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تقييم لفيضانات المياه الساخنة والبخار في خزان فارس السفلي

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خلاصة

عمليات استرداد النفط الحرارية من تقنيات الاسترداد المعزز الناجحة للنفط في العالم. تعتبر هذه العمليات من أهم مصادر الإنتاج اليومي من النفط في العالم. مدخلات الطاقة الحرارية في خزانات النفط والغاز تقلل من لزوجة النفط وتحسن حركية الزيوت الثقيلة. يمكن إدخال الطاقة الحرارية في التكوينات تحت السطحية من خلال الحرارة التي تحمل عن طريق عوامل مثل الماء الساخن أو البخار. تعتبر هذه الآليات من تقنيات الاسترجاع الحراري الهامة التي يتم تنفيذها حاليا في العديد من حقول النفط لزيادة كفاءة استرداد النفط.

تقييم اداء ضخ الحرارة في تحسين أنتاج النفوط عالية اللزوجة قضية بالغة الاهمية لتحسين اقتصاديات مشاريع الحقن الحراري. ولذلك، ينبغي التحقيق من أداء عمليات الاسترجاع الحراري تحت مختلف الظروف قبل التطبيق الميداني.

في هذا البحث، تم التحقيق في آثار العديد من العوامل على أداء الماء الساخن والبخار في خزان فارس السفلي فارس بالوسائل الرقمية. والهدف من هذه الدراسة تسليط الضوء على العلاقات بين الحقن بالحرارة وعامل استرداد النفط تحت مختلف الظروف التشغيلية و الخاصة بالخزان. هذه الشروط تشمل الترتيب لآبار الحقن والإنتاج، أبعاد الخزان الجانبية، معدل الحقن، علاقة اللزوجة في درجة الحرارة والنفط، و سمك الخزان. يتم عرض النتائج من حيث عامل استرداد النفط مقابل وحدة الحرارة التراكمية. وتبين النتائج أن العوامل التي تم التحقيق منها تأثر بدرجات مختلفة على اداء المياه الساخنة والبخار.

Assessment of hot-water and steam floodings in Lower Fars reservoir

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ABSTRACT

Thermal oil recovery processes have been proven successful enhanced oil recovery techniques worldwide and they are very good contributors to the world's oil daily production. The input of thermal energy into hydrocarbon reservoirs reduces oil viscosity and improves mobilization and production of heavy oils. Thermal energy might be introduced to subsurface formations through heat carrying agents such as hot water or steam. These mechanisms are important thermal recovery techniques which are currently implemented in many oil fields to increase oil recovery efficiency.

Evaluating the degree of heat involvement in improving oil recovery from high viscosity oil reservoirs is a crucial issue to optimize the economics of thermal injection projects. Therefore, the performance of thermal recovery processes should be investigated under various reservoir and/or surface conditions prior to field application.

In this work, the effects of several reservoir/operational parameters on the performance of hot water and steam flooding in Lower Fars reservoir are investigated by numerical means. The objective of this study is to highlight the relationships between heat injection and oil recovery factor under various reservoir/operational conditions. These conditions include the arrangement of injection and production wells, reservoir lateral dimensions, injection rate, temperature and oil viscosity relationship, and reservoir thickness. The results are presented in terms of oil recovery factor versus cumulative heat injected per unit reservoir volume. The results indicate that the investigated parameters have various degrees of influence on hot water and steam flooding performance.

Keywords: EOR; Heat Management; Thermal Recovery; Reservoir Engineering.

INTRODUCTION

Primary oil production mechanisms usually have low recovery factors for heavy oil reservoirs. Consequently, large quantities of oil are retained in these reservoirs by capillary and viscous forces after primary production phase. Enhanced Oil Recovery (EOR) techniques aim to increase oil recovery factor by diminishing the influence of retention forces. Thermal recovery processes are one form of EOR techniques which are usually used to improve oil recovery factor for heavy oil reservoirs (Shedid & Abbas, 2000; Abbas & Shedid, 2001). In thermal recovery methods, heat carrying fluids, such as steam or water, are injected in heavy oil reservoirs to reduce viscous forces and hence increase oil recovery efficiency.

Currently, the rate of heavy oil production in USA from thermal EOR processes is around 290 MSTB/day (Moritis, 2010). Figure 1 shows the daily oil production due to thermal recovery processes during the period from 1986 to 2010.

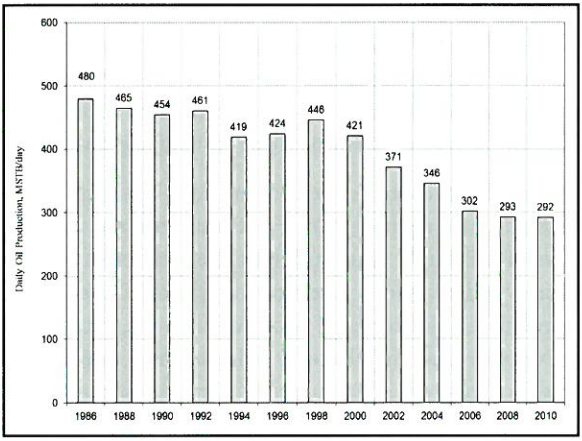


Fig.1. Daily Thermal EOR Oil Production in USA from 1986 to 2010. (Moritis, 2010)

Figure 1 indicates that around 3.6 billion barrels of oil were produced by thermal recovery techniques during the same period. Moreover, Figure 1 shows that the thermally-assisted oil production was declining over the last decade.

In the Middle East, heavy oil reservoirs are found in various quantities. The maturity level of primary production mechanisms in major oil fields and the accelerated global oil demand are main incentives to the recent interest for developing heavy oil resources in the region. Currently, regional oil companies are overlooking thermal EOR processes to develop their heavy oil resources. For example, Petroleum Development of Oman (PDO) conducted a cyclic steam stimulation pilot in 2007 for one of its heavy oil deposits (Thum *et al.* 2010). The results were encouraging and currently PDO is converting the pilot into a full field application.

In Kuwait, Lower Fars (LF) formation holds massive quantities of heavy oil deposits that draw the importance of thermal recovery techniques for the country's future oil production (Al-Shatti, 2005). The reservoir occurs at shallow depths, ranging from 500 - 1000 feet and is widely spread as it is encountered in the most wells drilled in the surrounding areas. In the past, LF reservoir was subjected to two cyclic steam stimulation pilots who indicated the effectiveness of thermal recovery processes in enhancing oil production from the reservoir (Milhem *et al.*, 1987; Ahmed *et al.*, 1989; Al-Qabandi *et al.*, 1995). Aside from these two pilots, this reservoir was left undeveloped for the past 20 years due to the high extraction cost. Currently, the economical attractiveness in developing the reservoir is favorable and LF reservoir management team had investigated many development plans. Recent reservoir studies indicate that LF reservoir is suitable for different forms of thermal recovery processes mainly cyclic steam stimulation, hot water and steam flood (Sanyal, 2009; Oskui *et al.*, 2009). Despite the conducted field studies, the effectiveness of injected heat in increasing oil production should be assessed under various reservoir/operational conditions.

In this work, the performance of hot water and steam flood applications in LF reservoir is investigated under several reservoir/operational conditions. The objective of the study is to evaluate the effectiveness of the added thermal energy in improving oil recovery factor. The performance of hot-water and steam flood in LF reservoir is simulated numerically to determine the relationship between the amount of injected thermal energy and oil recovery factor.

A numerical model representing a sector of LF reservoir was constructed and fed into a commercial reservoir simulator (Eclipse®-300) on which a series of numerical runs were conducted (Schlumberger Information System, 2005). The effects of production and injection wells arrangement, the sector lateral dimensions, injection rate, relationship between temperature and oil viscosity, and reservoir thickness on heat efficiency were investigated.

METHODOLOGY

In order to achieve the objective of this study, a three tasks plan was acted out. During the first task, a simulation model that imitates a sector area of LF reservoir was constructed based on available geological and petrophysical data in the literature. Next, series of planned simulation runs were conducted on the model to define the performance of hot water and steam flooding under various reservoir/operational conditions. Finally in the third task, the results from the simulation runs were analyzed and interpreted to highlight the relationships between the added heat efficiency and oil recovery factor for the investigated reservoir/operational conditions.

LOWER FARS (LF) OVERVIEW AND DESCRIPTION

The necessary rock and fluid data to construct a dynamic sector model for LF reservoir were collected from available literature studies (Sanyal, 2009; Milhem *et al.*, 1987, Ahmed *et al.*, 1989; Al-Qabandi *et al.*, 1995). These data were collected from fluid samples study reports, two cyclic steam stimulation pilots that were conducted in 1982 and 1986, and routine and Special Core Analysis reports (Milhem *et al.*, 1987; Ahmed *et al.*, 1989; Al-Qabandi *et al.*, 1995). The reservoir consists of heavy oil with an API range from 12 to 18 °API and a viscosity range from 400 to 1000 cp at reservoir temperature and pressure of 85 ºF and 250 psia, respectively. Several fluids sample studies are available for many wells in the reservoir. Table 1 shows the API, oil viscosity and density of LF heavy oil at reservoir conditions.

Table 1. Lower Fars oil properties

API	**12 - 18 API**
Viscosity	400-1000 cp
Density	0.98-0.97 g/cc
Sulphur Content, wt %	5.1
Nitrogen Content, wt %	0.2
Carbon residue, wt %	11.1
Vanadium, ppm	59.
Nickel, ppm	59.9

Moreover, the relationships between temperature and oil and water viscosities were determined experimentally, using Anton Paar viscometer, as shown in Figure 2.

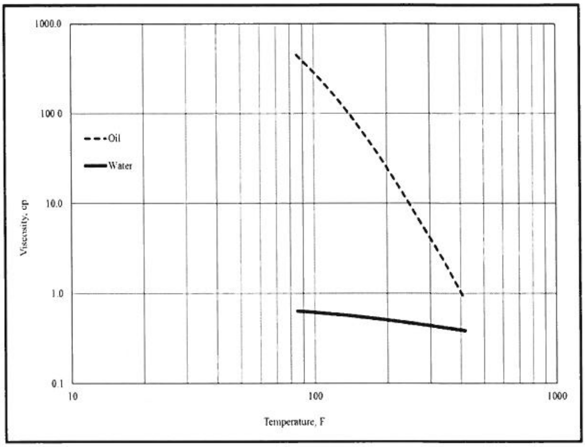


Fig. 2. Oil and water viscosities versus temperature for Lower Fars reservoir.

The figure shows that LF oil viscosity decreases rapidly as reservoir temperature is increased. The LF oil viscosity dropped down to less than 1 cp at 400 ºF. Furthermore, Figure 2 shows that water viscosity is not a strong function of reservoir temperature.

LF is a laminated unconsolidated sandstone reservoir that is frequently interrupted by shale layers, most of which are not continuous except in the middle of LF formation where the shale divides the sand body to upper and lower parts. Accordingly, LF reservoir can be described lithologically as a sand-shale sequence. At the surface, LF reservoir outcrops can be seen south-west of the reservoir area. LF reservoir thickness varies regionally from 300 feet to 1130 feet. Moreover, LF rock properties data are available from several core analysis reports for the region under consideration. LF rock properties are summarized in Table 2. The average porosity in LF reservoir was determined as 30% with initial saturations of 30% and 70% for water and oil, respectively. The average lateral permeability is 3 darcy for most of the reservoir regions. Additionally, thermal properties of the reservoir/cap rock and fluid such as conductivity and heat capacity were determined analytically using available correlations (Viloria & Farouq Ali, 1968). Oil and water relative permeability relationships were obtained experimentally and documented in SCAL reports.

Due to the huge extent of the reservoir and the limitations of data availability on some regions of the reservoir, this study focuses on a sector area where most of the data needed to construct a sector model are available (Sanyal, 2009).

Table 2. Rock properties of Lower Fars reservoir

Rock Type	Sandstone
Rock condition	Unconsolidated
Average depth	˜ 600 ft
Average thickness	˜ 109 ft
Average porosity	30%
Average horizontal permeability	˜ 1 Darcy
Average initial water saturation	30%
Average initial oil saturation	70%
Average reservoir pressure	250 psi
Average reservoir temperature	85 ºF
Reservoir rock heat capacity	31.22 Btu/ft^3/°F
Reservoir rock thermal conductivity	24 Btu/ft/day/°F
Cap rock heat capacity	31.22 Btu/ft3/°F
Cap rock thermal conductivity	30 Btu/ft/day/°F

Based on the available data, one area consisting of 3 wells, which lies in the northern part of LF reservoir, was picked as a location of the geological model. The geological model consists of 11,340 cells. The area of the selected geological model is 6 acres. The porosity values were quite consistent ranging from 28 to 32% over the entire area of the geological model. Permeability values ranges from about 3000 md to 2000 md. The thickness of the geological model was divided into 7 zones based on permeability and porosity data from well logs. Geostatistical reservoir conditioning software was used to generate permeability and porosity distribution maps for the sector model. A total of 100 realizations were generated for the distribution of permeability and porosity within the sector model. These realizations were, then, averaged into one permeability map and one porosity map. Due to the unconsolidated nature of the reservoir sand, the vertical permeability was assumed to be equivalent to the horizontal permeability. Furthermore, the pressure and oil saturation were assumed to be uniformly distributed within the sector model. The spatial domain of the sector model was discritized as 30 cells along the x-direction, 54 cells along the y-direction, and 7 cells along the z-direction to overcome grid orientation effect. Heat losses to over and under-burden zones are accounted for by placing new rock type at the top and bottom of the reservoir.

RESULTS AND DISCUSSION

The performance of hot water and steam flooding in LF reservoir under different reservoir/operational conditions is investigated to appraise the improvement in oil recovery factor due to injected thermal energy. The investigated conditions include the arrangement of production and injection wells, the lateral dimensions of sector model, injection rate, relationship between temperature and oil viscosity, and reservoir thickness.

Three different well patterns are considered: 5-Spot pattern, inverted 9-Spot and direct line drive. Figure 3 shows schematic representations of these patterns.

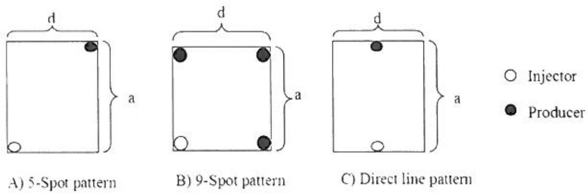


Fig. 3. A schematic presentation of the considered well arrangements.

For each well arrangement, 12 cases were considered to investigate the effects of injection rate, ratio of the lateral lengths of the sector area (d/a), the relationship between temperature and oil viscosity, and reservoir thickness on heat performance. In each case, four numerical runs were conducted with four different injection temperatures that mimic water, hot water, and steam flooding conditions. The injection temperatures were 85, 300, 400, 430 ºF representing various intensity of injected heat. Figure 4 shows two different relationships between temperature and oil viscosity (A and B) that were considered during this study.

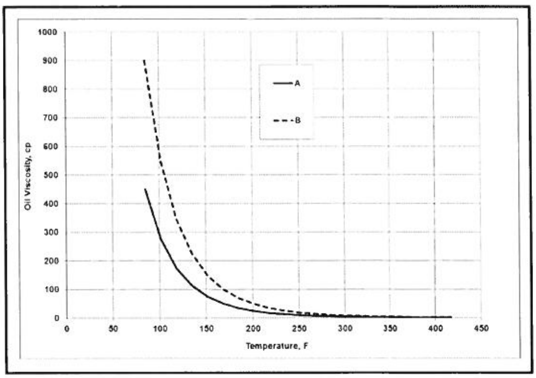


Fig. 4. Viscosity versus temperature for the fluid systems considered in the study

These relationships account for the variations in oil viscosity within LF reservoir. As shown, relationship (A) represents less viscous oil compared to B relationship. Moreover, two different values for reservoir thicknesses were selected to represent the variation in LF reservoir thickness across the region. Table 3 shows a list of the considered simulation cases.

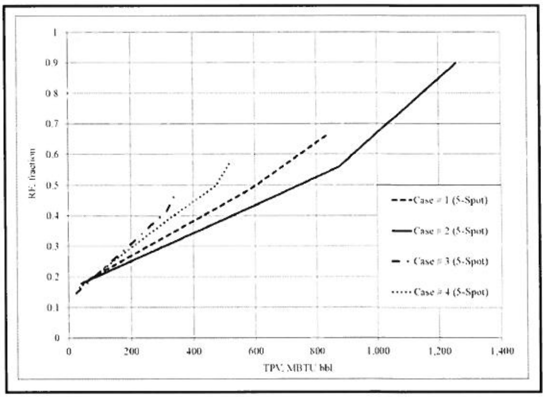
Table 3. Conducted simulation cases for each well arrangement

Case #	Injection rate, CWE bbl/day	d/a	Temperature-Viscosity relationship	Reservoir thickness, ft
1	500	0.54	M1	109
2	750	0.54	M1	109
3	500	1.5	M1	109
4	750	1.5	M1	109
5	500	0.54	M2	109
6	750	0.54	M2	109
7	500	1.5	M2	109
8	750	1.5	M2	109
9	500	0.54	M1	81.75
10	750	0.54	M1	81.75
11	500	1.5	M1	81.75
12	750	1.5	M1	81.75

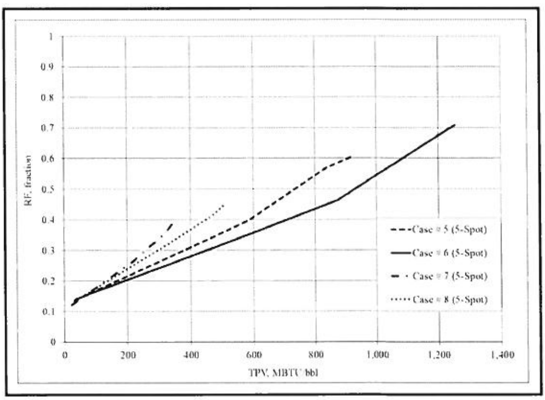
As shown in the table, Cases 1 and 2 account for the effect of injection rate in a sector model with a lateral aspect ratio (d/a) of 0.54, temperature versus oil relationship type A and reservoir thickness of 109 feet. Similarly, Cases 3 and 4 consider the effect of injection rate however under different lateral aspect ratio (d/a = 1.5). Cases 5 - 8 are similar to Cases 1 - 4 except that they consider temperature versus oil viscosity relationship type B. Cases 9 - 12 are similar to Cases 1 - 4 but for thinner reservoir thickness. The outcomes of the numerical runs are discussed in the following sections. The results are presented in terms of oil recovery factor, at 99% water cut, versus the cumulative injected heat per unit reservoir pore volume (TPV). The calculations of oil recovery factor are based on Initial Oil In Place (IOIP).

Five Spot Pattern

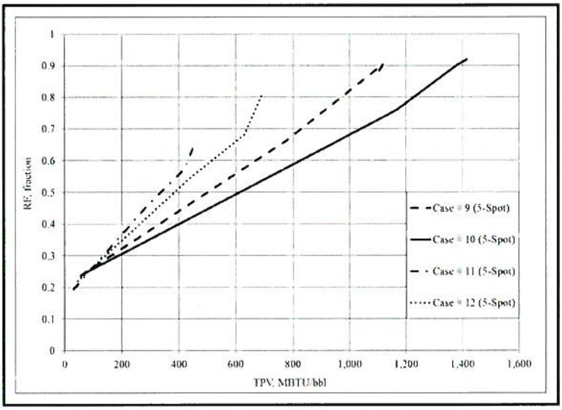
A schematic presentation of a quarter of a 5-Spot well pattern is shown in Figure 3-A where the length (d) is measured along the x direction and the length (a) is measured along the y direction. For a fixed sector area, the shortest distance between the injection and the production wells is achieved when (d/a) equals unity. Figure 5 shows oil recovery factor (RF), at 99% water cut, versus the cumulative injected heat per unit reservoir pore volume (TPV) for Cases 1 - 12. Figure 5-A shows the relationship between RF and TPV under different injection rates and lateral aspect ratios (d/a), i.e. Cases 1-4. For example, the curve which is labeled Case # 1 represents the results of oil recovery factor, at 99% water cut, for four different numerical runs with different injection temperature of 85, 300, 400, and 430 ºF. Figure 5-A shows that RF increases as TPV is increased for the four considered cases. This relationship is not linear, as shown in Figure 5-A, and cases with high heat intensity (steam floods) shows better heat utilization than cases with lower intensity (water and hot water flood). The change in the slope for each curve indicates two different trends between RF and TPV; the first for hot water flooding (Low values of TPV) and the second for steam flood (high values of TVP). This observation is valid for all investigated Cases 1 - 4. However, there is a variation of the slope escalation trend from case to case. Cases 3 and 4 (with d/a ratio of 1.5) have steeper slopes when compared to Cases 1 and 2 (with d/a ratio of 0.5).



A) Oil recovery factor versus TPV for Cases 1 - 4 for 5-Spot pattern



B) Oil recovery factor versus TPV for Cases 5 - 8 for 5-Spot pattern



C) Oil recovery factor versus TPV for Cases 9 - 12 for 5-Spot pattern.

Fig.5. Effect of injection rate and d/a ratio on oil recovery factor for 5-Spot pattern

Moreover, Figure 5-A shows that for a given d/a ratio, Cases 1 and 3 with lower injection rate yielded higher oil recovery than Cases 2 and 4 with higher injection rate at the same cumulative heat injected (TPV). It should be noted that more time is needed for low injection rate cases to reach a certain amount of cumulative heat injected; therefore, at a given TPV more fluids were injected into reservoir for Cases 1 and 3 compared to Cases 2 and 4 and hence higher oil recovery factors were obtained. On the other hand, cases with fixed injection rate show higher oil recovery when d/a ratio is decreased. For instance, Cases 1 and 3 show oil recovery factors of 0.68 and 0.48, respectively, for steam flooding runs. For a fixed project area, the distance between injection and production wells is longer for Cases 1 and 2 compared to Cases 3 and 4.

To further explore the effect of varying injection rate and d/a ratio on oil recovery factor, another set of oil viscosity versus temperature relationship (B) was considered for LF reservoir. Cases 5 - 8 which are similar cases to Cases 1-4 were considered however with different viscosity-temperature relationship. Figure 5-B shows the results of oil recovery factor at 99% water cut (RF) versus the cumulative heat injected per unit reservoir pore volume (TPV). Figure 5-B shows similar trends to those shown in Figure 5-A but with lower values of oil recovery factors due to the high oil viscosity encountered in B relationship.

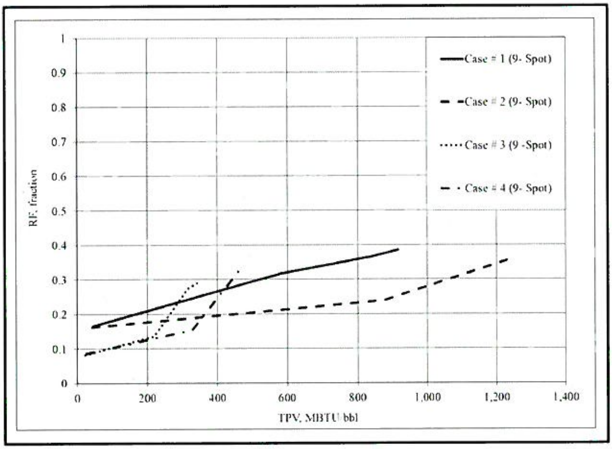
Due to the observed variations in reservoir thickness, more numerical runs were conducted to investigate the effect of injection rate and d/a ratio on oil recovery factor in thinner part of LF reservoir. Figure 5-C shows the oil recovery factor at 99% water cut (RF) versus the cumulative heat injected per unit reservoir pore volume (TPV) for Cases 9 - 12 which have a formation thickness of 81.75 ft. Figure 5-C shows similar trends to those shown in Figure 5-A and Figure 5-B but with higher values of oil recovery. Higher oil recovery factors were obtained for thinner reservoir segments. The increase in oil recovery factor in thin reservoirs is attributed to the reduction in displacement override effect.

9-Spot Pattern

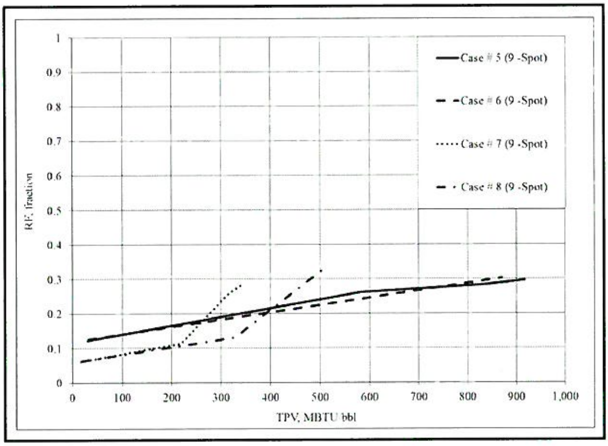
To further explore the effect of injection rate and d/a ratio on oil recovery factor, different well arrangements were considered. In this section, the performances of thermal flooding (water, hot water, and steam) are investigated under 9-Spot well arrangement. A schematic presentation of a quarter of a 9-Spot well pattern is shown in Figure 3-B where the dimension parameter (d) is measured along the x direction and the dimension parameter (a) is measured along the y direction. The effects of injection rate, lateral aspect ratio (d/a), reservoir thickness, and oil viscosity on the performance of thermal flood were investigated. Similar cases to those shown in Table 3 were considered.

The results of Cases 1 - 4 are shown in Figure 6-A in terms of oil recovery factor, at 99% water cut, (RF) versus cumulative heat injected per unit reservoir pore volume (TPV). For a fixed d/a ratio, increasing injection rate will reduce the obtained recovery factor at certain TVP. As mentioned previously, more time is needed for low injection rate cases to reach a certain amount of cumulative heat injected; therefore, at a given TPV more fluids were injected into reservoir for Cases 1 and 3 compared to Cases 2 and 4 and hence higher oil recovery factors were obtained. Moreover, by comparing Cases 1 to Case 3 and Cases 2 to Case 4, the results show that cases with same injection rate perform better when d/a ratio is decreased.

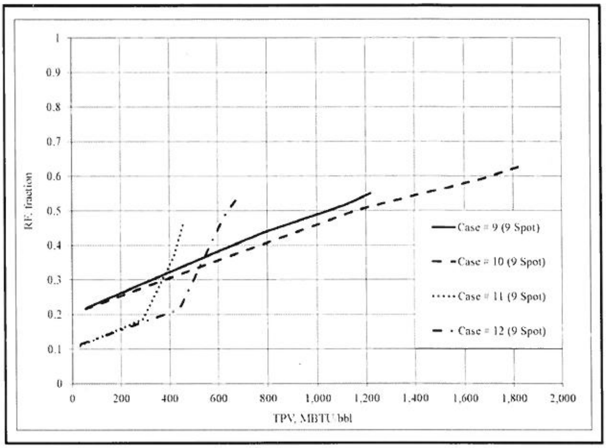
To further study the effect of injection rate and d/a ratio on oil recovery at higher viscosity, different oil was considered with a viscosity versus temperature relationship (B) as shown in Figure 4. Cases 5 - 8 which are similar cases to Cases 1- 4 were considered but with different viscosity-temperature relationship. Figure 6-B shows the results of oil recovery factor at 99% water cut (RF) versus the cumulative heat injected per unit reservoir pore volume (TPV). Figure 6-B shows similar trends to those shown in Figure 6-A but with lower values of oil recovery factors due to the high viscosity nature of B oil. Moreover, the figure shows that for lower values of d/a ratio (Cases 5 and 6) the effect of injection rate on oil recovery is minimal. Thus, for high viscosity oils, the determinant factor in finding the amount of oil produced from a low d/a well arrangement is how much heat is injected rather than how much fluid is injected. To predict the performance of 9-spot well pattern in different part of LF reservoir, more cases were investigated to highlight the effect of injection rate and d/a ratio on oil recovery factor in thinner formations. Figure 6-C shows the oil recovery factor at 99% water cut (RF) versus the cumulative heat injected per unit reservoir pore volume (TPV) for Cases 9 - 12.



A) Oil recovery factor versus TPV for Cases 1 - 4 for 9-Spot pattern.



B) Oil recovery factor versus TPV for Cases 5 - 8 for 9-Spot pattern



C) Oil recovery factor versus TPV for Cases 9 - 12 for 9-Spot pattern

Fig. 6. Effects of injection rate and d/a ratio on oil recovery factor for 9-Spot pattern.

Figure 6-C shows similar trends to those shown in Figure 6-A and Figure 6-B but with higher oil recovery factors. The oil recovery factor increases for all cases as reservoir thickness decreases. The increase in oil recovery factor in thin reservoirs is due to the reduction in displacement override effect.

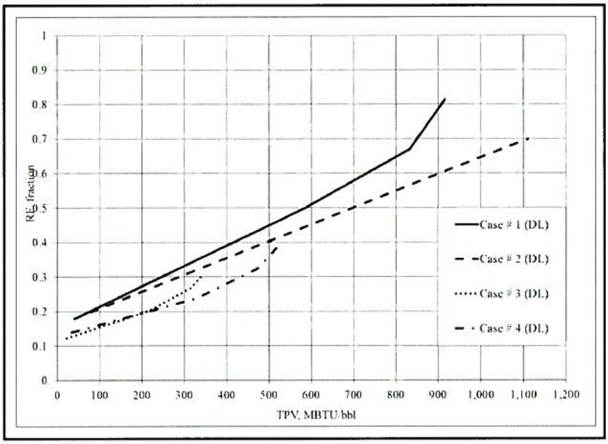
Direct Line Pattern

The third well arrangement in this work is the Direct Line pattern. A schematic presentation of a direct line pattern is shown in Figure 3-C where the dimension parameter (d) is measured along the x direction and the dimension parameter (a) is measured along the y direction. For a fixed pattern area, as d/a ratio increases the distance between the injector and the producer decreases.

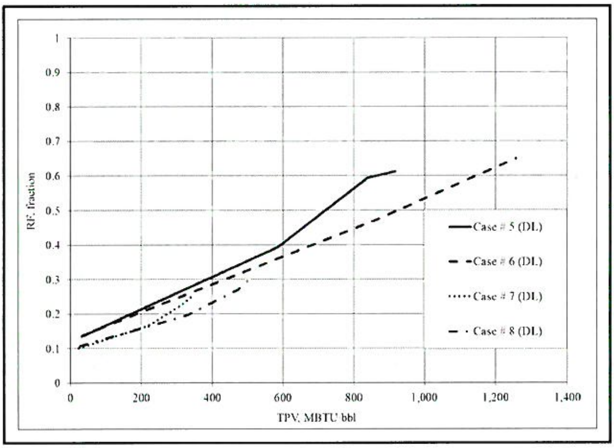
The effects of the same parameters, which were considered for 5-Spot and 9-Spot well patterns, were also investigated under direct line arrangement. A series of simulation runs were conducted to explore the effect of reservoir thickness, injection flow rate, viscosity-temperature relationship, and lateral aspect ratio (d/a) on the performance of oil displacement in LF heavy oil under direct line well arrangement.

The results of direct line drive are shown in Figure 7-A in terms of oil recovery factor, at 99% water cut, versus cumulative heat injected per unit reservoir pore volume (TPV). Figure 7-A shows that oil recovery factor in each case increases as the cumulative heat injected (TPV) is increased. Furthermore, Figure 7-A shows that the oil recovery factor at 99% water cut decreases as the lateral aspect ratio (d/a) is increased. For a fixed area, the distance between the injector and the producer is shorten as the d/a ratio is increased, hence early breakthrough and less effective displacement is observed.

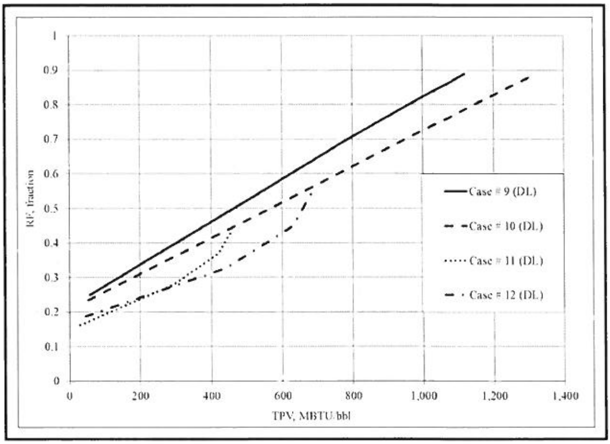
To investigate the performance of the injection processes in more viscous part of LF reservoir under direct line well arrangement, Cases 5 - 8 were considered with different oil viscosity as shown in Figure 4. Figure 7-B shows the results of oil recovery factor versus cumulative heat injected for these cases. Figure 7-B shows similar trends as of Figure 7-A however with lower values of oil recovery factors due to the higher oil viscosity. Finally, Cases 9 - 12 were considered to study the effect of heat injection on oil recovery for thinner reservoirs sections under direct line well arrangement.



A) Oil recovery factor versus TPV for Cases 1 - 4 for direct line drive.



B) Oil recovery factor versus TPV for Cases 5 - 8 for direct line drive



C) Oil recovery factor versus TPV for Cases 9 - 12 for direct line drive

Fig.7. Effect of injection rate and d/a ratio on oil recovery factor for direct line.

Figure 7-C shows oil recovery factor at 99% water cut versus cumulative heat injected per unit reservoir pore volume (TPV) for these cases. Figure 7-C shows similar trends to those shown in Figure 7-A however with higher oil recovery factors. The increase in oil recovery factor is due to the reduction in displacement override effect.

CONCLUSIONS

1 - Comparing the performance of different thermal recovery processes of hot-water and steam flooding based on heat utilization provides a mean to better manage the injected heat.

2 - Oil recovery factor at 99% water cut increases as the temperature of the injected fluid is increased.

3 - The rate at which the oil recovery factor at 99% water cut increases is accelerated for high injection temperature (i.e. steam)

4 - The choice of well arrangement, injection rate and injection temperature has a great impact on the performance of thermal EOR processes in LF reservoir. The difference in oil recovery for a given injection temperature might reach up to 20%.

5 - For LF reservoir, the effect of varying injection temperature is more noticeable in cases with smaller d/a ratio.

6 - For the investigated well patterns, for the same injection temperature, cases with lower injection rate produce higher oil recovery at 99% water cut.

7 - The variation in LF oil viscosity will suppress the relationship between oil recovery factor at 99% water cut with the injected heat.

8 - Among the investigated well pattern, 9-Spot shows the lowest oil recovery at 99% water cut in LF.

9 - Thinner section of LF reservoir shows a higher oil recovery factor at 99% water cut due to lessened gravity effect.

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NOMENCLATURE

EOR = Enhanced Oil Recovery

d/a = Ratio of reservoir lateral lengths

RF = Oil recovery factor at 99% water cut, fraction

TPV = Cumulative heat injected per unit reservoir pore volume (BTU/bbl)

CWE = Cold Water Equivalent

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