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# Feasibility Study on Steam and Gas Push with Dual Horizontal Wells in a Moderate-Depth Heavy Oil Reservoir

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***Abstract***

Non-condensable gas (NCG) with steam co-injection makes steam assisted gravity drainage less energy-intensive as well as reduces greenhouse gas emission and water consumption. Numerous studies have shown that the technology called steam and gas push (SAGP) is feasible for heavy oil and bitumen. However, most of these studies have focused on shallow heavy oil reservoirs and only a few works have investigated moderate-depth heavy oil reservoirs. In this study, laboratory experiments and numerical simulations were conducted to study shape change, steam chamber expansion, and temperature change after co-injecting NCG with steam into an actual moderate-depth heavy oil reservoir. Results showed that after co-injecting NCG with steam, the transverse expansion rate of the steam chamber accelerated, vertical expansion slowed down, thermal utilization increased, and oil–steam ratio improved. In addition, the injection parameters of SAGP were also optimized via numerical simulation, which indicated that SAGP could effectively improve development effect and recovery for moderate-depth heavy oil reservoirs.

*Keywords*: Non-condensable gas (NCG), steam assisted gravity drainage (SAGD), steam and gas push (SAGP), moderate-depth heavy oil reservoirs

## 1. Introduction

Steam assisted gravity drainage (SAGD), which was developed in the late 1970s and the early 1980s, was a revolutionary breakthrough in the development of heavy oil and bitumen. SAGD is a successful example that combines thermal recovery technology and horizontal well technology; it is also an effective means to develop heavy oil and bitumen [1]. During SAGD, steam is injected continuously into an oil layer through an upper horizontal well, and a steam chamber is formed in the reservoir. As the chamber expands, an increasing amount of crude oil is heated and its viscosity is reduced. Heated oil and steam condensate at the chamber surface and flow down to a lower production well because of gravity until it is finally recovered (as shown in Figures 1 and 2).

To improve economic performance and reduce energy consumption, reservoir engineers have proposed several corresponding technologies based on SAGD to improve the development effect of this process. One example of these technologies is steam and gas push (SAGP).

The process of injecting non-condensable gas (NCG) with steam is called SAGP. This procedure was described in the Canada Petroleum Conference by Butler. Since its introduction, SAGP has received considerable attention. Butler and Yee (1986) conducted physical model experiments that confirmed that adding a small amount of NCG had a beneficial effect on SAGD primarily because of the gas-insulation effect [3]. Kisman and Yeung (1995) pointed out that a small amount of NCG injected with steam in SAGD would improve heavy oil development; however, a large amount would be detrimental [4]. Ito et al. (2001) proved the observations of Butler through a numerical simulation by adding hydrocarbon gas in SAGD. Their research indicated that final recovery would be reduced if gas was co-injected with steam in the early SAGD stage; however, SOR would be improved in the late SAGD stage [5]. Yuan et al. (2006) determined that NCG accumulated at the interface and at the top of the reservoir based on large-scale laboratory experiments [6]. Bagci (2008) pointed out that injecting $CO_2$ in SAGD could improve the oil recovery factor [7]. Murayri (2011) studied the effects of naturally occurring as well as continuously and intermittently co-injected NCG at different stages of SAGD via numerical modeling [8]. Yuan (2011) and Ji (2011) studied NCG distribution in the SAGD chamber through reservoir simulation; they pointed out that NCG mainly accumulated on top of the reservoir and effectively suppressed the heat loss of steam [9], [10]. According to different reservoirs and injection, Li (2011) and Sharma (2012) studied the development effect of SAGP and determined that higher oil recovery factor could be achieved by SAGP [11], [12]. Mohebati (2012) separately optimized hydrocarbon additives in SAGD for three different oil–sand deposits and determined the appropriate amount of hydrocarbon injection [13]. Dehghan (2013) optimized the manner of development on the base of an actual heavy oil reservoir for steam–propane injection [14]. Dong (2015) indicated that SAGP was also applicable to thick heavy oil reservoir [15]. Hossein (2015) provided insights into the field scale simulation of NCG injection in a hybrid SAGD process using a comprehensive numerical simulation model [16].

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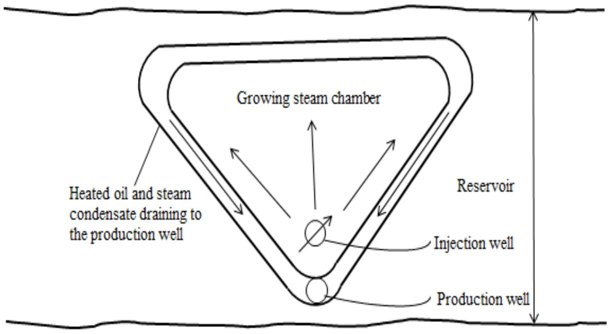


**Fig.1.** SAGD production mechanism

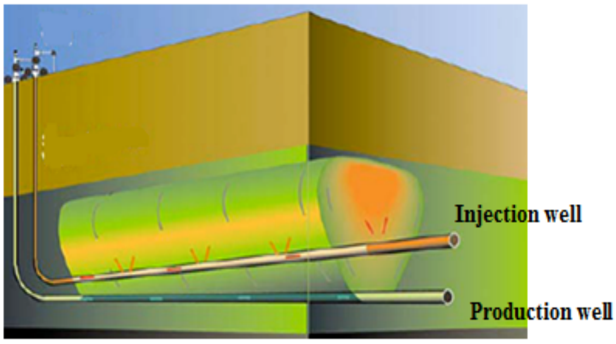


**Fig.2.** Sketch of SAGD construction

## 2 Description of the problem

SAGP has been adopted in several countries, such as Canada, for many years. However, most of the reservoirs that apply this technology belong to the shallow category, with depths less than 500 m. By contrast, the heavy oil reservoir in Liaohe Oilfield is approximately 1000 m, and thus, belongs to the deep reservoir category. Therefore, studying the feasibility of SAGP in moderate-depth heavy oil reservoirs is necessary. For convenience, the reservoir in Liaohe Oilfield was reclassified according to depth. The depth of shallow reservoirs is below 600 m, whereas that of deep reservoirs is more than 1300 m. Reservoirs with depths in between are classified as moderate-depth heavy oil reservoirs. The object of this study is the feasibility of SAGP in moderate-depth heavy oil reservoirs.

This study mainly investigates drainage theory of SAGP, indicates that SAGP can improve the development effect of SAGD in Liaohe Oilfield based on two sets of laboratory experiments, and optimizes the injection parameters of SAGP using a large number of STARS simulation models. To compare the results of the physical experiment and the numerical simulation, the same data, including pressure, temperature, porosity, initial oil saturation, rock thermal properties, etc., based on the X6 moderate-depth reservoir in Liaohe Oilfield were used in both the physical and simulation models. The results can provide guidance for the development of similar moderate-depth heavy oil reservoirs.

## 3. Reservoir simulation methodology

### 3.1 SAGP development mechanism

Numerous physical experiments and numerical simulations have shown that apart from the mechanism of heating oil and reducing oil viscosity, SAGP has other development mechanisms. The main advantages of SAGP are as follows.

(1) Reducing heat loss

In SAGP, NCG accumulates at the top of the steam chamber to form a gas zone. The zone can function as a barrier to reduce heat loss in the cap layer.

(2) Maintaining pressure

In SAGP, NCG plays a vital role in maintaining pressure in the steam chamber and reduces the requirement for high-temperature steam in the recovery process.

(3) Energy (temperature and pressure) distribution and flooding mechanism

In SAGP, NCG does not carry too much heat to the top of the steam chamber, but increases pressure on top of the steam chamber and provides an impetus to displace oil downward.

(4) Gas fingering

Co-injected NCG causes fingering and improves the flow capacity of the steam front.

### 3.2 Laboratory experiment reservoir parameter scaling

The high-temperature, high-pressure horizontal well pairs for the SAGD physical model was proportionally designed and built based on the similarity criterion. However, satisfying all the criteria required to design scaled laboratory experiments of SAGD is difficult, particularly when NCG is injected. The similarity criterion applied in this study is the criterion published by Butler. In this criterion, all the fluid properties, rock thermal properties, and pressure temperature conditions for the laboratory experiments are the same as the field conditions. Therefore, Equations 3 and 5 can be rewritten by combining Equations 1, 2, and 4.

B3 Key similarity criterion: This criterion guarantees a similar extended process of the SAGD steam chamber; it is used to implement the transformation of permeability between the physical model and the prototype.

$$B_3=\left(\sqrt{\frac{mkgh}{\phi\Delta S_o\alpha m\upsilon_s}}\right)_{field}=\left(\sqrt{\frac{mkgh}{\phi\Delta S_o\alpha m\upsilon_s}}\right)_{model} \tag{1}$$

$$(kh)_{field}=(kh)_{model} \tag{2}$$

$$k_{model}=\left(\frac{h_{field}}{h_{model}}\right)k_{field} \tag{3}$$

$t_D$ Dimensionless production time: This criterion is used to implement the transformation of time between the physical model and the prototype.

$$t_D=\left(\frac{t}{w}\sqrt{\frac{kg\alpha}{\phi\Delta S_o m\upsilon_s}}\right)_{field}=\left(\frac{t}{w}\sqrt{\frac{kg\alpha}{\phi\Delta S_o m\upsilon_s}}\right)_{model} \tag{4}$$

$$t_{model}=\left(\frac{h_{model}}{h_{field}}\right)^2 t_{field} \tag{5}$$

**Table 1.** Geological and fluid parameters of the prototype and the model

| Parameter | Prototype | Physical model |
|---|---|---|
| Reservoir thickness, (m) | 45 | 0.3 |
| Reservoir width, (m) | 90 | 0.6 |
| Reservoir length, (m) | 90 | 0.6 |
| Production–injection well spacing, (m) | 6 | 0.04 |
| Distance from the production well to the bottom of the reservoir, (m) | 3 | 0.02 |
| Porosity | 0.32 | 0.32 |
| Permeability, (μm$^2$) | 2.1 | 300 |
| Initial oil saturation | 0.8 | 0.8 |
| Initial reservoir pressure, (MPa) | 7.3 | 7.3 |
| Initial temperature, (°C) | 32 | 32 |
| Steam injection temperature, (°C) | 250 | 250 |
| Steam quality | >0.8 | >0.8 |
| Oil viscosity, (mPa•s at 50 °C) | 13540 | 13540 |
| Rock heat capacity, (J/m$^3$) | $2.28\times10^6$ | $2.28\times10^6$ |
| Rock conductivity, (J/m•d) | $1.63\times10^5$ | $1.63\times10^5$ |
| Oil conductivity, (J/m•d) | $1.15\times10^4$ | $1.15\times10^4$ |
| Water conductivity, (J/m•d) | $5.35\times10^4$ | $5.35\times10^4$ |

The ratio of the characteristic length of the laboratory experiment model to the same length under field condition is 1/150; therefore, 23 minutes of experiment time will be equivalent to 1 year in the field. Based on the reservoir data of horizontal well pairs in the SAGD pilot test area of the X6 moderate-depth reservoir in Liaohe Oilfield, we transformed the prototype into a physical model according to the similarity criterion and established a 3D model, as shown in Table 1.

### 3.3 Laboratory experiment process

The equipment used in the experiments includes an overburden pressure system, a steam injection system, a recovery system, and a data acquisition system. Figure 3 shows the experimental procedure, whereas Figure 4 shows the 3D model entity of the high-temperature, high-pressure physics simulator. Model entity includes three parts: cap rock, reservoir, and bottom rock. The model can perform different thermal physical tests under high temperature and high pressure, such as cyclic steam stimulation, steam flooding, SAGD, SAGP, etc.

Temperature monitors were arranged in the layer. Thermocouples were also arranged in the cap rock and in the bottom rock to monitor heat transfer to the outside of the reservoir. A data acquisition system was used to collect the output of the production liquid.

The main materials included crude oil from the X6 moderate-depth reservoir, configured water according to the actual components of the connate water from the X6 reservoir (salinity range was 2000–3000 mg/L), distilled water, quartz sand, and high-pressure $N_2$.

The experiment steps are as follows:

(1) First, the model was vacuumed and saturated with brine, and then with oil.

(2) Under reservoir conditions, the cyclic steam stimulation created thermal communication between two horizontal wells. Oil recovery was approximately 17% in the preheat stage, and the temperature between the two horizontal wells was higher than 100 °C.

(3) The process was turned to SAGD after the preheat stage. Steam injection rate was 180 mL/min, and the injection temperature of slightly superheated steam was 250 °C. SAGD production lasted for 330 minutes.

(4) Two sets of experiments exhibited the same operation process during the preheat stage. NCG, namely, $N_2$, will be injected with steam after the preheat stage in SAGP. The proportion of $N_2$ is equivalent to 40% of the steam volume (cold water equivalent), and production lasted for 330 minutes. Temperature data, as well as oil and water production, were monitored during the experiments.

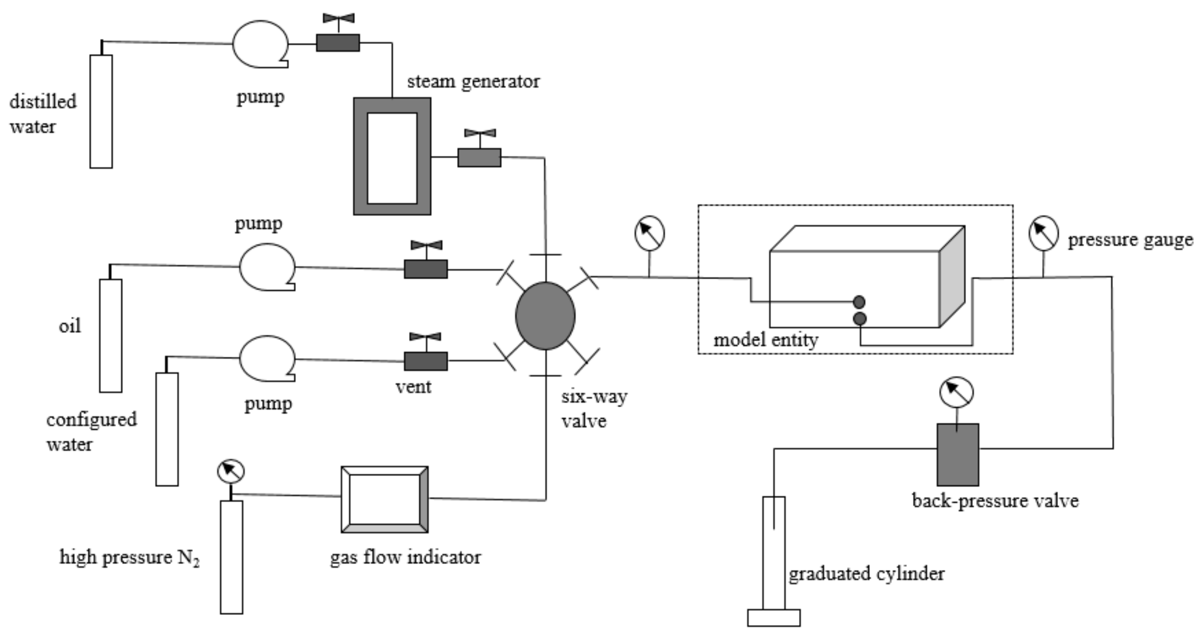


**Fig. 3.** Experimental flow diagram

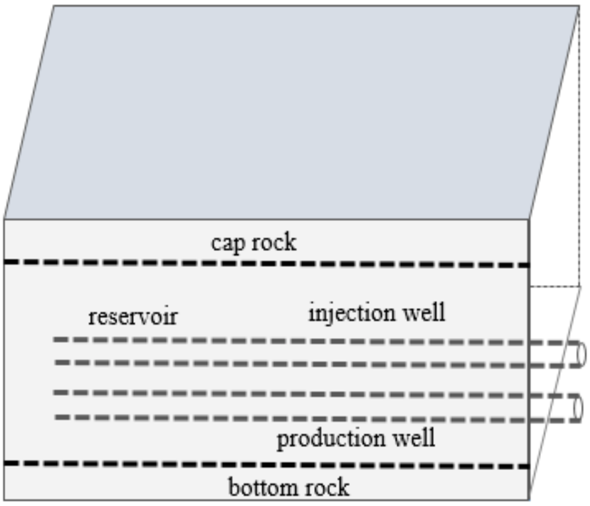


**Fig.4.** Equipment schematic of the physical model under high temperature and high pressure

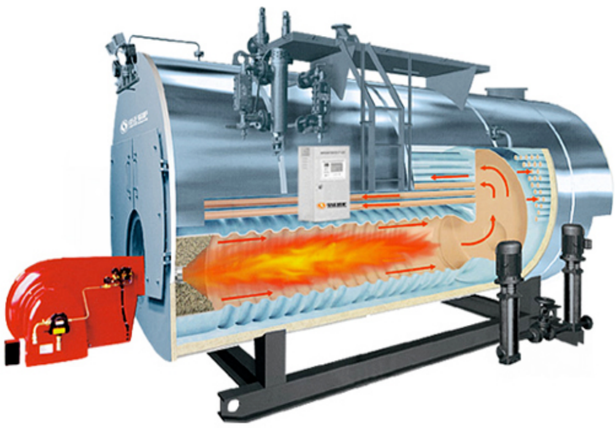

**Fig.5.** Equipment for SAGD

### 3.4 Numerical simulation model

In this study, the STARS model was used for the simulation. This 3D, four-phase, multi-component thermal recovery numerical simulator can verify the reserves; optimize the development methods, well patterns, and injection–production parameters; track the dynamic change of development; and predict the development index via simulation analysis. The parameters of the X6 moderate-depth reservoir are listed in Table 2. The simulation models assumed uniform reservoir properties. The dimensions of the domain are 98 m wide × 45 m thick × 400 m long. The grid used in the model, which is displayed as a stereogram in Figure 6, has 29,400 (49 m × 2 m + 20 m × 20 m + 30 m × 1.5 m) grid blocks. The SAGD well pair was positioned in the middle of the model. The steam injector was positioned roughly 6 m above the production well, which was located approximately 3 m above the bottom of the reservoir. The steam injection rate is 125 $m^3$/d and quality is 0.75 for the simulation cases. The viscosity–temperature curve is shown in Figure 7. All the simulation cases initially proceeded from the preheat stage to create thermal communication between two wells.

**Table 2.** Basic parameters of the reservoir and the fluid

| Parameter | Value |
|---|---|
| Top reservoir depth, (m) | 770 |
| Initial reservoir temperature, (°C) | 32 |
| Initial reservoir pressure, (MPa) | 7.3 |
| Crude oil density, (kg/$m^3$) | 980 |
| Porosity | 0.32 |
| Horizontal permeability, (μ$m^2$) | 2.1 |
| Vertical permeability, (μ$m^2$) | 1.1 |
| Rock heat capacity, (J/$m^3$) | $2.28\times10^6$ |
| Rock conductivity, (J/m•d) | $1.63\times10^5$ |
| Oil conductivity, (J/m•d) | $1.15\times10^4$ |
| Water conductivity, (J/m•d) | $5.35\times10^4$ |

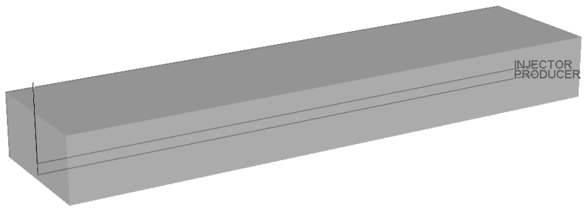


**Fig.6.** Model stereogram

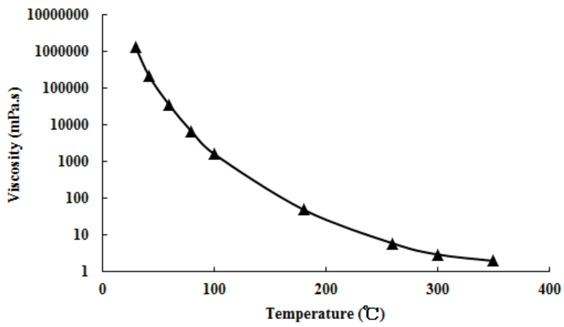


**Fig.7.** Viscosity–temperature curve

## 4 Results and discussion

The SAGP laboratory experiment models were used to investigate the following cases:
(1) Comparison of the temperature field;
(2) Comparison of the production effect.

### 4.1 Comparison of the temperature field

Figures 8–17 show the change in the temperature field for SAGP and SAGD. The results demonstrate that SAGP has a slower vertical expansion rate than SAGD. After co-injecting nitrogen with steam, nitrogen gradually floated and tended to accumulate at the top of the steam chamber. The gas zone served as a barrier layer to prevent heat exchange between steam and the cap rock effectively. This zone reduced the expansion rate of the steam chamber to the top, whereas most of the heat mainly acted on the rock on both sides of the steam chamber. Therefore, the SAGP steam chamber expanded more slowly in the vertical direction than SAGD and faster in the transverse direction. All these factors make SAGP more economical than SAGD. It also exhibited a higher SOR.

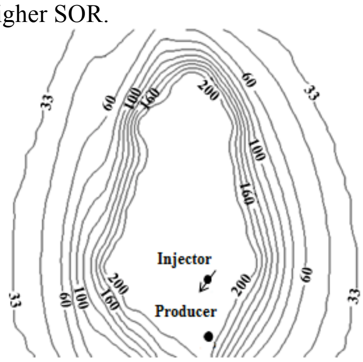


**Fig.8.** Middle plane temperature contour at 40 minutes in SAGD

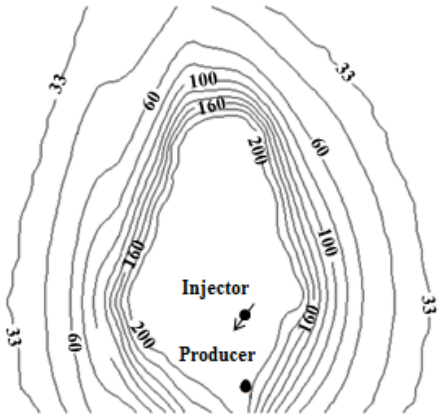


**Fig.9.** Middle plane temperature contour at 40 minutes in SAGP

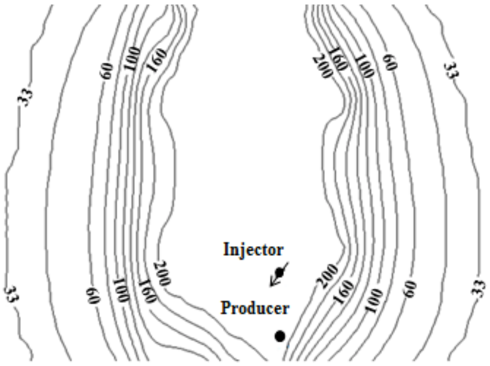


**Fig.10.** Middle plane temperature contour at 100 minutes in SAGD

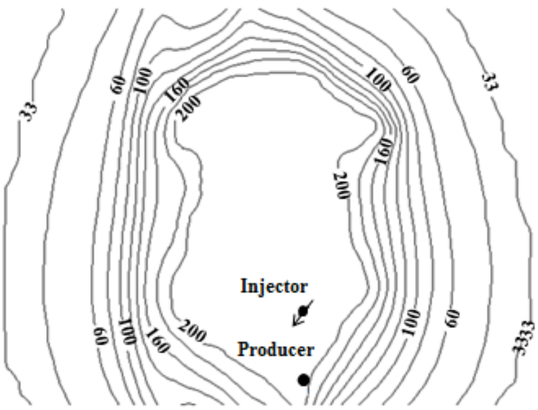


**Fig.11.** Middle plane temperature contour at 100 minutes in SAGP

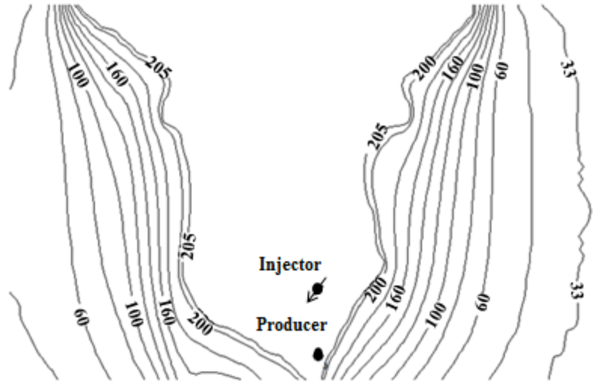


**Fig.12.** Middle plane temperature contour at 150 minutes in SAGD

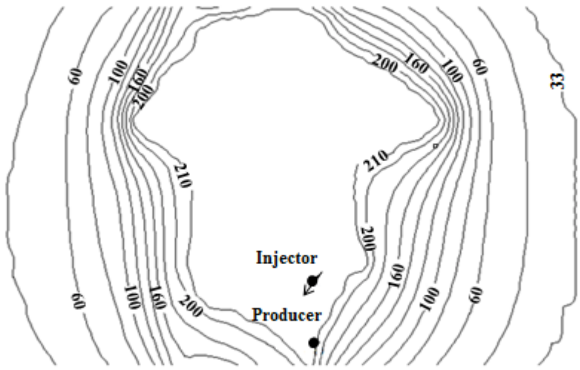


**Fig.13.** Middle plane temperature contour at 150 minutes in SAGP

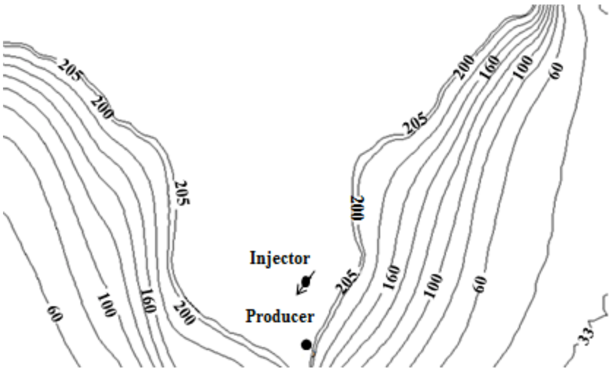


**Fig.14.** Middle plane temperature contour at 200 minutes in SAGD

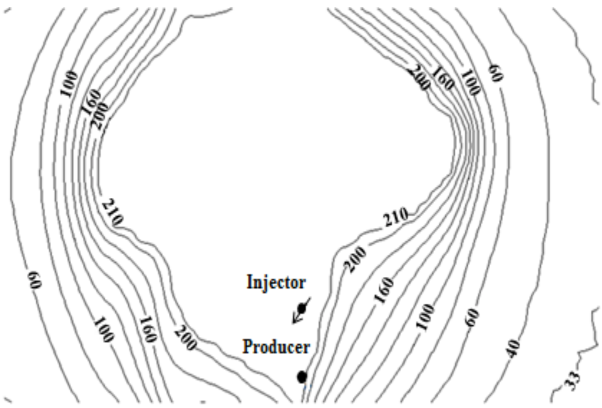


**Fig.15.** Middle plane temperature contour at 200 minutes in SAGP

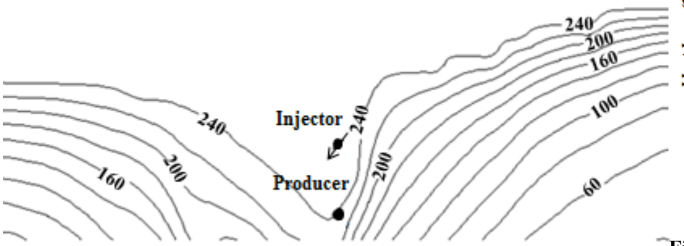


**Fig.16.** Middle plane temperature contour at 330 minutes in SAGD

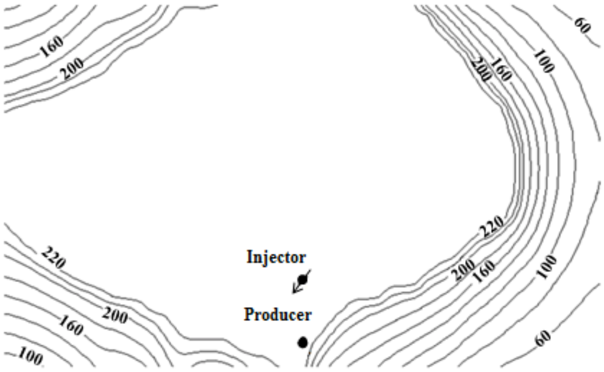


**Fig.17.** Middle plane temperature contour at 330 minutes in SAGP

## 4.2 Comparison of production effect

Figure 18 compares the amount of cumulative oil in the two schemes. As shown in the figure, cumulative oil amount in SAGD is slightly higher than that in SAGP, and the ultimate cumulative oil production is extremely close. The recoveries of the two schemes are 64.3% and 62.7%, respectively, which are higher than 60%. This result indicates that the incremental oil recovery factor of the two schemes is higher than 45% relative to cyclic steam stimulation.

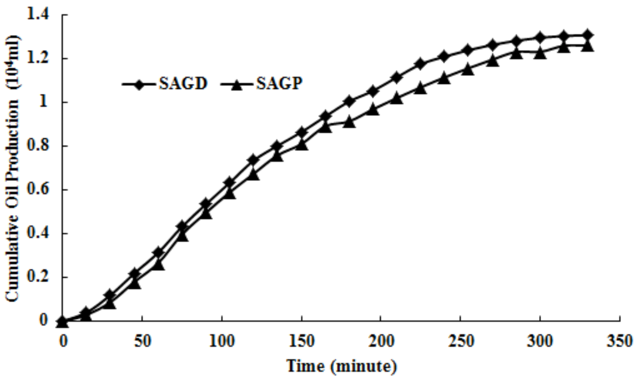


**Fig.18.** Cumulative oil production versus time

Heat loss in SAGP is always less than that in SAGD. As shown in Figure 19, heat loss is 43% lower by the end of production. Cumulative liquid in SAGD is always higher than that in SAGP. The difference increases with production, as shown in Figure 20. Heat loss mainly includes two parts: heat transfer into the cap rock and heat removal by the liquid. The produced liquid carried away a considerable amount of heat because of high temperature. This part of heat was not useful for production, and thus, regarded as a form of heat loss. That is, when the amount of produced liquid is considerable, heat loss is also high.

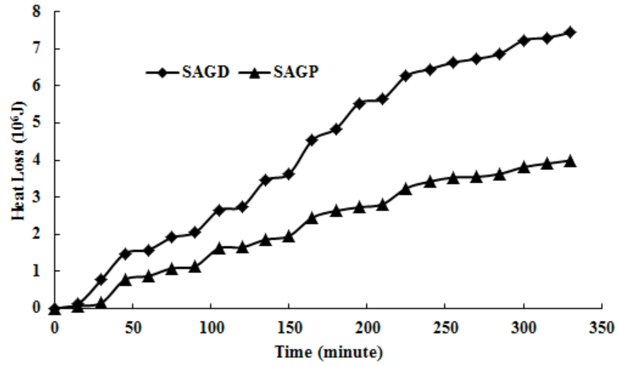


**Fig.19.** Cumulative heat loss versus time

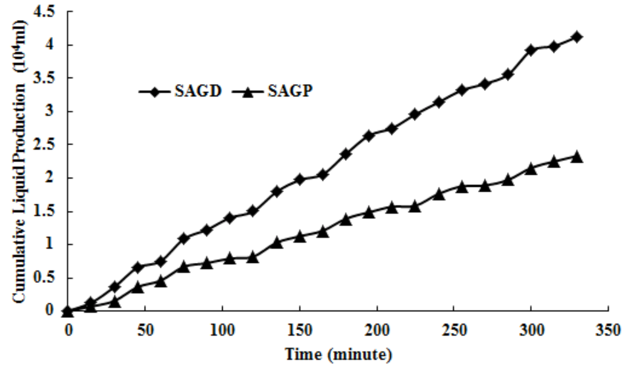


**Fig.20.** Cumulative liquid production versus time

The curve of cumulative SOR in SAGP is always above the curve in SAGD, and ultimately, 0.14 higher than that in SAGD, as shown in Figure 21. By the end of production, cumulative SOR is 0.36 and 0.22 for SAGP and SAGD, respectively.

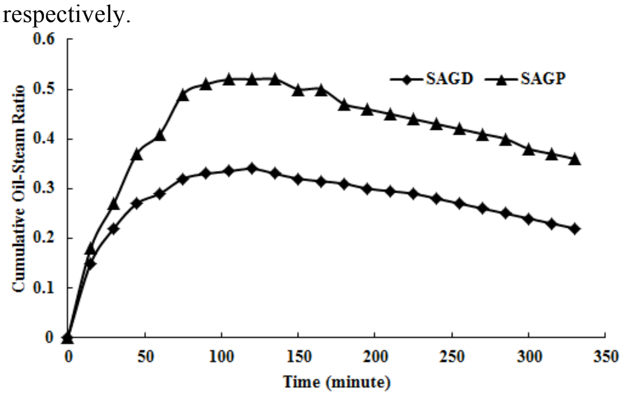


**Fig.21.** Cumulative SOR versus time

The SAGP numerical simulation models were used to optimize the following cases:

(1) Injection timing of $N_2$;
(2) Injection $N_2$ approach;
(3) $N_2$–steam ratio;
(4) Injection steam rate;
(5) Injection amount of $N_2$.

## 4.3 Injection timing of $N_2$

The injection timing of NCG is a significant parameter in SAGP. Five schemes were designed in this case. The first scheme is a continuous steam injection without nitrogen. The second scheme is heating for 6 months before $N_2$ injection. The remaining three schemes are delayed $N_2$ injection for 1 year, 1.5 years, and 2 years. Figure 22 indicates that cumulative oil production decreases, whereas cumulative SOR increases when $N_2$ injection is delayed. Consequently, $N_2$ injection is recommended to be delayed for 1 year after the preheat stage to obtain the optimal development effect.

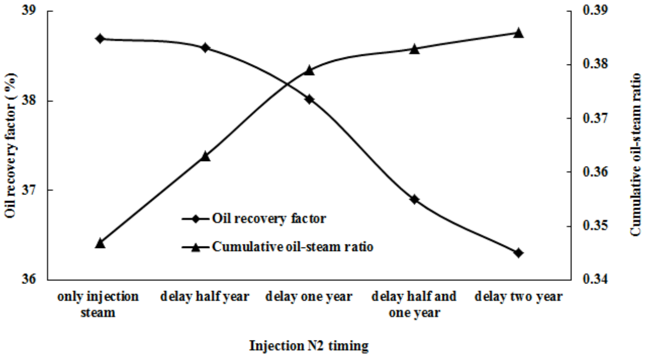


**Fig.22.** Oil recovery and cumulative SOR versus $N_2$ injection time

### 4.4 $N_2$ injection approach

To study the best $N_2$ injection approach, five schemes were simulated, i.e., continuous steam injection without nitrogen and slug injection of N2 for 2, 3, 4, and 6 months. Figure 23 shows that an optimum cumulative SOR exists with the increase in slug size. Theoretically, when the amount of injected $N_2$ is high, the insulation is good and the production time of SAGP is long. However, injecting too much $N_2$ will occupy too much pore volume, which will result in a corresponding reduction in steam chamber expansion. Although production time was extended, oil production rate and cumulative SOR were decreased. Considering all the development indicators, slug injection for 3 months is appropriate.

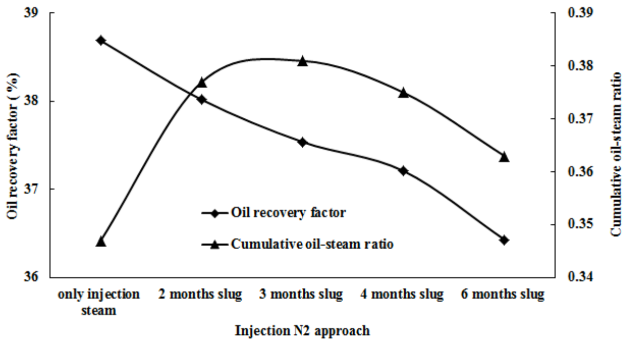


**Fig.23.** Oil recovery and cumulative SOR versus $N_2$ approach

### 4.5 $N_2$–steam ratio

$N_2$–steam ratio is a key parameter in SAGP development. To analyze sensitivity, five $N_2$–steam ratios were studied (0.2, 0.5, 0.8, 1.0, and 1.2). The units of these numbers 0.2–1.2 are standard $m^3$ nitrogen/standard $m^3$ steam (cold water equivalent). Figure 24 shows that as $N_2$–steam ratio increases, cumulative SOR gradually decreases. However, cumulative oil production initially rises and then declines because mobile gas saturation between the injection well and the production well increases as a result of excessive $N_2$ injection. Increased gas mobility leads to easy gas channeling, which finally decreases oil rate and SOR. Therefore, the optimum $N_2$–steam ratio is 0.5.

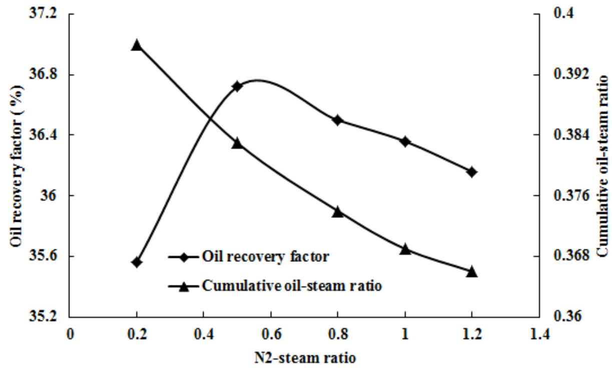


**Fig.24.** Oil recovery and cumulative SOR versus $N_2$–steam ratio

### 4.6 Injection steam rate

Moderately reducing the amount of injected steam can improve SOR and economic efficiency. To ensure that the steam quality at the bottom is more than 0.7, steam injection rate should be higher than 100 $m^3$/d in Liaohe Oilfield. Modeling works with varying injection steam rates, i.e., 125, 120, 110, and 100 $m^3$/d were conducted with $N_2$–steam ratio at 0.5 (cold water equivalent). Figure 25 shows that both SOR and oil recovery improved after steam injection rate is reduced. However, the continuous reduction of steam injection rate will deteriorate steam quality in the well bottom and the effect of development. As shown in Figure 22, recovery and cumulative SOR reach a peak when steam injection rate is 110 $m^3$/d.

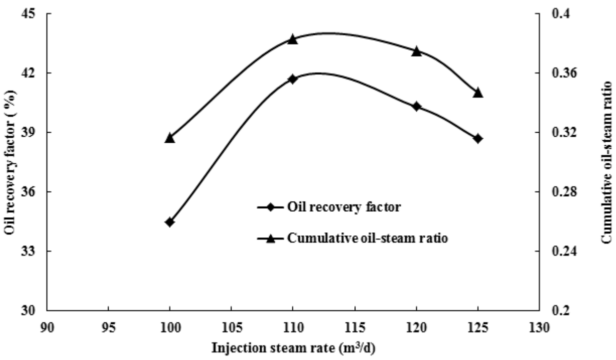


**Fig.25.** Oil recovery and cumulative SOR versus steam injection rate

### 4.7 Injection amount of $N_2$

Different injection amounts of $N_2$ (0.02, 0.05, 0.1, 0.15, 0.20, and 0.25 PV) were simulated. Figure 26 shows that a critical value of $N_2$ injection amount exists, i.e., approximately 0.10 PV. When $N_2$ injection amount is less than 0.10 PV, the $N_2$ insulation layer is too thin and insufficient for heat insulation; therefore, heat loss is considerable. For values over 0.10 PV, continuous nitrogen injection extends SADP production time; however, the development effect is not improved because of the reduction in oil production rate and SOR. Therefore, the optimum $N_2$ injection amount is 0.10 PV, which forms an acceptable $N_2$ layer on top of the steam chamber. The insulation layer is sufficiently stable to reduce heat loss and increase the transverse expansion of the steam chamber.

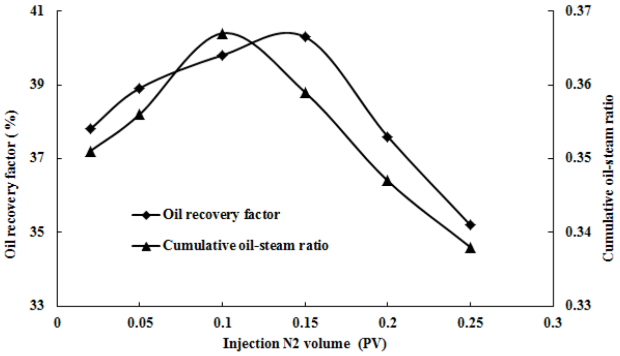


**Fig.26.** Oil recovery and cumulative SOR versus $N_2$ injection volume

## 5 Conclusion

Considerable depth and pressure will affect the expansion of the steam chamber and increase heat loss in SAGD. Therefore, relative to that for a shallow reservoir, SAGD development for moderate-depth heavy oil reservoir is more difficult. SAGD and SAGP experiments were conducted in a 3D scaled physical model. The results show that using horizontal SAGP well pairs for the X6 moderate-depth heavy oil reservoir in Liaohe Oilfield is feasible. Laboratory experiment results show that using horizontal SAGP well pairs in the X6 moderate-depth heavy oil reservoir significantly reduces heat loss; moreover, injecting $N_2$ with steam in SAGD is beneficial for the transverse expansion of the steam chamber. $N_2$ and steam co-injection in SAGD can reduce steam injection amount. Meanwhile, thermal efficiency is amplified and cumulative SOR is increased to over 0.14 for the X6 moderate-depth reservoir. Cumulative oil production decreases slightly, and the incremental oil recovery factor is approximately 45% based on cyclic steam stimulation. According to the numerical simulation results, the following parameters are obtained for the actual X6 moderate-depth reservoir: the optimum $N_2$ injection timing is 1 year after the preheat stage, the best injection slug is 2–3 months, the optimal $N_2$–steam ratio is 0.5 (cold water equivalent), the optimal steam injection rate is 110 $m^3$/d, and the optimum $N_2$ injection amount is 0.10 PV.

## Nomenclature

$B_3$ – Key criterion that controls SAGD similarity, dimensionless;
k – Permeability, μ$m^2$;
$k_{model}$ – Physical model permeability, μ$m^2$;
$k_{field}$ – Reservoir permeability, μ$m^2$;
h – Length, m;
$h_{model}$ – Physical model length, m;
$h_{field}$ – Reservoir length, m;
g – Acceleration of gravity, m/$s^2$;
α – Thermal diffusivity of reservoir, $m^2$/d;
Φ – Porosity, dimensionless;
ΔSo – Movable oil saturation at steam temperature, dimensionless;
m – Heavy oil viscosity–temperature index, dimensionless;
$\upsilon_s$ – Heavy oil kinematic viscosity at steam temperature, $m^2$/d;
$t_D$ – Production time, dimensionless;
t – Production time, d;
$t_{model}$ – Physical model production time, d;
$t_{field}$ – Field production time, d;
w – Distance between horizontal production well and boundary of well group, m.

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