Controlling the hybrid steam-solvent injection for increasing recovery factor and reducing solvent retention in heterogeneous reservoirs

by Suranto Am

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Abstract: The irregular steam chamber propagation has been a problem in hybrid steam-solvent injection in heterogeneous reservoirs. When the steam chamber is poor, the solvent passes through to the production well directly. If the steam chamber is good, the oil drain will be effective. In such a case, controlling the hybrid steam-solvent injection is necessary to spread the steam chamber uniformly. A synthetic reservoir model was developed to study the phenomenon using a real field data set. Adjusting steam injection pressure, grouping perforations, and controlling the openings of perforation were observed. The adjustment from the peak of production rate is more favourable because the steam chamber has reached its maturity. Then, the solvent effectiveness increases and the solvent retention reduces. The heat efficiency and recovery factor are increased by 7.4% and 8%, respectively. The NPV on the adjustment from the peak of production rate increases by 9% compared with no-adjustment case. [Received: January 21, 2015; Accepted: May 27, 2015]

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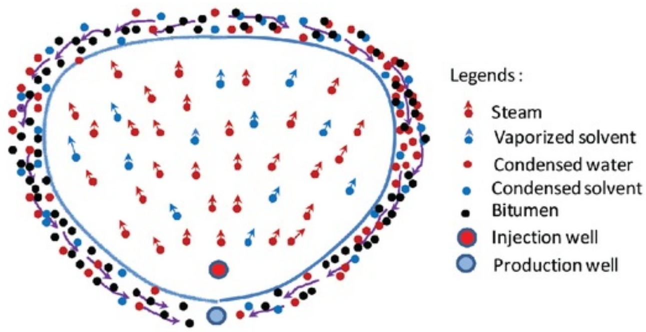
1 Introduction

The Alberta oil sand ranks third in proven global crude oil reserve, right after Saudi Arabia and Venezuela. Its total proven reserve was estimated to be 170.2 billion barrels or about 11% of total global reserves in 2011. About 99% of this comes from oil sand. By 2022, crude bitumen production is expected to be 3.8 million bbl/day (Government of Alberta, 2013).

Generally, the bitumen has high viscosity under reservoir conditions. The viscosity will reduce to less than 10 cp, if the bitumen is heated to more than 200°C. A large amount of energy is needed to increase the temperature of reservoir conditions of around 11°C to around 200°C. The heat that is used to increase the temperature is derived from natural gases combustion to produce steam and consequently, the greenhouse gas emission will increase (Gates and Chakrabarty, 2008; Deng et al., 2010). In order to minimise the energy usage and environmental impact, hybrid steam-solvent injection has been applied in the field. In a field trial, the production rate is increased from 300 tonnes/day to 470 tonnes/day. In such a case, more than 70% of the solvent retention was recovered from the reservoir (Gupta and Gittins, 2006; Dickson et al., 2011).

In the hybrid steam-solvent injection, a small amount of solvent is mixed with the steam and the mixture is injected into the reservoir. As a result, the solvent vapourises together with the steam. In the boundary of the steam chamber, the solvent distills and dissolves into the bitumen. Consequently, the bitumen viscosity is greatly reduced due to two factors, i.e., the dissolved solvent and the heat from the steam. This mechanism is demonstrated in Figure 1. A good solvent should condense at the same condition with the water phase. Hexane is a solvent which has the closest vapourisation temperature with the steam, which is 215°C at the pressure of 2,200 kPa (Nasr, 2003).

Figure 1 The concept of hybrid steam-solvent injection (see online version for colours)



Shu (1984) investigated that mixing of solvents with bitumen reduces the viscosity drastically even at small concentration of solvent. For example, the viscosity of bitumen decreases from 1.2E6 cp to 1.0E5 cp by adding10% volume of solvent at the temperature of 25°C. If 20% of volume solvent is added to the bitumen, the viscosity is decreased to 1.05E4 cp. In conclusion, if the solvent concentration increases, the bitumen viscosity decreases exponentially.

Small amount of injected solvent, which composition is from C_1 to C_8, will accelerate the production rate. The highest production rate can be obtained by injecting hexane and diluents (Nasr and Ayodele, 2006). The low pressure of approximately 500 kPa with adequate solvent concentration, mostly at low concentration, yields better results than those that are operated at higher pressure of approximately 2,100 kPa (Ayodele et al., 2009; Mohebati et al., 2009). However, for hexane cases, it will be beneficial to operate at pressure ranging from 1,500 kPa to 3,500 kPa (Mohebati et al., 2012). Four majors that strongly affect a hybrid steam-solvent process are operating condition, reservoir fluid composition, the heavy oil viscosity, and petrophysical properties of the reservoir (Mohebati et al., 2009, Ardali et al., 2012).

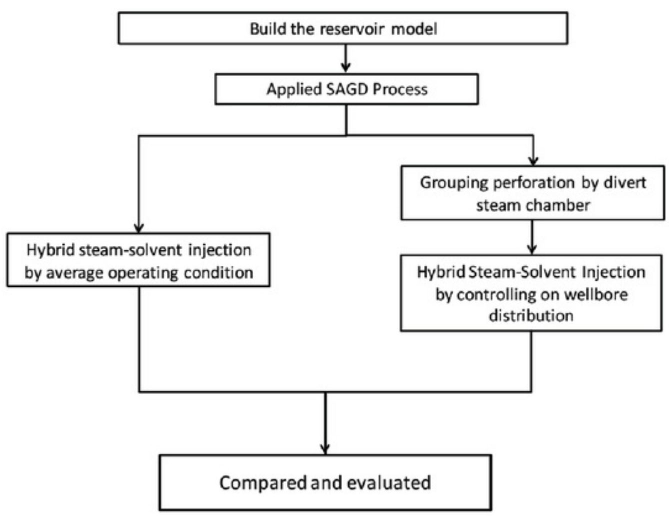
Optimising the process in heterogeneous reservoirs is difficult due to the permeability variation. The reservoir part in the length of the wellbore could be optimised individually. Here, it needs steam distribution with different injection pressures to obtain a uniform steam chamber. The higher permeability region needs lower injection pressure and the lower region needs higher pressure. In the production well, the higher permeability zone receives higher drawdown while the lower zone get slower drawdown. In order to improve the steam injection conformance and the producer different steam-trap control, a wellbore segmentation is required and the interval control valve (ICV) can be used (Shaw, 2012). In such a case, the cumulative steam oil ratio (cSOR) will decrease and the recovery factor will increase. Meanwhile, the ICV is controlled from the surface by electric or hydraulic line. The number of ICVs is proportional to the control line; but, too many control lines will possibly make the system complicated and the valve failure (Cullick, 2010). On the other hand, the tubing volume is reduced because of the ICV equipment and accordingly the well capacity is reduced causing the pressure drop in the wellbore to increase (Al-Khelaiwi, 2010).

There have been several experiments and simulations studies that relate to the hybrid steam-solvent injection performance. However, the impact of controlling the steam-solvent injection in heterogeneous reservoirs to maximise the recovery and minimise the solvent retention has not been well explained and documented in the literature. As a matter of fact, the steam chamber propagates unequally into each part of the reservoir. In the case of poor steam chamber, the solvent goes through the production well directly and the solvent effectiveness is useless accordingly. In the case of good steam chamber, the oil drain is effective but the steam-solvent will be ineffective after the steam reaches its maturity because of the reduced remaining reserve. This study addresses the adjustment of the hybrid steam-solvent injection operations in order to spread the steam chamber uniformly. The effects of this adjustment are discussed in detail.

2 Maximising the hybrid steam-solvent injection performance

Figure 2 shows the process used in this work. First, a basic reservoir model is built. After that, a pure-steam SAGD is applied to the model. Sensitivity analyses of operating conditions are conducted to find the optimum condition which has a high recovery factor and a low cumulative steam oil ratio (cSOR). The injection pressure is selected to be appropriate with targeted temperature. If a certain optimum condition is achieved, then the hybrid steam-solvent injection is applied.

Figure 2 Flowchart of the methodology in this study



There are two cases in the hybrid steam-solvent application. First, an average operating condition is used which means that the injection pressure is the same along the length of the injection well and the bottom hole pressure is the same along the length of the production well. Second, the steam-solvent injection control along the length of the injection well is applied. The reservoir is divided into several sections based on the propagation characteristics of the steam chamber. In the sections which the propagation of the steam chamber is good, the steam injection is stopped periodically while in the poor regions, the steam injection is continued. The two cases are compared and evaluated.

3 Reservoir model

A thermal reservoir simulator, STARS Version 2012 (CMG, 2012), is used to construct the reservoir model and to investigate the performance of the hybrid steam-solvent injection. The used reservoir data of McMurray Formation is described in Table 1. The model is three-dimensional containing one pair of wells at the centre. The model was built through geostatistical modelling for porosity, permeability, and oil saturation distributions and was validated using data obtained from several wells.

Table 1 Key reservoir simulation parameters used in this study

Reservoir properties	*Value*
Initial reservoir temperature, °C	12
Initial reservoir pressure at injection well depth, kPa	2,105
Depth of injection well, m	215
Bitumen viscosity at 100°C, cp	260
Bitumen viscosity at steam injection temperature (220°C), cp	5.7
Bitumen viscosity correlation	A_{visci} = 2.3693E–5
[$\mu_i = A_{visci} \cdot \exp(B_{visci}/T_{abs})$] (CMG, 2012)	B_{visci} = 6,046.7035
k_v/k_h	0.7
Residual oil saturation (s_{orw})	0.15
Connate water saturation (s_{wc})	0.15
Residual oil for gas-liquid (s_{org})	0.01
Connate gas saturation (s_{gc})	0.05
k_{rw} at reducible oil saturation	0.3
k_{ro} at connate water saturation	1
k_{ro} at connate gas saturation	1
k_{rg} at residual oil saturation	1
Underburden/overburden heat capacity, kJ/m^3°C	2,600
Underburden/overburden thermal conductivity, kJ/m-day°C	660
Bitumen thermal conductivity, kJ/m day°C	11.5
Hexane K-value correlation,	Kv1 = 1.01E+6 kPa
$\text{K-value} = \frac{kv_1}{p} e^{\frac{k_{v4}}{T+k_{v5}}}$	Kv4 = –2,697.55°C
	Kv5 = –224.37°C

There were no gas cap and bottom water driving mechanisms. The boundary condition was no-flow. The geo-mechanicals effects such as dilation related to pressure or temperature were also ignored. Due to the limited data, only porosity, permeability, and oil saturation were modelled to be heterogeneous, whereas the other parameters such as thermal conductivity, heat capacity, and fluid properties were assumed to be homogeneous.

Mixing of solvents with bitumen reduces the bitumen viscosity rapidly, even at small amount of solvent, as a result of solubility. The ratios of the mole fraction of each solvent in the vapour to the liquid phase are represented by K-values. In such blend, only the soluble solvent will reduce the bitumen viscosity while the vapour fluid will slightly increase the pressure. The reservoir simulation works in the both fluids. The K-value is a function of temperature, pressure, and some coefficients as shown in Table 1. In this study, the coefficient of Kv_1, Kv_2, Kv_3, and Kv_5 refer to the STARS manual (CMG, 2012).

Figure 3 3D view of reservoir permeability, porosity, and oil saturation model (see online version for colours)

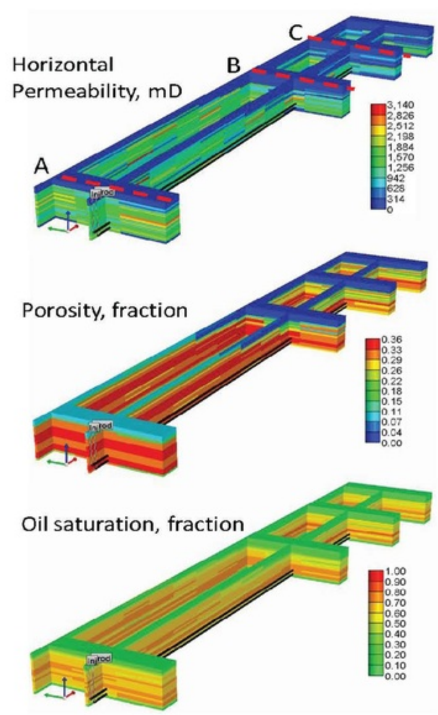


Figure 3 illustrates the permeability, porosity, and oil saturation distribution in the 3D form. The left part of the reservoir (Cross Section A) is very permeable while the right part (Cross Section C) is gradually tighter. The distributions of porosity and oil saturation follow the similar pattern. The production well is two metres above the bottom of the reservoir and the injection well is five metres above the production well. The thickness of the reservoir is 30 metres, the width is 110 metres, and the length is 750 metres. The total grid number is 30 × 44 × 15 (*i*, *j*, *k*) and the grid size is 25 m in i-direction, 2.5 m in j-direction, and 2 m in k-direction. To generate detailed data in the near-wellbore region, the grid blocks are refined to the size of 12.5 m × 1.25 m × 1 m. The initial pressure is 2,105 kPa, which is determined from the normal hydrostatic pressure gradient of 0.433 psi/ft at the depth of 215 m at the injection well location.

Preheating period is about six months and the temperatures in both of the wells are set to be 230°C. During this process, the heat is transferred via conduction mechanism to the surrounding wells and both the production and injection wells are connected hydrodynamically. After preheating, the wells are switched to become injection and production wells. The steam injection is operated at constant pressure at the sand face with a steam quality of 0.9. In order to achieve an optimum condition, the steam injection pressure and liquid production rate are varied. The control of hybrid steam-solvent distribution along the length of the horizontal well is done by closing and opening the perforations and also by changing the operating conditions. In the field cases, controlling the hybrid steam-solvent injection and liquid production rate can be done by using tubing valves, e.g., using ICVs.

4 Results and discussion

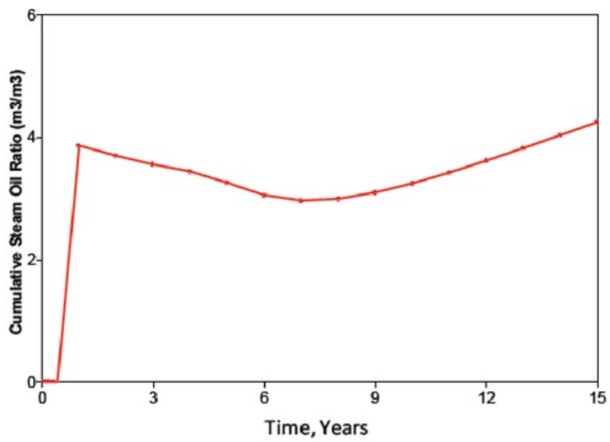
4.1 Base case model

The same operating condition is applied along the length of the horizontal wellbore. For this model, the optimum scenario was achieved in which the injection pressure was 2,500 kPa, the liquid production rate was 400 m^3/day, the cSOR was from 2.9 to 4.3 [Figure 4(a)] and the recovery factor was approximately 50% [Figure 4(b)]. Figure 5 shows the temperature distribution in the reservoir which is identical to the shape of the steam chamber propagating in the reservoir at the end of the project life.

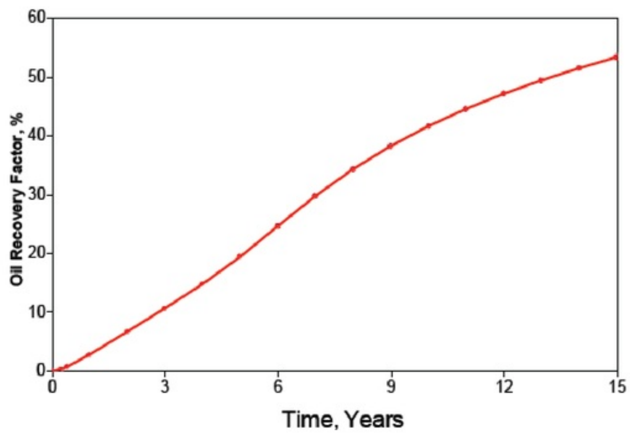
4.2 Controlling the hybrid steam-solvent injection

Based on the result of the Base Case Model, the reservoir zones are classified into two groups each of which has high-steam-penetration (Zone A and Zone C) and low-steam-penetration (Zone B, Zone D, and Zone E). In order to control the steam-solvent distribution, the good-steam-chamber zones are closed and opened periodically, while the poor-steam-chamber zones are opened continuously. The steam injection pressure and liquid production rate, in the case of which all the zones are opened, are 2,500 kPa and 400 m^3/day, respectively. While in the case of which the good-steam-chamber zones are closed and the poor-steam-chamber zones are opened, they are 2,700 kPa and 450 m^3/day, respectively. When the injection perforations are closed, the production perforations, which are directly opposite to them, are opened and vice versa. Only for the case of goodsteam-chamber, the zones are closed for a certain period of time then are opened for the next same period of time. A cycle of three months is applied for this repetitive adjustment process, started either from the beginning of the injection or after the peak of production rate is achieved. Table 2 shows the two scenarios of the base case and the adjustment.

Figure 4 Result of the base case model, (a) cumulative steam oil ratio (CSOR) and (b) oil recovery factor (see online version for colours)



(a)



(b)

Figure 5 The result of the base case model – temperature distribution in the pure steam process at the end project life (see online version for colours)

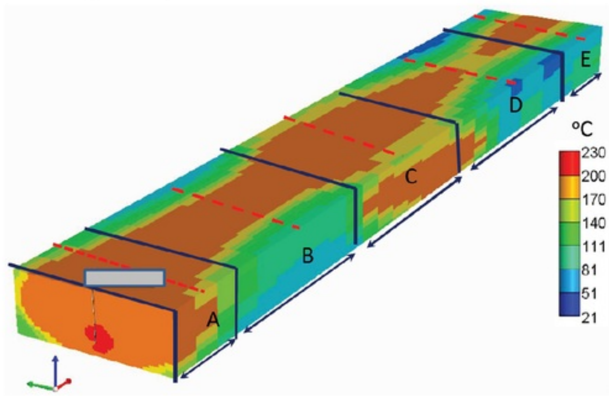


Table 2 The scenarios for adjustment of steam-solvent injection and operating condition

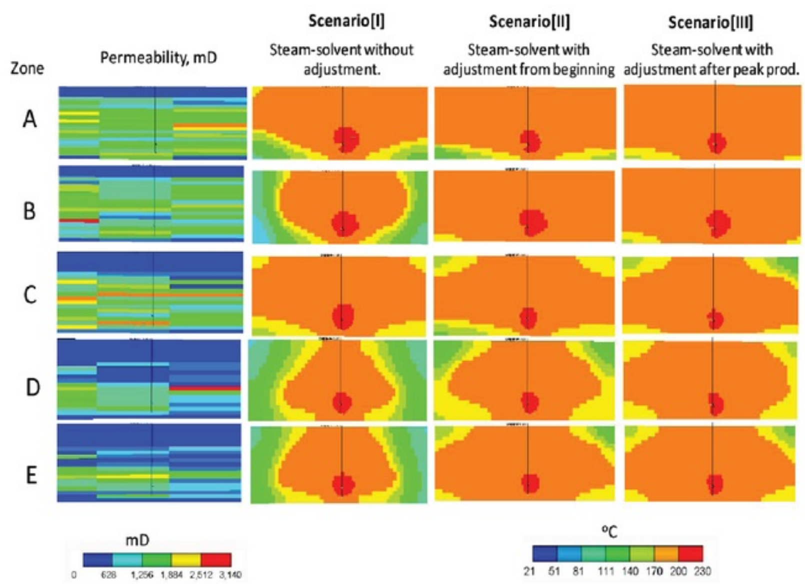
Zone/operating condition	*Base case operation*		*Adjustment*	
	Injection well	*Production well*	*Injection well*	*Production well*
A	Open	Open	Close	Open
B	Open	Open	Open	Close
C	Open	Open	Close	Open
D	Open	Open	Open	Close
E	Open	Open	Open	Open

Figure 6 demonstrates the gradual propagation of the simulated steam chamber into each zone for each scenario. There are three injection scenarios namely [I] 10% of solvent without the adjustment, [II] 10% of solvent with the adjustment from the beginning of the injection and [III] 10% of solvent with the adjustment starting after the peak of production rate is achieved. From the comparison, it can be seen that the steam chambers in Scenario [II] are generally wider than those of Scenario [I]. In Scenario [I], smaller steam chambers are found in Zone B, Zone D and Zone E leading to less solvent distribution into the bitumen. The use of solvent at these zones is ineffective because its movement is limited only to the upper side of the reservoir. It then condenses and goes toward the production well together with the condensed water.

Meanwhile, in Scenario [II] and [III], the steam chambers are rather more uniform. The steam chamber propagation for the two scenarios does not indicate significant difference. In this case, the alternate opening and closing perforations result in better steam chamber propagation. When the injection perforations are opened and the opposite production perforations are closed, the steam-solvent cannot move directly into the productions but instead it migrates diagonally; in other words, it propagates further into the reservoir. It will take more time for the steam-solvent to reach the production well and thus it will retain longer in the reservoir. The process will be more favourable if the injection pressure and liquid production rate are increased.

It is also found that the injection is even more effective if the adjustment is made after the production rate peak is reached. In such a case, the steam chamber will grow up into the more uniform permeability regions. After that, it will divert to penetrate the poor steam chamber regions; and therefore the steam chamber will be more uniform as it is demonstrated in Figure 5. Generally, the poor steam chamber occurs in low permeability and oil saturation regions. Therefore, it is understandable that in this zone, the steam efficiency is lower than those in the higher-permeability zones. Even so, the operation must be done any way for the steam to be distributed uniformly into the low permeability zone. It still has benefit compared without adjustment because in the excellent steam chamber, the remaining reserve of bitumen has been poor. Figure 6 shows the recovery factor for each scenario. As can be seen, the recovery factor is 8% higher in the two adjustment cases compared with that of the no-adjustment case.

Figure 6 The injection scenarios – comparison of temperature distribution in zones after pure steam and hybrid steam-solvent injections (see online version for colours)



There are three governing terms in the hybrid steam-solvent injection process. The first is the cumulative energy oil ratio (cEOR), which is defined as the sum of enthalpy, generated from the steam injection and utilised for producing bitumen per unit volume. The second is the cumulative solvent oil ratio (csOR) that is the amount of solvent needed to be injected to obtain the bitumen production per unit volume. The third is the solvent retention recovery (sRR) that is the amount of solvent recovered after the injection. Table 3 shows the result of simulations while Figure 8 shows comparison of the three terms for the three scenarios. Compared with the scenario of which the adjustment is made after the peak production is reached, the energy consumption for the scenario of which the adjustment is made right from the beginning is higher. But, it is lower compared with the no-adjustment scenario [Figure 8(a)]. Besides, the cumulative bitumen production is higher for the scenario of which the adjustment is made after reaching the peak of production compared with that of the other two cases (Table 3). To obtain 1 m^3 of bitumen, with 10% solvent by volume fraction, 7.3 GJ of energy per m^3 bitumen is needed. The required energy is reduced to approximately 7.10 GJ/m^3 if an adjustment is made right from the beginning and to approximately 6.80 GJ/m^3 if the adjustment is made after the peak of production is reached. Making the adjustment after reaching the peak of production rate is more favourable because the steam chamber has reached its maximum penetration or, in other words, the steam has reached its maturity. The adjustment is made for the purpose of spreading the steam chamber, allowing it to penetrate into non-uniform permeability regions. In the scenario, in which the adjustment is made from the beginning, the steam has not fully penetrated into the uniform permeability region. It stops and diverts into the non-uniform permeability region. As a result, the steam chamber will be collapsed. If the steam is diverted into the uniform permeability region again, the steam chamber will propagate slowly, and thus the effectiveness of steam is significantly reduced.

Table 3 Summary of results of the three scenarios

No.	*Scenario*	*Energy used (GJ)*	*Cum. bitumen prod. (m^3)*	*Cum. sol. inj. (m^3)*	*Cum. sol. prod (m^3)*
1	No-adjustment	3.37E+06	460,790	146,600	104,252
2	Adjust. from beginning	3.55E+06	498,091	154,342	127,699
3	Adjust. after peak of prod.	3.41E+06	500,870	148,350	123,083

Figure 7 Recovery factor comparison after injection with and without adjustments in hybrid steam-solvent injection (see online version for colours)

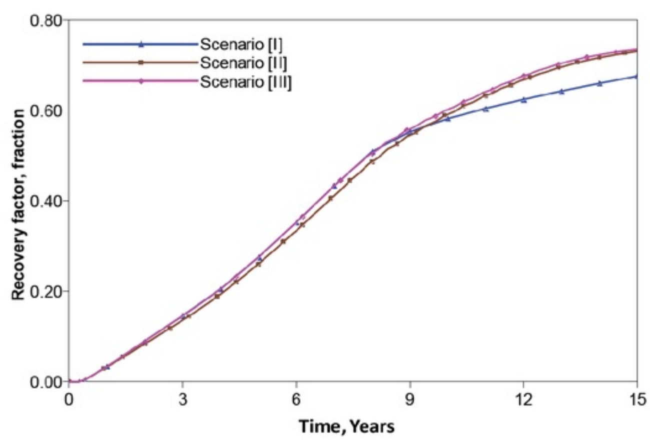
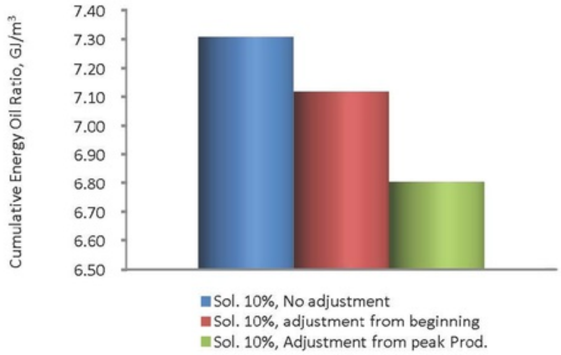
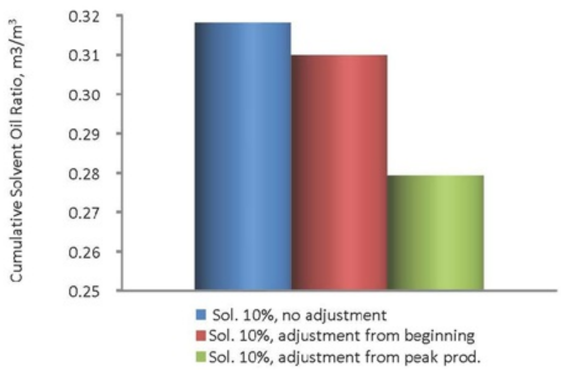


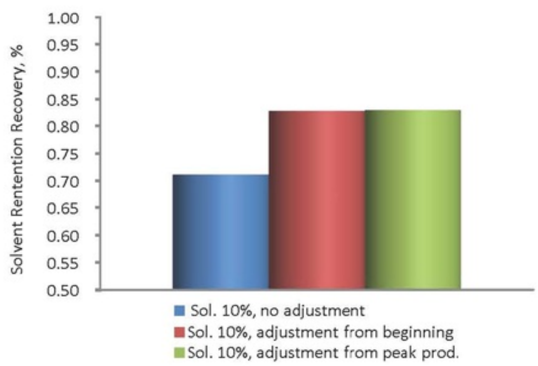
Figure 8 Comparison of (a) cEOR, (b) csOR, and (c) solvent retention in the hybrid steam-solvent injection of the three scenarios (see online version for colours)



(a)



(b)



(c)

The csOR of the no-adjustment case is approximately 0.32 m^3/m^3 compared with approximately 0.31 m^3/m^3 in the adjustment-from-the-beginning scenario [Figure 8(b)]. Thus, the difference is not significant between the two cases. However, there is a striking difference of approximately 12.5% between the adjustment-from-the-beginning and the adjustment-after-the-peak-production scenarios. Comparing Figure 8(a) with 8(b), it is clearly shown that the csOR behaviour is similar to that of cEOR because the solvent concentration does not change. On the other hand, the sRR of the no-adjustment case of approximately 72% is considerably lower compared with those of the cases with adjustments of approximately 83%. Note that the difference in sRR is not significant in the scenarios when the adjustment is made. In the steam injection process, when the injection perforations are closed, the bitumen production is faster compared with that when the injection perforations are continuously opened. However, this process is limited by the time because the production rate will suddenly drop when the heat and pressure decreases. Therefore, the scenario of alternately open and close the perforation plays an important role to obtain the injection efficiencies and/or maximum recovery.

4.3 Simple economic analysis

The economic analysis uses a common set of general assumptions in SAGD projects. The exploration cost is \$0.2E6 per well pair. The well costs are assumed to be \$0.9E6 for thermal well and \$0.45E6 for non-thermal well. The steam generation capital cost is \$2.05E6 for a 430 m^3/day-capacity generator. The water treatment capital cost is \$2.45E6 for a 400 m^3/day-capacity plant. The solvent capital cost is \$100 k. The solvent handling cost is \$20 k/year/well and the solvent recompression cost is \$0.17/std m^3 (Frauenfeld et al., 2006). The natural gas cost is assumed to be \$4.33/GJ. Other assumptions include the water treatment cost is \$1/barrel of water production, the fixed cost is assumed to be 0.9 MM \$/year, the interest rate is 12% per annum, the bitumen price is \$60/barrel, the hexane price is 1.5 times of the bitumen price or \$90/barrel. The cost of ICV equipment installation is \$1.0E6 (Botechia, 2014). The ICV installation cost is added in the first year for the adjustment from the beginning case and it is added in the seventh year for the adjustment from the peak of production rate case. To calculate the cash flow, the equation below is used:

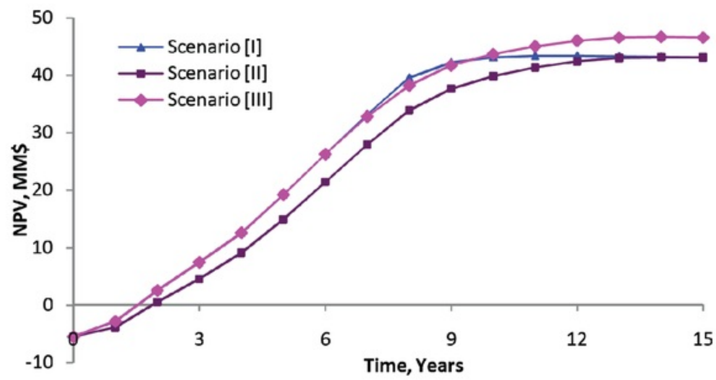
$$\begin{aligned} \text{NCF} = {} & [\text{Gross revenue}] \\ & -\big[\text{Well cost (thermal well + non-thermal well} + \text{exploration cost)}\big] \\ & -[\text{steam generation cost}] - [\text{water treatment capital cost}] \\ & -[\text{solvent capital cost}] - [\text{solvent handling cost}] \\ & -[\text{natural gas cost + water production treatment cost} \\ & \quad + \text{solvent usage cost}] \\ & -[\text{fixed cost}] - [\text{ICV equipment installation cost}] \end{aligned} \tag{1}$$

and

$$NPV = \sum_{t=0}^{N} \frac{NCF_t}{(1+i)^t} \tag{2}$$

Figure 9 shows the net present value (NPV) for the three scenarios. There is no significant difference in the NPV between Scenario [I] and Scenario [II] while the NPV of Scenario [III] increases by approximately \$3.60E6. Whereas the recovery factor of Scenario [II] and Scenario [III] is almost the same, the start of production rate in Scenario [III] is better. Figure 7 shows that from the beginning to the ninth year, the bitumen production in Scenario [II] is lower than that in Scenario [I] even though the injection in Scenario [II] has been controlled. For the two cases, beside the difference in the time investment, the production rate in Scenario [III] is better. Also, the NPV of Scenario [III] is 9% higher compared to that of Scenario [II]. It follows that the adjustment of the steam-solvent injection is more favourable if it is done after the peak of production rate.

Figure 9 Comparison of net present value in each scenario (see online version for colours)



The single operating condition in the conventional SAGD is simpler and more efficient compared to the injection and production scheme with adjustment procedures. However, the bitumen contained within difficult areas such as that of low permeability is often not recovered. There are same complicated processes in the injection and production scheme using zone selection controlled by opening and closing the ICV. One major problem is valve not working resulting from broken hydraulic line or valve failure. Meanwhile, the ICV equipment price and timing of installation must be carefully considered to obtain favourable economy. A mistake in the installation timing will result in the NPV to reduce even when the recovery factor at end of project life is increased. In field cases, the timing to open and close the ICV, valve failure, broken hydraulic line, inaccurate zone selection make the mission to fail. Furthermore, reservoir heterogeneity understanding and detailed planning are certainly needed to make the project successful.

5 Conclusions

This study demonstrates the effects of controlling the hybrid steam-solvent injection in heterogeneous reservoirs. Adjusting the injection starting from the peak of bitumen production, or when the steam chamber has reached its maturity, is favourable compared with the case when the adjustment is made from the beginning. In this case, 1 closing the injection perforations periodically in the good-steam-chamber regions,

2 opening the injection perforations continuously in the poor-steam-chamber regions,

3 when the injection perforations are closed, the production perforations, which are directly opposite to them, are opened and vice versa, result in the steam chamber to spread more uniformly.

This is because the steam-solvent cannot move directly into the productions but instead it migrates diagonally and propagates further into the reservoir. It takes more time for the steam-solvent to reach the production well or, in other words, it retains longer in the reservoir. As illustrated by the reservoir simulation, controlling the hybrid steam-solvent injection along the length of the horizontal wellbore increases the recovery factor by 8% compared with that of the no-control scenario. Furthermore, the solvent effectiveness increases by 12.5% and the solvent retention reduces by 11%. Economically, the installation of ICV after the peak of production rate provides better results among the studied cases. In such a way, the NPV increases approximately 9% compared to that of no adjustment case. It then follows that controlling hybrid steam-solvent injection provides significant advantages to the bitumen production process.

Nomenclature

SAGD	Steam assisted gravity drainage
ICV	Interval control valve
cSOR	Cumulative steam oil ratio
cEOR	Cumulative energy oil ratio
csOR	Cumulative solvent oil ratio
sRR	Solvent retention recovery
NCF	Net cash flow
NPV	Net present value
P	Pressure
T	Temperature
K-value	Ratio of the solvent mole fraction in the vapour and liquid phase
k_{v1}, k_{v2}, k_{v3}, k_{v5}	Constant coefficients

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