

**IMPROVED STEAMFLOOD ANALYTICAL MODEL**

A Thesis

by

SUANDY CHANDRA

Submitted to the Office of Graduate Studies of  
Texas A&M University  
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2005

Major Subject: Petroleum Engineering

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**ABSTRACT**

Improved Steamflood Analytical Model.

(August 2005)

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Co-Chairs of Advisory Committee: Dr. Daulat D. Mamora  
Dr. Robert A. Wattenbarger

The Jeff Jones steamflood model incorporates oil displacement by steam as described by Myhill and Stegemeier, and a three-component capture factor based on empirical correlations. The main drawback of the model however is the unsatisfactory prediction of the oil production peak: usually significantly lower than the actual. Our study focuses on improving this aspect of the Jeff Jones model.

In our study, we simulated the production performance of a 5-spot steamflood pattern unit and compared the results against those based on the Jeff Jones model. Three reservoir types were simulated using 3-D Cartesian black oil models: Hamaca (9°API), San Ardo (12°API) and that based on the SPE fourth comparative solution project (14°API). In the first two field cases, a 45x23x8 model was used that represented 1/8 of a 10-acre 5-spot pattern unit, using typical rock and reservoir fluid properties. In the SPE project case, three models were used: 23x12x12 (2.5 ac), 31x16x12 (5 ac) and 45x23x8 (10 ac), that represented 1/8 of a 5-spot pattern unit.

To obtain a satisfactory match between simulation and Jeff Jones analytical model results of the start and height of the production peak, the following refinements to the Jeff Jones model were necessary. First, the dimensionless steam zone size  $A_{cD}$  was modified to account for decrease in oil viscosity during steamflood and its dependence on the

steam injection rate. Second, the dimensionless volume of displaced oil produced  $V_{oD}$  was modified from its square-root format to an exponential form.

The modified model gave very satisfactory results for production performance up to 20 years of simulated steamflood, compared to the original Jeff Jones model. Engineers will find the modified model an improved and useful tool for prediction of steamflood production performance.

## **DEDICATION**

This thesis is dedicated to my family in Indonesia, especially to my mother, Sia Soei Hwa, for her endless love.

## ACKNOWLEDGEMENTS

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## CHAPTER I

### INTRODUCTION

Steamflooding is a major EOR process applied to heavy oil reservoirs. Steamflooding uses separate injection and production wells to improve both the rate of production and the amount of oil that will ultimately be produced. Injected steam heats the formation around the wellbore and eventually forms a steam zone that grows with continuous steam injection. Steam reduces the oil viscosity and saturation in the steam zone to a low value, pushing the mobile oil (i.e. difference between the initial and residual oil saturations) out of the steam zone. As the steam zone grows, more oil is moved from the steam zone to the unheated zone ahead of the steam front. Then the oil accumulates to form an oil bank. The condensed hot water also moves across the steam front, heating and displacing the accumulated oil. The heated oil with reduced viscosity moves towards the producing well and is produced usually by artificial lifting.

A steam flood project typically proceeds through four phases of development: (1) reservoir screening; (2) pilot tests; (3) fieldwide implementation; and (4) reservoir management. Performance prediction is essential to provide information for proper execution of each of these development phases. Three different mathematical models (statistical, numerical, and analytical models) are commonly used to predict steam flood performance.

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This thesis follows the style of *Society of Petroleum Engineers Journal*.

Statistical models are commonly based on the historical data of steamflood performance from other reservoirs which have similar oil and rock properties. This is the reason why statistical models do not give a unique result for one particular reservoir. Numerical models usually require extensive information about the reservoir and lengthy calculations using computers. They may be extremely comprehensive and better serve as tools for research or advanced reservoir analysis. Meanwhile, analytical models may be much more economical at the expense of the accuracy and flexibility and serve as tools for engineering screening of possible reservoir candidates for field testing.

For many years, attempts<sup>1-7</sup> have been made to provide analytical models for steamflood production performance prediction. One of the most widely-used analytical models is the Jeff Jones model.<sup>7</sup> Jeff Jones model incorporates oil displacement by steam as described by Myhill and Stagemeier,<sup>5</sup> and a three-component capture factor based on empirical correlations. The main drawback of the model however is the unsatisfactory prediction of the oil production peak: usually significantly lower than the actual. Our study focused on improving this aspect of the Jeff Jones model.

### **1.1 Objective of the Study**

The main drawback of the Jeff Jones model is the unsatisfactory prediction of the oil production peak: usually significantly lower than the actual. The main objective of this study is therefore to improve this aspect of the Jeff Jones model. The results of the modified model will be tested against results based on numerical simulation to verify its accuracy and validity. A more accurate steamflood model will provide engineers with an improved and useful tool for prediction of steamflood production performance.

## 1.2 Methodology

A series of simulation runs were conducted to simulate the production performance of a 5-spot steamflood pattern unit. The simulation results were then compared against that based on the Jeff Jones model. CMG STARS Thermal Simulator was used for this purpose. Three different reservoir types and fluid properties were simulated using 3-D Cartesian black oil models: Hamaca (9°API), San Ardo (12°API) and that based on the SPE fourth comparative solution project<sup>8</sup> (14°API). In the first two field cases (Hamaca and San Ardo), a 45x23x8 model was used that represented 1/8 of a 10-acre 5-spot pattern unit, using typical rock and reservoir fluid properties. In the SPE project case, three models were used: 23x12x12 (2.5 ac), 31x16x12 (5 ac) and 45x23x8 (10 ac), that represented 1/8 of a 5-spot pattern unit.

To obtain a satisfactory match between simulation and the Jeff Jones analytical model results of the start and height of the production peak, the following refinements to the Jeff Jones model were necessary. First, the dimensionless steam zone size  $A_{cD}$  was modified to account for decrease in oil viscosity during steamflood and its dependence on the steam injection rate. Second, the dimensionless volume of displaced oil produced  $V_{oD}$  was modified from its square-root format to an exponential form.

## 1.3 Chapter Organization

This thesis is organized into five chapters. Chapter I (Introduction) provides methodology used and the objective of the study. Chapter II provides description of the steamflooding process mechanism, description of methodologies used in steamflooding production performance prediction and literature review of available analytical methods for

steamflooding performance prediction. Chapter III discusses important concepts generally used in thermal simulation modeling. Simulation models used in this thesis will be explained in detail in Chapter III. Chapter IV gives a complete explanation of the new analytical method developed. This chapter also provides comparisons of oil production rate and cumulative oil steam ratio among the new model, the Jeff Jones model and the simulation results. Finally, main conclusions of this research are given in Chapter V.



## CHAPTER II

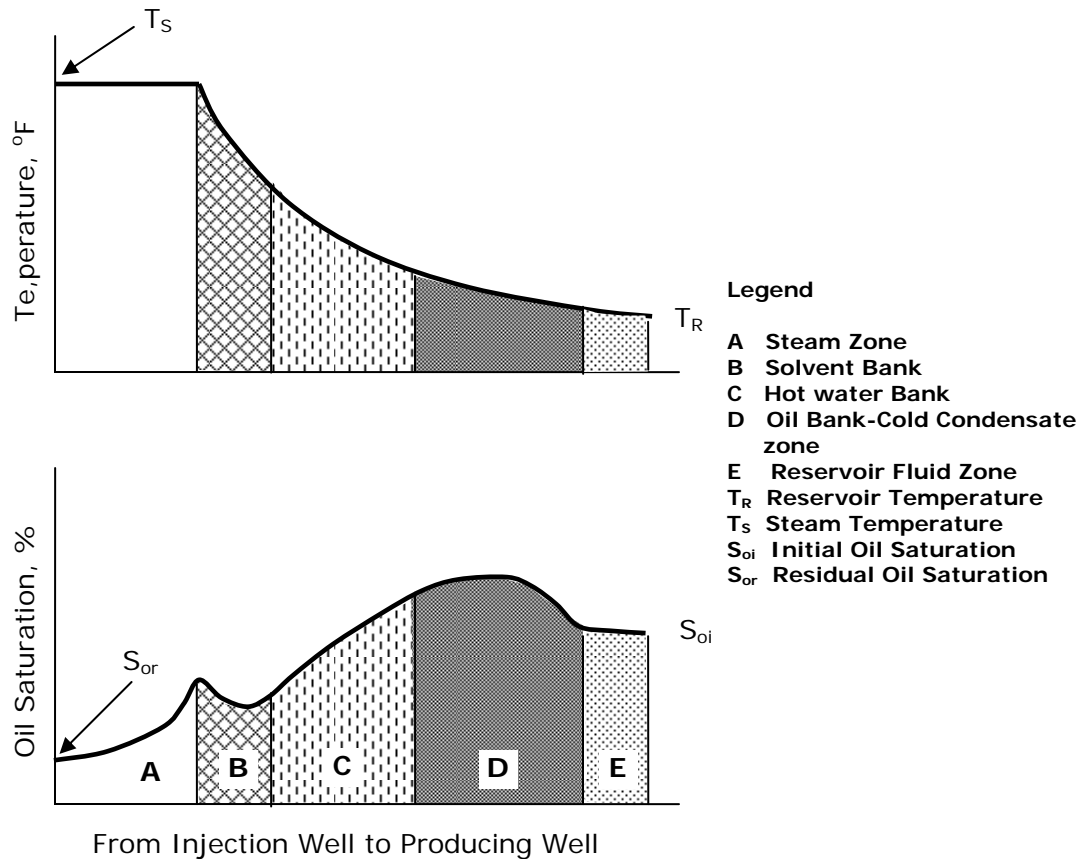
### THEORETICAL BACKGROUND

This chapter consists of four sections. First section of this chapter provides a description of the reservoir mechanics of steamflooding. Second section of this chapter gives detailed explanation of the methodologies used in steamflood production performance prediction. The third section of this chapter is a literature review of currently available analytical models for steamflood prediction. Since this work is a modification of the Jeff Jones model, the Jeff Jones model will be discussed in more detail and is given in the fourth section.

#### **2.1 Steamflooding Mechanism**

Steamflooding uses separate injection and production wells to improve both the rate of production and the amount of oil that will ultimately be produced. Heat from the injected steam reduces the viscosity of the oil as the injected fluid drives the oil from injector to producer.

As steam moves through the reservoir between the injector and producer, it typically creates five regions of different temperatures and fluid saturations.<sup>9</sup> All of these regions are shown in **Fig. 2.1**.



**Fig. 2.1–Steamflood typical temperature and saturation profile (after Hong<sup>9</sup>, 1994).**

As steam enters the reservoir, it forms a steam saturated zone around the wellbore. This zone, at about the temperature of injected steam, expands as more steam is injected. Ahead of the steam saturated zone (A), steam condenses into water as it loses heat to the formation and forms a hot condensate zone (B, C). Pushed by continued steam injection, the hot condensates carries some heat ahead of the steam front into the cooler regions further from the injector. Eventually, the condensate loses its heat to the formation, and its temperature is reduced to the initial reservoir temperature.

Because different oil displacement mechanisms are active in each zone, oil saturation varies between injector and producer. The active mechanism and hence, the

saturation depend mainly on thermal properties of the oil. In the steam zone (A), oil saturation reaches its lowest value because the oil is subject to the highest temperature. The actual residual saturation achieved is independent of initial saturation but rather depends on temperature and crude oil composition. Oil is moved from the steam zone to the hot condensate zone (B, C) by steam distillation at the steam temperature, creating a solvent bank (B) of distilled light ends just ahead of the steam front. Gas is also stripped from the oil in this region.

In the hot condensate zone, the solvent bank (B) generated by the steam zone extracts additional oil from the formation to form an oil-phase miscible drive. The high temperature in this zone reduces the oil viscosity and expands the oil to produce saturations lower than those found in a conventional waterflood.

The mobilized oil is pushed ahead by the advancing steam (A) and hot water (C) fronts. By the time the injected steam has condensed and cooled to reservoir temperature (in the cold condensate zone), an oil bank (D) has formed. Thus, oil saturation in this zone is actually higher than initial oil saturation. Displacement here is representative of a waterflood. Finally, in the reservoir fluid zone (E), temperature and saturation approach the initial conditions.

The decrease in oil viscosity ( $\mu_o$ ) with increasing temperature is the most important mechanism for recovering heavy oils. As the reservoir temperature increases during steam injection, the viscosity of oil ( $\mu_o$ ) decreases. The viscosity of water ( $\mu_w$ ) also decreases, but to a lesser degree. The net result of increasing temperature is to improve the water-oil mobility ratio,  $M$ , defined as follows.<sup>9</sup>

$$M = \frac{\mu_o k_w}{\mu_w k_o} \quad (2.1)$$

where  $k_w$  and  $k_o$  are the effective permeabilities to water and oil respectively.

With lower oil viscosity, the displacement and area sweep efficiencies are improved. Thus, a hot waterflood will recover more heavy oil than a conventional waterflood because at high temperatures the heavy oil behaves more like a light oil.

The change in oil viscosity with temperature is usually reversible. In other words, when the temperature decreases again, the oil viscosity reverts approximately to its original value.<sup>9</sup>

This reversible of the change in oil viscosity with temperature may account for oil banking. When a steam front moves through a reservoir, the temperature immediately ahead of the front increases, thereby decreasing the oil viscosity. Oil is readily displaced from the high temperature region to an area where the temperature may be considered lower. In this low temperature region, the oil viscosity increases again, thus retarding the oil flow; consequently, a large amount of oil accumulates as on oil bank. This bank, often observed when steamflooding heavy oil, is responsible for high oil production rates and low water/oil ratios just prior to or at the time of heat breakthrough at the producing well.<sup>9</sup>

## **2.2 Prediction of Steamflood Performance**

Steamflood performance can be predicted using a statistical model, numerical model or analytical model. Statistical models are commonly based on the historical data of steam flood performance from other reservoirs which have the same oil and rock properties. Numerical models require a large amount of data input about the reservoir (geometry and distribution of properties), its fluids (saturation, pressures, properties, and initial

conditions), wells (location, interval opens, skin effect, and well model to be used), and operational variables (rates, pressures and the constraints of both). **Table 2.1** indicates the amount of information required by a numerical model.<sup>10</sup>

**TABLE 2.1—TYPICAL DATA REQUIRED BY THERMAL RESERVOIR SIMULATORS (AFTER PRATTS<sup>10</sup>)**

Group	Property	Requirements
Reservoir	Principal values of the anisotropic absolute permeability and thermal conductivity, assigned to the directions x, y and z	Three values of permeability and conductivity
	Porosity and heat capacity of reservoir rocks	Two values for each block
	Relative permeabilities for each phase	One relation for each phase at each grid block; each relation is a function of saturations and temperature
	Capillary pressure	Two relations as functions of saturations; several pairs allowed.
	Reservoir geometry	Specify coordinate system to be used and locations of wells and boundaries
Overburden and underburden	Thermal conductivity and heat capacity	At least one of each for both caprock and base rock
Initial values	Saturations, pressure, temperature, and composition	One value for each variable at each grid block
Fluids	Density and viscosity of each phase; compressibility of the reservoir matrix	One relation for each phase; each relation is a function of temperature, pressure and possibly composition
	Component properties and K values (for compositional simulation)	Relations as a function of pressures and temperature
	Latent heat of vaporization and saturation pressure	Latent heat of vaporization and pressure/temperature relation at saturation for each component that

**TABLE 2.1 (CONTINUED)**

Group	Property	Requirements
	Enthalpy and internal energy of each phase	undergoes a phase change  A relation for each quantity for each phase as a function of temperature, pressure, and possibly composition
Well and boundary conditions	Rates, pressures, and temperatures	Maximum and minimum values, constraints and penalties

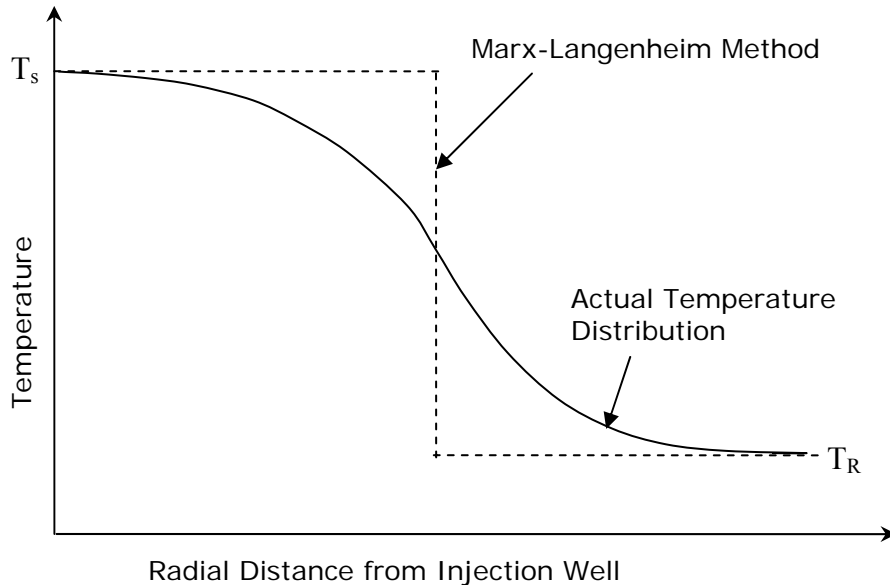
Specifically, reservoir properties such as permeability and porosity are required inputs for each grid block, and several sets of relative permeabilities and capillary pressures usually can be used to describe the reservoir. In other words, the simulator requires more information about the distribution of properties in the reservoir than is normally available.

By contrast, the analytical models generally require the entering of few but critical data.<sup>10</sup> Frequently, displacement is assumed to be piston-like. This means that there is a sharp drop in the oil saturation across the displacement front, leaving a uniformly low amount of oil in the swept zone. There are several analytical and semi-analytical methods for estimating steamflood production rate. In all of these models, certain simplifying assumptions have to be made to solve the complex heat and fluid flow equations. In the analytical methods, the reservoir is typically assumed to be homogenous. Since, it is much faster to obtain results from analytical models than from simulation, analytical models are still useful tools for preliminary forecasting purposes and sensitivity studies. In addition, the models provide a better insight than simulation into the physics of the thermal process.

### 2.3 Literature Review

Several analytical models for steamflood production performance have been published. In this section, a literature review covering the main analytical models will be presented.

Marx and Langenheim Method (1959).<sup>1</sup> Many of currently available simplified methods are based on the reservoir heating model of Marx and Langenheim (1959). The Marx and Langenheim (1959) model considers the injection of hot fluid into a well at constant rate and temperature. The operation element consists of a radial flow system, concentric about the point of injection. They assumed the temperature of the heated zone to be uniform at the downhole temperature of the injected fluid ( $T_s$ ) and the reservoir temperature outside the heated zone to be at the initial and reference temperature ( $T_R$ ). Marx-Langenheim's temperature model is schematically depicted in **Fig. 2.2**.



**Fig. 2.2–Temperature profile of Marx-Langenheim model.**

Their model is basically based on a heat balance relationship between the rate of heat injected, the rate of heat loss to the over and underlying strata and the rate of heat flow into the reservoir.

Mandl and Volek Method (1969).<sup>2</sup> Subsequent to the Marx-Langenheim model, Mandl and Volek developed a more rigorous reservoir heating model, which considers hot water transport ahead of the condensing steam front. They introduced a certain critical time,  $t_c$ , which depends on reservoir thickness, temperature, and quality of the steam. The critical time marks an important change in the heat flow across the condensation front, which are purely conductive during  $0 < t < t_c$ , becomes predominantly convective at  $t \geq t_c$ . Convective heat transport from the steam zone into the liquid zone does not start at the beginning of a steam-drive process, but rather at a later time, i.e. the critical time. Before the critical time, the Marx-Langenheim model is the same as that of Mandl and Volek's model. However, after the critical time, description for the steam zone growth must be developed by making use of upper and lower bounds for the exact solution of the problem.

Boberg and Lantz Method (1966).<sup>3</sup> The Boberg and Lantz developed a model for cyclic steam injection, based on the Marx-Langenheim model. Their model assumes that there is sufficient reservoir energy to produce oil at the initial reservoir temperature ( $T_R$ ) prior to steam injection. The Boberg and Lantz method works quite well for relatively thin reservoirs with sufficient energy to produce under unstimulated conditions. But their method is not satisfactory for thick, low-pressure reservoirs where the bulk of the produced oil must come from the heated zone.



Newman Method (1975).<sup>4</sup> The Newman method accounts for steam override. Model equations developed by Newman enable estimation of the rate of steam zone thickness increase and areal extent; the volume of oil displaced from the steam zone and the underlying hot water zone; the reduced injection rate, which will maintain a constant steam zone area; and the additional oil displaced after steam injection is stopped.

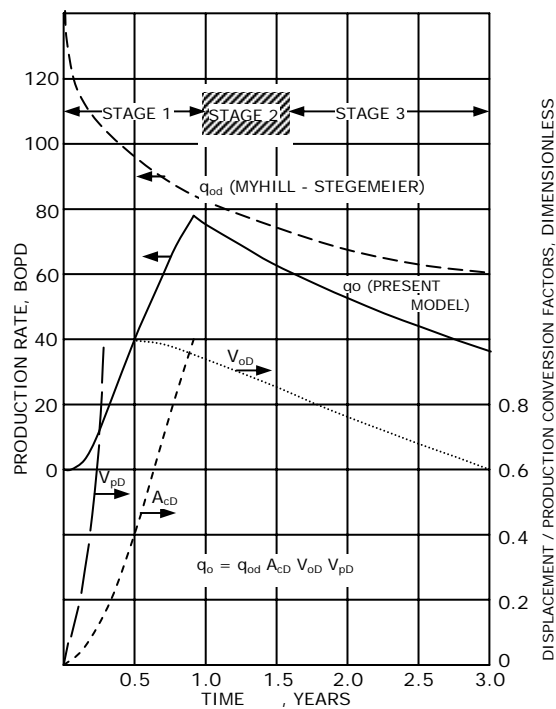
Myhill and Stegemeier Method (1978).<sup>5</sup> The Myhill and Stegemeier method is essentially an energy relationship based on Marx and Langenheim's model. The steam zone growth is calculated using a slightly modified version of Mandl and Volek's method, so that the steam zone volume would vanish when no steam is injected. The oil steam ratio is calculated assuming oil produced is equal to steam-zone pore volume times the change in oil saturation.

Gomma Method (1980).<sup>6</sup> The Gomma method is based on oil recovery correlations for a typical heavy-oil reservoir with an unconsolidated sand matrix. It was developed by determining the sensitivity of different parameters on a typical heavy oil project using a numerical steamflood simulator. The simulator was first used to history-match a Kern River Field steamflood project. It was then used to determine the sensitivity of oil recovery to several parameters. Based on the results of the sensitivity studies, correlations were developed for predicting oil recovery performance.

#### **2.4 Jeff Jones' Method**

Jeff Jones Method (1981).<sup>7</sup> Jeff Jones presents a model based on work published by Van Lookeren<sup>11</sup> and Myhill-Stegemeier. Jeff Jones' model is divided into two different parts. The first part of the model calculates an optimal steam injection rate (to the nearest 5

B/D) for a given set of steam and reservoir parameters by the method proposed by Van Lookeren. The second part of the model uses the optimal steam rate (or a given steam rate) and related data calculated in the first part in conjunction with additional inputs to predict the oil production history. Myhill-Stegemeier's oil displacement rate is converted to Jeff Jones' oil production rate based on correlation with 14 different steamflood projects. The conversion of Myhill-Stegemeier's displacement rate to the production rate is done by assuming that steamflooding process has the following three major stages of production. The first production stage is dominated by initial oil viscosity and possibly is affected by reservoir fillup if a significant void exists. The second stage of production normally is dominated by hot oil mobility and reservoir permeability. At the second stage, the production rate is essentially the displacement rate. The third phase of production is dominated by the remaining mobile fraction of original oil in place. **Fig. 2.3** gives an illustration of these three stages.



**Fig. 2.3—Three production stages of Jeff Jones' model (Jones<sup>7</sup>, 1981).**

**Appendix A** gives equations used for oil displacement ( $q_{od}$ ) calculations. This oil displacement calculation is essentially the same as in the Myhill-Stegemeier's method but with some simplifications. Major simplifications noticed are: (1) Assumption that heat capacity of the base rock and caprock is 1.2 times heat capacity of reservoir rock, (2) Simplification of equation used for overall reservoir thermal efficiency ( $E_{hs}$ ) calculation, and (3) using a correlation to calculate dimensionless critical time ( $t_{cD}$ ). These simplifications lead to some inaccuracies which are removed in the new model by not making these simplifications.

Jeff Jones' "Capture Efficiency" converts Myhill-Stegemeier's oil displacement rate ( $q_{od}$ ) to actual oil production rate. Jeff Jones' "Capture Efficiency" consists of three elements,  $A_{cD}$ ,  $V_{oD}$ ,  $V_{pD}$ . The product of these three elements yields the "Capture Efficiency". That is,

$$\text{Capture Efficiency} = A_{cD} \times V_{oD} \times V_{pD} \quad (2.2)$$

Formulas for  $A_{cD}$ ,  $V_{oD}$  and  $V_{pD}$  are given in **Eq. 2.3**, **Eq. 2.4** and **Eq. 2.5**. These formulas were determined empirically by Jeff Jones using data from numerous steamflooded fields.

$$A_{cD} = \left[ \frac{A_s}{A \{0.11 \ln(\mu_{oi}/100)\}^{1/2}} \right]^2 \quad (2.3)$$

(with these limits:  $0 \leq A_{cD} \leq 1.0$  and  $A_{cD} = 1.0$  at  $\mu_o \leq 100$  cp).

$$V_{oD} = \left( 1 - \frac{N_d S_{oi}}{N \Delta S_o} \right)^{1/2} \quad (2.4)$$

(with the limits:  $0 \leq V_{oD} \leq 1.0$ ).

$$V_{pD} = \left( \frac{V_{s,inj} 5.62}{4360 A h_n \phi S_g} \right)^2 \quad (2.5)$$

(with these limits:  $0 \leq V_{pD} \leq 1.0$  and  $V_{pD} = 1.0$  at  $S_g = 0$ ).

The area steamed ( $A_s$ ) in  $A_{cD}$  calculation is from Marx and Langenheim's model:

$$A_s = \frac{Q_{inj} h_n M_1}{4 k_h (t_s - t_f) M_2 \times 43,560} \left( e^{t_D} \operatorname{erfc} \sqrt{t_D} + 2\sqrt{t_D / \pi} - 1 \right), \quad (2.6)$$

where

$$Q_{inj} = 14.6 \times i_s \times \{h_f + f_s h_{fg} - C_w (T_f - 32)\}, \quad (2.7)$$

and

$$h_f = 91 \times p_s^{0.2574}. \quad (2.8)$$

Jeff Jones' oil production rate is then given as,

$$\begin{aligned} q_o &= q_{od} \times \text{Capture Efficiency} \\ &= q_{od} \times A_{cD} \times V_{oD} \times V_{pD}. \end{aligned} \quad (2.9)$$

### CHAPTER III

#### NUMERICAL SIMULATION

Numerical reservoir simulators for steamflood prediction performance have been extensively used in the past 20 years. Advances in reservoir simulation techniques have made it possible to model virtually all the important reservoir phenomena. The availability of high-speed and low-cost computers in the recent past allowed the use of more detailed and accurate numerical models at reasonable cost and with reduced computing time.

Numerical steamflood simulators are similar to other reservoir simulators, with the exception that thermal effects are considered. They are based on a mathematical model of steamflooding derived from the basic laws of conservation of mass and energy. The law of conservation of a quantity states that:

$$\text{Accumulation} = \text{Input} - \text{Output} + \text{Sources} - \text{Sinks} \quad (3.1)$$

Fluid flow in the reservoir associated with production and injection causes the transfer of mass from one location to another. This is generally modeled with the empirical Darcy's law. Heat is also carried with the mass. In addition, conduction causes the transfer of heat, which is usually modeled with Fourier's law.<sup>10</sup>

The simulator used to perform this study was CMG's STARS version 2003. It is a three-phase multi-component thermal simulator that can handle a wide range of processes such as steam drive, cyclic steam injection, in-situ combustion, polymer flooding, foam

and emulsion flow. Three simulation concepts used in this study are explained later in this chapter followed by description of the simulation models for SPE comparison, San Ardo and Hamaca cases.

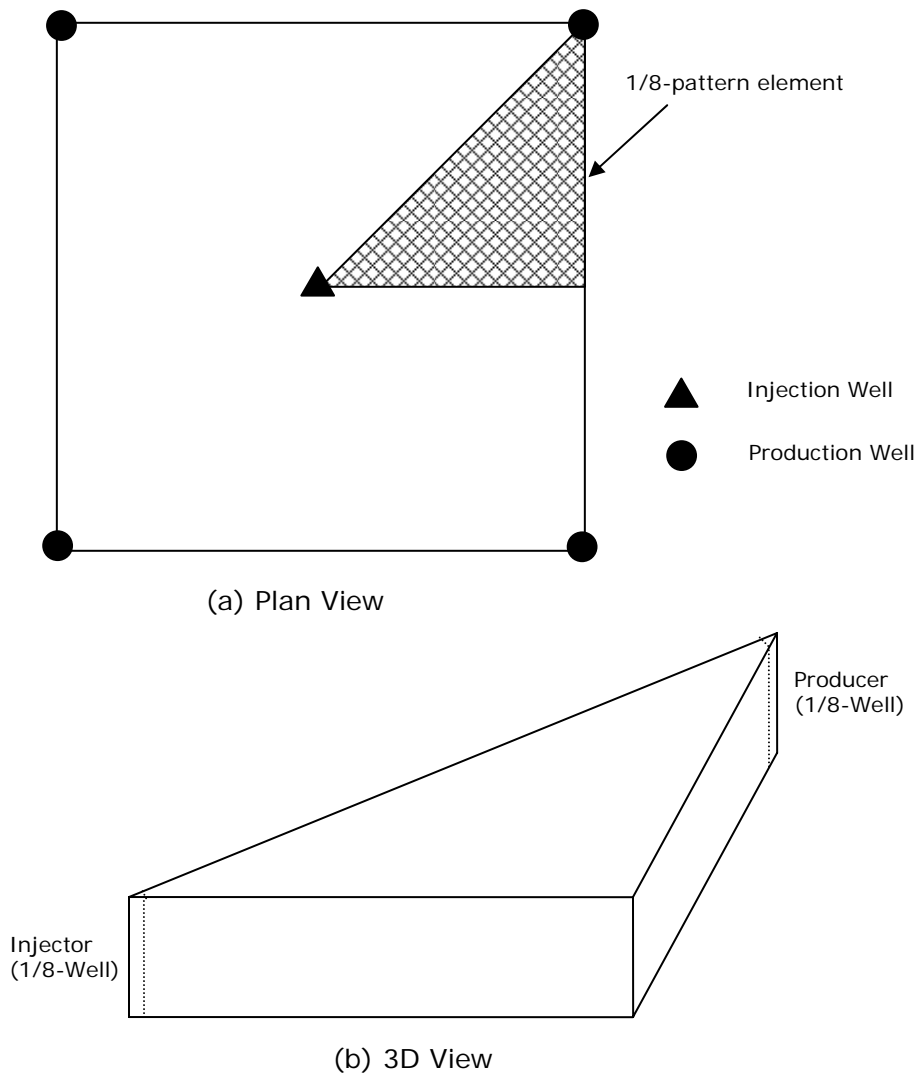
### 3.1 Symmetrical Element

Simulation of steamflood model can be done by taking advantage of a symmetrical element of one repeatable pattern unit. Symmetrical elements are used frequently in thermal simulation for a number of reasons:<sup>12</sup>

1. Compared with black-oil models, thermal models require much more CPU and storage per grid block. Therefore, less blocks can be used for a given computer storage limit.
2. Thermal EOR processes require more grid blocks per well or per pattern, since fronts are sharp and distinct.
3. Accuracy can be maximized for use in test and sensitivity runs.
4. Some results from one element may be generalized to other elements and pattern.
5. Pattern interference can be investigated by sensitivity runs with different injection share or production share.
6. Full-pattern or multipattern runs can be done once an acceptable course grid is obtained.

The minimal symmetrical element used in a 5-spot pattern simulation study is a 1/8-pattern element. A 1/8-pattern element of an inverted 5-spot model is illustrated in **Fig. 3.1**. Simulation of a 1/8-pattern element is preferred than other simulation styles

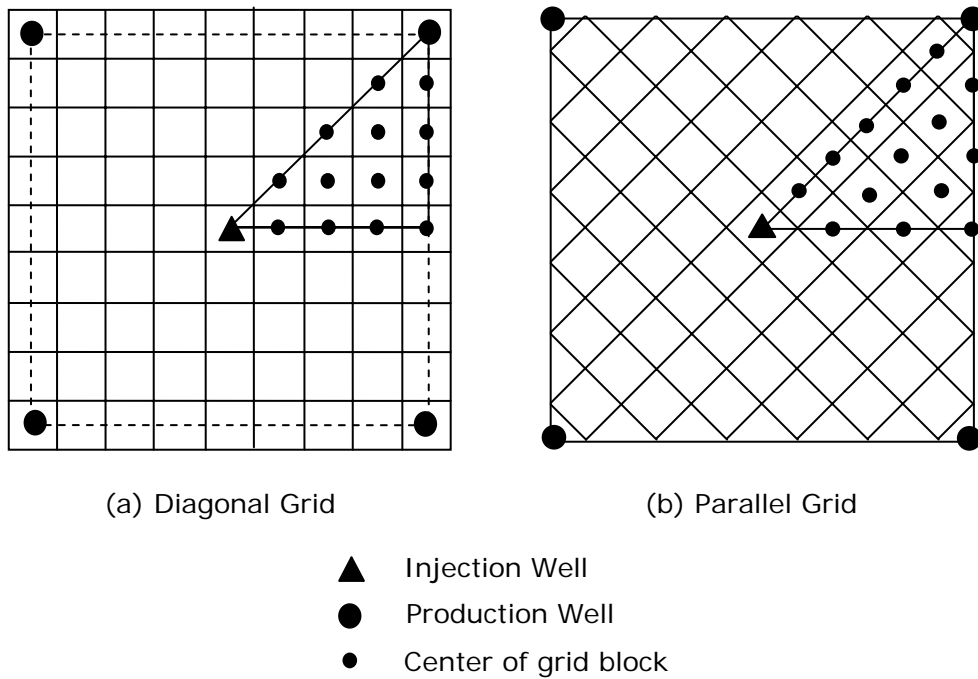
(1/4- pattern element or full pattern) because it is less time-consuming and more cost-efficient than others.



**Fig. 3.1—1/8 element of inverted 5-spot pattern model: (a) plan view; (b) 3D view.**

### 3.2 Grid Orientation Effect

This 1/8-pattern element can be simulated using two different approaches of grid orientation system: (a) diagonal grid and (b) parallel grid, as given in **Fig. 3.2**.



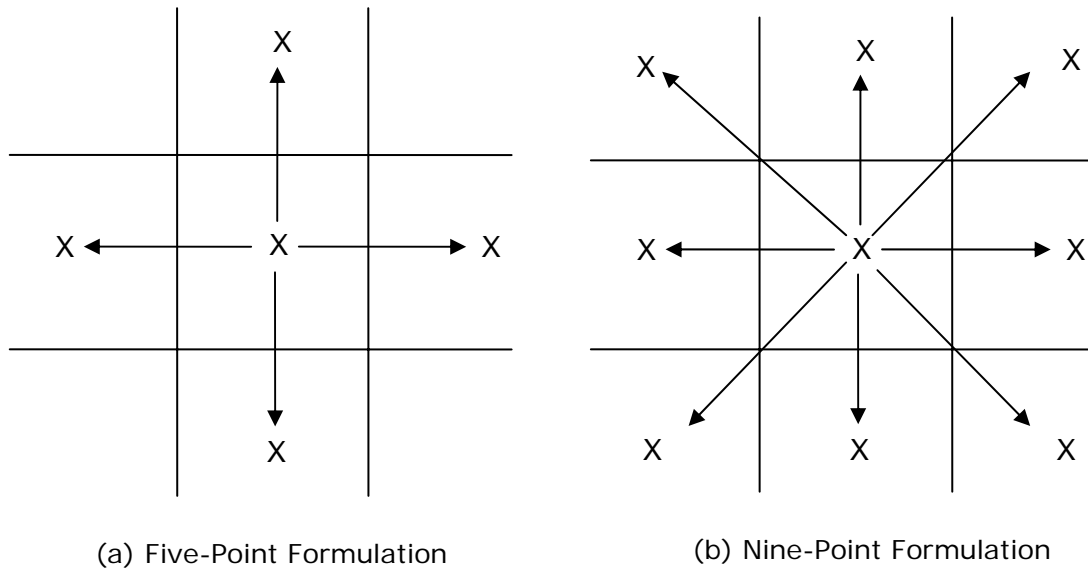
**Fig. 3.2—Five spot pattern grids: (a) diagonal grid; (b) parallel grid.**

The five-point difference scheme conventionally used in numerical simulation can introduce significant disparity in results for equivalent parallel and diagonal grids. This disparity was noted by Todd *et al.*<sup>13</sup> for adverse-mobility ratio waterfloods and later by Coats *et al.*<sup>14</sup> for steamfloods. Abou-Kasem and Aziz<sup>15</sup> reported a detailed comparison of the nine-point difference and other numerical schemes as remedies to the grid orientation problem in  $\frac{1}{4}$  of a five-spot steamflood pattern. They concluded that the nine-point scheme significantly reduces the grid orientation effect.

A schematic diagram of flow directions considered in the five and nine-point, finite-difference formulations is presented in **Fig. 3.3**. The five-point formulation only considers flow between a block and the four blocks that are adjacent to its boundaries.

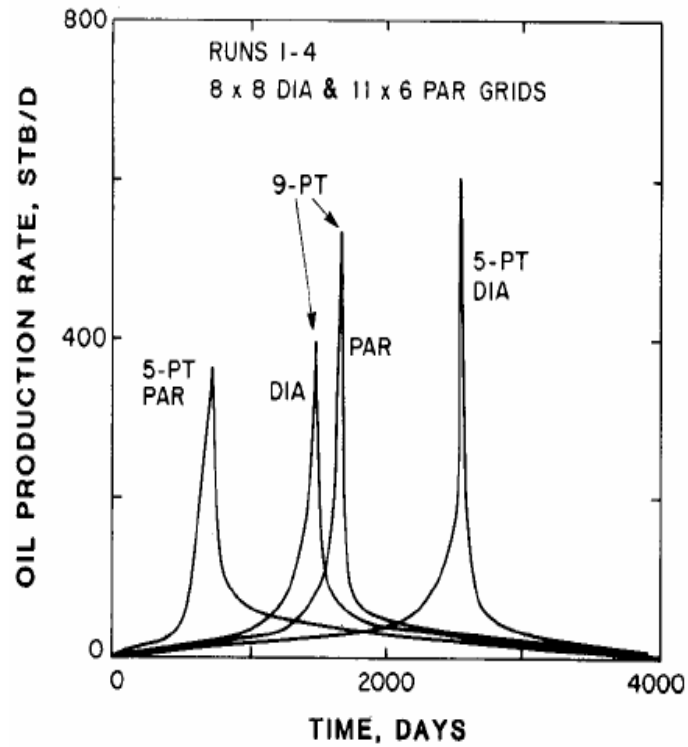


The nine-point formulation considers this flow as well as the flow between the block and the four blocks located at its corners.<sup>16</sup>



**Fig. 3.3—Five and nine-point, finite-difference formulation (after Yanosik and McCracken<sup>16</sup>, 1979).**

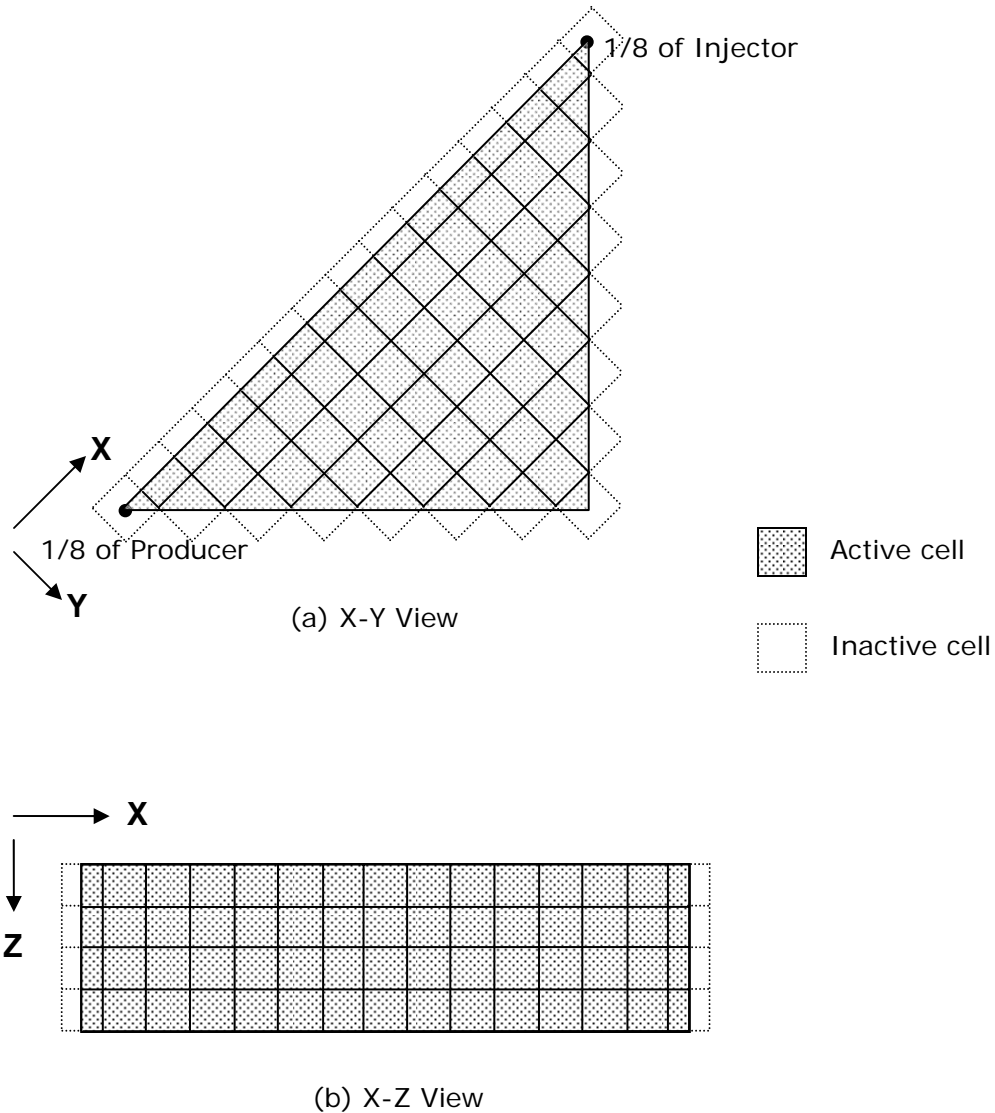
**Fig. 3.4** compares full pattern oil rate results for five-point and nine-point formulation. It indicates that the nine-point different scheme significantly reduced the grid orientation effect.<sup>17</sup>



**Fig. 3.4**—Five-point vs nine-point formulation on oil production rate in 1/8 five-spot (Coats and Ramesh<sup>17</sup>, 1987).

### 3.3 Block Geometry Modifier

In order to put grid nodes on injector-producer lines in a block-centered grid system, an oversized grid must be specified.<sup>12</sup> This grid is then modified by using block geometry modifiers. **Fig. 3.5** illustrates this idea for the parallel grid system.



**Fig. 3.5–Active and inactive cells in a 1/8 five-spot pattern model.**

All the grids at the edges and corners of the model are oversized, only half of the grids at the edges are active and only one-eighth of the grids at the corners are active. In order to get proper input parameters to be used in simulation, these grids are modified as given in **Table 3.1**.

**TABLE 3.1–MODIFICATION PARAMETERS FOR EDGES AND CORNER-GRIDS**

Parameter	Value for	
	Grids at Edges	Grids at Corners
Porosity	1/2 of value at normal grid	1/8 of value at normal grid
Transmissibility at z-direction	1/2 of value at normal grid	1/8 of value at normal grid
Grid block rock volume	1/2 of value at normal grid	1/8 of value at normal grid
Heat transmissibility at z-direction	1/2 of value at normal grid	1/8 of value at normal grid

Block geometry modifier in CMG STARS is done automatically by using \*VAMOD and \*VATYPE keywords.

### 3.4 SPE Comparative Case Simulation Model

SPE comparative case model is a modified version of Case No. 2a of “Fourth SPE Comparative Solution Project: Comparison of Steam Injection Simulators” by Azis *et.al.*<sup>8</sup>

SPE comparative case model simulates one-eighth of a five-spot repeatable pattern described as follows.

#### 1. Initial reservoir properties

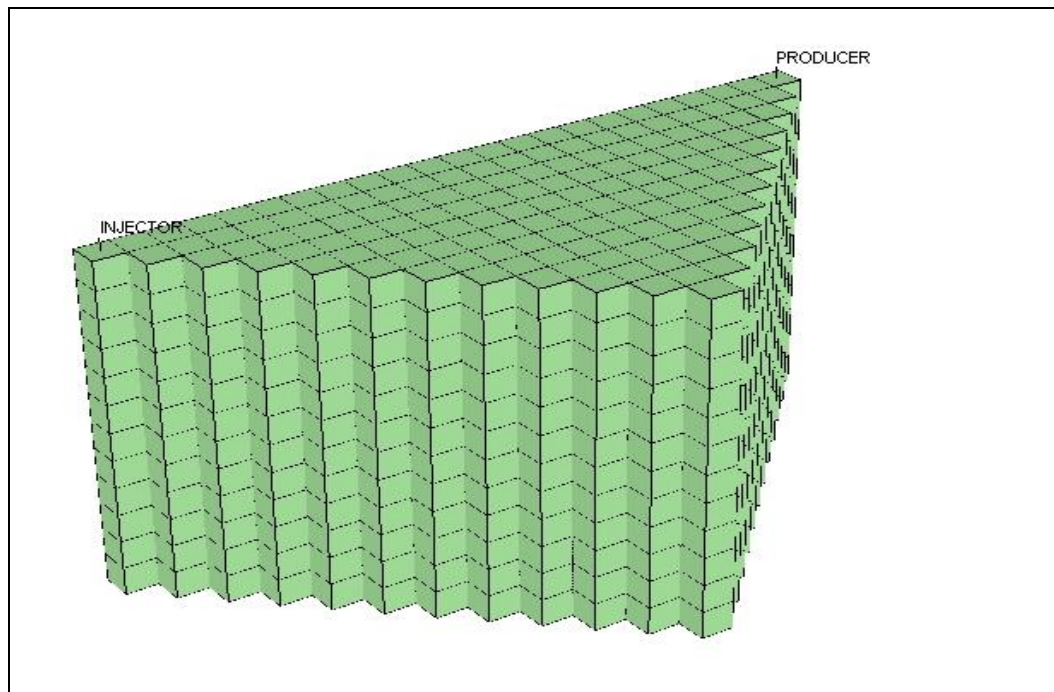
Initial reservoir properties for SPE Comparative Case are given in **Table 3.2**.

**TABLE 3.2–INITIAL RESERVOIR PROPERTIES**

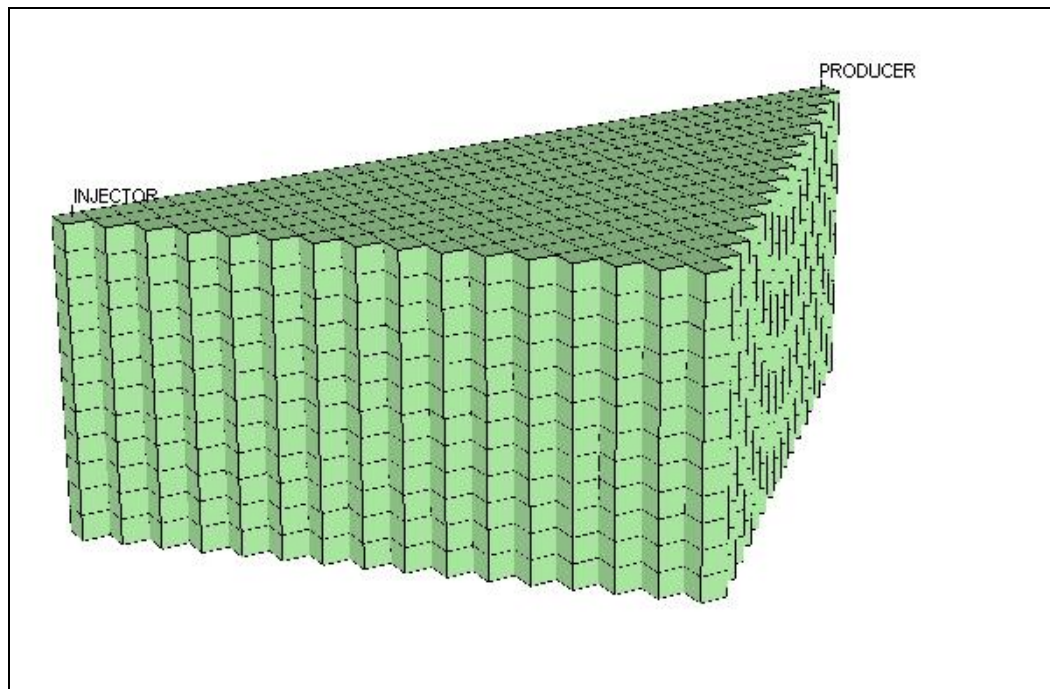
Properties	Values	Units
Oil gravity	14	°API
Initial pressure	75	psia
Initial temperature	125	°F
Net oil sand thickness	120	ft
Initial oil saturation	55	%
Initial water saturation	45	%
Permeability	1000	md
Porosity	30	%
In-situ oil viscosity at 125°F	487	cp

## 2. Simulation model grid

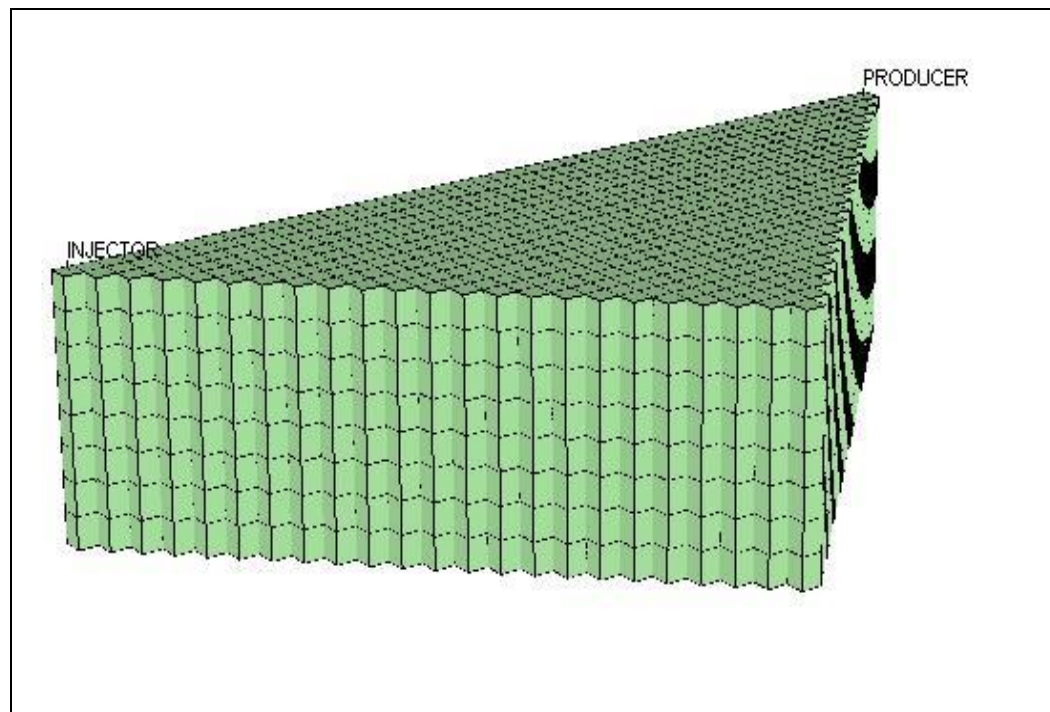
Three simulation grid models are used for SPE comparative case model, depending on the simulated area. 23x12x12 grid system is used for area of 2.5 ac, 31x16x12 for area of 5 ac, and 45x23x8 for area of 10 ac. **Fig. 3.6** to **Fig. 3.8** show these grid systems.



**Fig. 3.6–Simulation grid for area of 2.5 ac, SPE comparative case model.**



**Fig. 3.7–Simulation grid for area of 5.0 ac, SPE comparative case model.**



**Fig. 3.8–Simulation grid for area of 10 ac, SPE comparative case model.**

**Table 3.3** shows the cell dimensions for each of the area simulated for the SPE comparative case model.

**TABLE 3.3 CELL DIMENSIONS FOR SPE COMPARATIVE CASE MODEL**

Area (Acre)	Cell Dimensions (ft)		
	i	j	K
2.5	10.61	10.61	10
5	11	11	10
10	10.607	10.607	15

3. Rock properties

- Thermal conductivity of reservoir = 24 BTU/(ft-D-°F)
- Heat capacity of reservoir = 35 BTU/(ft<sup>3</sup> of rock-°F)
- Heat capacity of overburden and underburden = 42 BTU/(ft<sup>3</sup> of rock-°F)

4. Fluid properties

*Water properties.* Pure water is assumed and standard water properties are used.

*Oil properties.* Density at standard condition is 60.68 lbm/ft<sup>3</sup>. Compressibility is  $5 \times 10^{-6}$  psi<sup>-1</sup>. The molecular weight is 600. Viscosity data is shown in **Table 3.4**.

**TABLE 3.4—TEMPERATURE-VISCOSITY RELATIONSHIP FOR SPE COMPARATIVE CASE**

Temperature (°F)	Viscosity (cp)
75	5780
100	1380
150	187
200	47
250	17.4
300	8.5
350	5.2
500	2.5

## 5. Relative permeability data

The relative permeability expressions for water/oil system and water/gas system are based on Corey relationships as follows:

For water/oil system,

$$k_{rw} = k_{rwro} \left( \frac{S_w - S_{wir}}{1 - S_{orw} - S_{wir}} \right)^{2.5}, \quad (3.2)$$

$$k_{row} = k_{roiw} \left( \frac{1 - S_{orw} - S_w}{1 - S_{orw} - S_{iw}} \right)^2. \quad (3.3)$$

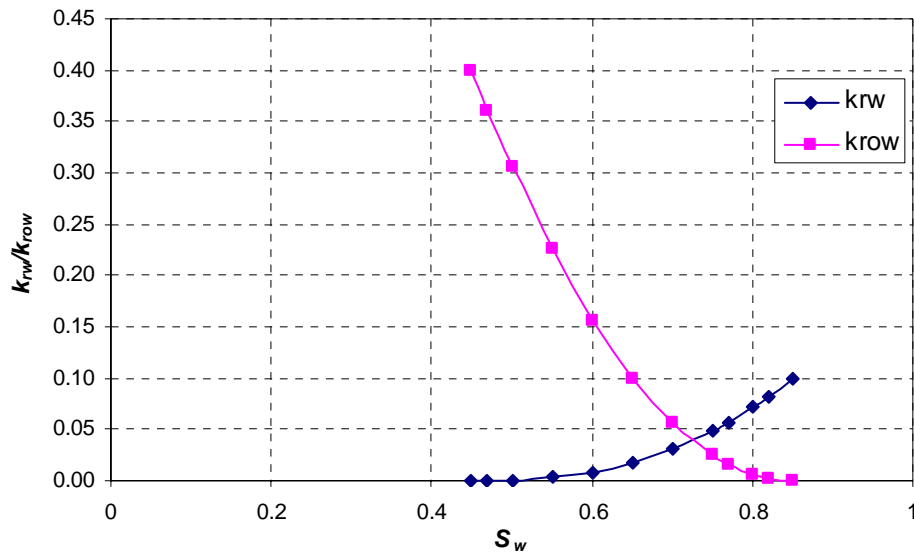
For gas/oil system,

$$k_{rog} = k_{roiw} \left( \frac{1 - S_{wir} - S_{org} - S_g}{1 - S_{wir} - S_{gc}} \right)^2, \quad (3.4)$$

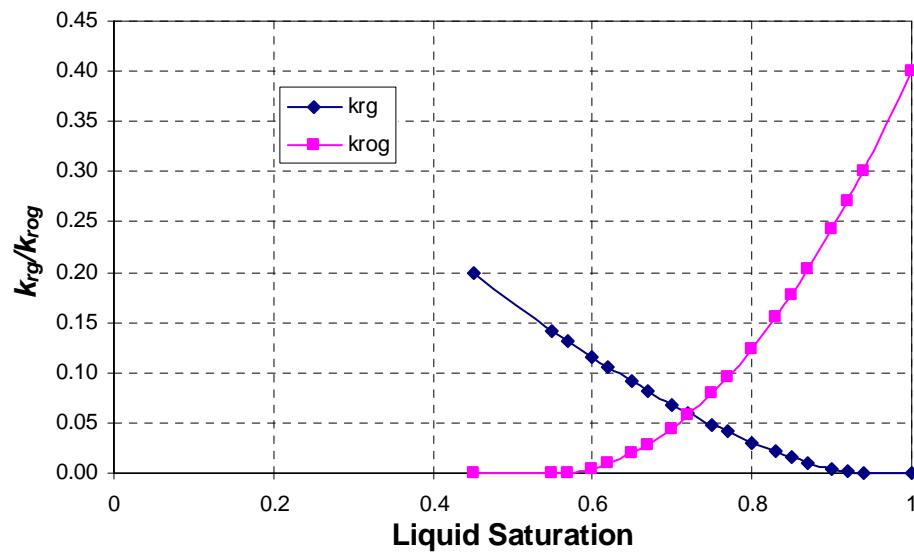
$$k_{rg} = k_{rgro} \left( \frac{S_g - S_{gc}}{1 - S_{iw} - S_{gc}} \right)^{1.5}. \quad (3.5)$$

The residual oil saturation (water/oil system)  $S_{orw} = 0.15$ , the residual oil saturation (gas oil system),  $S_{org} = 0.10$ , and the critical gas saturation,  $S_{gc} = 0.06$ . Oil relative permeability at interstitial water saturation,  $k_{roiw} \approx 0.4$ , water relative permeability at residual oil saturation (water/oil system)  $k_{rwro} = 0.1$ , and gas relative permeability at residual oil saturation (gas/oil system)  $k_{rgro} = 0.2$ . **Fig. 3.9** and **Fig. 3.10** show relative permeability curves for SPE comparative case model.





**Fig.3.9–Relative permeability curve (water/oil system) for SPE comparative case.**



**Fig. 3.10–Relative permeability curve (gas/oil system) for SPE comparative case.**

## 6. Operating conditions

Steam is injected at a temperature of 545°F. The quality of the steam at bottom hole condition is 0.7. Minimum bottom hole pressure at producer is 17 psia.

### 3.5 San Ardo Simulation Model

The San Ardo simulation study was conducted with the available information from Lombardi reservoir in San Ardo field.<sup>18</sup> San Ardo model simulates one-eighth of a 10-acre five-spot repeatable pattern described as follows.

#### 1. Initial reservoir properties

Initial reservoir properties for San Ardo model are given in **Table 3.5**.

**TABLE 3.5–INITIAL RESERVOIR PROPERTIES FOR SAN ARDO MODEL**

Properties	Values	Units
Oil gravity	12	°API
Formation top	1900	ft.
Initial pressure	275	psia
Initial temperature	127	°F
Net oil sand thickness	115	ft
Initial oil saturation	73.3	%
Initial water saturation	26.7	%
Permeability	6922	md
Porosity	34.5	%
In-situ oil viscosity at 275 psia	3000	cp

#### 2. Simulation model grid

45x23x8 grid system is used to simulate one-eighth of a 10-acre five-spot repeatable pattern. **Fig. 3.8** shows this grid system. The cell dimensions are  $i = 10.61$  ft,  $j = 10.61$  ft and  $k = 14.375$  ft.

#### 3. Rock properties

- Thermal conductivity of reservoir = 24 BTU/(ft-D-°F)
- Heat capacity of reservoir = 35.02 BTU/(ft<sup>3</sup> of rock-°F)
- Heat capacity of overburden and underburden = 60 BTU/(ft<sup>3</sup> of rock-°F)

#### 4. Fluid properties

A live, black oil model (2 pseudo-components and water) is used for the simulation.

*Water properties.* Pure water is assumed and standard water properties are used.

*Oil properties.* Oil consists of two components: “Oil” and “Gas” with the properties as given in **Table 3.6**. **Table 3.7** gives dead oil viscosity value for San Ardo’s oil.

**TABLE 3.6–OIL COMPONENT PROPERTIES FOR SAN ARDO MODEL**

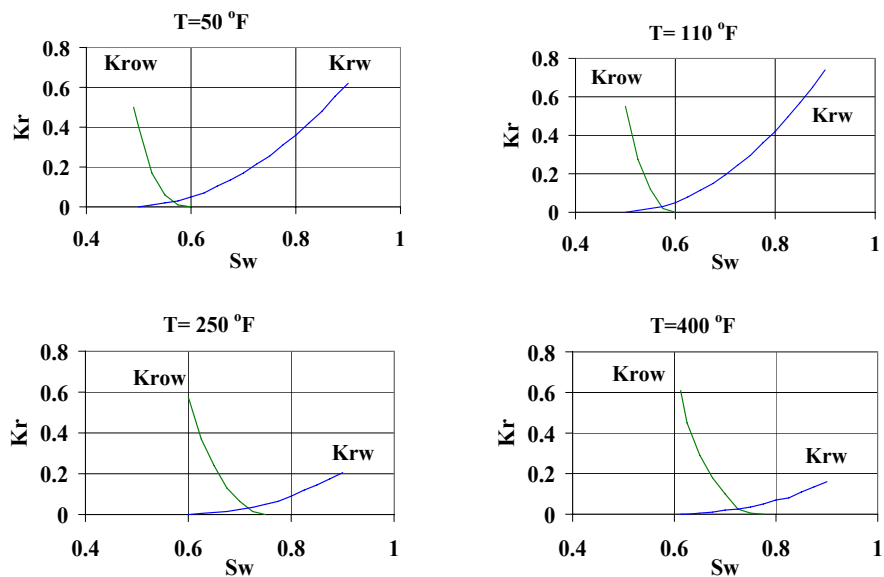
Component name	Oil	Gas
Molecular weight, (CMM)	456.015	16.7278
Critical pressure (PCRIT), psia	179.02	670.46
Critical temperature (TCRIT), °F	1036.21	-107.35
First coefficient in the correlation for gas-liquid K value (KV1), psi	5.165E+6	1.534E+5
Fourth coefficient in the correlation for gas-liquid K value (KV4), °F	-15362.5	-1914.1
Fifth coefficient in the correlation for gas-liquid K value (KV5), °F	-459.67	-459.67
Partial molar density at reference pressure and temperature (MOLDEN), lbmol/cft	1.356E-01	4.515E-02
Liquid Compressibility at constant temperature (CP), 1/psi	3.805E-06	3.754E-03
First coefficient of the thermal expansion coefficient (CT1), 1/°F	1.660E-04	1.910E-03

**TABLE 3.7–TEMPERATURE - VISCOSITY RELATIONSHIP FOR SAN ARDO OIL**

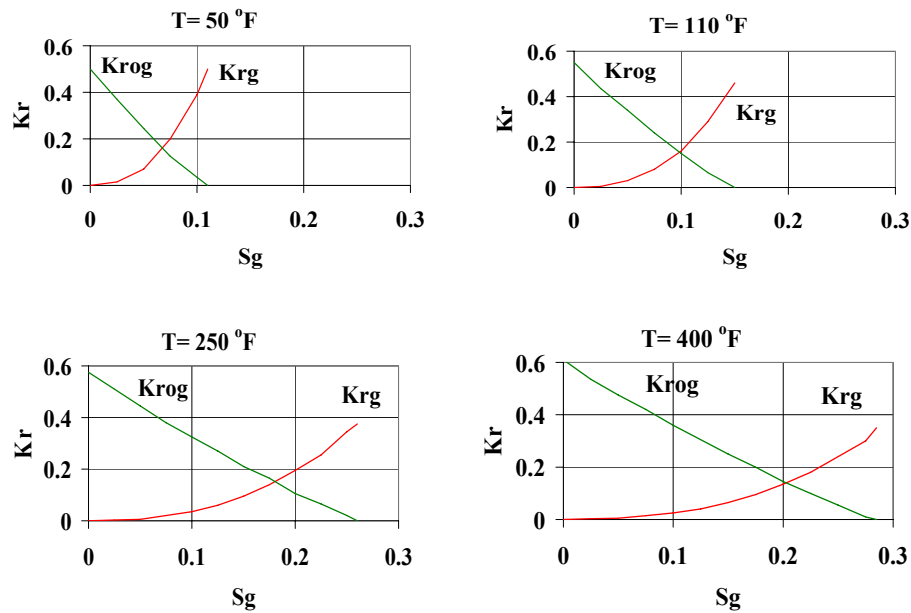
Temperature (°F)	Viscosity (cp)
50	500000
100	20000
150	1500
200	240
250	60
300	20
350	8
400	3.5

5. Relative permeability data

Temperature-dependent relative permeability data is used in San Ardo model. **Fig. 3.11** and **Fig. 3.12** show water-oil and gas-oil relative permeability plots of San Ardo oil at four temperatures.



**Fig. 3.11–Water-oil relative permeability curves with temperature dependence, San Ardo model.**



**Fig. 3.12–Gas-oil relative permeability curves with temperature dependence, San Ardo model.**

## 6. Operating conditions

Steam is injected at a temperature of 582.3°F. The quality of the steam at bottom hole condition is 0.8. Minimum Bottom hole pressure at producer is 15 psia.

## 3.6 Hamaca Simulation Model

Hamaca model simulates one-eighth of a five-spot repeatable pattern described as follows.<sup>19</sup>

### 1. Initial reservoir properties

Initial reservoir properties for Hamaca model are given in **Table 3.8**.

**TABLE 3.8—INITIAL RESERVOIR PROPERTIES FOR HAMACA MODEL**

Properties	Values	Units
Initial pressure	275	psia
Initial temperature	125	°F
Net oil sand thickness	100	ft
Initial oil saturation	83.2	%
Initial water saturation	16.8	%
Permeability	12000	md
Porosity	30	%
In-situ oil viscosity at 125 °F	25000	cp

## 2. Simulation model grid

45x23x8 grid system is used to simulate one-eighth of a 10-acre five-spot repeatable pattern. **Fig. 3.8** shows this grid system. The cell dimensions are  $i = 10.61$  ft,  $j = 10.61$  ft and  $k = 12.5$  ft.

## 3. Rock properties

- Thermal conductivity of reservoir = 24 BTU/(ft-D-°F)
- Heat capacity of reservoir = 35 BTU/(ft<sup>3</sup> of rock-°F)
- Heat capacity of overburden and underburden = 60 BTU/(ft<sup>3</sup> of rock-°F)

## 4. Fluid properties

*Water properties.* Pure water is assumed and standard water properties are used.

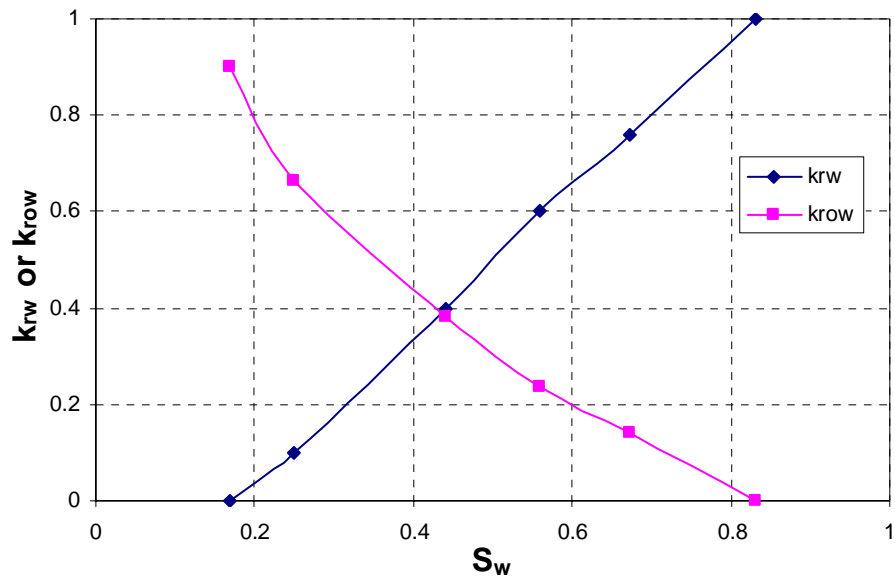
*Oil properties.* Density at standard condition is 63.18 lbm/ft<sup>3</sup>. Compressibility is  $5 \times 10^{-6}$  psi<sup>-1</sup>. The molecular weight is 511.78. **Table 3.9** gives dead oil viscosity value for Hamaca's oil.

**TABLE 3.9–TEMPERATURE - VISCOSITY RELATIONSHIP FOR HAMACA OIL**

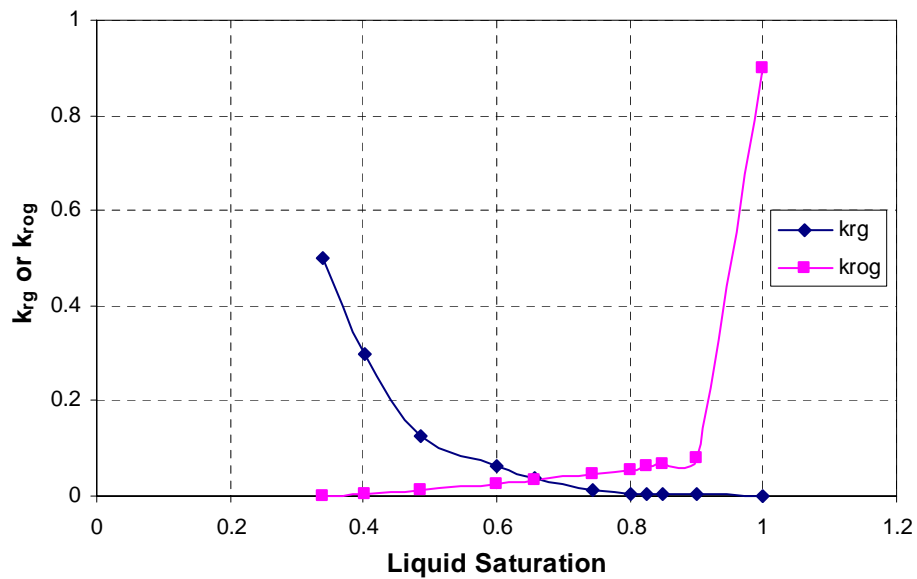
Temperature (°F)	Viscosity (cp)
122	25000.00
170	8077.48
190	3047.18
210	1277.60
230	588.57
240	412.51
260	214.80
280	120.05
300	71.46
320	44.99
340	29.79
360	20.62
370	17.42
380	14.86
390	12.78
400	11.09
410	9.70
420	8.54
430	7.58
440	6.77
450	6.09
460	5.50
470	5.01
480	4.58
490	4.20
500	3.88
1000	3.88

5. Relative permeability data

**Fig. 3.13** and **Fig. 3.14** show oil-water and gas-oil relative permeability plots used in the simulation model. Temperature dependent relative permeability data were not available.



**Fig. 3.13–Water-oil relative permeability, Hamaca model.**



**Fig. 3.14–Gas-oil relative permeability, Hamaca model.**

## 6. Operating conditions

Steam is injected at a temperature of 600°F. The quality of the steam at bottom hole condition is 0.8. Minimum bottom hole pressure at producer is 90 psia.

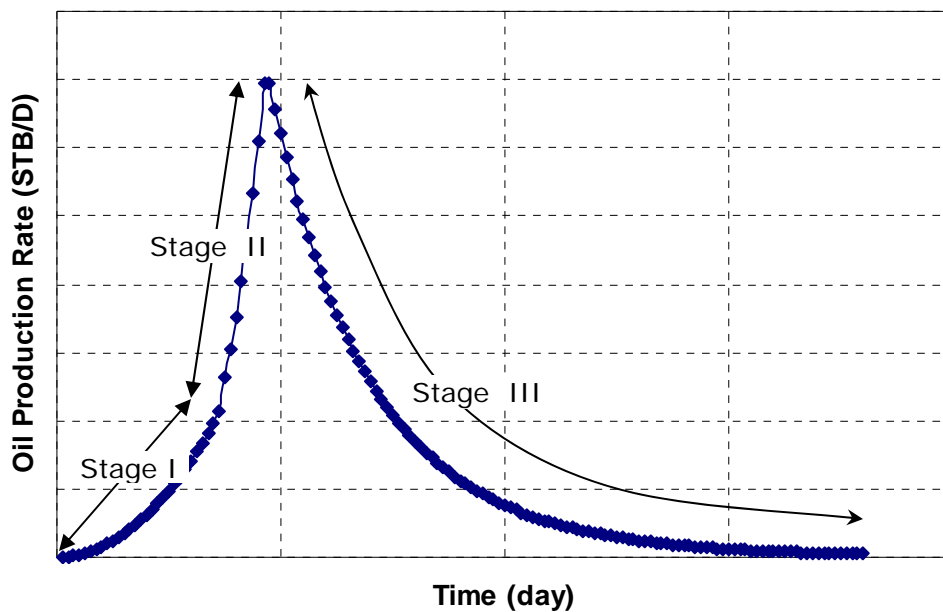


## CHAPTER IV

### NEW STEAMFLOOD MODEL

As described in section 2.4, in the Jeff Jones model, the capture factor consists of three components,  $A_{cD}$ ,  $V_{oD}$  and  $V_{pD}$ . The first two components had to be modified to obtain satisfactory match of oil production rate based on the new model and simulation. The component  $V_{oD}$  in the new model is unchanged from that in the Jeff Jones model because we have only studied the case where initial gas saturation is zero. Modification of  $A_{cD}$  and  $V_{oD}$  is described in the following.

First, as in the Jeff Jones model, oil production consists of three stages (Stage I, II and III) as schematically shown in **Fig. 4.1**.



**Fig. 4.1-New model: three different stages of oil production under steam drive.**

Stage I is related to cold oil production. As described by Jeff Jones, this stage is dominated by initial oil viscosity and possibly is affected by reservoir fillup if a significant initial gas saturation exists. During reservoir fillup, free gas initially in the reservoir is displaced by steam injected. This process ends after all of the moveable gas is displaced from the reservoir.  $V_{pD}$  is the capture factor component that describes this reservoir fillup phenomenon. This new model uses the same  $V_{pD}$  expression as given by the Jeff Jones model:

$$V_{pD} = \left( \frac{V_{s,inj} \times 5.62}{43,560 A h_n \phi S_g} \right)^2 \quad (4.1)$$

(limits:  $0 \leq V_{pD} \leq 1.0$  and  $V_{pD} = 1.0$  at  $S_g = 0$ )

$A_{cD}$  expresses viscosity and area dependence in oil production rate for the Stage I. Based on Jeff Jones model,  $A_{cD}$  is given by

$$A_{cD} = \left[ \frac{A_s}{A \{0.11 \ln(\mu_{oi}/100)\}^{1/2}} \right]^2 \quad (4.2)$$

(limits:  $0 \leq A_{cD} \leq 1.0$  and  $A_{cD} = 1.0$  at  $\mu_o \leq 100$  cp)

In this study, we found that steam injection rate has quite a significant effect on oil production rate in Stage I, and thus on  $A_{cD}$ . From **Eq. 4.2**, it can be seen that the constant in the denominator, 011, would have to vary with steam injection rate. In the new model, this constant is replaced by  $\alpha$  as follows.

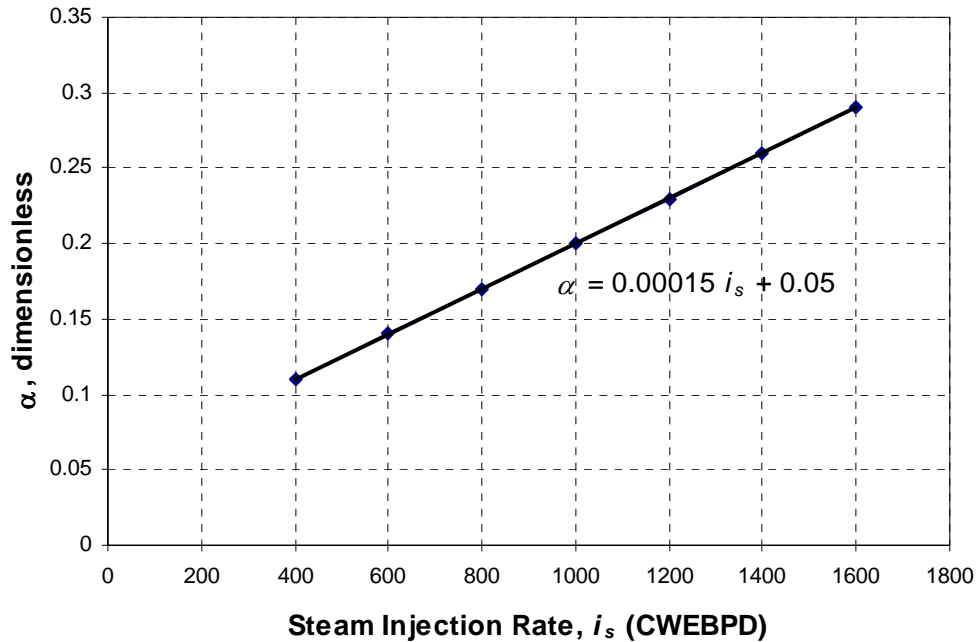
$$A_{cD} = \left[ \frac{A_s}{A \{\alpha \ln(\mu_{oi}/100)\}^{1/2}} \right]^2 \quad (4.3)$$

(limits:  $0 \leq A_{cD} \leq 1.0$  and  $A_{cD} = 1.0$  at  $\mu_o \leq 100$  cp)

Correlation between  $\alpha$  and steam injection rate was developed by making several simulation runs of SPE comparative model, each run with a different steam injection rate. By trial-and-error,  $\alpha$  for each steam injection rate was determined as that which gave the

best match of oil production rate based on the new model and simulation. A graph of  $\alpha$  versus steam injection rate is shown in **Fig. 4.2**, indicating the following linear relationship:

$$\alpha = 0.00015 i_s + 0.05. \quad (4.4)$$



**Fig. 4.2-  $\alpha$  vs injection rate relationship.**

Note that, in the new model, calculations of  $A_s$  and  $Q_{inj}$  are as in the Jeff Jones model, as given in **Eq. 2.6** and **Eq. 2.7**.

Stage II is related to the oil bank breakthrough. Oil bank is the region where a large amount of hot oil with lower viscosity is accumulated. At the beginning of steamflooding process, the oil bank region is formed near the injector. Producer still produces cold oil near to it which is not affected by the steam temperature. As the volume of steam injected increases, the oil bank region is pushed towards the producer. At the

same time, the oil viscosity in the reservoir continues to decrease, increasing the oil production rate.

When the oil bank region arrives at the producer, a large amount of the hot oil breaks through and results in a sharp increase in oil production. Oil production rate at this time will be significantly higher than the Myhill-Stegemeier oil displacement rate. This happens because the oil displaced previously, which is not produced but stored in the oil bank region, is produced at this time.

To account for the viscosity change due to heating, the viscosity value for  $A_{cD}$  in Stage II is described as an average viscosity between hot oil region and cold oil region as given in **Eq. 4.5**.

$$\bar{\mu}_o = \frac{\mu_{oi} (A - A_s) + \mu_o T_{steam} A_s}{A}. \quad (4.5)$$

With this average viscosity value, the value of  $A_{cD}$  will increase faster to properly describe the oil bank breakthrough.  $A_{cD}$  expression for Stage II of the new model is:

$$A_{cD} = \left[ \frac{A_s}{A \left\{ \alpha \ln \left( \bar{\mu}_o / 100 \right) \right\}^{1/2}} \right]^4. \quad (4.6)$$

(limits:  $1.0 < A_{cD} \leq A_{cD_{max}}$  and  $A_{cD} = 1.0$  at  $\bar{\mu}_o \leq 100$  cp)

Stage III is dominated by the remaining mobile portion of original oil-in-place as expressed in  $V_{oD}$ .  $V_{oD}$  of the Jeff Jones model is given as

$$V_{oD} = \left( 1 - \frac{N_d S_{oi}}{N \Delta S_o} \right)^{1/2}. \quad (4.7)$$

(limits:  $0 \leq V_{oD} \leq 1.0$ )

In this study, we observed that the simulation results always gave exponential trends for oil rate decline in the Stage III. Thus, the Jeff Jones  $V_{oD}$  expression was modified from its square-root format to an exponential form. Also, in the Jeff Jones model,  $V_{oD}$  may decline from a value of 1 in Stage I, while in the new model,  $V_{oD}$  starts to decline only at start of stage III. Thus, in the new model,  $V_{oD}$  is expressed as follows.

$$V_{oD} = A_{cD \max} \left\{ \text{Exp} \left[ -\beta \left( \frac{N_{D \max}}{N} \frac{S_{oi}}{\Delta S_o} \right) \right] \right\}. \quad (4.8)$$

(limits:  $A_{cD \max} \geq V_{oD} \geq 0$ )

where,  $A_{cD \max}$  is  $A_{cD}$  where oil production rate = injection rate, and

$N_{D \max} = N_D$  from Myhill-Stegemeier calculation -  $N_D$  up to  $A_{cD \max}$ .

We found that production decline rate was dependent on the steam injection rate. Thus, as can be seen in **Eq. 4.8**, the exponent had to vary with steam injection rate. To do this, we incorporated the parameter,  $\beta$ , in the exponent. We made several simulation runs using the SPE comparative solution model. By trial-and-error, we found that  $\beta$  is linearly dependent on a dimensionless parameter,  $N_c$ , as shown in **Fig. 4.3** and the following equation.

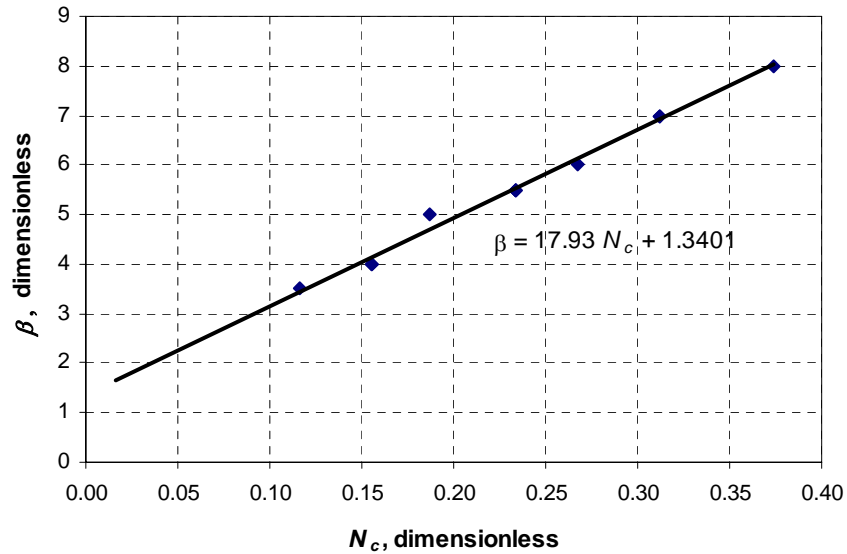
$$\beta = 17.93 N_c + 1.3401. \quad (4.9)$$

$N_c$  is the ratio of the volume of moveable oil to that of steam injection up to the critical time,  $t_c$ , as given in **Eq. 4.10**:

$$N_c = \frac{7758 A h \phi (1 - S_{or} - S_{wc})}{365 i_s t_c}, \quad (4.10)$$

where

$$t_c = \frac{t_{cD} h_t^2 M_1^2}{35040 k_h M_2}. \quad (4.11)$$



**Fig. 4.3- $\beta$  vs  $N_c$  relationship.**

In this study, the two components of capture factor,  $A_{cD}$  and  $V_{oD}$ , were developed using different simulation cases of SPE comparative model. The new model using these new components was then tested for the San Ardo and Hamaca models. Production rates based on the new model and simulation are in good agreement, verifying the validity of the new steamflood model, as described in section 4.2.

#### 4.1 New Model Calculation Steps

This section gives in detail the calculation steps for the new model. These calculation steps are divided into two sub-sections:

1. Displacement Calculations
2. Production Calculations

### 4.1.1 Displacement Calculations

Oil displacement calculations used in the new model is basically the method proposed by Myhill and Stegemeier.<sup>5</sup> In the Myhill-Stegemeier method, the oil displacement rate is a function of cumulative oil steam ratio ( $F_{os}$ ). This cumulative oil steam ratio is then a function of overall thermal efficiency ( $E_{hs}$ ). Overall thermal efficiency can be calculated by the following formula:

$$E_{hs} = \frac{1}{t_D} \left\{ G(t_D) + (1 - f_{hv}) \frac{U(t_D - t_{cD})}{\sqrt{\pi}} \left[ 2\sqrt{t_D} - 2(1 - f_{hv})\sqrt{t_D - t_{cD}} - \int_0^{t_{cD}} \frac{e^{-x} \operatorname{erfc} \sqrt{x}}{\sqrt{t_D - x}} dx - \sqrt{\pi} G(t_D) \right] \right\} \quad (4.12)$$

The dimensionless time,  $t_D$ , is given by

$$t_D = \frac{35040 \times k_h \times t \times M_2}{h_i^2 \times M_1^2}, \quad (4.13)$$

and the function  $G(t_D)$  is given by

$$G = 2\sqrt{\frac{t_D}{\pi}} - 1 + e^{-t_D} \operatorname{erfc} \sqrt{t_D}. \quad (4.14)$$

The  $\operatorname{erfc}(\sqrt{t_D})$  term in **Eq. 4.12** and **Eq. 4.14** can be approximate from Effinger and Wasson:<sup>20</sup>

$$\operatorname{erfc} \sqrt{t_D} = \left( 0.254829592 K - 0.284496736 K^2 + 1.421413741 K^3 - 1.453152027 K^4 + 1.061405429 K^5 \right) e^{-t_D}, \quad (4.15)$$

where

$$K = \frac{1}{1 + 0.3275911\sqrt{t_D}}. \quad (4.16)$$

The dimensionless critical time is calculated from the following expression:

$$e^{t_{cd}} \operatorname{erfc} \sqrt{t_{cd}} = 1 - f_{hv}, \quad (4.17)$$

where  $f_{hv}$ , the fraction of the heat injected in latent form, is given by:

$$f_{hv} = \left( 1 + \frac{C_w \Delta T}{f_s h_{fg}} \right)^{-1}. \quad (4.18)$$

The unit function,  $U(x)$ , in **Eq. 4.12** is 0 for  $x < 0$  and 1 for  $x > 0$ .

**Eq. 4.19** gives the relationship between overall thermal efficiency,  $E_{hs}$ , and cumulative oil steam ratio,  $F_{os}$ :

$$F_{os} = \frac{\rho_w C_w}{M_1} \frac{h_n}{h_t} \Delta S_o \phi (1 + F_{hD}) E_{hs}. \quad (4.19)$$

$F_{hD}$  is the dimensionless steam quality:

$$F_{hD} = \frac{f_s h_{fg}}{C_w \Delta T}. \quad (4.20)$$

Latent heat of vaporization,  $h_{fg}$ , is calculated from Ejiogu-Fiori equation<sup>21</sup> as follows,

$$h_{fg} = h_{sv} - h_{sc}. \quad (4.21)$$

Calculation of the enthalpy of condensate,  $h_{sc}$ , is divided into two pressure ranges:

$$h_{sc} = 77.036 p_s^{0.28302}, \quad (4.22)$$

where  $500 \leq p \leq 1500$  psia, and

$$h_{sc} = 0.12038 p_s + 430.984, \quad (4.23)$$

where  $1500 \leq p \leq 2500$  psia.

Enthalpy of vapor,  $h_{sv}$ , can be calculated as

$$h_{sv} = 1204.8 - 0.000197697 (p_s - 453.23)^{1.73808}. \quad (4.24)$$

With the preceding information, cumulative oil displacement is calculated as

$$N_d = F_{os} V_{s,inj}. \quad (4.25)$$



Oil displacement rate can be estimated from the time derivative of cumulative oil displacement function:

$$q_{od} = \frac{N_{d_n} - N_{d_{n-1}}}{\Delta t}. \quad (4.26)$$

#### 4.1.2 Production Calculations

The oil production rate is derived from the oil displacement rate as follows,

$$q_o = q_{od} A_{cD} V_{oD} V_{pD}. \quad (4.27)$$

These three factors,  $A_{cD}$ ,  $V_{oD}$  and  $V_{pD}$  are the three components of the capture factor. Each represents a fraction of the displaced oil that will be produced (or “captured”).  $V_{pD}$  is given in **Eq. 4.1**,  $A_{cD}$  is given in **Eq. 4.3** and **Eq. 4.6** and  $V_{oD}$  is given in **Eq. 4.8**.

**Table 4.1** gives comparisons of  $A_{cD}$ ,  $V_{oD}$  and  $V_{pD}$  between new model and Jones model. Program listing (in MS Visual Basic) of the new model is given in Appendix E.

#### 4.2 Oil Production Rate Performance

13 different cases were conducted to verify the validity of the new model:

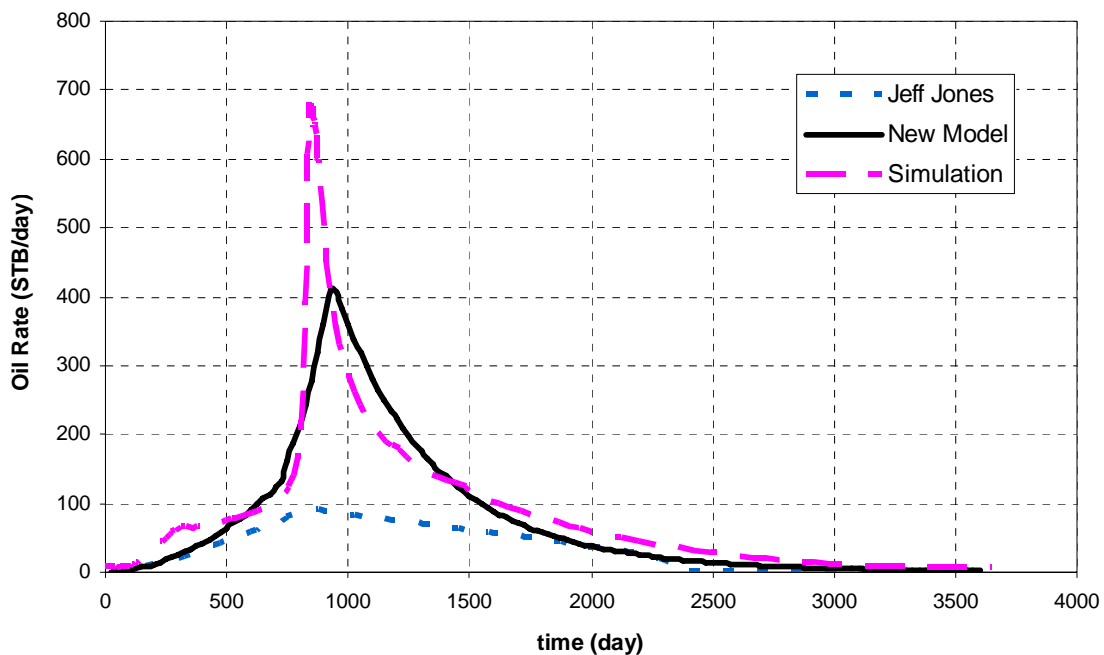
1. SPE comparative model, area = 2.5 ac, steam injection rate = 400 B/D.
2. SPE comparative model, area = 2.5 ac, steam injection rate = 600 B/D
3. SPE comparative model, area = 2.5 ac, steam injection rate = 800 B/D
4. SPE comparative model, area = 5.0 ac, steam injection rate = 600 B/D
5. SPE comparative model, area = 5.0 ac, steam injection rate = 800 B/D
6. SPE comparative model, area = 5.0 ac, steam injection rate = 1000 B/D
7. SPE comparative model, area = 5.0 ac. steam injection rate = 1200 B/D

**TABLE 4.1-FORMULAS FOR CAPTURE FACTOR COMPONENTS: NEW MODEL AND JONES MODEL**

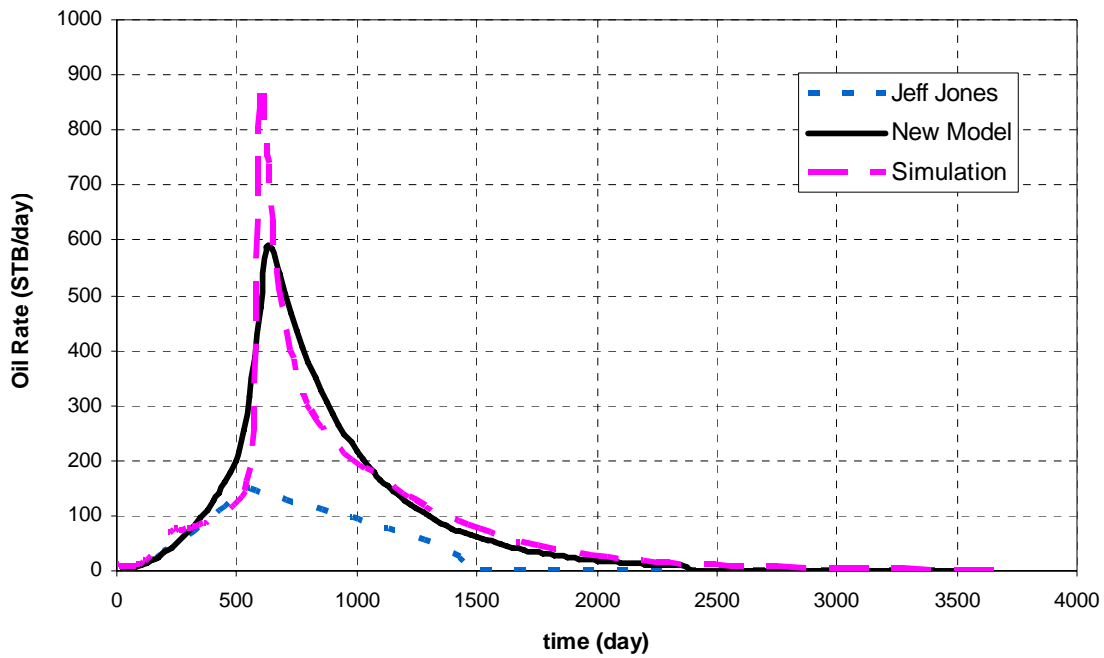
Stage	$A_{cD}$		$V_{oD}$		$V_{pD}$
	New Model	Jones Model	New Model	Jones Model	New Model = Jones Model
I	$A_{cD} = \left[ \frac{A_s}{A \{ \alpha \ln(\mu_{oi}/100) \}^{1/2}} \right]^2$ limits: $0 \leq A_{cD} \leq 1.0$ and $A_{cD} = 1.0$ at $\mu_o \leq 100$ cp. where, $\alpha = 0.00015i_s + 0.05$	$A_{cD} = \left[ \frac{A_s}{A \{ 0.11 \ln(\mu_{oi}/100) \}^{1/2}} \right]^2$ limits: $0 \leq A_{cD} \leq 1.0$ and $A_{cD} = 1.0$ at $\mu_o \leq 100$ cp.	1	$V_{oD} = \left( 1 - \frac{N_d S_{oi}}{N \Delta S_o} \right)^{1/2}$ limit: $0 \leq V_{oD} \leq 1.0$	$V_{pD} = \left( \frac{V_{s,inj} \times 5.62}{43,560 Ah_n \phi S_g} \right)^2$ limits: $0 \leq V_{pD} \leq 1.0$ and $V_{pD} = 1.0$ at $S_g = 0$
II	$A_{cD} = \left[ \frac{A_s}{A \{ \alpha \ln(\bar{\mu}_o/100) \}^{1/2}} \right]^4$ limits: $1.0 < A_{cD} \leq A_{cD_{max}}$  and $A_{cD} = 1.0$ at $\bar{\mu}_o \leq 100$ cp. where, $\alpha = 0.00015i_s + 0.05$	1	1	$V_{oD} = \left( 1 - \frac{N_d S_{oi}}{N \Delta S_o} \right)^{1/2}$ limit: $0 \leq V_{oD} \leq 1.0$	1
III	1	1	$V_{oD} = A_{cD_{max}} \left\{ \text{Exp} \left[ -\beta \left( \frac{N_{D_{max}} S_{oi}}{N \Delta S_o} \right) \right] \right\}$ limit: $A_{cD_{max}} > V_{oD} \geq 0$ where, $\beta = 17.93 N_c + 1.3401$ $N_c = \frac{7758 Ah(1 - S_{or} - S_{we})}{365 i_s t_c}$	$V_{oD} = \left( 1 - \frac{N_d S_{oi}}{N \Delta S_o} \right)^{1/2}$ limit: $0 \leq V_{oD} \leq 1.0$	1

8. SPE comparative model, area = 10.0 ac, steam injection rate = 1000 B/D
9. SPE comparative model, area = 10.0 ac, steam injection rate = 1200 B/D
10. SPE comparative model, area = 10.0 ac, steam injection rate = 1400 B/D
11. SPE comparative model, area = 10.0 ac, steam injection rate = 1600 B/D
12. San Ardo model, area = 10.0 ac, steam injection rate = 1600 B/D
13. Hamaca model, area = 10.0 ac, steam injection rate = 1600 B/D.

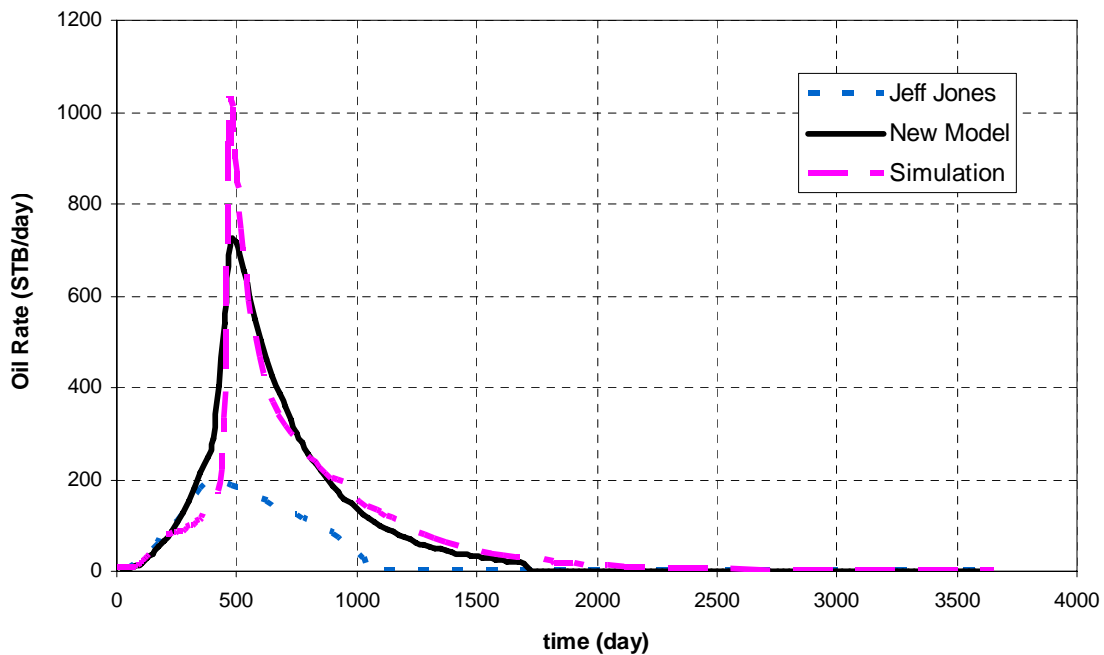
**Fig. 4.4 to Fig. 4.16** give oil rate production performances from simulation, the Jeff Jones model and new model for all of these cases.



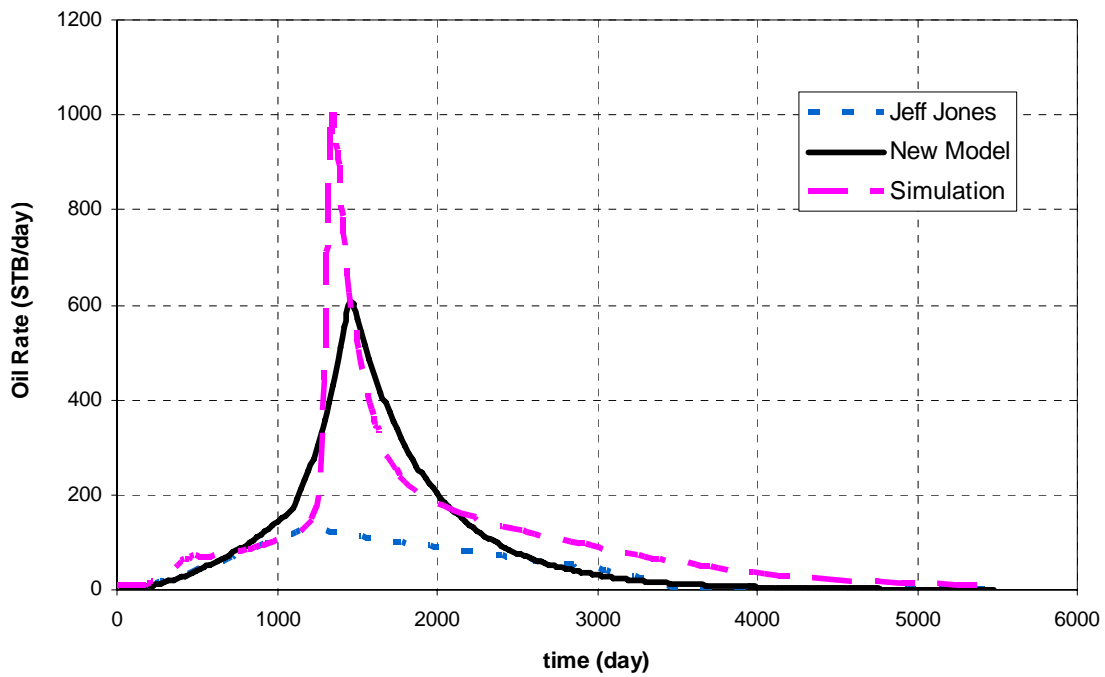
**Fig. 4.4-Oil production rate (SPE comparative model, area = 2.5 ac, injection rate =400 B/D).**



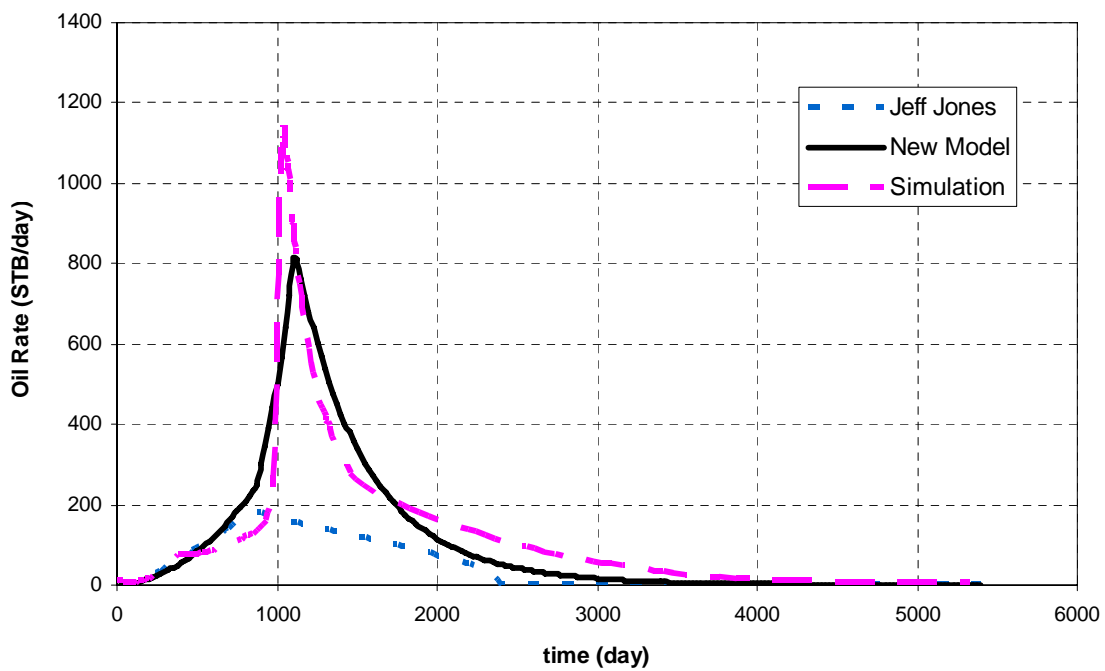
**Fig. 4.5-Oil production rate (SPE comparative model, area = 2.5 ac, injection rate = 600 B/D).**



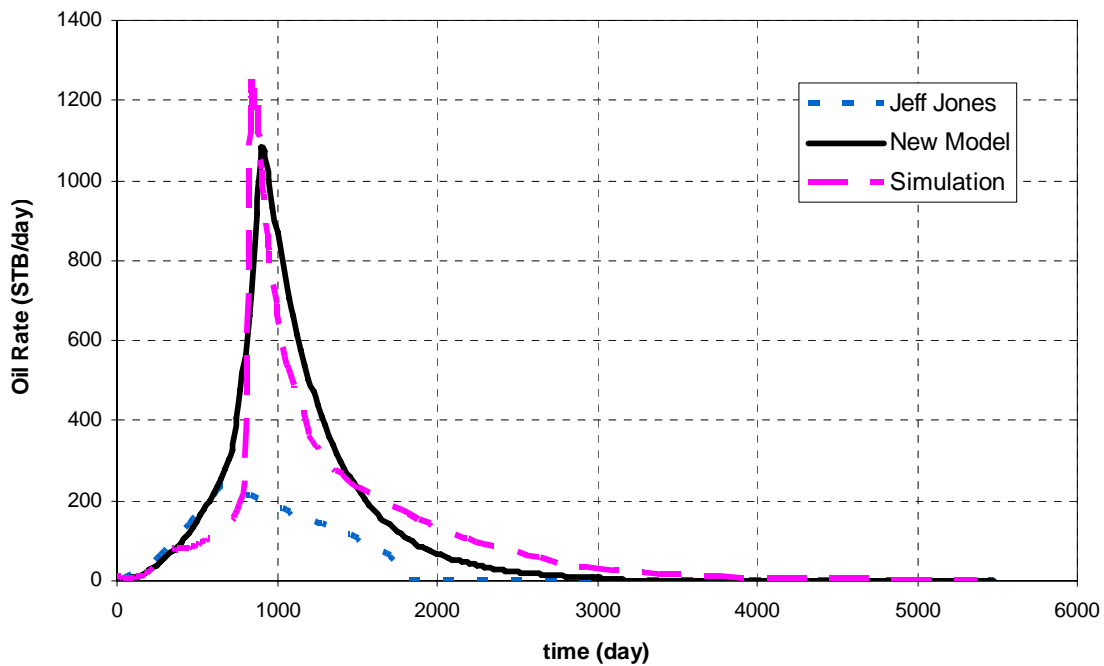
**Fig. 4.6-Oil production rate (SPE comparative model, area = 2.5 ac, injection rate = 800 B/D).**



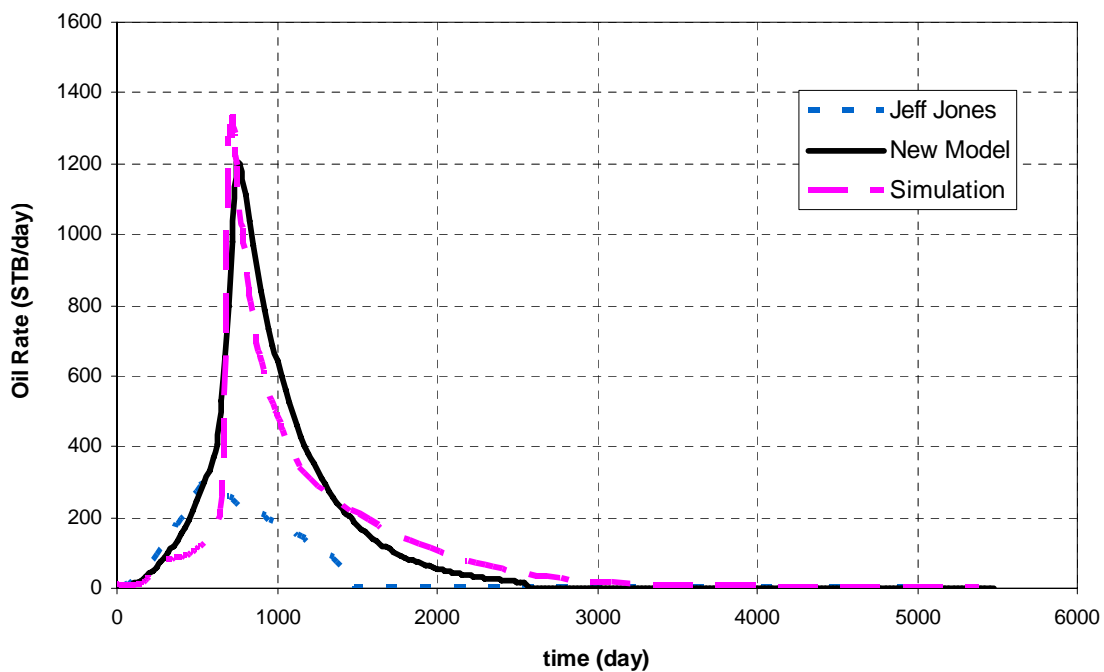
**Fig. 4.7-Oil production rate (SPE comparative model, area = 5.0 ac, injection rate = 600 B/D).**



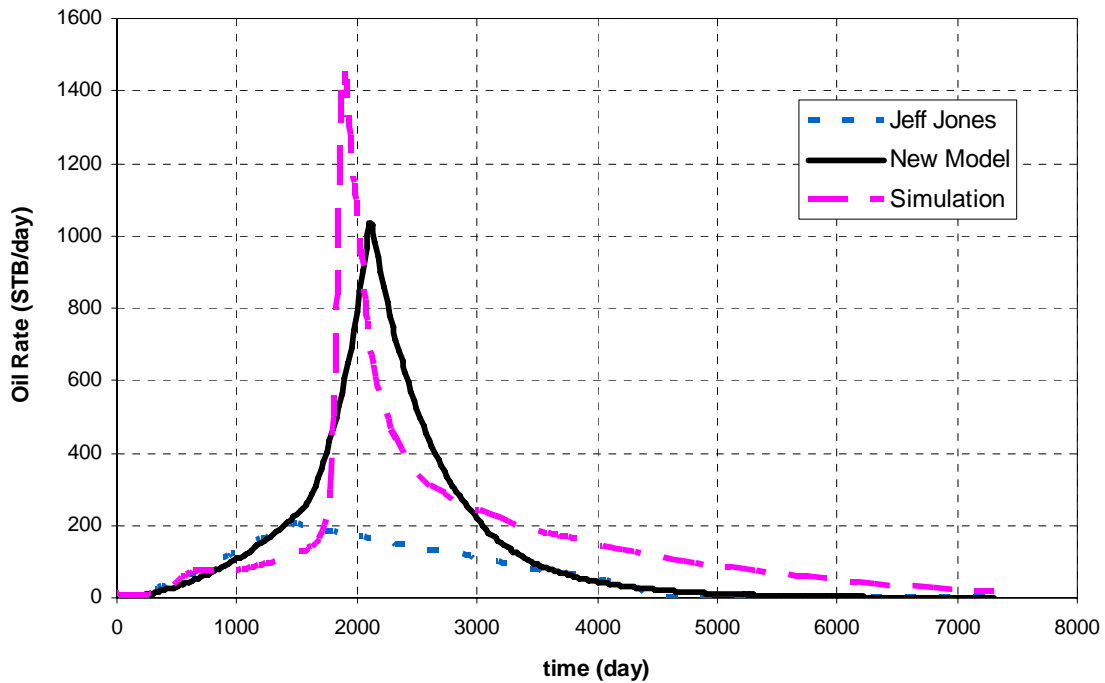
**Fig. 4.8-Oil production rate (SPE comparative model, area = 5.0 ac, injection rate = 800 B/D).**



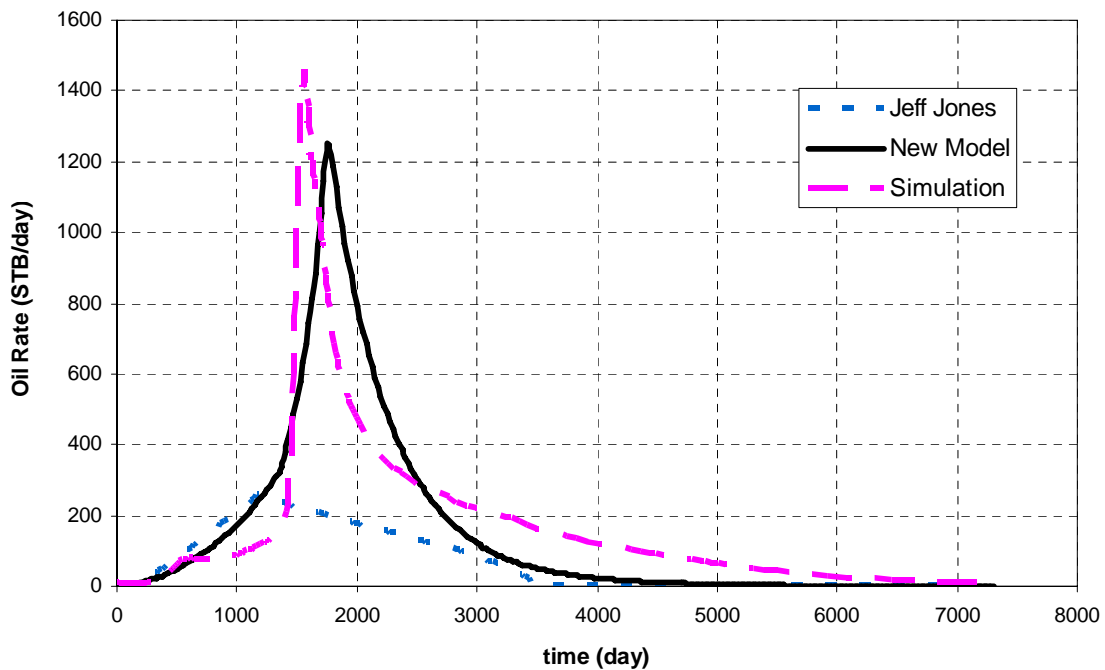
**Fig. 4.9-Oil production rate (SPE comparative model, area = 5.0 ac, injection rate = 1000 B/D).**



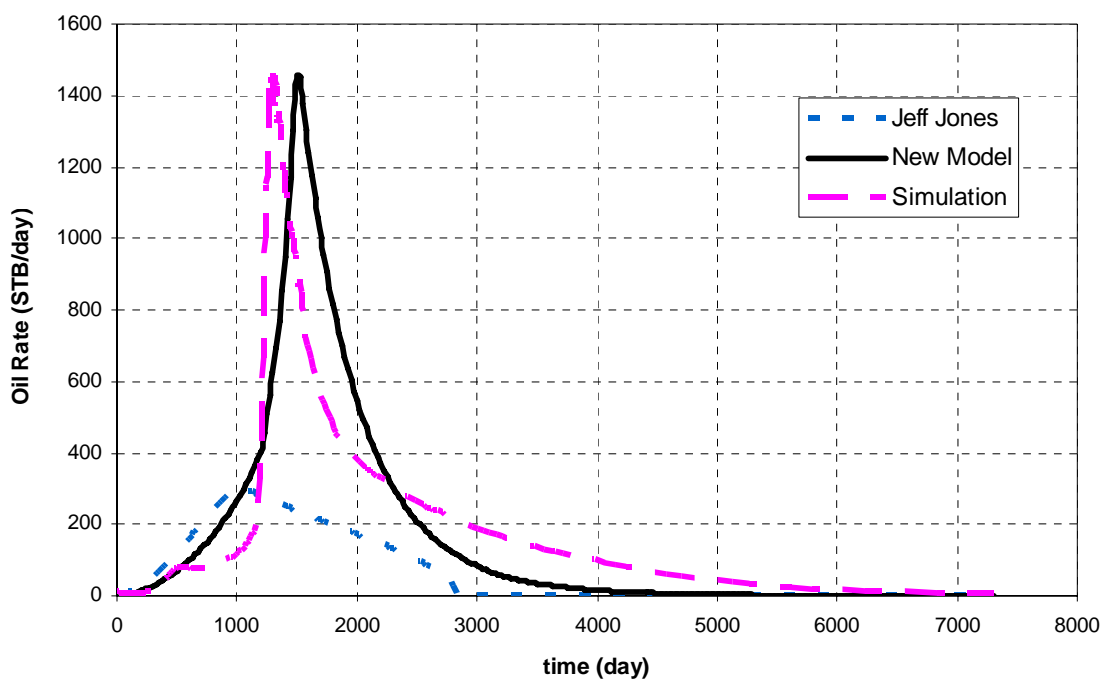
**Fig. 4.10-Oil production rate (SPE comparative model, area = 5.0 ac, injection rate = 1200 B/D).**



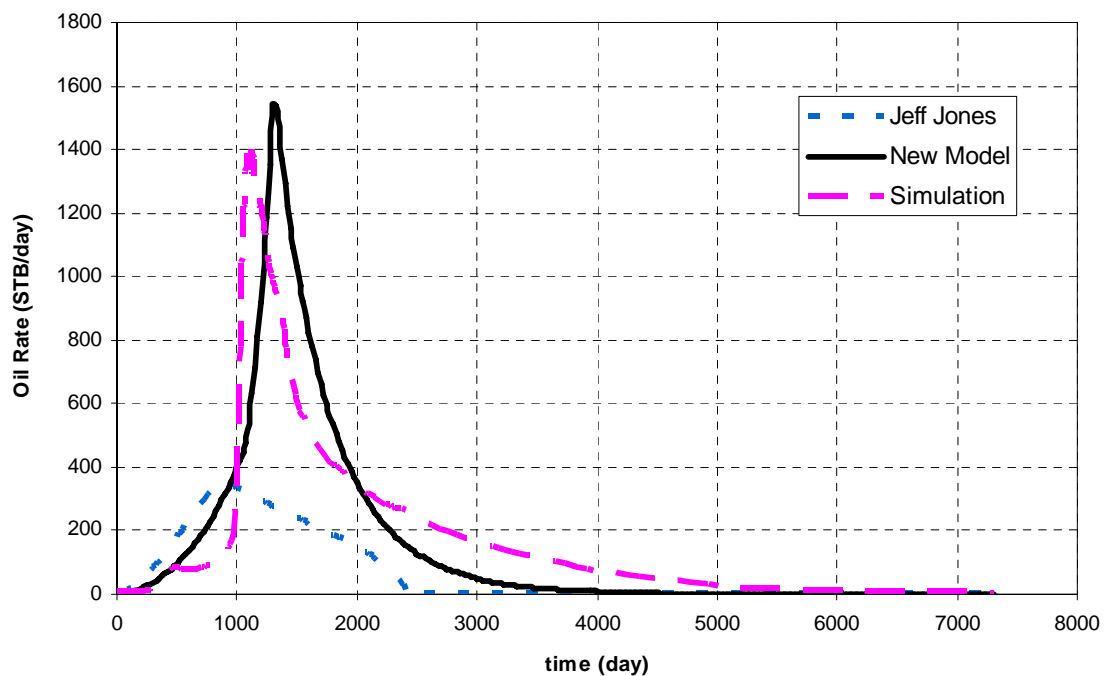
**Fig. 4.11-Oil production rate (SPE comparative model, area = 10 ac, injection rate = 1000 B/D).**



**Fig. 4.12-Oil production rate (SPE comparative model, area = 10 ac, injection rate = 1200 B/D).**

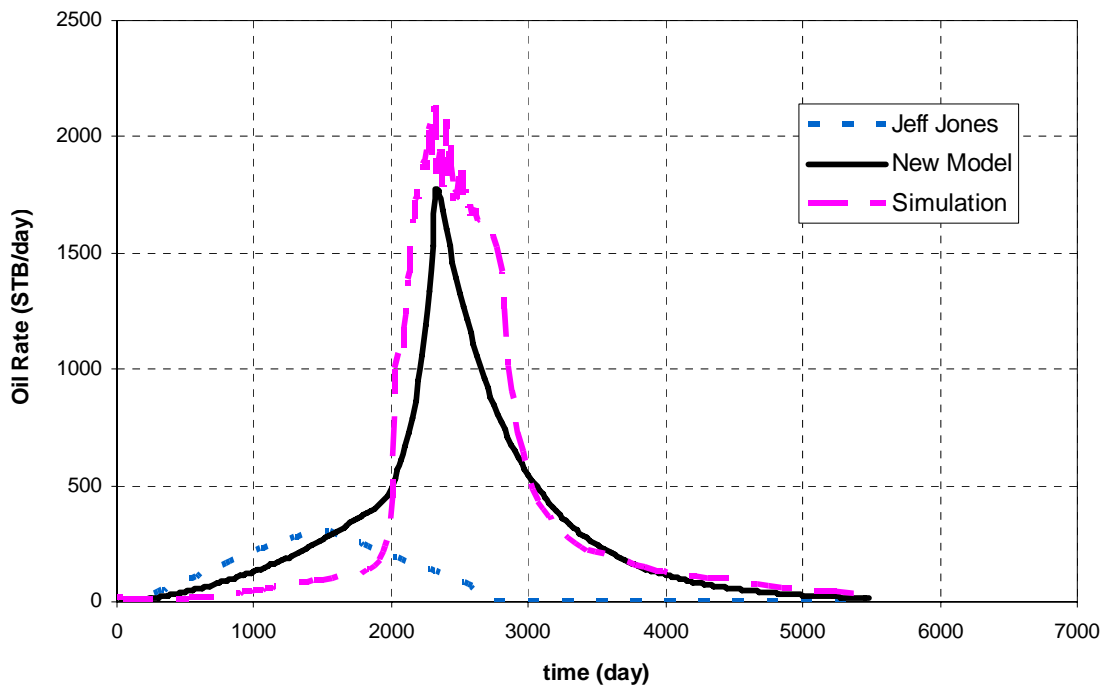


**Fig. 4.13-Oil production rate (SPE comparative model, area = 10 ac, injection rate = 1400 B/D).**

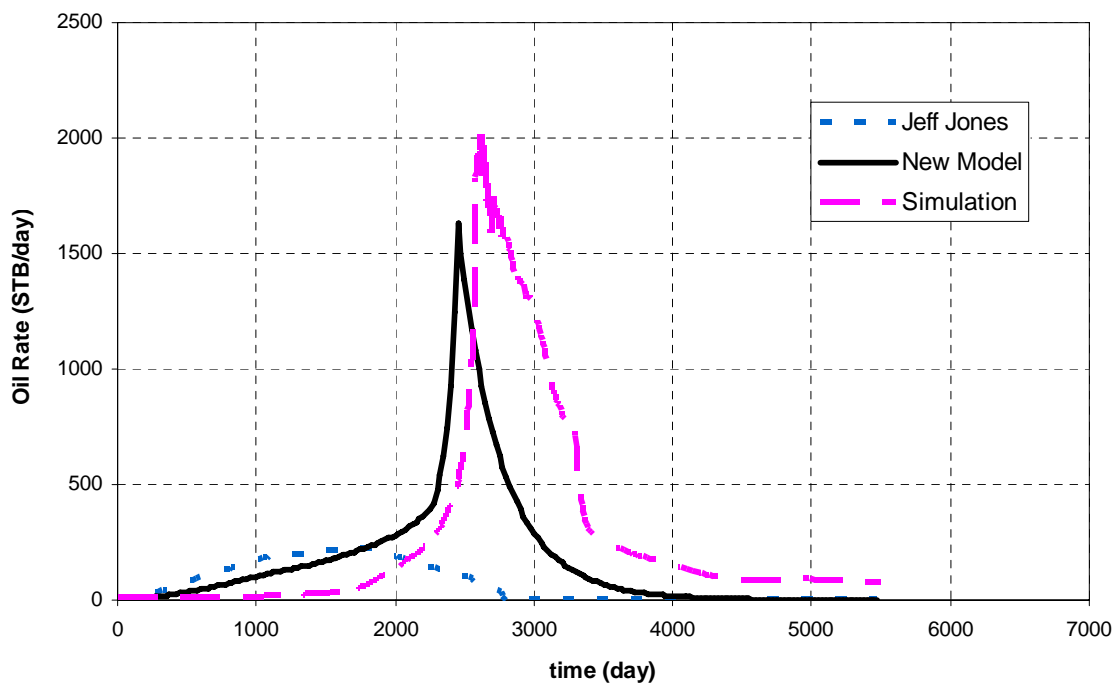


**Fig. 4.14-Oil production rate (SPE comparative model, area = 10 ac, injection rate = 1600 B/D).**





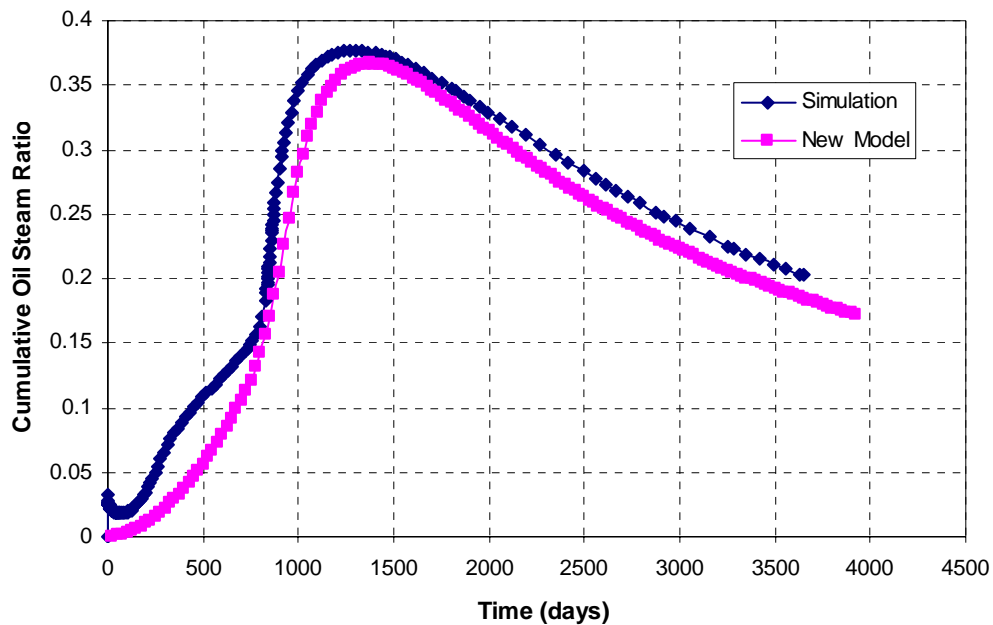
**Fig. 4.15-Oil production rate (San Ardo model, area = 10 ac, injection rate = 1600 B/D).**



**Fig. 4.16-Oil production rate (Hamaca model, area = 10 ac, injection rate = 1600 B/D).**

### 4.3 Cumulative Oil Steam Ratio

Cumulative oil steam ratio (OSR) is defined as cumulative oil produced divided by cumulative steam injected. **Fig. 4.17** until **Fig. 4.29** gives cumulative oil steam ratio plots for all of the cases. It can be seen that cumulative OSR based on the new model are in good agreement with simulation results.



**Fig. 4.17-Cumulative oil steam ratio (SPE comparative model, area = 2.5 ac, injection rate = 400 B/D).**

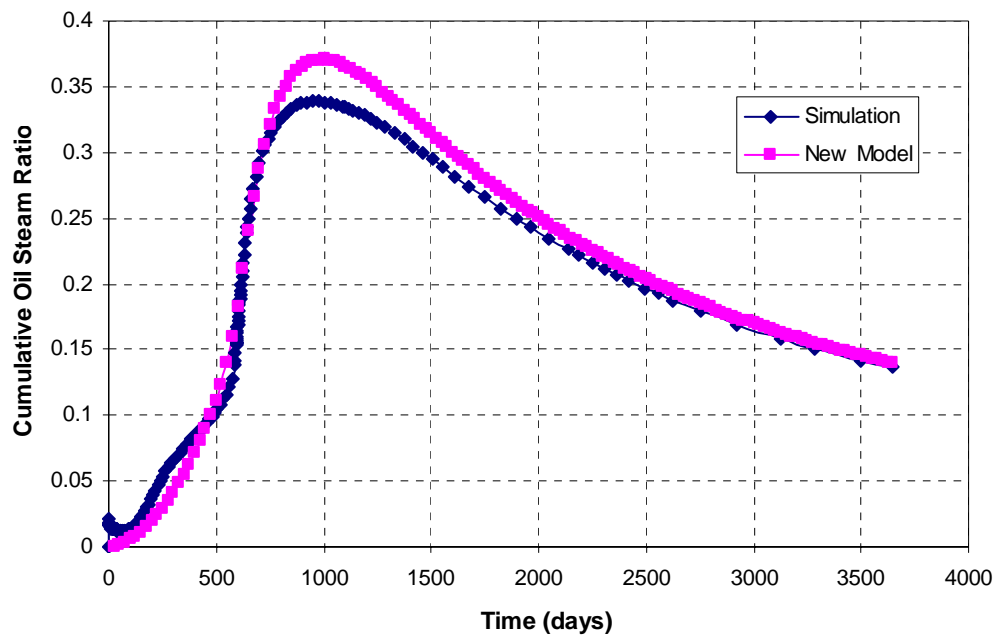


Fig. 4.18-Cumulative oil steam ratio (SPE comparative model, area = 2.5 ac, injection rate = 600 B/D).

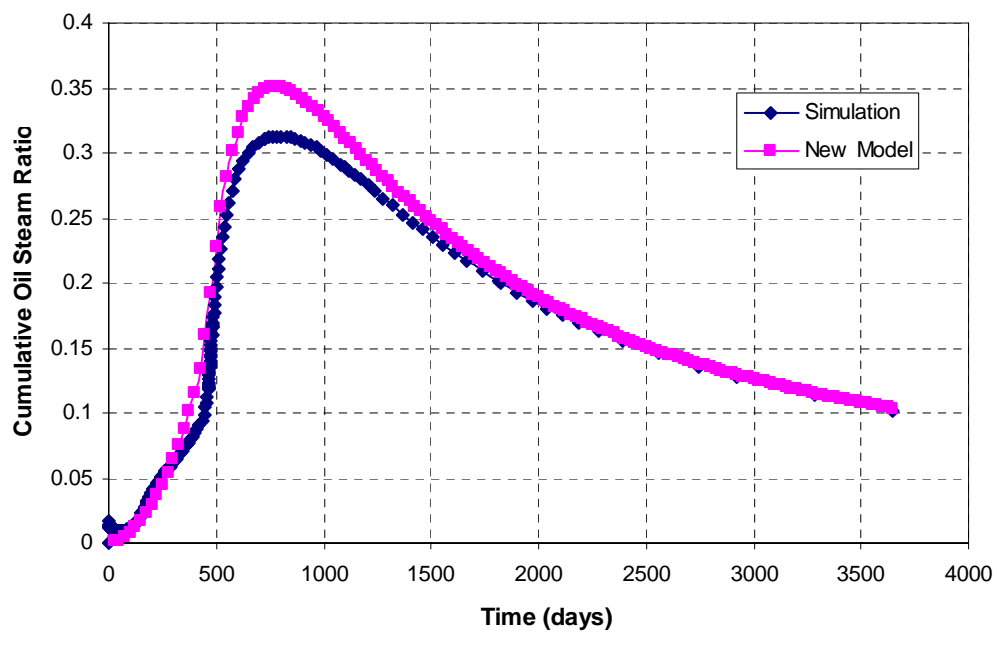
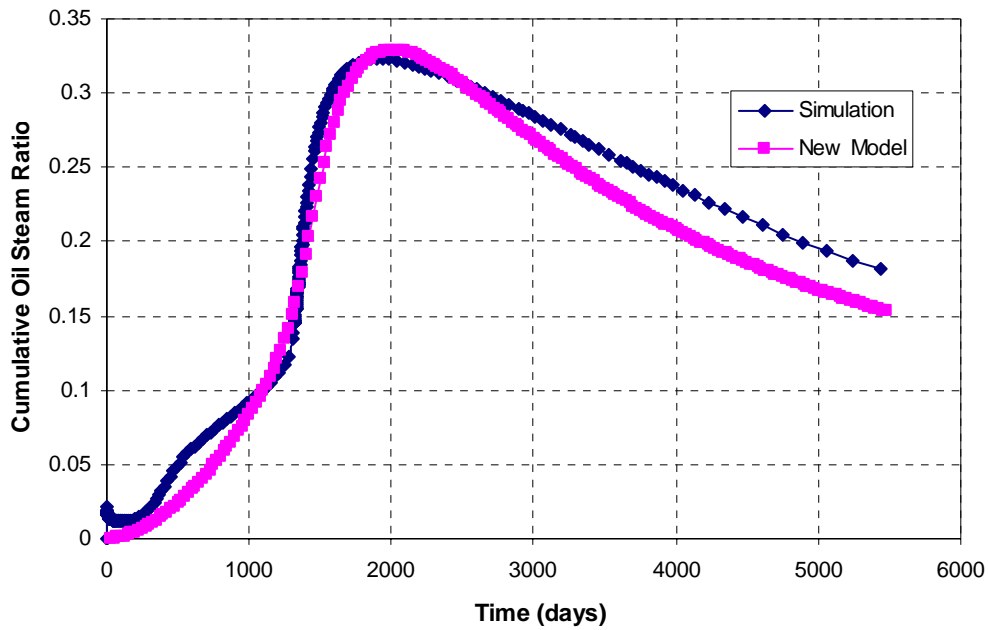
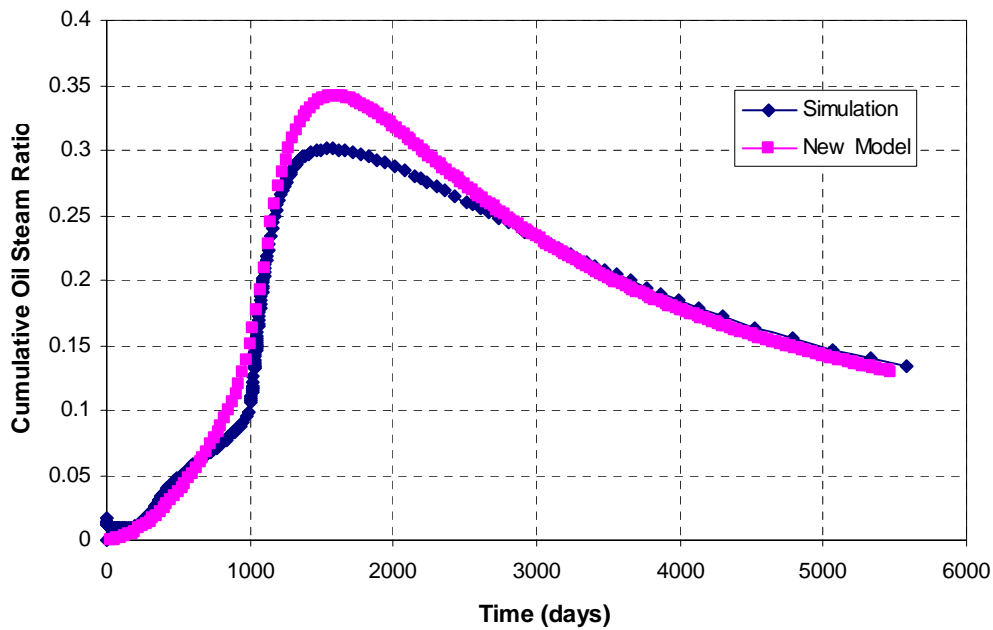


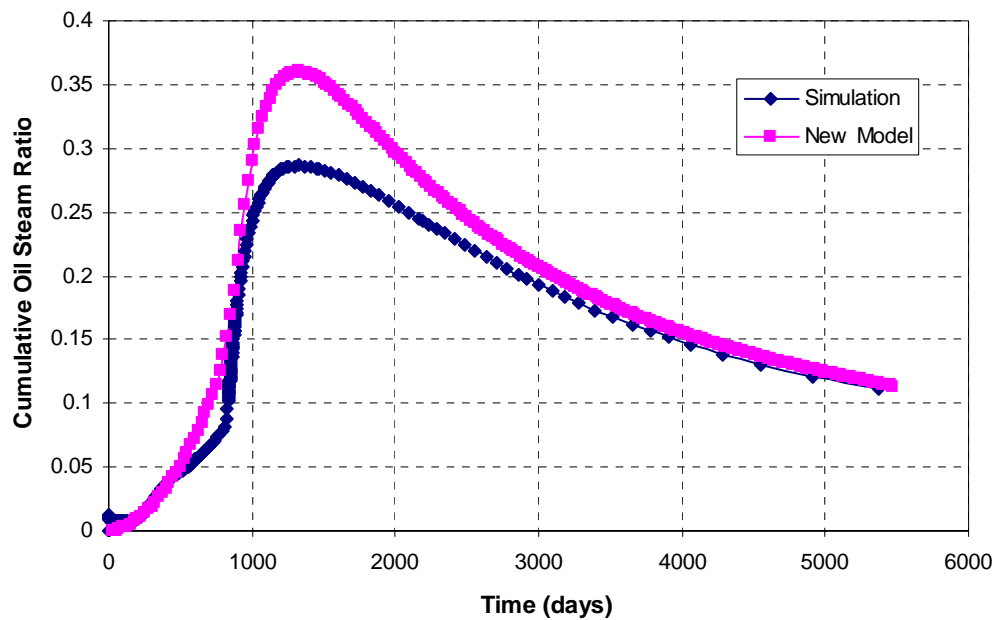
Fig. 4.19-Cumulative oil steam ratio (SPE comparative model, area = 2.5 ac, injection rate = 800 B/D).



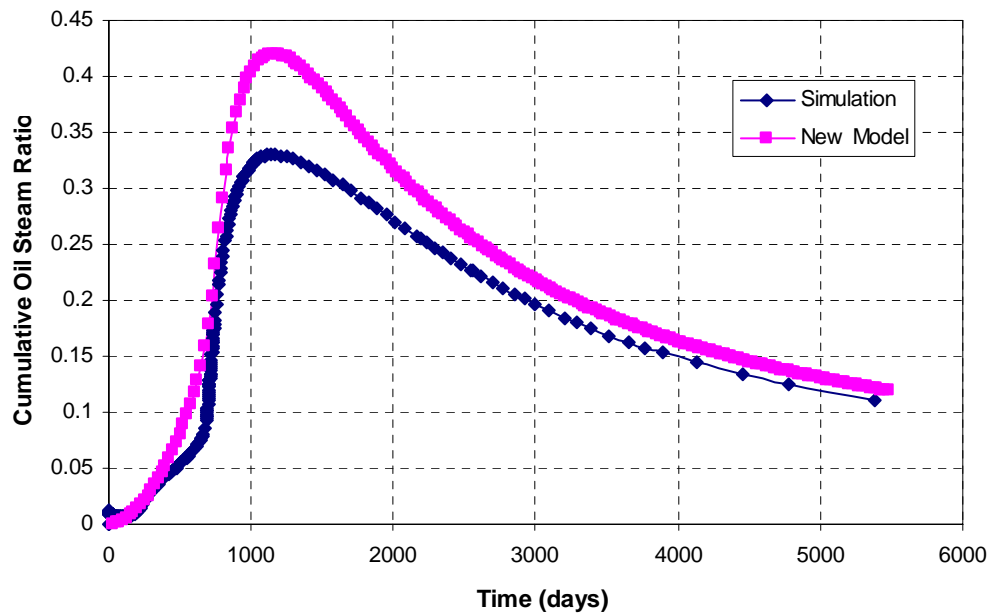
**Fig. 4.20-Cumulative oil steam ratio (SPE comparative model, area = 5.0 ac, injection rate = 600 B/D).**



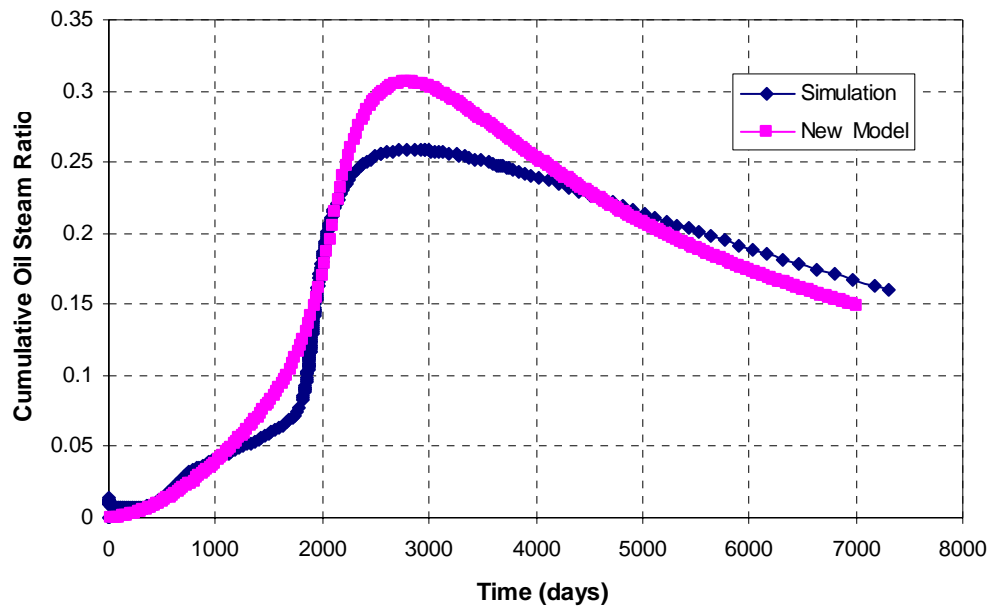
**Fig. 4.21-Cumulative oil steam ratio (SPE comparative model, area = 5.0 ac, injection rate = 800 B/D).**



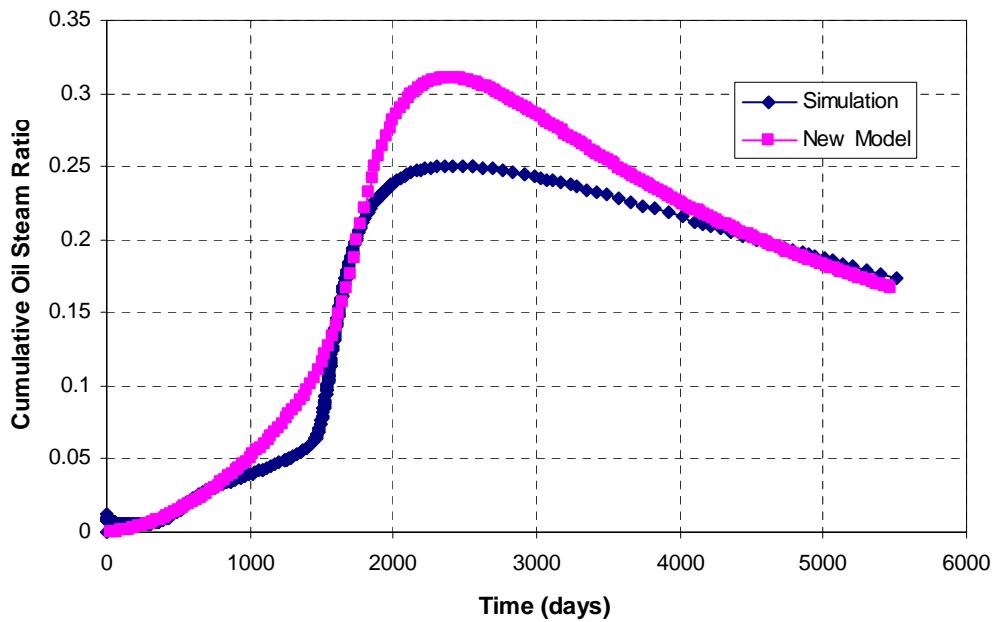
**Fig. 4.22-Cumulative oil steam ratio (SPE comparative model, area = 5.0 ac, injection rate = 1000 B/D).**



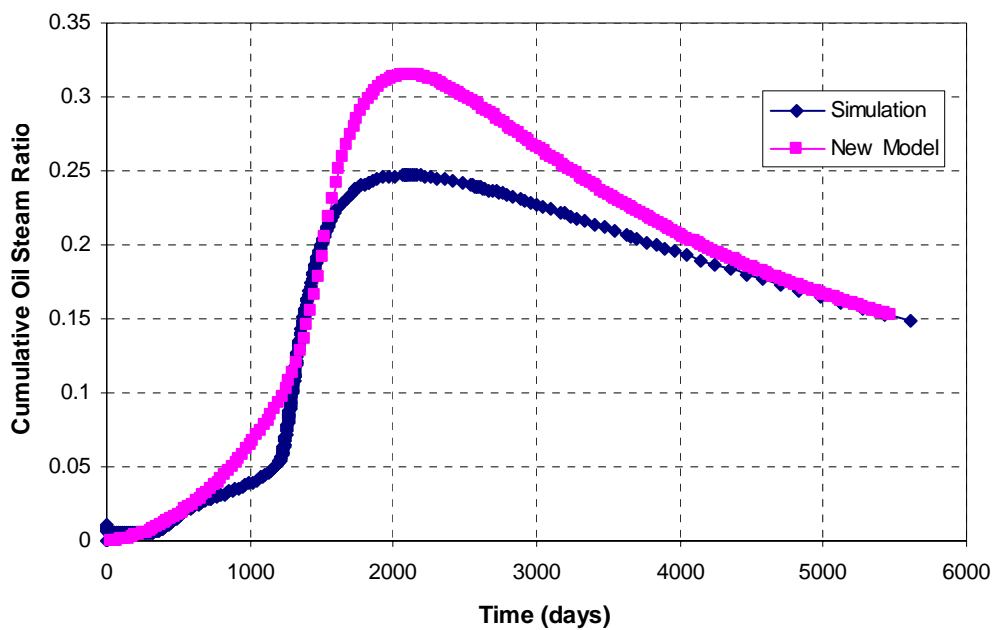
**Fig. 4.23-Cumulative oil steam ratio (SPE comparative model, area = 5.0 ac, injection rate = 1200 B/D).**



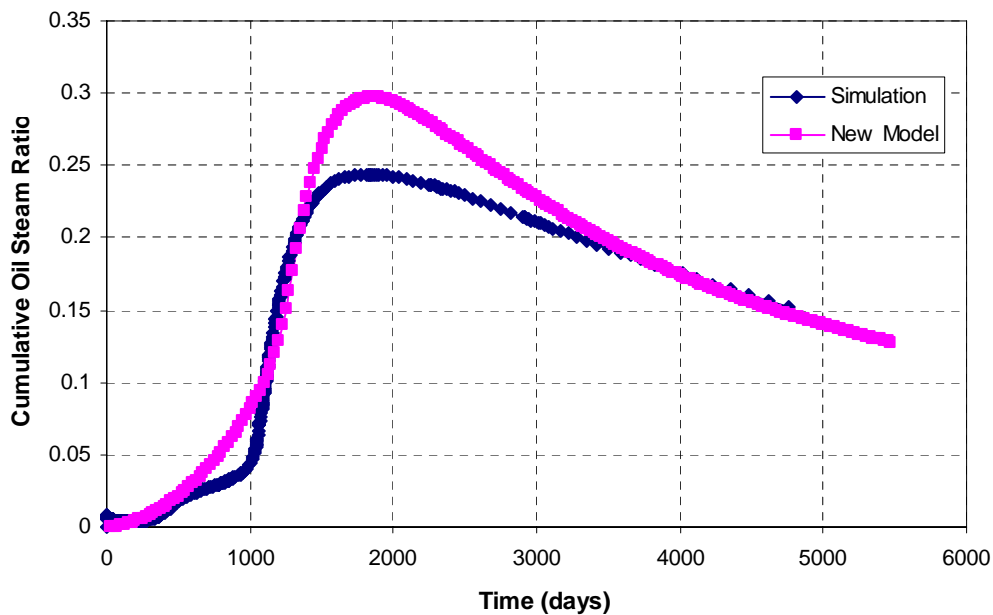
**Fig. 4.24-Cumulative oil steam ratio (SPE comparative model, area = 10 ac, injection rate = 1000 B/D).**



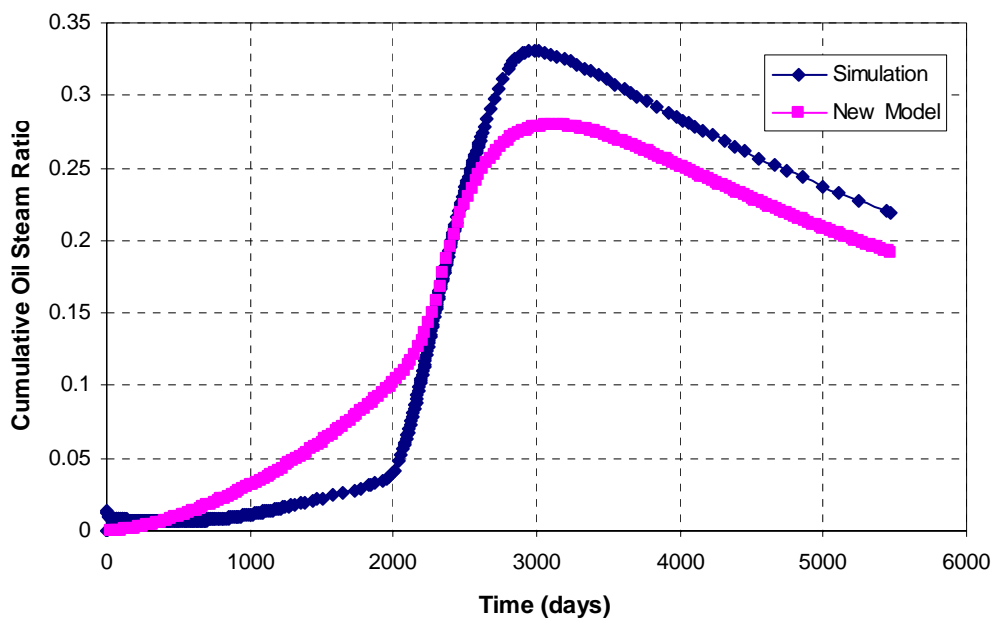
**Fig. 4.25-Cumulative oil steam ratio (SPE comparative model, area = 10 ac, injection rate = 1200 B/D).**



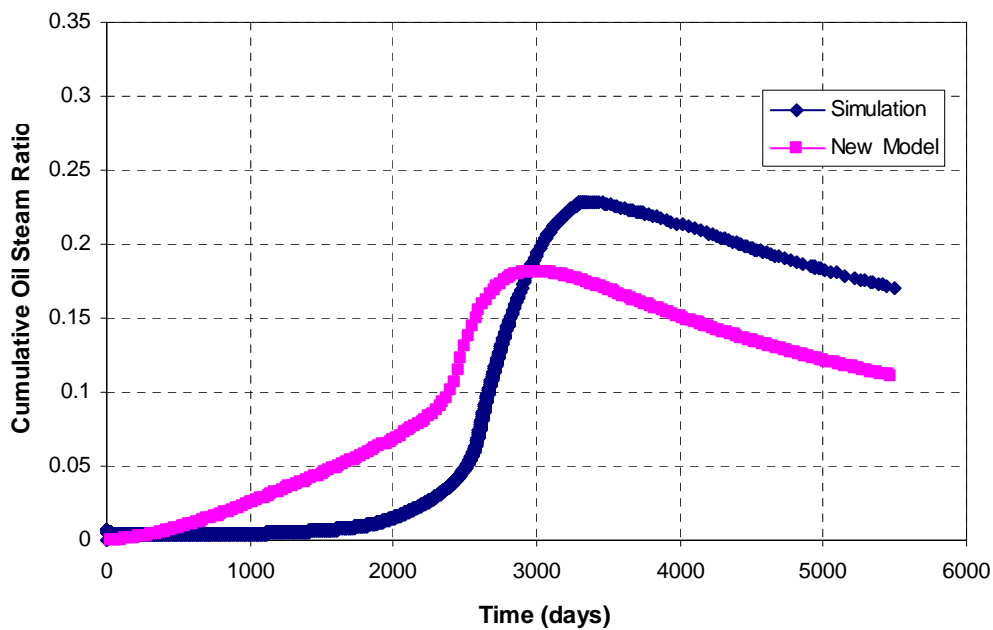
**Fig. 4.26-Cumulative oil steam ratio (SPE comparative model, area = 10 ac, injection rate = 1400 B/D).**



**Fig. 4.27-Cumulative oil steam ratio (SPE comparative model, area = 10 ac, injection rate = 1600 B/D).**



**Fig. 4.28-Cumulative oil steam ratio (San Ardo model, area = 10 ac, injection rate = 1600 B/D).**



**Fig. 4.29-Cumulative oil steam ratio (Hamaca model, area = 10 ac, injection rate = 1600 B/D).**



## CHAPTER V

### SUMMARY AND CONCLUSIONS

#### 5.1 Summary

The main drawback of the Jeff Jones analytical steamflood model is the unsatisfactory prediction of the oil production peak: usually significantly lower than the actual. The main objective of this study is therefore to improve this aspect of the Jeff Jones model.

As in the Jeff Jones model, oil production in the new model consists of three stages. The first production stage is related to cold oil production. The second production stage describes breakthrough of the oil bank. The third production stage is related to the production of the remaining mobile portion of original oil-in-place.

Two of the three components of the capture factor,  $A_{cD}$  and  $V_{oD}$ , given in Jeff Jones' model were modified to obtain a satisfactory match of the oil production rate based on the new model and simulation. In the new model,  $A_{cD}$  was modified to account for effect of steam injection rate on oil production in the first and second stages. In addition, the oil viscosity value for  $A_{cD}$  in the second stage is taken as that at the average of the steam and initial reservoir temperature. In the third stage, the Jeff Jones  $V_{oD}$  expression was modified from its square-root format to an exponential form, and took into account the effect of steam injection rate on production rate decline.

Steamflood production performances based on the new model were compared against simulation results for three cases: San Ardo field (12°API), Hamaca field (9°API), and that based on the SPE fourth comparative solution project (14°API). In the first two field cases, a 45x23x8 model was used that represented 1/8 of a 10-acre 5-spot pattern

unit, using typical rock and reservoir fluid properties. In the SPE project case, three models were used: 23x12x12 (2.5 ac), 31x16x12 (5 ac) and 45x23x8 (10 ac), that represented 1/8 of a 5-spot pattern unit.

Based on oil production rate and cumulative oil steam ratio performances of the 13 different cases investigated, the new model gives good agreement with simulation results, verifying the validity of the new steamflood model.

## **5.2 Conclusions**

1. Although the Jeff Jones model is commonly used for analytical steamflooding performance prediction, it gives unsatisfactory prediction of the oil production peak: usually lower than actual.
2. Simulation results indicate exponential decline trends for oil rate in the third production stage. This is different from the square-root trend of the Jeff Jones model.
3. A new analytical model for steamflooding performance prediction has been developed by modifying the Jeff Jones analytical model.
4. Results based on the modified model agree well with simulation results for thirteen different cases that includes three different sets of reservoir and fluid properties: that of the SPE fourth comparative project, San Ardo field and Hamaca field.
5. Engineers will find the modified model an improved and useful tool for prediction of steamflood production performance.

## NOMENCLATURE

$\Delta S_o$	= change in oil saturation before/after steam front passage, fraction
$\Delta T$	= temperature difference = $T_f - T_s$
$\phi$	= porosity, percent
$\mu_{oi}$	= initial oil viscosity (cp)
$\mu_w$	= water viscosity (cp)
$\bar{\mu}_o$	= average viscosity defined by <b>Eq. 4.5</b>
$\mu_{oi}$	= initial reservoir oil viscosity, cp
$\mu_{oT_{steam}}$	= oil viscosity value at steam temperature condition, cp
$\rho_w$	= water density, lb/cu-ft
$A$	= effective pattern area, acres
$A_s$	= steam zone size, acres
$A_{cD}$	= Jeff Jones' dimensionless steam zone size, dimensionless
$A_{cD \max}$	= maximum $A_{cD}$ value, obtained when oil production rate is equal to steam injection rate, dimensionless
$C_w$	= specific heat of water, Btu/lbm-°F
$E_{hs}$	= average thermal efficiency of steam zone, dimensionless
$f_{hv}$	= fraction of heat injected in vapor form, fraction
$f_s$	= bottomhole injection steam quality, dimensionless
$F_{hD}$	= ratio of enthalpy of vaporization to liquid enthalpy, dimensionless
$F_{os}$	= cumulative ratio of oil displaced from steam zone to water injected as steam, dimensionless
$G$	= function defined by <b>Eq. 4.14</b>

$h_f$	= enthalpy of saturated water at steam temperature, Btu/lbm
$h_{fg}$	= latent heat of steam, BTU/lbm
$h_n$	= net zone thickness, ft
$h_s$	= steam zone thickness, ft
$h_{sc}$	= enthalpy of condensate, BTU/lbm
$h_{sv}$	= enthalpy of vapor, BTU/lbm
$h_t$	= gross formation thickness, ft
$i_s$	= steam injection rate, cold water equivalent, B/D
$K$	= constant defined in Eq. 4.16, dimensionless
$k_h$	= bulk thermal conductivity of cap rock and base rock, BTU/ft-hr-°F
$k_o$	= oil relative permeability, fraction
$k_{rg}$	= gas relative permeability (gas/oil system), fraction
$k_{rgro}$	= gas relative permeability at residual oil saturation (gas/oil system), fraction
$k_{rog}$	= oil relative permeability (gas/oil system), fraction
$k_{roiw}$	= oil relative permeability at interstitial water saturation, fraction
$k_{row}$	= oil relative permeability (water-oil system), fraction
$k_{rw}$	= water relative permeability (water-oil system), fraction
$k_{rwro}$	= water relative permeability at residual oil saturation (water/oil system), fraction
$k_w$	= water relative permeability, fraction
$M$	= mobility ratio, dimensionless
$M_1$	= average heat capacity of steam zone, BTU/cu ft-°F
$M_2$	= average heat capacity of cap rock and base rock, BTU/cu ft-°F

$N$	= oil originally in place, STB
$N_c$	= ratio of the volume of moveable oil to that of steam injection up to the critical time, $t_c$
$N_D$	= cumulative oil displacement, RB
$N_{D_{\max}}$	= $N_D$ from Myhill-Stegemeier calculation - $N_D$ up to $A_{cD_{\max}}$ , RB
$p_s$	= steam injection pressure, psia
$Q_{inj}$	= heat injection rate, BTU/hr
$q_o$	= oil production rate (STB/D)
$q_{od}$	= oil displacement rate/ Myhill-Stegemeier's oil production rate (RB/D)
$S_g$	= gas saturation, fraction
$S_{gc}$	= critical gas saturation, fraction
$S_{iw}$	= interstitial water saturation, fraction
$S_{oi}$	= initial oil saturation, fraction
$S_{or}$	= residual oil saturation, fraction
$S_{org}$	= residual oil saturation (gas/oil system), fraction
$S_{orw}$	= residual oil saturation (water/oil system), fraction
$S_w$	= water saturation, fraction
$S_{wc}$	= connate water saturation, fraction
$S_{wir}$	= irreducible water saturation, fraction
$t$	= time of steam injection, years
$t_c$	= critical time, years
$t_{cD}$	= time of steam injection at onset of convective heat transport through condensation front, dimensionless
$t_D$	= time of steam injection, dimensionless

$t_f$	= initial formation temperature, °F
$t_s$	= steam temperature, °F
$U(x)$	= unit function, equals 0 for $x < 0$ , equals 1 for $x > 0$
$V_{oD}$	= volume of displaced oil produced, fraction
$V_{pD}$	= initial pore void filled with steam as water, fraction
$V_{s,inj}$	= cumulative steam injection, RB

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## APPENDIX A

### JEFF JONES OIL DISPLACEMENT CALCULATION

The method used is basically that proposed by Myhill and Stegemeier. The rate of oil displacement is a function of  $F_{os}$ , which is in turn a function of  $E_{hs}$  or overall reservoir thermal efficiency. Formula for  $E_{hs}$  calculation:

$$E_{hs} = \frac{1}{t_D} \left( e^{t_D} \operatorname{erfc} \sqrt{t_D} + 2\sqrt{t_D / \pi} - 1 \right) \quad (\text{A.1})$$

if  $t_D \leq t_{cD}$ ,

$$E_{hs} = \frac{1}{t_D} \left[ \left( e^{t_D} \operatorname{erfc} \sqrt{t_D} + 2\sqrt{t_D / \pi} - 1 \right) - \sqrt{\frac{t_D - t_{cD}}{\pi}} \left( \frac{1}{1 + F_{hD}} + \frac{t_D - t_{cD} - 3}{3} e^{t_D} \operatorname{erfc} \sqrt{t_D} - \frac{t_D - t_{cD}}{3\sqrt{\pi t_D}} \right) \right] \quad (\text{A.2})$$

if  $t_D > t_{cD}$ ,

where,

$$t_D = \frac{42,048 k_h t}{h_t^2 M_1}. \quad (\text{A.3})$$

The constant in **Eq. A-3** assumes that heat capacity of the base rock and caprock is 1.2 times that of the reservoir and converts time to a yearly basis. The dimensionless time is based on correlation:

$$t_{cD} = 0.48 F_{hD}^{1.71}. \quad (\text{A.4})$$

Dimensionless steam quality:

$$F_{hD} = \frac{f_s h_{fg}}{C_w \Delta T}. \quad (\text{A.5})$$

where,

$$h_{fg} = 865 - 0.207 p_s \quad (\text{A.6})$$

*erfc* function can be estimated from Effigier and Wasson equation:

$$\begin{aligned} \text{erfc} \sqrt{t_D} = & (0.2548292K - 0.284496736K^2 + 1.421413741K^3 \\ & - 1.453152027K^4 + 1.061405429K^5) \end{aligned} \quad (\text{A.7})$$

where,

$$K = \frac{1}{1 + 0.3275911\sqrt{t_D}}. \quad (\text{A.8})$$

Cumulative ratio of oil produced to water as steam injected:

$$F'_{os} = \frac{\rho_w c_w}{M_1} \frac{h_n}{h_t} \Delta S_o \phi (1 + F_{hD}) E_{hs}. \quad (\text{A.9})$$

With the preceding information, cumulative oil displacement is calculated as:

$$N_d = F'_{os} V_{s,inj}. \quad (\text{A.10})$$

Oil displacement rate is the time derivative of  $N_d$  function:

$$q_o = \frac{N_{dn} - N_{dn-1}}{\Delta t}. \quad (\text{A.11})$$



\*\*\*\*\*

\*\* ===== INPUT/OUTPUT CONTROL =====

RESULTS SIMULATOR STARS

\*FILENAME \*OUTPUT \*INDEX-OUT \*MAIN-RESULTS-OUT \*\* Use default file names

\*\*CHECKONLY

\*INTERRUPT \*STOP

\*TITLE1 'Base Case'

\*TITLE2 'Modified Fourth SPE Comparative Solution Project'

\*TITLE3 'Area = 2.5 Acre, Injection Rate = 400 STB/D'

\*INUNIT \*FIELD \*\* output same as input

\*OUTPRN \*GRID \*PRES \*SW \*SO \*SG \*TEMP \*Y \*X \*W \*SOLCONC \*OBHLOSS \*VISO

\*OUTPRN \*WELL \*ALL

\*WRST 300 \*WPRN \*GRID 300 \*WPRN \*ITER 300

\*OUTSRF \*WELL \*LAYER ALL

\*\* ===== GRID AND RESERVOIR DEFINITION =====

\*GRID \*CART 23 12 12

\*KDIR \*DOWN

\*NINEPOINT \*IJ

\*\* The triangular area of 1/8 of five-spot pattern is covered with a  
 \*\* 23x12 grid with grid lines horizontal to the line linking the injector  
 \*\* with the producer. These blocks are trimmed using block  
 \*\* modifiers.

\*\* In addition, a point-distributed grid is required in order to put  
 \*\* grid nodes on the injector-producer line. To do this, an oversized  
 \*\* grid is specified, and then trimmed back using block modifiers.

\*\* The interwell distance is divided into 22 equal segments, requiring  
 \*\*  $n_i = 23$ . The third corner is a 1/4 block, and is located at  $j = 12$ .

\*\* The five-spot pattern is 2.5 acres in area, or 330 ft square. The  
 \*\* distance between injector and producer is  $(330/2) * 1.414 =$   
 \*\* 233.3 ft, giving a block size of  $233.3/22 = 10.6045$  ft.

\*DI \*CON 10.6045

\*DJ \*CON 10.6045

\*DK \*CON 10

\*\* Trim grid to 1/8 of an inverted 5-spot pattern

\*VAMOD 2 0.5 0.5 1.0 0.5

\*VAMOD 3 0.5 1.0 1.0 0.5 \*9p 0.5 1.0

\*VAMOD 4 0.5 1.0 1.0 0.5 \*9p 1.0 0.5

\*VAMOD 5 0.125 0.5 1.0 0.125 \*9p 0.5 1.0





```

00000311111111111400000
000000311111111114000000
000000031111111400000000
000000003111114000000000
000000000311140000000000
000000000031400000000000
000000000006000000000000

```

```

52222222222222222222222225
0311111111111111111111140
0031111111111111111111400
0003111111111111111114000
000031111111111111140000
000003111111111111400000
000000311111111114000000
000000031111111400000000
000000003111140000000000
000000000311140000000000
000000000031400000000000
000000000006000000000000

```

```

52222222222222222222222225
0311111111111111111111140
0031111111111111111111400
0003111111111111111114000
000031111111111111140000
000003111111111111400000
000000311111111114000000
000000031111111400000000
000000003111114000000000
000000000311140000000000
000000000031400000000000
000000000006000000000000

```

```

52222222222222222222222225
0311111111111111111111140
0031111111111111111111400
0003111111111111111114000
000031111111111111140000
000003111111111111400000
000000311111111114000000
000000031111111400000000
000000003111140000000000
000000000311140000000000
000000000031400000000000
000000000006000000000000

```

```

*POR *CON 0.3
*PERMI *CON 1000
*PERMJ *EQUALSI
*PERMK *EQUALSI / 10

```

```

*END-GRID

```



\*CPOR 5e-4  
 \*PRPOR 75  
 \*ROCKCP 35  
 \*THCONR 24  
 \*THCONW 24  
 \*THCONO 24  
 \*THCONG 24  
 \*HLOSSPROP \*OVERBUR 42 24 \*UNDERBUR 42 24

\*\* ===== FLUID DEFINITIONS =====

\*MODEL 2 2 2 \*\* Components are water and dead oil. Most water  
 \*\* properties are defaulted (=0). Dead oil K values  
 \*\* are zero, and no gas properties are needed.

*COMPNAME	'WATER'	'OIL'	
**	----	-----	
*CMM	18.02	600	
*PCRIT	3206.2	0	** These four properties
*TCRIT	705.4	0	** are for the gas phase.
*AVG	1.13e-5	0	** The dead oil component does
*BVG	1.075	0	** not appear in the gas phase.
*MOLDEN	0	0.10113	
*CP	0	5.e-6	
*CT1	0	3.8e-4	
*CPL1	0	300	

\*VISCTABLE

**	Temp		
	75	0	5780
	100	0	1380
	150	0	187
	200	0	47
	250	0	17.4
	300	0	8.5
	350	0	5.2
	500	0	2.5
	800	0	2.5

\*PRSR 14.7  
 \*TEMR 60  
 \*PSURF 14.7  
 \*TSURF 60

\*\* ===== ROCK-FLUID PROPERTIES =====

\*ROCKFLUID

\*SWT \*\* Water-oil relative permeabilities

** Sw	Krw	Krow
** ----	-----	-----
0.45	0.0	0.4
0.47	0.000056	0.361
0.50	0.000552	0.30625
0.55	0.00312	0.225
0.60	0.00861	0.15625
0.65	0.01768	0.1
0.70	0.03088	0.05625
0.75	0.04871	0.025
0.77	0.05724	0.016
0.80	0.07162	0.00625
0.82	0.08229	0.00225
0.85	0.1	0.0

\*SLT \*\* Liquid-gas relative permeabilities

** Sl	Krg	Krog
** ----	-----	-----
0.45	0.2	0.0
0.55	0.14202	0.0
0.57	0.13123	0.00079
0.60	0.11560	0.00494
0.62	0.10555	0.00968
0.65	0.09106	0.01975
0.67	0.08181	0.02844
0.70	0.06856	0.04444
0.72	0.06017	0.05709
0.75	0.04829	0.07901
0.77	0.04087	0.09560
0.80	0.03054	0.12346
0.83	0.02127	0.15486
0.85	0.01574	0.17778
0.87	0.01080	0.20227
0.90	0.00467	0.24198
0.92	0.00165	0.27042
0.94	0.0	0.30044
1.	0.0	0.4

\*\* ===== INITIAL CONDITIONS =====

\*INITIAL

\*\* Automatic static vertical equilibrium

\*VERTICAL \*DEPTH\_AVE

\*REFPRES 75

\*REFBLOCK 1 1 1

\*TEMP \*CON 125

\*\* ===== NUMERICAL CONTROL =====

\*NUMERICAL \*\* All these can be defaulted. The definitions  
\*\* here match the previous data.

\*NORM \*PRESS 200 \*SATUR 0.2 \*TEMP 50

\*RUN

\*\* ===== RECURRENT DATA =====

\*\* Project starts on January 01, 2004

\*DATE 2004 01 01

\*DTWELL 1

\*WELL 1 'INJECTOR' \*VERT 1 1 \*FRAC .125  
\*WELL 2 'PRODUCER' \*VERT 23 1 \*FRAC .125

```

**      0
**     0 0 0
**    0 0 0 0 0
**   0 0 0 0 0 0 0
**  1 0 0 0 0 0 0 0 2

```

\*INJECTOR \*MOBWEIGHT 'INJECTOR'

\*INCOMP WATER 1.0 0.0

\*TINJW 545

QUAL .7

\*OPERATE \*BHP 1000

\*OPERATE \*MAX \*STW 400

*PERFV 'INJECTOR'	**	k	wi
		6	32235.39
		7	32235.39
		8	32235.39
		9	32235.39
		10	32235.39
		11	32235.39
		12	32235.39

\*\* Inject only in the bottom layer

\*\*  $2\pi k h / \ln(cc \sqrt{(dx^2 + dy^2)} / \pi) / rw$

\*\*  $k = 1000 \text{ md}$ ,  $h = 10 \text{ ft}$ ,  $dx = dy = 10.6045 \text{ ft}$ ,

\*\*  $cc = 0.249$ ,  $rw = 0.3 \text{ ft}$

\*PRODUCER 'PRODUCER'

\*OPERATE \*BHP 17

*PERFV 'PRODUCER'	**	k	wi
		1	32235.39
		2	32235.39
		3	32235.39
		4	32235.39
		5	32235.39
		6	32235.39
		7	32235.39
		8	32235.39
		9	32235.39
		10	32235.39
		11	32235.39

12 32235.39

OPEN 'PRODUCER'

OPEN 'INJECTOR'

\*TIME 365

\*TIME 730

\*TIME 1095

\*TIME 1460

\*TIME 1825

\*TIME 2190

\*TIME 2555

\*TIME 2920

\*TIME 3285

\*TIME 3650

\*STOP

## APPENDIX C

### SIMULATION INPUT DATA FOR SAN ARDO CASE AREA = 10 ACRE, STEAM INJECTION RATE = 1600 STB/D

```

*****
** Template San Ardo field – Lombardi Reservoir **
*****
*****
**
** FILE : SanArdo.DAT **
**
** MODEL:INVERTED 5 SPOT STEAM DRIVE FIELD UNITS 45X23X8 CARTESIAN GRID **
** AREA AND BLOCK MODIFIERS 1/8 PATTERN **
** 9 POINT TRANSMISSIBILITY **
**
** USAGE: SAN ARDO FIELD - LOMBARDI RESERVOIR STEAM DRIVE SIMULATION **
**
*****

```

\*\* ===== INPUT/OUTPUT CONTROL =====

#### RESULTS SIMULATOR STARS

\*FILENAME \*OUTPUT \*INDEX-OUT \*MAIN-RESULTS-OUT \*\* Use default file names

\*INTERRUPT \*STOP

\*TITLE1 'San Ardo Case'

\*TITLE2 ' SanArdo Field Lombardi Reservoir'

\*TITLE3 'Area = 10 Acre Injection Rate = 1600 STB/D'

\*INUNIT \*FIELD \*\* output same as input

\*OUTPRN \*GRID \*PRES \*SW \*SO \*SG \*TEMP \*Y \*X \*W \*SOLCONC \*OBHLOSS \*VISO

\*OUTPRN \*WELL \*ALL

\*WRST 300 \*WPRN \*GRID 300 \*WPRN \*ITER 300

\*OUTSRF \*WELL \*LAYER ALL

\*\* ===== GRID AND RESERVOIR DEFINITION =====

\*GRID \*CART 45 23 8

\*KDIR \*DOWN

\*NINEPOINT \*IJ

\*\* The triangular area of 1/8 of five-spot pattern is covered with a  
\*\* 45x23 grid with grid lines horizontal to the line linking the injector  
\*\* with the producer. These blocks are trimmed using block  
\*\* modifiers.











\*END-GRID

\*CPOR 8E-04

\*PRPOR 275

\*ROCKCP 35.02

\*THCONR 24

\*THCONW 24

\*THCONO 24

\*THCONG 24

\*HLOSSPROP \*OVERBUR 60 24 \*UNDERBUR 60 24

\*\* ===== FLUID DEFINITIONS =====

\*MODEL 3 3 3 \*\* Components are water and live oil (consists of 'GAS' and 'OIL').

COMPNAME	'WATER'	'OIL'	'GAS'
**	-----	-----	-----
CMM	0.0000	456.015	16.7278
PCRIT	0.00	179.02	670.46
TCRIT	0.00	1036.21	-107.35
KV1	0.000E+0	5.165E+6	1.534E+5
KV2	0.000E+0	0.000E+0	0.000E+0
KV3	0.000E+0	0.000E+0	0.000E+0
KV4	0.0	-15362.5	-1914.1
KV5	0.00	-459.67	-459.67
MOLDEN	0.000E+00	1.356E-01	4.515E-02
CP	0.000E+00	3.805E-06	3.754E-03
CT1	0.000E+00	1.660E-04	1.910E-03

VISCTABLE

** T, deg F	'WATER'	'OIL'	'GAS'
**	-----	-----	-----
50.000	0.0000E+00	500000	1.1018E-02
100.000	0.0000E+00	20000	1.1882E-02
150.000	0.0000E+00	1500	1.2721E-02
200.000	0.0000E+00	240	1.3536E-02
250.000	0.0000E+00	60	1.4326E-02
300.000	0.0000E+00	20	1.5094E-02
350.000	0.0000E+00	8	1.5840E-02
400.000	0.0000E+00	3.5	1.6566E-02
450.000	0.0000E+00	1.8	1.7273E-02
500.000	0.0000E+00	1	1.7962E-02
550.000	0.0000E+00	0.6	1.8635E-02
600.000	0.0000E+00	0.35	1.9293E-02
650.000	0.0000E+00	0.2	1.9937E-02
700.000	0.0000E+00	0.13	2.0568E-02

PRSR 275.000 \*\* reference pressure, corresponding to the density

TEMR 127.000 \*\* reference temperature, corresponding to the density

PSURF 14.696 \*\* pressure at surface, for reporting well rates, etc.

TSURF 60.000 \*\* temperature at surface, for reporting well rates, etc.

\*\* ===== ROCK-FLUID PROPERTIES =====

\*ROCKFLUID

\*RPT 1 \*WATWET \*STONE2 \*\*

\*SWT \*\*WATER-OIL

**	Sw	Krw	Krow	
**	----	-----	-----	
	0.500000	0.000000	0.550000	0.000000
	0.525000	0.010000	0.275000	0.000000
	0.550000	0.020000	0.120000	0.000000
	0.575000	0.030000	0.020000	0.000000
	0.600000	0.050000	0.000000	0.000000
	0.625000	0.080000	0.000000	0.000000
	0.650000	0.115000	0.000000	0.000000
	0.675000	0.150000	0.000000	0.000000
	0.700000	0.195000	0.000000	0.000000
	0.725000	0.245000	0.000000	0.000000
	0.750000	0.295000	0.000000	0.000000
	0.775000	0.360000	0.000000	0.000000
	0.800000	0.420000	0.000000	0.000000
	0.825000	0.495000	0.000000	0.000000
	0.850000	0.570000	0.000000	0.000000
	0.875000	0.650000	0.000000	0.000000
	0.900000	0.740000	0.000000	0.000000
	1.000000	1.000000	0.000000	0.000000

\*SLT \*NOSWC

**	SL	KRG	KROG	
**	-----	-----	-----	
	0.850000	0.460000	0.000000	0.000000
	0.875000	0.290000	0.065000	0.000000
	0.900000	0.160000	0.150000	0.000000
	0.925000	0.080000	0.240000	0.000000
	0.950000	0.030000	0.340000	0.000000
	0.975000	0.005000	0.435000	0.000000
	1.000000	0.000000	0.550000	0.000000

\*KRTEMTAB \*SWR \*SWCRIT \*SORW \*SOIRW \*SORG \*SOIRG \*KRWIRO

\*KROCW \*KRGCW

**	Temp	Swr	Swcrit	Sorw	Soirw	Sorg	Soirg	Krwiro	Krocw	Krgcw
	110.	0.5	0.5	0.4	0.4	0.85	0.85	0.05	0.55	0.46
	255.	0.6	0.6	0.25	0.25	0.74	0.74	0.05	0.575	0.375
	400.	0.6125	0.6125	0.225	0.225	0.715	0.715	0.05	0.61	0.35

\*\* ===== INITIAL CONDITIONS =====

\*INITIAL

\*\* Automatic static vertical equilibrium

\*VERTICAL \*DEPTH\_AVE

\*REFPRES 275  
\*REFDEPTH 1957.5

SW CON 0.267  
SO CON 0.733  
\*TEMP \*CON 127

MFRAC\_OIL 'OIL' CON 0.78904  
MFRAC\_GAS 'GAS' CON 0.21096

\*\* ===== NUMERICAL CONTROL =====

\*NUMERICAL

\*NORM \*PRESS 200 \*SATUR 0.2 \*TEMP 50

\*RUN

\*\* ===== RECURRENT DATA =====

\*\* Project starts on January 01, 2004  
\*DATE 2004 01 01

\*DTWELL 1

\*WELL 1 'INJECTOR' \*VERT 1 1 \*FRAC .125  
\*WELL 2 'PRODUCER' \*VERT 45 1 \*FRAC .125

```

**      0
**     0 0 0
**    0 0 0 0 0
**   0 0 0 0 0 0 0
**  1 0 0 0 0 0 0 2

```

\*INJECTOR \*MOBWEIGHT 'INJECTOR'  
\*INCOMP WATER 1.0 0.0 0.0  
\*TINJW 582.3

QUAL .8

\*OPERATE \*BHP 1350

\*OPERATE \*MAX \*STW 1600

\*PERFV 'INJECTOR' \*\* k wi

5	320715.436
6	320715.436
7	320715.436
8	320715.436

```

** Inject only in the bottom layer
**  $2 \cdot \pi \cdot k \cdot h / \ln(cc \cdot \sqrt{(dx^2 + dy^2)} / \pi) / rw$ 
** k = 6922 md, h = 14.375 ft, dx = dy = 10.607 ft,
** cc = 0.249, rw = 0.3 ft

```

\*PRODUCER 'PRODUCER'

\*OPERATE \*BHP 15

\*OPERATE \*MAX \*STL 5000

\*\*OPERATE \*MAX \*STEAM 10 \*\* Steam CWE in bbl/day

\*PERFV 'PRODUCER' \*\* k wi

5	320715.436
6	320715.436
7	320715.436
8	320715.436

OPEN 'PRODUCER'

OPEN 'INJECTOR'

\*TIME 365

\*TIME 730

\*TIME 1095

\*TIME 1460

\*TIME 1825

\*TIME 2190

\*TIME 2555

\*TIME 2920

\*TIME 3285

\*TIME 3650

\*TIME 4015

\*TIME 4380

\*TIME 4745

\*TIME 5110

\*TIME 5475

\*TIME 5840

\*TIME 6205

\*TIME 6570

\*TIME 6935

\*TIME 7300

\*STOP

## APPENDIX D

### SIMULATION INPUT DATA FOR HAMACA CASE AREA = 10 ACRE, STEAM INJECTION RATE = 1600 STB/D

```

*****
** Template Hamaca Field **
*****
*****
**
** FILE : Hamaca.DAT **
**
** MODEL: INVERTED 5 SPOT STEAM DRIVE FIELD UNITS 45X23X8 CARTESIAN GRID **
** AREA AND BLOCK MODIFIERS 1/8 PATTERN **
** 9 POINT TRANSMISSIBILITY **
**
** USAGE: HAMACA FIELD STEAM DRIVE SIMULATION **
**
*****

```

\*\* ===== INPUT/OUTPUT CONTROL =====

#### RESULTS SIMULATOR STARS

\*FILENAME \*OUTPUT \*INDEX-OUT \*MAIN-RESULTS-OUT \*\* Use default file names

\*\*CHECKONLY  
\*INTERRUPT \*STOP

\*TITLE1 'Hamaca Case'  
\*TITLE2 'Hamaca Field'  
\*TITLE3 'Area = 10 Acre Injection Rate = 1600 STB/D'

\*INUNIT \*FIELD \*\* output same as input

\*OUTPRN \*GRID \*PRES \*SW \*SO \*SG \*TEMP \*Y \*X \*W \*SOLCONC \*OBHLOSS \*VISO  
\*OUTPRN \*WELL \*ALL  
\*WRST 300 \*WPRN \*GRID 300 \*WPRN \*ITER 300

\*OUTSRF \*WELL \*LAYER ALL

\*\* ===== GRID AND RESERVOIR DEFINITION =====

\*GRID \*CART 45 23 8  
\*KDIR \*DOWN  
\*NINEPOINT \*IJ

\*\* The triangular area of 1/8 of five-spot pattern is covered with a  
\*\* 45x23 grid with grid lines horizontal to the line linking the injector  
\*\* with the producer. These blocks are trimmed using block











\*END-GRID

\*CPOR 4e-4

\*PRPOR 275

\*ROCKCP 35

\*THCONR 24

\*THCONW 24

\*THCONO 24

\*THCONG 24

\*HLOSSPROP \*OVERBUR 60 24 \*UNDERBUR 60 24

\*\* ===== FLUID DEFINITIONS =====

\*MODEL 2 2 2 \*\* Components are water and dead oil. Most water  
 \*\* properties are defaulted (=0). Dead oil K values  
 \*\* are zero, and no gas properties are needed.

*COMPNAME	'WATER'	'OIL'
**	----	-----
*CMM	18	511.78
*PCRIT	635	2415.7
*TCRIT	323	2280
*CPG1	0	0
*CPG2	0	0
*CPG3	0	0
*CPG4	0	0
*MASSDEN	62.7401	63.18664
*CP	0	5.e-6
*CT1	0	5.005E-4
*CT2	0	0

\*VISCTABLE

**	Temp	Water	Oil
	122	0	25000
	170	0	8077.48
	190	0	3047.18
	210	0	1277.603
	230	0	588.57
	240	0	412.51
	260	0	214.801
	280	0	120.0453
	300	0	71.4554
	320	0	44.9924
	340	0	29.7859
	360	0	20.6202
	370	0	17.4199
	380	0	14.8553
	390	0	12.7812
	400	0	11.0892

410	0	9.697
420	0	8.5443
430	0	7.5815
440	0	6.7721
450	0	6.0873
460	0	5.5044
470	0	5.0053
480	0	4.5756
490	0	4.2038
500	0	3.8805
1000	0	3.8805

\*PRSR 14.7  
\*TEMR 60  
\*PSURF 14.7  
\*TSURF 60

\*\* ===== ROCK-FLUID PROPERTIES =====

\*ROCKFLUID

\*SWT \*\* Water-oil relative permeabilities

**	Sw	Krw	Krow
**	----	-----	-----
	0.168000	0.000000	0.900000
	0.250000	0.100000	0.665000
	0.440000	0.400000	0.380000
	0.560000	0.600000	0.237500
	0.672000	0.760000	0.142500
	0.830000	1.000000	0.000000

\*SLT \*\* Liquid-gas relative permeabilities

**	Sl	Krg	Krog
**	----	-----	-----
	0.338000	0.500000	0.000000
	0.401100	0.300000	0.005670
	0.486700	0.125000	0.014400
	0.600000	0.062500	0.026700
	0.657800	0.037500	0.034400
	0.743300	0.012500	0.046700
	0.800000	0.005000	0.056700
	0.825000	0.002500	0.06222222
	0.850000	0.002500	0.06777778
	0.900000	0.002500	0.080000
	1.000000	0.000000	0.900000

\*\* ===== INITIAL CONDITIONS =====

\*INITIAL

\*\* Automatic static vertical equilibrium

\*VERTICAL \*DEPTH\_AVE

\*REFPRES 275

\*REFBLOCK 1 1 1

\*TEMP \*CON 125

\*\* ===== NUMERICAL CONTROL =====

\*NUMERICAL \*\* All these can be defaulted. The definitions  
\*\* here match the previous data.

\*NORM \*PRESS 30 \*SATUR 0.09 \*TEMP 15

\*RUN

\*\* ===== RECURRENT DATA =====

\*\* Project starts on January 01, 2004

\*DATE 2004 01 01

\*DTWELL 1

\*WELL 1 'INJECTOR' \*VERT 1 1 \*FRAC .125

\*WELL 2 'PRODUCER' \*VERT 45 1 \*FRAC .125

```

**      0
**     0 0 0
**    0 0 0 0 0
**   0 0 0 0 0 0 0
**  1 0 0 0 0 0 0 2

```

\*INJECTOR \*MOBWEIGHT 'INJECTOR'

\*INCOMP WATER 1.0 0.0

\*TINJW 600

QUAL .8

\*OPERATE \*BHP 1600

\*OPERATE \*MAX \*STW 1600

*PERFV 'INJECTOR'	** k	wi
	5	483472.39
	6	483472.39
	7	483472.39
	8	483472.39

\*\* Inject only in the bottom layer  
\*\*  $2\pi k h / \ln(cc \sqrt{(dx^2 + dy^2)} / \pi) / rw$   
\*\* k = 12000 md, h = 12.5 ft, dx = dy = 10.607 ft,  
\*\* cc = 0.249, rw = 0.3 ft

\*PRODUCER 'PRODUCER'

\*OPERATE \*BHP 90

\*OPERATE \*MAX \*STL 3500

*PERFV 'PRODUCER'	**	k	wi
		5	483472.39
		6	483472.39
		7	483472.39
		8	483472.39

OPEN 'PRODUCER'

OPEN 'INJECTOR'

\*TIME 365

\*TIME 730

\*TIME 1095

\*TIME 1460

\*TIME 1825

\*TIME 2190

\*TIME 3650

\*TIME 5475

\*STOP

## APPENDIX E

### VBA PROGRAM OF NEW MODEL

```

'Microsoft Excel Macro Program
'Modified Jeff Jones Model

'Define variables
Global limit As Single
Dim Acd1 As Double
Dim Acd2 As Double
Dim Acd3 As Double
Dim Acd4 As Double
Dim Acd1p2 As Double
Dim Acd2p2 As Double
Dim Acd3p2 As Double
Dim Acd4p2 As Double
Dim Vod1 As Double
Dim peakoilrate As Double
Dim Ms As Double
Dim check As Integer
Dim maxq As Double
Dim maxqnumber As Integer
Dim maxiter As Integer
Dim NdPartIII As Variant
Dim maxAcD As Double

'Define functions
Function ERFC(x As Double)
  y = 1 / (1 + 0.3275911 * x)
  ERFC = (0.254829592 * y - 0.284496736 * y ^ 2 + 1.421413741 * y ^ 3 -
  1.453152027 * y ^ 4 + 1.061405429 * y ^ 5) * Exp(-(x ^ 2)) + 0.00000015
End Function
Function Sqrt(temp As Double)
  Sqrt = temp ^ 0.5
End Function
Function Pi()
  Pi = 3.14159265358979
End Function
Function integration(td As Double, tcd As Variant, section As Double)
  delta = (tcd - 0) / section
  Start = delta / 2
  Sum = 0
  For i = 0 To section - 1
    Sum = Exp(Start + delta * i) * ERFC(Sqrt(Start + delta * i)) /
    Sqrt(td - (Start + delta * i)) * delta + Sum
  Next i
  integration = Sum
End Function

Sub JeffJones()

'Initialize value

```

```

check = 0
maxq = 0
NdPartIII = 0
StartIterVoD = 0

```

```
With Sheets("JJ Formula")
```

```
'Get data entry
```

```

a = Worksheets("JJ Formula").Range("A").Value 'Area
por = Worksheets("JJ Formula").Range("por").Value 'Porosity
Soi = Worksheets("JJ Formula").Range("Soi").Value 'Initial oil saturation
Sor = Worksheets("JJ Formula").Range("Sor").Value 'Residual oil saturation
Sgi = Worksheets("JJ Formula").Range("Sgi").Value 'Initial gas saturation
Oil_viscosity = Worksheets("JJ Formula")._
Range("oil_viscosity").Value 'Initial Oil viscosity
Tres = Worksheets("JJ Formula").Range("Tres").Value 'Reservoir temperature
Bo = Worksheets("JJ Formula").Range("Bo").Value 'Oil formation volume factor
kh = Worksheets("JJ Formula").Range("kh").Value 'Thermal conductivity of formation
Rock_Density = Worksheets("JJ Formula").Range("Rock_Density").Value 'Rock Density
Cr = Worksheets("JJ Formula").Range("Cr").Value 'Heat capacity of rock
Water_Density = Worksheets("JJ Formula")._
Range("Water_Density").Value 'Water density
Oil_Density = Worksheets("JJ Formula").Range("Oil_Density").Value 'Oil density
Cw = Worksheets("JJ Formula").Range("Cw").Value 'Heat capacity of water
Co = Worksheets("JJ Formula").Range("Co").Value 'Heat capacity of oil
ht = Worksheets("JJ Formula").Range("ht").Value 'Total thickness
hn = Worksheets("JJ Formula").Range("hn").Value 'Net thickness
M_1Temp = Worksheets("JJ Formula")._
Range("M_1Temp").Value 'Volumetric heat capacity of rock
Irate = Worksheets("JJ Formula").Range("Irate").Value 'Injection rate
Ps = Worksheets("JJ Formula").Range("Ps").Value 'Saturated steam pressure
fs = Worksheets("JJ Formula").Range("fs").Value 'Steam quality
Tinj = Worksheets("JJ Formula").Range("Tinj").Value 'Injection temperature
viscosity = Worksheets("JJ Formula")._
Range("viscosity").Value 'Oil viscosity @ steam temperature
Ms = Worksheets("JJ Formula")._
Range("Ms").Value 'Volumetric heat capacity of overburden and underburden
TotalDay = Worksheets("JJ Formula")._
Range("TotalDay").Value 'Total day of calculations
DeltaDay = Worksheets("JJ Formula")._
Range("DeltaDay").Value 'Delta day of calculations
peakoilrate = Irate 'Maximum oil production rate

```

```
'Calculate volumetric heat capacity of formation
```

```

If M_1Temp = 0 Then
    M_1 = (1 - por) * Rock_Density * Cr + por * Sor * Oil_Density * Co _
        + por * (1 - fs) ^ 0.5 * (1 - Sor) * Water_Density * Cw
Else
    M_1 = M_1Temp
End If

```

```
'Calculate enthalpy of condensate
```

```

If Ps >= 500 And Ps <= 1500 Then
    Hsc = 77.036 * Ps ^ 0.28302
ElseIf Ps > 1500 And Ps <= 2500 Then

```



```

    Hsc = 0.12038 * Ps + 430.984
End If

'Calculate enthalpy of vapor
Hsv = 1204.8 - 0.000197697 * (Ps - 453.23) ^ 1.73808

'Calculate latent heat of steam
hfg = Hsv - Hsc

'Calculate fraction of heat injected in vapor form
fhv = 1 / (1 + Cw * (Tinj - Tres) / (fs * hfg))

'Determine critical dimensionless time
Worksheets("JJ Formula").Range("goal").GoalSeek Goal:=fhv, _
    ChangingCell:=Worksheets("JJ Formula").Range("ChangingCell")
tcd = Worksheets("JJ Formula").Range("ChangingCell")

'Calculate ratio of enthalpy of vaporization to liquid enthalpy
fhD = fs * hfg / (Cw * (Tinj - Tres))

'Calculate dimensionless time constant
'Dimensionless time = tD_multiplier multiply by time
tD_multiplier = 35040 * Ms * kh / (ht ^ 2 * M_1 ^ 2)

'Calculate cumulative oil steam ratio constant
'Cumulative oil steam ratio = Fos_multiplier multiply by Ehs
Fos_multiplier = Water_Density * Cw / M_1 * hn / ht * _
    (Soi - Sor) * por * (1 + fhD)

'Calculate heat injection rate
Qinj = 14.6 * Irate * (Hsc + fs * hfg - Cw * (Tres - 32))

'Calculate oil originally in place
N = 43560 * a * hn * por * Soi / (5.62 * Bo)

'Calculate alpha
alpha = 0.00015 * Irate + 0.05

'Calculate betha
tc = tcd * ht ^ 2 * M_1 ^ 2 / (35040 * kh * Ms)
Nc = 7758 * a * hn * por * (Soi - Sor) / (365 * Irate * tc)
betha = 17.93 * Nc + 1.3401

*****
'Coefficient for AcD Stage I
AcD1 = alpha
AcD2 = 100
AcD3 = 0.5
AcD4 = 2

'Coefficient for AcD Stage II
AcD1p2 = 0.11
AcD2p2 = 100
AcD3p2 = 0.5
AcD4p2 = 4

```

'Coefficient for VoD

Vod1 = betha

\*\*\*\*\*

'Display the calculations result

.Cells(36, 3).Value = M\_1

.Cells(41, 3).Value = hfg

.Cells(40, 7) = Hsv

.Cells(41, 7) = Hsc

.Cells(47, 3).Value = fhD

.Cells(53, 3).Value = tcd

.Cells(60, 3).Value = tD\_multiplier

.Cells(78, 3).Value = Fos\_multiplier

.Cells(86, 3).Value = Qinj

.Cells(125, 3).Value = N

.Cells(95, 13).Value = fhv

.Cells(54, 13).Value = alpha

.Cells(76, 13).Value = alpha

.Cells(59, 19).Value = betha

'Iterations for each time step

Dim iter As Integer

limit = TotalDay / DeltaDay

.Range("A134:Z5000").Clear

For iter = 1 To limit

'Calculate time in days

.Cells(133 + iter, 2).Value = DeltaDay \* iter

'Calculate time in years

.Cells(133 + iter, 1).Value = .Cells(133 + iter, 2).Value / 365.25

'Calculate dimensionless time

.Cells(133 + iter, 3).Value = tD\_multiplier \* \_

.Cells(133 + iter, 1)

'Calculate function G(tD)

.Cells(133 + iter, 4) = 2 \* SQRT(.Cells(133 + iter, 3) / Pi()) - 1 \_

+ Exp(.Cells(133 + iter, 3)) \* ERFC(SQRT( \_

.Cells(133 + iter, 3)))

'Calculate average thermal efficiency of steam zone

If .Cells(133 + iter, 3) < tcd Then

.Cells(133 + iter, 5) = 1 / .Cells(133 + iter, 3) \* \_

.Cells(133 + iter, 4)

Else

.Cells(133 + iter, 5) = 1 / .Cells(133 + iter, 3) \* (.Cells(133 + iter, 4) \_

+ (1 - fhv) \* 1 / SQRT(Pi()) \* (2 \* SQRT(.Cells(133 + iter, 3)) - \_

2 \* (1 - fhv) \* SQRT(.Cells(133 + iter, 3) - tcd) - \_

integration(.Cells(133 + iter, 3), tcd, 5000) \_

- SQRT(Pi()) \* .Cells(133 + iter, 4)))

End If

'Calculate cumulative oil steam ratio

.Cells(133 + iter, 6) = Fos\_multiplier \* .Cells(133 + iter, 5)

'Calculate cumulative steam injection

.Cells(133 + iter, 7) = Irate \* .Cells(133 + iter, 2).Value

'Calculate cumulative oil displacement

.Cells(133 + iter, 8) = .Cells(133 + iter, 6) \* .Cells(133 + iter, 7) / Bo

```

'Calculate oil displacement rate
If iter = 1 Then
  .Cells(133 + iter, 9) = (.Cells(133 + iter, 8) - 0) / DeltaDay
Else
  .Cells(133 + iter, 9) = (.Cells(133 + iter, 8) - .Cells(132 + iter, 8)) _
    / DeltaDay
End If

'Calculate steam zone size
.Cells(133 + iter, 10) = Qinj * hn * M_1 / (4 * kh * (Tinj - Tres) _
  * Ms * 43560) * (Exp(.Cells(133 + iter, 3).Value) * _
  ERFC(SQRT(.Cells(133 + iter, 3).Value)) + 2 * _
  SQRT(.Cells(133 + iter, 3).Value / Pi()) - 1)

'Calculate AcD
If maxq = 0 Then
  If check = 0 Then
    If 132 + iter = 133 Then
      .Cells(133 + iter, 11) = (.Cells(133 + iter, 10) / (a * (AcD1 * _
        Log(Oil_viscosity / AcD2)) ^ AcD3)) ^ AcD4
    ElseIf .Cells(132 + iter, 11) < 1 Then
      .Cells(133 + iter, 11) = (.Cells(133 + iter, 10) / (a * (AcD1 * _
        Log((.Cells(133 + iter, 10) * viscosity + _
        (a - .Cells(133 + iter, 10)) * Oil_viscosity) / a / _
        AcD2)) ^ AcD3)) ^ AcD4
    Else
      check = 1
      .Cells(133 + iter, 11) = (.Cells(133 + iter, 10) / (a * (AcD1p2 * _
        Log((.Cells(133 + iter, 10) * viscosity + (a - _
        .Cells(133 + iter, 10)) * Oil_viscosity) / a / AcD2p2)) _
        ^ AcD3p2)) ^ AcD4p2
    End If
  Else
    If .Cells(132 + iter, 15) < peakoilrate Then
      .Cells(133 + iter, 11) = (.Cells(133 + iter, 10) / (a * (AcD1p2 * _
        Log((.Cells(133 + iter, 10) * viscosity + (a - _
        .Cells(133 + iter, 10)) * Oil_viscosity) / _
        a / AcD2p2)) ^ AcD3p2)) ^ AcD4p2
    Else
      .Cells(132 + iter, 15) = peakoilrate
      maxq = .Cells(132 + iter, 15)
      maxqnumber = 132 + iter
      maxiter = iter - 1
      maxAcD = peakoilrate / (.Cells(132 + iter, 12) * .Cells(132 + iter, 13) _
        * .Cells(133 + iter, 9))
      .Cells(132 + iter, 11) = maxAcD
      .Cells(132 + iter, 14) = maxAcD * .Cells(132 + iter, 12) * _
        .Cells(132 + iter, 13)
      NdPartIII = .Cells(132 + iter, 8)
      .Cells(133 + iter, 11) = 1
    End If
  End If
Else
  .Cells(133 + iter, 11) = 1
End If

```

```
'Calculate VpD
If Sgi = 0 Then
  .Cells(133 + iter, 12) = 1
Else
  If (.Cells(133 + iter, 7) * 5.62 / (43560 * a * hn * por * Sgi)) ^ 2 < 1 Then
    .Cells(133 + iter, 12) = (.Cells(133 + iter, 7) * 5.62 / _
      (43560 * a * hn * por * Sgi)) ^ 2
  Else
    .Cells(133 + iter, 12) = 1
  End If
End If
```

```
'Calculate VoD
If NdPartIII = 0 Then
  .Cells(133 + iter, 13) = 1
Else
  If (1 - (.Cells(133 + iter, 8) - NdPartIII) / N * Soi / (Soi - Sor)) > 0 Then
    .Cells(133 + iter, 13) = maxAcD * Exp(-Vod1 * _
      (.Cells(133 + iter, 8) - NdPartIII) / N * Soi / (Soi - Sor))
  Else
    .Cells(133 + iter, 13) = 0
  End If
End If
```

```
'Calculate Capture Factor
.Cells(133 + iter, 14) = .Cells(133 + iter, 11) * .Cells(133 + iter, 12) * _
  .Cells(133 + iter, 13)
```

```
'Calculate oil rate
.Cells(133 + iter, 15) = .Cells(133 + iter, 14) * .Cells(133 + iter, 9)
```

```
'Jeff Jones
```

```
*****
```

```
'Calculate Jeff Jones' AcD
If (.Cells(133 + iter, 10) / (a * (0.11 * Log(Oil_viscosity / 100)) ^ 0.5)) _
  ^ 2 <= 1 And Oil_viscosity > 100 Then
  .Cells(133 + iter, 16) = (.Cells(133 + iter, 10) / (a * (0.11 * _
    Log(Oil_viscosity / 100)) ^ 0.5)) ^ 2
Else
  .Cells(133 + iter, 16) = 1
End If
```

```
'Calculate Jeff Jones' VpD
If Sgi = 0 Then
  .Cells(133 + iter, 17) = 1
Else
  If (.Cells(133 + iter, 7) * 5.62 / (43560 * a * hn * por * Sgi)) _
    ^ 2 < 1 Then
    .Cells(133 + iter, 17) = (.Cells(133 + iter, 7) * 5.62 / _
      (43560 * a * hn * por * Sgi)) ^ 2
  Else
    .Cells(133 + iter, 17) = 1
  End If
End If
```

```
'Calculate Jeff Jones' VoD
If (1 - .Cells(133 + iter, 8) / N * Soi / (Soi - Sor)) > 0 Then
  .Cells(133 + iter, 18) = (1 - .Cells(133 + iter, 8) / _
```

```

        N * Soi / (Soi - Sor) ^ 0.5
    Else
        .Cells(133 + iter, 18) = 0
    End If
'Calculate Jeff Jones' Capture Factor
    .Cells(133 + iter, 19) = .Cells(133 + iter, 16) * .Cells(133 + iter, 17) * _
        .Cells(133 + iter, 18)
'Calculate Jeff Jones' oil production rate
    .Cells(133 + iter, 20) = .Cells(133 + iter, 19) * .Cells(133 + iter, 9)
    *****

Next

'Cell borders
Sheets("JJ Formula").Range(Sheets("JJ Formula").Cells(134, 1), _
Sheets("JJ Formula").Cells(133 + limit, 20)).Select
    Selection.Borders(xlDiagonalDown).LineStyle = xlNone
    Selection.Borders(xlDiagonalUp).LineStyle = xlNone
    With Selection.Borders(xlEdgeLeft)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlEdgeTop)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlEdgeBottom)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlEdgeRight)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlInsideVertical)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With
    With Selection.Borders(xlInsideHorizontal)
        .LineStyle = xlContinuous
        .Weight = xlThin
        .ColorIndex = xlAutomatic
    End With

Sheets("JJ Formula").Cells(20, 11).Select

End With
End Sub

```

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