Available online at www.elixirpublishers.com (Elixir International Journal)

Petroleum Engineering

Elixir Petro. Engg. 86 (2015) 35391-35394

ISSN: 2229-712X

Analysis of Reservoir Parameters for Heavy-Oil Thermal Recovery by Steam Assisted Gravity Drainage

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ARTICLE INFO

Article history:
Received: 21 August 2015;
Received in revised form:
25 September 2015;
Accepted: 29 September 2015;

Keywords
Heavy-oil,
Thermal Recovery,
Enhance-Oil-Recovery,
SAGD,
Production Optimization.

ABSTRACT

Reservoirs containing heavy oil are usually produced using any of the enhanced thermal oil recovery techniques. Steam assisted gravity drainage (SAGD) technique was used to extract heavy oil from the reservoir investigated. With the CMG STARS software, a theoretical analysis was performed and a numerical model was developed to simulate gravity-assisted steam-flood for a well that was subjected to thermal recovery technique where energy in the form of heat was supplied into the reservoir. Development of the simulation model was used for history matching. Sensitivity analysis was performed to determine the relationship between viscosity and temperature. Additional well placement was also modeled for production optimization. The methods applied and results obtained provide a platform for predicting production performance and establishes ways to improve recovery.

Introduction

Heavy oil can be defined as a class of oil with viscosity ranging from 50 mPa-s to about 50,000 mPa-s. This oil has limited mobility under reservoir temperature and pressure, and Darcy's law predicts that oil can flow under high applied pressure gradients. The recovery from primary production in heavy oil reservoirs may be as high as 20% as these reservoirs have some of the world's largest reserves with oil in place equal to that of the largest conventional oil fields. Heavy oil challenges are in extracting, recovering, producing, and selling this heavy crude within the often changing economic policies (Butler, 1997). At the end of the primary production, some significant oil-in-place in the reservoir still exists whereas the reservoir has been stripped of its natural energy. To recover additional oil, the reservoir energy has to be replenished by displacing the oil to the production well through a method of improved/enhanced oil recovery (EOR).

EOR methods involve reduction of oil viscosity through the addition of thermal energy which is the most effective and efficient technique used for heavy oil production. Gravity-assisted steam-flood is one of the methods widely used in thermal recovery as compared to other forms of technology including the Cyclic Steam Stimulation. Steam injection method extracts heavy crude oil effectively and is mainly applicable in oilfields having thicker and heavier oil than normal crude oil. Normally, some wells are used for steam injection and other wells for oil production.

Hot Fluid Injection

One of the mechanisms to improve heavy oil recovery is to heat the oil to higher temperatures to decrease its viscosity for a better flow through the formation towards the producing wells. In SAGD, high pressure dry steam is injected into the upper well, which extends lengthwise through the upper part of the oilsands deposit. The steam condenses, releasing its latent heat and sensible heat which melts and fluidizes the bitumen near the injector well. The bitumen then drains into the producing well. At low pressures, when the steam is injected it is expected to rise to the top of the reservoir and then spread horizontally. Hot water will descend through the reservoir, heating the oil and improving its mobility.

This work presents development and application to simulate steam assisted gravity drainage for a well subjected to steam injection. It aims at reducing the viscosity of the bitumen to the point where gravity pulls it down into the producing well. The analysis is done using scenarios such as history matching, sensitivity analysis and well placement. An exponential correlation was used to determine an optimum value for viscosity-temperature relationship.

Reservoir Model and Description

Heavy oil recovery is unlike conventional oil recovery. The heavy oil target rate and well pressure are known with depths as a function of time and the API gravity. The reservoir is divided into a number of grid blocks of dimensions i, j and k, (i = 30, j = 10, k = 5) with basic geological and reservoir data provided for each block. The accurate placement and construction quality of various well types (producers and injectors) gives the pressure and saturations for each block. The injector well is located in blocks 7 1:10 4 while the producer well is located in blocks 25 1:10 5. Adequate systems of data management gave information for planned production for both the geologic and reservoir models. The centre of the reservoir is divided into four regions along the j-direction. The reservoir is analysed with low permeability layers, top water, and bottom water.

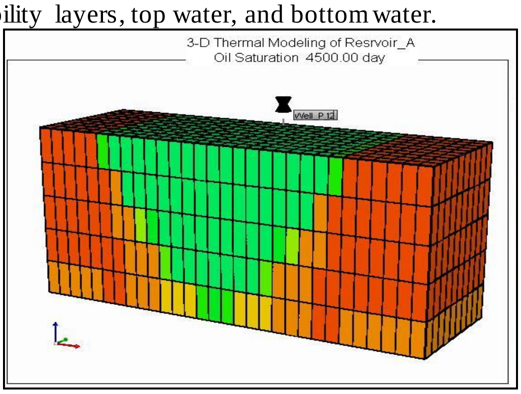

Figure 1. Reservoir Model

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History Matching

To get a match that can be used to reproduce past and present historical observations for parameters like Oil Rate, Water-cut and Bottomhole (Injection well) Pressure (using field data with actual well data), the transmissibility multiplier is modified with different uncertain range of values in the center region of the model. The main disparity in the model is in the reservoir property. Reservoir heterogeneity is ignored in the model.

Development of the simulation model to match the field data is done by establishing a series of simulation runs which determine the different values for the Vertical Transmissibility Multiplier 'TRANSK'. The runs also cut across different layers with different permeabilities. These values are implemented in the central region of i = 11:20, j = 1:10, k = 1:4; while the different TRANSK values used are 1.0, 0.8, 0.6, 0.3 and 0.1. Thereafter a stepwise workflow is developed as follows:

(i) create the historical data in CMG field history file format (.fhf);

(ii)adjust/modify the input parameters (transmissibility, permeability);

(iii)run computer simulation using STARS. If satisfactory result between simulation and historical data is achieved then end history matching process otherwise return back to step (ii) i.e. adjust/modify input parameters.

Sensitivity Studies

For this model, modification of reservoir parameters was done to see their influence on recovery. These sensitivity studies were done in two phases: First, a mathematical analysis on viscosity vs. temperature relationship was performed to determine an optimum value m (see tables 4 and 5) using the correlation in equations 1 through 4. The different m values where then used to calculate a new viscosity to determine its effect on oil saturation and recovery. Figure 2 shows simulation of oil saturation profile with respect to the new values of viscosity vs. temperature.

Secondly, with the determined value of m, the keywords and values contained in table 3 were introduced into the actual production data to account for critical saturation and Endpoint vs. Temperature relationship. This showed its effect on recovery as discussed in the result section. The parameters that were used as inputs were those that could be changed or manipulated by the operator and they were not measured properties of the reservoir but had values with varying degrees of uncertainty. Equations 1 to 4 describe the relationship between viscosity and temperature.

$$\theta = \frac{T - T_s}{T_s - T_R} \quad (1)$$

$$\frac{v_s}{v_o} = \theta^m \quad (2)$$

for kinematic viscosity at temperature T,

$$v_o = \frac{\mu}{\rho} \quad (3)$$

where ρ is dependent on temperature and calculated as:

$$\rho = \rho_r(1 - ct \times (T - T_r)) \quad (4)$$

and m is calculated using interactive method (solver) by driving $\sum\theta \rightarrow 0$ with the input data.

Well Placement

An additional well pair was added into the reservoir model to examine its production performance and predict future performance. The well pair was located in the middle of the idealized reservoir in grid 8 and 22 in the i-direction. After this, the average saturation of the reservoir was obtained by determining the total oil production and the oil saturation for each grid block.

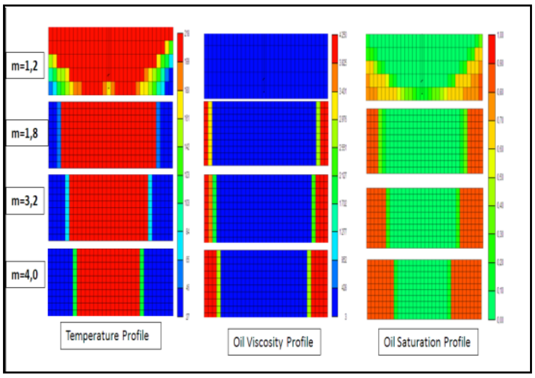

Figure 2. different m values influence on Oil temperature, viscosity and saturation profile

Results And Discussion

History Matching

In figures 4-6, due to the modification in critical parameters like the transmissibility; the transmissibility in the vertical direction had an effect on the entire flow behavior of the reservoir model. This adjustment in the model improved the quality of each of the factors. These factors include the oil production rate, the water-cut, and the bottom-hole pressure (figures 4-6).

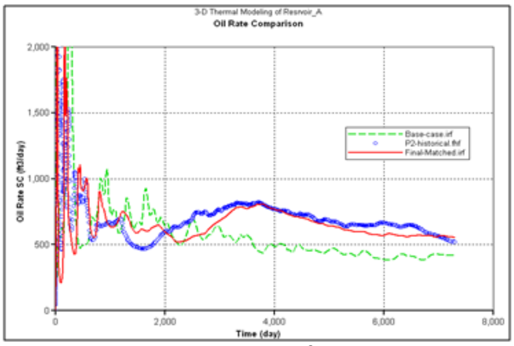

Figure 4. History Match of Oil Production Rate

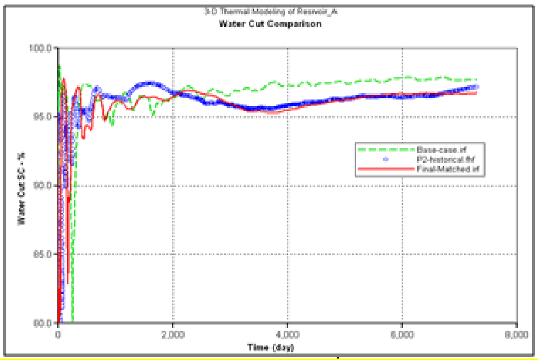

Figure 5. History Match of Water-cut

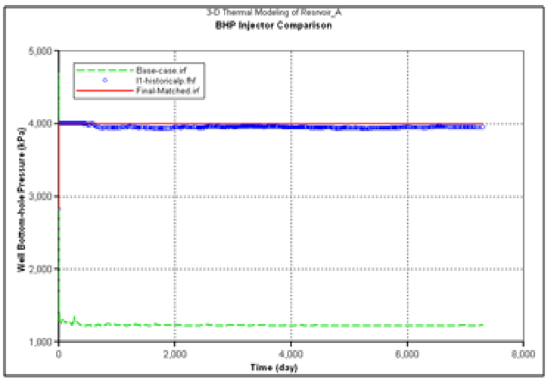

Figure 6. History Match of Well Bottom-Hole Pressure

Table 1. Heat (Rock and Fluid) Properties

Properties	Value
Rock Volumetric Heat Capacity, J/m^3-C	2589000
Oil Specific Heat Capacity, J/gmol-C	1047
Rock Heat Capacity, J/m.day.$^\circ$k	149600
Water Heat Capacity, J/m.day.$^\circ$k	149600
Oil Heat Conductivity, J/m.day.$^\circ$k	149600
Gas Heat Conductivity, J/m.day.$^\circ$k	149600

Table 2. Reservoir Data

Parameters	Value
Reservoir Temperature, T_R	296.5
Molecular weight, kg/g-mol	0.5
Molecular density, g-mol/m^3	1924.6
Reference density, ρ_r, kg/m^3	926.3
Steam temperature, T_S, K	468.5
Kinematic oil viscosity at Steam temperature v_s, m^2/s	5.41×10^{-6}
Thermal expansion, ct, K	7.20×10^{-4}

Table 3. keywords used for critical saturation and Endpoint vs. temperature relationship

KRTEMTAB	SWCON	KRCOW
300	0.13	1
433	0.28	0.9
573	0.3754	0.8

Table 4. Determination of Optimum value (m)

T, K	μ_o, Kpa-day	μ_o, Pa-sec	μ_o, cp	ρ, Kg/m^3	v_o, m^2/s	v_s/v_o	Θ	θ^m	delta
297	6.69E-08	5.78E+00	5.78E+03	9.62E+02	6.01E-03	9.01E-04	2.91E-03	2.50E-05	7.68E-07
310.9	1.60E-08	1.38E+00	1.38E+03	9.52E+02	1.45E-03	3.74E-03	8.37E-02	1.11E-02	5.44E-05
338.7	2.16E-09	1.87E-01	1.87E+02	9.33E+02	2.00E-04	2.70E-02	2.45E-01	7.82E-02	2.62E-03
366.5	5.44E-10	4.70E-02	4.70E+01	9.14E+02	5.14E-05	1.05E-01	4.07E-01	1.96E-01	8.19E-03
394.3	2.01E-10	1.74E-02	1.74E+01	8.95E+02	1.95E-05	2.78E-01	5.69E-01	3.59E-01	6.51E-03
422	9.84E-11	8.50E-03	8.50E+00	8.75E+02	9.71E-06	5.58E-01	7.30E-01	5.65E-01	4.72E-05
449.8	6.02E-11	5.20E-03	5.20E+00	8.56E+02	6.07E-06	8.91E-01	8.91E-01	8.12E-01	6.37E-03
533.2	2.89E-11	2.50E-03	2.50E+00	7.98E+02	3.13E-06	1.73E+00	1.38E+00	1.78E+00	3.13E-03
									2.69E-02

Table 5. Determination of Oil Saturation and Recovery Factor

Block	m = 1.2		m = 1.81		m = 3.2		m = 4.0	
	S_{or}	RF	S_{or}	RF	S_{or}	RF	S_{or}	RF
16 9 5	0.0892	89.14	0.1431	82.57	0.144	82.46	0.1658	79.81

Relating the effect of the several multipliers with range of values in the TRANSK region from 1.0 to 0.1, a best match of 0.1 multiplier was used in the TRANSK region (K=1000md). The selection of the best match was as a result of the modified reservoir parameters which minimizes the difference between the model performance and the historical performance of the well.

Sensitivity Analysis

Having determined all of the parameters in equation 1 through 4, Excel solver was used to find m as $\sum\theta \rightarrow 0$. The result of this gave the optimum value of m as 1.81. Other values of m were 1.2, 3.2, and 4.0. It was observed that as the value of m increased, the viscosity also increased; also from table 5 the lower the values of m the higher the recovery. It is enough to say that a lower m value gives a better recovery. The oil viscosity reduction due to a temperature increase during steam injection was the dominating mechanism in SAGD. The steam carrying latent heat spreads and exchanges heat to lower the oil viscosity.

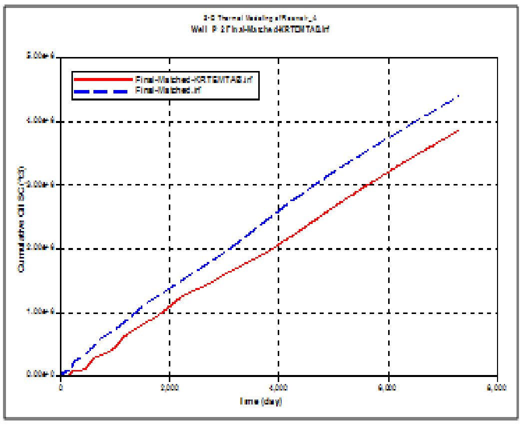

Figure 7. cumulative oil production (KRTEMTAB)

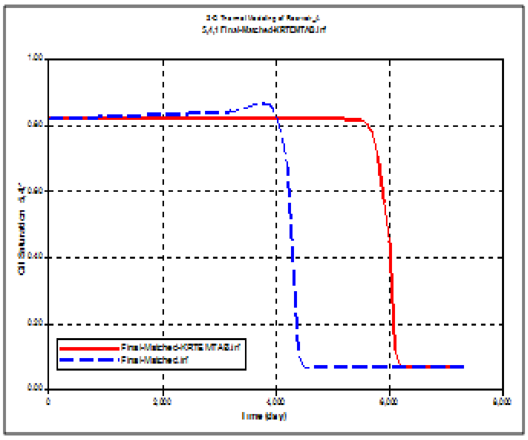

Figure 8. Oil saturation profile as a function of time (KRTEMTAB)

Figures 7 and 8 show cumulative oil produced and oil saturation for different values of m after the inclusion of the keyword *KRTEMTAB in table 3. The oil saturation increased despite having an oil/steam interface existing in the first 1900 days. This interface existed because the oil/steam didn't reach the initial water saturation but after 3300 days the oil/steam interface got to the residual oil saturation. In summary, water saturation was 10% less, oil saturation was 10% more and oil viscosity was 30 times more. The variation in the oil relative permeability reduced oil recovery by approximately 13%.

Well Placement

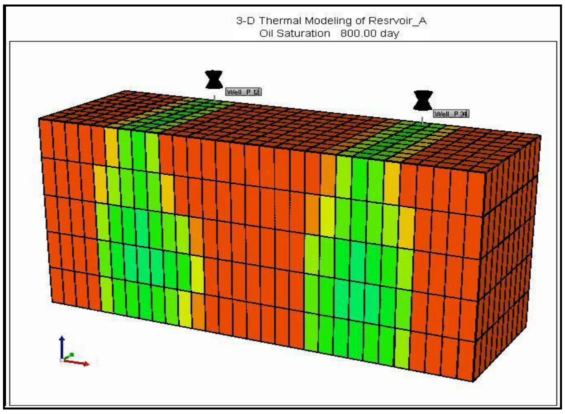

Figure 3. Additional well pair

As shown in figure 3, each of the well has the same drainage area and has the capacity to drain half of the reservoir. At the end of the drainage period of 20 years, the residual oil saturation was obtained as 18.5% for a single well pair configuration but took 9 years to reach residual oil saturation for the new well pair.

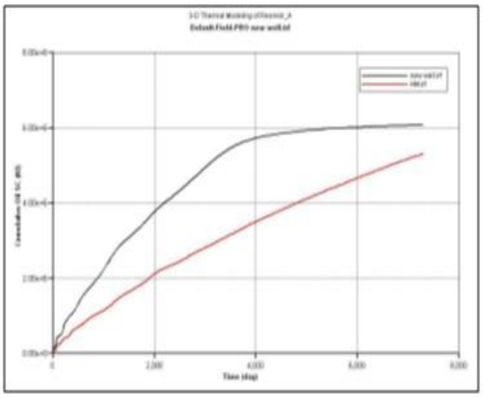

Figure 9. cumulative oil produced as a result of the additional well

With the addition of a new well, there was approximately 13% increase in cumulative oil (fig. 9) that can potentially be produced for the same drainage period of 20 years or 7200days.

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Nomenclature

ρ = Density, kg/m^3

ct = Thermal expansion, / $^{\circ}$C

T = Temperature

T_r = Reservoir Temperature, K

T_s = Steam Temperature, K

v_o = Kinematic oil viscosity at temperature T, m^2/s

v_s = Kinematic oil viscosity at steam temperature T, m^2/s