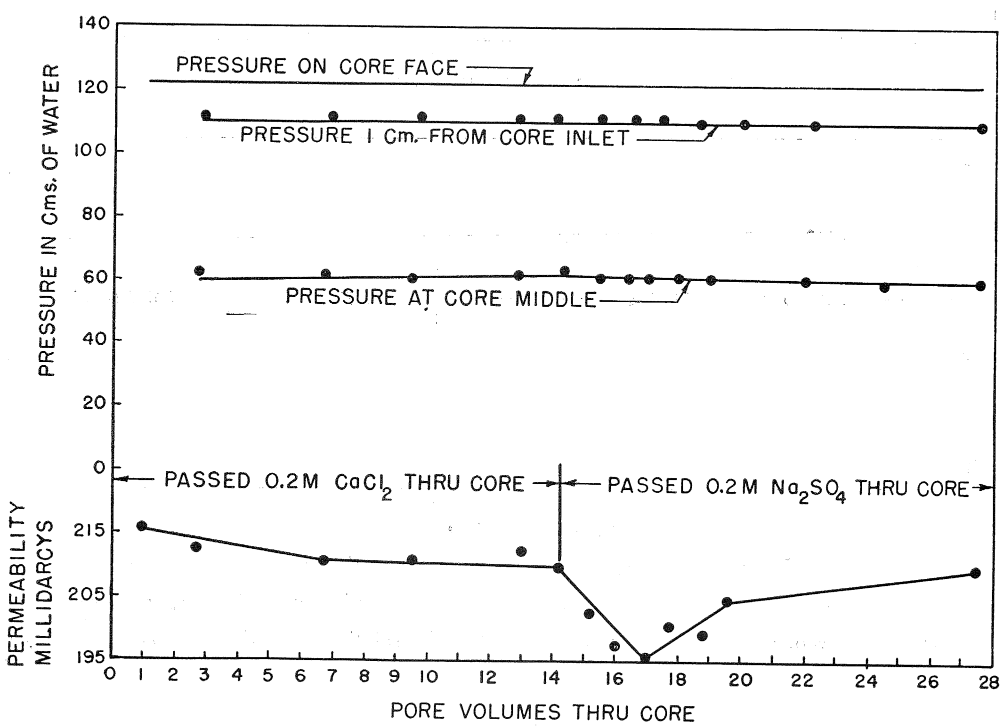
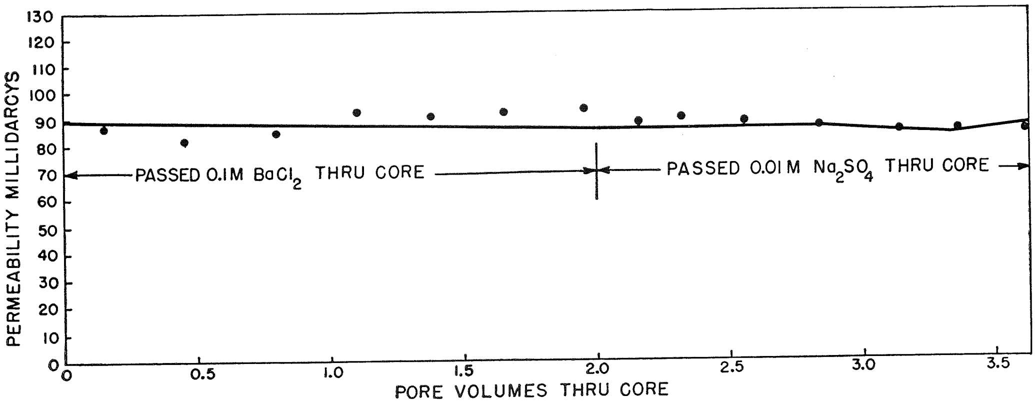
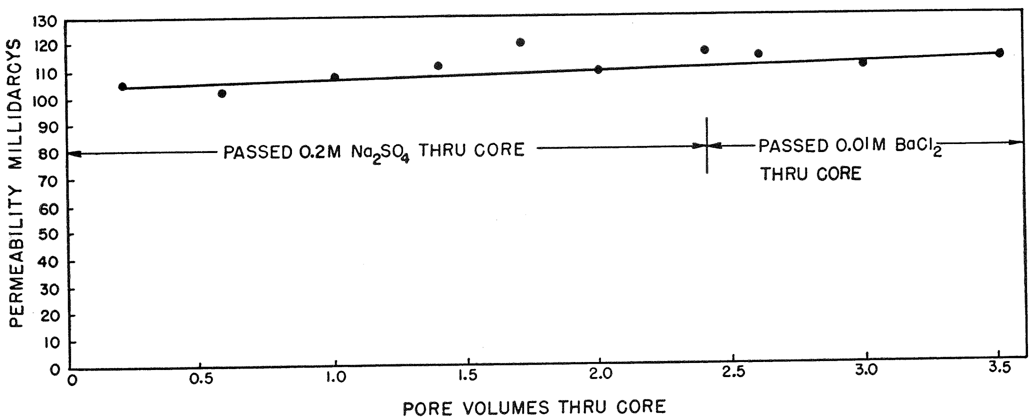


FIG. 4 (Above).—Effect of consecutive passage of $CaCl_2$ and Na_2SO_4 solutions through a Berea core 28 cm. long.

FIG. 5 (Below).—Effect of consecutive passage of $CaCl_2$ and Na_2SO_4 solutions through a Berea core 28 cm. long.





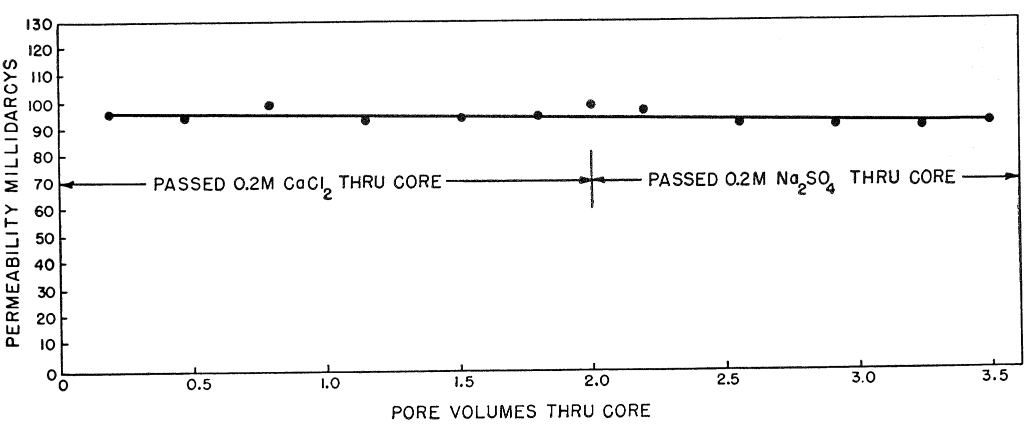


FIG. 6 (Upper).—Effect of consecutive passage of $BaCl_2$ and Na_2SO_4 solutions through a Berea core 88 cm. long.

FIG. 7 (Middle).—Effect of consecutive passage of Na_2SO_4 and $BaCl_2$ solutions through a Berea core 88 cm. long.

FIG. 8 (Lower).—Effect of consecutive passage of $CaCl_2$ and Na_2SO_4 solutions through a Berea core 88 cm. long.

The same procedure was followed with the $CaCl_2$ and Na_2SO_4 solutions. The solutions used in all of the experiments contained 1 percent NaCl by weight. The NaCl was added to minimize changes in permeability that might be caused by swelling of clay.

2. $FeSO_4$ and H_2S solutions

A neutral solution of $FeSO_4$ is readily oxidized by the oxygen of the atmosphere. The precipitated Fe_2O_3 may plug the core. In this experiment the plugging effect of FeS was being studied; therefore the oxidation of iron had to be minimized. This was done by adding Na_2SO_3 to the $FeSO_4$ solution. The solution used had the following concentrations in grams per liter: 0.66 Na_2SO_3, 10 NaCl, 0.78 $Fe(NH_4)_2\ (SO_4)_2 \cdot 6\ H_2O$ and 0.60 H_2SO_4. This solution was passed through the core till the effluent contained a substantial quantity of iron. This was determined by mixing the core effluent with the H_2S solution and obtaining a copious precipitate of FeS.

Next, the H_2S solution was passed through the core, till the core was saturated with H_2S and the effluent contained H_2S. The H_2S solution had the following composition in grams per liter: 10 NaCl, 3.3 $NaHCO_3$ and 3 H_2S. The $NaHCO_3$ was added to maintain the proper pH for precipitation of FeS.

After the last two operations the core was treated with $FeSO_4$ solution, then with H_2S solution. The results of these experiments are shown in figures 9 to 12.

3. $FeSO_4$ and O_2 solutions

A solution containing 10 g NaCl per liter and 1.57 g $Fe\ (NH_4)_2\ (SO_4)_2 \cdot 6H_2O$ per liter was covered with an inch layer of white oil to prevent oxidation of the iron. The iron solution was passed through the core until the cation exchange capacity of the core was satisfied.

Next, a 1 percent NaCl solution saturated with oxygen at 74° F. was passed through the core. The results of this experiment are shown in figure 13.

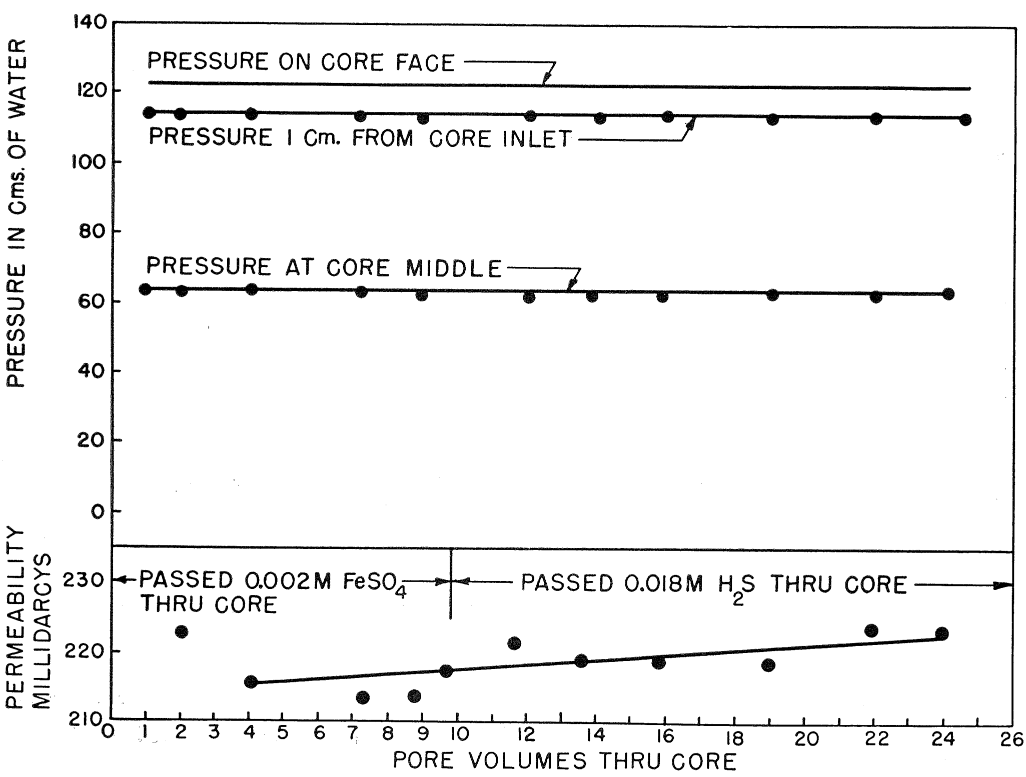
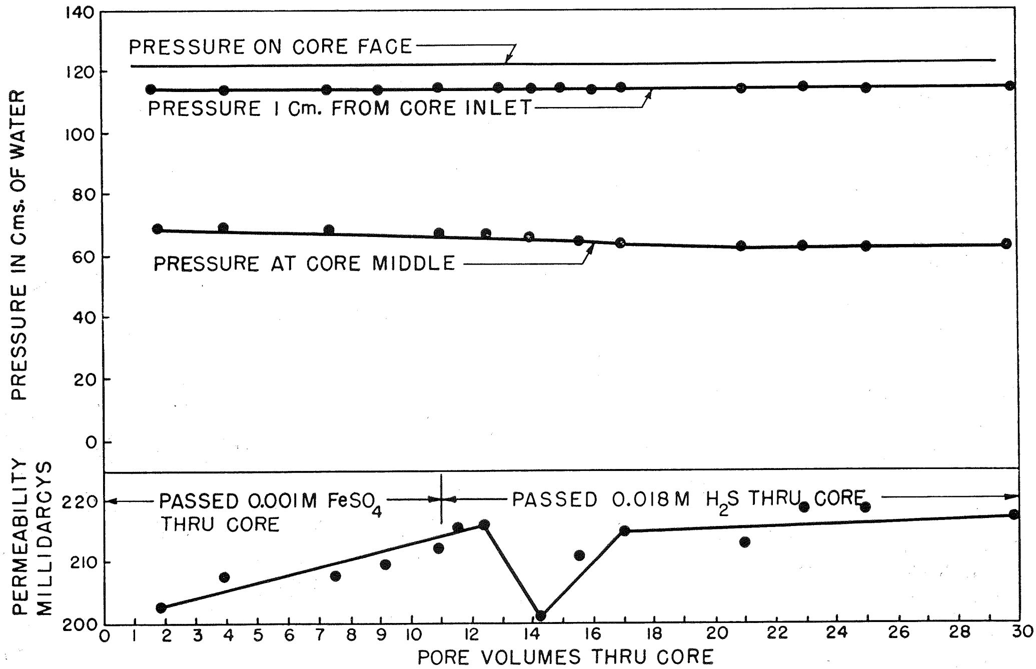


FIG. 9.—Effect of consecutive passage of $FeSO_4$ and H_2S solutions through a Berea core 28 cm. long.



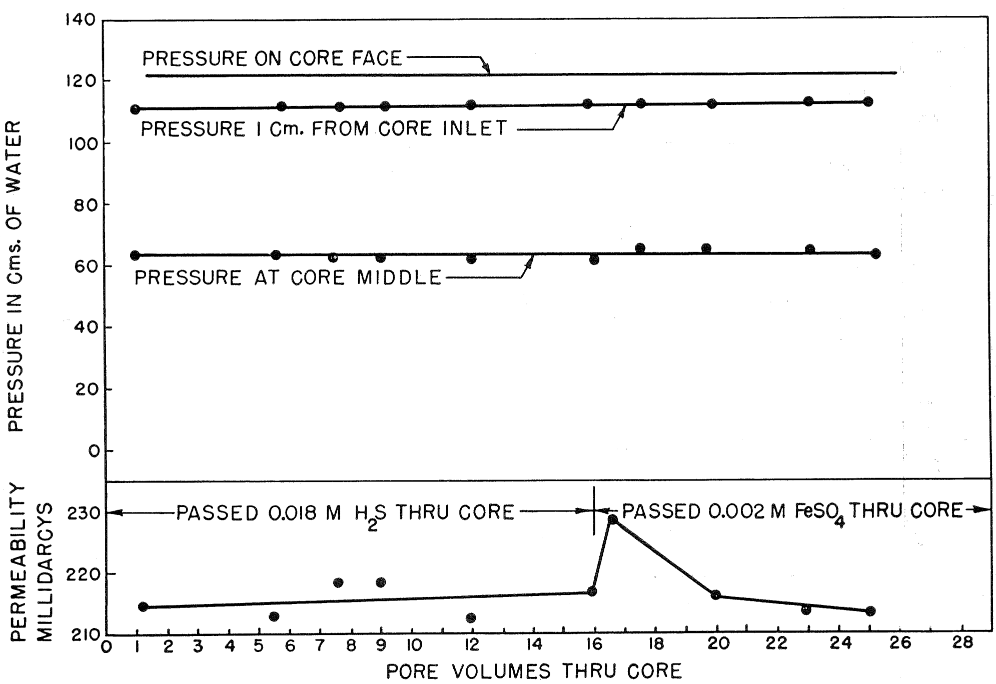
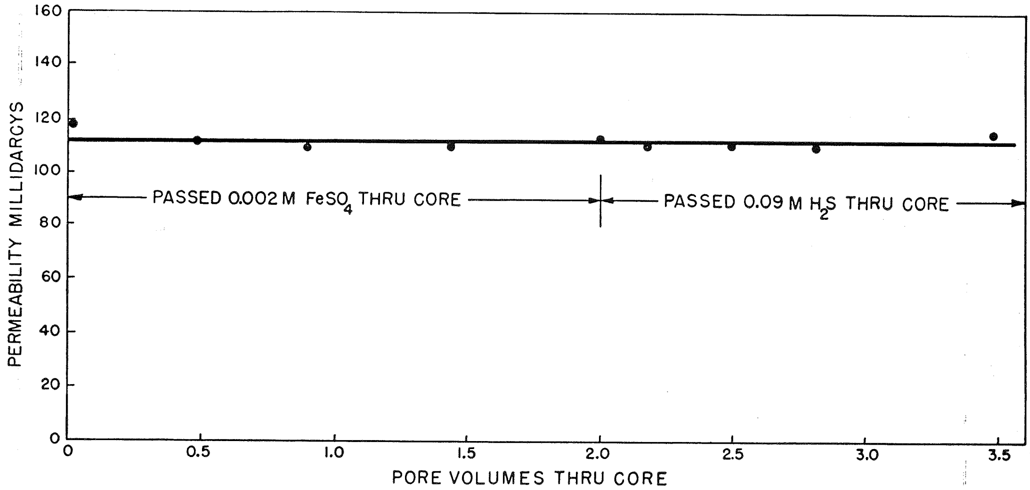


FIG. 10 (Above).—Effect of consecutive passage of $FeSO_4$ and H_2S solutions through a Berea core 28 cm. long.

FIG. 11 (Below).—Effect of consecutive passage of H_2S and $FeSO_4$ through a Berea core 28 cm. long.



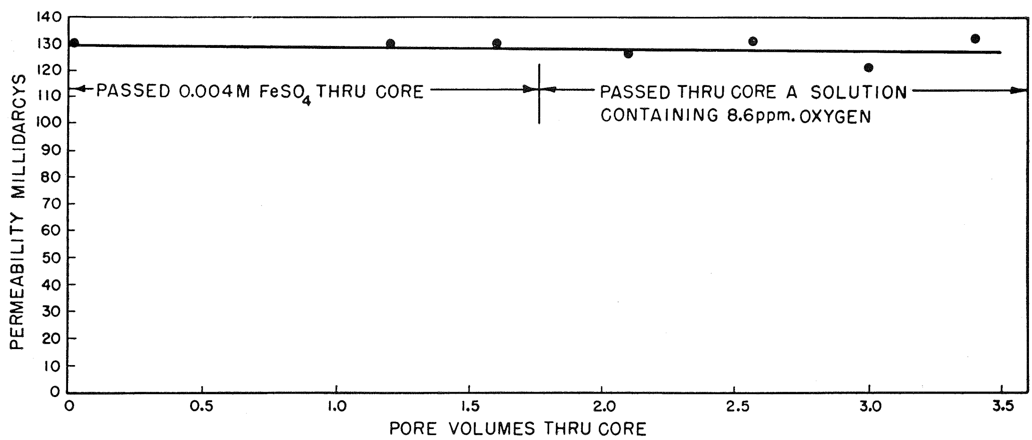


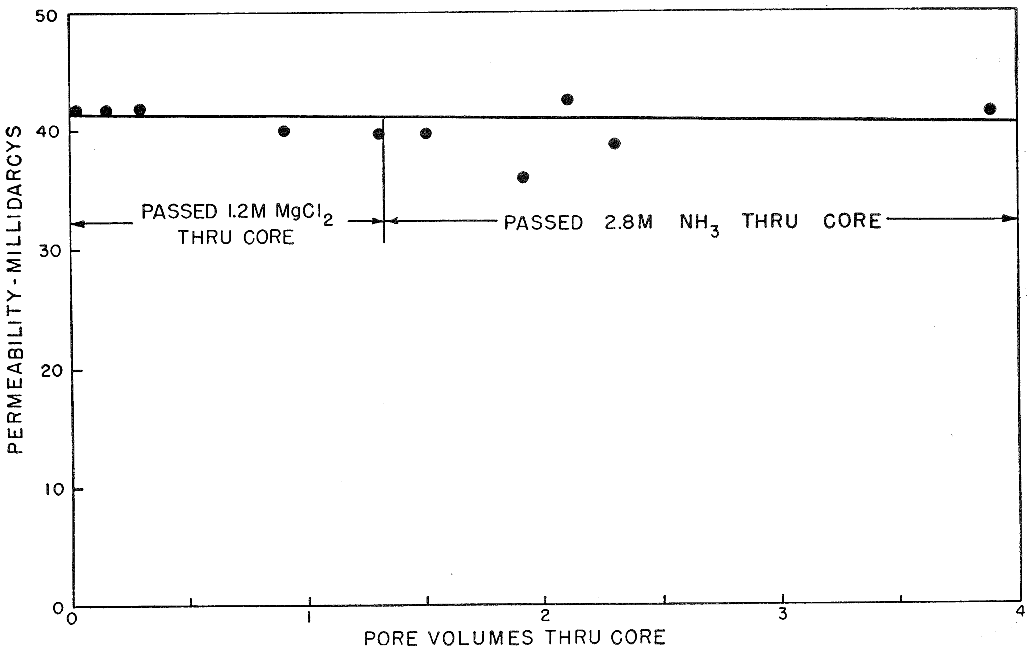
FIG. 12 (Above).—Effect of consecutive passage of $FeSO_4$ and H_2S solutions through a Berea core 88 cm. long.

FIG. 13 (Below).—Effect of consecutive passage of $FeSO_4$ and O_2 solutions through a Berea core 88 cm. long.

4. NH_3, $MgCl_2$ and $FeCl_3$ solutions

A core was saturated with 1.2 M $MgCl_2$ solution, then 2.8 M aqueous NH_3 solution was passed through the core. The effect of this procedure on core permeability is shown in figure 14.

In another similar experiment a 2.8 M aqueous NH_3 solution was displaced from the core by a 0.018 M $FeCl_3$ solution. Results of this experiment are shown in figure 15.



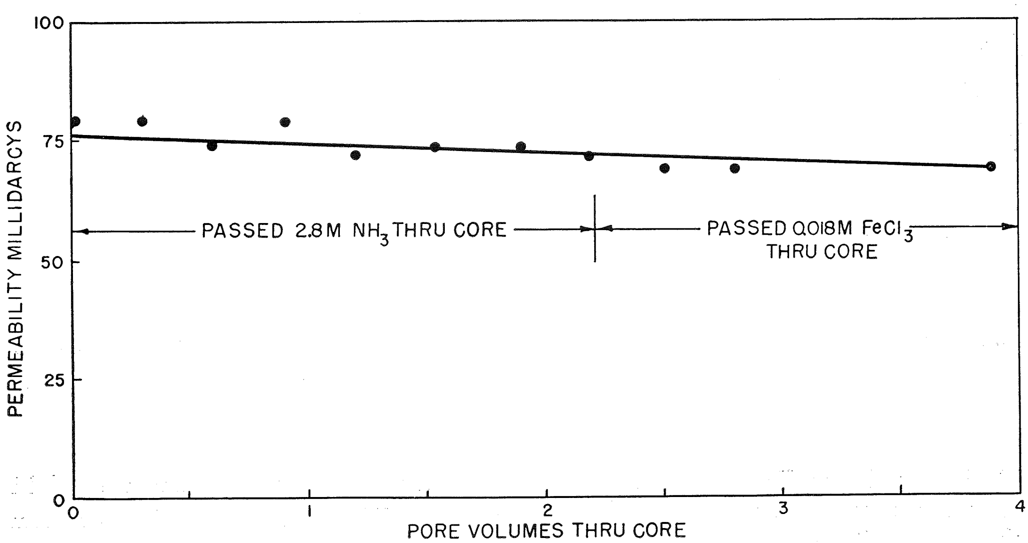
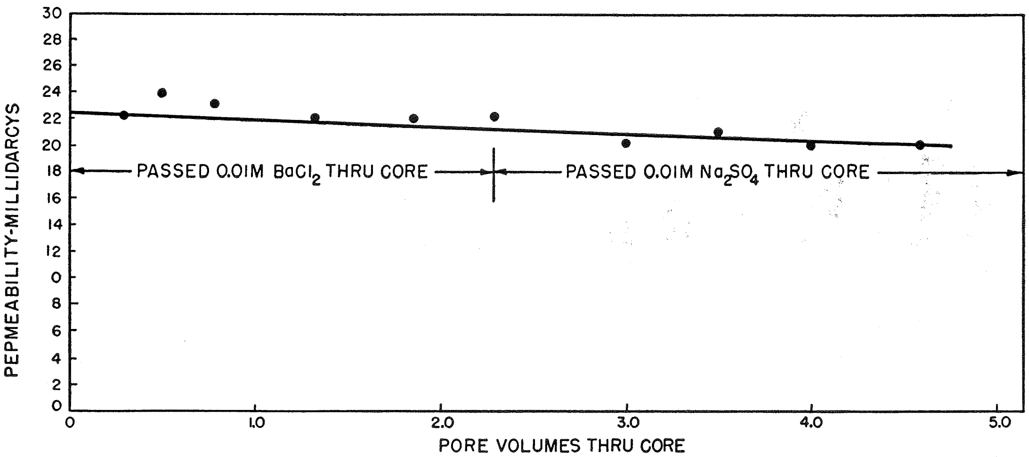
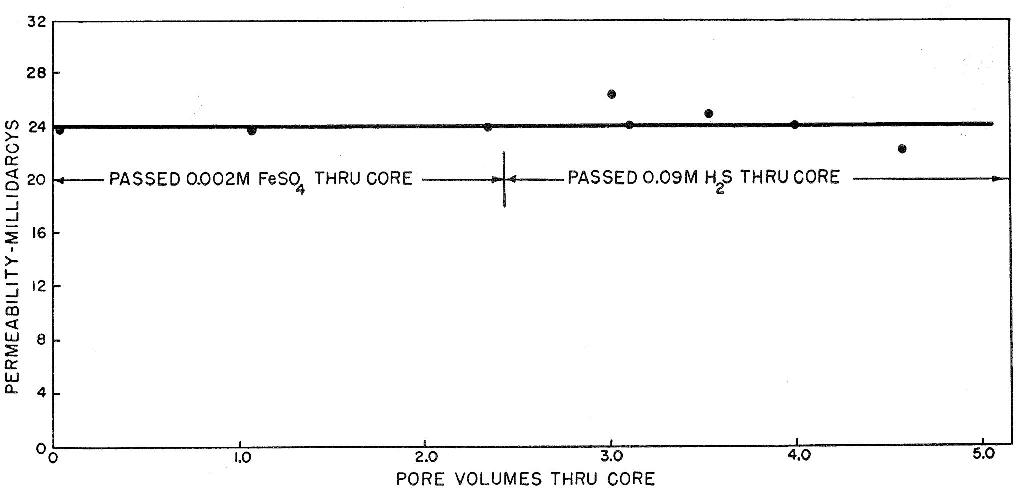


FIG. 14 (Above).—Effect of consecutive passage of $MgCl_2$ and NH_3 solutions through a Berea core 28 cm. long.

FIG. 15 (Below).—Effect of consecutive passage of NH_3 and $FeCl_3$ solutions through a Berea core 28 cm. long.





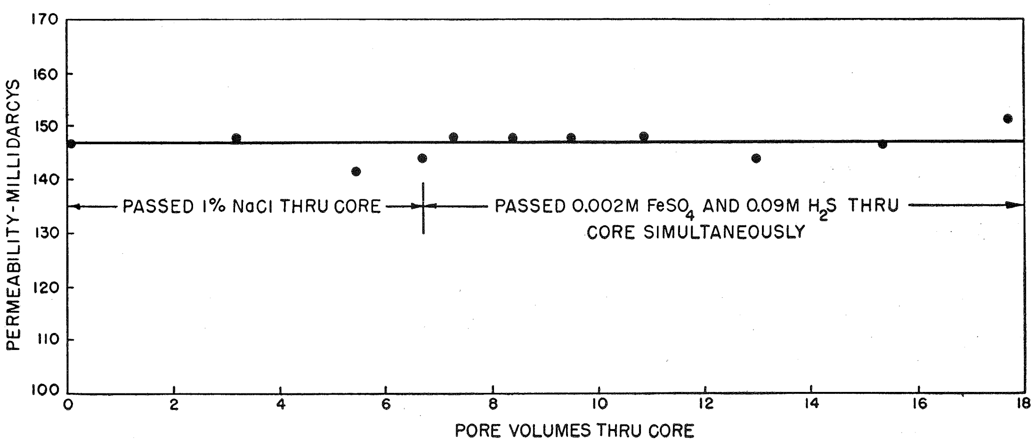


FIG. 16 (Upper).—Effect of consecutive passage of $BaCl_2$ and Na_2SO_4 solutions through a Berea core containing 32 percent residual oil.

FIG. 17 (Middle).—Effect of consecutive passage of $FeSO_4$ and H_2S solutions through a Berea core containing 32 percent residual oil.

FIG. 18 (Lower).—Effect of simultaneous passage of $FeSO_4$ and H_2S solutions through a Berea core 28 cm. long.

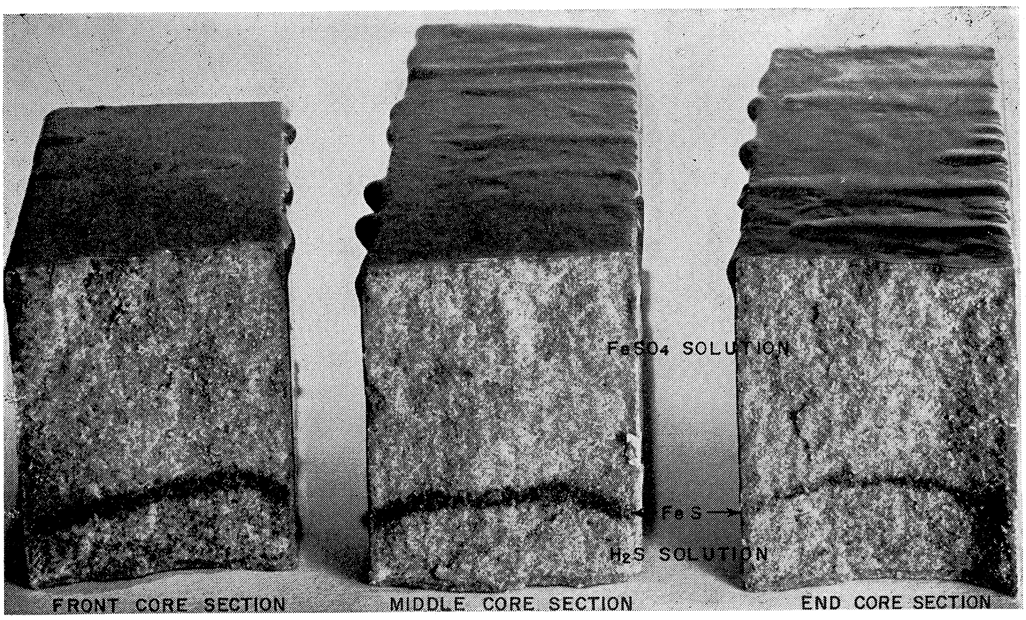


FIG. 19.—Effect of simultaneous passage of $FeSO_4$ and H_2S solutions through a Berea core 28 cm. long.

5. Incompatible waters in presence of oil

The following sequence of operations was carried out with Berea cores, 28 cm long:

a) 0.01 M $BaCl_2$ was passed through the core till the effluent contained Ba.

b) Soltrol C was passed through the core till residual water saturation was reached (44%).

c) 0.01 M Na_2SO_4 was passed through the core.

Results of this experiment are shown in figures 16 and 17.

6. Simultaneous injection of incompatible waters

Using a specially cut gasket, the inlet face of the core was divided into two sections. A 0.01 M Na_2SO_4 solution was injected into one section; at the same time a 0.01 M $BaCl_2$ solution was injected into the other section.

The same experiment was performed using H_2S and $FeSO_4$ solutions. Results of these experiments are shown in figures 18 and 19.

7. Experiments with radial cores

Radial cores from Adena Field (4 x 4 inches) were subjected to the following successive operations:

a) 1 pore volume of 0.01 M $BaCl_2$ was passed through the core.

b) 2 pore volumes of 0.01 M Na_2SO_4 were passed through the core.

c) 2 pore volumes of 0.2 M $CaCl_2$ were passed through the core.

d) 3 pore volumes of 0.2 M Na_2SO_4 were passed through the core.

The results of these experiments are shown in figure 20.

8. Efficiency of liquid displacement

A Berea sandstone core was saturated with a solution of NaCl (53,000 mg per liter Cl), then the NaCl solution was displaced by a solution of $NaHCO_3$ (51,000 mg per liter HCO_3). The efficiency of this displacement process was determined by analyzing core effluent for Cl and HCO_3. The results of this experiment are shown in figures 21 and 22.

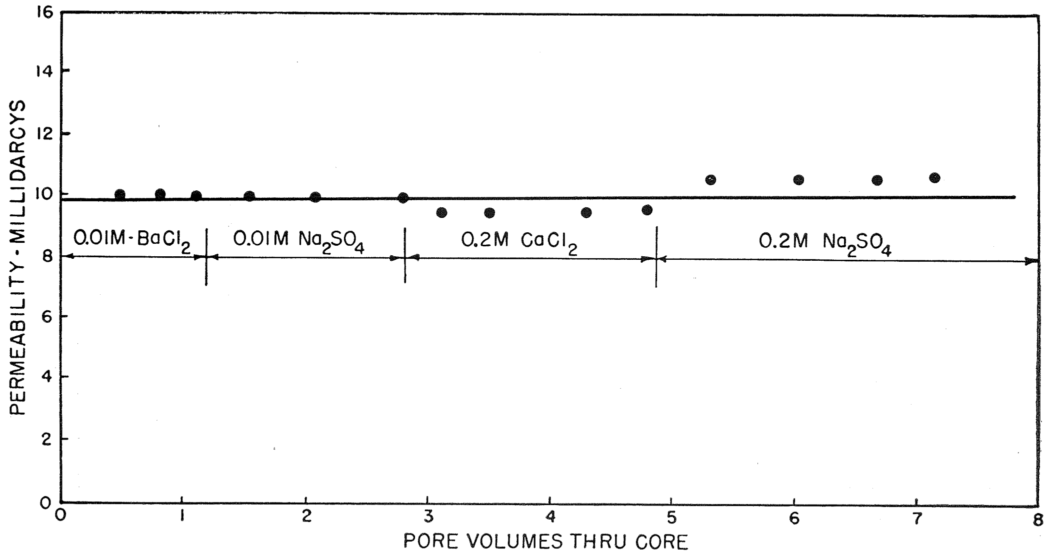


FIG. 20.—Effect of consecutive passage of $BaCl_2$, Na_2SO_4, CaCl, and Na_2SO_4 solutions through a radial core (4″ x 4″).

DISCUSSION OF RESULTS

A series of laboratory experiments was performed in which various waters were injected into Berea sandstone that were incompatible with the interstitial waters used to saturate the sandstone. Injection waters and interstitial waters containing many combinations of reacting constituents were used. The effects of the following factors on permeability were studied: 1) Efficiency of fluid displacement, 2) salt concentration, 3) types of precipitate, 4) linear and radial flow, 5) length of flow path, 6) variations in permeability, 7) presence of oil. Data covering these investigations are presented in figures 1 to 22.

A survey was conducted to obtain information on the use of incompatible floodwaters in the field. The results of this survey are contained in tables 1 and 2.

Following is a discussion of the various factors that were studied.

EFFICIENCY OF FLUID DISPLACEMENT

The compatibility of injection and interstitial waters is usually determined by mixing the two waters in a glass container and observing if a precipitate forms. In carrying out this incompatibility test it is reasoned that if two waters form a precipitate on mixing in a container, they will also form a precipitate in the reservoir.

The data (figs. 21, 22) show that the mechanics of displacement and the porous nature of the reservoir act to almost completely prevent fluids from mixing and reacting within the reservoir. Thus the data clearly indicate that, in the reservoir, the main body of interstitial water does not mix with the main body of floodwater.

From certain considerations a maximum value can be calculated for the amount of precipitate to be expected in the zone where injection and interstitial waters may mix. A 50/50 mixture of interstitial water and floodwater may occur at the boundary of the two liquids. The volume of this 50/50 mixture is less than 10 percent of the core pore volume, or 10 cc (fig. 21). If 5 cc of floodwater containing 1370 ppm of barium is mixed with 5 cc of interstitial water containing 960 ppm of sulfate, then about 0.0116 g (0.0026 cc) of barium sulfate will be precipitated, equal to 0.026 percent of the pore space. Thus, in the zone of the reservoir where these incompatible waters mix, the

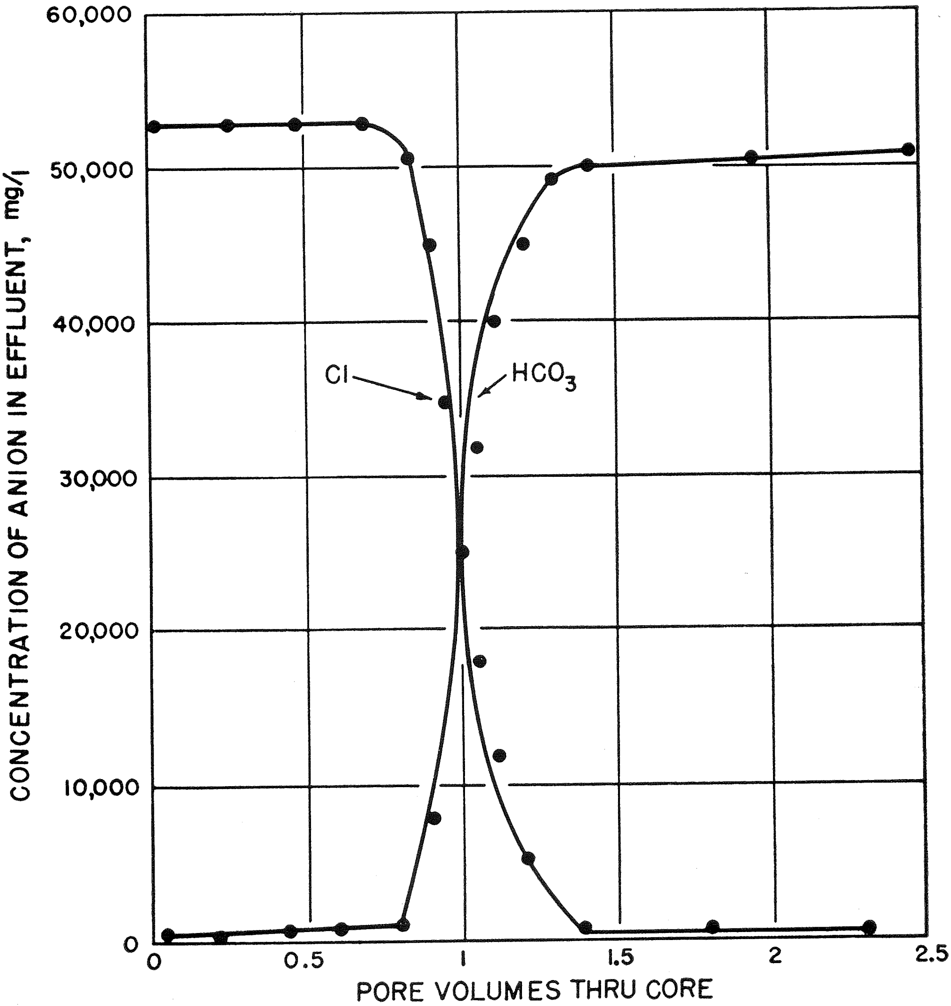


FIG. 21.—Displacement of NaCl solution from Berea core by $NaHCO_3$ solution.

precipitate will occupy only about 0.026 percent of the pore space, or less.

The data in figures 21 and 22 indicate that although normally it should not be possible to decrease permeability by use of incompatible waters, yet under abnormal conditions (extremely high salt concentrations) it should be possible to partially plug a core by injection of incompatible waters.

The results also indicate that one cannot measure the plugging action of two incompatible waters by carrying out the test in a container. Instead the test should be carried out in a rock. The following experiments were designed to test the compatibility of waters under various circumstances, when one water displaced another from a rock.

Effect of Salt Concentration

The results of displacement experiments have indicated that although the main body of injection water does not mix with the main body of interstitial water, nevertheless at their boundary the two liquids may mix. Thus it seems reasonable to suppose that at very high concentrations the permeability of a core can be decreased by reaction products of incompatible waters. Two experiments

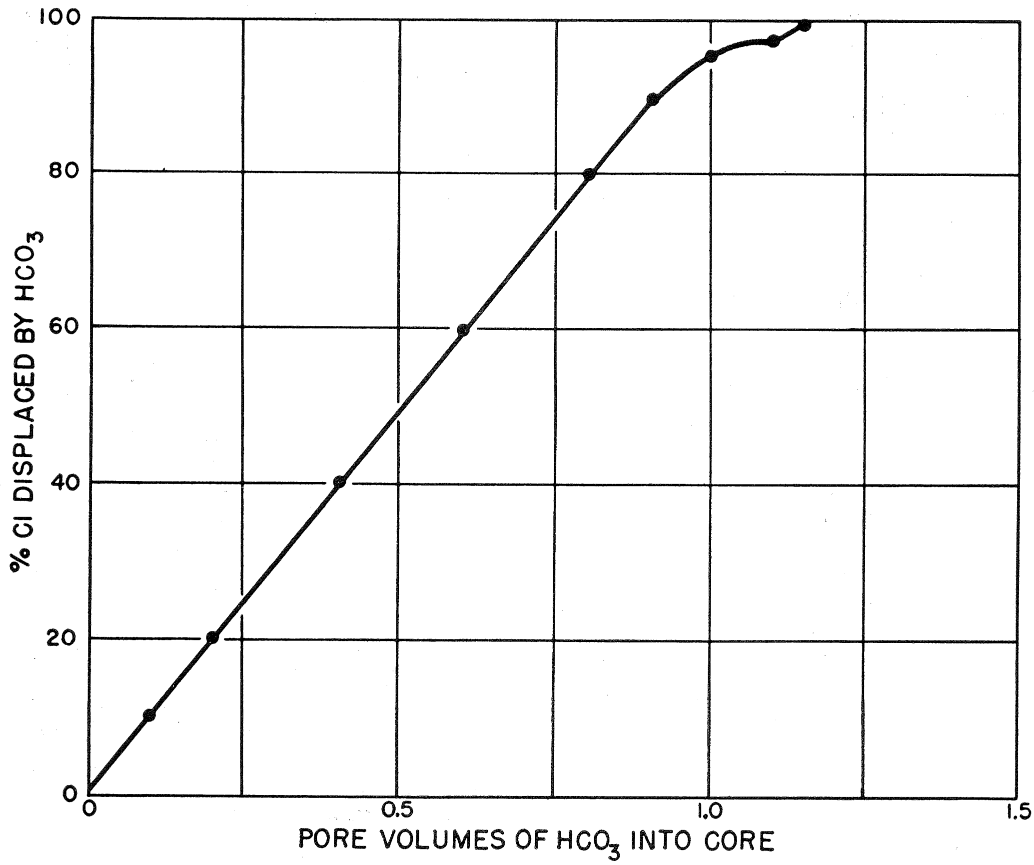


FIG. 22.—Efficiency of displacement of chloride solution by bicarbonate solution in Berea core.

were performed to determine what concentrations of incompatible ions will react to lower the permeability of a core.

In one experiment, the core was saturated with a 0.007 M $BaCl_2$ solution (962 ppm Ba) and then the Ba solution was displaced by a 0.007 M Na_2SO_4 solution (672 ppm SO_4). The results of this experiment are plotted in figure 2; apparently not enough $BaSO_4$ was precipitated in the core to affect the permeability.

In the second experiment, much more concentrated solutions were used. Here the core was first saturated with a 1 M $BaCl_2$ solution (117,000 ppm Ba), then the $BaCl_2$ solution was displaced by 1 M Na_2SO_4 solution (85,000 ppm SO_4). Figure 3 illustrates that when such extreme salt concentrations are used, a decrease in permeability occurs; however, the core is not completely plugged. The following two conclusions can be drawn from these experiments: 1) Solutions whose salt concentrations are comparable to those normally encountered in the field do not decrease the permeability of the reservoir rock; 2) even if a precipitate should form within the rock, it is likely that the floodwater would not be saturated with the precipitate, and therefore eventually the deposit would be dissolved and the original permeability of the reservoir would be restored.

TYPES OF PRECIPITATE

For the purposes of this discussion, we can divide precipitates into two general types, crystalline and gelatinous. $CaCO_3$, $CaSO_4$, and $BaSO_4$ are typical crystalline precipitates, whereas Fe_2O_3, FeS, Al_2O_3, and Mg $(OH)_2$ represent the gelatinous type. The gelatinous precipitates are noted for their effectiveness as plugging agents. A series of experiments were performed with combinations of incompatible waters that form both crystalline and gelatinous precipitates. The results, shown in figures 2 to 20, show that the amount of any of these precipitates normally formed in a core is too small to affect the permeability.

Linear and Radial Flow, Core Length, Permeability

Most of the experiments were performed on linear cores. It was suggested that different results might be obtained in a radial system. In figure 20, it is shown that in a radial system also, incompatible waters do not decrease permeability when passed consecutively through the core.

The relation of core length to effect of incompatible waters on permeability was studied by using cores 28 cm and 88 cm long. Figures 2 to 11 show that core length does not affect the results of these experiments; that is, incompatible waters do not decrease the permeability of long or short cores when one water displaces the other from the core.

The relation between permeability and plugging action of incompatible waters was studied. Cores with permeabilities of 10 to 200 millidarcys were used. None of the cores were plugged by consecutive passage of incompatible waters. This is shown in figures 2 to 20.

Effect of Oil

It was also suggested that oil in place might alter the behavior of incompatible waters and cause plugging. A number of experiments was performed to test this point. In figures 16 and 17 it is shown that in the presence of residual oil, consecutive passage of incompatible waters does not decrease core permeability.

Simultaneous Injection of Incompatible Waters

In figure 18 are shown the results of an experiment in which two incompatible solutions were simultaneously injected into one core. The two solutions, $FeSO_4$ and H_2S, followed separate paths through the core, and contacted each other only in the middle of the core. Figure 19 is a photograph of a cross section of the core. The black lines show where the two solutions met and reacted to form black FeS. In this experiment also, since the two solutions did not mix much, the permeability of the core did not decrease.

Use of Incompatible Waters in the Field

A survey was conducted to determine if incompatible waters are being used in the field, and if so, how successfully. A questionnaire was prepared requesting information concerning field experience with injection waters that were incompatible with interstitial waters, during waterflooding of oil reservoirs. This was sent to fifty persons who had had considerable experience with all phases of waterflooding. (See sample questionnaire.)

From the fifty questionnaires sent out, 19 replies were received. Three projects were reported which were using floodwaters that were incompatible with the interstitial waters; ten respondents indicated that although they were not then using incompatible waters, they believed that incompatible waters could be used in a flood. Especially significant was the fact that no one stated that incompatible waters could not be used.

Table 1.—Results of Questionnaire on Use of Incompatible Floodwaters

Questionnaires sent out	50
Replies	19
Projects using incompatible waters	3
People of opinion that incompatible waters can be used	10
People of opinion that incompatible waters cannot be used	0

Usually, when the subject of incompatible waters comes up, the formation of barium sulfate and iron sulfide in the reservoir is discussed. In flood number one, in table 2, the floodwater contained 18 ppm of H_2S whereas the interstitial water contained 85 ppm of iron. The chances seem excellent for plugging the formation with iron sulfide, yet the data indicate that normal injection rates were obtained.

Similarly, in floods 2, 3, and 5 (table 2), there was a possibility of plugging the for-

Data on Floods
In Which Injection Water Was
Incompatible with Insterstitial Water

1. Name of operator (optional)________
2. Name of flood (optional)________
3. Location of flood________
4. Producing formation________
5. Approximate average permeability________ Millidarcys________
6. Total number of injection wells________
7. Average total daily injection rate________bbls./day/well/foot
8. Injection pressure at plant________
9. Duration of water injection________

10. *Analysis of Floodwater*
Constituent ppm.

Na..........
Ca..........
Mg.........
Ba..........
Sr..........
Fe..........
Cl..........
SO_4.........
HCO_3.......
CO_3.......
H_2S........
pH.......
Sp. gr., 60°F.....
Dissolved Solids

11. *Analysis of Interstitial Water*
Constituent ppm.

Na.........
Ca.........
Mg.........
Ba.........
Sr..........
Fe..........
Cl..........
SO_4........
HCO_3......
CO_3......
H_2S.......
pH.......
Sp. gr., 60°F.....
Dissolved Solids

12. What compound precipitates when the floodwater and interstitial water are mixed?________
13. Were any injection wells more or less completely plugged?________
14. Were injection rates of any wells reduced substantially below normal?________
How many?________
15. If any wells were plugged, or if injection rates were decreased (a) is this attributed to precipitation within the reservoir rock?________
(b) Could it have been caused by other factors, such as:
Bacteria________ Turbid water________
Clay-swelling________ Unstable water________
Others________
16. Were injection rates normal, that is, approximately equal to the rates to be expected with *compatible* waters?________
17. In your opinion, can incompatible waters be used in practice?________

TABLE 2.—WATERFLOODS USING INCOMPATIBLE WATERS
(Data supplied in answer to questionnaire)

	Flood 1	Flood 2	Flood 3	Flood 4	Flood 5
Incompatible constituent in floodwater	H_2S, 18 ppm.	SO_4, 65 ppm.	SO_4, 95 ppm.	H_2S, 80 ppm.	SO_4, 540 ppm.
Incompatible constituent in interstitial water	Fe, 85 ppm.	Ba, 1059 ppm.	Ba, 181 ppm.	Fe, 57 ppm.	Ba, 210 ppm.
Potential precipitate	FeS	$BaSO_4$	$BaSO_4$	FeS	$BaSO_4$
Formation permeability, millidarcys	120	47	250	70	45
Location of flood	Glenn Pool, Okla.	Young County, Texas	Crawford County, Illinois	Anderson County, Kansas	Osage County, Oklahoma
Producing formation	Glenn sand	Strawn sand	Robinson sand	Bartlesville sand	Bartlesville sand
Total number of injection wells	6	8	15	50	9
Average injection rate, bbls./day/well/ft.	4.5	11	12	4.5	8.0
Injection pressure at plant, psi	500	1000	550	500	700
Duration of water injection, months	9	37	36	72	30
Were normal water injection rates observed	Yes	Yes	Yes	Yes	Yes

mation with $BaSO_4$. Here also, no noticeable plugging occurred, and normal water injection rates were obtained.

The data presented here must be carefully interpreted. Laboratory experiments indicate that different waters do not mix much in the reservoir; therefore it is feasible to use a floodwater that is incompatible with the intersitial water. Of course, if incompatible waters are mixed at the wellhead or within the well, one should expect plugging to occur on the face of the sand in the injection well. In this case, the incompatible waters will mix thoroughly in moving down the tubing, and the insoluble material will be filtered out on the sand face, thereby reducing the water intake rate.

CONCLUSIONS

Laboratory and field data indicate that under normal conditions a reservoir rock is not plugged by injecting into it a floodwater that is incompatible with the interstitial water.

The author wishes to thank those who answered the questionnaire on the use of incompatible waters in waterflooding operations.

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SOME FIELD RESULTS ON SELECTIVE PLUGGING OF INPUT WELLS

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ABSTRACT

Techniques of selective plugging are very briefly discussed, as are methods for testing the wells to determine the effectiveness of the plugging. Decline curve data are presented for three properties on which extensive selective plugging operations were carried out and for which detailed records have been kept for nine years following the selective plugging.

These records indicate greatly increased oil recovery and considerably reduced operating costs as a result of the well treatments, although only a portion of the injection wells on each property was treated. The three properties contained a total of 364 producers and 371 inputs, of which 205 were treated at an average well cost of $82.13. The total additional oil recovery to September 1955 is estimated at 440,900 barrels.

Two charts are presented, based on field data, by which water costs per 5-spot and water costs per acre may be quickly approximated for a projected waterflood.

Waterflood operators are continuously faced with the problem of maintaining maximum efficiency in their operations. By maintaining maximum efficiency, not only are the operators themselves benefited, but additional oil is recovered, thus extending the nation's petroleum reserves.

One of the problems facing all operators is that of produced water-oil ratio, which, beginning with water break-through, continues to increase throughout the remaining life of the flood. This water production affects the efficiency of operations in several ways; it necessitates large sources of water, it increases water treating and pressure plant costs, it increases lifting costs and also creates serious disposal or rehandling problems. Therefore, anything that can be done to reduce water-oil ratios, provided it is reasonably inexpensive and simple to apply, should be of considerable benefit to waterflood operators.

As a result of many laboratory experiments and general consideration of fundamental relationships, it is generally accepted that behind the water front in a flooding operation the flowing liquid is primarily water, producing relatively little oil from the flooded-out sand. This is true in a stratum of uniform permeability. In a single stratum of sand, in a pattern flood such as a five-spot, the water front from each injection well reaches the producing well in a single point. As the flood continues that point or line of initial contact gradually expands around the circumference of the producing well until areas of contact from the four injection wells meet and the well is producing essentially water from that one stratum. It is probably rare that an oil sand of any thickness is of uniform permeability throughout its vertical section. In practically all cases the sand consists of a number of layers of different permeabilities. These permeabilities may vary widely from layer to layer. In many cases there is no vertical permeability between layers. In such cases, each sand layer inherently behaves under waterflood as if it were an entirely separate reservoir.

If there are several layers of sand of different permeabilities in a given pay, the stage of development of the flood pattern in each zone at any time will be a function of the permeability in that zone. When water break-through has occurred in the most permeable zone, the flood front in less permeable zones will be at various intermediate positions between the injection and producing wells. If there is a wide range in the various layer or zone permeabilities, the flood front in the tightest zone may have progressed only a short distance from the injection well when water break-through has occurred in the most permeable zone. This means that in order to recover the oil from the tightest zone, large volumes of water will have to be pumped through the most permeable zone, doing very little useful work, in order to flood out the tightest sand.

In fact it is not at all improbable that in many cases, because of the large water through-put required, the economic limit of the flood will be reached long before the flood in the tightest sand layer has reached the producing well.

Any feasible method, therefore, of reducing the water intake into the sand of high permeability while not restricting injection into the tight sands, should be of great value to the operator. For several years some operators have been very successfully using selective plugging techniques which perform exactly this operation.

For nine years the South Penn Oil Company, Bradford, Pennsylvania, has been selectively plugging hundreds of input wells and keeping careful records of the performance of the floods involved. These results are most encouraging and are presented here in order to show other operators the very substantial benefits that may be derived from a systematic and carefully conducted selective plugging program.

The mechanical techniques of selective plugging have been described in some detail in the literature (Danielson and Martin, 1950; Dickey and Andresen, 1945; Martin et al., 1947; Yuster and Calhoun, 1944), and are only briefly summarized here.

Advantage is taken of the fact that if water is being injected into zones of differing permeabilities and the injection well is closed in, the tighter zones will back-flow into the zones of higher permeability. By proper timing and placing of the plugging material, it will be deposited on and in the more permeable zones and will not damage the tight layers. Sometimes several treatments on a single well are advantageous.

The success of selective plugging operations will be indicated by the reduction of the water-oil ratio in the producing wells or by reduction in water injection rates.

There are three relatively simple procedures which may be used to measure the effect of the plugging agent on the injection well. All of them involve the comparison of measurements made before the plugging job with similar measurements made after plugging. The methods are all described in the literature (Danielson and Martin, 1950; Dickey and Andresen, 1945; Joers and Smith, 1954), but are discussed here briefly.

The first method is that of determining the pressure fall-off curve for the injection well. The well is closed in and the well-head pressure versus time is recorded. When the log of the pressure is plotted as ordinate against the time as abscissa, a curve is obtained that is nearly a straight line. This curve is in one sense (other things being equal) a measure of the ratio of the tight to the loose sand. If this ratio is low the curve will fall fairly rapidly. If the ratio is increased (by plugging the loose sand) the curve will fall more slowly. Hence, a change in the general slope of this curve indicates the effectiveness of the plugging operation. This is indicated in figure 1, which shows successive pressure fall-off curves on a well following successive treatments.

A second method of determining whether plugging action has occurred is that of taking the localized injectivity index. This procedure is described in detail elsewhere (Dickey and Andresen, 1945). A decrease in slope of the injectivity index curve after treatment indicates that plugging has occurred at the sand face.

A third method is the determination of the skin effect at the injection well. This procedure presented by Joers and Smith (1954) is somewhat more complex to apply, but measures qualitatively any change in overall permeability at the well sand face.

Of the three procedures, the pressure fall-off method is the one which is sensitive to the selectivity of the plugging action. The other two simply indicate that a plugging has occurred.

Before any selective plugging operations are begun it is very important to be sure that the high water-oil ratios are not the result of pressure parting or of mechanical failure

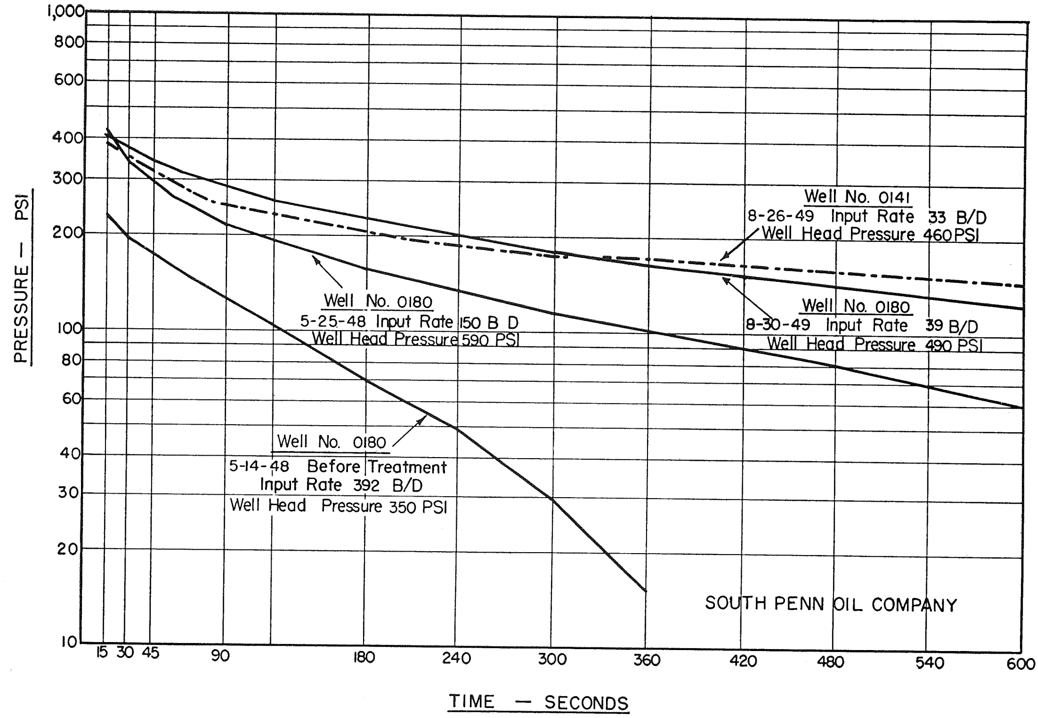

FIG. 1.—Kane leases, No. 3 five-spot, wells No. 01418–0180.

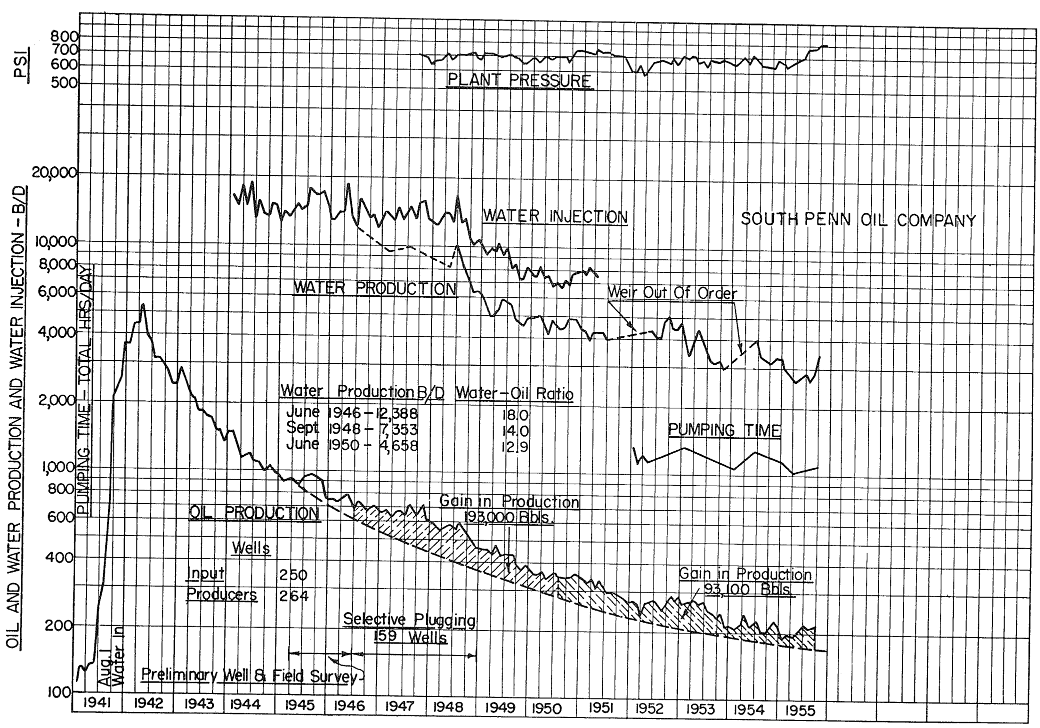

FIG. 2.—Record of water injection, water production, and oil production for Bingham leases 533.

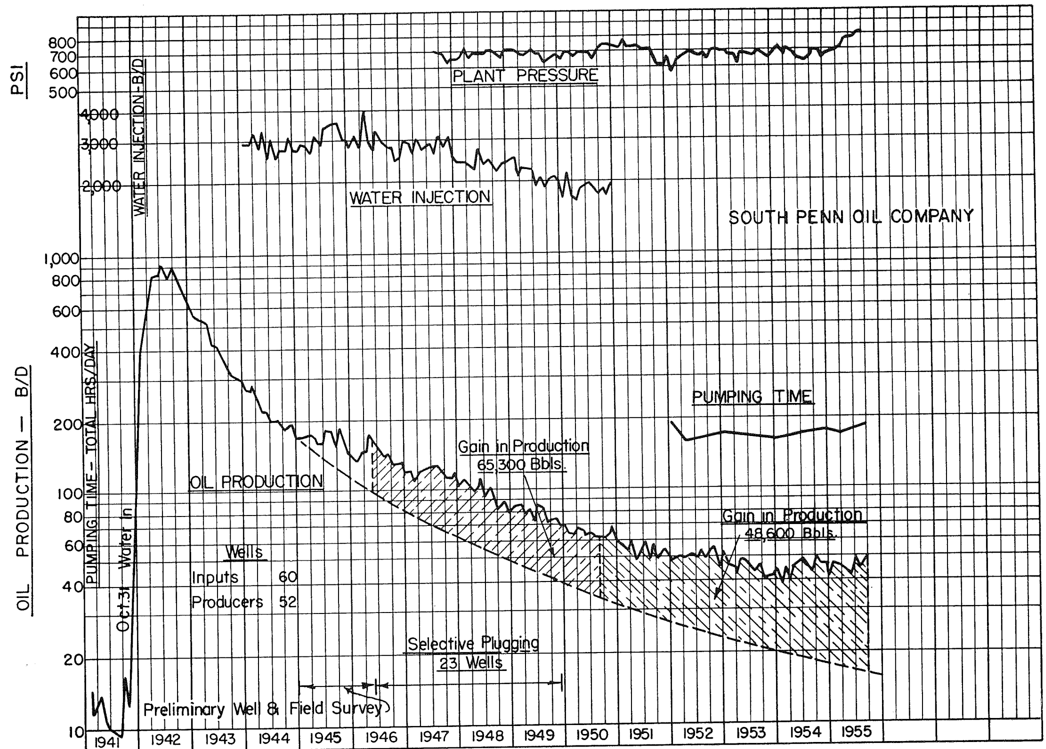

Fig. 3.—Record of water injection and oil production for Bingham leases 532–554.

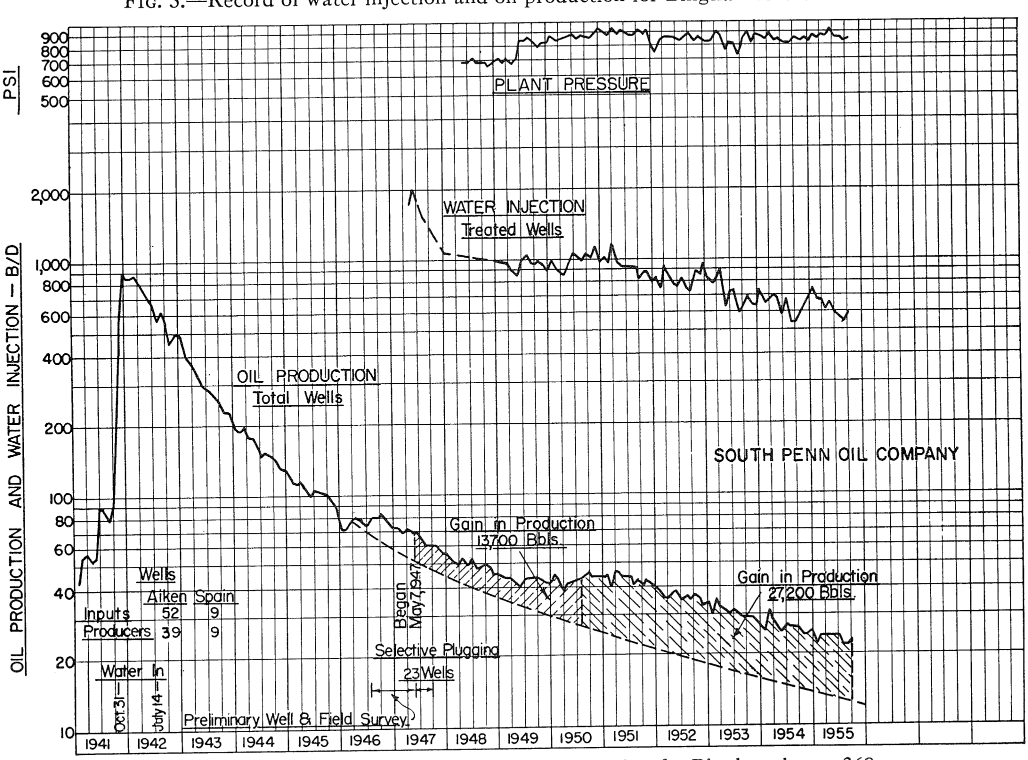

Fig. 4.—Record of water injection and oil production for Bingham leases 369.

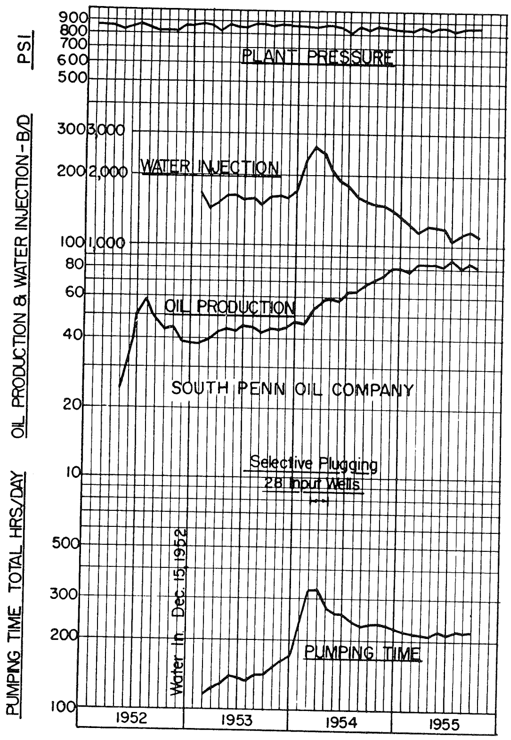

FIG. 5.—Record of water injection and oil production for Warrant 2685 (108 acres).

such as packer failures, tubing leaks, shot cracks around the packer, etc. Relatively low injection pressures are not necessarily a criterion as to the absence of pressure parting. A case has been cited where parting apparently occurred at a sand face pressure of 0.53 psi per foot.

The most common selective plugging agent used in the Pennsylvania area is Dresinol—an aqueous suspension of resin whose particle size (90 percent less than 1 micron, or 0.0004 inch) makes it particularly effective in the small pores of the low permeability Bradford sand. For formations whose pore sizes are larger, plugging materials of larger particle size, many of which are available for this purpose, should be equally effective. The technique of applying the plugging agent in order to obtain selectivity is described by Martin et al. (1949).

Extensive selective plugging operations have been carried out for many years by the South Penn Oil Company. The results of some of these operations will be presented.

Since 1946 several leases have been subjected to a selective plugging program. Accurate detailed records have been kept of the performance of these leases before and after plugging. Data are available through the latter part of 1955 for three properties known as Bingham 533, Bingham 532-554, and Bingham 369.

Bingham 533 comprises 832 acres, has 250 water input wells and 264 producing wells with a spacing of 350 feet input to input. Figure 2 shows the results of the operations on this property. Beginning in 1946, 159 (out of the 250) input wells were selectively plugged. It will be noted that the water-oil ratio ranged from a value of 18.0 to 12.9. It is estimated that 286,100 additional barrels of oil were produced through September 1955 as a result of this plugging operation. This amounts to an increase to date of about 28 percent over the recovery which would have been obtained without selective plugging. This increase was calculated from the decline curve as shown in figure 2, and its accuracy depends, of course, on the accuracy of the projected decline curve. It will be observed that the increased oil production rate has held fairly steadily above the projected decline curve for more than nine years. The plant injection pressure has remained essentially constant throughout this period.

The Bingham 532-554 property is adjacent to Bingham 533. It contains 60 water input wells and 52 oil producing wells, drilled on a spacing of 360 feet input to input. On this lease 23 water input wells were treated until the water input averaged about 50 barrels per day.

Figure 3 shows the results of the work on this lease. The data through September 1955 indicate an increased oil recovery at that time of 113,900 barrels of oil, or about 89 percent more oil than would otherwise have been recovered. The plant pressure on this lease also remained essentially constant over the eight-year period of measurement, while the water injection rate showed a definite decline through 1950.

The third property, Bingham 369, contains 61 water input and 48 producing wells

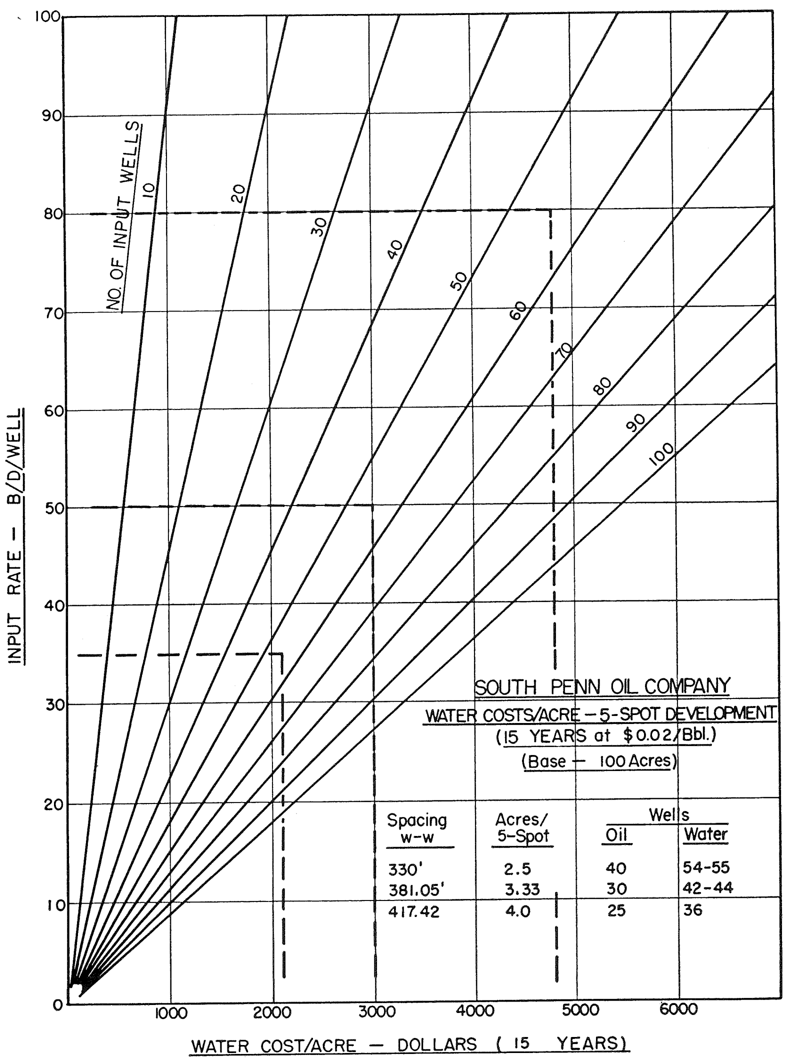

FIG. 6.—Water costs per acre.

on a 350-foot spacing, input to input. Selective plugging treatment was applied to 23 of the water input wells until their average daily input was 50 barrels of water per well. Figure 4 presents the results of this series of treatments. Again it will be seen that a substantial increase of production was obtained (40,900 barrels) through September 1955. This is an increased recovery of about 55 percent. The plant pressure also remained nearly constant while the water injection rate declined.

Among the factors which made selective plugging so effective on these leases was the fact that highly permeable strata transmitted so much water that it was difficult to pump off the producing wells in a twenty-four hour period. The effect of selective plugging on pumping time is evident in the curves of figure 5 which presents a typical example of the pumping time and water injection before and after plugging. These results are typical of several leases. On the Bingham property, the problem wells were treated un-

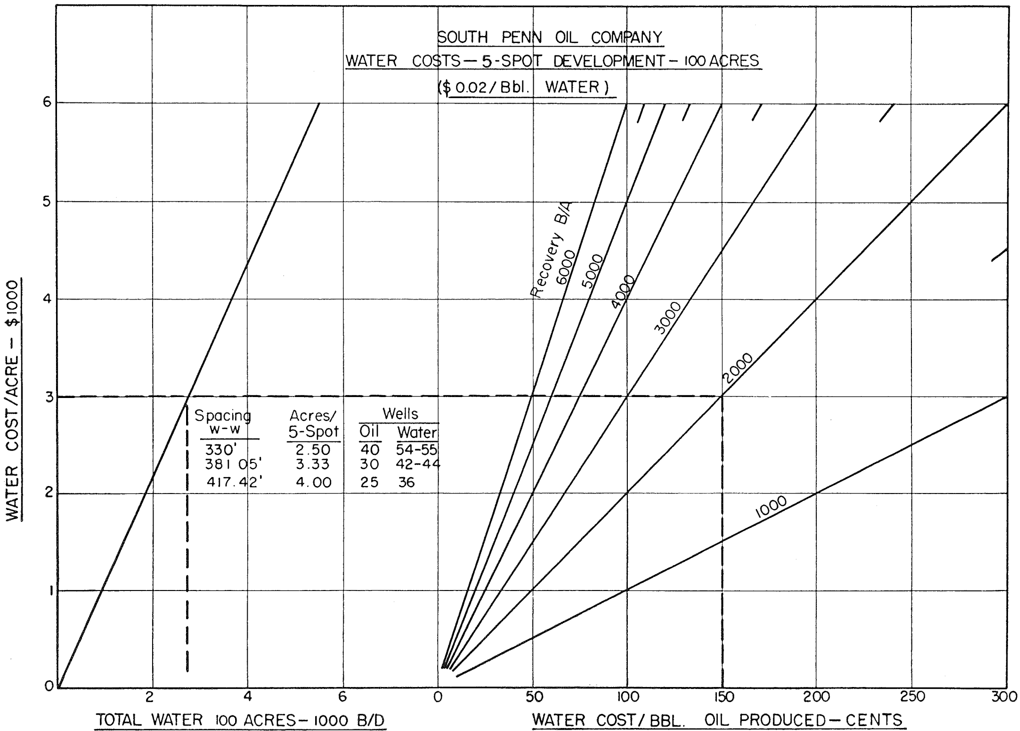

FIG. 7.—Water costs per acre.

til their intake was about 50 barrels of water per day. Before treatment, injection pressures were held down on some wells because of their high water through-put capacity. This restricted the flooding rate of the tighter strata in these wells. Following treatment full flooding pressure could be applied to these former problem wells with a resulting increase in flooding efficiency in the tighter strata.

The over-all summary of the South Penn Oil Company selective plugging operations through 1954 is contained in table 1. It will be noted that for the nine-year period, it is estimated that more than 248,467,000 barrels of water were saved, which meant a saving in water cost of more than $3,727,000. This estimate is based on a cost figure of $0.015 per barrel. This is undoubtedly low today, so that the savings today would be greater than those shown.

In addition to this, savings obviously occurred in the reduced lifting costs, equipment repairs, etc., not to mention the increased income resulting from the extra oil production.

The Engineering Department of the South Penn Oil Company has prepared two charts based on field experience, for three different spacings, by means of which water costs per 5-spot and water costs per acre may be determined for a projected flood. These charts are based on a 100-acre development, so that applying them to developments of other sizes is a matter of simple arithmetic. The first chart, figure 6, shows the relation between daily input rate per well, total number of input wells, and total water cost per acre based on a 15-year operation. For example, if the input rate is to be 50 barrels of water per day into 55 wells on a 100-acre development, the total water cost per acre (based on $0.02 per barrel) would be $3000 for the 15 years. From the second chart, figure 7, it will be seen that for $3000 per acre cost, the total water required for the

Table 1.—South Penn Oil Company Summary of Selective Plugging Bradford Field

	1946	1947	1948	1949	1950	1951	1952	1953	1954
Total wells treated	102	149	247	322	191	108	141	196	245
Total number of treatments	284	436	642	966	303	292	403	490	673
Total gallons of dresinol used	4,057	8,328	10,010	10,344	3,252	3,713	4,599	5,348	7,643
Average treatments per well	3	3	3	3	2	3	3	3	3
Average gallons dresinol per well	40	56	41	32	17	34	33	27	31
Average applied pressure—P.S.I.: Prior to treatment	406	427	494	542	550	692	689	803	915
After treatment	487	533	556	554	600	737	730	820	929
Average rate intake—B/D/W: Prior to treatment	184	278	193	95	68	105	104	80	84
After treatment	98	99	66	48	44	51	51	43	50
Average decrease intake—B/D/W	86	179	127	47	24	54	53	37	34
Total decrease water used—B/D	8,772	26,671	31,369	15,134	4,584	5,832	7,473	7,252	8,330
Total decrease water used—B/Yr.	3,201,780	9,734,915	11,481,054	5,523,910	1,673,160	2,128,680	2,735,118	2,646,980	3,040,450
Savings water costs: Average per year per well	$ 471	$ 980	$ 697	$ 257	$ 131	$ 296	$ 291	$ 203	$ 186
Total per year ($0.015/Bbl.)	$48,027	$146,024	$172,216	$82,859	$25,097	$31,930	$41,031	$39,705	$45,607

100 acres would be about 2,700 barrels. If the oil recovery from this property were to be 6000 barrels per acre, the water cost per barrel of oil produced would be 50 cents, if the oil recovery were only 2000 barrels per acre, the water cost would be $1.50 per barrel of oil. This is based upon lower water costs which prevailed during the period in which this work was carried out, and would undoubedly be considerably higher today.

CONCLUSIONS

The examples presented here illustrate the considerable economic benefits that can be achieved by a well planned and executed program of selective plugging of water input wells. It is hoped that this discussion will serve to stimulate increased interest in the application of selective plugging to those waterfloods which show evidence of abnormal water-oil ratios.

ACKNOWLEDGMENT

The authors wish to thank the South Penn Oil Company for making available the technical data on which this paper was based. In particular, we appreciate the co-operation of Harlan Danielson of the Engineering Department of that company who has been responsible for the actual selective plugging operations, and who has collected and developed most of the data presented here.

The authors wish to express their sincere thanks to Albert J. Sabella in the Petroleum Engineering Department of the University of Pittsburgh for his work in preparing the excellent drawings that accompany this paper.

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PROFILING WATER INJECTION WELLS BY THE BRINE-FRESHWATER INTERFACE METHOD

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ABSTRACT

In order to attack the problem of channeling in water-injection wells, Sinclair Research felt that as a basic step it was necessary to have an accurate means of injection profiling. The means had to be capable of profiling injection wells that are permanently completed with cement-lined tubing and are heavily shot to produce highly irregular well bores. The method chosen was the brine-freshwater interface. The equipment and techniques used for the method are illustrated and discussed.

The interface method can be broken down into two techniques—the moving interface technique and the constant interface technique. The two techniques have been found to be complementary for obtaining injection profiles over a wide variety of conditions. For the constant interface technique, precision to a hundredth of a foot relative to other stations is common. This unusual degree of accuracy has led to the discovery of many instances where significant volumes of water are injected in very small vertical intervals. This indicates that channeling can be a problem, even at moderate or low injection rates. In some cases the volumes of water injected have been so large and the formation intervals so small that flow through fractures rather than permeable streaks was considered probable.

It is possible that remedial procedures for fracture conditions could be quite different than remedial measures for permeable-streak thief zones. The accuracy of the method and possible workover potential make this method of practical significance for all types of water-injection wells.

INTRODUCTION

In order to waterflood a formation efficiently it is desirable that the injected water enter into all the strata of the formation uniformly. If this is not the case, but a substantial portion of the injected water channels through fractures or excessively permeable zones, the produced oil will be associated with excessive amounts of water. This obviously would affect adversely the economics of the operation.

Remedial measures of plugging excessively permeable strata or fractures and of increasing the water intake of the tight portions of the formation require, as a first step, that these zones be located. This is accomplished by injection profiling, which means here the determination of the vertical distribution of fluid entry into the formation of an injection well. Several methods (see references at end of paper) have been proposed for injection profiling.

The particular situation in most of Sinclair's water-injection wells caused the available instruments and methods to be inadequate. Some 1,100 of Sinclair's 1,300 water-injection wells are permanently completed with a 1½-inch or 2-inch cement-lined tubing and were shot with nitroglycerine to produce a very irregular well bore. The most promising approach to the problem appeared to be the one outlined by Pfister (1948). It involves injecting brine and fresh water, either simultaneously or successively, into the well and following the interface between these two fluids to determine the injection profile.

BASIC PROCEDURES

Two techniques that utilize the brine-freshwater interface method are available. Figure 1 shows a diagram of the constant interface method. A macaroni tubing string, with an electrical probe on the lower end, is landed opposite the formation. An electrical signal for measuring the conductivity of the fluid surrounding the probe is transmitted to the surface through a contact assembly inside the probe and an insulated electrical cable. Brine is injected down the macaroni tubing and fresh water down the annulus. Two flow-control systems are used

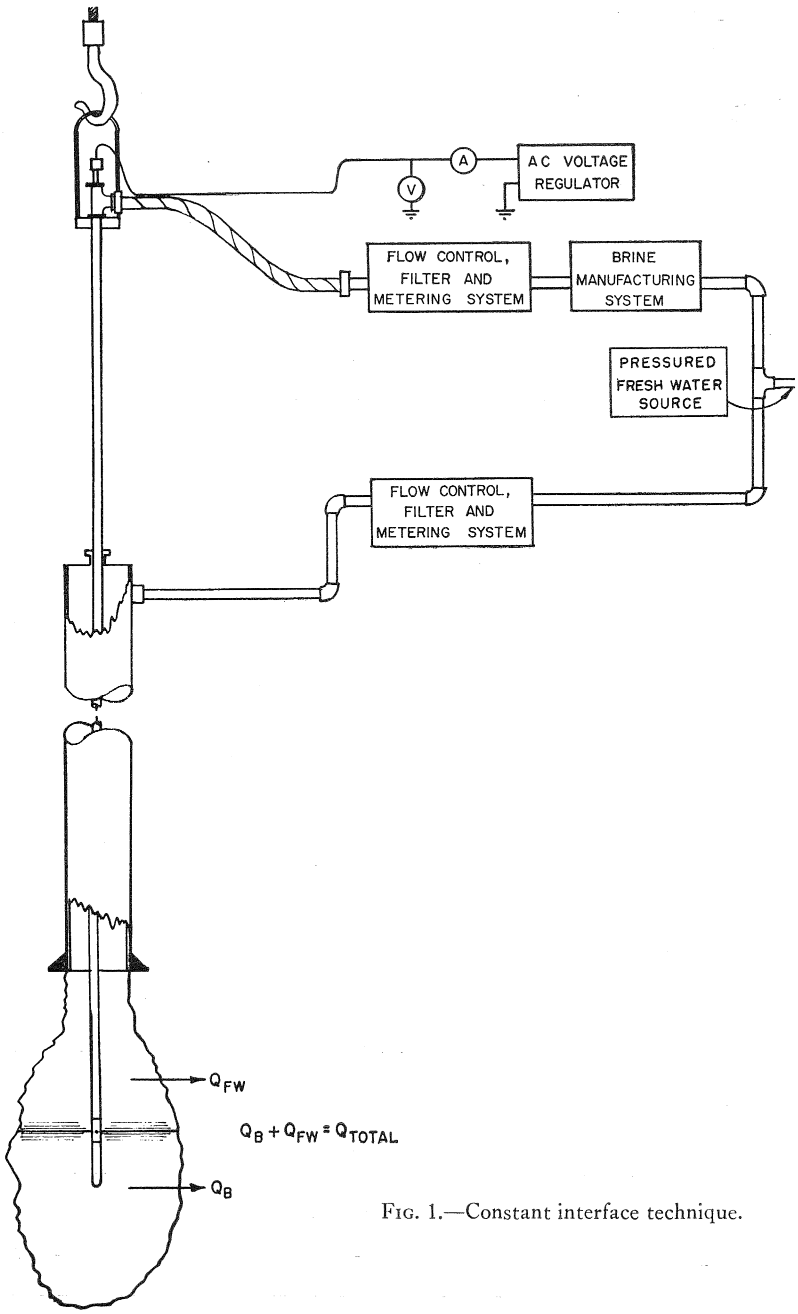


FIG. 1.—Constant interface technique.

at the surface to meter and maintain constant flow rates. The total flow rate of the two liquids is generally maintained at the same value as normally injected into the well. A constant voltage is applied to the electrodes of the probe. Current flow is then a direct measure of fluid conductivity. The interface between brine and fresh water is located by raising or lowering the entire macaroni tubing string with a pulling unit. The flow rates are held constant until the interface no longer moves. Once a station has been de-

TABLE 1.—CALCULATION PROCEDURE FOR THE MOVING INTERFACE TECHNIQUE

Depth from ground level	Elevator measurement	Up Δt (Min.)	Up Q_t (Gpm)	Down Δt (Min.)	Down Q_t (Gpm)	$\frac{\Delta t_u}{\Delta t_d}$	$\frac{Q_w 100}{1+\frac{\Delta t_u}{\Delta t_d}}$	ΔQ %/Ft.	$\frac{1}{\Delta t_d}$	$\frac{1}{\Delta t_u}$	Hole Dia. $\sqrt{\frac{\frac{24.5Q_t}{\Delta h}}{\frac{1}{\Delta t_d}+\frac{1}{\Delta t_u}}}$
642	0	3.77	3.0	41.37	3.0	0.091	91.7	8.3	0.024	0.265	16.0″
641	1	2.18	3.0	17.52	3.0	0.124	88.8	2.9	0.057	0.458	12.0″
640	2	2.25	3.0	6.87	3.0	0.327	75.3	13.5	0.1455	0.444	11.2″
639	3	6.15	3.0	13.04	3.0	0.472	68.0	7.3	0.0766	0.1625	17.5″
638	4	10.0	3.0	14.54	3.0	0.687	59.3	8.7	0.0688	0.1	20.8″
637	5	11.85	3.0	13.92	3.0	0.845	54.2	5.1	0.0718	0.0843	21.7″
636	6	10.43	3.0	10.72	3.0	0.97	50.7	3.5	0.0933	0.0958	19.7″
635	7	8.03	3.0	7.52	3.0	1.17	48.3	2.4	0.133	0.1244	16.9″
634	8	7.92	3.0	6.02	3.0	1.32	43.2	5.1	0.166	0.1263	15.9″
633	9	8.25	3.0	4.17	3.0	1.98	33.6	9.6	0.24	0.121	14.3″
632	10	13.62	3.0	5.60	3.0	2.43	29.15	4.45	0.1786	0.0735	17.1″
631	11	15.02	3.0	5.14	3.0	2.92	25.5	3.65	0.1944	0.0665	16.8″
630*	12	No	Data	4.68	3.0	—			—	—	—
629	13	13.63	3.0	3.68	3.0	3.70	21.30	4.2	0.272	0.0733	14.6″
628†	14	60.0	3.0			Moved Down Too	Swiftly to	20.47 Detect			
627.4	14.63							0			

*Instrument air off on up-run.
†Interface would not rise above 14.63′ out.

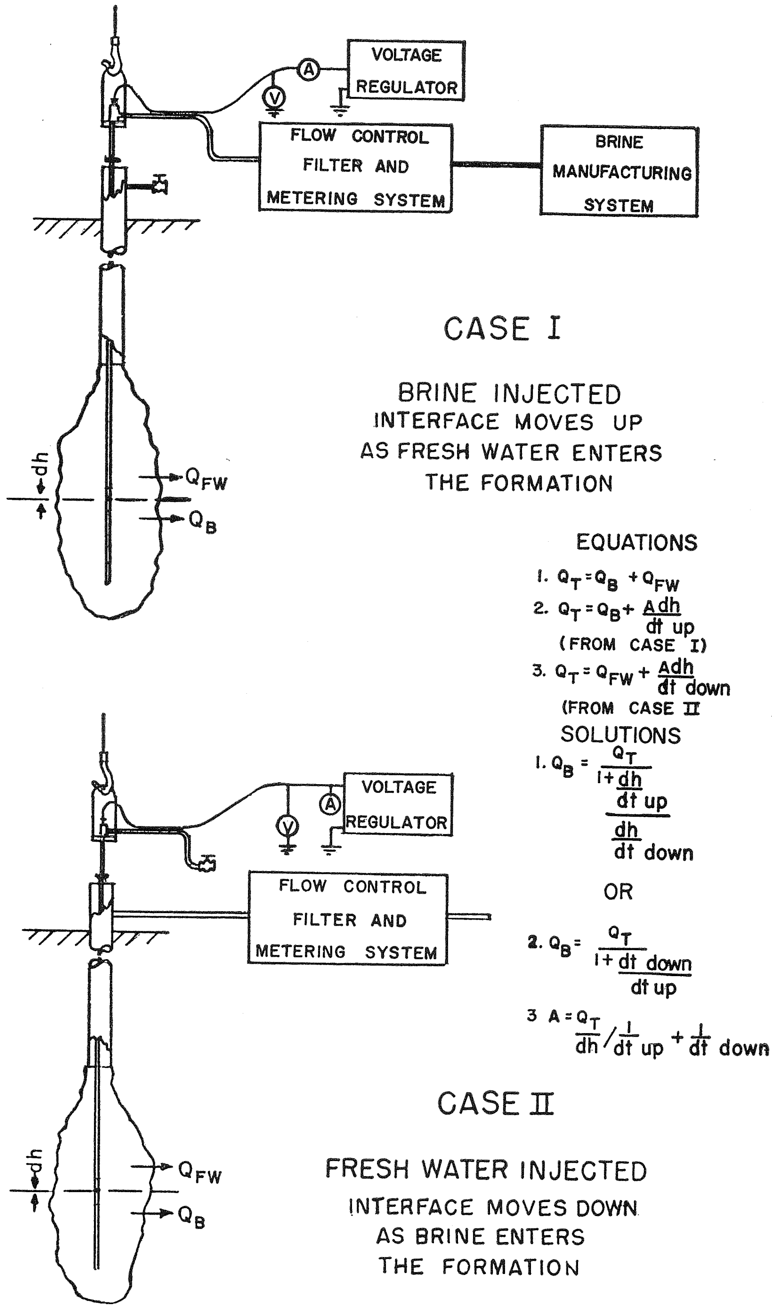


FIG. 2.—Moving interface technique.

termined, the division of flow is changed and the interface is again tracked to equilibrium. Sufficient stations are obtained to give a clear picture of the injection profile. Depth measurements are based upon the macaroni tubing tally.

A diagram of the two phases of the moving interface technique is shown in figure 2. In this technique, brine only is injected down the macaroni tubing, with the fresh water shut in, for one pass. The brine is injected at a constant flow rate as close to the

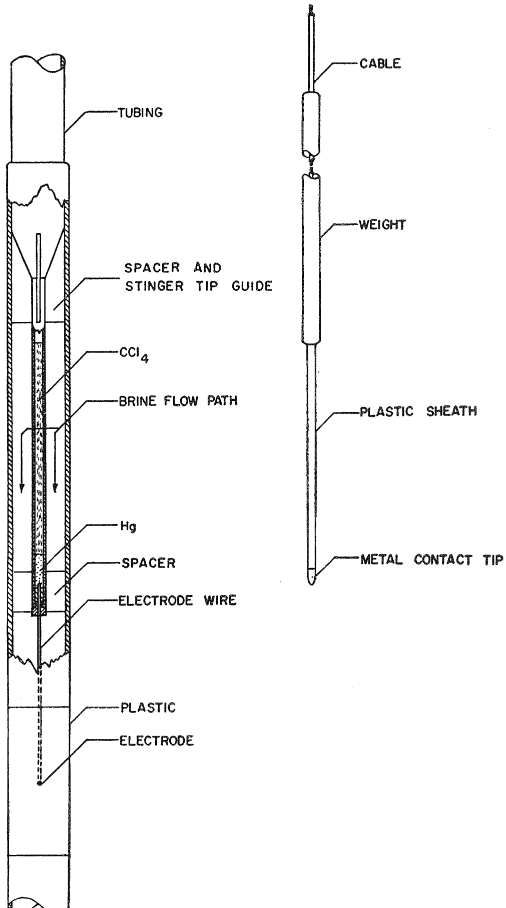


FIG. 3.—Probe and stinger assembly.

normal well injection rate as is practical. Injection of the brine is continued until the interface has been moved from the bottom of the formation to the top. The velocity of interface travel over convenient depth increments is measured. When the interface has reached the upper limit of its travel, brine flow is stopped and fresh water flow started. The fresh water flow rate is maintained constant at the same flow rate as used for brine injection. Measurement of the velocity of interface travel down over the same depth increments as previously used for the up-run constitutes the second pass. From the data obtained the injection profile and the mean average well bore diameter can be computed. The calculation procedure for a moving interface profile is shown in table 1. The calculation procedure is based upon the equations* and solutions shown in figure 2.

EQUIPMENT

The equipment used in both techniques is essentially the same. Below the surface the most important component is the probe. The probe is placed on the lower end of the tubing string and tripped into the well. A stinger is then lowered from the surface into a contact assembly inside the probe through the macaroni tubing. The current flow is through the cable, the contact assembly, a single electrode on the outside of the probe, through the fluid, and finally to the surface through the tubing. The smallest probe is just one inch in outside diameter. This small size permits profiling through 1½ or 2-inch cement-lined tubing. Figure 3 is a diagram of the probe. A short length of tail-pipe insures brine injection below the interface. A check valve prevents backflow. In shallow wells ½-inch galvanized line pipe is used as the macaroni tubing. In deeper wells ¾-inch external upset end-coated tubing has been used.

To maintain the constant flow rate referred to in the basic procedures, two flow control systems are used. One of the two identical flow control systems is shown diagrammatically in figure 4. Low and moderate injection rates are more characteristic of Sinclair operated waterfloods than are very high rates. Typical average injection rates range from 31 to 585 barrels per day. Operating pressures range from surface vacuum to surface pressures of 730 psig. The design limitations of each flow control system are an injection rate of from seven to 690 barrels per day and a working pressure of 1,000 psi. Figure 6 is a photograph of the flow control panel showing rotameters and recorders.

A constant voltage transformer, a voltmeter and an ammeter, shown in figure 5, constitute the probe's surface instrumentation. Voltages in the order of six to twenty volts are applied. The alternating current ammeter has a full scale reading of 500 milliamperes.

Figure 7 shows the pulling unit used to raise and lower the tubing string. The stinger cable reel and the wellhead are also shown.

*Nomenclature given at end of paper.

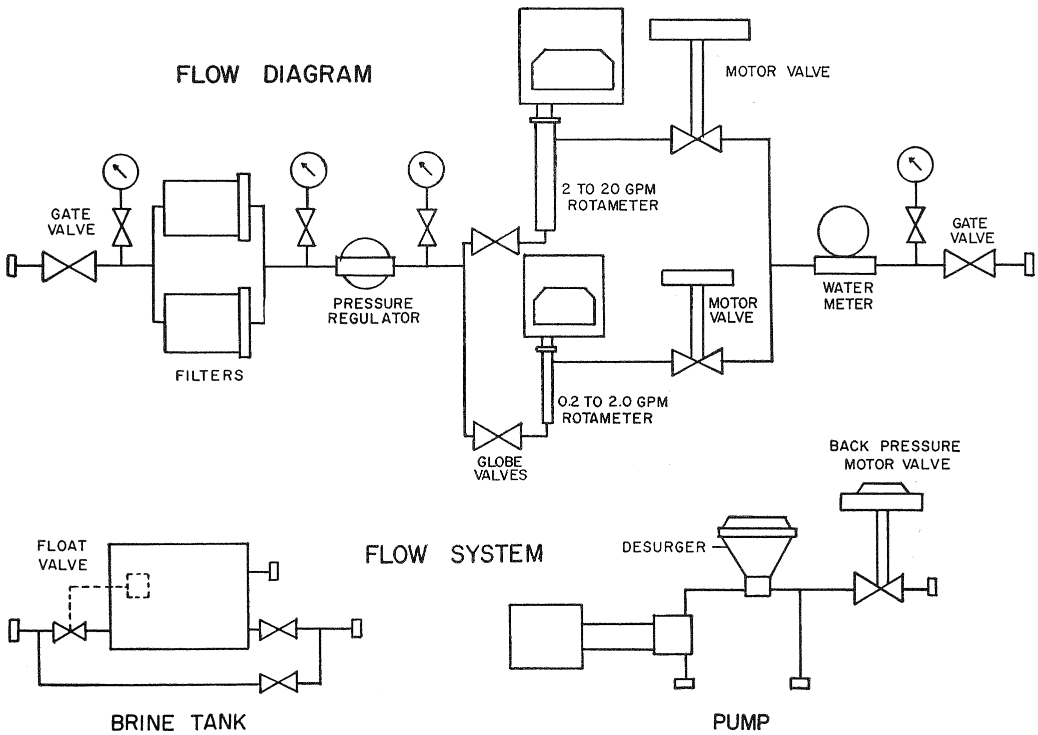


FIG. 4.—Injection profile unit.

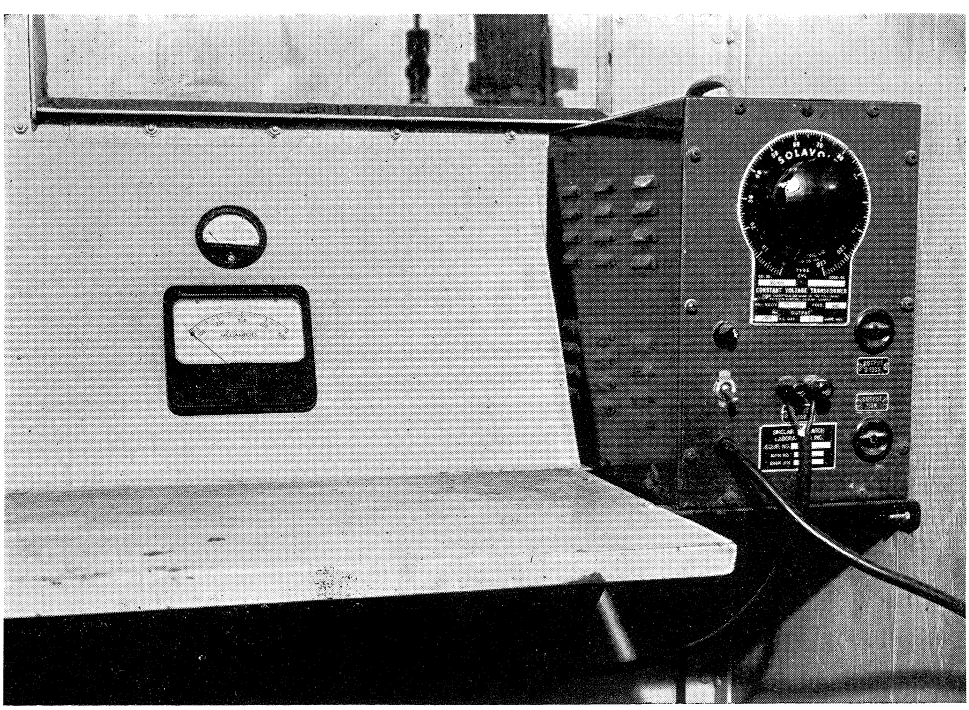


FIG. 5.—Probe instrument panel.

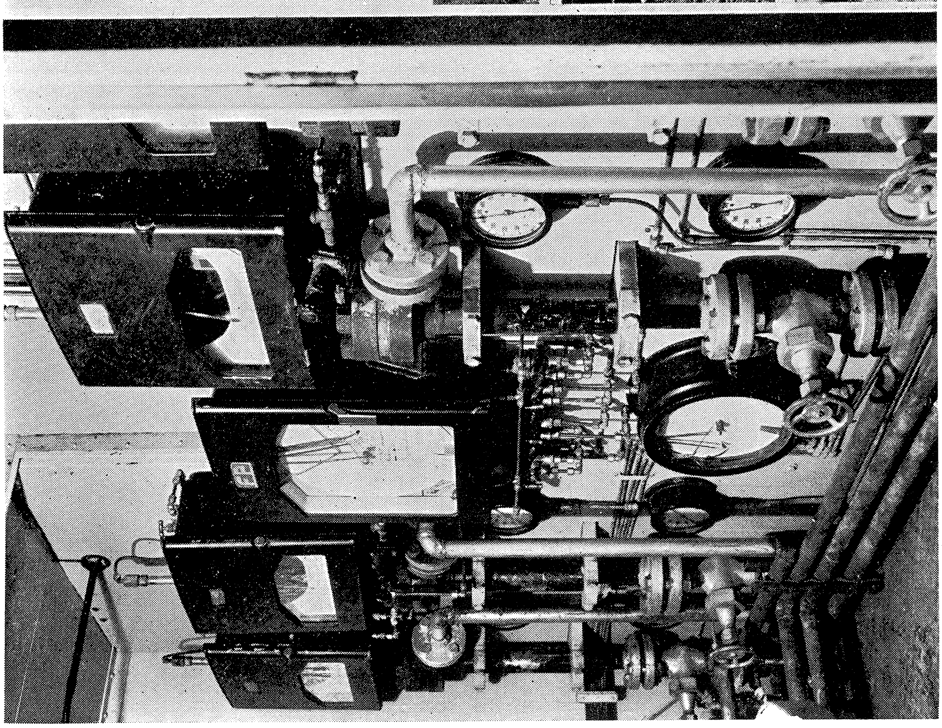


Fig. 6.—Flow control panel.

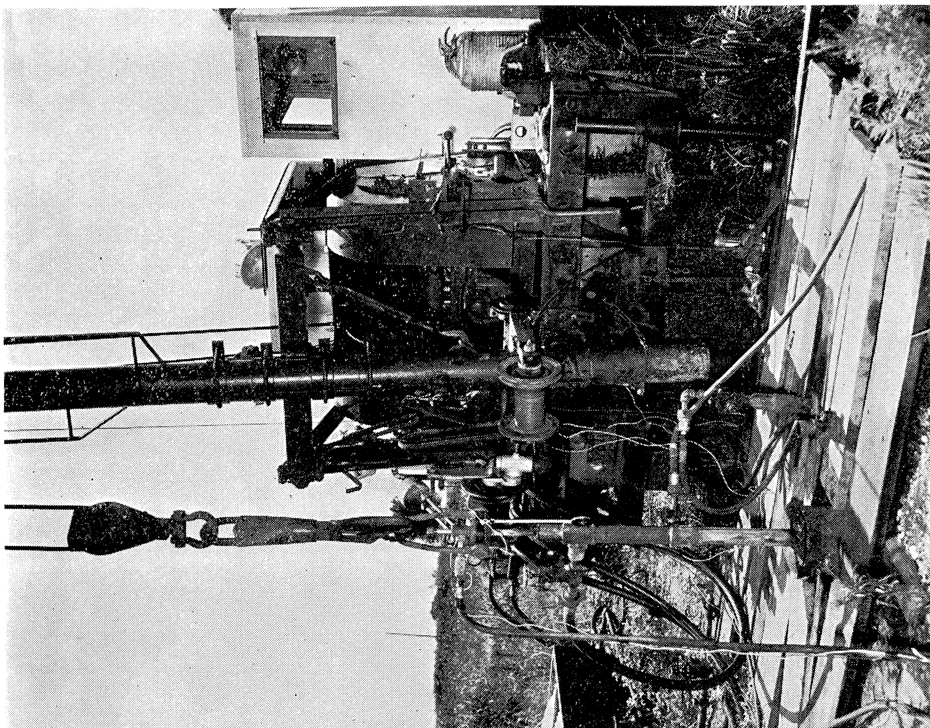


Fig. 7.—Pulling unit.

The measuring tape hung from the elevators is used for the depth measurements.

If the normal well injection fluid is fresh water, brine must be manufactured. Figure 8 is a photograph of the brine tank. If brine is the normal injection fluid, fresh water is hauled to the location. The pump shown in figure 9 is used to pressure either the manufactured brine or fresh water, whichever is necessary. On the same trailer with the pump are a light plant, which supplies the electrical instruments and night lighting, and an air compressor that provides air for the pneumatic flow controllers and motor valves.

Figure 10 is a photograph of the injection profiling unit on location.

OPERATIONAL CONSIDERATIONS

The moving interface technique is usually preferred because it is faster, yields well bore diameter data, and is self-checking. However, some well conditions prevent the successful use of the moving interface technique. The derivation of the equations of the moving interface technique is based upon piston-like displacement of the interface. Such displacement generally cannot be maintained over sections of the formation taking no fluid unless the interface velocity is very slow. In cases where the interface moves very rapidly, namely, where the injection rate is very high or the well bore diameter very small, turbulence destroys the interface or the interface moves too swiftly to be logged. In wells taking water under vacuum, the instability of the two fluid columns of different density usually prevents use of the moving interface technique. Better detail on horizontal fracture conditions can usually be obtained with the constant interface method.

The time required to profile a reasonably uniform injection well by the moving interface technique can be estimated by considering an idealized injection well. In such a well the input rate can be considered as a function of the sand thickness only.

Thus:
$$Q_b = Kh$$
$$K = \frac{Q_t}{h_t}$$

The basic equation for the interface moving upward is as follows:

$$Q_t = Q_b + A\frac{dh}{dt_u}$$

$$Q_t = Kh + A\frac{dh}{dt_u}$$

$$dt_u = \frac{A\,dh}{Q_t - \frac{Q_t h}{h_t}}$$

$$\int_0^{t_u} dt_u = \frac{A h_t}{Q_t}\int_0^{h}\frac{dh}{h_t - h}$$

$$t_u = \frac{A h_t}{Q_t}\ln\left(\frac{h_t}{h_t - h}\right) \qquad (1)$$

It would appear from equation (1) that the interface would never quite reach its equilibrium position. However, field experience indicates that the equilibrium position can be approached closely enough to be considered in its final position in a reasonable period of time. As the above equation is for one pass, the total profiling time would be about double the value calculated from the equation. The primary significance of the above equation is that the time necessary to complete a profile pass depends heavily upon the well bore diameter, the sand thickness, and the injection rate.

The accuracy of the method depends upon the accuracy with which the velocity of the interface can be determined and the flow rate can be maintained constant. Under the worst possible conditions the measurement error is estimated at less than five percent.

A possible source of error lies in the variation of permeability with salinity of the injected fluid. In a pressured injection well such an effect should most probably result in a decrease of required injection pressure as the interface moves up the well bore if a constant flow rate is maintained. Field experience has never disclosed such an effect to date. Of course, the fresh water used in flooding is generally a weak brine. Waters with salinities as high as 15,000 ppm have been used as the fresh water phase. Concentrations of brines range from 130,000 to 180,000 ppm.

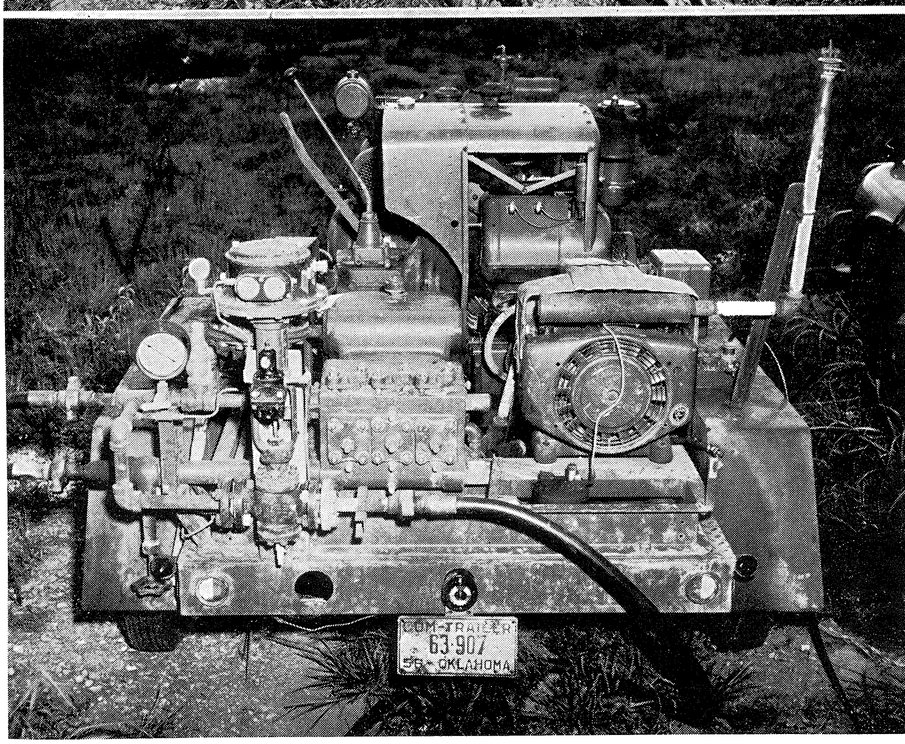


FIG. 8 (Above).—Brine manufacturing tank.

FIG. 9 (Below).—Auxiliary trailer.

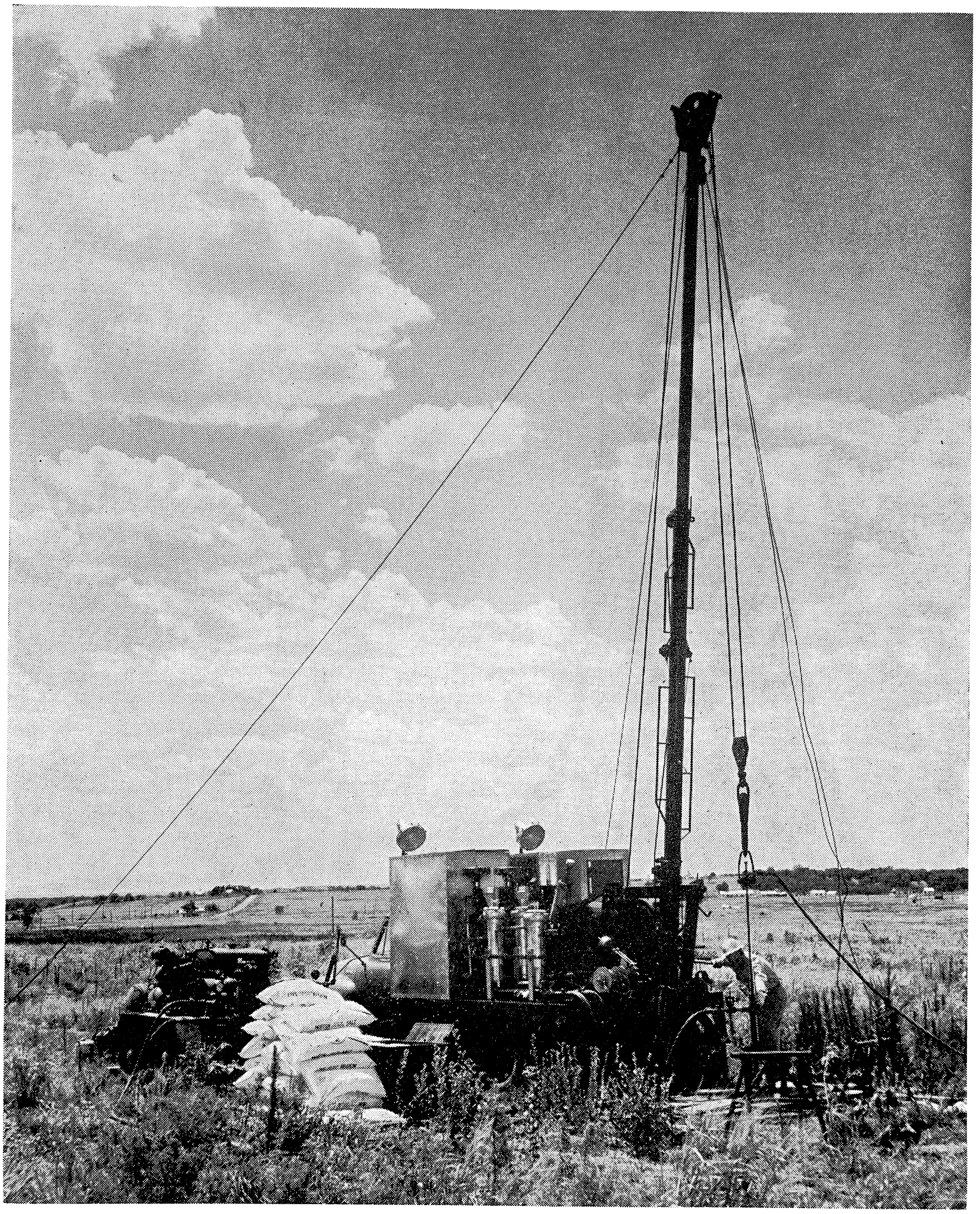
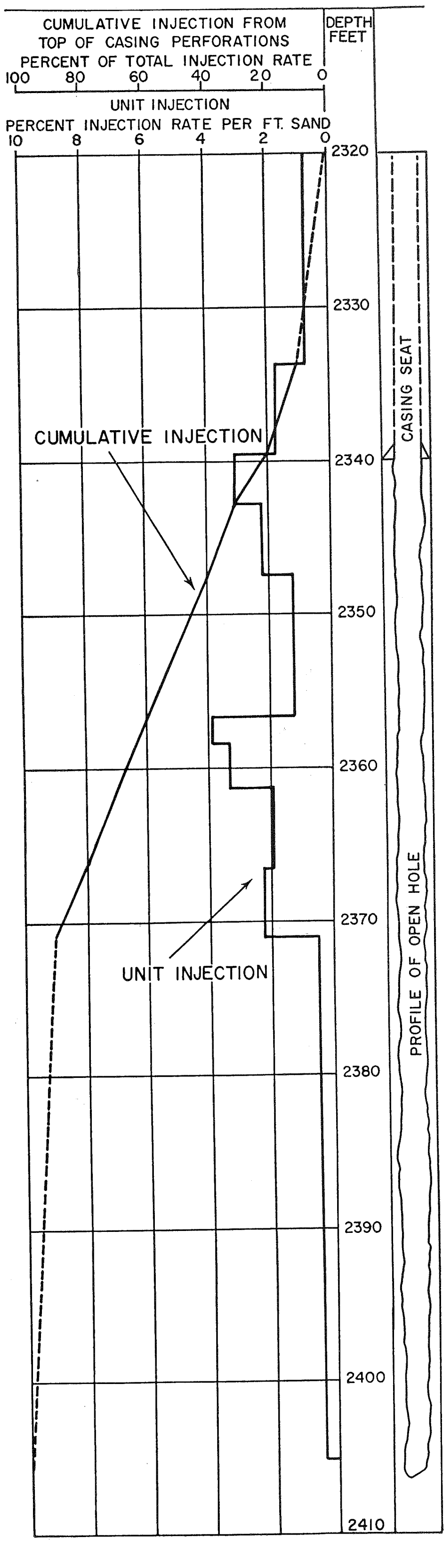


FIG. 10.—Injection profile unit.

Another possible source of error lies in the difference of viscosity between brine and fresh water. In a pressured injection well the effect of viscosity difference should be to increase the injection pressure as the interface moves up the well bore. Field experience indicates this effect is significant if the fresh water phase is truly fresh and not a weak brine.

Where the moving interface technique is inadequate, the constant interface technique is available. The constant interface technique is outstanding in depicting horizontal fracture conditions. This is due to the sharpness of



the interface. Often, movement of the interface can be detected to a hundredth of a foot. Of course, as depth measurements are based upon tubing tallies, such measurements have significance relative only to other stations and not as absolute measurements.

The time factor analysis for the moving interface technique can be adapted to the constant interface technique by consideration of the case where the interface is moved from the base of the sand to the 50 percent brine—50 percent fresh water station.

Thus:
$$t_u = \frac{A.\ \frac{1}{2}\,h_t}{\frac{1}{2}\,Q_t} \ln\left(\frac{\frac{1}{2}\,h_t}{\frac{1}{2}\,h_t - h}\right)$$
$$t_u = \frac{A\ h_t}{Q_t} \ln\left(\frac{h_t}{h_t - 2h}\right)$$

The time requirement for the interface to reach equilibrium at each station is nearly the same. Fractures or thief zones reduce the effective sand thickness to a small value and thus sharply decrease the time necessary for each station.

The accuracy of the constant interface method is affected by salinity and viscosity. Actually the constant interface method is a direct measurement between two different liquids. Any error would be in changing the values measured to a single-liquid flow condition.

The accuracy of the constant interface method is also dependent upon the determination of interface equilibrium, which is in turn dependent upon the accuracy with which the interface velocity can be deter-

FIG. 11.—Injection profile log of well A
Technique: constant interface.
Date: Feb. 29, March 1, 1956. Operator: Childers.
Total depth: driller, 2,406′; wire line, 2,407′.
Electrode setting, first: 2,340′
second: 2,360′
third: 2,380′.
Completion: 20′ perforated casing, 120 shots, and 65′ open hole, unshot.
Top of sand: 2,318′ (Bartlesville); base: 2,405′.
Casing: 5½″–14 # set at 2,340′; no liner.
Tubing: 2½″ E.U.E. cement lined.
Packer: 2½″ x 5½″ set at 2,300′; Baker Model "D"
20′ 2″ anchor.
Injection fluid: brine; rate 514 BPD at surface vacuum pressure.

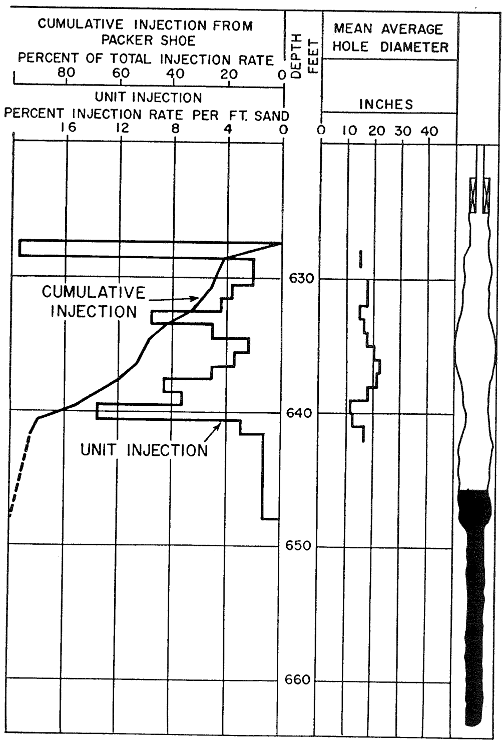


FIG. 12.—Injection profile log of well B

Technique: moving interface.
Date: May 19, 1955. Operator: Holbert.
Total depth: driller 663′; wire line, 654′.
Electrode setting: 645′.
Completion: open hole; shot 628′–648′ with 20 qts.
Top of sand: 623′; base: 648′.
No casing or liner.
Tubing: 2′ cement lined; rag packer set at 625′.
Injection fluid: fresh water; rate 103 BPD at 310 psig surface.

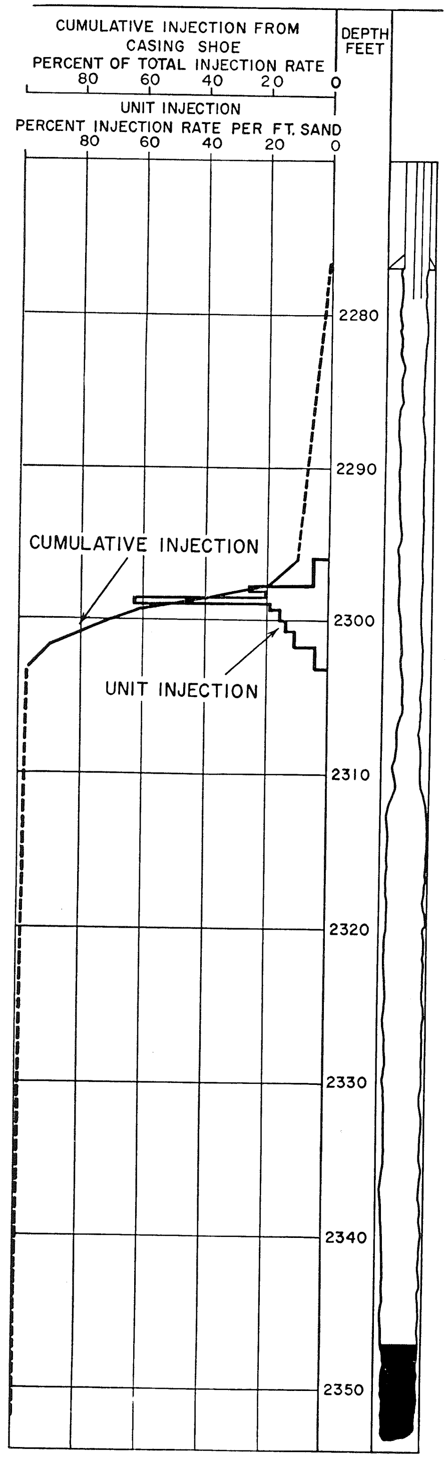


FIG. 13.—Injection profile log of well C

Technique: Constant interface.
Date: April 25, 1956. Operator: Childers.
Total depth: driller, 2353′; wire line, 2347′.
Completion: open hole, shot 2311′ to 2353′, 80 qts.
Top of sand: 2274′; base: 2353′.
Casing: 7″–20# H40 set at 2277′; no liner.
Tubing: 2½″ cement lined; packer set at 2265′, anchor at 2279′.
Injection fluid: brine; rate 514.5 BPD at surface vacuum pressure.

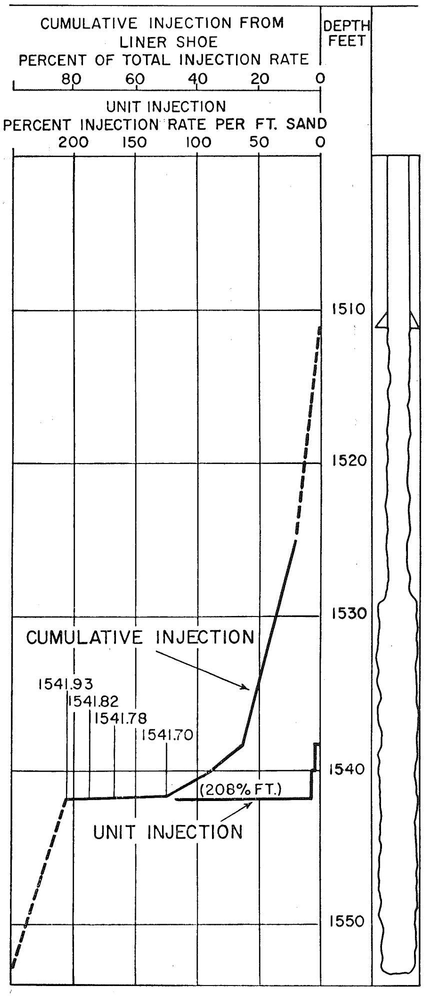


FIG. 14.—Injection profile log of well D

Technique: constant interface.
Date: Oct. 11 and 12, 1955. Operator: Childers.
Total depth: driller, 1553′ PBTD; wire line, 1550′.
Completion: open hole; shot 1529′ to 1545′ with 20 qts.
Top of sand: 1511′; base: 1553′.
Casing: 1469′ of $6\frac{5}{8}$″–17 #; liner: 66′ of $5\frac{1}{2}$″, 1445′ to 1511′ Larkin CID.
Tubing: 1464′ of $2\frac{1}{2}$″ E.U.E. C.L.; packer: $5\frac{1}{2}$″ x $2\frac{1}{2}$″ set at 1464′.
Injection fluid: brine; rate 412 BPD at surface vacuum pressure.

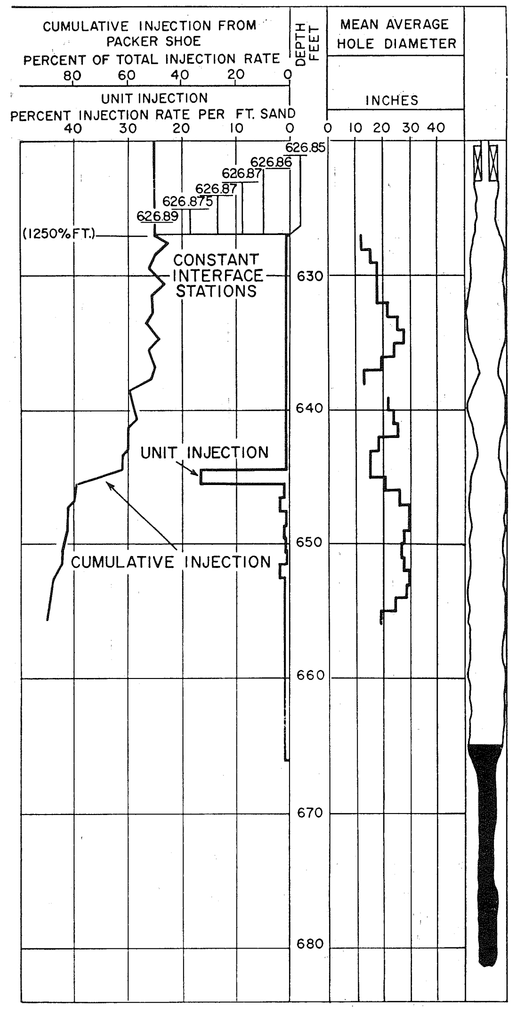


FIG. 15.—Injection profile log of well E

Technique: moving and constant interface.
Date: July 11 to 14, 1955. Operator: Scott.
Total depth: driller, 681′; wire line, 665′.
Electrode setting, first: 662′
second: 643′.
Completion: open hole; shot 631′ to 665′ with 35 qts.
Top of sand: 631′; base: 666′.
No casing or liner.
Tubing: 2″ cement lined; rag packer set at 623′.
Injection fluid: fresh water; rate 210 BPD at 300 psig surface.

mined and constant flow rates can be maintained. Unstable interfaces traveling at velocities in the thousandths of a foot per minute have been measured. If the interface is not sharp, a weary operator can mistake for equilibrium a situation where the interface is a considerable distance from its true final position.

In many cases the two interface techniques are combined. A moving interface profile is run first. With evidence that a significant amount of fluid is entering a small section, a few constant interface stations are obtained over the small section. This often provides a clue as to whether there is a thief zone or a fracture condition.

RESULTS

Since Sinclair Research Laboratories, Inc., began development of the brine-freshwater interface method, 41 different injection wells have been successfully profiled. Only 14 had a permeability profile that was even approximately uniform. An example of a reasonably uniform injection well profile obtained by the constant interface method is shown in figure 11. Another example determined by the moving interface method is shown in figure 12. In two wells tubing leaks were detected. In 15 wells thief zones were discovered, such as the example shown in figure 13. In nine wells a sizable volume of water was injected into such a small vertical interval that flow through a porous medium was considered improbable. Figure 14, with 137 barrels per day injected in 0.23 feet, and figure 15, with 69 barrels per day injected in 0.04 feet, are examples of wells with probable fracture conditions. Figure 16 is also a profile of a well where both the moving and the constant interface techniques were used.

CONCLUSIONS

Perhaps the outstanding contribution of this method of injection profiling has been the discovery of significant volumes of fluid injected into small vertical intervals of the formation. This suggests the possibility that damaging channeling can occur from relatively moderate volumes of injected water. Remedial procedures for plugging fracture conditions may be quite different from procedures for plugging porous thief zones, thus making the ability to distinguish between the two conditions of considerable value in plugging operations.

Profiling with the brine-freshwater interface method was originally developed as a research tool. The process is not simple, and necessary equipment is somewhat elaborate. Sometimes it takes more than twenty-four hours to obtain an injection profile. On the other hand, shot injection wells with small size tubing completions can be profiled accurately. The method is self-checking and the measured profiles can be dependably used as a basis for workover techniques. These factors give the method practical significance.

ACKNOWLEDGMENTS

The author is grateful to the managements of Sinclair Research Laboratories, Inc., and Sinclair Oil & Gas Company for permission to publish this paper.

The development of the interface profiling unit has been a group effort. Particular credit for original work is due S. E. Szasz and D. J. Bevington (formerly with SRLI). Space does not permit specific mention of other staff members working with this project.

NOMENCLATURE

Total injection rate into the well, gpm	Q_t
Injection rate of brine injected into the formation below the interface, gpm	Q_b
Injection rate of fresh water injected into the formation above the interface, gpm	Q_w
Distance from the base of the sand to the interface, feet	h
Total sand thickness, feet	h_t
Time for the interface to move up the well bore from the base of the sand, minutes	t_u
Time for the interface to move down the well bore from the top of the sand, minutes	t_d
Cross-sectional area of the well bore, square inches	A
Diameter of the well bore, inches	D
Velocity of the interface moving up the well bore, feet per minute	dh/dt_u
Velocity of the interface moving down the well bore, feet per minute	dh/dt_d
Constant relating flow rate as a function of depth, gpm per foot	K

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GAS INJECTION AS AN ADJUNCT TO WATERFLOODING

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ABSTRACT

The use of gas as an adjunct to waterflooding is not a simple problem. Its application in the field has been increasing in recent years but it has been difficult, partly because of lack of both controlled standards and standards of comparison, to evaluate the results of such use of natural gas.

This paper is an attempt to summarize the factors that are significant in the process and to raise pertinent questions about our present understanding of the total problem. The effects of injected gas are considered from the standpoint of its presence as a separate phase and as gas dissolved in the reservoir oil. The paper discusses the effects of injected gas on oil displacement by water and on areal sweep of the injected water and the effect on the manner in which reservoir heterogeneity and gravitational segregation would control the flood.

In essence, the use of gas as an adjunct in waterflooding is an attempt to use a three-phase situation where even two-phase situations are not understood. It is not possible to draw a general conclusion as to how or why gas should be used, and it is quite possible there are places where it should not be used. In any field use, results will be unsusceptible to analysis unless the tremendous number of factors enumerated are all considered and have been found to be absent or under control. There is some question as to whether any field use can be analyzed and results traced to a specific cause, to the exclusion of all other causes, with the tools presently available.

INTRODUCTION

The history of the use of gas in waterflooding is somewhat obscure. Isolated experiments on limited uses of gas have been in progress at least since 1937 (Booth, 1937), but organized experimentation of magnitude did not take place until the last ten years (Breston, 1952). Those of greatest magnitude have perhaps been in Pennsylvania, undertaken first by operators who injected gas into waterflood properties for temporary storage, and later by those who attributed success in waterflood operations to the fact that gas had been used for some unrelated reason. A parallel use of gas was developing in natural water drive fields, where it was deemed desirable to supplement natural water drive, and in other primary fields where pressure maintenance was practiced. In both instances, there arose the question as to how far below the bubble point, if any, the pressure could be allowed to fall without detriment to recovery by water drive.

These uses of gas are two facets of a single fundamental problem, though each approach has its own boundary conditions for application. Each use has the desired objective of a more efficient recovery process, measured in terms of lower reservoir oil residuals, better rates of recovery, or the use of less water. Each is concerned with the introduction of a third phase into situations where the two-phase behavior is not well understood. For this reason alone, it is not surprising that there is a general lack of agreement as to the role of gas.

Two approaches, separately or in combination, may be used by the engineer to find those answers necessary to the successful use of gas as an adjunct to waterflooding. He may correlate specific production histories with the use of certain types, amounts, or intended uses of gas, or he may make laboratory experiments and extrapolate them to field conditions. In either case, the engineer is not satisfied with merely reciting a certain procedure and its accompanying results. He wants to know why gas has been used successfully or unsuccessfully, and proceeds to form a mechanistic picture of cause and effect, a procedure which in general has tended to oversimplify the problem and has led to unwarranted conclusions.

My contribution to the question at this time is not to supply new data for correlation and prediction purposes or to describe experiments that will elucidate new concepts. My contribution is intended to be that of summarizing the factors that must be considered and of raising pertinent questions about our present status of understanding of the total problem.

The effects of injected gas on waterflooding can be grouped into several general headings: 1) Its effect on the process of oil displacement by water as it occurs in a linear system; 2) its effect on the areal sweep coverage attained by the injected water; 3) its effect on the manner in which reservoir heterogeneity would control the flood; and 4) its effect on the manner in which gravitational segregation would control the flood.

The analysis is further complicated by the fact that flooding rate, pressure of water injection, ratio of well diameter to spacing, or other operational variables might also have a control on any of the enumerated effects, which control could be altered by the use of gas. Further, each of the effects enumerated may be divided into two parts—that if gas is present as a separate phase and that if injected gas is to be dissolved in the reservoir oil.

EFFECT OF INJECTED GAS ON OIL DISPLACEMENT

If we look at the laboratory experiments that have been performed on the subject of gas in waterflooding, we note that the majority have been directed toward the role of gas under (1). It has been the general impression that the benefits of injected gas could or could not be traced to the effect of free gas space on the process of oil displacement by water as it occurs in a linear system. There can no longer be any doubt that a reduction of oil residual saturation will accompany the presence of free gas during water drive. In fact, experiments show that residuals of any displaced phase can be reduced when a third phase is present during the displacement process.

Two explanations are advanced for the reduced oil saturations in the presence of free gas. First, residual free gas space may substitute directly for residual oil space. Second, free gas may cause the water to do a more efficient job of penetrating pores wherein residual oil might otherwise lie. Neither explanation suffices for all data reported in the literature. The first explanation seems to be the most plausible for water-wet systems, within which oil and gas can be considered to be competitors for the same pore occupancy. However, such space competition would not be expected in an oil-wet system, in which case the second explanation seems to be preferred. In the oil-wet system, the gas and water may be thought of as competing for the same pore occupancy, the gas thus forcing the water to sweep other pores.

The reduction of oil residual by free gas has been documented by numerous references (Holmgren and Morse, 1951; Schiffman and Breston, 1950; Saxon et al., 1951; Freeland and Calhoun, 1952; and Kyte et al., 1956). Among the first to give comprehensive data that can be analyzed in terms of the question, although they did not present the data specifically for this purpose, were Dykstra and Parsons (1950). Holmgren and Morse (1951) were the first to call specific attention to a relationship between trapped gas and residual oil. Freeland and Calhoun (1952) showed that the relationship existed for a number of situations that had been reported in the literature. The recent work of Kyte et al. (1956) has verified the relationship for a number of porous materials, including both water-wet and oil-wet systems.

One might have deduced a relationship between gas saturation and residual oil from relative permeability concepts. In fact, some years before the specific experiments on the role of gas, Dickey and Bossler (1944) replotted the relative permeability data of Buckley and Leverett to show emphatically that oil saturation had to be reduced as gas saturation was increased if the water-oil ratio were to remain constant.

Dykstra and Parsons and also Dickey and Bossler bring out an additional item that is rarely mentioned in references dealing with the subject. This is the observation that the amount of oil (or water) in the system has a bearing on the effectiveness of free gas in reducing oil residuals. In fact, the early work was done to show the importance of water saturation. Kyte and others recently give information on this point when they show that the lowering of residual oil will change as the number of pore volumes of water through the flooded system is increased. However, they also show data in which additional water through the system does not result in a reduction in the effect of the gas.

It has been demonstrated not only that trapped free gas will result in lowered residual oil, but also that similar results follow when the gas is initially mobile. The work of Kyte et al. (1956) is perhaps most complete in this respect. Holmgren and Morse (1951) give similar data. Kyte et al. also adopt a scale for comparing the merits of gas toward lowering residual oil in several situations. To do this, they define the concept of "gas effectiveness" as the ratio of the reduction in oil saturation to the amount of gas saturation causing the reduction. If 10 percent of trapped gas saturation reduces residual oil by 10 percent, the "gas effectiveness" is 100.

They report values of gas effectiveness ranging from 50 to 100 at water breakthrough and from 0 to 80 after three pore volumes of water have passed through. Results published by other authors also show gas effectiveness values as high as 100. The value is more likely to be closer to 100 when the amount of trapped gas is small than when it is large. One would expect the effectiveness to be 100 in a water-wet system where the explanation was one of direct substitution for pore space. In an oil-wet system, there would be no readily apparent method for estimating gas effectiveness. One might even envision circumstances in which the gas effectiveness would be anticipated to be in excess of 100; no such data have yet been reported although there is one reported instance where gas effectiveness was greater than 100 during the displacement of water by oil (Calhoun et al., 1944).

Trapped free gas is expected to reduce the effective permeability to oil, water, or both. Consequently, the total time necessary to complete a flood would be increased, assuming fixed pressure gradients. This has been pointed out in most articles on the subject of free gas, but little attempt has been made to give actual magnitudes of the rate change. MacFarlane et al. (1955) give about the only complete discussion of relative flooding times on cores with trapped gas compared to cores without trapped gas. Oddly enough, these authors demonstrate only small time detriment on the experimental floods on which they report, a result which they say to be in disagreement with that given by Holmgren and Morse (1951).

From evidence of this nature, one must conclude that the presence of free gas will be beneficial in reducing residual oil during waterflooding, whether the gas is first present as a trapped or mobile phase, or introduced later. The wettability of the system appears to be of secondary importance, and the effect is possible at all stages of the flooding process. The only prerequisite seems to be that the gas remain as a free gas saturation. The effectiveness of the gas can be expected to be in the range of 50 to 100.

Effect of Injected Gas on Areal Sweep

Consider now the second effect of injected gas on waterflooding—that of the change in areal sweep coverage attained by the injected water. The literature on the subject is scanty. The two recent references that apply to the problem appear at first glance to be somewhat contradictory in their conclusions, but actually are not because they deal with two separate sets of conditions.

Dyes and Braun (1954) give a sweep efficiency of 84 percent at water breakthrough for a depleted sand situation, where 70 percent would be expected on the basis of the oil-water mobility ratio and two-phase flow. They conclude that in a depleted five-spot, a better sweep will be accomplished at any stage after water breakthrough than would have been accomplished had it not been depleted.

On the other hand, Craig and co-workers (1955) have the following to say on this subject, "If fill-up is accomplished before the flood front cusps, the breakthrough areal sweep efficiency will be the same as if no free gas had been present initially." This quoted sentence is preceded by statement of the assumption that the experimental studies covered by the paper were for the situation in which none of the initial gas saturation is trapped behind the flood front. It is not surprising to find little change in areal sweep on the basis of such an assumption. This is, however, quite a different situation from that envisioned by Dyes and Braun in their study which led to the results referred to above.

The following quotation from Dyes and Braun will suffice to give their point of view with reference to a situation depleted by solution gas drive: "Under this condition the gas saturation will in general be 15 to 25 percent of the pore space and gas will consequently have a high mobility. It is the high mobility of this gas with respect to the much lower mobility of the oil, coupled with the displacing efficiency of the water, that leads to the characteristic formation of an oil bank in water floods of this type of reservoir."

A consideration of the basic factors contributing to sweep efficiency will develop the point of view that it is not necessarily the oil-water mobility ratio that is important. The mobility ratio is only a device for scaling a situation that cannot be readily measured. The shape of pressure contours throughout the reservoir determines areal sweep—not the mobility ratio. When this is granted it follows that the presence of any third phase will demand a change in the sweep efficiency, unless the third phase is so distributed that three phases produce the identical shape of pressure contours that would have been produced without the third phase. One cannot say whether such changes in sweep efficiency are measurable, but they will exist. It is to be anticipated that the pressure gradients in a depleted gas zone are so much less than they would be if the same region were oil-filled, that a marked change will be made on the pressure contours and hence on the sweep efficiency.

A depleted zone ahead of the oil bank reduces cusping of the advancing oil-water front. In such a case, the oil-water boundary mobility ratio has little to do with the sweep. The sweep coverage is controlled more by the fact that pressure gradients are low in the depleted zone, so that pressure contours in both the oil bank and water-invaded zone will approach arcs of circles and tend to maintain the radial advance of the flood.

In the event that the reservoir was not depleted but that the region ahead of the oil-water boundary contained free gas, the mobility of the oil zone would be reduced. This would tend to produce greater pressure gradients in the oil bank than would be the case without the presence of gas. Consequently, the pressure contours would change and a lower areal sweep coverage would be expected than would be the case with no trapped gas.

Finally, should there be trapped gas in both the oil bank and the water invaded zone, and the pressure gradients are raised less in the oil bank than in the water zone, the sweep coverage should be improved over what it would be without gas. In short, one cannot predict the effect of injected gas on areal sweep coverage unless it is possible to say how the pressure gradients and contours will be changed.

To summarize, it can be said that our knowledge on this effect is meager, but sufficient fundamental information is on hand to conclude that the effect of free gas on sweep coverage cannot be generally stated. Three separate situations can be recognized. First, where there is a definite depletion, the advantage of the depleted zone is to increase areal sweep coverage. Second, if the free gas saturation is all within the oil bank, the areal sweep would be expected to go down. Third, if the free gas is in both the water and oil bank the areal sweep efficiency might change either way.

Effect of Reservoir Heterogeneity

Now consider the third effect earlier enumerated—that of the change in performance of a flood as controlled by heterogeneity. The data on hand are more meager than for the analysis of areal sweep coverage, although the article by Dyes and Braun (1954) has some information that applies. These authors made sweep coverage experiments for reservoirs assumed to have layers of oil-bearing strata of different permeabilities, first the strata being noncommunicating; second, the strata being communicating (cross-flow). Their conclusion appears to be that reservoirs with mobility ratios higher than unity will be more uniformly swept where cross-flow is present, but that reservoirs with mobility ratios less than unity will be less uniformly swept when cross-flow is present.

To extrapolate these conclusions in order to predict the changes that would result when gas is injected will require assumptions as to where the gas will be. In this respect, it is necessary to treat the situation with noncommunicating strata separately from the situation having cross-flow. In the case of noncommunication, the presence of free gas saturation in one stratum (but not in another) would reduce the effective permeability of the first relative to that of the second regardless of whether the gas were in the oil bank or water zone. If the gas were present in the high permeability beds, but not in the low, the result would be to smooth out the effect of heterogeneity, as measured by permeability, and permit better flooding. If the gas were injected preferentially into the low permeability beds, the opposite effect would be expected.

Considering the situation with cross-flow, it would appear that the proper analysis would be to determine, as in the case of areal sweep, where the free gas lies. If present in the oil bank, the gas might result in reduction of volumetric sweep efficiency. If gas is present in the water bank, or in both oil and water, its effect on coverage would depend upon which zone was reduced most in effective permeability.

Of course, vertical striation is only one form of heterogeneity. Heterogeneity often occurs in the horizontal plane due to lensing. This problem should be quite analogous to that of cross-flow in a vertical plane and is not discussed further.

In summary of this point, therefore, one must admit that the data are meager and rely upon fundamental concepts for a prediction. In stratified reservoirs with no cross-flow, free gas could be expected to be beneficial if it were present in the highly permeable strata. With cross-flow, benefits would be found only if the reductions in effective permeability were greater in the water-invaded portion of the reservoir than in the oil bank portion of the reservoir.

Effect of Gravitational Segregation

When one considers the possible effects of gas on the action of gravitational control in a waterflood, there appear to be no published data to rely upon. Hence, I will speculate even more than on the previous situations. In general, the deviation of the oil-water front from the vertical, due to gravity, will be directly related to the velocity with which the oil-water front moves forward. Therefore, the fundamental effect of gas would appear to be its control over the speed of interface advance. In a depleted reservoir, there is little doubt that the early speed of flood advance will be greater than in a liquid-filled reservoir. This advantage is lost, as soon as the fullup period has been reached, but it may last for sufficient time to produce a better volumetric sweep of the reservoir. The presence of free gas within either the water or oil will enhance any tendency for a gravity segregation to the degree that it slows down the flood. However, at the same time the horizonal advance is reduced, the vertical flow of oil and water is also reduced. This effect would be in the direction to counteract gravity segregation.

The effect of free gas on the importance of operating variables such as speed of waterflooding and spacing would be so much a matter of speculation that it should not be discussed. There is little enough known of these factors in two-phase systems without introducing the complicating effect of a gas saturation.

SEPARATE GAS PHASE VS. DISSOLVED GAS

Thus far the discussion has assumed that injected gas would exist as a separate phase and the many factors have been enumerated. The factors to be considered when gas is dissolved are almost as numerous. The solution of gas not only increases oil volume, it reduces oil viscosity, changes the oil-water interfacial tension, and changes the ability of oil to dissolve waxes and asphalts. Each of these changes is generally held to be desirable and in the direction of better linear displacement, better areal sweep coverage, and lowered oil residuals. It is difficult to cite an adverse effect on the anticipated recovery of oil when oil properties are changed by the solution of gas. These effects are generally held to be minor when gas is used in waterflooding because of the relatively small volumes of gas used. However, there is no proof of this point.

One comes finally to the most difficult part of the entire question. Which of these enumerated effects is the most important, and how can one produce the necessary reservoir conditions to gain the benefits of a particular effect? This question assumes that injected gas might produce different reservoir situations, so it might be well at this point to enumerate those alternatives that might be expected to take place when gas is injected. These are:

1) the gas increases present gas saturation by being distributed uniformly, or

2) the gas increases gas saturation locally around the injection well, or

3) the gas increases gas saturation locally along a line between injection and producer, or

4) the gas goes preferentially to strata of high or low permeability, probably the former, or

5) the gas goes preferentially to the top of the formation.

In a primary reservoir, injected gas might follow any of these alternatives, but if gas space were developed by dropping reservoir pressure, it is expected that the first alternative would be more or less accomplished. The order of magnitude of the lowering of residual oil by the presence of free gas would appear to be sufficient to make this effect of the first importance, therefore, if a primary reservoir were being considered.

In a depleted reservoir, on the other hand, where free gas saturation is already high, it is difficult to sustain an argument in favor of the idea that injected gas will raise the free gas saturation uniformly and result in a lowering of residual oil. Reservoirs depleted by solution gas prior to waterflooding are expected to have gas saturations of the order of 15-25 percent. In order to raise this saturation by gas injection, it is necessary to displace one of the liquids. It seems to me that this can be done only by a gas drive of some magnitude.

It is also difficult, in a depleted reservoir, to conceive of the injected gas as creating a high gas saturation around the well bore, then as moving ahead of the water drive and thus as effecting its beneficial results over the entire pattern. This concept is difficult to defend since it is known that gas does not bank oil very readily and a high gas saturation could not be achieved without such banking. Further, the gas saturation at depletion is generally conceived as being a continuous phase through which injected gas ought to flow in the manner of a gas drive. Gas banking under gas drive is notoriously difficult to accomplish.

In a depleted reservoir, injected gas could well increase gas saturation locally along a line between input and producing well. This, when followed by water, could conceivably produce a beneficial effect upon areal sweep coverage. Its advantage would depend upon the degree to which pressure gradients were increased along the line between input and producing wells compared to that along other flow lines. Although this situation would be easier to defend than the two first cited, it still requires that an appreciable amount of gas be injected into the depleted zone, enough, in fact, to give a gas drive down the center of a pattern.

If, for a depleted reservoir, one cannot defend the arguments that gas increases saturation uniformly or banks appreciably around the injection well, and if local accumulation between injection and producing wells is unlikely, the only alternatives left are that it goes preferentially to a stratum by virtue of permeability or to the top of the formation. In either of these events, the important effects to be achieved are those associated with heterogeneity or gravity control.

This would limit considerably the possible advantages to be derived from the injection of gas.

In some instances water may be injected to a depleted formation before gas is used (for instance, an old field may have been improperly flooded). Under this circumstance it is possible to defend the argument that gas can accumulate locally around the well bore. It can do so by displacing water, and there is no established gas space continuity to permit the gas to flow through. This reasoning would suggest that injected gas ought to follow just behind rather than just ahead of the first water injected. Free gas, so positioned, would also contribute most toward producing advantageous changes in sweep efficiency and hindering of channeling due to heterogeneity.

In all this reasoning there are at least two large unknowns which exist for all reservoir situations. First is the unknown of interaction of fluids within the formation—a concept we refer to vaguely as wettability. One cannot very well predict what course gas will take when injected into a formation, the degree to which it will followed established gas, oil, or water-channels until one has measured such fluid interactions. Generally, such knowledge is missing.

The second large unknown is the degree to which gas saturation is compressed as waterflood pressures are applied. Gas injected as a free phase can contribute benefits only as it remains free. If the gas is dissolved, the advantages must be sought from a different approach.

CONCLUSIONS

In summary, therefore, a primary reservoir should be susceptible to gas injection for the purpose of reducing residual oil and for producing advantageous effects on sweep efficiency or heterogeneity control, but it is difficult to defend any arguments for a depleted reservoir except that injected gas accumulates preferentially where it will have an advantage. The most likely accumulations are in high permeability zones, at the top of a formation, or along a line between input and producing well. For a depleted reservoir it would appear best to inject gas following some initial water rather than before. This does not take into account the beneficial effects resulting from the solution of gas within the oil.

The fact remains that many oil field operators have used gas as an adjunct to waterflooding and hold that their operations are thereby improved. This may result from more careful scrutiny of operations accompanying the use of gas rather than from the gas itself. The fact cannot be documented and the opinion of derived benefit sustained until close field records are kept, with particular attention being given to water-oil ratios and gas-oil ratios.

I trust I have made my point that the use of gas as an adjunct to waterflooding is not a simple problem. It is, in essence, an attempt to use a three-phase situation where even two-phase situations are not understood. It is not possible to draw a general conclusion as to how or why gas should be used. It is quite possible that there are places where it should not be used. In any use, results will be unsusceptible to analysis unless the tremendous number of factors I have enumerated here are all considered, and have been found to be absent or under control. There is some question in my mind as to whether any field use can be analyzed and results traced to a specific cause, to the exclusion of all other causes, with the tools presently available.

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STUDIES OF WATERFLOOD PERFORMANCE
I.—CAUSES AND CHARACTER OF RESIDUAL OIL

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ABSTRACT

Residual oil is that which is left unrecovered by the reservoir depletion process. The efficiency of waterflooding can be described in terms of the ratio of the amount of residual oil left after secondary recovery to that left after primary recovery.

There is only meager information about the exact causes and character of residual oil, but this is needed if accurate predictions are to be made about recovery factors. Also, an understanding of what residual oil is, and where it is and why, may provide the clue to how to control the depletion process so as to get maximum recovery of oil.

Experience shows that even under the most favorable conditions, residual oil is characteristic of ordinary methods of recovery. This implies that somehow the driving force effectively goes to zero, and/or the recovery path effectively is broken before all the oil is recovered. In some cases it is easy to visualize why the necessary condition of having simultaneously a driving force and recovery path is not met, and why therefore large volumes of oil are not recovered; but in other cases the reasons are obscure.

In this paper, residual oil is classified as that left in unswept regions, or as that left in swept regions of the reservoir because of microscopic bypassing and/or the effect of capillary restraining forces. Other distinctions are discussed that lead to a comprehensive description of the causes and character of residual oil, and to some implications about how residual oil might be minimized in field operations. The classification is thought to be complete as regards topics discussed, although it is evident that many details still are not known.

INTRODUCTION

Much of the modern literature of petroleum technology deals with the question of how to produce oil efficiently consistent with the demands of economics and conservation. More research and publication are to be expected because it is usually not easy, after the period of flush production, to produce oil. Moreover, no practical method is known, short of mining, that will recover all of the oil, although this statement may cease to hold once the economics of heat and solvent extraction methods are established.

The general reasons for the occurrence of residual oil are at least partially known, and it is surprising that there have been so few attempts to describe the causes and character of residual oil.

In this paper residual oil is defined as that left unrecovered by ordinary methods of depletion. Barrels of oil, barrels per acre, or percentage of pore space saturation are all convenient ways to express quantity of residual oil. Thus, a certain percentage of the pore space will be left saturated with residual oil at the end of the primary recovery history; and it is hoped that a lesser percentage will remain after secondary recovery. In fact, residual oil is to be expected in the unswept regions of reservoirs that have been depleted by theoretically 100 percent efficient recovery methods such as solvent extraction or *in situ* combustion.

The purpose of this paper is to describe what residual oil is, and what gives rise to its occurrence. The treatment is largely from the microscopic point of view because residual oil frequently is isolated in particular (microscopic) pore spaces, or groups of adjacent pores, as a result of the interplay between driving forces and restraining capillary forces. The latter, of course, have only microscopic significance.

It is reasonable to assume that the more we learn about the causes and character of residual oil, the better guide we have for the development of practical methods of oil recovery. Specifically, the delineation of where residual oil is, and why, in itself suggests what might be done to reduce its quantity and frequency of occurrence. Such extensions are not a primary part of this paper, however.

It is difficult to say who first recognized the existence of residual oil. However, the subject was discussed with considerable technical insight by many early workers including James O. Lewis in 1917, Mills in 1921, and H. C. Miller in 1929. Their publications predate the birth of the science of reservoir engineering in the early 1930's and the subsequent development of present-day concepts of oil occurrence and recovery. Much credit for the development of the early concepts about the causes and character of residual oil must be given to F. E. Bartell and the project workers and advisory committee of API Project 27 (1927-1945).

On the other hand, vacuum was applied to stimulate oil production as early as 1869 and secondary recovery methods were known by the turn of the century, so we can suppose that operators in general were early aware that sizable volumes of oil are left unproduced (API, 1950). In fact, as recently as 1949 it was generally conceded that known recovery methods produce only some 50 percent of the oil that is found (Muskat, 1949, p. 2). Chilingar (1956) suggests that 60 to 75 percent of the "oil initially present in the reservoirs is left behind and considered now unrecoverable because of technological and economic barriers."

The causes and character of residual oil have a special importance in considering secondary recovery operations, for here one is dealing not only with the oil left after primary depletion, but also with that which will still be left after the secondary recovery operation. Frequently, the residual oil left after primary recovery has a cause and character that can no longer be altered. That is to say, the operator planning secondary recovery accepts the situation as if it were the initial condition, and then devises ways of producing as much additional oil as possible. But in more favorable cases the operator has control of the primary depletion process so that he can obtain optimum conditions for minimum residual oil before he begins secondary recovery. Actually, modern exploitation practice is intended to achieve maximum depletion during primary recovery, obviating the need for subsequent secondary recovery operations. In any case, before starting secondary recovery it is desirable to know as much as possible about the oil reserves target that is sought.

Likewise, it is valuable to have advance information about the causes and character of residual oil that will be left after a given secondary recovery operation. It is true that in some cases this residual oil will differ only in quantity, rather than in character, from that left by the primary depletion method; but in all cases, such information provides the only rational basis for predicting recovery factors and economics. In addition, an advance estimate of the anticipated recovery by one secondary recovery operation may provide incentive to develop alternate methods of depletion that will give greater yields.

Much of what follows is only introductory to questions about the detailed causes and character of residual oil, but the importance of the subject is established so that the convenient excuse of "intractible complexity" does not justify continued neglect of these problems if future recovery programs are to be planned intelligently.

CLASSIFICATION OF THE CAUSES OF RESIDUAL OIL

It is axiomatic that if oil is to be recovered from an underground reservoir, all the following conditions must hold simultaneously: 1) the reservoir must contain recoverable oil; 2) the reservoir space occupied by each volume of oil produced must be replaced by some other fluid (e.g., by water, gas, or other oil); 3) there must be a path along which the oil can flow, joining the original location of the oil to the producing well bore; and 4) there must be a finite driving force that will move the oil along this path and bring in the displacing phase to occupy the vacated reservoir pore space.

Rose (1951, 1954) has discussed the capacity and replacement concepts as related to oil recovery, and the path and driving force requirements as related to the movement of oil. These factors have a special bearing on the causes of residual oil.

One major category of residual oil is that which is due to inherent properties of the reservoir system. For example, textural properties of the formation may either aid or hinder the establishment of paths for oil movement; boundary conditions that define the external limits of the reservoir or that set up internal barriers, such as faults, may isolate certain portions of the formation from the influence of the applied force fields; and fluid properties, such as those that determine the mobility ratio, can affect the efficiency of replacement.

Another category of residual oil is that due to imposed initial and boundary conditions. Thus, well spacing and the pattern arrangement between injection and production wells will be important; moreover, the past history of the primary recovery process, and the planned history of the secondary recovery process will affect significantly the resulting conditions of residual oil.

Other classifications of residual oil could distinguish between 1) oil left in swept versus unswept regions of the reservoir; 2) oil left after primary as opposed to the secondary recovery processes; and 3) residual oil having causes and character of microscopic as opposed to macroscopic significance.

But the fundamental causes would be that somehow the driving force or path conditions were not adequate for the oil to move to the recovery point and for the displacing phase to replace the oil. And these causes, in turn, would be the consequence of the nature of the reservoir system as it originally existed, and a result of the history of the field development and operation procedures as practiced and planned.

Behavior of Residual Oil

An example will illustrate our present imperfect understanding about the causes of residual oil. Take a random packing of uniform-sized spheres to represent the porous reservoir rock, and saturate the pore spaces with irreducible connate water and oil. Laboratory experience shows that such a hydrophilic system will still contain residual oil after waterflooding up to the point of a vanishingly small oil-water production ratio. The question may be asked: Why cannot 100 percent of the oil be produced from this system?

At first glance it is certainly remarkable that oil (which in the model may be regarded as the nonwetting phase) remains irreversibly trapped in the porous medium, so that even though the water imbibes in and displaces part of the oil, the system never reaches a state of minimum free-surface energy. Rather, experimental results imply that metastable equilibrium states are attained, and the trapped droplets of residual oil give rise to added energy for the system because of the existence of finite interfacial surface areas between the residual oil and the surrounding water and solid phases. For example, if the residual oil has the configuration of insular droplets, the energy per acre-foot of reservoir volume due to the existence of the water-oil interfaces is given by:

$$\text{ergs per acre-foot} = (3.6 \times 10^{9})\ (S_o f \gamma)$$

where S_o and f are the fractional residual oil saturation and reservoir porosity respectively and γ is the water-oil interfacial tension. Apparently there are energy barriers that are not easy to overcome so that the system finally can reach a stable equilibrium point (where the free energy of the water-oil interfaces has been removed by the complete displacement of the oil phase).

The point is this. Energy conditions in hydrophilic media favor the nearly complete displacement of oil by imbibing water. Moreover, the uniform pore dimensions associated with a random packing of uniform particles do not appear to possess the requisite geometry to trap large quantities of residual oil, that is, there are no cul-de-sac configurations. Although no one heretofore has seemed to consider or even recognize the paradox of finding residual oil where there is no obvious reason for its occurrence, one explanation combines the thinking of both early (Smith, 1929) and recent (Fatt, 1956) workers.

According to Smith, random packings of uniform-sized particles may be treated statistically as equivalent to ". . . an arrangement in separate hexagonal and cubic arrays

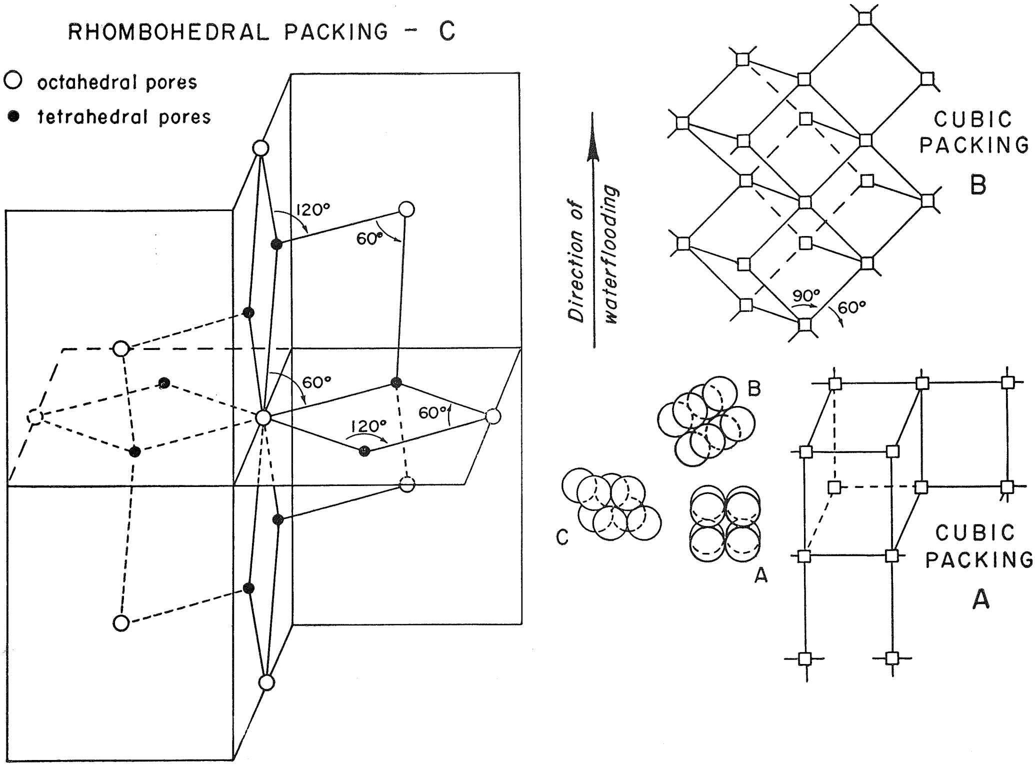

FIG. 1.—Network model representing random packing of uniform-sized spheres.

A) Cubic packing elements oriented in direction of flow.

B) Cubic packing elements resting on rhombohedral faces and oriented so no pores are orthogonal or parallel to direction of flow.

C) Rhombohedral packing showing each octrahedral pore enlargement connected to eight tetrahedral pore enlargements, and each tetrahedral pore enlargement connected to four octahedral pore enlargements.

in the proportion required to yield the observed porosity . . ." according to the formula:

$$X=(0.476-f) / (0.217)$$

or

$$f=0.2595X + 0.4764 \ (1-X)$$

where X is the fraction of the total pore volume packed hexagonally, and $(1-X)$ is the fraction packed cubically. Thus, the network model form (Fatt, 1956) of a random plane through a random packing of particles would show a random interconnection between single hexagonal and square patterns in the proportion of X to $(1-X)$. Actually consideration of single hexagonal and square patterns gives only an approximate two-dimensional representation. The same argument and consequences follow if three-dimensional tetrahedral and cubic patterns are considered (fig. 1).

To generalize further, no matter how the hexagonal elements are oriented with respect to the direction of water imbibition and oil displacement, there can be no trapping of residual oil because all pores will be sloping in the direction of flow. The square elements, on the other hand, will permit oil to be trapped in those pores that are oriented perpendicularly to the direction of flow and displacement. These considerations are illustrated schematically in three dimensions by figure 1.

What figure 1 suggests, and what in fact would be approximately the case if the packing were formed by pouring the particles on

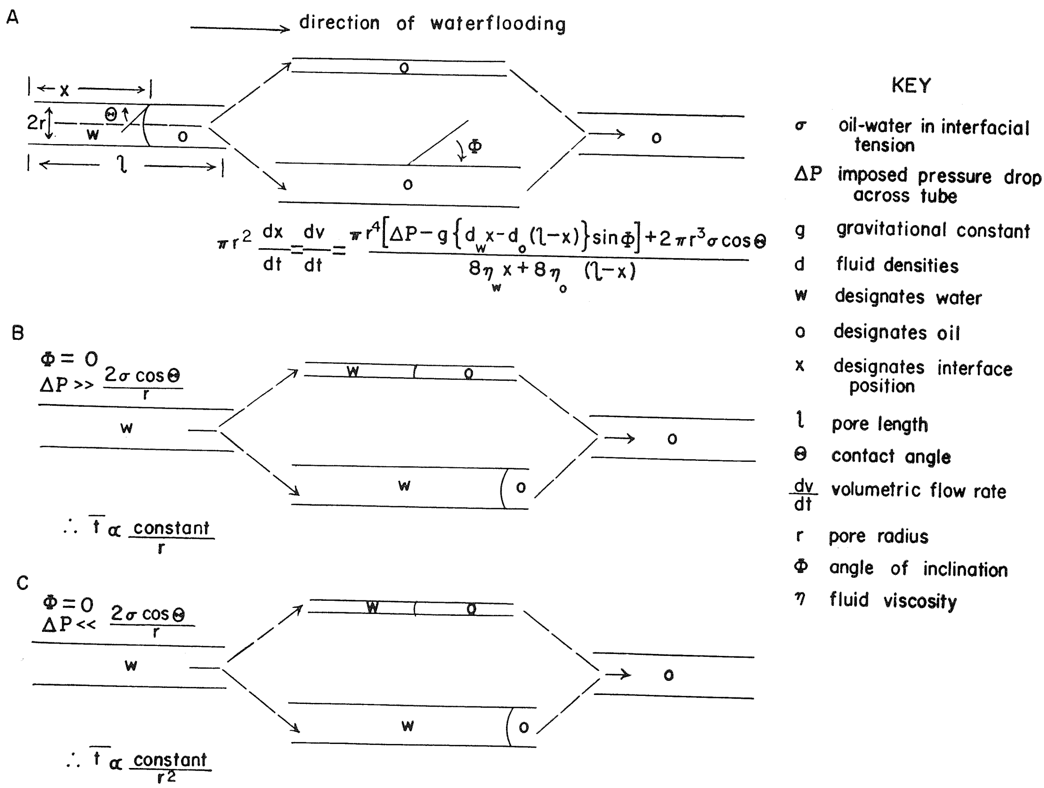

FIG. 2.—A schematic representation of displacement of oil in the pore doublet (diamond-pore configuration).

A) Water entering in the left tube with the water-oil interface moving at the rate given by the equation.

B) Displacement in the pore doublet under conditions of negligible capillary imbibition force.

C) Displacement in the pore doublet under conditions of negligible pressure-gradient driving force.

a base normal to the direction of flow, is that one-third of the spheres in cubic array would have pore spaces normal and parallel to the direction of flow (fig. 1-A); conversely, two-thirds of the spheres in square array would be oriented so that all pores sloped in the direction of flow (fig. 1-B). Likewise, all pores associated with spheres packed in hexagonal array would slope in the general direction of flow (fig. 1-C).

As uniform-sized particles (spheres) have been postulated, and as pore dimensions therefore will be uniform, it would appear that oil could be trapped by imbibing water only in pores that are normal to the direction of displacement. Actually, in three dimensions, two-thirds of the pores in "A" type of cubic array will have this orientation, which is to say two-ninths of all the pores in cubic array will contain residual oil. This is because a water-oil interface reaches both sides of the horizontal pores at the same time, effectively sealing off the oil from further displacement action. Using the notation of the above equation, the residual oil saturation S_{or} can be calculated as:

$$S_{or} = (2/9)\ (1 - X).$$

In the laboratory, random packing of uniform-sized particles usually gives a porosity of about 0.35 to 0.40 (Dallavalle, 1948, ch. 6), so that according to the above outlined theory, residual oil saturations of about 0.1 to 0.15 are to be expected. Such values have, in fact, been reported consistently.

Whether or not the foregoing discussion gives a true explanation for the cause of residual oil in waterflooding random packings of uniform-sized particles, the fact remains that there is no other convincing explanation to be found in the published literature, although we have made a reasonable numerical check of published laboratory results. And if there is uncertainty about the causes of residual oil in simple porous media systems, there must be even greater uncertainty about the causes of residual oil in reservoir rock depleted by ordinary recovery methods.

Network Model Indications

The continuing controversy about the effect of rate of flooding on increasing recovery in waterflood operations provides another example of how little is known about the causes of residual oil. Similarly, there is the long-standing question about the effect of curtailment of waterflood production (for example, by proration) on ultimate recovery. Laboratory treatment of these problems is inadequate for one reason or another; but if the causes of residual oil were known, theory could give at least semiquantitative answers.

For example, Benner, Riches, and Bartell (1943) discuss trapping of oil as influenced by surface (capillary) forces and by reservoir rock pore size distribution. Figure 2 reproduces the simple diamond pore configuration they used to illustrate the rate dependence of waterflooding recovery. They suggested correctly that at high rates of water injection the large (lower) pore empties first so that some oil is trapped in the smaller (upper) branch, but they concluded that at low rates when displacement was effected by natural water imbibition, oil would be trapped in the larger pore because of what they termed the "phenomenon of counterflow." They explained the latter by saying that the oil pressure in the smaller pore always exceeded the entry pressure that would permit oil to flow back into the larger pore. Thus, they inferred that an optimum (intermediate) flooding rate existed where oil would be trapped in neither branch (that is, 100 percent recovery).

Although the conclusion may be correct, the above treatment can be questioned in several ways. First, counterflow will not occur unless oil is constrained from escaping out the right-hand joining tube (fig. 2), which is in fact the experimental condition imposed by Benner et al. to illustrate their concept. In the more realistic case where oil is not so constrained, it is clear that oil is always trapped in the smaller (upper) pore regardless of rate, as shown, for example, by the analytical treatment of Barrer (1948). This would suggest that waterflooding efficiency *is* rate sensitive, but that the maximum recovery is not associated with the maximum rate as some claim from other evidence. Rose and Witherspoon (1956) have discussed these aspects in detail.

It will be clear, however, that the model shown in figure 2 is too simple for an accurate analysis of complex transient displacement processes. In fact, use of simple models often has been criticized on the grounds that pseudo-proofs of almost any proposition can be obtained, and this is part of the reason that evidently led Fatt (1956) to develop the more complex network models of porous media.

Work in this laboratory extending the usefulness of network models to treat such problems as waterflooding recovery, makes it appear that fairly accurate representations of two-phase (transient) displacement phenomena eventually can be obtained. This work will be reported when completed (Rose et al., in preparation) and depends on the use of a high-speed digital computer (ILLIAC) to specify the interstitial distribution of water and oil, and to trace the history of displacement in large (10,000-pore) three-dimensional network models that closely resemble real porous media prototype systems. As a matter of interest, in the procedure being followed, the initial (virgin) distribution of oil and water is obtained by a method analogous to that cited by Fatt, and then the equivalent of the relaxation method (Dykstra and Parsons, 1952) is employed to evaluate local pressures at pore junctions when displacement begins. By considering infinitesimal intervals of time, a succession of steady-state solutions is obtained that describes the transient displacement process.

It is still too early to anticipate results, but other preliminary ideas have been developed from studies using network models in accordance with Fatt's elementary method of

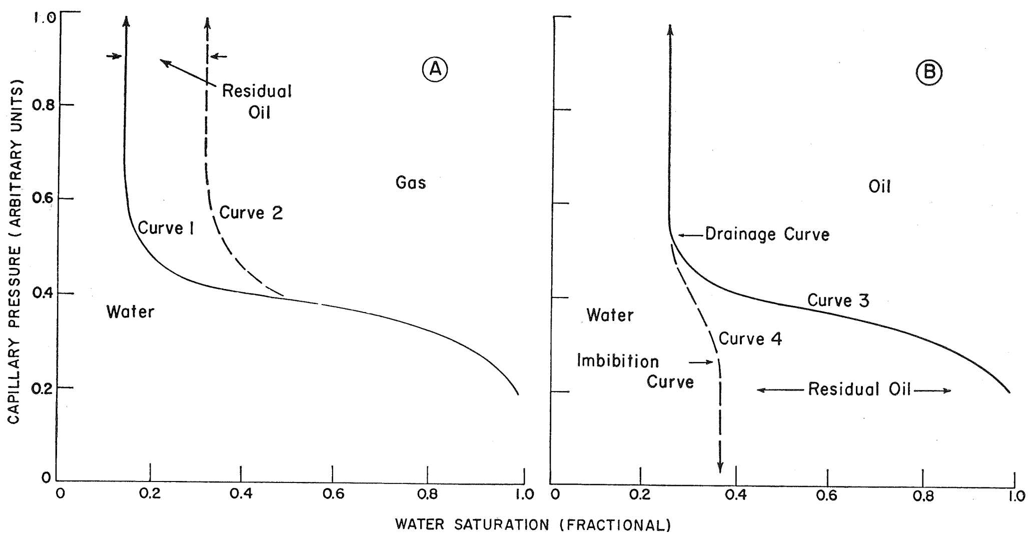

FIG. 3.—Capillary pressure curves obtained by network model analysis.

A) The data of Rose, Carpenter, and Witherspoon (1956) showing the magnitude of residual oil trapped during external gas-drive displacement. Curve 1 depicts oil displacing connate water as occurred during the accumulation process. Curve 2 depicts the entry of a gas-phase displacing oil.

B) Imbibition waterflooding showing the magnitude of trapped oil in this case. Curve 3 is analogous to curve 1 of figure 3-A. Curve 4 depicts the imbibition entry of water displacing oil.

treatment. Figure 3-A reproduces the capillary pressure curves of Rose, Carpenter, and Witherspoon (1956), which show that gas displacing oil from a system containing irreducible connate water leaves sizable volumes of trapped residual oil (compare curves 1 and 2). This was taken to explain why oil located in the largest pores, and not subject to the type of trapping illustrated in the first example (fig. 1), nonetheless would be bypassed in part because of pore size variation for the special case in which the gas pressure at the gas-oil interfaces is gradually increasing.

No one has mentioned the fact that 100 percent oil recovery is indicated in network models simply by imposing the condition that the gas pressure is always greater than the entry pressure for the smallest oil-filled pore; but this proposition is shown by the method of analysis that results in figure 3-A. Some of the effectiveness of the high-pressure gas injection method and the associated high recovery of oil obtained thereby may be thus explained as it is reasonable to suppose that in ordinary gas injection the gas pressure at local gas-oil interfaces may not suffice for gas entry into all oil-filled and oil-wetted pores. It will be recognized that P.V.T. effects also are important in establishing a transition zone of no gas-oil interfaces, so that capillary forces do not hinder the displacement of oil in the high-pressure gas-injection process. On the other hand, the idea of entrapment of oil due to insufficient gas entry pressure has not been mentioned before.

Figure 3-B also shows (curve 4) an imbibition curve, indicating the entrapment, via bypassing, of sizable volumes of oil as water slowly moves into the oil-water system. This curve is of special interest inasmuch as it depicts a situation experimentally reported by Welge (1949) and theoretically questioned by Rose (1949) and Purcell (1950). Welge's data showed hardly any spontaneous water imbibition into oil-filled (presumably hydrophilic) sandstones, and implied the necessity of negative capillary pressure conditions to explain high waterflood recoveries, which Rose disputed and Purcell rationalized.

The point of present interest is that analysis with the network model shows remarkable conformance to laboratory data with respect to defining the limits of the hysteresis zone; moreover, it says that recovery efficiency will be low for spontaneous (slow) imbibition of water. That is, curve C of figure 3 was obtained by assuming that the capillary pressure was gradually decreased (the water pressure gradually increased relative to the oil pressure at local points of water-oil interfacial contact). As in the case of gas-drive mentioned above, the network model analysis would give considerably more efficient recovery of oil by waterflooding under conditions of high-pressure water-injection, which is the same proposition proved by others in a variety of other ways.

No complete discussion of the microscopics of residual oil can be given until methods, such as those now being developed, are available to treat in detail the transients of the displacement process. Essentially all that has been established up to this point is that microscopic trapping can cause residual oil, and this trapping may depend mainly on pore orientation (fig. 1) or pore size distribution (fig. 3). Such trapping always implies there is no longer a continuous path for oil recovery even though the force field may continue to act. And, as a generality, the entrapment of oil and the breaking of the microscopic paths of continuity must always be associated with the interplay between surface forces and the prevailing driving forces. Surface forces also may give rise to residual oil by balancing the driving forces, even though the paths of continuity are not broken. Likewise, broken paths can occur far from regions of residual oil, as in the case of the flood front jumping ahead of sand lenses whose texture is different from that of the reservoir at large (Buckley and Leverett, 1942).

On the other hand, there are additional examples of residual oil caused by a zero or near-zero driving force. Oil left in the unswept portion of pattern floods belongs in this category, as does oil left in the tight layers of stratified reservoirs being waterflooded. The existence of impermeable faults and other textural anomalies can cause local conditions of near-zero force fields, as can partially penetrating injection and production wells, so that unrecovered oil will be lost as a consequence. Another example would be that oil unrecovered not because the original driving force was dissipated or destroyed, but because other opposing forces (such as those of capillary origin) became prominent. In addition, even some aspects of the phenomena of fingering can be thought of as due to the "uneven" transfer of driving force at the flood front, although in other respects such residual oil can be described as bypassed (trapped) oil. Finally, retrograde condensation phenomena represent hydrocarbon reserves that are no longer subject to a driving force (because of a phase change) so that residual oil results.

CHARACTER OF RESIDUAL OIL

Diversity in the character of residual oil parallels the diversity in causes. Thus, residual oil in unswept regions will appear in character exactly as undisturbed virgin oil; likewise, oil left after internal gas drive will appear different from that left by external gas displacement. Actually, however, given the problem of the secondary recovery of residual oil left by primary depletion, the technologist is interested in the causes of this primary residual oil only to the extent that such information helps to define its detailed character. It is the cause that must be known if an accurate evaluation is to be made of the secondary recovery prospects.

The location and configuration of residual oil thus is in part determined by its past history, that is, where it was during the transient period before it became residual. Also important is the past history which has given rise to the occurrence and distribution of the other pore saturants, such as water and gas. Of course, from the microscopic standpoint, the nature of the fluid-fluid and fluid-solid interactions (occurring in response to interfacial forces) will be especially important in determining character, as will be the more or less accidental matter of how much oil is initially present to be later trapped in whole or in part. Likewise, pore structure and physical properties of the fluid saturants will be important.

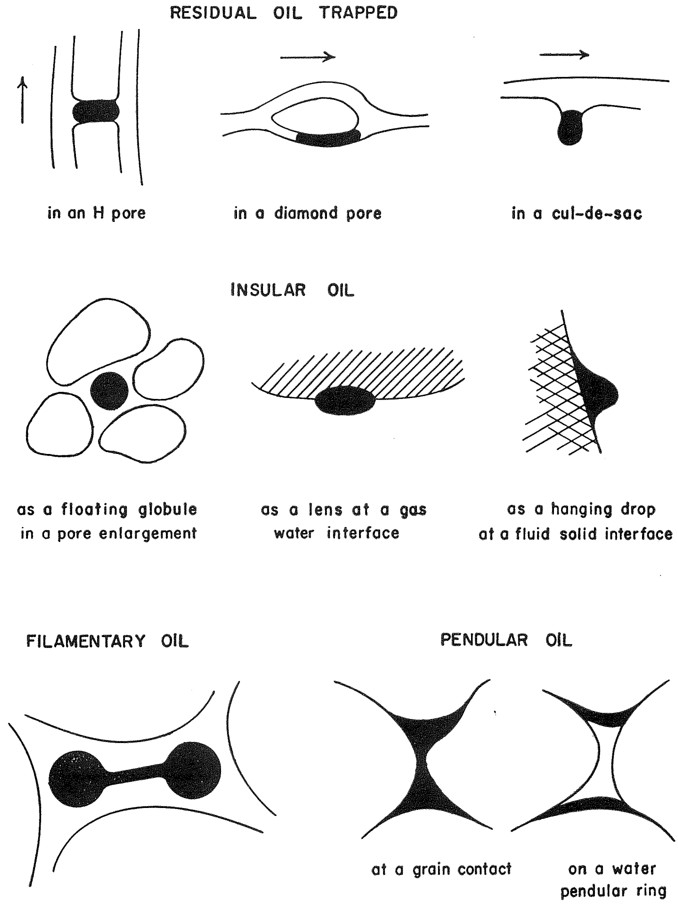

FIG. 4.—Examples of residual oil character shown in diagrammatic detail.

If for the moment, consideration is limited to residual oil that has resulted because of lack of path continuity over distances comparable to the pore dimensions, one or more of the following types of configurations can be expected (fig. 4)*:

1. Residual oil due to pore orientation or pore size distribution:
   a. in H-shaped pores (fig. 1)
   b. in bypassed small pores (fig. 3)
   c. in "diamond" shaped pores (Benner et al., 1943)
   d. in cul-de-sac pores
2. Insular† residual oil in the form of centrally located globules that rest in the central pore enlargements, and which lie where in its absence there would be:
   a. a gas-water interface
   b. a gas-solid interface
   c. a water-solid phase interface
   d. various types of fluid-fluid and/or fluid-solid phase interfaces; or where
   e. the globules are emulsified in the surrounding water phase
3. Funicular oil with filamentary interconnections between pore spaces
4. Pendular oil in situations where oil acts as the wetting phase.

In any case, residual oil located as a disconnected phase in single pores or groups of contiguous pores will be bounded by inter-

*See also figs. 1-23 given by Pirson (1951).

†Oil contained in cul-de-sacs that subsequently became closed by cementation may be thought of as "isolated" rather than insular oil. Acidizing and formation parting might be used to reach this oil.

facial surfaces affected by the local pore shapes, by the local pressures in the various fluids, and by the requirement that fluid-fluid interfaces seek to occupy minimum surface area (that is, one which has minimum free-surface energy). Such residual oil exists because of lack of oil-phase continuity, and without reference to the existing force fields (contiguous moving water) which could displace additional oil if a path were available.

W. O. Smith (1931), Dallavalle (1948), Gardescu (1930), and Leverett (1941) have discussed fluid-fluid interfacial shapes as derived from fundamental considerations. This subject is extremely complex, and satisfactory solutions have been obtained only for limiting (static equilibrium) cases where simple pore geometry is postulated. Perhaps no more can be expected. Nonetheless, the picture is quite incomplete, especially as the prevalence of fluid-fluid interfaces and the importance of transfer of viscous forces across fluid-fluid interfaces is not defined at all, even for static equilibrium and steady-state situations.

One important observation may be made, however, without explicit description of transient fluid-fluid interfacial shapes. In general, the specific surface area of the interfaces will increase as oil saturation decreases (that is, as the oil is produced) because the oil-phase continuity is never increasing. In other words, the ratio of surface to volume necessarily increases as the volume decreases, especially if oil-phase continuity is decreasing. Thus any recovery process that is marked by a decrease in oil saturation, but no change in degree of oil-phase continuity, will tend to be a reversible process except to the extent that this is prevented by hysteresis in contact angle, and so forth. On the other hand, if the increase in interfacial specific surface area arises because of the creation of new boundaries between the oil and the displacing phase, reversibility is not to be expected.

The above point is illustrated schematically for one case by figure 5. Here it is suggested that as the oil saturation is decreased, phase continuity is finally broken by coalescence of the displacing water phase. If oil saturation subsequently is increased, the

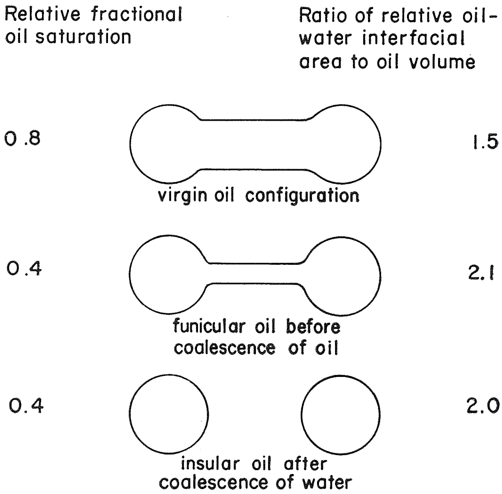

FIG. 5.—Schematic representation showing how funicular oil configurations finally assume insular configurations during oil recovery by coalescence of the filamentary interconnecting links.

water-block will tend to persist as a barrier between the disconnected oil globules. From this, one can deduce the general principle that oil recovery is favored (and residual oil minimized) in instances where oil saturation can be decreased without creating new interfaces between oil and the displacing phase. This is because oil phase continuity is maintained, an important consideration when subsequent secondary recovery is to be considered. Moreover, the energy requirements for the creation of new fluid-fluid interfaces is kept at a minimum.

It is clear (fig. 5) from simple geometric considerations that surface-free energy per unit volume of the two globules of residual oil is less than that of any other configuration, for example, globules joined by a filament in the manner of a dumbbell. This, in fact, is why the water coalesces between the two pore enlargements, as the net result is to reduce the free energy of the system. Similarly, this coalescence explains the inherent nonreversability mentioned above, because an energy barrier is created that tends to keep the separated globules continuously apart, at least until growth of the pore boundaries forces the globules to rejoin.

Unfortunately, the principle of increasing oil recovery by avoiding creation of new in-

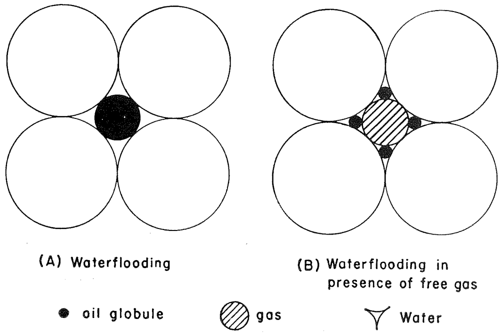

FIG. 6.—Schematic representation showing how globules of residual oil occupy less volume in the presence of free gas than when oil recovery involves only water displacement.

terfaces between the oil and the displacing phase is not subject to rigorous proof, although Brown (1956) recently referred to this principle. True, the more stable configuration of insular oil increases the requirements for a driving force that opposes the capillary forces and reestablishes continuity so oil can move. But we cannot state the absolute importance of this factor in quantitative terms. On the other hand, it is interesting to speculate that the reported increase in waterflooding efficiency due to free gas saturation at the flood frônt may provide a partial substantiation of the above theory. Thus, it would seem reasonable that the free gas occupying the central pore spaces would mean that the oil saturation could be reduced to relatively low values before discontinuous (insular) globules of residual oil were obtained. This explanation differs somewhat from that given by others (Kyte et al., 1956).

By taking a regular packing of uniform-size spheres as the reservoir model, Furnas' treatment of multicomponent systems for minimum voids (as quoted by Dallavalle, 1948) can be used to illustrate how residual oil in waterflooding is diminished by the presence of free gas. First let it be assumed that residual oil caused by waterflooding in the absence of free gas can be represented by the volume of small spheres which just fill the voids of the packing model without increasing the bulk volume. Then, using Furnas' calculations, in a 40 percent porosity system, the maximum residual oil saturation will be of the order of 50 to 60 percent; but with both gas and oil filling the central pore spaces (that is, analyzed by considering a three-component system), the maximum value of the residual oil will be reduced to a saturation of about 22 percent. That is to say, if free gas is brought in to occupy the largest pore spaces, then after waterflooding the residual or insular oil globules can occupy only 22 percent of the pore space instead of up to 60 percent in the absence of free gas.* Figure 6 schematically illustrates these concepts.

Dallavalle (1948, ch. 6) also gives calculations that show how smaller spheres can be fitted into the pore spaces of a rhombohedral packing of uniform sized spheres, and these can be used to further illustrate the principle that residual oil is probably diminished by the presence of free gas. For here it is shown that in the octrahedral and tetrahedral pore spaces there is room for about 27 percent of pore volume to be filled by residual oil globules if there is no free gas present. However, if this 27 percent of pore space is filled with free gas, then the residual oil globules will be confined to pore space amounting to some 12.3 percent of the total. Geometrically it can be shown that the residual globules (gas or oil) in the octrahedral and tetrahedral pores will be 0.414d and 0.225d, respectively, where d is the particle diameter; however, if free gas is in this pore space, the residual oil globules will then have a size of 0.177d with a number of them surrounding each globule of gas.

Pendular residual oil is possible but perhaps not of frequent occurrence. In hydrophylic reservoir rock, either gas drive or gravity drainage will produce residual oil, and the question may be asked: Is the oil in the form of pendular rings, lying for example on pendular rings of water? In this case the oil must be regarded as a wetting phase with respect to gas-solid phase contacts, although it is nonwetting with respect to the water-solid phase contacts. Muskat (1949b) implies it is unrealistic to expect to find pendu-

*In real reservoir rock, because of the influence of pore size distribution, not all of the central pore spaces will contain insular oil globules. Hence, the above quoted residuals of 60 and 22 percent saturation in the presence of free gas represent limiting maximum values not necessarily observed in nature. However, the ratio of 22 to 60 indicates an increase in efficiency of more than 50 percent, which is in accord with published figures showing the improvement in waterflooding attributed to the presence of free gas.

lar rings of oil on pendular rings of water, but that the more likely situation is that as the gas saturation increases and the oil saturation decreases, ". . . the oil and gas invert their roles. The gas becomes the continuous apparent wetting phase, and, relative to it, the oil will behave as the single nonwetting phase." In this way, Muskat circumvented the difficulty of having to assume oil as the wetting phase with respect to gas, and reaching the unverified conclusion that residual oil would approach zero for gas displacement processes.

Drawings in figure 3, which were obtained by network model analysis, are nonetheless representative of laboratory data that show finite residual oil for all cases. However, the residual oil depicted by figure 3 is bypassed oil which, for example, could be in locally funicular rather than pendular or insular configuration. Muskat felt that pendular configurations were patently not plausible, and that only insular globules would result in such a case. Actually, all three configurations are conceivable as can be shown by elementary considerations.

Residual oil is surrounded by either gas or water, or it lies at a gas-water interface, or it is in contact with the solid phase pore wall, or it has some intermediate kind of configuration. Just where the residual oil is located is determined by free energy considerations and by the history of the system.

Benner et al. (1943) explain the criteria for determining this in their discussion of concepts of work of adhesion and work of cohesion. If the oil has high cohesion, and if other contiguous fluids have high adhesion for the solid-phase boundaries, then residual oil will tend to assume an insular configuration. Globules of oil may also occur in spite of these energy considerations, if the history of generation is one where the oil does not "know" of the proximity of solid-phase boundaries. Likewise, the surface energy situation can be such that oil can lie in stable configuration on the gas-water interface (for example, as lenses or as pendular rings). On the other hand, the exact configuration may not be predictable, because of the complexity of evaluating the effect of the history of the system; but more basically because fluid-solid

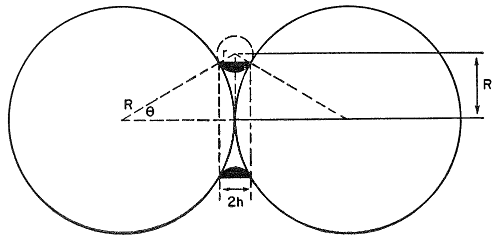

FIG. 7.—Diagram illustrating a stable configuration of pendular residual oil lying on a pendular ring of connate water.

phase interfacial tensions cannot be specified, and hence adhesion tensions cannot be stated. Contact angle hysteresis also introduces a complication.

The above discussion has referred only to hydrophilic media, but there is also a possibility of mixed wettability situations. In this case, residual oil in contact with solid-phase boundaries certainly would be expected on any oil-wetted pore surfaces. Unfortunately, there is little information about the prevalence of oil-wetted pores, or about the more complicated situations where the pore surfaces appear to be either hydrophilic or hydrophobic depending on the direction of saturation change. About all that can be said with certainty is that at least truly hydrophilic surfaces are of frequent occurrence, as exemplified by those pores coated with clays that swell when wet with water.

But we cannot neglect the possible occurrence of reservoir systems in which all the pore surfaces behave as though preferentially oil-wetted, at least during the recovery history of the reservoir. Residual oil in this situation would have pendular configuration of the type usually thought characteristic of irreducible connate water in water-wetted sandstones. Minimum quantities of pendular oil can be estimated from calculations based on the work of Smith (1930) as follows:

Porosity	Saturation of minimum-sized pendular rings Percent
26	23
30	18
34	13
38	10
42	7.4
46	5.4

The above data are for random packings of uniform-sized spheres, and hence represent limiting values. Thus we can expect large values of residual oil saturation in pendular configuration for packings of nonuniform particles, especially those having angular shapes, because there will be more grain contacts per unit volume. Also, the above data refer to minimum size pendular rings which occur when physical interconnection has just been broken. In actual reservoir situations there is probably volumetric interconnection although zero flow interconnections, which in nature would result in higher residual oil saturations.

To consider further the possibility of pendular rings of oil lying on pendular rings of water, refer to figure 7. Here the grain contact in a hydrophilic sandstone is represented by the tangent point between the two spheres. The pendular rings of water shown touch the sphere surfaces with zero contact angle at points making an angle of 30° with the line adjoining the sphere centers. Note that if θ equals 30° we have a water pendular ring that just misses coalescing with adjacent pendular rings in closest packing of spheres. The volume of this pendular ring is equal to the volume of a cylinder (having a circular base of radius $R_1 - r$, and an altitude of 2h) minus the volume of the half-moon of revolution (see below), minus the volume of two domes (having the same base as the cylinder and an altitude of h),* or

$$2\pi R^3 \left\{ 2 - 2\cos\theta - \tan\theta \left[2\sin\theta - \tan\theta + \left(\frac{\pi}{2} - \theta\right)\left(1 - \frac{1}{\cos\theta}\right)^2 \right] \right\}$$

*Dallavalle (1948, p. 288) gives the volume of such a pendular ring as:

$$\frac{\pi R^3 \sin^4\left(\frac{\theta}{2}\right)}{8\cos^2\left(\frac{\theta}{2}\right)} \left[1 - \tan\theta\left(\frac{\pi}{2} - \theta\right) \right]$$

This volume by calculation equals 60 if R=10, and represents 24.5 percent of the pore volume in a rhombohedral packing of spheres, and for this example will be thought of as filled with water, that is, the wetting phase. The surface area of this pendular ring is given by

$$4\pi R^2 \left[\left(\frac{\pi}{2} - \theta\right)\tan\theta - \left(1 - \cos\theta\right) \right] \left[\frac{1 - \cos\theta}{\cos\theta} \right]$$

and if R is taken as 10, will have a value of 105. If lying over this pendular ring of water, oil is located as shown in figure 7 (namely, so there is no oil-solid phase surface area of contact), and if the assumed contact angle (measured through the wetting oil phase) is 60°, its volume will be given by:

$$2\pi R^3 \left(1 - \cos\theta\right)^2 \left[\frac{\tan\theta}{\cos\theta} \left(\frac{\pi}{2} - \theta - \sin\theta\cos\theta\right) - \frac{2}{3}\left(1 - \cos\theta\right) \right]$$

If R is 10, this half-moon volume of revolution will equal 43 when θ is 30°, which represents an oil saturation of 17.5 percent pore volume for closest packing of spheres. The above surface area formula describes the oil-water contact, and the oil-gas area of contact is given simply by the surface of the right cylinder of altitude 2h and circular base of radius equal to $R_1 - r$. Numerically, the latter equals 84 when R is 10.

Taking 10, 25, and 70 dynes per centimeter as the oil-gas, oil-water, and gas-water interfacial tensions, respectively, the free energy associated with each pendular ring is therefore seen to be equal to $(105 \times 25 + 85 \times 10)$ or 3270 relative ergs. However, if the above mentioned volume of oil (43 square units of length) was contracted in the shape of a globular sphere, this sphere would be small enough (radius equals 2.17) to fit into either the tetrahedral or octahedral pores (fig. 1), and it would have a reduced surface area of about 59 units. This configuration is less stable than that of oil lying on pendular rings. This is because the free energy of the new water-gas interface (105×70) more than offsets the decrease in free energy associated with the oil-water (and/or oil-gas) interface (59×10 or 59×25). Evidently, residual oil is to be expected to occur sometimes on pendular water surfaces (rather than as globules) since the work of adhesion between the water and oil is greater (in the usual case) than the work of cohesion in the oil itself.

The above formulations do not take into account the fact that actual pendular rings are only approximately described by arcs of circles (Dallavalle, 1948; von Engelhardt 1956).

From the foregoing, we may conclude perhaps that insular oil is the most common configuration of residual oil that will be encountered in field situations. Pendular oil may sometimes occur, and cul-de-sac oil and oil trapped in H-pores and diamond-shaped pores certainly will occur in accordance with the frequency of occurrence of such pore configurations. These describe the nature of occurrences in single pores and pore enlargements. If larger volumes of residual oil characterize the depletion process, interconnections between adjacent pores and groups of pores can be expected, and hence the designation of residual oil in funicular (filamentary) configuration. As mentioned, these arrangements may have high free surface energy associated with them, but if a certain volume of residual oil is to be contained in the porous continuum, pore texture alone will determine whether insular or funicular configurations will be necessary. Finally, in residual oil left in unswept portions of the reservoir, such configurations can best be described as "virgin" to indicate they are those characteristic of the reservoir before any oil was withdrawn.

It is thus clear that the character of residual oil depends upon factors fixed by the nature of the reservoir itself—initial and boundary conditions, pore texture, fluid properties—and on other arbitrary factors that include the history of depletion. The time factor is especially important in the sense that funicular configurations of residual oil may characterize the economic depletion end-point, although insular configuration would be obtained later at the true depletion end-point where no more oil can be produced. Also, it is to be expected that there are gradations from one type of residual oil to others, going from point to point in given reservoirs, and considering the same point at different times during primary and secondary recovery history.

Muskat's discussion of recovery factors in gravity drainage (1949, p. 885 ff.) is particularly apropos in these connections. He speaks of ". . . the simple observation that as long as the oil phase has a nonvanishing permeability it will of necessity move in the direction of the net force acting on it. . . . Except for the time factor the ultimate recovery will thus be simply determined by the residual oil saturation at which the oil permeability becomes vanishing. . . . It is the magnitude of this residual-oil saturation that is the crux of the evaluation of . . . oil-recovery mechanism[s]. . . . The physical criterion of mobility [is] the limiting factor in all fluid-displacement processes. . . ."

Muskat also notes, "The upper saturation limit for the globular discontinuous distribution of the oil phase should be determined largely by the microscopic pore structure and the geometry of the porous medium. . . . It is conceivable, however, that the values of the interfacial tensions and the microscopic-flow processes will also affect the value of the saturation at which local continuity of the oil phase may be destroyed." These ideas are consistent with those presented in our paper, as is Muskat's conclusion that ". . . the construction of a detailed physical theory of these phenomena merely to rationalize the few data available . . . is hardly warranted."

On the other hand, our paper holds that the new methods of network model analysis offer promise that a theoretical treatment of limiting cases of residual oil causes and character eventually can be treated, whether or not there will ever be a point in seeking direct confirmation from experimental results. It appears that laboratory studies at best can offer only gross information about the microscopic quantities of residual oil left by depletion process; yet it is the microscopic details that are of prime importance.

This section on the character of residual oil would not be complete without reference to the pioneering work of API Project 47B, "Microscopic Behavior of Fluids in Porous Systems" (Calhoun and Chatenever, 1952).

The API work included microscopic (visual) examination of residual oil configurations, as also has the work of Templeton (1954). Calhoun and Chatenever (1952) suggest, "Most of the interest in residual oil formations derives from a desire to avoid them or, having formed them, to displace them." Consistent with their frequent observation of channel flow and displacement, they stated, "In waterfloods, the most apparent residual oil formations were those large volumes bypassed by the water . . ." which were ". . . continuous over many sphere diameters . . ." of their observation cells. However they also saw residual oil globules in single pore enlargement, sometimes rotating in accordance with the principle that there is a transfer of viscous forces across fluid-fluid interfaces (Yuster, 1953), and apparently firmly restrained from further displacement by capillary forces. Chatenever and Calhoun also observed pendular configurations of residual oil in oleophilic systems. Perhaps further work of this sort will be needed to clarify the true character of residual oil, although it is evident that techniques must be devised that minimize the dependence of the observed effects on the arbitrary situation caused by the observation window. Also, the displacement process should be similar to that of a scale model experiment according to well known requirements.

Templeton (1954) in observing the displacement of oil by water and by gas and water in small-diameter (3 to 7 microns) capillary tubes, observed interfacial instability and other "interesting microscopic phenomena" which he concluded "probably occur in petroleum reservoirs" during recovery. He observed that the displacing water advanced ahead of the displaced oil along the capillary walls, so that when displacement rate diminished or ceased, the distorted interfacial boundaries formed slugs of residual oil, sometimes bounded by tori of water. He also observed the tendency of oil to collect on the water-air interface when water followed air in the displacement of oil. In this case, as the volume of the collected oil increased, a semi-rigid oil "sac" was developed behind the advancing water-gas interface, which nonetheless was carried along even as it grew. This was interpreted as an example of the existence of film-forming constituents in crude oils which sometimes seem to cause angular interfacial boundaries.

Neiderhauser and Bartell (1950) suggest that these rigid films may have to do with surface oxidation effects rather than something that could be expected to occur naturally in the anaerobic subsurface environment. Much more must be learned about this apparent contradiction of surface energy principles that predicts that fluid-fluid boundaries have smooth shapes of minimum surface area compatible with the fluid volumes involved.

CONCLUSIONS

We have described the causes and character of residual oil in an elementary manner. Such a preliminary step has been necessary because of the complexity of the subject matter, and because only few authors in the past have given it deserved attention. Ultimately, the qualitative descriptions of causes, and the conceptual ideas about character, may be supplanted by fairly rigorous analytic (and fairly accurate experimental) statements concerning residual oil. Recent work by Iffly (1956) and Hubbert (1956), for example, show that there *is* hope of understanding the details of petroleum occurrence and recovery, derivable from the study of individual-pore situations.

Aside from academic interests, delineation of the causes and character of residual oil has a practical purpose. This is illustrated nicely by waterflooding. Answering the question of why oil is left unrecovered by the primary depletion process may suggest ways for revising the primary recovery operation so that subsequent secondary recovery will not be necessary. When waterflooding is indicated, however, knowledge of the exact character of the residual oil left after primary depletion helps determine what operating procedures should be followed. Anticipated recoveries are also more easily predicted than if the character of residual oil has not been specified. Finally, when the causes and character of residual oil become understood for particular cases, a guide is available for planning secondary recovery operations so that maximum recovery will be achieved.

This paper implies that the major causes of residual oil have to do with either 1) conditions that favor discontinuities developing in the oil phase and so breaking possible transfer paths, or 2) circumstances that tend to isolate large volumes of oil from the influence of possible driving forces.

This paper also implies that much residual oil may have globular (insular) configuration. Other possible configurations, however, include: cul-de-sacs, diamond-shaped pores, H-pores, adhesion-force trapping due to preferential wetting of certain pore surfaces by the oil phase, trapping at gas-water interfaces as lenses and multilayered films; and configurations that have filamentary continuity over several or many pores. In fact, the last is illustrated by the undisturbed (virgin) residual oil found in unswept portions of the reservoir where near-zero driving forces have been active.

In seeking ways to increase oil recovery, and to predict anticipated recoveries as a function of operating plans, the purpose of establishing causes and character of residual oil is evident. This paper defines the problem and suggests some of the work that must be undertaken in the future.

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