

GEOLOGICAL SURVEY CIRCULAR 687



Report on Water Injectivity Test,  
Lease OCS-P 0241, Well No. B-49-1,  
Dos Cuadras Field, Santa Barbara  
Channel, Off California



**Report on Water Injectivity Test,  
Lease OCS-P 0241, Well No. B-49-I,  
Dos Cuadras Field, Santa Barbara  
Channel, Off California**

**By Maurice V. Adams**

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**United States Department of the Interior**  
ROGERS C. B. MORTON, *Secretary*



**Geological Survey**  
V. E. McKelvey, *Director*

## FOREWORD

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By adherence to this policy, the Geological Survey has built a reputation for integrity and impartiality in its service to the Nation. In this context of public service, the information contained herein has been published for the benefit of all who have an interest in the subject matter.

Entitled "Water Injectivity Test, Lease OCS-P 0241, Well No. B-49-I, Dos Cuadras

Field, Santa Barbara Channel, Off California," this publication is a progress report on the subject project. It includes pertinent information from the time the application to drill was submitted by Union Oil Co. of California on January 28, 1971, through May 31, 1973.

The basic data utilized in preparing this report were submitted by Union Oil Co. of California in compliance with applicable regulations contained in Part 250, Title 30 of the Code of Federal Regulations. The analysis and interpretation of these data have been made by the author.



V. E. MCKELVEY  
*Director*



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# Report on Water Injectivity Test Lease OCS-P 0241, Well No. B-49-I, Dos Cuadras Field, Santa Barbara Channel, Off California

By **Maurice V. Adams**

## INTRODUCTION

Union Oil Co. of California submitted an application to drill and complete well B-49-I for a pilot water injectivity test in a portion of the upper 402 zone of the "Repetto" reservoirs, lease OCS-P 0241, Dos Cuadras field, Santa Barbara Channel, off California. The application, with attachments, was received in the U.S. Geol. Survey Santa Barbara office January 28, 1971, and after comprehensive review and recommendations, was approved by the Director, U.S. Geol. Survey, on March 24, 1971. A summary of the pertinent information and conclusions obtained from this pilot test is presented in response to public interest.

## ACKNOWLEDGMENTS

The author wishes to thank Union Oil Co. of California and their co-lessees Gulf Oil Co.-U.S., Mobil Oil Corp., and Texaco, Inc., for their permission to publish the basic data contained in this report. Special thanks are extended to Mr. D. W. Solanas, U.S. Geol. Survey, for his assignment of this project to the author. The author also extends his thanks to Mr. Edgar W. Guynn, U.S. Geol. Survey, who made a substantial contribution to this report by his early work on the subject.

## GEOLOGIC CHARACTERISTICS AND NOMENCLATURE

The trapping structure in the Dos Cuadras field is a doubly plunging east-west trending

anticline on the seaward extension of the Rincon trend. The productive zones are in the upper "Repetto Formation" of early Pliocene age. Longitudinally (E-W), the structure is fairly symmetrical, although detailed geology of the western one-quarter is not yet well known. The transverse section (N-S) is asymmetrical with substantially steeper dips on the south flank through the "Repetto Formation," but may be more symmetrical in deeper formations. There is a major longitudinal thrust fault (TF-1) cutting the anticline. The formations lying above the thrust fault have been designated as the P block, and those below the fault are the Q block.

Identifiable electric log markers, from B to L, have been established in the "Repetto Formation" (fig. 1). However, only those sandstones from the C marker through H have been commercially productive to date. In addition, arbitrary color designations have been made for the zone which lies below the E-log marker, as follows: C and D (Brown), E (Yellow), F (Purple), G (Orange), and H (Green). With this informal nomenclature, as an example, the Yellow zone above the thrust fault is called EP, but below the thrust fault it is EQ. Some of the zones are further subdivided by a numerically increasing designation, within the zone, such as F1P, F2P, F3P, etc.

The productive "Repetto" sandstones, in the Dos Cuadras field, have been combined into three development zones: (1) the upper Brown zone, consisting of the CP (Brown) and DP

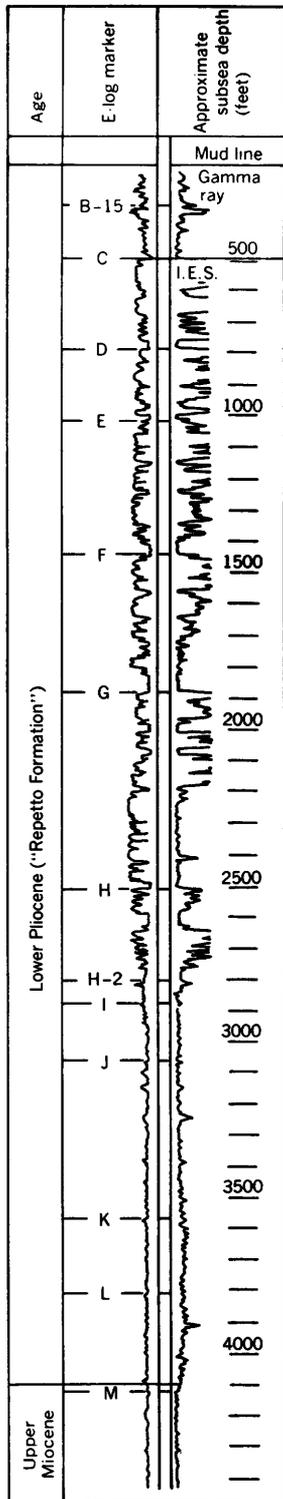
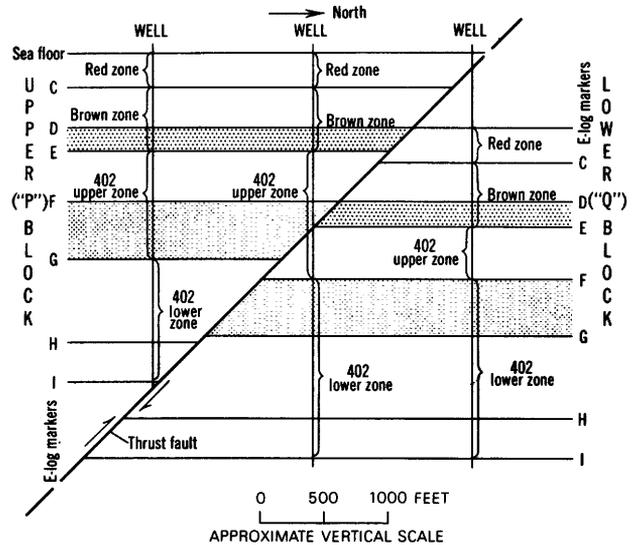


FIGURE 1.—Composite type log of the Dos Cuadras oil field. From McCulloh (1969, fig. 6).



Note: F-G markers are included in 402 upper zone above thrust fault and in 402 lower zone below thrust fault

FIGURE 2.—Schematic relations between producing "zones," stratigraphic subdivisions, and structural divisions in the Dos Cuadras oil field. From McCulloh (1969, fig. 10).

(Brown) intervals above the TF-1 fault; (2) the upper 402 zone including the EP (Yellow) and FP (Purple) intervals above TF-1 and the CQ (Brown), DQ (Brown), and EQ (Yellow) intervals below TF-1; and (3) the lower 402 zone comprising the GP (Orange), G3P (Orange), and HP (Green) intervals above TF-1 and FQ (Purple), GQ (Orange), G3Q (Orange), HQ (Green), and H1Q (Green) below the TF-1 fault. The upper 402 zone is usually abbreviated as EP, FP, /CQ, DQ, EQ, and the lower 402 zone as GP, G3P, HP, /FQ, GQ, G3Q, HQ, H1Q with the slash designating the TF-1 thrust fault (fig. 2). Not all these zones are productive throughout the entire areal extent of the field, nor, with few exceptions, are all of the intervals of a development zone present and productive in a particular well bore. (See structure maps and cross section, figs. 4-7).

#### WATER DRIVES—GENERAL DISCUSSION

In general, water drives, in an oil reservoir, may be either natural or artificial. Natural water drives can be divided into two basic types:

(1) those where the producing zone crops out, generally some distance from the field, and the edge water is replenished by natural sources (artesian effect) or (2) those where the volume of the surrounding aquifer is of such magnitude with respect to the volume of oil in place that reduction in reservoir pressure will cause the water in the aquifer to expand sufficiently to supply driving energy to the reservoir.

Artificial, or induced, water drives are those where water is injected, from the surface, through injection wells, to supplement the natural driving pressure energy contained within the reservoir. Artificial water drives can be divided into three basic types: (1) peripheral injection at, or near, the oil-water interface, (2) five-spot injection into the producing zone to drive oil to surrounding producing wells, or (3) line injection to drive oil to a line of producing wells. Each type of artificial water drive has various merits which make a particular one preferable for a certain set of existing conditions. As a generality, peripheral injection is more desirable when initiated early in the life of a field. In operation, it becomes an effective means of pressure maintenance. Line or five-spot injection is more commonly used in the late producing life of a field.

A majority of California oil fields probably have a limited degree of natural water drive. However, it is relatively rare that the degree of drive, or encroachment, is of sufficient magnitude to be considered effective. Where a natural effective drive does exist, the field is usually small and the encroachment results from expansion of the aquifer. A notable exception to this type of drive is the Kern River field, near Bakersfield, Calif. This giant field has produced a cumulative total of more than 552,000,000 barrels during its 73-year life. It has an effective drive because water in the aquifer is replenished by the Kern River where the producing zone crops out upstream from the field.

Artificial water drive is usually used as a means of secondary recovery to supplement the primary driving mechanism and to achieve an increase in ultimate oil recovery. Muskat (1937) established the basic premise that when a porous medium is saturated with a native fluid, the introduction of a non-native fluid

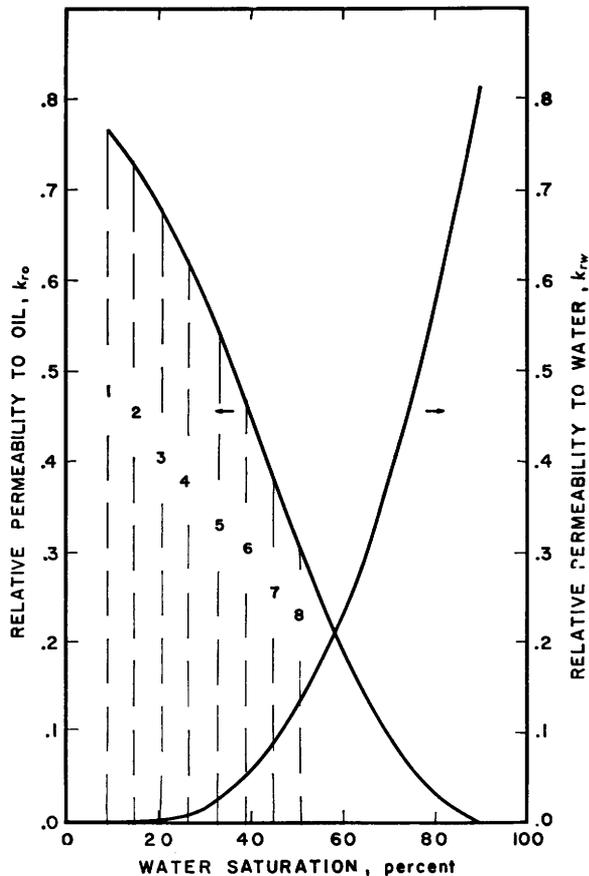


FIGURE 3.—Relative permeabilities of oil and water as a function of water saturation. From Douglas, Peaceman, and Rachford (1959, p. 297).

results in a decrease in permeability to the native fluid and an increase in permeability to the non-native fluid. In the case of a porous medium that is saturated with oil, the introduction of water as a non-native fluid results in a decrease of permeability to oil to essentially zero when the water saturation has reached about 80 to 90 percent and the oil saturation has been reduced to about 10 to 20 percent (fig. 3). The relationship of permeabilities to water saturation, shown in figure 3, should be considered only a general relationship because of the influence of such variables as oil gravity, oil viscosity, and absolute permeability of a particular zone. The major significance is that by water flooding, a field usually can be ultimately abandoned in the safest possible condition, that is, with the relative permeability to oil reduced to a level that immobilizes the remaining

oil in place. Alternatively, if the field were depleted by primary recovery only, then abandoned, and if even a nominal amount of natural water drive exists, reservoir pressures *might*, over a long period of time rebuild to near their virgin values.

The relationship in figure 3 should not be interpreted to mean that water flooding will result in the recovery of 80 to 90 percent of the original oil in place. To attain such an end would require a perfect flood, which in turn would require a completely homogeneous zone of absolutely uniform permeability. Such conditions seldom, if ever, occur in nature. Consequently, some oil will be bypassed; some, in areas of low permeability and porosity, will be held in place by surface tension; and some will never be reached by the sweeping effect of the flood. In fact, a highly successful water flood usually recovers on the order of 40 to 50 percent of the original oil in place. Water flooding, for many fields, is the only economical long-term secondary recovery method available.

#### RESERVOIR CHARACTERISTICS OF DOS CUADRAS FIELD

The primary recovery mechanism for the various reservoirs of the Dos Cuadras field is indicated to be solution gas drive. Only one reservoir is known to have a small gas cap; it is in the lower (H1Q) Green sand, south of Platform A, and is not open to production. Since solution gas appears to be the driving force in a relatively new field, the reservoir fluid must have been initially at, or near, saturation pressure. "Bubble point" of a reservoir fluid is defined as that pressure at which gas begins to be released from solution. If the reservoir fluid is saturated at virgin conditions, then "bubble point" and virgin pressure are equal. If the fluid is undersaturated, "bubble point" is lower than virgin pressure.

As in any hydraulic system, fluids move through a reservoir as a result of pressure differential, with the movement being from higher to lower pressure areas. An oil or gas well produces because the pressure within the well bore is lower than the pressure in the surrounding reservoir. When reservoir pressure is reduced below "bubble point" and gas breaks out of solution, gas becomes a non-native fluid in

the reservoir. According to Muskat's premise, the net result is an increase in permeability to gas and a decrease in permeability to oil. The relative relationship is similar to that shown in figure 3, but relative permeability to water is replaced with relative permeability to gas and water saturation is replaced with reservoir pressure. Continued reduction in reservoir pressure (decrease to right in fig. 3) aggravates the changes in permeability and results in dissipation of reservoir energy. Inefficient recovery of oil results and is indicated by a gas/oil ratio in excess of the solution gas contained in the reservoir fluid.

PVT (pressure-volume-temperature) analysis of a reservoir fluid sample from the upper 402 zone, taken at a subsea depth of minus 1,490 feet, indicated that the initial solution gas/oil ratio was approximately 115 cubic feet per barrel. During the early life of the Dos Cuadras field, the average overall gas/oil ratio was about 250 cubic feet per barrel; by September 1971, it had gradually increased to about 575 cubic feet per barrel; and since, has gradually decreased to about 400 cubic feet per barrel at the present time.

This energy waste, which has an adverse effect on ultimate oil recovery, can be retarded, or minimized, by a program of pressure maintenance. It can be completely avoided only if reservoir pressure is maintained at, or above, the "bubble point." Since it appears that the reservoir fluid was initially at, or near, the saturation pressure, it is not practical to maintain pressures above the "bubble point" nor would it be particularly desirable.

The efficiency of a solution gas drive is substantially less than either a gas cap drive or a water drive simply because the driving energy comes from within the reservoir fluid itself rather than from an external source; that is, external to the oil bearing portion of the reservoir. Accordingly, improvement in efficiency along with greater ultimate oil recovery can be attained by supplementing reservoir energy with a program of pressure maintenance. For the Dos Cuadras field it appears that a feasible means of effecting a program of pressure maintenance is peripheral water injection. Such a program would be in the interest of conservation by increasing ultimate

oil recovery. Additionally, as pointed out earlier, an artificial water drive is the best means of immobilizing the residual oil in place.

A limited natural water drive probably exists in some of the "Repetto" reservoirs of the Dos Cuadras field. It is known that an aquifer exists; therefore, as reservoir pressures are reduced, the aquifer will expand. Some water encroachment into the reservoirs has occurred as attested by the fact that during the early productive life of the field the overall average water production was only about 2 percent of the gross production, whereas it presently amounts to about 40 percent.

The areal extent of the various reservoirs in the "Repetto Formation" differs from reservoir to reservoir. On the other hand, it is probable that the areal extent of each aquifer is the same. If so, the degree of natural water drive will be related to the ratio of the volume of the aquifer to the volume of the oil reservoir. For the smaller reservoirs, the degree of effectiveness of natural water encroachment may be sufficient to flood the reservoir to depletion. Conversely, it is probable that the effectiveness of the natural water drive for the larger reservoirs will be minimal; hence, it will be necessary to supplement it with artificially induced energy in the form of injected water.

### INJECTION WATER SOURCE

Of significant importance in any water injection program is a source of water that is compatible with that contained in the injection zone; or, at least, does not have adverse effects on the formation into which it is being injected. In the case of an offshore water injection well an obvious source of supply is the surrounding sea water. Union Oil Co. made analyses of sea-water samples which are tabulated in table 1.

In addition to these analyses, cores from the producing zones were flushed with sea water, with the results indicating only a minor reduction in permeability. On the basis of these laboratory analyses and core tests, it was concluded that sea water was a suitable injection fluid that could be used without filtration with the possible exception of times when turbidity was high. Accordingly, instrumentation was installed to provide a positive means of monitor-

ing turbidity. During periods of high turbidity it was planned that the injection system would be shut down. Additionally, provisions were made for deaeration of the injection water, use of chemical corrosion inhibitors, and microbiological control.

Frequently, a more desirable source of injection water is the water produced in conjunction with the production of oil and gas. Since such water is formation water, it is usually compatible for reinjection into the formation. Use of produced water for injection has the additional advantage of being an environmentally acceptable method of disposal. Water from different zones is usually suitable for injection into any zone within the same formation even though there may be some chemical differences

TABLE 1.—Sea-water samples from Santa Barbara Channel. Sampled April 30, 1968, at OCS-P 0241, well 1

[With the exception of pH, units are expressed in parts per million]

	Depth		
	50 feet	100 feet	150 feet
pH -----	8.1	8.0	8.1
Na -----	10,390	10,390	10,580
Ca -----	414	406	404
Mg -----	1240	1270	1250
Cl -----	18,300	18,200	18,200
SO <sub>4</sub> -----	2610	2630	2630
CO <sub>3</sub> -----	30	20	20
HCO <sub>3</sub> -----	90	105	100
Total dissolved solids			
by evaporation -----	40,000	40,000	39,900
Millipore filterable solids ---	1.3	2.5	1.1

in the waters from the various zones. In the case of the Dos Cuadras field, chemical analyses have been made of the water produced from each zone in the "Repetto Formation". While the waters differ sufficiently enough that the chemical composition identifies the zone from which they were produced, water from any zone is suitable for reinjection in any zone.

Since early February 1973, the water injected into well B-49-I has been a composite of the free water produced at Platform B. The chemical analysis of a composite sample of produced water at Platform B is tabulated in table 2.

When oil, water, and gas are produced from a well, some of the water is in the form of an

TABLE 2.—Composite produced-water sample—Platform B. Sampled June 26, 1973

[With the exception of pH, units are expressed in parts per million]

pH	8.0
Na	7,600
Ca	Trace
Mg	49
Cl	10,100
SO <sub>4</sub>	Not detected
CO <sub>3</sub>	Trace
HCO <sub>3</sub>	3,098
Total dissolved solids	
by analysis	20,847
Millipore filterable solids:	
Out of Quadricell	28.2
Out of filter	13.0

oil-water emulsion, and some of it is in an unemulsified or free state. The amount of free water increases as the percentage of water in the gross production increases. Since the present overall water production for the Dos Cuadras field is on the order of 40 percent of the gross production, considerable free water is being produced. Free water can be separated from the gross production stream by means of an oil-water separator known as a "free-water knockout." Such a separator is in operation on Platform B.

Water from the free-water knockout usually is associated with some oil and suspended solids. The fluid is passed through a Quadricell unit for removal of these substances. The Quadricell unit in service on Platform B consists of four cells in series, each with an aerator mechanism to separate oil and suspended solids and carry them to the surface where they are removed by a skimmer. The unit is hermetically sealed and operates with natural gas aeration which results in a natural gas blanket over the fluid. The gas atmosphere prevents oxygen absorption, removes any oxygen present, and purges light hydrocarbons or entrained gases from the stream, with the gases being removed through a special vent. Prohibition of oxygen entering injection water, or its removal if it is present, is important in avoiding corrosion or scale formation by oxidation.

Before the water is injected into the well, it is passed through a cartridge type filter to remove very small additional suspended solids. The millipore test data shown in table 2 were obtained using a 45-micron millipore filter.

This same test showed zero parts per million of hydrocarbons present in the injection water, but this should not be interpreted as meaning the absolute absence of hydrocarbons. These data were obtained by using standard laboratory procedures for the determination of hydrocarbons in the form of oil and grease present in the water. Since the lighter ends of the paraffin series of hydrocarbons (methane, ethane, propane, normal butane, isobutane, pentane) have a degree of solubility in water, they are probably present but undetected by this laboratory procedure.

### SPECIAL INJECTION CONDITIONS

On March 24, 1971, the Director of the Geological Survey approved the drilling of water injection test well B-49-I, lease OCS-P 0241, subject to the following special conditions:

1. Coordination of Union's activities under this proposal with Sun Oil Company toward the goal of unitizing the structure if a full scale waterflood is initiated.
2. A representative of the Geological Survey must witness *all* initial water injection tests and all changes in rate of injection.
3. A continuous and accurate pressure recording shall be made of all injection pressures. No injection shall be allowed without pressure recording.
4. Injection pressures at the sand face in excess of 0.44 psi per vertical foot of water depth and 0.65 psi per vertical foot of rock overburden must first receive approval of the District Engineer. Complete justification for exceeding this minimum pressure must be made.
5. In no event will a pressure in excess of 0.44 psi per vertical foot of water depth and 0.80 psi per vertical foot of rock overburden be permitted.
6. Adequate tests and surveys shall be conducted to detect any communication between any zones in the structure. Special emphasis will be placed on the quality of the cement job above the EP zone. The quality of this cement shall be verified with a cement bond log."

## DRILLING AND COMPLETION HISTORY

In order to reach the aquifer of the EP and FP zones, it was necessary to drill well B-49-1 with the slant rig set at an angle of 25°. Additionally, because the bottomhole location was on the south flank of the anticline, it was necessary to use a platform drilling slot with a south-facing conductor. The well drilling commenced on May 2, 1971, and reached total depth on May 17, 1971. The hole was bottomed 1,163 feet south and 290 feet east of the surface location at a measured total depth of 2,625 feet below the kelly bushing (KB). The true vertical depth (TVD) was 2,290 feet below KB. The major geologic markers encountered are as follows:

	Depth, in feet, from kelly bushing		Subsea depth, in feet
	Measured	True vertical	
CP ----	816	723	— 638
DP ---	1,293	1,085	—1,000
EP ---	1,520	1,278	—1,193
FP ----	2,064	1,755	—1,670

NOTE.—Kelly bushing was 85 feet above sea level.

The various casing strings run in the well are at the following measured depths (MD), with respect to the kelly bushing (KB): 20 inch at 316 feet, 16 inch at 417 feet, 13 $\frac{3}{8}$  inch at 734 feet, and 10 $\frac{3}{4}$  inch at 1,516 feet. All casing strings were cemented through the shoe except the 20 inch, which was driven about 11 feet into the ocean floor. The EP and FP intervals were cased with an 8 $\frac{5}{8}$ -inch blank liner which was cemented through the shoe, extending from 1,331 feet to 2,620 feet (MDKB).

In compliance with special condition 6, a cement bond log was run to confirm the quality of the primary cementing jobs. This log indicated that the cement bond for the 8 $\frac{5}{8}$ -inch liner was not of good quality. Additionally, the lap between the 8 $\frac{5}{8}$ -inch liner and the 10 $\frac{3}{4}$ -inch casing did not pressure test satisfactorily. Accordingly, the liner was perforated and squeeze cemented at various points to repair the primary cementing job. After squeeze cementing and cleaning out, the liner lap and all perforations were pressure tested with satisfactory results. A second cement bond log was run after the remedial cementing which indicated that good cement bonding had been attained. (For detailed well history, and well

mud and drilling records, see well data at end of report.)

The well is completed with two strings of 2 $\frac{7}{8}$ -inch tubing, a single packer at 2,019 feet, and a dual packer at 1,450 feet. The single packer is between the EP and FP zones to isolate them from each other and the dual packer is above the EP zone to seal the annulus between the tubing strings and the casing. This annular space is filled with inhibited sea water to prevent corrosion.

## INJECTIVITY TESTING

Special condition 4 provided that initial injection pressure could not exceed a sand face pressure in excess of 0.44 pounds per square inch (psi) per vertical foot of water depth plus 0.65 psi per vertical foot of rock overburden. If it became necessary to exceed this pressure to attain adequate injection rates, prior approval of the District Engineer was required. However, under special condition 5, in no event could the sand face pressure exceed 0.44 psi per vertical foot of water depth plus 0.80 psi per vertical foot of rock overburden. It was necessary during the injectivity testing to go to the higher pressures permitted by special condition 5, but it was accomplished in an incremental and controlled manner. The injectivity testing was monitored at all times by petroleum engineers and technicians from the Santa Barbara District office. As pressures were increased above those permitted by special condition 4, the increase was made in 50 psi increments to establish stabilized flow. In this manner, any abnormal pressure or volume changes could be readily observed and corrected. No such changes were observed.

The injectivity testing was conducted in six stages as depicted in table 3. The computation of permissible well-head pressures was made by neglecting friction losses in the injection string. This procedure results in an added safety factor, which for low rates of injection is negligible but for higher rates would be significant.

All intervals open for injection were perforated with two jet shots per foot. Stages 1 and 4 were perforated with a casing gun prior to running tubing, but the remaining stages

TABLE 3.—Six stages of injectivity testing well B-49-I lease OCS-P 0241

Stage	Perforated interval MDKB	Zone	Subsea depth of top perforation	Maximum permissible pressure (psig)			
				Condition 4		Condition 5	
				Sand face	Well head <sup>1</sup>	Sand face	Well head <sup>1</sup>
1	2,376-2,427	F2P	-1,959	1,234	352	1,499	620
	2,488-2,509	F3P					
	2,516-2,523	F3P					
2	2,267-2,332	F1P	-1,854	1,165	330	1,415	580
	2,336-2,364	F1P					
	2,062-2,248	FP					
3	1,769-1,797	E2P	-1,668	1,044	292	1,266	513
	1,804-1,914	E2P					
	1,929-1,995	E3P					
4	1,643-1,754	E1P	-1,416	881	239	1,064	423
	1,522-1,554	EP					
	1,558-1,624	EP					
5			-1,303	807	215	974	382
6			-1,195	737	192	888	343

<sup>1</sup> Well head is 47 feet above sea level. Water depth is 190 feet.

(2, 3, 5, and 6) were perforated through the tubing using Schlumberger's 2-inch scallop gun.

On June 4, 1971, before starting water injection, temperature and bottomhole pressure surveys were made. At 2,514 feet MDKB (minus 2,095 feet subsea), which is in the lower F3P interval, a temperature of 107.5°F and a pressure of 981 psig were recorded. In the early development life of the Dos Cuadras field, Union Oil Co. determined that virgin pressures in the "Repetto Formation" were equal to 0.44 psi per foot of subsea depth plus 50 psi. These data would indicate a virgin pressure of 972 psig at the above depth of minus 2,095 feet. Sun Oil Co.'s measurements of virgin pressure indicated a gradient of 0.45 psi per foot of subsea depth plus 40 psi. Using the Sun data, the anticipated virgin pressure would be 983 psig. It was concluded that the observed pressure in well B-49-I was essentially a virgin pressure.

Stage 1 injection (F2P and F3P intervals) was started on June 7, 1971. Under special condition 4 the maximum permissible well-head pressure was 352 psig. At this pressure the formation would not take any water. Accordingly, with the approval of the District Engineer, the pressure was increased in 50 psi increments. The formation started taking water at the rate of five barrels per hour when the injection pressure reached 550 psig. Increasing the pressure to the maximum allowed under special condition 5 (620 psig) did not appreciably increase the rate of injection, but it did

reveal that the single packer separating the FP and EP zones was leaking. The packer was reset and injection was resumed on June 21, 1971. During the subsequent 4 days, the injected volume amounted to 94, 84, 100, and 72 barrels per day at a well-head pressure of 620 psig.

On July 1, 1971, the F1P intervals (stage 2) from 2,267 feet to 2,332 feet and 2,336 to 2,364 feet were perforated. This perforating was done through the tubing, and the perforating gun found sand fill at 2,477 feet MDKB sealing off all of the F3P interval. Because of the higher perforated interval of 2,267 feet, the maximum permissible injection pressure was reduced to 580 psig. At this pressure, the average daily rate was only 37 barrels of water per day.

On July 12, 1971, the injection intervals were acidized in one stage with 2,000 gallons of 7½-percent hydrochloric acid, and in a second stage with 1,000 gallons of 9-percent hydrochloric acid and 6-percent hydrofluoric acid. Seventy-five pounds of a diverting agent, known as Matriseal II, were used to make the acid enter the tighter formations. This acidizing job was quite successful in increasing injectivity. During the 6 days following the acid treatment the injection rate averaged 1,695 barrels per day at an injection pressure of 580 psig.

On July 19, 1971, the FP interval (stage 3) was perforated from 2,062 feet to 2,248 feet. The maximum permissible injection pressure for this interval is 513 psig, and it has subse-

quently been maintained at 510 psig most of the time. At this pressure the average injection rate during the next 11 days was 774 barrels per day.

A second acid treatment of the FP intervals was performed on August 5, 1971. This treatment used 3,000 gallons of 9-percent hydrochloric and 6-percent hydrofluoric acids with 200 pounds of Matriseal II diverting agent. Again the injection rate was improved. During the ensuing 10 days the average injection rate was 1,560 barrels per day at a pressure of 510 psig.

Stage 4 injection (E2P and E3P intervals) started on August 5, 1971. However, after 2 days during which 160 barrels were injected at a pressure of 100 psig, the pressure controller malfunctioned and was repaired. Injection was resumed on August 12, 1971. The maximum permissible pressure for this stage was 423 psig. The injection pressure was incrementally increased to 420 psig, and for a 4-day period the average injection rate was 2,027 barrels per day.

On August 18, 1971, the E1P (stage 5) interval was perforated from 1,643 feet to 1,754 feet MDKB. The maximum permissible injection pressure for this interval was 382 psig. The injection pressure was gradually increased to 380 psig. The injection rate averaged 1,551 barrels per day at this pressure.

On August 26, 1971, the EP (stage 6) interval was perforated from 1,522 feet to 1,554 feet and 1,558 feet to 1,624 feet MDKB. The maximum permissible injection pressure for this interval was 343 psig. However, injection at a pressure of 230 psig resulted in an average rate of 1,779 barrels per day for the next 19 days. The injection pressure was then increased to 250 psig and has remained at that point or lower to date.

On May 12, 1972, the EP interval was treated with a total of 3,000 gallons of 15-percent hydrochloric acid and 200 pounds of Matriseal II. On May 20, 1972, the FP interval was treated with 3,000 gallons of 15-percent hydrochloric acid and 150 pounds of Matriseal II. Table 4 shows that these acid treatments more than doubled injectivity into the EP interval and somewhat less than doubled injectivity into the FP interval.

## WITHDRAWAL AND INJECTION HISTORY

The upper 402 zone is comprised of the EP, FP, /CQ, DQ, and EQ intervals. Where these intervals are productive the reservoir fluids are commingled in a single well bore; therefore, it is not possible to maintain an exact record of production from each interval. Calculation of the original oil in place indicates that approximately 70 percent of the total in the upper 402 zone was contained in the EP and FP intervals. Allocation of withdrawals, by intervals, is made on the basis of original oil in place. On this basis, through May 31, 1973, the EP interval has produced 9,213,112 barrels of oil, 2,576,000 thousand cubic feet of gas, and 440,286 barrels of water. The FP interval has produced 4,691,579 barrels of oil, 1,610,000 thousand cubic feet of gas, and 275,160 barrels of water. These data are for lease OCS-P 0241 only. They do not include production from lease OCS-P 0240.

PVT (pressure-volume-temperature) analyses of reservoir fluid samples in the early life of the Dos Cuadras field indicated that the formation volume factor (the ratio of the volume of a barrel of oil in the reservoir under reservoir conditions and that same barrel of oil at the surface under atmospheric conditions) for the EP interval was 1.039 and for the FP interval it was 1.061. Typically, in a reservoir with a solution gas drive recovery mechanism, formation volume factor decreases as fluid is withdrawn from the reservoir. In the case of the Dos Cuadras field, the production, to date, has been only a small portion of the volume of the initial oil in place; hence, volume of reservoir space voided can be closely approximated at this point in time by using the originally determined formation volume factors. Through May 31, 1973, calculation indicates that 10,012,709 barrels of reservoir volume has been voided in the EP interval and 5,252,925 barrels in the FP interval.

Table 4 depicts the water injection history of well B-49-I, lease OCS-P 0241. To date, there has been no discernible reaction at the nearby producing wells; there has been no breakthrough of water; there has been no detectable change in producing characteristics; and there has been no observed anomaly in bottomhole pressures. Lack of reaction to water injection

TABLE 4.—Water injection history of well B-49-1 lease OCS-P 0241

Date	Days of injection	Water injected (bbls)		Daily average	Well-head pressure	Days of injection	Water injected (bbls)		Daily average	Well-head pressure
		Monthly	Cumulative				Monthly	Cumulative		
EP interval (Upper yellow)						FP interval (Upper purple)				
<b>1971:</b>										
June	0	0	0	0	0	10	1,434	1,434	143	620
July	0	0	0	0	0	30	18,236	19,670	608	545
August	19	30,419	30,419	1,601	250	31	39,454	59,124	1,273	510
September	26	39,493	69,912	1,519	250	26	30,767	89,891	1,183	510
October	28	28,077	97,989	1,008	250	28	26,864	116,755	959	510
November	30	40,654	138,643	1,355	250	30	25,048	141,803	835	510
December	31	48,021	186,664	1,549	250	31	24,335	166,638	801	510
<b>1972:</b>										
January	31	37,164	223,828	1,199	250	31	17,008	183,646	549	510
February	29	36,191	260,019	1,248	250	29	16,388	200,034	565	510
March	23	16,895	276,914	735	250	23	9,793	209,827	428	510
April	28	18,025	294,939	644	250	28	10,730	220,557	383	510
May	28	38,590	333,529	1,378	250	28	11,564	232,121	413	510
June	30	43,422	376,951	1,447	250	30	23,310	255,431	777	510
July	31	44,120	421,071	1,423	250	31	19,315	274,746	623	510
August	30	44,120	465,191	1,471	250	30	16,285	291,031	543	510
September	30	29,654	494,845	988	250	30	13,871	304,902	462	510
October	28	26,278	521,123	939	250	28	15,037	319,939	537	510
November	29	22,698	543,821	783	250	29	14,918	334,857	514	510
December	31	22,230	566,051	717	250	31	16,495	351,352	532	510
<b>1973:</b>										
January	4	2,557	568,608	639	250	4	1,539	352,891	385	250
February	26	6,827	575,435	263	135	24	13,562	366,453	565	396
March	31	2,798	578,233	90	74	31	20,791	387,244	671	500
April	29	2,639	580,872	91	60	29	20,876	408,120	720	500
May	31	2,936	583,808	95	55	31	22,263	430,383	718	500

is not unexpected inasmuch as the ratio of injected volume to withdrawal volume is nominal. For the two intervals, the volume of injected water has amounted to only 5.83 percent of the reservoir volume voided for the EP intervals and 8.19 percent for the FP intervals.

### SPECIAL TESTS AND SURVEYS

Special condition 6 imposed a requirement for various tests and surveys with particular emphasis on verification of the quality of the cementing of the 8 $\frac{5}{8}$ -inch liner through the EP and FP intervals. Additionally, an initial bottomhole formation pressure was determined and a base-line temperature gradient was run. These last two items are of primary value for future use for comparative purposes during the life of the well. All three of these special tests have been discussed earlier.

The single packer installed to separate the EP and FP intervals was discovered to be leaking during the initial injection. After resetting the packer and resuming injection, the F2P and F3P intervals were accepting water at a rate of less than 100 barrels per day even though the well-head pressure was at the maximum permissible pressure of 620 psig. It was known that the permeability of these intervals was such that the injection rate should be higher; there-

fore, it was postulated that reduction in permeability had occurred during the drilling of the well because of local invasion of the formation with drilling fluid in the immediate vicinity of the well bore. In order to confirm this theory a pressure "fall off" survey was made during the period of June 25 to 28, 1971. To make this survey, injection was stopped while dual bottomhole pressure gauges equipped with 120-hour clocks were run to 2,024 feet MDKB (minus 1,635 feet subsea). Injection was then resumed at a surface pressure of 620 psig for 5 hours to established stabilized flow. The pressure observed during this period was 1,390 psig. Injection was then stopped for 50 hours to permit the fluid column to stabilize at reservoir pressure. For the last 4 hours of this period the pressure was stable at 734 psig. Injection was then resumed for 30 hours before removing the pressure gauges and the observed pressure was 1,394 psig, essentially equivalent to the first observation of 1,390 psig.

The observed injection pressure of 1,390 psig at minus 1,635 feet subsea, with a surface pressure of 620 psig, indicates that the gradient of the fluid column was 0.471 psi per foot of vertical depth. This value would include friction loss, which would be negligible because the flow rate was only about four barrels per hour through 2 $\frac{7}{8}$ -inch tubing. Extrapolating the ob-

served static pressure at minus 1,635 feet subsea to minus 2,095 feet subsea with a gradient of 0.471 would result in a pressure of 951 psig at the lower depth. The initially observed bottomhole pressure at this lower depth was 981 psig, which earlier was considered to be in the appropriate range of a virgin bottomhole pressure. With the "fall off" test indicating a formation pressure some 30 psi lower, it was concluded that there had been reduction in permeability during the drilling of the well. The previously reported successful results of the acid treatments of July 12 and August 5, 1971, confirmed this conclusion.

On July 29, 1971, an injection profile survey was run on the FP, F1P, F2P, and F3P intervals. This survey revealed that 71 percent of the injected water was entering the F1P interval and 29 percent into the F2P. There was no entry into either the FP or F3P intervals. The sand fill at 2,477 feet MDKB, some 11 feet above the F3P interval, was the most likely reason for lack of entry into this interval. The second acid treatment of August 5, 1971, was performed subsequent to the injection profile survey for the purpose of improving the injection profile. As previously reported, it increased injectivity substantially.

On January 7, 1972, radioactive tracer surveys were made of both the EP and FP intervals. Both of these surveys revealed that neither the packer was leaking nor was there any upward movement of fluid above the top perforation of either interval. The survey also revealed that the FP interval was taking water, which is probably the result of the acid treatment of August 5, 1971.

### SUBSIDENCE INVESTIGATIONS

On May 12 and 13, 1969, a special scientific panel of the DuBridge Committee met in Los Angeles to consider future operations of lease OCS-P 0241. This panel recognized the *possibility* of subsidence in their recommendation 5 where they stated: "Reduce pressures throughout the reservoir to hydrostatic or less and maintain pressures with water injection, *if needed*, to minimize subsidence." (Emphasis added.) U.S. Geol. Survey Professional Paper 679 also refers to the *possibility* of subsidence

(McCulloh, 1969, p. 45-46; Hamilton and others, 1969, p. 65-66).

There are four general causes of subsidence: (a) subsurface removal of solids; (b) compaction of dry surface soils by wetting; (c) tectonic movement; and (d) net withdrawal of subsurface fluids. The first two do not concern Dos Cuadras operations. Tectonic subsidence could conceivably occur, but it is not within the scope of the discussion in this report. It is now generally accepted that oil-field subsidence, when it does occur, is caused by withdrawal of reservoir fluids. It is, therefore, a reasonable conclusion that if subsidence does occur at Dos Cuadras it will be caused by withdrawal of reservoir hydrocarbons and water that are not replaced by another fluid, either injected or supplied by natural water drive.

Some concern has been expressed that if subsidence should occur it might result in aggravation of the seepage problem at the crest of the Dos Cuadras structure. Fault movement as a result of subsidence is unlikely to occur in the present area of seepage. This type of subsidence faulting is normally experienced only around the periphery of the productive area, subparallel to the isobase contours, as a result of tension strains. In the center of the productive area, where subsidence is generally greatest formations undergo compaction, but the compressive force is seldom great enough to produce surface faulting. Therefore, even if there is subsidence, the seep areas are on the crest of the structure where surface faulting would not normally occur. The foregoing conclusion concurs with the statement in Professional Paper 679, (McCulloh, 1969, p. 45), that "It is possible that subsidence would be accompanied by localized peripheral tensional fracturing of the capping layers."

An additional significant point is that the occurrence of subsidence cannot be predicted. McCulloh (1969, p. 45) states: "The numerous complexly interrelated variables that determine whether or not subsidence occurs when pore fluids are withdrawn from a reservoir are understood so poorly that accurate prediction beforehand of the amount of subsidence is difficult, if not impossible." Similar opinions are held by many of the experts in the field of subsidence. It would appear to be more im-

portant to anticipate that subsidence *may* occur and to monitor it, so that, if it does, early detection will permit a course of remedial action to minimize it.

To this end, the Pacific Area initiated a program in mid-1970 with the operators of leases OCS-P 0240 and 0241 to determine platform elevations with a degree of accuracy that would detect minute subsidence. First, bench marks were established on each corner of the three platforms in the Dos Cuadras field. By periodically running elevations on these bench marks any tilting of the platform would be discovered. Second, the lease operators were requested to investigate the possibility of determining the elevation of each platform with respect to a known datum so that any change in elevation could be detected.

To obtain the latter information, it was planned that simultaneous measurement of reciprocal vertical angles from the platforms and a point of known elevation on land would yield accurate results because it would eliminate the need to apply corrections for curvature of the earth and refraction of light in the atmosphere. However, in attempting to use this method it was found that small vibrations caused by drilling and production machinery on the platforms made it impossible to measure an accurate vertical angle from the platform end of the survey line. Because of the distance involved, to survey from the land end of the line only would require correction for both curvature and refraction. Inasmuch as refraction will vary somewhat with atmospheric conditions, repeatability would not be such that a later survey would determine that there had been a small change in elevation. It was estimated that surveying from the land point only would yield results that were accurate to only about  $\pm 6$  inches.

Research by Lewis & Lewis Offshore, Inc., offshore surveyors of Ventura, Calif., revealed that an accurate elevation could be determined from records obtained with recording tide gauges installed on each platform. They estimated that a 60-day study would result in an accuracy of  $\pm 0.1$  foot, when compared with a suitable known station, and a 1-year study should provide an accuracy of  $\pm 0.05$  foot. The National Ocean Survey of the National Oceanic

and Atmospheric Administration (formerly the U.S. Coast and Geodetic Survey) has a tide station on nearby Rincon Island from which monthly reports are available for use as a standard station. Even without a standard station, any change of elevation of a particular platform would become apparent by comparing data obtained from each platform.

There are two basic types of tide gauges. One is a float type water-level recorder which requires the installation of a stilling well to eliminate the effect of wave action and surges. The other is a nitrogen pressure bubble gauge which does not require a supporting structure. Both types of gauges record water level on a 30-day clock driven strip chart. Both Union Oil Co. and Sun Oil Co. chose to use the water-level recorder type for their Platforms A, B, and Hillhouse. All three installations were made and became operational on October 1, 1971.

There are several tidal datum planes that can be computed from the data recorded by the tide gauges, such as: (1) daily highs and lows, (2) mean high water, (3) mean low water, (4) mean higher high water, (5) mean lower low water, (6) mean tide level, (7) diurnal high water inequality, and (8) diurnal low water inequality. Computation of several of the datum planes provides a "built in" check on computed results.

During the 20 months that the tide gauges have been in operation, since October 1, 1971, there has been no discernible change in relative elevation of the three platforms. The determination of absolute elevations of the platforms by comparison to the Rincon Island tide station has not yielded consistent results. Since there has been no relative change in elevation of the platforms one must conclude that either (1) the platforms are all changing in unison or (2) that the Rincon Island station is itself changing in elevation. The second condition seems to be the more likely, because the probability of the three platforms, each separated from the other by approximately 2,800 feet, consistently changing together is extremely remote. Surveys of the bench marks on the corners of the platforms have not indicated any tilting. The lack of any measurable differential subsidence adds to the probability that the platforms have not changed in elevation. These results are not sur-

prising as reservoir fluid withdrawal has been relatively nominal with respect to the initial volume of oil in place. Nevertheless, acquisition of these data early in the productive life of the Dos Cuadras field will serve as a reference for comparison with future data.

## CONCLUSIONS

In their original planning of this water injectivity test, Union Oil Co. reviewed injection projects in California oil fields with reservoir characteristics similar to the Dos Cuadras field. These investigations revealed that, in general, the injectivity index ranged from less than 1 to as much as 10 times the productivity index. On the assumption that the injectivity index would equal the productivity index, it was anticipated that the average water injection rate into the Yellow (EP) or Purple (FP) intervals would be on the order of 1,500 barrels per day. However, the primary purpose of this B-49-I injectivity test was to acquire information under actual field conditions to be used for a comprehensive analysis in planning a full-scale water injection program for the "Repetto" reservoirs in the Dos Cuadras field.

From the information contained in this report one can reasonably draw the following conclusions:

1. All phases of this injectivity test have been conducted in conformity with applicable regulations, OCS orders, and the six special conditions imposed upon this project.

2. The water injection rate into the Yellow (EP) interval has been approximately that anticipated in the original planning. During the first year, the daily average injection rate was 1,261 barrels at a well-head pressure of 250 psig. The maximum permissible injection pressure for this interval is 343 psig. By extrapolation, if the well-head pressure were increased to 343 psig the injection rate would be about 1,730 barrels per day. However, during recent months an unsatisfactory injection profile has developed in this well, and injection has been reduced until the condition can be corrected. Maintenance of a uniform injection profile is highly desirable; otherwise, the advancing front of the water flood would not be uniform and would result in water reaching a producing well

in a part of the interval, while other parts would not be efficiently swept by the flood.

3. The water injection rate into the Purple (FP) interval has not been as high as expected. During the first year, the daily average rate was 714 barrels at the maximum permissible well-head pressure of 510 psig. It is known that the F3P interval is covered with sand fill and, hence, is not accepting any injected water. Acid treatment of this interval has had good results; for example, during the month of August 1971 after two acid treatments the daily average injection rate was 1,273 barrels at a well-head injection pressure of 510 psig. It is probable that by cleaning out the sand fill and using additional acid treatments the injection rate can be improved.

4. Whether or not subsidence will occur in a particular oil field cannot be predicted. If it does occur, it will be the result of fluid withdrawal from the reservoirs. Additionally, the major problems created will be operational with little likelihood of causing any damage to the environment. At the present time the best known method to minimize subsidence is to replace the withdrawn fluid with an equivalent volume of another fluid; in this instance, water. The Pacific Area of the Conservation Division, USGS, has required a monitoring system so that should any subsidence occur it will be detected in its early stages, thus permitting early corrective action.

5. The overall concept of water injection into reservoirs such as the "Repetto" reservoirs of the Dos Cuadras field has a sound engineering basis. Early initiation of such a project results in a pressure maintenance mechanism, whereas, if it were delayed until the late productive life of the field it would be a secondary recovery method and result in lower oil recovery efficiency. A full-scale water injection program for the "Repetto" reservoirs of the Dos Cuadras field should reasonably be expected to yield the following beneficial results: (a) increase ultimate oil recovery, thus conserving a depletable natural resource; (b) decrease the productive life of the field, thereby permitting the return of the area to its natural environment at an earlier date; (c) inhibit subsidence, or, should it occur, minimize it; and (d) immobilize most of the residual oil in place thus,

upon abandonment, leaving the field in a condition so as to prevent or minimize possible future seepage.

#### REFERENCES CITED

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- Muskat, Morris, 1937, *The flow of homogeneous fluids through porous media*: New York, McGraw-Hill Book Co., Inc.

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**FIGURES 4-7 AND WELL DATA**

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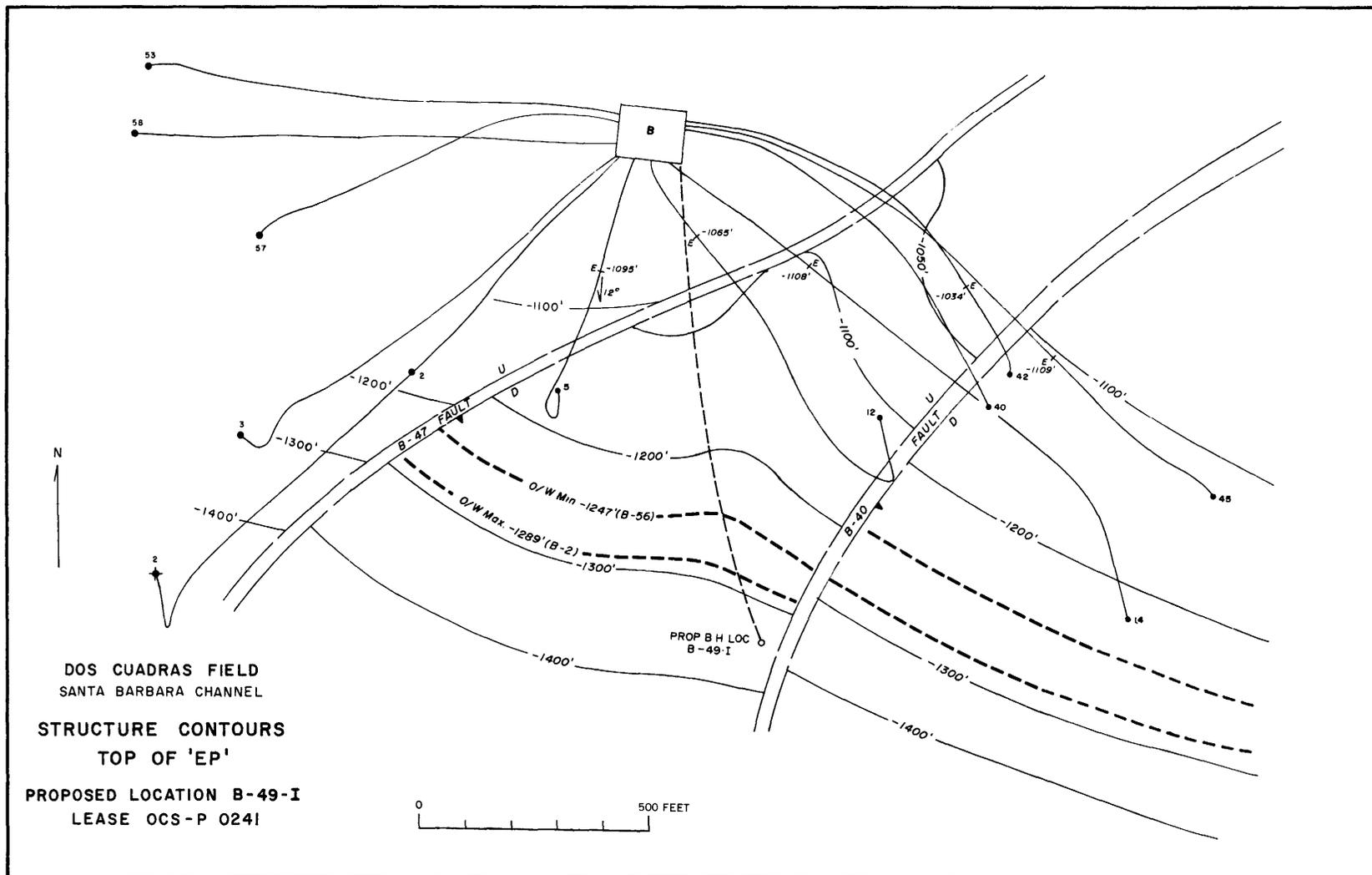


FIGURE 4.—Structure contours for the top of the EP interval.

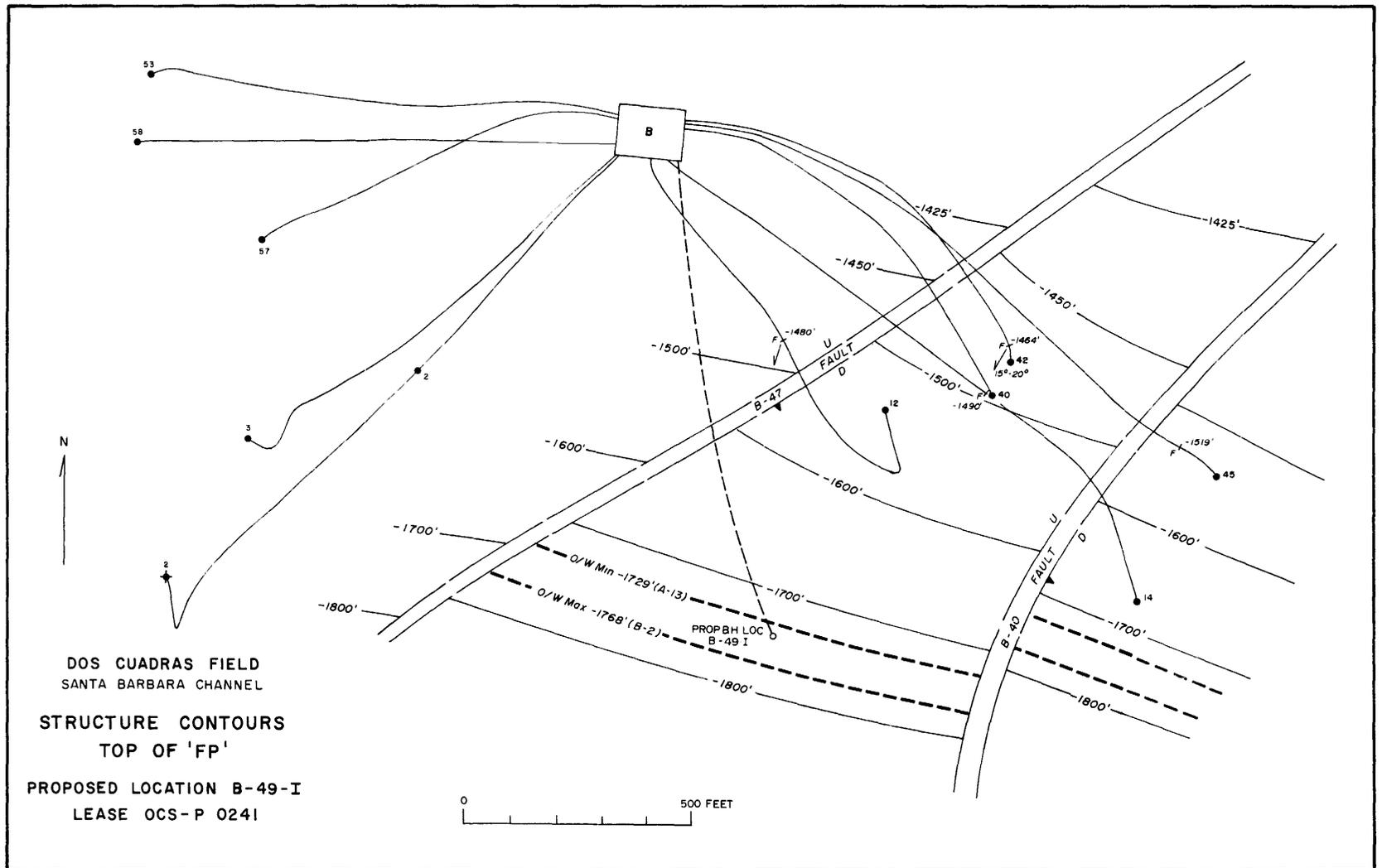


FIGURE 5.—Structure contours for the top of the FP interval.

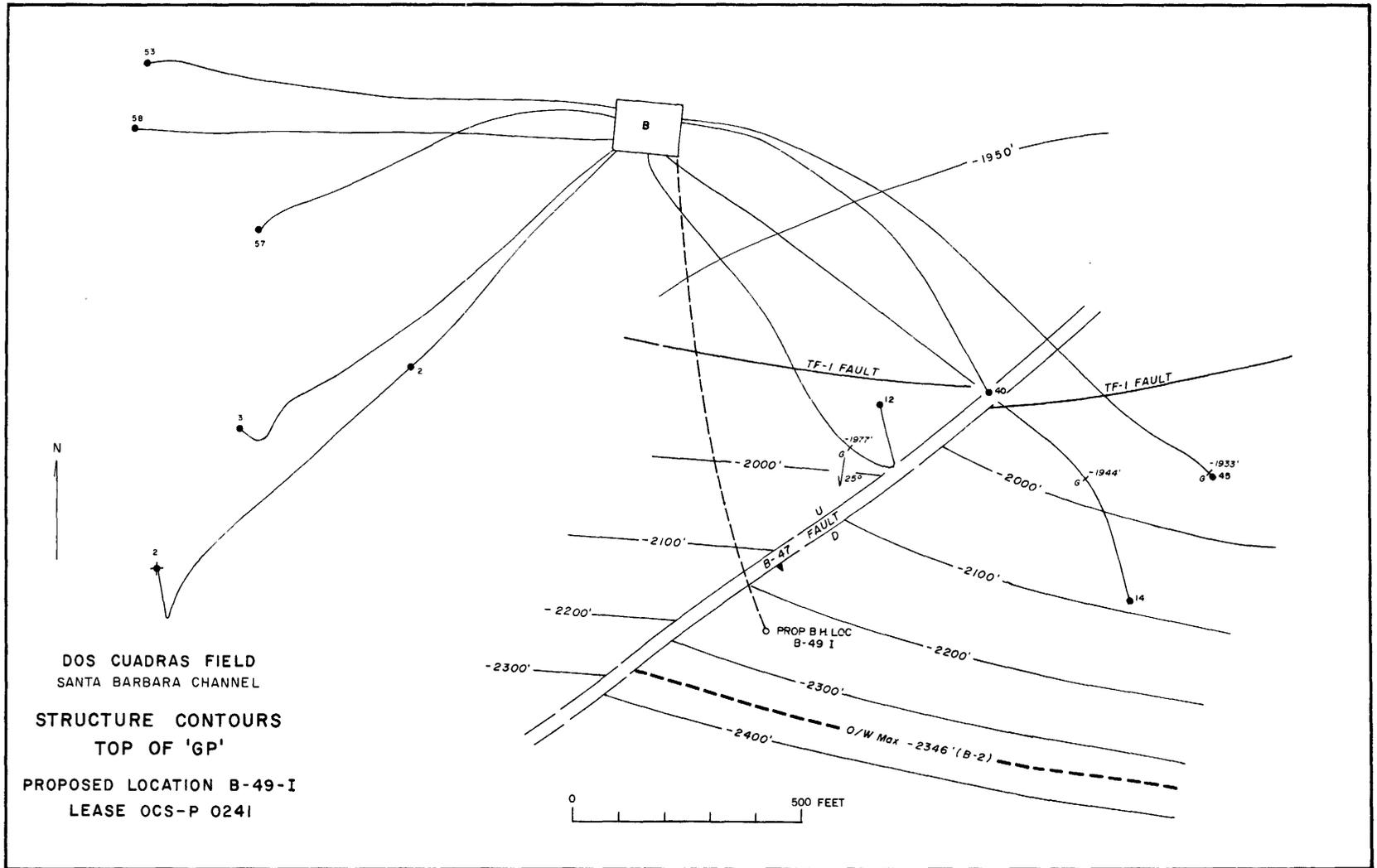


FIGURE 6.—Structure contours for the top of the GP interval.

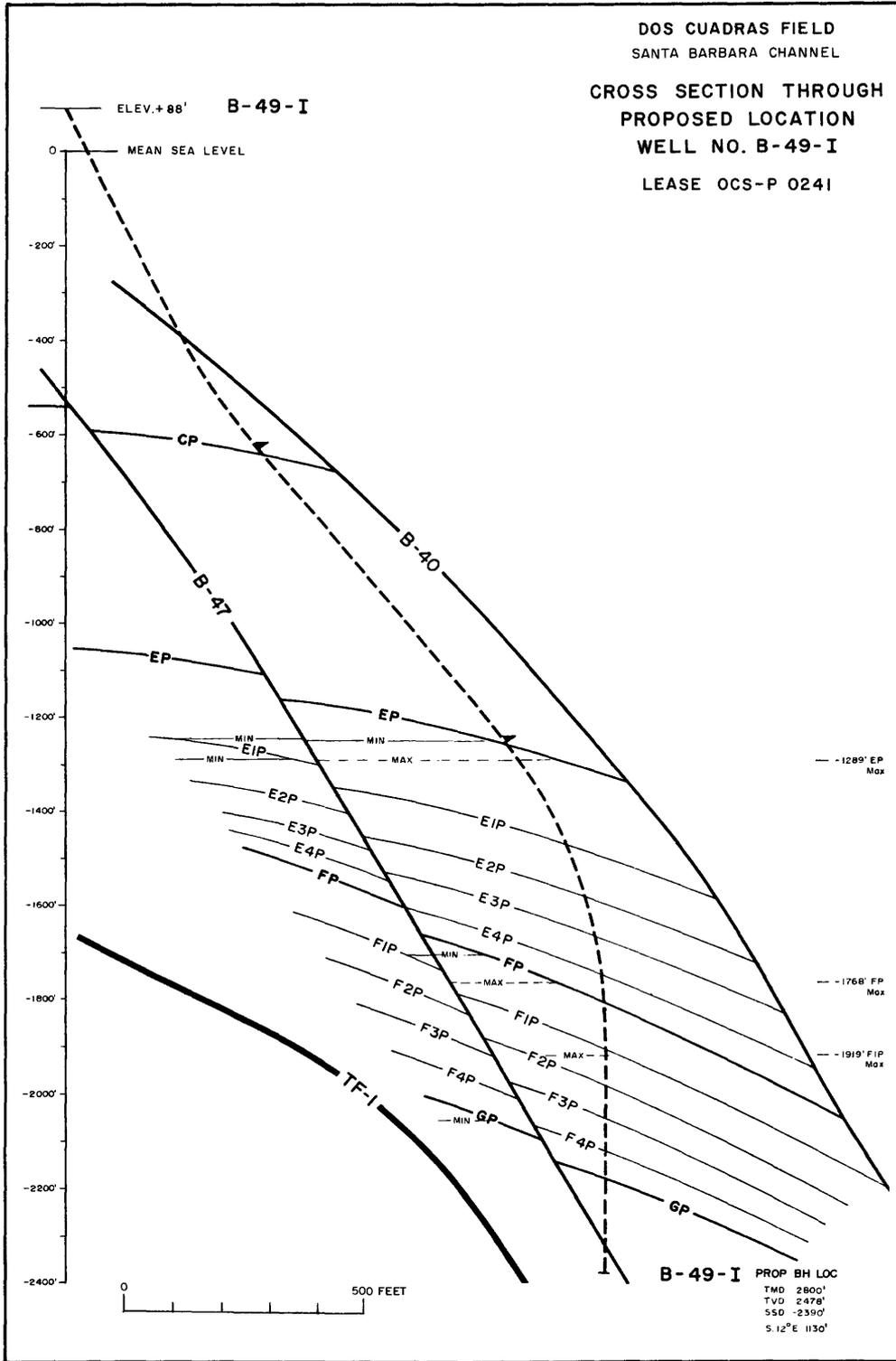


FIGURE 7.—Cross section through well No. B-49-I.

**UNITED STATES  
DEPARTMENT OF THE INTERIOR  
GEOLOGICAL SURVEY**

SUBMIT IN DUPLICATE\*

(See other instructions on reverse side)

Form approved.  
Budget Bureau No. 42-R355.5.

**WELL COMPLETION OR RECOMPLETION REPORT AND LOG\***

1a. TYPE OF WELL: OIL WELL  GAS WELL  DRY  Other Injection

b. TYPE OF COMPLETION:  
NEW WELL  WORK OVER  DEEP-EN  PLUG BACK  DIFF. RESRV.  Other \_\_\_\_\_

2. NAME OF OPERATOR  
Union Oil Company of California

3. ADDRESS OF OPERATOR  
2427 E. Harbor Blvd., Ventura, Calif. 93003

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)\*  
Lambert Grid Zone VI  
At surface X = 982,170 Y = 804,516  
At top ~~pool~~ interval reported below X = Inj. 982,296 Y = 803,738  
At total depth X = 982,422 Y = 803,344

14. PERMIT NO. \_\_\_\_\_ DATE ISSUED \_\_\_\_\_

5. LEASE DESIGNATION AND SERIAL NO.  
OCS Tract P 0241

6. IF INDIAN, ALLOTTEE OR TRIBE NAME  
--

7. UNIT AGREEMENT NAME  
--

8. FARM OR LEASE NAME  
P 0241 (Platform "B")

9. WELL NO.  
B-49-I

10. FIELD AND POOL, OR WILDCAT  
Dos Cuadras

11. SEC., T., R., N., OR BLOCK AND SURVEY OR AREA  
51N 65W Map 6B

12. COUNTY OR PARISH  
--

13. STATE  
R.T.

15. DATE SPUNDED 5-2-71 16. DATE T.D. REACHED 5-17-71 17. DATE COMPL. (Ready to prod.) 8-27-71 18. ELEVATIONS (DF, RKB, RT, GR, ETC.)\* Water depth 190' 19. ELEV. 85' above LLMT

20. TOTAL DEPTH, MD & TVD 2625 'MD/2290 'VD 21. PLUG, BACK T.D., MD & TVD 2551 'MD/2216 'VD 22. IF MULTIPLE COMPL., HOW MANY\* Dual 23. INTERVALS DRILLED BY to T.D. ROTARY TOOLS \_\_\_\_\_ CABLE TOOLS \_\_\_\_\_

24. ZONING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)\*  
injection (Purple)  
1522 'MD/1280 'VD - 1995 'MD/1695 'VD (Yellow) 2062 'MD/1753 'VD-2523 'MD/2189 'VD 25. WAS DIRECTIONAL SURVEY MADE Yes

26. TYPE ELECTRIC AND OTHER LOGS RUN NML and CDM logs. 27. WAS WELL CORRED Yes  
Dual Induction Laterolog, Cement Bond Log, Gamma Ray Log, FDC, CNP,

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
20"	104.13#	316'	--	Driven	
16"	75	417	20	250 sc "G" + 3% CaCl <sub>2</sub>	
13-3/8"	40.5	734	17-1/2	200 sx Gilsonite & 100 sx "G"	"G"
10-3/4"	32	1516	15	500 sx Gilsonite & 150 sx "G"	"G"

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)	SIZE	DEPTH SET (MD)	PACKER SET (MD)
8-5/8"	1331'	2620'	625'	Blank	2-7/8"	2038'	2016'
					2-7/8"	1454'	1451'

31. PERFORATION RECORD (Interval, size and number)

EP 1522-1995'	2 - 1/2" SPF
FP 2062-2523'	2 1/2" SPF

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
2267-2523'	2000 gal. 7-1/2% HCl 1000 gal. 9-6 HCl-HF
2062-2523'	3000 gal. 9%-6% HCl-HF

33.\* injection PRODUCTION  
DATE FIRST PRODUCTION \_\_\_\_\_ PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump) Injection well WELL STATUS (Producing or shut-in) on injection

6-7-71(FP)8-5-71(EP) Injection well  
DATE OF TEST HOURS TESTED CHOKE SIZE PROD'N. FOR TEST PERIOD OIL—BBL. GAS—MCF. WATER—BBL. GAS-OIL RATIO  
9-19-71 24 - - - - 1372 (FP) 1379 (EP)

Inj. TUBING PRESS. CASING PRESSURE CALCULATED 24-HOUR RATE OIL—BBL. GAS—MCF. WATER—BBL.\* OIL GRAVITY-API (CORR.)  
510(FP)250(EP) - - - - - - - -

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.) \_\_\_\_\_ TEST WITNESSED BY \_\_\_\_\_

35. LIST OF ATTACHMENTS \_\_\_\_\_

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records  
Orig. R. O. Engebretsen TITLE Drilling Engineer DATE 9-21-71  
SIGNED: \_\_\_\_\_

\*(See Instructions and Spaces for Additional Data on Reverse Side)

**UNION OIL CO. OF CALIFORNIA  
WELL RECORD**

**SHEET A**

PAGE NO. 1

LEASE OCS-P 0241 WELL NO. B-49-I  
 FIELD Dos Cuadras  
 LOCATION Conductor #49  
Lambert Grid Zone VI  
X = 982,170 Y = 804,516 at R.T.  
 PERMIT NO. \_\_\_\_\_ SERIAL NO. \_\_\_\_\_  
 T.D. 2625' T.V.D. 2290'  
 DEVIATION (B.H.L.) \_\_\_\_\_  
 COMPANY ENGINEER \_\_\_\_\_

SPUD DATE 5-2-71 COMP. DATE 6-3-71  
 CONTRACTOR Bawden Drig. Co. RIG NO. 8  
 TYPE UNIT National 55 at 25°  
 DRILL PIPE DESCRIPTION 4-1/2" FH 16.60, 18° taper  
4-1/2" FH, 40#, 18° taper  
 ELEVATIONS: WATER DEPTH 190'  
 R.T. TO OCEAN FLOOR 304'  
 R.T. TO MLLW 94'  
 R.T. TO DRILL DECK 17'  
 R.T. TO PRODUCTION DECK 43'  
 APPROVED: Orig. Sgd: R. O. Engebretsen

**CASING & TUBING RECORD**

SIZE	WEIGHT	THREAD	GRADE	DEPTH	REMARKS
20"	94#	Welded	K-55	316'	Driven
16"	75	Buttress	K-55	417'	Cmtd w/250 sks. "G" + 3% CaCl <sub>2</sub>
13-3/8	54.5	Seal-lock	K-55	734'	Cmtd w/200 sks. Gilsonite + 100 sks "G" + 3% CaCl <sub>2</sub>
10-3/4	40.5	Buttress	K-55	1516'	Cmtd w/500 sks. Gilsonite + 150 sks "G" + 3% CaCl <sub>2</sub>
8-5/8	32	Buttress	K-55	2620'	Cmtd w/475 sks. Gilsonite, 2% NaCl, 3/4% CFR2
2-7/8	6.5	A-95 Hydril	J-55	1454'	
2-7/8	6.5	A-95 Hydril	J-55	2038'	

**PERFORATING RECORD**

DATE	INTERVAL	E.T.D.	REASON	PRESENT CONDITION
5-21-71	2370' (4) 1/2" holes		Squeezed	Squeezed w/150 sks. "G" cmt and 3% CaCl <sub>2</sub>
5-22-71	2260' (4) 1/2" holes		Squeezed	Squeezed w/75 sks. "G" cmt and 3% CaCl <sub>2</sub>
5-23-71	2030' (4) 1/2" holes		Squeezed	Unable to break down formation.
5-23-71	2040' (4) 1/2" holes		Squeezed	Squeezed w/200 sks. "G" cmt and 3% CaCl <sub>2</sub>
5-23-71	1765' (4) 1/2" holes		Squeezed	Squeezed w/125 sks. "G" cmt and 3% CaCl <sub>2</sub>
5-24-71	1670' (4) 1/2" holes		Squeezed	Squeezed w/150 sks. "G" cmt and 3% CaCl <sub>2</sub>
5-28-71	2516-2523	2551'	Water Inj.	Open for water injection.
	2488-2509'			" "
	2376-2427'			" "
	1929-1995'			" "
	1804-1914'			" "
	1769-1797'			" "
7-2-71	2267-2332'	2477'		Open for water injection
	2336-2364'			" "
7-20-71	2062-2248'			
8-19-71	1643-1754'			
8-27-71	1558-1624'			
	1522-1554'			

**INITIAL PRODUCTION**

DATE	INTERVAL	NET OIL	CUT	GRAV.	C.P.	T.P.	CHOKE	MCF	GOR	REMARKS
	Water injection well									

**WELL HEAD ASSEMBLY**

TYPE: Shaffer unitized wellhead.

CASING HEAD: Two piece: 13-5/8" 3000# lower. 13-5/8" 3000# casing tubing head with 3000# (6 bx) C.I.W. clamp hubs.

CASING HANGER: 13-3/8" x 10-3/4" circulating landing mandrel with replaceable packing.

TUBING HANGER: 12" 59 ADJ dual tubing hanger.

TUBING HEAD TOP: 13-5/8" x 2-7/8" EUE 8-rd. tubing

MASTER VALVES: Two 2-1/2" 3000# W.P. flanged end Shaffer gate valves full port.

CHRISTMAS TREE TOP CONN: 3" female line pipe thread.



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LEASE OCS-P 0241 WELL NO. B-49-I FIELD Dos Cuadras

DATE	E.T.D.	DETAILS OF OPERATIONS, DESCRIPTIONS & RESULTS			
5-2-71	430'	Spudded in at 12:00 noon with Bawden Drlg. Co. rig #8. Drilled 15" hole to 430'.			
5-3-71	430'	Opened 15" hole to 20" from 316' to 425'. Ran 16" 75# casing to 417'. Cemented through shoe at 417' with 250 sacks "G" cement and 3% CaCl <sub>2</sub> . Displaced with 475 cu. ft. sea water. Cement in place 8:00 a. m. Waited on cement.			
<u>16" Casing Detail</u>					
<u>From</u>	<u>To</u>	<u>Length</u>	<u>Jts.</u>	<u>Description</u>	
417.56	415.56	2.00		16" Baker flexiflow fillup shoe.	
415.56	65.71	349.85	9	16" 75# K-55 buttress blank casing.	
65.71	46.05	19.66	1	16" 75# K-55 buttress thread blank pup joint.	
46.05	44.55	1.50		16" x 20" Vetco swage.	
44.55	0.00	44.55		Landed below zero.	
		417.56	10	Totals	
B&W centralizers located at 405', 379', 338', 299'.					
5-4-71	550'	Installed 16" x 20" Vetco swage. Drilled shoe at 417'. Cleaned out to 430'. Ran Sperry Sun gyro survey. Drilled 12-1/4" hole to 550'.			
5-5-71	750'	Drilled 12-1/4" hole to 750'. Opened 12-1/4" hole to 17-1/2" from 417-750'. Regauged hole 417-750'.			
5-6-71	750'	Ran 17 joints 13-3/8" 54.5# K-55 seal-lock casing to 734'. Float collar at 690'. Pumped 100 cu. ft. water ahead followed by 200 sacks "G" cement and 25# per sack Gilsonite and 2% CaCl <sub>2</sub> . Followed by 100 sacks "G" cement and 2% CaCl <sub>2</sub> . Displaced and bumped plug with 612 cu. ft. water. Cement in place at 4:45 p.m. Installed wellhead, 3000# riser, 12" 3000# W.P. double hydril, Shaffer gate and 12" 3000# W.P. G.K. hydril.			
<u>13-3/8" Casing Detail</u>					
<u>From</u>	<u>To</u>	<u>Length</u>	<u>Jts.</u>	<u>Description</u>	
733.97	731.87	2.10		13-3/8" Baker flexiflow fill up shoe.	
731.87	692.12	39.75	1	13-3/8" 54.5# K-55 Armco seal-lock casing.	
692.12	690.52	1.60		13-3/8" Baker flexiflow fill up collar.	
690.52	49.55	640.97	16	13-3/8" 54.5# K-55 Armco seal-lock casing.	
49.55	44.55	5.00		13-3/8" Shaffer lower landing head (fin joint)	
44 55	0.00	44.55		Landed below zero.	
		733.97	17	Totals	
B&W centralizers located at 721', 692', 610', 528', 453', 372'. Cement basket at 447'.					
5-7-71	750'	Installed blowout equipment. Tested pipe rams and blind rams to 3000 psi. Hydril to 1500 psi.			

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LEASE OCS-P 0241 WELL NO. B-49-I FIELD Dos Cuadras

DATE	E.T.D.	DETAILS OF OPERATIONS, DESCRIPTIONS & RESULTS
5-8-71	1017'	Drilled and dyna-drilled 12-1/4" hole 750-1017'.
5-9-71	1388'	Drilled 12-1/4" hole 1017-1318'. Lost fluid at 1300'. Mixed lost circulation material to stop lost circulation.
5-10-71	1625'	Drilled 12-1/4" hole to 1625'. Ran DIL. Opened 12-1/4" hole to 15" 734-1226'.
5-11-71	1625'	Opened hole to 1500' to 15". Ran 35 joints and 1 pup joint 10-3/4" 40.5# K-55 buttress casing. Cemented through shoe at 1516' with 500 sacks "G" with 25# per sack Gilsonite and 2% NaCl and 3/4% CFR2. Followed by 150 sacks "G" with 3% CaCl <sub>2</sub> . Lost returns first 900 cu. ft. Had partial returns for remainder of displacement. Cement in place at 8:00 p.m.
<u>10-3/4" Casing Detail</u>		
<u>From</u>	<u>To</u>	<u>Length</u> <u>Jts.</u> <u>Description</u>
1516.16	1514.16	2.00                      10-3/4" Baker flexiflow fill up shoe.
1514.16	61.87	1452.29    35                      10-3/4" 40.5# K-55 buttress blank casing.
61.87	45.77	16.10                      10-3/4" 40.5# K-55 buttress blank pup joint.
45.77	44.55	1.22                      13-3/8" x 10-3/4" Shaffer circ. landing mandrel.
44.55	0.00	44.55                      Landed below zero.
		<u>1516.16</u> <u>35</u> Totals
5-12-71	1625'	Waited on cement. Tested blowout equipment to 3000 psi. Hydril to 1500 psi. Ran CBL.
5-13-71	1645'	Drilled 9-7/8" hole to 1637'. Cut core #1 1635-1648'. Recovered 4' shale. Dyna-drilled to 1645'.
5-14-71	1827'	Dyna-drilled to 1701'. Cut core #2 1701-1721'. Recovered 20'. Dyna-drilled to 1827'.
5-15-71	2100'	Drilled 9-7/8" hole to 2100'.
5-16-71	2497'	Cut core #3 2100-2120'. Recovered 19'. Dyna-drilled to 2497'.
5-17-71	2625'TD	Drilled 9-7/8" hole to 2625'. Ran DIL, FDC, CNP, NML and CDM logs.
5-18-71	2625'	Opened 9-7/8" hole to 12-1/4" 1625-2625'. Conditioned hole for casing.
5-19-71	2625'	Ran and cemented 30 joints of 8-5/8" 32# blank casing. Cemented through shoe at 2680' and top of Burns hanger at 1330'. Pumped 50 cu. ft. fresh water ahead followed by 250 cu. ft. sea water. Mixed and pumped 475 sacks "G" cement and 25# per sack Gilsonite and 2% NaCl and 3/4% CFR2. Lost returns. Cement in place at 4:00 a.m. Waited on cement. Tested blowout equipment. Tagged top of liner at 1330'. No cement. Cleaned out to 2551'.

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LEASE OCS-P 0241 WELL NO. B-49-I FIELD Dos Cuadras

DATE	E.T.D.	DETAILS OF OPERATIONS, DESCRIPTIONS & RESULTS		
<u>8-5/8" Casing Detail</u>				
<u>From</u>	<u>To</u>	<u>Length</u>	<u>Jts.</u>	<u>Description</u>
2620.00	2618.00	2.00		8-5/8" Baker flexiflow shoe.
2618.00	2574.95	43.05	1	8-5/8" 32# K-55 buttress blank casing.
2574.95	2573.40	1.55		8-5/8" Baker flexiflow fill up collar.
2573.40	1332.60	1240.80	29	8-5/8" 32# K-55 buttress blank casing.
1332.60	1330.80	1.80		10-3/4" x 8-5/8" Burns plain liner hanger.
1330.80	0.00	1330.80		Landed below zero.
		<u>2620.00</u>	<u>30</u>	Totals
5-20-71	2551'	Ran CBL. Unable to test 10-3/4" x 8-5/8" lap. Shot four 1/2" holes at 2370'.		
5-21-71	2551'	Ran in hole with RTTS. Unable to work past hanger at 1330'. Made up open end 4" bull plug on bottom of RTTS. Set RTTS at 2215'. Broke down formation with 1700# 12 cu. ft. per minute. Pumped 75 sacks "G" with 3% CaCl <sub>2</sub> . Unable to obtain buildup. Cleared holes with 50 cu. ft. sea water. Waited 1 hour. Pumped 75 sacks "G" with 3% CaCl <sub>2</sub> . Displaced with 220 cu. ft. 72# NaCl water. Final pressure 2050#. Cement in place at 2:45 a.m. Rigged up Schlumberger lubricator and tested to 1000 psi.		
5-22-71	2551'	Shot four 1/2" holes per foot at 2260'. Set RTTS packer at 2118'. Broke down formation with 15 cu. ft. per minute at 1750 psi. Mixed and pumped 75 sacks "G" with 3% CaCl <sub>2</sub> . Displaced with 230 cu. ft. 72# NaCl. Final pressure 1950 psi. Shot four 1/2" holes per foot at 2030'.		
5-23-71	2551'	Set packer at 1870'. Could not break down with 1950 psi. Shot four 1/2" holes per foot at 2040'. Set RTTS at 1872'. Broke down formation with 34 cu. ft. per minute at 1400 psi. Mixed and pumped 100 sacks "G" with 3% CaCl <sub>2</sub> . Mixed and pumped 100 sacks "G" with 3% CaCl <sub>2</sub> . Had buildup up 500 psi to 1750 psi final pressure. Shot four 1/2" holes per foot at 1765'. Set packer at 1620'. Broke down with 20 cu. ft. per minute at 1400 psi. Mixed and pumped 125 sacks "G" with 3% CaCl <sub>2</sub> . Had buildup to 1500 psi. Cement in place at 3:30 a.m. Shot four 1/2" holes per foot at 1670'.		
5-24-71	2551'	Set packer at 1492'. Broke down formation with 30 cu. ft. per minute at 1350 psi. Mixed and pumped 150 sacks "G" with 3% CaCl <sub>2</sub> . Displaced 156 cu. ft. No buildup. Staged for 3-1/2 hours. Last stage to 1400 psi. Broke loose and circulated. Checked packer and reset. Still circulating. Set Baker retainer at 1520'. Stabbed into retainer. Broke down formation with 10 cu. ft. per minute at 1200 psi. Pumped 200 sacks "G" with 3% CaCl <sub>2</sub> . Waited 8 hours. Cleaned out to 1520'. Tested lap at 1000 psi. Approved by U.S.G.S. Cleaned out from 1520-1602'.		

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LEASE OCS-P 0241 WELL NO. B-49-I FIELD Dos Cuadras

DATE	E.T.D.	DETAILS OF OPERATIONS, DESCRIPTIONS & RESULTS
5-25-71	2551'	Cleaned out 1602-1609'. Cleaned out 1609-1612'. Approximately 4-1/2" cut out of center of economill. Cleaned out 1612-1620' with 7-5/8" junk mill.
5-26-71	2551'	Cleaned out 1609-1777' with 7-5/8" junk mill. Ran in hole with 8-5/8" burns wash tool. Tested perforations at 1670' to 720 psi. Ran in hole with 7-7/8" bit, 8-5/8" casing scraper. Cleaned out 1777'-2060'. Ran in hole with Burns washer. Attempted to test perforations 2030 and 2040'. Bypass on valve plugged, bottom cup torn. Ran in hole with open ended drill pipe. Circulated hole clean. No fill. Ran in hole with Burns washer.
5-27-71	2551'	Tested holes at 2030' and 2040' with 880 psi - O.K. (Ran in hole with 7-5/8" bit, junk sub, 8-5/8" casing scraper). Cleaned out cement from 2060' to 2275'. Set RTTS packer at 2200' and tested holes at 2260' to 985 psi - O.K. Picked up 7-5/8" bit assembly and cleaned out from 2275' to 2377'. Ran out of cement at 2377'.
5-28-71	2551'	Set packer at 2299'. Tested holes at 2370' to 1030 psi - O.K. Pulled out. Ran in hole with 7-5/8" bit. Cleaned out from 2388 to 2551'. Ran CBL. Shot two 1/2" holes per foot at following intervals: 2516-2523', 2488-2509', 2376-2427', 1929-1995', 1804-1914', 1769-1797'.
5-29-71	2551'	Unable to break down perforations with washer. Pulled out of hole. Found pieces of cement retainer and cement in wash tool. Ran in hole with wash tool. Washed perforations 2523-2516', 2509-2488', 2427-2376', 1995-1929', 1914-1804', 1797-1769'. Used 72# sea water for washing. Ran in hole with open end drill pipe to top of liner. Closed in well. Released rig, crews to B-38 at 8:00 p.m. 5-28-71.
6-2-71	2551'	Ran 2-7/8" Hydril 6.5# tubing with tail at 2038', single packer at 2019', sliding sleeve at 2012', dual packer at 1450', "F" nipple at 415'.
6-3-71	2551'	Landed long string. Ran 45 joints and 5 pups of A-95 6.5# 2-7/8" Hydril tubing. Stabbed into dual packer at 1454', "F" nipple at 1453', sliding sleeve at 1419', "F" nipple at 443'. Installed and tested Xmas tree to 3000 psi. Displaced with inhibited sea water.
6-4-71	2551'	Set dual packer at 1454' and single packer at 2015' and tested same. Released rig at 1:00 p.m. 6-3-71 to move to B-46. Primary tubing string on lower side of wellhead, north side. Secondary tubing string on upper side of wellhead, south side. (Remove secondary tubing string first when pulling)

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LEASE OCS-P 0241 WELL NO. B-49-I FIELD Dos Cuadras

DATE	E.T.D.	DETAILS OF OPERATIONS, DESCRIPTIONS & RESULTS		
<u>2-7/8" Tubing Detail - Long String</u>				
<u>From</u>	<u>To</u>	<u>Length</u>	<u>Jts.</u>	<u>Description</u>
2038.16	2028.76	9.40		2-7/8" Hydril pup joint.
2028.76	2025.01	3.75		2-7/8" Hydril pup joint.
2025.01	2024.01	1.00		"F" nipple.
2024.01	2015.96	8.05		8-5/8" Baker "FH" single hydrostatic packer.
2015.96	2015.49	.47		2-7/8" 8-rd. x 2-7/8" A-95 hydril Crossover.
2015.49	2012.74	2.75		Baker sliding sleeve.
2012.74	2012.27	.47		2-7/8" 8-rd. x 2-7/8" A-95 hydril crossover.
2012.27	1464.26	548.01	18	2-7/8" 6.5# A-95 Hydril tubing.
1464.26	1450.51	13.75		8-5/8" Baker "AL-5" hydrostatic dual packer.
1450.51	410.23	1034.28	34	2-7/8" 6.5# A-95 Hydril tubing.
416.23	415.23	1.00		"F" nipple.
415.23	50.35	304.88	12	2-7/8" 6.5# A-95 Hydril tubing.
50.35	46.65	3.70		2-7/8" Hydril pup joint.
46.65	45.65	1.00		Fatigue nipple.
45.65	44.55	1.10		Donut.
44.55	0.00	44.55		Landed below zero.
		<u>2038.16</u>	<u>64</u>	Totals
<u>2-7/8" Tubing Detail - Short String</u>				
<u>From</u>	<u>To</u>	<u>Length</u>	<u>Jts.</u>	<u>Description</u>
1454.30	1454.00	.30		Model "S" seal nipple.
1454.00	1453.00	1.00		"F" nipple.
1453.00	1422.40	30.60	1	2-7/8" A-95 Hydril 6.5# tubing.
1422.40	1421.93	.47		2-7/8" 8-rd. x 2-7/8" A-95 Hydril crossover.
1421.93	1419.21	2.72		Baker sliding sleeve.
1419.21	1418.74	.47		2-7/8" 8-rd. x 2-7/8" Hydril crossover.
1418.74	444.80	973.94	32	2-7/8" Hydril 6.5# tubing.
444.80	443.80	1.00		"F" nipple.
443.80	79.75	364.05	12	2-7/8" Hydril 6.5# tubing.
79.75	79.28	.47		2-7/8" 8-rd. x 2-7/8" A-95 Hydril crossover.
79.28	75.42	3.86		Baker 24" telescoping swivel sub.
75.42	74.95	.47		2-7/8" 8-rd. x 2-7/8" A-95 Hydril crossover.
74.95	71.23	3.72		(1) A-95 Hydril tubing pup 2-7/8"
71.23	65.17	6.06		(1) A-95 Hydril tubing pup 2-7/8"
65.17	55.33	9.84		(1) A-95 Hydril tubing pup 2-7/8"
55.33	51.64	3.69		(1) A-95 Hydril tubing pup 2-7/8"
1.64	46.12	5.52		(1) A-95 Hydril tubing pup 2-7/8"
46.12	45.65	.47		Fatigue nipple
45.65	44.55	1.10		Donut
44.55	.00	44.55		Landed below zero.
		<u>1454.30</u>	<u>45</u>	Totals
7-2-71	2477'	Ran Schlumberger through tubing 2" scallop guns and tagged fill at 2477'. Perforated 2267-2332' and 2336-2364' with 2 JSPF using 1/2" Hyperjets.		

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ACIDIZE

LEASE OCS-P 0241 WELL NO. B-49-I FIELD Dos Cuadras

DATE	E.T.D.	DETAILS OF OPERATIONS, DESCRIPTIONS & RESULTS
7-13-71	2551' fill at 2477'	Acidized through long string with 2000 gallons of 7-1/2% HCl and 1000 gallons 9% HCl - 6% HF in two stages. Used 75# of Matriseal II diverting agent.
8-6-71	2551' fill at 2477'	Acidized through long string with 3000 gallons of 9% HCl - 6% HF. Used 200# Matriseal II diverting agent.
7-20-71	2551'	Ran Schlumberger through tubing 2" Scallop guns and perforated 2062-2248' with 2 JSPF using 1/2" Hyperjets.
8-19-71	2551'	Ran Schlumberger "Oriented Type" through tubing 2" Scallop guns and perforated 1643-1754' with 2 JSPF using 1/2" Hyperjets.
8-27-71	2551'	Ran Schlumberger "Oriented Type" through tubing 2" Scallop guns and perforated 1522-1554' and 1558-1624' with 2 JSPF using 1/2" Hyperjets.
<u>Short String</u>		
5-12-72	1454'	<u>Short String Acid Job:</u> Pumped 500 gallons of 15% HCl at 275 psi. Followed with 500 gallons 15% HCl with 125# Matriseal II. Pumped 750 gallons 15% HCl at 275 psi at 6 cu. ft. per minute. Pumped 250 gallons 15% HCl with 75# Matriseal II at 10 cu. ft. per minute. Pumped 1000 gallons 15% HCl at 275 psi at 10 cu. ft. per minute. Displaced with 208 cu. ft. of sea water at 9 cu. ft. per minute. Put well back on injection.
<u>Long String</u>		
5-20-72	2038'	<u>Long String Acid Job:</u> Pumped 10 cu. ft. sea water at 500 psi at 3 cu. ft. per minute. Pumped 1000 gallons 15% HCl at 3 cu. ft. per minute at 525 psi. Pumped 750 gallons 15% HCl with 100 lbs. Matriseal II. Pumped 250 gallons HCl with 50# Matriseal II at 5 cu. ft. per minute and 540 psi. Rate decreased to 3 cu. ft. per minute. Pumped 1000 gallons 15% HCl at 3 cu. ft. per minute and 550 psi. Displaced acid with sea water at 2.5 cu. ft. per minute and 570 psi. After 180 cu. ft. could not pump water away within pressure limits. Put well back on injection.

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