Selection of optimal parameters of horizontal wells with SAGD technology based on numerical simulation

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Abstract. As the development of reserves of traditional oil takes place, an important component of the raw material base is the reserves of highly viscous oil and natural bitumen, one of the effective methods for the development of which is the SAGD technology. This paper is devoted to optimizing the length of the horizontal section of wells with the SAGD technology using numerical modeling for one of the fields of high-viscosity Caribbean oil and finding the analytical dependence of the technological characteristics of the method on the parameters of the wells. The solution of the tasks was carried out using a thermohydrodynamic simulator «CMG STARS» (Computer Modeling Group). The paper presents the results of calculations to determine the optimal rate of steam injection and the length of a horizontal wellbore at the SAGD, as well as the analytical dependence of the technological characteristics of the parameters of the well, which can be used for an initial assessment of the effectiveness of technology for specific geological and physical conditions in this area.

1 Introduction

The most important component of the raw material base of the oil industry of the countries of the world are stocks of heavy and bituminous oils. The IEA estimates that there are 6 trillion barrels of heavy oil worldwide, with 2 trillion barrels ultimately recoverable [1, 2]. Western Canada is estimated to hold 2.5 trillion barrels, Venezuela – 1.5 trillion barrels, Russia – more than 1 trillion barrels, United States – 180 billion barrels.

Heavy oil is also located – and being produced – in Indonesia, China, Mexico, Brazil, Trinidad, Argentina, Ecuador, Colombia, Oman, Kuwait, Egypt, Saudi Arabia, Turkey, Australia, India, Nigeria, Angola, Eastern Europe, the North Sea, Iran, and Italy [3].

The problem of involvement in the active development of high-viscosity oil fields is becoming increasingly urgent from year to year.

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Thermal methods of enhanced oil recovery currently have no alternative in the development of high-viscosity oil fields. The most common among thermal methods are steam thermal methods of influence, in particular, steam and gravity drainage of the reservoir or SAGD (steam-assisted gravity drainage) - the main method of extracting natural bitumen. This technology [4–6] uses two horizontal wells, which are drilled in parallel near the bottom of the formation at a distance of 5–10 m one above the other (Fig. 1). The upper well is designed to inject steam and create a high-temperature steam chamber in the reservoir, the lower one - for oil production. Currently, the SAGD method is widely used in the fields of superviscous oils in Canada, the USA, Venezuela, and China. In Russia, using this method, mining is carried out at the Ashalchinsky field in the Republic of Tatarstan [7], on the Lyaelskaya area of the Yaregsky field [8] and at the Usinsk field in the Komi Republic [9].

Experimental studies on the physical model and numerical calculations on the hydrodynamic simulator CMG STARS showed that there are three main stages of the process. At the initial stage, steam having a relatively low density rises and the steam chamber grows to the top of the seam. After that, it continues to expand in the horizontal direction. In its form, the steam chamber in a plane perpendicular to the wells, is close to a triangle, whose apex coincides with the producing well (Fig. 2). At the final stage, the steam chamber expands in the direction of the bottom of the formation (Fig. 3). When developing deposits of super-viscous oil according to the standard SAGD technology, rows of pairs of injection-producing wells are used. Steam chambers are formed over each pair of wells and, reaching the top of the reservoir, spread in a horizontal plane until they close. In fig. 4 shows the development stages of the steam chamber in an experiment on a physical model [10].

Fig. 1. Scheme of development of high-viscosity oil fields by the system of horizontal wells using the SAGD technology.

Fig. 2. Steam chamber in section (schematic image).

Fig. 3. Steps for the development of a steam chamber (numerical simulation).

Fig. 4. Physical Modeling SAGD.

The main capital cost of SAGD is the cost of the wells, and the main operating costs are the cost of generating steam [11]. Therefore, to achieve the maximum technological and economic efficiency of the method, it is necessary to optimize the well length and the volume of injected steam.

In this regard, in the present work the following tasks were solved:

- Determination of the optimal rate of steam injection for different lengths of a horizontal wellbore;
- Determination of the optimal length of a horizontal wellbore based on the criterion of maximum oil production;
- Determination of the approximate dependence of the cumulative oil production on the length of the horizontal wellbore and the steam injection rate.

2 Modeling conditions

The tasks were solved for one of the fields of natural bitums of the Caribbean, the main characteristics of which are presented in Table 1.

Hydrodynamic modeling was carried out on a sector model with geometrical dimensions of 1000 x 100 x 86 m (X * Y * Z) in the thermal simulator "CMG STARS" (Computer Modeling Group). The number of cells in the sector model was: along the X axis – 20, along the Y axis – 40, along the Z axis – 110. Typical dimensions of the cells: along the axis of the wells – 50 m, perpendicular to the axis of the wells – 2.5 m, on the vertical – 0.8 m .

At the initial moment of time, the fields of distribution of pressure and fluid saturations should ensure the static equilibrium of the model. Achieving such a state is possible using the option of gravitational-capillary equilibrium, present in all modern simulators.

The initial distribution of oil saturation of the reservoir was calculated according to the data of the digital geological model. The initial pressure distribution was constructed as a function of depth and saturation according to the known initial reservoir pressure at a certain absolute depth of the development object.

The dependence of oil viscosity on temperature, used in the model, is shown in Figure 5.

Fig. 5. Dependence of viscosity of degassed oil on temperature.

The work of one pair of SAGD wells with different lengths of a horizontal wellbore section was modeled.

The operating parameters of the injection well were as follows:

- Steam injection pressure – 8.5 MPa;
- Injected steam temperature – 300°C;
- Degree of steam dryness – 0.75.
- The operating parameters of the production well were as follows:
- Minimum bottomhole pressure – 5.5 MPa;
- Maximum liquid flow rate – 500 m³/day.

The work of the wells in the model was stopped when the current steam-oil factor (PNF) reached the value of the maximum economically viable level – 12 tons of steam/m³ of oil.

Since natural bitumens in reservoir conditions are practically immobile, in order to create an initial hydrodynamic connection between a pair of SAGD wells, in practice, the interwell zone is heated by circulating the pair simultaneously in the production and injection wells. In the model, this period was 6 months.

3 The sequence of problem solving

3.1 Stage 1

At the first, the optimal steam pumping rate was determined on the basis of multivariate calculations for various lengths of the horizontal section of the wellbore by the criterion of maximum oil production. The calculation results are presented in tables 2–5.

As we can see from the tables, the best values of steam injection rate for options with horizontal trunk lengths of 250 m, 500 m, 750 m and 1000 m are 450 m³/day, 500 m³/day, 550 m³/day and 600 m³/days respectively.

Table 1. Basic geological and physical characteristics.

No.	Significative	Units	Value
1	Average depth	m	600
2	Type of reservoir		massive
3	Type of collector		Carbonate
4	Average total thickness	m	207
5	Average effective oil saturated thickness	m	73
6	Porosity	unit fraction	0.38
7	Oil saturation	unit fraction	0.61
8	Permeability	10 ⁻⁶ m ²	869
9	Net to gross	unit fraction	0.63
10	Average number of permeable intervals	unit fraction	10
11	Initial reservoir temperature	°C	36
12	Initial reservoir pressure	MPa	6.16
13	Oil viscosity in reservoir conditions	mPa*s	35 552
14	Oil density in reservoir conditions	кг/м ³	1029
15	Oil density in surface conditions	кг/м ³	1021
16	Oil volume factor	unit fraction	1.0095
17	Bubble point pressure	MPa	1.95
18	Gas oil ratio	m ³ /m ³	2.40

Table 2. The results of the calculations (the length of the horizontal well – 250 m).

Steam rate, m ³ /day	Cumulative oil, 10 ³ m ³	Steam oil ratio, t/m ³	
		Current	Cumulative
200	278.5	11.9	6.4
250	309.9	11.9	6.2
300	335.9	11.7	6.3
350	356.4	11.8	6.5
400	371.3	11.2	6.7
450	380.8	11.6	6.5
500	378.0	11.4	6.6
550	375.5	11.3	6.8
600	370.5	11.8	6.9
650	360.6	11.7	6.7
700	345.6	11.8	7.0
750	322.1	11.9	6.9
800	293.1	11.4	7.1
850	258.5	11.1	7.3

Table 3. The results of the calculations (the length of the horizontal well – 500 m).

Steam rate, m ³ /day	Cumulative oil, 10 ³ m ³	Steam oil ratio, t/m ³	
		Current	Cumulative
200	539.1	11.7	6.5
250	579.8	11.5	6.6
300	613.4	11.9	6.2
350	640.0	11.7	6.0
400	659.6	11.3	6.5
450	672.2	11.2	6.8
500	677.8	11.6	6.6
550	676.4	11.7	6.7
600	668.0	11.5	6.8
650	652.6	11.9	6.7
700	630.2	11.4	6.8
750	600.8	11.2	6.9
800	564.4	11.1	7.0
850	521.0	11.3	7.1

Table 4. The results of the calculations (the length of the horizontal well – 750 m).

Steam rate, m ³ /day	Cumulative oil, 10 ³ m ³	Steam oil ratio, t/m ³	
		Current	Cumulative
250	711.1	11.6	7.0
300	741.2	11.8	6.9
350	770.2	11.7	6.9
400	790.3	11.4	6.8
450	804.7	11.2	6.7
500	810.9	11.1	6.8
550	820.3	11.8	6.6
600	811.0	11.7	6.7
650	794.8	11.6	6.9
700	773.7	11.2	7.0
750	745.7	11.4	7.2
800	710.6	11.5	7.1
850	668.6	11.9	7.3
900	619.5	11.3	7.4

Table 5. The results of the calculations (the length of the horizontal well – 1000 m).

Steam rate, m ³ /day	Cumulative oil, 10 ³ m ³	Steam oil ratio, t/m ³	
		Current	Cumulative
250	568.5	11.4	7.6
300	606.3	11.3	7.2
350	637.2	11.1	7.1
400	650.0	11.8	6.9
450	664.1	11.9	6.7
500	673.3	11.7	6.6
550	680.5	11.4	6.5
600	689.2	11.5	6.6
650	675.3	11.6	6.8
700	657.2	11.7	6.9
750	632.1	11.2	7.1
800	599.9	11.3	7.5
850	560.8	11.7	7.3

Steam rate, m ³ /day	Cumulative oil, 10 ³ m ³	Steam oil ratio, t/m ³	
		Current	Cumulative
900	514.6	11.4	7.5

3.2 Stage 2

At the second stage the optimal value of the length of the horizontal wellbore was determined based on the criterion of maximum oil production. The results of the calculations are presented in table 6 and figure 6.

Based on the obtained results it can be concluded that the optimal value of the length of horizontal wells is 750 m.

Table 6. The results of determining the optimal value of the length of horizontal wells

Well length, m	Steam rate,m ³ /day	Cumulative oil, 10 ³ m ³
250	450	381
500	500	678
750	550	820
1000	600	689

Fig. 6. Dependence of cumulative oil production on well length.

3.3 Stage 3

At the third stage we select the approximating dependence of the cumulative oil production on the length of the horizontal well and the rate of steam injection by the method of regression analysis. As a result, the following analytical dependence was obtained:

$$Q_o = -0.881 \cdot L^3 + 1.21 \cdot 10^{-3} \cdot L^2 - 1.5 \cdot 10^{-6} \cdot L - 0.157 \cdot q^3 + 1.513 \cdot 10^{-3} \cdot q^2 - 1.6 \cdot 10^{-6} \cdot q \tag{1}$$

Q_o – cumulative oil (10³ m³), L – well length (m), q – steam rate (m³/day).

The results of comparing the calculated values of cumulative oil production with the calculated by the formula data are presented in Fig. 7. The average difference in cumulative oil production is 2.5%.

According to the obtained analytical formula contour surfaces were constructed for the dependence of the cumulative oil production on the steam injection rate and the length of the horizontal well (Fig. 8).

Oval areas colored in different colors correspond to a definite range of changes in cumulative oil production depending on the steam injection rate and the length of the horizontal wellbore.

The resulting graphoanalytical dependence can be considered as the primary method for assessing the effectiveness of SAGD for specific geological and physical conditions of a given field.

Fig. 7. Cross-plot of cumulative oil production.

Fig. 8. Contour surface of cumulative oil production.

4 Results

As a result of the research, the following results were obtained:

- The best values of the steam injection rate were determined depending on the length of the horizontal wellbore for the SAGD technology in specific geologo-physical conditions;
- The optimal value of the length of horizontal wells was determined on the basis of the maximum oil production criterion;
- An analytical dependence of the cumulative oil production on the length of the horizontal wellbore and steam injection rate was obtained, which can be used for the initial assessment of the effectiveness of the SAGD technology for specific geological – physical conditions of this field.

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