FOSSIL ENERGY

DOE/BC/14957-14
(DE96001242)

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

Technical Report for the Period
June 17, 1994 through June 17, 1995

By
University of Kansas Center for Research, Inc.

July 1996

Performed Under Contract No. DE-FC22-93BC14957

The University of Kansas
Lawrence, Kansas

**National Energy Technology Laboratory**
**National Petroleum Technology Office**
**U.S. DEPARTMENT OF ENERGY**
**Tulsa, Oklahoma**

DOE/BC/14957-14
Distribution Category UC-122

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

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# Table of Contents

# List of Figures

# List of Tables

# Chapter 1

# Introduction

**ABSTRACT**
Common oil field problems exist in fluvial dominated deltaic reservoirs in Kansas. The problems are poor waterflood sweep 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 is due to lack of 1) data collection and organization, 2) integrated analysis of existing data by geological and engineering personnel, and 3) identification of optimum recovery techniques.

Two demonstration sites operated by different independent oil operators are involved in the project. The Stewart Field (on the latter stage of primary production) is located in Finney County, Kansas, and was operated by Sharon Resources, Inc. and is now operated by North American Resources Company. 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 type 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, and 6) overcoming problems associated with the unitization process in order that a field-wide improved oil recovery process will be implemented.

Future plans for the Stewart Field project consist of the design, construction and operation of a waterflood incorporated field-wide utilizing state-of-the-art, off-the-shelf technologies in an attempt to optimize secondary recovery. A reservoir management stategy has been developed which will utilize techniques to maximize the secondary oil recovery.

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, and 5) completion of a streamtube waterflood simulation.

Future plans for the Savonburg Field project consist of the continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. The waterflood optimization program is based on project results and will include the field testing of polymer flooding.

## 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 174,308,000 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 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 is due to lack of 1) data collection and organization, 2) integrated analysis of existing data by geological and engineering personnel, and 3) identification of 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 involves performance evaluation. This includes 1) reservoir characterization and the development of a reservoir database, volumetric analysis to evaluate production performance, 3) reservoir modeling, 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 broken down into three major tasks. The tasks are 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 overcome unitization problems in order to demonstrate a field-wide improved recovery process. 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, and 6) overcoming problems associated with the unitization process in order that a field-wide improved oil recovery process will be implemented.

Future plans consist of the design, construction and operation of a waterflood incorporated field-wide utilizing state-of-the-art, off-the-shelf technologies in an attempt to optimize secondary oil recovery. The waterflood design, installation and operation will be based on geological and engineering analysis conducted in Budget Period 1 of this project. The installation design will place special emphasis on production, injection and pressure data access and recording. The operation of the waterflood will utilize advanced data capture and transfer techniques, as well as production and injection well pressure tests. A

North American Resources Company (NARCO) reservoir management team, working in conjunction with the University of Kansas, will analyze the production and reservoir data and update the existing reservoir simulation. The analysis results will be utilized to optimize the waterflood plan and flooding techniques to maximize the secondary oil recovery.

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) 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. The geological and engineering analysis is complete. This 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, and 3) completion of three in-situ permeability modification treatments.

Future plans consist of the continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. The waterflood optimization program will be based on geological and engineering analysis conducted in Budget Period 1. The reservoir model developed in Phase 1 will be continually updated as additional data is collected. The air flotation unit in the waterplant will be monitored and adjusted as problems develop. A Russell Petroleum reservoir management team, working in conjunction with the University of Kansas, will analyze the reservoir and production data and determine remedial work for proper management of the reservoir. A pilot polymer flood will be implemented initially to determine any injectivity problems. If the pilot polymer flood is successful, the waterflood will be augmented with polymer where deemed economical.

# 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 involves performance evaluation and included such work as 1) reservoir characterization and the development of a reservoir database, 2) volumetric analysis to evaluate production performance, 3) reservoir modeling, 4) laboratory work, 5) identification of operational problems, 6) identification of unrecovered mobile oil, estimation of recovery factors, and identification of the most efficient and economical recovery process.

To accomplish these objectives the initial budget period was broken down into three major tasks. The tasks are 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 has been completed and approval has been received to continue this project into Budget Period 2.

Budget Period 2 objectives consist of the design, construction and operation of a waterflood incorporated field-wide 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 is broken down into five major tasks. The tasks are 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.

**BACKGROUND REVIEW**

**History**

The Stewart Field is located approximately 12 miles northeast of Garden City in Finney County, Kansas. The Field is about 1/4 - 1/2 mile wide, 4.5 miles long and covers approximately 2400 acres.

In August of 1967, Davidor and Davidor drilled the Haag Estate #1 well in the NE NE of Section 12-T23W-R31W, attempting to extend Mississippian production found to the northeast in Section 6. This was the discovery well for the Stewart Field. The Haag Estate #1 well was completed from a basal Pennsylvanian Morrow sand from 4755-4767 ft. for 99 BOPD. Davidor and Davidor drilled two additional producers (Haag Estate #2 and Mackey #1) and one marginal well (Mackey #2) in Section 12 (see well location plat in Figure 1).

In 1971, Beren Corporation acquired the lease and attempted to extend the field to the west with the Mackey #3 located in the NE NW of Section 12. The well was drilled in November, 1971 and temporarily abandoned in June, 1972 after minimal production.

In 1985, Sharon Resources, Inc. drilled the Sherman #1 located in C E/2 E/2 NE of Section 11 and penetrated 45 ft. of Morrow sand. This well was completed for 60 BOPD. This resulted in a more active development of the field. Sharon drilled four more producing wells in Section 11 through 1985 and early 1986, followed by two dry holes. Beren drilled two offset wells on the Mackey lease, both near the west line of Section 12. In 1986, Sharon extended the field north to Section 2 (four producers and two dry holes) on the Nelson and Carr leases. In 1987, Sharon continued a westward extension in Section 3 (four producers and two dry holes) and drilled the Bulger #7-1 east of the Haag lease in the C W/2 SW NW Section 7-T23S-R30W. Four producing wells were drilled on the Meyer lease in Section 10, around 1988, followed by wells on the Scott lease, in Section 4, in 1988 and 1989. North American Resources Company (NARCO) leased Section 9 and drilled a total of three producers and one dry hole in the north half of Section 9 during 1988. The eastern end of the field, the Bulger lease, was extended with two more Morrow producers, one St. Louis producer, and three dry holes in 1987.

Some locations were drilled during 1990 and 1991. Competitive forces resulted in development drilling with two additional wells in Section 12, one in Section 4 and three stepout wells in Sections 3 and 10. The Scott 4-8 was drilled in January 1992. During 1994, the final two wells, the Bulger 7-8 and 7-10, were drilled on the eastern end of the field.

The western extent of the field is currently defined by three tight Becker wells on the east edge of Section 5 and a wet Morrow test in Section 8. The eastern extent of the field is not as well defined with a suspected permeability barrier east of Bulger 7-10. Total field development resulted in 43 current producers and 14 dry or abandoned wells.

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. Most wells utilized approximately 450 ft. of 8-5/8 inch surface casing and a DV or stage collar around 2050 ft. with top stage cement to surface. Early completion practices included acid or diesel break-down jobs. Some wells were hydraulically fractured with gelled diesel. In 1990 and 1991, Sharon Resources implemented a field-wide fracture program consisting of a water-based gel with 3,000 to 43,500 lbs. of sand. All Morrow wells have currently been fracture stimulated, with the exception of Mackey #1. All wells are produced with pumping units and insert rod pumps.

Three wells within the Stewart Field were completed as St. Louis producers, namely Bulger #7-2, Sherman #5 and Nelson #2-3. The two latter wells have been recompleted into the Morrow, whereas the Bulger #7-2 remains a St. Louis producer with no Morrow sand present.

**Pressure**

The Stewart Field pressure history consists of drill stem tests (DST's) on 31 producers drilled from August 1987 to October 1991, and two field-wide shut-in surface buildup pressure tests in September 1989 and November 1991. The current average field pressure is estimated to be 100-150 psig.

The first well, the Haag Estate 1, was DST'd 8/14/67 with a final shut-in pressure of 1080 psig. The Haag Estate 2 was DST'd on 1/28/68 with a final recorded pressure of 1102 psig. No extrapolated pressures are available on these wells. Given the good permeability and absence of pressure depletion in the reservoir, the 1100 psig value is considered representative of an initial stabilized reservoir pressure. Subsequent extension wells proved the continuity of the reservoir over the 4.5 mile length of the field.

The initial two wells were drilled on the Mackey lease in 1968, on the west offset quarter section to the Haag wells. Only the Mackey 1 (SE NW Section 12) encountered productive Morrow sand. It tested with 1102 psig bottom-hole pressure(BHP). No further Morrow wells were drilled until the Sherman 1 was DST'd on 7/10/85. This well is near the east line of Section 11 and showed depleted pressures of 847 psig measured shut-in and 862 psig extrapolated. In the 18 years between 1968 and 1985 the two Haag wells and the Mackey well produced 323,196 bbls of oil. The field was extended west with drilling from 1985 to 1992. In 1987 the initial wells were offset to the east with the Bulger 7-1 DST having a final shut-in pressure of 718 psig. The latest Morrow DST producer was the Scott #4-8 which had a static BHP of 300 psig in January 1992. Two additional wells were drilled on the Bulger lease in the latter part of 1993 and early 1994. Pressure data on these wells is not available.

In September 1989, surface measured bottom-hole pressure buildup tests were run on 12 wells after 2-6 days of shut-in (depending on the well) to obtain an average reservoir pressure. Bottom-hole pressure calculations and an isobar map resulted in an average reservoir pressure of 575 psig.

In November 1991, the field was shut-in for 4 days and surface measured bottom-hole pressure buildup tests (6 wells) and static fluid levels (31 wells) were used to calculate bottom-hole pressures. Eliminating wells with high fluid levels due to St. Louis water communication, the field-wide average pressure was planimetered to be approximately 215 psig. Table 1 is a summary of all the DST and surface buildup data for the Stewart Field.

**Production**

Initially most of the wells in the Stewart Field were completed in the Morrow formation. Three wells were initially completed in St. Louis and Ste. Genevieve. Therefore, production is mainly from the Morrow. Production increased approximately eight-fold due to the fracture stimulation work in 1990-1991. As mentioned earlier, the field-wide hydraulic fracture program consisted of water-based gels, with sand volumes ranging from 3,000 to 43,500 lbs. There was also a substantial increase in water production which is believed to be due to communication with the underlying St. Louis formation.

The Morrow wells have produced approximately 3,479 Mbbl of oil and 1,200 Mbbl of water through December, 1994. Using decline curve analysis, extrapolation of this production data indicates estimated primary recovery to be 3.88 million barrels of oil. December 1994 average daily production was approximately 550 BOPD.

Gas production from the Field has been used to power the pumping units and to fire the gun barrels and heater treaters. Gas volumes were insufficient to market and any excess gas not being used on the leases is vented. No gas volume measurements from the field are available.

**Field Data Summary**

| | |
|---|---|
| <u>General</u> | |
| State: | Kansas |
| County: | Finney |
| Location: | Section 7, T23S - R30W and Sections 2,3,4,9,10,11,12, T23S - R31W |
| Well Count: | 43 Producers |
| <u>Reservoir Data</u> | |
| Formation | Morrow |

| | |
|---|---|
| Elevation (Field Average KB) | 2884 ft. |
| Depth to Top of Morrow Sand | 4764 ft. |
| Temperature | 125° F |
| Original Pressure | 1102 psig (estimated) |
| Average Initial Water Saturation | 32.2% |
| Area Within Zero Contour of Net Sand Map | 1,356 Ac. |
| Original Oil In Place (estimated) | 22,653 MSTB |
| Cumulative Production (as of 12-31-94) | 3,478.835MSTB |
| Cumulative Recovery Factor | 15.4% |
| Estimated Ultimate Primary Reserves | 3,881 MSTB |
| Primary Recovery Factor | 17.1% |
| Estimated Incremental Secondary Reserves | 3,738 MSTB |
| Incremental Secondary Recovery Factor | 16.5% |
| Estimated Primary plus Secondary | 7,619 MSTB |
| Primary plus Secondary Recovery Factor | 33.6% |

| | |
|---|---|
| Rock Properties | |
| Lithology | Sandstone |
| Average Thickness | 26 ft. |
| Average Porosity (11% cutoff) | 16.5% |
| Arithmetic Average Permeability (from Cores) | 138 md. |
| Compressibility | $10 \times 10^{-6}$ |
| Archie Equation Parameters: | $a = 1$ |
| | $m = n = 2$ |

| | |
|---|---|
| Fluid Properties | |
| Crude Oil - | |
| API Gravity | 28 |
| Viscosity at $P_i$ and $T_{res}$ | 12.1 cp |
| Initial Solution Gas-Oil Ratio | 37 SCF/STB |
| Gas Specific Gravity | 1.234 |
| FVF at $P_i$ | 1.038 RB/STB |
| Bubble Point Pressure ($P_{BP}$) | 180 psig |
| FVF at $P_{BP}$ | 1.045 RB/STB |
| Compressibility at $P_i$ | $5.83 \times 10^{-6}$ psi$^{-1}$ |
| Avg. Compressibility Above $P_{BP}$ | $7.88 \times 10^{-6}$ psi$^{-1}$ |
| Produced Water- | |
| Resistivity at 125° F | 0.04 ohm-m |
| Chlorides | 55,500 mg/l |
| Total Dissolved Solids | 91,300 mg/l |
| Compressibility at $P_i$ | $3.07 \times 10^{-6}$ psi$^{-1}$ |

## REVIEW AND UPDATE OF BUDGET PERIOD 1 ACTIVITIES

### Geological and Engineering Analysis

***Geology Summary***. The Stewart Field is situated on the northeastern edge of the Hugoton embayment of the Anadarko Basin. Morrowan or Atokan aged sands filled a valley incised into the underlying Ste. Genevieve and Mississippian limestones. This incision occurred during a major fall in sea level at the end of the Mississippian Period. A series of valleys were incised across the westerly dipping shelf along the eastern edge of the Hugoton embayment (Youle et al, 1994). The incised valley is filled with at least three and as many as six stacked, partly eroded liciclastic sedimentary intervals. Each sequence represents a transgressive and regressive succession reflecting flooding and then reemergence of the shelf and valley system. Local erosion and reworking of the sediments is common. The sands may be at least partially sourced from erosion of a local sandy Ste. Genevieve limestone. It is believed that marine reworking of the sands from the west contributed to cleaning up the sands. The Morrow reservoir is found at an average depth of 4780 ft. and average 26 ft. in thickness over 1,036 acres.

Log, core and dipmeter data indicate that the deposits prograded from east to west, landward to basinward. The channel thickens from around 20 ft. in the eastern end in Sec. 7-T23S-R30W to around 45 ft. in Sec. 9-T23S-R31W with a notable exception in the east half of Sec. 12-T23S-R31W, where a suspected karstic feature results in 61.5 ft. of gross sand. The lower half of this sand is poorly developed, possibly due to lack of marine reworking. The channel dips 3 to 5 degrees per mile until the paleogradient steepens in the western end of Sec. 3-T23S-R31W before emptying into a deltaic environment with shale and silty sandstones in Sec. 5-T23S-R31W. Deep fault planes or zones of weakness may have contributed to rapid directional changes of the center of the channel.

Charging of the reservoir is believed to have occurred by migration of hydrocarbons along faults and through porous reservoir rocks from the Woodford shale in the Anadarko Basin to the south. A thick black oil stain is found in some of the core samples, possibly indicative of an earlier hydrocarbon migration. The Morrow reservoir was underpressured in its undeveloped state, but a higher pressure region was tested in the west end.

The lithology is described as glauconitic quartzarenite to quartzarenite with varying grain size distribution from very fine to medium sized grains. In some wells, a coarse-grained conglomerate is reported at the base of the sand. Samples are typically subangular to subrounded, moderate to well sorted with intergranular to intercrystalline porosity development. Quartz overgrowths are abundant. X-ray diffraction indicates 0 - 6 % clay volume with a majority of the clay minerals being smectite along with lesser amounts of detrital chlorite and illite.

The fluvial influence of incised valley fill includes the proximal tributary channel system and the distal thickening and predominate direction of dip of the sandstones towards the west. In addition, the cores show layers of coarse grained, fining upwards successions with numerous instances of cross-bedding within the individual strata.

Episodic marine inundation is indicated by numerous calcareous and fossiliferous sandstone to thin sandy limestones punctuating this valley fill deposit. Even though individual lime streaks cannot be correlated across the whole length of the channel, the Pe curve identifies common no flow boundaries across 4-5 well distances. Core analysis revealed that these lime streaks were impermeable with no oil saturation. An abundance of glauconite, pyrite, coals, shales, marine body and trace fossils and caliche horizons are also found within the sandstone sequences. These components strongly suggest that significant fluctuations of sea level occurred during accumulation of this valley-fill deposit.

***Database Development.*** All the electric log data for the field were digitized into a computer database. The log data were analyzed by digitizing the Morrow interval of the printed logs using a commercial "Logdigi" computer program by "Logic Group". Existing core analyses and log data were analyzed to find a relationship between core porosity versus log porosity and porosity versus permeability. Figures

2 and 3 are plots of core porosity versus log porosity and permeability versus log porosity, respectively. A cumulative porosity plot was used to determine a porosity cut-off as related to net pay. The porosity cut-off was determined to be 11%, which corresponds to about 8% of the total porosity feet. Net pay thicknesses for individual wells were completed using this porosity cutoff value. A net pay map (Figure 4) was constructed for the purpose of the waterflood feasibility study. This map was planimetered to determine the reservoir volume of the Morrow and oil recovery factors.

Water saturation calculations from electric logs were done in order to be included in the database. The water saturations could not be calculated with sufficient accuracy to tabulate values for individual wells. Key problems identified were thin bed effects, thin conductive beds from pyrite cementation material, and conductive chloride clays. Capillary tests on cores were employed to estimate initial water saturation.

Production data for all wells in the Stewart Field was also entered into the computer database. Production data was tabulated by month since the discovery of the Field. The wells have been grouped by tank battery so that allocations for each well can be monitored. The production was allocated to each well by monthly barrel tests. Water production was estimated by applying the percent of water as determined by a grind-out test and relating that to the oil volume produced. The sales numbers for each tank battery were also listed to compare with the production numbers supplied by the operators. Production was divided between Morrow and non-Morrow for the wells that had produced from other zones. Gas production from the Field is minimal and is used to power the pumping units or vented.

The Stewart Field pressure history, including drill stem tests (DST) conducted on 31 wells, two field-wide shut-in surface pressure tests, and individual well fluid level tests were also tabulated into the database. Pressure tests indicate the continuity of the reservoir over the 4.5 mile length of the field.

A log stratification study was completed which indicated the Morrow formation can be divided into as many as eight different flow units. Three main flow units were identified as separate depositional sequences that appear to possess similar porosity and permeability characteristics. Moreover, core descriptions suggest that these three units represent distinct changes in sediment accumulation and sediment supply attributed to changes in relative sea level. Similar stratigraphic patterns are seen in other age-equivalent, incised valley fill deposits in this region. These three flow units correlate along the deepest parts of the channel, with some minor discrepancies within the thinner boundary wells. The three flow units were identified as the Red zone on top, Purple zone in the middle, and Yellow zone on the bottom. The depth and subsea elevation for the top and bottom of each zone was entered into the database for each well.

Porosity and resistivity log data (foot by foot) was cross plotted on log-log paper (Pickett plot) keeping track of depth trends. The three primary zones in the Morrow formed distinct clusters of points on these plots indicating that the zonation identified nicely groups the levels of heterogeneity. While most of the field is above the oil-water contact, several wells in the west half of the field indicate a transition zone and water leg.

Wettability tests, petrographic data, and standard core analysis was compared as a series of plots with log analysis results to define correlations. In particular, relationships between bulk volume water (water saturation and porosity) and relative permeability data, grain size and sorting, and mineral composition (clays) were sought.

Permeability was estimated using different relationships utilizing porosity and water saturation. One method investigated was the Timor relationship. This empirical relationship provided only fair results when comparing measured core permeability versus estimated permeability.

The possibility of open fractures in the Morrow reservoir was evaluated through three potential sources of information: (1) 4-arm dipmeters from the reservoir to examine for borehole breakouts to establish minimum horizontal compressive stress direction. (2) Paleomagnetic measurements of core samples to orient the cores to define directions of any open fractures that might be present. (3) Examination of the oriented core from the Sherman #3. The presence and characterization of fractures helped to define any anisotropy in the reservoir in addition to the influence of sedimentary structures on fluid flow.

***Volumetric Analysis***. Decline curve analysis from existing production data was completed for all the wells within the field. Utilizing a straight exponential decline analysis, calculated remaining primary reserves as of June 1, 1994 are 516,000 barrels of oil for an ultimate primary oil recovery of approximately 3,881,000 barrels. A plot of the field production is shown in Figure 5.

Over the past year a substantial flattening of the production decline has occurred for many leases, as more of the field is affected by gas expansion.

***Material Balance***. Material balance calculations were performed from initial pressure to the 1989 and 1991 field wide tests. Assuming no water influx and pressure above the bubble point, the fluid produced should be due to fluid and rock expansion over the given pressure drop. These calculations give original reserves in excess of 100 million barrels of oil in place. Volumetric mapping of the net sand indicates 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.

Development drilling and seismic data indicate that the reservoir boundaries are defined with reasonable certainty. Therefore, potential pressure support sources were investigated and identified. This was accomplished through the geological examination of well logs and drill stem test data from locations adjacent to the field. A complete collection of well logs from adjoining areas to the field was assembled.

Three potential sources of pressure support were identified. A water aquifer (1) associated with the Morrow formation is present at the west end of the field. Underlying formations, the Ste. Genevieve (2) and St. Louis (3), appear to be in communication with the Morrow reservoir in certain areas of the field.

***Polymer Flood Analysis***. Relative permeability tests were conducted on cores taken from the Stewart Field. Using the endpoints from the relative permeability curves, mobility ratios were calculated. All the mobility ratios calculated based on the average saturation behind the flood front were less than 1.0, which is highly favorable.

Analysis was conducted utilizing the Polymer Flood Predictive Model developed by Scientific Software-Intercomp for the National Petroleum Council's (NPC) 1984 survey of U.S. enhanced oil recovery potential (NPC, 1984). Using average reservoir properties the model did not predict significant incremental amounts of oil recovery for polymer flooding versus waterflooding. Figure 6 is a plot illustrating the results of this analysis. Based on these findings there is no justification for considering a polymer flood for this project.

*Reservoir Modeling*. Independent reservoir simulation studies were undertaken by Sharon Resources and the University of Kansas. Sharon Resources, located in Englewood, Colorado, was connected via Internet to the workstation at the University of Kansas. The studies are being performed using a Silicon Graphics workstation with Western Atlas VIP Executive simulation software. The VIP simulator is a conventional black oil simulator, equipped with a graphics interface. A major portion of the technology transfer associated with this phase of the grant 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, (2) a material balance model to establish a history match with the primary production, and (3) a waterflood predictive model to select the optimum waterflooding pattern for maximum economic oil recovery. The independent studies resulted in different models, however, the two models provide similar results.

**Simulation Conducted at the University of Kansas**

*Data Availability*. Necessary data required for simulation was provided by Sharon Resources. The most important data for reservoir description is the porosity /permeability correlations for the three major zones within the Morrow. These correlations were derived by Sharon Resources and the results of the correlations were used in the simulation for distribution of properties in the reservoir. Relative permeability data representative of the field was also required. This data was also supplied by Sharon Resources.

*Reservoir Description*. The Stewart Field model was developed in stages. Sharon Resources initially identified the three major pay zones in the reservoir. Based on core/log and permeability/porosity correlations they assigned porosity and permeability values to the zones present in all the producing wells. Digitized logs were also provided to get the tops and bottoms of each zone. Initially it was decided to divide the field in four different sections, which were assumed to be isolated from each other. The first section of the field consisted of the Sherman, Nelson, Carr and Mackey leases. These leases comprise 912,000 barrels of oil production from the Morrow, which is approximately 35% of the total field production from the year 1985. The assumptions used to match the production history of this section were also used in the subsequent sections.

Initially it was necessary to assign X and Y coordinates to each well from a zero reference point. The NE corner of Section 10 was chosen as the zero reference point.

To identify the distributions in the regions between the wells, it was necessary to contour the tops, bottoms, porosity, permeability and water saturations of each zone. Data files were created and CPS Radian software was used for contouring. Due to the absence of control points, other than the wells, CPS Radian mathematically extrapolated the reservoir boundaries. In order to get a more accurate reservoir description, about 100 Dry holes were introduced around the reservoir to force a NO FLOW boundary in the desired locations. The necessary files were converted to a format which was acceptable to the VIP black oil simulator's GRIDGENR, a preprocessor program to generate grids graphically for simulation purposes.

***Reservoir Simulation using VIP Simulator***. The VIP black oil simulator was developed by Western Atlas Inc. Its graphic interface enables the user to import geological and other data from various engineering and geological software. GRIDGENR is a utility of VIP which allows the user to import reservoir parameters in the form of contours. Based on the grid system selected, it calculates and assigns values to each grid block.

Using the VIP PRCORE utility, all rock and fluid parameters were input and the necessary data files relating to the formation structure, porosity and permeability distribution were imported into GRIDGENR. The initial simulation grid of 150x20x3 blocks was created and the values were calculated using the program. This allowed creation of the VIP-CORE initialization module file.

Once the initialization file was created, the next step was to create the VIP-EXEC file. This file consists of the history of all the wells which includes location, date of completion, perforation intervals, wellbore radius, skin factor, stimulation history, production history, pressure constraints, and any other information related to the wells. All relevant information was provided by Sharon Resources. Using the VIP PREXEC utility, all data was imported and a recurrent run file was created. The field consists of 44 producing wells.

***History Matching of Primary Production***. The model had the following initial assumptions:

1. Initial reservoir pressure was assumed to be 950-1000 psi (depending on the first date of production in the four sections). No external pressure support was provided.
2. The reservoir was under natural depletion drive.
3. There was no initial skin damage on the wells.
4. Based on the pressure buildup tests an average skin factor of -3 was assigned to each well after the fracture stimulation work.

Several cases were run to get an optimum history match for each section. Similar assumptions were used for the other three sections. 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 sections.

1. Permeability of the reservoir was increased by a factor of 2. Justifications for this could be that there was uncertainty in the porosity/permeability correlations developed using the core/log data or damage to the cores during the drilling process.
2. Reservoir volume was added to the northern portion of the Nelson and Carr leases. This led us to question whether the reservoir boundaries had been properly defined in this area.
3. Outside pressure support was included. It appears most logical that this support was coming from the underlying Ste. Genevieve/St. Louis formations. This results from the primary drive mechanism being a combination of depletion drive and water influx.
4. The initial skin had to be changed to +1 and the average skin after fracture stimulation remained at -3 for all wells. This post fracture skin used in the simulator is in agreement with the pressure transient analysis where the post fracture stimulation skin is within the range of -2.8 to -3.6.
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 the 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.

The model was developed based on the above assumptions. 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.

A model of the entire field was developed. The model was built using a grid of 150x20x4. Each gridblock had average dimensions of 190 x 250 ft. The resulting model had about 2-3 gridblocks between each well. The model contained a total of 12000 gridblocks. The OOIP for this model was 25256 MSTB. This figure does not match with the estimated OOIP based on the net sand map provided by Sharon Resources. One reason for this discrepancy could be the uncertainties associated with the reservoir boundaries. The following parameters were added to the reservoir description to obtain a history match.

1. Water saturations in the four layers:
   Layer 1 : 31 %
   Layer 2 : 31 %
   Layer 3 : 31 %
   Layer 4 : 99 %

2. Vertical permeability distribution within and between the layers.
   Layer 1 : $K_z$ = 0.05 md
   Layer 2 : $K_z$ = 0.01 md
   Layer 3 : $K_z$ = 0.05 md Only at the west end and in Section 12.
   Layer 4 : $K_z$ = 0.05 md Only at the west end and in Section 12.

The vertical permeability in the rest of the field in layers 3 and 4 was zero.

3. Initial pressure for the layers:
   Layer 1 : 1200 psi
   Layer 2 : 1200 psi
   Layer 3 : 1200 psi
   Layer 4 : 1500 psi

These values provided a primary history match in which the simulated production was 95.74% of the actual production. The actual and simulated results are plotted in Figure 7.

This was assumed to be a representative model of the field. This model looks different from the actual field in certain aspects, but behaves much the same as the actual reservoir in terms of the production and pressure history. One of the reasons for possible discrepancies could be the description of the reservoir properties within the interwell region. Many different models are capable of producing a history match for the same field.

***Waterflood Simulation.*** Reservoir simulators have served as an effective tool to predict and design the optimum recovery processes. The VIP simulator has the capability to simulate many of the enhanced oil recovery processes, including waterflooding. During the initial stages of this study it was observed that the mobility ratio was favorable for waterflooding. Thus, there was minimal incremental increase in oil production due to polymer flooding. Polymer flooding was analyzed using the DOE streamtube waterflood/polymerflood predictive model. Based on the results of the predictive model, it was decided to design an optimal waterflood recovery pattern.

*Waterflood Patterns Investigated.* Six different patterns were proposed by Working Interest Owners (WIO) and University personnel. The injection rate was restricted by the water availability of about 6000 BWPD (as informed by Sharon Resources). Thus, in each case the total water of 6000 BWPD was distributed equally between each injection well within the waterflood pattern.

All the patterns were run for a waterflood period of ten years. The production wells were set to a watercut limit of 90%. During the waterflood predictive runs, convergence failures were observed. To avoid excessive failures, timestep control was implemented in the simulation. Timestep control restricts the maximum change in the saturation profiles, pressure, etc, in order to avoid convergence failures by solving the fluid flow equations at small time intervals. This has no significant effect on the calculated results.

*Conclusions of the Waterflood Simulation.* The Stewart Field shows favorable results for waterflood. Simulation results are based on assumptions and accuracy of the field results cannot be achieved. The following conclusions can be derived for waterflood prediction based on the simulation results.

1. Based on the simulations, the cumulative oil production and the WOR for all the patterns would vary by less than 10%.
2. Simulation results suggest that the total oil recovery is a function of the volume injected, but not a strong function of the injection pattern.

**Simulation Conducted by Sharon Resources**

The simulation conducted by Sharon Resources was designed in two phases. A two-dimensional (2D) study was done with radial and linear models using a range of reservoir characteristics and sensitivities. Also a three dimensional (3D) study was conducted to history match the Morrow production history and predict the optimum waterflooding pattern.

***Two-Dimensional Study***. The objectives of the 2D simulation were to study oil recovery changes as reservoir characteristics varied within a range of known field data. This would acquaint Sharon Resources personnel with the simulator, assist in the understanding of the reservoir, and would also help simplify history matching in the 3D simulation. The following objectives were stated:

1. In a radial model, history match a typical fracture stimulation response.

2.(a) In a linear model, study the effect of layering and cross-flow between layers. Study oil recovery as a function of permeability variation and permeability ordering.

(b) Study the impact of wells with St. Louis communication. Study the effect of shutting in first line producing wells at various water cuts and converting them to injectors.

*Radial Model*. Sherman #3 was selected as the well to model via radial simulation. The well has good logs with clearly identified flow units, core analysis, pre- and post-stimulation pressure transient analysis and is an excellent example of the increased production rates obtained from hydraulic fracture treatments. The purpose of the radial model was to history match the fracture results.

Core porosities and permeabilities were used to represent eight layers identified from the logs. Production declined from a peak rate of 47 BOPD in January, 1986 to 3 BOPD in October, 1990. The well was fractured in November, 1990 with 11,000 gallons of 40 lb. Boragel with 1,300 lbs. 100 mesh sand and 18,200 lbs. 20/40 sand. Production reached a stable rate of around 120 BOPD before declining to 13 BOPD in December, 1993. This production response cannot be explained by changing from a +1 pre-frac skin to a -2 post-frac skin factor, but must be augmented by additional thickness opened at the wellbore. An eight layer radial model with 20 concentric cylinders with increasing radii away from the wellbore was used to match production from a 32 acre drainage area. The production could not be matched by depletion drive alone without substantial pressure support. This support is likely water influx, possibly from hydraulic fractures communicating with the St. Louis. It was also necessary to double the core permeabilities to match the actual flow rates.

The after-frac peak production rate was best modelled by adding a large outer cylinder of water reservoir, surrounding the drainage area, to represent an external pressure source. A no-flow boundary was needed to isolate half of the reservoir at original pressure. Half of the thickness was initially perforated, with the pressure support, and allowed to produce down to the pre-frac rate. The fracture was then responsible for opening up the other half of the thickness, releasing oil that was still at original pressure, matching the production increase. This is a plausible explanation as several shale and limestone streaks are evident in the core and pressure support could be seen from different sources.

The external pressure source and isolation of part of the reservoir accomplished the goal of approximating the well's performance. The model did not sustain the peak rate for as long as the actual production, but this can be accomplished by increasing the drainage area. The model requires a pressure constraint at the producing well. The well was allowed to produce at the actual rate if the BHP stayed above 50 psi. If the actual rate was too great and required a pressure lower than 50 psi, the pressure limit was invoked thereby reducing the rate at which the well could produce. The model performance shows that the well is able to produce at the actual rates while keeping the well essentially pumped off as evidenced by the pressure staying above 50 psi but not exceeding 200 psi. The only portion of the plot where the well is unable to keep up with the actual production is the extended peak rate after the frac.

*Linear Model.* (a) *Layering, Cross-Flow, Permeability Variation and Ordering*. The linear model was built using 25 x 5 x 8 gridblocks in the X, Y and Z directions, respectively. Each gridblock is 55 feet in the X and Y direction and 5 feet in the Z direction. One well at each end of the model approximates the 40 acre spacing seen across most of the field. (This is referred to as a 2D model since the purpose of including the Y-direction was to judge the directionality of the solution algorithm and not to describe the width of the channel.) The flow units were described by eight layers, two in the Red (top) and Purple (middle) and four in the Yellow (bottom). Eight layers represent the maximum amount of flow units identified in any well and was felt necessary to adequately describe the reservoir with a proper permeability variation. Since the permeability-porosity transforms are based on log analysis that averages data over several feet, the permeabilities calculated from the logs are too uniform. As an example, Sherman #3 plotted a permeability variation (V) = 0.7 from point specific lab measurements, but V=0.3 based on the log transforms. The linear model was run at V=0.3, 0.5 and 0.7 to quantify how much the log-derived permeability transforms overestimate waterflood performance. The recovery of reserves in a 2D model is very high as each layer will flood out eventually and areal sweep is complete for each case. Therefore, comparing ultimate recovery is not an indication of waterflood performance. The method chosen to compare waterflood performance in the 2D study is the number of months to recover 72,000 barrels of oil. The more efficient floods will have later water breakthrough, thereby recovering more reserves sooner and without the added operational cost of produced water. The V=0.7, 0.5 and 0.3 cases recovered 72,000 BO in 47, 28 and 24 months respectively. The 0.3 permeability variation case recovers the oil in almost half the time of the case with V=0.7.

The different permeability variation cases were all run with 1 md. of cross-flow between layers. The effect of cross-flow on a reservoir with V=0.7 was studied at 0, 1 and 100 md. The model uses the vertical permeability as the permeability to flow between the gridblocks. The 0, 1 and 100 md. cases recovered 72,000 BO in 48, 47 and 27 months, respectively. The no-flow barriers isolate the layers creating different pressure profiles in each layer. Cross-flow between layers allows the pressure to equalize so that a uniform pressure drop from the injector to the producer exists across all the layers. Based on these results, wells with low stratification would make better injection wells.

The impact of permeability ordering was seen to be negligible in the case of wells with no-flow boundaries. This was expected since cross-flow is not occurring and the pressure transients move through each zone individually with no effect of gravity. What was more surprising, however, was the small effect of permeability ordering in the presence of vertical permeability.

Sensitivity to number of layers was tested by comparing a three layer model with the eight layer model to see the validity of representing a V=0.7 with only three layers. The three layers recover 72,000 BO in 37, 31 and 24 months for the 0, 1 and 100 md cases, respectively. This is an improvement of 23%, 34% and 11% over the eight layer model with the same vertical permeability. The difference is caused not from the difficulty of representing a V=0.7 with three or eight data points, but from the vertical permeability. Seven no-flow barriers exist in an eight layer system as opposed to only two in a three layer. At low vertical permeability this causes a considerable difference. Increasing vertical permeability reduces the contribution of the barriers and puts more priority on the permeability variations. At high vertical permeability a three layer system only differs from an eight layer model by 11%.

The continuity of layers must be considered. The low vertical permeability in the Stewart Field would suggest that more layers are required, but if the eight layers are of limited extent it may not be necessary to model that many layers. The following cases are defined as follows:

| | |
|---|---|
| Case 8>3: | Eight layer model with seven no-flow barriers in the injector and two no-flow barriers in the producer. |
| Case 3>8: | Same as above, inject from the other direction. |
| Case 8: | Eight layer model, vertical permeability = 100 md. with two no-flow barriers. |
| Case 3-0: | Three layer model with two no-flow barriers. |
| Case 8F: | Eight layers, vertical permeability = 100 md., communication in all layers near well-bore, two no-flow barriers. |
| Case 3F: | Three layers, vertical communication near well-bore (100 md.), two no-flow barriers. |

Again, comparisons are based on time to breakthrough and time to recover 72,000 BO. Case 8>3, with the more stratified well used as the injector, showed water breakthrough in 12.6 months, two months sooner than Case 3>8. A well with more uniform stratigraphy makes a slightly better injector, but the two cases were not much different. Case 8 had slightly later breakthrough (15.7 months) and recovered the reserves in the same amount of time as Case 3>8. Therefore, it is not necessary to model eight layers if the no-flow barriers are discontinuous.

Case 8 was compared to Case 3-0 to see if a vertical permeability variation of 0.7 is better described with eight layers as opposed to three layers if only three continuous flow units exist in each well. The three layer case has water breakthrough in 15.2 months as compared to 15.7 months for the eight layer, but it recovers the reserves much faster than the eight layer model (35 months vs. 43.8 months). In comparing results with V=0.7, with three vs. eight layers, breakthrough occurs in the high permeability layer at about the same time. The three layer model is more efficient and results in more optimistic results regarding reserve acceleration.

Cases 8F and 3F were designed to study the same effects as above where fractures result in communication around the wellbores. Note, both cases have only two no-flow barriers. The results were similar to the comparison of Case 8 and 3-0 in the preceding paragraph. The eight layer model showed no difference between the fractured and non-fractured cases. The three layer model has a three month delay in breakthrough and recovers reserves three months sooner than the non-fractured. The three layer results are slightly optimistic as compared to the eight layer. Therefore, the configuration used in the 3F case will be used in the 3D simulation.

(b) *St. Louis Communication*. The effect of communication with the St. Louis in a linear model was duplicated by a thick, water aquifer underlying the Morrow. A third well was inserted between the two previous wells in the center block (20 acre spacing). No vertical flow was present between the Morrow and St. Louis except in the one gridblock containing the center well. A vertical permeability of 1.0 md was allowed in the 55 foot by 55 foot block containing the well to simulate the conductivity of a hydraulic fracture into the St. Louis. The pressures in the Morrow and St. Louis were 200 psia and 800 psia, respectively. The cases were run on a V=0.7 and kz=1 md in the Morrow. The center well was shut-in at different watercuts to determine the optimum time to shut-in the well and to observe any cross-flow into the St. Louis.

The first model had a fixed injection rate of 110 BWPD (approximately 1 ft/day advance rate in the reservoir). The center well was shut-in at 0 (not producing), 50, 80 and 98 percent watercut. The cumulative production after one year is 36,000 BO, 36,667 BO, 42,000 BO and 42,000 BO for the 0, 50, 80 and 98 case, respectively. Although producing the first well at high watercuts (80% and 98%) recovers more oil in the first year, producing the injection water is not cost effective as compared to keeping it in the ground. Shutting in the first line producer as soon as it begins to cut water allows the flood front to advance to the next well.

The model allows for injection to be controlled by a constant rate or constant injection pressure. The bottom-hole pressure in the 110 BWIPD case remains low enough that no cross-flow into the St. Louis occurred. Another case was run with the bottom-hole pressure in the injection well held constant at 3000 psia. The rate was allowed to vary to accommodate the pressure. Again, the recoveries were accelerated by producing the center well with the added cost of handling more produced water. A producing well pressure limit of 400 psia on the 40 acre producer was able to keep the pressure low enough at the center well to prevent cross-flow. Therefore, it appears that a communicated well may be shut in without the reservoir pressure building high enough to cross-flow into the St. Louis. This would need to be verified in the field with BHP tests in the communicated wells. Initial water influx from the St. Louis into the base of the Morrow was seen in both cases.

***Three Dimensional Study.*** The 3D study was divided into a material balance (MB) study and a reservoir description study. The objective of the MB portion of the simulation study was to utilize the simulator as a volumetric tool to establish a history match with the primary production. More attention was paid to reservoir volumes and areas of influx than to detailed reservoir description.

The results show that reservoir volume of the Morrow channel is insufficient to match produced volumes from depletion drive alone. The study identified three possible sources of influx that may contribute to the reservoir performance. These sources are 1) a Morrow or St. Louis reservoir communicated at the west end of the channel, 2) a juxtaposed productive Ste. Genevieve found in the E/2 of Section 11, Section 12 and the W/2 of Section 7 and 3) Mackey #3 (a temporarily abandoned well with fracture stimulation into the St. Louis, isolated behind a bridge plug).

The MB simulation was done with a two layer model to reduce computer run time associated with multiple layer models. The Morrow channel for the Stewart Field is represented by a single layer of varying thickness and average reservoir characteristics. The second layer serves as the source for "other" zones that may provide pressure support.

A net sand map was digitized using GridGenerator software included in the VIP Program package. The Morrow interval was mapped on screen and included some dry holes within the area mapped. However, the volume of the map calculated a satisfactory 26,468 MSTB OOIP. The field was mapped to include the production from the Chief operated wells found in Section 8, T23S-R30W. These wells were drilled beginning in July of 1990 and had a discovery pressure around 700 psig. The less than original pressure found in this section may have been an indication of pressure communication with the Stewart Field, but this was later found to be questionable. The final match did not include the estimated 86,000 barrels of oil produced from the Chief wells as part of the MB. The volume mapped for the Chief wells was left in the model to compensate for additional Morrow reservoir beyond the Bulger #7-10 or in the N/2 of Section 7.

A thick (up to 100 feet) aquifer was modelled underlying the Morrow that represents multiple geologic intervals. This "influx" zone was divided into four sections using zero permeability barriers around each section. This was done to prevent pressure communication between the influx zones and to reduce the number of gridblocks required to study three or four layers. The GridGenerator puts an overlying grid on the maps and assigns reservoir parameters to each gridblock including: structure top, gross and net thickness, porosity, water saturation and permeability in the X, Y and Z directions. The grid orientation chosen for this run had 100 blocks along the channel (east - west) and 15 blocks across the channel (north - south) approximately 320 by 320 feet. With 1,500 blocks for the Morrow and the influx zone, the entire model required 3,000 gridblocks.

The Stewart Field was divided by sections with reservoir parameters assigned to each as follows:

| Section | kx-ky-kz | porosity |
|---|---|---|
| 4 and 9 | 150 md | 18% |
| 3 and 10 | 120 md | 17% |
| 2 and 11 | 90 md | 15% |
| 12 | 80 md | 16% |
| 7 | 65 md | 16% |

These values are based on average log calculated data that show an increasing trend in permeability toward the west. The initial pressure of the Morrow was set at 1200 psig and an initial water saturation of 31% was used across the field.

The initial run had no aquifer influx and represented a total depletion drive system in the Morrow. The field recovered 2.11 MMBO (including Chief) as compared to 3.23 MMBO actual production through 7/1/93 (including Chief), or a 65% match.

Due to an increase in water production in the Scott #4-4, #4-5 and on the Pauls lease along with the presence of a permeable, high pressured zone DST'd in the Scott #4-3, the west end was chosen as the first area to introduce water influx. The influx support is represented by a 100% water saturated zone with 5 md. permeability in the X and Y directions with a pressure of 1400 psig. Communication between the Morrow and the aquifer was modelled with vertical permeability between the layers of 0.07 md. over an area of approximately 40 acres on the west end of the field, south of the Scott #4-4 and #4-5 and west of the Pauls #9-3. After trying varying values of vertical permeability, 0.07 md. was selected as the value providing the most pressure support without excessive water production.

The influx from the aquifer supports the early production from 1967 to 1985. In this time period only 3 wells in Section 12 are producing and the withdrawal from the Morrow is small compared to the size of the reservoir. From 1985 on, production increases sharply due to the drilling activity. As the production increases, the water influx becomes less adequate in supporting the producing wells.

Modelling wells fractured into the St. Louis was initially attempted, but water production from these wells caused the pressure in the aquifer to be drawn down too quickly. The influx from the west end was assumed to be from a different source than the St. Louis "C" zone in the fracture communicated wells. The water production from the St. Louis is from an independent zone and contributes little pressure support to the Morrow if the communicated wells remain on production or are only shut-in for short periods of time. Since only the Mackey #5 was shut-in for some of the recent months, modelling the water production from the St. Louis is unnecessary.

The west end influx increased the model recovery from 2.11 MMBO to 2.23 MMBO or 69% of actual recovery. The model was still having trouble keeping up with the post-1985 drilling program. The pre-frac skin was then reduced from +3.0 to +1.5 and the producing BHP was reduced from 50 to 15 psi. The skin was lowered to reduce the severity of the pressure drop from the grid block to the wellbore. Since the wells have historically been "pumped off", the BHP could be lowered to allow for lower fluid levels. These changes increased the model production to 2.49 MMBO, a 77% match.

Having obtained the maximum benefit from the west end influx, the Ste. Genevieve was identified as another source of influx. Many well logs calculate a productive Ste. Genevieve interval underlying the Morrow channel, especially in an area extending from the east half of Section 11 to the west half of Section 7. A study map of the Ste. Genevieve resulted in 1.5 MMBO in place. One section of the influx layer was allocated to represent the Ste. Genevieve. An area extending from the Sherman #1 to the Bulger #7-1 on the south side of the channel was used as the Ste. Genevieve source in the model. It was necessary to use a porosity of 1% and 40% water saturation to obtain an oil volume approximating that of the study map. The low porosity is only a means of adjusting the storage volume in the model and does not affect the flow capacity of the reservoir. The saturation value means both oil and water will flow from the Ste. Genevieve. These values increase the oil volume of the model by 1,703 MSTB for an OOIP of 28,171 MSTB. The Ste. Genevieve was given 0.07 md. communication with the Morrow channel. The Ste. Genevieve influx increased the model history match to 2.53 MMBO or 78% of actual.

In December 1971, the Mackey #3 was drilled and encountered 1 foot of Morrow sand. A fracture attempt communicated with the St. Louis, and the well tested 160 BWPD and was temporarily abandoned. In 1986, holes in the casing were repaired. Fluid levels after swab tests showed pressures to be 900-1100 psig. The well was again temporarily abandoned. Wells have been producing from Section 12 since 1967. In 1985, an offset well in Section 11 (Sherman #1) DST'd an extrapolated pressure (p*) of 862 psig, less than the original pressure. From 1972 to 1986 the fracture in the Mackey #3 has potentially allowed water influx from the St. Louis to cross-flow into the Morrow as the Morrow was being depleted. This represents the third source of pressure support used in the simulation.

Multiple runs showed that a high conductivity fracture between the Morrow and St. Louis in the Mackey #3 could be simulated by allowing 1 md. of vertical permeability in the gridblock containing the well without watering out offset wells. Fluids were allowed to move between the zones due to the pressure differential. No fluids were produced from the well. The simulation of the Morrow channel with these three sources of influx produced 2.57 MMBO through 7/1/93 as compared to an actual 3.23 MMBO (including Chief), an 80% match. Even though oil production only increased 40 MBO, the pressure history match was improved.

Core work performed by TORP on extracted cores from the Sherman #3 and Scott #4-4 indicate sensitivity to water resulting in a reduction in permeability. Meyer #10-4 and Mackey #1 have exhibited lower production rates subsequent to being exposed to water from casing leaks. The coring procedure itself is likely to reduce the permeability found in the routine core analysis due to water and mud filtrate. For these reasons and the need to increase transmissibility along the length of the channel, the permeability in the Morrow was doubled. This brought the model results up to 2.98 MMBO produced, a 92% match.

The fine tuning of the MB simulation case included removing the Chief production from the match and updating the production data to 1/1/94. Adjustments were made to the skin of individual wells to improve each well's match. The final case had a 98% match with 3.19 MMBO (without Chief) compared to the actual production of 3.27 MMBO as of 1/1/94.

Figure 8 shows the cumulative production for each case as compared to the actual. The pressure was also evaluated visually in the 3-D graphic display. Particular attention was paid to reservoir pressure as wells were drilled westward. Although the model pressure of the Sherman #1 was higher than actual (1000+ vs. 862 psig), the majority of the wells in the model were drilled with reservoir pressure around 800 psig. The simulation also showed a reservoir pressure of approximately 800 psig at the time of drilling the western-most wells on the Scott lease. This coincides with the p* of 775 psig exhibited by the DST of Scott #4-4 in January, 1989.

The final MB history match utilized the following parameters:

1. Three sources of water influx
   a. West end, kz=0.07 md, kx and ky = 5 md, Porosity = 12%, Sw = 100%, area of influx approximately 43 acres, pressure = 1400 psig.
   b. Ste. Genevieve, 1.7 MMB OOIP, kz = 0.07 md, kx and ky = 5 md, Porosity = 1%, Sw = 40%, pressure = 1400 psig.
   c. Mackey #3 cross-flow, one grid block with kz = 1.0 md, kx and ky = 5 md, Porosity = 12%, Sw = 100%.

2. A producing BHP of 15 psig.

3. A pre-frac skin = 1.5 and post-frac skin = -3.0 with the following exceptions:
   Bulger #7-4, #7-5 and Sherman #3-5 have post-frac skin = -4.5
   Sherman #5, Pauls #9-1 and Haag #4 have pre/post-frac skin =0.0/-4.5

4. Permeability and porosity values of:

| Section | kx-ky | kz | porosity |
|---|---|---|---|
| 4 and 9 | 300 md | 150 md | 18% |
| 3 and 10 | 240 md | 120 md | 17% |
| 2 and 11 | 180 md | 90 md | 15% |
| 12 | 160 md | 80 md | 16% |
| 7 | 130 md | 65 md | 16% |

5. Morrow pressure = 1200 psig.

6. OOIP Morrow = 26,468 MSTB, Morrow and Ste. Genevieve = 28,171 MSTB

***Waterflood Study***. The 3D reservoir description study was used in a predictive mode to quantify secondary reserves and to select the best pattern for waterflood operations. The objective of the predictive portion of the simulation study was to create a model with the reservoir characteristics that would affect waterflood performance, yet simple enough to maintain the history match found in the material balance portion of the simulation study.

A net sand map for each flow unit (Red, Purple and Yellow) was drawn using GridGenerator. Each zone was mapped honoring all data, including dry holes surrounding the field. The Red and Purple intervals were mapped with a maximum thickness of 10 feet. The Yellow zone was mapped with a maximum net thickness of 30 feet with a 15 foot contour being carried the entire length of the field. At an initial water saturation of 31%, the field was calculated to contain 27.8 MMSTB OOIP. The OOIP includes approximately 1.7 MMSTBO from the Ste. Genevieve leaving 26.1 MMSTB of Morrow oil.

No vertical permeability was allowed for the three Morrow layers except at the wellbore. A vertical permeability of 1 md. was assigned to each gridblock (approximately 300-320 feet square) containing a fracture stimulated well. Permeability was assigned to each zone so as to establish a 0.70 permeability variation. Utilizing the permeability-porosity transform derived from the core-log relationship, the most frequently occurring permeability ordering is the Yellow (bottom) zone with the highest permeability, the Purple (middle) zone with the lowest permeability and the Red (top) zone with the median permeability. The permeability distribution across the field was described as follows:

| | Sec 4&9 | Sec 3&10 | Sec 2&11 | Sec 12 | Sec 7 |
|---|---|---|---|---|---|
| Red (Top) | 300 | 240 | 180 | 160 | 130 |
| Purple (Middle) | 130 | 105 | 79 | 70 | 58 |
| Yellow (Bottom) | 680 | 550 | 400 | 350 | 285 |

Vertical permeability allows cross-flow from the three sources of influx into the Yellow zone. The bottom-hole pressure in each producer was reduced to 10 psig and all fractured wells were given a post-frac skin of -4.5. Increasing the post-frac skins on all wells in reality affected only a few wells, since most were limited by their actual producing rate. The pre-frac skins were retained from the material balance simulation study.

This predictive model was first run to compare the history match by using the same three sources of influx described in the material balance study. Ninety six percent of the historical production was matched with the new and more detailed model.

Several injection patterns were modelled. Each pattern was modelled with 6,000 and 10,000 barrels of water injected per day (BWIPD) for the field. The two injection rates were chosen to see the effect of injection rate and to bracket the range of available source water which is unknown until the waterflood is implemented. The injection volume was equally distributed among the number of injection wells with a maximum allowable BHP of 3000 psig. A favorable mobility ratio allows oil to move more easily than the water. As the reservoir fills with water, the injectivity goes down. The field injection curves show that the maximum rate (6,000 or 10,000 BWIPD) is sustained for two to four years until injection wells become pressure limited. The three line drive pattern was not modelled with 10,000 BWIPD because of an insufficient number of injection wells to allow such a large volume. The majority of the net present value of the waterflood occurs in the first five years. The predictive model was designed for a ten year life with all producing wells being shut in at an 80% watercut. Reserves are recoverable at a higher watercut, but would be recovered late in the life of the project having a small effect on the NPV. The 3-, 5- and 7-line drive patterns were chosen in order to select the optimum number of line drives. An additional run was made on the 5-line drive pattern where the producing wells are shut in at a 20% watercut and then returned to production on 7/1/97 and produced to a 97% watercut (labeled 5 L-D 20/97). Each pattern is associated with a different oil and water production curve, capital requirement and operating expense. Once the optimum number of line drives has been established, the results of the 2D simulation and the reservoir characteristics can be used in selecting individual wells in the final pattern.

The cases run with the high injection rate exhibit higher peak oil rates and earlier water breakthrough. The low injection rate cases break through later and recover more reserves. The ten year reserves and the recovery factors for the different cases are as follows:

| | Waterflood Recovery | Recovery Factor |
|---|---|---|
| 3 L-D | 2,986,000 | 11.4% |
| 5 L-D Lo | 2,776,000 | 10.6% |
| 5 L-D Hi | 2,764,000 | 10.6% |
| 7 L-D Lo | 2,796,000 | 10.7% |
| 7 L-D Hi | 2,713,000 | 10.4% |
| Beren Hi | 2,710,000 | 10.4% |
| 5 L-D 20/97 | 3,622,000 | 13.9% |

***Economic Analysis.*** Cost estimates were prepared for the purpose of determining a waterflooding pattern that optimizes the net present value. Higher water injection volumes will recover secondary oil reserves sooner, but at higher capital and operating costs. Price quotes were obtained from supply and service companies on major items in order to approximate total costs. Extensive cost analyses were performed on injection lines, injection wells, potential water supply sources, waterflood plant, and tank battery consolidation.

Footages for the injection lines were estimated for the different patterns. Bids were obtained for different materials for injection line pipe and downhole tubulars in the injection wells. The three possibilities investigated were: (1) fiberglass, (2) coated steel lined pipe, and (3) PVC lined tubing.

Extensive cost analyses were performed on potential source water for the waterflood. Six potential water sources were identified and are summarized as follows:

Ogallala - A fresh water formation 300 feet deep with an estimated potential of 10,000 barrels of water per day (BWPD). Positive aspects are cheap lifting costs and the Conservation Reserve Program may help make water available. Negative aspects include field cores have displayed sensitivity to fresh water and a political issue with farmers concerning depletion of irrigation water source.

Glorietta - A saltwater formation 600 feet deep with an estimated potential of 1,500 BWPD. The formation is currently being used for saltwater disposal. Positive aspects are three existing saltwater disposal wells could be converted to supply wells and economical lifting costs. This water was successfully used in the Ingalls Field at minimal capital outlay. Negative aspects are sand production problems and the expense involved to treat this water.

Topeka - A saltwater formation 4,400 feet deep with an estimated potential of 1,000 to 1,500 BWPD.

Morrow/St. Louis - Approximately 670 BWPD is currently being produced from Morrow and Morrow/St. Louis commingled wells in the field.

St. Louis - Two production wells in the field are completed in the St. Louis. These wells produce approximately 200 BWPD. This formation is approximately 5,000 foot deep and the water is very corrosive.

Devonian/Ordovician - A saltwater formation 5,700 feet deep with an estimated potential of 10,000 BWPD. Water quality from this formation is unknown.

The maximum design rate of 10,000 BWPD injection could be met several ways. Total cost per barrel of water produced was calculated from the potential sources including capital and operating costs. These costs included drilling and completion, appropriate pump size, electrical usage, service life, chemical usage, etc. It was determined a deep water source that can deliver all the water required is more economical than drilling numerous shallow, lower-deliverability wells.

Cost estimates were conducted for the water injection plant. The cost estimates include supplying electricity to the plant site, plant costs and injection pumps. Plant costs included the plant building, filtration system, valves, gauges, emergency shut-off systems, alarms, etc.

The preliminary design calls for the consolidation of the existing 19 tank batteries to three satellite batteries. Consolidation of the production facilities will result in the following benefits: (1) replacement of inefficient or inadequately sized equipment, (2) relocation of facilities to achieve operating and production data gathering efficiencies that will save on manpower and maintenance, (3) less potential for environmental damage, and (4) simpler produced water collection and handling.

Total capital costs used in the economic analysis for the installation of the waterflood ranged from approximately $1.4 to $1.7 million dollars. The range is due to variables associated with the different patterns investigated (length of line pipe, number of injection wells, etc).

Economic analyses were ran on all the waterflood patterns investigated in the simulation study. The economics were run based on 100% working interest with an 80% net revenue interest. The price of oil was held constant at $18.00 per barrel. The lease operating expense was $1600 per well per month. The economics were run using six month time units instead of yearly production to more accurately reflect discounting of future production back to the initial time of investment.

The lease operating expense included a fixed cost for the water injection plant operation, a variable water handling expense and a fixed per well cost. Injection water was made up of both water supply and produced water. The early life of the project primarily uses injection water from the supply well. As the production wells begin to produce water, this water is reinjected requiring less water from the supply well. The produced water was reinjected at one-third the cost of the water from the water supply well. Initially, all wells were shut in when they reached an 80% watercut. This prevents the producer from starving the flood front and allows the front to move to the next producer. Later, all the wells are reinstated to producing status and allowed to produce to a 97% watercut.

When the production profile of each pattern was subjected to the assumptions of the economic analysis, some of the production was below the economic limit. Thus, only economically recoverable reserves were used in the economic analysis. The net present value of the economic reserves were ran at discount rates of 10 and 40 percent.

Due to the favorable mobility ratio, the reserves recovered are similar for most patterns. The different patterns recover oil reserves at different rates throughout the project, since oil recovery is primarily a function of the volume of water injected. The net present value of economic reserves at a discount rate of 10% for the different patterns ranged from approximately \$23 to \$27 million dollars and at a discount rate of 40% ranged from approximately \$11 to \$17 million dollars. The sensitivity of the net present value to oil price was also investigated and is illustrated in Figure 9.

## LABORATORY TESTING

### Commercial Laboratories

Cores were recovered on the following six producing wells: Meyer #10-1, Scott #4-4, Scott #4-8, Sherman #3, Sherman #5 and Pauls #9-2, with a directional whole core routine analysis performed on Sherman #3. The other five wells were analyzed with plug analysis.

A special core analysis was run by Core Laboratories on the Meyer #10-1 with steady-state relative permeability tests on four extracted samples. The cores represent a slight water-wet condition. Connate water saturations ranged between 18 and 29%, whereas residual oil saturations varied between 33 and 42%. Formation compressibilities were measured over a range from 2400 to 800 psig to be $10X10^{-6}$ $psi^{-1}$. No apparent water sensitivity was experienced.

Laboratory tests were also conducted on preserved cores taken from the Stewart Field. These tests were conducted by Surtek, Inc. located in Golden, Colorado. The tests consisted of a fluid-rock linear core study to determine the relative permeability characteristics using reservoir fluids. Capillary pressure was determined by mercury injection method. The linear corefloods also define the initial and residual oil saturation, effective and absolute permeability, fractional flow, wettability of the reservoir rocks and the mobility ratio between water and oil. The capillary pressure test results were used to calculate the pore size distribution and saturation data.

The average initial oil saturation from three linear corefloods using the Scott #4-8 core was 71% and the average waterflood residual oil saturation was 44%. The average oil recovery was 38% OOIP.

The average initial saturation in the laboratory for two relative permeability determinations was at 0.67 PV, and the waterflood residual oil saturation was 0.48 PV for a recovery of 35% OOIP.

The mobility ratio averaged 1.0 using endpoint permeability and saturation values for water displacing crude oil. This indicates that water is a good fluid for displacing crude oil.

Fractional flow data from the two relative permeability tests indicate the producing water-oil ratio will be approximately 3.5 after water breakthrough. The average oil saturation at water breakthrough would be 0.62 for 7.5% OOIP recovery at breakthrough. Assuming an economic limit of 99% water, the average residual oil saturation would be 0.509 or a total of 24% OOIP recovered economically by waterflooding.

Total waterflood recovery in Coreflood 2 was 40.6% OOIP, and in Coreflood 3 was 30.1% OOIP for an average recovery of 35.4% OOIP. This indicates that approximately 11.4% of this waterflood oil cannot be recovered economically.

Mercury injection capillary pressure curves generated on the Meyer #10-1 and Sherman #3 cores suggest that the average initial non-wetting phase saturation would be 76% of the pore volume. Using the imbibition curve, the change in oil saturation by both primary production and waterflooding processes will be about 31%.

**University of Kansas Laboratory**

The objective of the laboratory testing conducted at the University of Kansas was to analyze the water sensitivity of Stewart Field cores. Initially the testing was to be done to determine the reservoir sensitivity to the proposed injection water. However, in the early stages of the testing, it was determined that the reservoir rock displayed sensitivity to formation brine. The following summarizes the results of these experiments.

***Introduction***. Water sensitivity analysis of Stewart Field cores was conducted through permeability measurements of the cores. Core plugs of known dimensions were cut, evacuated and saturated. Permeability measurements were made on these cores using different solutions at room temperature (X68°F) and reservoir temperature (125°F). Experiments were performed on the core plugs from the following wells:

(i) Scott #4-4 (depth 4796 ft.)
(ii) Sherman #3 (depth 4781 ft.)
(iii) Meyer #10-1 (depth 4800 ft.)

The following solutions were used for performing permeability measurements:

(a) 2.0% sodium chloride
(b) synthetic formation brine (composition given in Table 2)
(c) injection water (proposed)
(d) filtered produced water from Scott #4-5
(e) 3.0% potassium chloride
(f) 500 ppm aluminum (aluminum citrate)

**Table 2: Composition of Synthetic Formation Brine**

| Salt | Concentration (mg/l) |
|---|---|
| NaCl | 76,470 |
| $NaHCO_3$ | 430 |
| $Na_2SO_4$ | 1,700 |
| $CaCl_2.2H_2O$ | 15,010 |
| $MgCl_2.6H_2O$ | 9,930 |

pH adjusted to 6.5

***Experimental Procedure***. The core plugs were cut with approximate dimensions of 1" length and 1" diameter. The plugs were cut using fresh water unless otherwise specified. The core plugs were then evacuated and saturated with the desired solution. The experimental set-up consisted of placing the core plugs in a rubber sleeve within a metal casing. The rubber sleeve was subjected to a pressure of approximately 200 psi, which resulted in an air-tight seal around the plug. This was done in order to ensure no bypassing of the plug by the injected fluid.

The injection fluid was pumped into the core and the flow rate was measured by collecting the fluid from the effluent line. The pressure drop across the core was measured using two pressure ports situated upstream and downstream of the core, which were connected to a transducer to measure the pressure differential. Experiments were performed at room temperature and reservoir temperature by placing the apparatus in a water bath maintained at 125°F.

***Results of Permeability Measurements***. This section gives a brief summary of the results obtained from the permeability measurements of the core plugs from the three wells. Preliminary experiments were performed on Berea core plugs to validate the measurements by the apparatus being used.

Figure 10 shows the results of the experiment performed on a core plug from Scott #4-4. The core was injected with synthetic formation brine at 125°F. The results show the relative permeability as a function of the pore volumes injected. A continuous decrease in the permeability was observed for the entire injection period. Figure 11 shows similar results for a core plug from Sherman #3 injected with filtered produced water from Scott #4-5 at 125°F. The plug was continuously injected with produced water for a period of four days and a continuous decrease in permeability was observed. Figure 12 shows the results of the experiment performed on a core plug from Meyer #10-1. The core was injected with 3.0% potassium chloride solution at 125°F and for the entire injection period a continuous decrease in permeability was observed.

From the results obtained it was observed that there is a reduction in permeability for all the field cores. This behavior was observed with all the injection fluids at reservoir temperature, indicating a high sensitivity of the cores to the injection fluids.

***Conclusions***. Permeability reduction of at least 50% will occur in the immediate vicinity of the wellbore where large volumes of water flow through the porous rock. Consequently, there will be in an increase in the skin factor and decrease in the injection rates with time in water injection wells.

## UNITIZATION

A critical task associated with the initial budget period of this project was the unitization of the field. Unitization needed to occur in order to implement a field-wide improved oil recovery process. Initially, there were three operators and multiple working and royalty interest owners owning production interests within the field. A minimum of 75% of all interest owners needed to be in agreement on equity issues in order for the field to be unitized.

The Kansas Corporation Commission is the governing body concerning unitization in the State of Kansas. If 100% of the working and royalty interest owners agree to a unit operating agreement, then formal unitization by the Kansas Corporation Commission for waterflooding operations is not required. If 100% agreement cannot be reached, then a minimum of 75% of both working and royalty interest owners would have to be in agreement prior to initiating forced unitization proceedings with the Kansas Corporation Commission.

A technical committee was formed in order to help resolve some of the equity issues. Regular meetings and correspondence took place between the technical committee members and the working interest owners throughout the duration of this project. Difficulties arose concerning resolving equity issues necessary for unitization, with one major issue being the selection of the unit operator.

North American Resources Company (NARCO) resolved the unitization issue by offering to purchase the working interest of the other operators in the field. NARCO was successful and purchased 100% of the working interest in the Stewart Field. NARCO is currently in the process of acquiring agreements with the royalty interest owners in the field and filing for a hearing with the Kansas Corporation Commission, which will finalize unitization of the Stewart Field.

## BUDGET PERIOD 2 ACTIVITIES

### Summary of Plan

Budget Period 2 activities consist of the design, construction and operation of a waterflood installation that is safe and meets environmental standards. The waterflood will be incorporated field-wide utilizing state-of-the-art, off-the-shelf technologies in an attempt to optimize secondary oil recovery. The waterflood design, installation and operation is based on geological and engineering analysis conducted in Budget Period 1 of this project. The installation design will place special emphasis on production, injection and pressure data access and recording. The operation of the waterflood will utilize advanced data capture and transfer techniques, as well as production and injection well pressure tests. A North American Resources Company (NARCO) reservoir management team, working in conjunction with the University of Kansas, will analyze the production and reservoir data by using reservoir characterization techniques and by updating the existing reservoir simulation. The analysis results will be utilized to optimize the waterflood plan and flooding techniques to maximize the secondary oil recovery. Technology transfer activities will include 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.

### Detailed Statement of Work

*Task No. II.1 Design/Construct Waterflood Plant.*

1. Design and implementation of a state-of-the-art waterflood plant. The waterflood plant will consist of an all weather insulated building and water-supply tankage. The building will contain the injection pumps and motors, filtering equipment, suction and discharge piping, pressure recorders, flowmeters, electrical wiring and controls and small work/storage area. The final plant design will

be accomplished by NARCO with technical input by the University of Kansas and equipment suppliers as required. The preliminary injection pump design calls for two quintiplex positive displacement pumps capable of injecting up to a total 10,000 BWPD at 2000 psi. The use of two pumps will add flexibility to the proposed 6000 BWPD injection volumes while maintaining a significant standby capability at the plant should one of the pumps experience mechanical problems. The plant will also incorporate a water filtering and treating system to minimize solids plugging and precipitation in the formation. The electrical system will incorporate emergency shutdown and alarm devices to promote safety and environmental compliance.

*Task No. II.2 Design/Construct Injection System.*

1. Design and implementation of drilling, completing and equipping of water supply wells. Preliminary design calls for drilling two supply wells and converting an existing wellbore to a supply well. Supply wells will be equipped with electrical submersible pumps to supply a total of approximately 6000 BWPD. Final design and number of supply wells will depend on well productivity and water quality.

2. Design and installation of water injection lines from the waterflood plant to the water injection wells. The geometry of the Morrow reservoir at Stewart Field (5 mi x .5 mi) lends itself to the design of a trunkline injection system along the length of the field with short laterals branching from the trunkline to the individual injectors. The preliminary design calls for 2500 psi working pressure fiberglass pipe for all injection lines. The majority of the trunkline will be 4" pipe and will be reduced to 3" as it nears the ends of the field. The short laterals to the individual injectors will be 2" pipe. All the injection lines will be buried 3x4 feet.

3. Design and implement the conversion of producing wells to water injectors. The conversion work will include changing out the existing tubulars and installing new tubulars and downhole equipment in each injector. Some "clean-out" well work is also anticipated during the conversion process. The preliminary design calls for an initial six wells to be converted to injectors. The new tubulars in these injection wells will be internally plastic coated to reduce the chance of a tubing leaks due to corrosion. Each injector will be equipped with an injection meter and pressure recorder. New valves, chokes and wellhead equipment will be installed on each injector to adjust or shut off the rate of injection.

*Task No. II.3 Design/Construct Battery Consolidation and Gathering System.*

1. Design and implementation of consolidation of tank batteries. The preliminary design calls for the consolidation of the existing 19 tank batteries to three satellite batteries. Consolidation of the production facilities will result in the following benefits: (1) replacement of inefficient or inadequately sized equipment; (2) relocation of facilities to achieve operating and production data gathering efficiencies that will save on manpower and maintenance; (3) less potential environmental damage; and (4) simpler produced water collection and handling.

2. Design and install gathering and production test lines to facilitate the consolidated tank batteries. Additional test lines and headers will be installed to aid in the accuracy of individual well production information and data gathering. Additional gathering lines will be required to handle the additional production volumes anticipated.

*Task No. II.4 Waterflood Operations and Reservoir Management*

1. NARCO is planning on conducting the secondary recovery field operations of the Stewart Field

with a full-time company lease operator and a part-time contract lease operator. The company and contract lease operator will be supervised by a company production foreman who will coordinate and supervise all field operations. NARCO has hired a company project engineer who will be responsible for the reservoir and production engineering responsibilities, as well as Stewart Field operations supervision. An existing company development geologist who has worked the Stewart Field for several years will provide geologic support for the project. The project engineer, production foreman and development geologist will comprise NARCO's reservoir management team who will be responsible for monitoring, recommending, coordinating and implementing the development and enhancement plans/work for Stewart Field. NARCO's reservoir management team will be complemented by University of Kansas personnel, including engineers from the Tertiary Oil Recovery Project and geologists from the Kansas Geological Survey.

2. NARCO plans to utilize an in-house field data capture program, which utilizes off-the-shelf equipment and technologies to allow field employees to input tank gauges, produced water meter readings, water cuts, well tests, injection rates, pressures and other vital field information into a laptop computer. The data can then be transmitted via modem on a daily basis to the project engineer and production accounting system. This near instantaneous access to detailed production and operations information will aid in efficiency of the overall waterflood operations and aid in preventing problems before they are compounded resulting in a loss in production or expense.

3. NARCO will collect reservoir data that will aid in the reservoir analysis on a case-by-case basis as the waterflood is implemented. It is difficult to predict the frequency that this data will be collected, but it will occur whenever a change is noticed or a significant period of time has elapsed since the last test. The planned techniques of reservoir data collection are fluid levels on producing wells (static, producing, and buildup), injection surveys, tracer surveys, bottom hole pressure surveys (fall-off tests) and step rate tests.

4. The collection and utilization (reservoir simulation updates, Hall plots, WOR plots, injection/withdrawal plots, etc.) of the production, operations and reservoir information detailed in 2 and 3, above, is critical in analyzing the waterflood performance and making changes that will optimize efficiencies and maximize waterflood oil recoveries. Possibilities exist that injection changes and/or usage of permeability modification techniques will need to be implemented in the early stages of the waterflood based on the information that is collected and analyzed. These changes could include drilling or converting injectors to improve sweep efficiencies and the injection of polymer slugs or in-situ gel treatments to negate the effects of reservoir heterogeneity.

5. An ongoing water treatment program is anticipated at the Stewart Field during the waterflood to cost effectively minimize corrosion, scale and bacteria development. The anticipated amounts of water supply and produced water make this treatment a necessary expense during a waterflood operation.

6. Electrification of the producing wells in Stewart Field is anticipated as the waterflood is implemented. Currently 40 of the 43 pumping units are powered by fuel gas. Electrification of the field will provide a more reliable, lower maintenance power source that can be automated much easier.

7. The conversion to larger artificial lift equipment is common in waterfloods and is also anticipated in Stewart Field with one additional operational complication, overhead sprinkler systems. As

fluid volumes increase at the producing wells due to the encroachment of the flood front, the existing artificial lift equipment will not be able to keep up with the increased fluid volumes. The larger volume producing wells beneath the overhead sprinklers will require more expensive submersible and progressive cavity lift equipment due to the height restrictions imposed by the sprinkler systems.

***Task No. II.5 Technology Transfer***

1. This task will be accomplished through interaction between NARCO's reservoir management team and the University of Kansas. Primary communication and reporting is set up between NARCO's Project Engineer and the Project Coordinator at the University.

2. NARCO will supply the University of Kansas with activity reports during the installation of the waterflood. Post-installation reports will include monthly production, injection, pressure and well test information, as well as any significant activity or data gathering and analysis of any tests.

3. NARCO will report all information necessary for proper updating and revising the reservoir simulation model for the Stewart Field. The reservoir analysis provided by the simulator will be used as a very important tool in the reservoir management plan utilized by NARCO to maximize secondary oil recovery.

4. Project methodologies and results will be presented to Kansas and other Class 1 operators via publications, presentations, newsletters and seminars/workshops.

# 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 involves 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 (polymer flooding), 5) field operations, and 6) technology transfer.

## BACKGROUND REVIEW

### History

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 June 1994 has been 344,755 barrels. Of this production, 131;530 barrels were produced by primary depletion. Water injection began in March 1981 and 213,225 barrels have been produced under waterflood operations. The most current graph of waterflood production data is presented in Figure 13. A map presenting oil production by well since waterflood startup is included as Figure 14.

**WATERPLANT DEVELOPMENT**

The waterflood has been plagued with poor water quality. Bag filters have not been adequate in improving water quality to a level it can be injected without plugging injection wells. As a result, the injection wells have had to be cleaned regularly and injection pressures have been extremely high.

The water for the Nelson Lease waterflood operation is a combination of produced and make-up water. The produced water contains dissolved minerals, suspended clay and silt particles, and suspended oil. This water is passed through a 6 by 36 inch, 75-micron bag filter. The dirt load in the produced water was such to require a daily change of the filter bag. The make-up water is salt water obtained from Mississippian zone. This water contains dissolved minerals and sulfide which is the result of sulfate reducing bacteria in the water zone. The water from the well is clear and transparent, but rapidly becomes cloudy and black in color. The dissolved iron is oxidized by oxygen from the air and the ferric ion reacts with the sulfide to form insoluble ferric sulfide. The make-up water, before exposure to air, can be filter through a 75-micron or smaller filter. After exposure to air the make-up water has the same filtration problems as the produced water. The combination of the two waters results in a water with a suspended solids content that readily blinds a 75-micron filter bag. Due to the filtration problem, and the lack of automated equipment, the make-up water was added after the produced water had been filtered. The result was an injection water that still contained a sufficient quantity of suspended solids to cause filtration problems. Nevertheless, this combined water was sent to the injection wells. The result was partially to total loss of injectivity at the injection wells.

A major goal of the demonstration project was to modify and improve the water plant in order to obtain 700 to 1000 barrels of water per day which would pass through a 10-micron filtration system at the plant. In addition the injection well filters would also be changed from 75 to 10-micron filters. To obtain this quality of water an air flotation unit was purchased with the premise that the reduced work-over cost of the injection wells would pay for the air flotation equipment within 36 months.

Air flotation is a process by which dispersed liquids and solids can be removed from water by air bubbles. Air and oil are hydrophobic with respect to water. Air is lipophilic with respect to oil. Dispersed oil in water will eventually separate since most oils are less dense than water. An air bubble will adhere to an oil drop dispersed in water. This combined air-oil entity has density much less than the oil drop itself, and will rise to the surface of the water faster than the oil drop by itself. Most inorganic solids have a density greater than water and will settle. However, settling time for small particles, less than 50 microns, for quiescent water, is in the order of hours to days. Smaller particles may take years to settle. Microorganisms and organic solids have densities similar to water, and therefore, do not settle.

Inorganic and organic solids can be neutral or bear a charge, positive or negative. The solid particles, which are hydrophilic, can be altered by the adsorption of appropriate chemicals that render the particles hydrophobic. These altered particles will adhere to air bubbles, which allow them to float to the surface of the water. An alternate process is to use hydrophobic organic materials that bear a charge. An ion pair will form that is partially hydrophobic. This ion pair will then adhere to an air bubble and rise to the surface of the water. Additional air bubbles will coalesce with the air adhering to a solid particle. The large air bubble-solid particle decreases in density, and therefore, rises rapidly to the surface of the water.

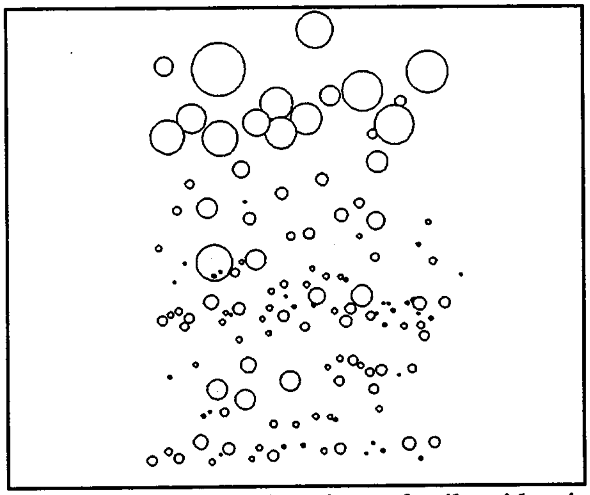


Illustration of the flotation of oil with air bubbles.

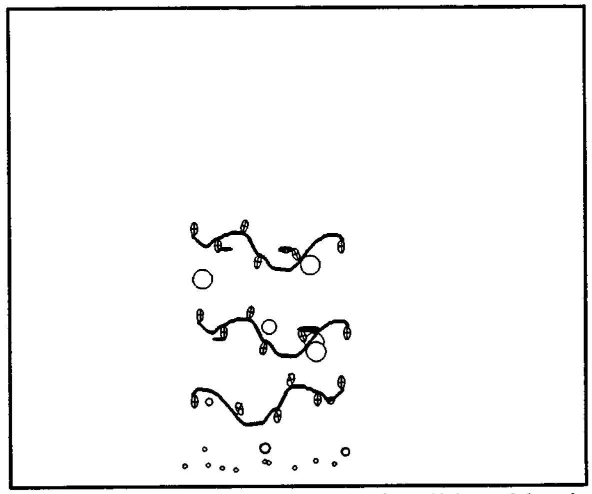


Illustration of the flotation of solids with air bubbles.

An injection water sample was tested in before and after installation of the air flotation unit. The test consisted of passing the water through a 47 mm, 5-micron nylon filter using a 10 psi pressure differential. A plot of volume versus the square root of time yields a straight line. The slope of this line multiplied by one hundred is taken as the injectivity index for the water. A mixture of 75% produced and 25% make-up water had an index of 26.4, whereas a sample of the water from the flotation unit had an index of 2.62. A ten fold change in the injectivity index clearly revealed the improvement of the water sent to the field.

Further improvement of the water has not been achieved to date. Part of the problem has been in learning how to optimize the operation and chemical selection for the air flotation unit. A major problem with oil production in Eastern Kansas is the lack knowledgeable people to provide the necessary support service for the technology which is new to the operator.

A second major goal for the project is to demonstrate that the cost of injection of water can be decreased by the use of quality flood water. The average cost is estimated at $1,500 for labor and materials to wash an injection well. Some of the wells had to be washed more than once per year in the past. All the injection wells were washed in May and June before the installation of the air flotation unit. To date none of the injection wells have required a wash job.

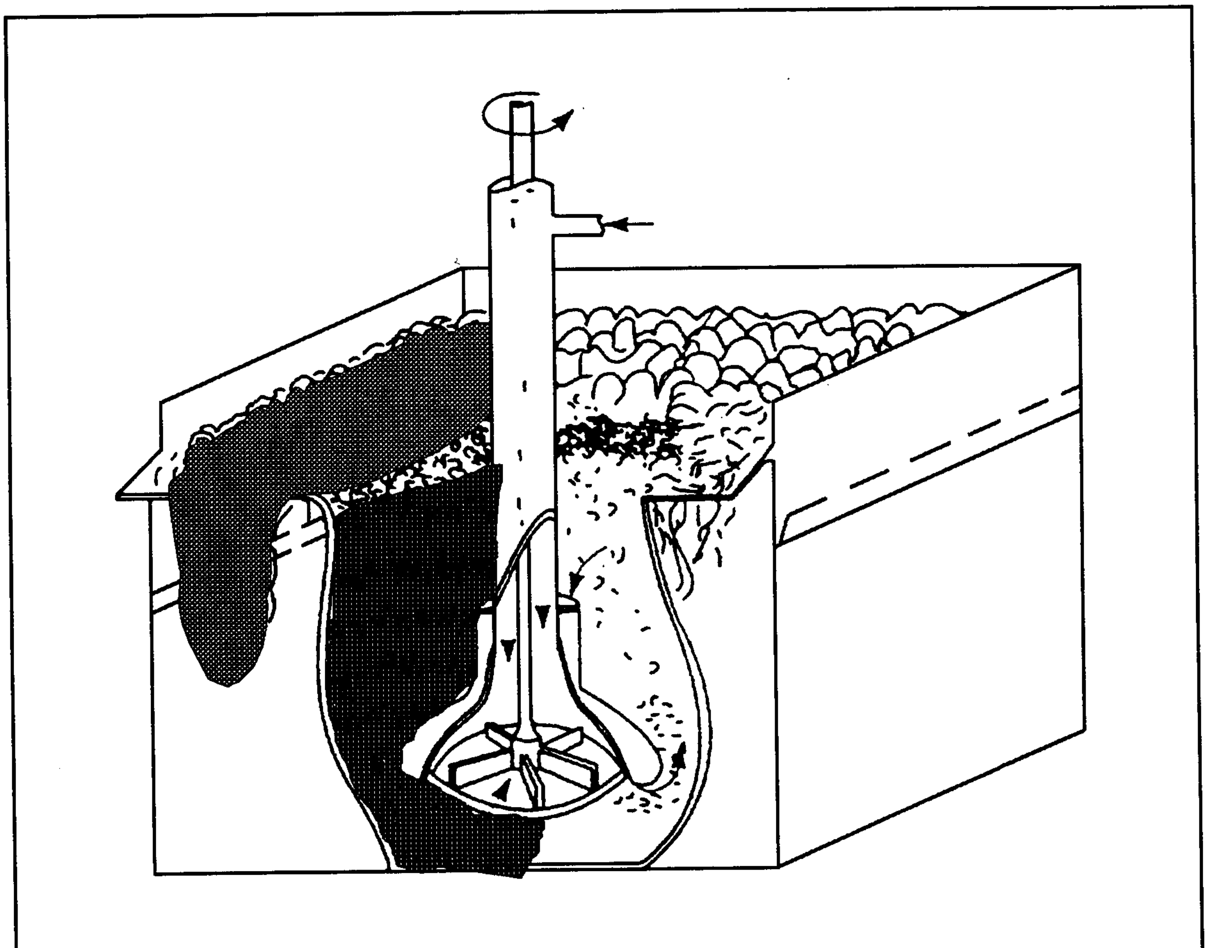
A record is being kept for each injection well to be compared with the past history for the well. The goal is to document that clean water will reduce the cost of injecting water into a well. However, due to the extensive work that occurred during and after the installation of the air flotation unit, it will take an additional six to twelve months to determine any change occurring at the injection wells. The lease hands do feel, from their experience, that the cleaner water is making a difference in the frequency in which filters at the well-head have to be changed, and the general time required to service each well. The pay-out for the air flotation equipment appears to be within the estimate. As additional data is accumulated over the next six to twelve months the actual pay-out time can be calculated.

ESTIMATED COSTS

| | | |
|---|---|---|
| 1. | Air flotation unit | $28,000.00 |
| 2. | Pumps and other equipment | $4,000.00 |

January-June (181 days)

Before installation of the air flotation equipment the produced water was passed through a 75-micron filter before the addition of make-up water from the supply well. Estimated average daily injection rates were approximately 700 barrels per day. A 75-micron bag filter was changed daily. A



Typical air flotation unit for removal of solids and oil from produced oilfield water.

200 mL sample of the injection water required 45 minutes to pass through a 5-micron membrane filter. Estimated costs per day are:

| | | |
|---|---|---|
| 1. | Chemicals | $38.00 |
| 2. | 75-micron bag filters | 7.00 |
| 3. | Electricity | 19.00 |
| | Total | 64.00 |
| | Cost per barrel of water | 0.09 |

July-October (123 days)

The air flotation unit was started on July 13, 1994. The produced and make-up water was combined before transfer to the air flotation unit. The water from the air flotation unit was passed through a 25, and later, a 10-micron filter bag. The residual solids have been a problem with the filter bags. Depending on the amount of produced and make-up water, the filter at times had to be changed twice a day. Average number of filters used is estimated at 1.5 filters per day. Estimated average daily injection rates were approximately 800 barrels per day. A 1000 mL sample of the injection water required 5 to 15 minutes to pass through a 5-micron membrane filter.
Estimate costs per day are:

| | | |
|---|---|---|
| 1. | Chemicals | $ 7.00 |
| 2. | 10 or 25-micron bag filters | 10.50 |
| 3. | Electricity | 24.00 |
| | Total | 41.00 |
| | Cost per barrel of water | 0.05 |

## REVIEW AND UPDATE OF BUDGET PERIOD 1 ACTIVITIES

### Geological and Engineering Analysis

***Database Development.*** Due to the abundance of data on the field, a computer database was set up to make data easily accessible. Spreadsheets were utilized in the development of the database. The computer database included, 1) reservoir properties from core analysis on a well basis, 2) production and injection data on a well basis since waterflood start up, and 3) lithology picks on a well basis.

This study used materials provided by J.E. Russell Petroleum Inc., including cores, unscaled gamma ray-neutron logs and core data. While cores collected before 1983 were discarded after description and analysis, cores were available for 23 wells drilled since Russell became operator of the field. Russell cores are simply designated by their well number, either RW-n (n=1 through 19) or O-n (n=1 through 4). The Russell cores were described and were the basis for much of the depositional interpretation of the reservoir rocks and associated strata. Core data provided was collected by Oil Field Research in Chanute Kansas, except for two descriptions carried out by CoreLab. Core data included a text and graphic description, measurements of porosity, permeability, and fluid saturation for nearly all wells, and, for the Russell cores, recoverable oil and effective permeability at residual oil saturation.

***Zone Description and Mapping Methods.*** Sandstone was mapped and identified utilizing two methods, 1) core reports to determine net floodable sand for volumetric analysis, and 2) gamma-ray logs to determine sand thicknesses and differences in lithologies for geological analysis. Both methods proved valuable.

In the volumetric study, net pay was determined from core analysis utilizing a porosity cut-off of 13% and effective water permeability cut-off of 1 md.

In the geological study, a shale line and a sand line were drawn on the g-ray log. The shale line was drawn at a deflection which was consistently reached by beds which did not appear to be anomalously radioactive. The sand line was drawn at the gamma-ray reading in the Cherokee Group. Rocks with a deflection greater than 1/2 of the difference between the sand and shale lines were considered to be shale and those with a smaller deflection were considered to be sandstone.

***Reservoir Parameters***. The reservoir characteristics were defined from log and core analyses. Average porosity and permeability are 18.4% and 27 md respectively. Average residual oil saturation, based on laboratory flood pot tests was 34.9 percent. Connate water saturation of 24 percent was estimated from core data and by applying an empirical relationship using permeability data. The gravity of the crude oil is 31.2 degrees API at 60° F. The viscosity of the reservoir crude oil at reservoir temperature is 15.4 cp.

***Volumetric Analysis***. A pattern volumetric analysis was conducted to determine recovery factors in BBL/Ac-ft for given segments of the field. Net pays were determined from flood pot data. From the database three grids and maps were developed; 1) net pay, 2) porosity, and 3) water saturation. The net pay grid was multiplied with the porosity grid to develop a porosity-foot grid for the field. Each segment or pattern was then integrated to determine acre-ft. The patterns or reservoir segments are presented in Figure 15. Areas of high potential are also presented in the figure.

Initial-oil-in-place at waterflood start up was determined by multiplying the porosity-ft with the the initial oil saturation of 24%. A formation volume factor (FVF) of 1.06 was included in the calculations.

A simulation study was conducted to determine waterflood and polymer flood recoveries. The study (along with input parameters) is presented in the following section. It was found that the recovery factor for waterflood and polymer flood were 255 and 335 BBL/Ac-ft respectively. Table 3 presents the remaining waterflood and polymer flood reserves remaining per segment. It also presents volumetrics for the B2 and B3 zone, and (oil & water) production by segment.

**Table 3:** Pattern Volumetric Analysis - Savonburg Field

| Well | Oil Prod. BBL/Ac-ft | Oil Left BBL/Ac-ft | Remaining Sec. Oil | Remaining Poly Oil | Remaining Tot. Oil | Segment Acres | B2 Vol. Ac-ft | B3 Vol. Ac-ft | Total Vol. Ac-ft | Oil Prod. June 94 | Water Prod. June 94 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| H-1 | 117 | 138 | 9,149 | 5,298 | 14,447 | 4.09 | 33.89 | 32.34 | 66.23 | 7,740 | 113,625 |
| H-11 | 75 | 180 | 9,708 | 4,304 | 14,012 | 2.47 | 19.81 | 33.99 | 53.80 | 4,012 | 92,014 |
| H-14 | 259 | (4) | (274) | 5,504 | 5,231 | 2.51 | 18.72 | 50.09 | 68.81 | 17,819 | 192,372 |
| H-15 | 184 | 71 | 2,043 | 2,312 | 4,355 | 1.01 | 4.56 | 24.34 | 28.90 | 5,327 | 58,965 |
| H-16 | 226 | 29 | 1,990 | 5,398 | 7,388 | 3.32 | 20.54 | 46.94 | 67.48 | 15,217 | 202,476 |
| H-17 | 127 | 128 | 12,377 | 7,709 | 20,086 | 3.82 | 40.13 | 56.24 | 96.37 | 12,196 | 203,703 |
| H-20 | 144 | 111 | 24,216 | 17,504 | 41,720 | 6.74 | 94.10 | 124.70 | 218.80 | 31,579 | 221,003 |
| H-22 | 134 | 121 | 6,656 | 4,389 | 11,046 | 2.49 | 23.22 | 31.65 | 54.87 | 7,335 | 101,718 |
| H-26 | 236 | 19 | 602 | 2,480 | 3,082 | 1.34 | 9.40 | 21.59 | 31.00 | 7,302 | 63,697 |
| H-27 | 21 | 234 | 10,430 | 3,568 | 13,999 | 2.57 | 19.98 | 24.62 | 44.60 | 944 | 76,606 |
| H-28 | 69 | 186 | 9,304 | 4,000 | 13,305 | 2.96 | 23.12 | 26.88 | 50.01 | 3,447 | 144,798 |
| H-3 | 65 | 190 | 30,164 | 12,681 | 42,846 | 6.46 | 79.33 | 79.19 | 158.52 | 10,258 | 169,577 |
| H-30 | 220 | 35 | 5,968 | 13,731 | 19,700 | 6.75 | 67.24 | 104.41 | 171.64 | 37,801 | 310,339 |
| K-36 | 35 | 220 | 9,401 | 3,415 | 12,816 | 2.83 | 11.65 | 31.04 | 42.69 | 1,485 | 34,205 |
| H-9 | 82 | 173 | 9,931 | 4,591 | 14,522 | 3.02 | 25.87 | 31.51 | 57.38 | 4,701 | 101,352 |
| K-39 | 153 | 102 | 16,361 | 12,880 | 29,242 | 6.69 | 56.04 | 104.97 | 161.01 | 24,695 | 345,730 |
| K-40 | 21 | 234 | 6,250 | 2,133 | 8,383 | 2.10 | 24.38 | 2.27 | 26.66 | 547 | 30,563 |
| K-41 | 129 | 126 | 4,256 | 2,694 | 6,950 | 2.55 | 31.71 | 1.97 | 33.67 | 4,331 | 131,973 |
| K-42 | 75 | 180 | 8,207 | 3,645 | 11,852 | 2.78 | 38.05 | 7.51 | 45.56 | 3,410 | 98,335 |
| K-43 | 178 | 77 | 4,115 | 4,280 | 8,394 | 3.08 | 49.52 | 3.98 | 53.50 | 9,527 | 107,389 |
| K-44 | 144 | 111 | 10,101 | 7,260 | 17,362 | 2.72 | 35.72 | 55.03 | 90.75 | 13,041 | 188,887 |
| K-45 | 85 | 170 | 12,295 | 5,773 | 18,068 | 3.01 | 55.02 | 17.14 | 72.17 | 6,107 | 130,939 |
| K-47 | 36 | 219 | 12,901 | 4,717 | 17,618 | 7.27 | 46.73 | 12.23 | 58.96 | 2,134 | 36,524 |
| K-49 | 112 | 143 | 1,460 | 815 | 2,275 | 0.31 | 9.88 | 0.31 | 10.19 | 1,137 | 18,253 |
| K-54 | 184 | 71 | 2,182 | 2,450 | 4,632 | 3.09 | 15.11 | 15.51 | 30.62 | 5,626 | 127,719 |
| TOTALS | | | 219,793 | 143,531 | 363,331 | 85 | 856 | 942 | 1,794 | 237,812 | 3,302,856 |

***Simulation Study***. To determine the potential recovery from waterflooding in the Savonburg Field, a streamtube simulator was utilized. The following input parameters were used in the simulation:

**Table 4:** Input Parameters for Streamtube Simulator

**FORMATION PROPERITIES AND PATTERN VOLUMES**

| | | |
|---|---|---|
| FORMATION DEPTH | 620.0 | FT |
| FORMATION TEMPERATURE | 70.0 | DEG.F |
| FORMATION AVE. PERMEABILITY | 27.0 | MD |
| FORMATION POROSITY | 0.2 | |
| TOTAL NET THICKNESS | 17.2 | FT |
| TOTAL PORE VOLUME | 61.4 | MBBL |
| ORIGINAL OIL IN PLACE | 45.8 | MSTB |
| OIL IN PLACE AT START OF FLOOD | 42.2 | MSTB |
| DYKSTRA-PARSONS COEFFICIENT | 0.63 | VDP |
| PATTERN AREA | 2.50 | ACRE |
| WELLBORE RADIUS | 0.50 | FT |
| INJECTIVITY COEFFICIENT | 1.00 | PSI/FT |
| INJECTION RATE OVERRIDE | 40.0 | RB/D |
| WATER-OIL MOBILITY RATIO | 7.38 | |
| POLYMER-OIL MOBILITY RATIO | 1.00 | |
| POLYMER CONCENTRATION | 500.0 | PPM |
| POLYMER ADSORPTION | 200.0 | LB/AC FT |
| POLYMER ADSORPTION PARAMETER | 0.147 | VOL SLUG/PV |
| POLYMER VISCOSITY | 12.700 | CP |
| RESISTANCE FACTOR | 7.40 | |
| RESIDUAL RESISTANCE FACTOR | 2.000 | |
| POWER-LAW COEFFICIENT | 4.774 | CP*SEC**(N-1) |
| POWER-LAW EXPONENT | 0.600 | |
| POLYMER SLUG SIZE | 0.300 | PV |
| MAXIMUM INJECTED PV, POLY+CHASE WAT | 2.000 | PV |

**FORMATION PROPERTY TABLE**

| | | |
|---|---|---|
| DISCRETE LAYER CALCULATION OPTION | 1 | LYROPT |
| NUMBER OF LAYERS | 5 | NLAYER OR NLDP |
| AVERAGE POROSITY | 0.1840 | |
| AVERAGE PERMEABILITY | 27.0 | MD |
| TOTAL NET THICKNESS | 17.2 | FT |
| AVERAGE INITIAL WATER SATURATION | 0.30 | |

| LAYER NO. | PHIL | PERML MD | PAYL FT | SWIL |
|---|---|---|---|---|
| 1 | 0.18 | 75.69 | 3.44 | 0.30 |
| 2 | 0.18 | 28.35 | 3.44 | 0.30 |
| 3 | 0.18 | 16.64 | 3.44 | 0.30 |
| 4 | 0.18 | 9.84 | 3.44 | 0.30 |
| 5 | 0.18 | 4.48 | 3.44 | 0.30 |

## RELATIVE PERM CURVES

| | | |
|---|---|---|
| IRREDUCIBLE WATER SATURATION | 0.240 | SWC |
| RESIDUAL OIL SATN AFTER WATER | 0.349 | SORW |
| OIL RELATIVE PERM END-POINT | 0.800 | XKROE |
| WATER RELATIVE PERM END-POINT | 0.300 | XKRWE |
| OIL RELATIVE PERM CURVATURE | 2.00 | XNO |
| WATER RELATIVE PERM CURVATURE | 2.00 | XNW |

## RELATIVE PERMEABILITY TABLE

| WATER SATURATION | OIL KRO | WATER KRW | FRACTION WATER | FRACTION POLYMER |
|---|---|---|---|---|
| 0.2400 | 0.8000 | 0.0000 | 0.0000 | 0.0000 |
| 0.2811 | 0.6480 | 0.0030 | 0.0835 | 0.0038 |
| 0.3222 | 0.5120 | 0.0120 | 0.3157 | 0.0190 |
| 0.3633 | 0.3920 | 0.0270 | 0.5755 | 0.0539 |
| 0.4044 | 0.2880 | 0.0480 | 0.7664 | 0.1211 |
| 0.4455 | 0.2000 | 0.0750 | 0.8807 | 0.2367 |
| 0.4866 | 0.1280 | 0.1080 | 0.9432 | 0.4109 |
| 0.5277 | 0.0720 | 0.1470 | 0.9757 | 0.6280 |
| 0.5688 | 0.0320 | 0.1920 | 0.9916 | 0.8322 |
| 0.6099 | 0.0080 | 0.2430 | 0.9983 | 0.9617 |
| 0.6510 | 0.0000 | 0.3000 | 1.0000 | 1.0000 |

## WATERFLOOD REPORT PATTERN PRODUCTION SUMMARY

| | | |
|---|---|---|
| PATTERN LIFE RATIO | 10.80 | |
| PATTERN AREA | 2.50 | ACRE |
| PATTERN PORE VOLUME | 61.4 | MBBL |
| ORIGINAL OIL IN PLACE | 45.8 | MSTB |
| OIL IN PLACE AT START OF FLOOD | 42.2 | MSTB |
| TOTAL OIL PRODUCTION | 11.0 | MSTB |
| OIL RECOVERY | 255 | BBL/AC-FT@WR-25 |

## POLYMERFLOOD REPORT PATTERN PRODUCTION SUMMARY

| | | |
|---|---|---|
| PATTERN LIFE RATIO | 10.80 | |
| PATTERN AREA | 2.50 | ACRE |
| PATTERN PORE VOLUME | 61.4 | MBBL |
| ORIGINAL OIL IN PLACE | 45.8 | MSTB |
| OIL IN PLACE AT START OF FLOOD | 42.2 | MSTB |
| TOTAL OIL PRODUCTION | 15.1 | MSTB |
| OIL RECOVERY | 335 | BBL/AC-FT@WR-60 |
| TOTAL POLYMER INJECTED | 3.2 | MLB |
| OIL/POLYMER RATIO | 4.67 | STB/LB |

The simulation run indicates that the recovery factor for waterflood and polymer flood are 255 and 335 BBL/Ac-ft respectively. This recovery factor is larger than most of the recovery factors in the volumetric pattern study. This would indicate that many of the patterns have a high potential for incremental oil if the continued development was optimized.

***Geological Analysis.*** The primary zone of oil production is a sandstone that is part of the Chelsea

Sandstone of the Cabaniss Formation, Cherokee Group. The sandstone, with associated mixed lithology (rippled sandstone, wavy- and linsen-bedded sandstone, siltstone and shale) and shale, fills a valley that was cut during a low stand of sea level. The low stand occurred after deposition of the Tebo Coal and some overlying strata but before deposition of the Scammon Coal. The most productive reservoir is structureless, fine-grained sandstone associated with the first stage of filling this valley, called the $B_3$ zone in this report. Rippled sandstones of the overlying interval, the $B_2$ zone, are potentially productive in the NW part of the lease, but are generally either saturated with dead oil, have low initial oil saturations, or are thin and discontinuous, making poor reservoirs.

Geological understanding of this reservoir results from two factors. One is the availability of good data. The operators, J.E. Russell Petroleum, Inc. provided cores, core descriptions and analyses, and logs. The other factor was the application of sedimentologic and stratigraphic principles that have emerged in the past few years, especially sequence stratigraphy and the understanding of the features of sediments deposited by tidal currents.

The stratigraphic framework of the Cherokee Group in the field area is a series of regional marker intervals that consist (ideally) of an underclay, a coal, a caprock of marine sandstone or limestone, and a dark gray or black shale. In terms of sequence stratigraphy, the boundary of the underclay and coal represents a sequence boundary, a surface of subaerial exposure. The boundary between the coal and the caprock represents the initial surface of marine transgression, with the caprock representing a lag deposit on a ravinement surface cut during transgression. The surface of maximum transgression lies in the overlying dark gray or black shale or in the medium gray shale that gradationally overlies it. These strata thus reflect the effects of rise and fall of sea level relative to the area of deposition of these sediments. Regional marker intervals extend across the Cherokee basin of southeastern Kansas and into the Forest City and Sedgwick basins (northeastern and south-central Kansas, respectively). They may continue into Iowa and southwestern Kansas.

Locally, the regional marker intervals are missing, notably in the vicinity of the Nelson Lease. The pattern of their absence in the field area suggests a valley eroded into underlying deposits; this is the valley referred to above. The sediments that fill this valley appear to carry indications of deposition by tidal currents. The sediments show gradational changes from shale to wavy- and linsen-bedded sandstone and mudrocks to rippled sandstone on a dm scale. The gradational nature of these changes suggests no little erosion between depositional events. The changes of grain size suggest frequent changes of current intensity, from essentially no current, when mudstone and macerated plant material accumulated in wavy- or linsen-bedded successions to times of current when ripples or sand or silt accumulated. This may correspond to currents during individual tidal cycles. The dm-scale gradation of shale to mudrocks to sand may reflect changes in intensity of ripple-forming episodes of the kind that would result from the neap-spring cycles of tidal activity. Because the mixed lithologies of the $B_2$ and $B_3$ zones suggest tidal activity, the sandstones and shales of these zones may also have formed in tidal environments. Tidal sandstones occur in mounded masses, convex upward, rather than in the convex-downward patterns of fluvial channels.

Planning for further development of this field should take into account the linear nature of the primary reservoir, the lower (or $B_3$) sandstone, and the sheet-like nature of the upper sand ($B_2$) in the northwestern part of the field, if that area is developed further. Additional drilling for improved waterflood recovery may be warranted in the central part of the deep valley and in the northwestern part of the lease. Several wells are completed in sandstones where petrophysics, saturations, and continuity of beds are unfavorable for either injection or production. Each well should be evaluated in view of current subsurface information, and those that are not likely to be productive should be abandoned. The field contains substantial amounts of dead oil, which not only cannot be produced but which act as a barrier to flow of fluids thought the reservoir. Wells drilled during further development the wells logged at least with g-ray--neutron logs. The wells should be cored and the cores analyzed for normal petrophysics, fluid saturations, recoverable oil and effective permeability. Cores should be described geologically and their character used to improve knowledge of the distribution of rocks in the field.

The geological study identified two sandstones, $B_2$ and $B_3$, which have potential for additional oil recovery. The study utilized regional marker horizons to form the basis for correlation of Cherokee Group rocks over the Cherokee Basin and to adjacent basins. East-West cross sections were developed on nearly all the wells identifying the continuity of the $B_2$ and $B_3$ pay zones. The cross sections are presented in Appendix E. Isopach maps were developed for the $B_2$ and $B_3$ sandstones.

It was concluded that the sandstones of the $B_3$ zone of the Chelsea valley fill in the eastern 1/2 of section 21 may not be completely drained by the current arrangement of wells. Specifically, injection wells may be needed between wells H-14 and H-16, between H-16 and K-44, between H-20 and H-21, and between H-30 and H-27. These locations lie along the trend of thickest sandstone in the axis of the Chelsea valley fill and adjacent injection wells are on the margins of the sandstone. While these steps would reduce spacing substantially, very high original oil saturations along the valley (as high as 5000 bbls/acre recoverable oil) and the potential for improved recovery may justify the step.

Cores of the $B_2$ zone in the northwest part of the Nelson Lease indicate recoverable oil averaging 2000 Bbls/acre, but production from that area has been low. Recompletion, additional development drilling, or some expansion of the field in this direction may be desirable, under the right economic conditions.

***Discussion of Field Recommendations***. As part of the Phase 1 work, selected field testing of the waterflood was completed. Based on the volumetric pattern study and geological evaluation, several recommendations were made. Field recommendations included well cleanups. Recommendations were based on zone potential. From examining the geological report, Zone B-3 is of better quality and of higher potential than Zone B-2. As a result, it is suggested that initial work be conducted on Zone B-3 in phase 1. Once these recommendations are implemented, areas of high potential will be identified in Zone B-2 and work will be continued.

The following injection wells had gel polymer treatments conducted, and wellbore cleanups occurred.

Well RW-8 - The original differential survey indicated that the fluid was entering above the oil producing horizon. A gel polymer treatment was conducted to plug the thief zone. A wellbore cleanup was conducted on the oil producing horizon with success. The final differential survey indicated that the water was entering the B3 zone which was the targeted formation. This well is currently injecting approximately 60 B/D with a pressure of 460 psi.

Well RW-3 - A gel polymer treatment was implemented to plug the channel to H-17. The wellbore was cleaned and a differential temperature survey was conducted indicating the water was being injected into the B2 and B3 oil zones.

Well RW-6 - A gel polymer treatment was implemented to plug the channel to K-44.

The following injection wells were cleaned to improve injectivity.

Well KW-51 - Placed on injection in September 94 utilizing 1 inch pipe and a packer. The wellbore was cleaned within the following two weeks. Injection has averaged 50 B/D.

Wells (KW-6, KCW-1, RW-7, RW-9, RW-12, RW-13, RW-1, HW-23) were cleaned and are currently active injectors.

The following producing wells were cleaned and remediated: (H-17, H-21, K-44, H-13, H-26, H-22, H-30, H-5, H-14, and O-1).

Producing Wells H-5 and H-14 were converted to injection wells in the April-95, and July-95, respectively.

***Conclusions and Summary.*** An engineering and geological study was conducted on the Savonburg Field with many conclusions and findings to date. Also a water cleanup process was selected to cleanup the low quality injection water in the field.

Air flotation was selected as the process to improve water quality. The air flotation unit was installed along with additional tanks and lines needed for proper installation. Steady-state operation has been achieved. A flocculation chemical was selected to aid in the performance of the air flotation unit. Economics look favorable.

Results from the engineering study include, 1) a volumetric study of selected patterns throughout the field, and 2) a waterflood and polymer flood simulation study of a five-spot with average properties of the Nelson Lease. The volumetric study provided waterflood efficiencies on a pattern basis to determine patterns of highest potential for additional recovery. The simulations indicated that a total recovery factor of 225 BBLS/Ac-ft could be achieved through continued operation of the waterflood and if a polymer flood was installed 335 BBLS/Ac-ft could be achieved. These recovery factors are larger than most of the recovery factors in the volumetric pattern study. This would indicate that many of the patterns have a high potential for incremental oil if the waterflood were optimized. If a polymer flood is installed incremental oil is estimated at 363,000 barrels.

## BUDGET PERIOD 2 ACTIVITIES

### Summary of Plan

The mature waterflood will be continually optimized by state-of-the-art off-the-shelf technologies in an attempt to optimize secondary and tertiary oil recovery. The waterflood optimization program will be based on geological and engineering analysis conducted in Budget Period 1. The reservoir model developed in Phase 1 will be continually updated as additional data is collected. The air flotation unit in the waterplant will be monitored and adjusted as problems develop. A Russell Petroleum reservoir management team, working in conjunction with the University of Kansas, will analyze the reservoir and production data and determine remedial work for proper management of the reservoir. Profile modification treatments will be implemented where water channelling is detected. Wellbores will be periodically monitored by temperature surveys and transient testing to determine skin and poor injection profiles. If problems are detected, wellbores will be worked over. Wells will be converted from producing wells to injection wells along with the drilling of at least two additional wells to optimize injection into oil bearing porous media. A pilot polymer flood will be implemented initially to determine any injectivity problems. If the pilot polymer flood is successful, the waterflood will be augmented with polymer where deemed economical. Technology transfer activities will include, 1) the importance of improving water quality in waterfloods, 2) demonstration of data collection and analysis, 3) the importance of a multi-disciplinary reservoir management team, 4) implementation of permeability modification treatments, 5) demonstration of wellbore cleanup techniques, and 6) monitoring waterflood performance such that real-time changes can be made to optimize oil recovery.

The Savonburg Project is based upon the premise that alterations in injection patterns, wellbore cleanup, permeability modification and polymer injection will allow the current operations of the field to become economic. Consequently, we need to view the economics of this project and subsequent justification based on the fact that the current waterflood operation is uneconomic. Since the waterflood reserves cannot be recovered, it is appropriate to include these reserves in the DOE Project as reserves that are attributed to reservoir management, assuming that we can increase production by anticipated activities described in the first paragraph. Using these assumptions, the anticipated reserves from the DOE Project are as follows: 1) Estimated Waterflood Reserves (cannot be recovered economically under current operations) - 220,000 bbls, 2) Estimated Polymer Flood Reserves (@ 6% OOIP) - 143,500 bbls, and 3) Total Reserves for DOE Project - 363,500 bbls.

**Detailed Statement of Work**

***Task No. II.1 Water Plant Development***

1. The waterflood plant will be continually monitored to determine problems. Waterfloods are dynamic and water chemistry changes at the plant through the life of a waterflood. These changes can cause upsets in the air flotation unit. Solutions will be implemented to improve the operation of the air flotation unit as needed. The air flotation unit will be demonstrated and tested as a new reliable economical alternative method of water cleanup in Eastern Kansas.

***Task No. II.2 Profile Modification Treatments***

1. Phase I analysis has indicated that numerous channels exist in the reservoir between injection and production wells. Profile modification treatments will be designed and implemented to plug the channels so water will be injected in oil bearing porous media. A variety of gel systems will be considered. Efficiency and environmental concerns will determine the appropriate process.

***Task No. II.3 Pattern Changes, New Wells and Wellbore Cleanups***

1. Pattern changes will be completed to redirect water into porous media not previously contacted. Wells identified for conversion in Phase 1 are H-14, O-1, and H-5. These wells will be converted within the first three months of budget period II. Additional wells will be identified and converted as needed. The conversions will involve placing new injection lines to converted injection wells along with proper cleaning.

2. At a minimum, two additional wells will be drilled to better contact the oil bearing porous media. These wells will be located in high potential areas identified in Phase 1. This work will be implemented within nine months of the Phase II award.

3. Wells exhibiting skin problems identified from transient tests will be cleaned up utilizing off-the-shelf technology identified in Phase I. Transient tests will be conducted utilizing the an echometer purchased for this project. Treatments will be designed based on the problem

identified.

*Task No. II.4 Reservoir Development (Polymer Flooding)*

1. The waterflood will be augmented with polymer in patterns with high potential for incremental oil due to polymer injection.

2. If polymer flooding proves feasible for reservoir development, a polymer plant will be built and will consist of an all weather insulated building. The building will contain the injection pumps and motors, electrical wiring and controls necessary for operations. The electrical system will incorporate emergency shutdown and alarm devices to promote safety and environmental compliance.

*Task No. II.5 Field Operations*

1. Russell Petroleum is responsible for operations of the field. Reports will include monthly production, injection pressure, and well test information, as well as any significant activity or data gathering and analysis of any test.

2. Russell Petroleum will supply the University of Kansas with activity reports on a monthly basis. These reports will include summary of activities for each task. If details on individual tasks are needed by the Project Coordinator, Russell Petroleum will provide material.

*Task No. II.6 Technology Transfer*

1. This task will be accomplished through interaction between Russell Petroleum's reservoir management team and the University of Kansas. Primary communication and reporting is set up between Russell Petroleum's Project Engineer and the Project Coordinator at the University.

2. Project methodologies and results will be presented to Kansas and other Class 1 operators via publications, presentations, newsletters and seminars/workshops.

# TABLES

| | Stewart Field DST Summary | | | | | | Surface Build Up Tests | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Well | Date | Pfinal | P* | k | h | | | Pfinal | k | h | | Pfinal | k | h |
| | | psig | psig | md | ft | Interval Tested | Date | psig | md | ft | Date | psig | md | ft |
| Haag 1 | 8/14/67 | 1080 | | | | 4750-67, GI=4755-69 | | | | | | | | |
| Haag 2 | 1/28/68 | 1102 | | | | 4752-73, GI=4765-79 | | | | | | | | |
| Sherman 1 | 7/10/85 | 847 | 862 | 192 | 14 | 4765-83, GI=4759-4802 | 5/12/88 | 477 | 73.9 | 44 | | | | |
| Sherman 2 | 10/28/85 | 829 | 836 | 268.5 | 10 | 4761-83, GI=4772-4805 | | | | | | | | |
| Sherman 3 | 12/9/85 | 830 | 852 | 14.5 | 30 | 4758-4804, GI=4773-4813 | 5/9/88 | 483 | 8.9 | 33 | | | | |
| Mackey 4 | 12/19/85 | 733 | 781 | 32.2 | 22 | 4758-80 | | | | | | | | |
| Sherman 4 | 1/8/86 | 795 | 810 | 174.7 | 18 | 4758-4803 | | | | | | | | |
| Mackey 5 | 2/14/86 | 755 | 820 | 11.2 | 8 | 4740-83 | | | | | | | | |
| Nelson 2-1 | 3/27/86 | 799 | 830 | 54.1 | 27 | 4748-4803 | | | | | | | | |
| Carr 2-1 | 5/9/86 | 718 | 712 | 112.6 | 30 | 4754-4804 | 11/12/91 | 57 | 185 | 26 | | | | |
| Nelson 2-2 | 6/16/86 | 714 | 749 | 45.6 | 16 | 4747-90 | 9/20/89 | 576 | 24.7 | 16 | | | | |
| Bulger 7-1 | 1/3/87 | 718 | 742 | 53.6 | 23 | 4762-95, GI=4764-4812 | 5/15/88 | 598 | 28.5 | 45 | 11/12/91 | 378 | 76.1 | 45 |
| Nelson 2-3 | 1/16/87 | 719 | 740 | 76.8 | 28 | 4744-82 | 11/12/91 | 220 | 114.8 | 29 | | | | |
| Sherman 3-1 | 3/14/87 | 828 | 849 | 193.9 | 11 | 4750-79, GI=4766-95 | | | | | | | | |
| Sherman 3-2 | 8/12/87 | 887 | 910 | 104.2 | 12 | 4774-4800 | 11/12/91 | 216 | 339.3 | 11 | | | | |
| Bulger 7-4 | 8/26/87 | 686 | 766 | 50.7 | 22 | 4755-92 | | | | | | | | |
| Bulger 7-5 | 9/24/87 | 689 | 766 | 41.5 | 22 | 4750-80 | | | | | | | | |
| Haag 3 | 10/1/87 | 642 | 685 | 20.9 | 5 | 4755-83, GI=4773-86 | | | | | | | | |
| Meyer 10-1 | 11/2/87 | 808 | 830 | 54 | 30 | 4766-4816 | | | | | | | | |
| Meyer 10-2 | 1/22/88 | 845 | 875 | 235.4 | 10 | 4759-85, GI=4772-4817 | 5/9/88 | 747 | 85.8 | 39 | | | | |
| Meyer 10-3 | 5/8/88 | 824 | | 80.4 | 10 | 4750-4810 | | | | | | | | |
| Scott 4-1 | 6/16/88 | 866 | 900 | 99.2 | 8 | 4750-4780 | | | | | | | | |
| Sherman 3-5 | 8/15/88 | 788 | 797 | 143.9 | 40 | 4755-4804 | | | | | | | | |
| Pauls 9-2 | 9/17/88 | 773 | 824 | 22.5 | 14 | 4770-4825 | | | | | | | | |
| Meyer 10-4 | 10/5/88 | 691 | 725 | 83.8 | 23 | 4769-4809 | | | | | | | | |
| Scott 4-2 | 10/17/88 | 790 | 813 | 388.7 | 22 | 4756-98, GI=4769-4806 | | | | | | | | |
| Pauls 9-3 | 12/17/88 | 815 | | | | Static BHP Survey | | | | | | | | |
| Scott 4-4 | 1/16/89 | 742 | 775 | 50.9 | 36 | 4765-4822, GI=4785-4826 | | | | | | | | |
| Haag 4 | 8/7/89 | 613 | 613 | 14.8 | 11 | 4764-85, GI=4772-96 | | | | | | | | |
| Haag 5 | 4/1/90 | 626 | 630 | 139.4 | 10 | 4760-80 | | | | | | | | |
| Meyer 10-3 | 6/22/90 | 388 | | | | Static BHP Survey | | | | | | | | |
| Sherman 3-6 | 8/12/90 | 534 | 542 | 124.4 | 38 | 4760-4818 | | | | | | | | |
| Scott 4-7 | 9/11/91 | 535 | | | | Static BHP Survey | | | | | | | | |
| Meyer 10-5 | 1/29/92 | 306 | | | | Static BHP Survey | | | | | | | | |
| Scott 4-8 | 2/26/92 | 212 | | | | Static BHP Survey | | | | | | | | |
| Bulger 7-8 | 2/1/94 | 175 | | | | Static BHP Survey | | | | | | | | |
| Bulger 7-10 | 4/5/94 | 371 | | | | Static BHP Survey | | | | | | | | |
| | | | | | | (GI=Gross Interval) | | | | | | | | |
| | | | | | | Indicates not all Morrow | | | | | | | | |
| | | | | | | was tested | | | | | | | | |

**Table 1: DST and Surface Buildup Tests Summary for the Stewart Field**

# FIGURES

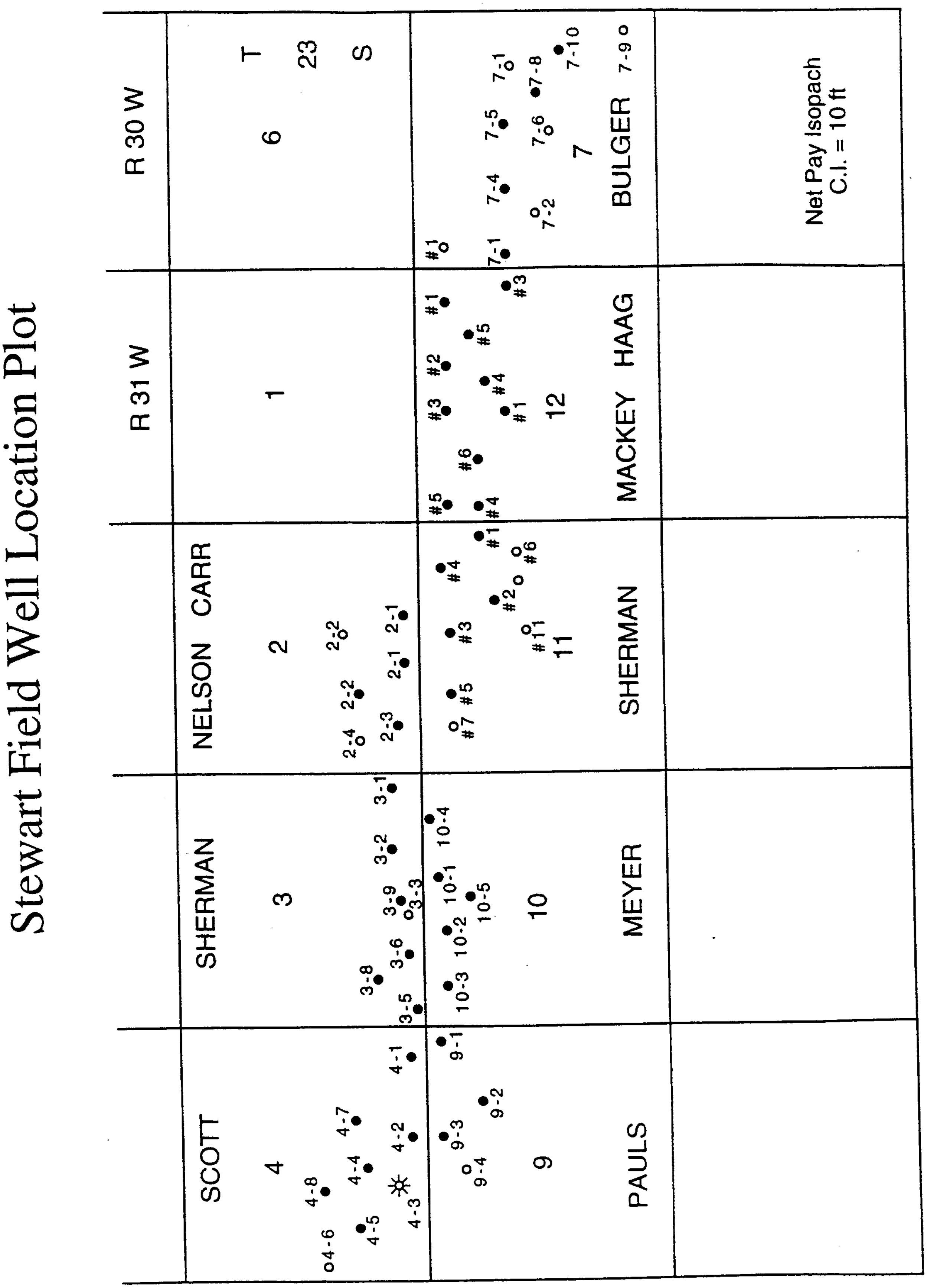



**Figure 1: Stewart Field Well Location Plat**

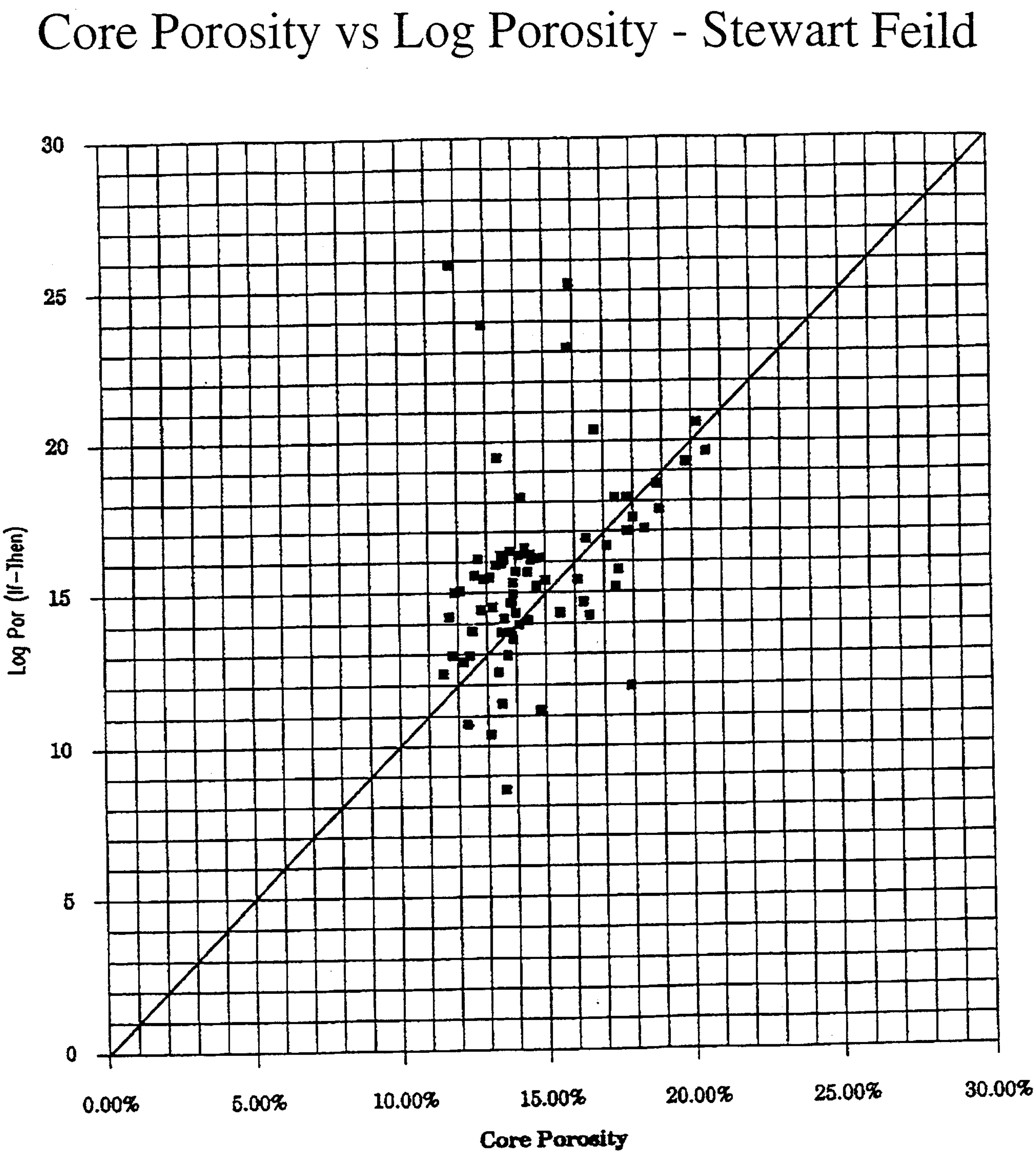



**Figure 2: Core Porosity versus Log Porosity - Stewart Field**

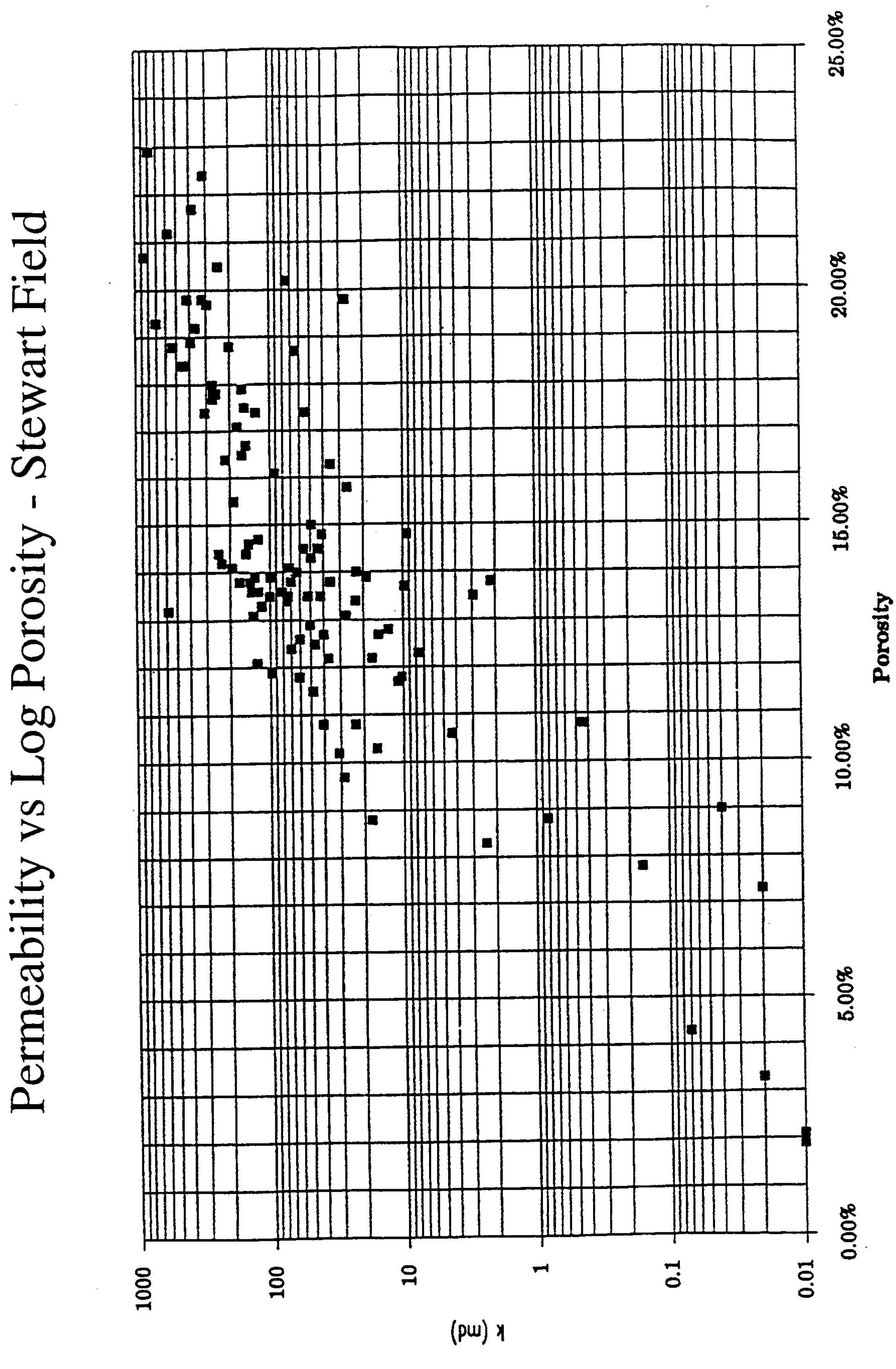



**Figure 3: Permeability versus Log Porosity - Stewart Field**

Stewart Field Net Isopach Map

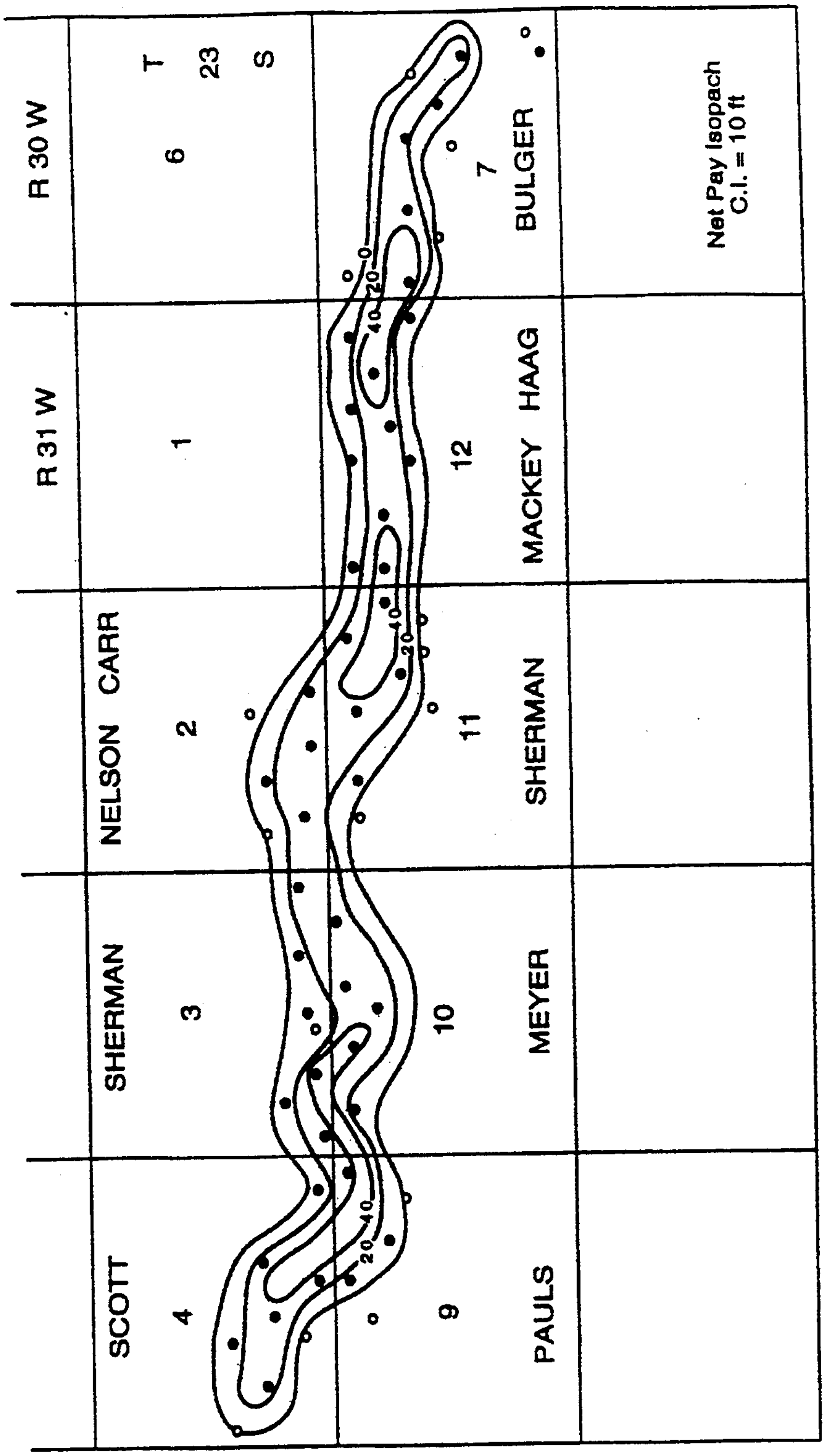



**Figure 4: Stewart Field Net Isopach Map**

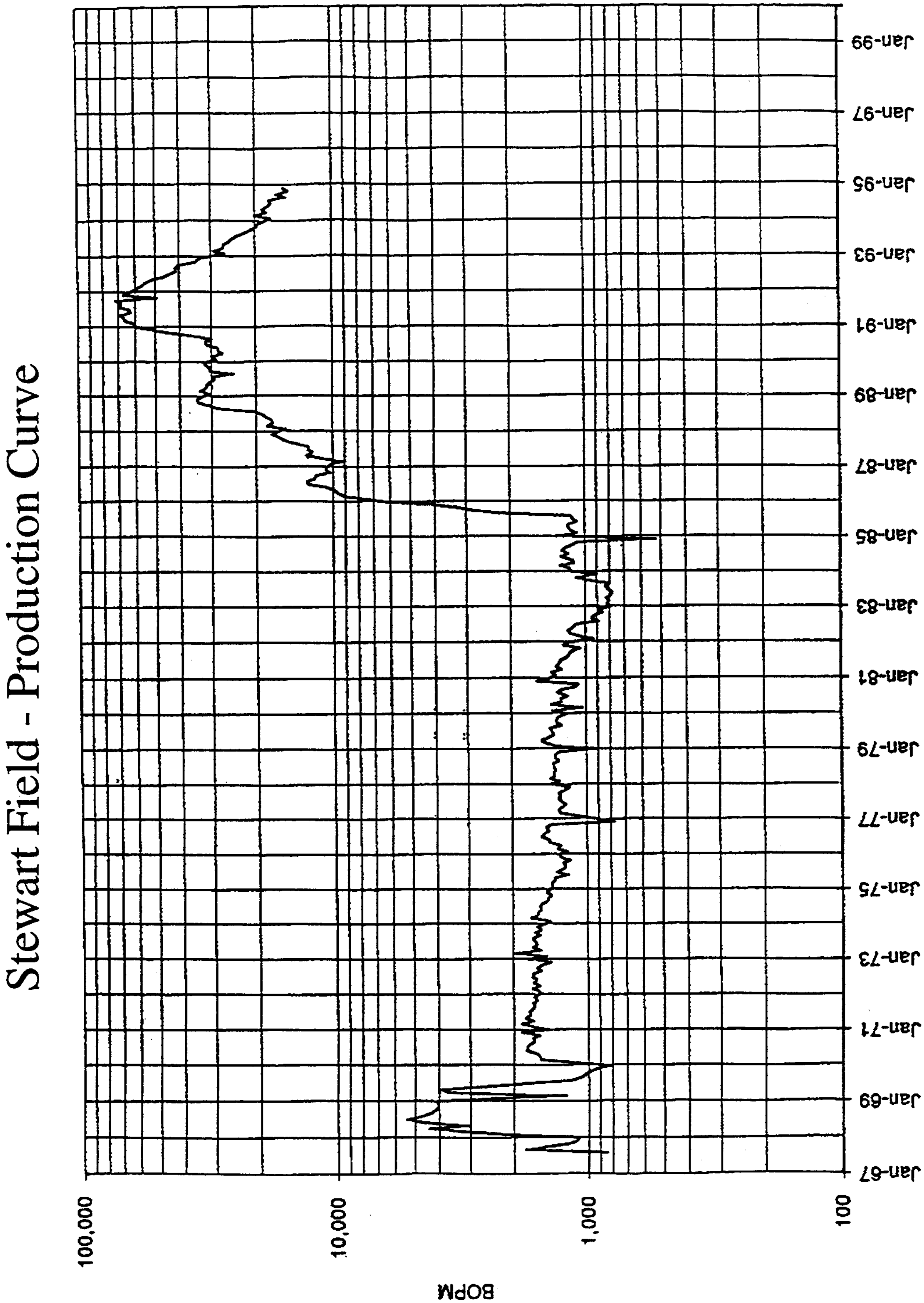



**Figure 5: Stewart Field Production Curve**

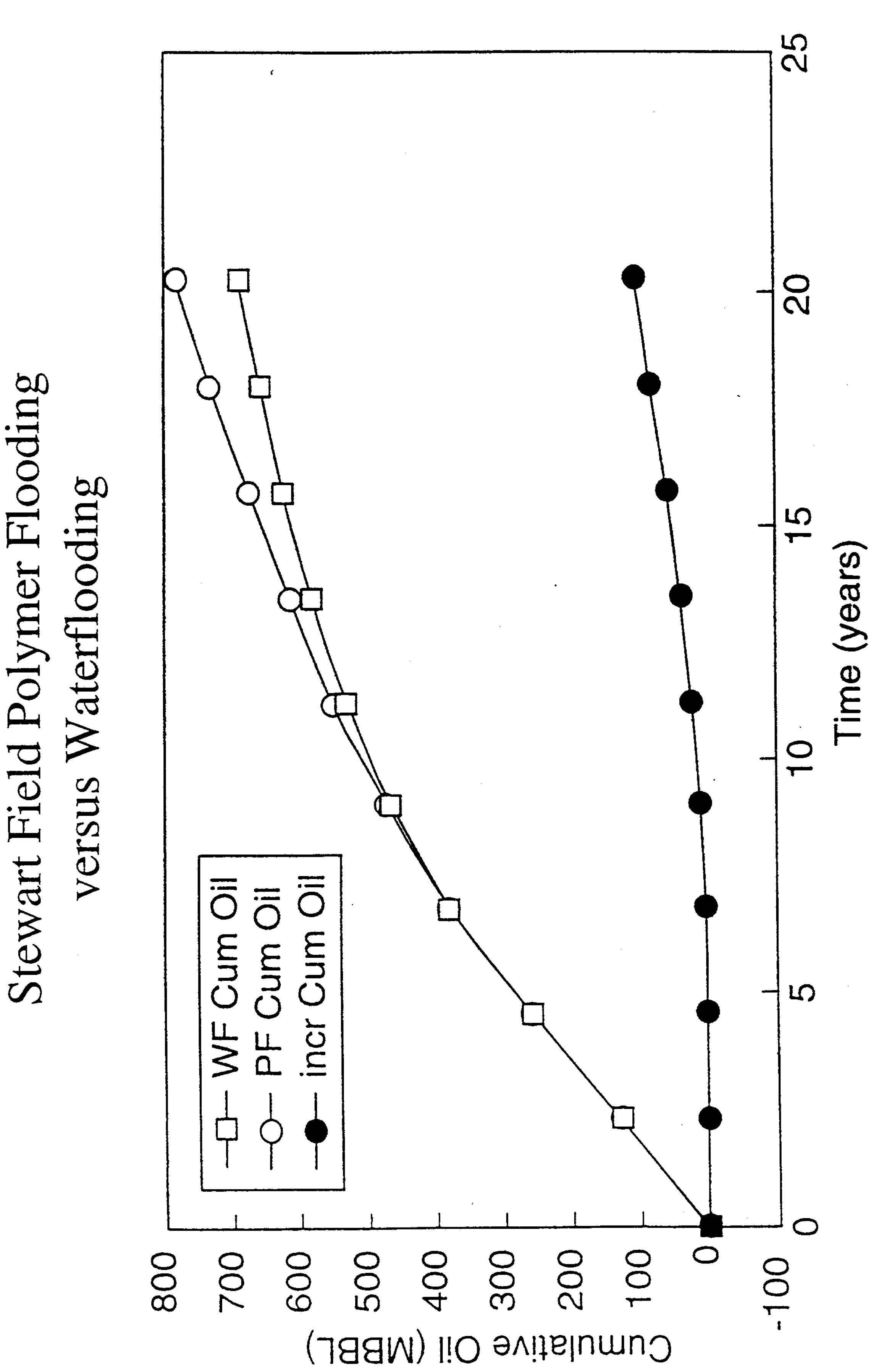



**Figure 6: Stewart Field Polymer Flooding versus Waterflooding Plot**

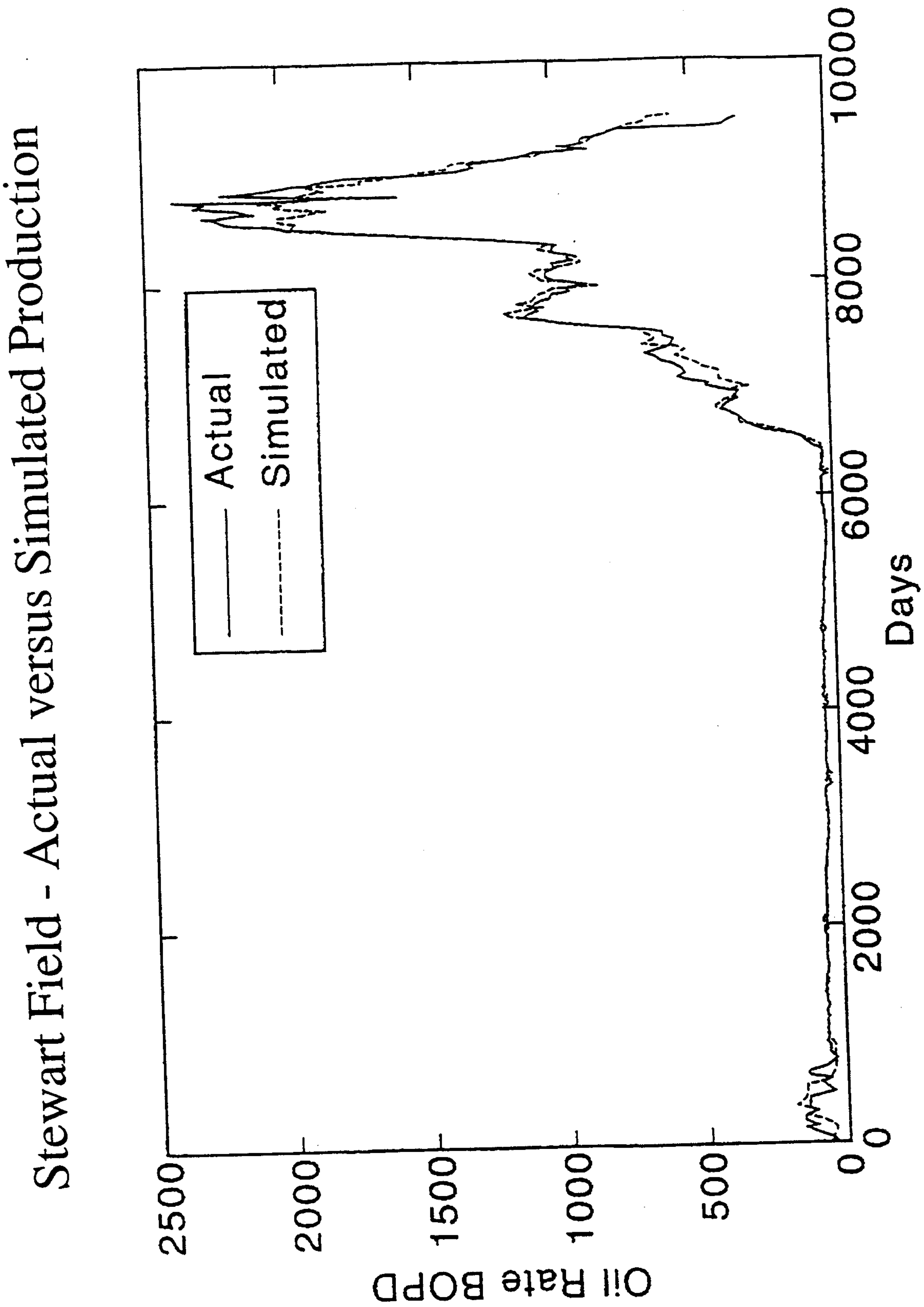



**Figure 7: Stewart Field Actual versus Simulated Production**

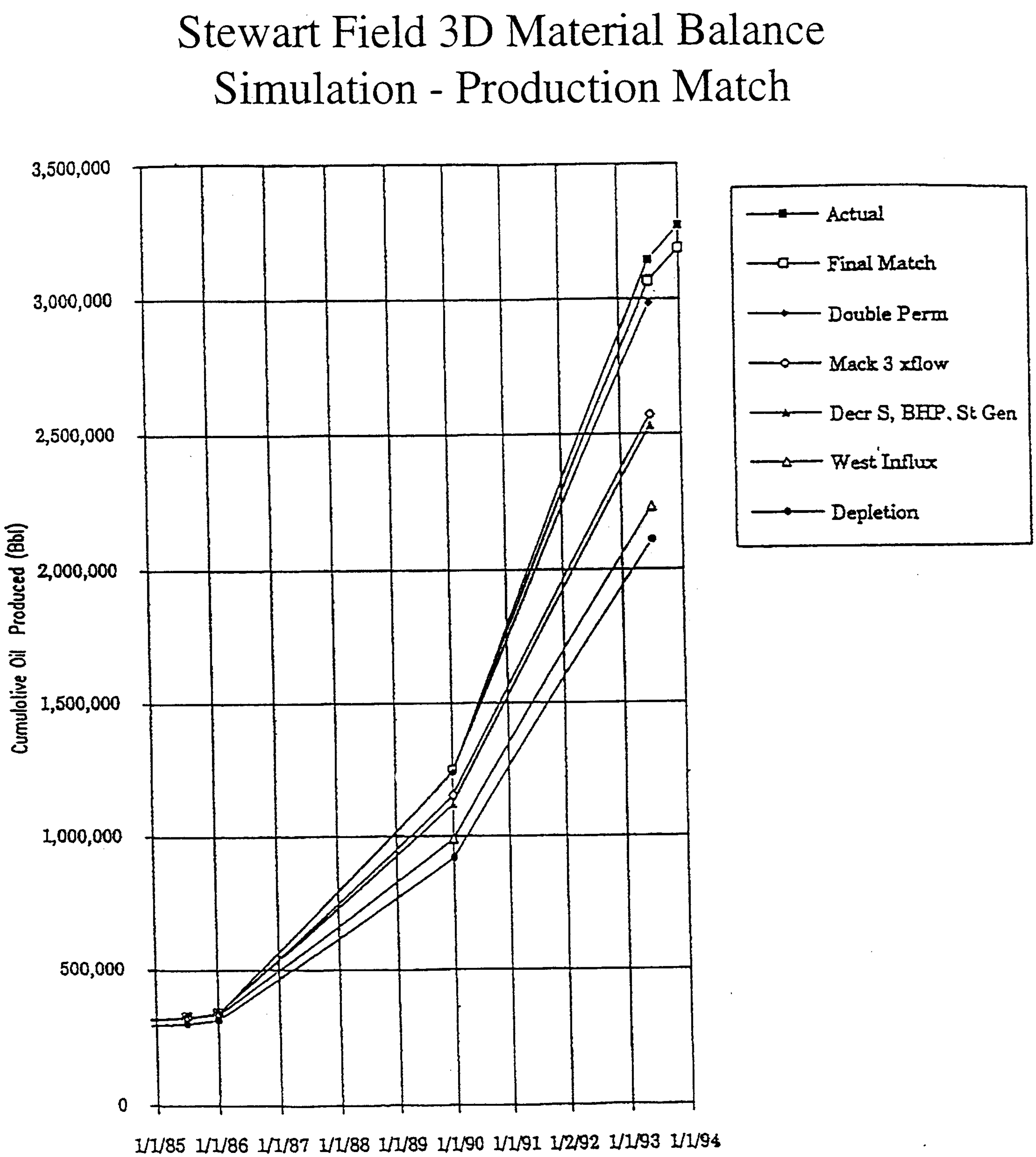



Figure 8: Stewart Field 3D Material Balance Simulation - Production History Match

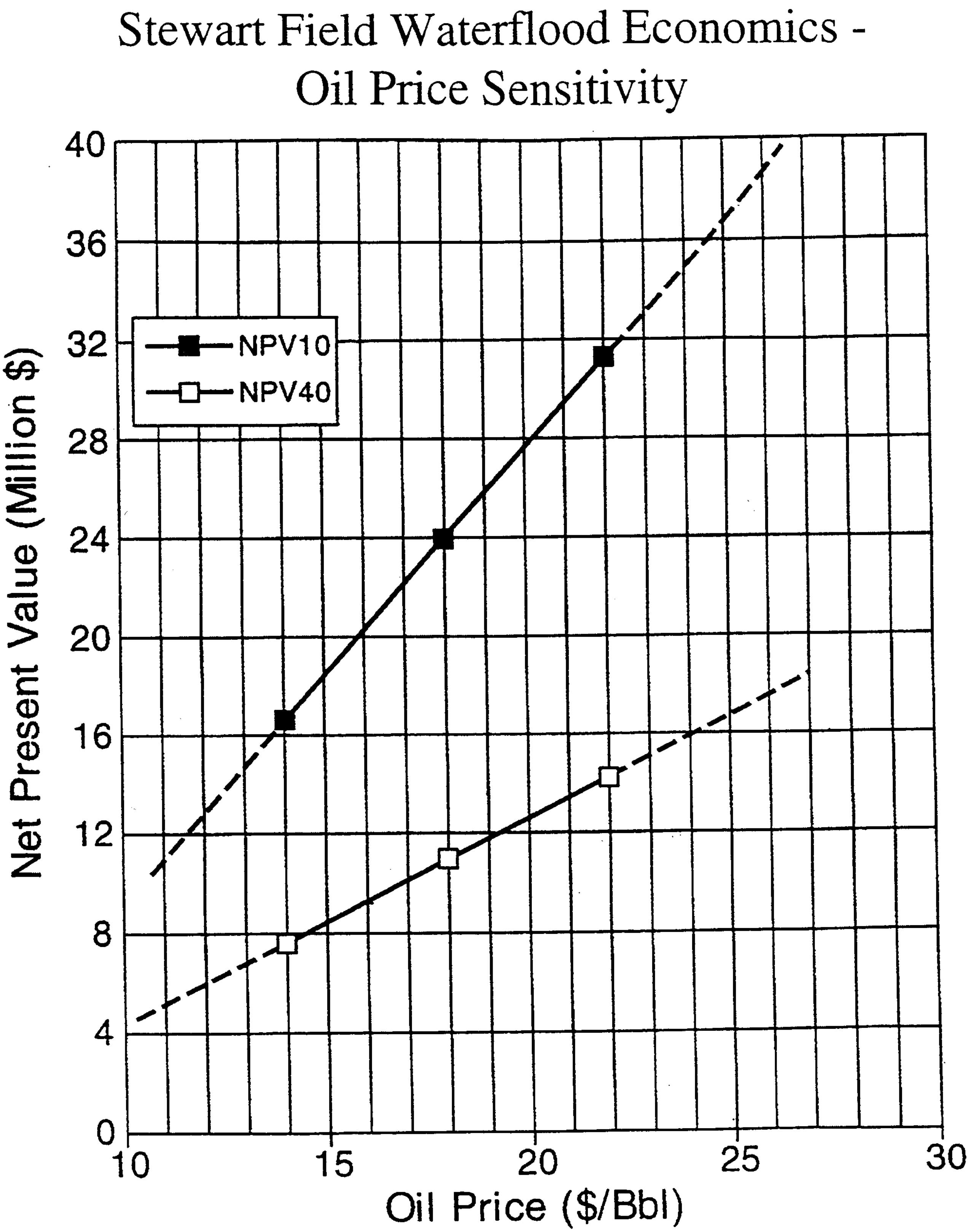



**Figure 9: Stewart Field Waterflood Economics - Oil Price Sensitivity**

Relative Permeability versus Pore Volumes Injected for Synthetic Formation Brine

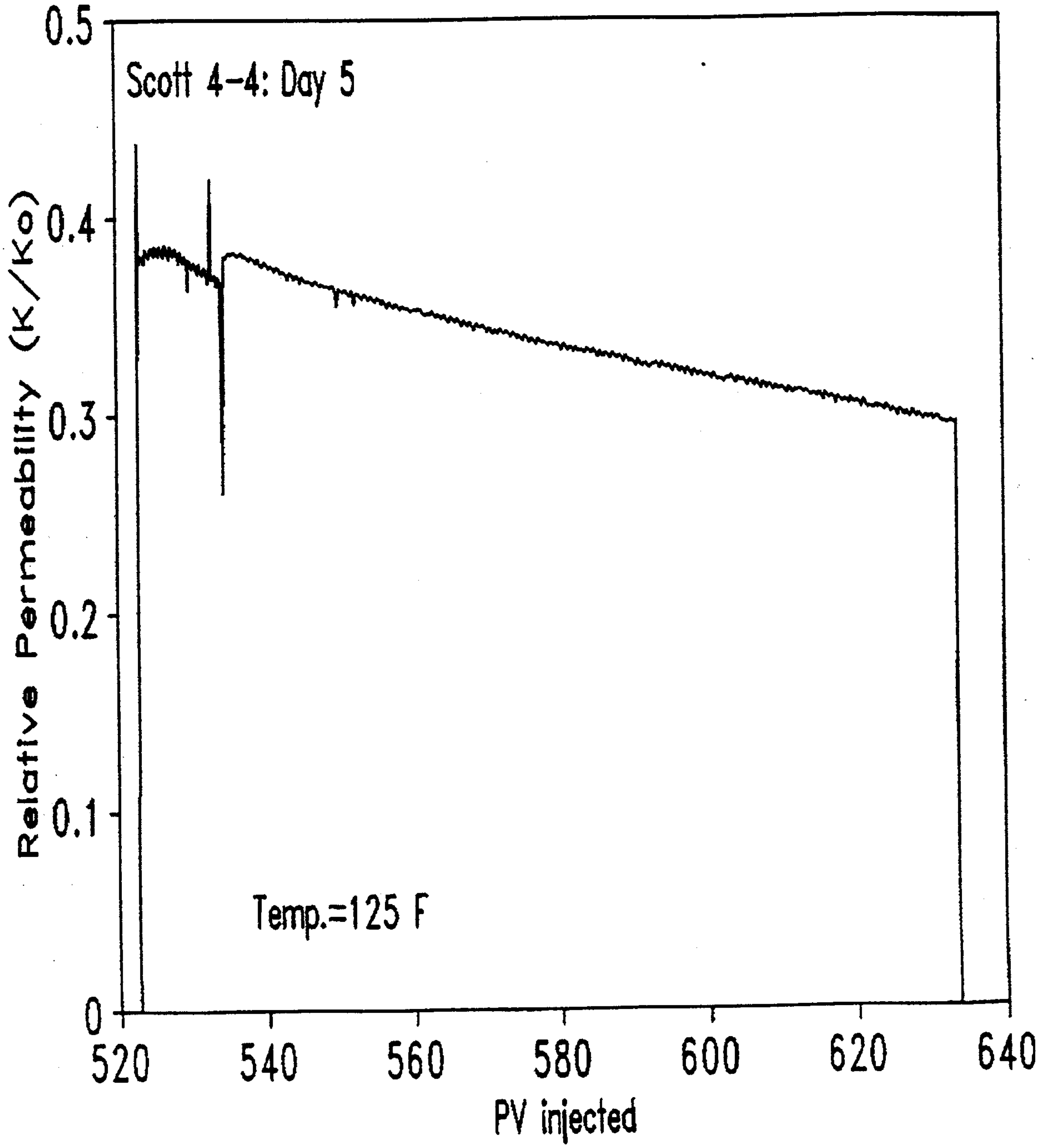



**Figure 10: Relative Permeability versus Pore Volumes Injected for Synthetic Formation Brine**

Relative Permeability versus Pore Volumes Injected for Filtered Produced Water

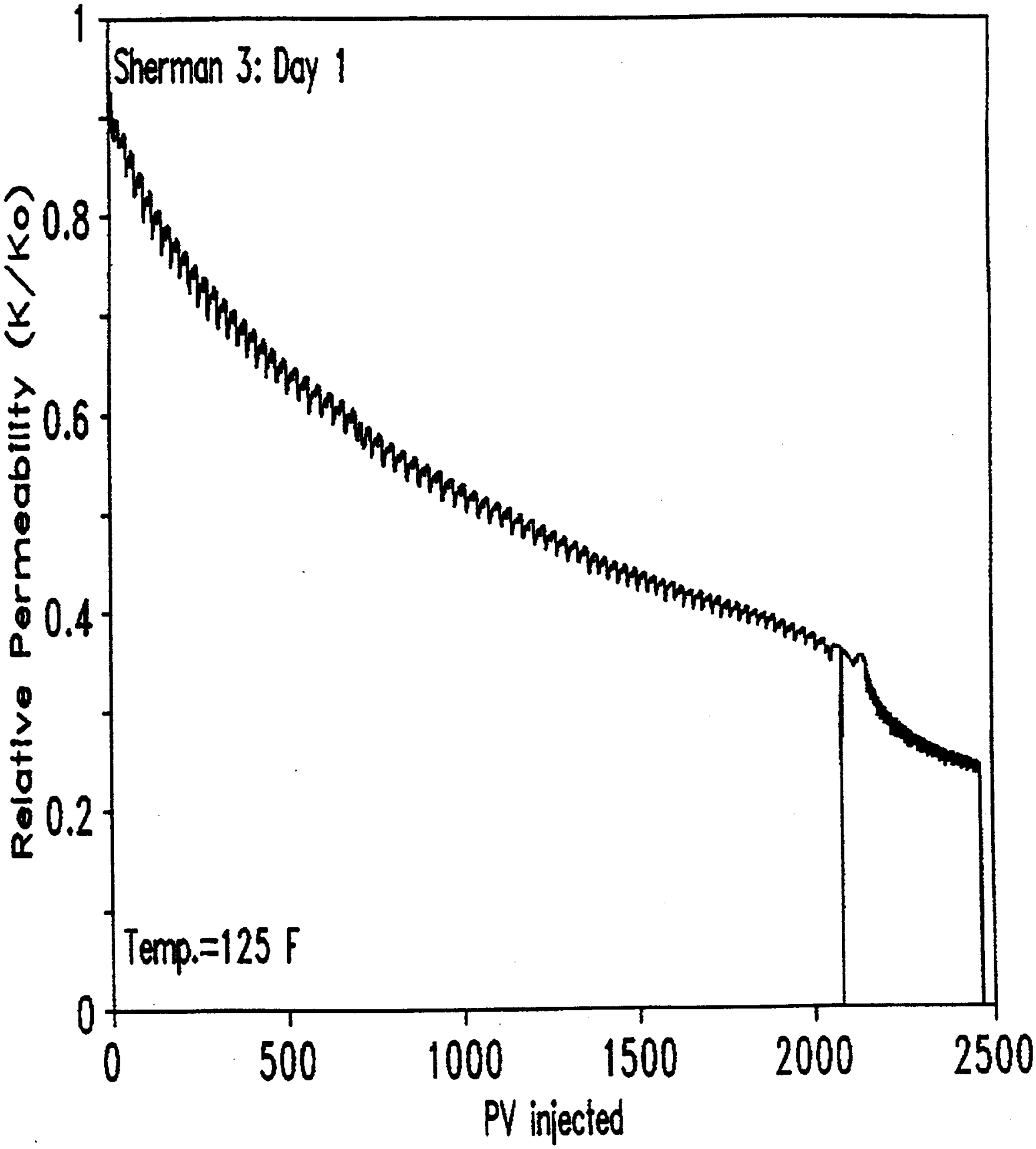



**Figure 11: Relative Permeability versus Pore Volumes Injected for Filtered Produced Water**

# Relative Permeability versus Pore Volumes Injected for 3.0% Potassium Chloride Solution

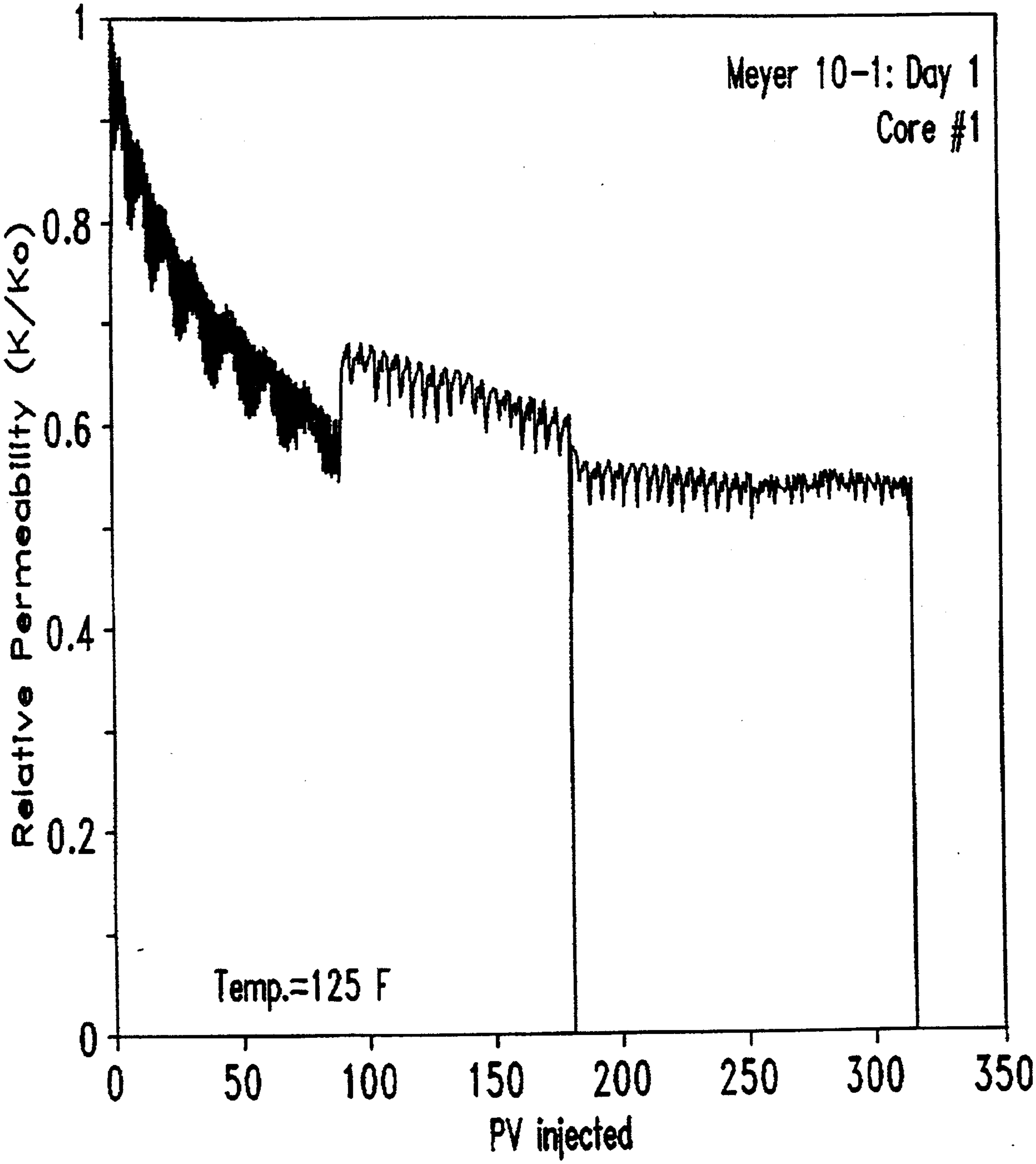



**Figure 12: Relative Permeability versus Pore Volumes Injected for 3.0% Potass. Chlor. Solution**

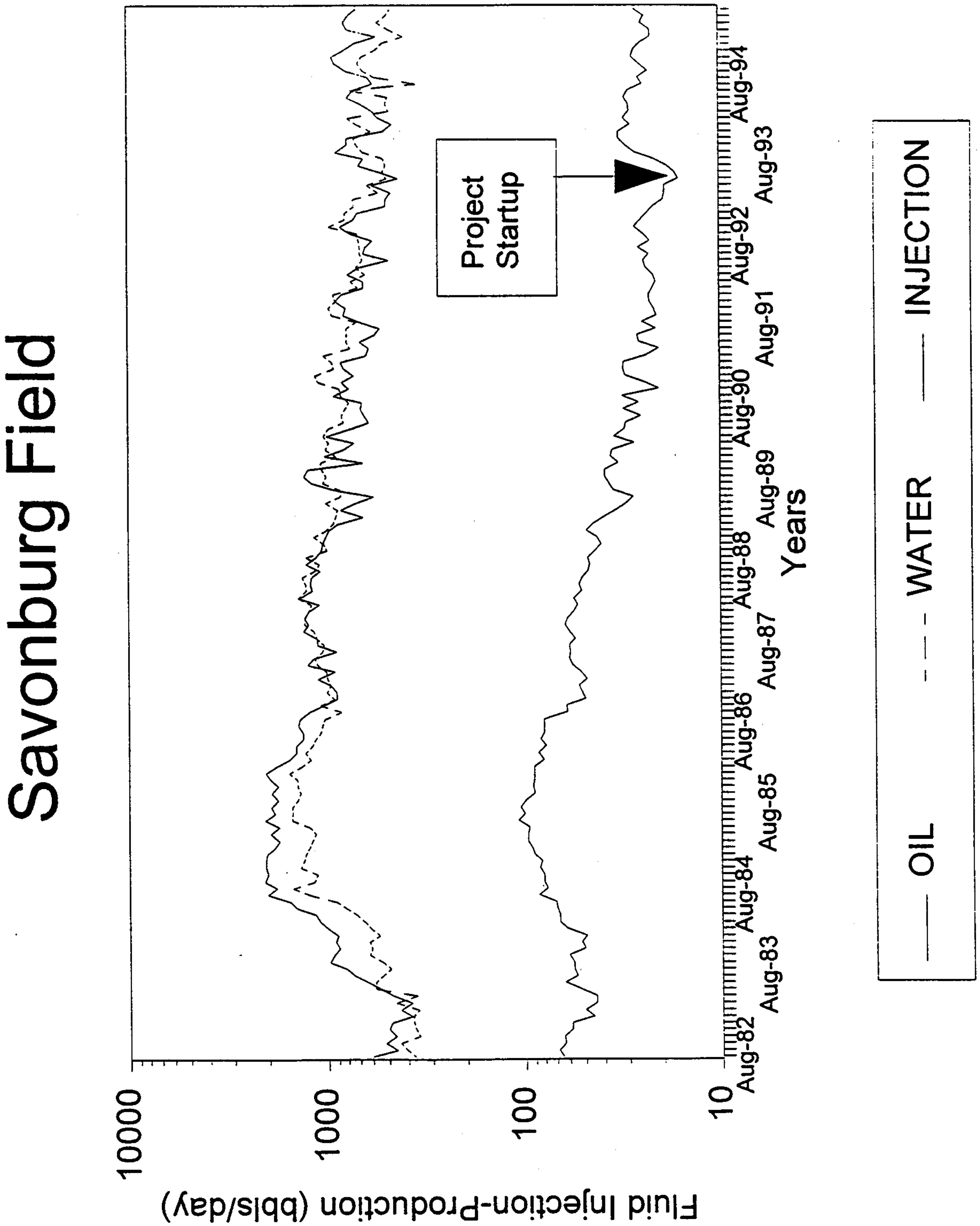



**Figure 13: Savonburg Field Production Curve**

# Nelson Lease Cum. Oil Prod. By Well as of June 1994

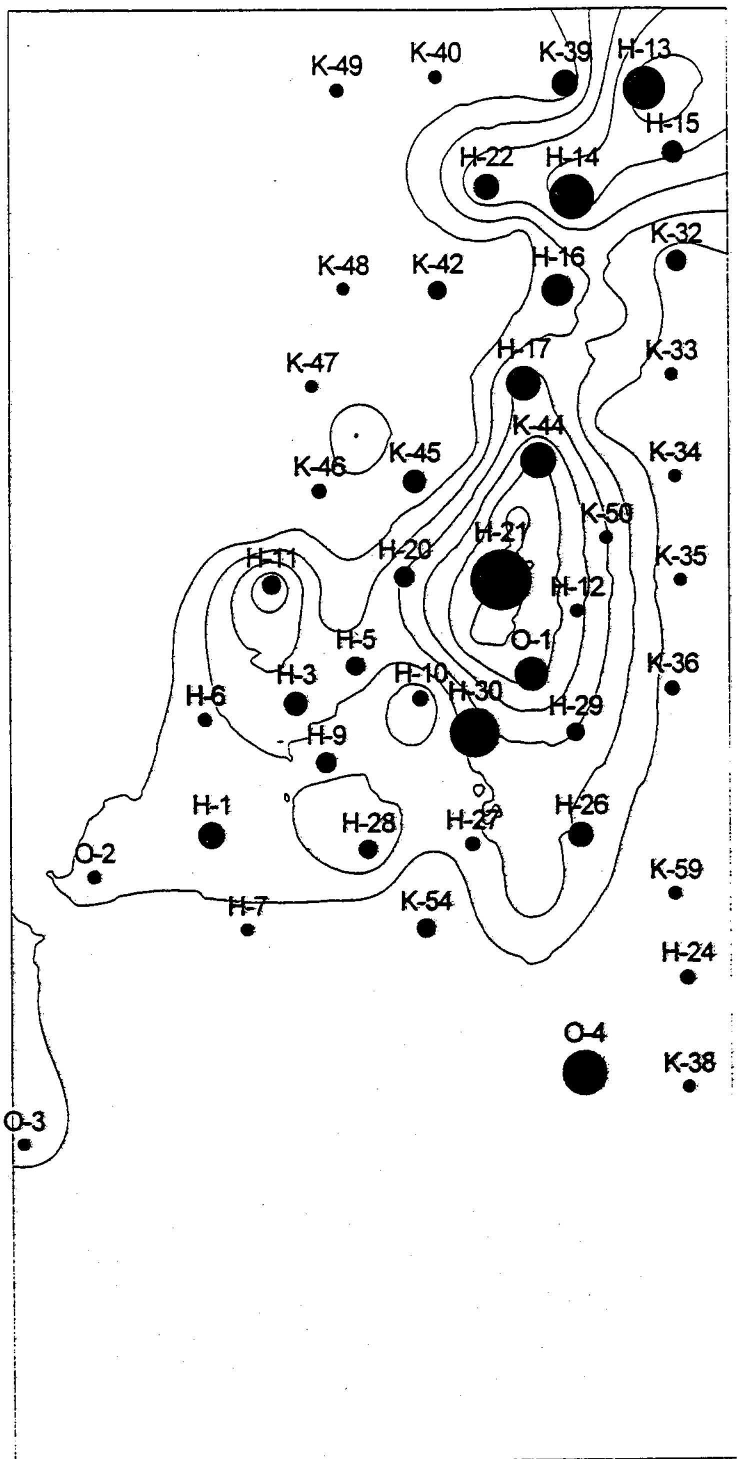



**Figure 14: Cumulative Oil Production by Well - Savonburg Field**

# Areas of High Potential

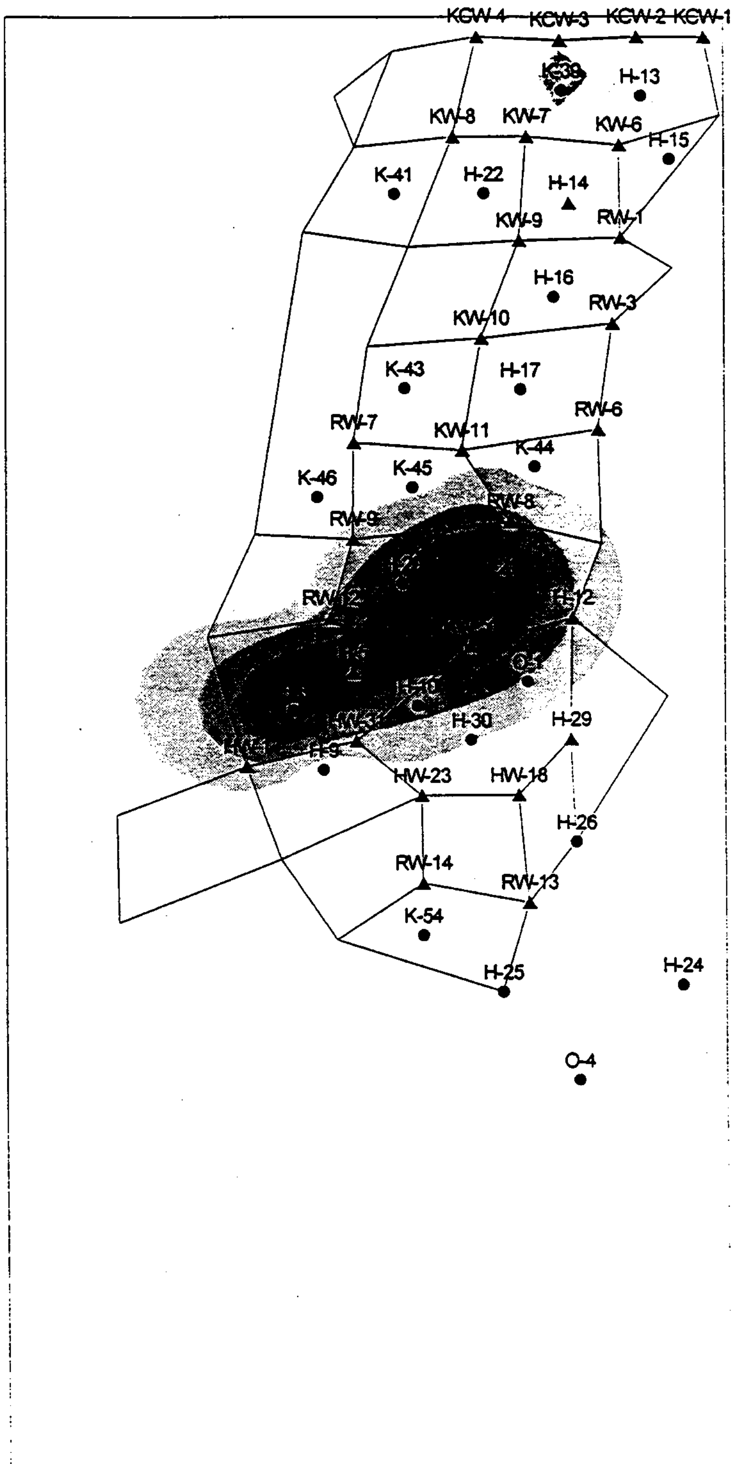



**Figure 15: Map of High Potential Areas - Savonburg Field**



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