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WILLIAMS HOLDING LEASE
STEAMFLOOD DEMONSTRATION PROJECT
CAT CANYON OILFIELD

Second Annual Report, June 1977-June 1978

Date Published—January 1979

Work Performed Under Contract No. EY-76-C-03-1188

Getty Oil Company
Ventura, California

U. S. DEPARTMENT OF ENERGY

MASTER

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**WILLIAMS HOLDING LEASE
STEAMFLOOD DEMONSTRATION PROJECT
CAT CANYON OIL FIELD**

Second Annual Report
for the period
June 1977-June 1978

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Prepared for the U.S. Department of Energy
Under Contract No. EY-76-C-03-1188

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SECOND ANNUAL REPORT TO USDOE

WILLIAMS HOLDING STEAMFLOOD PILOT CONTRACT NO. EY-76-C-03-1188

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I. SUMMARY

On June 25, 1976 Getty Oil Company was awarded a cost-sharing contract from the USDOE to conduct a joint steamflood pilot on the Williams Holding Lease of Cat Canyon Field in the Santa Maria Basin. The objective of this pilot program is to evaluate the efficiency and economics of the steam displacement process for future full-scale development in the Cat Canyon Sl-B reservoir and in similar heavy crude oil reservoirs.

Precontract activities of Getty Oil Company are reported in the Topical Report I - Project Design and Development. Pre-displacement activities, such as cyclic steam stimulation of the pilot producers and acquisition of steam generator permits, as well as preliminary displacement phase results, are discussed in The First Annual Report, June 25, 1976 - June 1, 1977.

The Second Annual Report discusses the project progress for the reporting period from June 1, 1977 to July 1, 1978. Pilot operations including the displacement steam generator performance, the status of sulfur dioxide scrubbing system, and major well workovers are summarized. Oil production and heat distribution within the pilot patterns are reviewed. The results of extensive computer thermal simulation studies are discussed in detail and a new production performance projection is made. Finally, project economics and future operations are summarized.

II. INTRODUCTION

On June 25, 1976, Getty Oil Company was awarded a cost-sharing contract by the Energy Research and Development Administration (now Department of Energy) to conduct a steam-flood pilot on the Williams Holding Lease of Cat Canyon Field, Santa Barbara County, California. The objective of the pilot program is to evaluate the efficiency and economics of the steam displacement process for future full-scale development in the Cat Canyon Sl-B reservoir and in other similar heavy oil reservoirs.

Precontract activities of Getty Oil Company are reported in the Topical Report I - Project Design and Development¹. These activities include site selection and preparation, and drilling of the production and injection wells. Figures 1 and 2 show the location of the Cat Canyon Field and the steam-flood pilot, respectively. Pilot configuration, shown in Figure 3, was selected on the basis of steamflood experience in the Kern River Field and projections resulting from preliminary computer thermal simulation studies conducted by Getty Oil Company.

Project progress from signing the contract to June 1, 1977 is discussed in the First Annual Report, Williams Holding Lease Steamflood Demonstration Project². Pre-displacement activities are summarized, including cyclic steam stimulation of the pilot producers and the acquisition of steam generator permits. Results of further computer simulation studies conducted under more restrictive assumptions for field operating conditions expected during the pilot project are also presented. Finally, a discussion of the preliminary results of the displacement phase of the project, which started in April, 1977, is included.

The reporting period of the First Annual Report included only the first two months of the steam displacement phase. Briefly summarized, this initial period was beset by repeated failures of the thermal packers in the steam injection wells.

Figure 1

LOCATION OF CAT CANYON FIELD SANTA BARBARA COUNTY

Figure 2

LOCATION OF WILLIAMS HOLDING STEAMFLOOD PILOT
CAT CANYON FIELD

Figure 3

WILLIAMS HOLDING
STEAMFLOOD PILOT CONFIGURATION

Operation of the 50 MM Btu/hr displacement steam generator was straightforward and uncomplicated by major problems. Generator downtime was predominantly due to replacement of thermal packers.

Initial pilot response and operations during the period June 1, 1977 to July 1, 1978 are discussed in detail in this second annual report. Operating economics to date, and performance projections based on further computer simulation studies, are also presented. Finally, future operations and studies related to the pilot are outlined.

III. PROJECT PROGRESS - OPERATIONS

Initial pilot response to continuous steam injection was adversely affected by repeated failures of the thermal packers used in the steam injection wells. The failures appeared to be caused by material problems in the elastomeric sealing element of the packer. Since this steamflood pilot is basically experimental, its operating conditions were severely testing the limits of thermal packer technology. A design sufficient to withstand present operating conditions has not been developed yet. However, a new material has been developed for the elastomeric sealing element which can withstand temperatures to 605°F and corresponding saturated steam pressures to 1590 psia. These conditions approximate the most severe conditions encountered during the displacement phase of the pilot. This new packer design has been successfully tested in cyclic steam stimulations of thermal wells in the Cat Canyon Field. Packer manufacturers are conducting further tests to develop elastomeric materials to withstand continuous steam injection conditions as encountered in steamflood operations.

After over two months of difficulties, thermal packers were removed from three of the steam injectors. A packer was maintained in Williams Holding 935 to protect cement-squeezed perforations in the casing which were made necessary due to problems encountered during primary cementing operations. The first extended period of continuous steam injection was then established.

Sand control in Williams Holding 935 was lost in September, 1977. The steam generator was shut down to allow the well to cool. Then the injector was recompleted with a new liner and gravel pack. The method of completion was changed from a gravel packed inner liner to an open-hole gravel pack to improve sand control. At the same time, a protective tubing string was cemented in place, eliminating the need for the thermal packer in that well. Upon completion, continuous steam injection resumed.

Starting in October, 1977 seven of the nine producers were cyclicly steam stimulated. Each well nominally received 6,000 barrels of water converted to steam. Williams Holding 205, the central producer, and Williams Holding/Recruit Fee 204 were not stimulated since both were showing increasing temperature response to the displacement phase and high fluid production rates. The steam stimulations are summarized in Table 1.

Continuous steam injection was maintained from October until mid-December, 1977 when sand control was lost in Williams Holding 205 and 36. The generator was shut down to allow the wells to cool sufficiently for the required well work. During the shut down, it was discovered that sand control had been lost in the three remaining injection wells. After the wells had cooled, generator downtime was further extended due to the unavailability of a workover hoist to replace the liners. The well work is discussed in more detail later.

In March, 1978, continuous steam injection was again established. Cyclic steam stimulations of the pilot producers, excluding WH 205 and WH/RF 204, were performed in May and June, 1978 to promote uniform heat advance in the pilot area. The two excluded producers were showing significant heat and fluid responses and did not require steam stimulation.

Steam Generator Operations

The operation of the 50 MM Btu/hr displacement steam generator has been straightforward and uncomplicated by major problems. Table 2 summarizes the steam generator performance since the beginning of steam displacement. The average performance values given for April through August, 1977 exclude generator downtime due to replacement of failed thermal packers. The generator was down the entire month of September, 1977 waiting on completion of well work for WH 935.

TABLE 1 - CYCLIC STEAM STIMULATION SUMMARY

Well	Injection Dates		Barrels Injected	Average Steam Quality (%)	Average Temp. (°F)	Average Pres. (psig)	Cycle Oil Produced* (Bbls)
	Start	Finish					
WH 25	12-03-76	12-17-76	10,982	66	530	1060	5,487
	10-19-77	10-28-77	7,168	74	533	1075	4,836
	6-06-78	6-13-78	6,055	74	565	1030	518
WH 26	12-29-76	1-09-77	10,089	91	555	1407	8,147
	12-02-77	12-10-77	6,532	63	562	1456	3,239
	5-08-78	5-15-78	6,080	75	600	1290	482
WH 35	2-06-77	2-19-77	10,925	83	565	1455	5,352
	11-26-77	12-02-77	6,470	75	550	1400	6,042
WH 36	1-26-77	2-06-77	10,201	87	550	1395	1,377
	10-12-77	10-19-77	5,905	59	503	1034	1,104
	6-14-78	6-20-78	6,203	72	610	1490	0
WH 105	1-09-77	1-26-77	10,567	79	570	1440	5,724
	11-09-77	11-15-77	6,107	77	545	1353	3,331
	5-15-78	5-26-78	10,040	78	600	1320	652
WH 205**	3-31-77	4-13-77	10,650	75	550	1330	12,391
WH 206	12-17-76	12-28-76	10,336	88	560	1430	5,983
	10-27-77	11-03-77	6,056	74	583	1590	3,145
	4-28-78	5-08-78	10,029	68	595	1295	832
WH 305	2-22-77	3-07-77	10,707	84	550	1345	1,966
	11-03-77	11-09-77	6,556	76	550	1400	6,678
	5-28-78	6-03-78	6,105	75	600	1310	307
WH/RF 204**	4-13-77	4-24-77	10,012	80	560	1355	11,016

* Cycle oil produced is given as oil produced during the cycle immediately following the steam stimulation. The number of barrels given for the last cycle of each well is the oil produced from the steam stimulation date to June 30, 1978.

** WH 205 and WH/RF 204 were showing good temperature response and high fluid levels in November, 1977 and therefore were not steamed then.

TABLE 2
PERFORMANCE SUMMARY OF THE
50 MM Btu/hr DISPLACEMENT STEAM GENERATOR

<u>Periods (Dates)</u>	<u>Average Injection Rate (BSPD**)</u>	<u>Average Steam Quality (%)</u>	<u>Average Discharge Temp. (°F)</u>	<u>Average Discharge Pres. (psig)</u>	<u>Average Wellhead Pres. (psig)</u>
Apr. 15-30*	2300	40	595	1900	1380
May 1-31*	2445	35	480	915	620
June 1-30*	2270	25	470	1240	735
July 1-31*	2450	40	575	1620	1100
Aug. 1-31*	2375	63	580	1700	1140
Sept. 1-30	-	-	-	-	-
Oct. 1-31	2370	80	630	1850	1270
Nov. 1-30	2225	77	610	1975	1220
Dec. 1-12	1730	67	625	2000	1275
Dec. 12- Feb. 28	-	-	-	-	-
Mar. 1-31	2220	80	580	1270	1070
Apr. 1-30	2360	79	580	1200	1100
May 1-31	2270	79	645	2045	1030
June 1-30	2100	80	645	2025	1000

* Average performance values given for April through August 1977 exclude generator downtime due to replacement of failed thermal packers.

** BSPD = equivalent barrels of water as steam per day.

During the period of December 12, 1977 to February 28, 1978 liners and gravel packs in WH 205 and WH 36 were replaced. Also, the three injectors WH 825, WH 826, and WH 925 were recompleted as detailed later. Continuous steam injection resumed in early March, 1978.

Figure 4 shows the dramatic improvement in steam quality that was achieved after all the packers were removed from the injection wells. Starting with October, 1977 the steam generator did not need to be shut down every few days to replace a thermal packer. Consequently, steam generation operations improved significantly.

Critical flow chokes were installed in the four steam injection wells on April 22, 1978. Since then, WH 825, WH 826, and WH 935 have been in critical flow continuously, while WH 925 has been in critical flow 85% of the time. Maintenance of critical flow allows for proper monitoring of the steam mass flow rates into each injector.

Sulfur Dioxide Scrubbing

Getty Oil Company is testing a stack gas scrubber for the removal of sulfur dioxide from emissions resulting from burning high sulfur crude oil as steam generator fuel in a 22 MM Btu/hr generator used for cyclically steam stimulating producing wells. The scrubber is of a disc-and-doughnut design with three sets of air-solution contact surfaces. The sulfur dioxide removal is achieved by an absorption process using soda ash (sodium carbonate, Na_2CO_3). A schematic of the scrubbing system is shown as Figure 5.

Testing of the scrubber efficiency was significantly delayed due to disputes with the manufacturer regarding completeness of materials supplied and the suitability of some components. During the first firing of the steam generator-flue gas scrubbing system

Figure 4

DISPLACEMENT STEAM INJECTION WILLIAMS HOLDING STEAM FLOOD DEMONSTRATION PILOT

Figure 5

SCHEMATIC OF SULFUR DIOXIDE REMOVAL SYSTEM

the demister pad was blown out the top of the scrubbing vessel. The pad could not be re-installed in a manner that would provide proper demisting action, and a new demisting pad had to be ordered.

Heavy rains in February and March, 1978 caused earth movement on the generator site. The location had to be excavated and re-compacted, and some tank repair work was done. Also, the electrical control panel, two tank heaters, and the fuel oil pump, as well as the SPCC spill containment wall had to be relocated. The required storm damage repair work was completed by mid-April and the generator was again prepared for testing.

In the latter part of April the generator was test fired once more. It was first fired on gas, then switched to lease crude. Operating problems developed almost immediately. The pH probe in the scrubber was not working properly. As adjustments were being made, the demister pad started plugging. After about 1-1/2 hours, the pad was completely plugged. Analysis of the deposited material showed it to be a combination of fly-ash and a sulfate.

A new demister pad, of a different design, was then installed. The generator was fired again in July, and a cyclic steam stimulation was performed on a thermal well in Cat Canyon. Preliminary sulfur dioxide removal tests were conducted at that time. Results showed that the chemical efficiency of the soda ash - SO_2 reaction was not as great as had been predicted for the desired pH range of 6.5-7.0. To achieve the required degree of SO_2 removal, it was necessary to operate at a pH of approximately 9. Operation of the process in this pH range can cause scaling problems. It is therefore planned to substitute the use of caustic (NaOH) for soda ash (Na_2CO_3). The caustic should have a higher chemical utilization, in addition to avoiding potential scaling problems created by operating the soda ash process at a high pH. Although somewhat

more expensive than soda ash on a theoretical basis, the higher efficiency of caustic should reduce the cost differential significantly.

Well Workovers

The steam injection wells were originally completed with seven-inch casing cemented and selectively perforated across the injection interval. Within the casing, a 3-1/2 inch, 30-mesh, wire-wrapped screen inner-liner was pressure gravel packed across the perforated section with 10-18 gravel. When sand control in Williams Holding 935 was lost, it was believed to be due to an insufficient thickness of gravel between the formation sandface and the inner liner. In addition, the gravel being used to gravel pack wells in the Cat Canyon Field at the time most of the pilot wells were drilled contained a low percentage of quartz and a high percentage of rock fragments. Tests performed by Getty Oil and other thermal recovery operators have shown that such a gravel can undergo significant deterioration when subjected to high temperature steam. To alleviate the effects of these two factors, WH 935 was recompleted using an open-hole gravel pack accomplished by milling a window in the casing across the completion interval and underreaming the hole to a diameter of 13 inches. A 3-1/2 inch, 25-mesh, wire-wrapped screen was then gravel packed using a gravel containing a high percentage of quartz. The gravel size was 16-20 U. S. mesh, and it was pre-screened on a 20-mesh screen to minimize fines.

This technique provides a thicker gravel sheath (4.75 inches) than that obtainable with the inner-liner completion. By mid-December, when the remaining injectors lost sand control and the steam generator was shut down, WH 935 had not experienced any sanding problems. Consequently, the three other injectors were recompleted using an open-hole gravel pack. Figure 6 shows a

Figure 6

GENERAL SCHEMATICS OF THE STEAM INJECTOR WELL COMPLETIONS

schematic of the original and of the present mechanical condition of Williams Holding 825, 826, and 925. Williams Holding 935 was additionally completed with a 3-1/2 inch protective tubing string landed above the liner and cemented in place. The injection wells were left uninsulated due to the lack of a suitable thermal packer.

Sand control was lost in two of the pilot producers in mid-December, 1977. These producers, Williams Holding 205 and 36, were originally completed with an older open-hole flow gravel packing technique. Field wide performance has shown significant reduction of liner failures using a pressure packing technique. The old flow-packs were averaging a failure rate of approximately one liner failure every three cycles per well. Both WH 205 and WH 36 were in their third cycles when they failed. WH 205, the central producer, was originally completed with a 5-1/2 inch, 40-mesh slotted liner flow-packed with 10-18 gravel in 14 inch hole. WH 36 was originally completed with 5-1/2 inch, 30-mesh slotted liner and 10-18 gravel. Both wells were recompleted using 25-mesh slotted liner pressure packed with 16-20 gravel which had been pre-screened on a 20-mesh screen.

IV. PROJECT PROGRESS - PRODUCTION

Initial pilot response to continuous steam injection was adversely affected by repeated failures of thermal packers in the steam injection wells. Once use of the packers had been eliminated, pilot production and heat response has paralleled the periods of continuous steam injection.

Production performance for the total pilot area and for the confined, central producer, Williams Holding 205, are shown in Figures 7 and 8, respectively. The low production rates shown for October, 1977, are due to erroneous well gauges which resulted from a malfunction of the automatic well test system. Peak oil production is expected to occur shortly after steam breakthrough at the producers. Prior to steam breakthrough, very high water cuts are anticipated due to the very adverse mobility ratios which exist prior to the time that a continuous heated path has been established between injector and producer. Figure 8 reflects this behavior for WH 205 since it was put back on production after the liner replacements in January, 1978. Production responses for the remaining pilot wells are shown in Appendix A.

Initial temperature response in WH 205 was seen in November, 1977. Flowline temperatures had reached 200°F prior to the liner failure in December. WH 205 was put back on production in February, 1978. Once continuous steam injection was again resumed in March, flowline temperatures for WH 205 increased very rapidly as shown in Figure 9. Temperature response for the other pilot producers are shown in Appendix B.

Cumulative monthly steam-oil ratios for the total project and for WH 205 are shown in Figures 10 and 11, respectively. The cumulative steam injected for the project includes the steam used for stimulating the producers as well as the displacement

steam injected. Similarly, the WH 205 cumulative steam injected includes stimulation steam, while the displacement steam is prorated as one fourth of the total displacement steam injected. From both figures it can be seen that the steam-oil ratio rises sharply as steam breakthrough is being approached. This response corresponds to the production projections discussed in a later section.

Previous studies³ had shown the importance of maintaining low fluid levels in the production wells of this steamflood pilot. Field experience has confirmed that low fluid levels are critical to oil production response. Prior to the liner failure in WH 205, water production in that well increased sharply due to increasing temperatures and mobilities. Corresponding oil production started declining as the fluid level rose in the well. After the well was recompleted and a larger capacity pumping unit was installed, oil production was recovered when the well was pumped-off. Meanwhile the water cut continued increasing, as anticipated, prior to steam breakthrough.

Another case showing the importance of maintaining low fluid levels to recover oil is Williams Holding/Recruit Fee 204. That well has seen a very significant temperature response, with flowline temperatures in excess of 250°F. In an attempt to redirect the steam more uniformly to the other producers of the pilot, the well was back-pressured by increasing the wellbore fluid level. Immediately thereafter the oil production declined to almost zero, while water production continued at 200-300 BPD. A few weeks later, the well was pumped-off. Subsequent oil production in January, 1977, peaked at over 100 BOPD for two weeks before declining to its expected deliverability at the given temperature.

In May, flowline temperatures increased very sharply in WH/RF 204. As temperature measurements exceeded 300°F, the fluid

levels also increased significantly. The well was idled June 16 to help induce steam breakthrough to WH 25 and WH 35. This will promote more uniform heat distribution within the patterns and thereby improve the ultimate oil recovery for the project.

Ultimate oil recovery from the pilot is anticipated to be 700 barrels per acre-foot, or 46% of the original oil in place. Stimulation recovery is expected to account for 234 Bbl/AF, while displacement recovery is projected to be 466 Bbl/AF. Thermal recovery to date for WH 205 is now 106 Bbl/AF.

Figure 7

"WILLIAMS HOLDING" STEAM DISPLACEMENT PILOT PRODUCTION PERFORMANCE.

Figure 8

"WILLIAMS HOLDING" 205-25 PERFORMANCE

Figure 9

WILLIAMS HOLDING 205-25 FLOWLINE TEMPERATURE GAUGES

Figure 10

Figure 11

WH 205 CUMULATIVE STEAM-OIL RATIO

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V. PROJECT ECONOMICS

The repeated thermal packer failures during the initial phase of continuous steam injection and the six sand control liner failures have adversely affected the overall project economics. Table 3 itemizes the operating costs of the pilot. The costs are given in terms of dollars per barrel of oil produced (BOP). Total operating costs for this period were \$11.26/BOP. Of this amount, \$1.88/BOP was due to major well workovers caused by the six liner failures.

As discussed in the section on well workovers, improvements in well completions have been made through the standardized use of a superior gravel, a change in the method of gravel placement, and the use of open hole packs in the injectors. It is expected that future steamflood operations in this area would not experience the excessive liner failures encountered in this pilot.

TABLE 3

WILLIAMS HOLDING STEAMFLOOD PILOT

SUMMARY OF ACTUAL OPERATING COSTS TO DATE

(\$/BBL OIL PRODUCED)

Period: June 25, 1976 to June 30, 1978

<u>Item</u>	<u>Cost</u>
Displacement Generator (excluding fuel)	\$ 0.85
Displacement Fuel	3.10
Contract Services	3.00
Company Services	0.61
Materials and Supplies	1.25
Utilities	0.31
Central Plants	0.32
Cyclic Stimulation	0.85
Engineering and Supervision	0.41
Computer and Deliverables	0.12
General and Administrative	<u>0.44</u>
GRAND TOTAL	\$11.26
Major Well Workovers ¹	- <u>1.88</u>
Net Operating Costs	\$ 9.38

¹ The major well workover costs only include the liner replacements that were required on WH 205, WH 36, and the four pilot steam injection wells.

VI. COMPUTER THERMAL SIMULATION

Introduction

The results of the Production and Injection Rates Study reported in the First Annual Report³ were based on operating the steamflood pilot under ideal conditions. Actual operating conditions to date have included numerous problems such as thermal packer failures and liner failures in both injection and production wells. The displacement steam generator had to be shut down for several extended periods to allow the wells to cool sufficiently to do the required well repairs. These downtime periods were expected to significantly affect the pilot production response and steam breakthrough times to the producers. Also sufficient data was now available to permit an attempt to history-match production to date. Consequently a new computer simulation study was undertaken which history matched the actual field operating conditions of Williams Holding 205-25, the central producer of the pilot. Based upon this history match, a new performance projection was made for the pilot.

The first phase of the study consisted of matching the stimulation response of WH 205. Due to cost considerations, the radial model configuration of the thermal simulator was used to achieve a reasonable history match of oil and water production. Thereafter, the history match was refined using a rectilinear gridblock configuration of the model.

The second phase of the study consisted of matching the displacement history of WH 205. As was expected, predicted steam breakthrough times and production response were adversely affected by the extended steam generator downtimes. The results are detailed later in this section. The grid-block configuration of the computer model was modified for this match to allow pressure dissipation to areas outside of the confined central pattern. This more accurately reflected actual steam movement as observed by temperature responses in the nine producing wells of the pilot.

The third phase of the study was the performance projection through the end of the pilot life. The steam injection scheme proposed in the Production and Injection Rates Study was first analyzed. These results were then compared to results obtained by varying the injection rates. The purpose of this comparison was to optimize performance and project economics, accounting for the extended generator downtimes and the well repairs required to date.

Williams Holding 205 Cyclic Steam Stimulation History Match

Williams Holding 205 was completed on February 5, 1975. Before the steam displacement phase of this project began in April, 1977, WH 205 was steam stimulated for two cycles. The first steam stimulation was done in May, 1975. The well was stimulated with 5,898 barrels of water converted to 69% quality steam with an average temperature of 538°F and an average injection pressure of 1380 psig. The cycle lasted 13-1/2 months during which 12.0 M barrels of oil and 14.6 M barrels of water were produced. The second steam stimulation was performed from July 8, 1976 to July 19, 1976. During this time, the well was stimulated with 11,335 barrels of water converted to 67% quality steam with an average temperature of 574°F and an average injection pressure of 1470 psig. The second cycle lasted for 9-1/2 months. A third steam stimulation was done in April, 1977, just prior to the beginning of steam displacement. However, this stimulation was included in the displacement phase of the study.

Figures 12A and 12B compare the actual production for oil and gross fluid, taken from daily gauges for WH 205, to the history matched simulator. Reservoir data used to obtain the match are given in Appendix C. These data were taken from logs, core analyses, and oil viscosity measurements done for WH 205. Other data and correlations used are indicated also in Appendix C.

This computer simulation study was conducted using a sophisticated thermal simulation model jointly developed by Getty Oil Company and Intercomp Resource Development and Engineering, Inc.

Figure 12-A

COMPARISON OF ACTUAL OIL PRODUCTION TO COMPUTER SIMULATION RESULTS

COMPARISON OF ACTUAL GROSS PRODUCTION TO COMPUTER SIMULATION RESULTS

The Thermal Model is a three-dimensional non-isothermal reservoir simulator that will calculate flow behavior of steam and hot water injection processes. The model equations account for viscous, gravity, and capillary forces affecting the three-phase flow of water, oil, and steam-hydrocarbon gas mixture in heterogeneous formations. The equations also represent the transport of heat by conduction to overlying and underlying strata. The model, in its most general usage, treats oil as a 3-component mixture consisting of solution gas (component 1), an intermediate distillable component (component 2), and a non-volatile component (component 3). Vaporization and condensation of the volatile components depends on local temperatures and pressures. The gas phase will thus contain three components - hydrocarbon components 1 and 2 as well as steam. Hydrocarbon mass transfer between the liquid and vapor phases is handled through the use of equilibrium K-values which are represented as functions of temperature and pressure. Saturated water and steam PVT behavior obey the thermodynamic constraints set forth in the standard steam tables. The oil and gas phase densities and gas viscosity are treated as functions of temperature, pressure and composition. Oil phase viscosity is a function of temperature and composition; and water viscosity is a function of temperature only. Relative permeabilities and capillary pressures are treated as functions of fluid saturations in accordance with Stone's⁴ simplified method and also incorporate a rather flexible but simple representation of temperature dependence. The gas phase relative permeability curve incorporates a hysteresis effect reflecting the critical gas saturation during periods of rising gas saturation and residual gas saturation during periods of decreasing gas saturation.

This model is used much the same as any conventional computer model. That is, the reservoir is represented by dividing it into a set of connected cells or grid blocks. Flow from one cell to another is controlled by Darcy's law modified for three-phase flow. The resultant mass balance equations, one for each phase, are solved

simultaneously with a thermal energy balance equation. The solution process is stepped forward in time in a series of discrete time increments. At each time, the "solution" is represented as the set of pressures, fluid saturations, and temperatures calculated for each cell. Fluid injection and production volumes are also supplied. The model can be run in one dimension; two dimensions, areally or vertically (cross-section); or three dimensions.

The primary oil recovery mechanism reflected in the model calculations is viscous displacement enhanced by the reduced oil viscosity at elevated temperatures. A secondary mechanism simulated, in cases where distillation occurs, is the "solvent extraction" resulting from the stripping of lighter ends from the oil in the steam bank where they condense. This effect lightens the oil at the leading edge causing the oil viscosity to be reduced at that point. In cases where solution gas and/or distillation effects are insignificant, the model simply treats the flow behavior of a single component oil phase, as well as steam and water.

Due to cost considerations, the initial portion of this study was conducted using a three-dimensional, radial configuration of the model shown in Figure 13. The external drainage radius of the model was set to correspond to the five-acre spacing of the pilot patterns. In the vertical direction, three layers were simulated. Finally, the oil was treated as a single-component, non-distillable phase since previous studies⁵ had found distillation effects to be negligible for this particular crude oil.

Using the raw reservoir data and the best engineering correlations available, the data and operating conditions were entered in the model. During subsequent runs, these data were refined until a reasonable history match was obtained. There-

COMPUTER SIMULATION STUDY

**CUT-AWAY VIEW OF RADIAL CONFIGURATION
OF THERMAL RESERVOIR SIMULATOR**

after, the model configuration was changed to a cartesian grid system.

The change in grid configurations was required since the radial model can handle only single well cases. Steam displacement involves interactions between multiple wells which can only be simulated using the cartesian or similar system. Once cyclic steam stimulation was history matched with the cartesian system, the same reservoir data would be used for steam displacement. Only operating conditions would then be varied to reflect the actual conditions occurring in the field and to achieve the history match for the steam displacement phase.

Symmetry conditions in the five-spot pilot pattern allowed simulation of only 1/8 of a five-spot as shown in Figure 14. Again, the grid system was set to correspond to the five-acre spacing of the pilot patterns and three vertical layers were simulated. Since the 1/8-five-spot cartesian system contains more cells, or grid blocks, than the radial model, more calculations are required to obtain a solution set at each time step. This increases computer costs for each run. After the radial model history match was achieved, only very minor data refinement was required to achieve the cartesian grid history match shown in Figures 12A and 12B.

Table 4 compares the actual oil and water production to the simulator results. These values show that cumulative oil production over both cycles was matched within 3M barrels while gross fluid was matched to within about 2M barrels.

Displacement Phase History Match

Once the cyclic stimulation history match was achieved for WH 205, displacement steam injection was simulated with the computer model. The steam rate was initially set at 600 barrels

COMPUTER SIMULATION STUDY

**AERIAL VIEW OF CARTESIAN CONFIGURATION
OF THERMAL RESERVOIR SIMULATOR
FOR 1/8 5-SPOT PATTERN
(THREE VERTICAL LAYERS)**

TABLE 4

Comparison of Simulator Results for
WH 205 Cyclic Steam Stimulation to
Actual Oil and Water Production

	<u>Cumulative Actual Production (M Bbls)</u>	<u>Cumulative Simulator Results (M Bbls)</u>	<u>Difference (M Bbls)</u>
<u>First Cycle:</u>			
Oil Production	12.0	14.9	+2.9
Water Production	14.6	16.1	+1.5
Gross Fluid	26.6	31.0	+4.4
<u>Second Cycle:</u>			
Oil Production	12.6	12.7	+ .1
Water Production	22.7	20.3	-2.4
Gross Fluid	25.3	33.0	-2.5
<u>Cumulative:</u>			
Oil Production	24.6	27.6	+3.0
Water Production	37.3	36.4	- .9
Gross Fluid	61.9	64.0	+2.1

per day of water converted to steam. This rate is representative of actual field average rates. The various steam generator downtimes required for well problems, such as packer and liner failures, were simulated by shutting in the steam injector for those periods. Any potential wellbore damage or enhancement caused by the well workovers was not simulated since quantitative measurements of these effects were not available.

Figure 15 compares the actual oil production, for WH 205, taken from daily gauges, to the computer simulation projection through the end of 1979. From this it is evident that during the period from April, 1977 through June, 1978 actual cumulative oil production has been significantly higher than the model projection; actual total oil production was 17.8M barrels compared to 12.6M barrels predicted.

The greater portion of this difference occurred between February and June, 1978. The difference may be attributable in part to an improved well completion after the liner and gravel pack were replaced in WH 205 in January, 1978. Also, uncertainties in the relative permeability data and reservoir heterogeneities, which were not simulated with the thermal model, are contributing factors to the differences in cumulative production. The magnitudes of these effects have not been determined at this time.

Although agreement between actual and predicted oil production for the preliminary portion of the displacement phase is not as good as that for the cyclic steam stimulation history match, there has been a good correlation between actual and predicted temperature responses. Consequently, it is expected that the predicted production response times shown in Figure 15 are reasonable.

Figure 15

DISPLACEMENT PHASE OIL PRODUCTION & THERMAL SIMULATOR PROJECTION FOR WH 205

Pilot Performance Projection

Figure 16 compares the oil production projection resulting from the WH 205 history match to that previously predicted as a result of the Production and Injection Rates Study reported in the First Annual Report. The responses of both studies are very similar with the current prediction showing an eight month delay in steam breakthrough time to WH 205. This delay corresponds closely to the total displacement steam generator downtime resulting from thermal packer failures and major well workovers.

Figure 16

COMPARISON OF WH 205 HISTORY MATCHED PROJECTION TO PREVIOUS OIL PRODUCTION PREDICTION

VII. FUTURE OPERATIONS

The Williams Holding Steamflood has now achieved heat breakthrough to several of the producers and has just passed Decision Point 4. During the next phase of the project, production and operations data will be closely monitored. Efforts will be made to achieve heat breakthrough in all producing wells and thus promote more uniform heat distribution within the pilot patterns.

It is anticipated that the peak production response will occur during the next twelve months. If necessary, additional computer simulations will be conducted to determine the effects of possible alternate operating strategies which may be considered as the project progresses.

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APPENDIX A
PRODUCTION PERFORMANCE
WILLIAMS HOLDING STEAMFLOOD PILOT
AND INDIVIDUAL WELLS

Figure A-1

"WILLIAMS HOLDING" STEAM DISPLACEMENT PILOT PRODUCTION PERFORMANCE

STIMULATION
STEAM INJECTED
(M BBLs.)

BBLs. PER DAY

Figure A-2

"WILLIAMS HOLDING" 25-25 PERFORMANCE

"WILLIAMS HOLDING" 26-25 PERFORMANCE

Figure A-4

"WILLIAMS HOLDING" 35-25 PERFORMANCE

Figure A-5

"WILLIAMS HOLDING" 36-25 PERFORMANCE

Figure A-6

"WILLIAMS HOLDING" 105-25 PERFORMANCE

Figure A-7

"WILLIAMS HOLDING" 205-25 PERFORMANCE

Figure A-8

"WILLIAMS HOLDING" 206-25 PERFORMANCE

Figure A-9

"WILLIAMS HOLDING" 305-25 PERFORMANCE

Figure A-10

"WILLIAMS HOLDING/RECRUIT FEE" 204-25 PERFORMANCE

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APPENDIX B
TEMPERATURE RESPONSE
WILLIAMS HOLDING STEAMFLOOD PILOT
INDIVIDUAL WELLS

FIGURE B-1

WILLIAMS HOLDING 25-25 FLOWLINE TEMPERATURE GAUGES

FIGURE B-2

WILLIAMS HOLDING 26-25 FLOWLINE TEMPERATURE GAUGES

FIGURE B-3

WILLIAMS HOLDING 35-25 FLOWLINE TEMPERATURE GAUGES

FIGURE B-4

WILLIAMS HOLDING 36-25 FLOWLINE TEMPERATURE GAUGES

FIGURE B-5

WILLIAMS HOLDING IO5-25 FLOWLINE TEMPERATURE GAUGES

FIGURE B-6

WILLIAMS HOLDING 205-25 FLOWLINE TEMPERATURE GAUGES

FIGURE B-7

WILLIAMS HOLDING 206-25 FLOWLINE TEMPERATURE GAUGES

FIGURE B-8

WILLIAMS HOLDING 305-25 FLOWLINE TEMPERATURE GAUGES

TEMPERATURE GAUGES BY WEEK

FIGURE B-9

WILLIAMS HOLDING/RECRUIT FEE 204-25
FLOWLINE TEMPERATURE GAUGES

APPENDIX C
RESERVOIR DATA
FOR
COMPUTER THERMAL SIMULATION

RESERVOIR DATA

<u>Data</u>	<u>Source</u>	<u>Symbol</u>	<u>Value</u>
Water compressibility, psi^{-1}	1	CW	3×10^{-6}
Oil compressibility, psi^{-1}	2	CO	5×10^{-6}
Rock compressibility, psi^{-1}	3	CR	3×10^{-4}
Oil thermal expansion factor, $^{\circ}\text{F}^{-1}$	4	CTO	3.5×10^{-4}
Oil specific heat, $\text{Btu/lb/}^{\circ}\text{F}$	5	CP	.5
Rock heat capacity, $\text{Btu/ft}^3/^{\circ}\text{F}$	16	CPR	35
Water density at TO, PINIT, lbs/ft^3	6	DWB	61.8
Initial reservoir temperature, $^{\circ}\text{F}$	7	TO	110
Stock tank oil density, lbs/ft^3	8	DOB	61.6
Oil formation volume factor at TO, PINIT, RB/STB	2	BORES	1.00
Solution gas/oil ratio at TO, PINIT, SCF/STB	9	RS	0
Molecular weight of solution gas	10	MW1	16
Reservoir thermal conductivity, $\text{BTU/ft/day/}^{\circ}\text{F}$	5	KTX, KTY, KTZ	38
Thermal conductivity of ORF and underburden, $\text{BTU/ft/day/}^{\circ}\text{F}$	5	KOB, KUB	23
Heat capacity of over and under burden, $\text{BTU/ft}^3/^{\circ}\text{F}$	5	CPOB, CPVB	32
Initial water saturation, fraction	11	SWI	.3505
Permeability, md.	11,12	KX, KY, KZ	2790
Porosity, fraction	11	PHI	.30
Initial reservoir pressure, psia	13	PINIT	1000
Sand thickness, ft.	14	TH	70

OIL VISCOSITY VS. TEMPERATURE DATA 8,9

<u>TEMP. (°F)</u>	<u>VISCOSITY (cp) *</u>
100	45,000
150	4,400
200	540
250	105
300	42
350	23
400	17
450	15
500	13
600	10.5
700	10.0

* Live oil viscosity

RELATIVE PERMEABILITY

<u>S_{WC}</u>	<u>K_{RW}</u>	<u>K_{RO}</u>	<u>S_L</u>	<u>K_{RG}</u>	<u>K_{RO}</u>
.350	0.0000	1.000	.600	.500	0.000
.380	.0015	.735	.709	.230	.020
.427	.0045	.350	.732	.180	.040
.464	.0070	.200	.763	.115	.100
.492	.0090	.150	.795	.090	.195
.524	.0115	.100	.828	.070	.300
.579	.0160	.050	.868	.050	.445
.662	.0260	.015	.908	.030	.640
.708	.0360	.005	.928	.020	.755
.750	.0500	0.000	.968	.005	.910
1.000	.2300	0.000	1.000	0.000	1.000

TEMPERATURE DEPENDENT ENDPOINT DATA 15

<u>TEMP (°F)</u>	<u>S_{WC}</u>	<u>S_{GC}</u>	<u>S_{ORW}</u>	<u>S_{ORG}</u>	<u>S_{GR}</u>	<u>K_{RWRO}</u>	<u>K_{ROCW}</u>	<u>K_{RGRO}</u>
150	.35	0.0	.25	.25	.20	.36	1.00	.50
250	.38	0.0	.22	.22	.20	.36	1.00	.50
350	.26	0.0	.34	.34	.20	.36	1.00	.50
450	.15	0.0	.45	.45	.20	.36	1.00	.50

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