

IMPROVED OIL RECOVERY IN FLUVIAL DOMINATED DELTAIC
RESERVOIRS OF KANSAS - NEAR-TERM

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Chapter 1

Introduction

ABSTRACT

Common oil field problems exist in fluvial dominated deltaic reservoirs in Kansas. The problems are poor waterflood sweep efficiency and lack of reservoir management. The poor waterflood sweep efficiency is due to 1) reservoir heterogeneity, 2) channeling of injected water through high permeability zones or fractures, and 3) clogging of injection wells due to solids in the injection water. In many instances the lack of reservoir management results from 1) poor data collection and organization, 2) little or no integrated analysis of existing data by geological and engineering personnel, 3) the presence of multiple operators within the field, and 4) not identifying optimum recovery techniques.

Two demonstration sites operated by different independent oil operators are involved in this project. The Stewart Field is located in Finney County, Kansas and is operated by PetroSantander, Inc. This field was in the latter stage of primary production at the beginning of this project and is currently being waterflooded as a result of this project. The Nelson Lease (an existing waterflood) is located in Allen County, Kansas, in the N.E. Savonburg Field and is operated by James E. Russell Petroleum, Inc. The objective is to increase recovery efficiency and economics in these types of reservoirs. The technologies being applied to increase waterflood sweep efficiency are 1) in situ permeability modification treatments, 2) infill drilling, 3) pattern changes, and 4) air flotation to improve water quality. The technologies being applied to improve reservoir management are 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

The Stewart Field project results are 1) the development of a comprehensive reservoir database using personal computers, 2) the completion of a simulation study to history match the primary production, 3) the simulation of waterflooding and polymer flooding, 4) an economic analysis to assist in identifying the most economical waterflood pattern, 5) completion of laboratory analysis conducted on reservoir rock, 6) unitization of the field so that a field-wide improved oil recovery process could be implemented, 7) design and construction of waterflood facilities, and 8) initiation and operation of the waterflood utilizing improved reservoir management techniques.

Water injection began on October 9, 1995 in the Stewart Field. In March 1996 oil production in the field began to respond to the water injection. Oil production has continued to increase and as of July 1, 1998 total incremental waterflood response is approximately 2000 BOPD. Total field production is approximately 2260 BOPD. Total incremental waterflood production through June 1998 is 1,145,644 BO.

Current activities and future plans for the Stewart Field project consist of the continued operation of the waterflood utilizing state-of-the-art technologies in an attempt to optimize secondary recovery. Production and reservoir data are analyzed using reservoir characterization techniques and by updating the existing reservoir simulation. The analysis of results is utilized to optimize the waterflood plan and flooding techniques to maximize secondary oil recovery. This project was awarded the "Best Advanced Recovery Project in the Mid-Continent" for 1995 by Hart's Oil and Gas World.

The Savonburg Field project results are 1) the installation and proving of the air flotation device to be effective in water cleanup in mid-continent oil reservoirs, 2) the development of a database which includes injection and production data, and reservoir data, 3) the development of a reservoir description, 4) the completion of a pattern volumetric study to select high potential areas, 5) completion of a streamtube waterflood

simulation, 6) an analysis of injectivity on individual wells as a result of clean water/wellbore cleanups, and 7) the results of infill drilling and pattern changes.

Current activities and future plans for the Savonburg Field project consist of the continual optimization of this mature waterflood in an attempt to optimize secondary oil recovery. The waterflood optimization program is based on project results and will include continued wellbore cleanups and pattern changes.

EXECUTIVE SUMMARY

This project involves two demonstration projects, one in a Morrow reservoir located in the southwestern part of the state and the second in the Cherokee Group in eastern Kansas. Morrow reservoirs of western Kansas are still actively being explored and constitute an important resource in Kansas. Cumulative oil production from the Morrow in Kansas is over 400,000,000 bbls. Much of the production from the Morrow is still in the primary stage and has not reached the mature declining stage of that in the Cherokee. The Cherokee Group has produced about 1 billion bbls of oil since the first commercial production began over a century ago. It is a billion barrel plus resource that is distributed over a large number of fields and small production units. Many of the reservoirs are operated close to the economic limit, although the small units and low production per well are offset by low costs associated with the shallow nature of the reservoirs (less than 1000 ft. deep).

Common recovery problems in both reservoir types include poor waterflood sweep efficiency and lack of reservoir management. The poor waterflood sweep efficiency is due to 1) reservoir heterogeneity, 2) channeling of injected water through high permeability zones or fractures, and 3) clogging of water injection wells with solids as a result of poor water quality. In many instances the lack of reservoir management results from 1) poor data collection and organization, 2) little or no integrated analysis of existing data by geological and engineering personnel, 3) the presence of multiple operators within the field, and 4) not identifying optimum recovery techniques.

The technologies being applied to increase waterflood sweep efficiency are 1) in situ permeability modification treatments, 2) infill drilling, 3) pattern changes, and 4) air flotation to improve water quality. The technologies being applied to improve reservoir management are 1) database development, 2) reservoir simulation, 3) transient testing, 4) database management, and 5) integrated geological and engineering analysis.

In the Stewart Project, the reservoir management portion of the project conducted during Budget Period 1 involved performance evaluation. This included 1) reservoir characterization and the development of a reservoir database, 2) volumetric analysis to evaluate production performance, 3) reservoir computer modeling and simulation, 4) laboratory work, 5) identification of operational problems, 6) identification of unrecovered mobile oil and estimation of recovery factors, and 7) identification of the most efficient and economical recovery process.

To accomplish these objectives the initial budget period was subdivided into three major tasks. The tasks were 1) geological and engineering analysis, 2) laboratory testing, and 3) unitization. Due to the presence of different operators within the field, it was necessary to unitize the field in order to demonstrate a field-wide improved recovery process. This work was completed and the project moved into Budget Period 2.

Budget Period 2 objectives consisted of the design, construction, and operation of a field-wide waterflood utilizing state-of-the-art, off-the-shelf technologies in an attempt to optimize secondary oil recovery. To accomplish these objectives the second budget period was subdivided into five major tasks. The tasks were 1) design and construction of a waterflood plant, 2) design and construction of a water injection system, 3) design and construction of tank battery consolidation and gathering system, 4) initiation of waterflood operations and

reservoir management, and 5) technology transfer. Tasks 1-3 have been completed and water injection began in October 1995.

The Stewart Field project results to date are 1) the development of a comprehensive reservoir database using personal computers, 2) the completion of a simulation study to history match the primary production, 3) the simulation of waterflooding and polymer flooding, 4) an economic analysis to assist in identifying the most economical waterflood pattern, 5) completion of laboratory analysis conducted on reservoir rock, and 6) unitization of the field so that a field-wide improved oil recovery process could be implemented, 7) design and construction of waterflood facilities, and 8) initiation and operation of the waterflood utilizing improved reservoir management techniques.

Water injection began on October 9, 1995 in the Stewart Field. In March 1996 oil production in the field began to respond to the water injection. Oil production has continued to increase and as of July 1, 1998 total incremental waterflood response is approximately 2000 BOPD. Total field production is approximately 2260 BOPD. Total incremental waterflood production through June 1998 is 1,145,644 BO.

Current activities and future plans for the Stewart Field project consist of the continued operation of the waterflood utilizing state-of-the-art technologies in an attempt to optimize secondary recovery. Production and reservoir data are analyzed using reservoir characterization techniques and by updating the existing reservoir simulation. The analysis of results is utilized to optimize the waterflood plan and flooding techniques to maximize secondary oil recovery. This project was awarded the "Best Advanced Recovery Project in the Mid-Continent" for 1995 by Hart's Oil and Gas World.

In the Savonburg Project, the reservoir management portion involves performance evaluation. This work included 1) reservoir characterization and the development of a reservoir database, 2) identification of operational problems, 3) identification of near wellbore problems such as plugging caused from poor water quality, 4) identification of unrecovered mobile oil and estimation of recovery factors, and 5) identification of the most efficient and economical recovery process.

To accomplish this work the initial budget period was subdivided into four major tasks. The tasks included 1) geological and engineering analysis, 2) waterplant optimization, 3) wellbore cleanup and pattern changes, and 4) field operations. This work was completed and the project has moved into Budget Period 2.

The Budget Period 2 objectives consisted of continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. To accomplish these objectives the second budget period is subdivided into six major tasks. The tasks were 1) waterplant development, 2) profile modification treatments, 3) pattern changes, new wells and wellbore cleanups, 4) reservoir development (infill drilling), 5) field operations, and 6) technology transfer.

The Savonburg project results to date include a complete geological and engineering analysis and field work. The geological and engineering analysis includes, 1) development of a database which includes injection and production data, and reservoir data, 2) development of a reservoir description, 3) completion of a pattern volumetric study to select high potential areas, and 4) completion of a streamtube waterflood simulation. The field work completed includes, 1) the installation of the air flotation device for improvement of water quality, 2) wellbore cleanups throughout the field, 3) completion of six in-situ permeability modification treatments, 4) two pattern changes, and 5) an in-fill well drilled and completed as an injection well.

Current activities and future plans consist of the continual optimization of this mature waterflood in an attempt to optimize secondary oil recovery. The waterflood optimization program is based on geological

and engineering analysis conducted in Budget Period 1. The reservoir model developed in Budget Period 1 is continually updated as additional data is collected. The air flotation unit in the waterplant will be continuously monitored to alleviate unforeseen problems and to optimize operation. The specific goals are four-fold: 1) to operate the plant effectively on a continuous basis, 2) to demonstrate that high quality water can be obtained by establishing an acceptable measure of water quality, 3) to determine the cost of treating water, and 4) to identify savings in water treatment and well cleanup costs that are directly attributed to the improvement in water quality. Possible future permeability modification treatments will be implemented and patterns changed if found necessary.

Chapter 2

Stewart Field Project

OBJECTIVES

The objective of this project is to address waterflood problems in Morrow sandstone reservoirs in southwestern Kansas. The general topics addressed are 1) reservoir management and primary drive performance evaluation, and 2) the demonstration of a recovery process involving off-the-shelf technology which can be used to enhance waterflood recovery and increase reserves.

The reservoir management portion of this project conducted during Budget Period 1 involved performance evaluation. This included 1) reservoir characterization and the development of a reservoir database, 2) volumetric analysis to evaluate production performance, 3) reservoir computer modeling and simulation, 4) laboratory work, 5) identification of operational problems, 6) identification of unrecovered mobile oil and estimation of recovery factors, and 7) identification of the most efficient and economical recovery process.

To accomplish these objectives the initial budget period was subdivided into three major tasks. The tasks were 1) geological and engineering analysis, 2) laboratory testing, and 3) unitization. Due to the presence of different operators within the field, it was necessary to unitize the field in order to demonstrate a field-wide improved recovery process. This work was completed and the project moved into Budget Period 2.

Budget Period 2 objectives consisted of the design, construction and operation of a field-wide waterflood utilizing state-of-the-art, off-the-shelf technologies in an attempt to optimize secondary oil recovery. To accomplish these objectives the second budget period was subdivided into five major tasks. The tasks were 1) design and construct waterflood plant, 2) design and construct injection system, 3) design and construct battery consolidation and gathering system, 4) waterflood operations and reservoir management, and 5) technology transfer. Tasks 1-3 have been completed and water injection began in October 1995.

BACKGROUND

The Stewart Field is located approximately 12 miles northeast of Garden City in Finney County, Kansas. The field is about 0.25 to 0.5 mile wide, 4.5 miles long and covers approximately 2400 acres. The field was discovered in 1967 with the drilling of the Davidor and Davidor #1 Haag Estate. The well was completed in a basal Pennsylvanian Morrow sand from 4755-4767 for 99 BOPD. Davidor and Davidor drilled three additional wells. In 1971, Beren Corporation acquired the Davidor and Davidor lease and attempted to extend the field to the west, drilling one marginal producer. Active development of the field by Sharon Resources, Inc. and North American Resources Company took place from 1985 to 1994. **Figure 1** is a well location plat of the field.

All wells were drilled through the Morrow, cased with 4.5 or 5.5 inch production casing, perforated through a majority of the net pay interval and stimulated. Early completion practices consisted of acid or diesel breakdown jobs. In 1990 and 1991 Sharon Resources implemented a field wide hydraulic fracture program consisting of a water base gel with 3,000 to 43,500 lbs of sand. All wells were produced with pumping units and insert rod pumps. There were 43 producing wells drilled in the field. A summary of the field data is contained in **Table 1**.

Table 1 Stewart Field Data Summary	
<u>General</u>	
Well Count	43 Producers, 14 Dry Holes
Operators	3
<u>Reservoir Data</u>	
Formation	Morrow
Depth to Top of Morrow Sand	4760 ft.
Temperature	125°F
Original Pressure	1102 psig
Average Initial Water Saturation	32.2%
Original Oil In Place (volumetric)	22,653 MSTB
Cumulative Production (as of 1-1-95)	3,479 MSTB, (15.4% OOIP)
Ultimate Primary Reserves	3,881 MSTB, (17.1% OOIP)
Incremental Secondary Reserves	3,738 MSTB, (16.5% OOIP)
Primary Plus Secondary	7,619 MSTB, (33.6% OOIP)
<u>Rock Properties</u>	
Lithology	Sandstone
Average Thickness	26 ft.
Average Porosity (11% cutoff)	16.5%
Arithmetic Average Permeability	138 md.
<u>Fluid Properties</u>	
Crude Oil -	
Gravity	28° API
Viscosity at P_i and T_{res}	12.1 cp
Initial Solution Gas-Oil Ratio	37 SCF/STB
FVF at P_{BP}	1.045 RB/STB
Produced Water -	
Resistivity at 125°F	0.04 ohm-m
Total Dissolved Solids	91,300 mg/l

Primary Production

Primary oil production for the field is shown in **Figure 2** (dashed line). The increase in production rates during the period from 1985-1989 is due to rapid development of the field to the east and west by Sharon Resources and North American Resources. Peak production rates were observed following the hydraulic fracturing program carried out in 1990 and 1991. A decline curve analysis was completed using production data for all the wells within the field. Utilizing a straight exponential decline analysis, calculated remaining primary reserves as of June 1, 1994 were 516,000 barrels of oil for an ultimate primary oil recovery of approximately 3,881,000 barrels.

Water production from the Morrow formation was small. Increases in produced water were observed when production wells were fractured. Most of the produced water was attributed to fractures that were thought to extend into the underlying St. Genevieve and St. Louis formations.

The Stewart Field contains 28°API oil with a small amount of solution gas (37 SCF/bbl). The initial reservoir pressure was estimated to be 1102 psig with a bubble point of approximately 180 psi. The reservoir oil was highly undersaturated and the expected primary production behavior was a rapid decline of reservoir pressure as the reservoir energy in the form of fluid and rock expansion was depleted.

Two field wide shut in tests were conducted in 1989 and 1991 to determine reservoir pressure distribution. Pressure tests indicated continuity of the reservoir over the 4.5 mile length of the field. Material balance calculations were performed from the initial reservoir pressure to the average reservoir pressures observed in the 1989 and 1991 field wide tests. Assuming no water influx, the fluid produced should be due to fluid and rock expansion over the given pressure drop. These calculations gave an estimate in excess of 100 million barrels of oil in place. Volumetric mapping of the net sand indicated only 22 million barrels in place.

It was determined that uncertainties in fluid and rock properties would not resolve the difference in determining the original oil in place between volumetric mapping of the net sand and material balance calculations. Either a large volume of the reservoir was yet to be defined or a limited water influx (pressure support) existed within the field. This uncertainty provided motivation for the extensive database development and reservoir study that was completed in Budget Period 1.

History Matching Primary Production

Sharon Resources and the University of Kansas undertook independent reservoir simulation studies. Sharon Resources, located in Englewood, Colorado, was connected via Internet to the workstation at the University of Kansas. The studies were performed using a Silicon Graphics workstation with Western Atlas VIP Executive simulation software. The VIP simulator is a conventional black oil simulator, equipped with graphics interface. A major portion of the technology transfer associated with this activity pertains to University personnel assisting Sharon Resources in their simulation efforts.

The objectives of each study consisted of 1) the characterization and distribution of the various reservoir parameters and 2) development of a reservoir description to obtain a history match with the primary production. This reservoir description was the basis for subsequent simulation of the waterflood recovery. The independent studies resulted in different models; however, the two models provided similar results.

Sharon Resources provided data for the simulation. This included porosity/permeability correlation's for the three major zones within the Morrow, relative permeability data, and the history of all the wells that included location, date of completion, perforation intervals, wellbore radius, skin factor, stimulation history, production history, pressure constraints, and other information related to the wells. To identify distributions in the regions between wells, it was necessary to contour the tops, bottoms, porosity, permeability, and water saturations for each zone.

The Stewart Field model was developed in stages. Initially, the field was divided into four different segments that were assumed to be isolated from each other. The following is a summary of the assumptions used and changes implemented to the field description in order to obtain a history match of the primary production of the four segments:

1. Permeability of the reservoir was increased by a factor of 2 above values obtained from core analyses.
2. Reservoir volume was added to the northern portion of the Nelson and Carr leases.
3. Outside pressure support was included from the underlying Ste. Genevieve and St. Louis formations.
4. The initial skin damage on the wells was +1 and skin after fracture stimulation was -3 for all wells.
5. The initial reservoir pressure was 1200 psi and the pressure of the underlying formation was assumed to be 1500 psi. Initially, it was assumed that the underlying formation was in pressure communication with the entire field, but based on geological analysis and production history it was observed that the direct communication of the permeable underlying formation is in the area of the Mackey and Scott leases.

This assumption was built into the model in order to describe the reservoir more realistically.

Based on the above assumptions the model was developed. An external aquifer, as described above in assumption 5, was included as the fourth layer in the model. None of the wells were perforated in the fourth layer.

After obtaining a history match for each section, a model of the entire field was developed. The model was built using a grid of 150x20x4. Each gridblock had average dimensions of 190x250 ft. The resulting model had about 2-3 gridblocks between each well. The model contained a total of 12,000 gridblocks. The resulting model provided a primary history match in which the simulated production was 95.74% of the actual production. The original oil in place in the Morrow sandstone was estimated to be 26.1 MMSTB from this history match. The history match is not unique because different models produced a history match for the same field. However, estimates of original oil in place were in reasonable agreement. Subsequently, the model was modified this last year in order to obtain a history match for both primary and secondary oil and water production. Additional details concerning the modifications are contained in the Waterflood Operations and Reservoir Management section of this report.

Waterflood Simulation

The reservoir description developed during the history match of primary production was used to estimate waterflood performance using the VIP simulator. Working Interest Owners and University personnel proposed six different waterflood patterns. The mobility ratio was favorable and high volumetric sweep efficiency was anticipated in regions contacted by the injected water. Thus, selection of injection wells was done with emphasis on getting water into wells that contacted as much of the productive sand as was possible. Since few new wells were anticipated, this meant conversion of some of the best production wells into injection wells. The injection rate was restricted by water availability of 6000 BWPD. In each case, the water was distributed equally between each injection well within the waterflood pattern. The patterns simulated were 3 line drive, 5 line drive, 7 line drive and three modified line drive patterns. All the patterns were run for a waterflood period of ten years. The production wells were set to be shut in at a watercut of 90%. Incremental oil recovery due to waterflooding ranged from 15.3% to 17.5% of the original oil in place.

The Stewart Field showed favorable results for waterflood. The following conclusions were based on waterflood predictions based on simulation results:

1. Cumulative oil production and the water/oil ratios for all the patterns varied by less than 10%. Thus, pattern selection is not critical. What is critical is injecting the water into the principal reservoir zones.
2. Total oil recovery is a function of the volume of water injected, but not a strong function of the injection pattern.

Summary

Integrated analysis of the existing data and computer simulation of the reservoir provided 1) a more accurate description of the reservoir and its fluid flow characteristics, 2) identified waterflooding as the most economical enhanced oil recovery process to be implemented, and 3) facilitated unitization of the field to permit field-wide waterflooding.

A waterflood was designed and implemented for the entire field based on the geological and engineering analysis conducted in Budget Period 1. More detailed information pertaining to the work conducted during Budget Period 1 is available in the Second Yearly Technical Report submitted in July 1995.

BUDGET PERIOD 2 ACTIVITIES

Design and Construct Waterflood Plant

The following is a summary of the work associated with this task. The only adaptation made to the waterplant during the last year was the installation of an additional horizontal injection pump, which increased the injection capacity from 10,000 to 15,000 BWPD. A more detailed description of the work associated with this task is available in the Third Yearly Technical report submitted in July 1996.

A centrally located area in the middle of the field was selected for the waterplant, central tank battery, and field office facilities. A pre-fabricated injection plant was purchased from Power Service, Inc. The injection plant is skid mounted and enclosed in an all weather insulated metal building. The plant had an original

maximum design of 10,000 BWPD at 2000 psi. The plant originally consisted of two quintuplex positive displacement pumps powered by two 200 Hp electric motors, filtering equipment, suction and discharge piping, pressure recorders, flowmeter, and control equipment. This past year an additional horizontal injection pump was installed which increased the injection capacity from 10,000 to 15,000 BWPD.

The water supply tankage consists of three 1000 bbl and one 300 bbl fiberglass tanks. The first 1000 bbl tank is used as a separation tank or retention tank for water off the heater treater and source water from the supply wells. The 300 bbl tank is a slop tank coming off the separation tank. The two additional 1000 bbl tanks are source tanks from which the injection plant draws from. All the tanks are gas blanketed to keep oxygen out of the system to minimize corrosion. The water supply tankage is part of the central tank battery facility.

The waterplant is also equipped with a computerized emergency shutdown (ESD) and call out system. This is a part of the computerized monitoring system for the central tank battery facility. The system uses industry standard data acquisition and control techniques that provide the facility with state-of-the-art automation.

Design and Construct Injection System

The following is a summary of the work associated with this task. A more detailed description of the original design and construction of the injection system is available in the Third Yearly Technical report submitted in July 1996.

Two existing wells in the field were recompleted as water supply wells. These wells were recompleted in the Topeka formation. The Topeka is a saltwater bearing dolomitic limestone formation. Each well was tested for water supply quantity and quality. Following the tests both wells were equipped with a 175 Hp electrical submersible pump with variable speed drive. The pumping equipment for each supply well was designed to produce approximately 3000 BWPD. The supply wells were plumbed into the central injection facility using fiberglass pipe and put into operation in October 1995.

The geometry of the Morrow reservoir at the Stewart Field lended itself to the design and installation of a trunkline injection system along the length of the field with short laterals branching from the trunkline to the individual injectors.

Originally a modified six line drive pattern (**Figure 3**) was selected for waterflooding the field based on the geological and engineering analysis conducted in Budget Period 1. Six existing producing wells were selected to be recompleted as water injection wells. The original six injection wells were the Bulger 7-1, Mackey #6, Meyer 10-2, Scott 4-2, Sherman #3 and Sherman 3-1. Each injector was equipped with an injection meter and pressure recorder. New valves, chokes, and wellhead equipment were installed on each injector to enable adjustment or shut off of injection rates. Subsequently, this past year an additional six existing wells were converted to injection to improve the sweep efficiency in several areas of the waterflood. December 1997 conversions were:

<u>Well</u>	<u>Previous Status</u>
Scott 4-5	Producing approx. 10-12 BOPD
Sherman 3-8	Producing < 1 BOPD
Nelson 2-2	Shut-in

March 1998 conversions were:

<u>Well</u>	<u>Previous Status</u>
Haag Estate No. 2	Shut-in

Bulger 7-5
Bulger 7-10

Producing 4 BOPD
Producing < 1 BOPD

Downhole injection profiles were attempted on several injection wells during the latter part of 1997. Difficulties with the plastic coated tubing prevented completion of this program. Profiles were obtained on the Sherman 3-1, Mackey #6 and Meyer 10-2 to evaluate injection distribution. The vertical injection distribution for these three injectors was good. The remaining injection wells will be modified in the future to allow these surveys to be run on all the injectors.

Design and Construct Battery Consolidation and Gathering System

The following is a summary of the work associated with this task. Only minor adaptations were made during the last year as needed for an efficient cost effective operation. A more detailed description of the work associated with this task is available in the Third Yearly Technical report submitted in July 1996.

The existing 19 tank batteries were consolidated into one central tank battery facility. All the old tank batteries were reclaimed. A concrete foundation and dike was poured for the central tank battery. The battery consists of four 1000 bbl welded steel oil stock tanks, 8 ft by 20 ft horizontal heater treater, and a truck liquid automated control terminal (LACT). Two of the 1000 bbl oil tanks have level sensors as part of the computerized monitoring system. Additional computerized monitoring equipment in the tank battery are oil and water dump line flowmeters off the heater treater, a level sensor in the heater treater overflow tank, and LACT unit totalizer and BS&W. The totalizer monitors oil sales and the BS&W sounds an alarm if the basic sediments and water content in the oil are too high.

A 4 inch fiberglass gathering line was trenched and installed across the length of the field which tied all the producing wells into the central tank battery. Two computer controlled emergency shut down valves were installed on the inlet to the tank battery from produced fluids coming in from the east and west sides of the field.

Waterflood Operations and Reservoir Management

North American Resources Company (NARCO) entered into a sales agreement on the Stewart Field waterflood with PetroSantander, Inc. of Houston, TX in September 1997. PetroSantander took over operations on October 11, 1997. PetroSantander conducts the secondary field operations of the Stewart Field with a full-time company lease operator and a full-time contract lease operator. A company production foreman who coordinates and supervises all field operations supervises the company and contract lease operators. A company project engineer is responsible for the reservoir and production engineering, as well as operations supervision. A company geologist provides geologic support for the project. The project engineer, production foremen, and geologist comprise PetroSantander's reservoir management team. University of Kansas personnel from the Tertiary Oil Recovery Project complement PetroSantander's reservoir management team.

PetroSantander, as did NARCO, utilizes an in-house field data capture program which allows field employees to input tank gauges, produced water meter readings, water cuts, well tests, injection rates, pressures, and other vital field information into a computer. The data is transmitted via modem on a daily basis to the project engineer and production accounting system.

Total oil and water production for the field is recorded daily. Daily injection volumes and pressure are monitored at each injection well. Portable well test trailers are used for production tests on individual producing wells. Individual well tests and fluid level measurements are normally run twice a month. Water supply volumes and fluid levels are monitored on both water supply wells.

Water injection began on October 9, 1995 into four injection wells. Water was being injected into the original six injection wells by the end of October. Initial injection rate was approximately one half the design

rate of 6000 BWPD due to alternating production of the supply wells to test their productivity. The injection rate was increased to 5600 BWPD the first week in February 1996. The total current injection rate into twelve injection wells is approx. 9,800 BWPD. Both supply and produced water are being injected. Initially, all the injection wells were taking water with the surface pressure being a vacuum. Current surface injection pressure ranges from a vacuum to 920 psi. Current injection pressures are shown in **Table 2**.

Well	Surface Injection Pressure (psi)
Nelson 2-2	920
Sherman #3	735
Haag Estate #2	600
Mackey #6	535
Sherman 3-1	535
Scott 4-5	380
Sherman 3-8	315
Meyer 10-2	270
Scott 4-2	260
Bulger 7-1	200
Bulger 7-5	vacuum
Bulger 7-10	vacuum

Cumulative water injection in the field from flood startup to July 1, 1998 is 6,011,754 BW. Monthly and cumulative injection volumes for the twelve injection wells are shown in **Table 3**.

Date	Bulger 7-1	Mackey #6	Meyer 10-2	Scott 4-2	Sherman #3	Sherman 3-1	Nelson 2-2	Sherman 3-8	Scott 4-5	Haag Est. #2	Bulger 7-5	Bulger 7-10	Total Injection
Oct '95	7026	9857	8561	9945	10008	9810							55207
Nov '95	15276	14301	13738	14091	14329	13912							85647
Dec '95	15657	14833	15237	14879	14849	14549							90004
Jan '96	14590	13822	14199	13865	13837	13558							83871
Feb '96	24850	24227	26030	24994	25198	24384							149683
Mar '96	28460	23410	34977	29205	28429	28516							172997
Apr '96	23618	19184	35069	34973	27575	28091							168510
May '96	27534	17056	34664	36381	31034	25792							172461
Jun '96	29382	17132	31117	34987	28904	22126							163648
Jul '96	33353	17439	31412	37216	30520	23356							173296
Aug '96	33277	17145	29430	36915	31909	23395							172071
Sep '96	28561	15055	22549	31826	28535	20513							147039
Oct '96	30884	16034	25275	35285	29858	20853							158189
Nov '96	33427	16341	28970	39391	30765	20681							169575
Dec '96	36044	17370	28205	43279	31429	21447							177774
Jan '97	35980	16826	30695	41950	30782	21043							177276
Feb '97	32862	15255	27909	38889	27553	16293							158761
Mar '97	37848	17212	32131	40647	30457	20169							178464
Apr '97	35374	17310	30874	37885	27194	21442							170079
May '97	36391	17944	31844	40300	30039	21985							178503
Jun '97	34775	17722	28592	38826	28367	21067							169349
Jul '97	39172	19320	30475	42271	30968	22979							185185
Aug '97	39721	19776	31016	42472	32151	23449							188585
Sep '97	39086	18710	30311	41122	30835	21811							181875
Oct '97	40363	19199	30314	42014	30856	22867							185613
Nov '97	41084	19965	27450	41716	30067	27627							187909
Dec '97	39953	21581	26121	40440	29456	22030	2304	2435	2409				186729

Jan '98	43203	25224	31069	42826	32778	33922	26802	29004	37310				302138
Feb '98	40513	25017	27958	40516	45716	38656	15752	21017	39183				294328
Mar '98	38811	25386	26958	39949	29894	39959	8703	9465	23494				242619
Apr '98	36051	24056	28954	39546	31009	32749	13860	20062	24204	13798	13645	12818	290752
May '98	44935	24051	29189	38724	31030	31235	13874	19952	24879	14089	17961	11287	301206
Jun '98	41814	23503	31614	38680	31770	31489	12664	18575	22209	10863	18236	10994	292411
Total	1079881	621269	912915	1166007	938104	781757	93959	120510	173688	38750	49842	35099	6,011,754

Individual well injection volume adjustments have been made based on response (both injection well pressure response and offset producing well response) and reservoir volume near each injector.

In March 1996 following the injection volume increase in February, oil production in the field began to respond to the water injection. Approximately 550,000 BW was injected prior to observing any increase in oil production. Oil production has continued to increase and as of July 1, 1998 total incremental waterflood response is approximately 2000 BOPD. Total field production is approximately 2260 BOPD and 3310 BWPD. Total incremental waterflood production through June 1998 is 1,145,644 BO. **Figure 4** is a plot showing average daily totals for injection and production data by month for the field since the initiation of the waterflood.

A 640 pumping unit and 2-inch insert pump was installed on the Bulger 7-4 to replace a 320 unit and 1.75-inch pump. A 320 pumping unit was installed on the Meyer 10-1, also lowered the tubing and installed a 1.75-inch pump. The 320 unit replaced a 114 unit on the Meyer 10-1. These two artificial lift upgrades were performed as a result of rising fluid levels.

Several additional pumping units were upsized during the year to lower producing fluid levels. New units were purchased for the Scott 4-7, Carr 2-1, and the Haag Estate #5. Two of the pumping units released from these wells were transferred to the Sherman #4 and Haag Estate #4. Also four new progressive gravity pumps were installed on producing wells to increase fluid production.

Ongoing pump changes and speeding up pumping units were performed during the year on several wells. These changes are made as a result of the well testing program that identifies wells with production problems, rising fluid levels, abnormal production trends and low pump efficiencies. The changes that were made are a continued effort to maximize oil production and keep all the wells near a pumped off condition.

Electrification of the producing wells in the field began in May 1996. Electrification of the field has provided a more reliable and lower maintenance power source that can be automated much easier. Electrification of the field was completed in November 1996.

A pressure build-up test was performed on the Mackey No.1 that indicated positive skin damage. An acid treatment was performed that resulted in a minor increase in production. Subsequently, this well was hydraulically fracture treated in an attempt to remove skin damage and increase production. The treatment was unsuccessful, as post treatment production was the same as before.

The computer model developed at the Tertiary Oil Recovery Project at the University of Kansas was revised to history match waterflood production and injection. The availability of waterflood data necessitated these modifications to the model. The basic structure of the model, the four layers, was retained but changes in the petrophysical (skin, x and y permeability) properties were made to get a reasonable match in the oil and water production peaks and the arrival of the waterflood front. The fluid levels were maintained equal to the reservoir reported data and well production was predicted accordingly, i.e. the simulation was performed under bottom hole pressure as the limiting constraint.

To arrive at a reasonable value for the gas-oil ratio, a series of runs were performed by changing gas-oil ratios and the flood front arrivals were compared with the actual water front arrival in the field. The original ratio of 37 SCF/STB turned out to be the most reasonable value. A revised set of relative permeability data regressed from the old relative permeability data were used. Also, the relative permeability data were further adjusted to reduce water production and the early arrival of the water response to the flood. The vertical permeability of the fourth layer was adjusted to study the effect of the pressure support of the fourth layer on water and oil production and on the arrival of the flood response. It was found that a vertical permeability factor of 0.005 (0.5%) of the original core value gave adequate pressure support. Different simulation runs were performed by varying the permeability of the top three layers and observing its effect on the match. It was observed that permeability values of 67.5 % of the original core permeability values produced a reasonable match. This is acceptable and justified because the original core values were measured with respect to air, and a factor of 0.7 is generally used to get the permeability with respect to liquid phase.

To history match fluid production of individual wells, the skin values of each well were modified. The skin only modifies the permeability of the well grid block. In cases where the maximum negative skin was reached (the negative maximum skin is a function of the grid block size) local modifications to the permeability were made to get better history matches. The local modifications typically extended to a 3 X 3 grid, and in some instances to a 5 X 5 grid, with the well located at the center. These modifications were applied to all the layers and were done at the time of completion and when hydraulic fracturing occurred, if needed.

A few wells had their flood front arriving later or earlier than observed in the field. To correct this, the grid permeability between the injector and the producing wells was altered. The altered path was as narrow and direct as possible. These modifications were applied to individual layers as needed. A few wells showed both oil and water responses to the flood when there was none observed in the field. These wells were generally directly above or near the region in communication with the underlying Ste. Genevieve and St. Louis formations (the fourth layer in this model). The communication between the third and fourth layer near these wells was removed by closing the vertical permeability (i.e., $K_z=0$). In other instances, some wells did not show a response or the water response to the flood was not large enough. These wells had some surrounding grid blocks opened to the fourth layer to allow additional water influx. The grid blocks altered were usually a 5 X 5 grid with the well located at the center. A few wells had two to three distinct oil spike responses to the flood indicating that different layers had broken through at different times. These wells were modeled by altering the path permeability, as needed, of the individual layers.

The revised history match for the field is shown in **Figure 2**. There are three distinct peaks in oil production. The first is due to the field-wide development, the second due to the hydraulic fracturing of the field and the third peak is the response to the waterflood. The data points indicate actual production figures while the solid lines indicate the simulated values. The recent decline in actual oil production is due to excessive downtime due to workovers to upsize pumping equipment, rod parts, pump changes, water supply well downtime and work on the injection system. This temporarily effected the normal trend in production, which has since stabilized and is following the trend predicted by the simulation. Oil production rates, cumulative oil, and water production rates are presented in red, green, and blue, respectively. Field wide oil, water, and gas cumulative productions are reported in **Table 4**. There are three regimes of production. The first is the primary production match, the second is the matching of the waterflood period to date and the third is the prediction of the field performance through the year 2010.

	Primary Production through 9/1995		Production through 4/1998		Production through 12/2010	
	Actual	Simulated	Actual	Simulated	Actual	Simulated
Cumulative Oil (MSTB)	3.593	3.776	4.62	4.645	N/A	8.872
Cumulative Water (MMSTB)	1.348	1.186	2.51	2.026	N/A	38.06

Cumulative Gas (MMSCF)	N/A	814	N/A	841	N/A	848
Pressure Drop (psi)	~1000		N/A		N/A	

The prediction indicates additional production of approximately 4 million barrels of oil. **Figure 5** illustrates the oil saturation distribution of the field as of June 1998. The three layers are separated from each other to provide better visualization. The color scale can be seen at the bottom. The first layer clearly indicates the presence of large areas of unswept oil that should be considered for further exploitation. These regions are represented in blue.

A meeting between PetroSantander and University personnel was conducted in May 1998 to discuss the model behavior and the prediction. PetroSantander presented two locations that they suspected had potential for oil production. These sites corresponded with the regions that had unswept oil on the simulated oil saturation distribution. This provided additional support to the accuracy of the model. Two simulated wells were drilled in these areas and their combined output was estimated to be 300,000 barrels from October 1, 1998 through the year 2010. A few additional runs were performed by drilling new wells at other sites that the model indicated had potential. The model predicted economic wells could be drilled at these locations.

Technology Transfer

Technology transfer activities for this project includes the demonstration of data collection and analysis, the importance of a multi-disciplinary reservoir management team, and monitoring waterflood performance such that real-time changes can be made to optimize oil recovery. The following are the technology transfer activities conducted during the past year:

1. A presentation on the Stewart Field waterflood was presented on August 25, 1997 at the annual meeting of the Kansas Independent Oil and Gas Association in Wichita, KS.
2. A presentation on the Stewart Field waterflood was presented on September 11, 1997 at the Noon Kiwanis Club meeting in Lawrence, KS.
3. A presentation titled, "Waterflooding Using Improved Reservoir Management: Stewart Field Case Study", was presented at a symposium sponsored by the University of Wyoming Enhanced Oil Recovery Institute on October 29-30, 1997 in Casper, WY.
4. Presentations on the Stewart Field waterflood were presented to the Tertiary Oil Recovery Project's advisory board meetings on November 7, 1997 in Lawrence, KS and April 7, 1998 in Wichita, KS.
5. Information pertaining to the Stewart Field waterflood was displayed on the exhibition booth for the Tertiary Oil Recovery Project at a workshop titled, "Horizontal Drilling Applications in Kansas", sponsored by the North Midcontinent Regional Lead Organization of the Petroleum Technology Transfer Council on June 16, 1998 in Wichita, KS. A brochure containing detailed information on the Stewart Field waterflood was developed, printed and distributed at the workshop.
6. Operators throughout the area continue to visit the field to view the state-of-the-art waterflood installation and computerized monitoring system.

CONCLUSIONS

A waterflood was designed and implemented for the entire field based on the geological and engineering analysis conducted in Budget Period 1. The waterflood installation includes state-of-the-art computerized monitoring and emergency shut down systems. The installation places special emphasis on production, injection, and pressure data access and recording.

Water injection began in October 1995. To date 6,011,754 BW has been injected resulting in an increase in oil production of 2000 BOPD; total field production is approximately 2260 BOPD. Total incremental waterflood production through June 1998 is 1,145,644 BO.

A PetroSantander reservoir management team, working in conjunction with the University of Kansas, analyzes the production and reservoir data. The existing reservoir computer simulation is updated based on waterflood response data. The analysis results are utilized to optimize the waterflood plan and flooding techniques to maximize the secondary oil recovery.

Chapter 3

Savonburg Field Project

OBJECTIVES

The objective of this project is to address waterflood problems in Cherokee Group sandstone reservoirs in eastern Kansas. The general topics addressed are 1) reservoir management and performance evaluation, 2) waterplant optimization, and 3) demonstration of off-the-shelf technologies in optimizing current or existing waterfloods with poor waterflood sweep efficiency. It is hopeful that if these off-the-shelf technologies are implemented the abandonment rate of these reservoir types will be reduced.

The reservoir management portion of this project involved performance evaluation and included such work as 1) reservoir characterization and the development of a reservoir database, 2) identification of operational problems, 3) identification of near wellbore problems such as plugging caused from poor water quality, 4) identification of unrecovered mobile oil and estimation of recovery factors, and 5) preliminary identification of the most efficient and economical recovery process i.e., polymer augmented waterflooding or infill drilling (vertical or horizontal wells).

To accomplish these objectives the initial budget period was broken down into four major tasks. The tasks included 1) geological and engineering analysis, 2) waterplant optimization, 3) wellbore cleanup and pattern changes, and 4) field operations.

Budget Period 2 objectives consist of the continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. To accomplish these objectives the second budget period is broken down into six major tasks. The tasks are 1) waterplant development, 2) profile modification treatments, 3) pattern changes, new wells and wellbore cleanups, 4) reservoir development, 5) field operations, and 6) technology transfer.

In Budget Period 1, it was determined that the lower B3 zone had not been flooded effectively and contained unswept mobile oil. The in-fill injection well drilled in December 1995 confirmed this assumption. The core results are presented in the July 1996 annual report. In the past year, main emphasis of all tasks was to target water injection into this B3 zone.

BACKGROUND

The Nelson Lease is located in Allen County, Kansas in the N.E. Savonburg Field about 15 miles northeast of the town of Chanute and one mile northeast of Savonburg. The project is comprised of three 160-acre leases totaling 480 acres in Sections 21, 28, and 29, Township 26 South, Range 21 East.

The first well drilled in the location of this project was in 1962. Fifty-nine production wells and forty-nine injection wells have been drilled and completed since 1970. A pilot waterflood was initiated in March 1981 and expanded in 1983. Full development occurred in 1985.

Production of oil in the Nelson Lease in the Savonburg NE Oil Field is from a valley-fill sand in the Chelsea Sandstone member of the Cabaniss Formation of the Cherokee Group. This lease is similar to a large number of small oil fields in eastern Kansas that produce from long, narrow sandstones, "shoestring sandstones" (Bass, 1934), at shallow depth.

The most productive part of the reservoir sand in the lease lies in the eastern half of the SW/4 of Section

21 and is a narrow valley cut to a depth of up to 40 feet (12 m) through the Tebo and Weir-Pittsburg horizons into the Bluejacket A coal (Harris, 1984). The deepest part of the valley is less than 300 m wide. Wells that encountered the most sandstone in the valley are the most productive.

In 1986, eleven gel polymer treatments were implemented successfully on the Nelson Lease. Overall incremental oil recovery was 3.5 barrels per pound of polymer placed which totaled 12,500 barrels. The production increase was not sustained due to wellbore plugging as a result of poor water quality.

Cumulative production through May 1997 has been 380,962 barrels. Of this production, 131,530 barrels were produced by primary depletion. Water injection began in March 1981 and over 249,000 barrels have been produced under waterflood operations. Cumulative water injection is 5,433,490 barrels. The graph of waterflood production and injection data is presented in **Figure 6**. Water-oil ratio since waterflood start-up is presented in **Figure 7**.

In 1993, this Class 1 project started Budget Period 1. The tasks included 1) geological and engineering analysis, 2) waterplant optimization, 3) wellbore cleanup and pattern changes, and 4) field operations, which have been completed and are presented in the 1994 annual report. In that report, the high potential areas for development were defined and are presented in Figure 4.

BUDGET PERIOD 2 ACTIVITIES

Waterplant Development

Air flotation was selected to improve the water quality of the mixed produced-supply water used for waterflooding the Nelson Lease. The original goal of the water quality portion of the Savonburg Project was to select an "off-the-shelf" unit, install, and turnover the daily operation of the air flotation equipment to field personnel. The equipment was designed by the manufacture to remove dispersed oil from the produced water in offshore operations. The equipment was warranted to reduce oil carryover to less than 10 mg/L of water. No specification or warranty was implied as to solids removal from the water. The air flotation unit reduced the oil in water to less than 10 mg/L, however did not effectively remove solids. The target for water quality improvement was that water sent to the field would contain less than 10 mg/L solids in the water and that 1000 barrels of water per day could be processed with two 10-micron bag filters. The failure of solids removal and plugging of the air generation turbines necessitated a study of the equipment, chemistry, and field operational procedures. In earlier reports the cause of air turbine failures was discussed.

The use of venturi tubes for air bubble generation was tried and implemented in the first quarter of 1997 to replace the air turbines. Although there were short periods where acceptable water quality was attained, good water quality could not be maintained for more than a few days. Operating conditions were unpredictable and the chemical system would not separate solids effectively. Consequently, water quality was poor for much of the past year. This is reflected in the large number of workovers required in injection wells as injectivity declined due to the injection of water with high solids content.

In February 1998, an experimental field-testing program was implemented to resolve operating problems and to demonstrate the feasibility of sustained operation of the water-treating unit at acceptable water quality (10 mg/L solids) with an acceptable level of supervision and maintenance by field personnel. The air flotation unit was reconfigured and a workable chemical system was developed. Additional operating parameters were identified which have led to a steady improvement in operation of the water-treating unit over the last three months.

Air Volume. In May of 1998 it was observed that the water quality in terms of suspended solids improved markedly when the unit was operated with a minimum of 4 SCFM air at a water flow rate of 30 GPM. Under these operation conditions 940 BPD of feed water could be processed in 22 hours with 100 BPD of water sent to the waste water tank. After the solids settle in the waste tank, 99% of the waste water is recycled to the feed water tank. A second major observation was made in May. In order to achieve 4 SCFM air flow additional centrifugal pumps were needed to operate the venturi tubes. At the present time there appears to be a major discrepancy between the centrifugal pump pressure-water volume curves and the venturi water flow-air flow curves supplied by the manufactures. Lack of water flow meters has hampered the quantification of water flow through the venturi tubes. The acquisition of water flow meters is pending at this time.

Relocation of Waste Weir. The sticky froth generated by the use of a cationic polymer formulation as the air flotation chemical caused a build up of solids at the water surface along the walls of the tank. Relocation of the waste weir from the edge to the center of the tank reduced the accumulation of solids that occasionally broke loose from the wall and exited with the clean water from the unit. Even though the waste water flow rate is less than 3 GPM, a 6-inch circular waste weir was found to be the minimum diameter to provide maximum water velocity across the lip of the weir without bridging of froth over the weir. The waste weir is a standard 6 to 4 inch PVC pipe reducer. The waste water flows out of the center of the tank through a 4-inch PVC pipe. The drainpipe descends 12 inches before a 90° elbow directs the water through a 4-inch collar installed through the wall of the air flotation vessel. It was noted that a 4 rpm or greater rotation of the water at the surface was required to move the solids to the center of the tank. Ideally, the waste water pipe should exit through the bottom of the tank in order not to interfere with the rotation of the water in the tank.

Three 1.5-inch collars were installed 90° apart, 14 inches above the bottom of the tank. The collars are angled at 45° with respect to the center of the tank. The 1.5-inch MAZZEI 1585-X venturi tubes are screwed into each collar. Water jets from the venturi tubes cause the water to rotate in the tank. The rising air bubbles now sweep the tank from the bottom to the surface. However, it was discovered that having the three venturi jets at the same level caused interference between the jets and caused the waste at the surface to accumulate towards one side of the tank. Thus, only the north and south venturi tubes are used for water rotation and air bubble generation. The water flow rate through the two venturi tubes must be equal in order to keep the froth at the center of the tank.

Dual Role of the Air Bubbles. The placement of venturi tubes near the bottom of the tank and at an angle of 45° to the center of the tank had two benefits. First, the water jets cause a rotation of the water, and second, a portion of the air bubbles rise along the wall of the tank. These air bubbles along the wall help keep the sticky floc from accumulating on the wall below the water surface, and reduce the floc buildup at the surface of the water at the wall. The system consisting of air bubbles with the cationic polymer flotation chemical formulation is working well. When 4 SCFM air was achieved the chemical feed rate had to be reduced and the water became cleaner.

Water Plant Chemical Costs. At the present time the cationic polymer is used at a rate of 0.4 to 0.5 (0.5 pints) pounds per 22 to 24 hour air flotation operational time. The daily chemical cost for the water plant is \$1.50 for cationic polymer (\$24.00 per gallon) and \$3.00 for 10% sodium hypochlorite (\$1.00 per gallon), for a total cost of \$4.50. The hypochlorite is added to the clean water as it exits the air flotation unit to deactivate the cationic polymer, which can blind the bag filters. The excess hypochlorite functions as a biocide controlling bacteria and algae in the filter and clear water storage tanks, especially during the summer months.

Solids Removal. **Figure 8** shows the removal of solids by the air flotation unit using a cationic polymer formulation. The flow rate through the air flotation unit fluctuates on a daily basis. Water fluctuation is caused when the operator makes changes in either the flow of feed water to the unit and/or flow of waste water from the unit. The demand for clean water changes as the water flow changes in the formation or as injection wells are shutoff for various reasons. The graph shows the improvement of water quality when air volume was increased and when the waste weir was relocated from the edge to the center of the tank. Lack of a functioning flow meter on the feed line has prevented quantitative evaluation of the air flotation unit. The flow meter problem is currently being addressed. Operation of the air flotation unit to obtain acceptable water quality on a continuous basis appears to be possible.

Permeability Modification Treatments

During the past year two wells on the Nelson lease were subject to permeability modification treatments. In September 1997 a channelblock treatment was performed on well No. H-14. A sixty-barrel batch of freshwater polymer solution was prepared with salts and thiosulfate added while agitating and hydrating the polymer. Sodium dichromate was added during the treatment at a concentration from 650-750 ppm. The injection treatment lasted slightly less than six hours.

Initial Pressure	450 PSI
Maximum Pressure	662 PSI
Final Pressure	620 PSI
Average Pressure	625 PSI
Polymer Injection Rate	3.64 BPH
Treatment Volume	60 Bbls.
pH of Solution	5.8-6.3
Viscosity	36.0-43.5 cp
Temperature	26.5-29.5° C
Polymer Alcoflood 935	137.5 lbs.
Sodium Dichromate	14.2 lbs.
Sodium Thiosulfate	10.5 lbs.
Sodium Chloride	100.0 lbs.
Calcium Chloride	65.0 lbs.

Offset producers were sampled throughout the treatment for evidence of polymer breakthrough. All tests were negative. The wellhead pressure increased well above prior levels when the well was placed on injection, indicating that the primary water channel was plugged. However, a tracer test conducted five weeks after the treatment indicated communication with H-15 in 23 hours and H-16 in 24.5 hours.

In October a 62 barrel channelblock treatment was performed on well RW-8 due to the injection entering only the B2 perforations. After setting a sand pack over the B3 zone the polymer solution was injected at 41 barrels per day and 540 psi. Sodium dichromate was added continuously at concentrations of 650-750 ppm.

Initial Pressure	420 psi
Final Pressure	500 psi
Average Pressure	500 psi
Polymer Injection Rate	3.68 bbl/hour
Treatment Volume	62 bbls
pH Solution	5.4-6.2
Viscosity	49.5-52 cp
Temperature	27.5° C

Polymer Alcoflood 935	137.5 lbs
Sodium Dichromate	14.2 lbs
Sodium Thiosulfate	10.5 lbs
Sodium Chloride	100.0 lbs
Calcium Chloride	65.0 lbs

A second channelblock treatment was performed six weeks later on November 19. The well was treated with two batches of polymer solution.

	FIRST BATCH	SECOND BATCH
Initial Pressure	335 psi	755 psi
Final Pressure	490 psi	590 psi
Average Pressure	480 psi	585 psi
Polymer Injection Rate	3.6 BPH	3.7 BPH
Treatment Volume	32.6 bbls	31.8 bbl
pH Solution	5.7	5.8-4.4
Viscosity	No measurements taken	
Temperature	51-43° F	11.8-9.3° C
Polymer Alcoflood 935	70 lbs	84 lbs
Sodium Dichromate	6.8 lbs	7.4 lbs
Sodium Thiosulfate	5.25 lbs	5.25 lbs
Sodium Chloride	50.0 lbs	50.0 lbs
Calcium Chloride	32.5 lbs	32.5 lbs
28% HCL Acid	None	2 quarts

Actual injected volume in batch two was reduced to 28.1 bbl.

A month later, on December 20, the well was washed to the plugged back total depth of 675'. An injection test of 3.68 BPH @ 550 psi indicated the treatment did not hold. Four weeks later injection was again attempted in the B2 zone and the well did not take water at pressures in excess of 700 psi. The well was then cleaned out and injection resumed in the B3 zone, through tubing and under a packer.

Pattern Changes and Wellbore Cleanups

Pattern Changes. No major changes were made to the well pattern. Injection well KW-51 and producer H-9 were plugged in February 1998 as both wells were in serious communication with other wells on the lease.

Wellbore Cleanups. After a one-year period of relatively clean injection wells, a large number of wellbore cleanouts were required due to the inconsistency of injection water quality. Prior to the cleanouts, the injection volumes were much lower than normal, resulting in lower total fluid and oil producing rates.

Injectivity improvement was obtained by wellbore cleaning. Clean-up treatments have involved acid and a wide variety of additives. Techniques include hydraulic jetting, jetting with air and foam, placement with a coiled tubing unit, and simply lubricating in the treatments. The principal functions of the acid additive are to remove wellbore emulsion, sludges and deposits, prevent iron precipitation, prevent clay swelling, and the attendant migrations of clays and fines.

A typical treatment involves the following chemicals: 1) 50 gallons of 28% hydrochloric acid, 2) two gallons of an iron control additive (ESA-91), 3) one-half gallon of clay stabilizer (ESA-50), and 4) two gallons of micellar acidizing additive (ESA-96).

During the past twelve months twenty-four wellbore cleanouts were performed at a total expense of

\$17,765.30. This equates to \$683 per injection well for the period.

Reservoir Development

No additional developmental activity has occurred on the lease since an infill injection well was drilled in 1996.

The original proposal included evaluation of the possibility of installing a polymer flood in the Savonburg Field. A reevaluation of the proposed polymer flood is underway.

Field Operations

Field operations consists of 1) monitoring and modifying the waterplant, 2) monitoring all wells and lines in field, and 3) testing each well at least on a monthly basis. During the year, Russell Petroleum has supplied monthly reports, which consist of monthly activities and barrel test/meter reading on active wells.

Russell Petroleum has been responsible for all field activities, 1) plant development, 2) wellbore cleanups, and 3) permeability modification treatments.

Technology Transfer

A mid-year test on Well No. RW-20 proved that successful pressure transient tests could be performed in shallow, slim-hole wellbores utilizing a computerized Echometer (fluid-level detector).

CONCLUSIONS

Operation of the air flotation unit was improved. Solids content of 10 mg/L appears to be attainable in the injected water during continuous operation with proper maintenance and supervision

Chemical costs for water treating were reduced to \$4.50/day or about 0.5 cents/barrel of water.

Permeability profile treatments on two wells were successful in deterring interwell communication and improving wellbore injection profiles, within the scope of this project.

A large number of wellbore cleanouts were necessary due the inconsistency of injection water quality.

A mid-year test on Well No. RW-20 proved that successful pressure transient tests could be performed in shallow, slim-hole wellbores utilizing a computerized Echometer (fluid-level detector).

**STEWART FIELD
FINNEY COUNTY, KS**

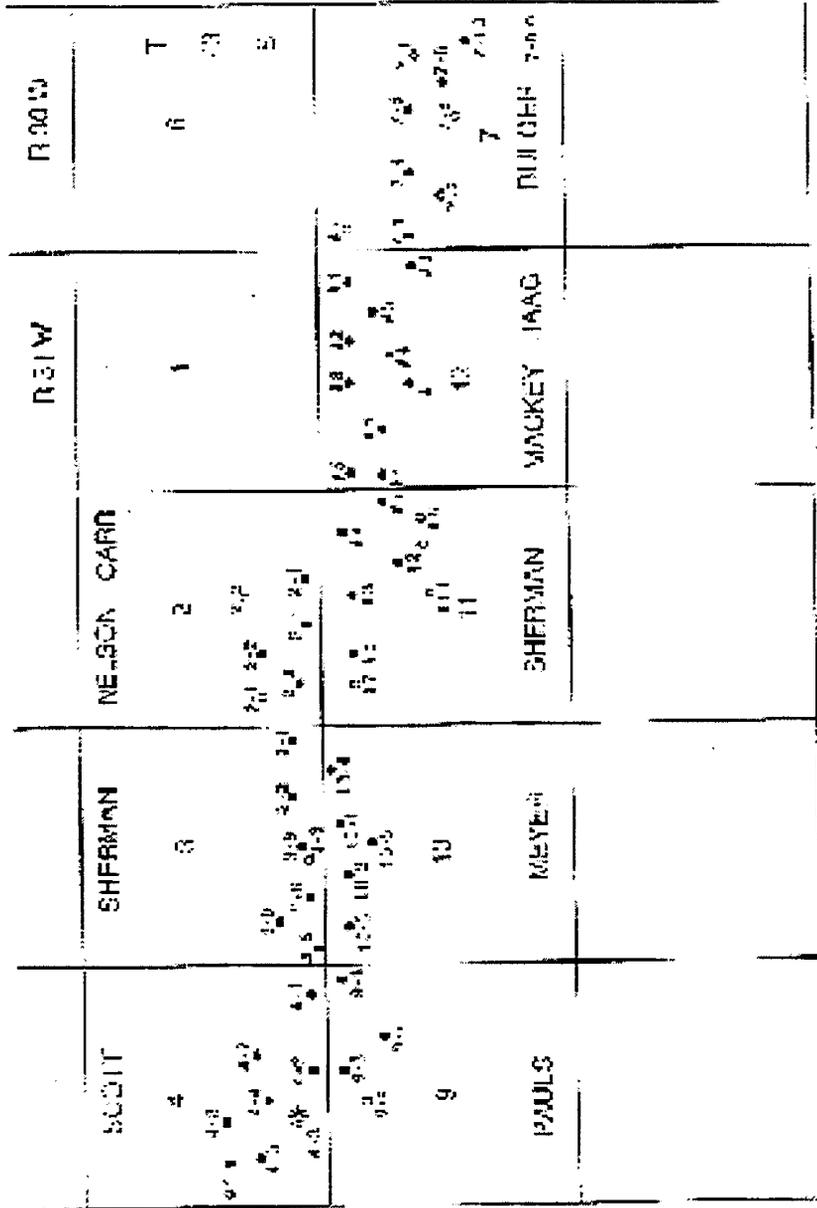


Figure 1. Stewart Field Well Location Plat.

**Field Oil and Water Production
Stewart Field, TCN Simulation**

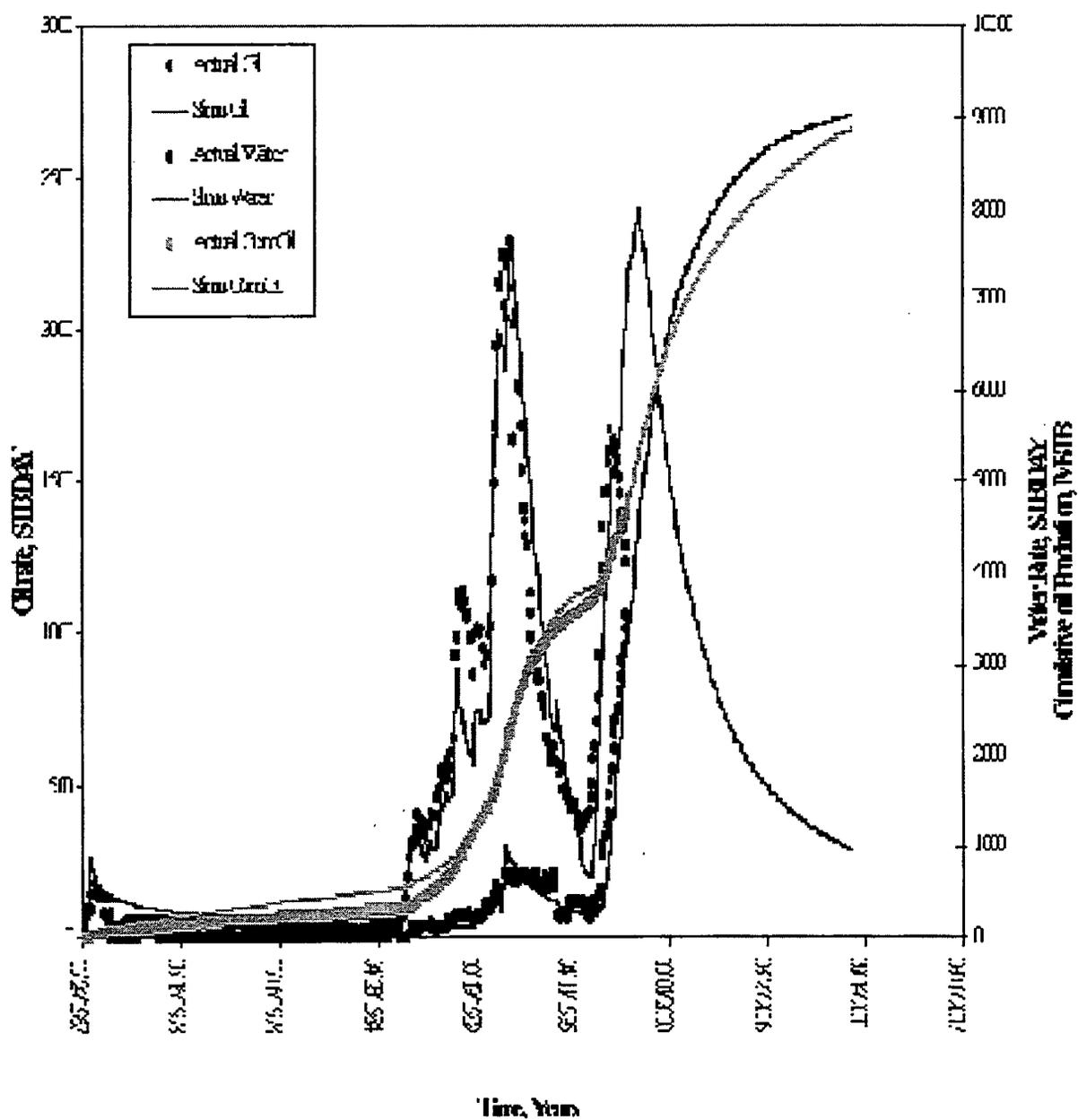


Figure 2. Stewart Field Actual Versus Simulated Primary Production.

STEWART FIELD FINNEY COUNTY, KS

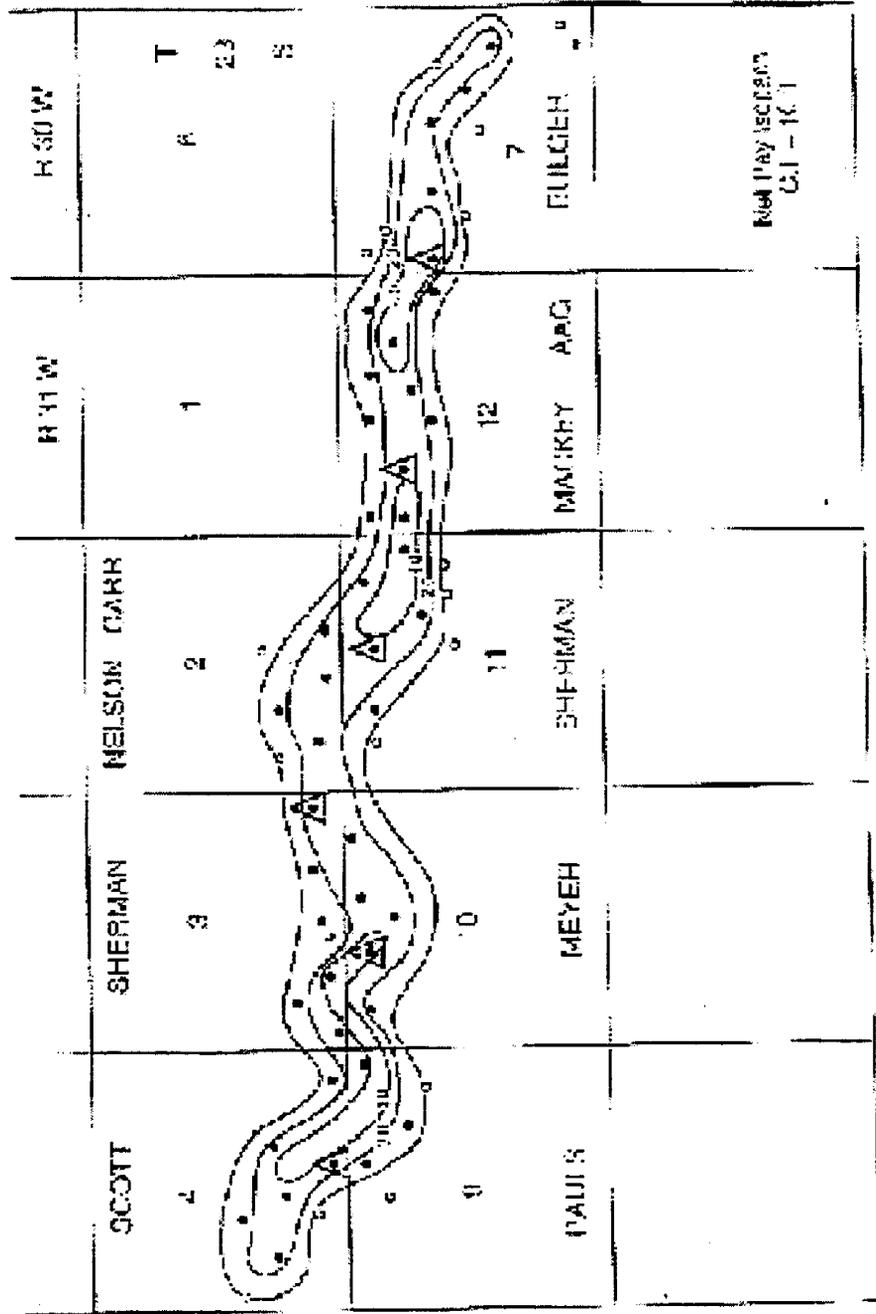


Figure 3. Stewart Field Net Pay Map and Waterflood Pattern Selected for Implementation.

Stewart Waterflood Average Daily Totals

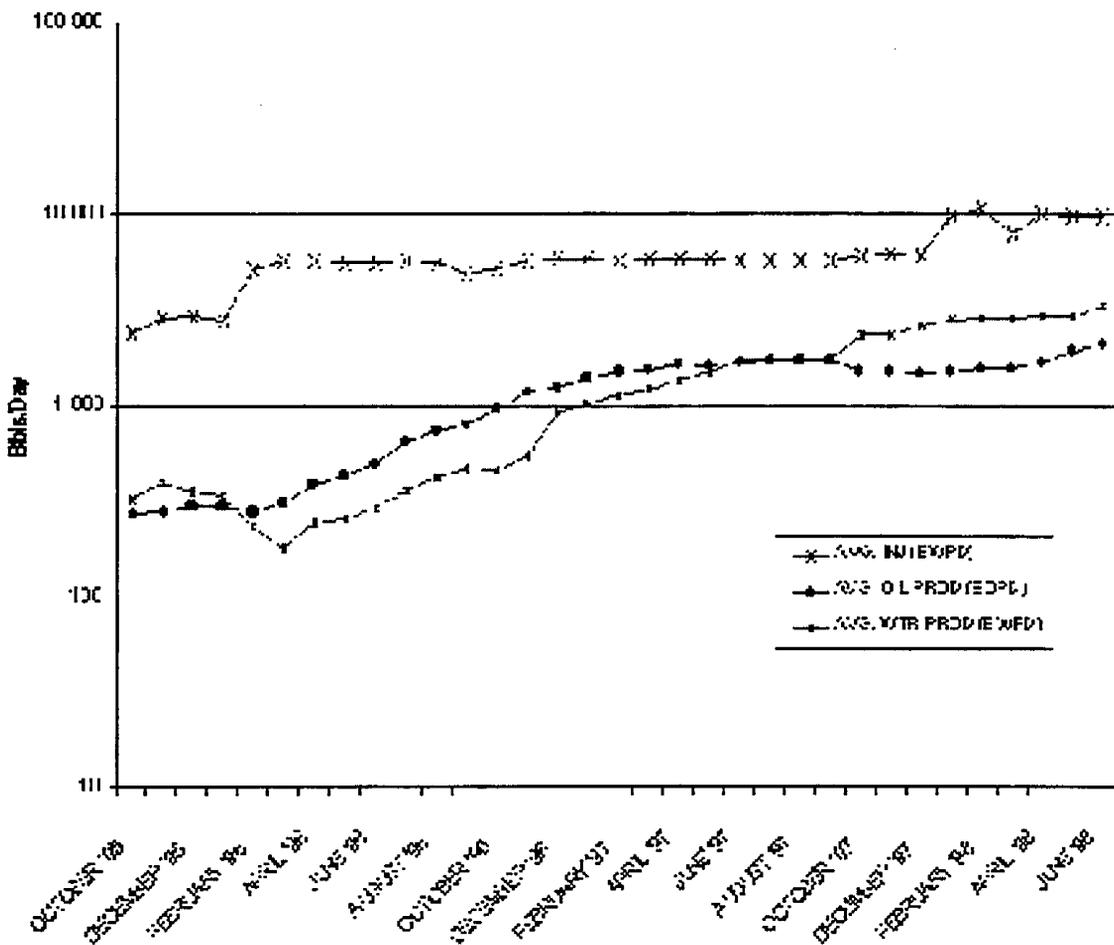


Figure 4. Stewart Field Injection and Production Data Since Initiation of Waterflood.

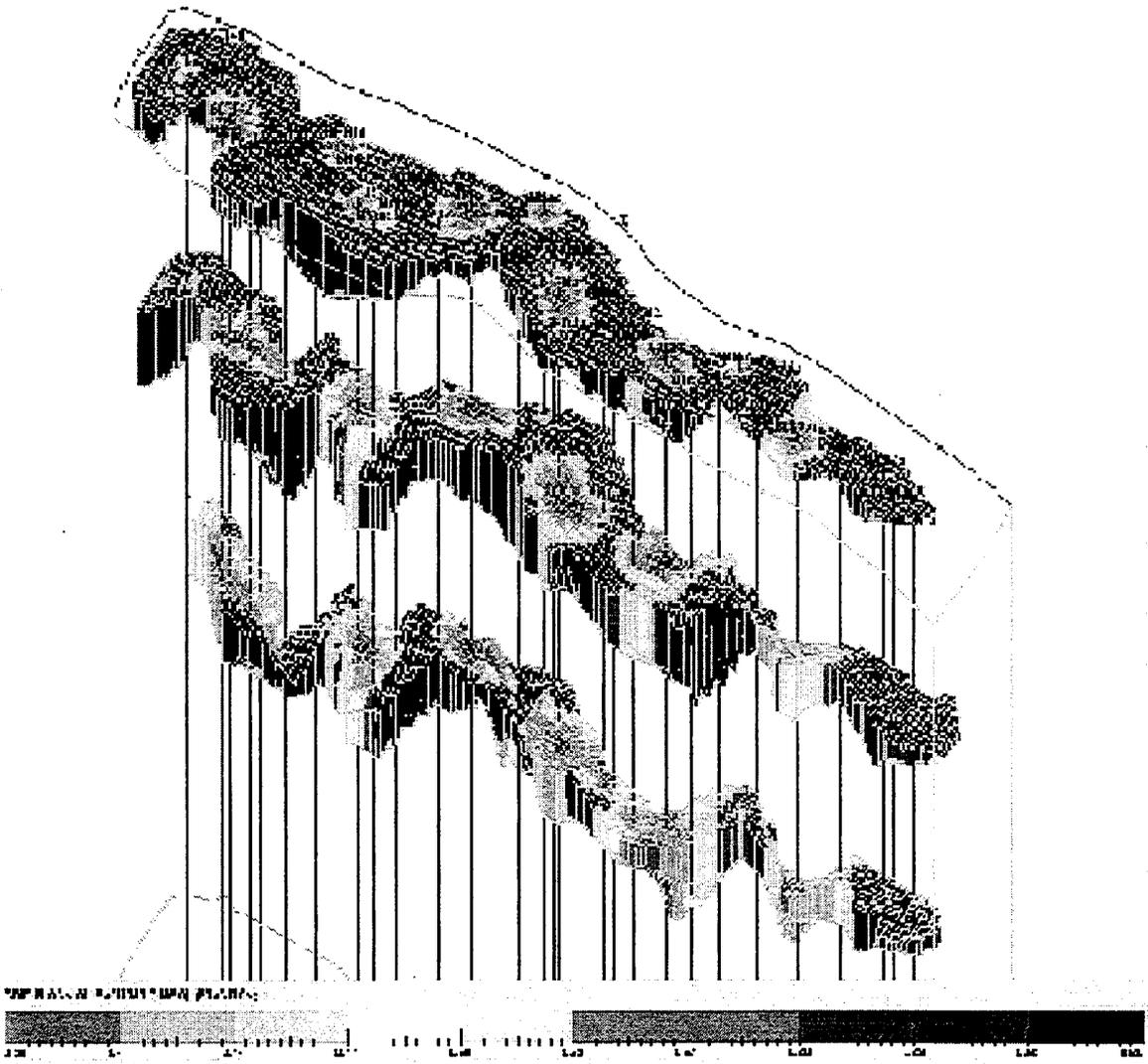
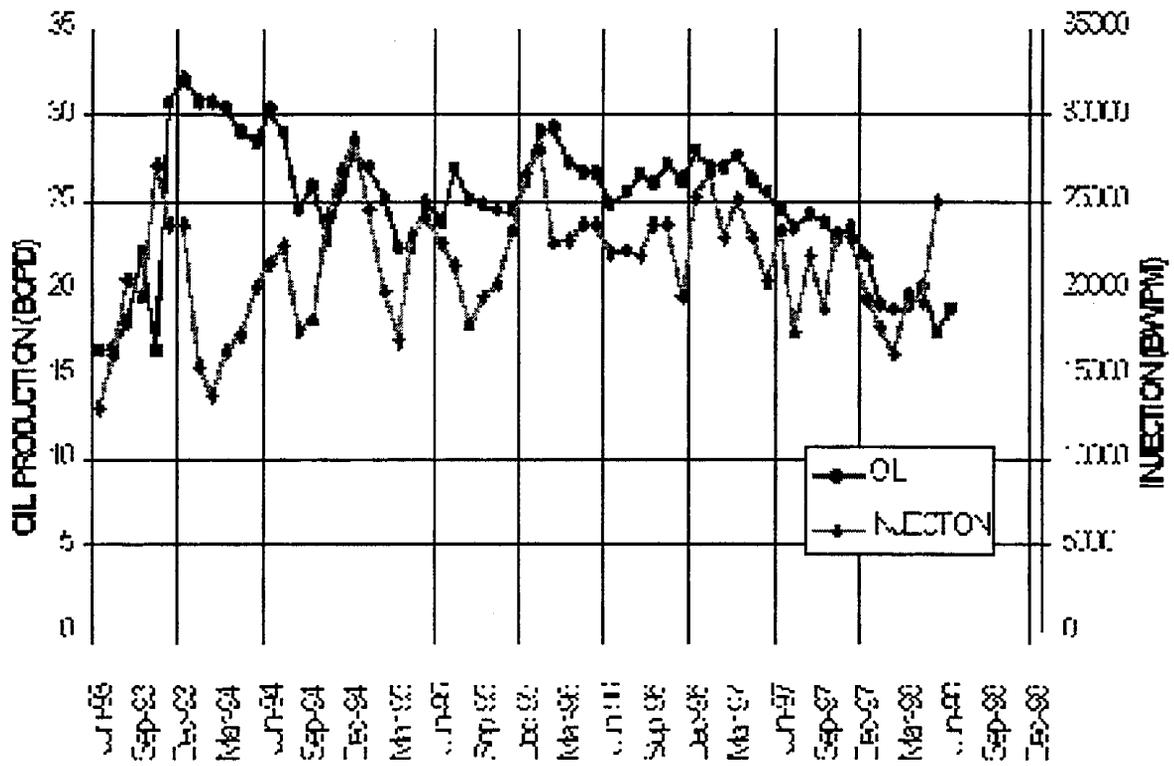


Figure 5. Stewart Field Simulated Oil Saturation Distribution as of June 1998.

NELSON LEASE



NELSON LLASL

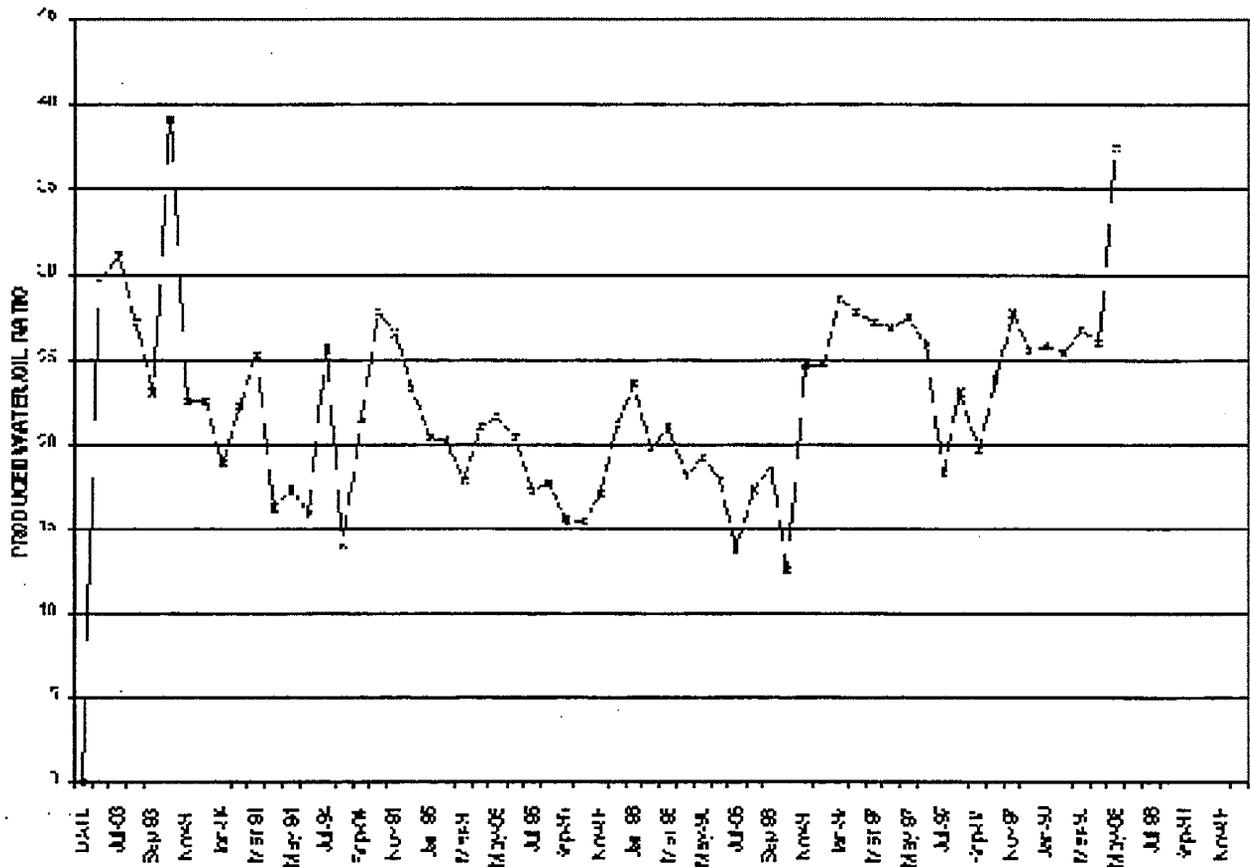


Figure 7. Savonburg Field Water-Oil Ratio.

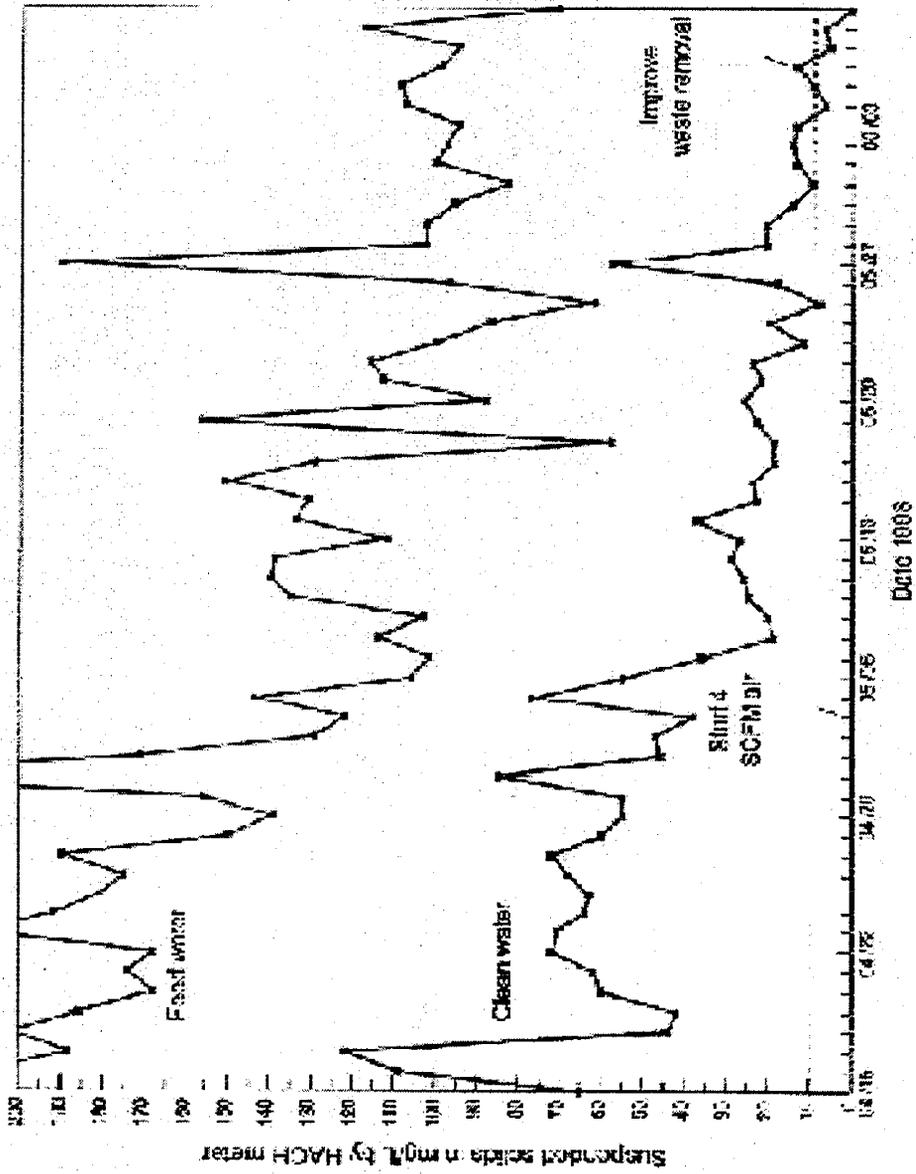


Figure 8. Savonburg Field Comparison of Suspended Solids Content for Water Entering and Existing the Air Flotation Unit.

