645
4-4-78

Lh. 2006

SAN/1188-2

MASTER

WILLIAMS HOLDING LEASE STEAMFLOOD DEMONSTRATION
PILOT CAT CANYON OIL FIELD

First Annual Report, June 25, 1976—June 1, 1977

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

Western Exploration and Production Division
Getty Oil Co.
Ventura, California

950
5304

FOSSIL
ENERGY

U. S. DEPARTMENT OF ENERGY

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

This report has been reproduced directly from the best available copy.

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Paper Copy \$5.25
Microfiche \$3.00

GETTY OIL COMPANY
WESTERN EXPLORATION AND PRODUCTION DIVISION

COASTAL DISTRICT
VENTURA, CALIFORNIA

WILLIAMS HOLDING LEASE
STEAMFLOOD DEMONSTRATION PILOT
CAT CANYON OIL FIELD

FIRST ANNUAL REPORT
PERIOD: JUNE 25, 1976 TO JUNE 1, 1977

EDITORS: EDWARD J. HANZLIK
HELM A SCIENCK

ERDA TECHNICAL PROJECT OFFICER: ALAN J. LEIGHTON
SAN FRANCISCO OPERATIONS OFFICE

Prepared for the United States Energy Research and
Development Administration Under Contract No. EY-76-C-03-1188

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

Table of Contents

ANNUAL REPORT TO ERDA

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

Period: June 25, 1976 to June 1, 1977

	<u>PAGE</u>
I. SUMMARY	1
II. INTRODUCTION	2
III. GENERAL PROJECT DESCRIPTION	6
IV. PROJECT ACTIVITIES PRIOR TO ERDA CONTRACT	11
V. PROJECT PROGRESS - CONTRACT INCEPTION, June 25, 1976 to June 1, 1977	12
A. PREDISPLACEMENT	
1. Steam Stimulation Performance of Pilot Wells	12
2. Acquisition of Permits	17
3. Computer Simulation Studies	20
B. DISPLACEMENT	
1. Initial Pilot Performance	23
2. Steam Generator Operations	24
3. Thermal Packer Failures	26
VI. FUTURE OPERATIONS	35
VII. REFERENCES	36
APPENDIX A - Production Performance of Pilot and Individual Wells	37
APPENDIX B - Steam Injection Survey Results for Pilot Injectors	49

LIST OF FIGURES

		<u>PAGE</u>
FIG. 1	Location of Cat Canyon Field	3
FIG. 2	Original (1966-1970) Steamflood Pilot Location	4
FIG. 3	a) Current Steamflood Pilot Location	7
	3 b) Current Steamflood Pilot Configuration	8
FIG. 4	a) Williams Holding Steam Displacement Pilot Production Performance	13
	4 b) Williams Holding Steam Displacement Pilot Cumulative Steam-Oil Ratio	14
FIG. 5	Williams Holding 205-25 Production Performance	16
FIG. 6	a) Computer Simulator Production Responses for an Initial Steam Injection Rate of 800 BSPD per Injector	22
	6 b) Computer Simulation Production Responses for an Initial Steam Injection Rate of 600 BSPD per Injector	22
FIG. 7	Components of Manufacturer A Thermal Packer Seal Section	27
FIG. 8	Detail of the Steel Back-up Ring in the Seal Section	27
FIG. A-1	Williams Holding Steam Displacement Pilot Production Performance	37
	A-2 WH 25-25 Performance	37
	A-3 WH 26-25 Performance	38
	A-4 WH 35-25 Performance	39
	A-5 WH 36-25 Performance	40
	A-6 WH 105-25 Performance	41
	A-7 WH 205-25 Performance	42
	A-8 WH 206-25 Performance	43
	A-9 WH 305-25 Performance	44
	A-10 WH/RF 204-25 Performance	45

		<u>PAGE</u>
FIG. B-1	Steam Injection Survey for WH 825-25	47
B-2	Steam Injection Survey for WH 826-25	48
B-3	Steam Injection Survey for WH 925-25	49
B-4	Steam Injection Survey for WH 935-25	50

LIST OF TABLES

		<u>PAGE</u>
TABLE 1	Steam Stimulation Summary	15
TABLE 2	Summary of 50 MM Btu/hr Displacement Steam Generator Performance	25
TABLE 3	a) Detail of Packer Replacement Well Work for WH 825-25	30
	3 b) Detail of Packer Replacement Well Work for WH 826-25	31
	3 c) Detail of Packer Replacement Well Work for WH 925-25	32
	3 d) Detail of Packer Replacement Well Work for WH 935-25	33
TABLE 4	Summary of Service Periods by Thermal Packer Type	34

I. SUMMARY

On June 25, 1976 Getty Oil Company was awarded a cost-sharing contract from ERDA to conduct a joint steamflood pilot on the Williams Holding Lease of Cat Canyon Field in the Santa Maria Basin. 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 S1-B reservoir and similar heavy oil reservoirs.

Precontract activities of Getty Oil Company are reported in Topical Report I - Project Design and Development. These activities include site selection and preparation, drilling of production and injection wells, and computer simulations of the steamflood process in the pilot area under projected operating conditions.

This annual report discusses the project progress from the inception of the contract to June 1, 1977. Included are summaries of the predisplacement activities such as cyclic steam stimulation of the pilot wells, acquisition of steam generator permits, and the results of further computer simulation studies conducted under more restrictive assumptions for field operating conditions expected for the pilot project. Discussion of the displacement phase of the project, which started in April, 1977, is divided into three sections: 1) initial pilot performance, 2) steam generator operations, and 3) thermal packer failures. Future operations are then summarized.

II. INTRODUCTION

The Cat Canyon Field is located approximately eight miles south-east of the town of Santa Maria in Santa Barbara County, California. Figure 1 shows its location within the Santa Maria Basin. The Basin is bounded on the south by the westward trending Santa Ynez mountains, and on the northeast by the northwestward trending San Rafael mountains.

The Sl-B sand of the Cat Canyon Field is a relatively deep, heavy crude oil reservoir found at an average depth of 2500 feet. It produces a 9° API crude oil which has an estimated average oil viscosity of 25,000 centipoises at fully gas saturated reservoir conditions.

Although the field was discovered in 1908, only sporadic, generally unsuccessful development of the Sl-B sand occurred prior to the advent of steam stimulation techniques in the 1960's. Since 1964, Getty Oil Company has been using steam stimulation to successfully recover this heavy crude. To date, about 150 steam stimulation wells have been completed in the Sl-B sand. However, only an estimated 10-15% of the initial oil in place will be recoverable by steam stimulation.

In an early attempt to improve the recovery efficiency in the Sl-B sand, Getty Oil Company initiated a steam displacement pilot on its Williams Holding Lease in 1966. Figure 2 shows the location of the six inverted 10-acre 5-spot patterns encompassed by the pilot by 1968. This pilot experienced a high incidence of casing failures due to the thermal stresses created by steam temperatures of up to 550°F. These failures, combined with a crude oil price of just over \$1.00 per barrel, contributed to the project being uneconomic. This initial attempt at steamflooding the Sl-B sand was terminated in 1970.

Figure 1
LOCATION MAP

Figure 2
EXTENT OF SI-B OIL SAND
SHOWING ORIGINAL PILOT

A review of the production performance of this pilot, however, indicated some significant response to steam displacement. Williams Holding 62A-25, the only well surrounded by four injectors during the entire project life, showed good response averaging nearly 150 BOPD for three years.

By 1974, the problem of excessive casing failures, encountered early in the life of S1-B thermal operations, had been solved by using stronger couplings and by applying a tensile pre-stress while completing thermal wells. Also, oil prices had improved significantly, and the steam displacement process was more fully understood. These factors then justified the design of a second steam displacement pilot.

The major goal of the second pilot is to provide additional reservoir data and operating experience which can be applied to forecasting the performance of a future full-scale field project. Although the known characteristics of the S1-B sand indicate that conventional displacement techniques should be successful, the S1-B sand will provide a very severe test of the process. The reasons are that the S1-B is at a greater depth and pressure, and has a substantially more viscous crude, than present commercial-scale steam displacement projects.

In March, 1976, Getty Oil Company responded to a request for proposals, issued by ERDA, for improved oil recovery by steamflooding. The objective of this program was to demonstrate and evaluate the efficiency and the economics of the steamflooding process through its application to reservoirs in the United States. On June 25, 1976 Getty Oil Company was awarded cost-sharing Contract No. E(04-3)-1188* to conduct a joint steamflood pilot on its Williams Holding Lease in the Cat Canyon Field.

*In August, 1977 the contract number was changed by ERDA to EY-76-C-03-1188.

III. GENERAL PROJECT DESCRIPTION

The site selected for the steamflood pilot is located on the southwest portion of the Williams Holding Lease in Cat Canyon Field. The site was in a previously undeveloped portion of the reservoir in which initial wells showed good production response to steam stimulation. Data obtained during the drilling of the pilot wells indicated that the reservoir characteristics are uniform and typical of the major productive area of the reservoir.

The location of the pilot site in an essentially virgin portion of the reservoir offered several advantages. Since all the wells would be new, the maximum amount of reservoir data available through current technology could be obtained. In addition, chances of mechanical problems in new wells would be reduced. Finally, one of the most important aspects of the site is that it is not in an area containing residual heat from the 1966-1970 steam displacement project.

Pattern type and size for the pilot were selected on the basis of steamflood experience in Kern River Field and of results from studies conducted at Getty Oil Company's research center. These studies have shown that very high sweep efficiencies are obtained for repeated five-spot patterns while any additional sweep efficiency obtained by using inverted seven or nine-spot patterns is not sufficient to justify the additional well costs incurred. The resulting design decision was that the pilot should consist of a minimum of four inverted five-spot patterns as shown in Figure 3. This is the smallest possible five-spot configuration that will maintain confinement typical of a full-scale field project around at least one producing well. Additional studies¹ showed that for the known reservoir characteristics of the Sl-B sand, five-acre spacing per pattern would result in optimum steamflood pilot performance.

Figure 3A-
EXTENT OF SI-B OIL SAND
SHOWING CURRENT PILOT

Figure 3B

CURRENT STEAMFLOOD PILOT CONFIGURATION

Well designs for the pilot producers and injectors are detailed in the Topical Report I - Project Design and Development.² Field facilities and equipment requirements are discussed³, as are the results of initial computer studies leading to selection of the steam injection schedule over the life of the project.⁴

These preliminary computer studies were conducted under idealized operational conditions based upon the best engineering data and estimates available.⁵ After determining the optimum steam injection rate schedule under these conditions, a more severe review of the computer simulator predictions was made.

This review included consideration of production rates achievable under existing field conditions, additional information on formation injectivity, and optimum equipment utilization. The resulting operational design for the pilot included a constant injection rate schedule of 600 barrels of water as steam per day per injector for the project life. This schedule is a preliminary design subject to change based upon pilot performance, possible additional computer simulator studies, and the fact that the initial study showed optimum performance was achieved using declining injection rates in the later stages of the project.

In selecting and designing the field equipment for the pilot, several environmental factors and regulations had to be considered. The most important of these was air quality requirements in selecting the fuel to be burned in the steam generators.³ In the past, Getty Oil Company's operations in Cat Canyon supplied sufficient natural gas to fuel the limited number of steam generators in use. Natural gas, either commercial or from field production, is not available to serve as a source of fuel for expanding thermal recovery efforts from cyclic steam stimulation to steam displacement. Therefore, a suitable liquid fuel had to be selected.

Surveys were made of fuels that were available and that would satisfy regulations established by the Environmental Protection Agency and the Santa Barbara County Air Pollution Control District. Results of the surveys are reported in the Topical Report I. It was found that purchased low sulfur oil, with less than 0.5% sulfur, would best meet present requirements for the pilot operations. However, tests using high sulfur (about 4.5%) produced crude oil with flue gas scrubbing are planned.

IV. PROJECT ACTIVITIES PRIOR TO ERDA CONTRACT

The major project activities prior to receipt of the ERDA cost-sharing contract were: site selection, site development, and computer simulation studies of the proposed steamflood project. The results of these activities are reported in detail in the Topical Report I. The reasons for selecting the particular site on the Williams Holding Lease are described therein as well, while all pertinent well data obtained during the drilling and logging operations are included in the Appendices of the Topical Report. Also, the results of preliminary computer simulation studies are discussed. However, the steam stimulation production response of the pilot wells prior to the ERDA contract date, June 25, 1976, is included in the following section on Project Progress.

V. PROJECT PROGRESS - CONTRACT INCEPTION,
JUNE 25, 1976 TO JUNE 1, 1977

A. PREDISPLACEMENT

1. Steam Stimulation Performance of Pilot Wells

Production response to date totals 210,070 barrels of oil and 483,662 barrels of water. Oil and fluid production for the pilot is given in Figure 4A in barrels per calendar day. Cumulative injected steam to produced oil ratio is plotted in Figure 4B, while Table 1 summarizes the steam stimulations performed on each producer of the project. The average cycle length over the 15 completed steam stimulation cycles of pilot wells is 12-1/2 months. This is just slightly longer than recent Cat Canyon Field-wide averages, which range between 9 and 12 months on Getty Oil properties.

The production response of WH 205-25, the only fully confined producer of the pilot, is given in Figure 5. During displacement, this central producing well will be prototypical of producers in a full-scale field project as it is the only producing well surrounded by four injectors. The performances of the remaining pilot wells are given in Appendix A.

Figure 4A

"WILLIAMS HOLDING"

STEAM DISPLACEMENT PILOT PRODUCTION PERFORMANCE

STEAM INJECTED
(M BBLs.)

BBLs. PER DAY

Figure 4B
 "WILLIAMS HOLDING" STEAM DISPLACEMENT PILOT PROJECT
 CUMULATIVE STIMULATION STEAM-OIL RATIO

TABLE 1 - STEAM STIMULATION SUMMARY

<u>Injection Dates</u>		<u>Barrels Injected</u>	<u>Avg. Steam Quality</u>	<u>Average Temp.</u>	<u>Average Pres.</u>	<u>Cycle Oil Produced*</u>
<u>Start</u>	<u>Finish</u>		<u>(%)</u>	<u>(°F)</u>	<u>(psig)</u>	<u>(Bbls)</u>
Williams Holding 25-25			Completed	1-2-75		
5- 8-75	5-20-75	13237	69	500	1135	11,556
12- 3-76	12-17-76	10982	66	530	1060	3,879
Williams Holding 26-25			Completed	5-7-74		
6-13-74	6-24-74	10535	66	570	1500	18,241
4-20-75	5- 7-75	12374	74	520	1300	24,338
12-29-76	1- 9-77	10089	91	555	1407	5,340
Williams Holding 35-25			Completed	6-4-74		
7- 2-74	7-10-74	8589	32	550	1510	11,209
3-26-75	4- 4-75	9179	64	570	1345	17,606
2- 6-77	2-19-77	10925	83	565	1455	1,748
Williams Holding 36-25			Completed	1-22-75		
4- 2-75	4-13-75	10167	63	530	1490	12,182
1-26-77	2- 6-77	10201	87	550	1395	889
Williams Holding 105-25			Completed	8-28-75		
12- 1-75	12-12-75	8893	49	590	1735	8,696
6- 9-76	6-22-76	10247	80	550	1110	3,737
1- 9-77	1-26-77	10567	79	570	1440	3,758
Williams Holding 205-25			Completed	2-5-75		
5-22-75	5-28-75	5898	69	535	1380	10,915
7- 8-76	7-19-76	11335	67	570	1470	12,776
3-31-77	4-13-77	10650	75	550	1330	1,253
Williams Holding 206-25			Completed	9-15-75		
2-12-76	2-23-76	10236	36	610	1640	15,063
12-17-76	12-28-76	10336	88	560	1430	4,497
Williams Holding 305-25			Completed	9-15-75		
9-28-75	10-12-75	9603	57	610	1685	4,996
7-24-76	8- 2-76	11372	73	590	1400	6,711
2-22-77	3- 7-77	10707	84	550	1345	908
Williams Holding/Recruit Fee 204-25			Completed	9-14-75		
10-13-75	10-25-75	10738	45	560	1425	11,053
6-30-76	7-11-76	10735	74	585	1350	7,501
4-13-77	4-24-77	10012	80	560	1355	1,459

*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 1, 1977.

Figure 5

"WILLIAMS HOLDING" 205-25 PERFORMANCE

2. Acquisition of Permits

Two regulatory agencies have to be considered for environmental impact of equipment design and generator fuel selection. The Environmental Protection Agency (EPA) has established ambient air standards for sulfur dioxide, which must be met. Also, the Santa Barbara County Air Pollution Control District (SBC-APCD) Regulation 32.1 prohibits the burning of a liquid fuel having a sulfur content greater than 0.5 percent by weight, unless sulfur compounds are removed from the combustion gases to the extent that the emissions are no greater than those produced by a liquid fuel containing 0.5% sulfur. The permitting process for each of these agencies will be discussed below.

Environmental Protection Agency Permits

A review of EPA permit requirements indicated that no permit would be required for steam generators under 250 MM Btu/hr capacity if they are burning natural gas with a sulfur content of under either 0.5 percent, or 20 grains sulfur per hundred cubic feet of gas. Cat Canyon Field gas averages 45 grains sulfur per hundred cubic feet. Therefore, to use field produced gas as fuel, a permit or a variance would be required.

On January 26, 1976 Getty Oil Company personnel went to San Francisco to discuss application for a variance with EPA personnel. It was decided to request a variance rather than a permit since the Cat Canyon steam generators have considerably less capacity (22 MM and 50 MM Btu/hr) than the 250 MM Btu/hr stipulated in the EPA regulations. The EPA requested a letter with complete details on the steam-flood pilot, including the locations of the generators in relation to other major emission sources. This letter was to serve as a request for exemption or as a permit application depending upon the results of an EPA review.

On February 3, 1976 a letter was submitted to the Director of Air and Hazardous Materials Divisions for EPA Region IX. This letter requested an exemption from the permit requirements for four generators which were delivered at the end of 1975. Among these generators was the 50 MM Btu/hr generator for injecting displacement steam. This generator was delivered in November, 1975. Also included among the four generators was a 22 MM Btu/hr generator scheduled for part time use on the pilot project.

On February 17, 1976 Cotty Oil Company was informed that, under the EPA regulations, an exemption could not be issued and that an EPA permit would be required.

On March 19, 1976 a formal permit application was made. This application was for a permit to operate the four generators delivered in 1975 and for eight additional generators on order. It included fuel options for the generators, i.e. the generators would burn either natural gas, 0.5% sulfur fuel oil, or high sulfur fuel oil with stack gas scrubbers to reduce emissions to the equivalent of the low sulfur fuel oil. This permit application also included a study on "Air Quality Impact of Proposed Generators in the Cat Canyon Field".

On April 27, 1976 additional data was submitted to the EPA in response to its requests. In a letter dated May 14, 1976 the EPA again requested more data, specifically additional studies on the air quality impact of the generators considering emission sources on a broader geographical area than was included in the original study. This information was needed to determine that the proposed steamflood project would not prevent or interfere with the attainment or maintenance of the National Ambient Air Quality Standards.

On May 20, 1976 Getty Oil and EPA representatives met to discuss the additional studies requested. The EPA representatives indicated the following information, as a minimum, would be required: an emission inventory of other sources of pollution in the Cat Canyon and Santa Maria areas, and short-term modeling data, which include the other pollution sources, for three-hour and twenty four-hour periods. Also, it was agreed that Getty Oil Company would resubmit the permit application as two separate applications: one for the four generators already delivered, and one for the remaining eight generators on order.

Following the May 20, 1976 meeting with the EPA, a revised air quality assessment study was completed and submitted to both the EPA and the SBC-APCD on July 29, 1976. Additional meetings and conversations were held with EPA personnel and, on November 19, 1976, the EPA completed their analysis of the Getty Oil studies.

Public notice was placed in the Santa Maria Times on November 24, 1976 for a thirty-day public comment period. Three comments were reviewed, two from the public which were readily answered, and one from the Santa Barbara County regarding oxidant evaluation.

On December 17, 1976 Getty Oil Company engaged Environmental Research and Technology, Inc. to prepare a report answering the questions raised by Santa Barbara County. This report was completed, reviewed, and approved by the SBC-APCD and submitted to the EPA on January 14, 1977. After the final review, the EPA issued permanent permits to operate the four generators, including the 50 MM Btu/hr steamflood project generator, on March 9, 1977.

Santa Barbara County Permits

Applications and reports were submitted to the County on a similar time scale as the EPA submittals were made. APCD action was predicated on EPA review and approval. Once the EPA issued the permits, the APCD did not require any further review, public notice, or public hearings. The APCD issued the generator permits on March 29, 1977.

3. Computer Simulation Studies

The preliminary design computer simulation studies of the Williams Holding Steam Displacement Pilot assumed idealized operating conditions since actual field limitations were not yet clearly defined.⁵ Prior to initiating the steam displacement phase of this project, additional simulator studies were made. These were to examine the operational characteristics of the pilot in detail, giving specific attention to the effects of varying schedules of fluid production and steam injection rates. The purpose of these studies was to select the optimum schedule of rates considering current economic conditions and more stringent operating limitations than those used in the initial studies.

A major concern was the effective utilization of the two steam generators allocated to the project. These two generators have different capacities, and will service the four injectors of the pilot. One is a 50 MM Btu/hr generator and the other has a 22 MM Btu/hr capacity.

The use of both generators simultaneously to inject displacement steam corresponds to a maximum injection rate of 800 barrels per day per injector of water as 55% quality steam at surface conditions. On the other hand, use of only the 50 MM Btu/hr generator for injecting displacement steam corresponds to a maximum injection rate of 600 barrels per

day per injector of water as 77% quality steam at surface conditions. In this case, the 22 MM Btu/hr generator would be used to cyclically steam stimulate the pilot producers.

The steam displacement responses for each of the two steam injection methods just mentioned are shown in Figure 6. The gross reserves for each case are approximately the same. However, the timing of the oil production is quite different. Production at a gross fluid production rate of 1000 BPD is considerably delayed from the 1600 BPD gross fluid production rate for both injection rate schedules.

Economic analysis of each case was then performed. The study concluded that the optimum combination of production and injection rates was as follows:

- Optimum gross fluid production capacity for confined wells (central producer, WH 205-25, in the pilot) is 1600 BPD for the life of the project.
- In conjunction with this fluid production rate, the optimum steam injection rate for each injector is as follows:

First Year:	600 BSPD
Second Year:	600 BSPD
Third Year:	600 BSPD
Fourth Year:	400 BSPD

where BSPD represents barrels of water as steam per day. The computer simulator projects for this optimum case, an estimated cumulative injected steam to produced oil ratio of 4:1 and produced water to oil ratios as high as 14:1 prior to steam breakthrough.

Two additional results of the study which directly affect successful operation of the pilot are summarized below. First, the importance of maintaining low fluid levels in the confined,

Figure 6A

COMPUTER SIMULATION PRODUCTION RESPONSES
FOR AN INITIAL STEAM INJECTION RATE OF 800
BSPD PER INJECTOR

Figure 6B

COMPUTER SIMULATION PRODUCTION RESPONSES
FOR AN INITIAL STEAM INJECTION RATE OF 600
BSPD PER INJECTOR

central producer was established as essential to the success of the pilot project. With the present gross production capacity on WH 205-25 of 400 to 500 BFPD the confined producer would never experience steam breakthrough unless the steam injection rates were lowered to 150-200 BSPD per injector. This would extend the life of the project by several years to recover the same reserves and the increased heat losses would have very adverse effects on the economics of the project. Therefore, since the majority of oil production in a steam displacement operation in heavy oil reservoirs occurs after steam breakthrough and since significant water production is experienced prior to breakthrough, a larger pumping unit has been selected for WH 205-25.

Finally, it was also found that cyclic steam stimulation of the pilot producers encouraged earlier and more uniform steam breakthrough at the producers.

B. DISPLACEMENT

1. Initial Pilot Performance

The reporting period of this annual report includes only the first two months of the steam displacement phase of the project. Steam displacement was not begun until April, 1977 due to delays in obtaining steam generator permits. Operating problems have beset the project during these two months.

The following sections of this report describe the operations of the 50 MM Btu/hr displacement steam generator from initial test firing through the initial on-stream steam injection periods. Also described are the problems with packer failures encountered in the steam injection wells. The production response of the pilot through June 1, 1977 was included in the steam stimulation performance section.

2. Steam Generator Operations

Operation of the 50 MM Btu/hr displacement steam generator has been straightforward and uncomplicated by major problems. The generator was first test-fired on April 15, 1977. During the next three days, operational adjustments were made and the refractory was conditioned under low firing rates. The only problem occurred when a check valve failed on the first day. The valve was removed and inspected. A welder's coupon was found lodged in the valve. Feedwater pump valves and the feedwater meter were damaged at the same time. These were replaced when the new check valve was installed. Since then, the generator has experienced no significant operational problems. Generator down-time was due mainly to thermal packer failures in the injection wells. These failures are discussed in detail in the following section. Table 2 summarizes the performance of the 50 MM Btu/hr generator from April 15, 1977 to June 1, 1977.

TABLE 2
SUMMARY OF 50 MM BTU/HR
DISPLACEMENT STEAM GENERATOR PERFORMANCE

<u>Dates</u>	<u>Hours On</u>	<u>Water as Steam* Rate (BPD)</u>	<u>Discharge* Pressure (psig)</u>	<u>Comments</u>
4-15-77 to 4-17-77	-	2400	1980	Initial firing of gen- erator; Start steam injection; Testing thermal packers.
4-18-77 to 4-20-77	0	-	-	Replaced thermal packers.
4-21-77 to 4-26-77	-	2265	1860	Sustained steam injection.
4-27-77 to 5-3-77	0	-	-	Replaced thermal packers; Insulated steam lines; Revised header system.
5-4-77 to 5-10-77	-	2610	910	Sustained steam injection.
5-11-77 to 5-12-77	0	-	-	Replaced thermal packers.
5-13-77 to 5-16-77	-	2570	945	Sustained steam injection.
5-17-77 to 5-23-77	0	-	-	Replaced thermal packers.
5-24-77 to 6-1-77	166	2150	900	Sustained steam injection; Generator downtime due to replacement of thermal packer.

*Rates and pressures are given as averages over the period listed.

3. Thermal Packer Failures

Each of the four injectors of the Cat Canyon steamflood pilot were originally equipped with Manufacturer A thermal packers.* Since the beginning of the displacement phase, all four injectors have experienced a very high incidence of packer failures. Table 3 details the well work associated with packer replacements in each well. Table 4 summarizes service periods of each type of replacement packer used in the injectors since steam displacement started in April, 1977. Note that Manufacturer A packers were in all injectors at the beginning of displacement operations.

At the end of April, packers from three of the injectors were inspected. All three packers failed in less than one week after steam injection had started. The failures appeared to be caused by a possible design problem in the seal section as discussed below.

Figure 7 shows the components of the seal section. When the packer is set, the elastomeric sealing element is compressed by the teflon and steel rings. The sealing element deforms and effects a seal against the casing wall. The teflon rings also seal against the well. The steel back-up rings expand out against the casing wall to contain the teflon rings and the elastomeric element. The steel rings are used to avoid cold flowing of the teflon and to contain the elastomeric element which will flow under elevated temperatures and pressures.

*Manufacturer's identities and the trade names of their products tested are in Getty Oil Company's project record. Getty Oil does not intend to disparage the manufacturers' products nor their design and engineering. This steamflood pilot is basically experimental and its operating conditions are at the frontiers of thermal packer technology.

Figure 7

COMPONENTS OF THE MANUFACTURER A
THERMAL PACKER SEAL SECTION

Figure 8

DETAIL OF THE STEEL BACK-UP RING
ON THE SEAL SECTION

The failure apparently occurred in the following manner:

- 1) The teflon back-up ring extruded through the slits in the steel back-up rings at the top of the seal section. The slits are shown in Figure 7. The pressure from below the seal section prevented the downward extrusion of the lower teflon ring.
- 2) The elastomeric sealing element, at an elevated steam temperature of about 630°F, then flowed into the void created by the extruded teflon.
- 3) After a short period of time, enough of the sealing element has been extruded to permit the steam to by-pass the seal section.

In an attempt to prevent additional failures, Manufacturer A redesigned the steel back-up ring on the top of the seal section. The slits on the new ring were eliminated. This packer was tested in Williams Holding 825-25 on April 28, 1977. The packer subsequently failed, and was replaced on June 10, 1977.

In addition to replacing the seal retainer slotted rings with solid rings, other operational procedures were implemented in an attempt to reduce packer failure incidents. These include:

- 1) Running a casing scraper ahead of the replacement thermal packers. This was done to reduce the potential of damage to the seal section when the packers were being run into the well.
- 2) Using 3-1/2" tubing rather than 2-7/8" tubing to reduce the potential for buckling.
- 3) Testing the expansion joints (with teflon seals) using warm water rather than cold water.

Due to the high incidence of packer failures and the current lack of a thermal packer design which will withstand the operating conditions encountered in the steamflood pilot, future plans are to operate present packers until they fail. Packers will be removed from all wells except Williams Holding 935-25 until a new design is available. If possible, a packer will be maintained in 935-25 due to cement-squeezed perforations in the casing which were made necessary by problems encountered during primary cementing operations.

In the meantime, use of aluminum tubing centralizers has been discontinued because they age harden and become very brittle. Also, tubing insulation has not yet been used since the packers available at this time will not withstand down-hole conditions.

TABLE 3a
DETAIL OF PACKER REPLACEMENT
WELL WORK FOR WH 825-25

<u>Date</u>	<u>Activity</u>
5-4-76	<u>Ran Manufacturer A packer</u> with expansion joint set at 2583'. Used centralizers.
4-28-77	<u>Pulled "A" packer</u> . Ran casing scraper. <u>Ran new "A" packer</u> with two expansion joints. Set at 2528'.
6-10-77	<u>Pulled "A" packer</u> . Ran steam injection survey. Laid down 38 joints of crooked tubing. <u>Ran "A" packer</u> with two expansion joints. Set at 2497'. Used no centralizers. Tested: no communications.

TABLE 3b
 DETAIL OF PACKER REPLACEMENT
WELL WORK FOR WH 826-25

<u>Date</u>	<u>Activity</u>
4-24-76	<u>Ran Manufacturer A packer</u> with expansion joint. Set at 2533'.
4-20-77	<u>Pulled packer.</u> Packing element was fluid cut. Laid down five joints of gaulded and crimped tubing. <u>Ran Manufacturer B packer.</u> Stopped with 18 stands in hole. Picked up and set down on packer to get in hole. <u>Pulled packer,</u> and found aluminum centralizers stuck and broken in "J" slots of packer. Ran casing scraper to top of liner adaptor with no restrictions. <u>Ran "B" packer.</u> Had circulation around packer. <u>Pulled packer.</u> Found sealing elements strung above packer on tubing; none were on packer. Tested casing: held okay.
4-21-77	<u>Ran "B" packer.</u> Set at 2514'. Tested packer: held okay.
4-27-77	<u>Pulled packer.</u> Laid down four joints gaulded tubing. Ran casing scraper to top of liner adaptor with no restrictions. Centralizers were removed coming out of hole.
4-28-77	<u>Ran "B" packer.</u> Set at 2491'.
6-9-77	<u>Pulled packer.</u> Ran tubing open-ended.
6-11-77	Laid down 54 joints bent tubing. Ran bit and scraper to top of liner anchor. <u>Ran "B" packer.</u> Pulled
6-13-77	<u>packer.</u> Ran bit and scraper. <u>Ran "B" packer.</u> Set at 2517'. Tested packer: held okay.

TABLE 3c
DETAIL OF PACKER REPLACEMENT
WELL WORK FOR WH 925-25

<u>Date</u>	<u>Activity</u>
5-3-76	Replaced liner; top of liner anchor at 2634'. <u>Ran</u> <u>Manufacturer A</u> with expansion joint. Set at 2593'.
4-20-77	<u>Pulled packer - slowly</u> . Packing fluid cut around packing element. Laid down two joints gaulded tubing. <u>Ran packer</u> with two expansion joints. Hydrotested: found expansion joints leaking. Failed in attempt to tighten packing. Got two new expansion joints. <u>Pulled packer</u> .
4-21-77	New expansion joints also leaked. Ordered additional expansion joints. <u>Ran packer</u> with expansion joints and set at 2597'. Pressured casing to 2000 psi: held okay.
5-12-77	<u>Pulled "A" packer</u> . Removed centralizers. <u>Ran</u> <u>"A" packer</u> and expansion joints. Set at 2599'. Tested casing to 2000 psi: held okay.
6-10-77	<u>Pulled packer</u> . Ran injection survey. Ran casing scraper. Laid down 50 joints crooked tubing. <u>Ran "A" packer</u> . Set at 2579'.

TABLE 3d
 DETAIL OF PACKER REPLACEMENT
WELL WORK FOR WH 935-25

<u>Date</u>	<u>Activity</u>
4-16-76	<u>Ran Manufacturer A packer</u> with expansion joint. Set at 2514'.
4-19-77	<u>Pulled packer</u> . Packing element washed and torn up. Laid down three joints gaulded tubing. <u>Ran "A" packer</u> with two expansion joints. Set at 2500'.
5-12-77	<u>Pulled packer</u> . <u>Ran "A" packer</u> with two expansion joints. Set at 2519'.
5-17-77	Pulled 13 stands tubing and hung up. Finished pulling out. Ran casing scraper, no restrictions. Bailed fine sand from 2625' to 2658'. <u>Ran Manufacturer C packer</u> with two expansion joints. Set at 2493'.
5-23-77	<u>Pulled packer</u> . Checked packer. Seal on inner mandrel had failed. Ran bridge plug and full-bore. Tested casing 1613' to 2540': held okay.
5-24-77	<u>Ran "C" packer</u> with two expansion joints. Set at 2493'. Ran fullbore and tested: no communications. Ran Dia-Log casing inspection log: looked good.
5-31-77	<u>Pulled packer</u> . Checked packer. Seal on inner mandrel had failed. Bailed sand and iron oxide from 2625' to 2653'. <u>Ran Manufacturer B packer</u> with expansion joint. Set at 2476'. Tested: no communications.
6-8-77	<u>Pulled packer</u> . Found brass screw on packing and washed body. Ran casing scraper. Bailed sand and iron sulfide to 2637'.
6-9-77	<u>Ran "B" packer</u> with expansion joint. Tested: no communications. Ran injection survey.

TABLE 4
SUMMARY OF SERVICE PERIODS
BY THERMAL PACKER TYPE

Thermal Packer Manufacturer						
Steam Injection Well	Manufacturer A		Manufacturer B		Manufacturer C	
	Date Run	Pulled	Date Run	Pulled	Date Run	Pulled
WH 825-25	5- 4-76	4-28-77				
	4-28-77	6-10-77				
	6-10-77	current				
WH 826-25	4-24-76	4-20-77	4-20-77	4-20-77		
			4-20-77	4-20-77		
			4-21-77	4-27-77		
			4-28-77	6- 9-77		
			6-11-77	6-11-77		
			6-11-77	current		
WH 925-25	5- 3-76	4-20-77				
	4-20-77	5-12-77				
	5-12-77	6-10-77				
	6-10-77	current				
WH 935-25	4-16-76	4-19-77	5-31-77	6- 8-77	5-17-77	5-23-77
	4-19-77	5-12-77	6- 9-77	current	5-24-77	5-31-77
	5-12-77	5-17-77				

VI. FUTURE OPERATIONS

The steamflood pilot project under the ERDA contract is divided into four phases which include five major decision points. The first three decision points have been approved and the project is now in the second portion of Phase II. The phases are outlined below, and future work is predicated on approval of the last two decision points.

<u>Phase</u>	<u>Work</u>	<u>Decision Point</u>	<u>Comments</u>
-	Precontract	D.P.1	Site selection, drilling of wells; D.P.1 approved August 21, 1976.
I	Preinjection	D.P.2	Steam stimulation of producing wells, acquisition of generator permits, preliminary computer simulations of steamflooding; D.P.2 approved April 11, 1977.
II	Steam Injection to Breakthrough	D.P.3	Minimum target injection rate of 1600 barrels of water as steam per day; D.P.3 approved June 21, 1977
		D.P.4	Steam breakthrough at the producers or 13 months on continuous steam injection
III	Steam Displacement After Breakthrough	D.P.5	Steam injection to continue for about 34 months. After the first 12 months, D.P.5 must be approved
IV	Evaluation	-	Drilling of core holes, project evaluation, submittal of final reports

VII. REFERENCES

1. Hanzlik, E. J., ed., Williams Holding Lease Steamflood Demonstration Project, Cat Canyon Oil Field, Topical Report I, Project Design and Development, p. 13
2. Ibid, pp. 23-27.
3. Ibid, pp. 28-38.
4. Ibid, pp. 11-16.
5. Ibid, pp. 19-21.

APPENDIX A

PRODUCTION PERFORMANCE OF PILOT AND INDIVIDUAL WELLS

Figure A-1

"WILLIAMS HOLDING"
STEAM DISPLACEMENT PILOT PRODUCTION PERFORMANCE

Figure A-2

"WILLIAMS HOLDING" 25-25 PERFORMANCE

Figure A-3

"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

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

APPENDIX B

STEAM INJECTION SURVEY RESULTS FOR PILOT INJECTORS

Figure B-1

"WILLIAMS HOLDING" 825-25
STEAM INJECTION SURVEY

Figure B-2

"WILLIAMS HOLDING" 826-25
STEAM INJECTION SURVEY

DEEP INDUCTION LOG

Figure B-3

"WILLIAMS HOLDING" 925-25
STEAM INJECTION SURVEY

Figure B-4

"WILLIAMS HOLDING" 935-25
STEAM INJECTION SURVEY