RECOVERY OF OIL IN CALIFORNIA
BY SECONDARY METHODS

IN TWO PARTS - PART II. LOS ANGELES BASIN
AND COASTAL OIL FIELDS

BY A. G. LOOMIS, A. N. FRIED, AND D. C. CROWELL

United States Department of the Interior—May 1952
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BUREAU OF MINES
J. J. Forbes, Director

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May 1952
PREFACE

This report, Recovery of Oil in California by Secondary Methods, is divided into two separate publications. Each has been published by the Bureau of Mines as a Report of Investigations and the respective titles follow:

Part I. - San Joaquin Valley Oil Fields.

Part II. - Los Angeles Basin and Coastal Oil Fields.

In each report the introduction summarizes gas-injection and water-injection projects in California in 1950, compares the characteristics of California reservoirs with those of Mid-Continent and Eastern fields and discusses the problems associated with repressuring and water flooding in this State.
# RECOVERY OF OIL IN CALIFORNIA BY SECONDARY METHODS

In Two Parts - Part II. Los Angeles Basin and Coastal Oil Fields

by

A. G. Loomis, ¹/ A. N. Fried, ²/ and D. C. Crowell ³/

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¹/ Petroleum engineer.
²/ Chemical engineer.

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<td>30.</td>
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INTRODUCTION

Although secondary-recovery methods have not been applied widely in California, it is apparent that increasing attention and effort must be given to this phase of recovery if the State is to maintain its high rank as a petroleum producer. Steadily increasing demands for petroleum products and decreasing rates of discovery of new oil fields, with rapid depletion of existing reserves, emphasize the prospect of an adverse situation of supply and demand in the not-far-distant future. If the trend of discoveries becomes more favorable or if more complete economic recovery of the oil in place can be obtained by secondary recovery, this situation can be averted. Not only are these reserves of economic importance to the petroleum industry for meeting increasing market demands; but economic reclamation of such reserves is an important conservation measure, which will prolong the productive life of many fields. Accordingly, progressive operators in California are alert to the possibilities of secondary recovery and have done much to implement such operations wherever feasible.

Most current operations are of the pressure-maintenance type, in which the reservoir pressure is maintained or partly maintained by injecting natural gas to increase oil recovery. The possibilities of recovering additional oil from stripper fields by gas drive and water flooding (including water disposal) also are being tested in experimental field projects. Table 1 summarizes current gas- and water-injection projects in California.

A comparison of the salient characteristics of California reservoirs with those of Eastern and Mid-Continent pools in which secondary-recovery methods have been applied is given in table 2.3/4/ In view of these wide differences in oil and reservoir characteristics, it is inevitable that the economic recovery of additional oil in California by secondary recovery will require considerable modification in the methods generally established in the Appalachian and Mid-Continent areas of the United States. Some areas of California may require development of entirely new methods for economic recovery. In particular, difficulties are encountered in repressuring or water flooding the thick, nonuniform sands, faulted and lensed, having extreme variations in permeability and yielding very viscous oils. Likewise, the presence in some California sands of argillaceous material that swells on contact with water presents a difficult problem in water flooding. The economic recovery of oil in the State by secondary recovery, particularly by water flooding, once seemed improbable. Now, however, both existing pressure-maintenance and experimental water-flooding projects, together with laboratory investigations, conclusively show that stimulative procedures may be applied with economic success in selected areas of the State.

### Gas Injection

<table>
<thead>
<tr>
<th>Field</th>
<th>Pool</th>
<th>Rate of injection in December 1950, Mcf. per day</th>
<th>Cumulative volume injected to January 1, 1951, Mcf.</th>
<th>Type of operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Belridge North</td>
<td>&quot;6&quot;/&quot;7&quot;</td>
<td>31,050</td>
<td>59,514,796</td>
<td>Pressure maintenance.</td>
</tr>
<tr>
<td></td>
<td>Temblor/</td>
<td></td>
<td>33,330,878</td>
<td>Pressure maintenance.</td>
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<td></td>
<td>&quot;19&quot;/Sand/</td>
<td>3,294</td>
<td>1,416,542</td>
<td>Pressure maintenance.</td>
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<td>Buena Vista</td>
<td>11-R</td>
<td>1,554</td>
<td>7,328,717</td>
<td>Do.</td>
</tr>
<tr>
<td></td>
<td>27-B</td>
<td>22,555</td>
<td>32,780,678</td>
<td>Do.</td>
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<td></td>
<td>Stevens</td>
<td>10,750</td>
<td>1,311,493</td>
<td>Pressure maintenance.</td>
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<td></td>
<td>&quot;F&quot;/Flores/</td>
<td>1,406</td>
<td>1,416,542</td>
<td>Low pressure injection.</td>
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<td>Erbaku</td>
<td>214</td>
<td>134,829</td>
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<td>Coalinga North/R</td>
<td>356</td>
<td>6,693,482</td>
<td>Do.</td>
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<td></td>
<td>25-A/</td>
<td>9,128</td>
<td>1,947,083</td>
<td>Do.</td>
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<tr>
<td></td>
<td>26,530</td>
<td>8,798,464</td>
<td>Do.</td>
<td>Do.</td>
</tr>
<tr>
<td></td>
<td>Western &quot;29&quot;</td>
<td>2,543</td>
<td>6,530,716</td>
<td>Do.</td>
</tr>
<tr>
<td></td>
<td>Main Western</td>
<td>46,399</td>
<td>96,885,920</td>
<td>Do.</td>
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<td></td>
<td>31-1</td>
<td>3,664</td>
<td>2,798,846</td>
<td>Do.</td>
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<td></td>
<td>Western &quot;29&quot;</td>
<td>2,543</td>
<td>6,530,716</td>
<td>Do.</td>
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<td></td>
<td>11-A/</td>
<td>8,798,464</td>
<td>Pressure maintenance.</td>
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<td></td>
<td>Cicero/</td>
<td>1,311,493</td>
<td>Do.</td>
<td>Do.</td>
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<td></td>
<td>1,416,542</td>
<td></td>
<td>Pressure maintenance.</td>
<td></td>
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<td></td>
<td>Coyote West</td>
<td>Lower 90 East</td>
<td>5,852,718</td>
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<td>Emery East</td>
<td>5,148</td>
<td>9,029,871</td>
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<td></td>
<td>do.</td>
<td>19,517</td>
<td>30,440,575</td>
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<td>Chumash South</td>
<td>3,616</td>
<td>1,418,289</td>
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<td>Shallow</td>
<td>7,144</td>
<td>13,084,678</td>
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<td></td>
<td>Avocado/</td>
<td>6,530,716</td>
<td>Do.</td>
<td>Repressuring and pressure maintenance.</td>
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<td>Vaqueros</td>
<td>1,663</td>
<td>2,690,535</td>
<td>Repressuring and pressure maintenance.</td>
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<td>Temblor</td>
<td>92,920</td>
<td>317,768,212</td>
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<td>Vaqueros/</td>
<td>519</td>
<td>16,094</td>
<td>Pressure maintenance.</td>
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<tr>
<td></td>
<td>193-D/</td>
<td>8,798,464</td>
<td>Experimental repressing.</td>
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<td></td>
<td>&quot;1-2-3&quot;</td>
<td>20,007</td>
<td>41,281,497</td>
<td>Pressure maintenance.</td>
</tr>
<tr>
<td></td>
<td>N. Sulphur Mtn/</td>
<td>97,544</td>
<td>Do.</td>
<td>Cycling and pressure maintenance.</td>
</tr>
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<td></td>
<td>Pacifico</td>
<td>107,194</td>
<td>128,465,531</td>
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<td>Río Bravo</td>
<td>Río Bravo-Vedder</td>
<td>13,726</td>
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<td>Russell Ranch</td>
<td>Dibblee</td>
<td>9,025</td>
<td>Pressure maintenance.</td>
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<td>Salt Creek</td>
<td>Carneros</td>
<td>2,238</td>
<td>Pressure maintenance.</td>
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<td></td>
<td>San Miguelito</td>
<td>6,781,109</td>
<td>Do.</td>
<td>Pressure maintenance.</td>
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<td></td>
<td>Lompoc/</td>
<td>1,332</td>
<td>90,017</td>
<td>Pressure maintenance.</td>
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<td>O'Beeli/</td>
<td>415</td>
<td>142,592</td>
<td>Pressure maintenance.</td>
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### Water Injection

<table>
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<tr>
<th>Field</th>
<th>Pool</th>
<th>Rate of injection in December 1950, bbl. per day</th>
<th>Cumulative volume injected to January 1, 1951, bbl.</th>
<th>Type of operation</th>
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<td>Barddfield</td>
<td>Sespe</td>
<td>431</td>
<td>231,372</td>
<td>Water flood and water disposal.</td>
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<td></td>
<td></td>
<td>Water disposal.</td>
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<tr>
<td>Cat Canyon</td>
<td>Pliocene</td>
<td>2,841</td>
<td>3,066,883</td>
<td>Pressure maintenance.</td>
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<td></td>
<td>Sherman</td>
<td>689</td>
<td>1,407,411</td>
<td>Pressure maintenance.</td>
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<td>Pliocene 5th</td>
<td>1,747</td>
<td>1,108,499</td>
<td>Experimental flood.</td>
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<td>Pliocene 3rd</td>
<td>9,220</td>
<td>3,067,192</td>
<td>Water disposal.</td>
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<td></td>
<td>Lompoc/</td>
<td>4,001</td>
<td>6,108,299</td>
<td>Primarily water disposal.</td>
</tr>
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<td></td>
<td>Tognazzini/</td>
<td></td>
<td>1,858,037</td>
<td>Water flood.</td>
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<td></td>
<td>Stevens</td>
<td>425</td>
<td>966,362</td>
<td>Water disposal.</td>
</tr>
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<td></td>
<td>Chapman</td>
<td>567</td>
<td>105,440</td>
<td>Experimental water flood.</td>
</tr>
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<td>Río Bravo-Vedder</td>
<td>Dibblee/</td>
<td>59,857</td>
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<td></td>
<td>Russell Ranch</td>
<td>135</td>
<td>45,036</td>
<td>Do.</td>
</tr>
<tr>
<td></td>
<td>Torrance</td>
<td>567</td>
<td>105,440</td>
<td>Do.</td>
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1/ Gas injection suspended April 1947 - resumed February 1950.
2/ Gas injection suspended September 1949.
7/ Gas injection began May 1950.
9/ Gas injection began December 1950.
10/ Gas injection suspended August 1949.
TABLE 2. - Comparison of California reservoir characteristics with those of eastern and mid-continent reservoirs

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<th></th>
<th>Eastern and mid-continent</th>
<th>California</th>
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<tr>
<td>1.</td>
<td>Sand thickness .... Small</td>
<td>Large - leading to difficulty in controlling effective flow of injected and driven fluids.</td>
</tr>
<tr>
<td>2.</td>
<td>Sand permeability.. Low to medium</td>
<td>Medium to high - affecting rate of recovery and residual oil reserve before flooding, depending on sand characteristics.1/</td>
</tr>
<tr>
<td>3.</td>
<td>Sand porosity ..... do.</td>
<td>Medium to high - favorable for larger oil reserves in place.</td>
</tr>
<tr>
<td>4.</td>
<td>Permeability uniformity ..... Good</td>
<td>Poor - leading to excessive bypassing of injected fluid. This ranks second only to the residual oil saturation in importance for secondary recovery.</td>
</tr>
<tr>
<td>5.</td>
<td>Oil gravity ....... High</td>
<td>Low - usually results in higher viscosities and lower prices.</td>
</tr>
<tr>
<td>6.</td>
<td>Oil viscosity ..... Low to medium</td>
<td>Medium to high - leading to an unstable interface with the flooding fluid, resulting in bypassing and fingering and consequently poorer secondary recovery.</td>
</tr>
<tr>
<td>7.</td>
<td>Oil value .......... High</td>
<td>Low - presenting a very serious handicap to the economic success of secondary-recovery projects.</td>
</tr>
<tr>
<td>8.</td>
<td>Pool depth ......... Shallow to medium</td>
<td>Medium to deep - usually meaning prohibitive development costs.</td>
</tr>
<tr>
<td>9.</td>
<td>Drilling costs .... Low</td>
<td>High - another serious economic liability.</td>
</tr>
</tbody>
</table>

1/ Average permeabilities of California oil sands are, in general, considerably greater than those of oil sands in the Appalachian region. The deeper California sands are comparable to mid-continent sands, but shallow California sands are of considerably greater permeability than those of the mid-continent area.

The estimated proved crude-oil reserve of the State is 4.123 billion5/ barrels as of January 1, 1951, utilizing primary methods of recovery. It is further estimated6/ that approximately 26.6 billion barrels of oil remain as residual oil in

5/ Ingalls, P. C., Review and Forecast: Oil and Gas Jour. vol. 49, No. 38, Jan. 25, 1951, pp. 197-199.
place in the depleted and near-depleted fields of the State. This quantity approximates three times the State's cumulative crude-oil production (approximately 8.66 billion barrels) to January 1, 1951 and about 6.5 times the estimated proved reserve of crude oil to the same date. In view of the scarcity of new major discoveries, it is evident that increased thought and effort must be given to exploitation of this large available reserve, and that the State's future as a leading producing area must be closely correlated with the successful application of secondary recovery.

This survey of representative secondary-recovery projects in California was undertaken as one phase of the general program, authorized through an amendment to the first Synthetic Liquid Fuels Extension Act of March 15, 1948 (Public Law 443, 80th Congress), to conduct research on secondary-recovery methods of increasing the ultimate recovery of oil in the United States. The fields selected for study were those that best illustrate the principal problems facing secondary-recovery operations in California. A description of the techniques applied to solve these problems and a summary of the results obtained may guide the development and operation of other similar projects. An attempt was made to include a representative cross section of reservoir types and conditions in the productive areas of the State. To this end, data obtained from 15 fields in the San Joaquin Valley, Santa Barbara and Ventura Coastal districts, and the Los Angeles Basin were assembled and analyzed. These selected fields include oil-productive formations, typical of upper Pliocene through Oligocene strata, ranging in depths from 1,400 to 11,000 feet below sea level and productive of various black oils and condensates ranging from 19° to 60° A.P.I. gravity. Stimulative methods of production include water injection, waste-water disposal, low-pressure gas injection and pressure maintenance by gas injection. The present survey includes analyses of 11 high-pressure gas-injection projects, 4 water-injection projects, and 1 low-pressure gas sweep. Figure 1 is a map showing the location of fields in which the secondary-recovery projects described in the report are being operated.

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Figure 1. - Oil and gas fields, central and southern California.
Figure 2. - Structure map, Newhall-Potrero field, Los Angeles County, Calif.

Figure 3. - Typical electric logs, Newhall-Potrero field, Los Angeles County, Calif.
E. E. Adams and R. W. Masters, lead-production engineers, and P. J. Craner, senior petroleum engineer, Standard Oil Co. of California; W. Tempelaar-Lietz, petroleum-production engineer, Shell Oil Co; C. W. Stephens, division petroleum engineer, The Ohio Oil Co.; M. C. Eastman, principal petroleum engineer, Navy Department (Naval Petroleum Reserves in California); J. A. Sargent, manager of operations, D. R. Knowlton, reservoir engineer, and T. H. Benton, petroleum engineer, Kettleman North Dome Association; Douglas Marcell, petroleum engineer, Havenstite Oil Co.; F. L. Wadsworth, chief petroleum engineer, General Petroleum Corp.; and W. E. Glenn, region engineer, Continental Oil Co. Thanks also are due W. R. Wardner, Jr., manager of the Conservation Committee of California Oil Producers, for supplying the list of current secondary-recovery projects shown in table 1.


LOS ANGELES BASIN AND COASTAL OIL FIELDS

Newhall-Potrero Field - Gas Injection

General Description of Field

The Newhall-Potrero oil field is in the northern foothills of the Santa Susana Mountains about 6 miles west of Newhall, Los Angeles County. The field comprises part of the old Rancho San Francisco and lies within secs. 26, 27, 30, 35 and 36, T. 4 N., R. 17 W., (S.B.B. and M.). By far the greatest acreage is controlled by the Sunray Oil Corp. (formerly by Barnsdall Oil Co.). Except for the central portion, which is situated in a small valley, the topography of the area is extremely rugged, with elevations ranging abruptly between 900 and 1,400 feet above sea level.

Oil is obtained from an asymmetrical, highly faulted, anticlinal nose approximately 3-1/2 miles long and 1/2 mile wide at the center. The major axis of the structure trends northwest-southeast and dips northwest 20° to 25°. The beds dip at angles of 40° to 45° on the north and more steeply at angles greater than 60° on the south. A structure map of the field is shown in figure 2.

Table 3 lists the discovery-well data for each of the seven oil-productive horizons. The combined upper three zones are referred to as the "123" pool. The overall structural closure is about 1,900 feet. Except in wells where it was expedient to exclude wet or nonproductive sands, the early wells were completed with all three upper zones open to the well bore. Later, many of these multizone producing wells were recompleted as single-zone wells or as dual-zone wells in which oil was produced from each zone separately.
TABLE 3. - Discovery-well data, Newhall-Potrero field, Los Angeles County, Calif.

<table>
<thead>
<tr>
<th>Zone</th>
<th>Discovery date</th>
<th>Discovery well No.</th>
<th>Well status</th>
<th>Initial oil production, bbl. per day</th>
<th>Choke size, in.</th>
<th>Oil gravity, °A.P.I.</th>
<th>Producing interval, ft.</th>
</tr>
</thead>
<tbody>
<tr>
<td>First</td>
<td>Mar. 1937</td>
<td>RSF 1</td>
<td>Flowing</td>
<td>118</td>
<td>35.2</td>
<td>1/6,160 - 6,472</td>
<td></td>
</tr>
<tr>
<td>Second</td>
<td>Feb. 1938</td>
<td>RSF 2</td>
<td>do.</td>
<td>631</td>
<td>3/64</td>
<td>32.6</td>
<td>2/6,376 - 6,713</td>
</tr>
<tr>
<td>Third</td>
<td>June 1938</td>
<td>RSF 3</td>
<td>do.</td>
<td>1,503</td>
<td>20/64</td>
<td>34.0</td>
<td>2/6,247 - 7,180</td>
</tr>
<tr>
<td>Fifth</td>
<td>June 1946</td>
<td>RSF 53</td>
<td>do.</td>
<td>336</td>
<td>19/64</td>
<td>36.5</td>
<td>8,680 - 8,890</td>
</tr>
<tr>
<td>Sixth</td>
<td>Mar. 1945</td>
<td>RSF 44</td>
<td>do.</td>
<td>530</td>
<td>15/64</td>
<td>36.7</td>
<td>9,665 - 9,842</td>
</tr>
<tr>
<td>Seventh</td>
<td>Apr. 1948</td>
<td>RSF 65</td>
<td>do.</td>
<td>430</td>
<td>25/64</td>
<td>28.0</td>
<td>11,305-12,121</td>
</tr>
<tr>
<td>Ninth</td>
<td>Dec. 1948</td>
<td>RSF 66</td>
<td>Gas-lift</td>
<td>55</td>
<td>28.5</td>
<td>13,936-14,501</td>
<td></td>
</tr>
</tbody>
</table>

1/ Well deepened in 1940 to produce from First, Second, and Third zones; later, First and Second zones were excluded to permit gas injection into Third zone.
2/ Subsequently deepened to include Third zone for production; later, recompleted with only Second zone open.
3/ Originally completed in First, Second, and Third zones; later converted to gas-injection well to permit injection into First and Third zones separately.

Reservoir Data

The upper 6,000 to 6,500 feet of rock penetrated by wells in the Newhall-Potrero field consist mainly of argillaceous beds in the Pico and Repetto formations of Pliocene age. The lower part of this section is made up of coarse sand and conglomerate interbedded with minor amounts of shale and white quartzitic sandstone. The three underlying oil zones of the "123" pool are in the Modelo (Delmontian) formations of upper Miocene age. The First zone, about 200 feet below the Pliocene-Miocene contact, is a highly lenticular interval approximately 375 feet thick in the northwestern part of the field, but it grades laterally into a single thick sand body near RSF well 1 and pinches out to the southeast of RSF well 362/ (fig. 3; numerals after well number indicate zones open to production or injection; hyphenated numerals indicate zones separated in well). The productive area of the First zone comprises less than one-third of the proved productive area of the field. The Second zone, also productive over less than one-third of the field, is confined to the southeastern end of the field where the maximum interval of 340 feet is reached. Its northeastern limit is between RSF wells 25 and 20. The Third zone, the main productive interval of the pool, extends over most of the field. It is about 550 feet thick at the northwestern end and grades laterally into shale at the southeastern end. The total bulk sand volume of the "123" pool was calculated to be 120,000 acre-feet, distributed as follows: 28,300 acre-feet in the First zone, 16,100 acre-feet in the Second zone, and 75,700 acre-feet in the Third zone. Typical electric logs of wells penetrating all three zones of the pool are shown in figure 3.

Oil sands in the "123" pool have relatively low permeability, which varies widely. Some wells have averaged as high as 200 millidarcys and others as low as 16 millidarcys, with individual values ranging much more widely. The estimated average dry-air permeability is 75 millidarcys. From analyses of well performance and reservoir behavior it was estimated that, under original reservoir conditions, the average effective permeability to oil was 6 to 8 millidarcys. The porosity of cores is relatively uniform and the average pool porosity has been calculated to be 17.7 percent. The interstitial water content of cores, as determined by the "restored-state" method, averages 30 percent of the average pore volume.


2/ Graybeal, Oran A., Performance of Primary Pressure Control in the First, Second, and Third Zone, Newhall-Potrero Field: Oil and Gas Jour., vol. 48, No. 5, June 9, 1949, pp. 86-91.
Figure 4 - Performance curves, "123" pool, Newhall-Potrero field, Los Angeles County, Calif.
Studies of reservoir performance data and results of laboratory tests on subsurface samples of reservoir fluids indicate that, under original reservoir conditions: (1) The average static reservoir pressure (datum, 6,000 feet below sea level) was 3,100 p.s.i.; (2) the average reservoir temperature was 170° F.; (3) the bubble-point pressure was 2,775 p.s.i.; (4) the solution gas-oil ratio was 650 cubic feet per barrel; and (5) the formation-volume factor was 1.351. The original solution gas-oil ratio is based upon interpretation of reservoir data, which show the relation between initial production gas-oil ratios and depth. It was concluded from available information that there was no gas cap of any consequence in any zone of the untapped "123" pool.\(^{10}\) A comparison of the production and the solution gas-oil ratios indicates that the oil in the upper part of the structure was slightly undersaturated, and the degree of undersaturation was progressively greater toward the lower part of the structure.

Production History

As most of the area within the limits of the productive portion of the structure is held by the Sunray Oil Corp., development of the three upper zones has been slow and orderly. There are 58 wells in the "123" pool; 7 of these have been converted to gas-injection wells, of which 5 are single and 2 are dual zone. None of the wells are now utilized for combined injection and production. As previously stated, it was the practice, during early development of the field, to open all productive zones to a common well bore. However, since early 1945, remedial work and recompletions have converted many multizone wells either to single-zone or dual-zone wells, in which oil is produced from the zones separately.

Figure 4 shows the production history of the "123" pool. The oil production increased steadily with development of the field and reached 5,300 barrels per day by early 1943, when 32 wells had been completed. By 1949, 27 additional wells had been drilled, and the rate of oil production had been maintained nearly constant at about 5,000 barrels per day. During this same time, the average reservoir pressure had declined from about 3,000 to about 1,750 p.s.i. while the pool gas-oil ratio increased slowly from 800 in 1938 to about 2,000 cubic feet per barrel in 1945. Currently, the gas-oil ratio is approximately 7,000 cubic feet per barrel. To conserve the natural reservoir energy, it has been the practice to shut in wells which have more than twice the average production gas-oil ratio of the pool. By following closely the reservoir pressure distribution, production from wells was allocated to maintain the pressure distribution throughout the pool as nearly uniform as practicable. This procedure tended to minimize migration of oil upstructure and permitted beneficial gravity-drainage effects to take place. Furthermore, it generally insured more efficient utilization of the natural reservoir energy through maintenance of favorable gas-oil ratios. By avoiding creation of low-pressure areas caused by excessive withdrawals, the reduction of oil viscosity resulting from dissolved gas coming out of solution also was minimized.

Despite the close control exercised over operating conditions, the average daily production of 5,000 barrels of oil and 18,000 M c.f. of gas reduced the average reservoir pressure about 250 p.s.i. per year from 1943 to 1945. Available pool performance data established that there is no active edge-water drive of enough magnitude to augment the dissolved-gas energy available for displacement of oil. Taking into account the cumulative effects of declining reservoir pressure, relatively low permeability, and low productivity indices of wells upon productive capacity and ultimate oil recovery, the Barnsdall Oil Co. (now Sunray Oil Corp.), decided to institute a gas-injection program as a means of "primary pressure control" in the "123" pool.

\(^{10}\) Work cited in footnote 9.
Preparatory to initiating gas injection, RSF wells 1, 3, 20, and 36 were selected for conversion to input wells. RSF well 1, which had been a triple-zone well, was altered to permit gas injection into the Third zone only. In RSF well 3, also a triple-zone well, the Second zone interval was excluded by cementing in place a blank liner, which also provided space for a packer so that gas could be injected into either the First or Third zone independently if desired. In RSF well 36, open to the Second- and Third-zone oil sands, the latter zone was packed off.

Small-scale injection was begun in December 1944 to determine the injective properties of the sands, and it was found that gas volumes of the order of magnitude of the calculated requirements could be pumped into the reservoir under surface pressure of 2,000 p.s.i. In mid-October 1945, installation of gas-injection equipment was completed and full-scale operations were begun at an average injection rate of 12,900 M c.f. per day. The rate was increased gradually; and by January 1946, a total volume of 1,745,000 M c.f. of gas had been returned to the "123" pool.

The dry injection gas is the residue gas from the field absorption plant, which processes all the wet gas produced with the oil from all zones in the field. The compressor plant comprises 15 units totalling 5,945 hp. Nine two-stage compression units boost the dry gas from absorber-plant pressure of 450 p.s.i. to 2,000 p.s.i. for the injection system.11/ A complete subsurface-pressure survey was conducted in January 1946 to determine the effects of the first 3 months of gas injection. It was found that, in some wells, near gas-input wells, subsurface pressures had risen as much as 200 p.s.i.; in other wells the previously observed pressure declines were reduced or completely checked. The survey also indicated existence of several fault blocks in the area around the input wells. A series of pressure profiles through wells near the axis of the structure (fig. 5) shows the pressure declines that took place in the Third zone before the gas-injection program. As pointed out, production had been regulated to obtain as uniform a pressure distribution as practicable; therefore, it was not until the 1946 pressure survey was completed that the nature of these faults became apparent. A study of figure 5 reveals that gas injected into RSF well 20 materially reduced the pressure decline in RSF wells 27, 25, and 17, and gas injected through RSF wells 1 and 3 resulted in a marked increase in pressure in RSF well 4. In wells between these two areas the subsurface pressure continued to decline at the same rate as before gas injection, indicating that the gas injected on both sides was having virtually no effect on wells in the intermediate area, presumably because of competent pressure barriers. To maintain a more nearly uniform pressure distribution, RSF well 16, which was producing oil from the First and Third zones, was recompleted to permit gas injection into the Third zone and oil production from the First zone; this well is now used for injection into the First zone also. Shortly after gas was turned into the new injection well, the pressure in the isolated fault block began to rise and soon attained a magnitude commensurate with the pressures of the adjoining areas. The subsequent pressure history of this section of the reservoir is shown in figure 5.

To obtain a greater degree of control over the migration and effect of the injected gas, a program of selective isolation of zones in eight producing wells throughout the field was instituted shortly after the gas-injection project was

Figure 5. - Pressure profiles, "123" pool, Newhall-Potrero field, Los Angeles County, Calif.
initiated. In some of these, all but one zone were cemented off; in others, the zones were isolated to permit producing each zone independently. At present, there are no producing wells with more than two zones open to production. Two other third zone wells, which had been previously shut-in because of excessive gas-oil ratios, were recompleted in the First zone, with resultant low gas-oil ratios. The zonal isolation program showed that at several well locations differences in reservoir pressure to a maximum of several hundred pounds per square inch existed between individual zones, and that "thieving" of large volumes of fluids by the lower pressure intervals may have occurred in the past.

Considering the volume of gas injected, the high permeability variation of the oil sands, and the effects of cross faults as pressure barriers, the increase in the average production gas-oil ratio following inauguration of the gas-injection program is lower than might be expected. The rather slow rise in average production gas-oil ratio may be attributed to initiation of the gas-injection program fairly early in the life of the field while fluid saturations were relatively high and to maintenance of pressure-equalization and production-allocation programs during most of the preinjection history of the field. Undoubtedly a large volume of injected gas has been produced with the oil, but it is evident from the stability of the oil production and the marked decrease in the rate of reservoir pressure decline that a considerable proportion of the injected gas is being stored in the reservoir and is displacing oil from the sands. Several high-gas-oil-ratio wells, which had been shut in before the gas-injection program, were returned to production about 8 months after injection was started. These wells exhibited lowered gas-oil ratios, which decreased for a time and then increased again. This behavior would seem to indicate that the oil in the more-saturated areas between wells was being gas-driven toward the producing wells as a result of the change in pressure gradients created by gas injection.12/

Inasmuch as the pressure-control program was begun before the oil production had declined appreciably, it is difficult to evaluate the effect of gas injection in producing additional oil over and above the amount that would have been produced without gas injection. The field operators have estimated that the injection of gas has had the over-all effect of sustaining the field maximum efficient rate in the neighborhood of 5,000 barrels per day, whereas, without introducing extraneous gas this rate would have declined 1,500 to 2,000 barrels per day by January 1949.

As shown in figure 4, the reservoir pressure decline has been partly arrested, so that, between October 1945 and January 1949, the reduction in reservoir pressure was about 750 p.s.i. less than would have taken place had the decline continued at the rate existing before injection. In addition to increased productive capacity, the sustained pool pressure resulting from gas injection also has materially reduced lifting costs. To date, the over-all effect of these benefits has been the production of about 1 million barrels more of oil than could have been produced without excessive waste of reservoir energy, and the present worth of the reservoir has been materially improved as well.

Gas Injection into the Fifth Zone13/

The Fifth zone, discovered in 1946, has been developed by the completion of 30 Sunray Oil Corp. wells by the middle of 1951, with a daily oil production of about

12/ Work cited in footnote 9.
13/ Graybeal, Oran A., Progress Report - California's Prolific Potrero Oil Field: Oil and Gas Jour., vol. 50, No. 10, July 12, 1951, pp. 80-81, 96.
3,400 barrels. Plans are under way to enlarge the capacity of the field compressor plant and to include the Fifth zone in the pressure-maintenance project previously in effect in the upper zones.

The mechanism of oil production in the Fifth-zone reservoir appears to be a solution-gas drive. The structural relief is such that nearly 3,000 feet of oil column is present. Although there was no gas cap originally in the Fifth zone, there is evidence of natural gravity segregation of the reservoir fluids, as indicated by differences in the A.P.I. gravity and solution gas-oil ratio prevalent in different parts of the reservoir. The A.P.I. gravity of the reservoir oil ranges from 25° for oil from wells on the flanks to 39° for oil from wells on the crest of the structure. The solution gas-oil ratios of oil samples taken from the crest of the structure are nearly twice those of samples from the extreme north flank.

The gross thickness of the Fifth zone ranges from less than 200 feet to more than 700 feet, and the average net effective thickness of the oil-saturated sand is about 240 feet. The productive sand (Miocene), which is generally tight and fine-to-medium-grained, grades into coarse-grained conglomeratic sand in places, particularly on the north flank of the structure. The top of the productive sand lies at a depth of about 8,000 feet near the crest of the structure, and the base of the sand has been logged at a depth of 10,959 feet in the lowest well from which Fifth-zone production is obtained.

Relatively few wells have been drilled near the crest of the structure because of the high solution gas-oil ratios prevalent in the upper parts of the reservoir. It is believed that rapidly increasing gas-oil ratios, after comparatively short producing lives, would necessitate the shutting in such wells to conserve reservoir energy. Recently, however, two wells have been completed near the highest part of the structure for use as gas-injection wells when partial-pressure maintenance in the Fifth zone is begun. Oil is now being produced from these wells to deplete the surrounding sands partly to obviate the necessity of displacing this oil when gas injection is begun.

Gas injection in the Fifth zone is believed promising, in spite of the low permeability of the productive interval. The productivity of wells in the Fifth zone decreases rapidly with decline in reservoir pressure. Engineering studies of the field indicate that partial-pressure maintenance will result in a higher ultimate recovery of liquid hydrocarbons than would be expected if the produced gas was not returned to the reservoir. It is believed that the relatively great structural closure of the Fifth zone will facilitate gravity segregation of the injected gas and permit it to be controlled more readily than in reservoirs with lower structural relief.

West Coyote Field, Emery West Pool - Gas Injection

General Description of Field

The West Coyote oil field, in Orange and Los Angeles Counties, is approximately 20 miles southeast of Los Angeles and 3 miles northwest of Fullerton. The field lies principally in secs. 13 and 24, T. 3 S., R. 11 W., and secs. 17 through 21, T. 3 S., R. 10 W., S.B.B. and M. The oil-productive structure is an elongated anticline approximately 2-1/2 miles long and 3/4 mile wide, having about 900 feet closure; its major axis trends, in general, east-west, with the crest of the dome near the western end of the structure. The eastward plunge of the axis is approximately 75 feet in 1,000 feet, becoming less steep toward the extreme eastern end, and the westward
plunge is about 170 feet in 1,000 feet; the southern flank of the structure is considerably steeper than the northern flank. The productive limits of the field are defined by the oil-water contact. The field comprises about 1,100 productive acres.

The West Coyote field is of considerable historic interest in the development of the Los Angeles Basin; it was the first field in this area whose discovery was not based upon the presence of surface oil and gas seepage. The discovery well was drilled as a result of oil showings in a water well in the immediate vicinity of the field. Moreover, it gave the first evidence of oil in an isolated group of hills and thus encouraged exploration throughout the basin, which eventually led to the discovery of such fields as East Coyote, Richfield, Dominguez, and Long Beach. A further distinguishing feature of the West Coyote field is that it is the only field in the Los Angeles Basin that has been almost completely under the control of one operator (Standard Oil Co. of California) since shortly after its discovery; consequently, its development has proceeded slowly, with relatively wide spacing, in contrast to the competitive drilling and close spacing so common in most of the other basin fields.14

Commercial production in the West Coyote oil field began with completion of Murphy Oil Co. Coyote well 3, on April 26, 1909, at a depth of 3,756 feet in the second, or Main, zone. In the course of the development of the field, 367 wells were drilled between 1909 and 1951, and approximately 169 million barrels of oil were produced. Well spacing in general has been developed on a 5-acre pattern.

Although the deepest well in the field penetrated about 11,000 feet of sediments, including the Pico (upper Pliocene) and Puente (upper and middle Miocene) formations, oil production, with the exception of that from one well, is derived from the Repetto (lower Pliocene) formation, which is approximately 4,000 feet thick. One well, Severns Drilling Co. McNally 4, producing 24 barrels of oil per day in 1950, is completed in the McNally zone, the top of which (at a subsurface depth of 6,750 feet) is believed to lie about 150 feet below the Pliocene-Miocene contact.15 The Upper, Main, "99", "138", and Emery productive zones lie in the Repetto formation at depths ranging from 2,300 to 5,600 feet below sea level.

The Upper zone, comprising the Top and "B4 - B5" pools, is approximately 200 feet thick and is productive over a comparatively small area near the crest of the structure. The top of the zone is about 2,300 feet below sea level. During 1950, 92,000 barrels of oil, ranging from 18° to 23° A.P.I. gravity, were produced from seven wells in the Upper zone. The Upper zone is separated from the underlying Main zone by 250 feet of shale.

The Main zone occurs 2,800 feet below sea level on the crest of the structure and is 600 to 700 feet thick. It has been a prolific source of 27° to 28° A.P.I. gravity oil. There were 133 producible wells at the end of 1950, and during that year the oil production from the Main zone was 1,394,000 barrels. A sandy shale member approximately 150 feet thick underlies the Main zone and separates it from the "99" zone.


The "99" zone, comprising the Upper "99" and the Lower "99" productive intervals, was discovered in May 1924, with the completion of Standard Oil Co. Murphy-Coyote well 99, at a depth of 4,307 feet. Initial daily production was 1,064 barrels of 29° to 30° A.P.I. gravity oil. The entire zone is about 600 feet thick. The Main zone and the Upper "99" are productive throughout the field and have a structural closure of 600 to 700 feet. The Lower "99", with a structural closure of 300 to 400 feet, is much smaller in productive area. During 1950 production from the "99" zone, exclusive of the Lower "99" East pool, was 1,146,000 barrels of oil, produced from 82 wells, of which 5 were completed during that year. During the same period, oil production from the Lower "99" East pool was 157,000 barrels, produced from 13 wells.

A competent shale member, about 50 feet thick, separates the "99" zone from the underlying "138" zone, which is approximately 300 feet thick. The "138" zone was discovered January 19, 1947, with completion of Standard Oil Co. Murphy-Coyote well 193 in the SE1/4 SE1/4 sec. 18, T. 3 S., R. 10 W. Initial production was 318 barrels a day of 33° A.P.I. gravity oil with 0.4 percent water content. In 1950 oil production from the "138" zone was 111,000 barrels, produced from five wells.

The first productive well in the Emery zone was completed in January 1930. This well, Emery 43A, in the SE1/4 SE1/4 sec. 13, T. 3 S., R. 11 W., flowed at the rate of 750 barrels of 30° to 35° A.P.I. gravity oil and 1 barrel of water per day at a gas-oil ratio of 390 cubic feet per barrel.16/ The Emery zone is the deepest commercially productive zone in the field, and the top of the zone occurs at about 4,600 feet below sea level on the crest of the structure. Although the productive area of the Emery zone extends farther along the axis of the structure, it is not as large as that of the Main zone, because the flanks become steeper with depth, especially on the south. The zone has a structural closure of 700 to 900 feet, an areal extent of approximately 800 acres, and a maximum thickness of about 900 feet, of which some 350 feet is productive sand. Development of the zone has been on a 5-acre well-spacing pattern, but the average spacing is considerably greater because all potential well locations have not been drilled. Seventy-five wells had been completed in the Emery zone by the beginning of 1951. A transverse fault, which is a barrier to the migration of oil, separates the Emery zone into two reservoirs, the Emery East pool and the Emery West pool. Gas produced in the field has been injected into the Emery West pool since July 1944 and into the Emery East pool since May 1946 to retard pressure decline, increase ultimate recovery, and maintain the highest efficient rate of production. Gas also is being injected into the Lower "99" East pool in the West Coyote oil field.

Reservoir Data, Emery West Pool17/

Structural contours on top of the productive formation of the Emery West pool are shown in figure 6. The pool, which has a productive area of about 250 acres, is bounded on the south and west by the oil-water contact, and on the north and east by faults. The transverse fault on the east is known to be a barrier to the migration of oil, and the longitudinal fault on the north is believed to be such a barrier, although eight wells (not shown in fig. 6) produce from the Emery zone on the flank north of the longitudinal fault. In describing gas-injection operations in the Emery West pool, however, it is assumed that the pool is limited to the area south and west of the faults indicated in figure 6.

17/ Work cited in footnote 16.
Figure 6. - Structure map, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.
Figure 7. - Electric and core logs, typical central well, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.
Figure 8. - Performance curves, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.
The productive zone is approximately 800 feet thick in the central and northern areas of the Emery West pool and thins progressively toward the western boundary. Although the major sands are persistent, the zone is somewhat lenticular, with interbedded fingers of sand and shale. Some individual sand members cannot be correlated for more than several well locations. The sands are clean and well-consolidated, and the net thickness exposed in different wells ranges from 60 to 360 feet. An electric log of a typical well near the center of the structure is shown in figure 7, which also includes the porosity and permeability of the lower 650 feet of the interval. The sand has an estimated average porosity of 20 percent and average permeability of 70 millidarcys; permeability varies appreciably, however, ranging from 5 to 800 millidarcys. The original productivity indices of the central wells were approximately 2.5 barrels per day per pound per square inch and the specific productivity indices averaged approximately 0.01 barrel per day per pound per square inch per foot.

As there was no primary gas cap in the pool, the production of oil from the Emery West pool had been entirely by solution-gas drive to July 1944, when injection of gas into the reservoir was begun. The initial reservoir pressure was approximately 2,650 p.s.i. at a depth of 5,300 feet below sea level. Original sand saturation was approximately 65 percent oil and 35 percent interstitial water. Pressure-volume-temperature measurements show that the oil originally was saturated with 500 cubic feet of gas per barrel of oil and that the original formation-volume factor was 1.3. The produced oil has an A.P.I. gravity of 33°. The average reservoir temperature is 184°F.

Production History, Emery West Pool

Development of the Emery West pool proceeded gradually following its discovery in 1930. By the end of 1943, there were 29 wells in the pool with an average spacing of 9 acres per well. In the eastern and central parts of the pool, substantially the entire zone of 800 feet thickness is exposed in all wells; in wells drilled in the western tip of the structure, only 150 feet of producing formation is exposed. Typical completion practice is to cement 8-5/8-inch casing in a competent shale body immediately above the Emery zone and finish with a 6-5/8-inch slotted liner opposite the productive zone. The tubing is generally hung approximately 100 feet above the bottom of the liners.

As shown by the performance curves (fig. 8) oil production from the Emery West pool was maintained at rates ranging from 2,400 to 3,700 barrels per day18/ from 1932 to 1935. Most of the wells were shut in during the next 6 years, and the daily production was approximately 1,000 barrels of oil. Production was increased to 3,600 barrels per day in September 1942 and averaged 2,650 barrels per day during the latter half of that year but had declined to 1,600 barrels per day by July 1944, the month in which gas injection was begun. The field was not operated at maximum capacity during these periods. Cumulative production of oil to January 1, 1951, equalled 10.9 million barrels and the net cumulative gas production was 18,600,000 M c.f.

Water production in edge wells, except for two wells, has been insignificant, and it appears that there has been no appreciable water encroachment. Total water production (not indicated in fig. 8) from the pool has been essentially constant since 1943, when it constituted less than 10 percent of the total fluid production.

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18/ The rates shown in figure 8 are average daily rates for semi-annual intervals. Oil production expressed as average daily rates for monthly intervals ranged from 2,000 to 4,000 barrels for the period 1932 to 1935.
Water-bearing sands, from which about half of the total water production has come, are exposed in two wells near the northern boundary of the field.

Reservoir pressure declined steadily from its initial 2,650 p.s.i. to 1,150 p.s.i. in July 1944, the month in which gas-injection operations were begun - a decrease of 56 percent. After the wells are shut in, pressure builds up very slowly to attain stabilized conditions; as a practical expedient, it has been standard practice to measure the static pressure after a shut-in period of 96 hours. Reservoir pressures have been obtained both by volumetrically weighted estimates and by material balances, assuming no encroachment of water. It is believed that the volumetrically weighted method gave reliable estimates of the static equilibrium pressure in the reservoir during the 6 years 1936 to mid-1942, while production was curtailed and most of the wells were shut in. The estimates checked closely with reservoir pressures determined by material balance, thus lending considerable weight to the belief that water encroachment was negligible.

The gas-oil ratio of the Emery West pool gradually increased during the initial 4 years of active production from an average of 591 cubic feet per barrel during the first half of 1932 to 1,830 cubic feet per barrel during the latter half of 1935. During the subsequent 6-year period of curtailed production, the pool gas-oil ratio decreased to a minimum of 940 cubic feet per barrel in the second half of 1940, and the average for the 6 years was 1,271 cubic feet per barrel. This decrease in the pool gas-oil ratio was due to the shutting in of high-gas-oil-ratio wells rather than to any reduction in gas-oil ratios of individual producing wells. When the rate of oil production was increased in 1942, the pool gas-oil ratio also increased steadily to 5,412 cubic feet per barrel in June 1944, just before the inception of gas injection. The cumulative gas-oil ratio to July 1944 was approximately 1,700 cubic feet per barrel.

Cumulative oil production to July 1944 was 7.8 million barrels or an average production of 5,200 barrels per pound per square inch decline in pressure, and total gas recovery was 13,000,000 M c.f. Production for June 1944 was 1,686 barrels of oil, 167 barrels of water, and 9,122 M c.f. of gas per day. At the beginning of the gas-injection project, 9 of the original 29 wells were shut in, mainly because of high gas-oil ratios, 13 wells were flowing, and 7 wells were being pumped.

Secondary Recovery, Emery West Pool

Unit Plan of Operation

During the war, it was necessary to operate the field at a high rate, and a steady decline in reservoir pressure and well productivity resulted. The need for partial-pressure maintenance was indicated to sustain production at a higher rate than otherwise would be possible and to increase ultimate recovery. Accordingly, a unit operating agreement was placed in effect November 1, 1945, between the Emery land lessors, the Murphy land lessor (The California Co.), and Standard Oil Co. of California, lessee of both properties in the West Coyote field. The area unitized in the agreement included 20 wells on the Emery lands and 24 wells on the Murphy lands that were producing from some or all of the formations in the Emery zone and included any future wells drilled in the unit area. The original lease terms of royalty payments were adhered to, but otherwise the leases were combined under the plan for the purpose of controlling development and production to the end that maximum efficiency from the reservoir would be obtained.19/

Gas Injection

The objective in establishing the gas-injection program was to sustain the production of oil at the existing rate of approximately 1,600 barrels a day as long as possible and to restrict the net withdrawal of gas to a maximum rate of approximately 5,000 M c.f. per day. Pilot-plant injection tests were dispensed with because of the urgency for maximum production, and a 1,200-hp. injection plant having a daily capacity of 10,000 M c.f. of gas was installed.

The two initial gas-injection wells, Emery 43-A and MC 120, are situated favorably with respect to two surrounding rings of productive wells and are approximately equidistant from the common lease boundary. Well MC 120 penetrates the entire pay interval, and Emery 43-A was drilled only through the upper half of the productive section. This well was deepened to the lower half of the Emery zone in 1947. The production histories of these two wells are summarized in Table 4.

**Table 4. - Production history of injection wells before gas injection, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.**

<table>
<thead>
<tr>
<th>Production terminated</th>
<th>Emery 43-A</th>
<th>MC 120</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>October 1943</td>
<td>December 1943</td>
</tr>
<tr>
<td>Production of oil ................. bbl. per day</td>
<td>112</td>
<td>381</td>
</tr>
<tr>
<td>Production of water ...................... do.</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Production of gas ....................... M c.f. per day</td>
<td>491</td>
<td>2,917</td>
</tr>
<tr>
<td>Gas:oil ratio .................. cu. ft. per bbl.</td>
<td>4,404</td>
<td>7,665</td>
</tr>
<tr>
<td>Cumulative production of oil ............. bbl.</td>
<td>797,475</td>
<td>485,820</td>
</tr>
<tr>
<td>Cumulative production of water ........... do.</td>
<td>1,637</td>
<td>2,085</td>
</tr>
<tr>
<td>Cumulative production of gas ............ M c.f.</td>
<td>899,615</td>
<td>1,142,678</td>
</tr>
<tr>
<td>Productivity index .......... bbl. per day per p.s.i.</td>
<td>0.4</td>
<td>1.4</td>
</tr>
</tbody>
</table>

To promote an even spread of the injected gas, it was planned to produce equal volumes of reservoir fluids from each of the inner ring of wells. For this purpose, it was necessary to return to production 6 wells that had previously been shut in because of their high gas-oil ratios.

Gas injection was begun on July 10, 1944, at an initial rate of approximately 4,000 M c.f. of gas per day, the volume of injected gas being divided equally between the two injection wells. The rate of injection was gradually increased and by January 1945, 10,000 M c.f. of gas per day, corresponding to the plant capacity, was being injected. Initial subsurface injection pressures in wells MC 120 and Emery 43-A, 20 and 190 p.s.i., respectively, were higher than the static reservoir pressures before gas injection. When, early in 1945, the rate of injection was increased to 10,000 M c.f., surface injection pressures increased to 1,150 p.s.i. by an increment of almost 100 p.s.i.

Injection was continued at this rate during 1945 and 1946, and production of oil was maintained at approximately 1,600 barrels per day (fig. 8). The net rate of gas withdrawal averaged about 3,000 M c.f. a day, or about one-third of that prevalent in June 1944, immediately before the inception of gas injection, and the decline in pressure in most of the wells was decreased materially. In well Emery 64, the shut-in pressure observation well in the western area of the pool, the pressure decline was reduced almost immediately at the inception of gas injection, and the regional pressure increased early in 1945 when the daily injection rate was stepped up to 10,000

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20/ Work cited in footnote 16.
M c.f. of gas. Pressure measurements in well MC 124, the eastern pressure-observation well, showed that regional pressure decline also was reduced in the eastern area of the pool. Material-balance calculations showed that the over-all decline in reservoir pressure was reduced to approximately 0.2 p.s.i. per day as compared to a decline of 0.65 p.s.i. per day before injecting gas.

The only notable evidence of bypassing of injected gas in the early life of the program occurred in well Emery 50, the nearest productive well to injection well Emery 43-A. Gas production from well Emery 50 increased from 450 M c.f. to 900 M c.f. per day during the first 6 months of gas injection, indicating that some 400 M c.f. of the total volume (5,000 M c.f. per day) of injected gas was bypassing to this well. Although these wells are 600 feet apart at the surface, a directional survey showed them to be only 350 feet apart in the productive zone, which may account for the excessive bypassing of gas to well Emery 50. The gas-oil ratio continued to increase at a reduced rate to a maximum of 23,000 cubic feet per barrel in January 1946, when the well was closed in and subsequently converted to an injection well. Only two other wells, Emery 68 and MC 111, adjacent to the injection wells - Emery 43-A and MC 120, respectively - showed significant increases in gas-oil ratio within 2 years after gas injection was begun. In both of these wells, however, the effect was much less pronounced and occurred later than at well Emery 50. There were no other large, abnormal increases in gas-oil ratio during the first 2 years of the injection program, and the pool gas-oil ratio increased normally until mid-1945.

An unusual reversal of the normally increasing trend of the pool gas-oil ratio occurred in 1945. As shown in figure 8, the average semiannual gas-oil ratio of the pool increased during the first year of gas-injection operations to 8,300 cubic feet per barrel for the first half of 1945 and then decreased to about 6,800 cubic feet per barrel for the latter half of 1945 and the first half of 1946. The average monthly gas-oil ratio showed an even more pronounced reversal, attaining a maximum of nearly 9,000 cubic feet per barrel in April 1945, followed by a minimum of 6,000 cubic feet per barrel in November of the same year. A substantial reduction in gas-oil ratio occurred in 14 individual wells, including all wells on the Emery lease north and west of injection well Emery 43-A. This decrease in ratio was not caused by selective operation of wells or by a change in withdrawal rates but resulted from increased oil production in the foregoing 14 wells. It appears that the injected gas forced oil to migrate from the central to the northwestern area of the structure thereby increasing oil saturation in this area. This increase in saturation resulted in increased productivity of the wells at reduced gas-oil ratios. This general result of the gas-injection project may be interpreted as favorable to increased ultimate recovery.

Following the interlude of decreasing gas-oil ratios during 1945, the ratio again resumed its upward trend in the second quarter of 1946 and reached 10,000 cubic feet of gas per barrel of oil in January 1947, with a total gas production of 18,000 M c.f. per day. As shown in figure 8, net gas production increased correspondingly in 1946 at a constant-injection rate of 10,000 M c.f. of gas per day. The injection rate was increased to 12,000 M c.f. of gas per day in January 1947. As the beneficial effects of the program became evident, steps were taken to increase the efficiency of the entire project by improving field operations.

Consideration was given early in the history of the injection project to use of a tracer to determine the movement of the injected gas, to identify the wells to which gas was bypassing, and to serve as a measure of the volume of bypassing gas. After field experiments showed that 1 percent air, which was present in the injection gas, was unsatisfactory as a tracer, further consideration led to the conclusion
Figure 9. - Spinner survey, Emery well No. 43-A, West Coyote field, Orange and Los Angeles Counties, Calif.
that tracers, in general, are now of minor value in the Emery West pool, as any serious bypassing is generally immediately apparent from gas-oil ratio anomalies.

Thermometric surveys in nine high-gas-oil-ratio wells under both static and flowing conditions at low and high rates were inconclusive, as the gas evidently was entering the wells over fairly broad intervals of sand, and no significant changes in temperature were produced. Similar measurements made in the injection wells were more conclusive, however, and showed that the gas was entering the upper portions of the injected zone. A spinner survey in Emery 43-A confirmed the general indications of the thermometric survey. As shown in figure 9, the spinner survey was sharply definitive in showing that about 4,500 M c.f. per day, or three-fourths of the total 6,000 M c.f. of injected gas, were entering the uppermost 100 feet of the injected zone.

Early in 1947 it was evident that considerable remedial work should be done. Capacity of the absorption plant for processing the produced gas had been reached and further increases in gas-oil ratio would require either additional plant facilities, remedial work in selected wells to reduce bypassing, or curtailment in oil-production rates. It also was realized that the injected gas was not displacing oil from the lower sand intervals of the zone, especially in the western portion of the pool. Inasmuch as enough remedial work on productive wells to meet these problems would require large expenditures and would be hazardous to oil productivity, it was decided to control the injected gas more closely by selective injection in the two gas-injection wells. As already mentioned, the thermometric measurements had shown that the injected gas was entering well MC 120 fairly uniformly, but similar measurements and especially the spinner survey in well Emery 43-A showed that injected gas was entering only the upper 100 feet of the zone. It was decided, therefore, to deepen Emery 43-A through the lower half of the Emery zone, using oil as the drilling fluid. The well was recompleted with a cemented liner selectively gun-perforated to expose only the intermediate and lower sand members to gas injection. A production packer was set in a cemented blank section of casing near the base of the intermediate section of the zone. Gas injection was resumed in the well in late 1947 at a daily rate of 6,000 M c.f., of which approximately 2,000 M c.f. was injected into the intermediate zones through the casing and 4,000 M c.f. into the lower zones through the tubing.

During the third quarter of 1947, when Emery 43-A was being deepened and repaired, the entire available volume of 12,000 M c.f. of gas per day was injected into MC 120. The static pressure in the eastern area of the pool increased slightly during this period, but there was no equivalent increase in bypassing of gas.

When gas injection into the upper part of the zone in Emery 43-A was stopped, many wells in the western area of the pool experienced sharp decreases in static pressure and gas-oil ratio. Pressures in the western wells, especially those that expose only the upper sands, continued to fall after injection was resumed in Emery 43-A. It was evident, therefore, that the upper sands in the western area again should be repressed, but at a lower rate. Well Emery 50, which is one location west of Emery 43-A and had been shut in because of its high gas-oil ratio, was utilized for injecting gas into the upper intervals of the zone. Gas was introduced through the casing of this well at an approximate rate of 2,000 M c.f. per day, and the desired effect of increased pressures was soon apparent in the surrounding wells.
Progress of Pressure-Maintenance Project

Since 1946, oil has been produced to the capacity of all wells except from those with very high gas-oil ratios. Production from the high-ratio wells has been limited to maintain net gas withdrawals from the pool within a maximum of 5,000 M c.f. of gas per day and gross production of gas within the capacity of the absorption plant. Production of oil averaged 1,150 barrels per day in January 1949. Cumulative recovery of oil to January 1, 1949, was 10.4 million barrels. Oil produced under the injection program amounted to 2.6 million barrels, or 25 percent of the total recovery to January 1, 1949.

The capacity of the absorption and injection plants was each increased by approximately 2,000 M c.f. per day in January 1947, and withdrawals from the restricted high gas-oil ratio wells were increased accordingly (fig. 8). Both plants again were enlarged early in 1948. Gas production was increased to 18,000 M c.f. and gas injection to 14,000 M c.f. per day, leaving a net gas production of 4,000 M c.f. per day.

Early in 1949, to conserve reservoir pressure, gas production was reduced to a minimum of 14,000 M c.f. per day while additional equipment was being installed to increase the rate of gas injection to 17,500 M c.f. a day. As the total volume of gas injected during that year exceeded the volume of the produced gas by about 75,000 M c.f., 200 M c.f. of gas per day was stored in the reservoir.

In 1950, both the gas-production and injection rates were increased to about 20,000 M c.f. per day, and the net gas production averaged less than 500 M c.f. per day.

In January 1951 the daily production from the pool was 905 barrels of oil, 226 barrels of water, and 19,001 M c.f. of gas. About 18,921 M c.f. of gas was injected daily, leaving a net daily gas production of 83 M c.f.

The gasoline content of the produced gas before the gas-injection program was begun ranged from 0.7 to 1.3 gallons per M c.f. and averaged 0.96 gallons per M c.f. After about 4 years of gas injection, tests showed that the average gasoline content was 0.94 gallons per M c.f. The gasoline content of the gas from wells producing large volumes of bypassed injected gas, with gas-oil ratios exceeding 30 M c.f. per barrel, was only about 20 percent lower than the original content. As the injected gas contains only 0.1 gallon of gasoline per M c.f., it is evident that it is absorbing large quantities of light hydrocarbons as it passes through the reservoir.

Figures 10 and 11, respectively, show the distribution in gas-oil ratios in individual wells in June 1944, immediately preceding the beginning of the gas-injection program, and in January 1949, after 4-1/2 years of gas-injection operations. The movement of the injected gas within the central area of the pool is evident from the changes that have taken place in the gas-oil ratios of the individual wells during the injection program. In January 1949 the gas-oil ratios of individual wells ranged from 1,000 cubic feet per barrel at the western tip of the pool to 30,000 cubic feet per barrel in areas in the immediate vicinity of the injection wells.

Figures 12 and 13, respectively, show pressure distribution in the reservoir on July 1, 1944, and January 1, 1949. There are no undesirable pressure gradients or sinks in evidence in figure 13; the pressure decreases uniformly from the injection wells to the outer wells of the pool.

Reservoir pressure declined from 1,150 to 700 p.s.i. from July 1944 to January 1, 1949. During this period, cumulative oil production was 2.6 million barrels, an
Figure 10. - Gas-oil ratio map, June 1944, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.

Figure 11. - Gas-oil ratio map, January 1949, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.
Figure 12. - Isobaric map, July 1, 1944, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.

Figure 13. - Isobaric map, January 1, 1949, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.
Figure 14. - Net current and net cumulative gas-oil ratios versus cumulative oil production, Emery West pool, West Coyote field, Orange and Los Angeles Counties, Calif.
average production of 5,778 barrels per p.s.i. drop in pressure, as compared to 5,200 barrels per unit of pressure drop before gas injection. Rate of pressure decline has decreased markedly since the beginning of gas injection, as shown in figure 8.

Table 5 summarizes production statistics for the over-all 6-1/2-year periods immediately before and after gas injection was begun. As the ultimate oil recovery from a solution-gas drive field depends upon the efficiency of utilization of the available gas volumes to displace oil, the relative recovery efficiency can be qualitatively evaluated by comparing net gas-oil ratios. As shown in table 5, the net gas-oil ratio during injection is 25 percent less than the net gas-oil ratio before gas injection. A comparison of the current and cumulative net gas-oil ratios as functions of the cumulative oil recovery for the over-all periods before and after gas injection shows that additional gas has continued to remain in the reservoir during the life of the injection program (fig. 14). The displacement efficiency of this volume of gas is expected to increase the ultimate oil recovery as well as the recovery rate.

**TABLE 5.** - Production statistics for 6-1/2-year periods before and after gas injection, West Coyote field, Emery West pool, Orange and Los Angeles Counties, Calif.

<table>
<thead>
<tr>
<th></th>
<th>6-1/2-yr. period 1/ before start of gas injection</th>
<th>6-1/2-yr. period 2/ after start of gas injection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil production .......... bbl.</td>
<td>3,350,000</td>
<td>3,185,000</td>
</tr>
<tr>
<td>Gas production .......... M c.f.</td>
<td>7,767,000</td>
<td>36,381,000</td>
</tr>
<tr>
<td>Gas injection ............. do.</td>
<td>0</td>
<td>30,890,000</td>
</tr>
<tr>
<td>Net gas production ........ do.</td>
<td>7,767,000</td>
<td>5,491,000</td>
</tr>
<tr>
<td>Gross gas-oil ratio .... cu. ft. per bbl.</td>
<td>2,318</td>
<td>11,422</td>
</tr>
<tr>
<td>Net gas-oil ratio ........ do.</td>
<td>2,318</td>
<td>1,724</td>
</tr>
</tbody>
</table>

1/ January 1, 1938-July 10, 1944.

Although the great thickness and the varying permeability of the reservoir sands and the tendency of the injected gas to flow preferentially into the upper sands with attendant bypassing of oil have complicated the pressure-maintenance project in the Emery West pool, these difficulties have been largely eliminated by selective injection, maintenance of a high injection rate, and controlled production. The decline in reservoir pressure has been nominal. In view of the demonstrated success of the project it will be continued.

**Richfield Field, Richfield Area - Water Injection**

**General Description of Field**

The Richfield oil field in northern Orange County comprises two separate productive areas, the Richfield area and the Kraemer area. The latter area, also

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known as the Santa Ana Canyon field, lies approximately 2 miles east of the Richfield area. The Richfield area, discovered in 1919, is about 6 miles east of Fullerton and comprises parts of projected secs. 27 to 34 inclusive, T. 3 S., R. 9 W., S.B.B. and M. Approximately 1,200 acres of the area are productive. Oil production is obtained from two zones, the Chapman and the Kraemer, both of upper Miocene age.

The productive structure of the Richfield area (fig. 15) consists of two nearly parallel anticlines, which trend easterly. A northeast extension of the major, more northerly anticline is separated from the main productive area by a saddle. The minor anticline, lying south and east of the main anticline, consists of two domes with an intervening saddle. It is designated as the Richfield Consolidated anticline and is separated from the main anticline by a zone of shear.

As shown in figure 15, the depth of the productive area of the Chapman zone ranges from 2,450 to 3,200 feet below sea level. The Chapman zone is almost 600 feet thick near the crest of the structure, and in the western part of the field it includes 300 to 350 feet of oil sand and about 250 feet of underlying shale and siltstone containing thin beds of oil sand. The net sand thickness of the zone is nearly 400 feet. A wedge of shale penetrating the sand body from the east divides the sand in the central and eastern parts of the field into two productive intervals, known as the Upper and Lower Chapman zones. A generalized geologic column,24/ shown in figure 16, illustrates conditions near the axis of the western plunge of the main anticline.

Well spacing in the Richfield area is irregular as a result of offset drilling and pronounced local variations in productivity. Average well spacing throughout the area is less than ¼ acres per well on a basis of presently productive wells and less than 3 acres per well if abandoned wells are included.

Reservoir Data

The productive part of the Chapman zone is an irregularly shaped sand body in which the net sand thickness varies widely. Interfingering shale bodies become more prominent as the productive limits of the field are approached and almost completely replace the sands in some areas. Babson, Sherborne, and Jones25/ report that the sand of the Chapman zone is of medium grain size, friable, usually argillaceous, and poorly sorted and has an average porosity of approximately 31 percent and an average permeability to air of about 1,100 millidarcys. The average interstitial-water content is estimated to be 37 percent. The gravity of the oil from the Chapman zone ranges from 16° to 22° A.P.I. and averages about 19° A.P.I. in the vicinity of the Chapman lease. The viscosity of the produced oil, free of dissolved gas, is approximately 50 centipoises at the reservoir temperature of 140° F. An estimate based on depth-pressure gradients prevalent in other Los Angeles Basin fields indicates that original reservoir pressures were about 1,400 p.s.i. in the Chapman zone. Bottom-hole pressures in a part of the Chapman zone were about 600 p.s.i. in 1936.26/

Figure 16. - Generalized geologic column, Richfield field, Orange County, Calif.
Figure 17. - Performance curves, Richfield field, Orange County, Calif.
The principal recovery mechanism in the Chapman zone was dissolved gas drive, although the presence of a partial water drive is indicated by considerable water production, which, in recent years, has surpassed the oil production. Water encroachment is localized, however, and is more evident in the eastern than in the western parts of the field.

In the first wells drilled through the Chapman zone into the Kraemer, no water was found between the zones. Consequently, many combination wells were completed in both zones, with no blank pipe below the top of the Chapman zone. Pressure differences between the zones, however, caused the loss of considerable oil from the newly developed Kraemer zone into the partly depleted Chapman zone. Consequently, the Chapman zone has been cased off in later wells completed in the Kraemer zone.

Gas-oil ratios were not recorded during the early history of the field, and the available production statistics do not permit computations of current production gas-oil ratios for each zone separately. Estimates by the State of California Railroad Commission and the State Department of Natural Resources indicate that the production gas-oil ratio for the field approached 1,500 cubic feet per barrel during 1923.\(^{27}\) Yearly average gas-oil ratios for the field from 1945 through 1949 ranged from 761 to 831 cubic feet per barrel. The production gas-oil ratio in one area of the Chapman zone in 1936 was approximately 300 cubic feet per barrel, and the gas-oil ratio of the field as a whole was 714 cubic feet per barrel during that year. The original formation-volume factor for the Chapman zone is estimated to be 1.12.

**Production History**

A rapid development program, following discovery of the field in March 1919, resulted in a peak oil production of 28,000 barrels per day in October 1921. In March 1925 production had declined to 10,800 barrels of oil per day. A second production peak of 23,000 barrels of oil per day was attained in July 1927, following extensive development of the Kraemer zone. The semiannual oil and water production, cumulative oil production, production gas-oil ratio, and average number of productive wells, at 6-month intervals throughout the history of the field, are shown graphically in figure 17. The data, other than those indicating gas-oil ratios before the latter half of 1929, were prepared from statistics published by the State Division of Oil and Gas.\(^{28}\) The gas-production figures used for the computation of gas-oil ratios from 1923 to 1929 were based on estimates of the California Railroad Commission and State Department of Natural Resources. The data include production from the Kraemer area (Santa Ana Canyon field), which has provided approximately 1-1/2 percent of the total oil production from an average of 10 productive wells, and the combined production from the Chapman and Kraemer zones in the Richfield area. Estimates by the Conservation Committee of California Oil Producers\(^{29}\) indicate that from 1938 to 1942 about one-third of the yearly oil production of the field came from the Chapman zone.

The usually low rate of decline in oil production since 1931 is the result of curtailment of production during 1930 to 1936 and subsequent infill drilling and

\(^{27}\) Railroad Commission of the State of California and Department of Natural Resources, Division of Oil and Gas, Estimate of the Natural Gas Reserves of the State of California as of Jan. 1, 1946: Case 4591, Special Study S-525, chap. 63, pp. 273-275.

\(^{28}\) Summary of Operations, California Oil Fields, vols. 6-35.

\(^{29}\) Petroleum World, California Oil-Field Data: Annual Review, 1938, 1939, 1940, 1941 and 1942.
remedial work. During the 21 years, 1927 to 1947, more than 220 productive wells were completed, with only a slight increase in the proved acreage of the field. In the same period some 80 productive and 50 nonproductive wells were abandoned. In 1948 and 1949 26 new wells were completed as producers, with an average initial production of 53 barrels of oil per well per day.

Water Flooding

With many wells in the Chapman zone approaching an unprofitable level of production, engineers\(^{30}\) of the Union Oil Co. of California investigated subsurface conditions in the Chapman zone. The study indicated that ultimate oil recovery by primary methods would be about 21 or 22 percent of the oil originally in place and that approximately 19 percent of the oil in place had been produced. As a result of this study, a small-scale water-flooding project was begun in 1944 to determine whether water would effectively displace some of the residual oil from the Chapman sand and to serve as a guide in future secondary-recovery operations.

Factors influencing selection of a site for the water flood included consideration of possible damage to the reservoir, extent of previous water encroachment, degree of depletion of the sands to be water-flooded, and minimization of offset difficulties. Because of the possibility of an unsuccessful flood, it was desirable to conduct the experiment in a sand finger of relatively limited volume. It was desirable also to select an area where there was a minimum of edge-water encroachment and where the wells were approaching an unprofitable level of production. A thin sand section near the productive limits of the Chapman zone on the north flank of the western plunge of the main anticline was selected for the experiment.

A water-injection well, Chapman well 47, was drilled midway between wells 39 and 41 (fig. 18). Each of these wells had been producing about 7 barrels of oil and 1 barrel of water per day. The injection well was drilled through both the Chapman and Kraemer zones to permit recompletion in the Kraemer zone at a later date and then plugged back to the Chapman zone. The Chapman sand body was cored through its entire thickness of 38 feet in well 47. Core analyses showed the average porosity of the sand interval to be 29.1 percent and the average air permeability 422 millidarcys.

Before running cement-lined tubing for water injection, well 47 was tested and produced 4 barrels of 18.2° A.P.I. gravity oil and 1 barrel of water per day over a period of more than a month. During this period, the well was treated with 250 gallons of inhibited hydrochloric acid to clean the sand face, but no increase in production was recorded.

Water for injection was obtained from the field water-disposal system, in which water produced from both zones was collected. This source proved ample, as the water production of the field ranged from five to nine times the maximum water requirement of the injection project to the end of 1949. The salinity of the composite water from the disposal system is nearly double that of the Chapman zone water.

Laboratory tests on Chapman zone core samples indicated that plugging of the sand would result from the use of field water which was untreated, treated by filtration only, or treated by flocculation with alum followed by filtration. Small pilot-plant tests showed that satisfactory water could be obtained by primary flocculation with alum, followed by chlorination, secondary flocculation with alum, and filtration. The purpose of the primary flocculation was to remove suspended solids

\(^{30}\) Work cited in footnote 25.
Figure 18. - Chapman lease map, Richfield field, Orange County, Calif.
from the water before chlorination, thereby reducing the amount of chlorination necessary to convert the unstable water-soluble organic material to a form susceptible to removal by a secondary flocculation.

A plant was constructed to treat a maximum of 1,000 barrels of water per day. The principal elements of the plant were a sand filter and two flocculator units of conventional design, an electrolytic chlorinator, and associated storage basins, pumps, and controls for automatic operation. The primary flocculator, which was designed to remove only suspended material, was considerably smaller than the secondary flocculator. The chlorinator consisted of closely spaced, multiplate, carbon electrodes mounted in a wooded trough. A direct current at potentials ranging from 4 to 6 volts was supplied to the chlorinator. Treated water from the clear-water storage basin of the plant was conveyed by a centrifugal pump through 3,500 feet of 3-inch Transite pipe to the intake of the high-pressure pump at the injection well.

Water injection was begun into Chapman well 47 on March 29, 1944, at a rate of 44 barrels of water per day. This rate was gradually increased until the average for the following month was 154 barrels of water a day. Interruptions caused by mechanical difficulties reduced the average injection rate for the first half year of operation to 119 barrels of water per day. The surface injection pressure increased from subatmospheric during the first few days of operation to an average of 812 p.s.i. during September 1944. Table 6 shows the water-injection history of Chapman well 47 from 1944 through 1949.31

<table>
<thead>
<tr>
<th>Year</th>
<th>Volume of water injected during year, bbl.</th>
<th>Cumulative volume injected to end of year, bbl.</th>
<th>Average volume injected daily, bbl.</th>
<th>Wellhead injection pressure, end of year, p.s.i.a.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1944</td>
<td>34,488</td>
<td>34,488</td>
<td>124</td>
<td>770</td>
</tr>
<tr>
<td>1945</td>
<td>1/73,000</td>
<td>1/107,488</td>
<td>1/200</td>
<td></td>
</tr>
<tr>
<td>1946</td>
<td>1/109,484</td>
<td>216,972</td>
<td>1/300</td>
<td>1,000</td>
</tr>
<tr>
<td>1947</td>
<td>109,928</td>
<td>326,900</td>
<td>301</td>
<td>700</td>
</tr>
<tr>
<td>1948</td>
<td>86,928</td>
<td>413,828</td>
<td>238</td>
<td>616</td>
</tr>
<tr>
<td>1949</td>
<td>85,487</td>
<td>499,315</td>
<td>234</td>
<td>280</td>
</tr>
</tbody>
</table>

1/ Estimated.

At one time during 1945 a break-through occurred, as evidenced by a sudden increase in injection rate without a proportional increase in applied pressure. Surface pressure at the time of the break-through was 1,050 p.s.i., corresponding to an estimated pressure of 2,500 p.s.i. at the sand face at an approximate depth of 3,400 feet. Inasmuch as the overburden factor, defined by Grandone and Holleyman32 as the ratio obtained by dividing the critical input pressure (in p.s.i.) by the mean depth (in feet), is considerably less than unity, it is assumed that the break-through did not involve a lifting of the overburden. Normal operation conditions were restored by sharply reducing the water-injection rate and the injection pressure and then gradually increasing the rate of injection until a pressure slightly below that of break-through was attained.

Water flooding in the Chapman lease was expanded in 1948, when water injection was begun through well 39, about 265 feet northwest of the original injection well 47, and through wells 43, 50, and 52, a group of adjacent wells about 1/3 mile northeast of well 47. Well 39 was a former producer that had been flooded out in 1945 during the early stages of the project. Wells 50 and 52 were equipped to permit simultaneous production of oil from the Kremer zone and injection of water into the Chapman zone. The volumes of water injected through each of the four supplementary injection wells during 1948 and 1949, and the wellhead pressures at the end of each year are given in table 7.

**TABLE 7. - Injection data covering wells into which water injection was begun during 1948, Chapman zone, Richfield field, Orange County, Calif.**

<table>
<thead>
<tr>
<th>Lease and well No.</th>
<th>Volume of water injected during year, bbl.</th>
<th>Wellhead injection pressure at end of year, p.s.i.a.</th>
<th>Injection rate at end of 1949, bbl. per day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chapman 39</td>
<td>22,529 28,450</td>
<td>638 935</td>
<td>112</td>
</tr>
<tr>
<td>Chapman 43</td>
<td>39,914 42,205</td>
<td>15 170</td>
<td>170</td>
</tr>
<tr>
<td>Chapman 50</td>
<td>42,431 56,626</td>
<td>8 3</td>
<td>160</td>
</tr>
<tr>
<td>Chapman 52</td>
<td>13,137 18,675</td>
<td>638 375</td>
<td>56</td>
</tr>
</tbody>
</table>

Utilizing the experience gained during almost 4 years of water injection through Chapman well 47 and the results of a study of the plugging effect of the injection water, the method of water treatment at Richfield was modified considerably in 1948. The use of flocculators was discontinued, the sand filter was replaced by one of a different type, and a polyphosphate was added to the water to inhibit precipitation of calcium compounds. Water treatment under the modified method consisted of chlorination, addition of polyphosphate, and filtration.

The filter in the improved water-treating plant had approximately 100 square feet of filtering surface provided by a 1/8-inch layer of diatomaceous silica supported on a Monel-metal screen. During operation, the pressure drop across the filter increased gradually from about 3 p.s.i. immediately after coating with silica to 20 p.s.i. just before back washing, which was done at intervals of 2 or 3 days. After back washing to disintegrate and remove the filter cake, the filter was recoated by cycling an aqueous suspension of diatomaceous silica through the filter at a rate of 1.2 gallons per minute. Formation of the silica layer or filter cake was indicated by an increase in the pressure drop across the filter to 2 or 3 p.s.i. Back washing and recoating of the filter required 1/2 to 1 hour. The filter had a maximum capacity of 200 gallons per minute but was operated at a fraction of its rated output. A minimum throughput of 1/4 gallon per minute per square foot of filtering surface was required to maintain the filter cake intact. Filtering rates of less than 25 gallons per minute were obtained, when necessary, by blanking off part of the screen with impermeable material. Some difficulty was experienced with corrosion of filtering equipment.

Although the water was completely sterile as it left the chlorinator of the original water-treating plant, micro-organisms reappeared so quickly that the bacterial

count of the injected water was many times that of the raw water. Laboratory tests showed that this water would plug sintered glass disks, although there had been no evidence, attributable to bacteria, of plugging the formation around the injection well. Accordingly, quartz-tube ultraviolet lamps with rated electrical input of 30 milliamperes (60 watts), were installed over the clear-water storage basin of the modified water-treating plant and the growth of micro-organisms was greatly inhibited. Altogether, three lamps were used, each containing 6 feet of quartz tubing.

Effects of Water Injection

The first definite effect of water injection into Chapman well 47 was noted less than 2 months after injection was begun; when an increase was recorded in the oil production of Chapman well 39, about 265 feet northwest of well 47 and 50 feet structurally lower. Well 39 had produced 226 barrels of oil and 28 barrels of water during March 1944. During May 1944, its oil and water production were increased one-half and one-third, respectively. Production from this well rose to 945 barrels of oil and 532 barrels of water in July 1944. A peak production of over 40 barrels of oil per day was reached in October of the same year. Oil production then declined and water production increased until 16 barrels of oil and 96 barrels of water per day were produced from the well at the end of 1944. By September 1945, when the casing collapsed and the well was shut in, the water production had risen to 94 percent of the daily fluid production. As stated, this well later was converted to an injection well.

Changes were recorded in the production rates of several other wells in the vicinity of the water flood, including wells 17, 38, 41, and 44.

The daily production from well 44, some 100 feet structurally higher than, and 600 feet northeast of, well 47, had increased by the end of 1944 to 53 barrels of oil and 80 barrels of water from 35 barrels of oil and 55 barrels of water in March 1944. The increase was coincident with a marked reduction in the operating fluid level of the well and may have occurred from the change in fluid level instead of the effects of the water flood. The daily production of this well was reported as 128 barrels of oil and 14 barrels of water at the end of 1947, but these figures are not considered representative because the water content of the produced fluid was measured just after the well had been returned to production after a shut-down of several weeks.

The daily production from well 38, about 900 feet northeast of well 47 and 50 feet higher on the structure, increased to 42 barrels of oil and 85 barrels of water by the end of 1947 from 14 barrels of oil and 46 barrels of water in March 1944. This increase, like that in well 44, was coincident with a marked decrease in the operating fluid level of the well. At the end of 1949 the oil production from well 38 had declined to 37 barrels, and the water production had increased to 132 barrels per day.

An increase in the fluid production from well 41, about 300 feet southeast of well 47 and 100 feet structurally higher, was recorded at the end of 1947, when production was 12 barrels of oil and 7 barrels of water per day. The daily production from this well in March 1944 was 7 barrels of oil and 1 barrel of water.

It was estimated that, of a cumulative total of approximately 217,000 barrels of water injected into well 47 by the end of 1946, about 41,600 barrels of water had been produced from adjoining wells. It is believed that most of the additional water production came from well 39.

35/ Work cited in footnotes 25 and 31.
During 1948, the daily oil production from well 17 increased temporarily. This increase is considered of little significance, as it occurred shortly after the tubing in well 17 had been lowered about 40 feet and lasted only a few months. The daily oil production from nearby wells, previously reported as increasing, decreased during 1948 by amounts ranging from 18 to 43 percent, and, with one exception, the water production from these wells increased by amounts ranging from 15 to 70 percent. Water production from the excepted well decreased about 20 percent.

After the water flood was extended by injection into wells 43, 50, and 52, an increase was recorded in the production from well 36, which is immediately adjacent to each of these three injection wells and down structure from wells 43 and 50. The daily production from well 36 increased during 1948 from a previous average of 15 barrels of oil and 9 barrels of water to 43 barrels of oil and 33 barrels of water, and at the end of 1949 production was 44 barrels of oil and 47 barrels of water per day.

An analysis of the well-production data given above indicates that from 1944 through 1947 there were temporary increases in the oil production from various wells in the vicinity of well 47. The oil production from one well downstructure from the injection well was increased immediately after water injection was begun, but the water production increased so rapidly that the well was flooded out within 18 months. If reported production rates alone are considered, it would appear that the combined daily oil production from four upstructure wells at the end of 1947 was triple that before water injection was begun, and in two of these wells substantially increased oil production rates had been maintained over a period of 3 years. However, in view of the questionable production rate of well 44 at the end of 1947 and the changes in operating conditions occurring during the period, it is evident that the effectiveness of the water flood cannot be determined quantitatively on the basis of available production statistics.

The effects of the water flood on oil-production rates of the Chapman lease and of the field as a whole are largely masked by the effects of infill drilling and remedial work. As an example, a comparison of production rates prevalent during 1949 with those of 1948 shows that production from the entire field increased by almost 3-1/2 percent, while Chapman-lease production increased by approximately 1 percent and production from the Kraemer 2 lease, immediately south of the Chapman lease, remained essentially constant. As the only large-scale secondary-recovery project in the field at that time was on the Chapman lease, the increases are mainly attributable to drilling and remedial work.

Definite conclusions as to the economic success of the project described herein are unwarranted on the basis of data available to the authors. The nonavailability of cost data and the limited availability of performance data prevent making the type of engineering study requisite to the support of such conclusions. It is evident, however, that operation of the project has proved that water injection into the Chapman sand can be sustained over a long period and that such injection can result in temporary increases in the oil-production rates of wells in the vicinity of the flood. Obviously, the extended period of operation of the flood, although not necessarily indicative of its economic success, demonstrates its importance to the operator.

**Dominguez Field - Water Injection**

Two experimental water-injection projects are being operated in the Dominguez oil field, Los Angeles County, by Union Oil Co. of California. Since February 1947,
Figure 19. - Structure map, Del Valle field, Los Angeles County, Calif.
formation water has been injected into the Pliocene Third zone, East Central block, through Hellman well 3, and into the Pliocene Fifth zone, West block, through Callender well 83. Early in 1949 water injection was begun through Callender well 90 to increase the volume of water entering the Fifth zone.

The Third-zone project involves flooding a partly depleted oil sand in which the recovery mechanism has been a combination dissolved-gas and natural water drive. Injection is into the edgewater on the north flank of the structure. The Fifth-zone project involves the primary pressure maintenance of a small pool in a part of this zone. This pool, which is separated by pressure barriers from other pools in the Fifth zone, was discovered late in the history of the field in January 1944.

Water for injection is obtained from the field water-disposal system. This source has been more than adequate, as the water-production rate of the field has been from five to six times the maximum water injection rate to the end of 1949. During that year, water for injection was being treated in two plants at Dominguez. The older plant, utilizing a flocculation process similar to that of the first water-treating plant in Richfield oil field (see p. 23), was operated at about half of its rated capacity of 1,800 barrels of water per day. The newer plant, similar to the improved plant in the Richfield oil field, operates near its full output of 1,500 barrels per day. Processing the field water for recovery of iodine removes the bulk of suspended material from the water before it enters the injection-water plants. The treated water has a salinity of about 30,000 parts per million.

Each project attained a water-injection rate of approximately 1,300 barrels per day in October 1949. Wellhead injection pressures in June 1949 ranged from 1,200 to 1,700 p.s.i. From the inception of water injection to the end of 1949, a cumulative total of 612,105 barrels of water had been injected through Hellman well 3 and 378,896 barrels of water through Callender wells 83 and 90.

Little information has been released concerning the effects of water injection at Dominguez, other than that the rate of pressure decline of the pool in the Pliocene Fifth zone, West block, had been reduced from 15 p.s.i. per month before injection was begun to less than 3 p.s.i. per month during 1949. Pressure maintenance by water injection was begun only 3 years after discovery of the pool while all five productive wells in the pool were still flowing. During 1949, three of the wells were being pumped and two were flowing.

Del Valle Field - Water Injection

General Description of Field

The Del Valle oil field in northwestern Los Angeles County was discovered in September 1940 by R. E. Havenstrie, operator. The decision to drill the discovery well was based on a geological study of the surface structure by R. W. Sherman. The field, shown in figure 19, is approximately 9 miles northwest of Newhall and

37/ Conservation Committee of California Oil Producers, Historical Section, Annual Review of California Crude Oil Production, Year 1949: Conservation Data, table 3; p. C.
38/ Sherman, R. W., Del Valle Anticline Oil Prospects: California Oil World and Petroleum Industry, vol. 33, No. 9, 1st issue, May 1940, pp. 2-9; also vol. 33, No. 17, 1st issue, September 1940, pp. 3-6.
about 40 miles north of the center of Los Angeles, in secs. 15-18, T. 4 N., R. 17 W., S.B.B. and M. The oil-productive reservoir is a nose on one of the folds in a faulted and folded east-west synclinal basin at the eastern end of the Ventura Basin of deposition.\textsuperscript{39} The Ventura Basin, approximately 55 miles long and 25 miles wide, contains approximately 40,000 feet of Eocene, Oligocene, Miocene, Pliocene, and Pleistocene deposits.

Rapid lithologic changes, which often occur in such a trough, may be a vital factor in the accumulation of oil in the Del Valle field.\textsuperscript{40} The field is similar to Coalinga Nose, and may be characterized as a stratigraphic trap with cross faulting and anticlinal structure. The accumulation of oil in the anticline is controlled on the north by a syncline, faulted in its westerly part, on the east by the easterly plunge of the folded sediments and on the south by the south flank of the Del Valle anticline. The surface geologic interpretation of the western part of the field is obscured by the Del Valle fault, and it is assumed that closure is of a stratigraphic nature because of the lenticular nature of the reservoir sands or their replacement farther west by shales.\textsuperscript{41, 42} The closure to the north also may be due to a replacement of the sand by shale and not by faulting, as originally supposed. Effective closure of the anticline is about 350 feet. The field comprises approximately 500 productive acres, of which approximately 250 acres comprise the Havenstrike leases.

The discovery well, R. E. Havenstrite, operator, Lincoln well 1, in the NW\textsuperscript{1}/4 SE\textsuperscript{1}/4 sec. 16, T. 4 N., R. 17 W., was completed on September 8, 1940, at a depth of depth of 6,954 feet, with a water shut-off at 6,653 feet, in the Del Valle zone of upper Miocene age. Initial daily production was 400 barrels of 59\textsuperscript{o} A.P.I. gravity oil, with 0.1 percent water content, and 10,000 M c.f. of gas. Casing and tubing pressures were 2,450 and 2,250 p.s.i., respectively. The gas-oil ratio of 25,000 cubic feet per barrel made a recompletion necessary, and the gas-oil ratio was reduced with a liner cemented through perforations and later gum-perforated just below the gas sand. The gas and oil intervals were separated for production by a packer on the tubing. On October 17, 1940, the recompleted well, with adjustable bottom-hole choke produced 800 barrels per day of 33\textsuperscript{o} A.P.I. gravity oil and approximately 2,000 M c.f. of gas per day through the tubing, together with 32 barrels per day of 50\textsuperscript{o} A.P.I. gravity oil and 4,500 M c.f. of gas per day through the casing.\textsuperscript{43}

The second well drilled in the field, R. E. Havenstrite, operator, Lincoln well 2, located approximately 825 feet southeast of the discovery well, proved the existence of the Videgain or Sherman zone, which was found approximately 650 feet higher stratigraphically than the Del Valle zone. The well was completed on December 31, 1940, at 6,220 feet with a water shut-off at 6,037 feet and had an initial daily production of 3,000 barrels of 36\textsuperscript{o} A.P.I. gravity oil and 3,000 M c.f. of gas.\textsuperscript{44} The Sherman sand had been cored but not tested in the discovery well. During 1941 all drilling operations in the Havenstrite or East area of the structure were entirely confined to development of the Sherman zone. During this period, however, production also was being developed in the west area of the field (fig. 19).


\textsuperscript{41} Work cited in footnote 8.

\textsuperscript{42} Sherman, R. W., Del Valle Oil Field: Pp. 408-411 of work cited in footnote 14; also works cited in footnotes 39 and 40.

\textsuperscript{43} Work cited in footnote 40.

\textsuperscript{44} Work cited in footnote 40; also pp. 17-25 of work cited in footnote 8.
The first well completed in the productive west area of the field, Fred Jasper, Jr., Videgain well 1, now designated as Jack Herley and Paul L. Kelley, Videgain well 1, and located in the SW1/4 sec. 17, T. 4 N., R. 17 W., more than 1-1/2 miles west of Lincoln well 1, was completed on July 3, 1941, in the Videgain or Sherman zone with an initial daily production of 1,000 barrels of 31° A.P.I. gravity oil and 1,000 M c.f. of gas. Production was obtained from the interval between the depths of 5,876 and 5,997 feet.45/

The third well completed in the West area, Ohio Oil Co. Vasquez well 1, in the SW1/4, sec. 17, T. 4 N., R. 17 W., proved the existence of the Vasquez zone. The well was completed at 6,195 feet on September 30, 1941, with an initial daily production of 1,512 barrels of 31.4° A.P.I. gravity oil and 885 M c.f. of gas from the gun-perforated intervals between the depths of 5,840 and 5,880 and 5,915 and 5,940 feet.46/

Standard Oil Co. of California, Sepulveda well 3, completed August 3, 1942, in the West area in the SE1/4, sec. 17, T. 4 N., R. 17 W., was the discovery well for the Sepulveda zone. Initial daily production from the interval between the depths of 5,040 and 5,120 feet was 707 barrels of 35.5° A.P.I. gravity oil and 235 M c.f. of gas.

The Bering zone of upper Miocene (Mohnian) age was discovered on February 16, 1943, by R. E. Havenstrite, operator, Barnes well 2 in the Del Valle or East area of the field, in the SW1/4, sec. 16. The well was drilled to 9,870 feet but proved to be wet when tested in the interval between the depths of 9,700 and 9,870 feet. The productivity of this deep zone was demonstrated, however, when an initial daily production of 972 barrels of 44° A.P.I. gravity oil with a 5 percent water cut and 580 M c.f. of gas was obtained from the gun-perforated interval between the depths of 7,900 and 8,065 feet.47/

The deepest productive horizon in the field, the Lincoln zone 15 was discovered on November 13, 1947, by R. E. Havenstrite, operator, Lincoln well 15, near the center of the SE1/4, sec. 16. The well was drilled to a total depth of 11,868 feet; initial daily production from the interval 10,505 to 10,110 feet was 75 barrels of 32° A.P.I. gravity oil with 0.8 percent water content and 160 M c.f. of gas.

The large structural difference in location of the oil-water interfaces of the East and West areas suggests that structural separation of the two areas is caused by faulting, mainly in the Miocene strata, but the separation could be due to the lenticular nature of the sands.

The exposed surface rocks within the Del Valle field consist of marine deposits of Pliocene age, except for a thin covering of Pleistocene terrace deposits of conglomerates and gravels of terrestrial origin present only in the East area. The upper member of the Pico formation (Pliocene), 2,100 feet thick at the location of Barnes well 2, unconformably underlies terrace deposits in the East area and forms a lithological unit easily recognized by the electric log throughout the field. The Lower Pico marine beds, analogous to the Repetto (Pliocene) formation of the Los Angeles Basin overlie the Upper Modelo formation of Upper Miocene (Delmontian stage), but the exact nature of the Pliocene-Miocene contact is uncertain. The upper Modelo formation is 1,900 feet thick in Barnes well 2 and decreases to approximately 1,500 feet at the west end of the field. The underlying lower Modelo formation of upper Miocene (Mohnian stage) age is 2,450 feet thick, as cored in Barnes well 2.48/
The main productive oil and gas sands in the Del Valle field are found within the upper Miocene formations, and include approximately the bottom 180 feet of lower Pliocene sediments. Accurate structural correlations between wells are complicated by the lenticularity of the sands, which vary considerably from well to well. It is almost impossible to prepare accurate contour and isopachous maps of the field, as extensive thrust faulting has occurred in several directions. Although there was probably only one sand body originally, thrust faulting has broken up the original formation and thrust one area over another to the extent that three sand bodies are sometimes penetrated by the same well, as indicated by the similarity of electric logs for two or three intervals in the same well. Thus, in some wells the electric logs tend to repeat themselves several times as the sand intervals are traversed, while other wells penetrate only one sand interval.

The Sepulveda zone, approximately 130 feet in thickness, comprises the productive beds of the lower Pliocene. There are 10 completed productive wells and one uncompleted abandoned well (Sepulveda No. 5) in this zone.

The Vasquez zone is productive only in the West area of the field. It is separated in this area from the overlying Sepulveda zone by approximately 200 feet of lower Pliocene and upper Miocene sediments, mostly shales. In general, the Vasquez zone is approximately 110 feet thick but may be somewhat more in individual wells. In this zone are 13 completed productive wells, 1 uncompleted abandoned well, and 1 uncompleted well being drilled.

The Videgain or Sherman zone, the upper productive interval in the East area, is the principal productive zone of the Del Valle field. This productive zone, which varies in thickness from 100 to 200 feet with sand bodies comprising 40 to 95 percent of the interval, is separated from the overlying Vasquez zone by 90 to 110 feet of shale. The base of the Sherman-zone shale is approximately 300 feet below the Pliocene-Miocene contact.\(^{49}\) This shale body serves as the best marker in the field, as it is fairly uniform in thickness and the underlying sand (Videgain) is productive in both the West and East areas of the Del Valle field. The sand is lenticular and detailed correlations are difficult. Initial productivity of wells has, in general, been 300 to 600 barrels of oil per day, but an initial rate as high as 3,000 barrels has been obtained. The initial gravity of the produced oil varies from 32° to 42° A.P.I., according to the structural position of the well. Initial gas-oil ratios have been especially large, exceeding 6,000 cubic feet per barrel for wells completed in the structurally high West area, suggesting the existence of a gas cap extending over part of the West productive area.\(^{50}\)

The Del Valle zone is separated from the overlying Videgain zone by approximately 500 feet of strata consisting of sand, referred to as the "Middle sand," in the extreme eastern and southern portions of the East area, but grading rapidly from sands to argillaceous beds toward the northwest. The Middle sand is not productive, except possibly in a very small area in the eastern part of the general area. The Del Valle zone exhibits pronounced lateral variations in thickness. From a maximum of over 300 feet at the southeastern edge of the field, the zone is approximately 200 feet thick along the structural axis but thins to about 80 feet toward the north; average thickness is approximately 100 feet. There is a free gas cap in the upper 50 feet of the zone. The initial gravity of the oil produced was 58° A.P.I. before the upper sands of the zones were excluded, and the present average is 33.5° A.P.I. There are 11 productive wells in the Sherman and Del Valle zones.

\(^{49}\) Work cited in footnote 40.
\(^{50}\) Pp. 17-25 of work cited in footnote 8.
The Bering zone is separated from the overlying Del Valle zone by approximately 1,150 feet of sediments, of which the bottom 700 feet are shales. The zone has an average productive thickness of 300 feet and is productive to a depth of 8,500 feet. There are nine completed productive wells and one uncompleted abandoned well in this zone; the gravity of the oil produced averages 43.5° A.P.I.\textsuperscript{51}

Reservoir Data

Reservoir data for the productive zones of the Del Valle field are summarized in table 8.\textsuperscript{52}

<table>
<thead>
<tr>
<th>Zone</th>
<th>Productive oil and gas volumes, acre-feet</th>
<th>Porosity, percent</th>
<th>Permeability, md.</th>
<th>Interstitial water, percent</th>
<th>Average original pressure, p.s.i.g.</th>
<th>Temperature, °F</th>
<th>Original gas-oil ratio, cu. ft. per bbl.</th>
<th>Formation volume factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vasquez</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Oil sand</td>
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<td>190</td>
<td>40</td>
<td>2,200</td>
<td>137</td>
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<td></td>
<td></td>
<td></td>
<td>137</td>
<td>11,000</td>
<td></td>
</tr>
<tr>
<td>Videgain-Sherman</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil sand</td>
<td>21,000</td>
<td>24</td>
<td>190-280</td>
<td>40</td>
<td>2,200-2,400</td>
<td>140</td>
<td>500</td>
<td>1.31</td>
</tr>
<tr>
<td>Gas sand</td>
<td>3,700</td>
<td>24</td>
<td></td>
<td></td>
<td></td>
<td>140</td>
<td>12,000</td>
<td></td>
</tr>
<tr>
<td>Del Valle</td>
<td>19,750</td>
<td>21</td>
<td>225</td>
<td>40</td>
<td>2,550</td>
<td>160</td>
<td>700</td>
<td>1.40</td>
</tr>
<tr>
<td>Bering</td>
<td>17,700</td>
<td>22</td>
<td>130</td>
<td>40</td>
<td>3,400</td>
<td>180</td>
<td>1,300</td>
<td>1.75</td>
</tr>
</tbody>
</table>

The permeability of the Videgain-Sherman sand is, in general, higher in the East than in the West area, and there are some 2,500- to 3,000-millidarcy values throughout the zone. Permeability of the Del Valle zone varies from 100 to 1,050 millidarcys, with an average value of approximately 225 millidarcys. The bubble point of the Del Valle reservoir oil is 2,200 p.s.i.

Production and reservoir data indicate that there is an effective water drive in the Videgain-Sherman zone in the East area of the field and an active gas drive in the Del Valle zone.

Production History - Lincoln Lease

An active development program of both the Del Valle and Videgain-Sherman zones on Havenstrite's Lincoln lease (fig. 19) in the East area of the field followed the zone discovery wells in 1940. At present there are 13 productive wells, 1 abandoned well, and 1 water-injection well on the Lincoln lease, which is developed on a 10-acre spacing pattern in a proved area of 125 acres. Of the 13 productive wells, 4 are produced exclusively from the Del Valle zone and 7 from the Videgain-Sherman zone; there are no dual completions.

Performance curves for the Lincoln lease are not shown, as the erratic production data would make the curves invalid. In this particular area each well is treated as a separate entity.

\textsuperscript{51} / Pp. 17-25 of work cited in footnote 8.
\textsuperscript{52} / Chap. 54, pp. 238-239 of work cited in footnote 27.
Maximum production rate was reached in November 1941, when the average rate of production amounted to 2,100 barrels of oil per day. Cumulative production to April 1, 1950, was 3,850,000 barrels of oil, 7,500 M c.f. of gas, and 2,020,000 (approximately) barrels of water. Reservoir pressure declined from an initial value of 2,550 to 1,700 p.s.i. by August 5, 1946, the date at which full-time water injection was begun. Cumulative oil production to August 5, 1946, was 2,530,000 barrels or an average production of 2,976 barrels per p.s.i. decline of pressure. The gas-oil ratio declined from a maximum of 4,000 cubic feet per barrel in January 1942 to a minimum of 1,900 in December 1949. The production water-oil ratio gradually increased to a value of approximately 2:1 at the beginning of water injection. Cumulative water-oil ratio to August 5, 1946, was approximately 1/2 barrel of water per barrel of oil.

Secondary Recovery

The water-injection project in the Del Valle zone, Lincoln lease, was started primarily for disposal of water produced in the field. There is only one injection well, Lincoln 3, in the extreme Southeast corner of Havenstrite's Lincoln lease. The well was drilled as a producer but was wet from the beginning. Figure 20 is an electric log of Lincoln well 3 and is as representative of the field as the log for any of the wells, even though it does not tie in with other well logs in the field. As previously mentioned, no type log can be made for the field because of thrust faulting.

Lincoln well 3 was drilled to a depth of 7,265 feet from the surface; 7-inch-O.D. casing was set at 7,265 feet, and the well was plugged with cement to 7,229 feet. The water string had been set at 6,125 feet, and the well had been squeeze-cemented through perforations at 6,350 and 6,800 feet to separate the three sand bodies, which occur in the intervals 6,145 to 6,355, 6,400 to 6,740, and 6,815 to 7,185 feet. Water is being injected into the upper interval only from 6,130 to 6,350 feet. At present, approximately 1,800 barrels of water is being injected daily during 10 hours operation, at the rate of 4,500 barrels per day, the injection equipment remaining idle during the remainder of the 24 hours. In 1950, the volume of injected water, which is the water produced from the Del Valle leases of Havenstrite and the lease of Standard Oil Co. of California that is west of Del Valle, exceeded 1,800 barrels per day. The injected water is untreated but clean and has a total salinity of 12,000 to 15,400 parts per million. The injection pressure is 1,000 to 2,000 p.s.i. at the surface, equivalent to 3,600 p.s.i. at 6,700 feet in depth. More than 1,300,000 barrels of water has been injected since the inception of the project on August 5, 1946. Before injection the reservoir pressure had decreased from an initial pressure of 2,200 p.s.i. to 1,700 p.s.i. in two wells and to 1,200 p.s.i. in another well. Withdrawal rates have been adjusted to the calculated rate of water influx, and the reservoir pressure has risen to 2,250 p.s.i. during the period of water injection. Production has been very steady at rates of 40 to 70 barrels of oil per day per well after the field was supposed to have reached its economic limit.

The water-injection program at Del Valle so far has served no other purpose than the disposal of the produced brines of the area. Some tangible effects on oil production may be realized if, in the future, water production increases greatly. The Lincoln 3 injection well is, however, an outpost well, and any repressuring due to injection of water may be dispelled very easily in other directions from the lease because of severe faulting.
Figure 20. - Electric log, Lincoln well No. 3, Del Valle field, Los Angeles County, Calif.
Figure 21. - Structure map, First Grubb pool, San Miguelito field, Ventura County, Calif.
Figure 22. - Typical electric log, permeability and porosity profiles, First and Second Grubb pools, San Miguelito field, Ventura County, Calif.
San Miguelito Field - Gas Injection

General Description of Field

The San Miguelito oil field is in Ventura County approximately 3/4 mile east of the coast line and 5 miles northwest of Ventura. The field lies mainly within projected sec.s 23, 24, and 25, T. 3 N., R. 24 W., and projected sec.s 19 and 30, T. 3 N., R. 23 W., S.B.B. and M. With surface elevations ranging from sea level to 1,200 feet, the topography of the area may be characterized as extremely rugged. The overall anticlinal structure is well-defined on the surface, however, and on the exposed strata of canyon walls. The San Miguelito structure, one of the series of anticlinal folds of the Ventura anticline, is approximately 2 miles long and 3/4 mile wide, with a southeast - northwest-trending major axis. The southwestern flanks of the San Miguelito anticline dip at angles averaging 40° and the northeastern flanks at angles ranging from 60° to 75°. The structural closure is 1,480 feet. Several faults striking approximately longitudinally on the structure are regarded as having no appreciable effect on oil accumulation or reservoir performance. The main structural features of the reservoir as defined by the location of the "H" electric log marker are shown on figure 21.

Commercial oil production was first obtained from the San Miguelito field in November 1931, when Continental Oil Co. Grubb well 1 in sec. 23 was completed in the First Grubb pool at 6,750 feet. The discovery well flowed initially 616 barrels per day of 32° A.P.I. gravity oil; in August 1932, it was deepened to 7,152 feet and flowed 2,449 barrels per day of 32° A.P.I. gravity oil through a 44'/64-inch choke, with tubing and casing pressures of 1,360 and 50 p.s.i., respectively.

The First Grubb pool consists of eight sand intervals separated by shale bodies, which are continuous throughout the major part of the structure and serve as fluid barriers between the individual sand bodies. A typical electric log of the pool is shown in figure 22. Shale layers make up 30 to 50 percent of the total productive interval; the average thickness of the productive interval is 1,220 feet and the average depth 6,400 feet. The sands contain numerous discontinuous thin shale and siltstone streaks, which apparently do not influence well performance to any great extent. The productive limits of the First Grubb pool are generally defined by: (a) The Padre fault and tight sands on the north; (b) faulting and low permeability on the east; (c) oil-water contact to the south; and (d) low permeability on the west.53/ The areal extent of the oil sands increases with depth; the uppermost sand (electric log markers G to H) has an area of 97 acres and the lowest sand interval (electric log markers Jc to L) extends over an area of 276 acres.

Wells drilled subsequent to Grubb well 1 were bottomed in a 30- to 40-foot-thick shale body, which serves as a marker to identify the base of the First Grubb pool. The Second Grubb pool was penetrated in April 1944, when Continental Oil Co. Grubb well 31-2 was completed in the interval 7,160 to 7,706 feet and produced 32° A.P.I. gravity oil at an initial rate of 1,538 barrels per day. This pool, which consists of eight oil-productive sands designated by electric log markers L to M (fig. 22), is a continuation of the series of alternate sand and shale layers found in the First Grubb pool. The average productive interval is approximately 750 feet, with depths ranging from 6,900 to 7,500 feet, depending upon location on the structure.

Continental Oil Co. Grubb lease contains 1,080 acres, of which 276 acres have been proved oil-productive. Because of the extremely rough terrain, it has been impracticable to maintain uniformity of the well-spacing pattern. Originally, attempts were made to select well locations such that a 10-acre area would be drained by each well, and in some instances directional drilling was used to accomplish this objective. Later drilling approximated a 6-1/2 acre per well configuration but present well density ranges from 2-1/2 to 8 acres per well.

A typical casing program consists of about 1,000 feet of 13-3/8-inch surface casing, a 7-inch water string cemented at the top of the oil zone, and a 5-inch slotted liner, extending through the entire productive interval.\(^{54}\) Flowing wells are produced through graduated tubing, which is 2 inches in diameter at the lower end and 2-1/2 inches in diameter at the top. Generally, wells are drilled with water-base drilling fluid to the top of the productive zone and completed with oil-base drilling fluid. Every well completed with a water-base mud fluid showed considerably lower productivity than wells completed with the oil-base fluid.

Reservoir Data

The oil sands in the San Miguelito field are in the lower Pico and the Repetto formations of Pliocene age and consist of well-consolidated tight sands and loosely cemented highly permeable sands, which are generally poorly sorted and interspersed with numerous siltstone and shale streaks and other argillaceous material. A stratigraphic classification of the formation properties of the First Grubb pool is shown in table 9. Vertical permeability variation is high and, with the exception of intervals J to Ja and Ja to Jc, the average permeability of individual sand intervals tends to decrease with depth. Typical permeability and porosity profiles are shown in figure 22. The average permeability of the First Grubb pool sands is 86 millidarcys, the average porosity is 18 percent, and the estimated water content of the oil sands is 27 percent of the pore volume. Average net effective sand thicknesses of the upper six sand intervals are fairly consistent, ranging from 65 to 82 feet; the two lowest intervals have a net effective sand thickness of 111 and 131 feet. The average total pool thickness is 1,220 feet, of which 685 feet is net effective pay. The total bulk volume of the First Grubb pool has been placed at 136,000 acre-feet.\(^{55}\)

As a result of tests on bottom-hole samples taken at a pressure of 2,700 p.s.i. in 1939 and 1940, it was necessary to recalculate the initial static reservoir pressure. Later studies of the pressure-production characteristics of the reservoir and of the pressure-volume-temperature relations of the reservoir fluids permitted recalculation of the original reservoir conditions as having been 3,000 p.s.i. at 5,500 feet below sea level and at 158° F. The pressure-volume-temperature relations also indicated that under these initial conditions the reservoir oil was saturated with gas and that the volume of gas in solution at the saturation pressure was 890 cubic feet per barrel of oil. This coincides closely with the initial production gas-oil ratios of the early wells, although several of these wells near the axis of the structure had gas-oil ratios over 890 cubic feet per barrel, presumably because of a small gas cap in at least one of the sand intervals.

The characteristics of the produced crude oil from the San Miguelito reservoir are fairly uniform throughout the field. Since oil is produced simultaneously from

\(^{54}\) Sanders, T. P., All Types of Engineering Required in Development of San Miguelito Field: Oil and Gas Jour., vol. 40, No. 5, June 22, 1941, pp. 38 and 41-43.

\(^{55}\) Work cited in footnote 53.
Figure 23. - Performance curves, First Grubb pool, San Miguelito field, Ventura County, Calif.
all the sand intervals of either the First or the Second Grubb pool, it is a com-
posite of an entire zone and A.P.I. gravities range from about 34° to 29°, part of the 
variation being due to differences in trap pressures. A typical analysis56 of 
crude oil from the interval 6,472 to 7,152 feet shows the following properties:

Specific gravity, 0.867; A.P.I. gravity, 31.7°.
Saybolt Universal viscosity, 63 seconds at 77° F., 52 seconds at 
100° F.
Carbon residue, 47 percent; total gasoline and naphtha content 
29.3 percent (58.2° A.P.I.).
Color, brownish black; base of crude, intermediate-paraffin.

TABLE 9. - Formation characteristics1 of productive intervals, First Grubb pool, 
San Miguelito field, Ventura County, Calif.

<table>
<thead>
<tr>
<th>Sand interval (electric log marker)</th>
<th>Average permeability, millidarcys</th>
<th>Average porosity, percent</th>
<th>Average stratigraphic thickness, feet</th>
<th>Average net effective thickness, feet</th>
<th>Productive area, acres</th>
</tr>
</thead>
<tbody>
<tr>
<td>G - H</td>
<td>237</td>
<td>17.2</td>
<td>100</td>
<td>71.3</td>
<td>97</td>
</tr>
<tr>
<td>H - Ha</td>
<td>79</td>
<td>18.1</td>
<td>125</td>
<td>77.5</td>
<td>148</td>
</tr>
<tr>
<td>Ha - I</td>
<td>71</td>
<td>17.2</td>
<td>130</td>
<td>75.2</td>
<td>180.5</td>
</tr>
<tr>
<td>I - Ia</td>
<td>56.6</td>
<td>19.5</td>
<td>115</td>
<td>65.4</td>
<td>158.3</td>
</tr>
<tr>
<td>Ia - J</td>
<td>47.8</td>
<td>17.9</td>
<td>140</td>
<td>70</td>
<td>258</td>
</tr>
<tr>
<td>J - Ja</td>
<td>109</td>
<td>18.5</td>
<td>125</td>
<td>82.7</td>
<td>262</td>
</tr>
<tr>
<td>Ja - Jc</td>
<td>107</td>
<td>19.2</td>
<td>215</td>
<td>111.1</td>
<td>165.3</td>
</tr>
<tr>
<td>Jc - K</td>
<td>56</td>
<td>17.6}</td>
<td>240</td>
<td>131.3</td>
<td>276</td>
</tr>
<tr>
<td>K - L</td>
<td>36.2</td>
<td>18.0</td>
<td>1,220</td>
<td>685</td>
<td>1,545</td>
</tr>
</tbody>
</table>

1/ Work cited in footnote 53.

The formation-volume factor was calculated for each sand interval at its mean 
depth by using 0.434 p.s.i. per foot for the hydrostatic pressure gradient and 
0.0209° F. per foot depth for the temperature gradient, as determined by a tempera-
ture survey. In this manner the average pool formation-volume factor was found to 
be 1,428.

Production History

Because of the difficulties attending exploitation of a field having the rough 
topography existing in the San Miguelito field, early development proceeded slowly 
and only nine producing wells were completed in the first 8 years. During the period 
1939 to 1943, development was more rapid, and, by 1943, about 4,500 barrels of oil 
per day were produced from 26 wells in the First Grubb pool. The majority of the wells 
were completed as flowing wells, and, as late as 1940, only one of the 20 produc-
tive wells required artificial lift. Considerably over 1-1/2 million barrels of oil 
had been produced alone from Grubb well No. 1, the discovery well, and it was still 
flowing 18 barrels per day. Production records of the San Miguelito field are ex-
ceptionally accurate and complete as a result of the managerial policies of the field 
operators. As shown by the production history and pool-performance curves (fig. 23), 
the peak oil-production rate was attained during 1944, when 5,500 barrels of oil were

56/ McKinney, C. M. and Blade, O. C., Analyses of Crude Oils from 263 Important Oil 
Fields in the United States: Bureau of Mines Rept. of Investigations 4289, 
1938, p. 31.

4784 - 35 -
produced daily from an average of 30 wells. The production decline following this period is due mainly to proration adjustments and not to declining productivity. It is to be pointed out that 20 wells have been drilled since the peak production year.

The abrupt rise of the gas-oil ratio of the pool during 1936 and 1937 coincides with the completion of Grubb well 5, which had an initial gas-oil ratio of over 5,500 cubic feet per barrel, and the completion of well 7, which initially produced 9,500 cubic feet of gas per barrel of oil. Gas-oil ratios of both of these wells dropped off gradually with dissipation of a small gas cap in the thin strata gas sands in the Ia to J interval near the axis of the structure, and by 1940 the individual gas-oil ratios of these wells compared favorably with the pool ratio of 1,250 cubic feet per barrel. Several wells drilled near the top of the structure, later in the life of the field, also had high gas-oil ratios where isolated gas caps were penetrated in the upper sands, but these too were rapidly depleted and the gas-oil ratios approached normal.

The upward trend of the gas-oil ratio of the pool during the war years reflects the effect of heavy withdrawals, which caused local areas of low liquid saturation and low pressure. Gas injection initiated in 1940 also adversely affected the gas-oil ratio because of channeling of the injected gas. Reversal of the pool gas-oil ratio trend in 1946 was mostly due to the completion of low gas-oil ratio wells downstructure.

Water production during the early life of the field was relatively unimportant. After 1939, when several wells were drilled along the southern flanks of the western half of the structure, water incursion through highly permeable parts of the Ia to J interval was found to be of such magnitude as to warrant water shut-off operations in the productive zones. The water front, moving northeasterly, has reached as far into the field as well L3, where the water cut increased twentyfold since 1942. Further downstructure, in well L9, the water-oil ratio increased from 3 barrels of water per barrel of oil in 1942 to 5-1/2 barrels per barrel in 1949. Total water production from the First Grubb pool amounts to about 1.3 million barrels, and the current daily rate of water production averages 370 barrels, of which 250 barrels is produced by five wells. To date, water influx has had little effect on the reservoir-pressure decline, and it probably will have little influence on pool performance until the rate of withdrawal of reservoir fluids more closely approaches that of water encroachment.

Periodic surveys of subsurface pressures and productivity tests of individual wells throughout the field have permitted the operators to follow closely the performance characteristics of the reservoir. Gravity drainage is considered to be an important factor as evidenced by generally higher productivity indices and lower gas-oil ratios of downstructure wells. It is, therefore, to be expected that these wells will tend to demonstrate relatively stable productivity and gas-oil ratios, provided production allocations are such as to avoid local reduced oil saturation.

By midyear 1939, the average weighted static reservoir pressure was 2,914 p.s.i.g., and about 3.4 million barrels of oil had been produced. Concentration of production from several wells created areas of localized reduced pressure and fluid saturation, but changes in allocation of withdrawals between wells and additional drilling permitted some degree of pressure equalization by December 1941. Although faults apparently act as pressure barriers between sand intervals, the effect is nullified by intercommunication of pressures through well bores in which all productive intervals are open.
Figure 24. - Curves showing effects of gas injection, First Grubb pool, San Miguelito field, Ventura County, Calif.
Gas Injection

The San Miguelito reservoir is primarily the solution-gas-drive type, and the over-all operating procedure is based on the performance characteristics of that type of reservoir. A small-scale gas-injection project was started in April 1940 to determine the feasibility of augmenting the natural reservoir energy and sweeping the oil sands with injected gas, thereby increasing the ultimate recovery of oil. The initial gas-injection well, Grubb well 3, is close to the northern productive limit of the structure in the western part of the field. The well bore is open to the H to Ha, Ha to I, and I to Ia intervals comprising approximately 180 feet of effective oil-sand face. During 1941 and 1942, the daily average of 450 M c.f. of gas was injected at a wellhead pressure of 3,200 p.s.i. The reservoir pressure at the datum of 5,500 feet below sea level was approximately 2,925 p.s.i. The volume of gas pumped into the reservoir was increased to 750 M c.f. a day during 1943, and by November 1943 the total volume injected was over 500,000 M c.f.

In September 1942, Grubb well 27, offsetting the injection well, was completed as a flowing well with an average gas-oil ratio of 2,285 cubic feet per barrel for the first month. Considering the low effective permeability of the sands open to production in this well, the low initial productivity index, and the high subsurface pressure, the gas-oil ratio is much higher than would be expected normally. Within a month, the gas-oil ratio had risen to 2,800 cubic feet per barrel, and it became evident that gas injected into well 3 was channeling through highly permeable sand streaks and adversely affecting well 27. Therefore, the operators deemed it advisable to return well 3 to a production status and to convert well 24 to a gas-injection well. It is noteworthy that, before a normal gas-oil ratio was attained, about 25,500 M c.f. of gas, at an average gas-oil ratio of 3,900 cubic feet per barrel and under a drawdown of 1,100 p.s.i., was produced from well 3 when it was returned to production. The performance of well 3 substantiates the evidence that gas had been blowing through to well 27 while gas was being injected into well 3, inasmuch as only a small proportion of the injected gas remained stored in the reservoir.

Injection well 24 is approximately midway on the longitudinal axis of the structure, about 975 feet west of the crest, and is open to all oil sands in the H to K interval plus 190 feet of the K to L interval. Completed in December 1941, this well had an abnormally high initial gas-oil ratio, averaging about 5,300 cubic feet per barrel. Cumulative oil production from well 24 to November 1943, when it was converted to a gas-injection well, amounted to 64,000 barrels; and, at the time, the reservoir pressure was 2,475 p.s.i. at the datum of 5,500 feet below sea level. Gas was injected into well 24 at the average rate of 1,500 M c.f. per day until September 1945, when installation of additional compressor capacity increased the input volume to 5,000 M c.f. per day. By September 1946 about 2,000,000 M c.f. of gas had been returned to the reservoir sands of the First Grubb pool through injection well 24.

Gas injected into well 24 primarily was entering the thin, highly permeable sand streaks of the Ia to J interval, bypassing the major portion of the exposed sands. Examination of the performance trends of individual wells surrounding the injection well indicated that the injected gas was fingering through this limited section of the productive zone and thus large increases in the gas-oil ratios of wells 5, 6, 9, 10, 13, 18, 21, and 25 occurred. This effect was further magnified when the injection rate was increased in September 1945, and the upward gas-oil ratio trend accelerated appreciably, as shown by figure 24. Productivity indices of high gas-oil ratio wells showed definite decreases, and well pressures declined at an abnormally high rate. It was obvious that neither pressure maintenance nor the effective sweeping of the productive zone sands was being accomplished by this injection. In November 1946 the field operators decided to investigate the effect
of selectively injecting gas into individual oil strata. A packer was set in the
blank liner opposite the Jc to K shale, thereby directing the injected gas into the
K to L interval. Using temperature and flow-meter surveys in the injection well and
in productive wells 17, 30, 18, 9, 29, 6, and 7, it was determined that the greater
portion of injected gas was entering two thin-sand streaks of the entire 190-foot
interval.

The next step was to plug off the K to L interval with a temporary bridge and
direct the injected gas into the Jb to Jc sand section. After 2,600,000 M c.f. of
gas had been pumped into this interval in well 24, a study of the performance of sur-
rrounding wells was made to determine the effect of injection. Temperature and flow-
meter surveys showed that the distribution of the injected gas was relatively uniform.
Wells 5, 6, 9, 13, 21, and 25 showed significant decreases in gas-oil ratios and re-
duced rates of decline in productivity indices and in well pressures, as demonstrated
by the changes in trend of the curves in figure 24. Gas-oil ratio maps (figs. 25, 26
and 27) show the over-all changes in gas-oil ratio distribution, in the area surround-
ning the gas-injection well, that resulted partly from the three injection procedures.
Probably the relatively stable gas-oil ratio distribution in downstructure wells is
due mainly to the effects of gravity drainage in maintaining high liquid saturation
and therefore low effective permeability to gas.

The gas-injection program in the San Miguelito field has not had any appreciable
over-all effect insofar as pressure maintenance is concerned. Since the beginning of
gas injection in the First Grubb pool, the total input has amounted to 6,500,000 M
c.f. - roughly 15 percent of the volume of wet gas produced with the oil. Compared
to withdrawals of approximately 11 million barrels of stock-tank oil and associated
gas during the same period, the volume of injected gas, most of which was not stored
in the reservoir because of channeling, could hardly be expected to have had any
measurable influence on reservoir pressure. However, the small-scale injection pro-
ject has provided the operators with data from which to determine the probable effec-
tiveness of a future full-scale gas-injection program and the most efficient method
of utilizing the injected medium for such a project. Thus far, it has been evident
that very little is to be gained from injecting gas into wells open to a multiplicity
of strata totaling as much as 850 feet of net sand thickness. The alternative is to
inject selectively into individual sand intervals, as was done in well 24. Another
factor to be considered is the magnitude of the reservoir pressure to be maintained
by injecting gas. High-pressure gas injection has the advantage of holding the dis-
solved gas in solution and thereby retaining the low viscosity and surface-tension
characteristics and the high formation-volume factor of the reservoir oil. Extension
of the flowing life of wells and prevention of early edge-water encroachment also
might be gained by such a program; however, high compression costs must be weighed
against these advantages. The experience with the small-scale, high-pressure, gas-
injection project has emphasized two important operational disadvantages: (1) Lack
of control over migration of the gas for effective sweeping of the sands; and (2)
creation of a large number of high-gas-oil-ratio wells, which, if closed in would
eliminate drainage of over 75 percent of the liquid saturation in the high gas-oil
ratio area, not considering gravity drainage.

The operators have proposed utilizing low-pressure gas selectively injected into
individual sands of the First Grubb pool. The advantages to be realized from this
type of operation include better control of gas dissemination, and therefore more ef-
efective utilization of injected gas and natural reservoir energy; larger displacement
volume per unit of gas handled at the surface; and lower cost of compression equip-
ment and operation. Inasmuch as the experience gained from injecting gas into wells
3 and 24 has shown which productive intervals can be effectively swept by gas, future
Figure 25. - Gas-oil ratio map, 1947, after gas injection into well No. 3, First Grubb pool, San Miguelito field, Ventura County, Calif.

Figure 26. - Gas-oil ratio map, 1948, after gas injection into well No. 24, First Grubb pool, San Miguelito field, Ventura County, Calif.

Figure 27. - Gas-oil ratio map, 1949, after selective gas injection into well No. 24, First Grubb pool, San Miguelito field, Ventura County, Calif.
Figure 28. - Structure map, Capitan field, Santa Barbara County, Calif.
selective gas injection into these sands should result in increased ultimate recovery of oil and economic gains attending efficient utilization of injected gas and natural reservoir energy.

**Summary**

The San Miguelito oil field has produced approximately 15-1/2 million barrels of oil, 45,000,000 M c.f. of gas, and 1-1/3 million barrels of water to date. The average static reservoir pressure has declined from the original value of 3,000 to 1,560 p.s.i.g., and the productivity index range is 0.08 to 1.04 as against an original range of 1.4 to 2.25. Although there is some evidence of a partial water drive from the southern flanks of the structure, the current rate of incursion is of such small magnitude that it does not affect the behavior of the solution-gas-drive reservoir. Gravity drainage is known to play an important role in the distribution of fluids, as evidenced by the stability of productivity and the generally low gas-oil ratios of downstructure wells.

It is recognized, theoretically, that some gains may be realized from a gas-injection program started early in the history of a depletion-type reservoir. In the San Miguelito field, however, the large number of zones open to production and the wide variation of permeability both laterally and vertically militate against an extensive gas-injection project that includes several zones. Experience with the small-scale gas-injection program, conducted April 1940 to September 1949, has emphasized the necessity of selective injection and has given the operators data from which injection-well orientation and injection-gas volume and pressure requirements may be determined for a future gas-injection project. Comparison of the advantages and disadvantages of high-pressure gas injection started relatively early in the history of the field, and low-pressure injection to be carried on at some future time when reservoir pressures have declined further indicates that the latter program will yield maximum oil recovery and ultimate economic gain.

**Capitan Field - Gas Injection**

**General Description of Field**

The Capitan oil field is in Santa Barbara County, approximately 20 miles west of Santa Barbara. The field, shown in figure 28, is on the shore of the Pacific Ocean, mainly in the S1/2 sec. 32, T 5 N., R. 30 W., S.B.B. and M. The oil-productive reservoir is a pear-shaped closed domal structure with the major axis trending east and west. On the north the structure is closed against the Orella fault, which trends northwest and southeast.

The discovery well, General Petroleum Corp. Erburo 1, was completed in October 1929, in the Vaqueros sand of Miocene age at a depth of 1,446 feet, and flowed 60 barrels of 19.5° A.P.I. gravity oil in an 8-hour test. The succeeding development of the field was slow; eight productive wells and two dry holes were drilled in the Vaqueros sand before operations were suspended in 1930. Further development of the zone was not undertaken until 1934.

The Vaqueros sandstone ranges in thickness from several feet to 300; only that portion of the sand lying above a depth of 1,280 feet below sea level - the level of the water table - produces oil.

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Initial production from the underlying Sespe formation of Oligocene age was obtained in January 1931, when General Petroleum Corp. well Erburu 8 was drilled to a depth of 4,071 feet after having penetrated the entire 2,500 feet of Sespe formation and 46 feet of the underlying Tejon sandstone of Eocene age. Well logs show that the oil sands occur in numerous thin beds within the Sespe zone. The two main productive horizons are in the upper 1,000 feet of the Sespe formation at depths from 2,296 to 2,430 and from 2,665 to 2,730 feet. Well Erburu 8 was plugged back and completed at a depth of 2,430 feet, in the upper or Erburu Eight zone. Initial average daily production was 241 barrels of 42.5° A.P.I. gravity oil with very low water content. Several months later the General Petroleum Corp. completed well Erburu 10 in the lower or Erburu Ten zone at a depth of 2,793 feet, with an initial production of 200 barrels of clean oil in 5 hours, after which gas broke in and shut off the oil. At a depth of 3,100 feet, a production test showed mostly water. After plugging back to 2,999 feet, an average of 90 barrels of oil and 5 barrels of water was produced daily by pumping before the well was closed in on August 27, 1931.

The contours, shown on figure 28, are drawn on top of the Erburu Eight zone (Marker G). A water sand about 130 feet below the top of the oil sand is a divisional horizon between the two productive zones. The Erburu Eight oil zone comprises an areal extent of 220± acres and the underlying Erburu Ten zone 320± acres. Oil from both zones is produced from most of the centrally located wells; and, as the productive area of the Erburu Ten zone extends beyond that of the Erburu Eight zone, the downstructure wells are limited to production from the Erburu Ten zone.

Approximately the upper half of the Sespe formation is designated the Erburu zone. The sands in the lower 300 feet of the zone are principally oil-bearing, and the sands in the interval above contain dry gas. The Sespe sands consist of interbedded, variegated sands and shales that vary in thickness and permeability. On the whole, however, there is good correlation over the entire field, indicating continuity throughout the zone of at least some of the oil sands. Figure 29 is a type electric log of the Sespe zone. A study of electric logs and cores from the wells shows that the oil sands occur in numerous thin beds ranging in thickness from 1 foot to rarely more than 15 feet. In many parts of the field, the sands are separated by and blend into impervious shaly sand, hence, the thickness of individual sands varies greatly over the field. The oil sands fall naturally into four groups - two in the Erburu Eight zone and two in the Erburu Ten zone - which correlate satisfactorily throughout the field. The average formation thickness and weighted average sand thickness in these intervals are shown in the following tabulation:

<table>
<thead>
<tr>
<th>Zone</th>
<th>Interval electric log markers</th>
<th>Average formation thickness, feet</th>
<th>Weighted aver. sand thickness, feet</th>
<th>Sand, percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Erburu Eight</td>
<td>(G to H)</td>
<td>55</td>
<td>12.5</td>
<td>23</td>
</tr>
<tr>
<td></td>
<td>(H to H + 60 feet)</td>
<td>60</td>
<td>24.5</td>
<td>41</td>
</tr>
<tr>
<td>Erburu Ten</td>
<td>(K to L)</td>
<td>70</td>
<td>10</td>
<td>14</td>
</tr>
<tr>
<td></td>
<td>(L to M + 10 feet)</td>
<td>120</td>
<td>10</td>
<td>8.3</td>
</tr>
<tr>
<td>Total Erburu zone</td>
<td></td>
<td>305</td>
<td>57</td>
<td>18.5</td>
</tr>
</tbody>
</table>

60/ Work cited in footnote 57.
Figure 29. - Type electric log, Sespe interval, Capitan field, Santa Barbara County, Calif.
Figure 30. - Decline curves, Sespe pool, Capitan field, Santa Barbara County, Calif.
The apparent well spacing in the Erburu Eight and Erburu Ten zones is 12 and 17 acres per well, respectively. The apparent well spacing in the Erburu Eight zone is 11.5 acres per well on the Shell Oil Co. leases and 13.5 acres per well on General Petroleum Corp. leases; on the same leases, the average spacing in the Erburu Ten zone is 15 and 20.5 acres per well, respectively. Figure 28 shows, however, that there are large, undrilled areas in the southern portion of the field where the sands are thin. Therefore, the actual spacing in the developed area of the Erburu Eight zone and Erburu Ten zone is about 8 and 12 acres per well, respectively.

Reservoir Data

The production of oil from the Erburu zone has been entirely by solution gas drive, except for 10 months in 1937, when gas was injected into the zone. From subsurface-pressure surveys made in 1936, it was estimated that the initial reservoir pressure was 1,100 p.s.i., at the datum of 2,200 feet below sea level; the temperature at this depth is 120° F. The initial solution gas-oil ratio was 400± cubic feet per barrel. In the absence of laboratory measurements, reference to composite pressure-volume-temperature curves indicates a formation-volume factor of 1.176.

Analyses of more than 70 core samples taken from Shell Oil Co. wells revealed marked variation in the porosity and permeability of the different sand intervals, and indicated an average porosity of 18.3 percent and an average permeability of 89 millidarcys for the entire Erburu zone.

As calculated from a total sand volume of 14,300 acre-feet for both Erburu sand zones, an average porosity of 18.3 percent, an interstitial water saturation of 35 percent, and a formation volume factor of 1.176, the total quantity of tank oil originally in place was 11,221,400 barrels, an average of 788 barrels of oil per acre-foot of sand.

Production History

Active development of the Erburu zone was begun in 1934; and the maximum production rate was reached in November 1934, when the daily average rate of production was 2,000 barrels. The zone was developed by the middle of 1937, and daily oil withdrawals at that time were 1,100 barrels. During the following 4-1/2 years, oil production declined at an almost constant yearly rate of 35 percent. During December 1945, the month before gas injection was begun, the Erburu zone yielded only 96 barrels of oil per day; on the Shell Oil Co. property the production rate ranged from 3 to 13 barrels of oil per day and averaged 7 barrels per day, virtually the economic limit of production. Figure 30 is a production-decline curve for all wells in the Sespe zone.

To December 31, 1945, the Erburu zone produced 2,024,000 barrels of oil, of which 1,150,000 barrels was produced by the Shell Oil Co., 851,000 barrels by the General Petroleum Corp., and 23,000 by B. D. Owens. As estimated from the produced volume of oil and the sand volume, the unit recovery to the beginning of gas injection was 142 barrels of oil per acre-foot of sand for the entire reservoir, or 18 percent of the estimated original oil content of 788 barrels per acre-foot. Before gas was injected, pressure surveys in five Shell Oil Co. wells indicated an average reservoir pressure of 135 p.s.i., which is 965 p.s.i. less than the original formation pressure of 1,100 p.s.i. Thus, the recovery of oil from the Erburu zone has averaged 0.15 barrel per p.s.i. decrease in pressure per acre-foot of sand.

Core analyses show that the permeability of the Erburu Eight zone is considerably higher than that of the Erburu Ten zone and hence, on a per acre-foot recovery
basis, the Erburu Eight zone probably has produced more oil than the Erburu Ten zone. It is not possible, however, to evaluate the unit recovery from each zone, as the majority of wells in the field were completed to produce from both zones. The few wells completed to exploit only one of the zones either have much greater than average spacing or were completed early in the life of the field and therefore gained the advantage of wide spacing during flush production.

The total volume of gas produced from the Erburu zone cannot be determined accurately because the gas from the General Petroleum wells was not measured before 1937 and the total Vaqueros and Erburu gas produced from the Shell Oil Co. wells was measured through a single meter from the early part of 1941 to the beginning of gas-injection in 1946. Trends, which were established when Erburu gas was accurately measured, indicate the cumulative gas-oil ratio of the zone was between 2,100 and 2,200 cubic feet per barrel and that between 85 and 90 percent of the solution gas was produced before extraneous gas was injected into the oil-bearing reservoirs.

A substantial quantity of oil - over 9,000,000 barrels - remained in the sands at the beginning of the gas-injection period. As the pressure in the zone averaged less than 150 p.s.i. and most of the solution gas had been produced, it is evident that additional energy was required to move the remaining oil to the wells if economic quantities of it were to be recovered.

Secondary Recovery

The principal reason for choosing gas drive instead of water drive in the initial attempt to obtain additional oil from the Erburu zone in the Capitan field was the possibility that water might cause the clays in the sand to swell and thereby reduce the relative permeability to oil. The behavior of Shell Oil Co. well, Covarrubias 1-5, illustrates the magnitude of the damage that can be caused when these oil sands are wetted by water. This well became flooded with mud and water while it was flowing at a rate of 70 barrels of oil per day; after the well was bailed and the perforations were washed, a maximum of only 5 barrels of oil per day was produced by pumping. Furthermore, the desirability of utilizing gas as the driving medium was enhanced further by the fact that a supply of high-pressure gas was readily available in the field.

As best results in California generally are obtained when the driving fluid is injected into a thin sand interval, it seemed to be especially desirable to follow that practice for the Erburu zone in view of wide ranges in the permeability of the various oil-bearing sands. Accordingly, it was decided to inject gas into a thin section of the oil zone, continuing the injection until the gas blew through to surrounding wells at excessive rates, then to plug off that section of the oil zone in the injection well, and finally to repeat the operation in another sand section. Four sand intervals in the Erburu zone were tentatively selected for successive periods of gas injection, starting with the lowest interval. It was decided to inject gas first into the Erburu Ten zone, as the sands in that zone were more highly saturated with oil and probably would produce more oil than the more permeable sands of the Erburu Eight zone.

It is important to note that the injection project at Capitan is a low-pressure gas sweep and is not an attempt to repressurize the oil sands. The ordinary criteria for evaluating the benefits of standard repressuring operations are, therefore, inapplicable. This sweeping operation must be regarded as a trial-and-error method and its success evaluated solely by results obtained in individual wells. The use of gas sweeping permitted continued operation, while further decline of production was minimized during the gas-injection process.
Figure 31. - Performance curves for wells producing from a portion of Erburu Ten zone, Capitan field, Santa Barbara County, Calif.
Progress of Gas-Injection Experiment

Shell Oil Co. well, Covarrubias 1-4, a crestal well, which had been completed in the Erburu Eight zone, was selected as the initial gas-injection well and was deepened to the bottom of the Erburu Ten zone. A blank liner then was cemented opposite the entire Erburu zone. A 70-foot interval in the lower half of the Erburu Ten zone - marker L to approximately marker M - was gun-perforated, and gas from the 400 p.s.i. pressure system was injected into this sand interval. No oil had been produced from the Erburu Ten sands in the immediate area of this well.

During the 10 months between January and November 1946, 30 M c.f. of gas per day was injected into Covarrubias well 1-4 directly from Covarrubias well 1-48. During this period the wellhead injection pressure increased from 300 to 355 p.s.i. With the exception of Shell Oil Co. well Covarrubias 1-25, the oil-production rates of all wells producing from the sand interval into which gas was being injected remained virtually constant between January and November 1946. Covarrubias 1-25 is approximately 650 feet from the injection well and had been shut in since February 1944, when its production had declined to less than 1 barrel of oil a day. In May 1946, 5 months after initiation of gas injection, the well was restored to production and was pumped for an average of 23 barrels of oil per day. By November 1946, however, production had declined to 5 barrels of oil per day. The pump was pulled, and the liner was found to be filled with sand.

Beginning in November 1946, the gas-injection rate was increased to 90 M c.f. per day and since that time has varied between 80 M c.f. and 100 M c.f. per day, with an increase in injection pressure from 380 to 425 p.s.i.

Figure 31 shows that there was a marked increase in the rate of oil production from the wells affected by the injection of gas that coincided with the beginning of the high gas-injection rate. The noticeable decline in the oil-production rate during the middle of 1947 is attributed to reentry of sand into the Covarrubias 1-25 well and the shutting in of two productive wells for several weeks. By September 1948, the pressure in Covarrubias 1-48, the well supplying the injection gas, decreased below the required injection pressure, and the operation was suspended until November 18, when gas injection was resumed, using a portable compressor. Gas was injected at a daily rate of 500 M c.f.; and in 9 days the pressure at the injection well, Covarrubias 1-4, rose from 375 to 450 p.s.i. Injection was discontinued in January 1949, pending installation of a permanent compressor, and operations were not resumed until November 1949.

Mercaptan has been continuously introduced with the injected gas to trace its migration, but only occasionally has the tracer gas been detected in the gas produced from the wells surrounding the injection well. The gas-oil ratios of the productive wells have remained essentially constant throughout the gas-injection period and it does not appear that any substantial portion of the injected gas has blown through the oil sand from the injection to the oil-productive wells.

The results obtained to date by gas injection are encouraging, as production of oil from the zone into which the gas is injected has increased. The records show that during the 20 months from February 1, 1944, to October 1, 1945, before injection, production from the zone averaged 4.6 barrels of oil per day per well and during the 20 months after the beginning of gas injection, the average production rate was 7.2 barrels of oil per day per well.

By the middle of 1945, just before gas injection, the decline in production had reached a level of diminishing returns. As shown in figure 31, the rate of production
was increased sharply (approximately 60 percent) during 1946 following gas injection and the normal decline began at a new level corresponding with the production obtained in late 1942. Furthermore, the newly established rate of decline apparently is lower than in 1942 and, thus, it appears that gas injection has added at least 5 years to the life of these wells. In view of these favorable results it is planned to continue with the project.

CONCLUSION

Field operations have demonstrated conclusively the economic value of secondary recovery in California by gas injection. Such a definite statement regarding the economic soundness of water flooding in California is precluded at this time by a multitude of complex problems, which have not been solved by the few experimental water-flooding projects so far undertaken in this state. Most engineers in the State believe, however, that the future of water flooding is promising and should not summarily be rejected on the basis of any comparison of reservoir conditions in California with those in the Eastern and Mid-Continent areas of the United States, as reservoir characteristics are far from being ideal in the latter areas, also. In this respect, the urgent need for collecting additional field data is generally recognized.

One of the major problems posed by California gas-injection projects, in view of the prevalence of heterogeneous oil-bearing strata in most reservoirs, is the control of the selective movement or bypassing of gas. It is a generally established principle that in most instances selective injection of gas into thin sand intervals is the economic solution to this problem of excessive gas-oil ratios and loss of oil through bypassing gas in the earlier life of the project. Closely correlated with the problem of bypassing injected gas is the relative efficiency and economics of high-pressure as compared with low-pressure gas injection. Despite theoretical advantages of high-pressure gas injection early in the life of the field, two main operational disadvantages may arise: (1) Lack of control over the migration of gas and its ineffectiveness in sweeping the sands in a thick heterogeneous zone where the lateral and vertical permeabilities vary widely; and (2) creation of a large number of high-gas-oil-ratio wells. In such reservoirs the choice between high- and low-pressure gas injection usually is a compromise between optimum operating costs and maximum recovery of oil, and selective low-pressure injection into individual sand intervals offers an attractive and economic solution to the problem. Provision of course must be made to insure an adequate supply of gas for the low-pressure injection program in the latter life of the reservoir, either by purchase or by utilization of gas stored during the earlier life of the field.

The same general principle of injecting the flooding fluid into relatively short sand intervals, which have adequate shale beds above and below, also applies to the problem of water flooding the thick heterogeneous sands of the State. Notwithstanding the concept that the viscosity of the reservoir oil should not greatly exceed 20 centipoises for a successful water flood, it is believed that many California sands can be flooded successfully because of favorable permeability-viscosity ratio and other favorable sand characteristics.\(^{61}\) Increased recovery by accidental water flooding in two California fields, Salt Lake and Midway, both of which produce low-gravity crudes, indicates that recovery of such crudes by water injection is possible. Although possible fingering and bypassing will cause higher water-oil ratios, it is probable that the economic ratio will not be much different than in other areas. Experimental field results will be necessary, however, to establish the economic balance between additional recovery and operating costs.

\(^{61}\) Works cited in footnotes 3 and 4.
In the light of water-flooding experience in the central and eastern areas of the United States, it is stated\textsuperscript{62} that the optimum oil saturation before flooding should be 55 percent or more of the pore space for a successful operation; it is recognized, however, that this figure is highly dependent upon the physical characteristics of the oil and the productive sand, as well as upon various economic factors. It will be necessary to establish the residual oil saturation at the economic completion of a water flood by field experiments, but it is generally anticipated that this figure is not likely to be less than 25 percent saturation.

In view of the large differences between maximum and minimum permeabilities within any given sand section, the lenticularity and faulting of many of the formations subject to water flooding, the excessive depths of the productive formations, and the high cost of drilling input wells in California, the standard well-spacing patterns, in general, cannot be utilized.

Experimental floods on a field scale also must be utilized to establish optimum input pressures and rates under California conditions. Although some engineers have advocated maximum input pressures just below the pressure required to lift the overburden, present practice is to increase the required initial input pressure by small increments to establish the best procedure for optimum recovery. Field data collected so far indicate that the optimum pressure is under 1 pound per foot of depth. Apparently there will be no tendency toward higher pressures until more field experience is available.

An important problem influencing the success of future water-flooding operations in California is swelling of the argillaceous content of some reservoir sands by water, with attendant large decrease in permeability. Homogeneous-fluid measurements on a large number of core samples have shown that the permeabilities of reservoir sands to air, brine, and fresh water vary over a wide range. It is of particular interest in this connection that the presence of illite and/or montmorillonite has been reported\textsuperscript{63} in cores from the Stevens zone in the San Joaquin Valley and of kaolinite, anauxite or both in cores from the Gatchell zone in the same region. These findings are consistent with the observed susceptibility of the Stevens sand to damage by fresh water and the relative immunity of the Gatchell sand to such damage, as illite and montmorillonite have a relatively much greater tendency to swell in the presence of fresh water.

In California high recovery of oil usually has resulted wherever conditions are favorable for an effective natural water drive, indicating that the hazards of both clay swelling and bypassing of the flooding water may be overrated in importance. The best examples of a complete natural water drive in the State are Mount Poso, Round Mountain, and Wasco. Several fields, including Dominguez, Ventura, and the Northeast extension of Coalinga, are known to have partial water drives. It is common experience in California, however, for a natural water drive to stop after becoming well established, a circumstance which may be explained by swelling of the argillaceous material in the sand. An alternative and more likely explanation is that the aquifers exist in lenses or zones of limited extent and the amount of expansion of the water therefore is limited. Water from one zone partly floods an adjacent zone but is not enough to maintain pressure for more than a short period.

\textsuperscript{62} Works cited in footnotes 3 and 4.
of time. Faulting also frequently limits water encroachment, as at Dominguez, where water fails to enter large portions of the field.

With several notable exceptions, California sands appear to be suitable for flooding with brine, which in general minimizes swelling of the clay content of sands. Formation water is being injected successfully into the Chapman zone of the Richfield field and in the Dominguez, Lompoc, Greeley and Del Valle fields. It is doubtful, however, whether the Paloma or South Coles Levee field could be flooded successfully, as they are outstanding examples of fields in which water swells the clay in reservoir sand. Laboratory measurements of the effect of water on formation cores are essential before any field work is attempted.

It is evident that a comprehensive research program is necessary to resolve and evaluate the many problems upon which the economic success of full-scale secondary-recovery operations in California may largely depend. In this respect, the need for collecting additional field data is generally recognized. Accordingly, an accelerated program of secondary-recovery research in the State, both in the laboratory and in the field, with special emphasis on field experimental projects, is in order.