Selection of the Optimum Production Scenario for One of Iranian Offshore Oil Reservoirs

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Effectiveness of two enhanced oil recovery techniques on recovery of Soroosh oil field, an Iranian offshore oil reservoir is investigated and compared. The approach used is the numerical reservoir simulation by means of a well-known numerical reservoir simulator, Eclipse, and the real full field model. Water injection and immiscible gas injection processes have been simulated and compared in terms of ultimate recovery factor. It was found that natural production of oil by depletion and water drive from aquifer will result in very low ultimate recovery factor. Simulation runs also showed that waterflooding can be efficient just for upper high permeability layers which contain lighter oil. Finally, from the gas injection simulation runs, it was found that immiscible gas injection can enhance ultimate recovery to 27% which is higher than that of waterflooding. The decline rate of production during gas injection was slower than that of waterflooding, which results in higher oil flow rate and ultimate recovery.

Introduction

The initial oil in place (IOP) for Iranian heavy oil reservoirs is estimated to be 85.77 MMMSTB. Also, Iran has the world's second largest reserves of conventional crude oil of 133 MMMSTB. Therefore it is necessary to undertake extensive study to find suitable enhanced oil recovery methods to maximize the recovery of such these large amounts of reserves.

In general, the important deposits of heavy crude oil in Iran are limestone and dolomite which range in age from Cretaceous to Eocene. Heavy oil traps are mainly anticlinal structures, located in the southwest part of Iran (Zagros area). Some of important Iran's heavy oil reservoirs are as follows: Kuh-e-Mond, Zaqeh, Sousangerd, Paydar, West Paydar, and Soroosh. In this paper, Soroosh oil field is taken into consideration. Water injection and immiscible gas injection schemes are investigated and compared in terms of recovery factor. In addition, the natural production of oil by pressure depletion will be also taken into consideration as a basis for comparison.

1. Theory

1.1 Theory of Heavy Oil Production

As defined by the U.S. Geological Survey (USGS), heavy oil is a type of crude oil characterizedby an asphaltic, dense, viscous nature (similar to molasses), and its asphaltene (very large molecules incorporating roughly 90 percent of the sulfur and metals in the oil) content (Szasz and Thomas, 1965). It also contains impurities such as waxes and carbon residue that must be removed before being refined. Although variously defined, the upper limit for heavy oil is 22 °API gravity with a viscosity of 100 cP. Some heavy oil production can be accomplished via conventional methods, such as vertical wells, pumps, and pressure maintenance, but these methods are considered highly inefficient. Other technologies being used to recover heavy oil include, but are not limited to cold heavy oil production with sand (CHOPS), vapor extraction (VAPEX), and thermal in-situ methods. The main oil-related challenges involved in production are gravity and the viscosity of heavy oil (Szasz and Thomas, 1965).

With a worldwide resource base that may exceed 6 trillion barrels, heavy oil will be a major energy source for the 21st century as the availability of conventional oil declines. Some predictions show Canada's heavy oil sand production to exceed 1.2 million bbl/d (Barrel Per Day) in the near future (Wang, 1998). In Venezuela, the government and oil companies are forming partnership to enhance recovery in the Orinoco tar sands, which contain about 300 billion barrels of recoverable heavy oil. It is expected that Venezuela will produce 600,000 bbl/d. The China National Petroleum Corporation produces about 150,000 bbl/d of heavy oils from about 8 billion barrels of reserves (Wang, 1998).

Iran has the world's second largest reserves of conventional crude oil at 133×10^9 barrels, although it should be noted that both Canada and Venezuela have larger reserves if non-conventional oil is included. Iran is the second largest oil holder globally with approximately 10% of the world's oil.

In Iran, the proved and probable heavy oil reservoirs are mostly located in southwestern part of the country. These reservoirs are highly fractured, and the rocks are of different mineralogy, e.g., marly limestone, dolomite argillaceous limestone,etc. Based on the studies performed so far by National Iranian Oil Company the OIP for Iranian heavy oil reservoirs is estimated to be 85.77 MMMSTB.

The decreasing trend of discovery of new oil reservoirs and the expanding worldwide demand for energy increases the importance of Enhanced Oil Recovery processes.

In "primary recovery", naturally occurring energies, such as gas and liquid expansion and water influx from aquifers, are utilized to produce the oil. Primary recovery efficiency varies greatly from reservoir to reservoir, depending on the production mechanisms and reservoir properties. A typical range for primary recovery efficiency is 5 to 20% of original oil in place (OOIP) (Stalkup, 1983).

Fluid injection into reservoirs gradually became accepted as a method for pressure maintenance and additional oil recovery. Water and/or natural gas, at pressures where the gas is immiscible with oil, have been the injection fluids used almost exclusively for this purpose in the past and present. Injecting gas into the gas cap, water into the aquifer near the water-oil contact (WOC), or either fluid into the oil column are common fluid injection techniques. The improved recovery from this technique results from moderating or preventing a decline in reservoir pressure so the producing rate could be maintained at a higher level for a longer time than would have been possible from primary producing mechanisms only. In addition to supporting reservoir pressure, the injection fluids also displaces some oil from the rock pore space and drove it to producing wells. Today fluid injection following some short or prolonged period of primary production usually is called "secondary recovery". Ultimate oil recovery resulting from both primary recovery and secondary recovery by water or immiscible gas injection generally is in the range of 20 to 40% OOIP (Stalkup, 1983), although there are instances where ultimate recovery is significantly higher or lower.

A variety of CO_2 or gas injection strategies can be implemented for recovering oil from a reservoir. Some of these are gas slug (small slug size) injection, water-alternating-gas (WAG) injection, water-gas co-injection, continuous gas injection (to high gas-oil ratio: GOR), and single-well huff 'n' puff process. If the gas injection is implemented after primary recovery, it is considered a secondary injection, whereas if the gas is injected after initial waterflood, it is known as a tertiary process. Thus, secondary slug Process implies gas injection to the reservoir after primary depletion, whereas tertiary slug injection will occur after the initial waterflood. Details on these processes have been provided by researchers (Hatzignatiou and Lu, 1994; Rojas and Farouq Ali, 1988). The performance of each process is affected by different operating parameters. Previous studies have shown that the immiscible CO_2 or gas flooding process is affected by the gas slug size, number of slugs, injection rates of water and gas slugs for WAG injection, the WAG ratio and WAG cycle, the reservoir operating pressure, the extent of phase equilibrium, and other factors related to rock-fluid interaction (Rojas, 1985; Dyer and Farouq Ali , 1990). With no readily available sources of CO_2 in the Soroosh oil field where the heavy oil reservoirs are located, the emphasis of the research work has shifted to investigating the suitability of water flooding and gas injection.

1.2 Description of Soroosh Oil Field

The Soroosh field, located 80 km from Kharg Island in the Northern Persian Gulf, was initially developed in the 1970's and produced 86 MMbbl until it was damaged in the Iran-Iraq war. Oil production takes place by natural depletion of the reservoir and also water drive from aquifer water influx. The field began redevelopment by Shell in 2000 under a buy back contract. It will be developed by 10 ESP horizontal wells drilled into the crest of the Burgan-B reservoir to produce a plateau of 100,000 bbl/d using depletion and aquifer drive

The Soroosh Burgan-B is at a depth of 2200 m and the high quality (more than 4 darcies) target channel sands are generally between 10 to 40 m thick. The reservoir has a 140 m column of viscous oil of varying quality both areally and with depth, with the more viscous oil found deeper in the reservoir: The distribution of the oils is not fully established, but over the upper 80 m the viscosity generally deteriorates from 15 cP to 50 cP and is a factor of 10 or more higher towards the WOC.

Past and currently planned development is of the Middle Cretaceous Burgan-B Formation, the main reservoir interval, which ranges in thickness across the field from 52 to 73 m. The Burgan B target interval comprises well connected channel sands of 25- 29% porosity and permeability in the range of 5-11 Darcy.

Fluid properties in the reservoir vary with 20 °API degrading to 15 °API oil over the upper 50 m of the reservoir (23 cP to 70 cP), and heavy oil and tar observed towards the WOC at 2272 m.

The Burgan Formation is underlain by the Basal Shale and low permeability carbonates of the Shuaiba Formation and as a result only a flank aquifer is expected. Regional correlations suggest that the Burgan-B Reservoir is very extensive and that a volumetrically large flank aquifer exists.

It has been established from well tests that the oil quality varies through the field and it appears that this is at least partially depth dependent. The higher viscosities have a major impact on the ability of the oil to move through the reservoir and at the oil-water contact they appear to act as a significant baffle suppressing aquifer support and influx. The uncertainty currently assumed in the viscosity model represents the largest contributor to the uncertainty range on the reserves.

To illustrate the expected viscosity distribution with depth a breakdown of STOIIP per depth interval is given in **Table 1** from the Soroosh Subsurface Development Review.

2. Production Strategies

Due to the very adverse mobility ratio between oil and water, the 10 well development plan is currently predicted to achieve a further recovery of only around 500 million bbl over 25 years, or a total recovery factor of only some 7% of the 8.5 billion bbl of STOIIP. An option is a flank water injection scheme which would aim to replace voidage at up to 180,000 bbl/d. The scheme was envisaged as a pressure maintenance mechanism rather than to improving sweep efficiency. As such, it would increase recovery within a 25-year period, but only by the order of some percentage points. In order to make a significant improvement in the recovery, sweep efficiency must be improved. Sweep efficiency could be improved by dense drilling of a pattern waterflood, however the gross throughput of such a scheme would need to be enormous to reach high recoveries.

Gas Oil Gravity Drainage (GOGD) may be a much more suitable mechanism to improve recovery in Soroosh. A peculiarity of the Soroosh field which makes gas injection attractive is that the oil is very undersaturated with a bubble point pressure of around one fifth of the initial pressure. In order for GOGD to be effective, the process must be occurring over a reasonable column height with a high vertical permeability: this may be practicable in Soroosh with its approximate 30m of highly permeable sands. A total number of 8 wells are open to production.

The simulation was run using the full field model for 30 years with the same production history and well completion data as before redevelopment program. The total oil production was found to be 1.82×10^{8} STB oil and gas production of 3.12×10^{7} SCF. Based on the initial oil in place of 2.8×10^{9} STB, natural production will recover only 6.5% of the initial oil in place after 30 more years.

2.1 Gas Injection Scenarios

The gas injection scheme was set up. A light gas (with 98.5% methane) was injected with a total injection rate of 150 MMSCF/day. This injection rate is assumed according to the capacity of ordinary gas processing and compression plants. Since the average reservoir pressure before gas injection was 3220 psia, the injection pressure must be higher, due to the frictional pressure drops in the well column and through perforations.

We assume that the wells are completed in all layers. Additionally, we assume that the injectivity of all gas injector wells is such that each one can inject 50 MMSCF/day gas. The total production rate for all 16 wells was assumed to be maximum 120000 STB/day, i.e., 7500 STB/day per well. Three gas injector wells were assumed in any case in different configurations. The simulation model was run with the specified conditions (3 gas injection wells and 16 oil production wells) and gas injection scenario was assumed to last 30 years.

At the end of 30 years of gas injection scenario, the field will produce 7.532×10^{8} STB oil and 8.72×10^{10} SCF of associated gas. Based on the estimated initial oil in place of 2.8 MMMSTB, the ultimate recovery factor will be approximately 27%.

2.2 Water Injection Scenarios

In case of water injection, some edge wells were set as water injectors and crestal wells were put on production. Unfortunately, there are a few edge wells that can be good candidates for water injection into aquifer or waterflooding in upper layers.

We assumed that there is a water treatment plant with a capacity of at least 24000 STB/day for chemical treatment of seawater salts and compatibility purposes. We ignore the formation damage of probable incompatibility of injection water with formation water. Therefore, all injection wells are assumed to run with constant injectivity. Three water injection wells are planned to inject 8000 STB/day per well. We assume that the wells are completed in all layers. The total production rate for all 16 wells was assumed to be maximum 90000 STB/day, i.e., 5625 STB/day per well. The water injection scenario was let to last to continue for 30 years. At the end of 30 years of water injection scenario, the field will produce 6.93×10^{8} STB oil and 8.0×10^{7} SCF of associated gas. Based on the estimated initial oil in place of 2.8 MMMSTB, the ultimate recovery factor will be 24.7%.

3. Results and Discussion

In this section the best cases of gas injection and water flooding are compared. **Figures 1** to **7** compare oil production rate, total oil produced, water production rate, total water produced, gas production rate, total gas produced, gas-oil ratio, water cut, and average field pressures of best water injection and gas injection cases. **Table 2** lists a comparison of produced oil and recovery factor for all cases.

In **Figure 1**, oil production rates of waterflooding and gas injection are compared. In gas injection scenarios, field produces the oil with a rate of 120,000 STB/day, while in waterflooding scenario; it produces 90,000 STB/day. The starting rate in gas injection is higher, therefore the plateau is very short and production rate declines. However, the decline rate in gas injection is slower than waterflooding. Almost in all times, the total oil flow rate of the field is higher in case of gas injection. As a result, the cumulative oil production is higher when gas injection is applied (**Figure 2**).

Figure 3 shows gas production rate for two scenarios. Since the oil flow rate is higher in case of gas injection, the same trend is expected for gas production rate. During gas injection, if the gas breakthroughs the production wells, the flow rate of gas production will be much larger than rate of gas production in water flooding. However, in this case gas breakthrough has not been occurred.

Surprisingly, the rate of water production is higher in case of gas injection (**Figure 4**). This may be due to possible water coning as a result of higher flow rate and higher pressure drop in the near wellbore region. Natural water influx from the reservoir is a major drive force in Soroosh field.

Figure 5 compares the gas-oil ratio for two cases. This confirms that the gas production in case of gas injection scenario is exactly the associated gas which is produced with oil. In other words, gas has not been breakthrough in gas injection scenario.

Figure 6 illustrates the water cut of produced liquid in two cases. The difference between the two water cut curves is just 2-5%. This fact shows that higher production rate of water in gas injection case is due to the higher rate of oil production. Additionally, since the water cut does not increase sharply in case of waterflooding, one can conclude that water has not breakthrough in waterflooding scenario.

Finally, **Figure 7** displays average reservoir pressure is in two cases. In gas injection scenario, the pressure decreases more rapidly than in water flooding. After 2800 days from the start of water and/or gas injection, the pressure tends to increase slightly in case of water injection and then decreases slowly at the end.

Conclusions

Natural production of oil by depletion and water drive from aquifer will result in very low ultimate recovery factor due to relatively heavy to heavy oil in Soroosh Burgan-B reservoir. The ultimate recovery factor will be around 6.5% after a production period of 30 years.

The variation in oil viscosity in Burgan-B reservoir is very large, ranging from 15 to 800 cP. Almost half of the initial reserve of this reservoir belongs to the bottom layer which bears high viscosity heavy oil. Conventional production drives such as rock and fluid expansion, water influx, and solution gas drive are not efficient in recovering this heavy oil. Therefore special enhanced oil recovery methods should be applied in Soroosh field.

Waterflooding can be efficient just for upper high permeability layers which contain lighter oil. From simulation runs, it was found that water flooding can increase recovery factor to 24.7% over a period of 30 years. With a starting oil rate of 90,000 STB/day, the plateau remains longer than gas injection scenario and lower pressure drop occurs in the reservoir, but the decline rate is slightly larger than that of gas injection.

From the gas injection simulation runs, it was found that immiscible gas injection can increase ultimate recovery to 27% which is higher than that of waterflooding. The decline rate of production during gas injection was slower than that of waterflooding, which results in higher oil flow rate and ultimate recovery.

In both cases, the injected fluid did not breakthrough the reservoir and was not produced in wells. This shows that both cases must be investigated in a longer period of time to examine the final effect of injection/production scenarios. In addition, both scenarios may be considered as pressure maintenance, secondary oil recovery methods. The pressure drop was slower after fluid injection and breakthrough did not occurred.

There are two vertical shale barriers which divide the reservoir into three parts and isolate three parts. These barriers are a deficiency for any enhanced oil recovery process. They also necessitate larger number of wells to deplete the reservoir.

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Table 1 STOIIP Distribution per Depth Interval

(TVD m)	Oil density (°API)	Viscosity (cP)	% of STOI
Top - 2150	21-20	14-18	5%
2150 - 2160	20-18	18-27	4%
2160 - 2170	18-16.5	27-35	5%
2170 - 2180	16.5-15.5	35-46	5%
2180 - 2190	15.5-14.7	46-68	6%
2190 - 2200	14.7-14	68-95	6%
2200 - 2210	14-13	95-172	7%
2210 - 2220	13-12	172-307	8%
2220 - 2230	12-10	307-859	9%
2230 - WOC	<10	>859	46%

Table 2 Comparison between different scenarios

Case	Total Oil Production (MMSTB)	Recovery Factor (%)
Before Development	86	3.1
Natural Production	182	6.5
Water Injection	693	24.7
Gas Injection	753	27

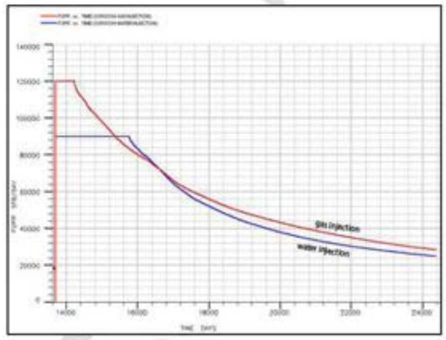

Fig. 1 Comparison of oil production rate for two scenarios

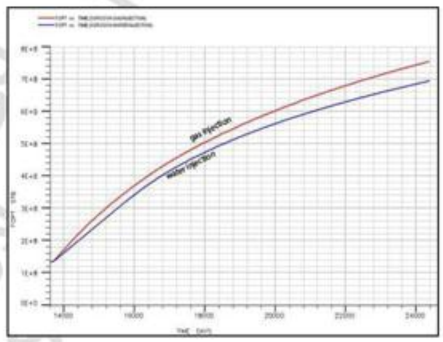

Fig. 2 Comparison of total oil production for two scenarios

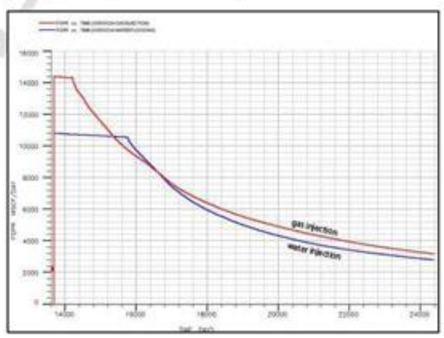

Fig. 3 Comparison of gas production rate for two scenarios

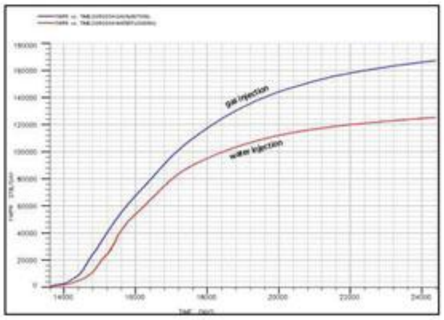

Fig. 4 Comparison of water production rate for two scenarios

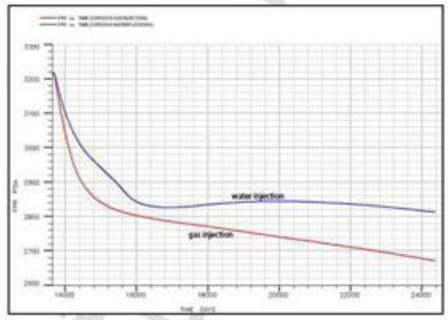

Fig. 7 Comparison of average field pressure for two scenarios

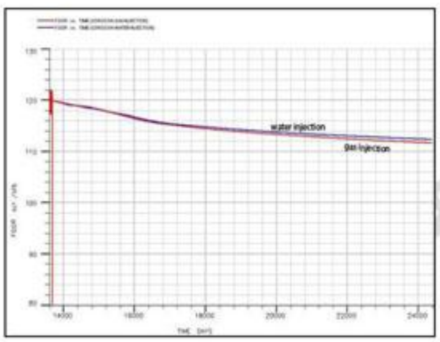

Fig. 5 Comparison of production GOR for two scenarios

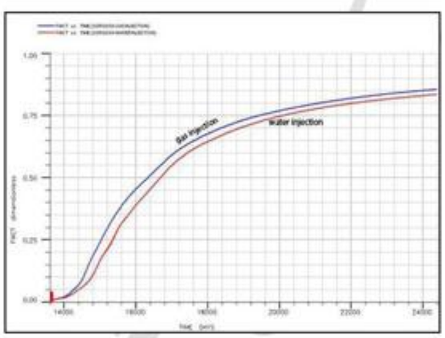

Fig. 6 Comparison of production water cut for two scenarios