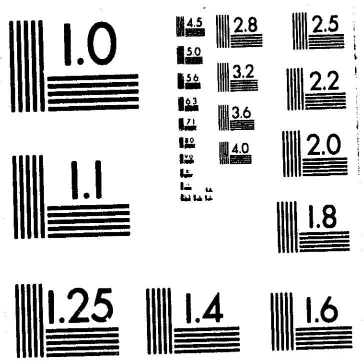
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Feasibility of Steam Injection Process in a Thin, Low-Permeability Heavy Oil Reservoir of Arkansas--A Numerical Simulation Study

Topical Report

By
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FEASIBILITY OF STEAM INJECTION PROCESS IN A THIN LOW PERMEABILITY HEAVY OIL RESERVOIR OF ARKANSAS— A NUMERICAL SIMULATION STUDY

By A. K. Sarkar and P. S. Sarathi

ABSTRACT

This report details the findings of an in-depth study undertaken to assess the viability of the steam injection process in the heavy oil bearing Nacatoch sands of Arkansas. Published screening criteria and DOE's steamflood predictive models were utilized to screen and select reservoirs for further scrutiny. Although, several prospects satisfied the steam injection screening criteria, only a single candidate was selected for detailed simulation studies. The selection was based on the availability of needed data for simulation and the uniqueness of the reservoir. The reservoir investigated is a shallow, thin, low-permeability reservoir with low initial oil saturation and has an underlying water sand.

The study showed that the reservoir will respond favorably to steamdrive, but not to cyclic steaming. Steam stimulation, however, is necessary to improve steam injectivity during subsequent steamdrive. Further, in such marginal heavy oil reservoirs (i.e., reservoir characterized by thin pay zone and low initial oil saturation) conventional steamdrive (i.e., steam injection using vertical wells) is unlikely to be economical, and nonconventional methods must be utilized. It was found that the use of horizontal injectors and horizontal producers significantly improved the recovery and oil-steam ratio and improved the economics. It is recommended that the applicability of horizontal steam injection technology in this reservoir be further investigated.

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EXECUTIVE SUMMARY

One of the objectives of the U.S. National Energy Strategy is to reduce U.S. dependence on foreign oil by increasing U.S. oil production using known implemented oil recovery technology. The United States has a massive heavy oil resource, and much of it remains unrecovered in known reservoirs. This resource represents a significant future source of domestic oil and can make a substantial contribution to domestic production, if developed. Steam injection is the most efficient way to produce this resource. This technology, however, has not found widespread application outside of California. Steam injection is not universally applicable to all types of heavy oil fields, and the technical and economic success of the process is reservoir dependent. Hence, the applicability of steam injection in heavy oil reservoirs must be individually evaluated.

A recent study by NIPER concluded that heavy oil resources in the Gulf Coast sedimentary basin hold promise to augment domestic heavy oil production and may be exploited. The objective of this study are to assess the steamflood potential of heavy oil reservoirs in Arkansas. Screening guides and DOE steamflood predictive models were used to screen and select reservoirs for their steamflood applicability. A single reservoir was then selected from the promising ones for in-depth simulation study. A commercial steamflood simulator was utilized for this purpose. The reservoir investigated was a thin, low-permeability reservoir with low initial oil saturation, and has an underlying water sand. The study indicated the following:

- Steamflooding is viable in this type of reservoir.
- Because of the thin pay zone and low initial oil saturation, steamdrive using conventional vertical wells will not be economical in this reservoir at an oil price of less than $24/bbl.
- Horizontal well steamdrive technology holds greater promise for economic recovery of oil from this reservoir.
- For the pattern area studied, conventional steamdrive using vertical wells recovered 53% of oil in place at an estimated cost of $23.47/bbl.
- The use of horizontal injectors and horizontal producers, on the other hand, recovered 68% of the oil in place at an estimated cost of $15.33/bbl.

Improvement in reservoir characterization and an in-depth analysis of the technical and economic merits of horizontal injectors and producers are recommended. After completion of this assessment, a decision could be made whether or not to undertake a steamflood pilot in this reservoir.

CHAPTER 1

INTRODUCTION

The steadily increasing crude oil demand, accompanied by a steady decline in domestic production, has increased the United States dependence on foreign oil. Currently, more than 46% of the crude oil supplies needed to meet domestic demands are imported. This large and growing dependence on foreign oil indicates economic sensitivity to OPEC actions that can only be mitigated by increased domestic production and conservation.

The United States has a massive heavy oil resource base, and it is estimated that the total U.S. heavy oil resources represent about one-fifth of the estimated 500 billion bbl of crude oil discovered to date (Dowd et al., 1988). Of this amount, 45 billion bbl is considered mobile oil that can be produced using conventional and thermal techniques. Only a small portion of the known U.S. heavy oil resource has been produced to date, and much of it remains in known reservoirs. To increase U.S. domestic crude oil production and to reduce its dependency on foreign oil, efforts must be expanded to develop this massive domestic oil resource.

BACKGROUND

In the United States, heavy oil can be found in almost all oil-producing provinces ranging geographically from Arkansas to California and Texas to Alaska. Not all of these resources can be developed economically using the known extraction technology. California has the largest concentration of heavy oil in the United States and accounts for the bulk of current U.S. heavy oil production. Next to California, Alaska and the U.S. Gulf Coast States (Arkansas, Mississippi, Louisiana, and Texas) account for the bulk of remaining U.S. heavy oil resources, but contribute very little to heavy oil production because heavy oil is more expensive to produce and transport and commands lower prices than light oil.

In the United States, heavy oil has been produced since the early 1900s using primary and waterflooding techniques and with thermal methods since the 1960s. Steam injection is the preferred technique for the extraction of heavy oil because of its higher recovery efficiency and long history of successful applications. Most U.S. steam injection projects are concentrated in California, where the heavy oil reservoirs meet the classic definition of thermal recovery prospects: (1) they are less than 4,500 ft deep (most less than 3,000 ft); (2) they have massive oil sandbodies, ranging from a minimum of 40 ft to more than 500 ft in thickness; (3) the oil-in-place amounts to more than 1,200 bbl/acre-ft; and (4) the sandbodies range from highly unconsolidated to poorly consolidated.

The previous guidelines reflect the current technology and economic climate. They merely suggest that by implementing steam injection projects in reservoirs that meet these criteria, operators can ensure economic successes. However, more than half of the successful U.S. steam injection projects (Chu, 1985) have been implemented in reservoirs that fail to satisfy one or more of the previous criteria. Each reservoir must be examined closely on an individual basis and engineering judgment applied before deciding whether or not to implement a thermal project.

A recent study, conducted by NIPER, identified several heavy oil containing reservoirs in the Gulf Coast area that exhibit characteristics similar to those of California reservoirs and hence are potential steamflood candidates (Olsen et al., 1991). These include the Cenozoic and Mesozoic Age sandstone reservoirs of Arkansas, Louisiana, and Texas. Several of these reservoirs have been successfully steamflooded even though they failed to satisfy one or more of the steamflood screening criteria. An example of this is the Phillips Petroleum Company's Smackover field steam injection project in the Nacatoch sand of Quachita County, Arkansas (Smith et al., 1973).

In spite of this and other successful steam injection projects, much of the Gulf Coast states heavy oil resource remains undeveloped. These heavy oil resources represent a significant future source of domestic liquid fuel and can make a substantial contribution to domestic crude oil production if and when developed. Steam injection is the most efficient way to produce these resources. Application of thermal techniques, however, are not universally suitable for heavy oilfields and the technical and economic success of the process is reservoir dependent. For example, implementation of conventional steam injection processes in reservoirs with thin pay and low oil content may not be economically attractive; hence, heavy oil reservoirs must be individually evaluated for the applicability of steam injection.

The small to medium-size independent operators who own most of the heavy oil leases in the United States lack the necessary technical expertise, tools, and resources needed to undertake such a study. Furthermore, since steam injection is more costly than conventional recovery techniques and the price received for heavy oil may not be sufficient to justify the expense of injecting heat into a reservoir for recovering heavy oil, independents may be reluctant to try this proven technique. To minimize the United States dependence on imported oil and to increase domestic production, reservoirs amenable to steamflooding must be identified, and operators must be encouraged to try this technology where suitable.

OBJECTIVES OF STUDY

The objectives of this study were to assess the steamflood potential of heavy oil reservoirs in Arkansas and make specific recommendations as to the viability of the process in these reservoirs. The methodology used to achieve the stated objectives was as follows:

- Screen the heavy oil bearing reservoirs of Arkansas for their suitability for steam injection application.
- Compile and evaluate geological, fluid, and reservoir information for a candidate reservoir.

- Conduct detailed simulation studies to determine the applicability of steam injection in the selected reservoir; and
- Comment on the technical and economical viability of steam injection in the targeted reservoir.

APPROACH

The NIPER heavy oil data base was reviewed to identify and collect data on all heavy oil reservoirs in Arkansas and Louisiana. Published guides were then used to screen these reservoirs and the best steamflood candidates were identified. DOE's steamflood predictive models were used to predict the performance of these reservoirs and select the best candidate for further study. The operator of this reservoir was then contacted, and geological and reservoir data were acquired. The gathered information was then reviewed, and missing information was estimated. This information was input into a numerical simulator, and the steamflood performance of the reservoir was evaluated for various operating scenarios. The simulation results were then analyzed, and specific conclusions were made.

CHAPTER 2

SELECTION OF POTENTIAL RESERVOIRS USING SCREENING GUIDES AND PREDICTIVE MODELS

2.1 Introduction

Screening guides are typically used to quickly identify reservoirs that are most amenable to steam injection. The analysis is based on the effects of individual reservoir characteristics on the performances of steam injection projects and on the histories of past performances. However, the screening guides cannot be used to analyze the combined effects of favorable and unfavorable reservoir characteristics. The issues of reservoir heterogeneities (property distributions of porosity, permeability, saturation, pressure, thickness, etc.) and boundary conditions (gas cap, bottom water, reservoir dip, etc.) are not considered at all. The objective for using a predictive model is to predict steam injection performance based on average values of reservoir properties. In this process, the combined effects of different reservoir characteristics are considered, but reservoir heterogeneities and boundary conditions are not considered. Compared to screening guides, predictive models offer more insight but require more effort. The objective of using a thermal simulator is to predict the steam injection performance of a reservoir under more realistic conditions. A simulator takes into account the issues of reservoir heterogeneities and boundary conditions. It provides a thorough analysis of the predicted performance but requires maximum effort.

The approach for using screening guides, predictive models, and thermal simulators in this study was as follows: First, screening guides were used efficiently in a spreadsheet environment to screen many reservoirs. Second, predictive models were used to analyze promising reservoirs, and to select a few reservoirs with very high recovery potential. Finally, thermal simulators were used for a more detailed analysis of recovery performance of selected reservoirs. With completion of each stage of prediction of reservoir performance, the confidence accuracy of performance prediction increases, but at the same time the effort and the cost associated with the prediction process increases. For a reservoir with heterogeneous characteristics and with complicated boundary conditions, the use of thermal simulators is necessary.

2.2 Reservoir Data

From the heavy oil database developed by NIPER, 31 heavy oil reservoirs in the Nacatoch sands of Arkansas and Louisiana were identified. Only Caddo Pine Island and Bellevue fields are located in the State of Louisiana, and the remaining fields are located in the State of Arkansas. Data on location, density, depth, area, thickness, porosity, connate water saturation, cumulative oil production, and formation volume factor (FVF) were obtained from this database (also available in Annual Oil & Gas Report, 1988). It should be noted that the data are fieldwide average values.

Data on acreage for Bodcaw, Lake June, and Langley fields in Arkansas and Caddo Pine Island in Louisiana were not available. Reports on several pilot projects, including one waterflood, three steamfloods, and four firefloods, conducted in Caddo Pine Island field (19° to 21° API crude) were available, but no information about the structure of the field or the primary production was available (Louisiana Department of Conservation Report, 1974). Bellevue field in Louisiana had been produced by fireflooding, however, no data on current cumulative oil production or present oil saturation values was not available. Also, the permeability values for Caddo Pine Island and Bellevue fields are low (about 600 mD). For these reasons, Bodcaw, Lake June, Langley, Caddo Pine Island (Caddo and Bossier counties), and Bellevue fields were eliminated from the screening process. The remaining 25 reservoirs were considered for screening (Table 2.1).

Permeability data were available for Sandy Bend, Charivari Creek, Elliott South, Gum Creek, Hampton, Irma, Langley, Lloyd Creek, Smackover, Troy, and Willisville fields in Arkansas. Except for the reservoir in Charivari Creek, Gum Creek, Buena Vista and Lloyd Creek fields the permeability values for all the reservoirs were found to be greater than 1,500 mD, and permeability values were arbitrarily assumed to be 1,500 mD for those reservoirs for which data were not available.

Reservoir temperatures were estimated by Eq. A-1. Viscosities of oil for some of the fields were available in Saybolt second unit (USBM IC 8428, 1969). These data were converted from a Saybolt second unit to a centipoise unit using a conversion chart (Farouq Ali, 1970: Fig. 2.3). Viscosities of oil for the other fields at reservoir temperatures were obtained from interpolations of viscosity vs. temperature graphs for Gulf Coast crudes of various densities (Braden, 1966). Initial and current oil saturations were calculated by Eqs. A-2 and A-3. Absence of free gas or the reservoir pressure being higher than the bubblepoint pressure was assumed. Oil-in-place (OIP) and oil recovery [in % of oil initially in place (OIIP)] were calculated for all of the fields according to Eqs. A-4 and A-5, respectively. Cumulative production data for 1988 were used for these calculations.

2.3 Screening Guides

Screening guides proposed by several authors have been summarized elsewhere (Table 4.1 in Butler, 1991). With the advancement in technology and changes in the economic environment, the magnitude of desired values for basic reservoir properties used in the guides have changed. In addition, some screening guides may be considered as more restrictive than others. The ranges of desired values, as proposed by different authors, for various reservoir characteristics are as follows: density, 10° to 40° API; viscosity (μ), 300 to 1,000 cP; depth, 400 to 5,000 ft; minimum thickness (h), 10 to 30 ft; minimum permeability (k), 1,000 mD; minimum porosity (ϕ), 0.2 to

0.3; minimum oil saturation (S_o), 0.40; minimum ϕS_o, 0.065 to 0.15; and minimum transmissibility (kh/μ), 20 to 100 mD ft/cP. In Chu's guide there is no restriction for values of permeability, viscosity, and kh/μ. Also, he has pointed out that steamfloods might be successful even if one or two of the screening conditions are not met, provided that the other conditions are strongly favorable. The COSR (Cumulative Oil Steam Ratio) is the most commonly used criterion for predicting the economic performance of a project. A value of 0.2 or more for COSR is considered good, and most of the field projects have values from 0.14 to 0.25 (Chu, 1985). The COSRs of the Kern River 10 pattern, Brea, Slocum South Belridge, and Mount Poso fields are about 0.15, and those of Kern River, Inglewood, Midway-Sunset, and Shiells Canyon fields are about 0.25. All these field projects are known to be economically successful.

In this work the Chu's guide, which is the most recent one, has been followed. From the basic data of permeability (k), porosity (ϕ), oil saturation (S_o) and viscosity of oil (μ), ϕS_o and kh/μ were estimated for all of the reservoirs. The COSRs were estimated using Eq. A-6. The results show that all of the reservoirs meet the screening criteria for depth and density. The reservoirs were arranged in descending order for thickness (> 6 ft ; relaxed from screening criterion of 10 ft), oil saturation (>0.4), and ϕS_o (>0.08), in three successive stages. In each stage, only the qualified reservoirs were considered. The top 17 reservoirs meet these criteria, but five of these—Woodley, Elliott South, Buena Vista, Wesson North, and Troy North—have thicknesses of less than 10 ft. The maximum thickness is found to be 25 ft (Sandy Bendy field) and the top four reservoirs have thicknesses of more than 10 ft. Elliott South has the best values for S_o (0.65), ϕS_o (0.24), and COSR (0.17), but it has a small thickness of 7 ft. Finally, the reservoirs were arranged in a descending order for OIP. Sandy Bend has the highest values for area, thickness, and OIP, but the value for S_o (0.46) is just marginally higher than the minimum required. Irma field has good values for S_o (0.53), ϕS_o (0.19), thickness (19 ft), and permeability (2,500 mD). The values for area and OIP are second to those for Sandy Bend. Charivari Creek field has good values for thickness and oil saturation, but the permeability is low, and the oil viscosity is 55 cP.

The screening study suggests that the five reservoirs having the best recovery potential are: Sandy Bend, Irma, Troy, Charivari Creek, and Elliott South.

2.4 Predictive Models

The DOE steamflood predictive model (Ray and Espinoza, 1986) was used for predicting steamflood performances of the five best reservoirs selected using the screening guides. The model allows a user to choose from the four types of oil recovery models: SUPRI, GOMAA, JONES, and INTERCOMP. The model was used by Ray and Espinoza (1986) to conduct sensitivity studies showing the effects of the type of recovery model, steam injection rate, pattern area, porosity, and oil saturation, steam quality, oil gravity, and net to gross thickness ratio on the recovery performance of a field. The results of the sensitivity studies should be viewed carefully because some of the results may be reservoir-specific or specific to the standard chosen in comparing various cases. From analytical considerations, smaller pattern area, which reduces the operation time, and higher steam quality, which increases injected heat, are always better (Figs. 3.11 and 3.15 in Butler, 1991). The limitations on these parameters arise from operational and economic considerations. It is likely that each reservoir has technical and economic optimum steam injection rates. Higher steam injection rates are better as long as the mobility of the reservoir does not become restrictive. In addition to the mobility, area of the steamflood pattern may be another factor in the evaluation of optimum steam injection rate. Applications of higher steam injection rates in low-permeability reservoirs result in ineffective reservoir heating where the mass and enthalpy of injected steam are used for raising the temperature and pressure of the reservoir to very high levels. A brief discussion about the basic principles of these four oil recovery models is given below.

The JONES (1981) model is based upon the concept of heat and simplified material balances, and does not take into consideration relative permeability or fractional flow relations. It is based on the work done by Marx and Langenheim (1959), Mandl and Volek (1969), and Myhill and Stegemier (1978). It is modified with three practical empirical factors to account for reservoir fillup (initial gas saturations), poor displacement efficiency of a cold waterflood taking place ahead of steam and hot water fronts (initial oil viscosity), and the reservoir depletion effect (reduction in mobile oil saturation with time). These factors, in a sense, mimic some of the effects of relative permeability/fractional flow relations. The model is analytically more sophisticated than the SUPRI (Williams et al., 1980) model, which is based on Marx and Langenheim calculations alone, and is theoretically simpler than the INTERCOMP model (Aydelotte and Pope, 1983). The INTERCOMP model, unlike other predictive models, allows the use of relative permeability relationships. The GOMAA (1980) model is based on correlations developed from numerical simulations of Kern River heavy oil reservoirs. The types of reservoirs under consideration here are thinner than those found in the Kern River. Moreover, the correlations developed in the model are for lower injection rates (up to 0.6 MMBtu/D/acre/ft). Considering the limitations mentioned above for SUPRI and GOMMA models, only the JONES and INTERCOMP models were used for analyzing the performances of these reservoirs.

All the reservoirs under consideration here have low reservoir thickness. The thermal efficiency of steam injection decreases with a decrease in reservoir thickness (Fig. 3.11 in Butler, 1991). This condition limits economic potential using standard recovery methods; however, thermal efficiency increases with a decrease in time of operation. The time period of operation can be decreased by increasing steam injection rates. Two injection rates: 350 and 3,500 BBL/d, were used to evaluate the effect of time period of operation on steamflood processes. Inclined/horizontal wells can be used for achieving high injection rates in thin reservoirs. A tenfold increase in the injection rate may necessitate approximately a 10 times or more (depending upon vertical to horizontal permeability ratio) increase in the wellbore length (length of the portion of the well contacting the formation). Achieving a higher injection rate of 3,500 BBL/d, especially in cases of thin and low-permeability reservoirs, may be difficult in reality; however, an order of magnitude higher rate is used here to illustrate the rate effect. In the predictive models, there is no option for using horizontal wells. Injection rates of 2 to 15 BBL/d/ft have been used in field projects using vertical well configurations (Table 4.4 in Butler, 1991).

The operating data used in the predictive models are summarized in Table 2.2. For each of these reservoirs, a single 5-spot pattern of 5 acres was used for modeling, and only the pattern results are discussed here. The time step sizes were 2 months (0.16 years) for all cases. An arbitrarily chosen surface steam quality of 70% was used in all cases. The bottomhole/sandface steam quality was evaluated using a default equation (Zolotukhin, 1979), which is a linear function of the surface steam quality and depth. The steam conditions, cold and hot oil viscosities, and residual oil saturations in the steam zone (S_{or}) are shown in Table 2.3. Oil production rate, cumulative oil rate and COSR histories are the three basic criteria used to compare performances of different reservoirs. The dimensionless critical time or Mandl-Volek time (t_{DC}), breakthrough time (t_{BT}), initial injectivity index (PI), and thermal and recovery efficiencies (E_r and E_h) are the other criteria which have been used here. Thermal and recovery efficiencies are expected to be strongly related in energy intensive thermal operations. The results obtained from the use of JONES and INTERCOMP models for the five reservoirs are summarized in Table 2.3.

2.4.1 JONES Model

For the cases run using this model, the bottomhole pressure was arbitrarily assumed to be 100 psi above (by default) the formation pressure, which was evaluated using a default pressure gradient of 0.22 psi/ft. A depleted reservoir condition was assumed. For a reservoir, bottomhole steam conditions and hot and cold zone viscosities were assumed to be the same whether a low rate or a high rate operation was used.

TABLE 2.2

Steamflood Data Used in the Predictive Models

Pattern type	5 spot
Pattern area, acres	5.0
Surface steam quality, %	70.0
Time step, months	2.0
Steam injection rates, bbl/d	350-low rate operations 3,500-high rate operations

TABLE 2.3

Results From JONES and INTERCOMP Models

Field	General Conditions					JONES Model											INTERCOMP Model				
						High Rate Operations, 3,500 bbl/d						Low Rate Operations, 350 BBL/d					Low Rate Operations, 350 BBL/d				
	Steam Condn. T_s °F	Steam Condn. P_s psi	Steam Condn. x frac.	Viscosity μ_c/μ_h cP	PI BBL/D /psi	t_{DC} frac.	A_h @t_{DC} frac.	t_{BT} yr.	E_r @t_{BT} frac.	E_h @t_{BT} frac.	Np @1.5 yr MSTB	A_h @t_{DC} frac.	A_h @15 yr frac.	E_r @15 yr frac.	E_h @15 yr frac.	Np @15 yr MSTB	A_h @t_{DC} frac.	A_h @15 yr frac.	E_r @15 yr frac.	E_h @15 yr frac.	Np @15 yr MSTB
Sandy Bend	487	606	0.56	60/0.4	81	0.6	0.77	0.74	0.82	0.54	91.8	0.08	0.84	0.72	0.21	76.6	0.70	0.81	0.55	0.14	59.7
Irma	435	364	0.63	1270/0.4	94	1.05	1.25	0.82	0.87	0.53	118.6	0.10	0.78	0.56	0.22	75.3	0.80	0.80	0.62	0.12	83.4
Troy	440	379	0.63	1260/0.6	113	1.01	0.78	0.38	0.83	0.50	97.3	0.08	[1]1.0	0.61	0.18	85.9	0.82	0.82	0.63	0.07	70.1
Charivari Creek	492	630	0.56	55/0.4	3	0.57	0.66	0.67	0.87	0.53	140.5	0.07	0.87	0.76	0.20	118.2	0.68	0.81	0.66	0.13	102.8
Elliott South	470	517	0.59	165/0.4	7	0.73	0.17	0.33	0.95	0.31	59.9	0.02	0.71	0.91	0.15	57.1	0.84	0.84	0.76	0.04	47.9

Note: [1] Hot water breakthrough occured at 10.4 years.

2.4.1.1 High rate operations. Figures 2.1, 2.2 and 2.3 compare the histories of oil rate production, cumulative oil production, and COSR for the five reservoirs operated at high steam injection rates of 3,500 bbl/d. Charivari Creek and Troy reservoirs were found to have the highest oil rates and COSRs. Incidentally, the results show that the maximum values for the oil rates (1,000 bbl/d), COSRs (0.29), and the time (0.15 year) at which these values are observed are also the same. For the Charivari Creek reservoir the COSR decreases to 0.15 at 0.75 years and the oil recovery by that time is 88%. A lower net to gross thickness ratio of the Irma reservoir (0.6 compared to 0.8 for the other reservoirs) is likely to have caused the delay in time at which the production rate peaks. Thermal efficiencies are about 53% for all of the reservoirs, except the Elliott South reservoir which has a low efficiency of 31% because of a low thickness of 7 ft. Recovery efficiencies are more than 80% in all cases, and about 95% in Elliott South reservoir because of much smaller pore volume in the formation. Times for hot fluid breakthrough are smaller for Elliott South and Troy reservoirs because of smaller formation thicknesses. Mandl-Volek critical time (Mandl and Volek, 1969) and fractional area heated at that time are higher for Irma and Troy reservoirs, compared to the other three reservoirs.

On the basis of performance, according to this type of operation, the top three reservoirs are: Charivari Creek, Troy, and Sandy Bend. For a time period up to 0.2 year, the Elliott South reservoir shows good performance. The Irma reservoir shows a good performance after 0.32 year.

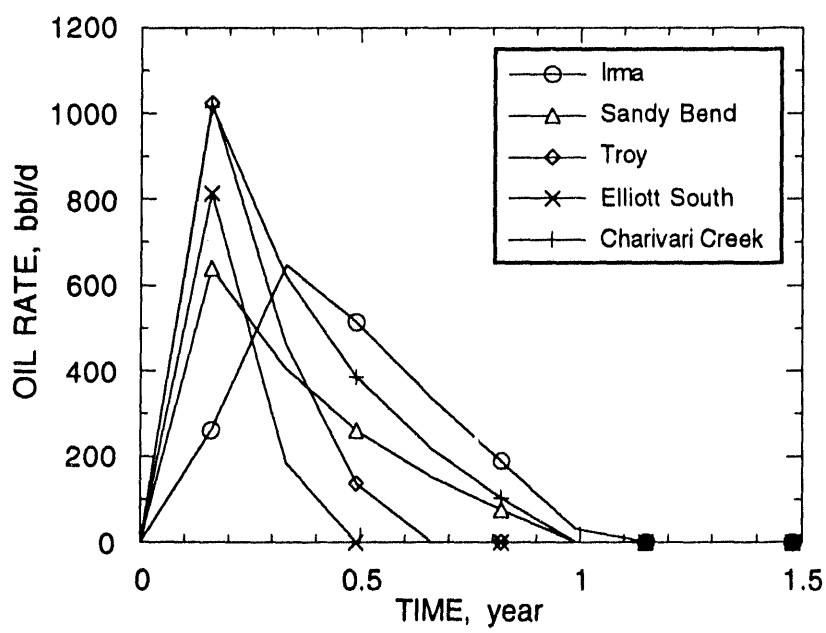


FIGURE 2.1 - Oil production rate histories for high rate operations for the reservoirs using the JONES model.

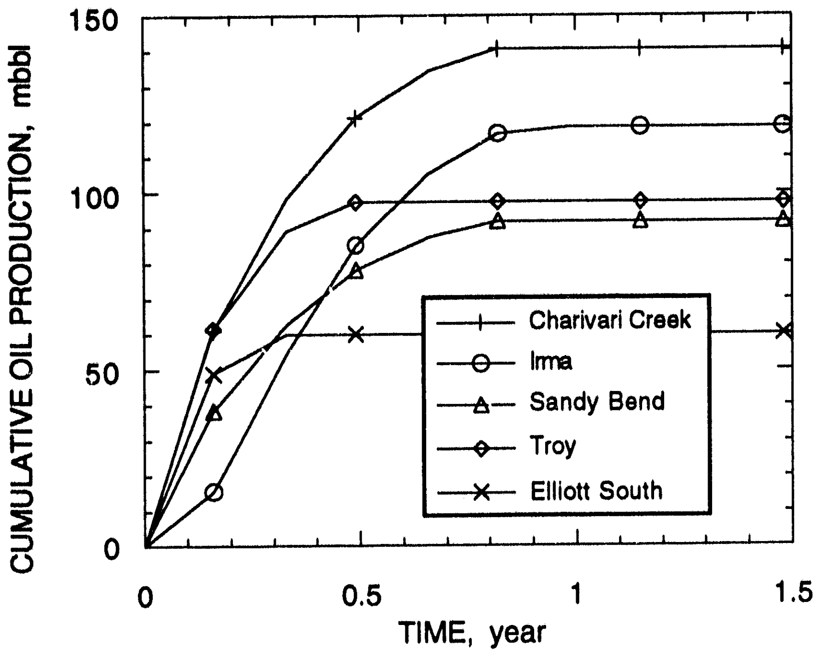


FIGURE 2.2 - Cumulative oil production histories for high rate operations for the reservoirs using the JONES model.

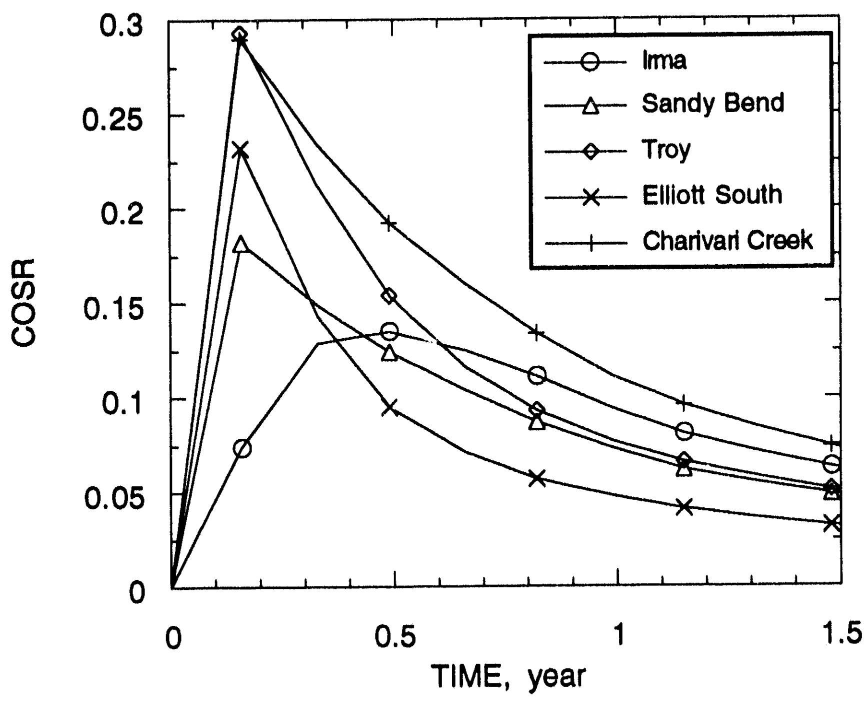


FIGURE 2.3 - COSR histories for high rate operations for the reservoirs using the JONES model.

2.4.1.2 Low rate operations. Figures 2.4, 2.5 and 2.6 compare the histories of oil production rate, cumulative oil production, and COSR for the five reservoirs operated at low steam injection rates of 350 bbl/d. The Charivari Creek reservoir is found to have the highest peak oil production rate (100 bbl/d) and peak COSR (0.29). The peak oil rate is 10 times lower than that obtained from the high rate operation, where the injection rate is 10 times higher. Interestingly, the peak COSR value is the same as that obtained from the high rate operation. The Sandy Bend reservoir case compares similarly, where the peak oil production rate is proportional to the injection rate, and the COSR is the same for both the high and low rate operations. For other reservoirs, the COSRs are much lower for the low rate operations. It is most likely that fluctuations in oil production rates between 2 and 10 years are introduced while taking derivatives of cumulative recovery histories to evaluate the oil rates.

The peak COSRs under the high and low rate operations of other reservoirs are: Troy, 0.29 and 0.06; Irma, 0.14 and 0.04; Elliott South, 0.23 and 0.07; respectively. The results are combined effects of the different reservoir characteristics. For the Charivari Creek reservoir, under low rate operation the COSR decreases to 0.15 at the end of 2 years and the oil recovery at that time is 24%.

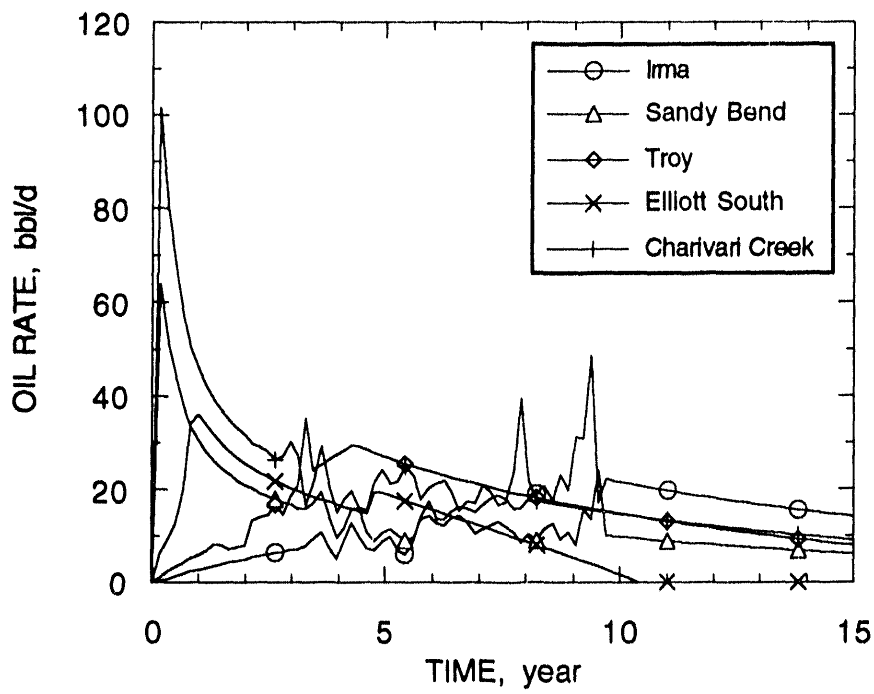


FIGURE 2.4 - Oil production rate histories for low rate operations for the reservoirs using the JONES model.

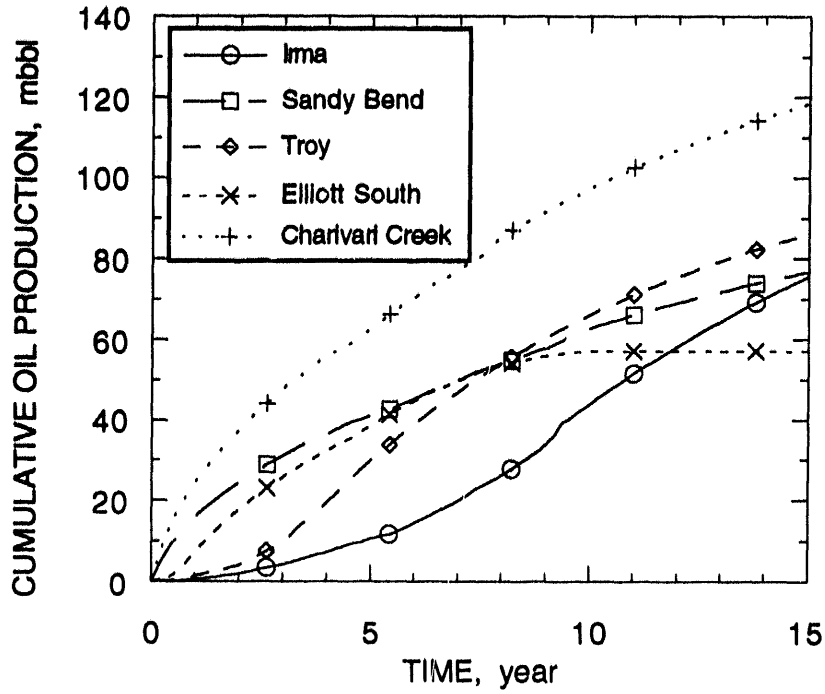


FIGURE 2.5 - Cumulative oil production histories for low rate operations for the reservoirs using the JONES model.

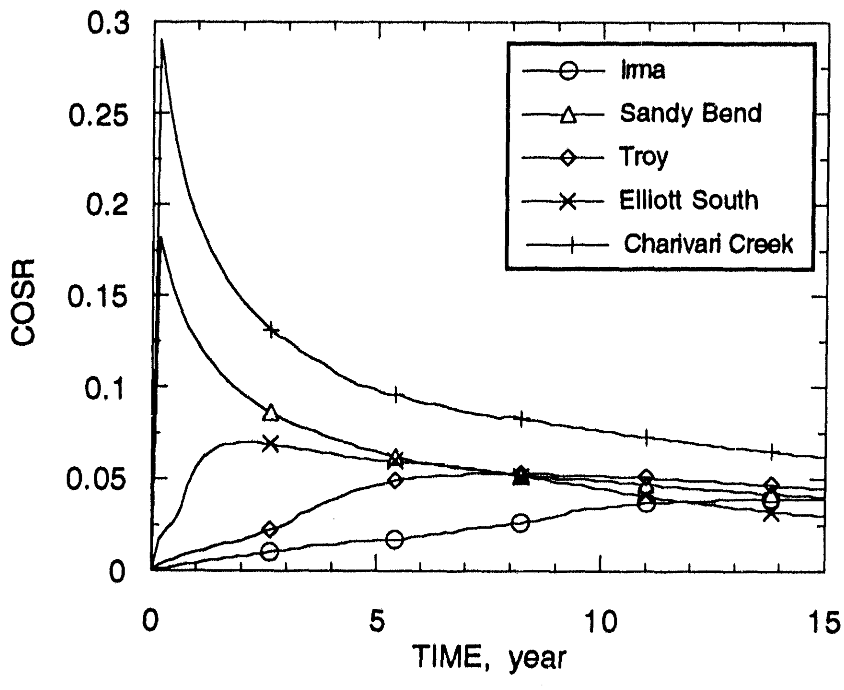


FIGURE 2.6 - COSR histories for low rate operations for the reservoirs using the JONES model.

The thermal efficiency values for the high rate operations (~52%) are 30% higher than those of the low rate operations (~22%). For the Elliott South reservoir, the thermal efficiency values for the high and low rate operations are 31% and 15%, respectively. Compared with other reservoirs these values are substantially lower because of its much lower thickness. The thermal efficiency for the high rate operations are higher because of shorter time periods of operations. The recovery efficiency values for the high rate operations (~84%) are 10% to 15% higher than those of the low rate operations (56% to 76%).

Except in the case of Troy reservoir, hot fluid does not break through by the end of 15 years. Troy reservoir has a breakthrough time of 10.36 years, and the recovery and thermal efficiency values are given at the breakthrough time (Table 2.3). The fractional areas of steam zone obtained at the end of Mandl-Volek critical time for high rate operations are much higher than those obtained from the low rate operations. Hence, the hot waterflood start inside a reservoir at a much earlier stage in the case of a low rate operation than in the case of a high rate operation. Considering the COSR as an operating criterion, a reservoir will reach the economic limit of operation at an earlier stage of oil recovery in the case of low rate operations. On the basis of performance under low rate operations the top three reservoirs are: Charivari Creek, Sandy Bend, and Troy. The Elliott South reservoir shows a good performance for the first 5 years of operation.

For high rate operations the initial investment cost (additional capital cost for the inclined well) will be higher, but the total operation cost may be lower because of shorter operational time and higher thermal efficiencies. Moreover, some of the well costs may be recovered by retrieving the casing and the downhole and surface equipment. Casing and cementing costs are considered to be one-third of total well cost. The downhole and surface equipment costs are another one-third of total well costs. The retrieval operation should be of significance for high rate operations because the project life may be limited to 2 years of steamflooding and another 1 year of waterflooding. At the end of 3 years of operation, the casings and equipment are expected to be in good condition.

Comparing the performance of five reservoirs under high and low rate operations, the Charivari Creek reservoir appears to be the most attractive. Figures 2.7 and 2.8 show histories of COSR and cumulative oil production for the high and low rate operations conducted on the Charivari Creek reservoir.

2.4.2 INTERCOMP Model: Low rate operations

In contrast to the JONES model, the amount of steam that can be injected at a particular time in a particular reservoir is limited by the formation injectivity, which depends upon the product of mobility and thickness of the reservoir ($h * kk_{rl}/\mu_l$), and the position of the steam front. To

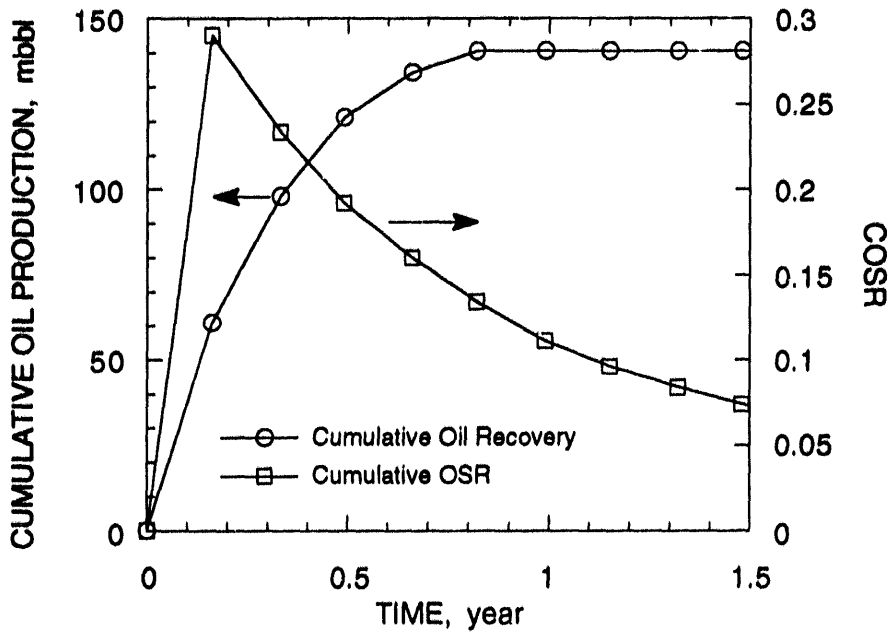


FIGURE 2.7 - Cumulative oil production and COSR histories for high rate operations for the Charivari Creek reservoir using the JONES model.

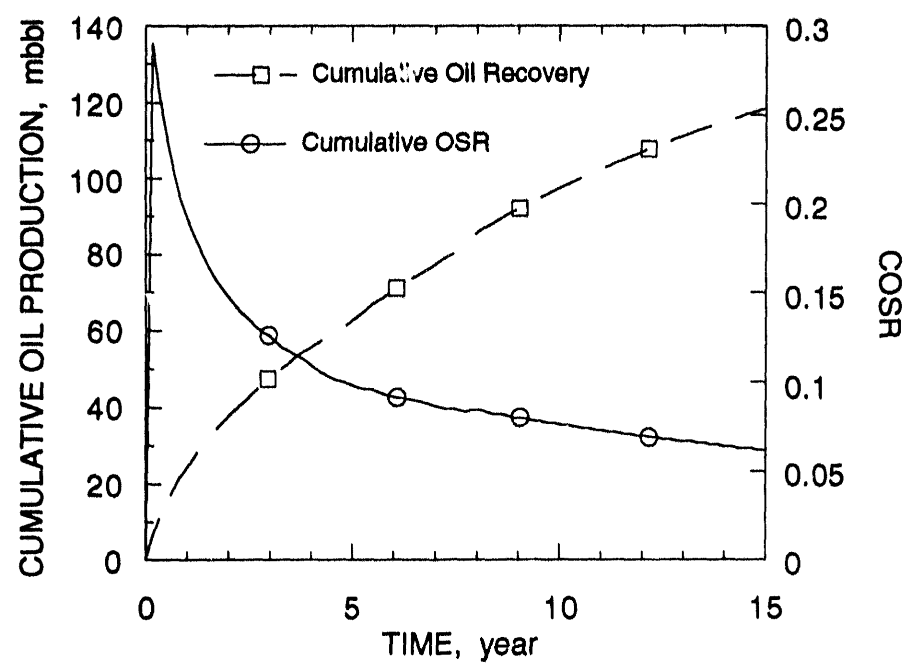


FIGURE 2.8 - Cumulative oil production and COSR histories for low rate operations for the Charivari Creek reservoir using the JONES model.

compare the results obtained from the JONES and INTERCOMP models for a particular reservoir, the operating conditions (injection rate and temperature, pressure, and quality of steam) should be the same. The bottomhole steam pressure (p_S) and temperature (T_S) decrease slightly as steam injection continues. Because of limited injectivity, the model could not be run for some of the reservoirs at low rate operations (steam injection rate of 350 BBL/D). To maintain a uniform basis, the low rate operations were conducted by artificially increasing the permeabilities by 10 times for all the reservoirs. Higher permeabilities will provide more optimistic results, but it is assumed that outcome of the selection process consisting of comparison of relative reservoir performances will remain unchanged. In the JONES model, permeability is not a factor; hence, the comparison of results obtained from JONES and INTERCOMP models should be viewed with caution. The model could not be run for any of the reservoirs at high rate operations (steam injection rate of 3,500 BBL/D). To use this model appropriately, it is necessary to know the relative permeability data. In the absence of any relative permeability data, the same default equations and parametric values have been used for all the reservoirs.

Figures 2.9, 2.10, and 2.11 compare the histories of oil production rate, cumulative oil production, and COSRs for the five reservoirs operated at low steam injection rates of 350 bbl/d.

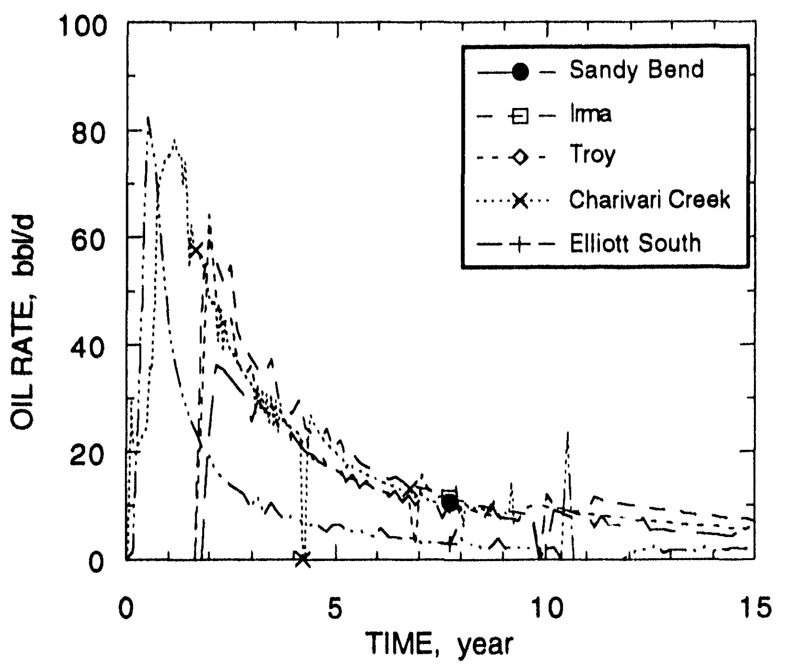


FIGURE 2.9 - Oil production rate histories for low rate operations for the reservoirs using the INTERCOMP model.

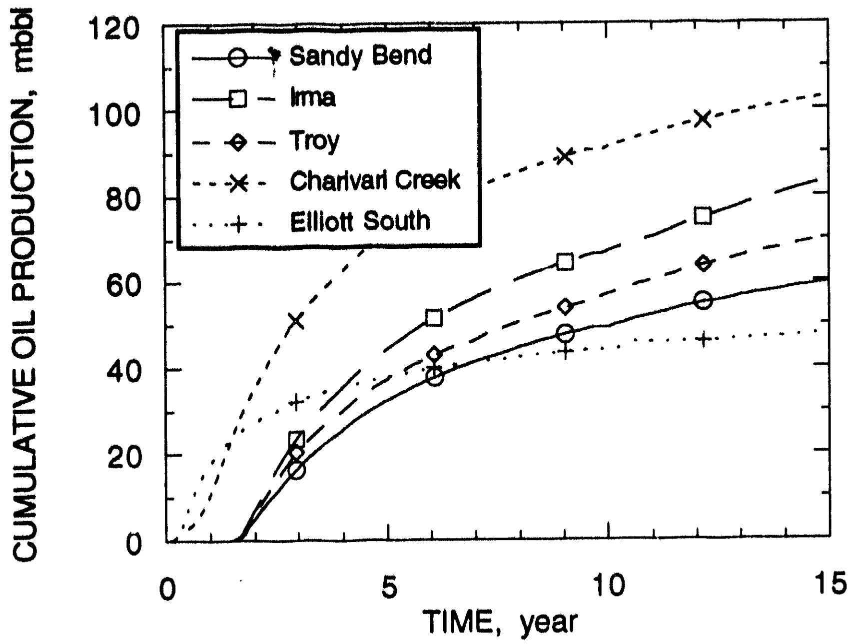


FIGURE 2.10 - Cumulative oil production histories for low rate operations for the reservoirs using the INTERCOMP model.

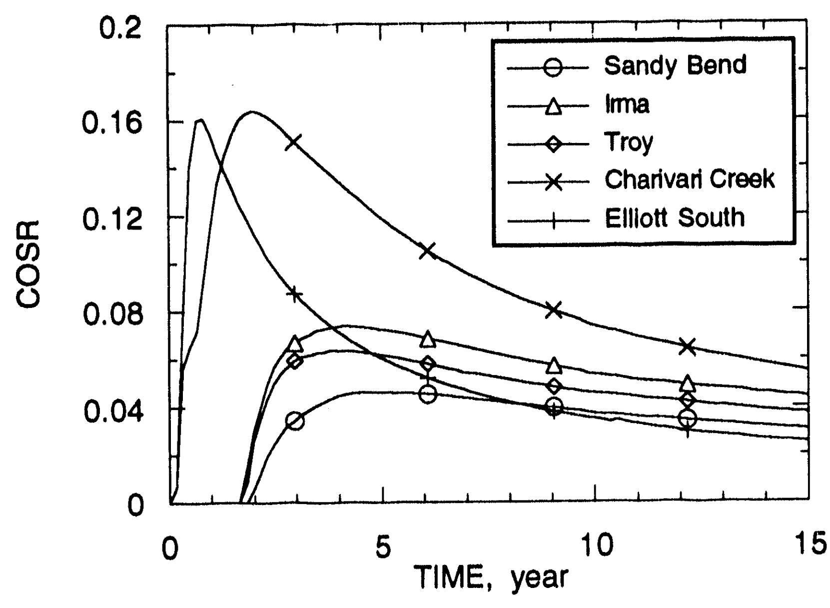


FIGURE 2.11 - COSR histories for low rate operations for the reservoirs using the INTERCOMP model.

The Charivari Creek and Elliottt South reservoirs show similar peak COSRs of 0.16 and similar peak oil rates of approximately 80 STB/d. For Charivari Creek reservoir, the COSR decreases to 0.15 at the end of 2 years. For Elliott South reservoir, the COSR and the oil rate decrease very sharply. The poor performance by Sandy Bend reservoir is probably resulting from the relative permeability effect caused by a low oil saturation. The delay in time at which oil rates peak probably results from the combined effects of relative permeability, viscosity, and poor displacement efficiency in the cold reservoir zones. The Charivari Creek reservoir has a low cold zone viscosity as well as a high oil saturation. The Sandy Bend reservoir has a low cold zone viscosity but a low oil saturation. Figure 2.12 shows the different lagging periods that different reservoirs have before reaching the full injection rate of 350 BBL/D.

Based on the performances according to the low rate operations, the top three reservoirs are: Charivari Creek, Irma, and Troy. The Elliott South reservoir shows a good performance only during the early period of the operation.

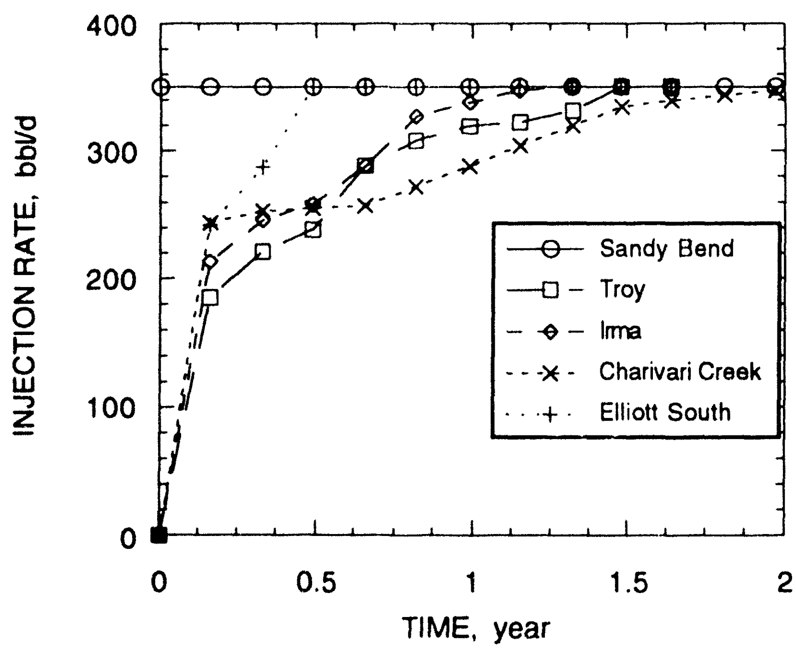


FIGURE 2.12 - Steam injection rate history for the reservoirs using the INTERCOMP model.

2.4.3 Effect of Models

The influence of models on the performances of the five reservoirs operated under low rate operations is discussed here. The final thermal efficiency values obtained from the INTERCOMP model are 7 to 11% less as compared to the values obtained from the JONES model. The recovery efficiency values for the Charivari Creek, Sandy Bend, and Elliott South reservoir are 10 to 15% less as compared to the values obtained from the JONES model. However, the model values for recovery efficiency for the Irma and Troy reservoirs are similar. The values of fractional area heated at 15 years obtained from the JONES and INTERCOMP models are similar for all the reservoirs. It is not clear why the values for fractional area heated at Mandl-Volek critical time obtained from the INTERCOMP models are much higher compared to those obtained from the JONES model.

Compared to the Sandy Bend and Charivari Creek reservoirs, the Irma and Troy reservoirs show a delay in the beginning of oil production. This is likely because of higher viscosity for Irma and Troy reservoirs. Both the models predict recovery efficiency values near 65% for all the reservoirs, except the Elliott South reservoir where it reaches about 80%.

The JONES and INTERCOMP performance prediction results indicate that Charivari Creek has the highest potential for steamflood operations. Figures 2.13, 2.14, and 2.15 compare the

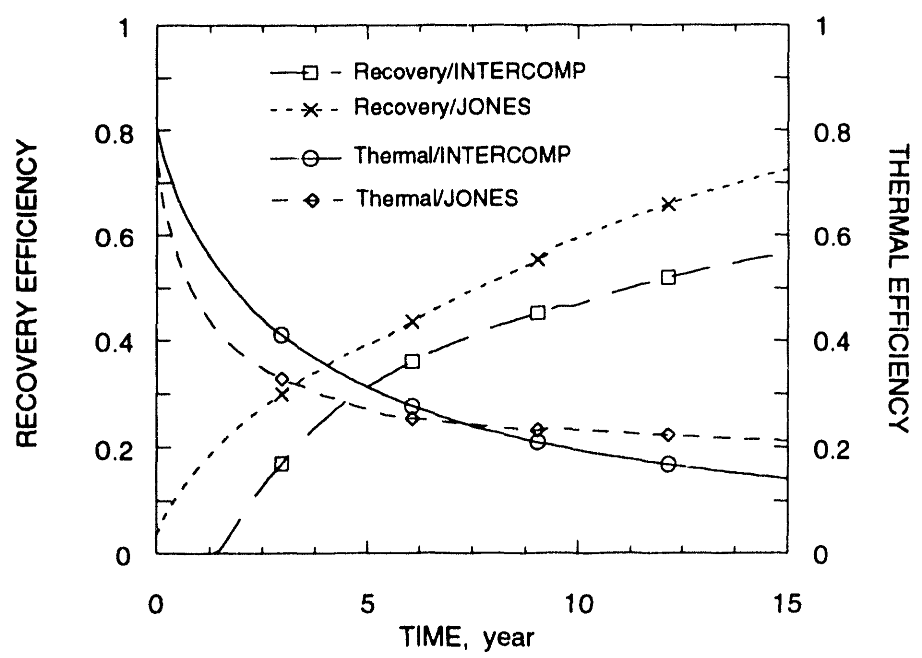


FIGURE 2.13 - Comparison of the oil production rate histories obtained from the JONES and INTERCOMP models for low rate operations of the Charivari Creek reservoir.

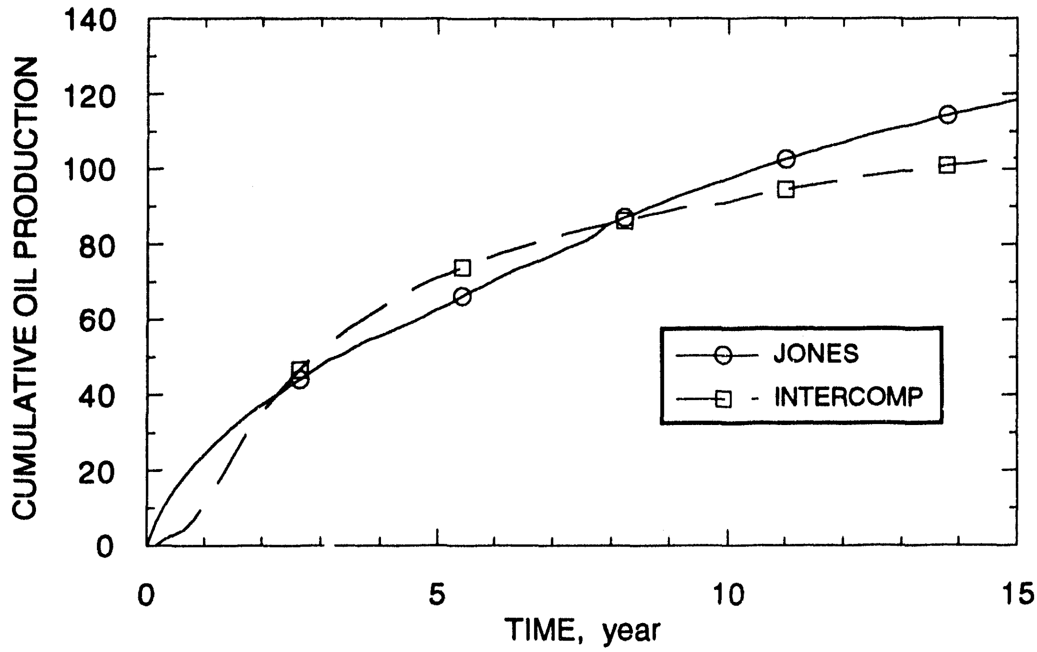


FIGURE 2.14 - Comparison of the cumulative oil production histories obtained from the JONES and INTERCOMP models for low rate operations of the Charivari Creek reservoir.

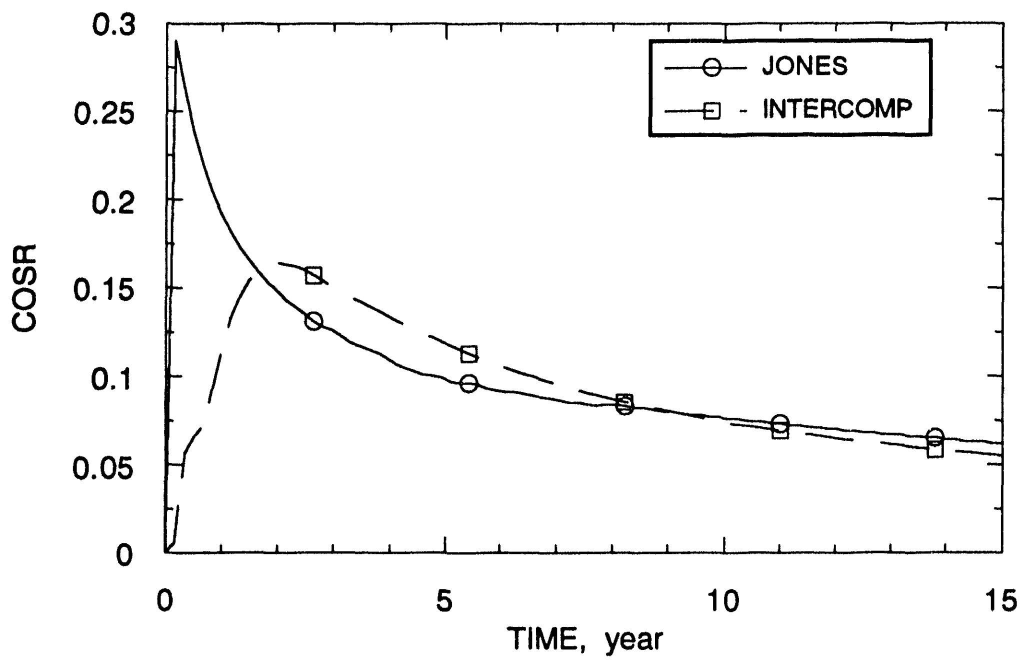


FIGURE 2.15 - Comparison of the COSR histories obtained from the JONES and INTERCOMP models for low rate operations of the Charivari Creek reservoir.

histories of oil production rate, cumulative oil production, and COSR obtained from the JONES and INTERCOMP models. These results show that the JONES model is more optimistic in its prediction with a much higher peak COSR than that predicted by the INTERCOMP model.

2.5 Conclusions

(1) Results from screening all the heavy oil reservoirs in the Nacatoch formation of Arkansas and Louisiana indicate that the five reservoirs with highest potentials for steamflood applications are Sandy Bend, Irma, Charivari Creek, Troy, and Elliott South.

(2) DOE steamflood predictive model suggests that the Charivari Creek reservoir has the highest potential for steamflood applications, and Irma and Troy reservoirs have good potentials.

(3) Based on model results, Charivari Creek reservoir was selected for further in-depth performance analysis.

CHAPTER 3
GEOLOGICAL AND RESERVOIR DESCRIPTION OF CHARIVARI CREEK RESERVOIR

INTRODUCTION

3.1 Introduction

Based on core-log calibration, characteristics of the fractured wells, and the production characteristics of the reservoir, an attempt was made to characterize the Nacatoch formation at Charivari Creek field (also referred to as Charivari Creek reservoir) and to identify the more productive part of the reservoir. Core analyses and the type and number of logs available for this field are limited.

Charivari Creek field is about 35 miles northeast of El Dorado in the lower part of Bradley County, Arkansas. The field is in sections 6 and 7 of R-10-W, T-17-S and sections 1 and 12 of R-11-W, T-17-S. This area is within the Mississippi alluvial plain and the Gulf coastal plain. Phillips Petroleum Co. completed the first well in the field on November 26, 1963. The well produced 17° API gravity oil at the rate of 66 BOPD (based on bailing for 8 hours). The producing formation for the subject field is the Nacatoch sand of late or Upper Cretaceous age. Figure 3.1 shows the well locations with a geographical location map insert. Figures 3.2 and 3.3 show structural contours on the top of the Nacatoch sand and net oil isopachs of the Nacatoch sand over the field. Figures 3.4 and 3.5 are the north-south and east-west structural cross-sections along the lines AA' and BB', respectively. Wadkins (1992) reinterpreted the geological data and prepared these maps (Figs. 3.1 to 3.5), which are different from those available from the Arkansas Oil and Gas Commission Office, El Dorado, Arkansas.

The trap for the accumulation of hydrocarbons is considered both structural and stratigraphic. The oil-bearing sand pinches out in all directions. The north boundary of the sand is truncated by a fault. A coarsening upward sequence, observed on the SP logs (not shown here) of the peripheral wells on the south side of the field, and a moderate salinity of the formation water (resistivity is 0.065 Ω.m at the reservoir temperature of 114° F) suggest the possibility of a stream-mouth bar/barrier bar type of depositional environment.

Out of a total area of 549 acres, 360 acres are considered drilled and proven, 144 acres are considered proven but undrilled, and 45 acres are of questionable status. The average pay thickness is 15.2 ft. The wells were drilled on 10-acre spacing. Based on the oil isopach map and a preliminary analysis of SP logs, the cleaner and thicker parts of the field, which can be referred to as the potential steamflood area, are shown in Fig. 3.6 as the area inside the dotted curve. The total area having thickness more than 14 ft is approximately 130 acres. Oil-in-place in this area is about 2.5 MMSTB. The geological description will focus on this area.

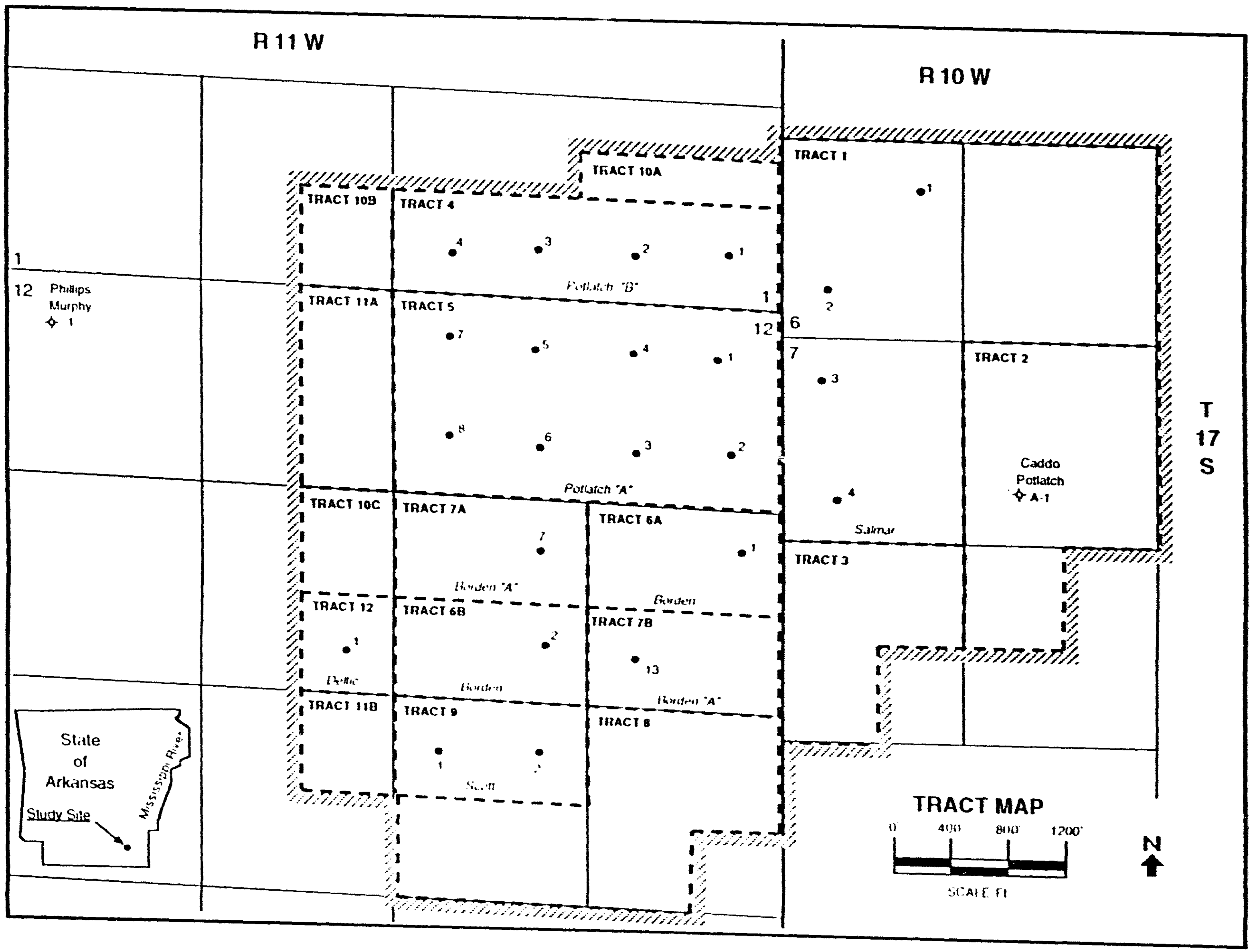


FIGURE 3.1 - Well locations with geographical location map insert of the Charivari Creek field, Bradley County, Arkansas (from Wadkins, 1992).

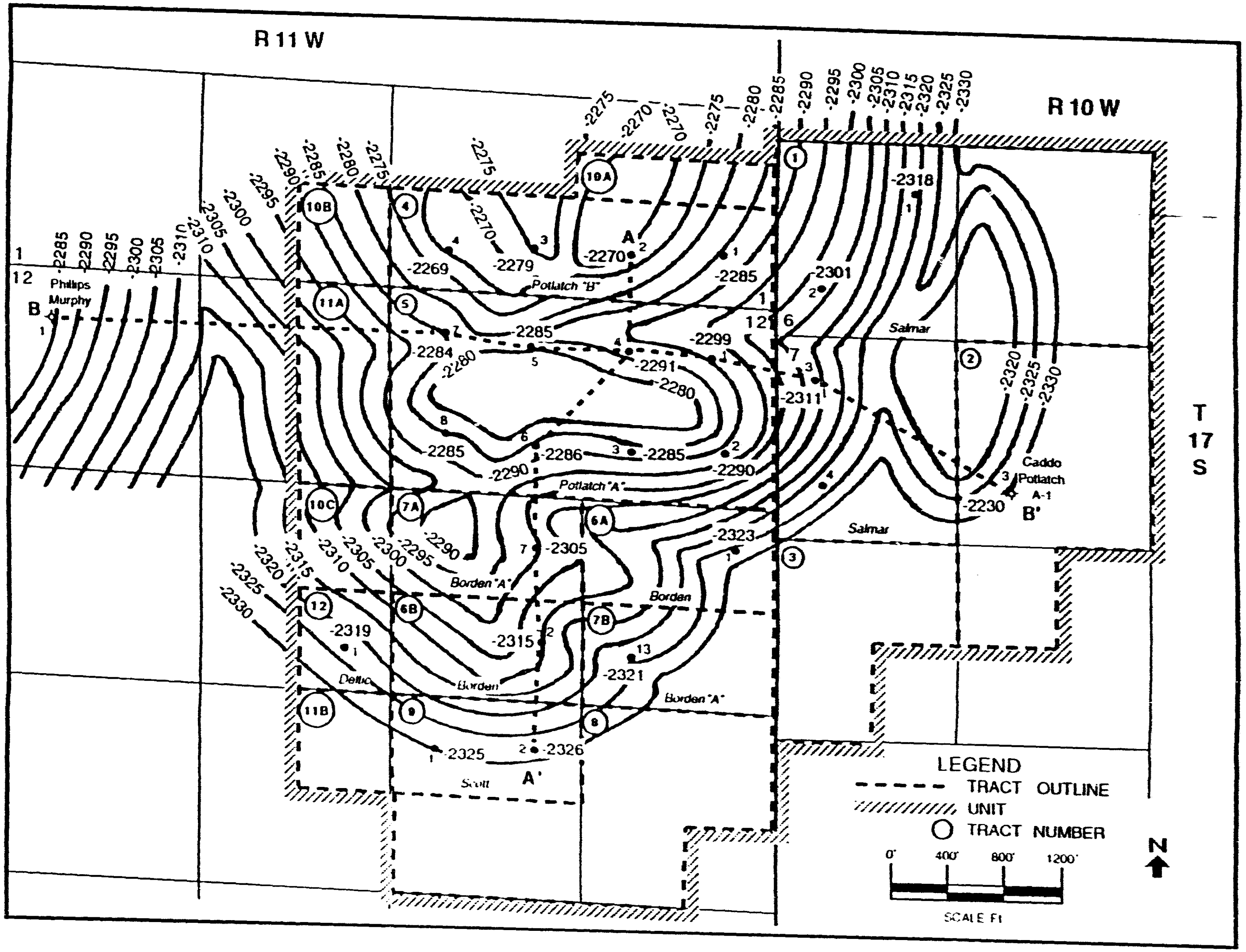


FIGURE 3.2 - Structural contours on the top of the Nacatoch formation (from Wadkins, 1992).

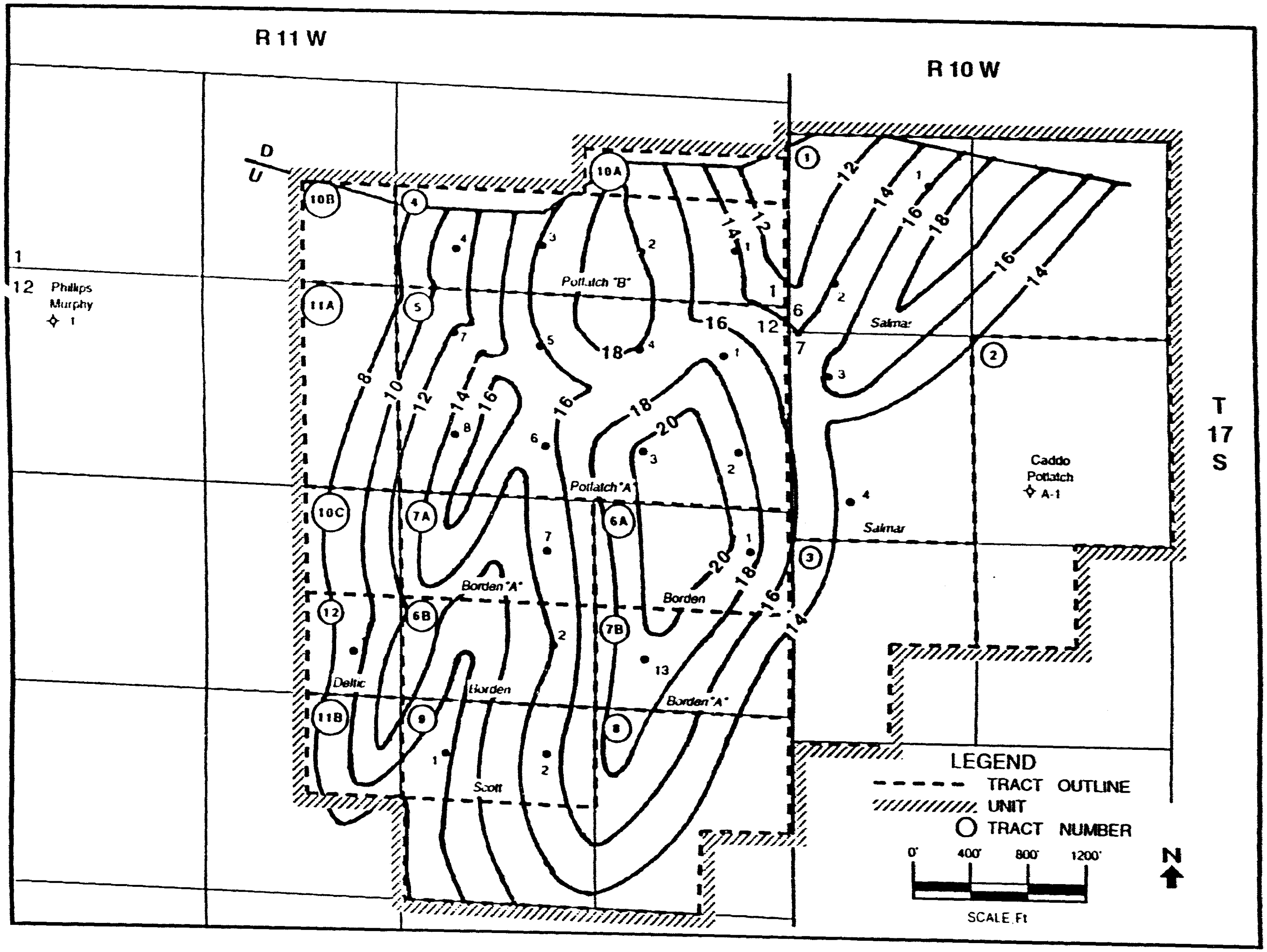


FIGURE 3.3 - Net oil isopach map of the field (from Wadkins, 1992).

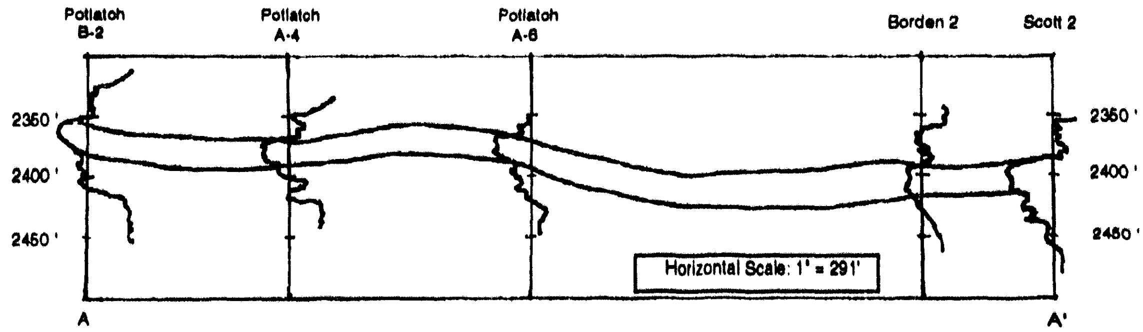
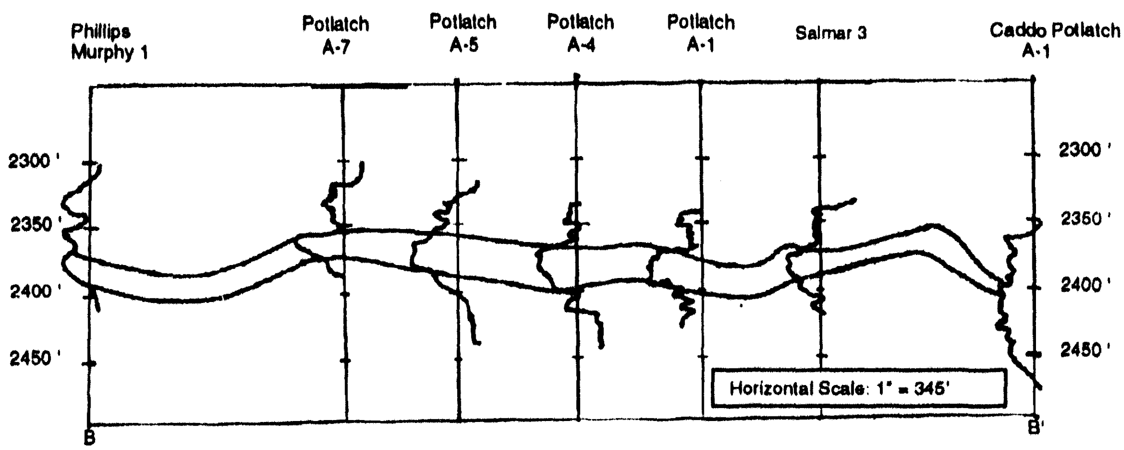


FIGURE 3.4 - North-south structural cross section along line AA' of Fig. 3.2 (from Wadkins, 1992).



FIGURES 3.5 - East-west structural cross section along line BB' of Fig. 3.2 (from Wadkins, 1992).

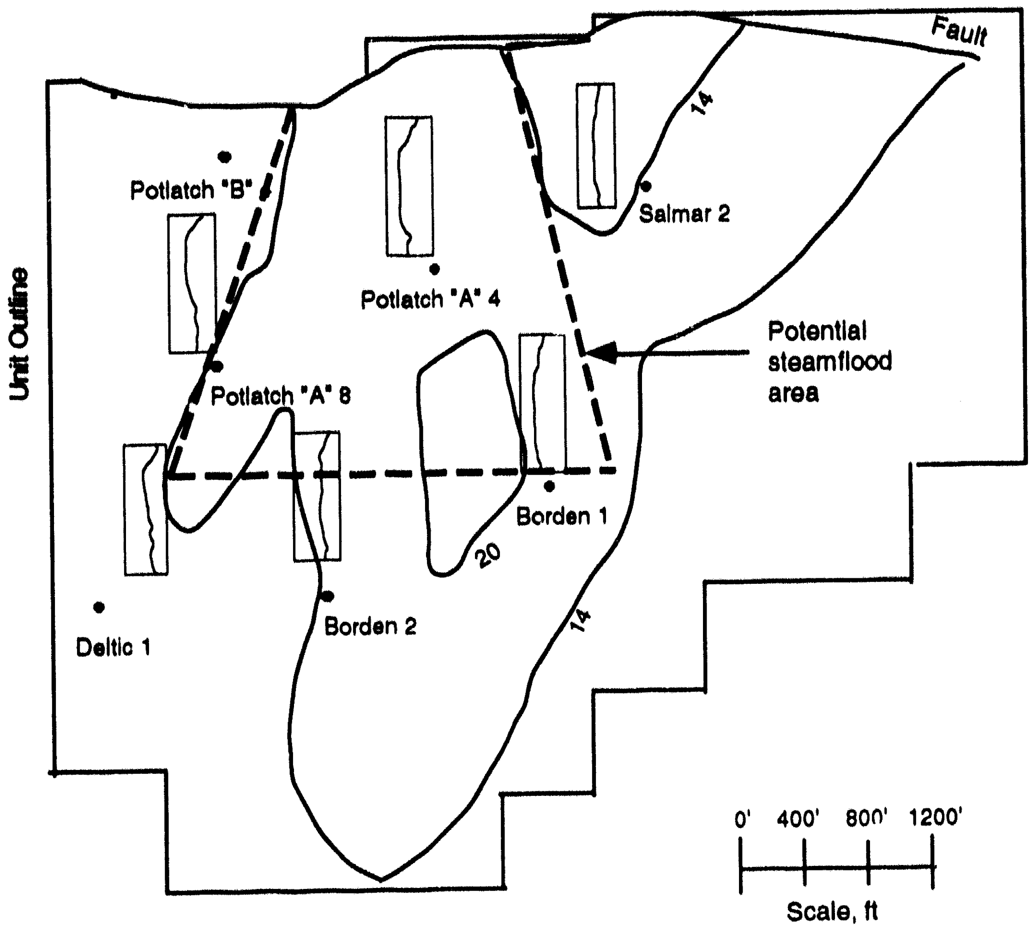


FIGURE 3.6 - Net oil isopach contours (14 and 20 ft) and SP logs of Nacatoch formation at selected well locations.

3.2 Core-Log Calibration

To calibrate core and log data at a well, it is necessary to have core analysis reports and well logs such as spontaneous potential (SP), gamma ray, porosity and resistivity available for the same well. The SP, resistivity logs, and a sidewall core analysis report were available for well Borden 1, located on the south-east part of the area (Fig. 3.6). In the absence of gamma ray and porosity logs for this well, the gamma ray log for well Potlatch "A" 4 and the sonic porosity log for well Salmar 2 were used for approximate information on the clay content and porosity of the well. In fact, Salmar 2 has the only porosity log available in this whole field. From comparison of SP logs for these three wells, it was observed that formation features compare well among these three wells. The top of the pay zone at Borden 1 is located 30 and 16 ft below the similar locations of Potlatch "A" 4 and Salmar 2 wells, respectively.

In the potential area, the formation thickness varies from 80 to 90 ft. The Nacatoch formation at Borden 1 is 90 ft thick (2,370 to 2,460 ft) and can be divided into three sections: top (~ 27 ft), middle (~ 23 ft), and bottom (~ 40 ft). The thickness of the middle section decreases, and the thicknesses of the top and bottom sections increase towards the periphery of the area. The lithological description of the formation will be based on the sidewall core analysis report available for Borden 1. Only the middle section contains hydrocarbons, and the limited core data on top and bottom section do not indicate any presence of hydrocarbons.

The top section of the formation is composed of siltstone, silty fine grained sandstone, calcareous fine grained sandstone, silty limestone, and limy fine grained sandstone layers. These layers have little permeability. The presence of lime at the bottom of the upper section is indicated by very low values of the gamma rays, but the high resistivity associated with a thick limestone are not present on the Induction-Laterolog. The fairly high resistance portrayed on the Induction-Laterolog is probably indicative of limy sandstone.

The middle section (from 2,397 to 2,420 ft) can be divided into 3 zones: Zone 1, Zone 2 and Zone 3. The thicknesses of these zones are 4, 9 and 10 ft, respectively. Zone 1 consists of fine grained sandstone with shale content decreasing in the downward direction. A thin, limy, and fine-grained sandstone layer separates Zone 2 from Zone 1. Zone 2 consists of fine-grained sandstone, but the top parts, of the zone are silty and limy. Zone 3 also consists of fine-grained sandstone. This zone is slightly shaly and silty at the top that marks the separation of this zone from the Zone 2. Presence of free gas has been reported in the top 1 ft segment of the top zone at Borden 1. It is most likely that all three zones laterally extend over the potential area, but there are thin discontinuous (not reservoir-wide) laminations of limy and silty sandstone layers. Water is indicated within the lower part of zone 3 in all the wells.

A cross plot of porosity and permeability of the middle section of the formation at well Borden 1 is shown in Fig. 3.7. It shows little increase in permeability with an increase in porosity. SP and resistivity logs (Induction and Short Normal), and core and log-derived porosity, permeability, and water saturations of Nacatoch formation in well Borden 1 are shown in Fig. 3.8.

The figure shows three types of porosities: core, core (calibrated) and log-derived effective (corrected for clay content). The core porosity is directly obtained from the core analysis report. The core (calibrated) porosity is obtained by first correcting the core porosities for the overburden

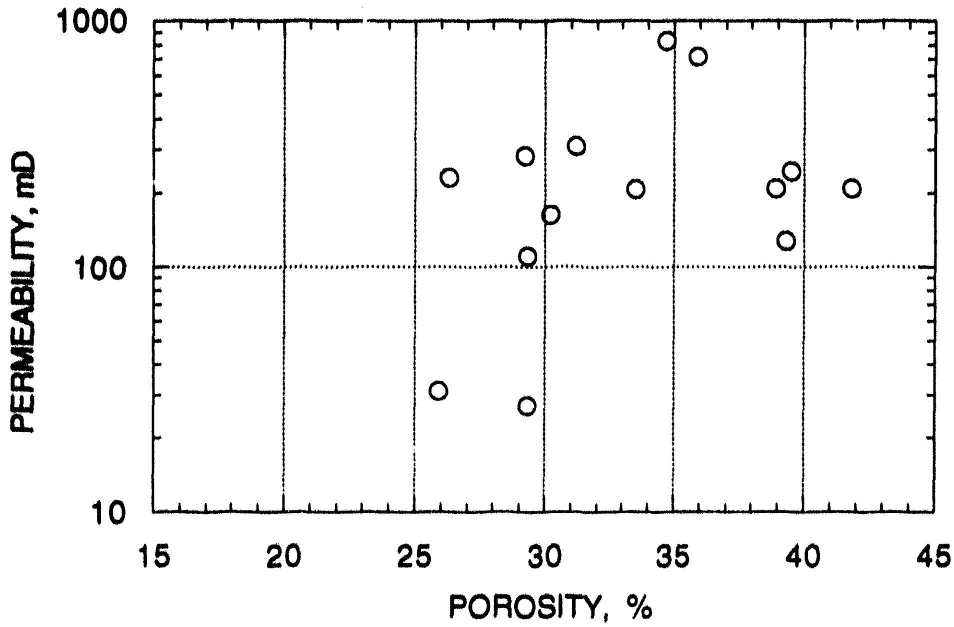


FIGURE 3.7 - Permeability-porosity crossplot at Borden 1 well.

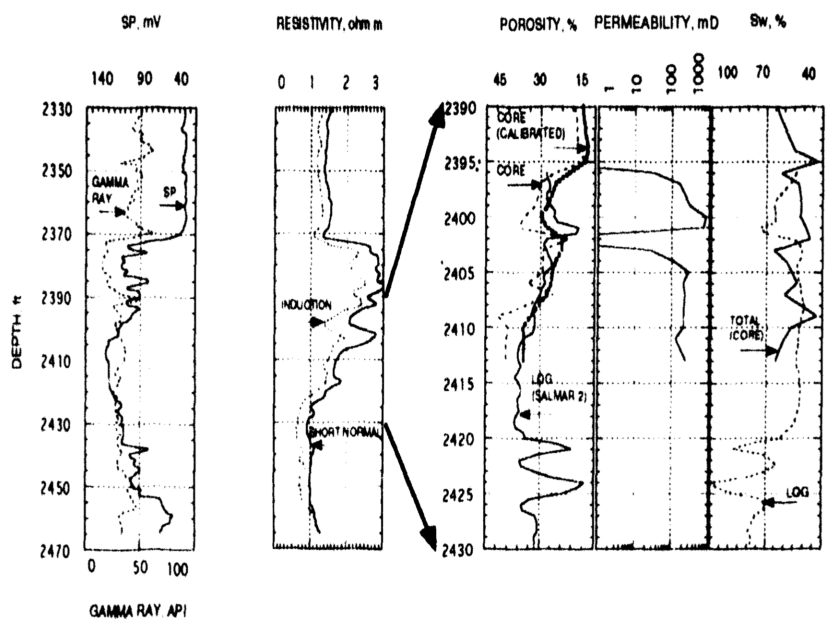


FIGURE 3.8 - SP and induction resistivity logs and core and log-derived porosity, permeability and water saturations of Nacatoch sandstone in well Borden 1.

pressure and then by taking a moving average over a 3-ft interval, as discussed below. For an approximate net overburden pressure of 1,344 psi, a correction factor of 0.88 has been applied to all the porosity values (Mattax et al., 1975). The corrected data are averaged using 1:2:1 weights (Hilchie, 1989: Chapter 10). The log-derived total porosity has been evaluated from interpretations of the sonic log taken at well Salmar 2. An average clay content value for each zone of the middle section was obtained from interpretations of the gamma ray log in Potlatch "A" 4 well. The log-derived effective porosity values were then obtained by correcting the total porosity values for the clay content. A brief discussion of the procedure is given in appendices B.1 and B.2. The core analysis report shows the presence of limestone and calcareous sandstone layers but a constant matrix transit time of 55.5 μsec has been used for the whole interval; consequently, underestimation of porosities are obtained for limy layers, where matrix transit time is lower. The core (calibrated) porosity data show good agreement with the log-derived effective porosity values.

Figure 3.8 shows two types of water saturation values: log-derived and total core. To evaluate log-derived water saturation values for this shaly sand reservoir, the automatic compensation method of Asquith (1990) has been used. The log-derived total porosity values have been used to evaluate the effective water saturation at Borden 1. A brief discussion of the procedure is given in appendix B.3. The total water saturation values are directly obtained from the core analysis report.

It is typically found that in the absence of any gas the total water saturation values match log-derived water saturation values (Table 1-2 in Anderson, 1975). In this case, the log-derived water saturation values match well with the core values in Zone 2, but are higher in the Zone 1 and lower in the Zone 3. For Zone 1 water saturation values are taken to be the same as total water saturation values. From limited core data, the Zone 3 is believed to be a transition zone where saturation increases continuously from 57% at the top. For a fine-grained shaly sand reservoir a transition zone of 10 ft is quite feasible. But, log-derived values indicate that the average water saturation in the top half is 53% and the transition zone starts from the middle of the zone. The saturation values range from 53 to 65% in the bottom half. Considering the lack of data and the assumptions involved in the calculation procedure, averages of total water saturation from core and log-derived values are considered. The average water saturation value for the top half is 58% (core-63% and log-derived-53%) and that for the bottom half is 65% (core-70% and log-derived-59%).

The bottom section consists of limy fine-grained sandstone, very fine-grained sandstone, siltstone, and shale layers. For the bottom section of the formation, a gradual increase in SP in the upward direction, prominently observed in the wells on the south and east side of the field, suggests that the shaliness decreases and the grain size increases in the upward direction. A very limy, thin and fine grained sandstone layer separate the bottom section from the middle section. This layer is not present in the north-western part of the area. Based on the information that the wells in this field are fractured and the WOR (water-oil ratio) is non-zero from the beginning of production, it is highly likely that the shaly, silty layers lying at the bottom of the middle section are contributing towards water production. A bottom water layer with a net pay of 19 ft is considered as a part of the reservoir for simulation purposes. The values for porosity and permeability are arbitrarily assumed for this zone (considered to be Zone 4).

From the analysis, the average values of thickness, porosity, permeability, and water saturation for the three zones in the middle section are shown in Table 3.1. In the absence of data to calibrate other wells, the characteristics found at Borden 1 well will be considered applicable to other wells, except for the thickness which is known from the SP logs available for the other wells.

3.3 Fractured Well Characteristics

All of the wells in the Charivari Creek field were hydraulically fractured and propped with sand. So, it is important to estimate the orientation and geometry of the fractures, and evaluate the influence of fractures on the flow performances of the wells. To evaluate the flow performance of a fractured well, first, the values for length, width, height, and permeability of fractures first need to be evaluated. The long-term PI (productivity index) may then be calculated using the McGuire-Sikora chart (Fig. 6.1 in Gidley et al., 1989). It is important to know the orientation of the fractures for determining the optimum well locations to improve the drainage efficiency during primary recovery processes, and the areal sweep efficiency during any subsequent displacement

TABLE 3.1

Thickness, Porosity, Permeability, and Water Saturation Values at Well Borden 1

Zone	Thickness, ft	Porosity, %	Permeability, mD	Water saturation, %
1	4	0.28	235	0.50
2	9	0.29	181	0.52
3a	5	0.335	171	0.58
3b	5	0.335	171	0.65
4 (Sec. 3)	19	0.29	100	1.00

process (waterflood, steamflood, etc.). The sweep efficiency is improved by preventing early breakthrough of the injected fluid in the production wells (Bradley et al., 1989: Fig. 16.1 and 16.2).

Not enough data are available to do a complete fracture analysis of the wells. An attempt has been made to conduct a rough evaluation of the fracturing jobs. An analysis of the fracture data of the well Potlatch "A" 4 have been shown in appendix C. As mentioned before, this well is located at the center of our area of interest and is considered as a typical good well in the reservoir. Calculations on fracture orientation show that the fracture will have a vertical orientation. Azimuth of the fracture has never been predicted or determined for this field. Before a steamflood operation is initiated, the azimuth should be determined. To calculate dynamic fracture dimensions a computer model, based on the approximate solutions for 2-D constant -height analytical models of PKN (Perkins-Kern-Nordgreen), has been developed. It can account for non-Newtonian fluids and net sand less than fracture height (Appendix G in Bradley et al., 1989). The results obtained from the use of the PKN model shows that the propped fracture length is 507 ft and the fracture width is 0.047 inches. From the McGuire-Sikora model, the PI ratio has been found to be 1.4. The improvement in PI ratio is very poor because the improvement in conductivity is limited and the long length of the fracture is ineffective. The low width of the fracture is obtained primarily because of low proppant concentration (2.75 lb/gal) in the suspension.

Some other wells (Potlatch B-1, 2, and 3) are fractured with smaller size sands (20/40 mesh size), keeping other parameters constant. In most cases the fractures are long and thin, and present over the entire formation in the vertical direction.

Well production data of Salmar 2 indicated that after fracturing the rate of production increased significantly from 1 to 12 STB/d of oil. The oil production rate and WOR histories at Salmar 2 well is shown in Fig. 3.9. The initial (March 1964) oil rate was 12 bbl/d with a WOR of 1.0, but decreased very quickly to 4 STB/D with a WOR of 1.8 within 3 years of operations. Whether the improvement in production resulted from improvement in skin or from the improved performance of a fractured well cannot be determined from limited data available. A well may be refractured to obtain higher conductivity, and its production performance analyzed to answer the question.

3.4 Production Characteristics

Since the reservoir has a fault in the north and it pinches out in all other directions, the primary production mechanism is most likely to be liquid expansion drive. All the wells in this field were put on production using SRP (sucker rod pump) from the beginning of production. The

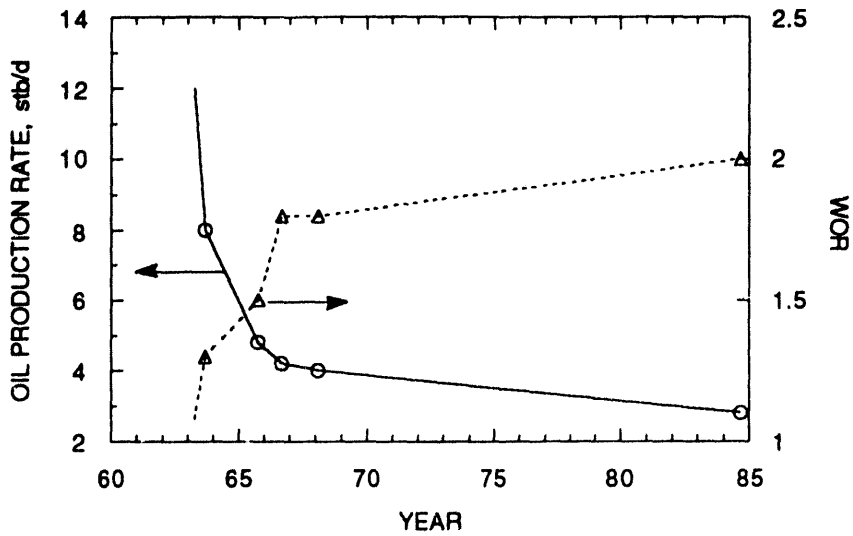


FIGURE 3.9 - Oil production rate and WOR histories of Salmar 2 well.

field has seven leases. Although production from the field started with a well in the Salmar lease in 1963, the development of the field was slow; and the last well that was added to the field was drilled in 1980. There are a total of 23 wells. The field oil production history is shown in Fig. 3.10. During primary operations, several peaks in the production curve indicate addition of new wells to the leases. The production reached a peak value of 41,000 STB/yr in 1978 as a result of addition of wells in Potlatch "A" and "B" leases in 1976 and 1977. The OOIP for this field is 5.9 MMSTB, and the primary production is 0.337 MMSTB (5.7%).

The shut-in pressure was found to be 1,060 psi at a depth of 2,413 ft from a test conducted in October 1962 by Schlumberger using a formation tester in well Caddo Oil Potlatch No. A-1 (located on the east side and now abandoned). The sub-sea depth for this well is 2,330 ft which is almost at the lowest level for this field. The core analysis report from Salmar 1 (core was taken using a diamond bit in May 1963) shows that the solution gas-oil ratio was 180 SCF/bbl, the formation volume factor was 1.13, and the average calculated connate water saturation was 39% .

The field was unitized in May 1984, and a secondary operation was initiated in October 1989 to maintain reservoir pressure by injecting all the produced water in a single well. Well Borden "A" 13 was used for injection from October 1984 to August 1990, and since then well Salmar 4 has been used for that purpose. Both wells used for water disposal are located at structurally

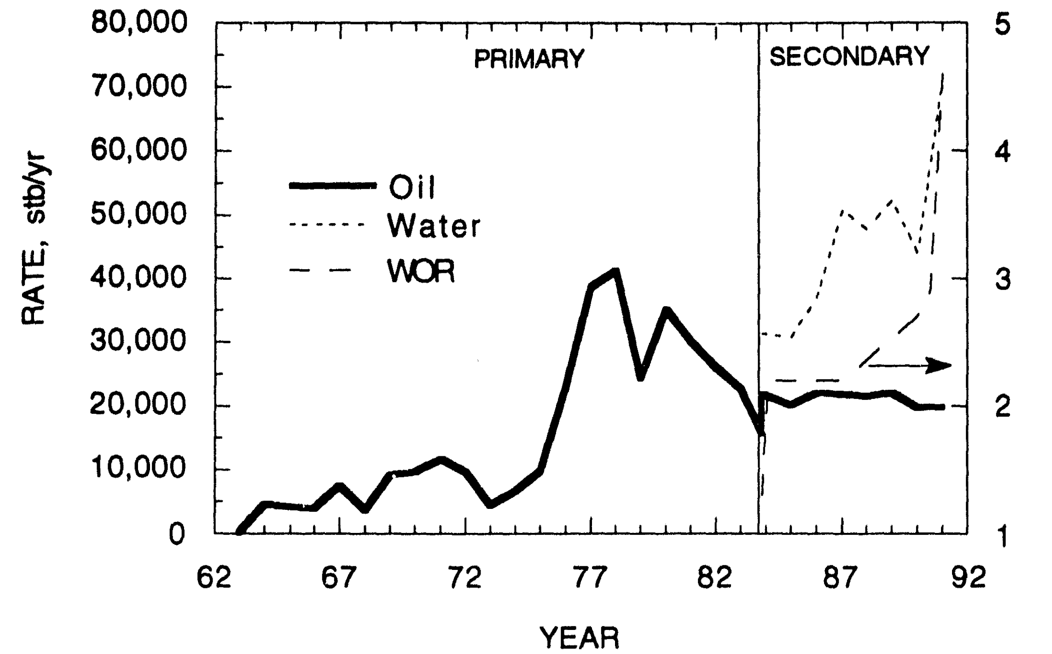


FIGURE 3.10 - Oil and water production rates and WOR histories for Charivari Creek field.

lower elevations. The histories of field oil and water production rates and WOR are shown in Fig. 3.10. The secondary production, until the end of 1991, was 0.335 MMSTB (5.67%); therefore, the total recovery is 11.4%. The WOR data are based on the monthly production data. The WOR was about 1.5 at the time of unitization, but increased to about 2.2 by the end of 1984. The WOR remained constant around 2.2 for about 4 years (until 1988), and then gradually increased to 2.8 in August 1990. With the change in location of the injection well from Borden "A" 13 to Salmar 4, the WOR started increasing and reached a value of 9.5 by the end of 1991. Water seems to have invaded part of good productive areas of Potlatch "A" and "B" leases. Water injection rate and injection pressure histories at the injection wells are shown in Fig. 3.11. The injectivity of well Borden "A" 13 increased from 0.064 bbl/psi/d in October 1984 to 0.086 bbl/psi/d in August 1990. The injectivity of well Salmar 4 increased from 0.105 bbl/psi/d in August 1990 to 0.138 bbl/psi/d in December 1991. The higher injectivity in both cases may be attributed to the higher mobility of the aqueous phase.

Individual well production tests were carried out at several wells in September 1985, within 1 year from the start of water injection program. The results presented in terms of ranges for the leases, are shown in Table 3.2. The results show that wells located closer (in terms of distance and elevation) to Borden "A" 13 (south-east side of the field, elevation = -2321 ft) like Borden 1

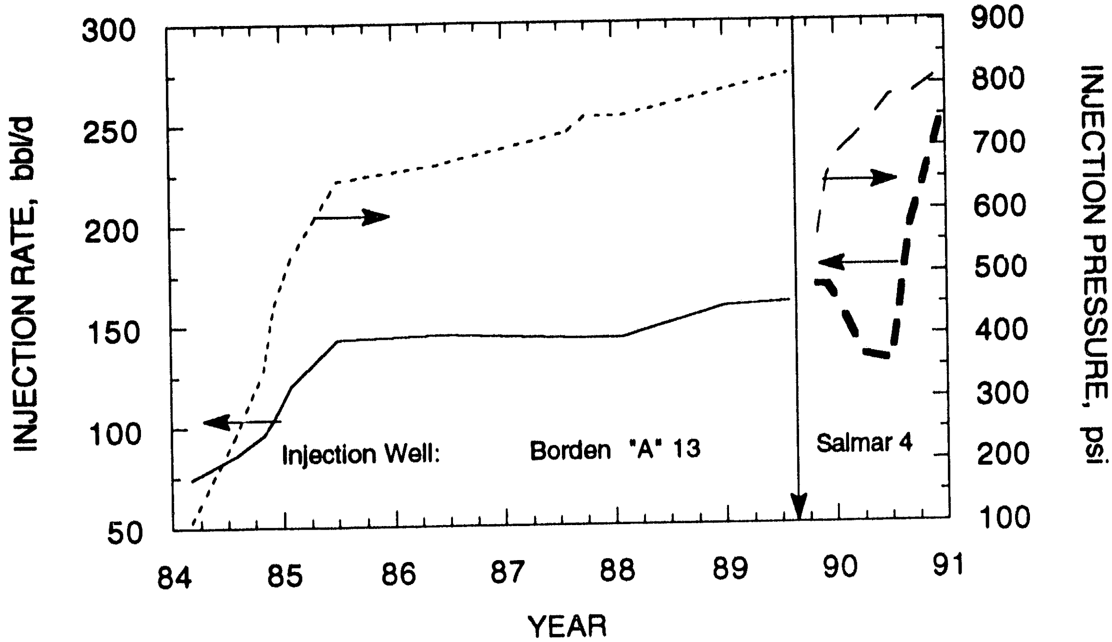


FIGURE 3.11 - Water injection rate and injection pressure histories at Borden "A" 13 and Salmar 4 wells.

TABLE 3.2

Results of Individual Well Production Test Analyses Presented in Terms of Ranges for the Associated Leases

Descriptions	Lease Name					
	Potlatch "A"	Potlatch "B"	Borden	Deltic	Salmar	Scott
Number of wells	8	4	4	1	4	2
Total prodn. rate, STB/d	4.5-8.3	2.4-11	2.8-7	11.8	8.3-9.4	2.4
Oil prodn. rate, STB/d	1.4-4.9	2.4-4.2	2-4.8	4.9	1-2.8	0.7
WOR	0.5-3.7	0-2.2	0.7-3.4	1.43	2-8	1.0

and Potlatch "A" 1 are showing higher WOR, possibly because of influence from the injection processes. The north-west and center parts of the field are showing less WOR.

Since waterflooding began in 1984, the oil production rate has decreased only slightly from 23,000 to 20,000 STB/yr (only 1.8% /yr) over a period of 7 years. The rate of decline before waterflood was 9%/yr. The most important knowledge gained from the secondary operation is that there is lateral and vertical continuity in the reservoirs and that the silty and shaley aspects of the formation should not be a deterrent in the sense of any reservoir-wide barrier.

3.5 Conclusions

(1) Based on core-log calibration, characteristics of the fractured wells and the production characteristics, a cleaner and thicker part of the Nacatoch formation in the Charivari Creek field has been characterized.

(2) The zones containing oil have a gross thickness of 23 ft and average porosity of 31%. The oil saturation ranges from 50% at the top to 35% at the bottom. The average permeability has a low value of 186 mD. A water zone that exists below the oil zone has a net thickness of 14 ft, contains some low permeability streaks, and has permeabilities less than those of the oil zone.

(3) A simplified fracture analysis of a typical well shows that the fracture orientation is vertical, and improvement in PI ratio was marginal, possibly because of low proppant concentration used during fracturing.

(4) Primary and secondary production characteristics of the field indicate that the values for primary and secondary (until 1991) oil recoveries are about 5.7% each. The lateral and vertical continuities within the reservoir are good.

CHAPTER 4
CYCLIC STEAM STIMULATION STUDY

INTRODUCTION

4.1 Introduction

The approach taken to study cyclic-steam-stimulation (CSS) performance of the Charivari Creek reservoir by conducting reservoir simulation was as follows. First, an optimization study was conducted to find out the optimum steam injection volume and then a parametric sensitivity study was conducted by varying values of certain parameters such as: reservoir pressure, vertical communication, absolute permeability, and oil saturation. A brief description of the reservoir simulator used and the collection of additional data required for simulation are given in following sections.

4.1.1 Reservoir Simulator

Computer Modeling Group's STARS (Steam and Additive Reservoir Simulator) was used for making all the simulation runs including cyclic and steamflood operations. This is a fully implicit, multiphase, multicomponent, finite difference thermal simulator. Interblock flow is calculated using a single-point upstream fluid mobility and enthalpy applied to a five- or nine-point block-centered finite difference scheme on cartesian, radial, variable thickness and curvilinear grids (Aziz et al., 1985).

4.1.2 Additional Data

In addition to the basic reservoir data on thickness, porosity, permeability, and saturation (Table 3.1), additional data on rock-fluid properties and thermal properties of rocks and fluids are required to conduct simulation studies. Viscosity and density as functions of temperature are available for the field crude (Table 4.1). Kinematic viscosities are calculated and plotted on the Standard Viscosity - Temperature Chart for Liquid Petroleum Products, ASTM: D-341-43 (Fig. 4.1). The results show a straight-line relationship which is extrapolated to obtain viscosities at higher temperatures. In the absence of real data for rock-fluid properties such as, oil-water and gas-liquid relative permeabilities and capillary pressures, and thermal properties of rocks and fluids, appropriate data have been chosen from the literature. The oil-water relative permeability data for a reservoir composed of fine-grained sand (Morgan et al., 1970) have been chosen to represent this field (Fig. 4.2). The gas-liquid relative permeability (Fig. 4.3) was arbitrarily chosen to be similar to that used in the 4th SPE comparative solution project (Aziz et al., 1985). Capillary pressure data for Frio sandstone, similar in values as those for Charivari Creek reservoir of permeability 170 mD (Fig. 3-15 in Amyx, Bass and Whiting, 1960), were used here (Fig. 4.4). Properties of rocks and fluids were arbitrarily assumed to be the same as those used by Aziz et al. (1985) and are given in Table 4.2.

TABLE 4.1

Crude Oil Viscosity Data as a Function of Temperature

Temp, °FcP	Viscosity, gm/mL	Density, Centistokes	Kinematic Viscosity,
60	1391.7	1.028	1354.1
110	201.9	1.004	201.1
160	54.5	0.9823	55.5
210	21.4	0.9615	22.3
260	10.5	0.9416	11.2
310	5.9	0.9225	6.4
*350	4.1	0.9074	4.5
410	2.6	0.8857	2.9
450	2.0	0.8710	2.25
480	1.6	0.8606	1.8

* Viscosity values at 350° F and above are obtained from extrapolated kinematic viscosity curve.

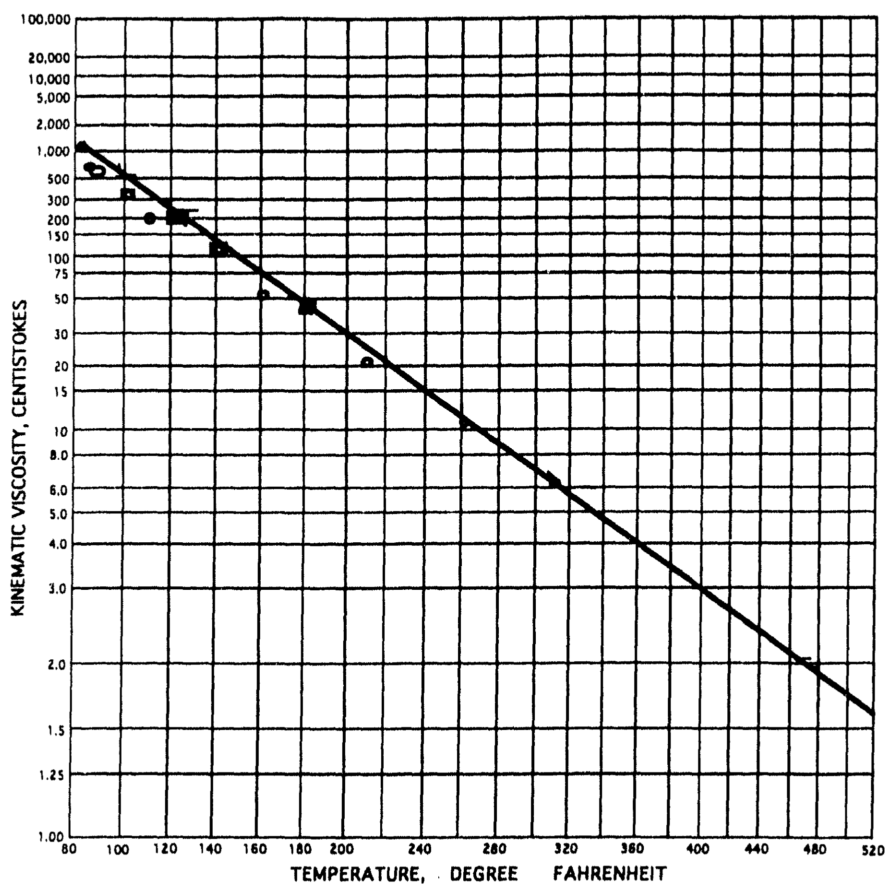


FIGURE 4.1 - Viscosity of the Charivari Creek crude.

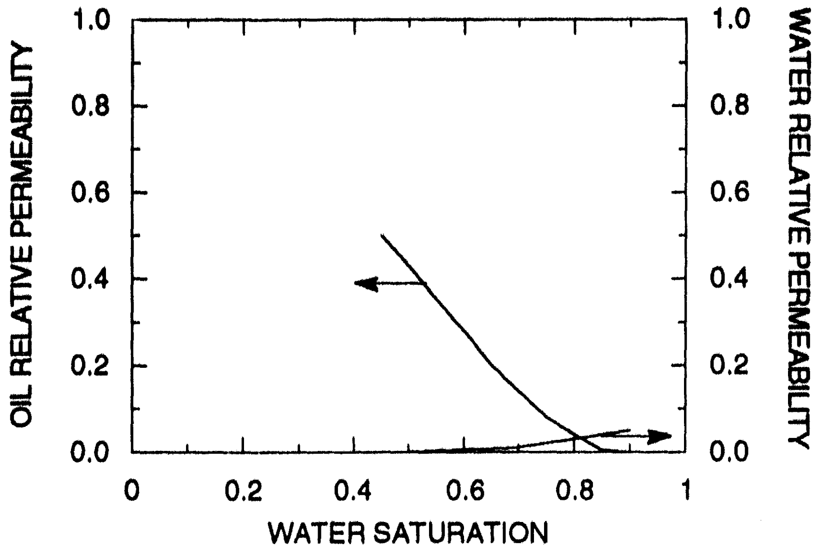


FIGURE 4.2 - Oil-water relative permeability.

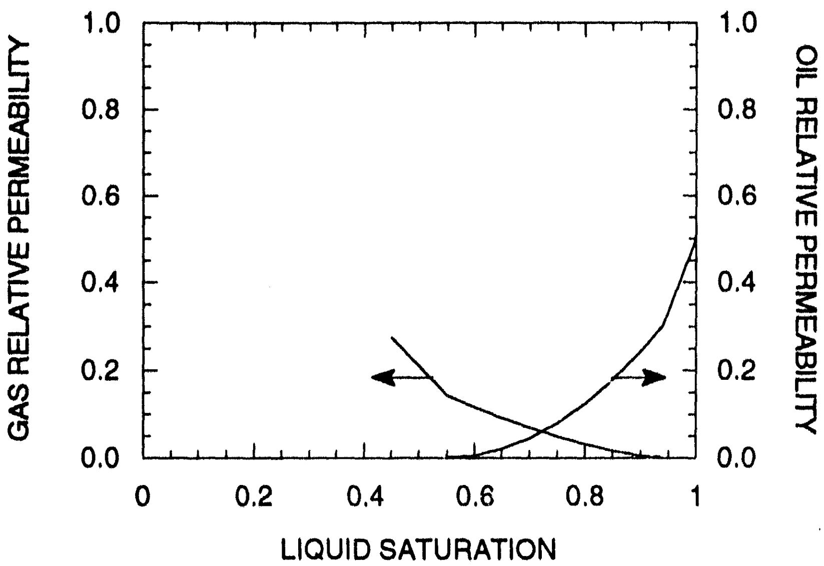


FIGURE 4.3 - Gas-liquid relative permeability.

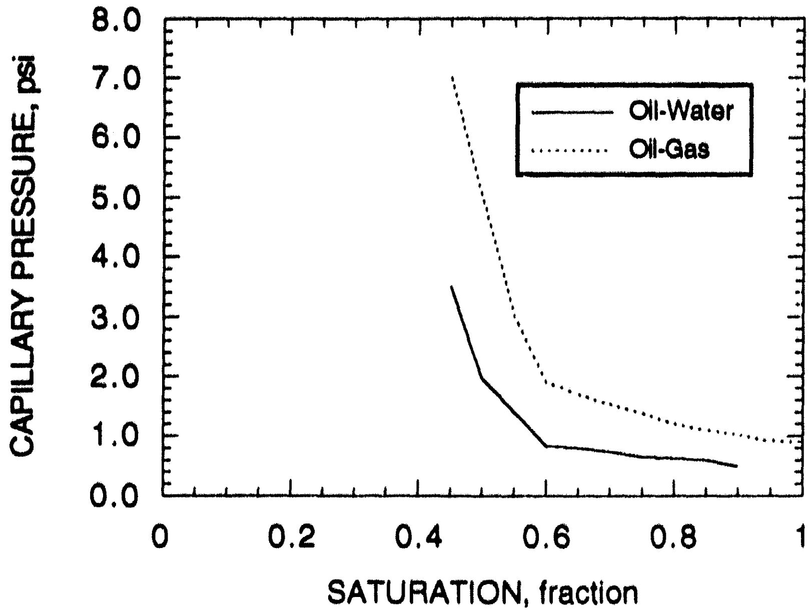


FIGURE 4.4 - Capillary pressure vs. saturation.

TABLE 4.2
Oil and Rock Properties

Oil	
Molecular weight	440
Isothermal compressibility, psi^{-1}	5.0×10^{-6}
Thermal expansion coefficient, °R^{-1}	4.43×10^{-4}
Specific heat, BTU/lb °F	0.5
Rock (reservoir, overburden and underburden)	
Isothermal compressibility, psi^{-1}	5.0×10^{-4}
Heat capacity, BTU/ft^3/ °F	35.0
Thermal conductivity, BTU/ft/d/°F	24.0

4.2 Base Case

For CSS processes there is no optimum rate of steam injection, and the strategy commonly used is to inject as high a rate as possible without fracturing the formation (Fig. 6.5 in Butler, 1991. In some cases where injectivity is low, the injection rate in the very beginning is chosen high, even if the injection pressure exceeds the fracturing pressure, to improve the injectivity by preheating the formation. Here, the injection strategy is assumed such that the steam is injected in the top four layers containing oil at a rate of 250 bbl/d for the first day (or 24 hours), 500 bbl/d for the second day and 1,000 bbl/d for subsequent days. The injected steam quality and steam saturation temperature are arbitrarily assumed to be 70% and 545° F (1,000 psi), respectively. The general operating conditions and numerical data are described in Table 4.3. The areal grid that has been used here is similar to that used by Aziz et al. (1985) for cyclic operations. In the vertical direction there are five grid blocks to represent Zone 1, Zone 2, Zone 3a, Zone 3b and Section 3 of the formation (Table 3.1), respectively. The layer at the top will be referred to as the first layer.

The effect of steam injection volume is discussed in the next section. The soak period was limited to 1 day, because a longer soak period was found to decrease the temperature of the heated zone (discussed later). The production period is chosen such that the minimum rate of oil production is 3 STB/d, which is the current unstimulated approximate rate of production. This criterion to mark the end of production period is somewhat arbitrary.

TABLE 4.3

Cyclic Steam Operating Conditions and Numerical Parameters

Steam injection strategy	250 bbl/d x 1 D + 500 bbl/d x 1 d + 1000 bbl/d x subsequent days
Steam conditions	quality, 70%; saturation temperature - 545° F (1,000 psi)
Cycle data	
Injection period, days	limited by the injection strategy
Soak period, days	1.0
Production period, days	limited by a minimum rate of oil production of 3.0 STB/d
Numerical data	
Simulated pattern area, acres	5.0
Coordinate system	cylindrical
No. of grid blocks ($r \times z \times \theta$)	13 x 5 x 1

Cumulative injection/production data and simplified economic criteria were used to compare different CSS cases on an overall basis. Detailed results including histories for the rate of oil production, WOR, cumulative oil production and COSR were shown only for the base case and the high-permeability case, which was found to be an important one. To analyze CSS performances, radial and vertical profiles of pressure, temperature and saturation at different times are constructed. All the vertical profiles are constructed at a distance of 8 ft from the center of the well (center of second block). Because of the small volume of the steam slug a small distance were chosen. All the radial profiles are created using data in the central layer which is at a distance of 15.5 ft from the top of the formation. To avoid interference from the overburden and underburden layers the central layer were chosen.

A phenomenon observed here in several cases is that during steam injection in the reservoir the pressure and temperature increased to a much higher level. It resulted in ineffective heating of the reservoir i.e., increase in temperature of the reservoir occurred without much gain from the reduction in viscosity of crude oil above certain temperature. This has been termed as ineffective reservoir heating.

4.2.1 Optimum Steam Injection Volume

CSS simulation runs were conducted with different steam injection volumes (60 to 13,634 bbl) to find an optimum value for maximizing the COSR (cumulative oil steam ratio) and minimizing operating costs. Only one cycle was simulated in each case. Although the COSR is a good criterion to evaluate overall performance, it could not be used alone to find out an optimum steam injection volume. This is because of high WORs which contribute towards the fluid handling costs, and the variations in production period which contribute differently towards the manpower costs. A simplified economic calculation procedure has been followed here to evaluate the operating costs (appendix D). The well costs have been excluded from the calculations. This type of calculation should not be taken for granted on an absolute basis, but may be worth considering for comparison purposes.

The production performance data are summarized in Table 4.4. The results show that with an increase in the slug size the cumulative oil production increases, but the WOR also increases and the COSR decreases. The plot of COSR and operating cost vs. volume of injected steam (Fig. 4.5) shows that the final COSR decreases exponentially with increase in slug sizes, but the operating cost is minimum at an injection volume of 747 bbl. This case gives the highest peak oil production rate of 30 STB/d and a relatively low final WOR of 9. In cases of larger slugs the oil around the wellbore seems to be pushed too far in the formation and the oil relative permeability around the wellbore becomes too low to effect a good oil recovery during the production period.

TABLE 4.4

Results of Steam Injection Volume Optimization Study

Run No.	Volume of steam, bbl	Production time, day	Oil rate$_{max}$ STB/d	WOR$_f$	COSR fraction	Cumulative oil, STB	Cumulative liquid, Mbbl	Operating cost,$/STB
1	60.0	28	7	4.6	1.54	92.0	0.48	18.80
2	247.0	79	18	7.6	1.19	295.0	2.02	17.29
3	747.0	100	30	9	0.59	443.0	3.56	16.49
4	1,747.0	143	26	11.5	0.39	678.0	6.54	17.13
5	3,747.0	189	27	13.8	0.25	944.0	10.76	18.72
6	5,747.0	230	19	15.0	0.19	1318.0	16.63	18.06
7	8,721.0	273	13	15.6	0.16	1395.0	18.81	21.97
8	13,634.0	349	6	16.8	0.13	1798.0	26.12	23.92

NOTE: Suffix: max = maximum; f = final

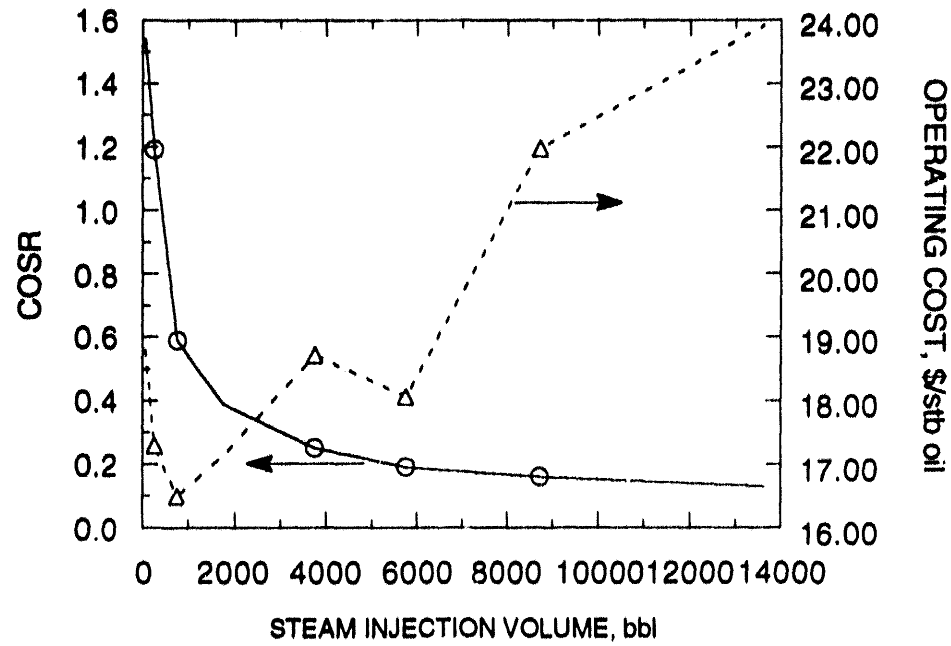


FIGURE 4.5 - COSR and operating cost vs. steam injection volume.

Therefore, a steam injection volume of 747 bbl seems to be the optimum for the conditions mentioned. This case has been considered to be the base case. The detailed results from this case are discussed below.

The results in Table 4.5 show that depending upon the length of the production period the cumulative liquid production can be very different from the steam injection volume. In the base case, the liquid production is about 4 times higher than the steam injection volume at the end of 100 days of operation. Because of the presence of a cold zone outside a stimulated radius of about 30 ft, the water will flow mainly from the unstimulated to the stimulated zone. The huge liquid production is attributable to the depletion of the reservoir, which is indicated by a decrease in the pressure at the boundary (263 ft from the well) from 205 to 198 psi.

4.2.2 Detailed Base Case Results

The base case was simulated for two cycles using the same injection schedule and steam injection volume of 747 bbl. Figure 4.6 shows the oil production rate and WOR histories for the two cycles. During the first cycle, the rate of oil production peaks at 30 BOPD in the beginning of production period, and then decreases to 5 STB/d by the end of 30 days. The production period ends at 100 days when the rate of oil production falls below 3 STB/d. The WOR approaches 9 at the end of 100 days of production. During the second cycle, the oil rate reaches similar peak values but decreases very sharply and the WORs are higher. Figure 4.7 shows the cumulative oil production and COSR histories. During the first cycle the final cumulative oil production and COSR are 443 STB and 0.59, respectively. During the second cycle, the cumulative oil production increases by 325 STB, and the final COSR decreases to 0.5.

TABLE 4.5

Base Case Results, With Steam Injection Volume of 747 bbl, at Different Times

Time days	Oil rate, STB/d	WOR	Cum. Oil STB	Cum. Liq. STB	COSR	Temp.(2,3)[1] °F	Viscos. cP	Pressure(2,3)[1] psi	Pressure(13,3)[1] psi
10	7.8	6.1	104	571	0.14	313	6	96	205
25	5.7	6.4	194	1246	0.26	232	16	90	205
100	2.6	9.4	443	3558	0.59	149	71	110	198

[1] (2,3) means second block in (8 ft) the radial direction and third block (15.5 ft) in the vertical direction. 13th block is at a radial distance of 203 ft.

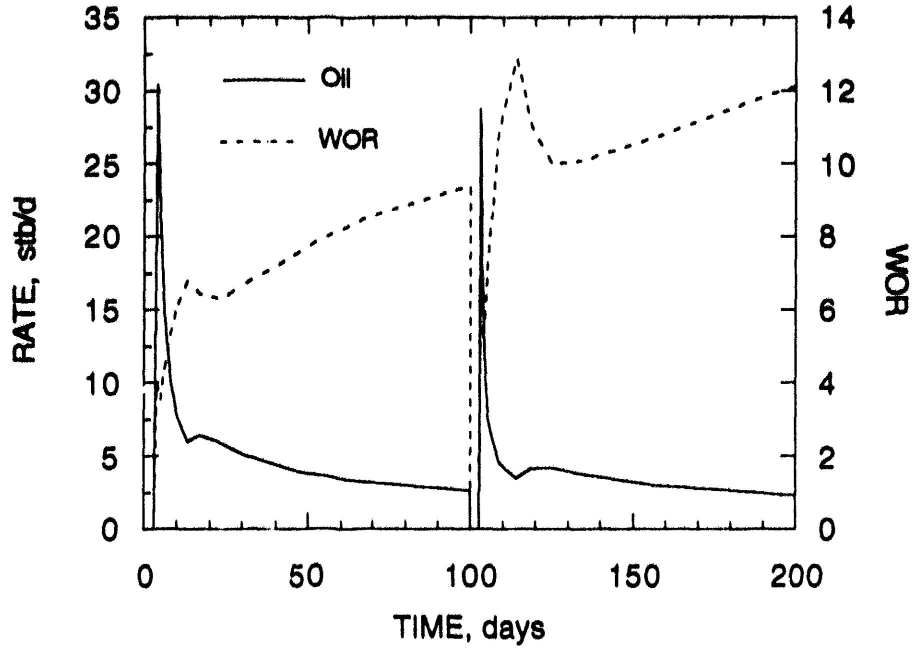


FIGURE 4.6 - The rate of oil production and WOR histories for the base case (2 cycles).

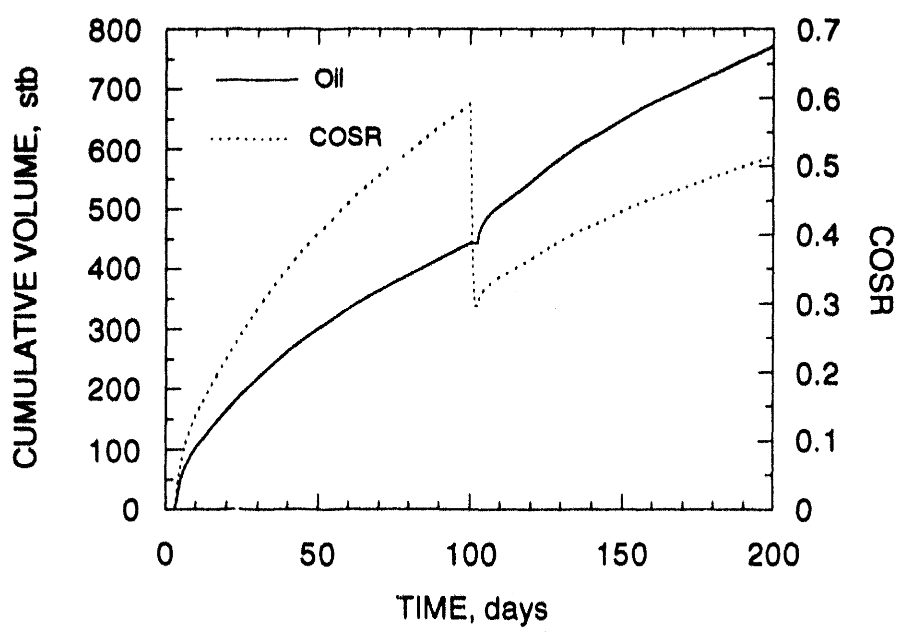


FIGURE 4.7 - The cumulative oil production and COSR histories for the base case (2 cycles).

Figure 4.8 shows vertical temperature profiles at different times during the first cycle. Because of steam injection in the top four layers and a limited vertical communication with the bottom water layer, the injected steam remained mainly in the top layers. At the end of the injection period (2 days) the maximum temperature was observed in the fourth layer (from the top), probably because of higher aqueous phase relative permeability from higher aqueous phase saturation in this layer. The differences in permeability among the top four layers are not significant. At the end of the production period (100 days), the temperature profile was almost vertical and only slightly above the initial reservoir temperature profile. The expansion and contraction of the heated zone in a radial fashion suggests that the important production mechanisms are (1) improvement in oleic phase mobility from decrease in viscosity of oil with increase in temperature, and (2) increase in potential gradient from compression of fluids in the near wellbore region. The gravity drainage mechanism, found to be an important one in cases of thick reservoirs, seems to be not important for thin reservoirs (Butler, 1991: Chapter 6).

In one case, as a variation of the base case, the soak time was changed from 1 to 5 days. Figure 4.9 shows the radial temperature profiles at different times. The temperature in heated zones decreased continuously with longer soak periods. The results suggest that heat conduction in the radial direction is less significant than the heat losses to the overburden and underburden layers; therefore a soak period longer than 1 day is not beneficial.

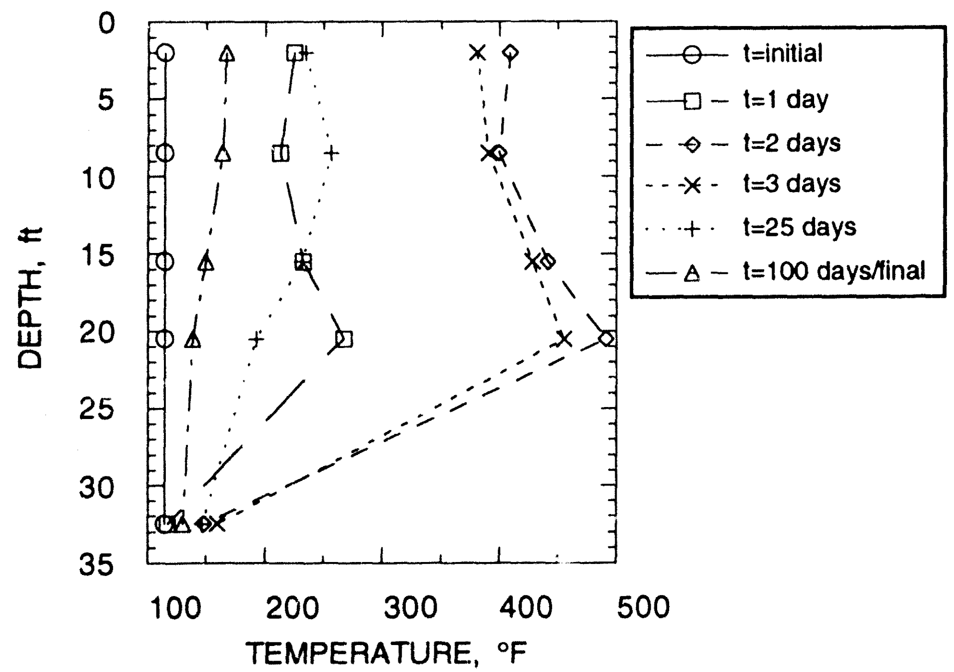


FIGURE 4.8 - Vertical temperature profiles at different times.

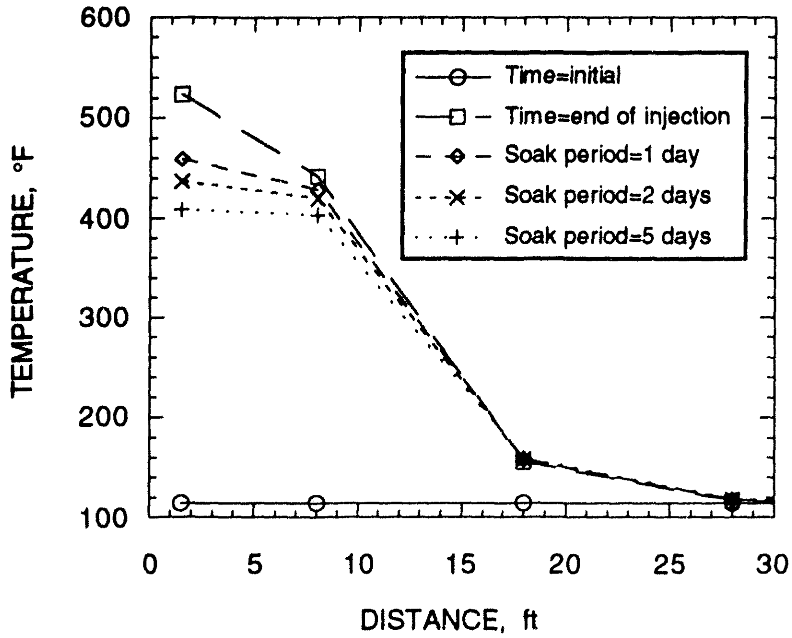


FIGURE 4.9 - Radial temperature profiles at different times.

In the base case, the radial extent of the heated zone is limited to approximately 28 ft. The pressure and temperature in the injection block in the central layer at the end of injection are 825 psi and 525° F, respectively. Assuming a maximum stimulated radius of 50 ft, the oil recovery efficiency is 10% of OIIP.

4.3 Sensitivity Studies

The reservoir data obtained from the reservoir description study (Chapter 3) may not be accurate. Sensitivity studies are conducted to have an understanding of the range of CSS performance that might be obtained as a result of differences in estimated and real reservoir data. Sensitivity studies are conducted by varying only one parameter at a time, except in the high permeability and oil saturation case where two parameters are changed simultaneously. Another benefit of conducting a sensitivity study is that one of the different scenarios created with a particular set of parameters can be found in another reservoir, in which case the predicted performance may be accepted as a possible solution. For example, the Irma and Troy reservoirs (described in Chapter 2) have characteristics similar to that of the Charivari Creek reservoir except the absolute permeability which is 13-fold higher in the case of Irma and Troy reservoirs. The performances of these two reservoirs under CSS operations are likely to be similar to that of the very high permeability case studied here.

The sensitivity study results are summarized in Table 4.6. The results are compared with those of the base case except as noted. The initial and final radial and vertical profiles of pressure, temperature, and oil saturation during the first cycle for the base case and sensitivity runs are shown in Figs. 4.10 through 4.15. The initial and final times refer to the end of steam injection and end of production time, respectively.

TABLE 4.6
Results From Parametric Sensitivity Studies

Run No.	Description	Volume of steam, bbl	Production time, days	Oil $rate_{max}$ STB/d	WOR_f	COSR fraction	Cum. oil, STB	Cum. liquid, MMbbl
1	Base case	747	100	30	9	0.59	443	3.56
2	Steam injection in central layers	742	100	27	9	0.62	460	3.47
3	High reservoir pressure	743	510	57	15	3.02	2248	27.99
4a	Communicating layers	747	76	28	11	0.47	348	3.23
4b	Non-communicating layers	747	150	40	4	0.85	633	2.85
4c	Non-communicating bottom layer	747	100	38	3	0.66	497	2.12
5	High oil saturation	740	225	40	5	1.60	1188	5.48
6a	High permeability in oil layers	750	886	73	5	7.85	5885	37.59
6b	High permeability in all layers	750	240	58	26	1.99	1489	34.07
6c	Very high permeability in oil layers	750	790	97	4	9.86	7393	40.81
7	High permeability and oil saturation	750	1700	110	2	22.00	16527	39.65

Note: Suffix f = final, Cum. = cumulative.

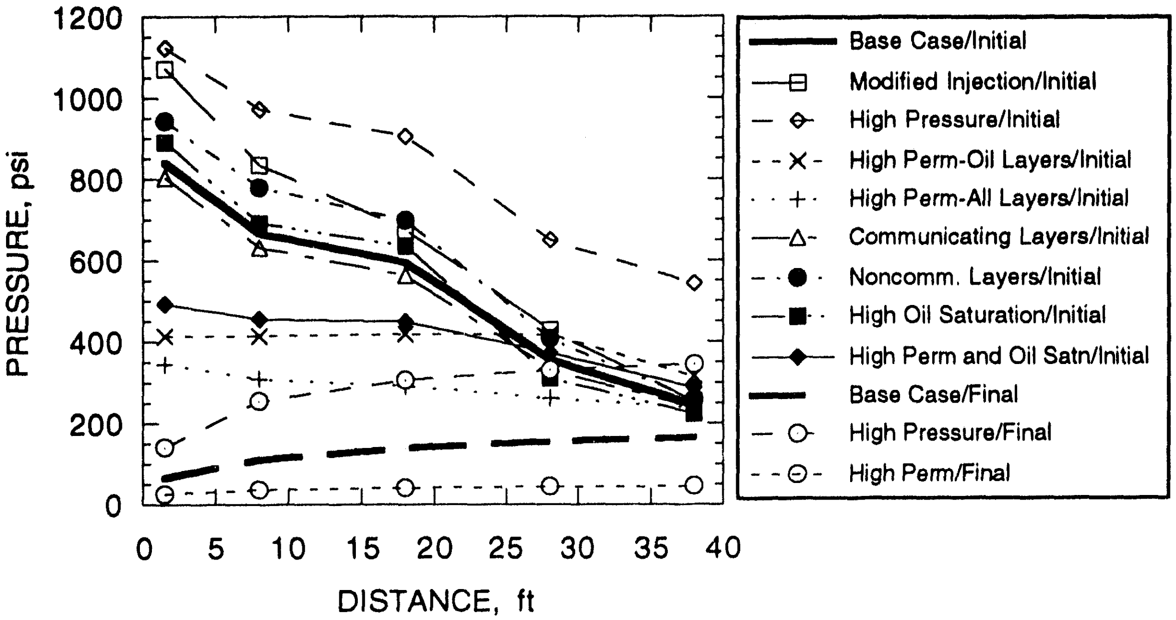


FIGURE 4.10 - Radial pressure profiles at the end of injection (initial) and final production time.

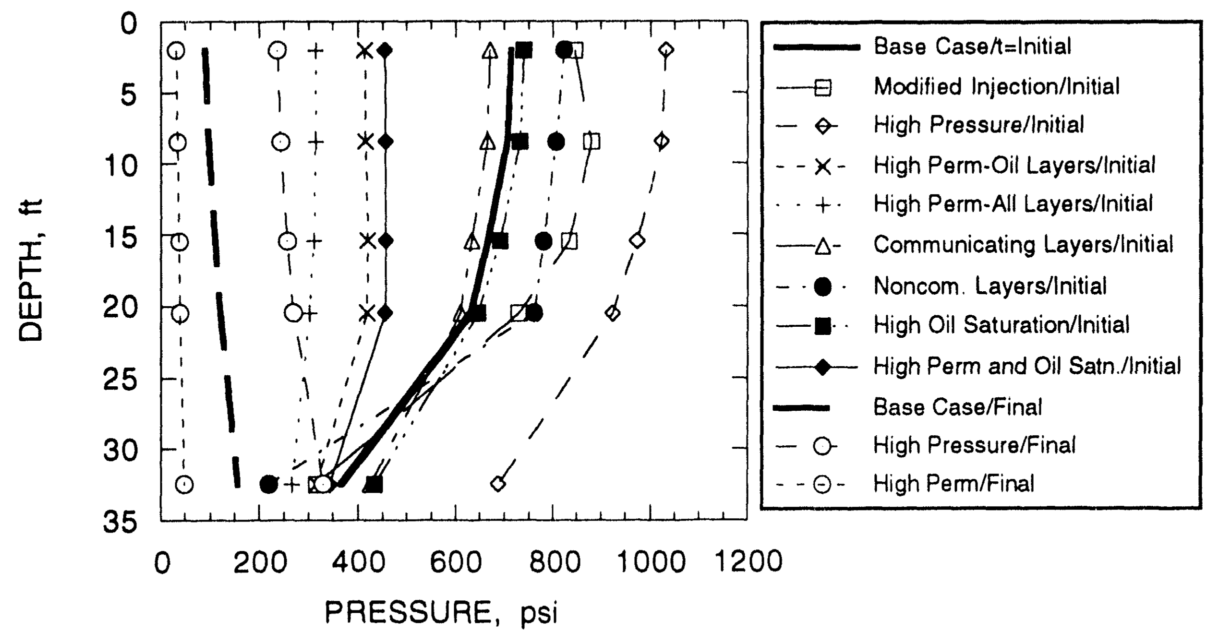


FIGURE 4.11 - Vertical pressure profiles at the end of injection (initial) and final production time.

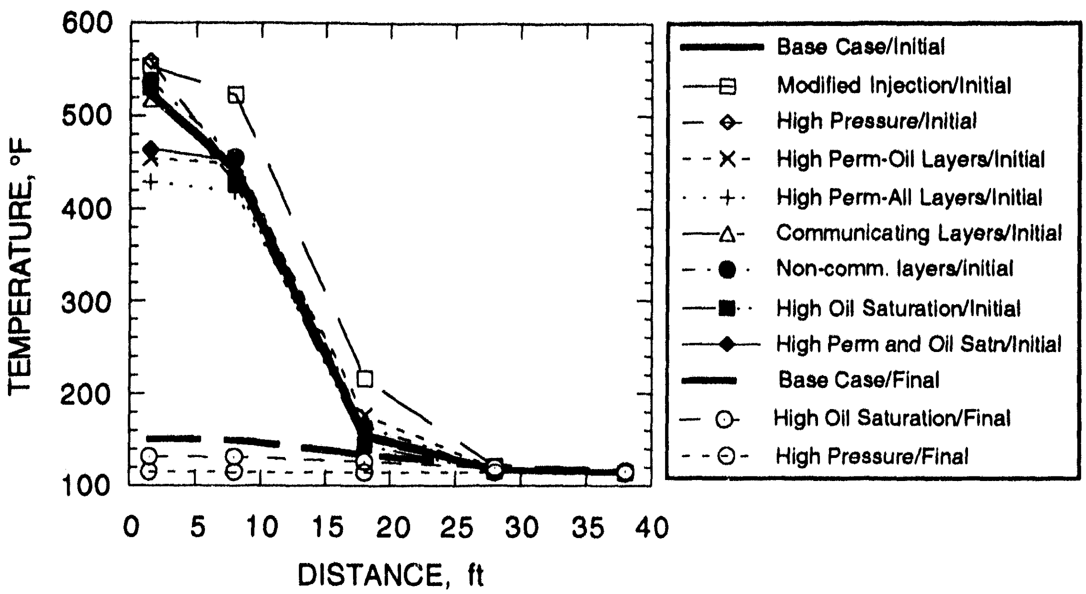


FIGURE 4.12 - Radial temperature profiles at the end of injection (initial) and final production time.

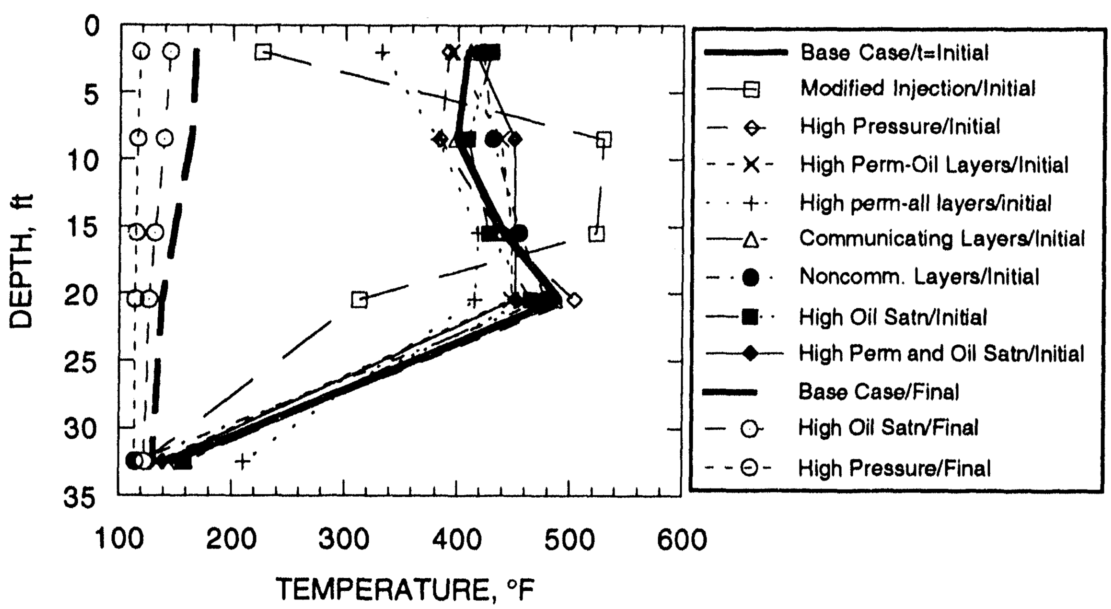


FIGURE 4.13 - Vertical temperature profiles at the end of injection (initial) and final production time.

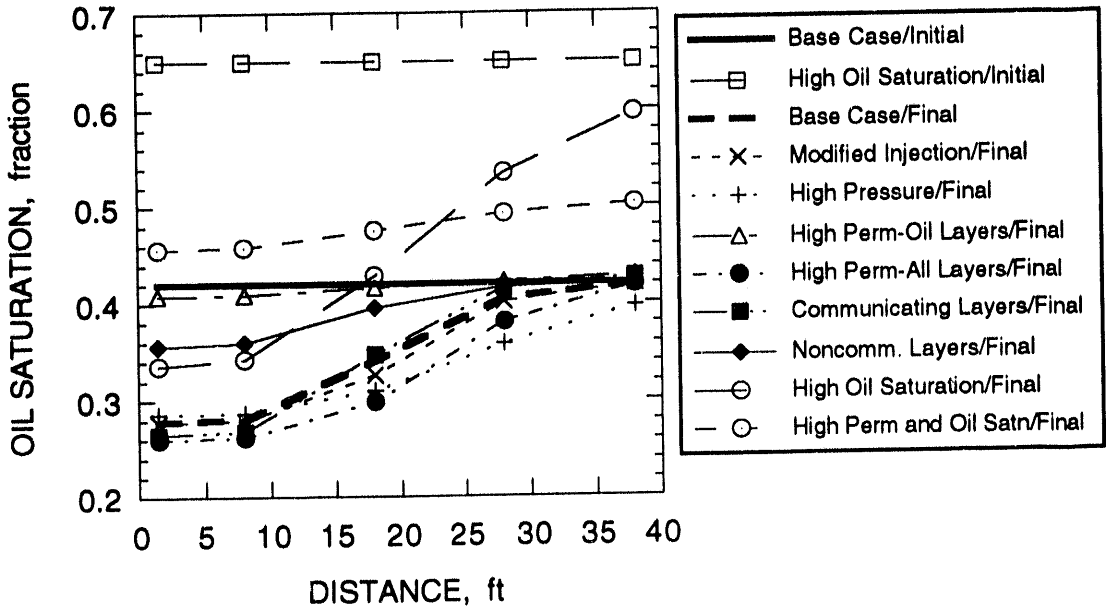


FIGURE 4.14 - Radial saturation profiles at initial and final production time.

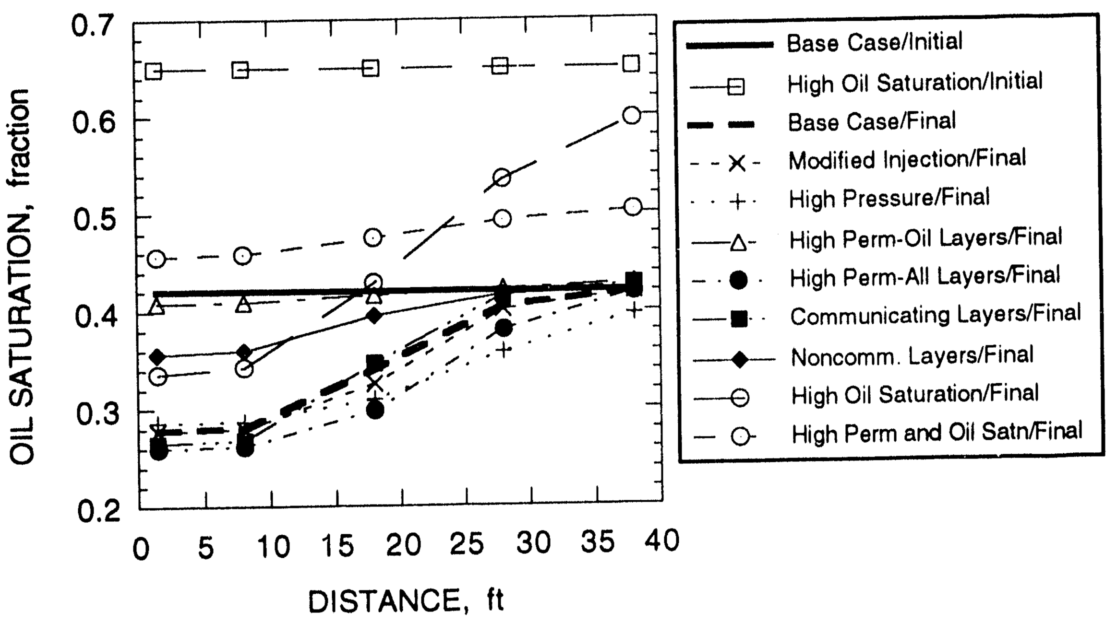


FIGURE 4.15 - Vertical saturation profiles at initial and final production time.

4.3.1 Effect of Steam Injection in Central Layers

In this simulation run, the injection strategy was changed such that the steam was injected only in the second and third layers to reduce overburden and underburden conductive heat losses (Run No. 2: Table 4.6). The first and fourth layers in which steam was not injected were 4 and 5 ft thick, respectively. The results showed that the conductive heat loss was reduced marginally by 1.6%, and the production time remained the same.

The cumulative oil production and COSR were slightly better than those of the base case. The radial and vertical pressure and temperature profiles showed that pressure and temperature in the second and third layers at the end of injection were higher than those of the base case. The final radial and vertical pressure and temperature profiles were similar to those of the base case. The oil production from the fourth layer was found to be less than that in the base case. A lower pressure and temperature in the fourth layer may have been the reason for this low oil recovery. The beneficial effect of steam injection in central layers was probably offset by ineffective reservoir heating and low vertical permeability between the third and fourth layers.

4.3.2 Effect of Reservoir Pressure

The initial reservoir pressure was changed from 200 to 500 psi (Run No. 3: Table 4.6). The results show that the production time increased significantly from 100 to 510 days. The COSR and cumulative oil production increased significantly from 0.59 to 2.11 and from 443 to 1,568 STB, respectively. At the end of 100 days of production the cumulative oil production and the COSR were 857 STB and 1.15, respectively.

The radial and vertical pressure profiles showed that pressures at the end of injection were 300 psi higher than those of the base case. During the production period a higher pressure gradient was available, wellbore pressure being the same in both the cases, to increase the rate of production. The peak production rate was 57 STB/d compared to 30 STB/d in the base case. However, the rate of oil production fell below 5 STB/d after 100 days. The radial and vertical temperature profiles at the end of injection were similar to those of the base case. However, at the end of production temperatures were slightly lower than those of base case values because of more conductive heat losses from a longer flow period and more convective heat losses from higher liquid production (about 5 times). Consequently, the final pressure gradients were higher to maintain the same minimum rate of oil production including a relatively higher WOR. The radial saturation profiles over the radial distance from 12 to 37 ft showed that the reduction in oil saturation was higher in the third layer but lower in the top two layers (not shown). A higher oil saturation around the wellbore improved oil phase mobility from increased relative permeability.

4.3.3 Effect of Vertical Communication

In this category there were three sub-cases: (a) perfectly communicating layers (implemented by imposing k_v/k_h = 1.0) (Run No. 4a: Table 4.6), (b) noncommunicating layers (implemented by imposing k_v/k_h = 0.01) (Run No. 4b: Table 4.6) and noncommunicating bottom layer (implemented by imposing $k_{v,\text{bottom layer}}$ = 0.05 mD) (Run No. 4c: Table 4.6). As mentioned before, the k_v/k_h was one-half in all the layers for the base case.

For the communicating layer case, the production time decreased by 24 days, the COSR decreased from 0.59 to 0.47 and the cumulative oil production decreased from 443 to 348 STB. For the noncommunicating layer case, the production time increased by 50 days, the COSR increased from 0.59 to 0.85 and the cumulative oil production increased from 443 to 633 STB. For the noncommunicating bottom layer case, the production time remained the same, the COSR increased marginally from 0.59 to 0.66, and the cumulative oil production increased marginally from 443 to 497 STB. No pressure, temperature or saturation profiles are shown for this non-communicating bottom layer case.

The better performance of the noncommunicating layer case was mainly caused by the isolation of the underlying water layer. The injected steam was confined to oil layers resulting in a state of higher pressure and temperature, which in turn improved the oil mobility and pressure gradient. The final temperature profiles were similar to those of the base case. The poor vertical communication decreased water production from the underlying water layer. Moreover, in the case of communicating layers, some oil was lost in the water layer in the form of an annular oil zone. For example, the final oil saturation in the second block (3 to 13 ft) of the bottom layer was 7%. Mainly during the injection period, the heated low viscosity oil was pushed into the bottom water layer because of higher pressure and temperature in the fourth layer.

4.3.4 Effect of Oil Saturation

The initial oil saturation was increased to 65% for all the top four layers containing oil corresponding to an increase in OIIP of 48%. (Run No. 5: Table 4.6) The shapes of the relative permeability curves were unchanged, but the endpoints were modified. A perfect vertical communication among the oil layers was assumed. The results show that production time increased by 125 days, the COSR increased from 0.59 to 1.60, and the cumulative oil production increased from 443 to 1,188 STB. The cumulative oil production and the COSR at the end of 100 days of production were 775 STB and 1.05, respectively.

The end-of-injection vertical and radial pressure profiles show that pressures were slightly higher than those in the base case probably because of lower aqueous phase mobility from lower aqueous phase saturation. With an increase in the pressure, the temperatures also were slightly higher than those of the base case. The final pressure profiles were similar to those of the base case. The final temperature profiles were slightly below those of the base case. The radial oil saturation profile showed a higher decrease in oil saturation than that found in the base case. This decrease in oil saturation was caused by higher mobility of oil from higher relative permeability at a higher oil saturation. The vertical saturation profile showed that the reduction in oil saturation increased with vertical distance from the top.

4.3.5 Effect of Absolute Permeability

In this category there were three sub-cases: (a) the absolute permeabilities of the top four layers containing oil were increased to 1,500 mD (Run No. 6a: Table 4.6), (b) the absolute permeabilities of all the five layers, including the underlying water layer, were increased to 1,500 mD (Run No. 6b: Table 4.6) and (c) the absolute permeabilities of the top four layers containing oil were increased to 2,500 mD (Run No. 6c: Table 4.6). A perfect communication (k_v/k_h = 1.0) was assumed for the layers with increased permeabilities.

For the high-permeability-oil layers case, the critical production time increased from 100 to 886 days. The COSR increased from 0.59 to 7.85, and the cumulative production increased from 443 to 5,885 STB. The maximum WOR decreased from 9 to 5. In cases (a) and (b) the vertical pressure profiles were more uniform, and radial profiles had less gradient. The end-of-injection radial pressure and temperature profiles showed that pressures were about 400 psi less, and temperatures were about 75° F less in the near-wellbore area.

For the high-permeability-all layers case, the production time increased from 100 to 240 days. The COSR increased from 0.59 to 2.0, and the cumulative production increased from 443 to 1,489 STB. The maximum WOR increased from 9 to 26. The end-of-injection radial pressure profile showed that pressure values were about 500 psi less in the near-wellbore area. In the high permeability-all layers case, more steam was lost in the water layer, flow potential available during production was less, water production from bottom layer was higher, and some oil was trapped in an annular region around the wellbore.

For the very high-permeability-oil layers case, the production time increased from 100 to 790 days. The COSR increased from 0.59 to 9.86 and the cumulative production increased from 443 to 7,325 STB. The maximum WOR decreased from 9 to 4. No pressure, temperature or saturation profiles are shown for this case.

In the high-permeability-oil layers and high-permeability-all layers cases, the end-of-injection radial temperature profiles showed lower temperatures associated with lower pressures in the near-wellbore area. The final temperatures of the heated zone were similar to those of the original reservoir temperatures. The final radial and vertical pressure profiles showed a decrease in pressure in the drainage radius region. The production rate in both cases increased significantly because of much higher mobility from an increase in absolute permeability. Very little decrease in oil saturation in the near wellbore area in the high-permeability-oil layers case was probably caused by the flow of oil from the area outside the heated zone. In addition to the longer transient phase of production, the pseudo steady state phase of production was longer as well. The significant decrease in oil saturation in the near wellbore area in the high-permeability-all layers case was probably caused by flow of water from the bottom layer.

4.3.6 Effect of High-Permeability and Oil Saturation

The initial oil saturation was increased to 65%, and the absolute permeabilities were increased to 1,500 mD in the top four layers (Run No. 7: Table 4.6). The production time increased significantly from 100 to 1,700 days. The COSR and cumulative oil production increased by an order of magnitude to 22.0 and 16,527 STB, respectively.

In this case, a multiplicative effect of higher oil saturation and higher permeability was observed. The end-of-injection pressure profile was between those of the high-permeability and the high-saturation cases, but at a lower level than that of the base case. Although the radial temperature profile in the third layer was at a lower level than that in the base case, the similar profiles in other layers were at a higher level than those of the base case. This was indicated also in the vertical temperature profile. The saturation profiles suggest that oil saturation in the near wellbore area decreased such that there was a significant recovery, but the oil relative permeability remained at a relatively higher level. A significant reduction in oil saturation was observed in the whole simulated area.

4.4 Conclusions

(1) Simulation results indicate that steam injection volume of 747 bbl is the optimum for cyclic steam stimulation using 70% quality steam at 1,000 psi pressure, and vertical wells in the Charivari Creek reservoir. The radius of stimulation is limited to a short distance of approximately 30 ft. The cumulative oil steam ratio (COSR) is limited to 0.59 in the first cycle and to 0.5 in the second cycle. The liquid expansion drive and increase in mobility of the oil seem to be the main oil recovery mechanisms, while the gravity drainage mechanism is unlikely to have any influence.

(2) Sensitivity studies suggest that the characteristic of the low permeability of the reservoir, among all the parameters studied here, has the most negative influence on the cyclic-steam-stimulation performance. The low permeability limits the rate and volume of steam injection and causes ineffective reservoir heating where the injected steam is consumed for raising the pressure and temperature of the reservoir to a much higher level. Using the same volume of steam for a case using sevenfold higher permeability, the radius of stimulation is higher, and the end-of-injection pressures in the near wellbore area are half of those in the base case. The injected fluids penetrate deeper into the formation and the oil is drained from an area with higher drainage radius.

(3) Higher permeability and higher oil saturation have mutiplicative effects, far influential than the individual effects of higher permeability or higher oil saturation, on the cyclic-steam-performance of the reservoir.

(5) The cyclic steam stimulation may be used as a precursor for steamflood processes, but not as a process by itself for recovering a significant amount of oil.

CHAPTER 5

SIMULATION OF STEAMFLOOD PROCESSES IN THE CHARIVARI CREEK FIELD

INTRODUCTION

5.1 Introduction

The results from screening of heavy oil reservoirs in Nacatoch formation of Arkansas, using screening guides and predictive models, suggest that Charivari Creek, Irma, and Troy are the three having the most potential reservoirs for applying steam injection processes. Because of availability of complete data only for Charivari Creek field, the steamflood simulation study was conducted on this field. The Nacatoch formation in Charivari Creek field is referred to as the Charivari Creek reservoir.

The approach taken here to study steamflood performances of the Charivari Creek reservoir by conducting reservoir simulations was as follows. First, optimization studies were conducted to find out the optimum steam injection rate and the optimum steamflood pattern area. The steamflood case using the optimum steam injection rate and the optimum steamflood pattern area is termed the base case. Second, a parametric sensitivity study was conducted by varying values of important parameters such as: reservoir pressure, absolute permeability, vertical communication, and oil saturation. Third, use of horizontal or inclined wells to improve steamflood performances was evaluated.

Mainly the cumulative injection/production data, and simplified economic criteria have been used to compare different steamflood cases on an overall basis. Detailed results have been shown only for important cases. To compare cumulative results it is necessary to choose the appropriate basis for injection/production or operation time. This time is termed as the critical production time here and is arbitrarily defined as the time when the oil production rate during steamflood falls to 80% of its peak value. This is the time around which the steam injection strategy is commonly changed to reduce the amount of steam breakthrough. Moreover, for thin reservoirs it is more likely that steam override and gravity drainage will not be the dominant production mechanisms. Therefore, a project will be expected to be profitable by that time. The WOR is another criterion which may be used alone or in combination with oil production rates for evaluating production time. Spivak et al. (1987) found that cutting the steam injection rate has advantages over cutting the steam quality. All oil recovery efficiencies in this report were calculated on the basis of OIIP. All conductive heat losses to the overburden and underburden rocks were calculated on the basis of the gross heat injected.

As mentioned before, a phenomenon that has been observed, in the case of a low-permeability reservoir, is that during the process of steam injection in a reservoir, the pressure and temperature reached very high levels. A significant fraction of the injected steam was consumed, as the compressed volume for raising the pressure of the reservoir. The injected energy is consumed raising the reservoir temperature without gaining much from the reduction in viscosity of oil above certain temperature. This phenomenon is referred to as ineffective reservoir heating.

5.1.1 Reservoir Description and Thermal Simulator

The results from reservoir description studies are given in Table 3.1. The procurement of additional data on rock-fluid properties and thermal properties of rocks and fluids are described in Section 4.1.2. A brief discussion on STARS simulator, which has been used here, is given in Section 4.1.1. The general steamflood operating conditions and numerical parameters are described in Table 5.1.

5.1.2 Pattern Configuration and Grid System

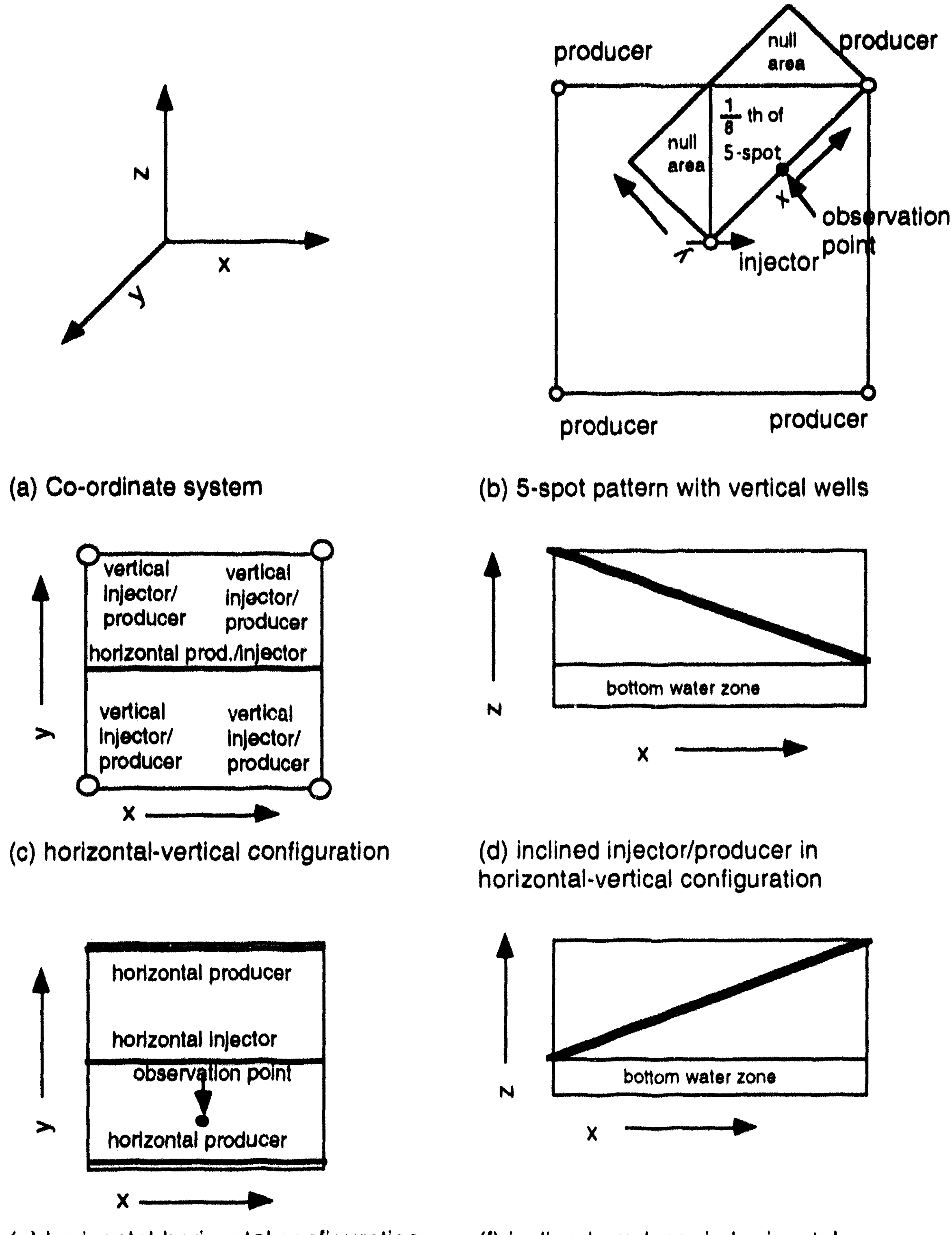
Figure 5.1 shows sketches of the coordinate system (Fig. 5.1a) and the well configurations used in this study. A sketch of a 5-spot pattern showing location of vertical wells and the simulated area, which is 1/8th of a 5-spot, is shown in Fig. 5.1b. This configuration was used in all the simulation cases during the selection of the base case and the sensitivity studies. Configurations using horizontal or inclined wells (Fig. 5.1c through 5.1f) are discussed later.

Nine-point differencing was used in the simulator to minimize grid orientation effects. In the vertical direction, five grid blocks were used for five zones found from reservoir description studies. The thickness of different layers or the block dimension in the vertical direction range from 4 to 19 ft. The layer at the top is referred to as the first layer. For 5-spot patterns using only

TABLE 5.1

Steamflood Operating Conditions and Numerical Parameters

Steam Conditions	
Saturation temperature, °F	596.2 (saturation pressure = 1500 psi)
Quality, %	70.0
Numerical Data	
Coordinate system	rectangular
Simulated pattern element	$\frac{1}{8}$ th of 5-spot for patterns using only vertical wells; 1/2 of pattern area for patterns using horizontal/inclined wells.
Grid system (x * y * z)	9 x 5 x 5 for patterns using only vertical wells; 12 x 9 x 5 for patterns using horizontal/inclined wells.



(a) Co-ordinate system

(b) 5-spot pattern with vertical wells

(c) horizontal-vertical configuration

(d) inclined injector/producer in horizontal-vertical configuration

(e) horizontal-horizontal configuration

(f) inclined producer in horizontal-horizontal configuration

FIGURE 5.1 - Coordinate system and well configurations.

vertical wells, one-eighth of the area was used for simulation (Fig. 5.1b). A 9x5 areal grid system, which gives block dimensions of 29.16 ft x 29.16 ft in a 2.5-acre pattern, was used (Aziz et al., 1985). The same grid system was used for all of the simulation runs using only vertical wells. In the area optimization study, the pattern areas were varied from 1 to 10 acres. Correspondingly, the block dimensions varied from 18.5 ft x 18.5 ft to 58.3 ft x 58.3 ft. No grid sensitivity study was conducted because the base case was found to have an area of 2.5 acres, the same area for which the grid system had already been tested (Aziz, 1985). It was unlikely that the results for areas other than 2.5 acres would be heavily influenced from grid size effects. The vertical permeability for the underlying bottom water was arbitrarily assumed to be 0.05 mD. A low value was assumed because the SP logs showed presence of shale layers.

5.1.3 Initial and Well Conditions

For all simulation runs, initial reservoir temperature and pressure were specified to be 114° F and 200 psi, respectively. For injection wells, the maximum BHP (bottomhole pressure) was specified to be 1,400 psi. For production wells, the minimum BHP and the maximum liquid production rate were specified to be 17 psi and 2,300 bbl/d, respectively. A closed pattern area, i.e. no fluid enters or leaves through the boundary of the pattern, was assumed. Additional operational conditions are mentioned later in relevant sections.

To simulate an occurrence of higher temperatures around the wellbore from the effect of cyclic steam operations, generally conducted before a steamflood, the temperature of the blocks containing a well and of the adjacent blocks to the well was increased by 100° F. Because steam was injected only in the top four layers, the temperature of the relevant blocks in the fifth layer was increased by 50° F. The results from the simulation of cyclic steam operations show that the temperature around the wellbore increases by more than 400° F at the end of injection period and then decrease with the length of the production period (Figs. 4.8 and 4.9).

5.2 Base Case

First the steam injection rate was optimized, because injection rate is more dependent on the inherent properties of a reservoir, such as permeabilities, thickness, saturations and viscosity of oil. Then the pattern area was optimized using the optimum steam injection rate. No optimization study was conducted on the quality of the steam injected, because technically it is always better to use higher quality steam (Section 2.4). Spivak et al. (1987) have shown that higher quality steam is better economically as well. This hypothesis has been found to be right in a base case sensitivity study where the injected steam quality was reduced from 70 to 10%.

5.2.1 Optimum Steam Injection Rate

Table 5.2 shows the effects of steam injection rates on steamflood results for a 2.5-acre 5-spot pattern. With increases in steam injection rate, the critical production time decreased, the maximum oil production rate increased and the final WOR (at the end of critical production time) decreased. The cumulative oil production or the oil recovery efficiency decreased slightly (59 to 53%), but the COSR passed through a maximum of 0.117 at the injection rate of 250 bbl/d. The absolute values of COSRs were low and not very sensitive to changes in rates. Following a simplified economic calculation procedure (appendix D.1) the operating cost was found to be the minimum at the injection rate of 250 bbl/d (Table 5.2). Therefore, a steam injection rate of 250 bbl/d seems to be the optimum for the conditions mentioned here.

5.2.2 Optimum Pattern Area

Table 5.3 shows the effects of pattern area on steamflood results for a steam injection rate of 250 bbl/d in a 5-spot pattern. With increases in pattern area, the critical production time increased, the maximum oil production rate decreased, the final WOR increased, and the final COSR decreased. The oil recovery efficiency reached the highest value of 58% in the 5-acre case.

To compare the operating costs, a common development area of 10 acres was arbitrarily chosen. Results from a pattern of particular area were then converted to equivalent results of a 10-acre area. For example, the values for cumulative steam, cumulative oil, and number of wells (mathematically there are two wells in a 5-spot pattern) for the 1-acre pattern area were multiplied by 10. The operating cost was found to be the minimum for the 2.5-acre pattern (Table 5.3). Therefore, a steamflood pattern area of 2.5 acres is the optimum for the conditions mentioned here.

TABLE 5.2

Results of Steam Injection Rate Optimization Study in a 2.5-Acre 5-Spot Pattern

Run No.	Steam Inj. rate, bbl/d	Cr. prod. time/d	Oil $rate_{max}$ bbl/d	WOR_f fraction	Cum. Steam, Mbbl (PV)	Cum. oil, STB (%)	Cum. liquid, Mbbl	COSR	Operating cost, $/bbl
1	062.5	5500	7.3	13.6	343.8(1.32)	36,660(59)	370.68	0.107	29.74
2	125.0	2500	20.8	10.2	312.5(1.20)	36,050(58)	327.38	0.115	24.72
3	250.0	1260	50.3	9.0	284.4(1.09)	33,168(53)	272.23	0.117	23.48
4	350.0*	1098	67.1	8.6	289.8(1.11)	32,936(53)	268.96	0.114	23.61

Note: Cr. = Critical, Inj. = Injection, Cum. = cumulative.
* Although specified to be 350 bbl/d, the average rate was 264.0 bbl/d because of pressure limitations.

TABLE 5.3

Results of Pattern Area Optimization Study for a Steam Injection Rate of 250 bbl/d and a 5-Spot Type of Pattern

									On a 10.0-acre area basis			
Run No.	Area, acres	Cr. prod. time/d	Oil $rate_{max}$ bbl/d	WOR_f fraction	Cumulative steam, MMbbl	Cumulative oil, STB	Cumulative liquid, Mbbl	COSR	Cumulative steam, MSTB	Cumulative oil, MSTB, %	No. of wells	Operating cost, $/STB
1	1.0	336	76.8	6.0	76.66	12,725	76.08	0.166	706.6	127.25(51)	20	27.98
2	2.5	1260	50.3	9.0	284.40	33,168	272.23	0.117	1137.6	132.67(53)	8	23.48
3	5.0	3988	31.1	14.7	865.33	72,322	875.11	0.084	1730.7	144.64(58)	4	26.25
4	10.0	10000	18.8	19.0	1981.89	109,120	1802.40	0.055	1981.9	109.12(44)	2	36.54

Notes Cr. = Critical, max = maximum, f = final, Prod. = Production.

5.2.3 Detailed Base Case Results

The results from the steam injection rate and pattern area optimization studies indicate that a steam injection rate of 250 bbl/d and a pattern area of 2.5 acres are the optimum steamflood operational parameters for the Charivari Creek reservoir. The critical production time of 1,260 days is referred to as the final time. Histories of oil production rate and WOR are shown in the top part of Fig. 5.2. The oil production rates are higher in the very beginning, because of higher temperatures in the near wellbore area. The oil production rate increases slowly till 800 days, increases sharply reaching its peak value of 50 STB/d at around 1,050 days, and finally fall rapidly after 1,200 days. The WOR remains below 7 till 800 days, and then increases gradually exceeding a value of 10 after 1,300 days. Histories of cumulative oil production and COSR are shown in the bottom part of Fig. 5.2. The oil recovery is 53% at the end of the production time. The COSR which reaches its peak value around 1,200 days is 0.117. The final pressure and temperature in the top layer of the injection block are 746 psi and 510° F, respectively. The conductive heat losses to the overburden and underburden rocks at the critical production time is 42.5%. The results for the high-permeability sensitivity case, which are included in Fig. 5.2, are discussed later.

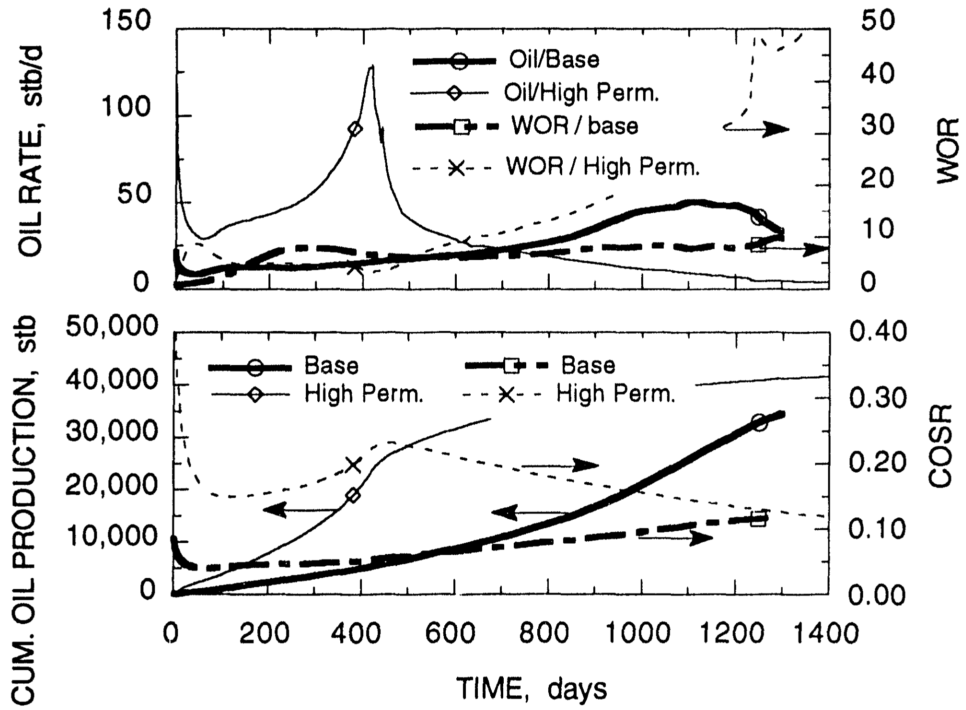


FIGURE 5.2 - Histories of oil production rate, WOR, cumulative oil production, and COSR for the base and high-permeability reservoir cases.

Figure 5.3 shows final oil saturation contours at for all the top four layers containing oil. The corner areas between the injector and the producer remain unswept in all four layers. The extent of unswept area in a layer increases with depth. Figure 5.4 shows final steam saturation, temperature, and pressure contours at for the third layer (central layer). The saturation and temperature contours show that enough steam do not invade the corner region in a distribution of lower steam saturation and higher residual oil saturation. The temperature data (not shown) suggest that the vertical temperature profiles (in the x-z plane) in the central part and in the corner region are more or less uniform. The occurrence of an unswept corner region is one of the reasons a mature 5-spot steamflood is commonly converted to a 9-spot steamflood to improve oil recovery (Fig. 4.16 in Butler, 1991).

5.3 Sensitivity Studies

The reservoir data obtained from the reservoir description study may not be perfect. Sensitivity studies were conducted to have an understanding of the range of steamflood performance that might be obtained as a result of differences in evaluated and real reservoir data. Sensitivity studies were conducted by varying only one parameter at a time, except in the high permeability and oil saturation case where two parameters were changed at the same time, while holding others constant at their base case values. In only one case, an operational parameter, namely the steam quality, was changed to evaluate its effect on the performance. All cumulative results are presented at 1,260 days which is the critical production time for the base case. The descriptions and overall production performance of the different cases are summarized in Table 5.4. All the comparisons, except as mentioned otherwise, are made with respect to the base case results.

As mentioned in Section 4.3, one more beneficial effect of conducting sensitivity studies is that one of the different scenarios created with different combinations of parameters may be found similar to the parameters of another reservoir and in that case the predicted performance may be accepted as a possible solution. For example, Irma and Troy fields (described in Chapter 2) have characteristics similar to these of Charivari Creek field except the absolute permeability which is 13-fold higher in the case of Irma and Troy reservoirs. This was found from an incomplete reservoir characterization study done with limited data available on those reservoirs. The steamflood performances of these two fields are likely to be similar to that of the high permeability case studied here. The results show that conductive heat losses to the overburden and underburden layers ranged from 41 to 44%, except in the high permeability cases where it was around 40%.

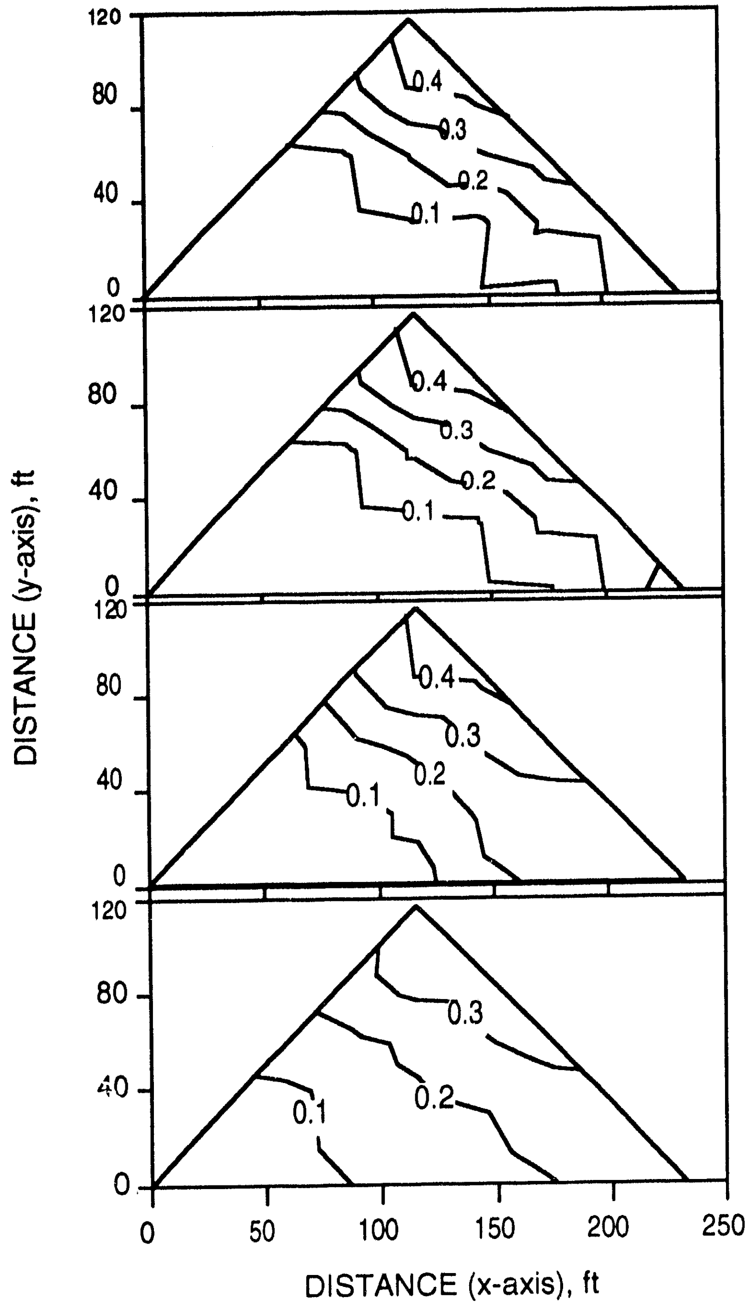


FIGURE 5.3 - Final oil saturation (in fraction) contours for the base case.

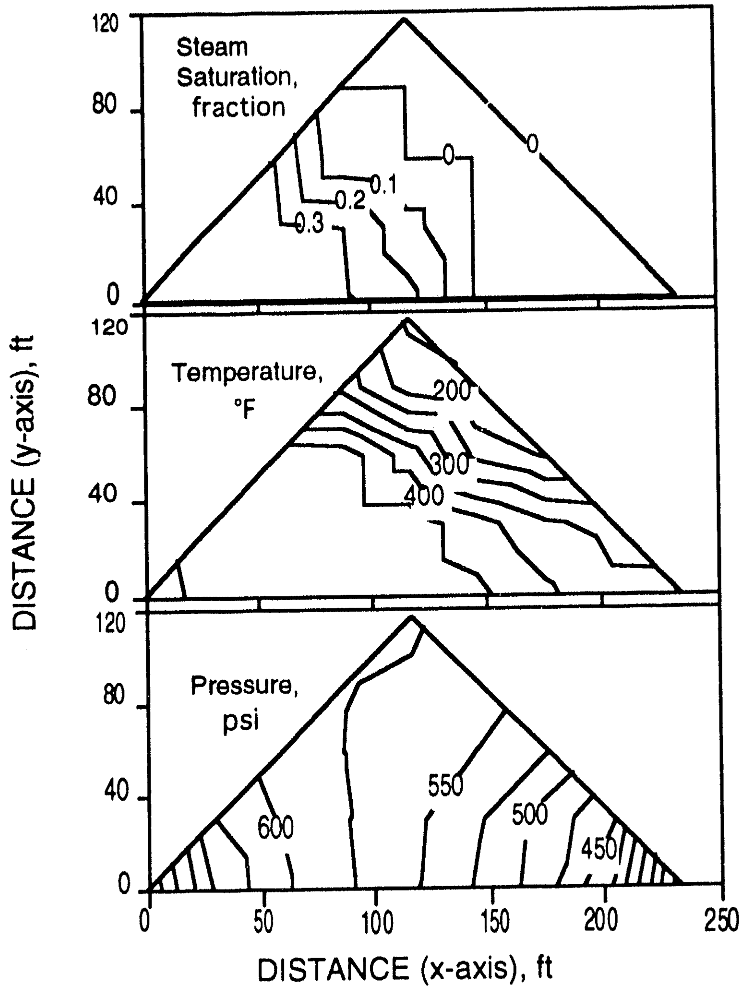


FIGURE 5.4 - Final steam saturation, temperature and pressure contours for the third layer of the base case.

TABLE 5.4

Results From Parametric Sensitivity Studies Obtained at the End of 1,260 Days for a 2.5-Acre 5-Spot Pattern With a Specified Maximum Steam Injection Rate of 250 bbl/d

Run no.	Description	Oil $rate_{max}$ STB/D	WOR_f	Volume of steam, Mbbl (PV)	COSR fraction	Cumulative oil, STB (%)	Cumulative liquid, Mbbl	Conductive heat loss, %	Top layer inj. block,[1] Pressure, psi	Temp., °F
1	Base case	50.3	9.0	284.40(1.09)	0.117	33,168(53)	272.23	42.4	746	510
2	Steam injection in central layers	43.7	8.7	255.80(0.98)	0.095	24,330(39)	203.00	44.0	1,097	556
3	High reservoir pressure	48.4*	7.7	228.34(0.88)	0.122	27,925(45)	194.61	44.0	1,293	572
4A	Communicating layers	50.17	8.9	283.20(1.09)	0.117	33,015(53)	270.60	42.5	739	509
4B	Non-communicating layers	48.5	8.7	284.42(1.09)	0.117	33,323(54)	272.56	41.3	758	512
5	Low quality steam (10%)	21.2*	13.6	274.95(1.06)	0.063	17,186(28)	187.01	41.6	1,287	576
6	High oil saturation	56.2	6.9	253.11(0.97)	0.14	35,323(47)	210.07	43.4	1,006	545
7	High permeability in oil layers	129.0	47.2	315.00(1.21)	0.13(0.23)**	40,940(66)	354.63	39.7	350	430
8	High permeability and oil saturation	108.8	32.1	315.00(1.21)	0.17(0.33)**	52,731(71)	353.30	39.4	349	430

Note: [1] pressure and temperature values are observed at the injection block of the top layer.
f = final.
* The maximum value was reached at a later date.
** The maximum value was reached at an earlier date.

5.3.1 Steam Injection in Central Layers

In this simulation run, the injection strategy was changed such that the steam was injected only in the second and third layers to reduce overburden and underburden conductive heat losses. The results show that the amount of steam injected by 1,260 days was 10% less. The oil recovery decreased by 13%, and the final COSR decreased to 0.095. The peak oil rate and final WOR decreased slightly. The pressure and temperature in the top layer of the injection block, particularly the pressure, were much higher compared to those of the base case. The likely reasons for low recovery efficiency are low volume of steam injected and the ineffective reservoir heating.

5.3.2 Effect of Reservoir Pressure

The initial reservoir pressure was changed from 200 to 500 psi. The results show that the amount of steam injected was 20% less, but the oil recovery was only 8% less. However, the COSR improved marginally at 1,260 days. The pressure in the top layer of the injection block was about 500 psi higher than that of the base case.

Because of higher pressure gradient from higher initial pressure in the system (wellbore pressure being the same), initial production rates were much higher. However, on the injection side, because of the injection pressure constraint, the amount of steam injected was limited. It seems that the beneficial effect of higher pressure is offset by ineffective reservoir heating. The maximum oil rate was found to be 53.3 STB/D at 1,371 days and the maximum COSR was found to be 0.14 at 1,500 days. The displacement process was slowed down, and the hot fluid broke through at a later date.

5.3.3 Effect of Vertical Communication

In this category there were two sub-cases: (a) perfectly communicating layers, implemented by imposing $k_v/k_h = 1.0$, and (b) noncommunicating layer, implemented by imposing $k_v/k_h = 0.01$. As mentioned before the k_v/k_h was 1/2 for the base case. This vertical communication was with regard to the top 4 layers containing oil. The vertical communication with the underlying water layer is discussed later.

The results from these two cases differed slightly, and varied in the opposite direction from the base case results as would be expected. For the noncommunicating layer case, the volume of steam injected and the volume of oil produced were slightly higher. However, the final COSR remained the same. The likely reason for vertical communication having little effect was that a piston type of displacement was occurring in these two and base cases probably as a result of lower thickness, similar mobility among the layers (resulting from horizontal permeabilities and phase saturations), and higher steam injection rate.

5.3.4 Effect of Low Quality Steam

The injected steam quality was reduced from 70 to 10%. The amount of steam injected is reduced by 3%; however, the amount of heat injected was reduced by a large extent of 36%. The oil recovery was reduced by 25% and the final WOR became higher. In this case, the COSR was not a valid criterion to compare performance results, because heat contents and costs per BBL of steam for 70% and 10% quality steams are different. The COHR (cumulative oil heat ratio, STB/MMBTU) seemed to be a better criterion (Spivak et al., 1987). The COHR for the base case and this case were 2.66 and 2.15 STB/MMBTU, respectively. The pressure and temperature in the top layer of the injection block were 1,287 psi and 576° F. These values were the highest among the cases considered. Although cumulative heat loss was slightly less, the ineffective reservoir heating was possibly the reason for poor performance. The operating cost was $28.28/STB of oil as compared to $23.48/STB of oil for the base case.

5.3.5 Effect of Oil Saturation

The initial oil saturation was increased to 55% for the top 3 layers and to 45% for the fourth layer. This increased the OIIP of the pattern by 16.8% (7,4771 STB). A perfect vertical communication (k_v/k_h = 1.0) was assumed among the oil layers. The amount of steam injected at 1,260 days was reduced by 11% because of lower aqueous phase mobilities from lower aqueous phase saturations. The oil recovery was reduced by 6%, however, the final WOR was less and the final COSR was slightly higher (0.14). Allowing the steamflood to continue until the critical production time for this case was (1,417 days) reached, the final COSR and the recovery efficiency increased to 0.148 and 58%, respectively. The likely reasons for lower recovery efficiency were lower volume of steam injected and the ineffective reservoir heating.

5.3.6 Effect of Absolute Permeability

The absolute permeability for the top four layers were increased to 2,500 mD. A perfect communication (k_v/k_h = 1.0) was assumed for those layers. At 1,260 days, the amount of steam injected was 11% higher and the oil recovery was 12% higher. The maximum oil rate increased significantly from 50.3 to 129 STB/D and the final WOR was much higher at 47.

In this case the critical production time was reached much earlier at 429 days. The COSR and the oil recovery at that time were 0.226 and 39%, respectively. The maximum COSR was found to be 0.232 at the end of 461 days when the oil recovery efficiency was 43% and the WOR was 3.8. The cumulative oil recovery in this case exceeds that of the base case at 663 days when the COSR was still 0.20.

At some intermediate time of 400 days the amount of steam injected (~96,000 bbl) and the conductive heat loss (~35%) were similar for this case and the base case. In the high permeability case the pressure and temperature in the top layer of the injection block were 247 psi and 398° F, respectively. These values were much lower compared to the base case values of 1,394 psi and

587° F, respectively. The pressure difference between the injection and the production blocks were 126 and 763 psi for this case and the base case. The oil recovery at this time were, respectively, 33% and 7%, for this case and the base case. Therefore, comparing the two cases at a particular time, keeping all operational and reservoir parameters same, except the absolute permeability, the steam injection in a low permeability reservoir leads to ineffective reservoir heating. If the steamflood operation is conducted in such a way that pressure and temperature distributions are similar for both the cases, the low-permeability reservoir slows down the displacement process by limiting the rates of injection and production. The effect of permeability is most significant among all the effects considered here.

Histories of oil production rate and WOR are shown, along with the base case results, in the top part of Fig. 5.2. As mentioned before the oil production rates were high in the very beginning because of higher temperature in the near wellbore area. The oil production rate increased slowly till 200 days, increased sharply reaching its peak value of 129 STB/D at around 421 days, and then fell rapidly. The WOR remained below 4 until 461 days. Histories of cumulative oil production and COSR are shown in the bottom part of Fig. 5.2.

5.3.7 Effect of High Permeability and Oil Saturation

Both absolute permeabilities and the oil saturation were increased according to the conditions mentioned above with regard to their individual increases. The absolute permeability for the top 4 layers containing oil were increased to 2,500 mD. The initial oil saturation was increased to 55% for the top three layers, and to 45% for the fourth layer. The amount of steam injected at 1,260 days increased by 11%, but the oil recovery increased by 18%.

In this case, the critical production time was reached earlier at 405 days. The oil recovery by that time was 45% and the COSR was 0.334. In this case, a multiplicative effect of higher saturation and higher permeability was observed. The pressure profiles lay between high permeability and high saturation profiles, and at a lower level than the base case profiles. The effect of higher oil saturation was found to be significant when the permeabilities also were higher.

5.3.8 Vertical Communication with the Bottom Sand

The effect of vertical communication between the oil layers at the top and the water layer at the bottom was investigated by changing the vertical permeability of the bottom layer over a wide range from 0.05 to 50.0 mD. The results are summarized in Table 5.5. The results indicated that with increase in the vertical permeability of the bottom layer, the amount of steam that could be injected by a fixed time period of 1,260 days increased, the maximum oil production rate decreased, and the final COSR decreased. Under the conditions of higher vertical permeability more oil was first being pushed into the bottom layer and then became trapped as the residual oil saturation.

TABLE 5.5

Results Showing the Effect of Vertical Communication With the Bottom Water Zone at the End of 1,260 Days for a 2.5-Acre 5-Spot Pattern With a Specified Maximum Steam Injection Rate of 250 bbl/d.

Run no.	Vertical Perm. mD	Volume of steam, Mbbl	COSR fraction	Cum. oil, STB	Cum. liquid, Mbbl	Oil $rate_{max}$ STB/d	WOR_f
1	0.05	284.4	0.117	33,168	272.23	50.3	9.0
2	0.5	294.8	0.108	31,787	292.65	48.8	11.0
3	5.0	303.07	0.083	25,083	292.23	43.4	11.7
4	50.0	315.00	0.063	19,725	308.97	[1]39.9	12.2

[1] The maximum oil production rate is reached at a later date; cum. - cumulative; suffix "max"-maximum, "f"- final.

5.4 Potential of Using Horizontal Wells

The results from steamflood sensitivity studies using vertical wells indicated that the main reason for poor steamflood performance in the base case was ineffective reservoir heating caused by low permeability of the reservoir. To keep the pressure and temperature of the reservoir at a lower level, the use of horizontal or inclined wells instead of vertical wells seemed to be a solution. To test this idea, steamflood simulations using horizontal wells were conducted.

The types of well configurations used were: (1) one horizontal injector and four vertical producers, (2) one horizontal producer and four vertical injectors, and (3) one horizontal injector and two horizontal producers. The configurations 1 and 2 can be termed as horizontal-vertical and the configuration 3 can be termed as horizontal-horizontal configurations. The sketches of configurations 1 and 2 are shown in Fig. 5.1c and that of configuration 3 is shown in Fig. 5.1e. For configurations using one horizontal well, the horizontal well was located centrally in the y-direction and are oriented parallel to x-axis. For configurations using one horizontal injector and two horizontal producers, the injector was located as before, but the two producers were located at y = o and y = pattern length in the y-direction. Both the wells were parallel to the x-axis. In the vertical plane, wells were located in the fourth layer from the top.

As variations of exactly horizontal wells, low angle (2.8° in a 5-acre pattern) inclined wells were used to study the influence of more realistic situations where horizontal wells are not exactly horizontal (Gussis, 1985), and the effects of contacting all the layers of the formation for injection and production. The sketches of an inclined injector/producer in configurations 1 and 2, and of an inclined producer in configuration 3 are shown in Fig. 5.1d and f, respectively. In the areal x-y plane the configurations were similar to those of horizontal well configurations (Fig. 5.1c and e). In configuration 3, the injection and production wells had inclinations in the opposite direction in the x-z plane (at different values of y), looking like the alphabet "X". This was done with the assumption that it would improve sweep efficiency.

A steamflood pattern area of 5 acres was chosen for the following reasons. In the base case of a 2.5-acre area and 5-spot pattern, mathematically there are two wells. Hence, there are four vertical wells per 5-acre area. According to the horizontal well configurations mentioned above, the number of wells per 5-acre pattern area are one horizontal and one vertical for horizontal-vertical configurations, and two horizontal wells for horizontal-horizontal configurations. Assuming the costs of a horizontal well to be double the cost of a vertical well, the fixed costs of four vertical wells in two patterns of 2.5 acres each are equivalent to that of two horizontal wells in a 5-acre pattern. The fixed costs of one vertical and one horizontal well in horizontal-vertical configurations in a 5-acre pattern are less than that of the base case using four vertical wells. Of course, in terms of physical number of wells, the wells located on the outskirts of the area to be developed will introduce additional well costs, because physically there is nothing like a quarter well. For patterns using inclined/horizontal wells, half of the pattern area was used for simulation (Figs. 5.2c and 5.2e). A 12x9 areal grid system, which gives block dimensions of 42.42 ft x 29.16 ft, was used for all of the runs. The horizontal wells were completed in second through eleventh blocks with a total length of 424.2 ft, leaving 21.2 ft of first and twelfth blocks being not completed. In configurations 1 and 2, the inclined injector/producer well was completed in block 2 of the first (top) layer, blocks 3 through 7 of the second layer, blocks 8 through 10 of the third layer, and blocks 11 and 12 of the fourth layer. In configuration 3, the injection well (at $y = \frac{1}{2}$ of the length of a side of the pattern) was completed as described above. But, the inclined producer well (at $y = 0$) was completed in block 11 of first (top) layer, blocks 7 through 10 of second layer, blocks 4 through 6 of third layer, and blocks 2 and 3 of fourth layer. In case of inclined wells, the second layer received or injected maximum amount of produced fluid or steam because it was the thickest layer among the four layers that contained oil.

The steamflood results for these three types of configurations, using horizontal (Cases 2a, 3a and 4a) and inclined type of wells (Cases 2b, 3b and 4b), along with the results of the base case using vertical wells, are summarized in Table 5.6. As mentioned before, the critical production time is defined as the time when the rate of oil production falls below 80% of the peak rate. The cumulative results are computed at the critical production time for each case. For the base case using vertical wells in a 2.5-acre pattern area, the oil rate and cumulative injection and production data were doubled to obtain equivalent results for a 5-acre area.

5.4.1 Horizontal Injector and Vertical Producers

For horizontal and inclined injector cases (Run Nos. 2a and 2b), the COSRs were 0.081 and 0.073, and recovery efficiencies were 34% and 29%, respectively. The 5% reduction in recovery efficiency could be partly explained by a 6% reduction in the amount of steam injected. The COSR values were even lower than the base case values. The critical production time was approximately 1,500 days for both the cases. The final conductive heat losses (for the base case and the horizontal injector cases) were 42% and 47%, respectively. In the case of horizontal injector and vertical producers, the peak rate of oil production of 90 STB/d was reached at 1,485 days, but in the case of inclined injector and vertical producers, the peak rate of oil production of 60 STB/d was reached at 1,396 days. Similarly, the production time was 81 days less in the case of inclined injector and vertical producers. This occurred because of non-uniform displacement in the case of inclined injector and vertical producers. The hot fluid broke through first in the well on the left-hand side, probably because of a combined effect of permeability distributions and the locations of the completed interval in a layer. This was indicated on the temperature contour of the second layer at around 1,400 days for both the cases (Fig. 5.5). In the case of inclined injector and vertical producers, the temperature in the wells on the left- and right-hand sides were 400° and 225° F, respectively. However, in the case of horizontal injector and vertical producers, the temperature in the wells on both the left- and right-hand sides were 300° F. The amounts of steam injected at this time were very similar for the two cases.

5.4.2 Horizontal Producer and Vertical Injectors

There was not much difference in the performance of horizontal and inclined producers with that of vertical injectors. The values for production time, COSR, and recovery efficiency for horizontal and inclined producer cases and vertical injectors were approximately 400 days, 0.208, and 34%, respectively. Compared to the base case results, COSR was much higher, but the recovery efficiency was 20% less.

Interestingly, the configurations using horizontal or inclined producer and vertical injectors (Run Nos. 3a and 3b) were showing better process efficiency than the configurations using horizontal or inclined injector and vertical producers (Run Nos. 2a and 2b). The amount of steam injected in the horizontal injector and vertical producers (Run No. 2a) case was 8% less, but in the

TABLE 5.6

Results Showing the Effect of Horizontal and Inclined Wells for a 5.0-Acre Pattern With a Specified Maximum Steam Injection Rate of 500 bbl/d

Run no.	Description	Cr. production time/d	Oil $rate_{max}$ bbl/d	WOR_f fraction	Cum. steam, Mbbl (PV)	Cum. oil, STB (%)	Cum. liquid, Mbbl	COSR	Conductive heat loss, %	Operating cost, $/STB
1	Base case (on a 5 acre basis)	1260	100	9.0	568.80(1.09)	66,336(53)	544.46	0.117	42	23.47
2a	Horizontal injector & vertical producers	1533	90	10.6	524.88(1.00)	42,512(34)	399.30	0.081	47	31.90
2b	Inclined injector & vertical producers	1452	70	11.3	489.37(0.94)	35,539(29)	335.47	0.073	48	35.89
3a	Horizontal producer & vertical injectors	394	171	4.9	197.04(0.38)	40,948(33)	198.62	0.208	35	18.10
3b	Inclined producer & vertical injectors	418	166	5.2	209.06(0.40)	43,486(35)	212.70	0.208	33	17.67
4a	Horizontal injector & producer	800	145	5.6	400.00(0.77)	84,870(68)	458.59	0.212	42	15.33
4b	Inclined injector & producer	707	152	5.6	353.49(0.68)	74,215(60)	391.91	0.210	42	16.09

Note: Suffix "max"-maximum, Cum. - Cumulative; "f"- final.; Cr. - Critical

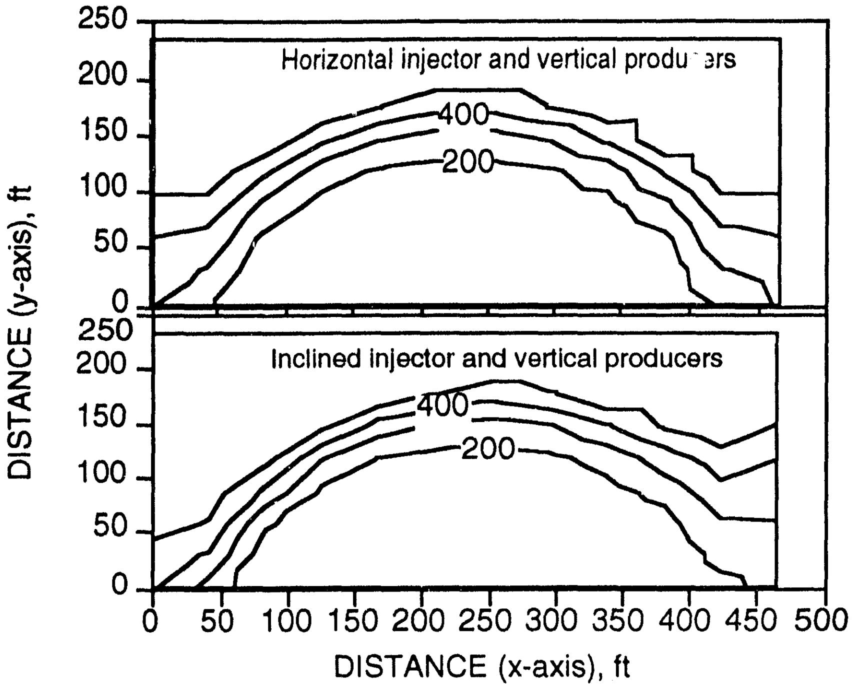


FIGURE 5.5 - Temperature contours (in °F) of the second layer for horizontal injector and vertical producer (2a) and inclined injector and vertical producers (2b) cases at 1,400 days.

horizontal producer and vertical injector (Run No. 2b) case was 65% less, when compared to the amount of steam injected in the base case. The oil recovery efficiencies were similar for these two cases. Figures 5.6 and 5.7 show contours of oil saturation and pressure in second layer at an intermediate time of 400 days for the horizontal injector and vertical producers (2a), and horizontal producer and vertical injectors (3a) cases. The required potential gradient for fluid flow around a horizontal well was low, but that around a vertical well was very high, because of the difference in the length of contact with the reservoir. Moreover, in the case of vertical producers receiving colder oil of higher viscosity, the required potential gradient became even higher. In the case of horizontal injector and vertical producers, a bottle-neck type of situation was created where the injected fluid was used for building up higher pressure and temperature in a significant portion of the area of the pattern.

5.4.3 Horizontal Injector and Horizontal Producer

The configuration using horizontal wells for both injection and production showed the best results (Run No. 4a). The COSR was 0.212, which is generally perceived as a desired value for a

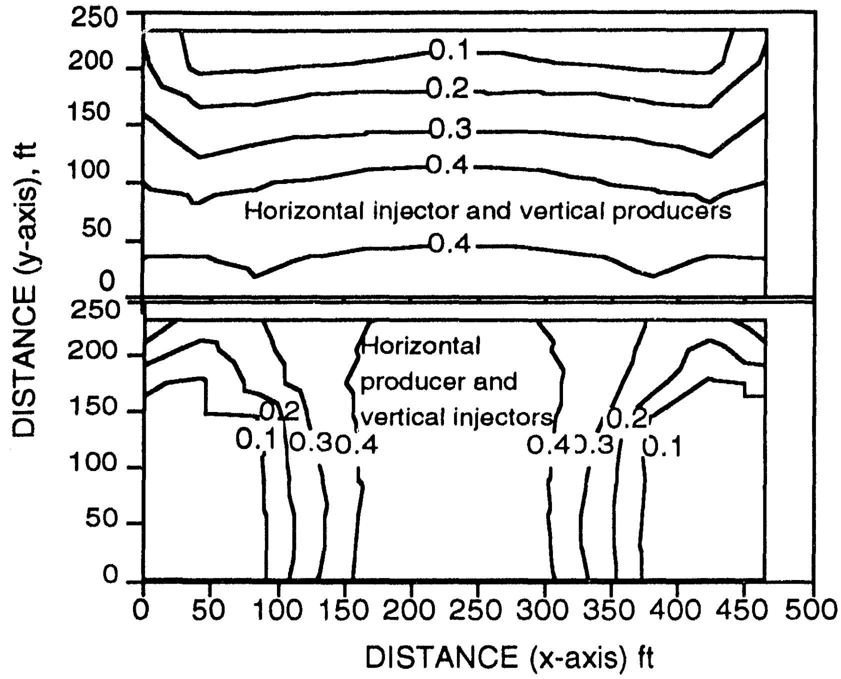


FIGURE 5.6 - Oil saturation (in fraction) contours in second layer for horizontal injector and vertical producers (2a) and horizontal producer and vertical injectors (3a) cases at an intermediate time of 400 days.

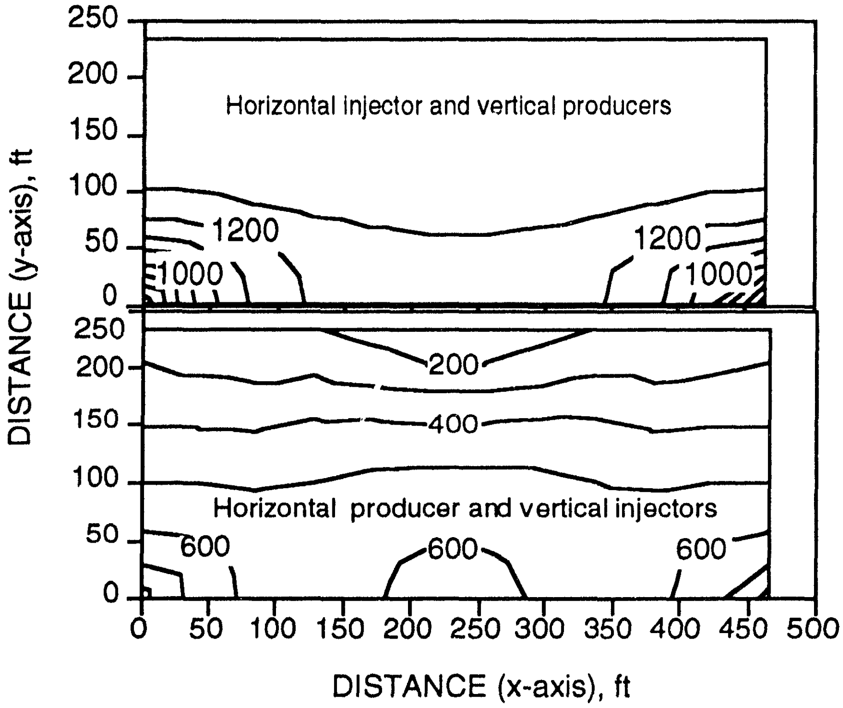


FIGURE 5.7 - Pressure (in psi) contours in second layer for horizontal injector and vertical producers (2a) and inclined injector and vertical producers (3a) cases at an intermediate time of 400 days.

successful steamflood (p. 107 in Butler, 1991). This was much higher than that of 0.117 obtained in the base case using vertical wells. The oil recovery efficiency was about 68%, which was 15% higher than that of the base case. The amount of steam injected was about 30% less.

Figure 5.8 shows oil saturation contours at 800 days for all the top four layers containing oil. Areal sweep was best in the second layer, good and similar to each other in the first and third layers, and worse in the fourth layer. Figure 5.9 shows steam saturation, temperature and pressure contours at 800 days for the second layer. Although steam was injected in the fourth layer, areal extent of steam zone in this layer was less. The different factors involved were horizontal and vertical permeabilities of the layers, overriding tendency of steam, and different displacement efficiency of steam and hot water. Figure 5.10 shows histories of pressure, temperature and steam saturation at an observation point located centrally between an injector and a producer for the base case and the horizontal injector and horizontal producer case. The observation points are marked with small circles in Figs. 5.1b, c and e.

The configuration using inclined wells for both injection and production showed poorer results (Run No. 4b) compared to those of the previous case, where both the wells were exactly horizontal. Both the oil recovery efficiency and the amount of steam injected were about 8% less compared to the values in the horizontal wells case. Figure 5.10 shows oil saturation contours at 800 days for all the top four layers, containing oil. Areal sweep was relatively better in the first and second layers, but worse in the third and fourth layers. Compared to the horizontal wells case (4a), the displacement in this case was nonuniform creating a nose in the central part of the pattern in the first and second layers. When this nose broke through, the areal sweep remained poor on the both sides of the pattern. This happened probably for two reasons. First, in an "X" type of well configuration, the distance between the injector and the producer was minimum in the second layer. Second, because of saturation and permeability distributions, the first and second layers had higher mobilities. Figure 5.12 shows steam saturation, temperature, and pressure contours for the second layer at 800 days. The temperature and steam saturation contours showed low temperatures and low or no steam saturation on both the sides of the pattern. The values of pressures and temperatures were similar to those of the horizontal wells case (4a).

The histories of oil production rate and WOR for horizontal injector and vertical producers (2a), horizontal producer and vertical injectors (3a), horizontal injector and horizontal producer (4a), and the base case are shown in Fig. 5.13. The oil production rates reached their peak values at around 350, 600, 1,100 and 1,500 days for these cases, respectively. The WOR was below 5 for first 200 days and remained around 7 for time less than 1,000 days for all the cases. The cumulative oil production and COSR histories for the horizontal injector and horizontal producer and base cases are shown in Fig. 5.14.

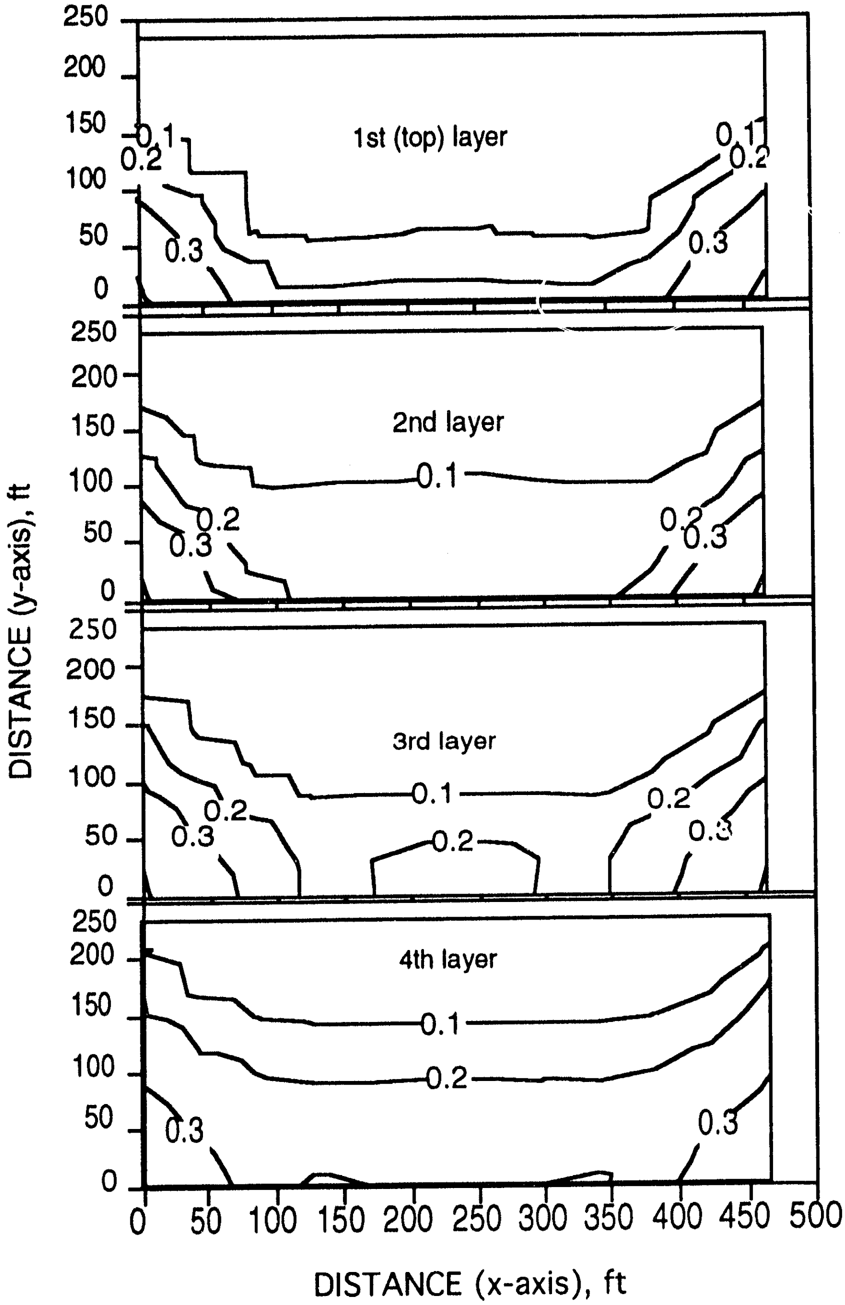


FIGURE 5.8 - Oil saturation (in fraction) contours for the top four layers for the horizontal injector and horizontal producer case (4a) at 800 days.

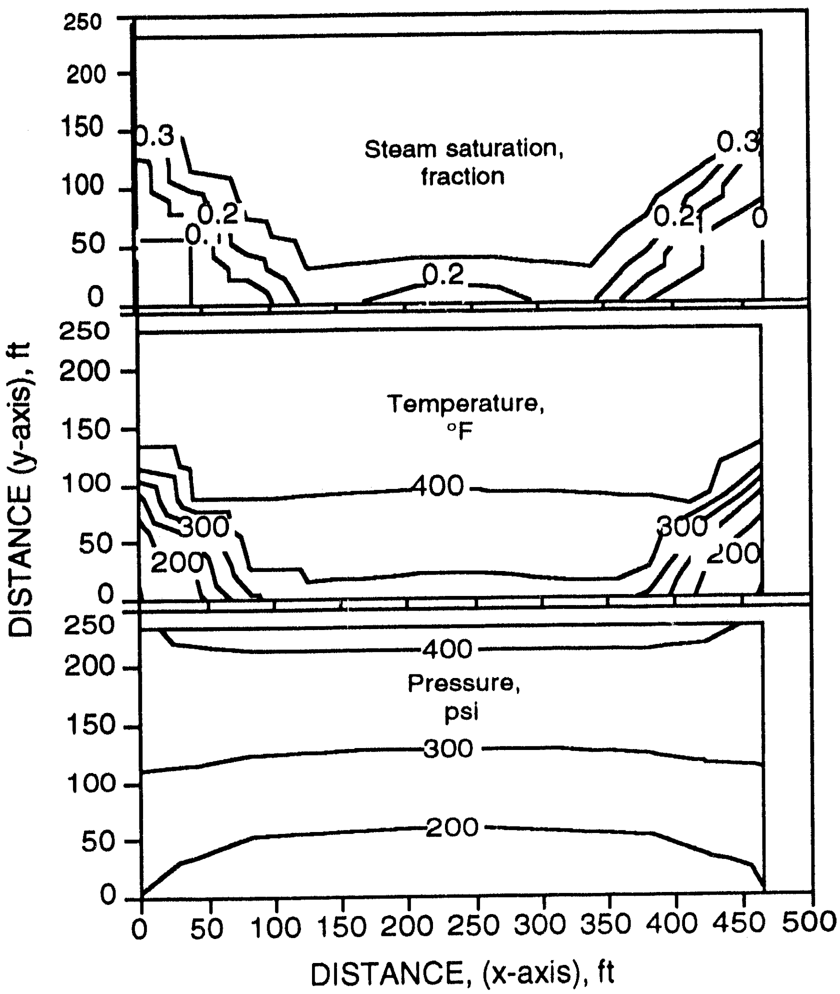


FIGURE 5.9 - Steam saturation, temperature, and pressure contours of the second layer for the horizontal injector and horizontal producer case (4a) at 800 days.

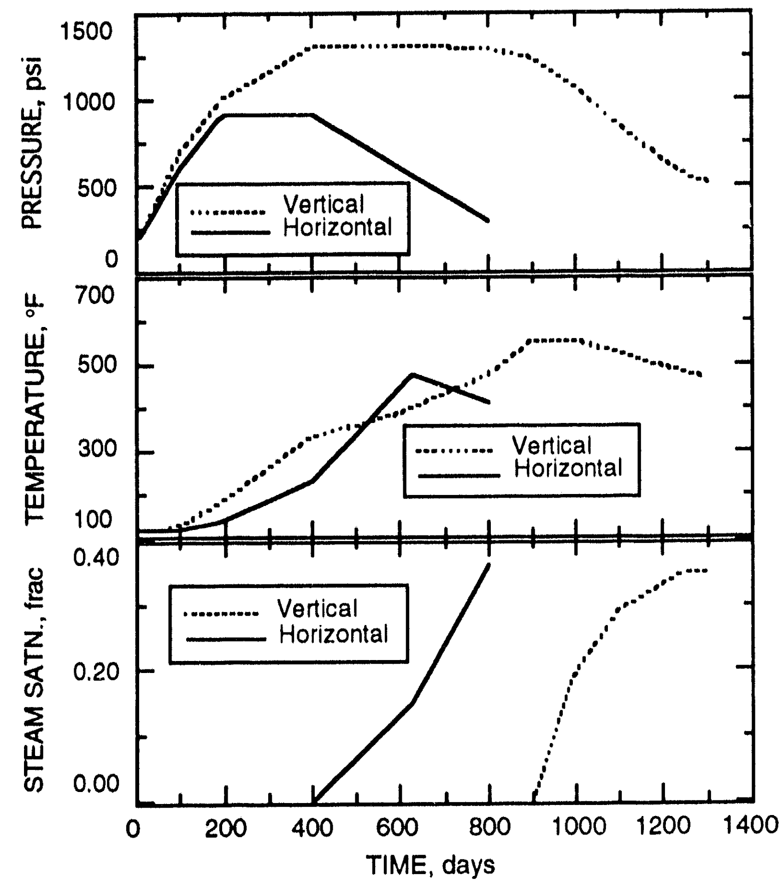


FIGURE 5.10 - Histories of pressure, temperature and steam saturation at an observation point located centrally between the injector and the producer for the base case and the horizontal injector and horizontal producer case.

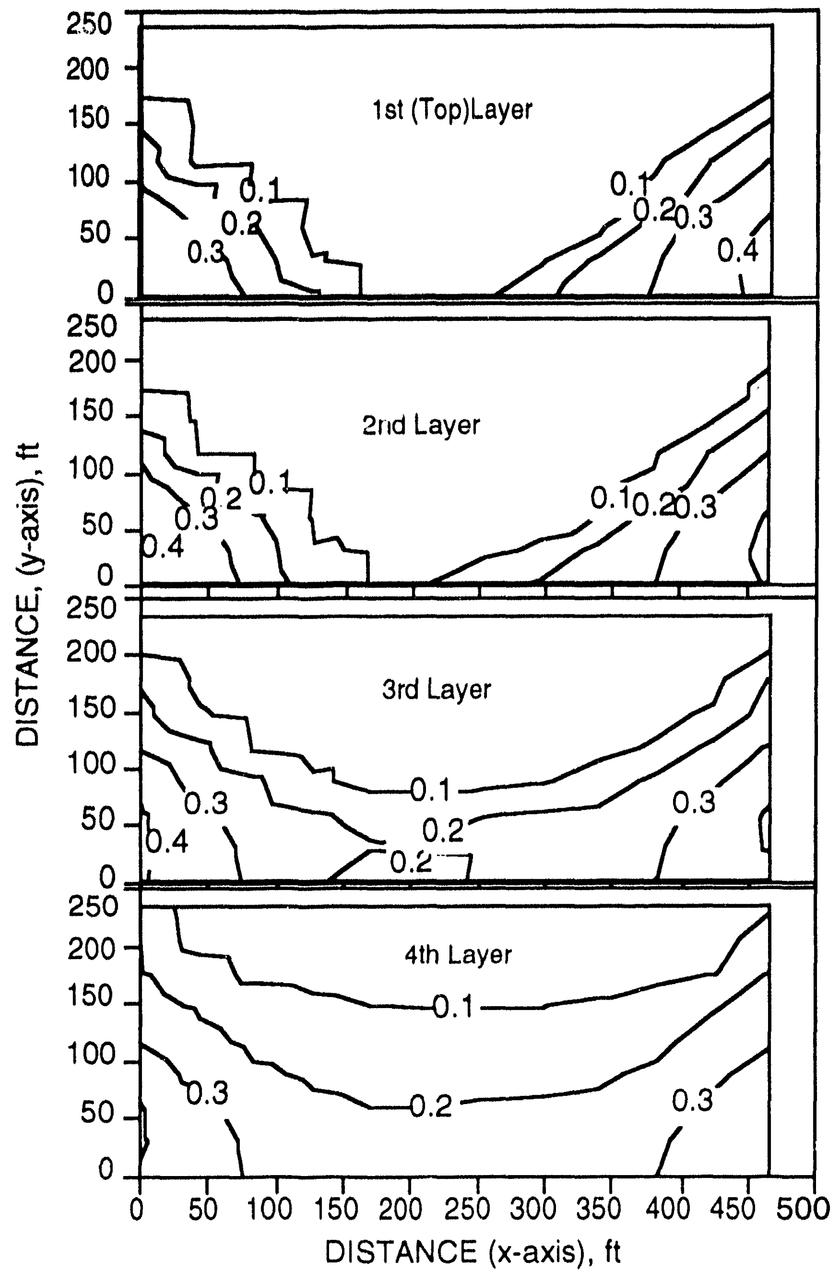


FIGURE 5.11 - Oil saturation (in fraction) contours for the top four layers for the inclined injector and inclined producer case (4b) at 800 days.

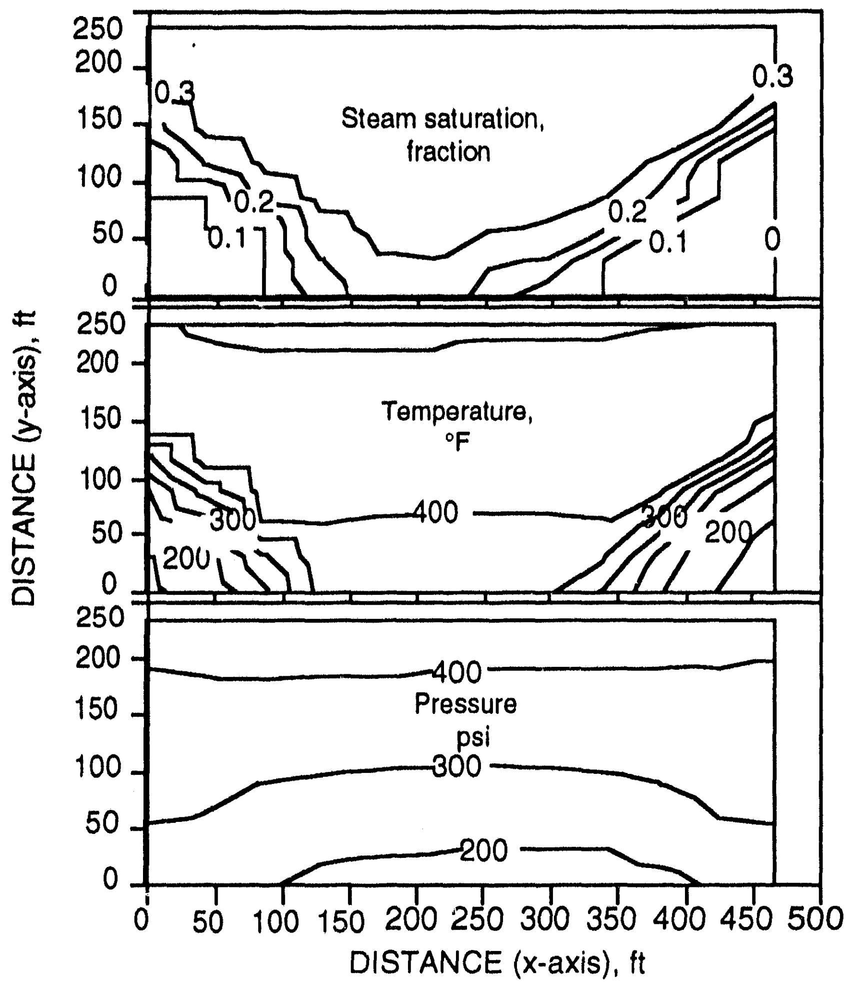


FIGURE 5.12 - Steam saturation, temperature and pressure contours for the second layer for the inclined injector and inclined producer case (4b) at 800 days.

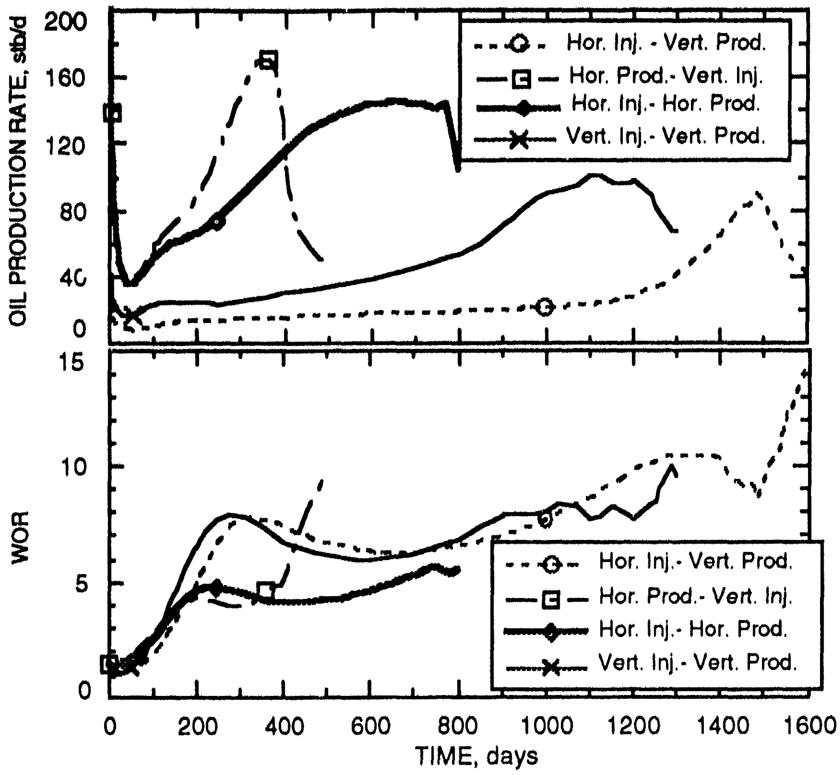


FIGURE 5.13 - Histories of oil production rate (top part) and WOR (bottom part) for horizontal injector and vertical producer, horizontal producer and vertical injector, horizontal injector and horizontal producer and base cases.

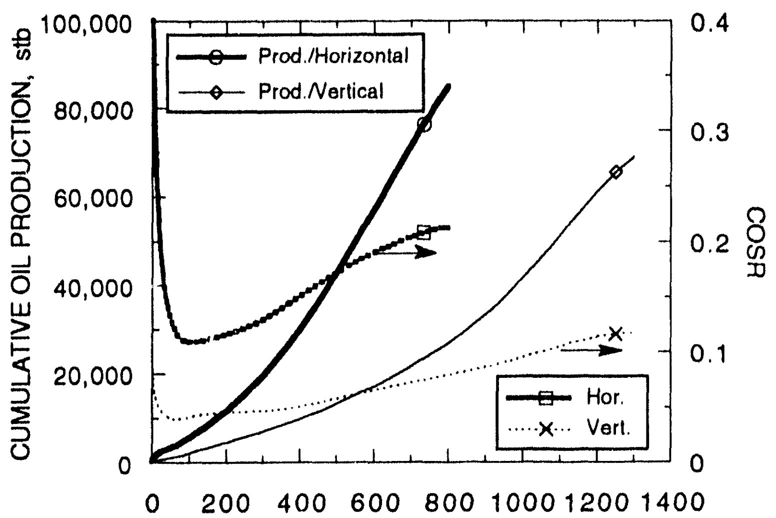


FIGURE 5.14 - Histories of cumulative oil production and COSR for the horizontal injector and horizontal producer and base cases.

5.5 Conclusions

(1) The results from simulation of steamflood operations indicate that a steam injection rate of 250 BBL/D (cold water equivalent) and a pattern area of 2.5 acres are the optimum values for steamflood processes using 70% quality steam at 1,500 psi pressure in a 5-spot pattern using vertical wells. The COSR at 1,260 days is limited to 0.12, indicating a possibility that the operation might be economically unsuccessful. The steamfront progresses almost like a piston with no gravity override, because the thickness of the oil zone is small and variation of permeabilities within the zone are small.

(2) As observed in the cyclic-steam-stimulation cases, the characteristic of the low permeability of the Charivari Creek reservoir has the most negative influence on the steamflood performance. It limits the rate of steam injection and causes ineffective reservoir heating, where the mass and energy of the injected steam is consumed for raising the pressure and temperature of the reservoir to a much higher level. The strong effects of higher oil saturation are clearly noticeable when the permeabilities also are higher. A hundred-fold increase in vertical permeability of the underlying water layer, although less likely in reality, reduces oil recovery by 13%.

(3) Use of horizontal wells improves the recovery performance very significantly by reducing the ineffective reservoir heating, increasing sweep efficiency, and accelerating the oil recovery process. At 800 days, the COSR is 0.2, which is considered a desired value for a successful steamflood, and the recovery efficiency is 68% of OIIP. The higher cost of horizontal wells is presumably offset by reducing the number of wells per acre. Simplified economic calculations suggest that the project might be economically successful.

(4) Sensitivity studies suggest that an increase in vertical permeability of the underlying water layer can reduce oil recovery much more significantly than that observed in the configurations using vertical wells. Zones of higher oil saturation are created in the water layer along the lines parallel to the horizontal injector.

(5) Configurations using horizontal producers and vertical injectors show much better performance than configurations using horizontal injectors and vertical producers, because in the latter configurations ineffective reservoir heating occurs as a result of a bottle-neck type of situation created at the producers receiving the cold oil.

CHAPTER 6

SUMMARY

Results from screening all the heavy oil reservoirs in the Nacatoch formation of Arkansas and Louisiana, using screening guides, indicate that five reservoirs with highest potentials for application of steam injection processes are Sandy Bend, Irma, Charivari Creek, Troy, and Elliott South. According to predicted performances, using steamflood predictive models, the Charivari Creek reservoir has the highest potential for application of steam injection processes. Irma and Troy are two other reservoirs with good potentials for successful steamfloods.

A cleaner and thicker part of the Nacatoch formation in Charivari Creek field is identified and characterized based on core-log calibration, characteristics of the fractured wells and the production characteristics of the reservoir. The zones containing oil have a gross thickness of 23 ft and an average for oil saturation of 44%. The values for porosity and permeability in different layers are more or less uniform with averages at 31% and 186 mD, respectively. A water zone that exists below the oil zone has a net thickness of 14 ft, contains some low-permeability streaks, and has permeabilities less than those of the oil zone. A simplified fracture analysis of a typical well shows that fracture orientation is vertical and improvement in PI ratio is marginal possibly because of low proppant concentrations used during fracturing. Primary and secondary production characteristics of the field indicate that the lateral and vertical continuities within the reservoir are good. The primary and secondary (waterflood till 1991) oil recoveries are about 5.7% each.

Numerical simulation of cyclic-steam-stimulation operations using a thermal simulator show that the optimum steam injection volume has a small value of 747 bbl; consequently, the radius of stimulation is limited to a short distance of approximately 30 ft. The COSR is limited to 0.59 in the first cycle and to 0.5 in the second cycle. The liquid expansion drive and increase in mobility of the oil seem to be the main oil recovery mechanisms, while the gravity drainage mechanism is unlikely to have any influence here. The characteristics of low permeability, low thickness, and low oil saturation are the major reasons for poor recovery performance. A sensitivity study using seven-fold higher permeability shows that the pressures in the near-wellbore area at the end of injection period are half of those observed in the base case using original permeability. The injected fluids penetrate deeper into the formation, and the oil is drained from an area with higher drainage radius. Higher permeability and higher oil saturation combined have mutiplicative effects. The cyclic steam stimulation may be used as a precursor for steamflood processes but not as a process by itself for recovering a significant amount of oil in thin reservoirs such as Charivari Creek.

Simulation of steamflood operations using vertical wells shows that the optimum steam injection rate is 250 bbl/d and the optimum pattern area is 2.5 acres. The COSR at 1,260 days is limited to 0.12, indicating a possibility that the operation might be economically unsuccessful. The steamfront progresses almost piston like with very little gravity override, because the thickness of the oil zone is small and permeabilities of the oil layers are more or less similar. Sensitivity studies suggest that the characteristic of low permeability of the reservoir, among all the parameters studied here, has the most negative influence on the recovery performance. It causes ineffective reservoir heating where the mass and energy of injected steam is consumed for raising the pressure and temperature of the reservoir to a much higher level without gaining much from reduction in viscosity of oil. A 100-fold increase in vertical permeability of the underlying water layer, although less likely, reduces oil recovery by 13%.

Use of horizontal wells in steamflooding improves the recovery performance very significantly by reducing the ineffective reservoir heating, increasing sweep efficiency, and accelerating the oil recovery process. At 800 days, the COSR is 0.2, which is considered as a desired value for a successful steamflood, and the recovery efficiency is 68% of OIIP. The higher cost of horizontal wells is presumably offset by reducing the number of wells per acre by half. Simplified economic calculations suggest that the project might be economical. A 100-fold increase in vertical permeability of the underlying water layer can seriously jeopardize the process by reducing oil recovery by 34%. Zones of higher oil saturation are created in the water layer, along lines parallel to the length of the wells and at a distance half-way between the injector and the producer.

A configuration using a horizontal producer and vertical injectors shows much better performance than a configuration using a horizontal injector and vertical producers, because in the latter configuration ineffective reservoir heating occurs as a result of a bottle-neck type of situation created at the producers receiving the cold oil. For the configuration using horizontal producer and vertical injectors the recovery efficiency is 20% less, because of a poor areal sweep efficiency. The COSR is similar (0.2), when compared with the values of the configuration using a horizontal producer and a horizontal injector.

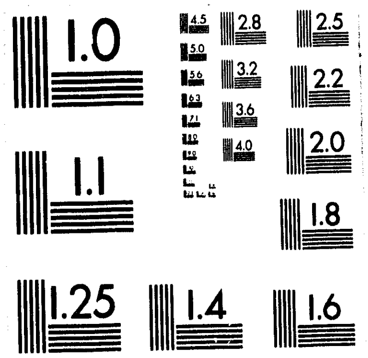
CHAPTER 7
CONCLUSIONS AND RECOMMENDATIONS

A commercial thermal simulator was used to evaluate the steamflood potential of a marginal heavy oil reservoir in the Nacatoch formation of Arkansas. This is a shallow, thin, low-permeability reservoir with low initial oil saturation and is underlaid by water sand.

This investigation has shown that the reservoir will respond favorably to steam injection and at current oil prices ($18.00/bbl) the economy seems to favor horizontal well steam injection technique over the vertical well steamdrive. The following specific conclusions were derived from this study.

CONCLUSIONS

1. Due to thin pay-zone (23 ft net), low permeability (~186 mD) and higher initial water saturation (56%), cyclic steaming is not effective in this reservoir. However, stimulation is necessary to improve steam injectivity during subsequent steamdrive.
2. Steamdrive simulation studies indicated that because of the thin pay-zone and high water saturation, the steamfront progressed almost piston-like with very little gravity override. The in situ water by virtue of its higher heat capacity and thermal conductivity, absorbed much of the injected heat which resulted in very low heat losses to the overburden. During the early stages of steamdrive, the bulk of the injected heat was expended in converting the in situ water to steam. This resulted in large steam zone volume that progressed in almost piston-like fashion and displaced oil toward the producer.
3. The residual oil saturation in the steam invaded zone was less than 8%. However, not all of the displaced oil was produced. Due to vertical communication between the water saturated bottom layer and the oil layer, approximately 20% of the displaced oil was drained into the water sand and was not produced. When the water sand was sealed off, almost all of the displaced oil was produced.
4. No detailed economic study was performed. However, a back of the envelope type economic calculation indicated that at an oil price of less than $23.00/bbl, steamdrive using vertical wells will not be economical in this reservoir.
5. Oil recovery and oil steam ratio increased significantly using horizontal well steam injection technique suggesting that the economics may be more favorable with horizontal wells.
6. For the pattern area studied conventional steamdrive using vertical injectors and producers recovered 66,336 bbl of oil (53% of OIIP) at an estimated cost of $23.47/bbl.
7. For the same area, the use of horizontal injectors and horizontal producers recovered 84,870 bbl of oil (68% of OIIP) at an estimated cost of $15.33/bbl. This reduction in


1.0
4.5
5.0
5.6
6.3
7.1
8.0
2.8
3.2
3.6
4.0
2.5
2.2
2.0
1.1
1.8
1.25
1.4
1.6

the production cost is due to the improvement in the cumulative oil-steam ratio from 0.12 (for vertical wells) to 0.21 for horizontal configuration.

RECOMMENDATIONS

1. The description of the reservoir needs to be improved. Wells may be drilled on the top of the formation, according to the new structure and isopach maps prepared in this work. All three sections of the Nacatoch formation may be cored and analyzed. It will be important to know the vertical and horizontal permeabilities of the bottom section (underlying water layer). A suite of logs including SP, gamma ray, porosity, and resistivity should be run in a single well for proper core-log calibration. Well tests should be conducted for evaluating skin factor of wells, and pressure and permeability of the reservoir.
2. Fracturing, if necessary, should be carried out with higher proppant concentration to obtain any significant improvement in productivity index (PI) ratio. Tests should be carried out to determine height, length, and conductivity of the fracture. It will be important to know if the vertical growth of the fracture can be limited to the middle section only.
3. Since this study indicates that steamflooding using horizontal wells has good potential, an in-depth study using improved reservoir data and appropriate economic data should be conducted before implementing any steamflood project.

APPENDIX A—CALCULATIONS OF RESERVOIR TEMPERATURE, OIL SATURATIONS, OIIP, OIL RECOVERY, AND COSR

Reservoir temperature ($T_{reservoir}$) are estimated from the following equation.

$$T_{reservoir} = T_{surface} + \alpha * Depth_{reservoir} \tag{A-1}$$

Here α is the temperature gradient. The surface temperature ($T_{surface}$) and the temperature gradient (α) were assumed to be 70° F and 2° F/100 ft (Frick, 1962), respectively.

Initial oil saturation (S_{oi}) is estimated from the following equation.

$$S_{oi}=1-S_{wc} \tag{A-2}$$

No free gas was assumed to be present in the reservoir. Here S_{wc} is the connate water saturation.

Present oil saturation (S_o) is estimated from the following equation.

$$S_o=S_{oi} - \frac{N_p B_o}{7758\ Ah\phi} \tag{A-3}$$

Here N_p is the cumulative amount of oil (BBL) produced, B_o is the formation volume factor, A, h, and ϕ are the area (acre), thickness (ft), and porosity of a reservoir, respectively.

Oil in place (OIP) is estimated from the following equation.

$$OIP = 7758*Ah\phi S_o B_o \tag{A-4}$$

Oil recovery is estimated from the following equation.

$$Recovery = \frac{S_{oi} - S_o}{S_{oi}} *100 \tag{A-5}$$

Cumulative steam-oil ratio (CSOR) is the reciprocal of the cumulative oil -steam ratio (COSR). COSR is evaluated from the following correlation (p. 110 in Butler, 1991).

For COSR>5, (English unit: same as the units used in the screening table)

$$COSR = -0.011253 + 0.00002779D + 0.0001579h - 0.0013570\theta + 0.000007232\mu$$
$$+ 0.00001043kh/\mu + 0.5120\phi S_o \tag{A-6}$$

Here D, θ, and k are the depth (ft), dip angle (degree) and permeability (mD) of a reservoir, respectively. μ is the viscosity (cP) of the oil.

APPENDIX B—THE LOG ANALYSIS PROCEDURE

B.1 Volume of Clay

Gamma ray index is evaluated as,

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

where,

GR_{log} = gamma ray from the log
GR_{min} = gamma ray minimum (clean sand) = 25
GR_{max} = gamma ray maximum (shale) = 60

Volume of clay is (assuming an unconsolidated sand) evaluated as,

$$V_{clay} = 0.083*[2^{(3.7*I_{GR})} - 1]$$

B.2 Porosity

The total sonic porosity is evaluated as,

$$\phi_t = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} * \frac{100}{\Delta t_{sh}}$$

The effective porosity is evaluated as,

$$\phi_e = \phi_t - V_{clay} * \frac{\Delta t_{sh} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$$

where,

Δt_{log} = interval transit time of shaly formation, μ sec
Δt_{ma} = interval transit time of formation's matrix = 55.5 μ sec
Δt_f = interval transit time of fluid = 189 μ sec
Δt_{sh} = interval transit time of adjacent shale = 125 μ sec

B.3 Water Saturation

The effective water saturation is evaluated as,

$$S_{we} = \left(\frac{F\,R_w}{R_t}\right)^{1/2}$$

where, the formation resistivity factor for shaly sands is expressed as (Asquith, 1990),

$$F = \frac{1.65}{\phi_t^{1.33}}$$

R_w = free water resistivity =0.065 Ωm (at the formation temperature of 114 ° F)

R_t = deep resistivity of the formation, Ωm

APPENDIX C—FRACTURE ANALYSIS

The gross thickness is evaluated on the basis of the idea that only the thick shale layers at the top and bottom of the formation can be considered to be the boundaries. Following this basis, the gross fracture height is the thickness of the middle section of the formation, and the net fracture height includes the thickness of the oil zone and the underlying low permeability water zone. The fracture will be extended over the oil and water zones in the vertical direction. The drainage area for the well is 10 acres. Details of the fracture job, conducted at the Potlatch "A" 4 well in July, 1976, may be summarized as:

Injection rate, bbl/min	18
Gross fracture height, ft	80
Net fracture height, ft	42
Pad volume, bbl	30
Suspension volume, bbl	500
Proppant type	10/20 sand (average size = 0.0559 inches, sp. gravity =1.53)
Proppant mass, lb	32,000
Average permeability, mD	129

Immediate shut-in pressure at the surface was 500 psi. The long-term transient phase pressure data are not available. This shut-in pressure may be considered as the upper limit for the closure stress. Fracture fluid data are not available and they are arbitrarily assumed as follows.

Fluid loss coefficient, ft/min$^{1/2}$	0.002
Fluid loss, ft^3/ft^2	0.01
Viscosity, cP	300
Specific gravity	1.0

The fluid pressure gradient is assumed to be 0.44 psi/ft. The maximum proppant concentration was 2.75 ppg (pound per gallon). From the correlation chart the fracture permeability is 1,150 D (Fig. 6.2: Bradley, 1989; Fig. 6.2; Brady type sand is considered here).

C.1 Fracture Orientation

P_{ISIP}, Instantaneous shut-in pressure = 500 psi

P_h , hydrostatic pressure 0.44 psi/ft * 2,370 ft = 1,043 psi

P_{BISIP} , Bottomhole instantaneous shut-in pressure = $P_{ISIP} + P_h$ = 1,543 psi

Fracture gradient = P_{BISIP} /Depth = 1,543/2,370 = 0.65 psi/ft

Normal overburden stress is 1.0 psi/ft. Since the fracture gradient is less than the overburden stress, it is most likely that a vertical fracture will form.

C.2 Fracture Dimension and Productivity Ratio

Assuming a medium hard sand formation the Poisson's ratio (ν) is found to be 0.17 (Bradley et al., 1989; Table 11.1). Young's modulus has been approximated from the following equation (Bradley et al., 1989; Eq. 11.1).

$$E = \frac{2.16*10^8(1-2\nu)(1+\nu)[165(1-\phi) + \phi\,\rho_f}{(1-\nu)\,(\Delta t_c)^2}$$

Here,

Δt_c, sonic travel time = 120 μsec/ft (from the sonic log at Salmar 2),

ϕ, porosity = 0.29,

ρ_f, reservoir fluid density = 62.4 lb/ ft^3.

Or, $E = 1.613*10^6$ psi

From the PKN model the results are propped fracture length equals to 507 ft and width = 0.047 inches. Although, the dynamic fracture width at the wellbore is 0.4 inches, the propped width is only 1/10th of the dynamic width. From the McGuire-Sikora chart (Bradley et al., 1989; Fig. 6.1) the PI ratio is 1.4. As the fluid viscosity was unknown a sensitivity run was made with a viscosity of 30 cP. The results show that the fracture length increases to 587 ft and the width remains almost same at 0.041 inches. These differences are unlikely to make any difference on the value for PI ratio.

C.3 Fracture Pressure Analysis

The fracturing process can be divided into four phases: formation breakdown, fracture propagation, fracture closure, and transient phases (Bradley et al., 1989; Fig. 14.10). The maximum surface pressure observed during the fracturing process was 1,150 psi (hydrostatic pressure is 1,050 psi). So, the formation breakdown pressure is about 2,200 psi. The average surface pressure during fracturing process was 700 psi, which indicates that the fracture propagation pressure was about 1,750 psi. The history of surface pressure data during the propagation phase are plotted in log-log coordinates in Fig. C.1. The plot can be qualitatively analyzed following an example analysis given by Bradley et al. (1989; Fig. 14.16). After the initial time period, the slope of the pressure curve shows slight negative value, which is a indication of the fact that the fracture propagated more in the vertical direction and less in the horizontal direction. The immediate shut-in pressure was 1,543 psi. A sharp decrease in the

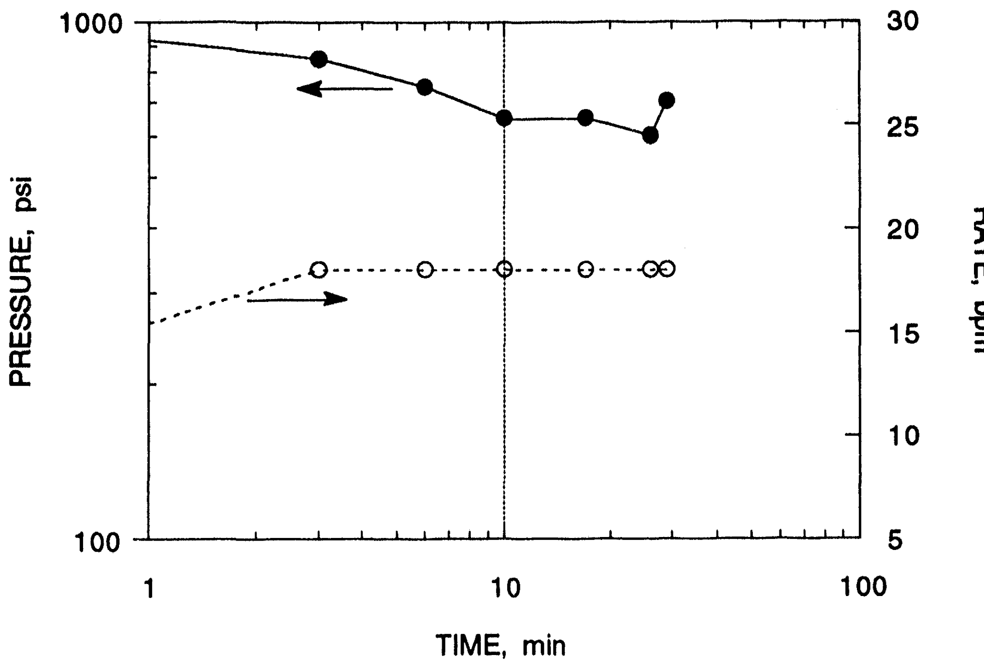


FIGURE C.1 - Surface pressure and injection rate histories during fracturing of Potlatch "A" 4 well.

pressure value at the beginning of closure phase indicates a quick fluid leak-off from the fracture channel. This may be a result of low viscosity fracture fluid or low proppant concentration in the slurry. This value can be considered as the upper limit for the closure stress. The 15-minute shut-in pressure data are available only at Salmar 2, and the data show a decrease of only 50 psi (from the immediate shut-in value) and it seems that the fracture closure phase is almost completed by that time. No data are available for the transient phase .

APPENDIX D—CALCULATION OF OPERATING COST

Following the detailed economic calculation procedure shown by Dowd, Kuuskraa and Godec (1988), a simplified procedure has been developed here for comparison purposes. The fixed and variable operating costs have been lumped into single indicators of fixed operating cost per day per well and variable operating costs per unit volume of oil produced, respectively. The capital and operating costs for steam generation and water treatment/disposal have been lumped into single indicators of steam cost per unit volume of steam and water disposal cost per unit volume of water, respectively. At present the field is developed on a 10 acre/well basis. Because new wells need to be added before initiating steam injection processes capital well costs have been included. The capital costs for surface facilities have not been included because they are already existing. Financial costs, such as royalty, severance tax, income tax, interest, etc., have not been included.

The data for fixed operating cost per day per well, variable operating costs per unit volume of oil produced, and water disposal cost per unit volume of water have been assumed to be \$25.00/day /well, \$2.50/STB and \$0.025/BBL, respectively (Dowd, Kuuskraa and Godec, 1988). These cost data, expressed in 1986 dollars, assume a standard thermal EOR facility that uses a 50 MMBTU/hr steam generator operating at up to 2,500 psi and injecting steam into wells as deep as 3,000 ft. The data for steam cost per unit volume and vertical well cost have been assumed to be \$1.50/BBL and \$100,000.00 (Chapter 4 in Sarathi et al., 1992). The cost of a horizontal or inclined well has been arbitrarily assumed to be double the cost of a vertical well (\$200,000.00). All of these cost data should be considered as average values.

So,

Total operating cost = Fixed operating cost + Variable operating cost + Water disposal cost + Steam cost + Well cost

Here,

Fixed operating cost = Production period, days * no. of wells * \$25.00/day /well

Variable operating cost = Cumulative volume of oil produced, STB * \$2.50/STB

Water disposal cost = Cumulative volume of water produced, BBL * \$0.025/BBL

Steam cost = Cumulative volume of steam injected, BBL * \$1.50/BBL

Well Cost = Number of wells * cost of a well, \$/well

Finally,

$$\text{Operating cost, \$/STB} = \frac{\text{Total operating cost, \$}}{\text{Cumulative oil produced, STB}}$$

NOMENCLATURE

A	=	Area of the reservoir, acre
A_h	=	Area heated, fraction
B_o	=	Oil formation volume factor, bbl/stb
COSR	=	Cumulative oil-steam ratio
D	=	Depth, ft
E_h	=	Thermal efficiency, fraction
E_r	=	Oil recovery efficiency, fraction
F	=	Formation resistivity factor
GR	=	Gamma Ray Value, API
h	=	Thickness of a reservoir, ft
I_{GR}	=	Gamma Ray Index
k	=	Permeability, mD
N_p	=	Cumulative oil recovery, MSTB (10^3 STB)
OIP	=	Oil in place, STB
OIIP	=	Oil initially in place, STB
PI	=	Productivity/Injectivity Index, bbl/d/psi
p_s	=	Steam pressure, psi
R_w	=	Free water resistivity, Ωm
R_t	=	Deep resistivity of formation, Ωm
S	=	Saturation, fraction
T	=	Temperature, °F
t_{BT}	=	Time for hot fluid breakthrough (fractional area heated equals to 1), yr
t_{DC}	=	Dimensionless critical time/ Mandl-Volek time, fraction
V_{clay}	=	Volume of clay, fraction
x	=	Steam quality, fraction
Δt	=	Interval transit time, μ sec

Suffix

c	=	Cold
h	=	Hot
log	=	Log value
min	=	Minimum
max	=	Maximum
ma	=	Matrix
o	=	Oil

oi	=	Initial oil
or	=	Residual oil
Sh	=	Shale
wc	=	Connate water
we	=	Effective water

Greek Symbols

α	=	Temperature gradient, °F/100 ft
ϕ	=	Porosity, fraction
μ	=	Viscosity, cP
θ	=	Dip angle, degree

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