

EXPERIMENTAL AND SIMULATION STUDIES ON STEAM STIMULATION WITH MULTIPLE FLUIDS FOR OFFSHORE HEAVY OIL RESERVOIRS

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Abstract. Steam flooding and stimulation processes have proven to be the most promising method for the commercial in situ recovery of heavy oil. For high quality and thick oil reservoirs, these processes can achieve an oil recovery factor of over 30% OOIP. However, for thin, deep and offshore oil reservoirs, they are uneconomic due to the excessive heat loss to the overburden and great heat requirement to heat the reservoir rock. A new process, Steam and Multiple Fluids (SMF), is being developed to improve the efficiency of the steam stimulation process for offshore heavy oil reservoirs. It involves a combination of steam and non-condensable gases. The injected gases accumulate in the region away from the well and lower the temperature. Only the regions temperature near the well is close to the temperature of steam. The heat loss to the overburden and the heat requirement to heat the reservoir rock can be significantly reduced due to a lower temperature requirement. Considerable saving can be achieved from the reduction in the quantity of steam required for the process. This process is studied by using laboratory experiments and numerical simulations via a 3D thermal model for an offshore heavy oilfield. The results show that, compared to the cold production and standard steam stimulation processes, the oil recovery factor from the SMF is the highest. The application of this process makes the production of offshore heavy oil economic and should extend the range of reservoirs that can be produced economically. A pilot test for calibrating this new process is also reported.

Key words. offshore heavy oil, steam stimulation, multiple fluids, SMF, oil recovery, laboratory experiments, numerical simulation, pilot test

1. Introduction

Abundant heavy oil and bitumen exist in the globe. More than ten trillion barrels of oils in place are attributed to the heaviest hydrocarbons - triple the combined world reserves of conventional oil and gas [2, 5]. These vast heavy oil and bitumen resources are produced primarily using cold production and enhanced recovery methods. The cold production involves two key recovery mechanisms: foamy oil and wormhole network [7, 11, 12], while the enhanced recovery methods involve steam-based processes (steam flooding and stimulation) and solvent-related processes (solvent flooding and stimulation) [1, 8, 4]. Among them, the steam flooding and stimulation processes have proven to be the most promising method for the potential commercial in situ recovery of heavy oil. For high quality and thick oil reservoirs, these processes can achieve an oil recovery factor of over 30% OOIP (original oil in place). However, for thin, deep and offshore oil reservoirs, they are uneconomic due to the excessive heat loss to the overburden and great heat requirement to heat the reservoir rock.

The offshore oil in the Bohai Bay in China contains very rich heavy oil; the heavy portion is more than 70% of its total proven reserves. Under cold production, its recovery factor is very low. In particular, for those parts with a depth of 900-1,000 m and viscosity of 350-1,000 mPa.s, their recovery factor is even worse. For

Table 1: Production data for the south block of NB35-2 oilfield

Total oil wells	Producing wells	Monthly production 10^4 m^3	Daily rate m^3/d	GOR (gas-oil ratio)	Water cut %	Production rate %	Current recovery factor %
25	17	0.79	308	2	56	0.3	1.2

example, the NB35-2 oilfield in the Bohai Bay that was started in October 2005 has a recovery factor of only 2.8 by the end of March 2010 [10, 3]. For the more viscous block of this oilfield that is called the south block, the recovery factor is only 1.2%. The detailed production data for this field is shown in Table 1. In addition, the operating and capital costs in the offshore oilfield development are extremely high. For example, the average facility construction and well drilling costs per platform in the China offshore are usually 1-10 billion RMB [9, 13]. Furthermore, the lifetime for the production facilities is as short as 15-20 years. Therefore, the offshore oilfields must have a high recovery factor for the ultimate recovery to be economic. If an offshore oilfield producing in a production method is not profitable, a new production technology must be utilized.

As mentioned above, thermal recovery technologies are the best choice for the heavy oilfields development. They could produce the heavy oilfields with high recovery factors, and increase the development profits. Due to the offshore nature of the heavy oilfields in Bohai, however, implementing a thermal recovery process must take into account many critical factors; for example, the process must have a high thermal and volume sweep efficiency in order to offset the large well spacing and large drainage areas in an offshore oilfield, and must be equipped with a small and light heat generator because of limited space and operating and crane capabilities on a platform. Health, safety and environmental issues and economic feasibilities must be strictly examined because of the marine environment and high capital and operating costs on the platform that is remote from shore.

Unfortunately, there has been no satisfactory recovery process that can overcome the above challenges for the offshore heavy oilfield development. In this paper, a new process, Steam and Multiple Fluids (SMF), is being developed to improve the efficiency of the standard steam stimulation process. It involves a combination of steam and non-condensable gases (CO_2 and N_2). The injected gases accumulate in the reservoir region away from the well, act as insulation between reservoir formation and overburden, prevent heat losses and thus lower the temperature. Only the region near the well is heated to the temperature of steam. The heat loss to the overburden and the heat requirement to heat the reservoir rock are significantly reduced due to the lower temperature requirement. Furthermore, the co-injection of non-condensable gases with steam can further reduce the oil-water interfacial tension to achieve higher production because these gases accumulate at the interface and form an adsorbed film that lowers the interfacial tension. Compared to the standard thermal recovery processes, this new process improves the steam-oil ratio so considerable saving can be achieved from the reduction in the quantity of steam required. We mention that while the concept of mixed steam and non-condensable gas was used early [2, 6], it all involved the single non-condensable gas CO_2 . As shown in this paper, the proposed SMF process involves multiple fluids and potentially has more thermal and volume sweep efficiency.

The proposed process is studied by using laboratory experiments and numerical simulations via a 3D thermal model for an offshore heavy oilfield in Bohai. A pilot test for calibrating this new process is also reported. The results show that, compared to the cold production and standard steam stimulation processes, the oil recovery factor from the SMF is the highest. The application of this process makes the production of offshore heavy oil reservoirs economic and should extend the range of reservoirs that can be produced economically.

The rest of the paper is organized as follows: In the next section, the basic concept of the new process is outlined. Then, in the third section, we report our laboratory experimental approach, apparatus and results. In the fourth section, a numerical simulation study is performed and the corresponding results are illustrated. For completeness, we describe the facilities, equipment and well completion technologies used for a pilot test for this new process in the fifth section. The pilot test is summarized in the sixth section. Some concluding remarks are stated in the final section.

We end with two remarks. First, it is challenging to study the optimal compositions of the non-condensable gases in the injected fluids at different temperatures, which will be our future research topic to optimize the new SMF process by using a numerical simulator and an optimizer. Second, the economics between this SMF process and other standard processes such as the pure steam stimulation process in terms of operating and capital costs will be also studied in our future work. The present paper focuses on the introduction of the SMF process and its experimental and simulation studies.

2. Concept of the New SMF Process for an Offshore Oilfield

A thermal process can only be implemented in an offshore oilfield provided that a suitable heat generator is used that has the necessary properties: small size, light weight, excellent efficiency and strong reliability to suit an offshore platform. Also, the generator is often operated under limited conditions on the platform, such as the water supply being limited to aquifer water, the fuel supply limited to natural gas or diesel, and the electricity supply limited to the capability of the platform all near the underlying offshore oilfield.

The heavy oil reservoirs in the Bohai Bay are buried in the depth of more than 800 m, and their oil viscosity is only 350-1000 mPa.s (not as high as bitumens). In addition, these reservoirs have high permeability so that if steam is injected into them the heavy oil may be easily driven away in the form of slugs because of its high mobility. If this phenomenon does occur, the heavy oils viscosity may not be reduced effectively. Furthermore, because of the large well spacing and large drainage areas in these offshore reservoirs, the injected heat must be effectively conducted to have a high thermal and volume sweep efficiency.

By extensive and intensive comparisons and studies for many years, a Steam and Multiple Fluids (SMF) generator has been manufactured for our offshore thermal process to satisfy the above requirements. This generator produces multiple fluids that consist of steam, hot water, CO₂, N₂, and CO. The steam and hot water are heat carriers, and the gases are non-condensable. It is through their proper combination that can significantly improve the steam stimulation process, effectively dilute the heavy oil, and greatly improve the thermal and volume sweep efficiency.

In this paper, we study the SMF process in terms of steam and the non-condensable gases CO₂ and N₂. Some of the mechanisms for this process include:

(1) The non-condensable gases can easily enter a remote region, which limits the

heavy oil driven away from a stimulation well.

(2) The non-condensable gases increase the reservoir pressure and generate more energy for oil production. Because gas has a low density, it rises to the top of the formation to prevent heat lost to the overburden.

(3) As CO_2 is injected into the reservoir, it can dissolve into the heavy oil to dilute it, which means that steam and CO_2 can simultaneously reduce the oil viscosity.

(4) The multiple fluids have more thermal and volume sweep efficiency than steam and a single non-condensable gas (CO_2 or N_2) have.

In summary, this SMF process on offshore includes more enhanced mechanisms: The multiple fluids have a combined dilutive role, increase the reservoir pressure, increase the stimulated reservoir volume, and decrease the heat loss to the overburden.

3. Experimental Approach

To calibrate some of the above mechanisms and simulate the new SMF process, physical laboratory tests are carried out by the China Oilfield Service Company (COSL) Research Institute per CNOOCs request. These tests contain high pressure instruments that consist of four thermal couples, two pressure sensors, a sample sand pack, a transfer cylinder for drainage, a steam generator, two transfer cylinders for CO_2 and N_2 , metering instruments, gauge pumps, and a computer data acquisition system, as shown in Fig. 1.

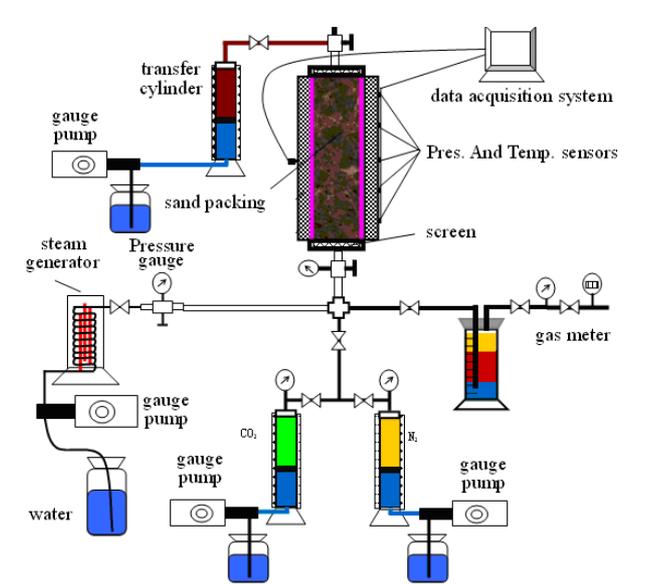


Figure 1: Physical test apparatus and flowchart for the SMF process.

The physical tests for simulating the SMF process has been carried out by the following procedure and materials:

- (1) Clean sand samples.
- (2) Sample pack with a sample volume: 5.0 L, pore volume: 1.2 L, water volume: 0.54 L, and oil saturated: 1.25 L.
- (3) Saturated with water at the reservoir temperature and kept for 12 h.

- (4) Saturated with oil until no water is produced and kept for 12 h.
- (5) Cold production tests: Inject oil at a stable injection pressure, record data about the production rates of both oil and water and pressure with four gauges; remove backup pressure and record data about the rates and pressure.
- (6) Steam huff and puff tests: Inject steam at a designed rate, record data about the injection rate and pressure; after injection, wait for steam soak at a designated time; remove backup pressure and record data about the rates and pressure.
- (7) SMF huff and puff tests: Inject steam, N_2 and CO_2 at a designed rate, record data about the injection rates and pressure; after injection, wait for steam soak at a designated time; remove backup pressure and record data about the rates and pressure.

In the SMF tests, the injection pressure is 10 MPa, and the multiple fluids consist of steam: 0.35 L, N_2 : 0.125 L, and CO_2 : 0.05 L. The soak time is 15 min.

The production index (PI) [4] is regarded as an important factor for comparison of cold production, steam stimulation and the SMF process. The PI for the steam stimulation is shown in Fig. 2, and for the SMF it is shown in Fig. 3. From these figures, we can see that the PI is considerably influenced by temperature. The PI for cold production is only 28.0 mL/(minMPa) at 56°C (the reservoir temperature). The PI for steam huff and puff is 66.7 mL/(minMPa) at 240°C and is 2.5 times that for the cold production. The PI for the SMF is four times that for the cold production and 1.6 times that for the standard steam stimulation.

The gas saturation also has an effect on the production index during the steam stimulation and SMF, as shown in Figs. 4 and 5. The PI with the saturated natural gas is obviously higher than that without the solution gas. From the above production index analysis, the SMF process is better than steam stimulation for oil from the NB35-2 oilfield. The comparison tests also show that when the saturated natural gas is produced and the reservoir pressure decreases, the reservoir pressure bounces back after injecting non-condensate gases N_2 and CO_2 .

4. Numerical Simulation Study

The laboratory experimental tests in the previous section have shown that the SMF process is very effective. To understand its mechanisms and roles more, it is necessary to perform a numerical simulation study. This study will be also useful to compare the steam stimulation and SMF processes in the full reservoir scale and design key factors for the latter process. Finally, it helps in the design of a pilot test.

A thermal model by using the commercial simulator Eclipse-Thermal is constructed to simulate the new SMF process. On the basis of the reservoir properties of the NB35-2 oilfield, a thermal compositional model with seven components ($N_2CO_2CH_4C_2-C_5C_6-C_{12}C_{13}-C_{29}$, and C_{30+}) is used, and is discretized on a $50 \times 40 \times 25$ grid. A horizontal well is utilized in the reservoir, as shown in Fig. 6. The depth of the reservoir top is 1,000 m, the formation thickness is 25 m, the distance between the horizontal well and the reservoir top is 17 m, and the lateral length of this well is 340 m. The reservoir dimensions are 1,000 m \times 200 m \times 25 m. Its porosity is 0.33, the horizontal permeability is 1,200 mD, and the vertical permeability is 792 mD.

By a PVT property analysis, the viscosity data for the gas and liquid phases are shown in Tables 2 and 3. On the basis of laboratory experiments and their analysis, the oil and water relative permeabilities are obtained. The end saturation values and the corresponding permeabilities are given in Tables 4 and 5. In Table 4, Swc,

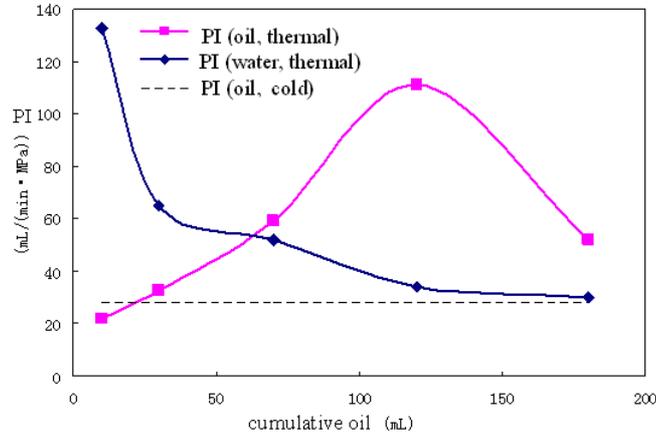


Figure 2: PI of cold production and steam stimulation at 240°C.

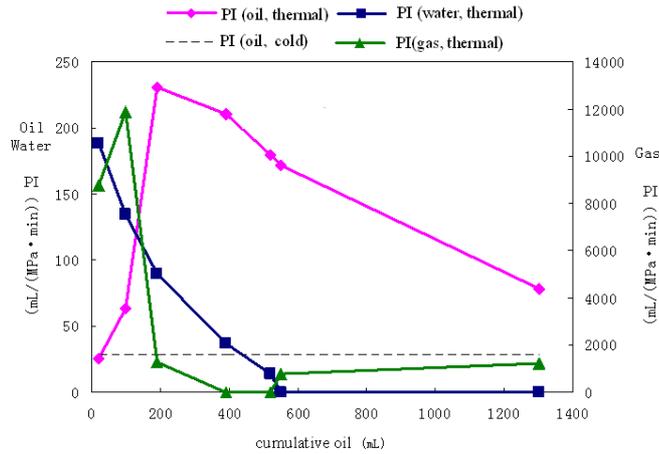


Figure 3: PI of cold production and the SMF at 240°C.

Swir, Swmax, Sgc, Sgr, and Sgmax represent the critical, irreducible and maximum water and the critical, residual and maximum gas saturation end points and Sorw and Sorg denote the residual oil saturation in the presence of water and gas, respectively. Table 5 indicates the corresponding values of relative permeabilities at these end points.

The fluid injections for steam stimulation and SMF are calculated by equal enthalpy in this simulation. 24 months are the stimulation time for the different production processes. The oil increments and average production rates for 12 months are calculated and compared with each other. The results are shown in Table 6. The accumulative oil production for different production methods is shown in Fig. 7.

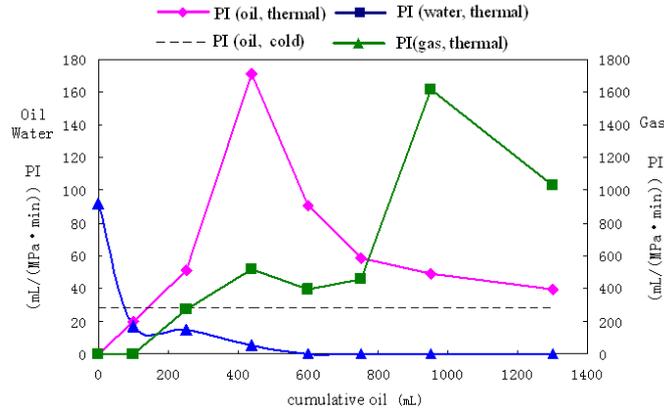


Figure 4: PI of cold production and steam stimulation at 240°C with gas saturated heavy oil.

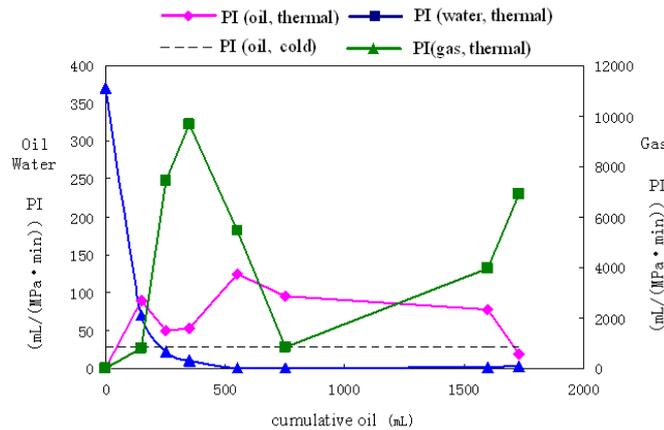


Figure 5: PI of cold production and the SMF at 240°C with gas saturated heavy oil.

From Table 6 and Fig. 7, we can see that the period of effective time for steam stimulation is about 300 days and the period of effective time for SMF is about 400-500 days. It is obvious that the latter can have a higher recovery factor than the former. After 300 days of production, the average daily rate for the SMF process at 300°C is 38.3 m³/d, it is 2.1 times that of cold production with 18.3 m³/d, and it is 1.24 times that of steam stimulation with 30.8 m³/d. It can be seen from Fig. 7 that SMF also gives the most accumulative oil production. By the comparison of steam stimulation and SMF at 300°C, as shown in Fig. 8, the latter obviously has a higher daily production rate and a longer period of effective life.

Remark: S represents steam, FG represents fuel gases CO₂ and N₂, and S-FG means injection in sequence.

Considering the reservoir properties and horizontal well parameters, a sensitivity study is carried out in the numerical simulation for SMF. Totally nine important factors and 32 scenarios are studied as shown in Table 7. The sensitivity results

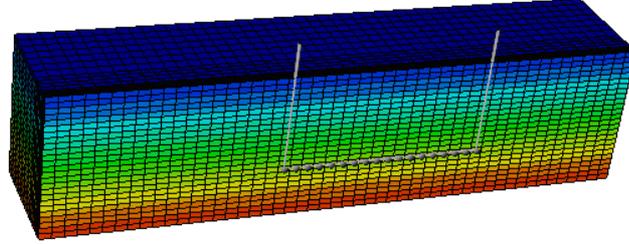


Figure 6: A model for the SMF process.

Table 2: Viscosity for compositions in the gas phases at different temperature (mPa.s)

Temp.(°C)	N ₂	CO ₂	CH ₄	C ₂ -C ₅	C ₆ -C ₁₂	C ₁₃ -C ₂₉	C ₃₀₊
75	0.0123	0.0183	0.0158	0.0214	0.0244	0.0285	0.0385
10	0.0129	0.0189	0.0165	0.0223	0.0255	0.0297	0.0397
150	0.0141	0.02	0.0178	0.0241	0.0275	0.0321	0.0421
200	0.0152	0.0212	0.019	0.0259	0.0296	0.0345	0.0445
250	0.0164	0.0224	0.0203	0.0276	0.0315	0.0368	0.0468
300	0.0176	0.0236	0.0217	0.0294	0.0335	0.0391	0.0491
350	0.0187	0.0257	0.0229	0.0311	0.0355	0.0414	0.0514
500	0.0221	0.0291	0.0267	0.0362	0.0414	0.0483	0.0583

Table 3: Viscosity for compositions in the liquid at different temperature (mPa.s)

Temp.(°C)	N ₂	CO ₂	CH ₄	C ₂ -C ₅	C ₆ -C ₁₂	C ₁₃ -C ₂₉	C ₃₀₊
75	2.3	3.3	511.9	926	1397	2129	3280
100	2	2.9	127.4	225.4	392.4	586.2	880
150	1.55	2.3	18.1	30.4	54.4	74	107
200	1.2	1.7	5	8.3	14.1	17.9	27
250	0.9	1.3	2.1	3.3	5.2	6.7	9.4
300	0.7	1	1.2	1.8	2.6	3.3	4.5
350	0.55	0.8	0.9	1.2	1.9	2.2	3.2
500	0.3	0.5	0.5	0.6	0.8	1	1.5

Table 4: Saturation end points at different temperatures

Temp.(°C)	Swc	Swir	Swmax	Sgc	Sgr	Sgmax	Sorw	Sorg
56	0.3	0.3	0.55	0.1	0.1	0.65	0.45	0.35
300	0.42	0.42	0.75	0.1	0.1	0.8	0.25	0.2

for different cumulative oil production in a cycle with the nine factors are shown in Fig. 9. From this figure, we can see that the sequence of the influence factors (from

Table 5: Permeability end points at different temperatures

Temp.(°C)	Krwmax	Krgmax	Kromax	Krwro	Krgro	Krorg	Krowr
56	0.12	0.1	1	0.12	0.1	0.51	0.82
300	0.24	0.25	1	0.12	0.24	0.25	0.9

Table 6: Simulation results for the different recovery processes

Process	Cold production	SMF at 300°C	Steam stimulation at 300°C
Oil increment in 24 months (m ³)	-	7108	5252
Average oil daily rate in 24 months (m ³ /d)	15.1	24.7	22.3
Oil increment in 12 months (m ³)	-	6018	3750
Average oil daily rate in 12 months (m ³ /d)	17.8	34.2	28.1

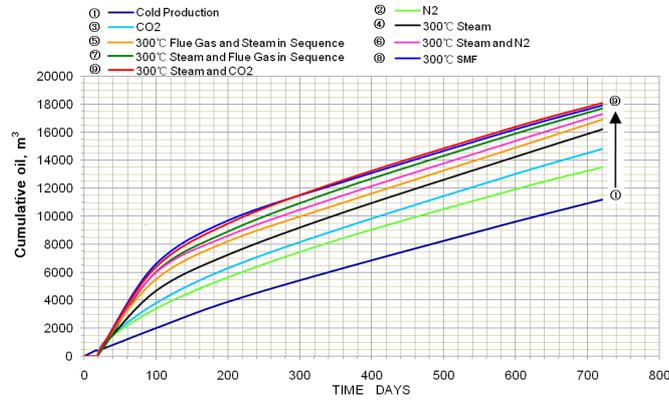


Figure 7: Accumulative oil production comparison.

the most to the least) is: reservoir pressure, CO₂ intensity, N₂ intensity, steam intensity, injection method, steam temperature, ratio of bottom hole and reservoir pressure, soak time, and injection rate.

5. Equipment and Facilities

For completeness, in this and next sections we report the use of equipment and facilities for a pilot test performed in Bohai for our new process SMF.

5.1. Multiple fluids generator. Our multiple fluid generator is based on a rocket burning motor, and it follows the basic theory of material, energy and chemical balances. A certain mixture of fuel and oxidants are injected into a boiler to deflagrate and generate high temperature mixing gases. This approach converts chemical

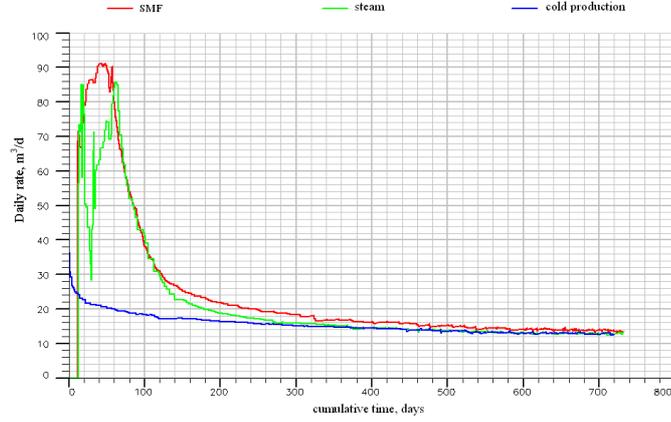


Figure 8: Daily oil production rate comparison .

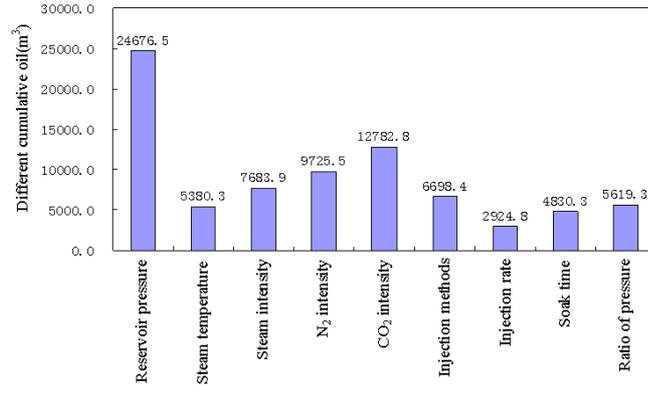


Figure 9: Influence results with nine factors.

energy into heat energy. The burning process includes diesel atomization, dew evaporation, diesel mixing with oxidant gas, and chemical reactions. It produces N_2 , CO_2 and H_2O and temperature can be as high as $2000-3000^\circ C$. Water is pumped into a tube connecting to the boiler and contacts with the heat, and then the water becomes steam instantaneously. The final products of this process mainly consist of steam, N_2 and CO_2 .

5.2. Injection process. Taking into account the thermal process requirements and the limited, realistic offshore oilfield conditions, such as limited space and limited water and electricity supply capacities, an injection process has been designed and optimized and is shown in Fig. 10. This injection process has been used for 12 wells in the NB35-2 oilfield and proven to be a suitable and stable process.

5.3. Steam injection equipment layout. Considering the limited platform space and transportation and lifting convenience, most of the equipment is contained

Table 7: A sensitivity study

Factor	Reservoir Pressure (MPa)	Steam Temp. (°C)	Steam injection intensity (m ³ /m)	N ₂ injection intensity (m ³ /m)	CO ₂ Injection intensity (m ³ /m)	Injection method	Injection rate (m ³ /d)	Soak time (d)	Ratio of down-hole and reservoir pressure
1	3	100	0	0	0	Simultaneous	192	1	0.2
2	5	180	5	1000	1000	S-FG	384	3	0.5
3	8	240	10	2000	2000	FG-S	960	5	0.8
4	10	300	20	5000	5000	S-FG-S	1440	7	1

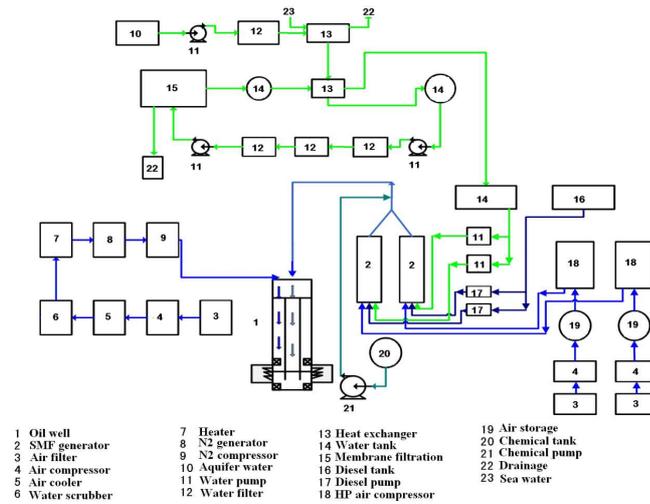


Figure 10: Injection process flowchart.

in skid containers. By carefully studying load and stress distribution, the equipment is laid out on the top deck of the platform, as shown in Fig. 11.

5.4. Thermal well completion. The main difficulties for thermal well completion in offshore oil fields are summarized as follows: Unconsolidated sandstone and active bottom and edge water make sand easily produce. In a thermal process, hot temperature may change formation stress and make unconsolidated sandstone more unstable. Because the multiple fluids in the SMF process contain CO₂ and hot water, a corrosion problem may happen. It is difficult to gravel-pack a horizontal well. Tremendous temperature changes may harm sand control tools, screen connections, and other important facilities.

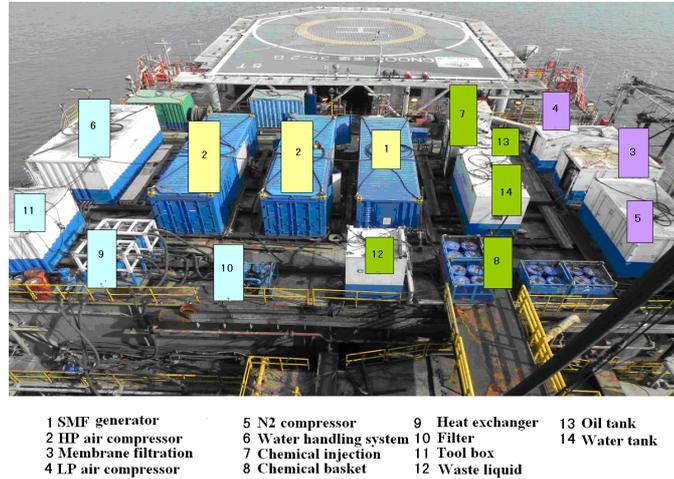


Figure 11: Equipment layout.

After taking advantages of onshore thermal practices, gravel packing with premium screen is chosen for the NB35-2 oilfield. To reduce the impact of large temperature changes, some thermal compensators are used in well completion strings. In the same time, the lateral length of the wells, specially designed tools and specific gravel packing parameters are optimized for these wells. A well completion string is shown in Fig. 12.

Through a liability comparison for some types of screens in five wells, the CMS (metal mesh) and compound screens are chosen for thermal well completion because mesh-rite screens have failed to survive in sand control tests. Three types of screens are shown in Fig. 13.

6. An Offshore Pilot for the SMF Process

From January 2010 to October 2012, totally 12 wells in the NB35-2 oilfield were performed with the SMF process. The pilot was divided into four stages with different purposes including equipment testing, injection validating, well completion testing, and field scale extension to increase economic feasibility. For example, the SMF operation at 240°C for the B28h well is shown in Fig. 14. This operation included two injection stages that consisted of the first 4,560 t at 240°C in 18 days and 1,790 t at 120°C in 5 days. In this stimulation operation, 6,330 t steam and fuel gas that was generated from 1,578,900 kg air and 143.5m^3 diesel were injected into the reservoir formation. The injection facilities worked smoothly. The well was put into production after soaking for three days.

The maximum daily oil production rate of the B28h well reached $134\text{ m}^3/\text{d}$ and the average daily oil production rate is $49\text{ m}^3/\text{d}$ in the first 400 days. During those days, the well produced $19,584\text{ m}^3$ oil with the total liquid of $28,297\text{ m}^3$. Compared with cold production, the increment oil of the B28h well is $7,824\text{ m}^3$. The production data is shown in Table 8.

The production rate changes of the south block in NB35-2 can be seen in Fig. 15. Previously, the south block had 25 cold production wells but the daily production rate was only about $200\text{ m}^3/\text{d}$. After seven thermal wells were put on line, the daily

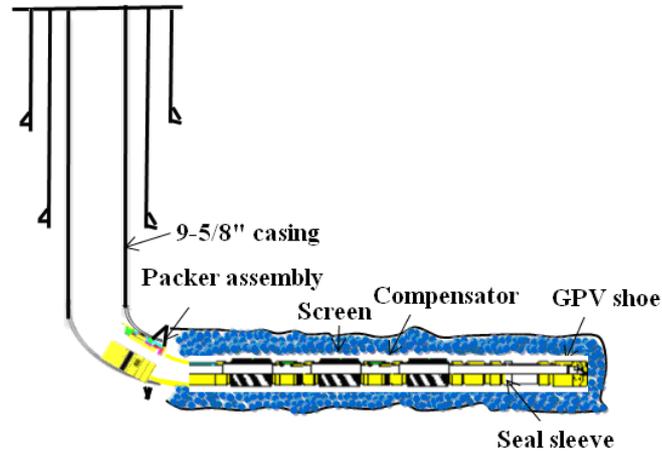


Figure 12: Well completion string for NB35-2 thermal wells.

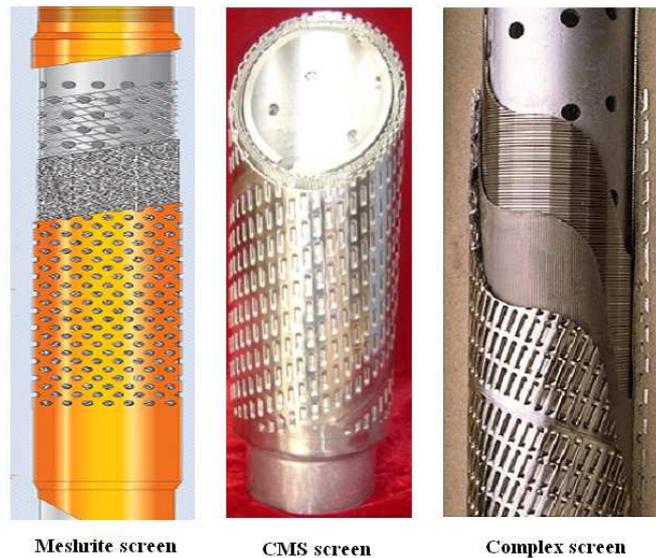


Figure 13: Three types of screens tested in NB35-2 oilfield.

production rate of this block increased to nearly $500 \text{ m}^3/\text{d}$. Some other thermal wells sanded out during the well completion testing stage.

7. Conclusions and Future Work

After the laboratory experiment, numerical simulation and pilot test studies, the newly proposed SMF process has been proven to be technically and economically feasible in the NB35-2 oilfield in the Bohai Bay. For the heavy oil reservoir with a viscosity of $350\text{-}1,000 \text{ mPa}\cdot\text{s}$, the daily oil production rate per well in cold production were only $10\text{-}20 \text{ m}^3/\text{d}$. However, the average daily oil production rate per well for thermal wells in the SMF process can be as much as $45\text{-}60 \text{ m}^3/\text{d}$ during the first 300-400 days and the maximum daily oil production rate can be over $100 \text{ m}^3/\text{d}$. The

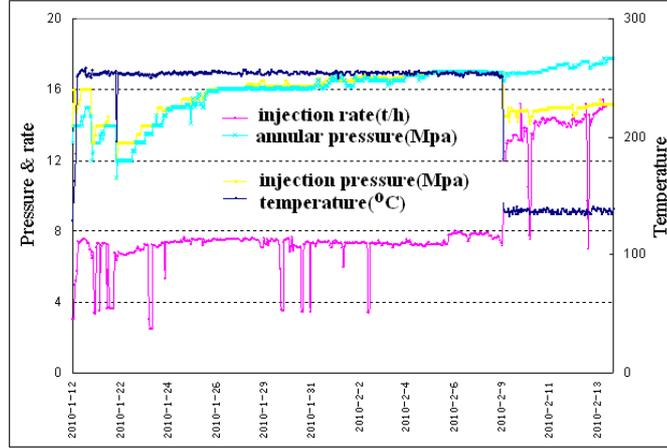


Figure 14: Injection curves for B28h well in NB35-2 oil field.

Table 8: Production data of B28h well

Lifting method	days(d)	Maximum daily liquid rate(m^3/d)	Maximum daily oil rate(m^3/d)	Liquid cumm. (m^3)	Oil cumm. (m^3)
Blow out	24	187	134	2342	1160
ESP	376	101	82	25955	18424

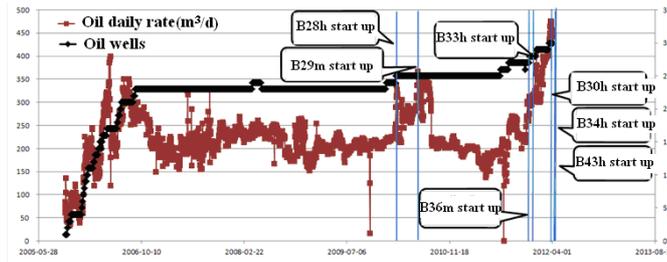


Figure 15: Production rate of south block in NB35-2.

heat generator and other injection facilities used in this recovery process have been proven to be reliable and suitable for offshore platforms. In the well completion, the mesh-rite types of screens sanded out, and the CMS and compound screens survived in the first a few thermal cycles. The present study will have tremendous potential offshore applications for the SMF process.

Further research will be performed for the SMF process. The optimal compositions of the non-condensable gases in the injected fluids at different temperatures will be studied by using a numerical simulator and an optimizer. There are other technical problems that must be answered, such as an ESP (electrical submersible pump) that cannot be run properly in wellbore during thermal injection, which

means workover must be carried out after the well starts up and loses blowout ability. Corrosion influence with CO₂ in wellbore is also needed to evaluate in our future practice. Economics will be another issue to be studied.

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