Waterflooding of Oilfields in Western Nebraska

By Donald P. Blasko, Joseph N. Harstead, and Paul Biggs

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WATERFLOODING OF OILFIELDS IN WESTERN NEBRASKA

by

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CONTENTS

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CONTENTS--Continued

ILLUSTRATIONS

ILLUSTRATIONS--Continued

ILLUSTRATIONS--Continued

TABLES

TABLES--Continued

SUMMARY

In June 1949 oil was discovered near the small town of Gurley in the western Nebraska "panhandle." The discovery led to extensive drilling activity in the Denver-Julesburg Basin, now one of the significant oil producing provinces in the United States.

Most oilfields in the basin are small stratigraphic traps productive in either or both the "D" and "J" sands of Cretaceous age. The waterfloods for secondary recovery of petroleum are concentrated largely in Banner and Kimball Counties. Many fields in Cheyenne County have a natural water drive. Where a natural water drive is present, high primary recovery makes waterflooding uneconomical.

Of the 49 waterflood projects cited in this report, 36 are in the "J" sand, 8 in the "D" sand, and 5 in both the "D" and the "J" sands. Collectively, the "J" sand reservoirs have responded far more favorably to waterflooding than have the "D" sand reservoirs.

Sixteen "J" sand projects, three "D" sand projects, and one "D" and "J" sand project are well underway, presenting every indication of eventual success; two "D" sand projects are apparent failures. The outcome of the remaining projects is indeterminate because they are at an early stage of flood life.

Based on volumetric determinations, an estimated 72,600,000 barrels of primary oil and an estimated 63,200,000 barrels of secondary (waterflood) oil will be recovered from the 49 projects. Oil recovered to the end of 1963 amounted to 91,010,000 barrels or 67 percent of estimated total recovery (primary plus secondary oil). Estimated recoverable oil remaining was 44,790,000 barrels. The estimated water requirements are 480,856,000 barrels, or 61,982 acre-feet. Data for oil reserves and water requirements are provided to the Nebraska Oil and Gas Conservation Commission by the project operators.

Considering the projects as a group, some general factors are evident. Water supply is adequate and cheap. Little or no trouble has been experienced from increasing injection pressure or from corrosion of metals. When trouble has occurred, bactericides and corrosion inhibitors have been applied. If not injected into the oil reservoir, produced water is disposed of in open pits. The projects are small-scale operations, partly because the fields are small and partly because 21 of the fields are not completely unitized. Producing zones are relatively thin and, therefore, will have a short flood life. In most cases, the secondary oil recovered will approach that obtained by primary methods. The problems in waterflooding in western Nebraska seem more economic than technical.

Some natural gas is produced with all crude oil. Gas produced from the projects was considered of little importance and was not reported.

Included in the appendix are the following: Rules and regulations of the Nebraska Oil and Gas Conservation Commission covering pollution and surface drainage, disposal of water, and unit operation and secondary recovery projects; a table listing 28 water analyses from western Nebraska, including water from supply wells and water produced from the "D," "G," and "J," sands; and 10 analyses of crude oils from the area.

INTRODUCTION

This study, part of a comprehensive survey of water requirements for the mineral industry in the Missouri River basin contains individual reports on 49 waterflood projects in western Nebraska. Significant answers sought were: (1) The amount of water needed for waterflooding; and (2) the oil to be recovered by waterflooding. The overall objective is to provide government and industry with a detailed resumé of waterflooding in an area on which little information has been published.

Data for oil reserves and water requirements are provided to the Nebraska Oil and Gas Conservation Commission by the project operators. Some of the data in this report were rechecked by the operators.

Geographically, the area lies on the western edge of the Great Plains of the central United States. The terrain is relatively flat, having an average elevation above sea level of about 5,000 feet. The principal towns are Scottsbluff, Sidney, and Kimball; Scottsbluff, having a population of nearly 15,000, is the largest. Two major east-west arterial routes, the main line of the Union Pacific Railroad and U.S. Highway 30, pass through Sidney and Kimball (figs. 1 and 2).

Geologically, the area is part of the Denver-Julesburg Basin of western Nebraska, northeastern Colorado, and southeastern Wyoming. The oilfields produce from the "D" and "J" sands of Lower Cretaceous age. Generally the "D" sand is separated from the underlying "J" sand by 75-100 feet of shale. Pay zones vary in thickness from as little as 3 feet to 60 feet or more, but usually the sands are relatively thin, about 5-10 feet. In western Nebraska, the "D-J" sands are found at depths ranging from 5,000 to 7,000 feet.

As it does in most new producing areas, the discovery of oil near Sidney in 1949 created geologic name problems. The new oil-productive zones were not exact equivalents of zones in older Rocky Mountain oil-producing areas. However, the terms "D" and "J" sands were used for the producing zones soon after discovery. A stray or local sand, sometimes occurring between the "D" and "J" sands, was called the "G" sand.

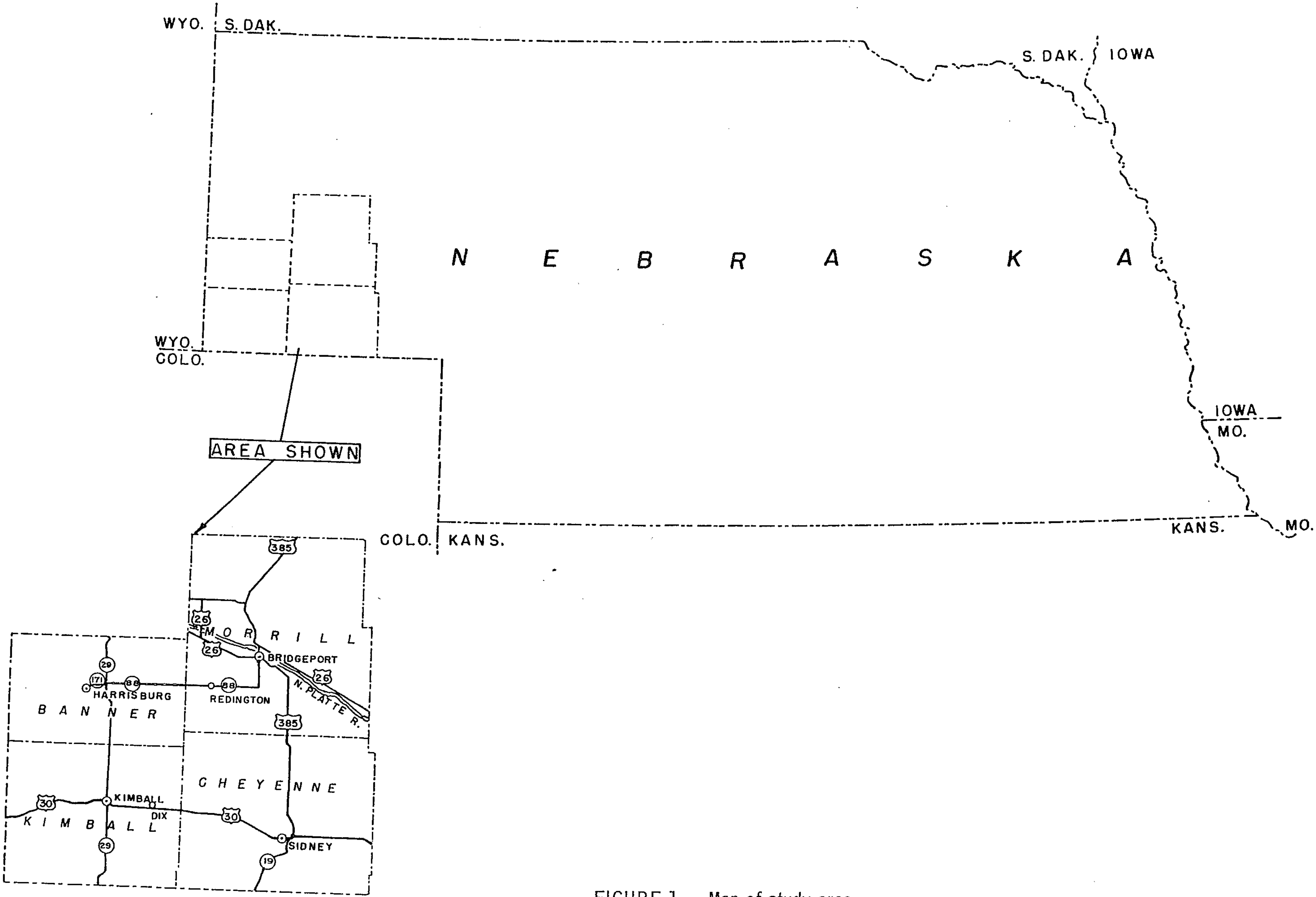


FIGURE 1. – Map of study area.

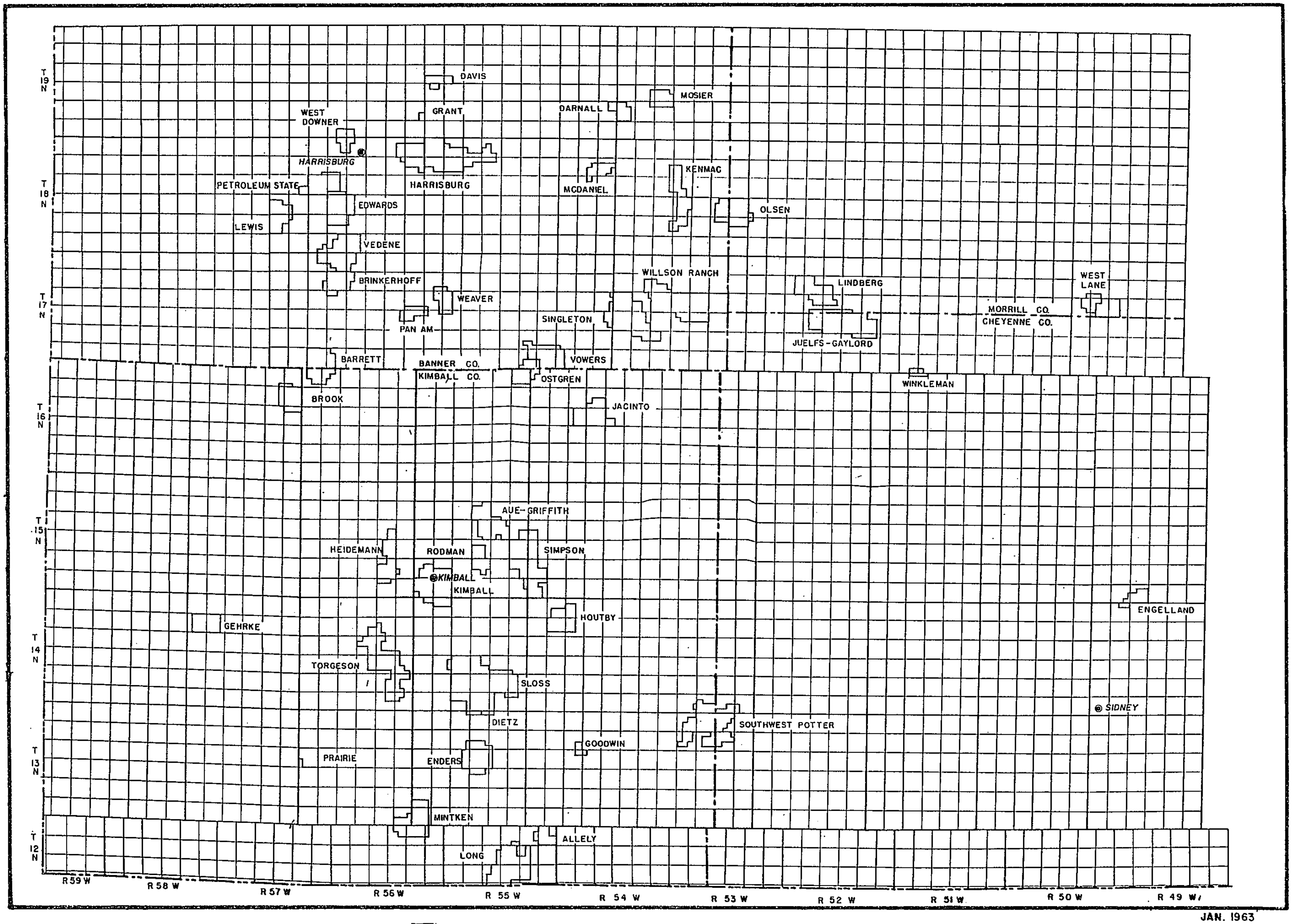
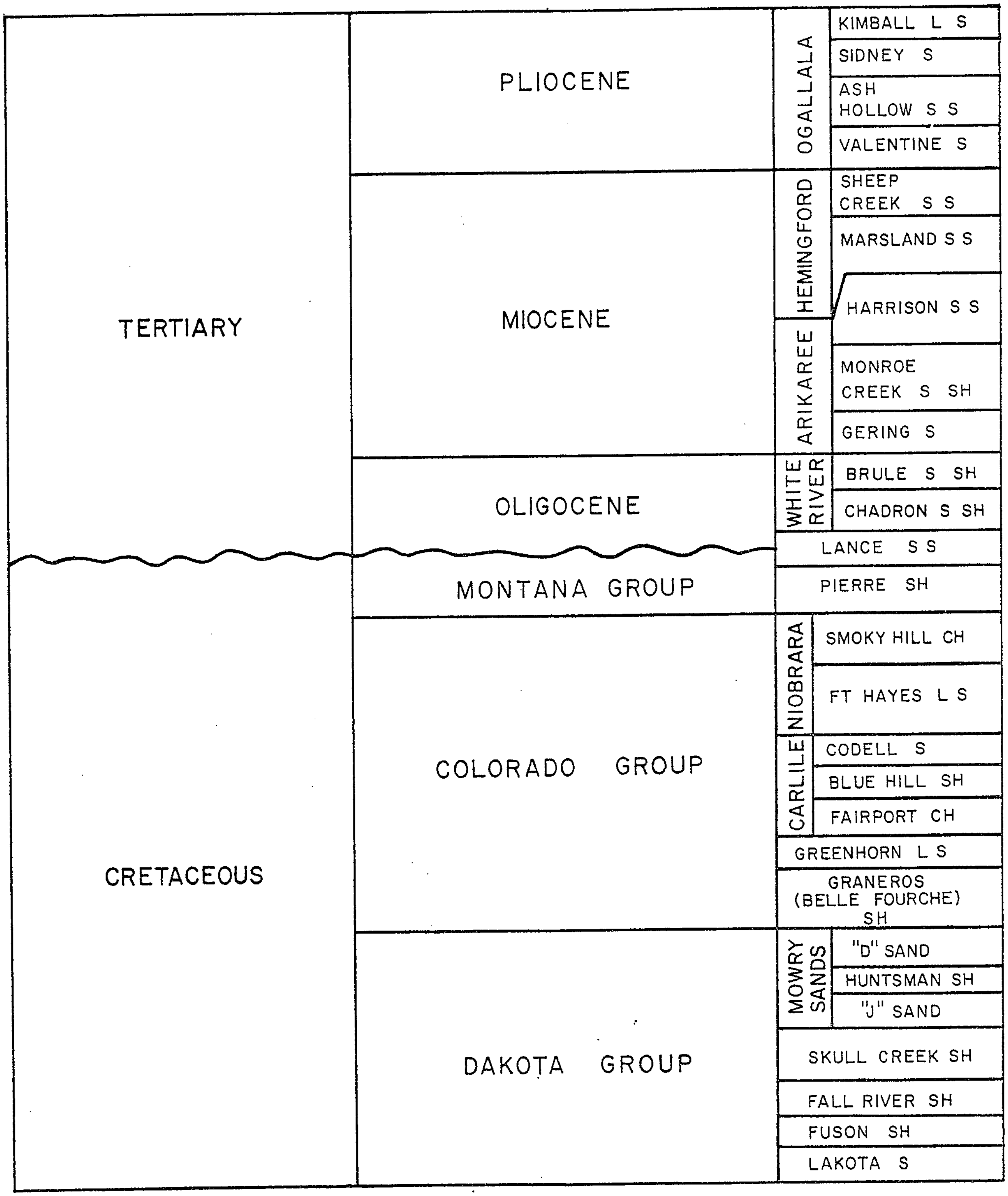


FIGURE 2. – Nebraska oilfields containing waterflood projects that were studied.



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LEGEND

CH	CHALK
L S	LIMESTONE
S	SAND
S SH	SANDY SHALE
S S	SANDSTONE

FIGURE 3. – Tertiary and Cretaceous stratigraphic section of western Nebraska.

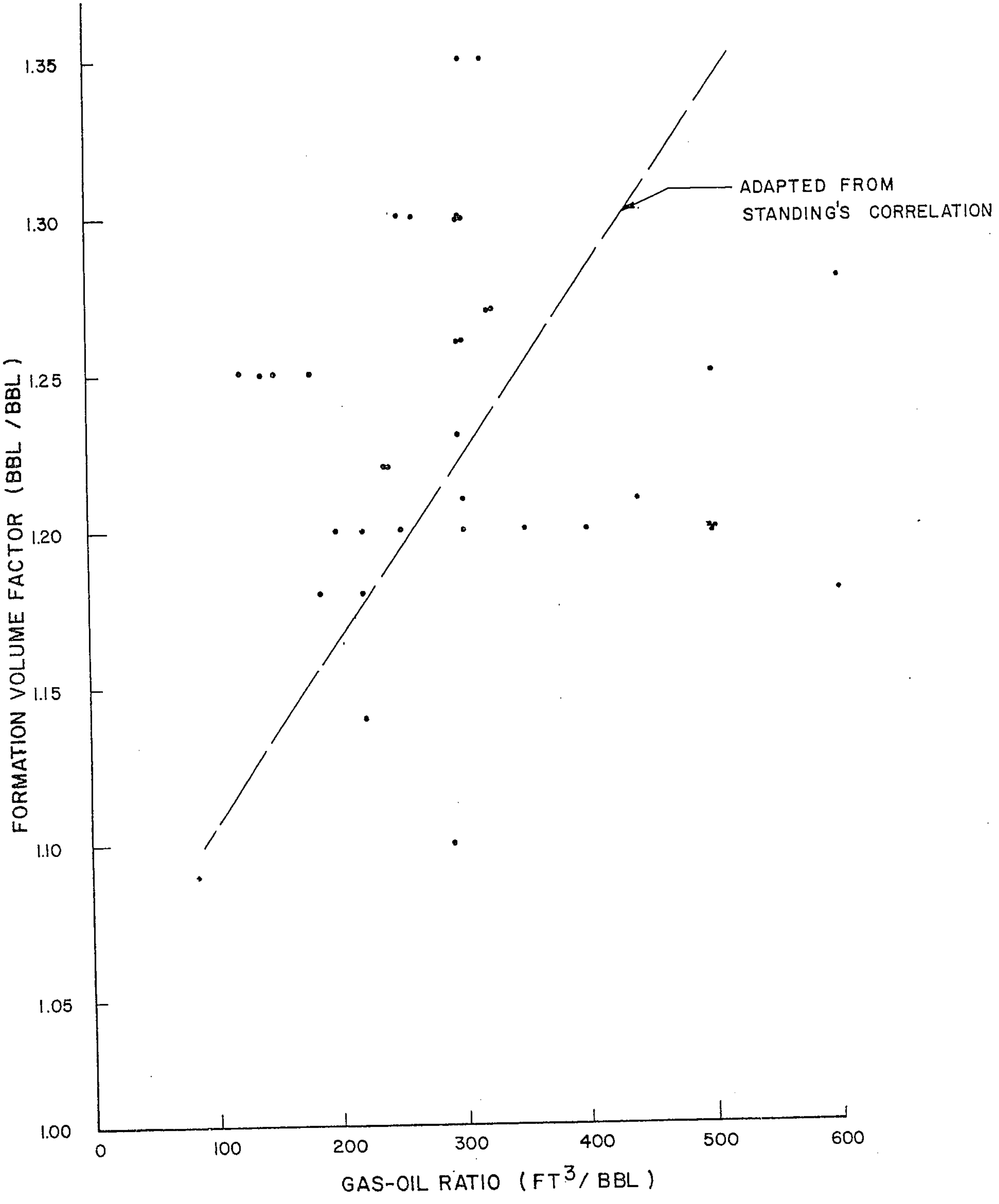

FIGURE 4. – Formation volume factors versus original solution gas-oil ratios.

Early reports on the Denver-Julesburg Basin reported the "D-J" sands to be in the Graneros shale or "Graneros series" of the Colorado group of Upper Cretaceous age. After enough well logs and cores had been studied, the "D-J" sands were classified as Lower Cretaceous in age. Sternberg and Crowly split the Lower Cretaceous sediments into six divisions (5, p. 17).[4/] In descending order these divisions are: (1) Mowry shale, (2) Gurley sand, (3) Huntsman shale, (4) Cruise sand, (5) Skull Creek shale, and (6) Cloverly formation. The Gurley sand includes the "D" and "G" sands. The Cruise sand is the "J" sand. In time the nomenclature of Gurley and Cruise may replace the alphabetical nomenclature; however, in this report, the terms "D-J" are used (fig. 3).

All of the oil reservoirs are thought to be stratigraphic traps. Some exhibit structural closure, but most are small isolated sand lenses.

The predominant primary production mechanism is solution gas drive. Many of the fields in Cheyenne County have a natural water drive (some may be limited). High primary recoveries from natural water drive make waterflooding uneconomical. The "J" sand reservoirs are more likely to have a natural water drive.

The "D-J" sand reservoir rocks generally have an average porosity between 15 and 20 percent. Permeabilities vary widely, but most range between 50 and 300 millidarcys; water saturations, with few exceptions, range from 20 to 35 percent.

The first commercial oil in western Nebraska was discovered near the small town of Gurley in June 1949. Fourteen and one-half years later, on January 1, 1964, 273 separate oilfields in western Nebraska were producing from "D," "G," or "J" sand reservoirs.

The "D" and "J" reservoirs are undersaturated, and initial reservoir pressures range from 1,100 to 2,000 psi. Original solution gas-oil ratios are about 200-500 cubic feet per stock tank barrel. The reported original oil in place ranges from 450 to 1,150 barrels an acre-foot. A typical discovery well initially pumps daily from 100 to 300 barrels of sweet crude (API gravity between 34° and 38°).

Some natural gas is produced at all of the projects, but it is not reported because of the small daily amounts.

The first waterflood in the basin, the Willard project in Colorado, was begun in June 1956. Later that same year waterflooding was initiated in western Nebraska at the Enders field in Kimball County.

The Enders project and most of the subsequent waterflood projects in Nebraska are unitized operations. All projects, both unitized and

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4/ Underlined numbers in parentheses refer to items in the list of references at the end of this report.

nonunitized, must be approved by the Nebraska Oil and Gas Conservation Commission before water injection is started. The Commission, established in 1959, makes no legal distinction between a unitized and a nonunitized operation.

Unit area is expressed in acres and represents surface ownership. Productive area is the subsurface area of the oil deposit as determined by analysis of available reservoir data. Obviously, productive area and unit area will not coincide. To form a unit, operators must agree voluntarily on the productive area and oil-zone thickness.

Western Nebraska fields have proved susceptible to water injection, and perhaps in no other area of the United States is there a more abundant supply of readily accessible, good quality water. The water usually is obtained from shallow Tertiary gravels or fractured clays that blanket the area, mostly at depths ranging from 100 to 300 feet. Good quality water virtually has eliminated the need for complex water systems and costly chemical treatment.

On January 1, 1964, 58 waterflood projects existed in western Nebraska. Individual reports have been written on the 48 projects started before January 1, 1963, and on one project started during January 1963. Each report has the same basic organization: Location, discovery well, field development, unitization (most reports), water supply, flood pattern, reserves and recovery estimates, estimated water requirements, and estimated project life. Production and injection data and a map of the project area (not necessarily field area) are also included. In accordance with the terminology of the Nebraska Oil and Gas Conservation Commission the unitized projects are referred to as units and the nonunitized projects are referred to simply as projects.

The volumetric method was used to estimate original oil in place in each reservoir. In barrels of stock tank (surface) oil, the estimate was obtained by inserting data in the following equation:

$$\text{Stock tank oil} = \frac{7{,}758\ Ah\ \phi\ (1-Sw)}{Bo}$$

In the equation, 7,758 barrels is the equivalent of 1 acre-foot; A is the productive area expressed in acres; h is the average net pay thickness expressed in feet; ϕ is the average porosity as a fraction of bulk; Sw is the interstitial water as a fraction of the pore volume; and Bo is original formation volume factor expressed in reservoir barrels per stock tank barrel.

Original formation volume factors varied considerably. When items such as formation volume factors are estimated, different engineers give different weights to available data.

A plot of the original formation volume factors versus the solution gas-oil ratios as reported for the various projects is shown in figure 4. The straight line superimposed on the plot is a correlation prepared according to Standing (7). A wide scatter of the data is apparent. The difference in the extreme values shown for 300 standard cubic feet of gas per barrel is enough to account for a 20 percent difference in the estimated oil in place or recovered. Formation pressure, formation temperature, fluid properties, and gas-oil ratio all affect formation volume factor to some extent.

The differences in formation volume factors are mentioned to illustrate the difficulties in comparing values, such as oil in place or percent recovery, without considering how such estimates were prepared.

Estimated water requirements are expressed both in barrels and pore volumes, 1 pore volume for any reservoir being equal to the total pore space in that particular reservoir. The pore volume estimate provides a basis for comparison independent of reservoir size. Estimated water requirements for the 49 projects range from 0.4 to 1.8 pore volumes, and the large majority averages close to 1. Nearly all of the projects have an estimated life of 6-10 years.

On January 1, 1964, about 155 million barrels or 20,003 acre-feet of water had been injected in the 49 projects. The injected volume is about 32 percent of the estimated water requirements.

Nine projects (not covered in this study) were started during 1963, and several were in the planning stage. Presumably, projects eventually will be started in fields as yet undiscovered. Water requirements have increased and will continue to increase.

The Commission records do not show the method or methods used to estimate water requirements. Sufficient data seldom are available to make complete water-injection calculations. Experience factors normally are used in lieu of complete reservoir data.

Minimum information needed to form a unit would include: (1) Sand thickness map prepared from well logs; (2) estimates of original and recoverable oil in place; (3) estimated flood efficiency or "sweep pattern"; and (4) costs of project.

The amount of data available constitutes the main variable in planning units. Many procedures or patterns are used in establishing such waterfloods. Agreement even on acre-feet of reservoir (area in acres X average or weighted thickness in feet) is seldom obtained by a simple presentation of geologic and engineering calculations. Agreement was not reached in several instances in western Nebraska; and only parts of oil reservoirs were unitized.

Percent recovery estimates are shown as reported because rounding could change recovery estimates by many thousands of barrels. Figures shown in the basic data tables and summary tables were not rounded. For practical purposes, however, figures in the written field reports for oil and water volumes were rounded to the nearest hundreds of barrels.

ACKNOWLEDGMENTS

This report was prepared at the Laramie Field Office of the Area V Mineral Resource unit, Bureau of Mines, Department of the Interior, under the supervision of Paul Biggs, Project Coordinator. W. C. Henkes, now with the Bureau's Division of International Activities, Washington, D.C., helped gather much of the basic information. Neal Marsh drafted all of the maps.

The authors are grateful to H. N. Rhodes, Director of the Nebraska Oil and Gas Conservation Commission; to his staff, Paul Roberts and Jack Fish; and to his office personnel, Diane Sharp, Jean O'Connell, and Nora Stecher, for their help and cooperation. The authors want to thank the oil operators and their office and field personnel for their cooperation.

WATERFLOOD PROJECTS

Allely Unit

The Allely unit (fig. 5) is in sec 1, T 12 N, R 55 W, Kimball County, approximately 12 miles southeast of the town of Kimball. Average elevation is 4,870 feet.

The Allely field was discovered in February 1953 when H. J. Williams completed the No. 1 Allely, SW$\frac{1}{4}$NW$\frac{1}{4}$ sec 1, for an initial pumping production of 146 barrels daily from the "J" sand through perforations from 6,209 to 6,219 feet. Subsequent development resulted in a field of seven producing wells and four dry holes.

Part of the field, including six of the seven producing wells, was unitized in August 1959 with Alwaco, Inc., as unit operator. A shallow fresh water supply well was drilled in the SW$\frac{1}{4}$NW$\frac{1}{4}$ of sec 1.

Waterflooding was begun in October 1959 with initial injection of 500 barrels daily. The injection well is in the southeast corner of the unit area.

In December 1963 the Allely unit contained two active producing wells and one injection well. Daily production was approximately 50 barrels of oil and 140 barrels of water. Produced water was disposed

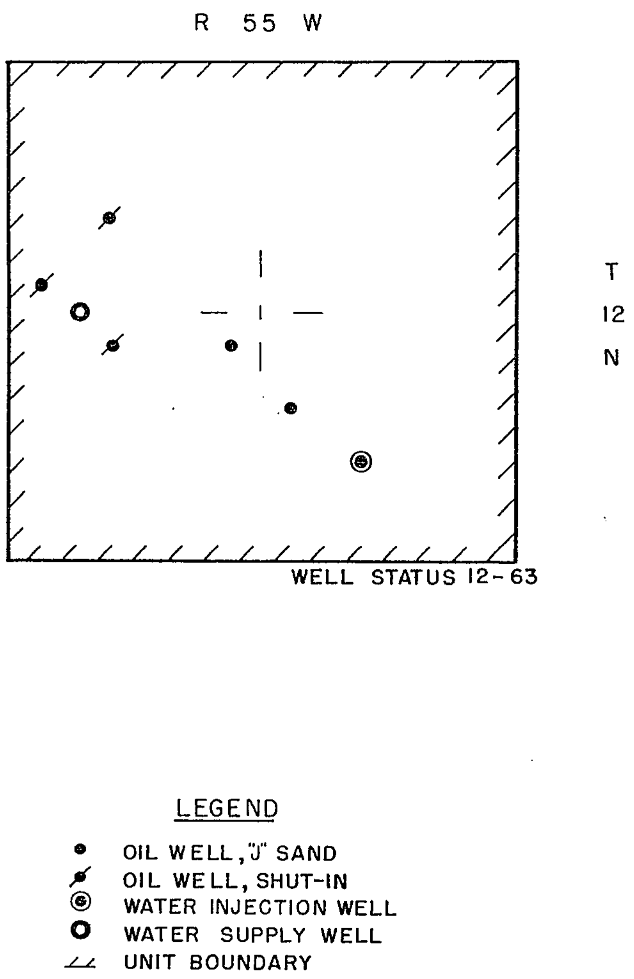

FIGURE 5. – Allely unit, Kimball County, Nebr.

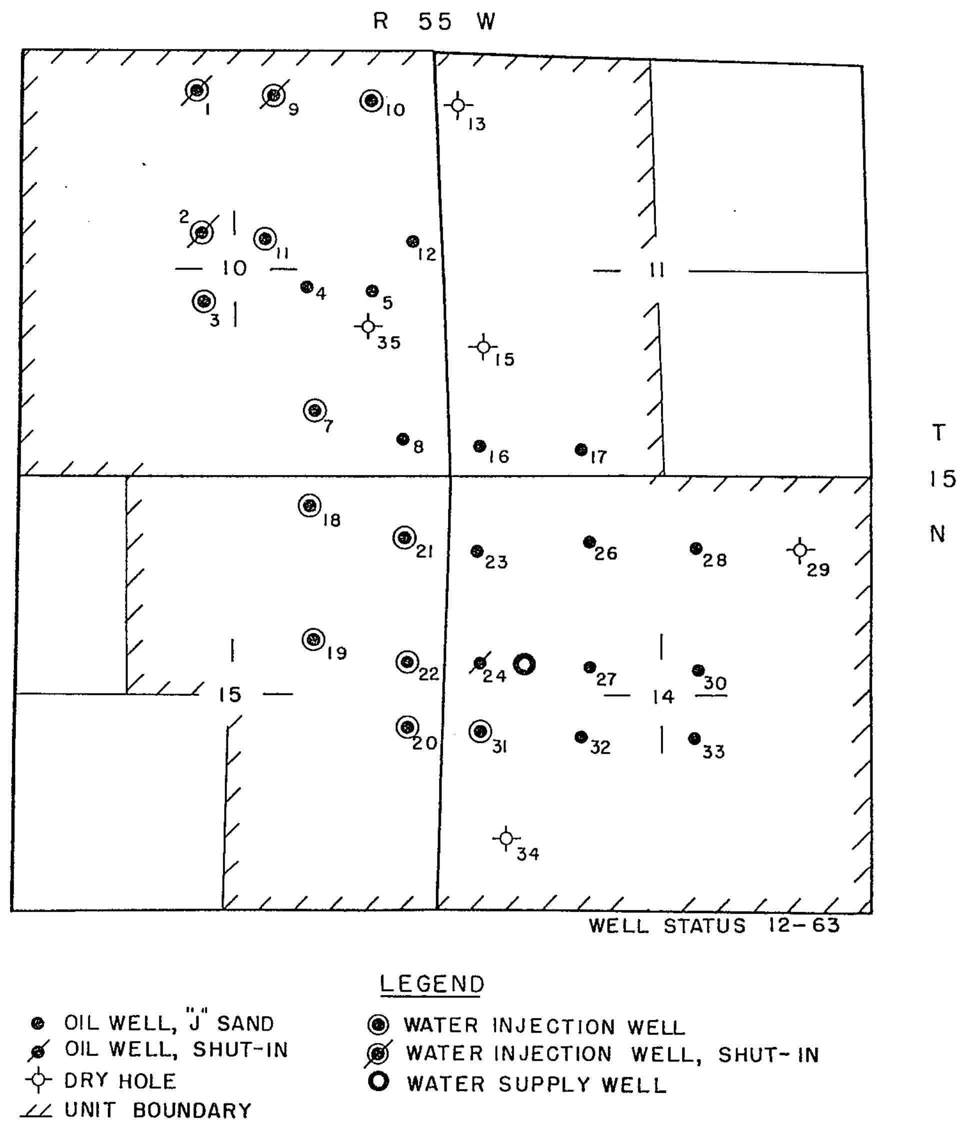

FIGURE 6. – Aue-Griffith unit, Kimball County.

of in surface pits. Daily injection was approximately 350 barrels at a pressure of about 80 psi.

By volumetric determination the oil in place at original reservoir conditions was 2,298,000 barrels or 766 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 20 percent; secondary, 15 percent; and ultimate, 35 percent.

Estimated primary oil recovery is 460,000 barrels or 153 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 418,000 barrels or 91 percent of the estimated primary recovery. Estimated secondary oil recovery is 345,000 barrels or 115 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was approximately 55,000 barrels of oil and 65,000 barrels of water. Cumulative water injection for the same period was approximately 716,000 barrels.

Estimated water requirements are 3,700,000 barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 11:1. The estimated flood life is 10 years.

At the end of 1963 only 4 percent of the estimated secondary oil and 21 percent of the original oil in place had been recovered. Water injected was approximately 19 percent of the estimated water required. The outcome of the project is indeterminate.

See table 1 for basic engineering data.

Aue-Griffith Unit

The Aue-Griffith unit (fig. 6) is in secs 10, 11, 14, and 15, T 15 N, R 55 W, Kimball County, about 4 miles northeast of the town of Kimball at an average elevation of 4,800 feet.

The Griffith field was discovered in June 1956 when the Bass, Vessels, and Brown No. 1 Griffith was completed successfully in the E$\frac{1}{2}$NW$\frac{1}{4}$NE$\frac{1}{4}$ sec 10, T 15 N, R 55 W, Kimball County. Initial daily pumping production was 134 barrels from the "J" sand interval between 6,206 and 6,228 feet. A development well drilled in 1956 resulted in a dry hole.

In March 1957 Chandler-Musgrove drilled No. 1 Aue, the discovery well, in SE$\frac{1}{4}$SE$\frac{1}{4}$NE$\frac{1}{4}$ sec 15, T 15 N, R 55 W, Kimball County. Oil was pumped from the "J" sand through perforations from 6,157 to 6,171 feet for an initial 216 barrels daily. Because development drilling proved that the "J" sand underlying the Griffith field was common to the "J" sand underlying the Aue field, the fields were combined.

TABLE 1. - Basic data for Allely unit ("J" sand)

I. Reservoir data

Productive area	300 acres
Average thickness	10 ft
Reservoir volume	3,000 acre-ft
Average porosity	16 pct
Average water saturation	29 pct
Formation volume factor	1.15 bbl/stb
Initial reservoir pressure	1,500 psi
Bubble point pressure	- - psi
Average permeability	310 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 300 \times 10 \times .16 \times .71}{1.15} = 2{,}298{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .16 \times .71}{1.15} = 766 \ \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	20	153	460,000
Secondary	15	115	345,000
Ultimate	35	268	805,000

IV. Estimated water requirements and flood life

Total	3,700,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	11:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	October 1959
Oil recovery (pct original oil in place)	21
Water injection (pct estimated water required)	19

The Aue-Griffith field was unitized during January 1961 with Chandler-Simpson, Inc., as unit operator. The unit area contained 4 injection wells and 20 producing wells.

A water supply well in the SW$\frac{1}{4}$SW$\frac{1}{4}$NW$\frac{1}{4}$ sec 14, T 15 N, R 55 W, was drilled to 300 feet into shallow Tertiary gravel deposits and initially was capable of producing 20,000 barrels of water daily.

Water injection started in July 1961 at 2,700 barrels daily.

The flood pattern is a line drive, and the injection wells are on the west side of the unit.

A daily average of 3,824 barrels of untreated water was injected during December 1963 through 10 injection wells which were taking the water on vacuum. Oil production was from 13 wells at 849 barrels daily.

By volumetric determination the oil originally in place was estimated to be 10,083,000 barrels or 1,056 barrels an acre-foot.

The estimated recovery factors, expressed in percent of initial oil in place, are 26.3 percent for primary and 19.9 percent for secondary or an ultimate of 46.2 percent.

Estimated primary oil recovery is 2,652,000 barrels or 278 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 2,005,500 barrels or 76 percent of the estimated primary oil. Cumulative water production at the start of waterflooding was 277,100 barrels.

Estimated secondary oil recovery is 2,007,000 barrels or 206 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 828,700 barrels. Cumulative unit water injection for the same period was 4,646,800 barrels. The ratio of water injected to oil produced was about 5:1. Water production amounted to 939,500 barrels. Produced water was run to pits.

Estimated water requirements during the project are 8 million barrels in 5 years. The 8 million barrels make up about one-half of the pore volume. Estimated water needs are 4 barrels to recover each barrel of secondary oil.

At the end of 1963 only 9 percent of the estimated secondary oil and only 28 percent of the original oil in place had been recovered. Water injected was 58 percent of the estimated water required, indicating a low pore volume estimate. The outcome of the project is indeterminate.

See table 2 for basic engineering data.

Barrett Unit

The Barrett unit (fig. 7) is in secs 33 and 34, T 17 N, R 56 W, Banner County, and secs 5 and 6, T 16 N, R 56 W, Kimball County, approximately 11 miles south of the town of Harrisburg. The average elevation is 5,020 feet.

The Barrett field was discovered in November 1958 when Brinkerhoff Drilling Co. completed the No. 1 Barrett, SW$\frac{1}{4}$NE$\frac{1}{4}$ sec 33, for an initial pumping production of 277 barrels daily from the "J" sand through perforations from 6,671 to 6,681 feet. Subsequent development resulted in a field of 25 producing wells and 7 dry holes.

The field, including all 25 producing wells and 6 of the 7 dry holes, was unitized in April 1960 with Pan American Petroleum Corp. as unit operator.

Waterflooding was begun in April 1960 when fresh water was injected into four wells at approximately 3,500 barrels daily. Three of the injection wells were recompleted dry holes and one was a former producing well. Fresh water was obtained from a shallow well drilled in the SW$\frac{1}{4}$NE$\frac{1}{4}$ of sec 33. The well was tested capable of producing 20,000 barrels daily from alluvial gravel at approximately 300 feet.

The flood pattern is a modified line drive. The injection wells are in the southwest and the northwest corners of the unit area.

In December 1963 the Barrett unit contained 10 active producing wells and 5 active injection wells. Daily production was approximately 760 barrels of oil and 1,800 barrels of water. Produced water was injected with fresh water. Daily injection was approximately 4,400 barrels of untreated water at a pressure of 1,500 psi.

By volumetric determination the oil in place at original reservoir conditions was 11,300,000 barrels or 600 barrels an acre-foot. The estimated recovery factors expressed in percentage of original oil in place are: Primary, 23 percent; secondary, 20 percent; and ultimate, 43 percent.

Estimated primary oil recovery is 2,600,000 barrels or 138 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 1,050,000 barrels or 40 percent of the estimated primary recovery. Estimated secondary oil recovery is 2,300,000 barrels or 120 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was approximately 1,600,000 barrels of oil and 1 million

TABLE 2. - Basic data for Aue-Griffith unit ("J" sand)

I. Reservoir data

Productive area	796 acres
Average thickness	12 ft
Reservoir volume	9,552 acre-ft
Average porosity	22.3 pct
Average water saturation	28 pct
Formation volume factor	1.18 bbl/stb
Initial reservoir pressure	1,400 psi
Bubble point pressure	- - psi
Average permeability	300 md
Original solution GOR	600 cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7,758 \times 796 \times 12 \times .223 \times .72}{1.18} = 10,083,000$$

$$\frac{7,758 \times .223 \times .72}{1.18} = 1,056 \ \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	26.3	278	2,652,000
Secondary	19.9	206	2,007,000
Ultimate	46.2	484	4,659,000

IV. Estimated water requirements and flood life

Total	8,000,000 bbl
Equivalent pore volume	0.5
Injection water:secondary oil	4:1
Flood life	5 years

V. Project status--January 1, 1964

Flood started	July 1961
Oil recovery (pct original oil in place)	28
Water injection (pct estimated water required)	58

barrels of water. Cumulative unit water injection for the same period was about 5 million barrels.

Estimated water requirements are 22 million barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 10:1. The estimated flood life is 7 years.

Only 2 percent of the estimated secondary oil and only 23 percent of the original oil in place had been recovered at the end of 1963. Water injected was 23 percent of the estimated water required. The outcome of the project is indeterminate.

See table 3 for basic engineering data.

Brinkerhoff Unit

The Brinkerhoff unit (fig. 8) is in secs 9, 10, and 15, T 17 N, R 56 W, Banner County, approximately 6 miles south of the town of Harrisburg. Average elevation is 5,025 feet.

The Brinkerhoff field was discovered in June 1959 when Pan American Petroleum Corp. and Brinkerhoff Drilling Co. completed the No. 1 Van Pelt "K," NE$\frac{1}{4}$SW$\frac{1}{4}$ sec 10, for an initial pumping production of 500 barrels daily from the "J" sand through perforations from 6,621 to 6,629 feet. Subsequent development resulted in a field of 16 producing wells and 4 dry holes.

Part of the field, containing nine producing wells and three dry holes, was unitized in April 1960 with Pan American as unit operator. Later, three more producing wells were drilled in the unit area.

Waterflooding was begun in April 1960 when fresh water was injected into a recompleted dry hole at approximately 1,300 barrels daily. The fresh water was obtained from a shallow well drilled in the NW$\frac{1}{4}$SW$\frac{1}{4}$ of sec 10. The well was tested capable of producing 2,500 barrels daily from alluvial gravel at approximately 300 feet.

In August 1960 a second well, also a recompleted dry hole, was injected with approximately 2,300 barrels daily.

The flood pattern is a line drive with the injection wells in the west end of the unit area. Additional wells probably will be converted to injection as the flood front moves farther east.

In December 1963 the Brinkerhoff unit contained four active producing wells and one active injection well. Daily injection was 600 barrels of untreated water at 150 psi. Daily production was approximately 85 barrels of oil and 500 barrels of water. Produced water was injected into the oil reservoir.

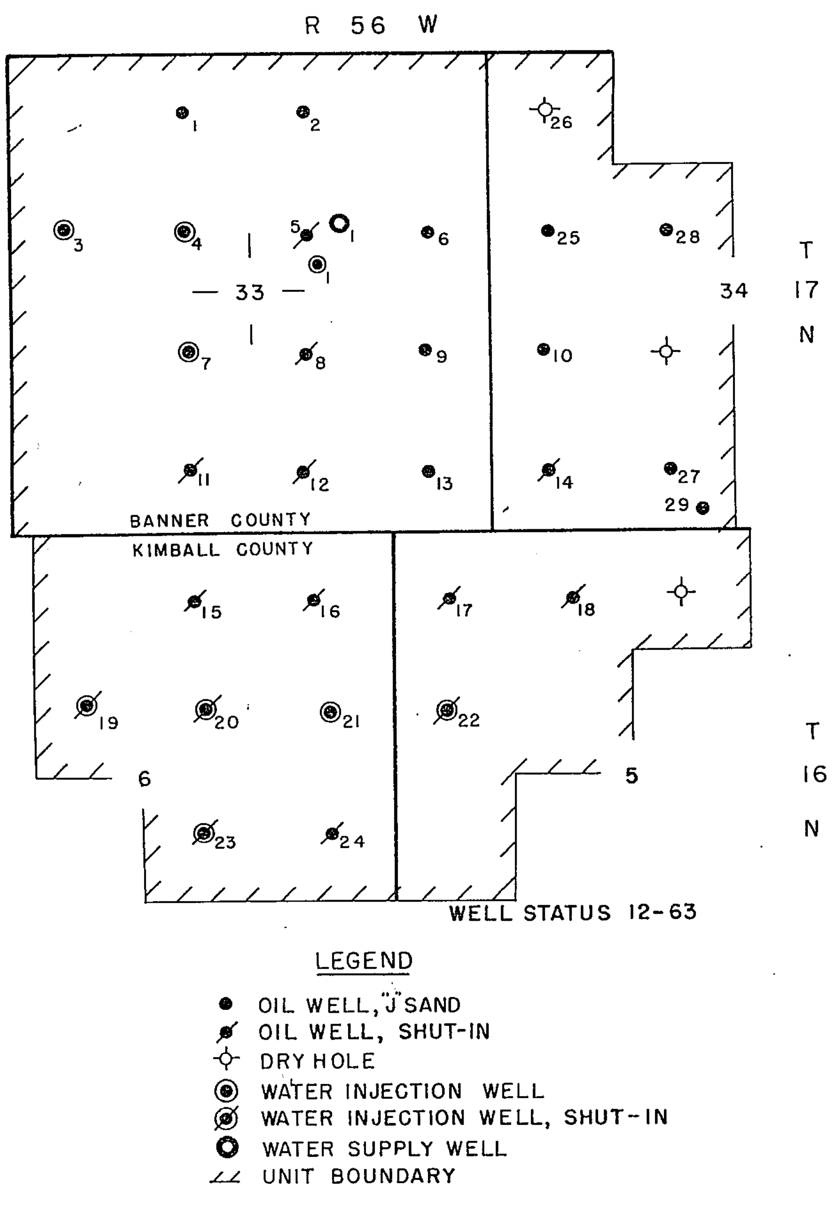

FIGURE 7. – Barrett unit, Banner and Kimball Counties.

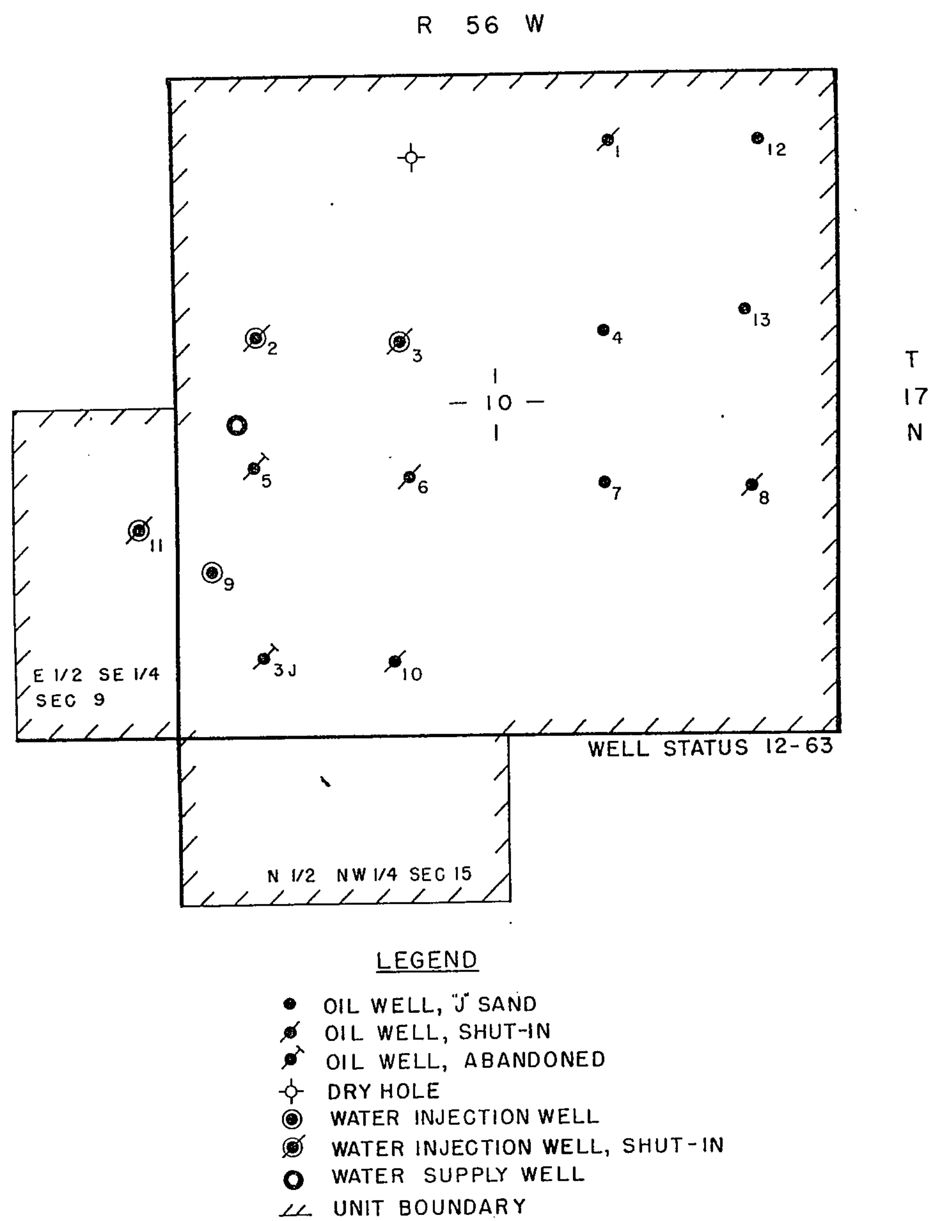

FIGURE 8. – Brinkerhoff unit, Banner County.

TABLE 3. - Basic data for Barrett unit ("J" sand)

I. Reservoir data

Productive area	1,350 acres
Average thickness	14 ft
Reservoir volume	18,900 acre-ft
Average porosity	14.8 pct
Average water saturation	35 pct
Reservoir volume factor	1.25 bbl/stb (est)
Initial reservoir pressure	2,044 psi
Bubble point pressure	- - psi
Average permeability	138 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 18{,}900 \times .148 \times .65}{1.25} = 11{,}300{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .148 \times .65}{1.25} = 600 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	23	138	2,600,000
Secondary	20	120	2,300,000
Ultimate	43	258	4,900,000

IV. Estimated water requirements and flood life

Total	22,000,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	10:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	April 1960
Oil recovery (pct original oil in place)	23
Water injection (pct estimated water required)	23

By volumetric determination the oil in place at original reservoir conditions was 2,980,000 barrels or 739 barrels an acre-foot. The estimated recovery factors expressed in percentage of total oil in place are: Primary, 25 percent; secondary, 15 percent; and ultimate, 40 percent.

Estimated primary oil recovery is 745,000 barrels or 185 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 416,000 barrels or 56 percent of the estimated primary recovery. Estimated secondary oil recovery is 447,000 barrels or 111 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 696,100 barrels of oil and 845,100 barrels of water. Cumulative unit water injection for the same period was 2,205,300 barrels.

Estimated water requirements are 5,300,000 barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 12:1. The estimated flood life is 6 years.

By the end of 1963 approximately 82 percent of the estimated secondary oil and 37 percent of the estimated original oil in place had been recovered. Water injected was 42 percent of the estimated water required. The project is apparently successful.

See table 4 for basic engineering data.

Brook Unit

The Brook unit (fig. 9) is in secs 2, 11-13, T 16 N, R 57 W, Kimball County, approximately 11 miles northwest of the town of Kimball. Average elevation is about 5,025 feet.

The Brook field was discovered in December 1959 when Enbrook Oil & Gas Co. completed the No. 1 Evertson, C SE$\frac{1}{4}$NW$\frac{1}{4}$ sec 12, for an initial pumping production of 152 barrels daily from the "J" sand through perforations from 6,733 to 6,738 feet. Before the discovery, three dry holes had been drilled in the ultimate unit area. Subsequent development resulted in a field of 14 producing wells and 11 dry holes.

The field, including 12 producing wells and 9 dry holes, was unitized in January 1962 with Pan American Petroleum Corp. as unit operator.

Two dry holes were recompleted as water injection wells, and a fresh water supply well was drilled in the NW$\frac{1}{4}$NW$\frac{1}{4}$ of sec 12. Water is obtained from alluvial gravel at approximately 200 feet.

TABLE 4. - Basic data for Brinkerhoff unit ("J" sand)

I. Reservoir data

Productive area	492 acres
Average thickness	8.2 ft
Reservoir volume	4,034 acre-ft
Average porosity	17 pct
Average water saturation	30 pct
Formation volume factor	1.25 bbl/stb
Initial reservoir pressure	1,425 psi
Bubble point pressure	- - psi
Average permeability	156 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7,758 \times 492 \times 8.2 \times .17 \times .70}{1.25} = 2,980,000 \text{ STB}$$

$$\frac{7,758 \times .17 \times .70}{1.25} = 739 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB Acre-ft	STB
Primary	25	185	745,000
Secondary	15	111	447,000
Ultimate	40	296	1,192,000

IV. Estimated water requirements and flood life

Total	5,300,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	12:1
Flood life	6 years

V. Project status--January 1, 1964

Flood started	April 1960
Oil recovery (pct original oil in place)	37
Water injection (pct estimated water required)	42

Waterflooding was begun in April 1962 when fresh water was injected into two wells at a rate of approximately 850 barrels daily. One of the two wells was taken off injection within 2 months, presumably because of its inability to take water in sufficient quantities.

The flood pattern is a line drive. Water is injected along a diagonal (northwest-southeast) front in the southwest corner of the unit area.

In July 1963 the Brook unit contained two injection wells and six producing wells. Daily injection was approximately 1,600 barrels of untreated water at 1,000 psi. Daily production was approximately 300 barrels of oil and 570 barrels of water. Produced water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was 7,400,000 barrels or 776 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 20 percent; secondary, 20 percent; and ultimate, 40 percent.

Estimated primary oil recovery is 1,480,000 barrels or 155 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 871,000 barrels or 59 percent of the estimated primary recovery. Estimated secondary oil recovery is also 1,480,000 barrels or 155 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 271,000 barrels of oil and 226,600 barrels of water. Cumulative unit water injection for the same period was 726,000 barrels.

Estimated water requirements are 13 million barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 9:1. Estimated flood life is 6 years.

At the end of 1963 only 77 percent of the estimated primary oil and only 15 percent of the original oil in place had been recovered. Water injected was only 6 percent of the estimated water required. The outcome of the project is indeterminate.

See table 5 for basic engineering data.

Darnall Project

The Darnall project (fig. 10) is in sec 30, T 19 N, R 53 W, Banner County, approximately 12 miles east of the town of Harrisburg. The average elevation is approximately 4,160 feet.

Darnall field, also known as the Freeport field, was discovered in December 1956 when Shell Oil Co. completed the No. 1 Darnall,

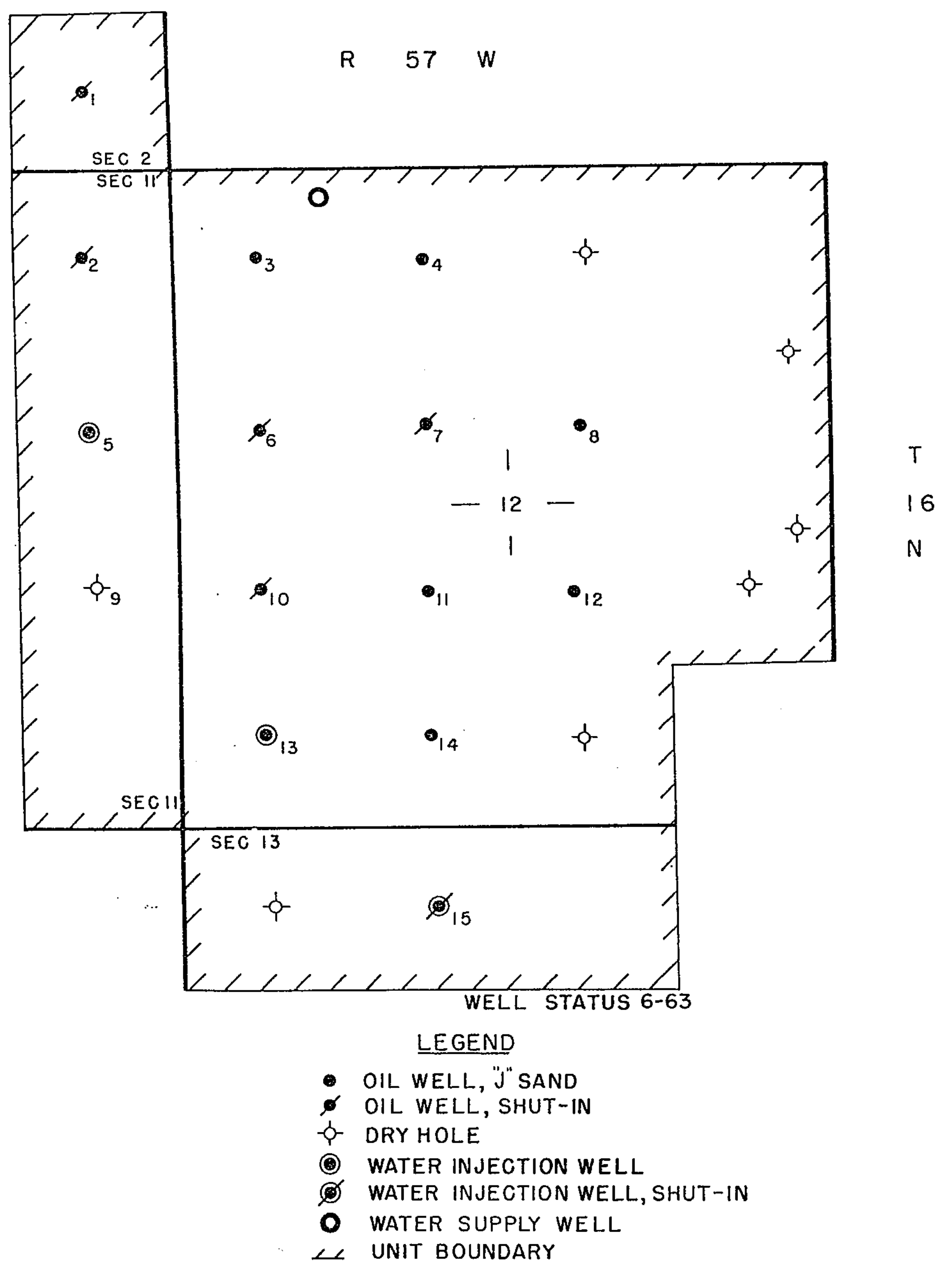

FIGURE 9. – Brook unit, Kimball County.

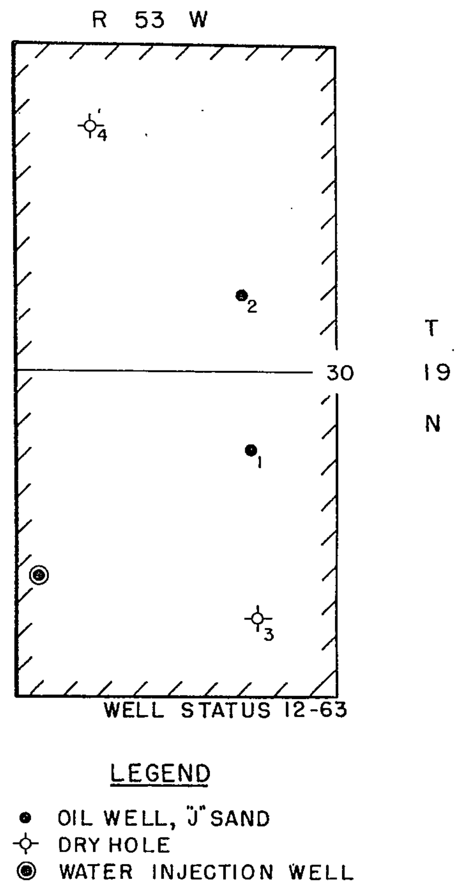

FIGURE 10. – Darnall project, Banner County.

TABLE 5. - Basic data for Brook unit ("J" sand)

I. Reservoir data

Productive area	562 acres
Average thickness	17 ft
Reservoir volume	9,554 acre-ft
Average porosity	17.4 pct
Average water saturation	30 pct
Formation volume factor	1.22 bbl/stb
Initial reservoir pressure	1,270 psi
Bubble point pressure	668 psi
Average permeability	186 md
Original solution GOR	239 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 9{,}554 \times .174 \times .70}{1.22} = 7{,}400{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .174 \times .70}{1.22} = 776 \ \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	20	155	1,480,000
Secondary	20	155	1,480,000
Ultimate	40	310	2,960,000

IV. Estimated water requirements and flood life

Total	13,000,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	9:1
Flood life	6 years

V. Project status--January 1, 1964

Flood started	April 1962
Oil recovery (pct original oil in place)	15
Water injection (pct estimated water required)	6

C $NE\frac{1}{4}SW\frac{1}{4}$ sec 30, for an initial daily pumping production of 202 barrels from the "J" sand through perforations from 5,153 to 5,172 feet. Subsequent development resulted in a field of four producing wells and seven dry holes.

In June 1961 Shell Oil Co. obtained the approval of the Nebraska Oil and Gas Conservation Commission to conduct a waterflood "project" in the $W\frac{1}{2}$ of sec 30. The project area included two producing wells and two dry holes. Later an injection well was drilled in the $SW\frac{1}{4}SW\frac{1}{4}$ of sec 30.

Waterflooding was begun in February 1962 when fresh water was injected into a well in the southwest corner of the project at approximately 430 barrels daily. The fresh water was obtained from a supply well in the nearby Mosier project.

In December 1963 daily production was approximately 175 barrels of oil and 1 barrel of water. Daily injection was about 290 barrels at a pressure of 1,200 psi. The injection water was treated with a bactericide and corrosion inhibitor.

By volumetric determination the oil in place at original reservoir conditions was 1,030,000 barrels or 666 barrels an acre-foot. The estimated recovery factors, expressed in percentage of oil in place, are: Primary, 21 percent; secondary, 14 percent; and ultimate, 35 percent.

Estimated primary oil recovery is 216,000 barrels or 140 barrels an acre-foot. Cumulative oil production at the start of waterflooding was approximately 213,000 barrels or 99 percent of the estimated primary recovery. Estimated secondary oil recovery is 144,000 barrels or 93 barrels an acre-foot.

Cumulative production from the start of waterflooding until the end of 1963 was 67,100 barrels of oil and only 28 barrels of water. Cumulative water injection for the same period was 260,600 barrels.

Estimated total water requirements are 1 million barrels or 0.51 pore volume. The estimated ratio of water injected to secondary oil recovered is 7:1. Estimated flood life is 6 years.

By the end of 1963 approximately 44 percent of the estimated secondary oil and 27 percent of the original oil in place had been recovered. Water injected to that time was approximately 26 percent of the estimated water required. Available data indicate a successful project.

See table 6 for basic engineering data.

TABLE 6. - Basic data for Darnall project ("J" sand)

I. Reservoir data

Productive area	193 acres
Average thickness	8 ft
Reservoir volume	1,544 acre-ft
Average porosity	16.5 pct
Average water saturation	35 pct
Formation volume factor	1.25 bbl/stb
Initial reservoir pressure	1,265 psi
Bubble point pressure	693 psi (est)
Average permeability	60 md
Original solution GOR	123 cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 193 \times 8 \times .165 \times .65}{1.25} = 1{,}030{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .165 \times .65}{1.25} = 666 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	21	140	216,000
Secondary	14	93	144,000
Ultimate	35	233	360,000

IV. Estimated water requirements and flood life

Total	1,000,000 bbl
Equivalent pore volume	0.51
Injection water:secondary oil	7:1
Flood life	6 years

V. Project status--January 1, 1964

Flood started	February 1962
Oil recovery (pct original oil in place)	27
Water injection (pct estimated water required)	26

Davis Unit

The Davis unit (fig. 11) is in secs 15, 16, and 21, T 19 N, R 55 W, Banner County, about 5 miles northeast of the town of Harrisburg in an area of low relief.

The Davis field was discovered in April 1958 when Davis Oil Co. drilled the No. 1 Olsen in the C SE$\frac{1}{4}$SW$\frac{1}{4}$ sec 15, T 19 N, R 55 W. The well pumped 69 barrels of oil in 19 hours from "D" sand perforations from 5,449 to 5,452 feet. Subsequent development drilling resulted in 11 more "D" sand producers and 10 dry holes.

The field was unitized in January 1961 with Davis Oil Co. as unit operator. Two wells were drilled for water injection, one in SE$\frac{1}{4}$SW$\frac{1}{4}$SW$\frac{1}{4}$ sec 16, and the other in NE$\frac{1}{4}$SE$\frac{1}{4}$NW$\frac{1}{4}$ sec 21. Production was from 11 wells, one well having been shut-in prior to unitization.

The original water supply well was drilled in NW$\frac{1}{4}$SW$\frac{1}{4}$SE$\frac{1}{4}$ sec 16. Because this well did not have the capacity to supply the volume of water needed, it was plugged. Another supply well, capable of producing between 800 and 900 barrels of water daily from the Brule clay at about 500 feet, was drilled in NW$\frac{1}{4}$NW$\frac{1}{4}$SW$\frac{1}{4}$ sec 16.

Waterflooding started in July 1961 when about 500 barrels daily was injected in the southwest corner of the unit area near the oil-water contact. The flood front was directed toward the northeast where sand thickness and permeability decreased. (A sharp permeability barrier was thought to exist in the southeast corner of the field.)

During December 1963 the entire Davis unit was shut-in. A large volume water breakthrough had occurred at wells in the easternmost part of the field, and oil production had declined with continued water injection. Bypassing the oil, the water probably had channeled through a vertical fracture system in the reservoir. Every core taken in the field showed vertical fractures. Water injection wells Nos. 1 and 2, and producing wells unit Nos. 5 and 11, were plugged and abandoned. Wells on the north end of the unit were reworked for conversion to water injection. Crossflooding the unit from north to south will be attempted. Harper High has succeeded Davis Oil Co. as unit operator.

By volumetric determination the oil originally in place was 2,604,000 barrels or 839 barrels an acre-foot.

The estimated recovery factors expressed in percentage of initial oil in place were 22.3 percent for primary and 25.3 percent for secondary, or an ultimate recovery of 47.6 percent.

Estimated primary oil recovery is 581,000 barrels or 187 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 484,100 barrels or 83.5 percent of the estimated primary oil.

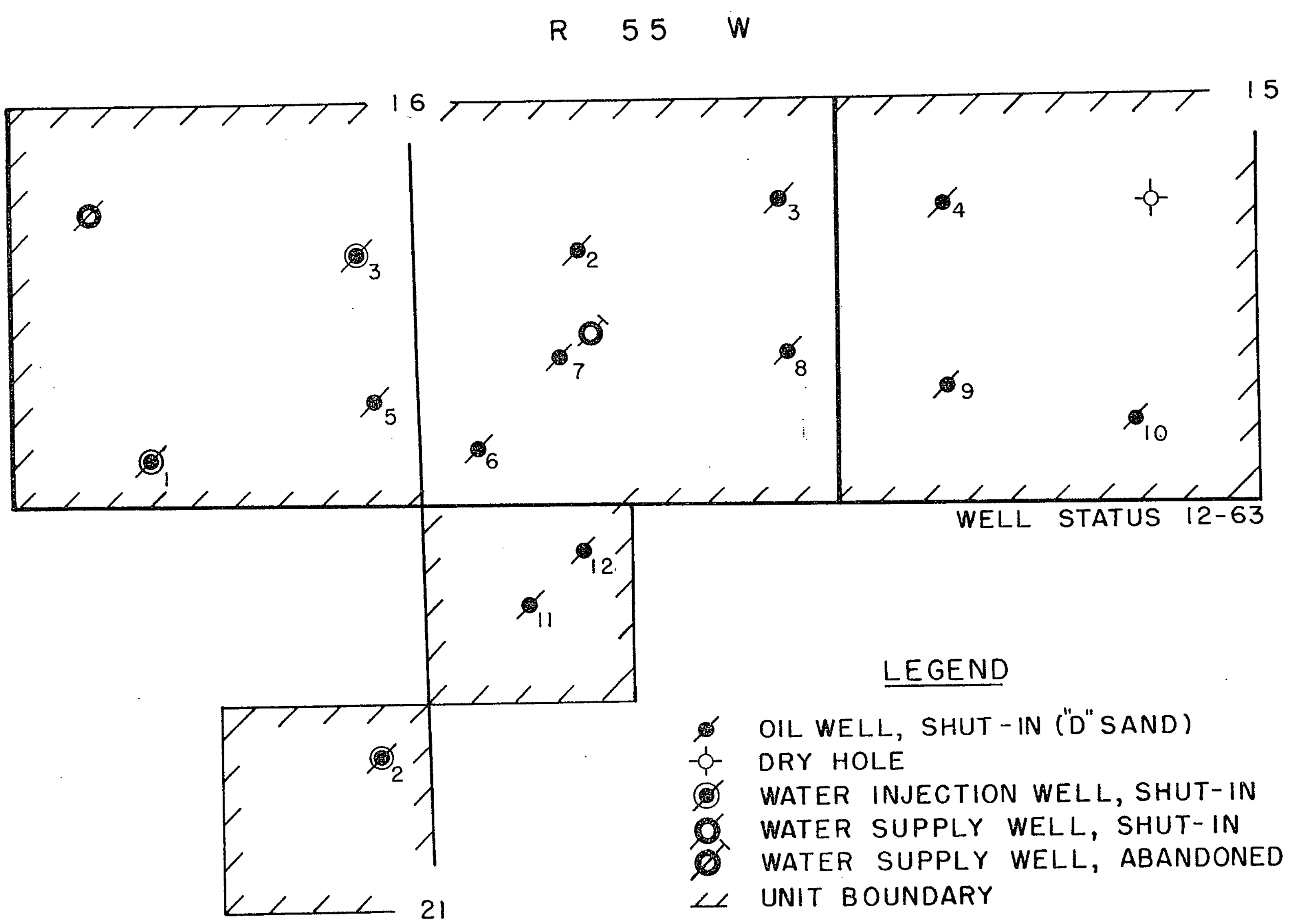

FIGURE 11. – Davis unit, Banner County.

Cumulative unit water production at the start of waterflooding was 18,500 barrels.

Estimated secondary oil recovery was 659,000 barrels or 213 barrels an acre-foot for the original flood.

Cumulative unit oil production from the start of waterflooding until the end of October 1963 was 76,500 barrels. The unit was completely shut-in and remedial work was in progress on some wells before cross-flooding was attempted. Cumulative water injected from the start of flooding to the end of October 1963 was 770,300 barrels. The ratio of water injected to oil produced was about 10:1. Water production was 90,200 barrels.

Estimated water requirements are 2,480,000 barrels of fresh water in 10 years. If produced water is injected, only 1,370,000 barrels of fresh water is needed. The 2,480,000 barrels of water equal about two-thirds of the pore volume. The estimated ratio of water injected to secondary oil recovered is 4:1.

When operations were suspended, 97 percent of the estimated primary oil or 22 percent of the original oil in place had been recovered. Water injected was 31 percent of the estimated water required. The first attempt to waterflood the Davis unit had failed.

The recovery estimates shown in table 7 are for the original flood and not the proposed crossflood. Comparison of the performance of the Davis unit with other "D" sand waterfloods makes the secondary recovery estimate of 25.3 percent appear too high.

See table 7 for basic engineering data.

Dietz Unit

The Dietz unit (fig. 12) is in sec 3, T 13 N, R 55 W, Kimball County, approximately 7 miles south of the town of Kimball. Average elevation is about 4,880 feet.

The Dietz field was discovered in March 1954 when Superior Oil Co. completed the No. 64-3 Dietz, SE$\frac{1}{4}$SW$\frac{1}{4}$NE$\frac{1}{4}$ sec 3, for an initial pumping production of 99 barrels daily from the "J" sand through perforations from 6,328 to 6,339 feet. Subsequent development resulted in 11 more producing wells and 8 dry holes.

The field, including nine producing wells and two dry holes, was unitized in January 1960 with Producing Properties, Inc., as unit operator.

TABLE 7. - Basic data for Davis unit ("D" sand)

I. Reservoir data

Productive area	566 acres
Average thickness	5.5 ft
Reservoir volume	3,113 acre ft
Average porosity	17 pct
Average water saturation	22 pct
Formation volume factor	1.23 bbl/stb
Initial reservoir pressure	1,328 psi
Bubble point pressure	- - psi
Average permeability	63 md
Original solution GOR	296 cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 566 \times 5.5 \times .17 \times .78}{1.23} = 2{,}604{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .17 \times .78}{1.23} = 839 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery

Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	22.3	187	581,000
Secondary	25.3	213	659,000
Ultimate	47.6	400	1,240,000

IV. Estimated water requirements and flood life

Total	2,480,000 bbl
Equivalent pore volume	0.6
Injection water:secondary oil	4:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	July 1961
Oil recovery (pct original oil in place)	22
Water injection (pct estimated water required)	31

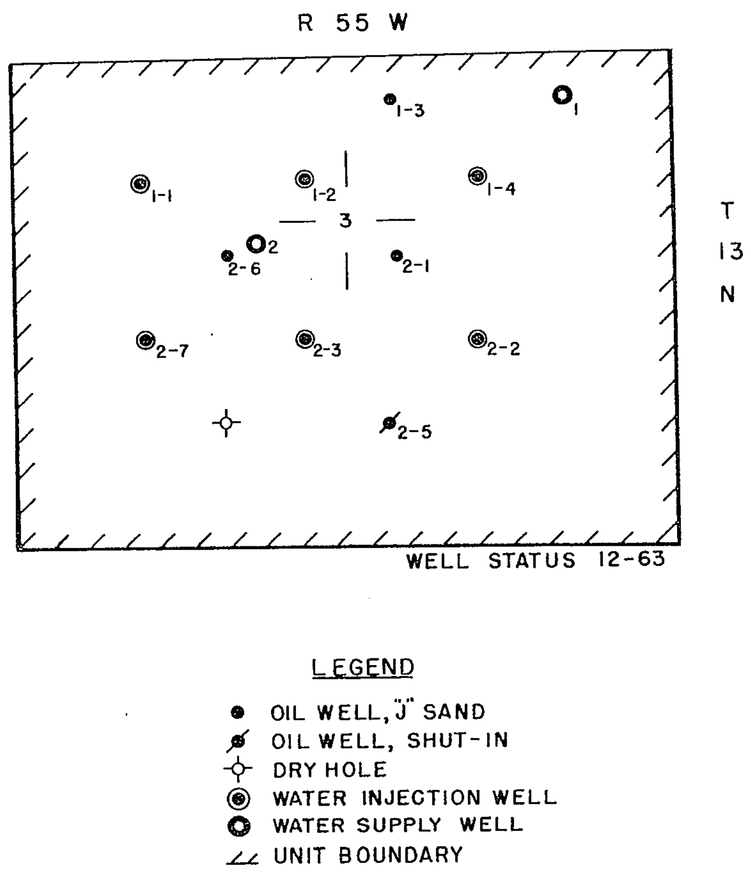

FIGURE 12. – Dietz unit, Kimball County.

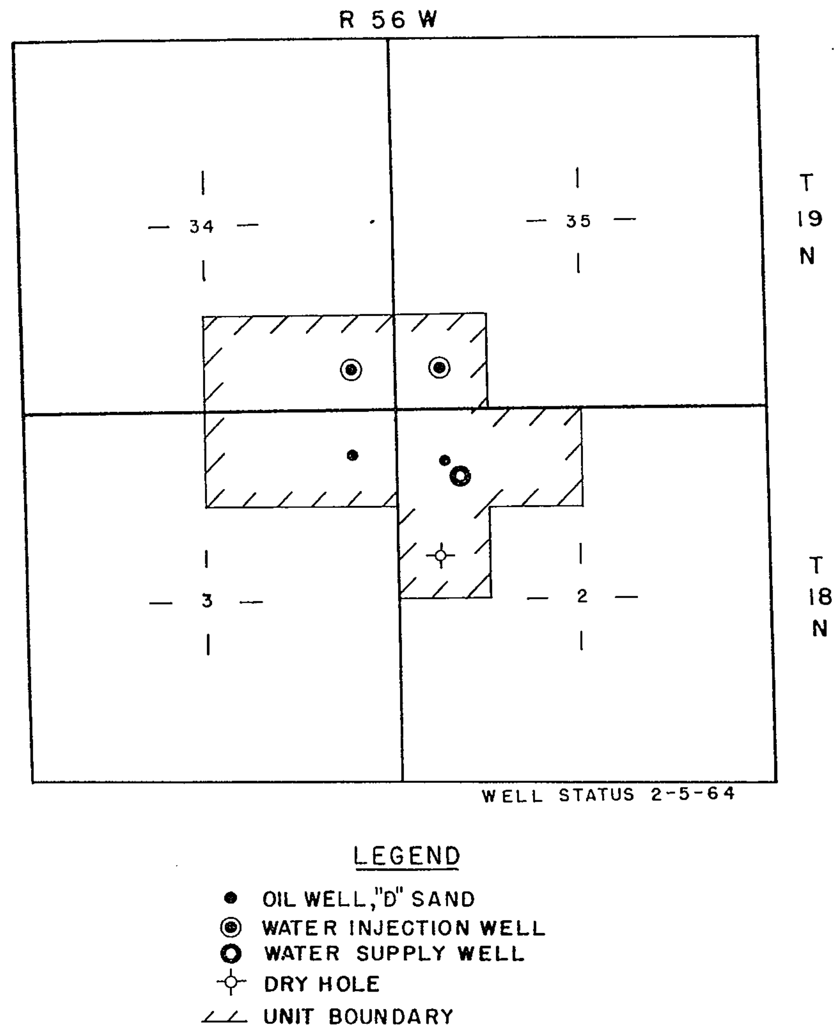

FIGURE 13. – West Downer unit, Banner County.

Waterflooding was begun in June 1960 when fresh water was injected into six wells at a rate of approximately 1,100 barrels daily. Five of the injection wells were former producing wells and one was drilled and completed as an injection well. Two water supply wells were completed in sec 3. Fresh water was obtained at 632 and 1,260 feet.

The flood pattern is the standard five-spot. Six injection wells and two producing wells form two adjoining five-spots in the center of the unit area. The other two producing wells are outside the pattern, one north and the other south.

In December 1963 Reserve Oil & Gas Co. became unit operator, using six injection wells and three producing wells in the Dietz unit. Daily injection was approximately 750 barrels of untreated water at a pressure of 1,200 psi. Daily production was approximately 26 barrels of oil and 480 barrels of water. Produced water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was 2,204,000 barrels or 696 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 22.9 percent; secondary, 14.8 percent; and ultimate, 37.7 percent.

Estimated primary oil recovery is 505,000 barrels or 159 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 423,000 barrels or 84 percent of the estimated primary recovery. Estimated secondary oil recovery is 327,000 barrels or 103 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 136,000 barrels of oil and 295,800 barrels of water. Cumulative unit water injection for the same period was 1,037,900 barrels.

Estimated water requirements are 5 million barrels of fresh water or approximately 1.34 pore volumes. The estimated ratio of water injected to secondary oil recovered is 15:1. The estimated flood life is 8 years.

At the end of 1963 about 17 percent of the estimated recoverable secondary oil and 25 percent of the original oil in place had been recovered. Water injected was approximately 21 percent of the estimated water required. The outcome of the project is indeterminate.

See table 8 for basic engineering data.

TABLE 8. - Basic data for Dietz unit ("J" sand)

I. Reservoir data

Productive area	226 acres
Average thickness	14 ft
Reservoir volume	3,165 acre-ft
Average porosity	15.2 pct
Average water saturation	25 pct
Formation volume factor	1.27 bbl/stb
Initial reservoir pressure	1,600 psi
Bubble point pressure	1,043 psi
Average permeability	63 md
Original solution GOR	325 cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 3{,}165 \times .152 \times .75}{1.27} = 2{,}204{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .152 \times .75}{1.27} = 696 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	22.9	159	505,000
Secondary	14.8	103	327,000
Ultimate	37.7	262	832,000

IV. Estimated water requirements and flood life

Total	5,000,000 bbl
Equivalent pore volumes	1.34
Injection water:secondary oil	15:1
Flood life	8 years

V. Project status--January 1, 1964

Flood started	June 1960
Oil recovery (pct original oil in place)	25
Water injection (pct estimated water required)	21

West Downer Unit

West Downer unit (fig. 13) is in secs 2 and 3, T 18 N, R 56 W, and secs 34 and 35, T 19 N, R 56 W, Banner County. The field slopes gently southward at an elevation of about 4,490 feet. The unit lies about 1 mile west of Harrisburg, the county seat of Banner County.

Downer field was discovered in 1954 when Harry Royster drilled the No. 1 Downer in the C NE$\frac{1}{4}$NE$\frac{1}{4}$ sec 11, T 18 N, R 56 W, to 6,079 feet and pumped 30 barrels daily from the "J" sand perforations between 6,030 and 6,037 feet. "D" sand production was obtained early in 1955 when Empire Drilling Co. completed the No. 1 Olsen in the NE$\frac{1}{4}$NE$\frac{1}{4}$NE$\frac{1}{4}$ sec 2, T 18 N, R 56 W. This well pumped 66 barrels daily from perforations between 5,811 and 5,816 feet. The "D" sand discovery was named the Olsen field, but later became part of the Downer field. The Olsen and Downer areas sometimes were confused with the Harrisburg field to the east.

During June 1961 part of the Downer field was unitized for purposes of waterflooding the "D" sand. The area unitized, known as the West Downer unit, included one dry hole, two producing wells, and two former producing wells later converted to water injection. Basin Pipe and Supply Co. became the unit operator.

A fresh water supply well was drilled in SE$\frac{1}{4}$NW$\frac{1}{4}$NW$\frac{1}{4}$ sec 2, T 18 N, R 56 W. The depth to water-bearing formation was 45 feet.

Secondary recovery operations were begun in August 1961 when 300 barrels of water daily was injected through two wells. Oil production was obtained from two wells.

The flood pattern is a line drive with two injection wells on the north end of the unit.

During February 1964 the two wells were producing 118 barrels of oil daily and no water. Untreated fresh water was injected at 420 barrels daily at about 2,000 psi.

Oil originally in place was an estimated 1,351,000 barrels or 1,000 barrels an acre-foot. The estimated recovery factors expressed in percentage of initial oil in place are 22.8 percent for primary and 17.2 percent for secondary or a total of 40 percent.

Estimated primary oil recovery is 308,000 barrels or 228 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 272,000 barrels or approximately 89 percent of the expected primary oil.

Estimated secondary oil recovery is an additional 232,000 barrels or 172 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 29,900 barrels of oil and 3,200 barrels of water. The amount of water injected during the same period was 339,400 barrels, or a ratio of water injected to oil produced of about 11:1.

Estimated water requirements during the project are 867,000 barrels over $4\frac{1}{2}$ years. The 867,000 barrels of water is the equivalent of about one-third of the estimated pore volume. The estimated ratio of water injected to secondary oil recovered is 4:1.

Almost all, 98 percent, of the estimated primary oil but only 22 percent of the original oil in place had been recovered at the end of 1963. Water injected was 39 percent of the estimated water required indicating a low water estimate. The outcome of the project is indeterminate. (Nebraska Drillers, Inc., has assumed operation of the West Downer unit.)

See table 9 for basic engineering data.

Edwards Unit

The Edwards unit (fig. 14) is in secs 15, 22, 23, and 27, T 18 N, R 56 W, Banner County, approximately 3 miles southwest of the town of Harrisburg. The average elevation is 4,900 feet.

The Edwards field was discovered in March 1957 when Pan American Petroleum Corp. completed the No. 4 Edwards, C SE$\frac{1}{4}$SW$\frac{1}{4}$ sec 22, for an initial pumping production of 162 barrels daily from the "J" sand through perforations from 6,584 to 6,586 feet. Subsequent development resulted in a field of 17 producing wells and 5 dry holes. Of the 17 producing wells, 15 were completed in the "J" sand and 2 were completed in the "D" sand.

The "J" sand reservoir, including 12 producing wells and 2 dry holes, was unitized in 1959 with Pan American as unit operator. Later one producing well and one dry hole were drilled in the unit area.

Two of the producing wells were converted to water injection wells and a fresh water supply well was drilled near the center of sec 22. Water was obtained from alluvial gravel at approximately 200 feet.

Waterflooding started in July 1959 when fresh water was injected in two wells at 1,100 barrels daily. In October 1959 another producing well was converted to an injection well.

The flood pattern is a line drive with the injection wells in the west end of the field.

In December 1963 the Edwards unit contained four injection wells and four producing wells. Daily injection was approximately 1,500

TABLE 9. - Basic data for West Downer unit ("D" sand)

I. Reservoir data

Productive area	- - acres
Average thickness	- - ft
Reservoir volume	1,350 acre-ft
Average porosity	21.5 pct
Average water saturation	24.5 pct
Formation volume factor	1.25 bbl/stb
Initial reservoir pressure	- - psi
Bubble point pressure	- - psi
Average permeability	- - md
Original solution GOR	- - cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 1{,}350 \times .215 \times .75}{1.25} = 1{,}351{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .215 \times .75}{1.25} = 1{,}000 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	22.8	228	308,000
Secondary	17.2	172	232,000
Ultimate	40.0	400	540,000

IV. Estimated water requirements and flood life

Total	867,000 bbl
Equivalent pore volume	0.4
Injection water:secondary oil	4:1
Flood life	4½ years

V. Project status--January 1, 1964

Flood started	August 1961
Oil recovery (pct original oil in place)	22
Water injection (pct estimated water required)	39

barrels of untreated water at a pressure of 1,150 psi. Daily production was approximately 160 barrels of oil and 600 barrels of water. Produced water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was 2,700,000 barrels or 972 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 25 percent; secondary, 25 percent; and ultimate, 50 percent.

Estimated primary oil recovery is 675,000 barrels or 243 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 437,000 barrels or 65 percent of the estimated primary recovery. Estimated secondary oil recovery is also 675,000 barrels or 243 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was approximately 824,000 barrels of oil and 470,000 barrels of water. Cumulative unit water injection for the same period was approximately 2,320,000 barrels.

Estimated water requirements are 4 million barrels of fresh water or 0.85 pore volume. The estimated ratio of injected water to secondary oil produced is 6:1. Estimated flood life is 7 years.

By the end of 1963 approximately 87 percent of the estimated secondary oil and 47 percent of the original oil in place had been recovered. Water injected was 58 percent of the estimated water required. The project is apparently successful.

See table 10 for basic engineering data.

Enders Unit

The Enders unit (fig. 15) is in secs 9-11, 14-16, and 22, T 13 N, R 55 W, Kimball County, about 12 miles south of the town of Kimball. The topography is flat farmland at an average elevation of 4,854 feet.

The Enders field was discovered during November 1951. The discovery well, the No. 1 Enders, NE$\frac{1}{4}$NW$\frac{1}{4}$SE$\frac{1}{4}$ sec 15, T 13 N, R 55 W, was drilled by the Twin Oil Co. and the Rock Hill Co. and initially flowed 40 barrels hourly from the "J" sand below 6,302 feet. Subsequent drilling resulted in 35 more producing wells and 9 dry holes before unitization. Wells drilled totaled 39 producers, including the discovery well, and 14 dry holes.

Part of the field was unitized during June 1956 with Producing Properties, Inc., as unit operator. Initially, 4 wells were converted to injection wells, and oil production was from 30 wells. This was the first unitized waterflood project in Nebraska.

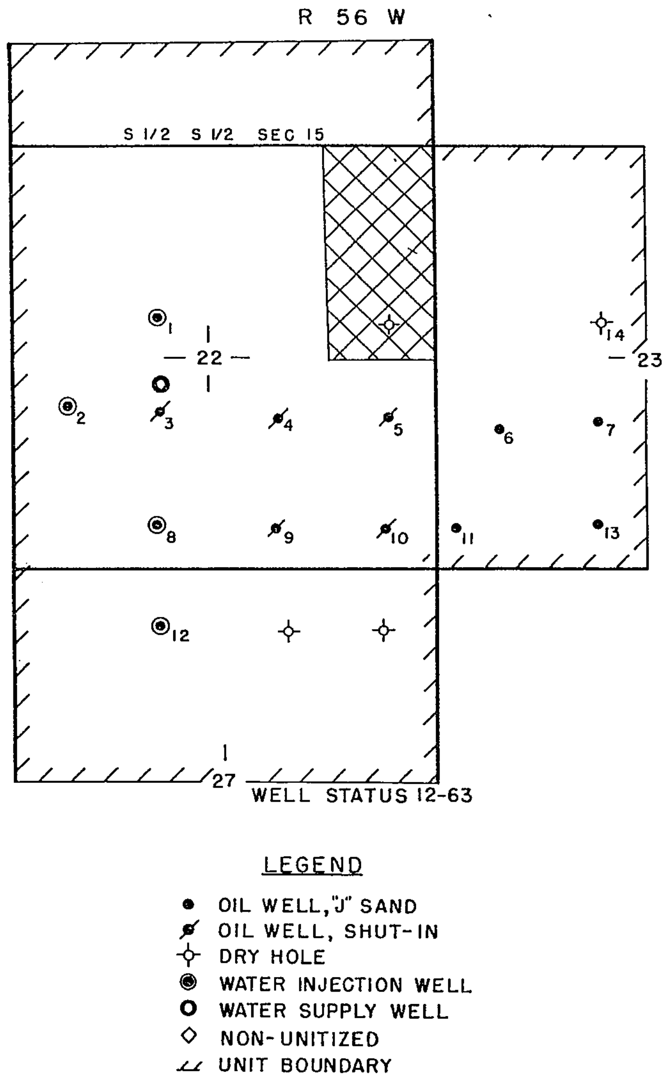

FIGURE 14. – Edwards unit, Banner County.

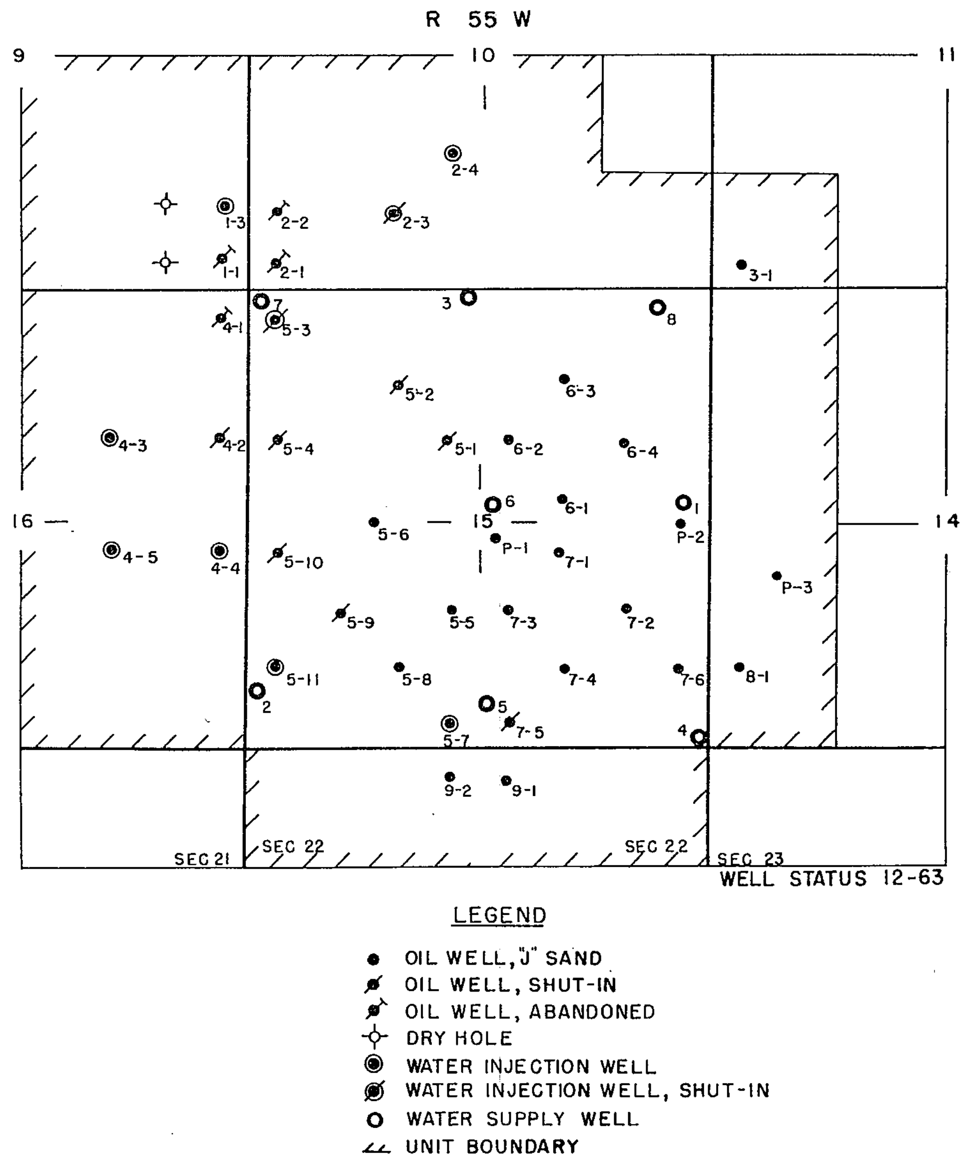

FIGURE 15. – Enders unit, Kimball County.

TABLE 10. - Basic data for Edwards unit ("J" sand)

I. Reservoir data

Productive area	454 acres
Average thickness	6.2 ft
Reservoir volume	2,815 acre-ft
Average porosity	21.7 pct
Average water saturation	25 pct
Formation volume factor	1.3 bbl/stb
Initial reservoir pressure	1,240 psi
Bubble point pressure	- - psi
Average permeability	250 md
Original solution GOR	250 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 454 \times 6.2 \times .217 \times .75}{1.3} = 2{,}700{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .217 \times .75}{1.3} = 972 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	25	243	675,000
Secondary	25	243	675,000
Ultimate	50	486	1,350,000

IV. Estimated water requirements and flood life

Total	4,000,000 bbl
Equivalent pore volume	0.85
Injection water:secondary oil	6:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	July 1959
Oil recovery (pct original oil in place)	47
Water injection (pct estimated water required)	58

Water is obtained from eight water supply wells scattered throughout the unit. The source is a sand varying from 1,000 to 1,400 feet deep. Each well initially tested approximately 50 barrels of water hourly or 1,200 barrels of water daily.

Waterflooding got underway during December 1956 when 3,300 barrels of water was injected daily through the four injection wells.

The flood pattern is peripheral, water being injected on the north, west, and south edges of the field.

During December 1963, 19 wells in the unit were producing at the combined average daily rate of 1,065 barrels of oil and 1,800 barrels of water. Produced water was injected into the producing formation through well No. 1-3. Well No. 5-3 previously had been used for this purpose. Fresh water was injected in six wells at 1,861 barrels daily at about 350 psi.

By volumetric determination, the oil originally in place was 35,748,000 barrels or 688 barrels an acre-foot. The estimated recovery factors expressed in percentage of initial oil in place are 16.7 percent for primary and 27.4 percent for secondary, or a total of 44.1 percent.

Estimated primary oil recovery is 5,970,000 barrels or 114 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 2,912,400 barrels or approximately 49 percent of the estimated primary oil. Water production up to the time of secondary recovery operations was negligible.

Estimated secondary oil recovery is 9,795,000 barrels or 188 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 3,248,100 barrels. Cumulative unit water injection for the same period was 9,466,500 barrels. The ratio of water injected to the oil produced was about 3:1. The water produced during the same period was 2,545,900 barrels.

Estimated water requirements are 27 million barrels over about 20 years. The 27 million barrels equal 60 percent of the pore volume. The estimated ratio of injected water to secondary oil recovered is 3:1.

Nineteen percent of the estimated secondary oil and only 17 percent of the original oil in place had been recovered at the end of 1963. Water injected was 35 percent of the estimated water required. The project appears to be successful. (Reserve Oil & Gas Co. has assumed operation of the Enders unit.)

See table 11 for basic engineering data.

TABLE 11. - Basic data for Enders unit ("J" sand)

I. Reservoir data

Productive area	1,760 acres
Average thickness	19 ft
Reservoir volume	33,440 acre-ft
Average porosity	17.5 pct
Average water saturation	35.5 pct
Formation volume factor	1.27 bbl/stb
Initial reservoir pressure	1,593 psi
Bubble point pressure	1,043 psi
Average permeability	252 md
Original solution GOR	325 cu ft per bbl
Gravity of crude	39° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 1{,}760 \times 19 \times .175 \times .645}{1.27} = 35{,}748{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .175 \times .645}{1.27} = 688 \; \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	16.7	114	5,970,000
Secondary	27.4	188	9,795,000
Ultimate	44.1	302	15,765,000

IV. Estimated water requirements and flood life

Total	27,000,000 bbl
Equivalent pore volume	0.6
Injection water:secondary oil	3:1
Flood life	20 years

V. Project status--January 1, 1964

Flood started	December 1956
Oil recovery (pct original oil in place)	17
Water injection (pct estimated water required)	35

Engelland Unit

The Engelland unit (fig. 16) is in secs 32 and 33, T 15 N, R 49 W, Cheyenne County, about 7 miles north of Sidney in an area of rolling farmland. The average elevation is 4,239 feet.

The field was discovered in December 1953 when Ohio Oil Co. completed its No. 1 Engelland well in the SE$\frac{1}{4}$NW$\frac{1}{4}$SE$\frac{1}{4}$ of sec 33, T 15 N, R 49 W. The wildcat was drilled to 4,755 feet and perforated between 4,580 and 4,589 feet in the "D" sand with 80 shots before being put on pump for an initial production of 250 barrels daily. Development of the field was slow, three producers being completed in 1954, two in 1955, and one dry hole in 1956. Subsequent development was suspended until 1960 when six wells were drilled. Only one of these was completed as a producer in the "D" sand. Of the other five wells drilled that year two were completed as "J" sand producers, two were dry holes, and one was completed as a water injection well. Initial production from the "J" sand producers was low (less than 65 barrels daily combined) and both made water. The "J" sand wells were spudded before the effective date of unitization and were in the original unit agreement.

The Engelland field was unitized in May 1960 with S. D. Johnson as unit operator. The unit included five wells (one "D" sand producer, two shut-in "D" sand wells, and two dry holes) in the adjacent Neimann field, in the SE$\frac{1}{4}$ of sec 32, T 15 N, R 49 W.

A dry hole in the SE$\frac{1}{4}$NE$\frac{1}{4}$ sec 33 was reworked and converted to injection in the "D" sand. A new well was drilled in the NE$\frac{1}{4}$NW$\frac{1}{4}$SW$\frac{1}{4}$ sec 33, as a "D" sand injection well. The "J" sand producing well in the C SE$\frac{1}{2}$ sec 33 was reworked and converted to a "J" sand injection well.

A fresh water supply well was drilled to 380 feet in the SW$\frac{1}{4}$NW$\frac{1}{4}$SE$\frac{1}{4}$ sec 33. It has a 40-foot, water-bearing sand, and tests indicated it was capable of supplying enough water for injection into both formations.

The secondary recovery project began in the "D" sand reservoir during June 1960. Injection was through two wells at 2,000 barrels daily. Oil production was from four wells.

The flood pattern is irregular. One injection well is on the west side of the unit and the other is in the northeast corner.

During December 1963 one well was injecting about 1,577 barrels of untreated water daily into the "D" sand at 600 psi. Two wells were producing around 37 barrels of oil and 117 barrels of water daily. Produced water was injected into the "D" sand.

Average reservoir data showed the estimated oil originally in place in the "D" sand to be 1,930,000 barrels or 955 barrels an acre-foot.

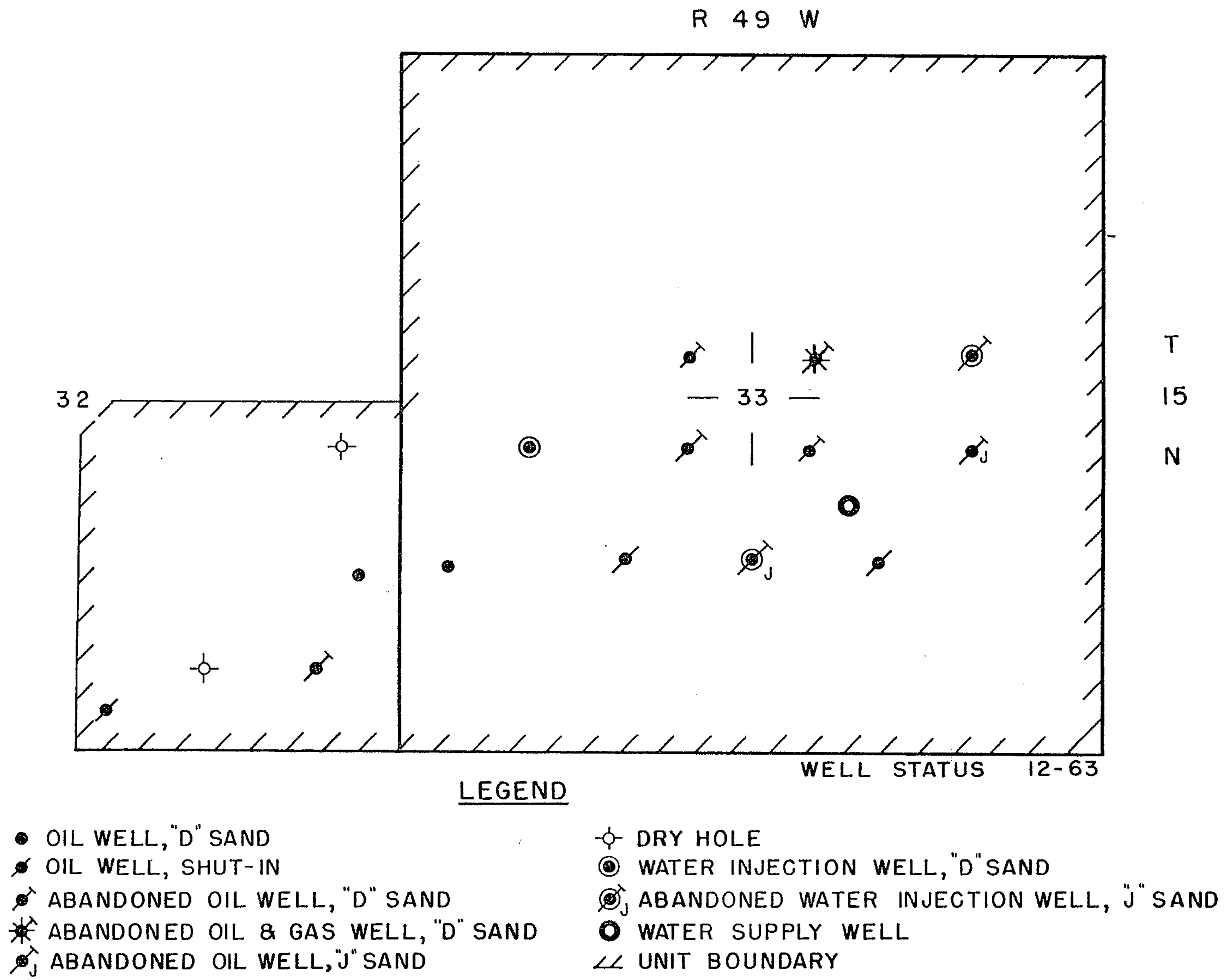

FIGURE 16. – Engelland unit, Cheyenne County.

The estimated recovery factors for the "D" sand, expressed in percentage of initial oil in place, are 12.8 percent for primary and 15.4 percent for secondary, or a total of 28.2 percent.

Estimated primary oil recovery from the "D" sand is 247,000 barrels or 122 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 242,066 barrels or 98 percent of the estimated primary recovery.

Estimated secondary oil recovery from the "D" sand is 297,000 barrels or 147 barrels an acre-foot. Cumulative unit "D" sand production from the start of waterflooding until the end of 1963 was 74,200 barrels of oil and 196,900 barrels of water. Cumulative unit water injection for the same period was 1,220,622 barrels. The ratio of water injected to oil produced is 17:1. Injection operations were shut down between September 30, 1962, and July 22, 1963, but production was continued.

The estimated water requirements are 3,860,000 barrels or 1 pore volume. The estimated ratio of injected water to secondary oil recovered is 13:1. Estimated flood life is 10 years.

At the end of 1963 approximately 23 percent of the estimated secondary oil and only 16 percent of the original oil in place had been recovered. Water injected was 32 percent of the estimated water required. The outcome of the project is indeterminate.

Waterflooding was begun in the "J" sand reservoir in April 1961 when water was injected into one well at approximately 670 barrels daily. The project was discontinued in February 1962 after 36,000 barrels had been injected. Because of the short duration of the "J" sand project, its effect is considered negligible. It can be classified as incomplete or a possible failure. Centennial Oil Co. was unit operator on January 1, 1964.

See table 12 for basic engineering data.

Gehrke Unit

The Gehrke unit (fig. 17) is in secs 7 and 8, T 14 N, R 57 W, Kimball County, approximately 11 miles west of the town of Kimball. The average elevation is approximately 5,080 feet.

The Gehrke field was discovered in August 1957 when Pan American Petroleum Corp. completed the No. 1 Gehrke, C NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 7, for an initial pumping production of 313 barrels daily from the "J" sand through perforations from 6,982 to 6,998 feet. Subsequent development resulted in a field of 7 producing wells and 10 dry holes.

TABLE 12. - Basic data for Engelland unit ("D" sand)

I. Reservoir data

Productive area	- - acres
Average thickness	- - ft
Reservoir volume	2,025 acre-ft
Average porosity	24.6 pct
Average water saturation	38 pct
Formation volume factor	1.24 bbl/stb
Initial reservoir pressure	1,125 psi
Bubble point pressure	- - psi
Average permeability	457 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7,758 \times 2,025 \times .246 \times .62}{1.24} = 1,930,000 \text{ STB}$$

$$\frac{7,758 \times .246 \times .62}{1.24} = 955 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	12.8	122	247,000
Secondary	15.4	147	297,000
Ultimate	28.2	269	544,000

IV. Estimated water requirements and flood life

Total	3,860,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	13:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	June 1960
Oil recovery (pct original oil in place)	16
Water injection (pct estimated water required)	32

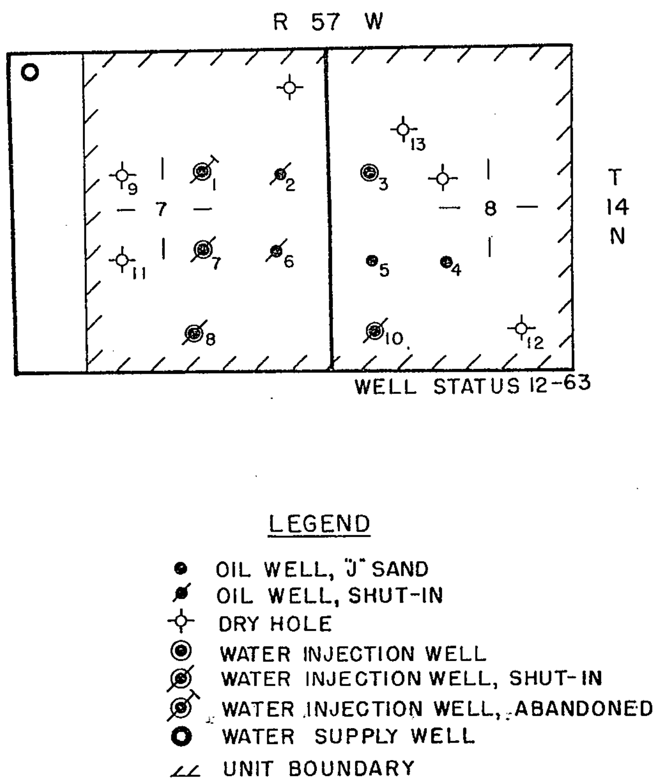

FIGURE 17. – Gehrke unit, Kimball County.

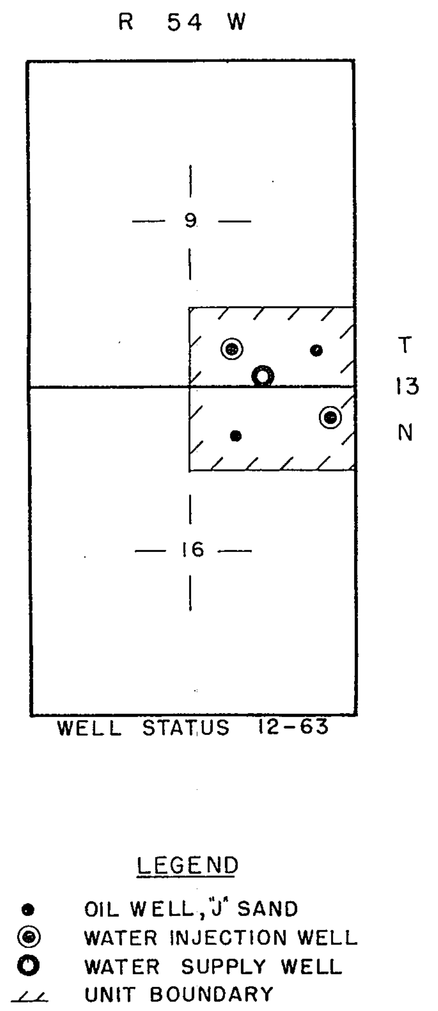

FIGURE 18. – Goodwin unit, Kimball County.

The field, including 7 producing wells and 8 of the 10 dry holes, was unitized in 1958 with Pan American as unit operator. One of the producing wells was converted to a water injection well. A fresh water supply well outside the unit area in the NW$\frac{1}{4}$NW$\frac{1}{4}$ of sec 7 was drilled to alluvial gravel at approximately 200 feet.

Waterflooding was begun in December 1958 when fresh water was injected into one well at 750 barrels daily. Later, additional wells were placed on injection. Between February 1962 and April 1963 injection was suspended to evaluate flood performance and to revise the injection pattern.

The flood pattern is a modified line drive. Initially water was injected into a single well in the west end of the unit area. Later, two dry holes in the south end of the unit area and an infield producing well were converted to injection wells.

In December 1963 the Gehrke unit contained two active producing wells and one active injection well. Daily production was approximately 27 barrels of oil and 215 barrels of water. Produced water was disposed of in surface pits. Daily injection was approximately 550 barrels of untreated water at 200 psi.

By volumetric determination the oil in place at original reservoir conditions was 3,530,000 barrels or 708 barrels an acre-foot. The estimated recovery factors, expressed in percentage of oil in place, are: Primary, 25 percent; secondary, 25 percent; and ultimate, 50 percent.

Estimated primary oil recovery is 883,000 barrels or 177 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 402,000 barrels or 46 percent of the estimated primary recovery. Estimated secondary oil recovery is also 883,000 barrels or 177 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was approximately 1,316,000 barrels of oil and 360,000 barrels of water. Cumulative unit water injection for the same period was approximately 1,950,000 barrels.

Estimated water requirements are 3,150,000 barrels or 0.5 pore volume. The estimated ratio of injected water to secondary oil recovered is 4:1. Estimated flood life is 7 years.

By the end of 1963 approximately 95 percent of the estimated secondary oil and 49 percent of the original oil in place had been recovered. Water injected was only 62 percent of the estimated water required, indicating a high estimate. The project is apparently successful.

See table 13 for basic engineering data.

TABLE 13. - Basic data for Gehrke unit ("J" sand)

I. Reservoir data

Productive area	554 acres
Average thickness	9 ft
Reservoir volume	4,986 acre-ft
Average porosity	16.3 pct
Average water saturation	30 pct
Formation volume factor	1.25 bbl/stb
Initial reservoir pressure	1,790 psi
Bubble point pressure	- - psi
Average permeability	150 md
Original solution GOR	500 cu ft per bbl (est)
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 554 \times 9 \times .163 \times .70}{1.25} = 3{,}530{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .163 \times .70}{1.25} = 708 \; \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	25	177	883,000
Secondary	25	177	883,000
Ultimate	50	354	1,766,000

IV. Estimated water requirements and flood life

Total	3,150,000 bbl
Equivalent pore volume	0.5
Injection water:secondary oil	4:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	December 1958
Oil recovery (pct original oil in place)	49
Water injection (pct estimated water required)	62

Goodwin Unit

The Goodwin unit (fig. 18) is in secs 9 and 16, T 13 N, R 54 W, Kimball County, approximately 10 miles southeast of the town of Kimball. Average elevation is about 4,780 feet.

The Goodwin field was discovered in May 1952 when Vaughey and Vaughey completed the No. 1 F.L.B. Goodwin, C SE$\frac{1}{4}$SE$\frac{1}{4}$ sec 9, for an initial pumping production of 260 barrels daily from the "J" sand through perforations from 6,040 to 6,047 feet. Subsequent development resulted in a field of five producing wells and four dry holes.

The field, including four of the five producing wells, was unitized in July 1957 with Vaughey and Vaughey as unit operator. Two producing wells were converted to water injection wells, and a water supply well was drilled near the center of the unit area. The water supply well was drilled to 1,600 feet and tested capable of producing 800 barrels daily from the interval between 1,250 and 1,500 feet. Waterflooding was begun in August 1957, water being injected into two wells at 650 barrels daily.

The flood pattern is irregular with one injection well in the northwest corner and the other in the southeast corner of the unit area.

In December 1963 the original wells were still in active status. Daily production was approximately 48 barrels of oil and 340 barrels of water. Produced water was injected into the "J" sand. Daily injection was approximately 680 barrels on vacuum surface pressure.

By volumetric determination the oil in place at original reservoir conditions was 1,335,000 barrels or 783 barrels an acre-foot. The estimated recovery factors, expressed in percentage of oil in place, are: Primary, 27 percent; secondary, 11 percent; and ultimate, 38 percent.

Estimated primary oil recovery is 360,000 barrels or 211 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 350,000 barrels or 97 percent of the estimated primary recovery. Estimated secondary oil recovery is 147,000 barrels or 86 barrels an acre-foot.

Cumulative unit production of waterflooding until the end of 1963 was approximately 131,000 barrels of oil and 375,000 barrels of water. Cumulative water injection for the same period was approximately 1,437,000 barrels.

Estimated water requirements are 1$\frac{1}{2}$ million barrels or 0.66 pore volume. The estimated ratio of injected water to secondary oil recovered is 10:1. Estimated flood life is 9 years.

By the end of 1963 approximately 82 percent of the estimated secondary oil and about 36 percent of the original oil in place had been recovered. Water injected was approximately 96 percent of the estimated water required, indicating a low estimate. The project apparently is successful.

See table 14 for basic engineering data.

Grant Unit

The Grant unit (fig. 19) is in the NE$\frac{1}{4}$ and S$\frac{1}{2}$ of sec 29, T 19 N, R 55 W, Banner County, approximately 2 miles northeast of the town of Harrisburg. Average elevation is approximately 4,360 feet.

The Grant field was discovered in May 1959 when Davis Oil Co. completed the No. 1 Grant, SW$\frac{1}{4}$NE$\frac{1}{4}$ sec 29, for an initial pumping production of 240 barrels of oil daily from the "D" sand through perforations from 5,572 to 5,575 feet. A dry hole had been drilled in the field in 1955. Following completion of the discovery well, subsequent development resulted in four more producing wells and one dry hole.

The field (including six wells, five producing and one dry hole) was unitized in August 1962 with Kimbark Exploration Co. as unit operator. A shallow (100 feet) fresh water supply well was drilled north of the unit area in sec 20, T 19 N, R 55 W.

Waterflooding was begun in November 1962 when fresh water was injected into a former producing well at approximately 560 barrels daily. At that time there were four producing wells and one injection well. The single injection well was the northernmost well in the unit area.

During July 1963 three wells were producing a daily total of 25 barrels of oil and no water. Another producing well had been changed to an injection well and the original injection well had been abandoned. The daily average injection rate was 850 barrels at 1,800 psi. A corrosion inhibitor was added to the injection water.

Determined volumetrically the oil in place at original reservoir conditions was 905,000 barrels or 905 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 21.4 percent; secondary, 11 percent; and ultimate, 32.4 percent.

Estimated primary oil recovery is 194,000 barrels or 194 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 155,000 barrels or 80 percent of the estimated primary recovery. Estimated secondary oil recovery is 100,000 barrels or 100 barrels an acre-foot.

TABLE 14. - Basic data for Goodwin unit ("J" sand)

I. Reservoir data

Productive area	310 acres
Average thickness	5.5 ft
Reservoir volume	1,705 acre-ft
Average porosity	17.3 pct
Average water saturation	30.0 pct
Formation volume factor	1.20 bbl/stb (est)
Initial reservoir pressure	1,250 psi
Bubble point pressure	- - psi
Average permeability	99 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 310 \times 5.5 \times .173 \times .70}{1.20} = 1{,}335{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .173 \times .70}{1.20} = 783 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	27	211	360,000
Secondary	11	86	147,000
Ultimate	38	297	507,000

IV. Estimated water requirements and flood life

Total	1,500,000 bbl
Equivalent pore volume	0.66
Injection water:secondary oil	10.1
Flood life	9 years

V. Project status--January 1, 1964

Flood started	August 1957
Oil recovery (pct original oil in place)	36
Water injection (pct estimated water required)	96

Cumulative unit production from the start of waterflooding until the end of 1963 was 20,200 barrels of oil and no water. Cumulative unit water injection for the same period was 184,100 barrels.

Estimated water requirements are 1,550,000 barrels of fresh water or 1 pore volume. The estimated ratio of injected water to secondary oil recovered is 16:1. The estimated flood life is 6 years.

Almost all, 90 percent, of the estimated recoverable primary oil but only 19 percent of the original oil in place had been recovered at the end of 1963. Water injected was 12 percent of the estimated water required. The outcome of the project is indeterminate.

See table 15 for basic engineering data.

Harrisburg Project

The Harrisburg project (fig. 20) is in sec 10, T 18 N, R 55 W, Banner County, about 3 miles east of the town of Harrisburg. The area lies at the bottom of the south escarpment of the Pumpkin Creek valley. Average elevation of the field is 4,547 feet.

The Harrisburg field was discovered in March 1951 when Kerr-McGee, Phillips, and Pan American completed the No. 1 Downer, NE$\frac{1}{4}$NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 6, T 18 N, R 55 W, for an initial pumping production of 323 barrels of oil daily from the "J" sand through perforations from 5,878 to 5,907 feet. Subsequent development resulted in a field of 63 producing wells and 8 dry holes.

The project was approved by the Nebraska Oil and Gas Conservation Commission in January 1961 with E. A. Obering (Warrier Oil Co.) as project operator. Twelve producing wells were in the project: 3 were completed in the "D" sand, 2 in the "J" sand, and 7 were dual completions. The formations to be flooded included both the "D" and the "J" sands. Two producing wells, one in the "D" sand on the west side of the project and the other in the "J" sand on the east side of the project, were reworked and converted to water injection wells. The well on the west injects into both the "D" and the "J" sands while the well on the east injects into the "J" sand only.

The project is a cooperative flood with the West Harrisburg unit (Pan American) and the East Harrisburg unit (Walter Duncan). Operator agreement and cooperation were considered essential to provide the greatest ultimate recovery without undue expense to the working-interest owners.

Water supply wells are in the NW$\frac{1}{4}$NW$\frac{1}{4}$ sec 11, T 18 N, R 55 W, which is in the East Harrisburg unit, and the NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 11, T 18 N, R 55 W, which is just outside the East Harrisburg unit boundary. The two wells were tested capable of producing more than 3,500 barrels of water daily.

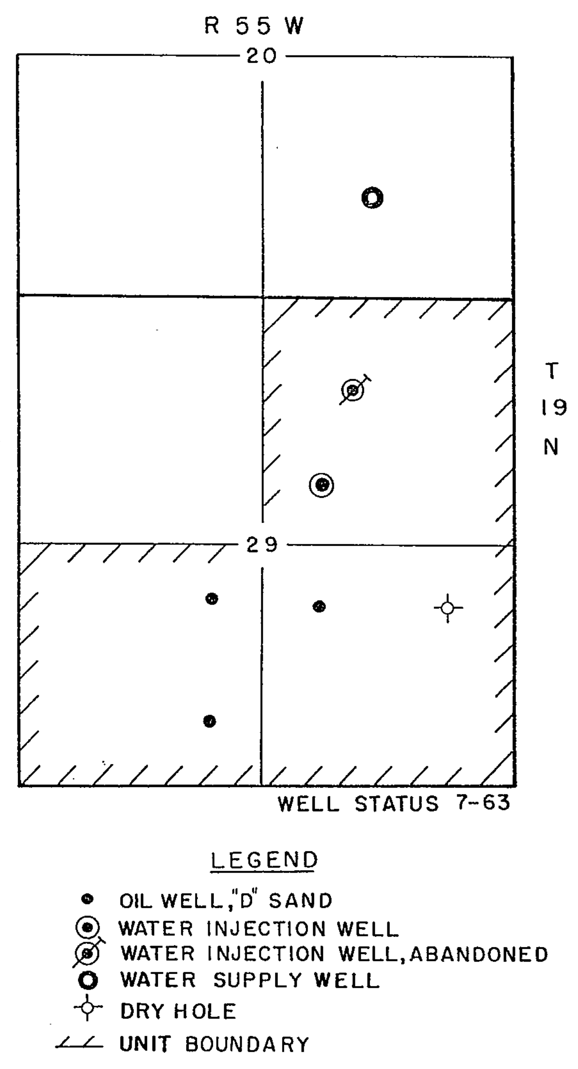

FIGURE 19. – Grant unit, Banner County.

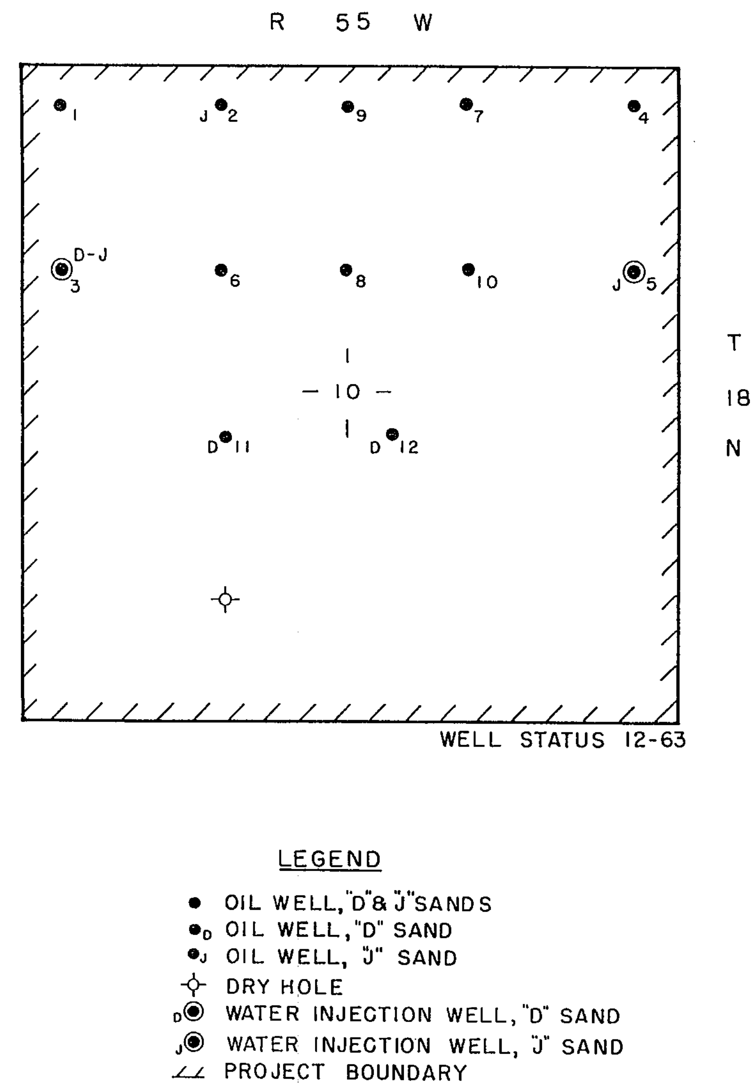

FIGURE 20. – Harrisburg project, Banner County.

TABLE 15. - Basic data for Grant unit ("D" sand)

I. Reservoir data

Productive area	200 acres
Average thickness	5 ft
Reservoir volume	1,000 acre-ft
Average porosity	20 pct
Average water saturation	30 pct
Formation volume factor	1.2 bbl/stb (est)
Initial reservoir pressure	1,250 psi
Bubble point pressure	- - psi
Average permeability	150 md
Original solution GOR	400 cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7,758 \times 200 \times 5 \times .20 \times .70}{1.2} = 905,000 \text{ STB}$$

$$\frac{7,758 \times .20 \times .70}{1.2} = 905 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	21.4	194	194,000
Secondary	11.0	100	100,000
Ultimate	32.4	294	294,000

IV. Estimated water requirements and flood life

Total (fresh)	1,550,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	16:1
Flood life	6 years

V. Project status--January 1, 1964

Flood started	November 1962
Oil recovery (pct original oil in place)	19
Water injection (pct estimated water required)	12

The secondary recovery operations began during August 1961. Water was injected into two wells at 920 barrels daily. Production was from two "D" sand wells, one "J" sand well, and seven dual completions.

During December 1963 untreated water was being injected into two wells at 33,165 barrels monthly. Injection pressure in the "D" sand was about 580 psi while injection into the "J" sand was on vacuum. Production was 3,008 barrels of oil and 10,168 barrels of water from 10 wells. Produced water was run to surface pits. Future plans call for produced water to be treated and injected along with fresh water.

By volumetric determination the oil originally in place was 1,365,000 barrels in the "D" sand and 2,350,000 barrels in the "J" sand. Production is commingled.

The estimated recovery factors, expressed in percentage of initial oil in place for the "D" and the "J" sands combined, are 23.3 percent for primary, and 11.3 percent for secondary, for a total of 34.6 percent.

Estimated primary oil recovery from the "J" sand and the "D" sand combined is 866,000 barrels or 330 barrels an acre-foot. Cumulative project oil production at the start of waterflooding was 821,600 barrels or approximately 96 percent of the estimated primary recovery.

Cumulative project water production to the start of waterflooding was 2,500 barrels.

Estimated secondary oil recovery is 420,000 barrels or 160 barrels an acre-foot.

Cumulative production from the start of waterflooding until the end of 1963 was 67,100 barrels of oil and 38,800 barrels of water. Cumulative water injection for the same period was 655,400 barrels. The ratio of water injected to oil produced is about 10:1.

Estimated water requirements are 11 million barrels for the "D" and the "J" sands combined. The 11 million barrels of water make up about 1.8 pore volumes. The estimated ratio of water injected to secondary oil recovered is 26:1.

At the end of 1963 only 5 percent of the estimated secondary oil and only 24 percent of the original oil in place had been recovered. Water injected was 6 percent of the estimated water required. The outcome of the project is indeterminate.

See table 16 for basic engineering data.

TABLE 16. - Basic data for Harrisburg project ("J" and "D" sands)

I. Reservoir data

	"D" sand	"J" sand
Productive area	400 acres	320 acres
Average thickness	5 ft	10 ft
Reservoir volume	- - acre-ft	3,200 acre-ft
Average porosity	14.7 pct	15 pct
Average water saturation	19.2 pct	20.5 pct
Formation volume factor	1.35 bbl/stb	1.26 bbl/stb
Initial reservoir pressure	1,703 psi	1,743 psi
Bubble point pressure	- - psi	- - psi
Average permeability	172 md	119 md
Original solution GOR	318 cu ft per bbl	297 cu ft per bbl
Gravity of crude	36° API	36° API

II. Oil in place at original conditions

"D" sand $$\frac{7{,}758 \times 400 \times 5 \times .147 \times .808}{1.35} = 1{,}365{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .147 \times .808}{1.35} = 684 \ \frac{\text{STB}}{\text{Acre-ft}}$$

"J" sand $$\frac{7{,}758 \times 320 \times 10 \times .15 \times .795}{1.26} = 2{,}350{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .15 \times .795}{1.26} = 734 \ \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery

Estimated recovery	Pct oil in place	STB
Primary ("D" and "J")	23.3	866,000
Secondary ("D" and "J")	11.3	420,000
Ultimate ("D" and "J")	34.6	1,286,000

IV. Estimated water requirements and flood life

Total	11,000,000 bbl
Equivalent pore volumes	1.8
Injection water:secondary oil	26:1
Flood life	$8\frac{1}{2}$ years

V. Project status--January 1, 1964

Flood started	August 1961
Oil recovery (pct original oil in place)	24
Water injection (pct estimated water required)	6

East Harrisburg Unit

The East Harrisburg unit (fig. 21), about 3 miles east of the town of Harrisburg, is in secs 2, 3, and 11, T 18 N, R 55 W, Banner County. Average elevation of the field is 4,564 feet.

The Harrisburg field was discovered in March 1951 when Kerr-McGee, Phillips, and Pan American completed the No. 1 Downer, NE$\frac{1}{4}$NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 6, for an initial pumping production of 323 barrels daily from the "J" sand between 5,878 and 5,907 feet. Subsequent development resulted in a field of 63 producing wells and 8 dry holes.

The east portion of the Harrisburg field, including both the "D" and the "J" sands, was unitized during January 1961 with Walter Duncan as unit operator.

The waterflood is cooperative with West Harrisburg unit (Pan American) and the Harrisburg project (Warrior Oil Co.). To protect the correlative rights and interests of the leaseholders of the Harrisburg project and the East and West Harrisburg units, injection wells are placed along common boundaries.

A water supply well was drilled in the NW$\frac{1}{4}$NW$\frac{1}{4}$ sec 11 and tested capable of supplying 2,100 barrels daily. The water injection plant for both the East Harrisburg unit and the Harrisburg project is in the East Harrisburg unit.

Secondary recovery operations began in February 1961 with 1,500 barrels of water injected through three wells simultaneously into the "D" and the "J" sands. Production was from 1 "D" sand well, 1 "J" sand well, and 14 wells dually completed in both the "D" and the "J" sands.

On the basis of cooperative injection with adjoining units, the flood pattern is line drive. The injection well on the extreme west end of the unit offsets injection wells in the West Harrisburg unit and the Harrisburg project to the south. The other two injection wells complete the line drive.

During December 1963, the 12 remaining active wells produced 3,397 barrels of oil. Oil from the "D" sand is commingled with oil from the "J" sand in dual producers. Water production during December was 1,165 barrels. Produced water was run to surface pits. Water injection during the same period was 55,739 barrels. Injection water was treated with a corrosion inhibitor and injected at pressures ranging from 500 psi to 1,300 psi. Three wells were used for injection.

By volumetric determination the oil in place at original reservoir conditions in the "D" and the "J" sands combined was 5,781,000 barrels or 712 barrels an acre-foot.

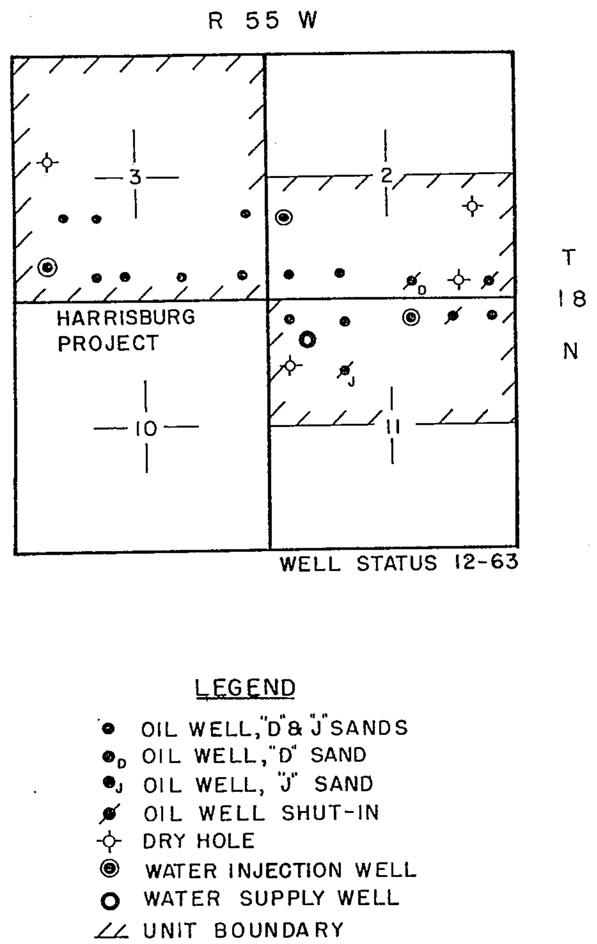

FIGURE 21. – East Harrisburg unit, Banner County.

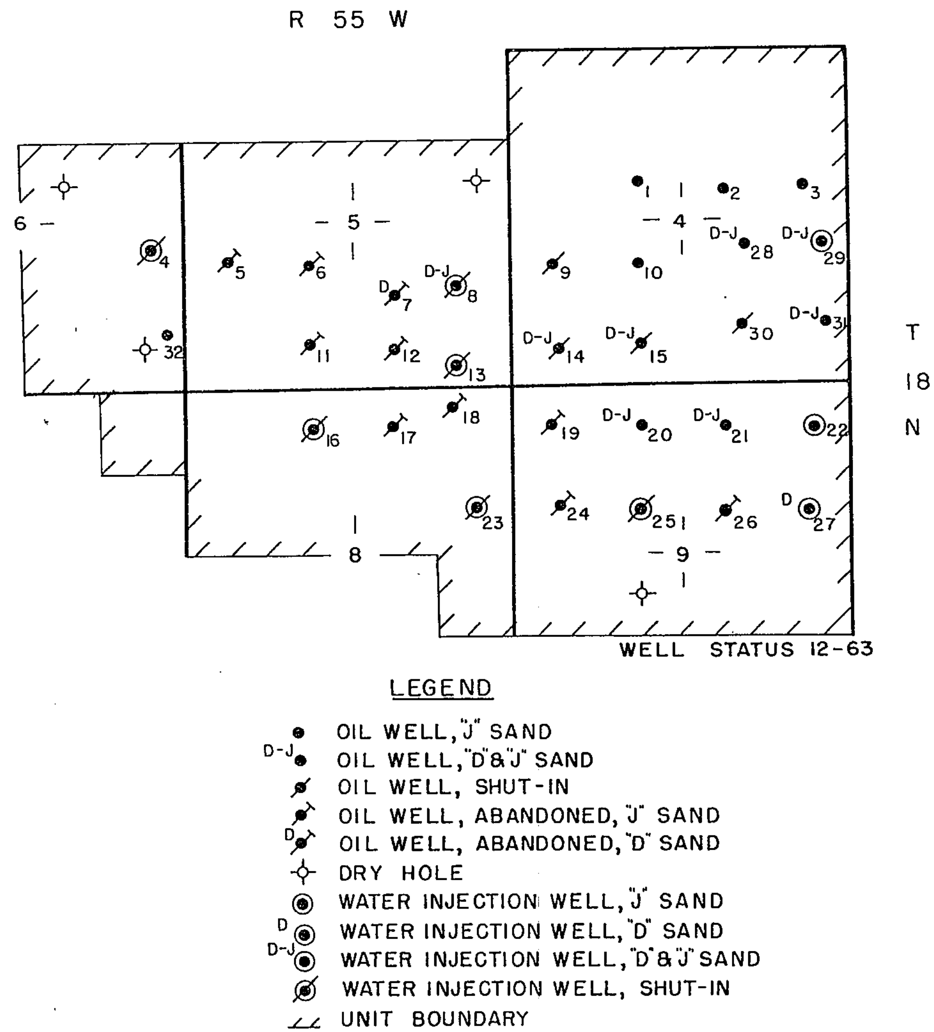

FIGURE 22. – West Harrisburg unit, Banner County.

The estimated recovery factors expressed in percentage of initial oil in place are 18.1 percent for primary, and 11.6 percent for secondary or a total of 29.7 percent from both the "D" and the "J" sands.

Estimated primary oil recovery is 1,046,000 barrels or 129 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 1,026,200 barrels or approximately 98.4 percent of the estimated primary oil from both the "D" and "J" sands.

Estimated secondary oil recovery is 671,000 barrels or 83 barrels an acre-foot from both the "D" and "J" sands.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 75,000 barrels. Cumulative unit water injection for the same period was 1,067,300 barrels. The ratio of water injected to oil produced is about 14:1. Water production since injection began was 34,600 barrels.

Estimated water requirements for the "D" and the "J" sands are 17 million barrels over $8\frac{1}{2}$ years. The 17 million barrels make up 1.7 pore volumes. The estimated ratio of water injected to secondary oil produced is 25:1.

Only 8 percent of the estimated secondary oil and only 19 percent of the original oil in place had been recovered at the end of 1963. Water injected was only 6 percent of the estimated water required. The outcome of the project is indeterminate.

See table 17 for basic engineering data.

West Harrisburg Unit

The West Harrisburg unit (fig. 22) is in secs 4-9, T 18 N, R 55 W, Banner County, approximately 1 mile east of the town of Harrisburg. Average elevation is 4,550 feet.

The Harrisburg field was discovered in March 1951 when Kerr-McGee, Phillips, and Pan American completed the No. 1 Downer, NE$\frac{1}{4}$NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 6, for an initial pumping production of 323 barrels of oil daily from the "J" sand in open hole from 5,878 to 5,907 feet. Subsequent development resulted in a field of 63 producing wells and 8 dry holes.

The west end of the field, including 32 producing wells and 2 dry holes, was unitized in 1959 with Pan American as unit operator. Of the 32 producing wells, 23 were completed in the "J" sand, 6 in the "D" sand, and 3 in both the "D" and "J" sands.

Waterflooding was begun in May 1959 when fresh water was injected into five wells at 3,000 barrels daily. Four of the five injection wells were former "J" sand producers and one was a former "D" sand

TABLE 17. - Basic data for East Harrisburg unit ("D" and "J" sands)

I. Reservoir data

Productive area	- - acres
Average thickness	- - ft
Reservoir volume	8,124 acre-ft
*Average porosity	15.9 pct
Average water saturation	25 pct
Formation volume factor	1.3 bbl/stb
Initial reservoir pressure	1,723 psi
Bubble point pressure	- - psi
**Average permeability	108 md
Original solution GOR	300 cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7,758 \times 8,124 \times .159 \times .75}{1.3} = 5,781,000 \text{ STB}$$

$$\frac{7,758 \times .159 \times .75}{1.3} = 712 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary ("D" and "J")	18.1	129	1,046,000
Secondary ("D" and "J")	11.6	83	671,000
Ultimate ("D" and "J")	29.7	212	1,717,000

IV. Estimated water requirements and flood life

Total	17,000,000 bbl
Equivalent pore volumes	1.7
Injection water:secondary oil	25:1
Flood life	$8\frac{1}{2}$ years

V. Project status--January 1, 1964

Flood started	February 1961
Oil recovery (pct original oil in place)	19
Water injection (pct estimated water required)	6

*Porosity (percent) - "D" sand 15.5%, "J" sand 16.3%
**Permeability (millidarcys) - "D" sand, 152, "J" sand, 64

producer. The "D" sand well was recompleted as a dual ("D" and "J") injection well. A fresh water supply well had been drilled in the SE$\frac{1}{4}$NW$\frac{1}{4}$ sec 32, T 19 N, R 55 W. The water was obtained from alluvial gravels at approximately 200 feet.

The flood pattern in the west end of the unit area is irregular, whereas the flood pattern in the east end is a staggered line drive. The west end contains the five initial injection wells. The three injection wells in the east end are part of a cooperative flood agreement with the adjoining Harrisburg project and the East Harrisburg unit.

In December 1963 the West Harrisburg unit contained nine active producing wells and three active injection wells. Daily production was approximately 66 barrels of oil and 154 barrels of water. Produced water was injected into the "J" sand reservoir. Daily injection was approximately 1,000 barrels of untreated water, of which 500 barrels was injected into the "D" sand at 1,500 psi and 500 barrels was injected into the "J" sand at 1,725 psi.

By volumetric determination the oil in place at original reservoir conditions was 8,713,000 barrels for the "J" sand and 811,000 barrels for the "D" sand. The estimated recovery factors for both "D" and "J" sands, expressed in percentage of oil in place, are: Primary, 20 percent; secondary, 15 percent; and ultimate, 35 percent.

Estimated primary oil recovery ("D" and "J") is 1,905,000 barrels. Cumulative unit oil production ("D" and "J") at the start of waterflooding was 1,643,000 barrels or 86 percent of the estimated primary recovery. Estimated recoverable secondary oil ("D" and "J") is 1,429,000 barrels.

Cumulative unit production from the start of waterflooding until the end of 1963 was 358,900 barrels of oil and 1,665,400 barrels of water. Cumulative unit water injection for the same period was 3,835,500 barrels.

Estimated total water requirements are 15,100,000 barrels or 1 pore volume. Estimated ratio of water injected to oil recovered is 11:1. The estimated flood life is 10 years.

At the end of 1963 only 7 percent of the estimated secondary oil and only 21 percent of the estimated original oil in place had been recovered. Water injected was 25 percent of the estimated water required. The outcome of the project is indeterminate.

See table 18 for basic engineering data.

TABLE 18. - Basic data for West Harrisburg unit ("D" and "J" sands)

I. Reservoir data

	"J" sand	"D" sand
Productive area	1,310 acres	300 acres
Average thickness	9 ft	4 ft
Reservoir volume	11,790 acre-ft	1,200 acre-ft
Average porosity	15 pct	14.7 pct
Average water saturation	20 pct	20 pct
Formation volume factor	1.26 bbl/stb	1.35 bbl/stb (est)
Initial reservoir pressure	1,703 psi	- - psi
Bubble point pressure	1,101 psi	- - psi
Average permeability	119 md	172 md
Original solution GOR	297 cu ft per bbl	- - cu ft per bbl
Gravity of crude	36° API	- - API

II. Oil in place at original conditions

"J" sand $$\frac{7{,}758 \times 1{,}310 \times 9 \times .15 \times .80}{1.26} = 8{,}713{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .15 \times .80}{1.26} = 739 \frac{\text{STB}}{\text{Acre-ft}}$$

"D" sand $$\frac{7{,}758 \times 300 \times 4 \times .147 \times .80}{1.35} = 811{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .147 \times .80}{1.35} = 676 \frac{\text{STB}}{\text{Acre-ft}}$$

Total oil in place ("D" and "J") = 9,524,000 STB

III. Estimated recovery

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
"D" sand			
Primary	20	135	162,000
Secondary	15	101	122,000
Ultimate	35	236	284,000
"J" sand			
Primary	20	148	1,743,000
Secondary	15	111	1,307,000
Ultimate	35	259	3,050,000

TABLE 18. - Basic data for West Harrisburg unit--Continued

			STB	
III.	Estimated recovery	Pct oil in place	Acre-ft	STB
	Total "D" and "J"			
	Primary			1,905,000
	Secondary			1,429,000
	Ultimate			3,334,000

IV. Estimated water requirements and flood life

Total ("D" and "J")	15,089,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	11:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	May 1959
Oil recovery (pct original oil in place)	21
Water injection (pct estimated water required)	25

Heidemann Unit

The Heidemann unit (fig. 23) is in secs 13, 14, 23, 24, 26, and 35, T 15 N, R 56 W, Kimball County, approximately 2 miles west of the town of Kimball. Average elevation is 4,750 feet.

The Heidemann field was discovered in November 1956 when Petroleum, Inc., completed the No. 1 Heidemann, C $SE\frac{1}{4}NE\frac{1}{4}$ sec 23, for an initial pumping production of 120 barrels daily from the "J" sand through perforations from 6,343 to 6,350 feet. Subsequent development resulted in a field of 25 producing wells and 13 dry holes.

The field, including all of the producing wells and 9 of the 13 dry holes, was unitized in October 1961 with Shell Oil Co. as unit operator.

Waterflooding was begun in May 1962 when fresh water was injected into seven former producing wells at approximately 4,600 barrels daily. The fresh water was obtained from a shallow well drilled in the $SE\frac{1}{4}NE\frac{1}{4}$ of sec 26. The well was completed in alluvial gravel at approximately 160 feet.

The flood pattern is semiperipheral. The reservoir is elongated (north-south) roughly three times as long as it is wide. The injection wells are on the west, north, and south ends of the unit area.

In December 1963 the Heidemann unit contained 14 active producing wells and 7 active injection wells. Daily production was approximately 675 barrels of oil and 1,300 barrels of water. Produced water was treated with a bactericide and corrosion inhibitor and injected into the oil reservoir. Daily injection was approximately 4,900 barrels of fresh and produced water at a pressure of 975 psi. The fresh water was untreated.

By volumetric determination the oil in place at original reservoir conditions was 8,716,000 barrels or 807 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 22 percent; secondary, 14 percent; and ultimate, 36 percent.

Estimated primary oil recovery is 1,918,000 barrels or 178 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 1,900,000 barrels or 99 percent of the estimated primary recovery. Estimated secondary oil recovery is 1,220,000 barrels or 113 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 377,000 barrels of oil and 567,100 barrels of water. Cumulative unit water injection for the same period was 3,191,400 barrels.

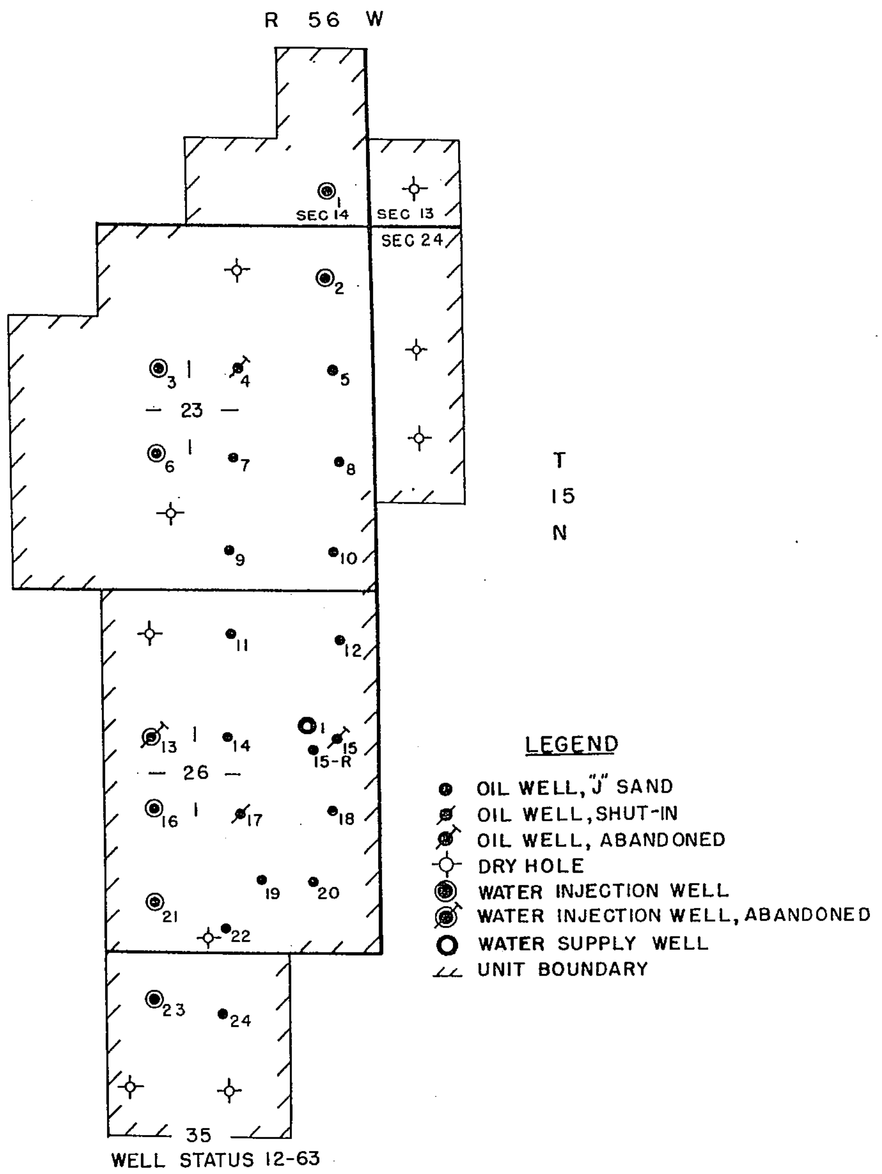

FIGURE 23. – Heidemann unit, Kimball County.

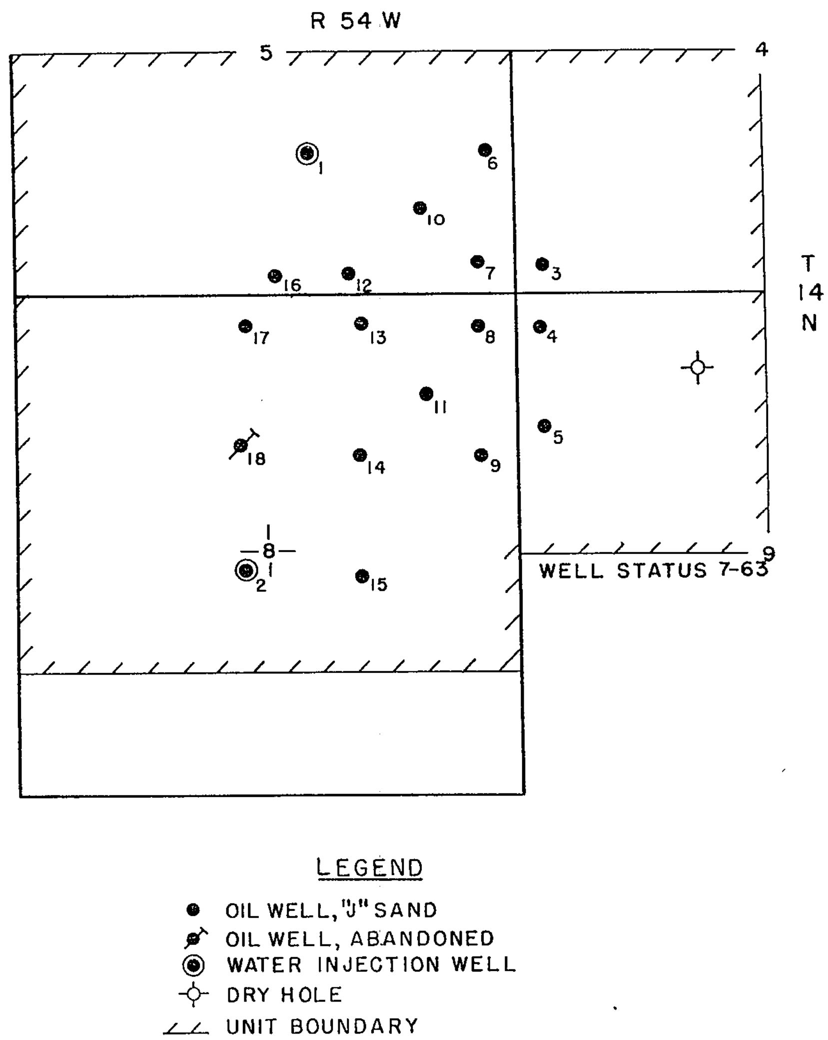

FIGURE 24. – Houtby unit, Kimball County.

Estimated water requirements are 7,100,000 barrels of make-up (fresh) water and 3,000,000 barrels of produced water totaling 10,100,000 barrels or 0.60 pore volume. The estimated ratio of water injected to secondary oil recovered is 8:1. The estimated flood life is 6 years.

By the end of 1963 approximately 29 percent of the estimated secondary oil and 26 percent of the original oil in place had been recovered. Water injected was approximately 32 percent of the estimated water required. Available data indicate a successful project.

See table 19 for basic engineering data.

Houtby Unit

The Houtby unit (fig. 24) about $2\frac{1}{2}$ miles southeast of the town of Dix in an area of rolling hills, is in secs 4, 5, 8, and 9, T 14 N, R 54 W, Kimball County. Average elevation of the field is 4,775 feet.

The Houtby field was discovered in 1954 with the completion of Sam Joseph's No. 1 Houtby in the SE$\frac{1}{4}$SE$\frac{1}{4}$SE$\frac{1}{4}$ sec 5, T 14 N, R 54 W. Initially the wildcat pumped 20 barrels of oil hourly from the "J" sand at 6,002 to 6,010 feet. Field development was slow, and only two more wells were completed in 1955. In 1956 seven wells were completed, and then development slacked off. Eighteen wells were drilled in the Houtby field, 15 of these completed as producers and 3 completed as dry holes.

During September 1962 the Houtby unit was formed with Sage Oil Co. as unit operator. The unit consists of 15 producing wells in the Houtby field, plus 3 producing wells and 1 dry hole from what was known as the Kenton field to the east. Two of the original Houtby producing wells were reworked and converted to water injection wells, leaving 16 producing wells.

The fresh water supply well is located about 2.7 miles southeast of the Houtby unit. The well was completed in the Ogallala formation.

Secondary recovery operations got underway in January 1963 with 7,000 barrels of water daily injected through two injection wells. Production was from 15 producing wells, one of the producing wells having been temporarily shut-in.

The flood pattern is irregular with the injection wells in the northwest and the southwest corners of the unit area.

In July 1963 the field was producing about 205 barrels of oil and 150 barrels of water from 15 wells. Water was injected into two wells at 4,500 barrels daily at 1,000 psi. The injection water was treated with a corrosion inhibitor. Produced water was disposed of in surface pits.

TABLE 19. - Basic data for Heidemann unit ("J" sand)

I. Reservoir data

Productive area	1,200 acres
Average thickness	9 ft
Reservoir volume	10,800 acre-ft
Average porosity	20 pct
Average water saturation	35 pct
Formation volume factor	1.25 bbl/stb
Initial reservoir pressure	1,550 psi
Bubble point pressure	700 psi (est)
Average permeability	145 md
Original solution GOR	180 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 1{,}200 \times 9 \times .20 \times .65}{1.25} = 8{,}716{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .20 \times .65}{1.25} = 807 \ \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB Acre-ft	STB
Primary	22	178	1,918,000
Secondary	14	113	1,220,000
Ultimate	36	291	3,138,000

IV. Estimated water requirements and flood life

Make-up (fresh)	7,070,000 bbl (70 pct)
Produced	3,030,000 bbl (30 pct)
Total	10,100,000 bbl
Equivalent pore volume	0.60
Injection water:secondary oil	8:1
Flood life	6 years

V. Project status--January 1, 1964

Flood started	May 1962
Oil recovery (pct original oil in place)	26
Water injection (pct estimated water required)	32

During September 1962 the Houtby unit was formed with Sage Oil Co. as unit operator. The unit consists of 15 producing wells in the Houtby field, plus 3 producing wells and 1 dry hole from what was known as the Kenton field to the east. Two of the original Houtby producing wells were reworked and converted to water injection wells, leaving 16 producing wells.

The fresh water supply well is located about 2.7 miles southeast of the Houtby unit. The well was completed in the Ogallala formation.

Secondary recovery operations got underway in January 1963 with 7,000 barrels of water daily injected through two injection wells. Production was from 15 producing wells, one of the producing wells having been temporarily shut-in.

The flood pattern is irregular with the injection wells in the northwest and the southwest corners of the unit area.

In July 1963 the field was producing about 205 barrels of oil and 150 barrels of water from 15 wells. Water was injected into two wells at 4,500 barrels daily at 1,000 psi. The injection water was treated with a corrosion inhibitor. Produced water was disposed of in surface pits.

By volumetric determination the oil originally in place was 6,152,000 barrels or 841 barrels an acre-foot. The estimated recovery factors, expressed in percentage of initial oil in place, are: 25 percent for primary, and 15 percent for secondary, for a total of 40 percent.

Estimated primary oil recovery is 1,538,000 barrels or 210 barrels an acre-foot. Cumulative oil production to the start of waterflooding was 1,426,700 barrels or 93 percent of the estimated primary oil. Estimated secondary oil recovery is 923,000 barrels or 126 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 124,000 barrels of oil and 73,000 barrels of water. Cumulative water injection for the same period was 1,439,460 barrels.

Estimated water requirements are 15 million barrels of fresh water or 1.3 pore volumes. The project is expected to last $10\frac{1}{2}$ years. The estimated ratio of water injected to oil recovered is 16:1.

Only 1 percent of the estimated secondary oil and little more than 25 percent of the original oil in place had been recovered at the end of 1963. Water injected was 10 percent of the estimated water required. The outcome of the project is indeterminate.

See table 20 for basic engineering data.

TABLE 20. - Basic data for Houtby unit ("J" sand)

I. Reservoir data

Productive area	660 acres
Average thickness	11 ft
Reservoir volume	7,271 acre-ft
Average porosity	20 pct
Average water saturation	35 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,375 psi
Bubble point pressure	1,400 psi
Average permeability	150 md
Original solution GOR	500 cu ft per bbl
Gravity of crude	39° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 660 \times 11 \times .2 \times .65}{1.2} = 6{,}152{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .2 \times .65}{1.2} = 841 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	25	210	1,538,000
Secondary	15	126	923,000
Ultimate	40	336	2,461,000

IV. Estimated water requirements and flood life

Total	15,000,000 bbl
Equivalent pore volume	1.3
Injection water:secondary oil	16:1
Flood life	$10\frac{1}{2}$ years

V. Project status--January 1, 1964

Flood started	January 1963
Oil recovery (pct original oil in place)	25
Water injection (pct estimated water required)	10

Jacinto Unit

The Jacinto unit (fig. 25) is in secs 10, 14, and 15, T 16 N, R 54 W, Kimball County, approximately 10 miles northeast of the town of Kimball. Average elevation is about 4,760 feet.

The Jacinto field was discovered early in 1955 when Zoch, Campbell, and Love-Miller completed the No. 1 Pound, $NW\frac{1}{4}NE\frac{1}{4}$ sec 14, for an initial pumping production of 295 barrels daily from the "J" sand through perforations from 5,786 to 5,790 feet. Subsequent development resulted in a field of 35 producing wells and 17 dry holes.

In 1960 Shell Oil Co. unitized its leases in the Jacinto field to conduct a pressure maintenance project. The unitized area contained 24 producing wells and 2 dry holes.

At the time of unitization, the field was being depleted by edgewater encroachment and solution gas drive. The water encroachment rate was less than the oil withdrawal rate, and reservoir pressure was declining. To prevent further pressure decline and a resultant decrease in ultimate oil recovery, maintenance was initiated through water injection.

In April 1960 water was injected into two former producing wells at approximately 3,000 barrels daily. Water was obtained from a well drilled in the $N\frac{1}{2}NW\frac{1}{4}$ of sec 15, to 600 feet.

Late in 1961 Shell acquired State sec 16, which borders the unit area to the west. Two of the eight producing wells and one of the two dry holes in sec 16 were converted to water injection wells.

The injection pattern is semiperipheral. The injection wells are in the west and south ends of the field where edgewater is encroaching into the oil reservoir under a natural water drive.

In December 1963 eight producing wells and three injection wells were in the unit area and two injection wells were in sec 16. The other wells in sec 16 had been abandoned. Daily production was approximately 850 barrels of oil and 1,350 barrels of water. Daily injection was approximately 4,600 barrels of fresh water and 1,350 barrels of produced water, totaling 5,950 barrels. The fresh water was treated with a corrosion inhibitor and bactericide and injected into four of the five injection wells. Produced water was injected, untreated, into the "J" sand in well No. 15, $SE\frac{1}{4}SW\frac{1}{4}$ sec 15. All of the injection wells were taking water on vacuum.

By volumetric determination the oil in place at original reservoir conditions was 11,943,000 barrels or 847 barrels an acre-foot. Estimated ultimate recovery, expressed in percentage of oil in place, is 45 percent.

Cumulative field oil production at the start of the pressure maintenance project was approximately 3 million barrels. Estimated ultimate oil recovery is 5,374,000 barrels or 381 barrels an acre-foot.

Cumulative production from the start of water injection until the end of 1963 was 1,672,200 barrels of oil and 1,397,100 barrels of water. Cumulative water injection for the same period was 6,963,300 barrels.

Estimated water requirements are 10,625,000 barrels of fresh water and 1,875,000 barrels of produced water totaling $12\frac{1}{2}$ million barrels or 0.55 pore volume. The estimated project life is 6 years.

By the end of 1963 approximately 39 percent of the original oil in place had been recovered. Water injection to that time was approximately 56 percent of the estimated water requirements. The project is apparently successful.

See table 21 for basic engineering data.

West Juelfs Unit

The West Juelfs unit (fig. 26) is in secs 18 and 19, T 17 N, R 51 W, and secs 13, 14, 23, and 24, T 17 N, R 52 W, Cheyenne and Morrill Counties, approximately 17 miles southwest of the town of Bridgeport. Average elevation is about 4,550 feet.

The Juelfs field was discovered in March 1955 when British-American Oil Co. completed the No. 1 Juelfs, C $NE\frac{1}{4}NE\frac{1}{4}$ sec 23, T 17 N, R 52 W, Cheyenne County, for an initial production of 269 barrels of oil daily from the "J" sand through perforations from 5,293 to 5,296 feet. Subsequent development resulted in 31 more producing wells and 10 dry holes.

The Juelfs field at one time was thought to be two separate fields; the west end was called Dogleg and the east end Gaylord. After Dogleg and Gaylord were found to have a common reservoir, the field was named Juelfs.

An attempt to unitize the entire field was unsuccessful. However, in February 1961 the western part, including 21 producing wells and 6 dry holes, was unitized with British-American Oil Co. as unit operator.

Seven producing wells and one dry hole were converted to water injection wells. Two fresh water supply wells were drilled in the west end of the unit area in sec 23. The supply wells were tested and found capable of producing at a combined 48,000 barrels of water daily from the Brule clay formation at approximately 500 feet.

Waterflooding was begun in June 1961. Fresh water was injected into eight wells at approximately 7,600 barrels daily.

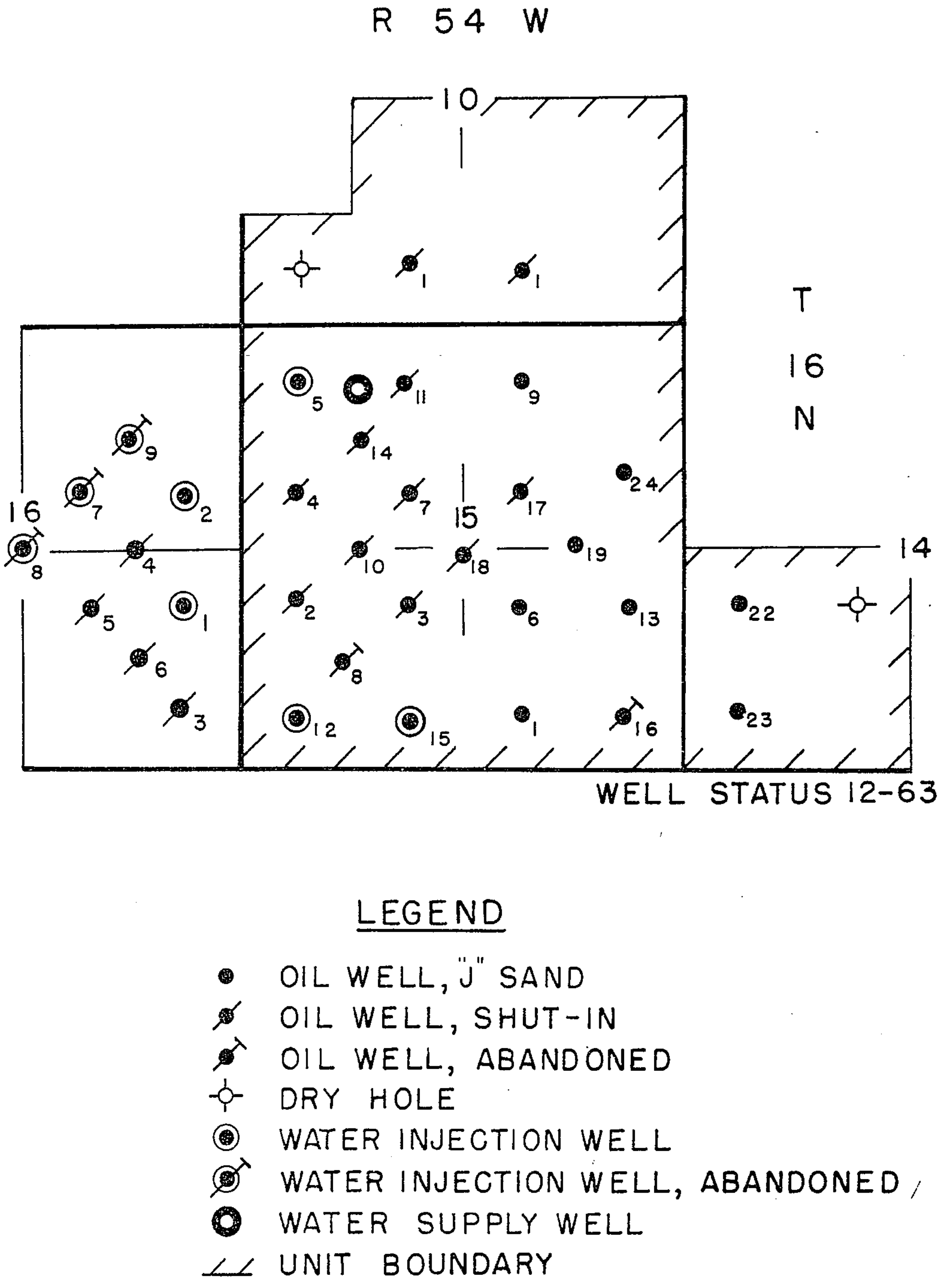

FIGURE 25. – Jacinto unit, Kimball County.

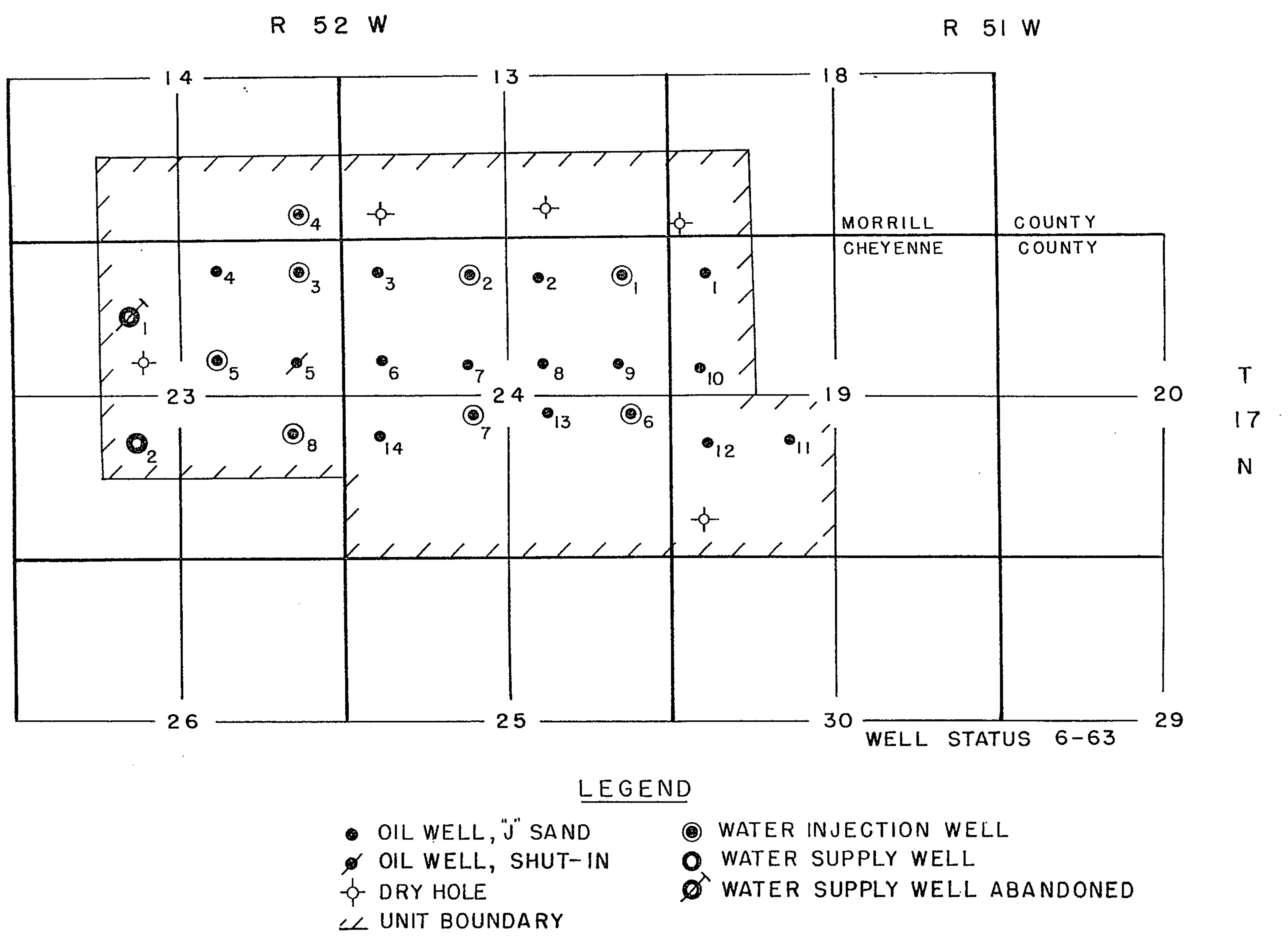

FIGURE 26. – West Juelfs unit, Cheyenne and Morrill Counties.

TABLE 21. - Basic data for Jacinto unit ("J" sand)

I. Reservoir data

Productive area	1,007 acres
Average thickness	14 ft
Reservoir volume	14,098 acre-ft
Average porosity	21 pct
Average water saturation	35 pct
Formation volume factor	1.25 bbl/stb (est)
Initial reservoir pressure	1,420 psi
Bubble point pressure	693 psi
Average permeability	300 md
Original solution GOR	140 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 1{,}007 \times 14 \times .21 \times .65}{1.25} = 11{,}943{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .21 \times .65}{1.25} = 847 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Total (press. maint.)	45	381	5,374,000

IV. Estimated water requirements and flood life

Fresh water	10,625,000 bbl
Produced water	1,875,000 bbl
Total water	12,500,000 bbl
Equivalent pore volume	0.55
Flood life	6 years

V. Project status--January 1, 1964

Flood started	April 1960
Oil recovery (pct original oil in place)	39
Water injection (pct estimated water required)	56

The flood pattern is a modified nine-spot, open ended on the east end of the unit. The rest of the field was unitized in 1963.

In July 1963 the West Juelfs unit contained 13 producing wells and 8 injection wells. One of the water supply wells had been abandoned. Daily production was approximately 620 barrels of oil and 2,700 barrels of water. Produced water was disposed of in surface pits. Daily injection was 3,900 barrels of fresh water at a pressure of 1,380 psi. The injection water was treated with a bactericide. Plans had been made to install a produced water gathering system and to inject the produced water.

By volumetric determination the oil in place at original reservoir conditions was 7,926,000 barrels or 928 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 25.2 percent; secondary, 22.2 percent; and total, 47.4 percent.

Estimated primary oil recovery is 1,997,000 barrels or 234 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 1,586,000 barrels or 79 percent of the estimated primary recovery. Estimated secondary oil recovery is 1,761,000 barrels or 206 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 738,100 barrels of oil and 1,239,100 barrels of water. Cumulative unit water injection for the same period was 4,483,900 barrels.

Estimated water requirements are 11 million barrels or 0.84 pore volume. The estimated ratio of water injected to secondary oil recovered is 6:1. The estimated flood life is 7 years.

By the end of 1963 approximately 19 percent of the estimated secondary oil and 29 percent of the original oil in place had been recovered. Water injected was approximately 41 percent of the estimated water required. Available data indicate a successful project.

See table 22 for basic engineering data.

Kenmac Unit

The Kenmac unit (fig. 27) is in secs. 9, 10, 15, 16, and 22, T 18 N, R 53 W, Banner County, approximately 14 miles southeast of the town of Harrisburg. Average elevation is some 4,350 feet.

The unit area includes parts of two contiguous fields, the Kenmac and the Hackberry, which have a common "J" sand reservoir. The Hackberry field lies north and west of the Kenmac field.

TABLE 22. - Basic data for West Juelfs unit ("J" sand)

I. Reservoir data

Productive area	- - acres
Average thickness	- - ft
Reservoir volume	8,541 acre-ft
Average porosity	18.8 pct
Average water saturation	23.6 pct
Formation volume factor	1.2 bbl/stb (est)
Initial reservoir pressure	1,290 psi
Bubble point pressure	720 psi (est)
Average permeability	116 md
Original solution GOR	220 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 8{,}541 \times .188 \times .764}{1.2} = 7{,}926{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .188 \times .764}{1.2} = 928 \ \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	25.2	234	1,997,000
Secondary	22.2	206	1,761,000
Ultimate	47.4	440	3,758,000

IV. Estimated water requirements and flood life

Total	11,000,000 bbl
Equivalent pore volume	0.84
Injection water:secondary oil	6:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	June 1961
Oil recovery (pct original oil in place)	29
Water injection (pct estimated water required)	41

The Kenmac field was discovered in October 1954 when Rex Petroleum completed the No. 1 Johnson Estate, C SW$\frac{1}{4}$NE$\frac{1}{4}$ sec 27, T 18 N, R 53 W, for an initial pumping production of 100 barrels daily from the "J" sand through perforations from 5,456 to 5,466 feet. Field development resulted in 8 more producing wells and 11 dry holes.

The Hackberry field was discovered in March 1956 when Rite-Way Oil and Investment completed the No. 1-B Schneider, C NW$\frac{1}{4}$NW$\frac{1}{4}$ sec 15, T 18 N, R 53 W, for an initial pumping production of 170 barrels daily from the "J" sand through perforations at 5,310 to 5,314 feet. Subsequent development resulted in 16 more producing wells and 6 dry holes.

Adjoining parts of the two fields were unitized in March 1961 with British-American Oil Co. as unit operator. Five producing wells and 2 dry holes in the Kenmac field and 17 producing wells and 4 dry holes in the Hackberry field were included in the unit area. Three producing wells were converted to water injection wells and one new injection well was drilled.

Waterflooding was begun in August 1961 when fresh water was injected into the four wells at approximately 5,300 barrels daily. The fresh water was obtained from two shallow (50 feet) wells in the SE$\frac{1}{4}$ of sec 22.

The flood pattern is a modified line drive. Two injection wells are at each end of the elongated (north-south) unit area. As the flood progresses toward the center of the unit area conversion of additional wells to injection appears likely.

In July 1963 the Kenmac unit contained 4 injection wells and 13 producing wells. Daily injection was approximately 5,500 barrels at a pressure of 1,440 psi. The injection water was treated with a corrosion inhibitor. Daily production was approximately 2,100 barrels of oil and 3,500 barrels of water. The water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was $6\frac{1}{2}$ million barrels or 941 barrels an acre-foot. Estimated recovery factors expressed in percentage of oil in place are: Primary, 26.6 percent; secondary, 23 percent; and total, 49.6 percent.

Estimated primary oil recovery is 1,731,000 barrels or 250 barrels an acre-foot. Cumulative oil production at the start of waterflooding was approximately 1,652,000 barrels or 95 percent of the estimated primary recovery. Estimated secondary oil recovery is 1,495,000 barrels or 216 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 1,192,600 barrels of oil and 1,492,700 barrels of water. Cumulative water injection for the same period was 4,728,600 barrels.

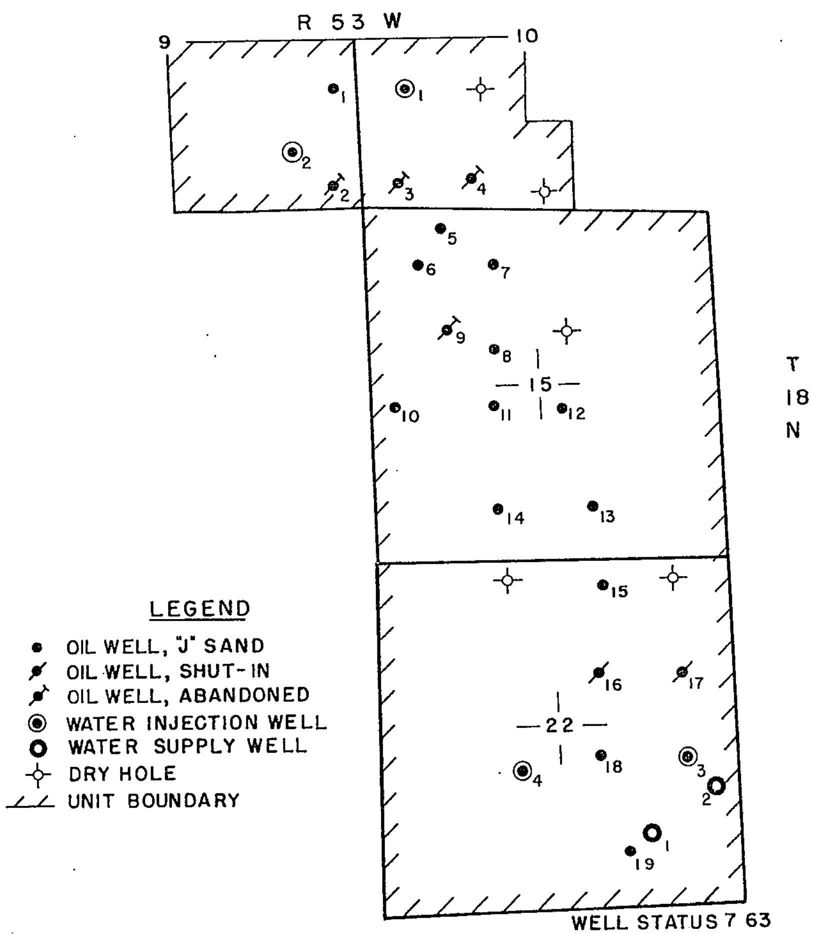

FIGURE 27. – Kenmac unit, Banner County.

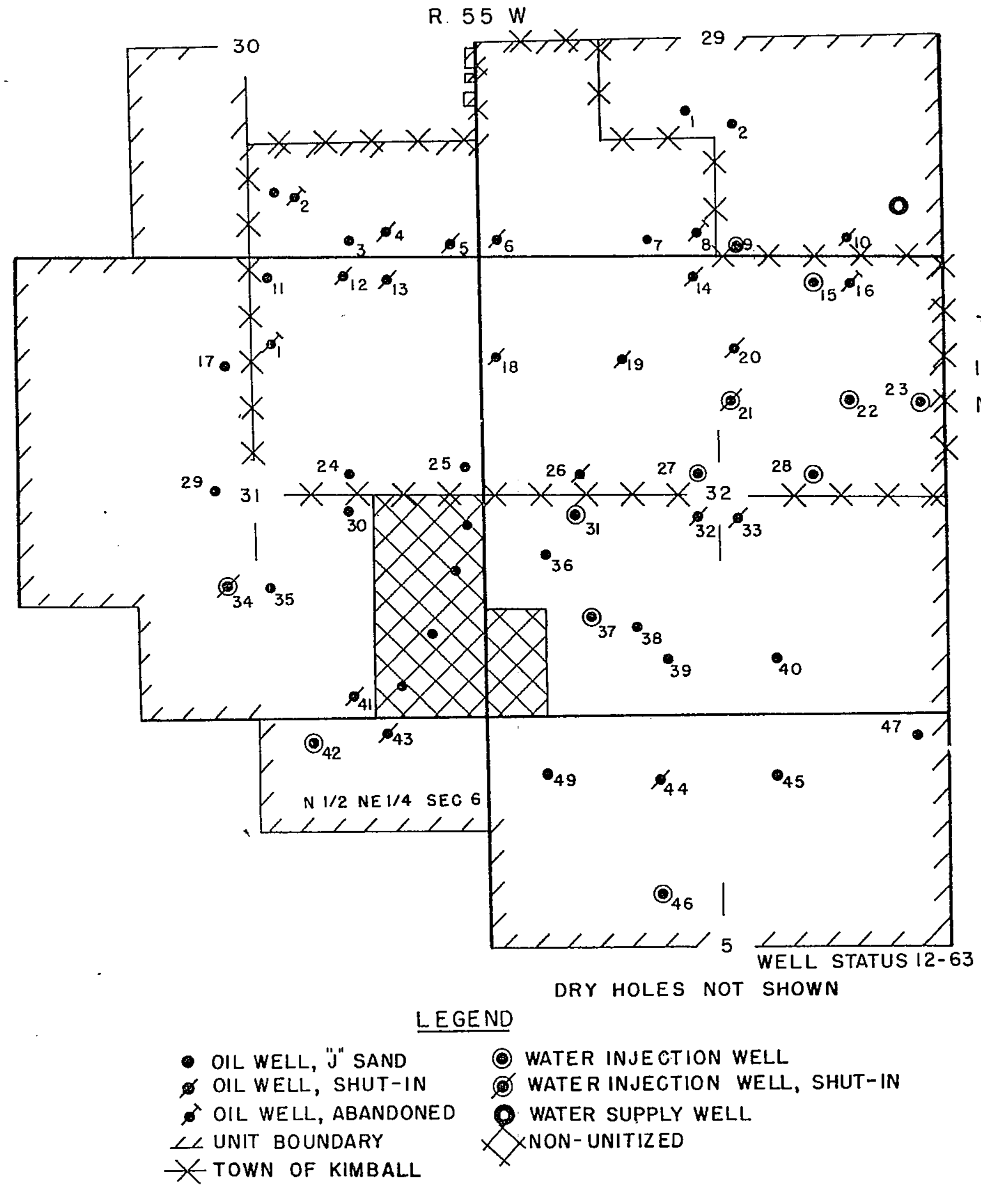

FIGURE 28. – Kimball unit, Kimball County.

Estimated water requirements are 10,400,000 barrels or 1 reservoir pore volume. The estimated ratio of water injected to secondary oil recovered is 7:1. The estimated flood life is 7 years.

By the end of 1963 approximately 75 percent of the estimated secondary oil and approximately 44 percent of the original oil in place had been recovered. Water injected was approximately 45 percent of the estimated water required. The project is apparently successful.

See table 23 for basic engineering data.

Kimball Unit

The Kimball unit (fig. 28) is in secs 5 and 6, T 14 N, R 55 W, and secs 29-32, T 15 N, R 55 W, Kimball County, in and adjacent to the town of Kimball. Average elevation is about 4,725 feet.

The Kimball field was discovered in June 1954 when Natural Gas and Oil Co. completed the No. 1 Durland Trust, C NE$\frac{1}{4}$NW$\frac{1}{4}$ sec 5, for an initial pumping production of 390 barrels daily from the "J" sand through perforations from 6,306 to 6,312 feet. Subsequent development resulted in a field of 58 producing wells and 14 dry holes.

The field, including 51 producing wells and 8 dry holes, was unitized in 1959 with Pan American Petroleum Corp. as unit operator.

Waterflooding was begun in December 1959 when fresh water was injected into five former producing wells at approximately 5,400 barrels daily. The water was obtained from a well drilled outside the unit area in the SW$\frac{1}{4}$SW$\frac{1}{4}$ of sec 33. The well was completed in alluvial gravel at approximately 200 feet. A second water supply well later was drilled in the SE$\frac{1}{4}$SE$\frac{1}{4}$ of sec 29.

The flood pattern is a modified line drive. The well arrangement is unusual because a row of injection wells extends diagonally (northeast-southwest) across the midportion of the field. The pattern is designed to minimize oil movement to or from the nonunitized acreage inside the unit boundaries.

In December 1963 the Kimball unit contained 19 active producing wells and 10 active injection wells. Daily production was approximately 650 barrels of oil and 2,300 barrels of water. Produced water was injected into the oil reservoir. Daily injection was approximately 5,700 barrels of untreated water at a pressure of 1,000 psi.

By volumetric determination the oil in place at original reservoir conditions was 12,400,000 barrels or 931 barrels an acre-foot. The estimated recovery factors, expressed in percentage of original oil in place, are: Primary, 26 percent; secondary, 16 percent; and ultimate, 42 percent.

TABLE 23. - Basic data for Kenmac unit ("J" sand)

I. Reservoir data

Productive area	1,051 acres
Average thickness	6.6 ft
Reservoir volume	6,937 acre-ft
Average porosity	19.4 pct
Average water saturation	25 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,300 psi
Bubble point pressure	800 psi
Average permeability	200 md
Original solution GOR	200 cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 1{,}051 \times 6.6 \times .194 \times .75}{1.2} = 6{,}500{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .194 \times .75}{1.2} = 941 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	26.6	250	1,731,000
Secondary	23.0	216	1,495,000
Ultimate	49.6	466	3,226,000

IV. Estimated water requirements and flood life

Total	10,400,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	7:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	August 1961
Oil recovery (pct original oil in place)	44
Water injection (pct estimated water required)	45

Estimated primary oil recovery is 3,224,000 barrels or 242 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 2,900,000 barrels or 90 percent of the estimated primary recovery. Estimated secondary oil recovery is 1,984,000 barrels or 149 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 1,306,000 barrels of oil and 3,721,000 barrels of water. Cumulative unit water injection for the same period was 7,886,000 barrels.

Estimated water requirements are 20,700,000 barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 10:1. The estimated flood life is 10 years.

By the end of 1963 approximately 49 percent of the estimated secondary oil and approximately 34 percent of the original oil in place had been recovered. Water injected was approximately 38 percent of the estimated water required. Available data indicate a successful project.

See table 24 for basic engineering data.

West Lane Unit

The West Lane unit (fig. 29) is in secs 7, 8, 17, and 18, T 17 N, R 49 W, Morrill County, approximately 16 miles southeast of the town of Bridgeport. Average elevation is approximately 4,170 feet.

The Lane field was discovered in January 1956 when Marathon (formerly Ohio) Oil Co. completed the No. 1 Lane, C NW$\frac{1}{4}$SE$\frac{1}{4}$ sec 17, for an initial pumping production of 35 barrels daily from the "J" sand through a perforated interval from 4,596 to 4,600 feet. Because of the marginal producing rate of the discovery well, development drilling was delayed until about the middle of 1958. Marathon then drilled the No. 2 Lane, SW$\frac{1}{4}$NW$\frac{1}{4}$NW$\frac{1}{4}$ sec 17, and completed it in the "J" sand for 125 barrels daily. Subsequent development resulted in 11 more producing wells and 3 dry holes.

Part of the field, including seven producing wells and two dry holes, was unitized in September 1960 with Marathon Oil Co. as unit operator. Four producing wells, including the discovery well, were not included. Unit wells are separated from nonunit wells by a permeability pinch-out in the "J" sand reservoir.

A producing well in the SW$\frac{1}{4}$SW$\frac{1}{4}$SW$\frac{1}{4}$ sec 8, was converted to a water injection well, and a new water injection well was drilled in the NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 18. The fresh water supply well, drilled in the NE$\frac{1}{4}$NE$\frac{1}{4}$ of sec 18, was tested capable of producing 5,000 barrels of water daily from the Ogallala formation between 195 and 270 feet.

TABLE 24. - Basic data for Kimball unit ("J" sand)

I. Reservoir data

Productive area	1,435 acres
Average thickness	9.3 ft
Reservoir volume	13,346 acre-ft
Average porosity	20 pct
Average water saturation	25 pct
Formation volume factor	1.25 bbl/stb
Initial reservoir pressure	1,525 psi
Bubble point pressure	400 psi (est)
Average permeability	317 md
Original solution GOR	150 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7,758 \times 1,435 \times 9.3 \times .20 \times .75}{1.25} = 12,400,000 \text{ STB}$$

$$\frac{7,758 \times .20 \times .75}{1.25} = 931 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	26	242	3,224,000
Secondary	16	149	1,984,000
Ultimate	42	391	5,208,000

IV. Estimated water requirements and flood life

Total	20,700,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	10:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	December 1959
Oil recovery (pct original oil in place)	34
Water injection (pct estimated water required)	38

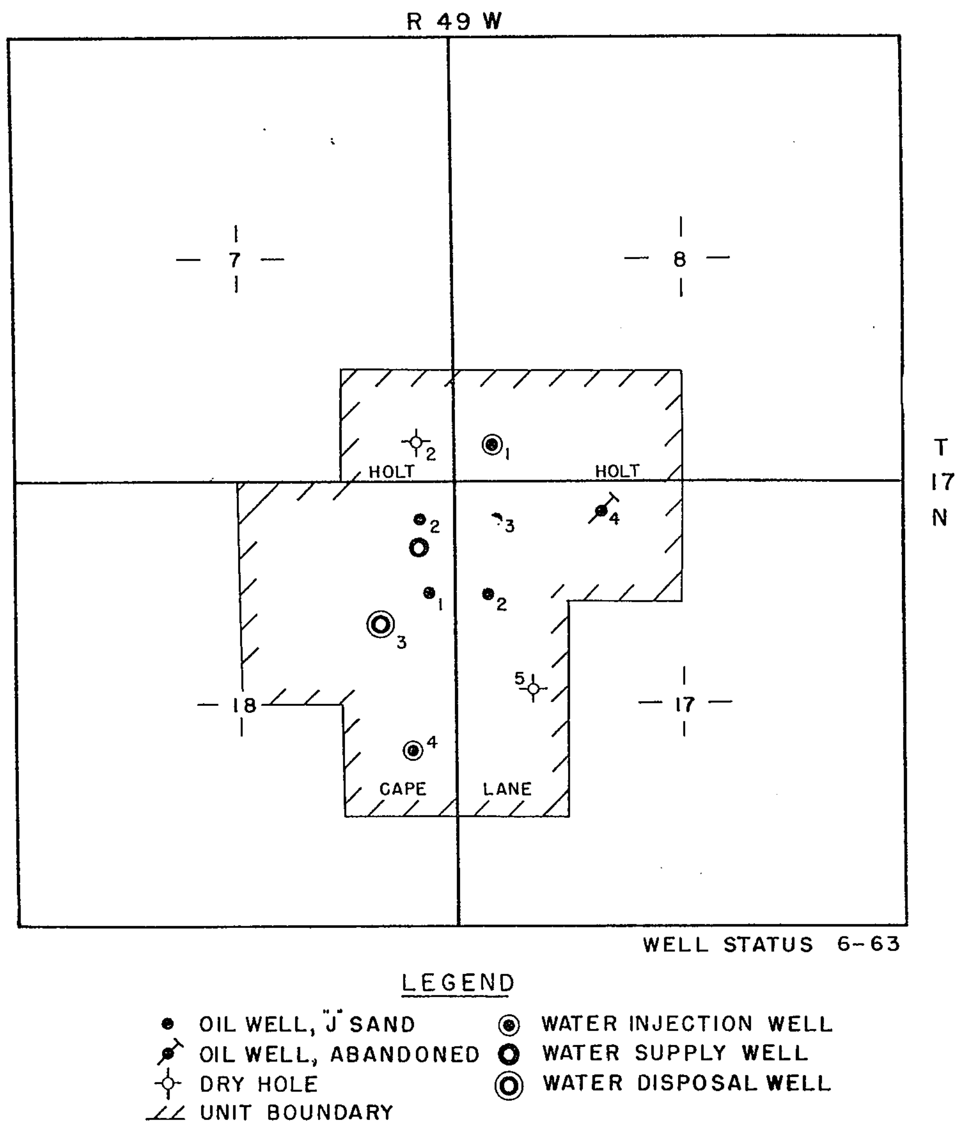

FIGURE 29. – West Lane unit, Morrill County.

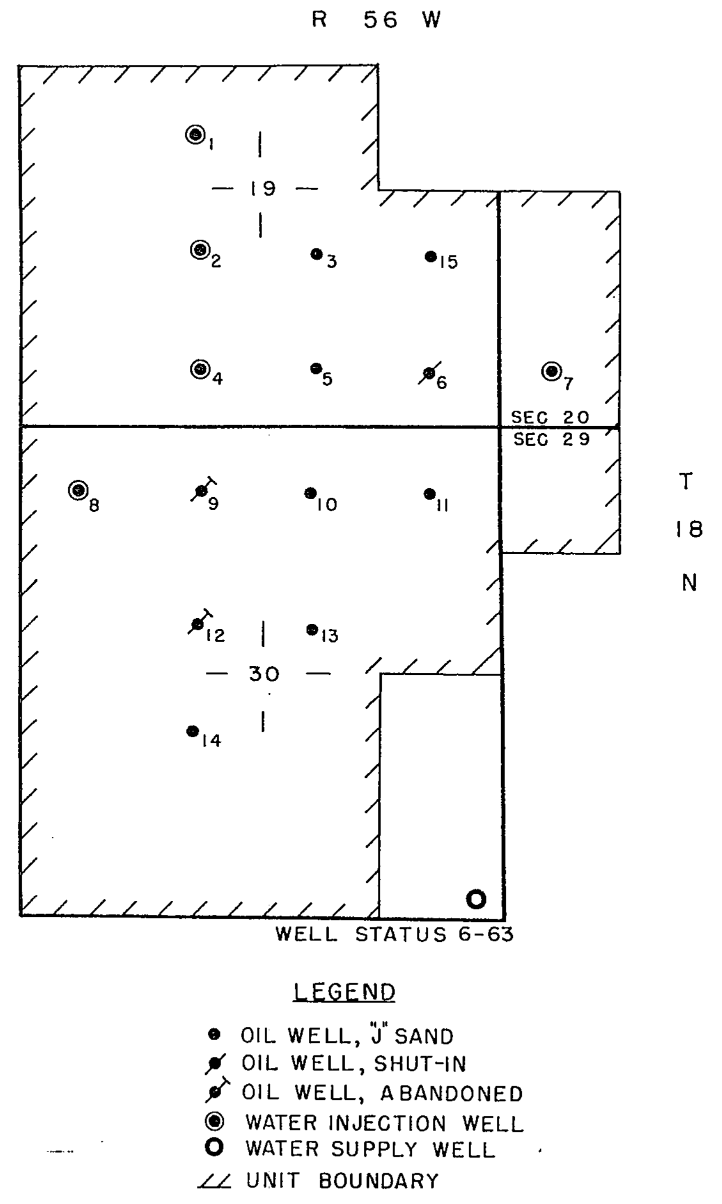

FIGURE 30. – Lewis unit, Banner County.

Waterflooding was begun in November 1960 when fresh water was injected into two wells at a combined 3,400 barrels daily. At that time there were five producing wells, one producing well having been abandoned.

In November 1961 a producing well (No. 3 Cape, NW$\frac{1}{4}$SE$\frac{1}{4}$NE$\frac{1}{4}$ sec 18) was converted to a water injection well. After $4\frac{1}{2}$ months this same well was converted to a water disposal well in the "D" sand.

The flood pattern is a modified line drive. Two injection wells are at opposite (north-south) ends of the unit area and four producing wells are centered roughly between the injection wells. Fresh water is injected in the south end of the unit area and both fresh and produced water are injected in the north end of the unit area.

During June 1963 four wells were producing a daily total of 200 barrels of oil and 2,000 barrels of water. Of the 2,000 barrels of produced water, 500 barrels was being injected into the "J" sand in the north end of the unit and 1,500 barrels was being injected into the disposal well ("D" sand). The produced water returned to the "J" sand was treated with a corrosion inhibitor. Serious corrosion of subsurface equipment occurred at West Lane unit. Daily injection was approximately 3,100 barrels at a pressure of about 100 psi.

By volumetric determination the oil in place at original reservoir conditions was 2,800,000 barrels or 1,050 barrels an acre-foot. Estimated recovery factors expressed in percentage of oil in place are: Primary, 22.5 percent; secondary, 12.3 percent; and total, 34.8 percent.

Estimated primary oil recovery is 631,000 barrels or 236 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 475,000 barrels or approximately 75 percent of the estimated primary recovery. Estimated secondary oil recovery is 344,000 barrels or 129 barrels an acre-foot.

Cumulative unit water production at the start of waterflooding was 213,000 barrels. The large volume of produced water indicates that waterflooding is supplemented by a natural water drive.

Cumulative unit production from the start of waterflooding until the end of 1963 was 418,500 barrels of oil and 1,450,500 barrels of water. Cumulative unit water injection for the same period was 3,228,300 barrels.

Estimated water requirements are 3,800,000 barrels of fresh water and 650,000 barrels of produced water, totaling 4,450,000 barrels or approximately 1 reservoir pore volume. The estimated ratio of injected water to secondary oil recovered is 13:1. The estimated flood life is 6 years.

By the end of 1963, 76 percent of the estimated secondary oil and 32 percent of the original oil in place had been recovered. Water injected was 73 percent of the estimated water required. The project is apparently successful.

See table 25 for basic engineering data.

Lewis Unit

The Lewis unit (fig. 30) is in secs 19, 20, 29, and 30, T 18 N, R 56 W, Banner County, approximately 5 miles southwest of the town of Harrisburg. Average elevation is about 5,030 feet.

The Lewis field was discovered in June 1958 when Lewis Brothers, Stuarco Oil, and Carver Dodge completed the No. 1 Johnson, C NE$\frac{1}{4}$NW$\frac{1}{4}$ sec 30, for an initial pumping production of 175 barrels daily from the "J" sand through the perforated interval from 6,725 to 6,740 feet. Subsequent development resulted in a field of 14 producing wells and 6 dry holes. Of the 14 producing wells, 12 were completed in the "J" sand, 1 was completed in the "D" sand, and 1 was completed in both the "D" and "J" sands.

The "J" sand was unitized in March 1960 with Pan American Petroleum Corp. as unit operator. Eleven "J" sand producing wells, one "D" and "J" producing well, and two dry holes were included in the unit area. Well No. 15 was drilled after March 1960.

Waterflooding was begun in March 1960 when fresh water was injected into three wells at approximately 1,200 barrels daily. Two of the injection wells were recompleted dry holes, and one was a former producing well. Fresh water was obtained from a shallow well drilled outside the unit area in the SE$\frac{1}{4}$SE$\frac{1}{4}$ of sec 30. The well was tested capable of producing 4,000 barrels of water daily from alluvial gravel at approximately 200 feet.

The flood pattern is semiperipheral. The three initial injection wells are widely spaced: One in the west end, one in the north end, and one in the east end of the unit area. Subsequent injection wells are in the northwest end of the unit area.

In July 1963 the Lewis unit contained seven active producing wells and five active injection wells. Daily production was approximately 300 barrels of oil and 500 barrels of water. Produced water was disposed of in surface pits. Daily injection was approximately 2,400 barrels at a pressure of 1,700 psi.

By volumetric determination the oil in place at original reservoir conditions was 5,900,000 barrels or 656 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 20 percent; secondary, 12 percent; and ultimate, 32 percent.

TABLE 25. - Basic data for West Lane unit ("J" sand)

I. Reservoir data

Productive area	190 acres
Average thickness	14 ft
Reservoir volume	2,660 acre-ft
Average porosity	21.7 pct
Average water saturation	32 pct
Formation volume factor	1,091 bbl/stb
Initial reservoir pressure	1,077 psi
Bubble point pressure	514 psi
Average permeability	539 md
Original solution GOR	84 cu ft per bbl
Gravity of crude	34° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 190 \times 14 \times .217 \times .68}{1.091} = 2{,}800{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .217 \times .68}{1.091} = 1{,}050 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	22.5	236	631,000
Secondary	12.3	129	344,000
Ultimate	34.8	365	975,000

IV. Estimated water requirements and flood life

Fresh	3,800,000 bbl
Produced	650,000 bbl
Total	4,450,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	13:1
Flood life	6 years

V. Project status--January 1, 1964

Flood started	November 1960
Oil recovery (pct original oil in place)	32
Water injection (pct estimated water required)	73

Estimated primary oil recovery is 1,180,000 barrels or 131 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 645,000 barrels or 55 percent of the estimated primary recovery. Estimated secondary oil recovery is 710,000 barrels or 79 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 499,600 barrels of oil and 327,200 barrels of water. Cumulative unit water injection for the same period was 2,328,300 barrels.

Estimated water requirements are 10,100,000 barrels or 1 pore volume. The estimated ratio of injected water to secondary oil recovered is 14:1. The estimated flood life is 10 years.

At the end of 1963, 97 percent of the estimated primary oil and only 19 percent of the original oil in place had been recovered. Water injected was 26 percent of the estimated water required. The outcome of the project is indeterminate.

See table 26 for basic engineering data.

Lindberg Project

The Lindberg project (fig. 31) is in secs 10 and 11, T 17 N, R 52 W, Morrill County, approximately 7 miles south of Reddington in an area of eroded gullies and hills. The area was known as Pine Valley.

The field was discovered in 1956 when Skelly Oil Co. completed the No. 1 Lindberg in NW$\frac{1}{4}$NW$\frac{1}{4}$SW$\frac{1}{4}$ sec 11, T 17 N, R 52 W, in the "J" sand for an initial production of 330 barrels daily through perforations from 5,215 to 5,225 feet. Subsequent drilling resulted in 12 producing wells and 10 dry holes.

The project was authorized by the Nebraska Oil and Gas Conservation Commission in October 1960 with Skelly Oil Co. as operator.

Originally the project area contained two injection wells, four producing wells, and two dry holes. Three wells have been drilled since the project was approved. Initial injection through two wells was 350 barrels daily.

A water supply well was drilled in an old creek bed in the NW$\frac{1}{4}$SE$\frac{1}{4}$SE$\frac{1}{4}$ sec 3, T 17 N, R 52 W, to 77 feet. The initial rated capacity of the well was in excess of 12,000 barrels daily.

Secondary recovery operations got underway during October 1960. The flood pattern is a line drive with the injection wells in the west end of the project area.

TABLE 26. - Basic data for Lewis unit ("J" sand)

I. Reservoir data

Productive area	600 acres
Average thickness	15 ft
Reservoir volume	9,000 acre-ft
Average porosity	14.5 pct
Average water saturation	30 pct
Formation volume factor	1.2 bbl/stb (est)
Initial reservoir pressure	1,775 psi
Bubble point pressure	- - psi
Average permeability	54.3 md
Original solution GOR	500 cu ft per bbl (est)
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7,758 \times 600 \times 15 \times .145 \times .70}{1.2} = 5,900,000 \text{ STB}$$

$$\frac{7,758 \times .145 \times .70}{1.2} = 656 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	20	131	1,180,000
Secondary	12	79	710,000
Ultimate	32	210	1,890,000

IV. Estimated water requirements and flood life

Total	10,100,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	14:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	March 1960
Oil recovery (pct original oil in place)	19
Water injection (pct estimated water required)	26

During December 1963 four wells were producing 276 barrels of oil and 9 barrels of water daily. Untreated water was injected into two wells at 1,295 barrels daily at an average pressure of 1,225 psi. Produced water was disposed of in pits.

By volumetric determination, the oil originally in place was 2,091,000 barrels or 977 barrels an acre-foot. The estimated recovery factors, expressed in percentage of initial oil in place, are 22 percent for primary and 20 percent for secondary or a total of 42 percent.

Estimated primary oil recovery is 460,000 barrels or 215 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 442,200 barrels or approximately 96 percent of the estimated primary recovery. Water production was only 1,100 barrels.

Estimated secondary oil recovery is 418,000 barrels or 195 barrels an acre-foot. Cumulative unit oil production from the start of waterflooding until the end of 1963 was 348,400 barrels. Cumulative water injection for the same period was 663,800 barrels. The ratio of water injected to oil produced is about 2:1. Water production was 87,100 barrels.

Estimated water requirements are 1,291,000 barrels over 7 years. The 1,291,000 barrels of water make up less than half the pore volume. The estimated ratio of injected water to secondary oil recovered is 3:1.

By the end of 1963 approximately 79 percent of the estimated secondary oil and 38 percent of the original oil in place had been recovered. Water injected to that time was approximately 51 percent of the estimated water required. The project is apparently successful.

See table 27 for basic engineering data.

Long Unit

The Long unit (fig. 32) is in secs 3, 9-11, 14-16, 21 and 22, T 12 N, R 55 W, Kimball County, about 17 miles southeast of the town of Kimball in an area of gently rolling hills. Elevation of the field is about 4,900 feet.

The discovery well in the long field was completed during January 1953. Gene Goff drilled the No. 1 Long in the SW$\frac{1}{4}$SW$\frac{1}{4}$NW$\frac{1}{4}$ sec 15, T 12 N, R 55 W, and completed the well in the "D" sand from 6,103 to 6,111 feet for an initial pumping production of 160 barrels daily. Early in 1954 oil was discovered in the "J" sand in the No. 1 Harris well in the SW$\frac{1}{4}$SE$\frac{1}{4}$NW$\frac{1}{4}$ sec 11, T 12 N, R 55 W. Initial flowing production was 20 barrels hourly from 6,262 to 6,265 feet. Development of the field resulted in 61 more wells producing from the "D" sand, 2 wells producing

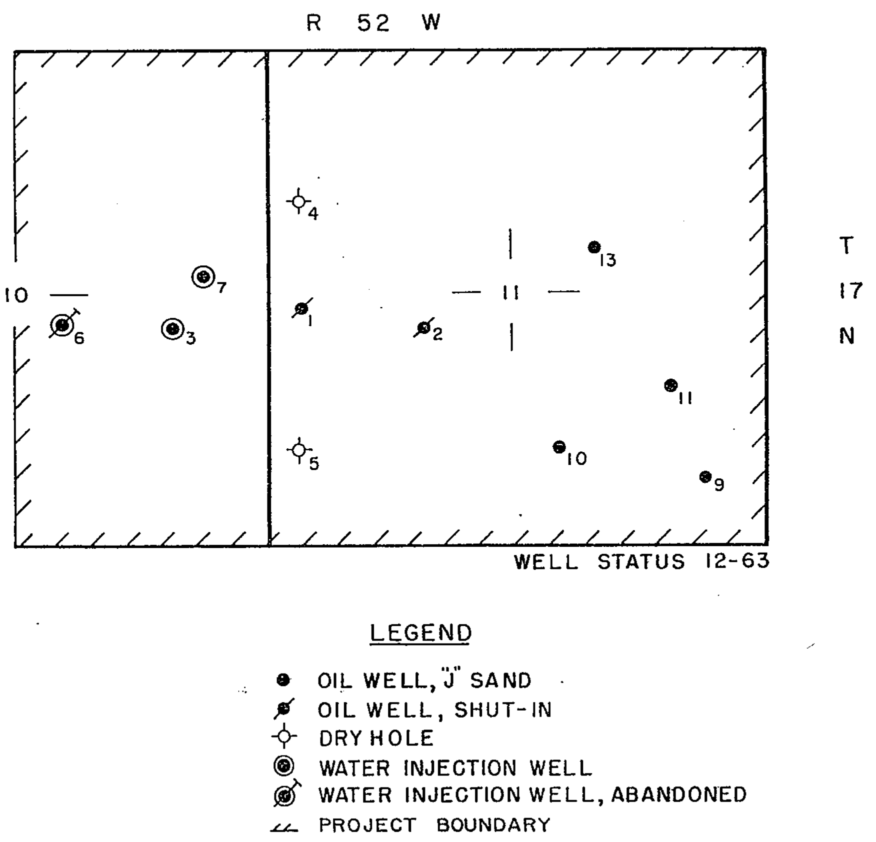

FIGURE 31. – Lindberg project, Morrill County.

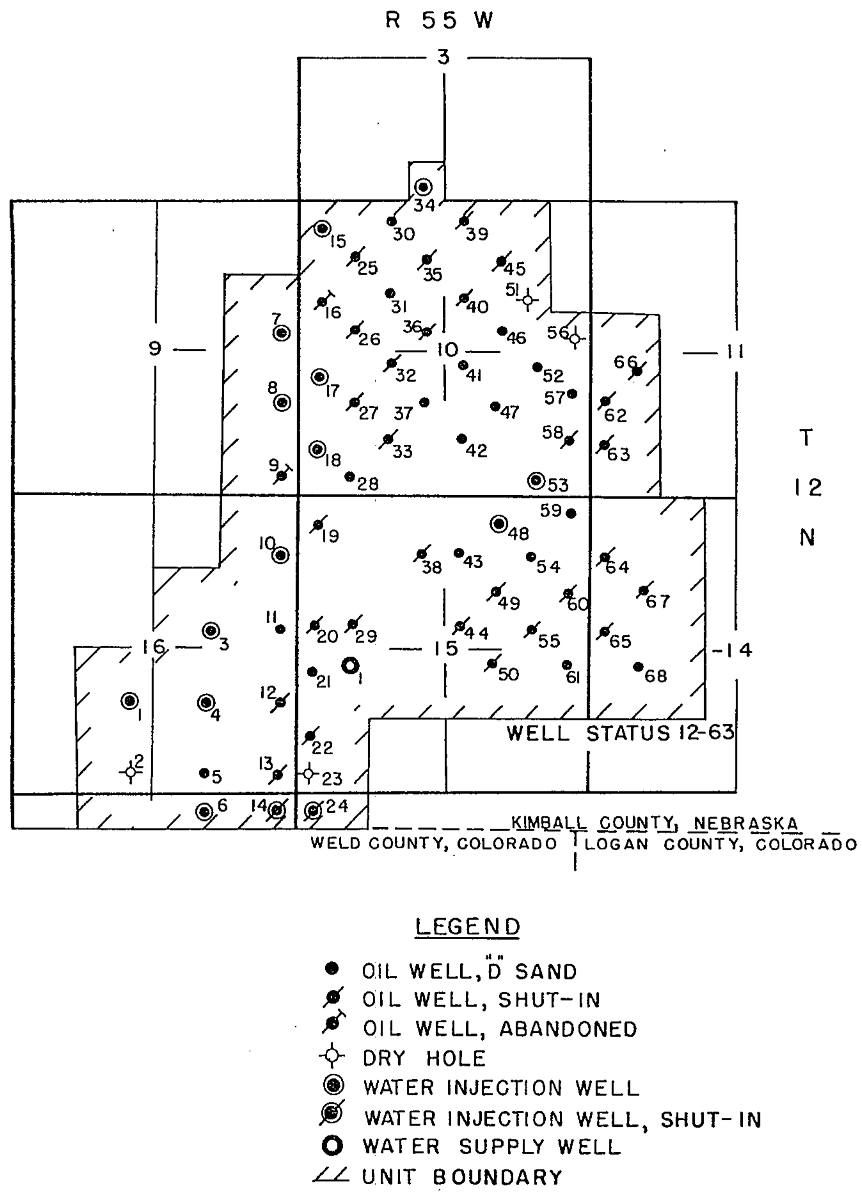

FIGURE 32. – Long unit, Kimball County.

TABLE 27. - Basic data for Lindberg project ("J" sand)

I. Reservoir data

Productive area	430 acres
Average thickness	5 ft
Reservoir volume	2,150 acre-ft
Average porosity	17.8 pct
Average water saturation	20 pct
Formation volume factor	1.14 bbl/stb
Initial reservoir pressure	1,221 psi
Bubble point pressure	650 psi
Average permeability	100 md
Original solution GOR	221 cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 430 \times 5 \times .178 \times .8}{1.14} = 2{,}091{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .178 \times .8}{1.14} = 977 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	22	215	460,000
Secondary	20	195	418,000
Ultimate	42	410	878,000

IV. Estimated water requirements and flood life

Total	1,291,000 bbl
Equivalent pore volume	0.44
Injection water:secondary oil	3:1
Flood life	7 years

V. Flood status--January 1, 1964

Flood started	October 1960
Oil recovery (pct original oil in place)	38
Water injection (pct estimated water required)	51

from the "J" sand, 1 well dually completed in the "D" and "J" sands, and 16 wells drilled and abandoned.

Part of the Long field was unitized in August 1960 for waterflooding the "D" sand with Mobil Oil Co. as unit operator. The unit area contained none of the field wells in Colorado. At the time of unitization, however, four of the five wells in Colorado were abandoned, as were the Nebraska "J" sand producing wells.

Upon unitization, four producing wells, one abandoned well, and four shut-in wells were converted for water injection.

The water supply well, drilled in the NE$\frac{1}{4}$NW$\frac{1}{4}$SW$\frac{1}{4}$ sec 15, T 12 N, R 55 W, produces from shallow gravel deposits.

Secondary operations were started during November 1960 with injection of 8,500 barrels of water through nine wells. Oil production was from 18 wells.

The flood pattern is a line drive with all but two injection wells on the west side of the unit.

During December 1963 there were 18 producing wells, 13 water injection wells, 1 water supply well, 29 shut-in oil wells, 2 shut-in injection wells, 2 abandoned oil wells, and 3 dry holes. The 18 wells were producing about 484 barrels of oil and 3,120 barrels of water daily. At that time the produced water was mixed with fresh water, and approximately 11,000 barrels of water daily was injected at about 650 psi. The fresh water was not being treated. Future plans were to inject each type of water separately.

By volumetric determination, the oil in place at original reservoir conditions was 24,293,000 barrels or 894 barrels an acre-foot. The estimated recovery factors expressed in percentage of initial oil in place are: 16 percent for primary; 14 percent for secondary; or a total of 30 percent.

Estimated primary oil recovery is 3,887,000 barrels or 143 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 3,747,600 barrels or approximately 96 percent of the estimated primary recovery.

Cumulative water production at the start of waterflooding was 2,479,600 barrels.

Estimated secondary oil recovery was 3,401,000 barrels or 125 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 401,500 barrels. Cumulative unit water injection for the same period was 10,711,800 barrels. The ratio of water injected to oil produced is about 27:1. Water production amounted to 2,161,900 barrels.

Estimated total water requirements are 24 million barrels over 7 years. The 24 million barrels of water make up over half the pore volume. The original estimated ratio of water injected to secondary oil recovered of 7:1 is too low.

By the end of 1963 only 8 percent of the estimated secondary oil and only 17 percent of the original oil in place had been recovered. Water injected was approximately 45 percent of the estimated water required. The unit operator intends to continue operations to the economic limit, but expresses little hope for realization of the secondary recovery estimate of 14 percent of the original oil in place. The project is an apparent failure.

See table 28 for basic engineering data.

McDaniel Unit

The McDaniel unit (fig. 33) is in secs 11, 12, and 14, T 18 N, R 54 W, Banner County, approximately 10 miles east of the town of Harrisburg. Average elevation is about 4,300 feet.

The McDaniel field was discovered in September 1957 when McDaniel Drilling Co. completed the No. 1 Brown, C NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 11, for an initial pumping production of 288 barrels daily from the "J" sand through perforations from 5,391 to 5,395 feet. Subsequent development resulted in a field of 13 producing wells and 9 dry holes.

The field, including all 13 producing wells and 5 of the 9 dry holes, was unitized in July 1961 with S. D. Johnson as unit operator. Three of the producing wells were converted to water injection wells.

A shallow fresh water supply well, drilled in the NW$\frac{1}{4}$SW$\frac{1}{4}$ of sec 11, was tested capable of producing approximately 3,500 barrels of water daily from the Brule formation at 83 feet.

Waterflooding was begun in July 1961 when fresh water was injected into one well at 450 barrels daily. A second well was placed on injection in March 1962. The third injection well would not take water and was shut-in. In August 1962 Bayview Oil Corp. succeeded S. D. Johnson as unit operator.

The flood pattern is a modified line drive. The injection wells are at opposite (east-west) ends of the unit area.

In July 1963 the McDaniel unit contained three injection wells and six active producing wells. Daily injection averaged 780 barrels of

TABLE 28. - Basic data for Long unit ("D" sand)

I. Reservoir data

Productive area	1,510 acres
Average thickness	18 ft
Reservoir volume	27,180 acre-ft
Average porosity	20 pct
Average water saturation	28 pct
Formation volume factor	1.25 bbl/stb
Initial reservoir pressure	1,500 psi
Bubble point pressure	- - psi
Average permeability	142 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7,758 \times 27,182 \times .2 \times .72}{1.25} = 24,293,000 \text{ STB}$$

$$\frac{7,758 \times .2 \times .72}{1.25} = 894 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	16	143	3,887,000
Secondary	14	125	3,401,000
Ultimate	30	268	7,288,000

IV. Estimated water requirements and flood life

Total	24,000,000 bbl
Equivalent pore volume	0.6
Injection water:secondary oil	7:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	November 1960
Oil recovery (pct original oil in place)	17
Water injection (pct estimated water required)	45

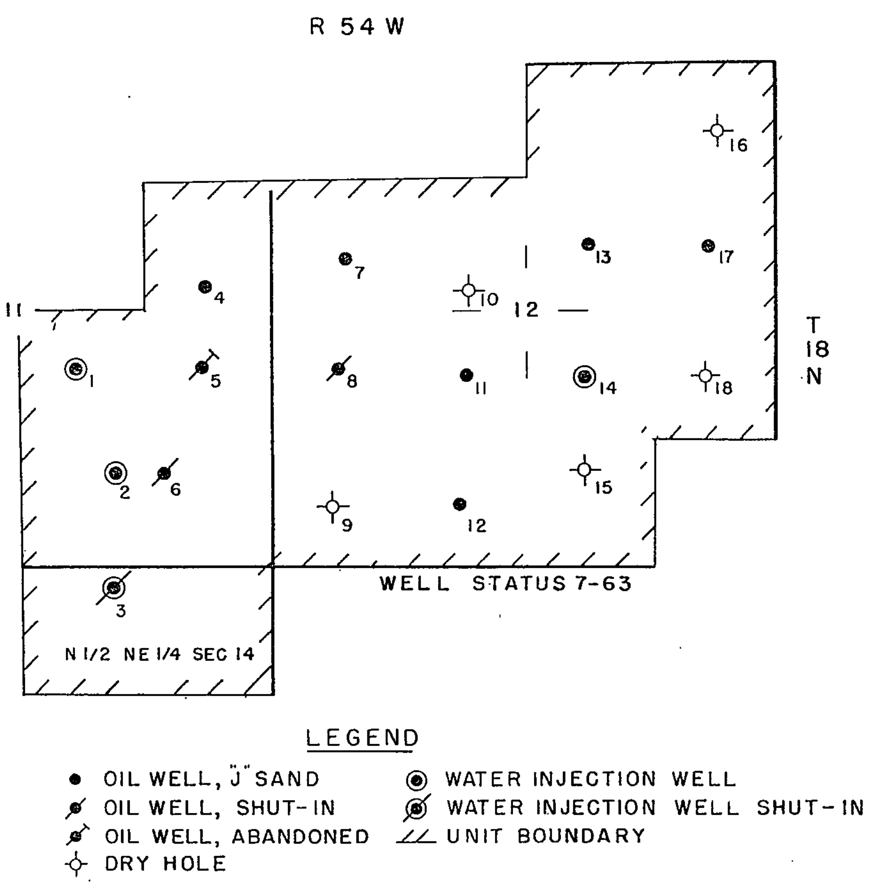

FIGURE 33. – McDaniel unit, Banner County.

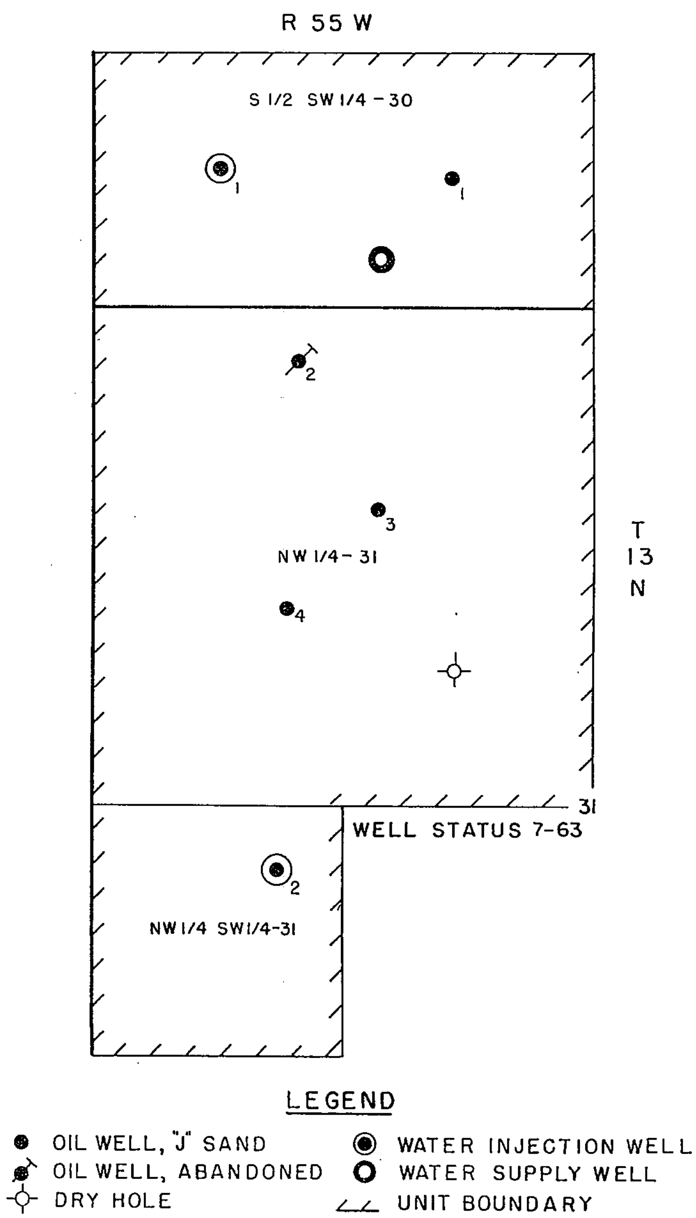

FIGURE 34. – North Mintken unit, Kimball County.

untreated fresh water at a pressure of 500 psi; daily production was 83 barrels of oil and no water.

By volumetric determination the oil in place at original reservoir conditions was 2,630,000 barrels or 688 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 21.1 percent; secondary, 19.5 percent; and total 40.6 percent.

Estimated primary oil recovery is 555,000 barrels or 145 barrels an acre-foot. Cumulative oil production at the start of waterflooding was approximately 534,000 barrels or 96 percent of the estimated primary recovery. Estimated secondary oil recovery is 513,000 barrels or 134 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 88,400 barrels of oil and 33,000 barrels of water. Cumulative unit water injection for the same period was 563,700 barrels.

Estimated water requirements are 6,200,000 barrels or 1.3 reservoir pore volume. The estimated ratio of water injected to secondary oil recovered is 12:1. The estimated flood life is $5\frac{1}{2}$ years.

At the end of 1963 only 13 percent of the estimated secondary oil and only 24 percent of the original oil in place had been recovered. Water injected was only 9 percent of the estimated water required. The outcome of the project is indeterminate.

See table 29 for basic engineering data.

North Mintken Unit

The North Mintken unit (fig. 34) is in secs 30 and 31, T 13 N, R 55 W, Kimball County, about 16 miles south of Kimball in flat, rolling farmland. Elevations in the field range from 4,960 to 5,015 feet.

In September 1958 a wildcat well drilled by Signet Operating and Exploration Co. in the C $SW\frac{1}{4}SW\frac{1}{4}$ sec 30, T 13 N, R 55 W, produced 216 barrels of oil daily from the "J" sand from 6,536 to 6,558 feet. Development drilling indicated an impermeable streak (or complete absence of a common zone) between the producing pools of the Signet area and the adjoining Mintken field to the south. However, in 1960 the Nebraska Oil and Gas Conservation Commission defined the Signet area as part of the Mintken field.

In June 1962 the Mintken area was unitized for secondary recovery by waterflooding. Because of the apparent disparity in reservoir conditions between the north and south areas of the Mintken field, two units were formed--North Mintken and South Mintken. Both are operated by Sunray DX Co.

TABLE 29. - Basic data for McDaniel unit ("J" sand)

I. Reservoir data

Productive area	558 acres
Average thickness	6.9 ft
Reservoir volume	3,850 acre-ft
Average porosity	16 pct
Average water saturation	33 pct
Formation volume factor	1.21 bbl/stb
Initial reservoir pressure	1,325 psi
Bubble point pressure	- - psi
Average permeability	54 md
Original solution GOR	300 cu ft per bbl (est)
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 558 \times 6.9 \times .16 \times .67}{1.21} = 2{,}630{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .16 \times .67}{1.21} = 688 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	21.1	145	555,000
Secondary	19.5	134	513,000
Ultimate	40.6	279	1,068,000

IV. Estimated water requirements and flood life

Total	6,200,000 bbl
Equivalent pore volumes	1.3
Injection water:secondary oil	12:1
Flood life	5½ years

V. Project status--January 1, 1964

Flood started	July 1961
Oil recovery (pct original oil in place)	24
Water injection (pct estimated water required)	9

The North Mintken unit is composed of six producing wells and one dry hole that were formerly in the Signet field area. Two of the producing wells were reworked and converted to water injection, leaving four producing wells.

A fresh water supply well, which also supplies water to the South Mintken unit, was drilled in the $S\frac{1}{2}SE\frac{1}{4}SW\frac{1}{4}$ sec 30, T 13 N, R 55 W, into a shallow sand deposit (Arikaree).

The secondary recovery project was started in October 1962, injecting 1,500 barrels daily into two wells. The injection pattern is irregular with an injection well at each end (north-south) of the unit area.

During July 1963 the unit contained three producing wells, one abandoned well, and two injection wells. The three wells were producing 33 barrels of oil daily and no water. Fresh water injection was 600 barrels daily at 1,000 psi. Injection water was being treated with a corrosion inhibitor.

By volumetric determination, the oil in place at original reservoir conditions was 1,121,300 barrels or 450 barrels an acre-foot. The estimated recovery factors expressed in percentage of initial oil in place are: 22.1 percent for primary and 22.1 percent for secondary; or a total of 44.2 percent.

Estimated primary oil recovery is 248,000 barrels or 99.5 barrels per acre-foot. Cumulative oil production to the start of waterflooding was 227,300 barrels or 92 percent of the expected primary oil.

Estimated secondary oil recovery is 248,000 barrels or 99.5 barrels per acre-foot.

Cumulative unit oil production from waterflooding until the end of 1963 was 19,800 barrels of oil and 119,000 barrels of water. Cumulative water injection for the same period was 335,100 barrels. The ratio of the water injected to the oil produced is about 16:1.

Estimated water requirements are 1 million barrels over 8 years. The 1 million barrels of water comprise close to one-half of the pore volume. The estimated ratio of water injected to secondary oil recovered is 4:1.

Almost all (99 percent) of the estimated primary oil, but only 22 percent of the original oil in place had been recovered at the end of 1963. Water injected was 34 percent of the estimated water required. The outcome of the project is indeterminate.

See table 30 for engineering data.

TABLE 30. - Basic data for North Mintken unit ("J" sand)

I. Reservoir data

Productive area	280 acres
Average thickness	8.9 ft
Reservoir volume	2,492 acre-ft
Average porosity	11.6 pct
Average water saturation	35 pct
Formation volume factor	1.3 bbl/stb
Initial reservoir pressure	- - psi
Bubble point pressure	- - psi
Average permeability	15.5 md
Original solution GOR	300 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 280 \times 8.9 \times .116 \times .65}{1.3} = 1{,}121{,}311 \text{ STB}$$

$$\frac{7{,}758 \times .116 \times .65}{1.3} = 450 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	22.1	99.5	248,000
Secondary	22.1	99.5	248,000
Ultimate	44.2	199.0	496,000

IV. Estimated water requirements and flood life

Total	1,000,000 bbl
Equivalent pore volume	0.5
Injection water:secondary oil	4:1
Flood life	8 years

V. Project status--January 1, 1964

Flood started	October 1962
Oil recovery (pct original oil in place)	22
Water injection (pct estimated water required)	34

South Mintken Unit

The South Mintken unit (fig. 35) is in Kimball County, in sec 31, T 13 N, R 55 W, and secs 1 and 2, T 12 N, R 56 W, about 16 miles south of the town of Kimball in rolling farmland.

The Mintken field (South Mintken unit area) was discovered in January 1958. The British-American Oil Producing Co. drilled the No. 1 Mintken in C NE$\frac{1}{4}$NE$\frac{1}{4}$ sec 2, T 12 N, R 56 W, and produced oil from the "J" sand pumping at 226 barrels daily. This wildcat, at a surface elevation of 4,988 feet, was drilled to 6,605 feet and selectively perforated between 6,516 and 6,535 feet. Development drilling resulted in nine more wells producing from the "J" sand, and seven dry holes.

In June 1962 the South Mintken unit, containing six producing wells and one injection well, was formed with Sunray DX Oil Co. as unit operator. The three omitted producing field wells lie west of the unit boundary. A producing well in the C NE$\frac{1}{4}$NW$\frac{1}{4}$ sec 2, T 12 N, R 56 W, was reworked and converted to an injection well.

A fresh water supply well, which supplies water to both the North and South Mintken units, was drilled in the S$\frac{1}{2}$SE$\frac{1}{4}$SW$\frac{1}{4}$ sec 30, T 13 N, R 55 W, and completed in the Arikaree sand at 275 feet.

Secondary recovery operations were started during October 1962 when 1,000 barrels of water daily were injected through one well. In December 1962 unit well No. 2, NE$\frac{1}{4}$SW$\frac{1}{4}$SW$\frac{1}{4}$ sec 31, T 13 N, R 55 W, was converted to water injection because the original injection well would not take a sufficient amount of water. Later, in 1963, unit well No. 1, SW$\frac{1}{4}$NE$\frac{1}{4}$SW$\frac{1}{4}$ sec 31, T 13 N, R 55 W, also was converted to water injection. The flood pattern is a line drive.

During December 1963, four wells were producing at a combined 40 barrels of oil daily with no water. Three injection wells were receiving 450 barrels daily at 2,350 psi. The water was treated with a corrosive inhibitor.

By volumetric determination, the oil originally in place was 1,383,000 barrels. Total recovery was estimated at 36.5 percent of the original oil in place, 19.2 percent being primary oil and 17.3 percent secondary oil. Estimated primary oil recovery was 266,000 barrels. Cumulative unit oil production at the start of waterflooding was 249,000 barrels or approximately 93 percent of the expected primary oil. Estimated secondary oil recovery is 239,000 barrels or 78 barrels an acre-foot.

Cumulative oil production from the start of waterflooding until the end of 1963 was 23,000 barrels of oil and 4,600 barrels of water. Cumulative water injection for the same period was 189,101 barrels. The ratio of water injected to oil recovered was about 8:1.

Estimated water requirements are 1 million barrels over 8 years. The 1 million barrels comprise about one-third of the pore volume. The estimated ratio of injected water to secondary oil recovered was 4:1.

Only 3 percent of the estimated secondary oil and 20 percent of the original oil in place had been recovered at the end of 1963. Water injected was 19 percent of the estimated water required. The outcome of the project is indeterminate.

See table 31 for basic engineering data.

Mosier Project

The Mosier project (fig. 36) is in secs 20 and 21, T 19 N, R 53 W, Banner County, approximately 14 miles northeast of the town of Harrisburg. Average elevation is approximately 4,050 feet.

The Mosier field, also known as the Pumpkin Creek field, was discovered in September 1956 when Shell Oil Co. completed the No. 2 Mosier "B," C SE$\frac{1}{4}$SW$\frac{1}{4}$ sec 21, for an initial pumping production of 140 barrels daily from the "D" sand (open hole) from 4,820 to 4,838 feet. Field development resulted in 11 producing wells and 10 dry holes.

In January 1959 Shell Oil Co. obtained the approval of the Nebraska Oil and Gas Conservation Commission to conduct a waterflood project in the northern part of the field. Seven producing wells were included in the project area.

Waterflooding was begun in May 1959 when fresh water was injected into two wells at 400 barrels daily. The fresh water was obtained from a shallow well drilled in the SE$\frac{1}{4}$SW$\frac{1}{4}$ of sec 21. The well was completed in alluvial gravel at 100 feet.

The flood pattern is a modified line drive with the injection wells on the west side of the project area.

In December 1963 the Mosier project contained four producing wells and two injection wells. Daily production was approximately 140 barrels of oil and 80 barrels of water. Produced water was disposed of in surface pits. Daily injection was approximately 580 barrels of fresh water at a pressure of approximately 1,200 psi. The injection water was treated with a corrosion inhibitor and bactericide.

By volumetric determination the oil in place at original reservoir conditions was 968,000 barrels or 733 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 20 percent; secondary, 13 percent; and ultimate, 33 percent.

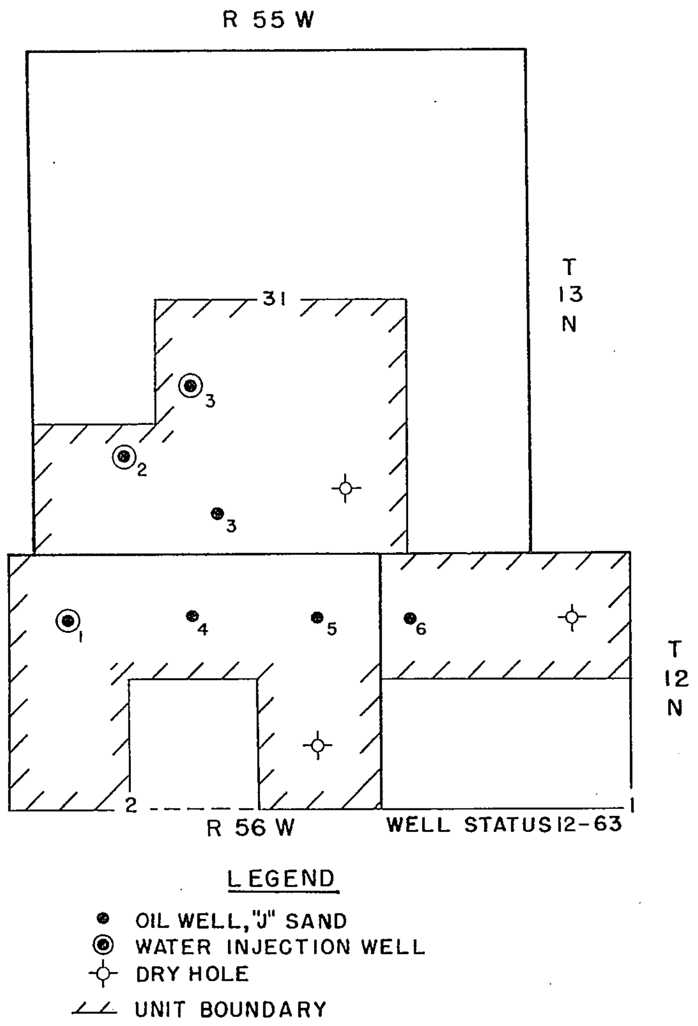

FIGURE 35. – South Mintken unit, Kimball County.

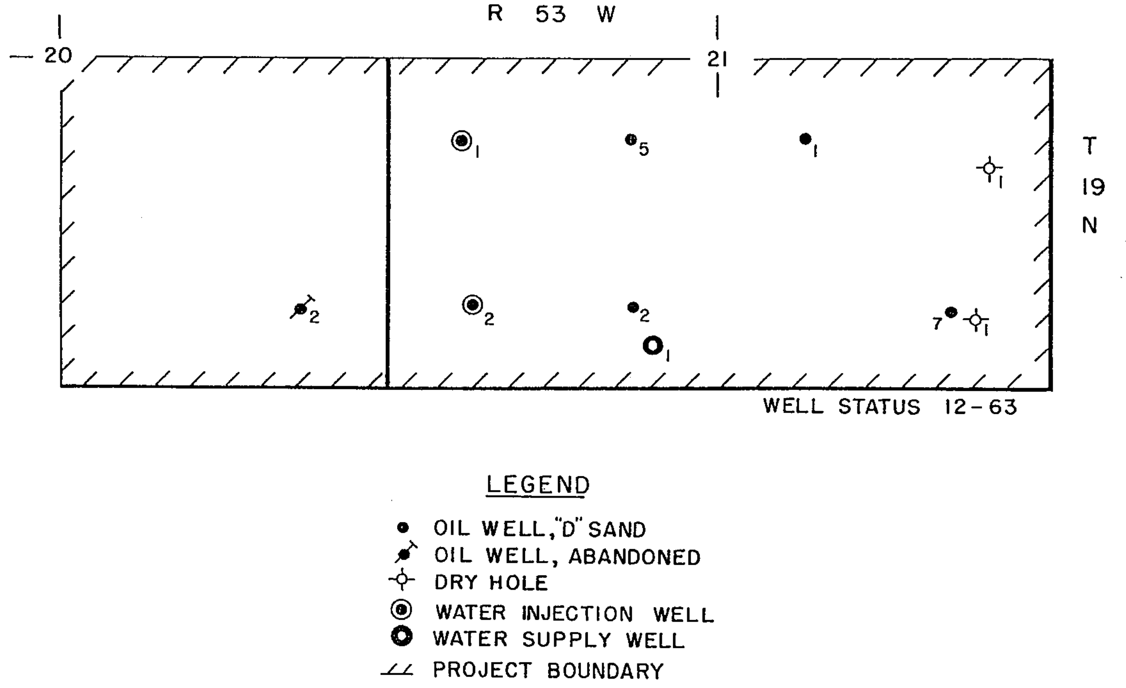

FIGURE 36. – Mosier project, Banner County.

TABLE 31. - Basic data for South Mintken unit ("J" sand)

I. Reservoir data

Productive area	480 acres
Average thickness	6.4 ft
Reservoir volume	3,072 acre-ft
Average porosity	11.6 pct
Average water saturation	35 pct
Formation volume factor	1.3 bbl/stb
Initial reservoir pressure	1,525 psi
Bubble point pressure	- - psi
Average permeability	15.5 md
Original solution GOR	300 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7,758 \times 480 \times 6.4 \times .116 \times .65}{1.3} = 1,383,000 \text{ STB}$$

$$\frac{7,758 \times .116 \times .65}{1.3} = 450 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	19.2	86	266,000
Secondary	17.3	78	239,000
Ultimate	36.5	164	505,000

IV. Estimated water requirements and flood life

Total	1,000,000 bbl
Equivalent pore volume	0.4
Injection water:secondary oil	4:1
Flood life	8 years

V. Project status--January 1, 1964

Flood started	October 1962
Oil recovery (pct original oil in place)	20
Water injection (pct estimated water required)	19

Estimated primary oil recovery is 194,000 barrels or 147 barrels an acre-foot. Cumulative oil production at the start of waterflooding was approximately 141,000 barrels or 73 percent of the estimated primary recovery. Estimated secondary oil recovery is 126,000 barrels or 95 barrels an acre-foot.

Cumulative production from the start of waterflooding until the end of 1963 was 160,000 barrels of oil and 36,000 barrels of water. Cumulative water injection for the same period was 685,600 barrels.

Estimated water requirements are 1½ million barrels or 0.92 pore volume. The estimated ratio of water injected to secondary oil recovered is 12:1. The estimated flood life is 6 years.

By the end of 1963 approximately 85 percent of the estimated secondary oil and 31 percent of the original oil in place had been recovered. Water injected was 46 percent of the estimated water required. The project is apparently successful.

See table 32 for basic engineering data.

Olsen Unit

The Olsen unit (fig. 37) is in secs 19 and 30, T 18 N, R 52 W, and secs 24 and 25, T 18 N, R 53 W, Banner and Morrill Counties, approximately 17 miles east of the town of Harrisburg. Average elevation is about 4,425 feet.

The Olsen field was discovered in July 1955 when Superior Oil Co. completed the No. 68-19 Olsen, SE¼SW¼SE¼ sec 19, T 18 N, R 52 W, for an initial pumping production of 175 barrels daily from the "J" sand through perforations from 5,256 to 5,262 feet. Continued development resulted in a field of 33 producing wells and 9 dry holes.

The field was unitized in August 1961 with Superior Oil Co. as unit operator. Six producing wells were converted to water injection wells and a water supply well was drilled in the SW¼SE¼ sec 29, T 18 N, R 52 W. The water supply well was tested capable of producing 35,000 barrels daily from the Brule formation between 60 and 98 feet.

Waterflooding was begun in December 1961. Fresh water was injected into the six injection wells at approximately 14,000 barrels daily.

The flood pattern is a modified line drive with injection wells in the west end and the southwest corner of the unit area.

In June 1963 the Olsen unit contained 3 injection wells and 16 producing wells. Four injection wells and 12 producing wells had been abandoned. The daily injection rate was 8,500 barrels at an injection

TABLE 32. - Basic data for Mosier project ("D" sand)

I. Reservoir data

Productive area	264 acres
Average thickness	5 ft
Reservoir volume	1,320 acre-ft
Average porosity	16 pct
Average water saturation	35 pct
Formation volume factor	1.1 bbl/stb
Initial reservoir pressure	1,200 psi
Bubble point pressure	1,090 psi (est)
Average permeability	175 md
Original solution GOR	290 cu ft per bbl
Gravity of crude	39° API

II. Oil in place at original conditions

$$\frac{7,758 \times 264 \times 5 \times .16 \times .65}{1.1} = 968,000 \text{ STB}$$

$$\frac{7,758 \times .16 \times .65}{1.1} = 733 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	20	147	194,000
Secondary	13	95	126,000
Ultimate	33	242	320,000

IV. Estimated water requirements and flood life

Total	1,500,000 bbl
Equivalent pore volume	0.92
Injection water:secondary oil	12:1
Flood life	6 years

V. Project status--January 1, 1964

Flood started	May 1959
Oil recovery (pct original oil in place)	31
Water injection (pct estimated water required)	46

pressure of approximately 1,360 psi. The daily producing rate was 2,400 barrels of oil and 3,900 barrels of water.

Produced water was injected into one well at 2,000 barrels daily. Both fresh and produced water were treated with a corrosion inhibitor.

By volumetric determination the oil in place at original reservoir conditions was 11½ million barrels or 1,164 barrels an acre-foot. Estimated recovery factors are: Primary, 33.4 percent; secondary, 14.9 percent; and total, 48.3 percent.

Estimated primary oil recovery is 3,841,000 barrels or 389 barrels an acre-foot. Cumulative oil production at the start of waterflooding was 3,143,200 barrels or 82 percent of the estimated primary recovery. Estimated secondary oil recovery is 1,714,000 barrels or 173 barrels an acre-foot.

The high primary recovery estimate is based on a partial natural water drive from the south and west. Depending on the magnitude of the natural water drive, ultimate recovery might exceed 50 percent of the oil in place.

Cumulative unit production from the start of waterflooding until the end of 1963 was 1,156,900 barrels of oil and 1,954,400 barrels of water. Cumulative water injection for the same period was 8,016,900 barrels.

Estimated water requirements are 13 million barrels of fresh water and 12 million barrels of produced water totaling 25 million barrels or 1.36 reservoir pore volume. The estimated ratio of water injected to secondary oil recovered is 15:1. Estimated flood life is about 9 years.

By the end of 1963 approximately 27 percent of the estimated secondary oil and 37 percent of the original oil in place had been recovered. Water injected was approximately 32 percent of the estimated water required. Available data indicate a successful project.

See table 33 for basic engineering data.

Ostgren Unit

The Ostgren unit (fig. 38) is in sec 6, T 16 N, R 54 W, and sec 1, T 16 N, R 55 W, Kimball County, and sec 32, T 17 N, R 54 W, Banner County, approximately 10 miles northeast of the town of Kimball. Average elevation is 4,750 feet.

The Ostgren field was discovered in February 1957 when Pan American Petroleum Corp. completed the No. 7 Ostgren, C SE¼NW¼ sec 1, for an initial pumping production of 193 barrels of oil daily from the "J" sand

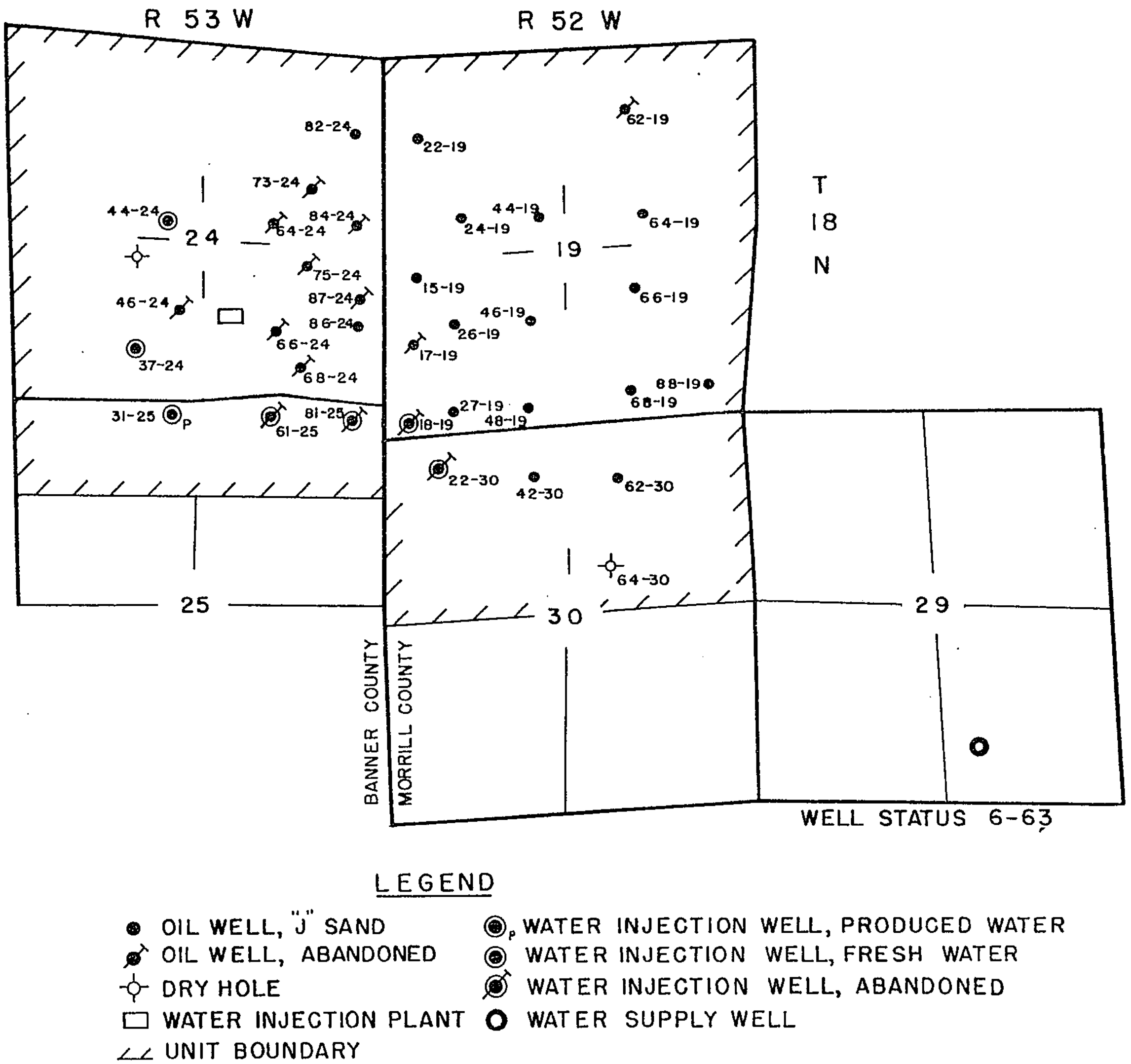

FIGURE 37. – Olsen unit, Banner and Morrill Counties.

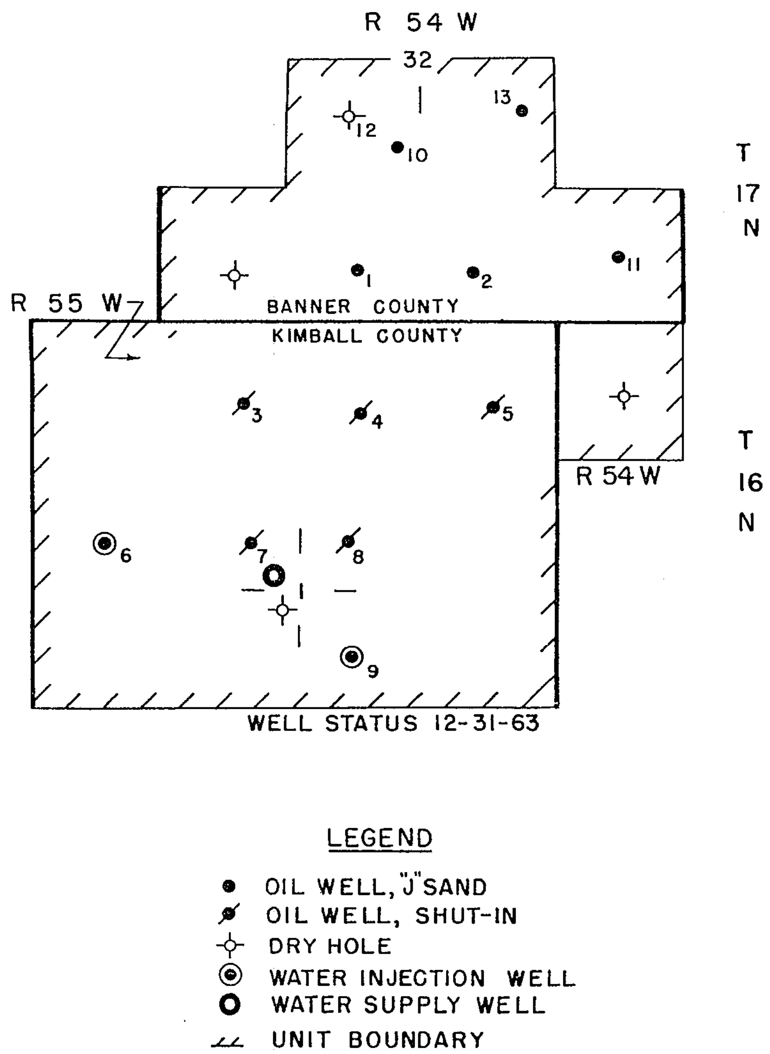

FIGURE 38. – Ostgren unit, Banner and Kimball Counties.

TABLE 33. - Basic data for Olsen unit ("J" sand)

I. Reservoir data

Productive area	1,523 acres
Average thickness	6.5 ft
Reservoir volume	9,900 acre-ft
Average porosity	24 pct
Average water saturation	25 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,200 psi
Bubble point pressure	700 psi
Average permeability	400 md
Original solution GOR	250 cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7,758 \times 1,523 \times 6.5 \times .24 \times .75}{1.2} = 11,500,000 \text{ STB}$$

$$\frac{7,758 \times .24 \times .75}{1.2} = 1,164 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	33.4	389	3,841,000
Secondary	14.9	173	1,714,000
Ultimate	48.3	562	5,555,000

IV. Estimated water requirements and flood life

Fresh water	13,000,000 bbl
Produced water	12,000,000 bbl
Total	25,000,000 bbl
Equivalent pore volumes	1.36
Injection water:secondary oil	15:1
Flood life	9 years

V. Project status--January 1, 1964

Flood started	December 1961
Oil recovery (pct original oil in place)	37
Water injection (pct estimated water required)	32

through perforations from 5,928 to 5,930 feet. Continued development resulted in nine more producing wells and six dry holes.

The field, including all 10 producing wells and 6 dry holes, was unitized in 1959 with Pan American Petroleum Corp. as unit operator.

Waterflooding was begun in January 1959 when fresh water was injected into two recompleted dry holes at 1,800 barrels daily. Fresh water was obtained from a shallow well in the SE$\frac{1}{4}$NW$\frac{1}{4}$ of sec 1, completed in alluvial gravel at approximately 200 feet.

The flood pattern is a line drive. The injection wells are on the southwest end of the northeast-southwest trending reservoir.

In December 1963 the Ostgren unit contained five active producing wells and two active injection wells. Daily production was approximately 250 barrels of oil and 650 barrels of water. Produced water was disposed of in surface pits. Daily injection was approximately 1,400 barrels of untreated water at a pressure of 725 psi.

By volumetric determination the oil in place at original reservoir conditions was 3,768,000 barrels or 935 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 25 percent; secondary, 23 percent; and ultimate, 48 percent.

Estimated primary oil recovery is 942,000 barrels or 234 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 470,000 barrels or 50 percent of the estimated primary recovery. Estimated secondary oil recovery is 867,000 barrels or 215 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 1,118,800 barrels of oil and 753,800 barrels of water. Cumulative unit water injection for the same period was 3,076,000 barrels.

Estimated water requirements are 5,900,000 barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 8:1. Estimated flood life is 7 years.

By the end of 1963 approximately 75 percent of the estimated secondary oil and about 42 percent of the original oil in place had been recovered. Water injected was approximately 52 percent of the estimated water required. The project is apparently successful.

See table 34 for basic engineering data.

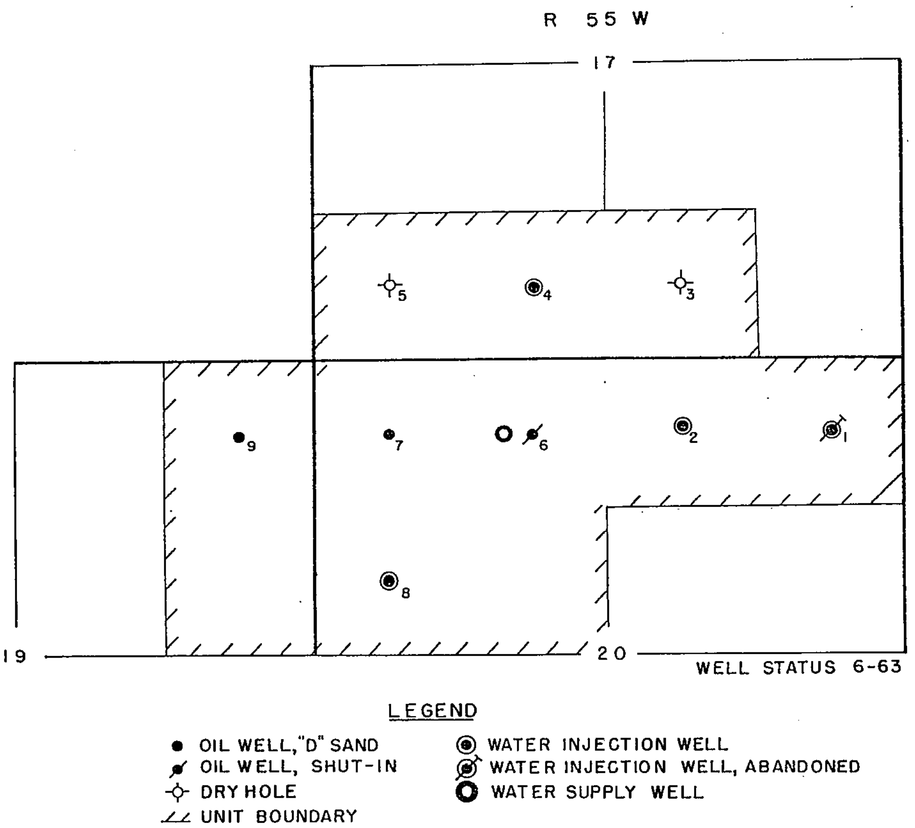

FIGURE 39. – Pan Am unit, Banner County.

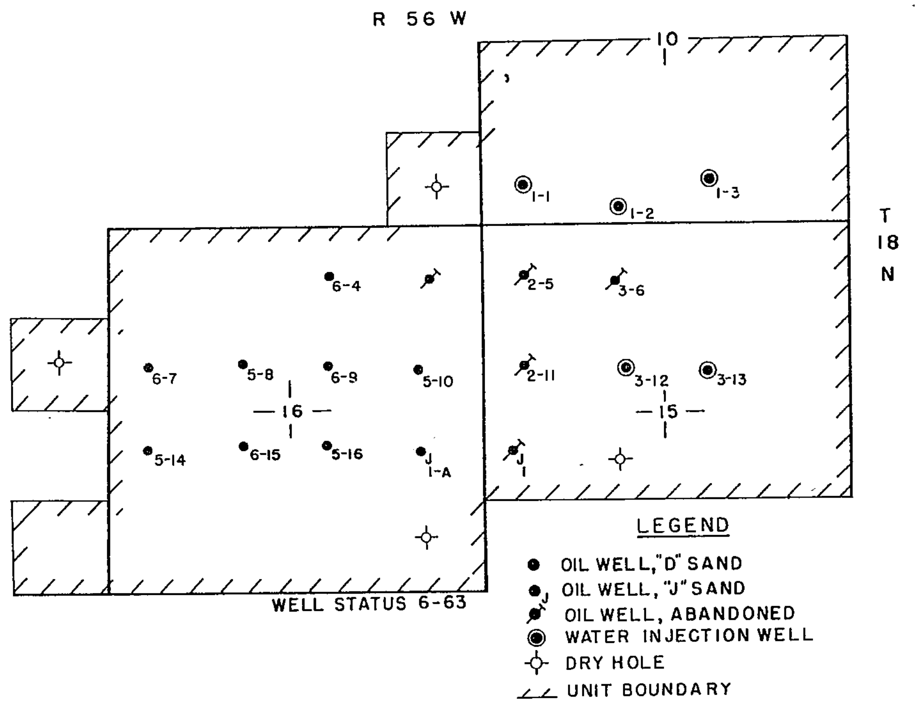

FIGURE 40. – Petroleum State unit, Banner County.

TABLE 34. - Basic data for Ostgren unit ("J" sand)

I. Reservoir data

Productive area	504 acres
Average thickness	8 ft
Reservoir volume	4,023 acre-ft
Average porosity	18.8 pct
Average water saturation	23 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,260 psi
Bubble point pressure	- - psi
Average permeability	84 md
Original solution GOR	350 cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 504 \times 8 \times .188 \times .77}{1.2} = 3{,}768{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .188 \times .77}{1.2} = 935 \ \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery

Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	25	234	942,000
Secondary	23	215	867,000
Ultimate	48	449	1,809,000

IV. Estimated water requirements and flood life

Total	5,900,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	8:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	January 1959
Oil recovery (pct original oil in place)	42
Water injection (pct estimated water required)	52

Pan Am Unit

The Pan Am unit (fig. 39) is in secs 17, 19, and 20, T 17 N, R 55 W, Banner County, approximately 8 miles southeast of the town of Harrisburg. Average elevation is about 4,923 feet.

The Pan Am field was discovered in June 1957 when Pan American Petroleum Corp. completed the No. 1 State, C $SW\frac{1}{4}SW\frac{1}{4}$ sec 16, T 17 N, R 55 W, for an initial pumping production of 130 barrels daily from the "J" sand through perforations from 6,430 to 6,438 feet. In December 1959 Chandler and Simpson completed the "D" sand discovery well, the No. 1 Mossburg, C $NE\frac{1}{4}NW\frac{1}{4}$ sec 20, for an initial production of 476 barrels daily through perforations from 6,262 to 6,280 feet. Field development resulted in three more "J" sand producers, four more "D" sand producers, and six dry holes.

In September 1961 part of the field was unitized to waterflood the "D" sand. Chandler and Simpson became the unit operator. The five "D" sand producing wells, a former "J" sand producing well, and three dry holes were included in the unit area.

The former "J" sand well was recompleted in the "D" sand as a water injection well, and a fresh water supply well was drilled in the $NE\frac{1}{4}NW\frac{1}{4}$ of sec 20. The water supply well was tested capable of producing 2,000 barrels daily from shallow Tertiary gravel deposits.

Waterflooding was begun in February 1962 with injection into one well at 700 barrels daily.

The flood pattern is irregular. The initial injection well is on the east end of the unit area.

During December 1963 two wells were producing 153 barrels of oil and 380 barrels of water daily. Produced water was run to surface pits. Untreated water was injected at 305 barrels daily through three wells at an average pressure of 1,140 psi.

By volumetric determination the oil originally in place was 1,382,000 barrels or 609 barrels per acre-foot. The estimated recovery factors, expressed in percentage of initial oil in place, are 21.9 percent for primary and 13.1 percent for secondary or a total of 35 percent.

Estimated primary oil recovery is 303,000 barrels or 133 barrels an acre-foot. Cumulative oil production to the beginning of waterflood operations was 230,000 barrels or approximately 76 percent of the estimated primary recovery. Cumulative water production was 131,500 barrels.

Estimated secondary oil recovery is 181,000 barrels or 79 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 140,200 barrels. Cumulative water injection during the same period was 596,300 barrels. The ratio of water injected to oil produced was about 4:1. Water production amounted to 86,300 barrels.

Estimated water requirements are 2 million barrels over 4 years. The 2 million barrels of water comprise about three-fourths of the pore volume. The estimated ratio of water injected to secondary oil recovered is 11:1.

By the end of 1963, 37 percent of the estimated secondary oil and 27 percent of the original oil in place had been recovered. Water injected was 30 percent of the estimated water required. Available data indicate a successful project.

See table 35 for basic engineering data.

Petroleum State Unit

The Petroleum State unit (fig. 40) is in secs 9, 10, 15-17, T 18 N, R 56 W, Banner County, approximately 2 miles southwest of the town of Harrisburg. Average elevation is approximately 4,850 feet.

The Petroleum State field was discovered in August 1955 when Petroleum Inc. completed the No. 1 State "A," C NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 16, T 18 N, R 56 W, for an initial pumping production of 120 barrels of oil daily from the "J" sand. The "D" sand discovery well, the Petroleum Inc. No. 1 Cross "B," C SW$\frac{1}{4}$SW$\frac{1}{4}$ sec 10, was completed in September 1955 for an initial pumping production of 80 barrels daily through perforations from 6,211 to 6,217 feet.

Field development resulted in 19 more producing wells and 8 dry holes. Of the 21 producing wells, 15 were completed in the "D" sand, 3 in the "J" sand, and 3 dually completed in the "D" and "J" sands.

The field was unitized in September 1959, with Petroleum Inc. as unit operator, for waterflooding the "D" sand. Thirteen "D" sand producing wells, one "J" sand producing well, three "D" and "J" sands producing wells, and six dry holes were included in the unit area.

Waterflooding was begun in October 1960. Fresh water was obtained from a shallow well in the SW$\frac{1}{4}$SW$\frac{1}{4}$ sec 22 and injected into two former producing wells at a rate of 1,200 barrels daily. The water zone in the supply well is between 150 and 500 feet deep.

The flood pattern is a line drive with the injection wells in the east end of the unit area. As the flood front moves farther west, additional wells likely will be converted to injection.

TABLE 35. - Basic data for Pan Am unit ("D" sand)

I. Reservoir data

Productive area	190 acres
Average thickness	12 ft
Reservoir volume	2,280 acre-ft
Average porosity	15.7 pct
Average water saturation	40 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,505 psi
Bubble point pressure	- - psi
Average permeability	205 md
Original solution GOR	800 cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 12 \times 190 \times .157 \times .6}{1.2} = 1{,}382{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .157 \times .6}{1.2} \doteq 609 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	21.9	133	303,000
Secondary	13.1	79	181,000
Ultimate	35.0	212	484,000

IV. Estimated water requirements and flood life

Total	2,000,000 bbl
Equivalent pore volume	0.7
Injection water:secondary oil	11:1
Flood life	4 years

V. Project status--January 1, 1964

Flood started	February 1962
Oil recovery (pct original oil in place)	27
Water injection (pct estimated water required)	30

In June 1963 the unit contained five injection wells and nine producing wells. Daily injection was approximately 970 barrels of untreated water at a pressure of 2,900 psi. Daily production was approximately 48 barrels of oil and 19 barrels of water. Produced water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was 3,803,000 barrels or 595 barrels an acre-foot. Estimated recoveries, expressed in percentage of oil in place, are: Primary, 20 percent; secondary, 26 percent; and total, 46 percent.

Estimated primary oil recovery is 760,000 barrels or 119 barrels an acre-foot. Cumulative oil production at the start of waterflooding was approximately 600,000 barrels or 79 percent of the estimated primary recovery. Estimated secondary oil recovery is 988,000 barrels or 155 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 92,400 barrels of oil and 63,400 barrels of water. Cumulative water injection for the same period was 829,700 barrels.

Estimated water requirements are 7,100,000 barrels or 1 reservoir pore volume. The estimated ratio of water injected to secondary oil recovered is 7:1. Estimated flood life is 7 years.

At the end of 1963, 91 percent of the estimated primary oil and only 18 percent of the original oil in place had been recovered. Water injected was approximately 12 percent of the estimated water required. The outcome of the project is indeterminate.

See table 36 for basic engineering data.

Southwest Potter Unit

The Southwest Potter unit (fig. 41) is in secs 2, 3, 10, and 11, T 13 N, R 53 W, and sec 34, T 14 N, R 53 W, Kimball and Cheyenne Counties, approximately 13 miles southeast of the town of Kimball. Average elevation is approximately 4,650 feet.

The Southwest Potter field was discovered in September 1951 when Wytex Petroleum and Derby Oil completed the No. 1 Dunn in the NE$\frac{1}{4}$NE$\frac{1}{4}$SE$\frac{1}{4}$ sec 3, T 13 N, R 53 W. Initial daily pumping production was 86 barrels of oil and 19 barrels of water from the "J" sand at 5,658 to 5,663 feet. In October 180 barrels of oil daily was pumped from the "D" sand at an interval between 5,536 and 5,542 feet. Continued development resulted in a field of 92 wells, of which 44 were completed in the "D" sand, 18 in the "J" sand, 9 in both the "D" and "J" sands. Twenty-one were abandoned.

TABLE 36. - Basic data for Petroleum State unit ("D" sand)

I. Reservoir data

Productive area	639 acres
Average thickness	10 ft
Reservoir volume	6,390 acre-ft
Average porosity	14.28 pct
Average water saturation	35 pct
Formation volume factor	1.21 bbl/stb
Initial reservoir pressure	1,550 psi
Bubble point pressure	- - psi
Average permeability	57 md
Original solution GOR	440 cu ft per bbl
Gravity of crude	35° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 6{,}390 \times .1428 \times .65}{1.21} = 3{,}803{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .1428 \times .65}{1.21} = 595 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	20	119	760,000
Secondary	26	155	988,000
Ultimate	46	274	1,748,000

IV. Estimated water requirements and flood life

Total	7,100,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	7:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	October 1960
Oil recovery (pct original oil in place)	18
Water injection (pct estimated water required)	12

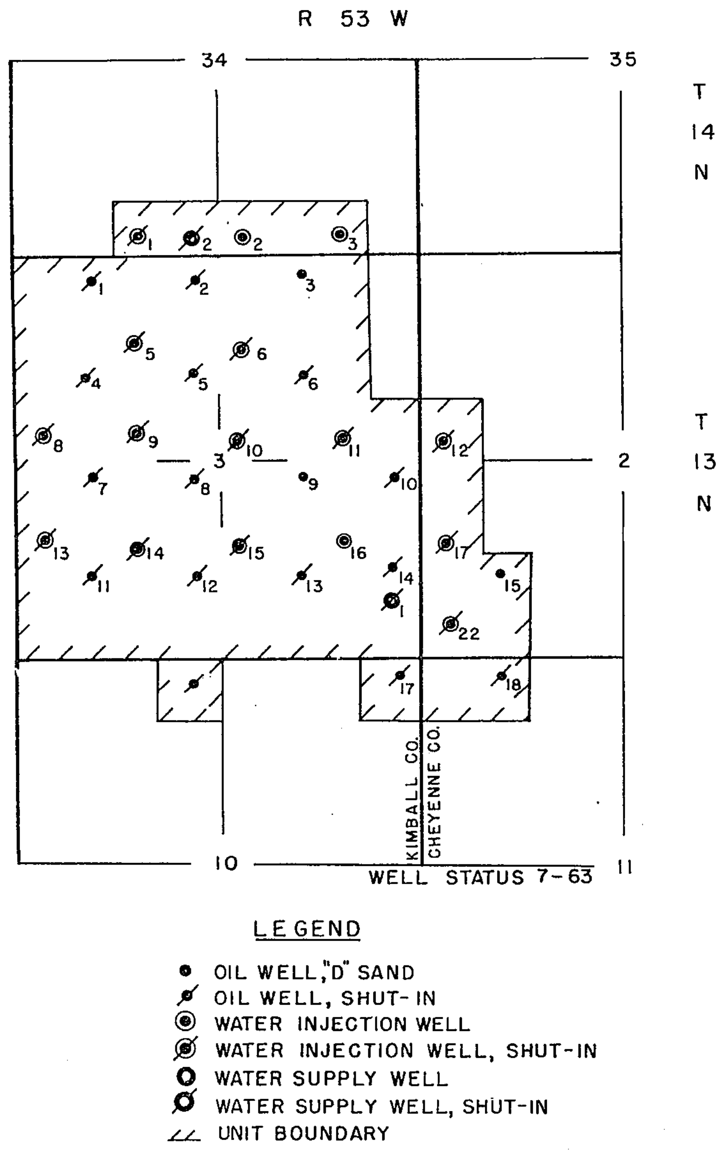

FIGURE 41. – Southwest Potter unit, Cheyenne and Kimball Counties.

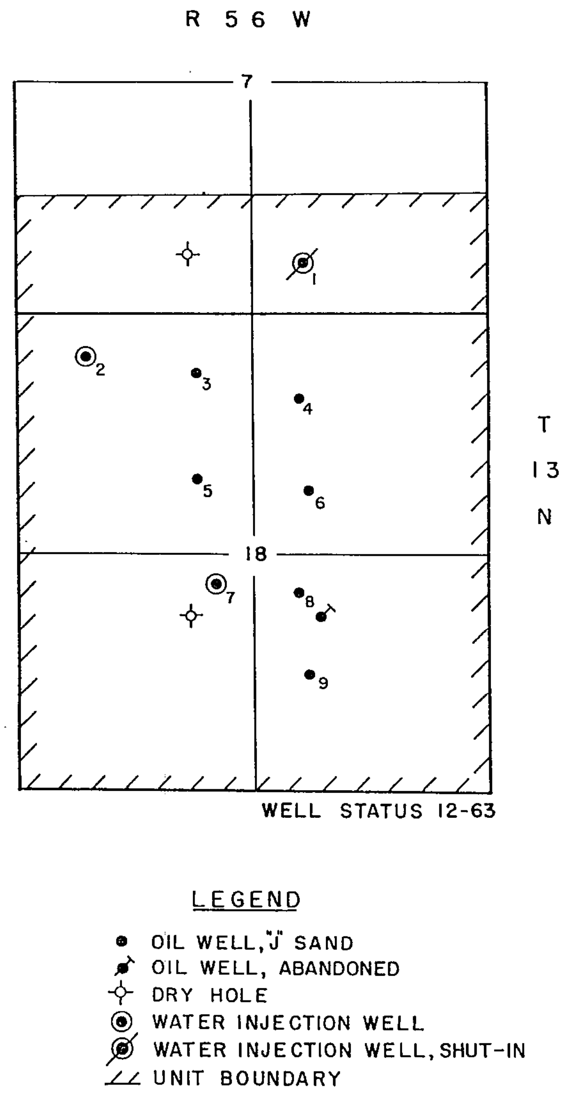

FIGURE 42. – Prairie unit, Kimball County.

Part of the field was unitized late in 1958, with Shell Oil Co. as operator, to waterflood the "D" sand. The unit area contained 34 producing wells and 1 abandoned well (casing collapsed). Of the 34 producing wells, 27 were completed in the "D" sand and 7 in both the "D" and "J" sands.

Waterflooding was begun in October 1958 when 7,000 barrels of fresh water daily was injected into 21 wells. Five of the 21 wells were drilled as injection wells. The other 16 were former producing wells. Fresh water was obtained from a well drilled in the SE$\frac{1}{4}$SE$\frac{1}{4}$SW$\frac{1}{4}$ of sec 34, to 650 feet. The flood pattern is a modified five-spot.

In July 1963 the unit contained only three active producing wells and three active injection wells. Daily production was 95 barrels of oil and 500 barrels of water. Fresh water injection had been terminated and the produced water was injected on vacuum.

By volumetric determination the oil in place at original reservoir conditions was 6,280,000 barrels or 750 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 26 percent; secondary, 11 percent; and ultimate, 37 percent.

Estimated primary oil recovery is 1,633,000 barrels or 195 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 1,535,000 barrels or 94 percent of the estimated primary recovery. Estimated secondary oil recovery is 691,000 or 83 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 734,800 barrels of oil and 4,826,700 barrels of water. Cumulative unit water injection for the same period was 10,680,300 barrels.

Estimated water requirements are 5,554,000 barrels of make-up (fresh) water and 5,446,000 barrels of produced water, totaling 11 million barrels or 0.89 pore volume. The estimated ratio of injected water to secondary oil recovered is 16:1. The estimated flood life is 7 years.

By the end of 1963 approximately 92 percent of the estimated secondary oil and 36 percent of the estimated original oil in place had been recovered. Water injected was approximately 97 percent of the estimated water required. The project is apparently successful.

See table 37 for basic engineering data.

Prairie Unit

The Prairie unit (fig. 42) is in secs 7 and 18, T 13 N, R 56 W, Kimball County, about 11$\frac{1}{2}$ miles southwest of Kimball. Surface topography

TABLE 37. - Basic data for Southwest Potter unit ("D" sand)

I. Reservoir data

Productive area	762 acres
Average thickness	11 ft
Reservoir volume	8,382 acre-ft
Average porosity	19 pct
Average water saturation	38 pct
Formation volume factor	1.22 bbl/stb (est)
Initial reservoir pressure	1,072 psi
Bubble point pressure	1,090 psi
Average permeability	142 md
Original solution GOR	239 cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 762 \times 11 \times .19 \times .62}{1.22} = 6{,}280{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .19 \times .62}{1.22} = 750 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	26	195	1,633,000
Secondary	11	83	691,000
Ultimate	37	278	2,324,000

IV. Estimated water requirements and flood life

Make-up (fresh)	5,554,000 bbl
Produced	5,446,000 bbl
Total	11,000,000 bbl
Equivalent pore volume	0.89
Injection water:secondary oil	16:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	October 1958
Oil recovery (pct original oil in place)	36
Water injection (pct estimated water required)	97

consists of eroded rolling hills, and the elevation ranges from 5,091 feet near the center of the field to 5,037 feet on the north end and 5,005 on the south end.

The Prairie field was discovered in June 1955 when Shell Oil Co. drilled the No. 1 Schrack, C NE$\frac{1}{4}$NW$\frac{1}{4}$ sec 18. The well pumped 172 barrels of oil daily through "J" sand perforations from 6,800 to 6,830 feet at an initial 172 barrels daily. Subsequent field development to May 1962 resulted in seven more producing wells and five dry holes.

The field was unitized in May 1962 with Canyon Oil as unit operator. One of the eight oil wells had been abandoned and another was converted to injection. One dry hole was reworked and converted to injection. A new well was drilled in the NW$\frac{1}{4}$ sec 18 and completed as a water injection well.

A water supply well was drilled in the SE$\frac{1}{4}$SE$\frac{1}{4}$ sec 11, T 13 N, R 57 W, to 90 feet in gravel.

The secondary recovery project began in September 1962 when 1,200 barrels of water was injected daily through three wells. The flood pattern is semiperipheral.

During December 1963 six wells were producing a total of 42 barrels of oil and 383 barrels of water daily. Produced water was run to surface pits. Untreated fresh water was injected into two wells at 766 barrels daily at about 2,350 psi.

By volumetric determination the oil originally in place was 2,755,000 barrels or 633 barrels an acre-foot. The estimated recovery factors, expressed in percentage of initial oil in place, are 9.3 percent for primary and 11.0 percent for secondary, or a total of 20.3 percent.

Estimated primary oil recovery is 256,000 barrels or 59 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 168,700 barrels or about 66 percent of the estimated primary oil. Cumulative water production was 88,600 barrels.

Estimated secondary oil recovery is 303,000 barrels or 70 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding to the end of 1963 was 25,400 barrels. Cumulative water injection during the same period was 328,500 barrels. The ratio of water injected to oil produced is about 13:1. Water production amounted to 28,600 barrels.

Estimated water requirements are 3,363,000 barrels over about 8 years. The 3,363,000 barrels make up about 60 percent of the pore volume. The estimated ratio of water injected to secondary oil recovered is 11:1.

Development Services Corp. has assumed operation of the unit.

At the end of 1963, 76 percent of the estimated primary oil and only 7 percent of the original oil in place had been recovered. Water injected was 10 percent of the estimated water required. The outcome of the project is indeterminate.

See table 38 for basic engineering data.

Rodman Unit

The Rodman unit (fig. 43) is in secs 22 and 27, T 15 N, R 55 W, Kimball County, approximately 1 mile northeast of the town of Kimball. Average elevation is approximately 4,650 feet.

The Rodman field was discovered in September 1956 when Chandler-Musgrove and Rock Island Refining Co. completed the No. 1 Rodman "A," C NE$\frac{1}{4}$NW$\frac{1}{4}$ sec 27, for an initial pumping production of 239 barrels daily from the "J" sand through perforations from 6,089 to 6,093 feet and 6,106 to 6,107 feet. Subsequent development resulted in seven more producing wells and seven dry holes.

The field, including eight producing wells and three of the seven dry holes, was unitized in August 1961 with Chandler and Simpson the unit operator. Three producing wells were converted to injection wells and a shallow fresh water supply well was drilled in the NW$\frac{1}{4}$SE$\frac{1}{4}$ of sec 22 to 250 feet.

Waterflooding began in January 1962 with injection into three wells at approximately 800 barrels daily. A fourth well was converted to injection in December 1962.

The flood pattern is a modified line drive. Three of the injection wells are in the north end of the unit and the fourth is in the southwest corner.

In December 1963 the Rodman unit contained four injection wells and four producing wells. Daily injection of untreated water was approximately 1,350 barrels at 1,000 psi. Daily production was approximately 200 barrels of oil and 700 barrels of water. Produced water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was 1,830,000 barrels or 659 barrels an acre-foot. The estimated recovery factors expressed in percentage of oil in place are: Primary, 23.7 percent; secondary, 10.9 percent; and total, 34.6 percent.

Estimated primary oil recovery is 435,000 barrels or 156 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 389,000 barrels or 89 percent of the estimated primary

TABLE 38. - Basic data for Prairie unit ("J" sand)

I. Reservoir data

Productive area	500 acres
Average thickness	8.7 ft
Reservoir volume	4,350 acre-ft
Average porosity	15.8 pct
Average water saturation	38 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,500 psi
Bubble point pressure	- - psi
Average permeability	30 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	38° API

II. Oil in place at original conditions

$$\frac{7,758 \times 500 \times 8.7 \times .158 \times .62}{1.2} = 2,755,000 \text{ STB}$$

$$\frac{7,758 \times .158 \times .62}{1.2} = 633 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	9.3	59	256,000
Secondary	11.0	70	303,000
Ultimate	20.3	129	559,000

IV. Estimated water requirements and flood life

Total	3,363,000 bbl
Equivalent pore volume	0.6
Injection water:secondary oil	11:1
Flood life	8 years

V. Project status--January 1, 1964

Flood started	September 1962
Oil recovery (pct original oil in place)	7
Water injection (pct estimated water required)	10

recovery. Estimated secondary oil recovery is 200,000 barrels or 72 barrels an acre-foot. The low secondary estimate may reflect low sweep efficiency and possibly wide variations in reservoir rock permeability.

Cumulative production from the start of waterflooding until the end of 1963 was 69,900 barrels of oil and 172,800 barrels of water. Cumulative water injection for the same period was 1,041,300 barrels.

Estimated water requirements are 3 million barrels of fresh water or approximately 0.82 pore volume. The estimated ratio of water injected to secondary oil recovered is 15:1. The estimated flood life is 5 years.

Only 12 percent of the estimated recoverable secondary oil and only 25 percent of the original oil in place had been recovered at the end of 1963. Water injected was approximately 35 percent of the estimated water required. The outcome of the project is indeterminate.

See table 39 for basic engineering data.

Simpson Unit

The Simpson unit (fig. 44) is in secs 19, 30, and 31, T 15 N, R 54 W, secs 23-26, and 36, T 15 N, R 55 W, Kimball County. The unit lies about 3½ miles northeast of Kimball on a bench overlooking Lodgepole Creek. Average elevation of the field is 4,600 feet.

The Simpson field was discovered in June 1958 when Chandler and Simpson completed the No. 1 Rodman "G," C SE¼SW¼ sec 24, T 15 N, R 55 W, for an initial production of 235 barrels of oil daily from "J" sand perforations at 5,917 to 5,927 feet. Development of the field resulted in 24 additional producing wells and 12 dry holes. Unit wells 23 through 30, thought to be a separate field, were called the Rounds field.

The greater part of the Simpson field was unitized during September 1961 with Chandler and Simpson as unit operator. The unit included 20 producing wells and 3 dry holes from the Simpson field and six producers and one dry hole from the Rounds field. Adding of the N½NE¼ and SE¼NE¼ sec 36, T 15 N, R 55 W, to the unit during November 1961 brought in one additional dry hole from the Rounds field. Unit wells Nos. 31 and 32 were drilled on this acreage.

Eight producing wells and one dry hole were reworked and converted to injection wells following unit approval.

The water supply well was drilled in the NE¼SE¼ sec 25, T 15 N, R 55 W, to 200 feet into Tertiary gravels. It had a capacity of 20,000 barrels daily.

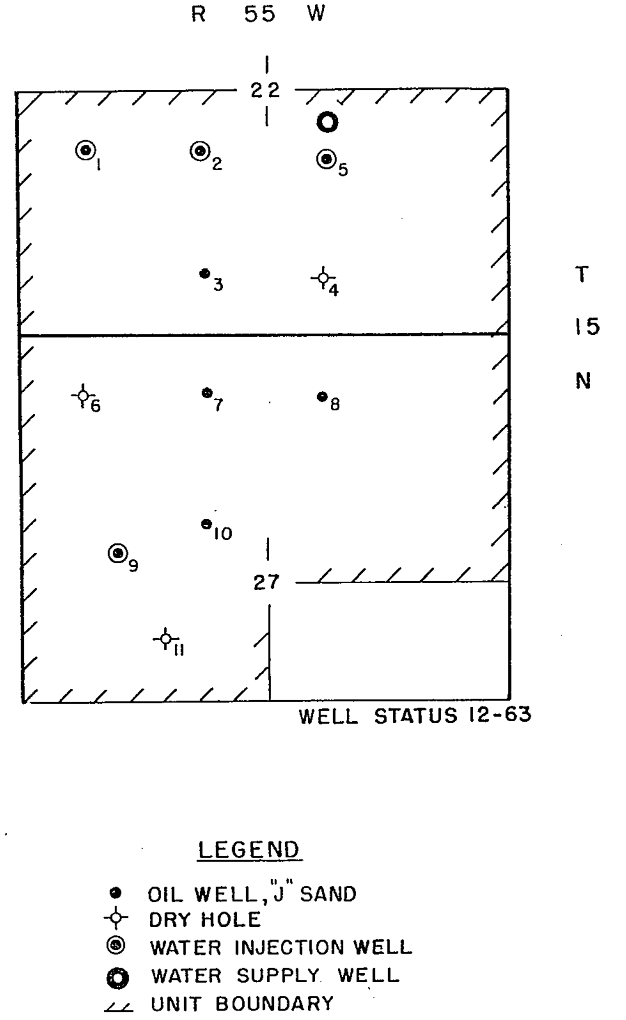

FIGURE 43. – Rodman unit, Kimball County.

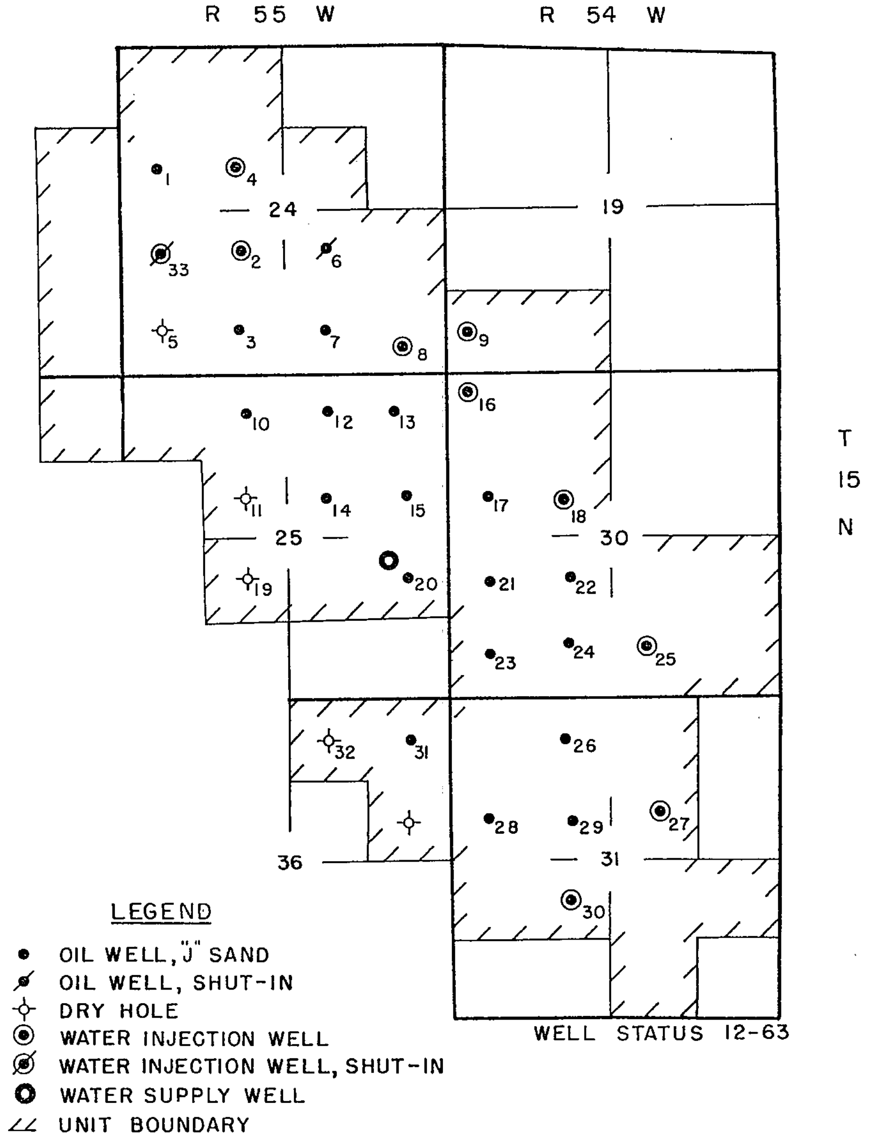

FIGURE 44. – Simpson unit, Kimball County.

TABLE 39. - Basic data for Rodman unit ("J" sand)

I. Reservoir data

Productive area	- - acres
Average thickness	- - ft
Reservoir volume	2,777 acre-ft
Average porosity	16.9 pct
Average water saturation	35 pct
Formation volume factor	1.29 bbl/stb
Initial reservoir pressure	1,200 psi
Bubble point pressure	- - psi
Average permeability	80 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 2{,}777 \times .169 \times .65}{1.29} = 1{,}830{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .169 \times .65}{1.29} = 659 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	23.7	156	435,000
Secondary	10.9	72	200,000
Ultimate	34.6	228	635,000

IV. Estimated water requirements and flood life

Total	3,000,000 bbl
Equivalent pore volume	0.82
Injection water:secondary oil	15:1
Flood life	5 years

V. Project status--January 1, 1964

Flood started	January 1962
Oil recovery (pct original oil in place)	25
Water injection (pct estimated water required)	35

The project began during February 1962 with 3,500 barrels of water injected through 9 wells and oil production from 18 wells.

The flood pattern is a line drive with the "J" sand flooded down-dip, east to west, to use the poorer producing wells for water injection.

During December 1963 injection of untreated water was 59,372 barrels through nine wells at 1,300 psi. Oil production from 18 wells amounted to 11,133 barrels for the month.

By volumetric determination the oil originally in place was 5,341,000 barrels or 655 barrels an acre-foot. The estimated recovery factors, expressed in percentage of initial oil in place, are 18.2 percent for primary and 20.6 percent for secondary, or a total of 38.8 percent.

Estimated primary oil recovery is 972,000 barrels or 119 barrels an acre-foot. Cumulative unit oil production at the start of water-flooding was 903,200 barrels or approximately 93 percent of the primary oil. Cumulative water production to the start of waterflooding was 16,400 barrels.

Estimated secondary oil recovery is 1,100,000 barrels or 134 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 233,000 barrels. Cumulative water injection during the same period was 1,054,100 barrels. The ratio of water injected to water produced was 5:1. Water production was 141,700 barrels. Produced water was run to pits.

Estimated water requirements are 8 million barrels over 7 years, which comprises about 80 percent of the pore volume. The estimated ratio of water injected to secondary oil recovered is 7:1.

At the end of 1963 only 15 percent of the estimated secondary oil and 21 percent of the original oil in place had been recovered. Water injected was only 13 percent of the estimated water required. The outcome of the project is indeterminate.

See table 40 for basic engineering data.

Singleton Unit

The Singleton unit (fig. 45) is in secs 17-20, and 29, T 17 N, R 53 W, and secs 13 and 24, T 17 N, R 54 W, Banner County, approximately 19 miles northeast of the town of Kimball. Average elevation is 4,600 feet.

TABLE 40. - Basic data for Simpson unit ("J" sand)

I. Reservoir data

Productive area	1,020 acres
Average thickness	8 ft
Reservoir volume	8,160 acre-ft
Average porosity	15 pct
Average water saturation	28 pct
Formation volume factor	1.28 bbl/stb
Initial reservoir pressure	1,337 psi
Bubble point pressure	- - psi
Average permeability	65 md
Original solution GOR	600 cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 1{,}020 \times 8 \times .15 \times .72}{1.28} = 5{,}341{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .15 \times .72}{1.28} = 655 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	18.2	119	972,000
Secondary	20.6	134	1,100,000
Ultimate	38.8	253	2,072,000

IV. Estimated water requirements and flood life

Total	8,000,000 bbl
Equivalent pore volume	0.8
Injection water:secondary oil	7:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	February 1962
Oil recovery (pct original oil in place)	21
Water injection (pct estimated water required)	13

The Singleton field was discovered in November 1958 when Miracle-Fifer Drilling Co. completed the No. 3 Singleton, W$\frac{1}{2}$NW$\frac{1}{4}$SE$\frac{1}{4}$ sec 19, for an initial pumping production of 360 barrels daily from the "J" sand through perforations from 5,651 to 5,661 feet. Field development resulted in 32 additional producing wells and 15 dry holes.

All of the producing wells were completed in one or both of two separate oil zones in the "J" sand. The zones are separated by 10 to 15 feet of shale and are referred to as the "J-1" (upper) and the "J-2" (lower). The "J-1" is larger than the "J-2," but the physical characteristics of the two zones are essentially alike.

The field, including 33 producing wells and 7 dry holes, was unitized in October 1961 with Sinclair Oil Co. as unit operator. A shallow (65 feet) fresh water supply well was drilled in the NW$\frac{1}{4}$NW$\frac{1}{4}$NW$\frac{1}{4}$ of sec 29.

Waterflooding was begun in March 1962 when approximately 11,000 barrels of fresh water daily was injected into seven wells. At that time there were 26 producing wells.

The flood pattern for the "J-1" zone is peripheral, whereas the flood pattern for the less extensive "J-2" zone is a modified line drive. The zones are flooded simultaneously utilizing the same wells where both zones are present.

In July 1963, the unit contained 10 injection wells and 18 producing wells. Daily injection (untreated water) was approximately 12,000 barrels at pressures ranging from vacuum to 1,643 psi. Daily production was approximately 3,500 barrels of oil and 1,500 barrels of water. Produced water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was 17,646,000 barrels or 1,020 barrels an acre-foot. Estimated recovery factors expressed in percentage of oil in place are: Primary, 20.7 percent; secondary, 22.5 percent; and total, 43.2 percent.

Estimated primary oil recovery is 3,653,000 barrels or 211 barrels an acre-foot. Cumulative oil production at the start of waterflooding was 3,475,000 barrels or 95 percent of estimated primary recovery. Estimated secondary oil recovery is 3,970,000 barrels or 230 barrels an acre-foot.

According to the estimates cited, the Singleton field will yield more secondary oil than primary oil. The forecast is based largely on the relative homogeneity (little variation in permeability) of the reservoir rock and the high sweep efficiency of the peripheral flood pattern.

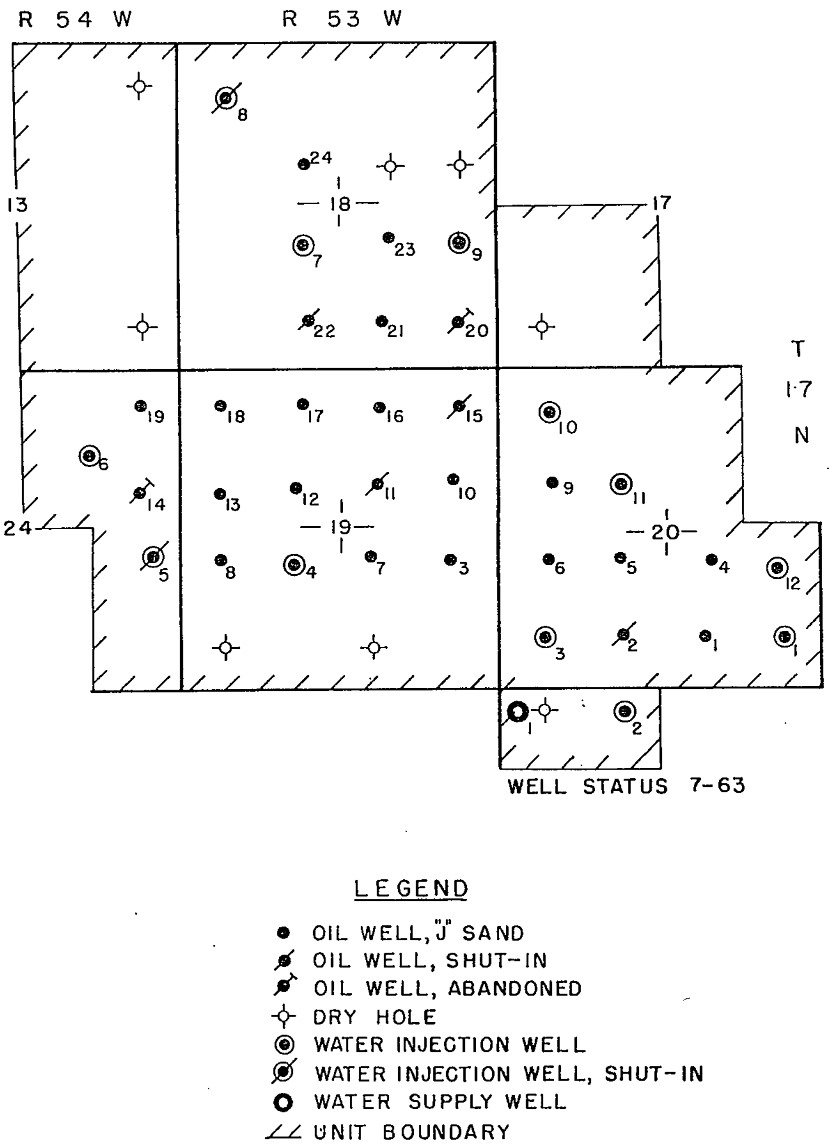

FIGURE 45. – Singleton unit, Banner County.

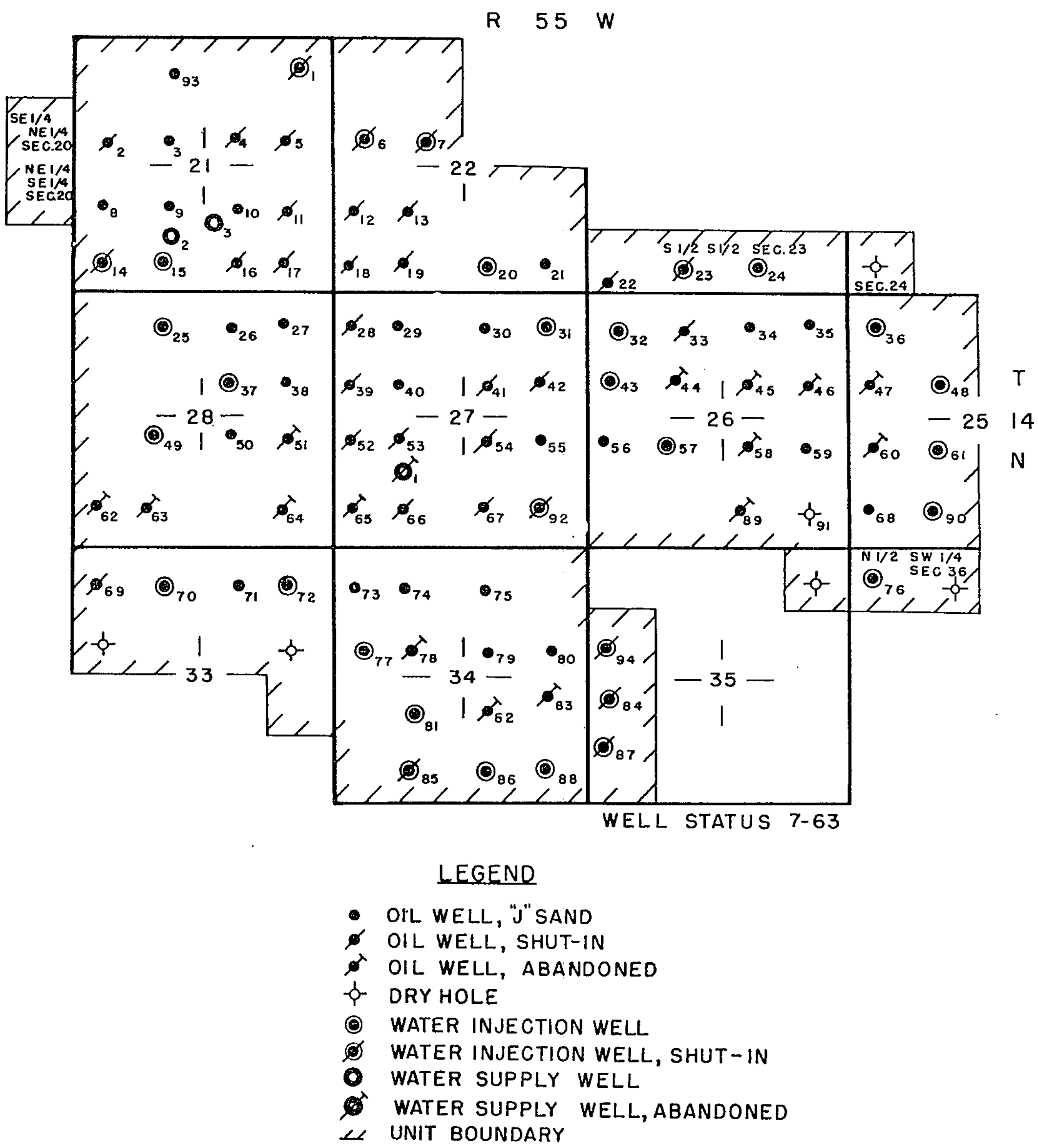

FIGURE 46. – Sloss unit, Kimball County.

Cumulative unit production from the start of waterflooding until the end of 1963 was 1,645,000 barrels of oil and 1,411,500 barrels of water. Cumulative water injection for the same period was 7,667,800 barrels.

Estimated water requirements are 32,800,000 barrels or 1.25 reservoir pore volume. The estimated ratio of water injected to secondary oil recovered is 8:1. The estimated flood life is 11 years.

By the end of 1963 approximately 37 percent of the estimated secondary oil and 29 percent of the original oil in place had been recovered. Water injected was 23 percent of the estimated water required. Available data indicate a successful project.

See table 41 for basic engineering data.

Sloss Unit

The Sloss unit (fig. 46) is in secs 21-28 and 33-36, T 14 N, R 55 W, Kimball County, approximately 3 miles southeast of the town of Kimball. Average elevation is approximately 4,800 feet.

The Sloss field was discovered in November 1954 when Nebraska Drillers completed the No. 2 State, C NW$\frac{1}{4}$NW$\frac{1}{4}$ sec 36, for an initial pumping production of 142 barrels daily from the "J" sand through perforations from 6,214 to 6,225 feet. By mid-1963 continued development resulted in a field of 94 producing wells and 10 dry holes. Of these, 93 were completed in the "J" sand and 1 was completed in the "D" sand.

The field is one of the largest in western Nebraska. During its development two extension wells were so far removed from the discovery well that separate fields were established. The Marion field was approximately 3$\frac{1}{4}$ miles northwest and the Hein field approximately 3 miles west of the discovery well. Both fields were incorporated in the Sloss field.

The "J" sand contains two oil-bearing zones separated by 5-15 feet of shale. The upper zone, "J-1," is larger than the lower zone, "J-2," but the rock characteristics of the two zones are essentially alike.

The field was unitized in 1958 with Pan American Petroleum Corp. as unit operator. The initial flood plan called for 21 injection wells.

Waterflooding was begun in June 1958 when approximately 7,000 barrels of fresh water daily were injected into six wells. In four of the wells water was injected into both the "J-1" and the "J-2" zones. In the other two wells water was injected into only one zone, the "J-2." Four more wells were placed on injection before the end of the year.

TABLE 41. - Basic data for Singleton unit ("J" sand)

I. Reservoir data

Productive area	1,730 acres
Average thickness	10 ft
Reservoir volume	17,300 acre-ft
Average porosity	19.5 pct
Average water saturation	20.7 pct
Formation volume factor	1,178 bbl/stb
Initial reservoir pressure	1,344 psi
Bubble point pressure	770 psi
Average permeability	328 md
Original solution GOR	220 cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7,758 \times 1,730 \times 10 \times .195 \times .793}{1.178} = 17,646,000 \text{ STB}$$

$$\frac{7,758 \times .195 \times .793}{1.178} = 1,020 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	20.7	211	3,653,000
Secondary	22.5	230	3,970,000
Ultimate	43.2	441	7,623,000

IV. Estimated water requirements and flood life

Total	32,800,000 bbl
Equivalent pore volumes	1.25
Injection water:secondary oil	8:1
Flood life	11 years

V. Project status--January 1, 1964

Flood started	March 1962
Oil recovery (pct original oil in place)	29
Water injection (pct estimated water required)	23

Fresh water was obtained from three shallow wells, two in sec 21 and one in sec 27. The wells are completed in alluvial gravel at approximately 200 feet.

The flood pattern is a field-wide peripheral network. There are also four infield injection wells, all on the east side of the unit area.

In June 1963 the Sloss unit contained 25 producing wells and 21 injection wells. Daily production was approximately 3,125 barrels of oil and 2,700 barrels of water. Some of the produced water was injected in the South Torgeson unit, but most was disposed of in surface pits. Daily injection was approximately 10,900 barrels of untreated water at a pressure of 1,350 psi.

By volumetric determination the oil in place at original reservoir conditions was 38 million barrels or 853 barrels an acre-foot. The estimated recovery factors, expressed in percentage of oil in place, are: Primary, 20 percent; secondary, 20 percent; and ultimate, 40 percent.

Estimated primary oil recovery is 7,600,000 barrels or 171 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 4,300,000 barrels or 57 percent of the estimated primary recovery. Estimated secondary oil recovery is also 7,600,000 barrels or 171 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 8,579,100 barrels of oil and 5,161,600 barrels of water. Cumulative unit water injection for the same period was 22,635,300 barrels.

Estimated water requirements are 60 million barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 8:1. The estimated flood life is 10 years.

By the end of 1963 approximately 66 percent of the estimated secondary oil and 33 percent of the original oil in place had been recovered. Water injected was 38 percent of the estimated water required. The project is apparently successful.

See table 42 for basic engineering data.

Torgeson Unit

The Torgeson unit (fig. 47) is in secs 13, 14, 23-26, T 14 N, R 56 W, Kimball County, about 4 miles south of the town of Kimball. Average elevation is 4,890 feet.

TABLE 42. - Basic data for Sloss unit ("J" sand)

I. Reservoir data

Productive area	4,131 acres
Average thickness	10.7 ft (est)
Reservoir volume	44,202 acre-ft
Average porosity	17.6 pct
Average water saturation	18.6 pct
Formation volume factor	1.3 bbl/stb
Initial reservoir pressure	1,415 psi
Bubble point pressure	689 psi
Average permeability	150 md
Original solution GOR	261 cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 4{,}131 \times 10.7 \times .176 \times .814}{1.3} = 38{,}000{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .176 \times .814}{1.3} = 853 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	20	171	7,600,000
Secondary	20	171	7,600,000
Ultimate	40	342	15,200,000

IV. Estimated water requirements and flood life

Total	60,000,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	8:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	June 1958
Oil recovery (pct original oil in place)	33
Water injection (pct estimated water required)	38

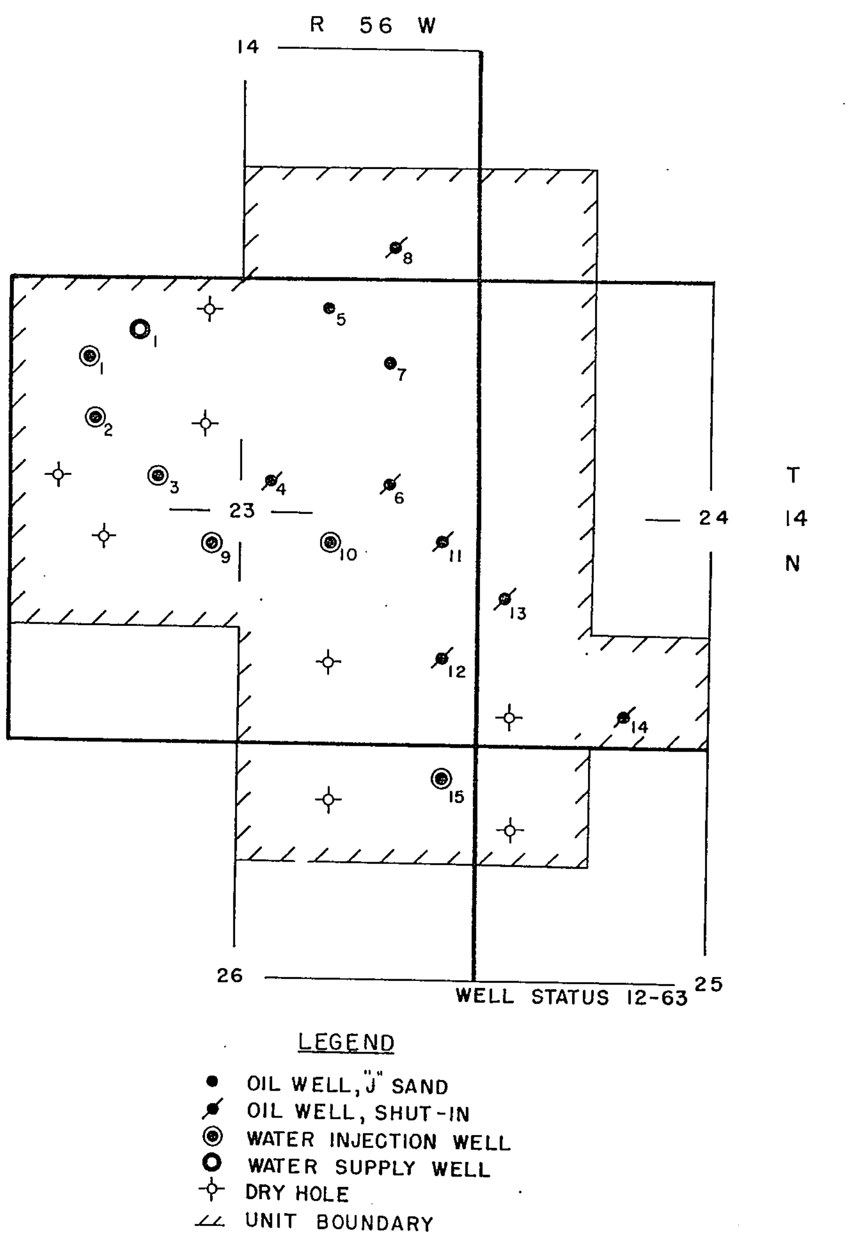

FIGURE 47. – Torgeson unit, Kimball County.

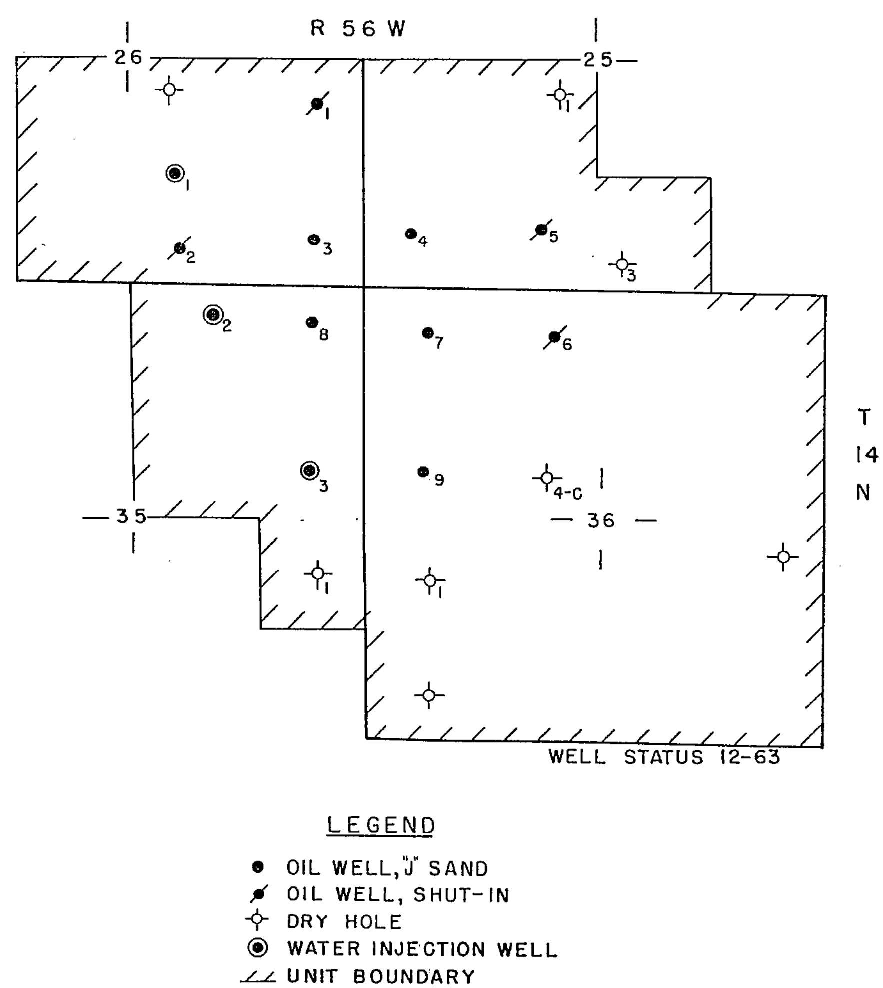

FIGURE 48. – South Torgeson unit, Kimball County.

The Torgeson field was discovered in December 1951 when Nebraska Drillers, Inc., completed the wildcat, No. 1 Torgeson, in the SE$\frac{1}{4}$NW$\frac{1}{4}$NW$\frac{1}{4}$ sec 23, T 14 N, R 56 W, for an initial pumping production of 150 barrels daily from the "J" sand. Extensive drilling in the field was curtailed until 1955-56 when 41 wells were completed. Later, wells in the southwest Kimball area were added to the Torgeson field. Also, nine producing wells and four dry holes from the Durland or Durland Trust areas were included in the Torgeson field. Within the enlarged Torgeson field, 87 wells were drilled. Of these 53 produced from the "J" sand and 38 were dry holes.

Part of the Torgeson field was unitized in October 1962 with Nebraska Drillers, Inc., as unit operator. The unit originally contained 14 producing wells, 2 of which were converted to water injection, and 8 dry holes.

The fresh water supply well was drilled in the N$\frac{1}{2}$NW$\frac{1}{4}$ sec 23, T 14 N, R 56 W. It produces water from alluvial deposits at 154 feet.

The project began in October 1962 with 47,297 barrels of water injected through six wells during the month. Production originally was from five wells.

The flood pattern is a line drive with injection wells forming a diagonal (northwest-southeast) front on the west side of the unit area.

During December 1963, two wells were producing about 190 barrels of oil and 20 barrels of water daily. Produced water was disposed of in surface pits. Untreated water was injected into six wells at 2,500 barrels daily at about 950 psi.

By volumetric determination the oil originally in place was estimated to be 5,620,000 barrels or 725 barrels an acre-foot. The estimated recovery factors expressed in percentage of initial oil in place are 22.7 percent for primary and 23.7 for secondary, or a total of 46.4 percent.

Estimated primary oil recovery is 1,275,000 barrels or 165 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 1,133,000 barrels or 89 percent of the estimated primary oil. Cumulative water production was 217,300 barrels.

Estimated secondary oil recovery is 1,331,000 barrels or 172 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 50,200 barrels. Cumulative water injection for the same period was 1,003,800 barrels. The ratio of water injected to oil produced is about 20:1. Water production amounted to 68,900 barrels.

Estimated water requirements are 11,086,000 barrels over about 8 years. The 11,086,000 barrels of water comprise about 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 8:1.

At the end of 1963 not all (93 percent) of the estimated primary oil and only 21 percent of the original oil in place had been recovered. Water injected was 9 percent of the estimated water required. The outcome of the project is indeterminate.

See table 43 for basic engineering data.

South Torgeson Unit

The South Torgeson unit (fig. 48) is in secs 25, 26, 35, and 36, T 14 N, R 56 W, Kimball County, about 5 miles south of the town of Kimball.

The Torgeson field history was discussed in the Torgeson unit writeup (p. 105).

The South Torgeson unit was formed from part of the Torgeson field in March 1962. Originally nine producing wells, three injection wells, and nine dry holes were within the unit. Of the three injection wells, two were converted from producing wells and one was a reworked dry hole. The formation flooded is the "J" sand, and the unit operator is British-American Oil Co.

The South Torgeson unit is unusual because, instead of fresh water, it uses water produced from the nearby Sloss unit.

The secondary recovery project began during October 1962 with 5,000 barrels of water injected through two of the three injection wells.

The flood pattern is a line drive with the injection wells on the west side of the unit.

During December 1963 five wells were producing about 86 barrels of oil and 36 barrels of water daily. Produced water was disposed of in surface pits. Water was injected at 526 barrels daily through two wells.

By volumetric determination the oil originally in place was 3,088,000 barrels or 588 barrels an acre-foot. The estimated recovery factors expressed in percentage of initial oil in place are 19.3 percent, primary, and 22.4 percent, secondary, or a total of 41.7 percent.

Estimated primary oil recovery is 596,000 barrels or 113 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was 515,900 barrels or approximately 87 percent of the estimated primary recovery.

TABLE 43. - Basic data for Torgeson unit ("J" sand)

I. Reservoir data

Productive area	726 acres
Average thickness	10.2 ft
Reservoir volume	7,405 acre-ft
Average porosity	18 pct
Average water saturation	30 pct
Formation volume factor	1.35 bbl/stb
Initial reservoir pressure	1,475 psi
Bubble point pressure	- - psi
Average permeability	75 md
Original solution GOR	300 cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 7{,}759 \times .18 \times .70}{1.35} = 5{,}620{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .18 \times .70}{1.35} = 725 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	22.7	165	1,275,000
Secondary	23.7	172	1,331,000
Ultimate	46.4	337	2,606,000

IV. Estimated water requirements and flood life

Total	11,086,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	8:1
Flood life	8 years

V. Project status--January 1, 1964

Flood started	October 1962
Oil recovery (pct original oil in place)	21
Water injection (pct estimated water required)	9

Cumulative unit water production at the start of waterflooding was 104,400 barrels.

Estimated secondary oil recovery is 692,000 barrels or 131 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding until the end of 1963 was 46,100 barrels. Cumulative water injection for the same period was 180,900 barrels. The ratio of water injected to oil produced is about 4:1. Water production amounted to 18,100 barrels.

Estimated water requirements are $7\frac{1}{2}$ million barrels over 7 years, which comprises about 1.3 pore volumes. The estimated ratio of water injected to secondary oil recovered is 11:1.

At the end of 1963 not all (94 percent) of the estimated primary oil and only 18 percent of the original oil in place had been recovered. Water injected was only 2 percent of the estimated water required. The outcome of the project is indeterminate.

See table 44 for basic engineering data.

Vedene Unit

The Vedene unit (fig. 49) is in secs 2-4, T 17 N, R 56 W, and secs 33-35, T 18 N, R 56 W, Banner County, approximately 4 miles south of the town of Harrisburg. Average elevation is about 5,000 feet.

The Vedene field was discovered in March 1956 when Miracle-Fifer Drilling Co. and Gibraltar Oil Co. completed the No. 1 Vedene, C $NW\frac{1}{4}NW\frac{1}{4}$ sec 2, for an initial flowing production of 280 barrels daily from the "D" sand through perforations from 6,448 to 6,454 feet. Development resulted in a field of 25 producing wells and 7 dry holes. Of the producing wells, 15 were completed in the "D" sand and 10 in the "J" sand.

The field, including all 25 producing wells and 3 of the 7 dry holes, was unitized in 1959 with Pan American as unit operator.

Waterflooding was begun in January 1959 when 3,700 barrels of fresh water daily was injected into two former producing wells. Injection was into both the "D" and the "J" sands in one well and into only the "D" sand in the other. The water was obtained from a shallow well drilled in the $S\frac{1}{2}$ of sec 34, producing from alluvial gravel at approximately 200 feet.

The flood pattern is irregular. The reservoirs are overlapping although the "J" sand extends beyond the "D" sand in the west and south ends of the unit area.

TABLE 44. - Basic data for South Torgeson unit ("J" sand)

I. Reservoir data

Productive area	535.6 acres
Average thickness	9.8 ft
Reservoir volume	5,249 acre-ft
Average porosity	14 pct
Average water saturation	35 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,430 psi
Bubble point pressure	800 psi
Average permeability	30 md
Original solution GOR	300 cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 535.6 \times 9.8 \times .14 \times .65}{1.2} = 3{,}088{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .14 \times .65}{1.2} = 588 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	19.3	113	596,000
Secondary	22.4	131	692,000
Ultimate	41.7	244	1,288,000

IV. Estimated water requirements and flood life

Total	7,500,000 bbl
Equivalent pore volumes	1.3
Injection water:secondary	11:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	October 1962
Oil recovery (pct original oil in place)	18
Water injection (pct estimated water required)	2

In December 1963 the unit contained 11 active producing wells and 7 active injection wells. Daily production was approximately 410 barrels of oil and 1,700 barrels of water. Produced water was disposed of in surface pits. Daily injection of untreated water was 1,000 barrels into the "D" sand at 1,280 psi and 1,100 barrels into the "J" sand at 1,200 psi.

By volumetric determination the oil in place at original reservoir conditions was 8,333,000 barrels. The estimated recovery factors, expressed in percentage of oil in place, are: Primary, 18 percent; secondary, 15 percent; and ultimate, 33 percent.

Estimated primary oil recovery is $1\frac{1}{2}$ million barrels. Cumulative unit oil production at the start of waterflooding was approximately 1,200,000 barrels or 80 percent of the estimated primary recovery. Estimated secondary oil recovery is 1,250,000 barrels.

Cumulative unit production from the start of waterflooding until the end of 1963 was 1,322,000 barrels of oil and 1,063,000 barrels of water. Cumulative unit injection for the same period was 4,764,000 barrels.

Estimated water requirements are 14 million barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 11:1. The estimated flood life is 10 years.

By the end of 1963 approximately 82 percent of the estimated secondary oil and approximately 30 percent of the original oil in place had been recovered. Water injected was approximately 34 percent of the estimated water required. The project is apparently successful.

See table 45 for basic engineering data.

Vowers Unit

The Vowers unit (fig. 50) is in secs 27-29, and 32-34, T 17 N, R 54 W, Banner County, approximately 11 miles northeast of the town of Kimball. Average elevation is approximately 4,800 feet.

The Vowers field was discovered in October 1955 when Petroleum, Inc., completed the No. 1 Vowers, C $SW\frac{1}{4}SW\frac{1}{4}$ sec 28, for an initial pumping production of 124 barrels daily from the "J" sand through perforations from 5,986 to 5,989 feet. Subsequent development resulted in a field of 25 producing wells and 8 dry holes. Of the 25 producing wells, 22 were completed in the "J" sand and 3 in the "D" sand.

In 1959 the "J" sand, including 21 producing wells and 2 dry holes, was unitized with Pan American Petroleum Corp. as unit operator. The two "D" sand producing wells in sec 34 are nonparticipating in the "J" sand unit.

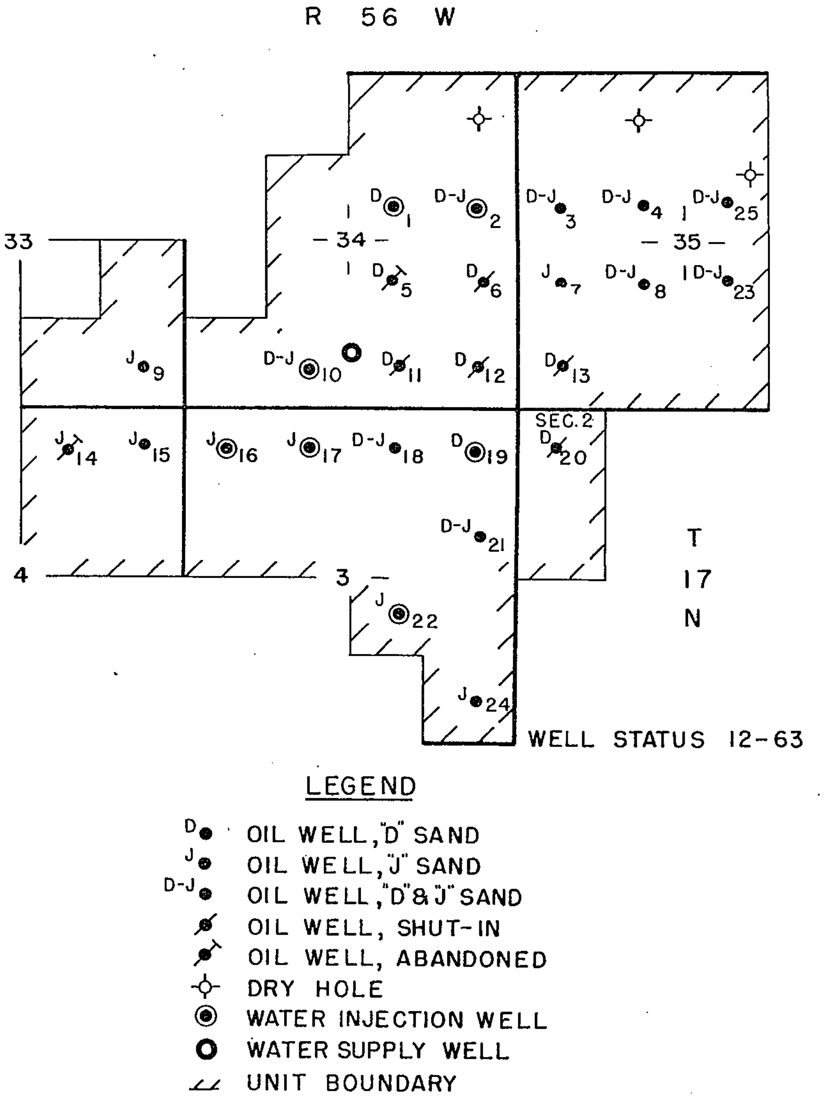

FIGURE 49. – Vedene unit, Banner County.

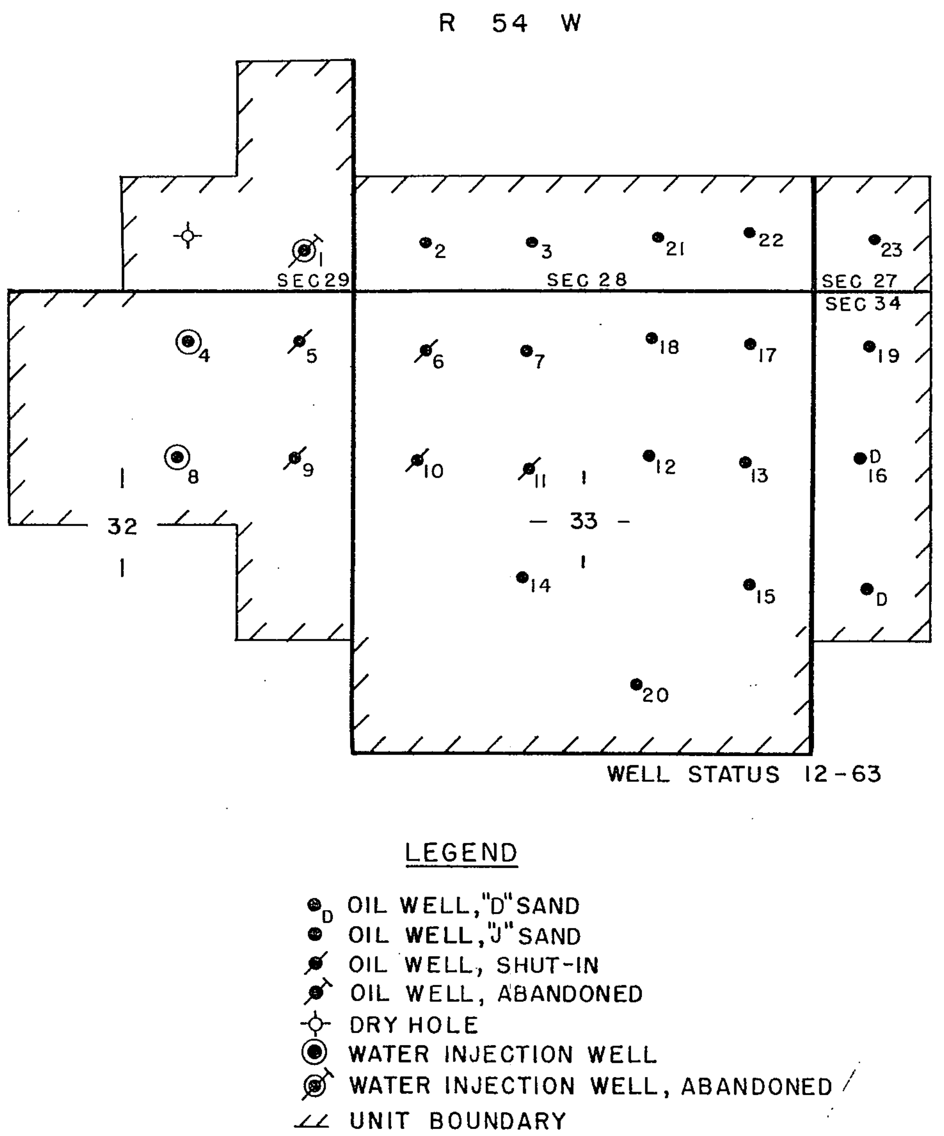

FIGURE 50. – Vowers unit, Banner County.

TABLE 45. - Basic data for Vedene unit ("D" and "J" sands)

I. Reservoir data

	"D" sand	"J" sand
Productive area	851 acres	1,350 acres
Average thickness	9 ft	4.5 ft
Reservoir volume	7,659 acre-ft	6,075 acre-ft
Average porosity	14.8 pct	10.8 pct
Average water saturation	25 pct	25 pct
Formation volume factor	1.25 bbl/stb (est)	1.25 bbl/stb (est)
Initial reservoir pressure	1,500 psi	1,500 psi (est)
Bubble point pressure	- - psi	- - psi
Average permeability	79 md	16 md
Original solution GOR	- - cu ft per bbl	- - cu ft per bbl
Gravity of crude	39° API (commingled)	

II. Oil in place at original conditions

"D" sand $$\frac{7{,}758 \times 7{,}659 \times .148 \times .75}{1.25} = 5{,}277{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .148 \times .75}{1.25} = 689 \frac{\text{STB}}{\text{Acre-ft}}$$

"J" sand $$\frac{7{,}758 \times 6{,}075 \times .108 \times .75}{1.25} = 3{,}056{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .108 \times .75}{1.25} = 503 \frac{\text{STB}}{\text{Acre-ft}}$$

Total oil in place ("D" and "J") = 8,333,000 STB

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
"D" sand			
Primary	18	124	950,000
Secondary	15	103	792,000
Ultimate	33	227	1,742,000
"J" sand			
Primary	18	91	550,000
Secondary	15	75	458,000
Ultimate	33	166	1,008,000

TABLE 45. - Basic data for Vedene unit ("D" and "J" sands)--Continued

			STB Acre-ft	STB
III.	Estimated recovery	Pct oil in place		
	Total ("D" and "J")			
	Primary			1,500,000
	Secondary			1,250,000
	Ultimate			2,750,000

IV. Estimated water requirements and flood life

Total	14,000,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	11:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	January 1959
Oil recovery (pct original oil in place)	30
Water injection (pct estimated water required)	34

Waterflooding was begun in May 1959 when 1,900 barrels of fresh water daily was injected into two wells. One of the injection wells was a former producing well (Unit No. 1), and the other was a recompleted dry hole (Unit No. 8). Split casing caused Unit No. 1 to be taken off injection, and shortly thereafter it was abandoned. Producing well No. 4 ($NW\frac{1}{4}NE\frac{1}{4}$ sec 32) was changed to injection well status.

Fresh water was obtained from a shallow well drilled in the adjoining Ostgren unit in the $SE\frac{1}{4}NW\frac{1}{4}$ of sec 1, T 16 N, R 55 W. Completed in alluvial gravel at approximately 200 feet, the well supplies water to both the Ostgren and the Vowers units.

The flood pattern is a line drive, and the injection wells are in the west end of the unit area. Additional wells likely will be converted to injection as the flood front moves farther east.

In December 1963 the unit contained 14 active producing "J" sand wells and 2 active injection wells. Daily production was approximately 1,000 barrels of oil and 740 barrels of water. Produced water was disposed of in surface pits. Daily injection was approximately 2,150 barrels of untreated water at 350 psi.

By volumetric determination the oil in place at original reservoir conditions was 4,600,000 barrels or 1,086 barrels an acre-foot. The estimated recovery factors, expressed in percentage of oil in place, are: Primary, 25 percent; secondary, 25 percent; and ultimate, 50 percent.

Estimated primary oil recovery is 1,150,000 barrels or 272 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 672,000 barrels or 58 percent of the estimated primary recovery. Estimated secondary oil recovery is also 1,150,000 barrels or 272 barrels an acre-foot.

Cumulative unit production from the start of waterflooding until the end of 1963 was 1,157,000 barrels of oil and 522,800 barrels of water. Cumulative unit water injection for the same period was 2,534,200 barrels.

Estimated water requirements are 6,900,000 barrels or 1 pore volume. The estimated ratio of water injected to secondary oil recovered is 6:1. The estimated flood life is 10 years.

By the end of 1963 approximately 59 percent of the estimated secondary oil and 40 percent of the estimated original oil in place had been recovered. Water injected was approximately 37 percent of the estimated water required. The project is apparently successful.

See table 46 for basic engineering data.

TABLE 46. - Basic data for Vowers unit ("J" sand)

I. Reservoir data

Productive area	1,010 acres
Average thickness	4.2 ft
Reservoir volume	4,242 acre-ft
Average porosity	21 pct
Average water saturation	20 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,500 psi
Bubble point pressure	- - psi
Average permeability	146 md
Original solution GOR	- - cu ft per bbl
Gravity of crude	37° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 1{,}010 \times 4.2 \times .21 \times .80}{1.2} = 4{,}600{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .21 \times .80}{1.2} = 1{,}086 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	25	272	1,150,000
Secondary	25	272	1,150,000
Ultimate	50	544	2,300,000

IV. Estimated water requirements and flood life

Total	6,900,000 bbl
Equivalent pore volume	1.0
Injection water:secondary oil	6:1
Flood life	10 years

V. Project status--January 1, 1964

Flood started	May 1959
Oil recovery (pct original oil in place)	40
Water injection (pct estimated water required)	37

Weaver Unit

The Weaver unit (fig. 51) is in sec 15, T 17 N, R 55 W, Banner County, about 13 miles north of the town of Kimball in an area of flat farmland. Average elevation of the field is 4,875 feet.

The Weaver field was discovered in January 1959 when W. R. Weaver completed the No. 1 Huffman, C SE$\frac{1}{4}$SW$\frac{1}{4}$ sec 15, T 17 N, R 55 W, for an initial pumping production of 140 barrels of oil daily from the "J" sand through perforations from 6,312 to 6,317 feet. Development of the field resulted in three more producing wells in the SW$\frac{1}{4}$ of sec 15, a producer in the NW$\frac{1}{4}$ sec 15, a dry hole in the SE$\frac{1}{4}$ sec 15, and a producer in the NE$\frac{1}{4}$ sec 16.

Unitization became effective during June 1962 with Sage Oil as unit operator. The unit area contained only the four wells in the SW$\frac{1}{4}$ sec 15. The well in the C NW$\frac{1}{4}$SW$\frac{1}{4}$ sec 15 was reworked and converted to water injection, and a fresh-water supply well was drilled in the SW$\frac{1}{4}$SW$\frac{1}{4}$SW$\frac{1}{4}$ sec 17, T 17 N, R 55 W. Secondary operations began during September 1962 and 1,000 barrels of water was injected daily.

During June 1963 the original three producing wells and the injection well were still operating. Production was about 125 barrels daily with no water. About 500 barrels of untreated water was injected daily at an average pressure of 2,800 psi.

By volumetric determination the oil originally in place was 869,000 barrels or 775 barrels an acre-foot. The estimated recovery factors expressed in percentage of initial oil in place are 18 percent for primary and 18 percent for secondary or a total of 36 percent. Estimated primary oil recovery is 156,000 barrels or 139 barrels an acre-foot. Cumulative unit oil production to the start of waterflooding was 109,900 barrels or about 70 percent of the estimated primary recovery. Water production amounted to 9,700 barrels. Estimated secondary oil recovery is also 156,000 or 139 barrels an acre-foot.

Cumulative unit oil production from the start of waterflooding to the end of 1963 was 53,200 barrels; water production was 3,300 barrels. Cumulative water injection was 196,700 barrels. The ratio of water injected to oil produced was 4:1.

Estimated water requirements are 1 million barrels or 0.6 pore volume. The estimated ratio of water injected to secondary oil recovered is 7:1.

Only 4 percent of the estimated secondary oil and 19 percent of the original oil in place had been recovered at the end of 1963. Water injected was 20 percent of the estimated water required. The outcome of the project is indeterminate.

See table 47 for basic engineering data.

TABLE 47. - Basic data for Weaver unit ("J" sand)

I. Reservoir data

Productive area	160 acres
Average thickness	7 ft
Reservoir volume	1,120 acre-ft
Average porosity	20 pct
Average water saturation	40 pct
Formation volume factor	1.2 bbl/stb
Initial reservoir pressure	1,800 psi
Bubble point pressure	1,800 psi (est)
Average permeability	12 md
Original solution GOR	500 cu ft per bbl
Gravity of crude	39° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 160 \times 7 \times .2 \times .6}{1.2} = 869{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .2 \times .6}{1.2} = 775 \frac{\text{STB}}{\text{Acre-ft}}$$

III.

Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	18	139	156,000
Secondary	18	139	156,000
Ultimate	36	278	312,000

IV. Estimated water requirements and flood life

Total	1,000,000 bbl
Equivalent pore volume	0.6
Injection water:secondary oil	7:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	September 1962
Oil recovery (pct original oil in place)	19
Water injection (pct estimated water required)	20

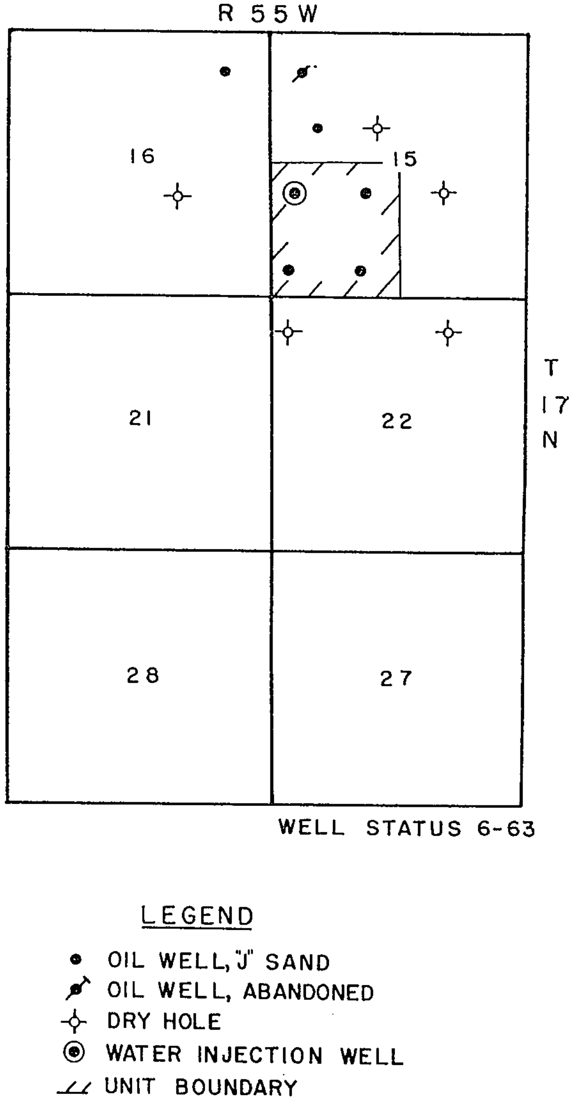

FIGURE 51. – Weaver unit, Banner County.

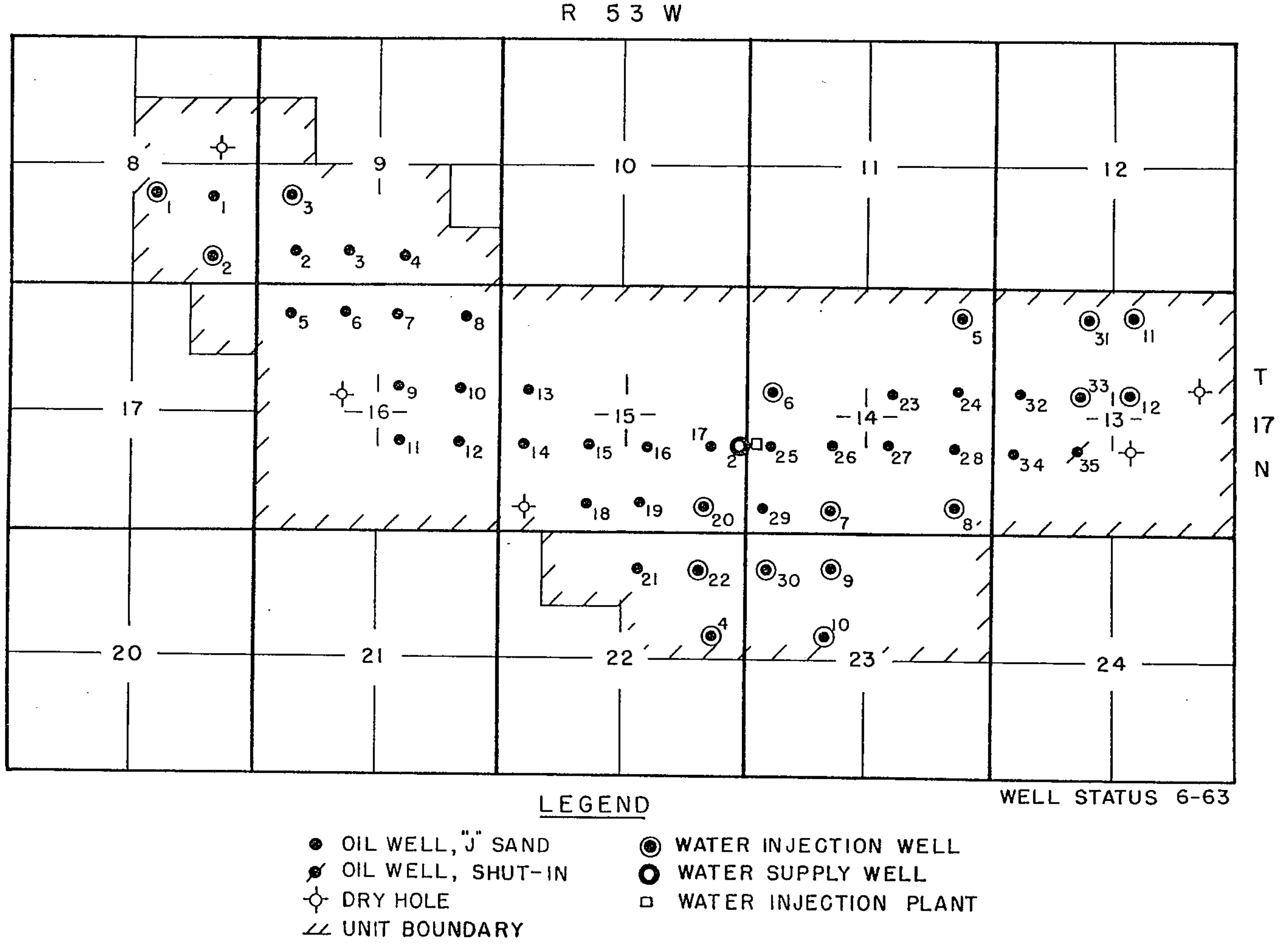

FIGURE 52. – Willson Ranch unit, Banner County.

Willson Ranch Unit

The Willson Ranch unit (fig. 52) is in secs 8, 9, 13-17, 22, and 23, T 17 N, R 53 W, Banner County, approximately 15 miles southeast of the town of Harrisburg. Average elevation is about 4,450 feet.

The Willson Ranch field was discovered in August 1957 when British-American Oil Co. completed the No. 2 Willson-A, C SE$\frac{1}{4}$NW$\frac{1}{4}$ sec 13, for an initial pumping production of 308 barrels daily from the "J" sand through perforations from 5,251 to 5,254 and 5,264 to 5,270 feet. Subsequent development resulted in a field of 43 producing wells and 14 dry holes.

The "J" sand contains two oil-bearing zones referred to as the "J-1" and the "J-2." The upper zone, the "J-1," is a field wide, blanket-type sand, whereas the lower zone, the "J-2," consists of two comparatively small, widely separated, sand lenses. The continuity of the "J-1" zone is broken by a permeability barrier, dividing the zone into separate reservoirs. The west reservoir is the larger of the two.

The east end of the field was unitized in October 1960 with British-American as unit operator. Waterflooding was begun in December 1960 by injection into one well. In late 1961 operations were expanded to fieldwide coverage, and by January 1, 1962, approximately 10,000 barrels of water daily was injected into 12 wells.

The injection water is obtained from a shallow (107 feet) well drilled in the SE$\frac{1}{4}$NE$\frac{1}{4}$ of sec 15. The well was tested capable of producing approximately 70,000 barrels daily.

The flood pattern in the east end of the unit area is peripheral, whereas the pattern in the west end is a modified line drive.

In June 1963 the unit contained 17 injection wells and 29 producing wells. Daily injection was approximately 10,000 barrels of untreated water at pressures ranging from 1,450 psi in the east end of the field to 2,175 psi in the west end. Daily production was approximately 2,000 barrels of oil and 2,000 barrels of water. Produced water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was 18$\frac{1}{2}$ million barrels or 796 barrels an acre-foot. Estimated recovery factors, expressed in percentage of oil in place, are: Primary, 27 percent; secondary, 13 percent; and total, 40 percent.

Estimated primary oil recovery is 4,995,000 barrels or 215 barrels an acre-foot. Cumulative oil production at the start of waterflooding (fieldwide) was approximately 3,800,000 barrels or 76 percent of the estimated primary recovery. Estimated secondary oil recovery is 2,405,000 barrels or 103 barrels an acre-foot.

Reportedly, a natural partial water drive exists in the west end of the field. Depending on its magnitude, this supplemental drive could result in an ultimate recovery higher than the present estimate of 40 percent.

Cumulative unit production from the start of waterflooding until the end of 1963 was 1,338,900 barrels of oil and 1,213,700 barrels of water. Cumulative unit water injection for the same period was 6,856,300 barrels.

Estimated water requirements are 20 million barrels or 0.7 reservoir pore volume. The estimated ratio of water injected to secondary oil recovered is 8:1. The estimated flood life is 7 years.

Only 6 percent of the estimated secondary oil and only 28 percent of the original oil in place had been recovered at the end of 1963. Water injected was 34 percent of the estimated water required. The outcome of the project is indeterminate.

See table 48 for basic engineering data.

Winkleman Unit

The Winkleman unit (fig. 53) is in secs 34 and 35, T 17 N, R 51 W, and sec 4, T 16 N, R 51 W, Cheyenne County, approximately 17 miles southwest of the town of Bridgeport. Average elevation is about 4,440 feet.

The Winkleman field was discovered in 1954 when Anschutz Drilling Co. completed the No. 1 Winkleman, C SW$\frac{1}{4}$SE$\frac{1}{4}$ sec 34, for an initial pumping production of 66 barrels daily from the "J" sand through perforations between 5,083 and 5,090 feet. Eleven wells, five producing wells, and six dry holes were completed in 1955 for a field of 12 wells.

The field, including all six producing wells and one dry hole, was unitized in January 1961 with British-American Oil Co. as unit operator. One producing well was converted to a water injection well, and one producing well was abandoned.

A dump-type waterflood was begun in July 1961. Water was taken from the "D" sand well, raised to a higher level to increase the hydrostatic head, and injected into the "J" sand in the same well. Figure 54 is a schematic diagram of the combination supply-injection well.

In November 1961 the dump-type waterflood was discontinued after approximately 13,000 barrels of water had been injected. In October 1962 surface injection was begun using the same injection well. Water was obtained from a shallow (400 feet) well drilled 150 feet west of the injection well. The water supply well was tested capable of producing 10,000 barrels daily.

TABLE 48. - Basic data for Willson Ranch unit ("J" sand)

I. Reservoir data

Productive area	2,036 acres
Average thickness	11.4 ft
Reservoir volume	23,210 acre-ft
Average porosity	16 pct
Average water saturation	24.3 pct
Formation volume factor	1.18 bbl/stb
Initial reservoir pressure	1,240 psi
Bubble point pressure	550 psi
Average permeability	122 md
Original solution GOR	186 cu ft per bbl
Gravity of crude	35° API

II. Oil in place at original conditions

$$\frac{7{,}758 \times 2{,}036 \times 11.4 \times .16 \times .757}{1.18} = 18{,}500{,}000 \text{ STB}$$

$$\frac{7{,}758 \times .16 \times .757}{1.18} = 796 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB/Acre-ft	STB
Primary	27	215	4,995,000
Secondary	13	103	2,405,000
Ultimate	40	318	7,400,000

IV. Estimated water requirements and flood life

Total	20,000,000 bbl
Equivalent pore volume	0.7
Injection water:secondary oil	8:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	December 1960
Oil recovery (pct original oil in place)	28
Water injection (pct estimated water required)	34

The single injection well in the northwest part of the unit area was less than one-half mile from any of the four producing wells.

In June 1963 the unit contained two producing wells and one injection well. Daily injection was approximately 780 barrels of untreated water at 90 psi. Daily production was 18 barrels of oil and 3 barrels of water. Produced water was disposed of in surface pits.

By volumetric determination the oil in place at original reservoir conditions was 1,840,000 barrels or 766 barrels an acre-foot. Estimated recovery factors expressed in percentage of oil in place are: Primary, 17.4 percent; secondary, 13 percent; and total, 30.4 percent.

Estimated primary oil recovery is 320,000 barrels or 133 barrels an acre-foot. Cumulative unit oil production at the start of waterflooding was approximately 306,000 barrels or 96 percent of the estimated primary recovery. Estimated secondary oil recovery is 239,000 barrels or 100 barrels an acre-foot. The low secondary recovery estimate reflects the low sweep efficiency of the flood pattern.

Cumulative unit production from the start of waterflooding until the end of 1963 was 28,600 barrels of oil and 18,800 barrels of water. Cumulative unit water injection for the same period was 245,400 barrels.

Estimated water requirements are $2\frac{1}{2}$ million barrels or 0.76 pore volume. The estimated ratio of water injected to secondary oil recovered is 10:1. The estimated flood life is 7 years.

At the end of 1963 only 6 percent of the estimated secondary oil and only 18 percent of the original oil in place had been recovered. Water injected was approximately 10 percent of the estimated water required. The outcome of the project is indeterminate.

See table 49 for basic engineering data.

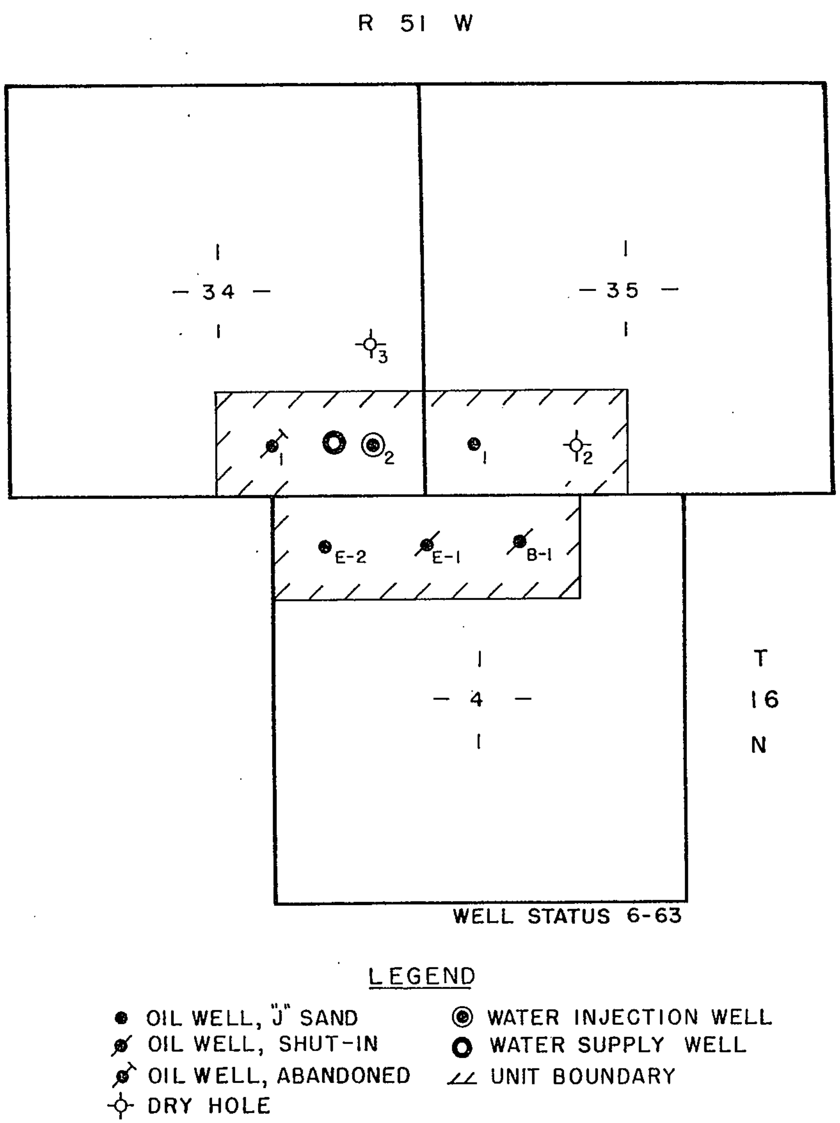

FIGURE 53. – Winkleman unit, Cheyenne County.

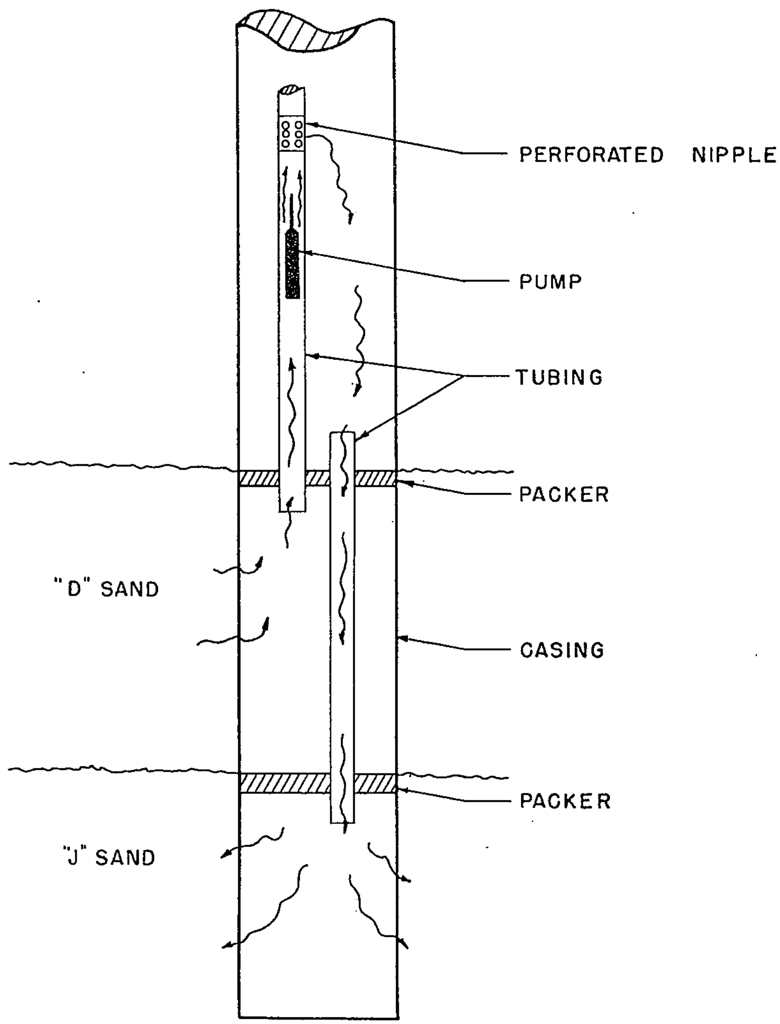

FIGURE 54. – Schematic diagram of dump-type waterflood injection well.
Adapted from Hearing Exhibits, Nebraska Oil and Gas Conservation Commission, submitted by British American Oil Co.

TABLE 49. - Basic data for Winkleman unit ("J" sand)

I. Reservoir data

Productive area	400 acres
Average thickness	6 ft
Reservoir volume	2,400 acre-ft
Average porosity	17.6 pct
Average water saturation	33.8 pct
Formation volume factor	1.18 bbl/stb (est)
Initial reservoir pressure	1,175 psi
Bubble point pressure	- - psi
Average permeability	- - md
Original solution GOR	- - cu ft per bbl
Gravity of crude	36° API

II. Oil in place at original conditions

$$\frac{7,758 \times 400 \times 6 \times .176 \times .662}{1.18} = 1,840,000 \text{ STB}$$

$$\frac{7,758 \times .176 \times .662}{1.18} = 766 \frac{\text{STB}}{\text{Acre-ft}}$$

III. Estimated recovery	Pct oil in place	STB / Acre-ft	STB
Primary	17.4	133	320,000
Secondary	13.0	100	239,000
Ultimate	30.4	233	559,000

IV. Estimated water requirements and flood life

Total	2,500,000 bbl
Equivalent pore volume	0.76
Injection water:secondary oil	10:1
Flood life	7 years

V. Project status--January 1, 1964

Flood started	July 1961
Oil recovery (pct original oil in place)	18
Water injection (pct estimated water required)	10

TABLE 50. - Water injected and additional water needed for waterflood projects considered in report

Unit or project	Water injected by Dec. 31, 1963	Estimated water to be injected after Dec. 31, 1963	Estimated total water needed
Allely unit	716,000	2,984,000	3,700,000
Aue-Griffith unit	4,646,800	3,353,200	8,000,000
Barrett unit	5,000,000	17,000,000	22,000,000
Brinkerhoff unit	2,205,300	3,094,700	5,300,000
Brook unit	726,000	12,274,000	13,000,000
Darnall project	260,600	739,400	1,000,000
Davis unit	770,300	1,709,700	2,480,000
Dietz unit	1,037,900	3,962,100	5,000,000
Downer unit, West	339,400	527,600	867,000
Edwards unit	2,320,000	1,680,000	4,000,000
Enders unit	9,466,500	17,533,500	27,000,000
Engelland unit	1,220,600	2,639,400	3,860,000
Gehrke unit	2,950,000	200,000	3,150,000
Goodwin unit	1,437,000	63,000	1,500,000
Grant unit	184,100	1,365,900	1,550,000
Harrisburg project	655,400	10,344,600	11,000,000
Harrisburg unit, East	1,067,300	15,932,700	17,000,000
Harrisburg unit, West	3,835,500	11,253,500	15,089,000
Heidemann unit	3,191,400	3,878,600	7,070,000
Houtby unit	1,439,500	13,560,500	15,000,000
Jacinto unit	6,963,300	5,536,700	12,500,000
Juelfs unit, West	4,483,900	6,516,100	11,000,000
Kenmac unit	4,728,600	5,671,400	10,400,000
Kimball unit	7,886,000	12,814,000	20,700,000
Lane unit, West	3,228,300	1,221,700	4,450,000
Lewis unit	2,328,300	7,771,700	10,100,000
Lindberg unit	663,800	627,200	1,291,000
Long unit	10,711,800	13,288,200	24,000,000
McDaniel unit	563,700	5,636,300	6,200,000
Mintken unit, North	335,100	664,900	1,000,000
Mintken unit, South	189,100	810,900	1,000,000
Mosier project	685,600	814,400	1,500,000
Olsen unit	8,016,900	4,983,100	13,000,000
Ostgren unit	307,600	5,592,400	5,900,000
Pan Am unit	596,300	1,403,700	2,000,000
Petroleum State unit	829,700	6,270,300	7,100,000
Potter unit, Southwest	10,680,400	319,600	11,000,000

TABLE 50. - Water injected and additional water needed for waterflood projects considered in report--Continued

Unit or project	Water injected by Dec. 31, 1963	Estimated water to be injected after Dec. 31, 1963	Estimated total water needed
Prairie unit	328,500	3,034,500	3,363,000
Rodman unit	1,041,300	1,958,700	3,000,000
Simpson unit	1,054,100	6,945,900	8,000,000
Singleton unit	7,677,800	25,122,200	32,800,000
Sloss unit	22,635,300	37,364,700	60,000,000
Torgeson unit	1,003,800	10,082,200	11,086,000
Torgeson unit, South	180,900	7,319,100	7,500,000
Vedene unit	4,764,000	9,236,000	14,000,000
Vowers unit	2,534,200	4,365,800	6,900,000
Weaver unit	196,700	803,300	1,000,000
Willson Ranch unit	6,856,300	13,143,700	20,000,000
Winkleman unit	245,400	2,254,600	2,500,000
Total (barrels)	155,186,300	325,669,700	480,856,000
Total (acre-feet)	20,003	41,979	61,982

Source - Monthly reports of operators and hearing records of the Nebraska Oil and Gas Conservation Commission.

TABLE 51. - Oil and water production from the Nebraska waterflood projects considered in report[1/]

Unit or project	Oil production, bbl: To start of injection	Oil production, bbl: From start of injection to 12/31/63	Oil production, bbl: Total to 12/31/63	Water production, bbl: To start of injection	Water production, bbl: From start of injection to 12/31/63	Water production, bbl: Total to 12/31/63
Allely unit	418,000	55,000	473,000	[2/] - - -	65,000	65,000
Aue-Griffith unit	2,005,504	828,688	2,834,192	277,124	939,482	1,216,606
Barrett unit	1,050,000	1,600,000	2,650,000	139,939	1,000,000	1,139,939
Brinkerhoff unit	416,000	696,087	1,112,087	24,429	845,085	869,514
Brook unit	871,000	270,955	1,141,955	251,480	226,638	478,118
Darnall project	213,000	67,077	280,077	- - -	28	28
Davis unit	484,142	76,547	560,689	18,504	90,239	108,743
Dietz unit	423,000	136,002	559,002	1,434	295,838	297,272
Downer unit, West	272,020	29,942	301,962	1,738	3,180	4,918
Edwards unit	437,000	824,000	1,261,000	31,369	470,000	501,369
Enders unit	2,912,411	3,248,117	6,160,528	- - -	2,545,924	2,545,924
Engelland unit	242,066	74,192	316,258	176,363	196,899	373,262
Gehrke unit	402,000	1,316,000	1,718,000	4,000	360,000	364,000
Goodwin unit	350,000	131,000	481,000	7,358	375,000	382,358
Grant unit	155,000	20,207	175,207	- - -	- - -	- - -
Harrisburg project	821,613	67,097	888,710	2,500	38,783	41,283
Harrisburg unit, East	1,026,198	74,968	1,101,166	305	34,605	34,910
Harrisburg unit, West	1,643,000	358,853	2,001,853	43,000	1,665,422	1,708,422
Heidemann unit	1,900,000	377,003	2,277,003	602,100	567,083	1,169,183
Houtby unit	1,426,665	124,028	1,550,693	69,243	73,001	142,244
Jacinto unit	3,000,000	1,672,170	4,672,170	428,042	1,397,096	1,825,138
Juelfs unit, West	1,586,000	738,080	2,324,080	98,845	1,239,070	1,337,915
Kenmac unit	1,652,000	1,192,616	2,844,616	106,947	1,492,665	1,599,612
Kimball unit	2,869,000	1,306,000	4,175,000	101,000	3,721,000	3,822,000
Lane unit, West	475,000	418,491	893,491	213,000	1,450,514	1,663,514
Lewis unit	645,000	499,575	1,144,575	89,566	327,156	416,722
Lindberg unit	422,156	348,388	790,544	1,094	87,094	88,188
Long unit	3,747,594	401,498	4,149,092	556,525	2,161,938	2,718,463

TABLE 51. - Oil and water production from the Nebraska waterflood projects considered in report1/ --Continued

Unit or project	Oil production, bbl: To start of injection	Oil production, bbl: From start of injection to 12/31/63	Oil production, bbl: Total to 12/31/63	Water production, bbl: To start of injection	Water production, bbl: From start of injection to 12/31/63	Water production, bbl: Total to 12/31/63
McDaniel unit	521,577	88,393	609,970	26,653	32,988	59,641
Mintken unit, North	227,250	19,774	247,024	2/- - -	119,000	119,000
Mintken unit, South	249,000	22,975	271,975	- - -	4,600	4,600
Mosier project	141,000	160,000	301,000	9,536	36,000	45,536
Olsen unit	3,143,186	1,156,886	4,300,072	2,962	1,954,394	1,957,356
Ostgren unit	470,000	1,118,841	1,588,841	25,000	753,796	778,796
Pan Am unit	229,976	140,172	370,148	131,521	86,267	217,788
Petroleum State unit	600,000	92,436	692,436	2/- - -	63,430	63,430
Potter unit, Southwest	1,535,000	734,805	2,269,805	5,257	4,826,656	4,831,913
Prairie unit	168,741	25,438	194,179	88,608	28,637	117,245
Rodman unit	389,000	69,904	458,904	113,992	172,793	286,785
Simpson unit	903,189	233,028	1,136,217	16,380	141,712	158,092
Singleton unit	3,475,000	1,644,965	5,119,965	2/- - -	1,411,544	1,411,544
Sloss unit	4,300,000	8,579,096	12,879,096	2/- - -	5,161,561	5,161,561
Torgeson unit	1,133,000	50,187	1,183,187	217,277	68,860	286,137
Torgeson unit, South	515,845	46,125	561,970	104,364	18,081	122,445
Vedene unit	1,200,000	1,322,000	2,522,000	7,000	1,063,000	1,070,000
Vowers unit	672,000	1,157,000	1,829,000	19,000	522,791	541,791
Weaver unit	109,936	53,159	163,095	9,705	3,335	13,040
Willson Ranch unit	3,800,000	1,338,861	5,138,861	154,135	1,213,669	1,367,804
Winkleman unit	306,000	28,550	334,550	53,097	18,780	71,877
Total	55,975,069	35,035,176	91,010,245	4,230,392	39,370,634	43,601,026

1/ Monthly reports of operators to the Nebraska Oil and Gas Conservation Commission.
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APPENDIX

Selected Rules and Regulations of the Nebraska Oil and Gas Conservation Commission

322. Pollution and Surface Drainage

Owner shall take all reasonable precautions to avoid polluting streams and underground water. If useless liquid products of wells cannot be treated or destroyed or if the volume of such products is too great for disposal by the usual methods without damage, the Director must be consulted and the useless liquids disposed of by some method approved by him.

326. Underground Disposal of Water

Hereafter, the underground disposal of salt water, brackish water or other water unfit for domestic, livestock, irrigation or other general uses is permitted only upon order of the Commission. Disposal wells shall be cased and the casing cemented in such manner that damage will not be caused to oil, gas, fresh water or other sources.

327. Procedure for Disposal of Water

The application to dispose of salt water, brackish water or other water unfit for domestic, livestock, irrigation or other general uses, shall be certified by the applicant, and filed in triplicate with the Commission, containing:

(a) A plat showing location of the disposal well or wells and the location of all oil and gas wells including abandoned and drilling wells and dry holes and the names of all fee owners and owners as defined in the Act of record within one-half ($\frac{1}{2}$) mile of the proposed disposal well or wells.

(b) The name, description, and depth of the formation into which water is to be injected.

(c) The log of the disposal well or wells, or a description of the typical stratigraphic level of the disposal formation in the disposal well or wells.

(d) A description of the casing in the disposal well or wells, or the proposed casing program and the proposed method for testing casing before use of the disposal well or wells.

(e) A statement specifying the source of water to be injected.

(f) The estimated minimum and maximum amount of water to be injected daily.

(g) The names and addresses of those notified by the applicant, as required in item (j) of this rule.

(h) Applications may be made to include the use of more than one disposal well on the same lease or on more than one lease.

(i) The designated operator of a unitized or cooperative project shall execute the application.

(j) In addition to the notice required by law, notice of the application shall be given by the applicant by certified mail or by delivering a copy of the notice to each owner of record as defined in the Act and such other persons as may be designated by the direction of the Commission within one-half ($\frac{1}{2}$) mile of the proposed disposal well. Such notice shall be mailed to or filed with the Commission, and the applicant shall certify that notice by certified mail or by delivery to each owner of record within one-half ($\frac{1}{2}$) mile of the proposed disposal well has been accomplished, or give sufficient reason for being unable to do so.

(k) In the event no fee owner or owner of record as defined in the Act within one-half ($\frac{1}{2}$) mile of the disposal well, or the Commission itself files written objection or complaint to the application within fifteen (15) days of the date of application, then the application shall be granted; but if any person or the Commission itself files written objection within fifteen (15) days of the application, then a hearing shall be held as soon as practicable.

(l) No notice is necessary to any person who has consented to the proposed installation in writing.

401. Applications

Applications for waterflooding, repressuring or pressure maintenance operations, cycling or re-cycling operations, including the extraction and separation of liquid hydrocarbons from natural gas in connection therewith, or for carrying on any other method of unit or cooperative development or operation of a field or a part of either, may be filed by any one or more of the parties involved or the operator of said project, with the Commission. Such application shall contain the following:

(a) Plat showing the area involved together with the well or wells, including drilling wells, dry and abandoned wells located therein, all properly designated. If the plan of operation is for secondary recovery, such plat shall show the names and addresses of fee owners and owners of record as defined in the Act within one-half ($\frac{1}{2}$) mile of the intake well or wells.

(b) A full description of the particular operation for which approval is required.

(c) A copy of the proposed agreement.

(d) If waterflooding, gas or air injection is proposed, the application shall show:

(1) the formation from which wells are producing or have produced,

(2) the name, description, and depth of the formations to be affected,

(3) the log of the intake well or wells or such information with respect thereto as is available,

(4) description of the intake wells casing or the proposed casing program and the proposed method for testing casing before use of the input wells,

(5) statement as to whether gas, air or water is to be used for injection, its source and the estimated amounts to be injected daily,

(6) the names and addresses of the operator or operators of the project.

402. Notice and Date of Hearing

Upon the filing of any application, the Commission shall issue notice thereof, as provided by the Act and these regulations. Said application shall be set for public hearing at such time as the Commission may fix.

403. Additional Notice

If a secondary recovery method is proposed by said application, in addition to the notice required by the Act, notice of such application shall be given by the applicant by certified mail or by personal delivery of a copy of the said notice to each owner of record as defined in the Act within one-half ($\frac{1}{2}$) mile of the proposed intake well or wells and to such other persons as may be designated by the direction of the Commission providing that their consent in writing has not been secured by the applicant. Such notice shall be given as soon as the application is filed. A certificate shall be attached to the application showing the names and addresses of the parties on whom the notice is being served.

404. Casing and Cementing of Injection Wells

Wells used for injection of gas, air, or water into the producing formation shall be cased with safe and adequate casing or tubing so as to prevent leakage and shall be so set or cemented that damage will not be caused to oil, gas, or fresh water resources.

405. Notice of Commencement and Discontinuance of Injection Operations

The following provisions shall apply to all injection projects whether or not they are approved by the Commission:

(a) Immediately upon the commencement of injection operations, the operator shall notify the Commission of the injection date.

(b) Within ten (10) days after the discontinuance of injection operations, the operator shall notify the Commission of the date of such discontinuance and the reasons therefor.

(c) Before any intake well shall be plugged, notice shall be served on the Commission by the owner of said well and the same procedure shall be followed in the plugging of such well as provided for the plugging of oil and gas wells.

406. Records

The operator of an injection project shall keep accurate records showing oil produced, injected volumes and injection pressure (see form 11, page 133).

Required Monthly Report

REPORT OF INJECTION PROJECT

For the month of.. 19............

Instructions: Each operator of an injection project shall submit this form in duplicate, not later than the 25th day of the month following the month reported. If several projects are operated jointly, report each project on a separate form.
Report all volumes of oil, LPG and water in barrels and volumes of gas in standard MCF (corrected to 15.025 psia and 60° F.)
Pb = 14.7 psia

Operator

Address

Field Name and Reservoir	County or Counties
Type of Injection Project	Name of Injection Project

WATER INJECTION

Total net active water inj. wells beginning of month	Net active water inj. wells added or subtracted during month	Total net active water inj. wells end of month	Total water inj. during month	Total water inj. to date
	+ —			

GAS INJECTION

Total net active gas inj. wells beginning of month	Net active gas inj. wells added or subtracted during month	Total net active gas inj. wells end of month	Total gas inj. during month	Total gas inj. to date
	+ —			

LPG INJECTION

Total net active LPG inj. wells beginning of month	Net active LPG inj. wells added or subtracted during month	Total net active LPG inj. wells—end of month	Total LPG inj. during month	Total LPG inj. to date
	+ —			

PRODUCTION

Total oil wells beginning of month	Oil wells added or subtracted during month	Total oil wells end of month	Total oil produced during month	Total oil produced since project started
	+ —			
Total gas producing wells beginning of month	Gas producing wells added or subtracted during month	Total gas producing wells—end of month	Total gas produced during month	Total gas produced since project started
	+ —			

INJECTED VOLUMES (Reservoir Barrels)

	Current Month	Since Project Started
Water (Surface bbls = reservoir bbls.)		
LPG (Surface bbls. = reservoir bbls.) Indicate type of LPG: Butane, Propane or other		
Gas = Standard CF X volume factor v, where v = $\left(\frac{Z \times Tr \text{ (Res. temp., °F abs.)} \times Pb}{5.6146 \text{ cf/bbl} \times Pr \text{ (Res. press., psia)} \times 520}\right)$		
TOTAL FLUIDS INJECTED (in reservoir bbls.)		

PRODUCED VOLUMES (Reservoir Barrels)

Oil (Stock tank bbls. X formation volume factor*)		
FREE GAS Total gas produced in standard cubic feet less solution gas produced, (Stock tank bbls. oil produced X solution gas oil ratio), X volume factor (v) calculated for produced gas.		
WATER (Surface bbls. = reservoir bbls.)		
TOTAL PRODUCED VOLUMES (in reservoir barrels)		
NET INJECTED (or produced) VOLUMES		

* For water floods in reservoirs nearing primary depletion, use l as formation volume factor.

Average reservoir pressure this month: psia

Nebraska Oil and Gas Conservation Commission Form 11

Analyses of Water Samples from Western Nebraska

For those interested in water quality in the area we have prepared table 52.

Water analyses were not included in the main report because they were not available for all projects. Also, water quality has caused few, if any, problems in the area. There have been some corrosion and bacterial action but much less than found in most waterflooding areas.

Analyses one through six are from water supply wells. These waters have little mineral content (average 260 parts per million). Waters produced from the oil sands tend toward high chloride content and show almost no carbonate content. The "J" sand water from the West Lane unit is the most "salty" with 126,000 ppm dissolved solids.

In general, the salt content of the water in the "D" and "J" sands seems to increase from west to east in the area.

TABLE 52. - Analyses of water samples from western Nebraska[1]

Index No.	Field or unit	Location Sec	T	R	Formation	Sodium and Potassium[2]	Calcium	Magnesium	Sulfate	Chloride	Carbonate	Bicarbonate	Total	Observed ph	Resistivity at °F	Resistivity ohm-meters
						Constituents in parts per million										
1	Long unit	15	12N	55W	shallow sand	6	38	6	8	4	0	146	208	7.45	77	31.7
2	Sloss unit	21	14N	55W	do.	2	42	16	13	7	0	185	265	7.9	--	--
3	Do.		do.		do.	4	43	12	10	6	0	180	255	7.7	--	--
4	Harrisburg (west unit)	32	19N	55W	do.	20	44	13	23	14	0	201	315	7.4	77	23.4
5	Lewis unit	30	18N	56W	do.	12	38	8	tr.	17	tr.	159	234	8.2	68	36.0
6	Vedene unit	34	17N	56W	do.	6	40	18	7	7	0	207	285	7.9	77	29.07
7	Cook field	24	14N	47W	"D" sand	28,843	176	130	6,321	40,000	59	770	76,299	8.3	68	0.125
8	Spearow field	15	15N	49W	do.	11,548	87	24	2,450	15,200	tr.	1,757	17,386	8.2	68	0.255
9	Do.	24	15N	49W	do.	25,904	478	170	6,125	36,500	---	342	69,519	7.6	68	0.125
10	Do.		do.		do.	26,161	478	153	5,900	37,000	---	366	70,058	7.8	68	0.122
11	Doran field	33	14N	50W	do.	6,219	24	8	1,168	7,720	133	1,590	16,862	8.7	68	0.49
12	Kimball unit		12N	55W	do.	802	7	1	33	1,080	---	293	2,216	7.4	77	2.45
13	Harrisburg (west unit)	4	18N	55W	do.	473	4	1	36	88	60	952	1,614	8.1	77	5.28
14	Vedene unit	34	18N	56W	do. (?)[3]	2,855	21	4	5	3,191	---	2,159	8,235	7.8	77	0.794
15	Spearow field	23	15N	49W	"G" sand	25,273	509	146	6,250	35,400	---	390	67,968	7.8	68	0.130
16	Do.		do.		do.	16,885	200	61	1,525	24,600	---	1,415	44,686	8.1	68	0.180
17	Do.		do.		do.	18,252	301	110	1,683	27,000	---	1,318	48,664	7.7	68	0.170
18	Kugler field[4]	5	14N	48W	"J" sand	26,747	596	138	4,550	39,000	---	512	71,543	8.0	68	0.120
19	Do.		do.		do.	27,022	649	120	5,200	39,000	---	476	72,468	7.9	68	0.132
20	Lane (west unit)	17	17N	49W	do.	47,080	1,423	355	3,800	73,000	---	537	126,195	8.0	68	0.074
21	Dorman field	15	14N	50W	do.	3,634	7	3	391	3,680	601	1,630	9,946	8.6	68	0.800
22	Do.		do.		do.	3,049	11	tr.	285	3,220	216	1,781	8,562	8.5	68	0.920
23	Do.	22	14N	50W	do.	3,520	9	4	385	3,560	36	2,700	10,214	8.2	68	0.850
24	Singleton unit		17N	53W	do.	1,267	---	9	227	1,219	---	1,016	3,738	8.1	76	1.722
25	Sloss unit	21	14N	55W	do.	4,111	59	10	522	4,964	---	1,925	11,591	7.7	77	0.525
26	Harrisburg (west unit)	6	18N	55W	do.	2,882	22	1	161	3,364	96	1,525	8,051	9.9	77	0.824
27	Vedene unit	34	18N	56W	do.	3,055	17	5	217	3,457	---	1,952	8,703	7.6	77	0.732
28	Lewis unit		18N	56W	do.	2,978	8	---	221	2,980	96	2,318	8,601	8.2	68	0.910

1/ Table prepared from analyses supplied by Nebraska Oil and Gas Commission and oil companies.
2/ In a few analyses ppm of potassium and lithium were shown. They were added to ppm sodium and are in this column.
3/ This may not be true "D" sand sample.
4/ Samples No. 18 and No. 19 are from same well and were obtained about 6 months apart.

Analyses of Crude Oil Samples from Western Nebraska

Bureau of Mines crude oil analyses for four "D" sand and six "J" sand oil samples show the general properties of crude oils of western Nebraska. Several of the samples are from fields other than those covered in the report. API gravities reported by the Bureau are determined on a water- and sediment-free basis under precise laboratory conditions. The API gravities shown in the field discussions are those reported by the operators and may be observed, uncorrected, field determinations. Therefore, some variation between the gravity as reported by the Bureau and those in the field descriptions should be expected.

Samples for the Bureau analysis are obtained at the wellhead where possible. Samples taken from a stock tank have gone through a heater and probably contain some emulsion-breaking chemical. Long residence time in the stock tank causes "weathering" or loss of gravity.

All crude oils contain some dissolved gas. The reservoir pressure drops as fluid is withdrawn and some of the dissolved gas is released. Thus the gravity of crude oil from a field is always changing even though the change may be too small to measure on a daily basis.

Crude oils from western Nebraska have a good quality, as is reflected in the 10 analyses by the gravity range of 34.4° to 37.2° API and the low sulfur content range from less than .10 to .23 percent.

TABLE 53. - Analyses of crude oils from western Nebraska

6-485
(January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-55-375

IDENTIFICATION

Allely field
"J" sandstone Cretaceous
6185 feet

Nebraska
Kimball County
NW 1/4 SE 1/4 sec. 1,
T. 12 N., R. 55 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.845 A. P. I. gravity 36.0 ° Pour point, ° F. 50
Sulfur, percent, 0.14 Color, greenish-black
Saybolt Universal viscosity at 100 ° F., 44 sec.; at ___ ° F., ___ sec. Nitrogen, percent, 0.102

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 24 ° C. (75 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum. Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	0.9	0.9	0.683	75.7				
2	75	167	5.2	6.1	.695	72.1	19	56.4		
3	100	212	3.4	9.5	.731	62.1	27	52.5		
4	125	257	3.7	13.2	.747	57.9	25	53.1		
5	150	302	4.3	17.5	.761	54.4	24	53.4		
6	175	347	5.8	23.3	.781	49.7	27	53.9		
7	200	392	3.4	26.7	.797	46.0	28	56.5		
8	225	437	3.7	30.4	.808	43.6	28	60.6		
9	250	482	4.3	34.7	.819	41.3	28	64.8		
10	275	527	5.9	40.6	.830	39.0	28	68.9		
STAGE 2—Distillation continued at 40 mm. Hg.										
11	200	392	9.0	49.6	0.846	35.8	32	76.2	41	20
12	225	437	4.7	54.3	.855	34.0	32	82.1	42	45
13	250	482	4.3	58.6	.864	32.3	33	85.5	60	70
14	275	527	5.8	64.4	.875	30.2	35	89.6	83	85
15	300	572	5.1	69.5	.902	25.4	45	93.8	130	100
Residuum			27.1	96.6	.953	17.0		too dark		

Carbon residue of residuum, 6.3 percent; carbon residue of crude, 1.9 percent.

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	9.5	0707	68.6	
Total gasoline and naphtha	26.7	0749	57.4	
Kerosine distillate	8.0	814	42.3	
Gas oil	19.3	842	36.6	
Nonviscous lubricating distillate	9.5	858-.885	33.4-28.4	50-100
Medium lubricating distillate	6.0	885-.915	28.4-23.1	100-200
Viscous lubricating distillate				Above 200
Residuum	27.1	953	17.0	
Distillation loss	3.4			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1

6-485
(January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-55-371

IDENTIFICATION

Dietz field
"J" sandstone
6343 feet

Nebraska
Kimball County
SW 1/4 SE 1/4 sec. 3,
T. 13 N., R. 55 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.837 A. P. I. gravity 37.6 ° Pour point, ° F. 25
Sulfur, percent, 0.14 Color, brownish-green
Saybolt Universal viscosity at 100 ° F., 43 sec.; at ___ ° F., ___ sec.

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 24 ° C. (75 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum. Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	2.7	2.7	0.651	85.9		- -		
2	75	167	3.0	5.7	.683	75.7	14	- -		
3	100	212	4.0	9.7	.723	64.2	23	52.3		
4	125	257	7.9	17.6	.747	57.9	25	52.8		
5	150	302	3.9	21.5	.767	53.0	27	52.7		
6	175	347	4.5	26.0	.782	49.5	27	53.7		
7	200	392	3.4	29.4	.798	45.8	29	56.7		
8	225	437	3.9	33.3	.806	44.1	27	60.7		
9	250	482	5.8	39.1	.821	40.9	29	65.9		
10	275	527	6.8	45.9	.832	38.6	29	71.1		
STAGE 2—Distillation continued at 40 mm. Hg.										
11	200	392	3.0	48.9	0.847	35.6	32	76.8	41	25
12	225	437	5.8	54.7	.851	34.8	30	81.1	45	40
13	250	482	6.3	61.0	.864	32.3	33	84.7	57	65
14	275	527	5.0	66.0	.875	30.2	35	89.8	78	85
15	300	572	5.2	71.2	.881	29.1	35	93.5	120	95
Residuum			26.5	97.7	.947	17.9		too dark		

Carbon residue of residuum, 5.7 percent; carbon residue of crude, 1.7 percent.

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	9.7	0.690	73.6	
Total gasoline and naphtha	29.4	0.742	59.2	
Kerosine distillate	9.7	.815	42.1	
Gas oil	15.4	.842	36.6	
Nonviscous lubricating distillate	11.5	.856-.877	33.8-29.9	50-100
Medium lubricating distillate	5.2	.877-.884	29.9-28.6	100-200
Viscous lubricating distillate				Above 200
Residuum	26.5	.947	17.9	
Distillation loss	2.3			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1

TABLE 53. - Analyses of crude oils from western Nebraska -- (Continued)

6-135 (January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-56-194

IDENTIFICATION

Doran field
"D" sandstone
4,589-4,592 feet

Nebraska
Cheyenne County
NE¼ NE¼ sec. 33,
T. 14 N., R. 50 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.839 A. P. I. gravity 37.2 ° Pour point, ° F. 50
Sulfur, percent, 0.11 Color, brownish green
Saybolt Universal viscosity at 100 ° F., 46 sec.; at ° F., sec. Nitrogen, percent, 0.094

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 25 ° C. (77 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum. Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	1.5	1.5	0.640	89.6				
2	75	167	5.1	6.6	.686	74.8	15	58.0		
3	100	212	7.4	14.0	.729	62.6	26	60.1		
4	125	257	1.1	15.1	.739	60.0	21			
5	150	302	3.8	18.9	.755	55.9	21	58.0		
6	175	347	4.8	23.7	.766	53.2	20	59.3		
7	200	392	3.4	27.1	.783	49.2	22	62.0		
8	225	437	3.8	30.9	.798	45.8	23	64.6		
9	250	482	4.1	35.0	.809	43.4	23	68.8		
10	275	527	6.5	41.5	.821	40.9	24	72.5		
STAGE 2—Distillation continued at 40 mm. Hg.										
11	200	392	11.1	52.6	0.840	37.0	29	81.2	42	30
12	225	437	5.1	57.7	.862	32.7	36	87.1	56	60
13	250	482	5.1	62.8	.872	30.8	37	90.4	75	80
14	275	527	9.1	71.9	.899	25.9	47	94.0	145	100
15	300	572	3.6	75.5	.905	24.9	46	96.8	210	110
Residuum			22.8	98.3	.948	17.8		too dark		

Carbon residue of residuum, 8.9 percent; carbon residue of crude, 2.3 percent.
Ramsbottom 6.2 1.6

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	14.0	0.704	69.5	
Total gasoline and naphtha	27.1	0.733	61.5	
Kerosine distillate	14.4	.811	43.0	
Gas oil	10.4	.840	37.0	
Nonviscous lubricating distillate	10.7	.854-.881	34.2-29.1	50-100
Medium lubricating distillate	10.1	.881-.904	29.1-25.0	100-200
Viscous lubricating distillate	2.8	.904-.907	25.0-24.5	Above 200
Residuum	22.8	.948	17.8	
Distillation loss	1.7			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1

6-135 b (April 1958)

CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-64-156

IDENTIFICATION

Downer, West field
"D" sandstone - M. Cretaceous
5,856-5,861 feet

Nebraska
Banner County
NW1/4NW1/4, sec 2,
T 18 N, R 56 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.842 Gravity, ° API, 36.6 Pour point, ° F., 65
Sulfur, percent, .15 Color, brownish green
Viscosity, Saybolt Universal at 100°F, 49 sec Nitrogen, percent, 0.084

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 87 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum. percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122									
2	167	3.3	3.3	0.667	80.6		1.37405	187.8		
3	212	3.5	6.8	.718	65.6	20	1.40032	124.8		
4	257	4.6	11.4	.739	60.0	21	1.41059	130.2		
5	302	3.7	15.1	.756	55.7	22	1.42163	136.8		
6	347	3.1	18.2	.772	51.8	23	1.42893	135.7		
7	392	3.2	21.4	.785	48.8	23	1.43585	138.2		
8	437	4.1	25.5	.796	46.3	22	1.44259	137.0		
9	482	4.3	29.8	.811	43.0	24	1.45065	143.4		
10	527	5.8	35.6	.819	41.3	23	1.45717	146.5		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	2.8	38.4	.833	38.4	26	1.46317	149.0	38	20
12	437	8.5	46.9	.836	37.8	23	1.46609	149.9	45	40
13	482	5.9	52.8	.848	35.4	26	1.47113	151.1	51	60
14	527	4.2	57.0	.853	34.4	25			63	75
15	572	6.4	63.4	.866	31.9	28			86	90
Residuum		33.7	97.1	.935	19.8					

Carbon residue, Conradson: Residuum, 5.3 percent; crude, 2.0 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	6.8	0.693	72.7	
Total gasoline and naphtha	21.4	.739	60.0	
Kerosine distillate	14.2	.810	43.2	
Gas oil	13.0	.839	37.2	
Nonviscous lubricating distillate	14.8	.847-.874	35.6-30.4	50-100
Medium lubricating distillate				100-200
Viscous lubricating distillate				Above 200
Residuum	33.7	.935	19.8	
Distillation loss	2.9			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-3

TABLE 53. - Analyses of crude oils from western Nebraska -- (Continued)

6-435 (January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-56-132

IDENTIFICATION

Enders field
"J" sandstone
6347 feet

Nebraska
Kimball County
SW 1/4 NW 1/4 sec. 15,
T. 13 N., R. 55 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.842 A. P. I. gravity 36.6° Pour point, ° F. 55
Sulfur, percent, 0.21 Color, greenish-black
Saybolt Universal viscosity at 100° F., 42 sec.; at ° F., sec. Nitrogen, percent 0.098

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 31 ° C. (88 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	2.1	2.1	0.655	84.5				
2	75	167	2.4	4.5	.689	73.9	17	56.1		
3	100	212	3.1	7.6	.725	63.7	24	52.5		
4	125	257	5.6	13.2	.741	59.5	22	52.6		
5	150	302	5.6	18.8	.759	54.9	23	52.8		
6	175	347	4.2	23.0	.780	49.9	26	53.1		
7	200	392	4.3	27.3	.794	46.7	27	56.1		
8	225	437	3.5	30.8	.808	43.6	28	63.2		
9	250	482	5.4	36.2	.819	41.3	28	65.7		
10	275	527	5.1	41.3	.830	39.0	28	68.6		

STAGE 2—Distillation continued at 40 mm. Hg.

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
11	200	392	5.3	46.6	0.844	36.2	31	74.5	39	15
12	225	437	7.1	53.7	.848	35.4	29	80.1	45	40
13	250	482	5.5	59.2	.870	31.1	36	84.4	55	65
14	275	527	5.7	64.9	.878	29.7	37	88.9	75	80
15	300	572	6.5	71.4	.888	27.9	38	92.7	130	95
Residuum			26.3	97.7	.947	17.9		too dark		

Carbon residue of residuum, 5.9 (Ramsbottom 4.8) percent; carbon residue of crude, 1.5 (1.3) percent.

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	7.6	0.694	72.4	
Total gasoline and naphtha	27.3	0.746	58.2	
Kerosine distillate	8.9	.815	42.1	
Gas oil	17.2	.845	36.0	
Nonviscous lubricating distillate	11.4	.860-.883	33.0-28.8	50-100
Medium lubricating distillate	6.6	.883-.893	28.8-27.0	100-200
Viscous lubricating distillate				Above 200
Residuum	26.3	.947	17.9	
Distillation loss	2.3			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1

6-435 (January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-55-380

IDENTIFICATION

Goodwin field
"J" sandstone
6040 feet

Nebraska
Kimball County
SE 1/4 SE 1/4 sec. 9,
T. 13 N., R. 54 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.853 A. P. I. gravity 34.4° Pour point, ° F. 45
Sulfur, percent, 0.20 Color, greenish-black
Saybolt Universal viscosity at 100° F., 49 sec.; at ° F., sec. Nitrogen, percent, 0.113

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 26 ° C. (79 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	0.4	0.4	0.681 (fractions 1-2)					
2	75	167	1.4	1.8		76.3				
3	100	212	2.9	4.7	.723	64.2	23	53.7		
4	125	257	5.5	10.2	.743	58.9	23	54.1		
5	150	302	5.6	15.8	.761	54.4	24	54.5		
6	175	347	5.6	21.4	.779	50.1	26	54.4		
7	200	392	4.1	25.5	.797	46.0	28	56.4		
8	225	437	3.8	29.3	.809	43.4	28	60.5		
9	250	482	4.5	33.8	.821	40.9	29	64.7		
10	275	527	6.2	40.0	.831	38.8	29	68.8		

STAGE 2—Distillation continued at 40 mm. Hg.

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
11	200	392	6.1	46.1	0.845	36.0	31	75.2	40	20
12	225	437	6.2	52.3	.852	34.6	31	80.2	49	40
13	250	482	5.4	57.7	.864	32.3	33	83.9	57	60
14	275	527	5.8	63.5	.876	30.0	36	88.3	80	80
15	300	572	5.3	68.8	.889	27.7	39	92.1	130	95
Residuum			29.1	97.9	.954	16.8		too dark		

Carbon residue of residuum, 6.3 percent; carbon residue of crude, 2.0 percent.

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	4.7	0.707	68.6	
Total gasoline and naphtha	25.5	0.757	55.4	
Kerosine distillate	8.3	.815	42.1	
Gas oil	16.7	.841	36.8	
Nonviscous lubricating distillate	12.4	.853-.881	34.4-29.1	50-100
Medium lubricating distillate	5.9	.881-.895	29.1-26.6	100-200
Viscous lubricating distillate				Above 200
Residuum	29.1	.954	16.8	
Distillation loss	2.1			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1

TABLE 53. - Analyses of crude oils from western Nebraska -- (Continued)

G-435 (January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-51-314

IDENTIFICATION

Harrisburg field
Dakota "J" sandstone
5,880 - 5,907 feet

Nebraska
Banner County
NE NE 1/4 SE 1/4 sec. 6,
T. 18 N., R. 55 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.849 A. P. I. gravity 35.2° Pour point, ° F. 35
Sulfur, percent, 0.15 Color, brownish-green
Saybolt Universal viscosity at 100° F., 49 sec.; at ° F., sec.

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 27 ° C. (81 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	1.8	1.8	0.670	79.7				
2	75	167	5.4	7.2	.691	73.3	17			
3	100	212	5.3	12.5	.734	61.3	28	54.0		
4	125	257	3.4	15.9	.750	57.2	27	52.4		
5	150	302	4.4	20.3	.763	54.0	25	52.7		
6	175	347	4.4	24.7	.779	50.1	26	53.4		
7	200	392	3.7	28.4	.793	46.9	26	55.5		
8	225	437	5.1	33.5	.808	43.6	28	59.2		
9	250	482	4.6	38.1	.823	40.4	30	64.0		
10	275	527	7.2	45.3	.833	38.4	30	68.7		
STAGE 2—Distillation continued at 40 mm. Hg.										
11	200	392	1.2	46.5	0.849	35.2	33	74.4	39	30
12	225	437	6.5	53.0	.851	34.8	30	78.2	44	40
13	250	482	5.7	58.7	.862	32.7	32	82.6	53	60
14	275	527	5.6	64.3	.877	29.9	36	86.0	72	80
15	300	572	8.0	72.3	.886	28.2	37	90.7	130	95
Residuum			26.5	98.8	.959	16.0		too dark		

Carbon residue of residuum, 6.5 percent; carbon residue of crude, 1.9 percent.

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	12.5	0.706	68.9	
Total gasoline and naphtha	28.4	0.743	58.9	
Kerosine distillate	9.7	.815	42.1	
Gas oil	15.5	.843	36.4	
Nonviscous lubricating distillate	11.2	.858-.881	33.4-29.1	50-100
Medium lubricating distillate	7.5	.881-.891	29.1-27.3	100-200
Viscous lubricating distillate	0.0			Above 200
Residuum	26.5	.959	16.0	
Distillation loss	1.2			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1

G-435 (January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-55-376

IDENTIFICATION

Long field
"D" sandstone
6141 feet

Nebraska
Kimball County
NW 1/4 NE 1/4 sec. 10,
T. 12 N., R. 55 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.840 A. P. I. gravity 37.0° Pour point, ° F. 65
Sulfur, percent, less than 0.10 Color, brownish-black
Saybolt Universal viscosity at 100° F., 43 sec.; at ° F., sec. Nitrogen, percent, 0.078

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 25 ° C. (77 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	1.5	1.5	0.644	88.2				
2	75	167	1.5	3.0	.678	77.2	11			
3	100	212	3.8	6.8	.717	65.9	20	53.2		
4	125	257	6.9	13.7	.743	58.9	23	52.1		
5	150	302	3.4	17.1	.762	54.2	25	52.7		
6	175	347	4.3	21.4	.775	51.1	24	54.7		
7	200	392	3.4	24.8	.788	48.1	24	58.4		
8	225	437	4.5	29.3	.801	45.2	24	63.7		
9	250	482	3.6	32.9	.814	42.3	25	67.7		
10	275	527	5.6	38.5	.824	40.2	25	71.9		
STAGE 2—Distillation continued at 40 mm. Hg.										
11	200	392	5.2	43.7	0.837	37.6	28	77.7	39	20
12	225	437	6.5	50.2	.842	36.6	26	83.6	44	45
13	250	482	6.2	56.4	.854	34.2	28	88.5	55	70
14	275	527	6.1	62.5	.864	32.3	30	94.1	75	90
15	300	572	5.8	68.3	.896	26.4	42	98.1	115	105
Residuum			29.0	97.3	.939	19.2		too dark		

Carbon residue of residuum, 5.2 percent; carbon residue of crude, 1.8 percent.

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	6.8	0.692	73.0	
Total gasoline and naphtha	24.8	0.742	59.2	
Kerosine distillate	13.7	.814	42.3	
Gas oil	11.8	.840	37.0	
Nonviscous lubricating distillate	12.8	.848-.883	35.4-28.8	50-100
Medium lubricating distillate	5.2	.883-.911	28.8-23.8	100-200
Viscous lubricating distillate				Above 200
Residuum	29.0	.939	19.2	
Distillation loss	2.7			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1

TABLE 53. - Analyses of crude oils from western Nebraska -- (Continued)

G-485 (January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-51-315

IDENTIFICATION

Lovercheck field
Dakota "D" sandstone
6060-6091 feet

Nebraska
Banner County
NE 1/4 SE 1/4 sec. 18,
T. 18 N., R. 55 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.842 A. P. I. gravity 36.6 ° Pour point, ° F. 50
Sulfur, percent, 0.13 Color, brownish-green
Saybolt Universal viscosity at 100° F., 46 sec.; at ° F., sec.

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 29 ° C. (84 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum. Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	0.9	0.9)						
2	75	167	1.6	2.5)	0.675	78.1				
3	100	212	4.8	7.3	.713	67.0	18	54.0		
4	125	257	6.2	13.5	.741	59.5	22	51.7		
5	150	302	4.1	17.6	.760	54.7	24	52.0		
6	175	347	4.3	21.9	.775	51.1	24	54.3		
7	200	392	3.9	25.8	.789	47.8	24	58.3		
8	225	437	4.7	30.5	.802	44.9	25	63.4		
9	250	482	5.0	35.5	.815	42.1	26	67.8		
10	275	527	7.0	42.5	.825	40.0	26	73.0		

STAGE 2—Distillation continued at 40 mm. Hg.

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum. Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
11	200	392	1.8	44.3	0.839	37.2	28	79.3	40	25
12	225	437	6.7	51.0	.843	36.4	27	82.4	43	40
13	250	482	6.1	57.1	.853	34.4	28	86.4	52	60
14	275	527	6.0	63.1	.867	31.7	31	90.4	68	80
15	300	572	6.8	69.9	.878	29.7	34	93.8	107	95
Residuum			29.1	99.0	.939	19.2		too dark		

Carbon residue of residuum, 4.1 percent; carbon residue of crude, 1.3 percent.

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	7.3	0.700	70.6	
Total gasoline and naphtha	25.8	0.745	58.4	
Kerosine distillate	16.7	.816	41.9	
Gas oil	10.0	.844	36.2	
Nonviscous lubricating distillate	12.8	.851-.876	34.8-30.0	50-100
Medium lubricating distillate	4.6	.876-.884	30.0-28.6	100-200
Viscous lubricating distillate	0.0			Above 200
Residuum	29.1	.939	19.2	
Distillation loss	1.0			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1

G-485 (January 1949)

REPORT OF CRUDE PETROLEUM ANALYSIS

Bureau of Mines Laramie Laboratory
Sample PC-56-172

IDENTIFICATION

Owasco field
"J" sandstone
6002-6029 feet

Nebraska
Kimball County
SE 1/4 SE 1/4 sec. 26,
T. 15 N., R. 55 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.851 A. P. I. gravity 34.8 ° Pour point, ° F. 50
Sulfur, percent, 0.23 Color, brownish-black
Saybolt Universal viscosity at 100° F., 45 sec.; at ° F., sec. Nitrogen, percent 0.141

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.
First drop, 27 ° C. (81 ° F.)

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum. Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	1.7	1.7	0.650	86.2				
2	75	167	1.9	3.6	.682	76.0	13	57.7		
3	100	212	4.0	7.6	.711	67.5	17	52.7		
4	125	257	5.6	13.2	.738	60.2	21	54.9		
5	150	302	4.5	17.7	.756	55.7	22	54.9		
6	175	347	4.1	21.8	.776	50.9	24	54.9		
7	200	392	4.2	26.0	.788	48.1	24	56.1		
8	225	437	4.4	30.4	.805	44.3	26	60.1		
9	250	482	4.5	34.9	.818	41.5	27	64.1		
10	275	527	5.8	40.7	.830	39.0	28	68.2		

STAGE 2—Distillation continued at 40 mm. Hg.

Fraction No.	Cut at ° C.	Cut at ° F.	Percent	Sum. Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
11	200	392	6.1	46.8	0.846	35.8	32	74.0	39	15
12	225	437	6.0	52.8	.853	34.4	31	79.4	46	40
13	250	482	5.1	57.9	.870	31.1	36	83.2	57	65
14	275	527	5.8	63.7	.882	28.9	39	87.8	82	80
15	300	572	5.0	68.7	.892	27.1	40	91.2	135	100
Residuum			29.2	97.9	.964	15.3		too dark		

Carbon residue of residuum, 8.2 percent; carbon residue of crude, 2.7 percent.
Ramsbottom 6.3 2.1

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	7.6	0.690	73.6	
Total gasoline and naphtha	26.0	0.741	59.5	
Kerosine distillate	8.9	.812	42.8	
Gas oil	16.9	.844	36.2	
Nonviscous lubricating distillate	10.9	.859-.885	33.2-28.4	50-100
Medium lubricating distillate	6.0	.885-.897	28.4-26.3	100-200
Viscous lubricating distillate				Above 200
Residuum	29.2	.964	15.3	
Distillation loss	2.1			

U. S. GOVERNMENT PRINTING OFFICE 16—57835-1