یک چند به کودکی به استاد شدیم

یک چند به استادی خود شاد شدیم

پایان سخن شنو که ما را چه رسید

از خاک در آمدیم و بر باد شدیم

خیام

Myself when young did eagerly frequent

Doctor and Saint, and heard great Argument

About it and about: but evermore

Came out by the same Door where in I went.

Khayyam

Translated by Edward FitzGerald

University of Alberta

Heavy Oil/Bitumen Recovery by Alternate Injection of Steam and Solvent (Hydrocarbon and CO_2) in Fractured Carbonates and Oilsands

by

Khosrow Naderi

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Dedicated with sincere gratitude to

my wonderful family

Fariba, Ali, Azade, Roshanak, Navid

whose generous support allowed me to be where I am

ABSTRACT

The world energy demand is constantly increasing and fossil fuels are still by far the main energy resource that supplies the world energy consumption market, therefore increasing oil recovery from all types of reservoirs is an important matter. The burning of fossil fuels for energy purposes, on the other hand, emerges another issue: the accumulation of greenhouse gases into the atmosphere which is considered to be the primary cause of climate change. CO_2 sequestration is a way of mitigating this greenhouse gas from the environment and storing it in underground reservoirs. Naturally fractured reservoirs may be worthy locations for CO_2 storage and if a suitable method of injection is applied, both oil recovery and CO_2 sequestration goals can be met simultaneously.

Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR) is a recently proposed method for heavy oil recovery from fractured reservoirs. This method normally consists of three phases: Phase-I, initial thermal phase that produces oil by thermal expansion and viscosity reduction; Phase-II, solvent phase to dilute and drain oil and; Phase-III, final thermal phase for additional oil recovery and solvent retrieval.

This dissertation extends and modifies the SOS-FR method to employ CO_2 as solvent through extensive experimental and numerical analyses. The experiments were conducted under various pressure and temperature conditions on different porous media including preserved oilsand ores, unconsolidated sandpacks,

sandstone, and carbonate cores. While CO_2 was of central interest, different solvent types were investigated to form a range of comparisons. Solvents were examined in both liquid and gas forms. Temperature was changed for thermal stages to consider hot water, low temperature steam, and high temperature steam. Pressure was also changed in solvent stage. Oil, gas, and porous medium analysis were performed to see the effects of SOS-FR on fluid and matrix properties, as well. Numerical analysis was also done for history matching of experimental data and field scale application of this method to see the results of various injection schemes on both oil recovery and CO_2 sequestration in larger scales.

This work presents the applicability of carbon dioxide as solvent in the SOS-FR method which gives acceptable oil recoveries while reducing the costs of solvent and steam with an additional value of CO_2 storage in naturally fractured reservoirs or post-CHOPS oilsands applications. It is shown that the method is viable and effective for a wide range of applications from unconsolidated sands to fractured carbonates containing heavy-oil and bitumen through vigilant selection of steam-solvent injection strategy ad solvent type under general SOS-FR concept.

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Chapter 1 : Introduction

With rising concerns about the depletion of conventional oil reservoirs, more attention is directed to heavy oil reservoirs as potential energy resources. The difficulties and costs of heavy oil production urge further research to find new methods to overcome these difficulties and/or reduce the cost of production. The challenge becomes more complicated when it deals with fractured and carbonate reservoirs. The main target in this type of reservoir is the oil in the tight matrix, but fracture network controls the flow due to its high permeability. Recovery of matrix -heavy- oil while the injected fluid flows in fractures is a challenge and yet, no systematic technique has been proposed for this type of reservoir.

Unlike conventional oil reservoirs, one has to resolve the issues impediment to flow; i.e., density and viscosity, first. Oil viscosity, in specific, is the major concern. In order to make the oil flow, several methods are proposed, on top of which there are thermal methods that reduce the viscosity by increasing temperature. Other methods can be considered such as solvent applications and mixed thermo-solvent techniques.

The most popular thermal method employed in heavy oil fields is steam injection. The major concerns affecting the efficiency of the process in this method are the heat loss through the well and to the adjacent formation, water requirement, waste water treatment, the cost of steam generation, and excessive CO_2 emission from the steam generation plants. Another critical issue is the condensation of steam after losing its heat, which in some cases might be an obstacle to the flow of oil.

Solvent, on the other hand, dissolves in the oil and cleanses it off the rock matrix. It can be more effective in terms of extracting the oil out of matrix; however, its economics is the major concern. Although it provides in-situ upgrading of heavy oil, the solvent has to be retrieved to a great extent to make the process economically viable. Also, the diffusion of solvent into oil is a critical issue; the heavier the oil, the slower the diffusion and the process takes longer. The solvent should be given enough time to effectively dissolve into the heavy-oil and this time can be reduced by high pressures, which usually does not exist in shallow heavy-oil deposits like the ones in Alberta.

Hydrocarbon solvents are more expensive than oil itself as they are the products of oil through pricey processes. Hence, they need to be reclaimed and reused. CO_2, on the other hand, can be used as solvent and, on the contrary, it is preferred to be disposed of for environmental purposes as it is considered as the major greenhouse gas. Thus, a co-practice of sequestrating the carbon dioxide and using it as a solvent for oil extraction can be implemented and optimized to make both objectives come true. This needs much work on understanding the solvent-oil contact behavior under different conditions of pressure, rate and miscibility conditions.

A combination of thermal and solvent methods has been recently considered to be more effective in oil recovery from heavy oil reserves. Several methods have been suggested such as cyclic solvent-steam injection or alternate injection of solvent and steam. In this research the focus is on a new approach to combine steam as the thermal component and CO_2 as the solvent and employing them efficiently to recover the most oil out of the matrix. As matrix, we considered sandstone samples, carbonate rocks and unconsolidated sands (both preserved oilsand ores and synthetic sandpacks) to mimic fractured sandstone, carbonate and oilsands reservoirs in which the main driving force is gravity drainage.

Background

Enhanced oil recovery (EOR) refers to the invented methods that are employed after primary (oil recovery by its natural flow due to reservoir pressure) and secondary recovery (oil recovery by pressure maintenance methods such as gas or water injection) to increase the production by removing the oil remaining in the reservoir. EOR methods are generally categorized as thermal recovery, chemical recovery, gas recovery and unconventional recovery methods. **Fig. 1-1** shows a simplified chart of recovery methods.

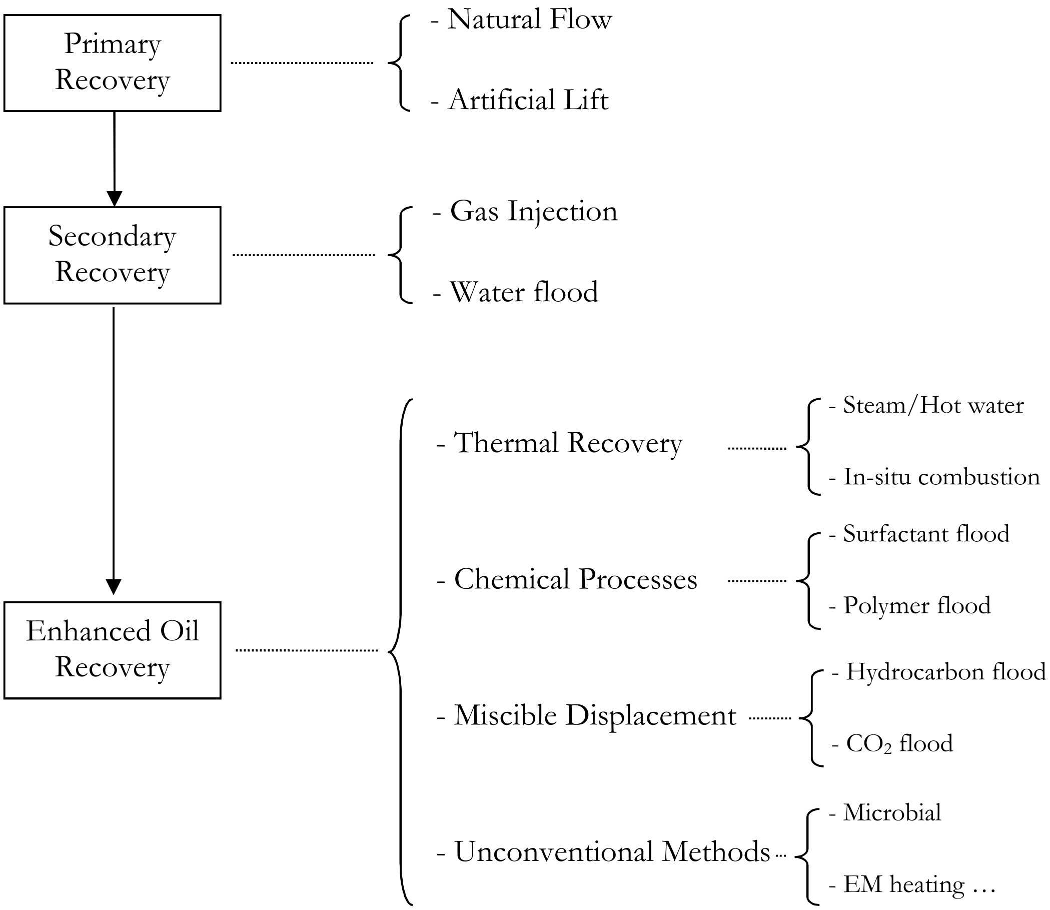

Figure 1-1: Main oil recovery methods.

In case of heavy-oil recovery, the period to move to the EOR methods is much shorter than in conventional reservoirs and often starts right at the beginning of the exploitation. The most common EOR techniques for heavy-oil recovery are thermal (steam) and miscible (solvent) displacement (mainly CO_2) methods (Kokal and Al-Kaabi 2010). Relevant literature regarding the details of the applicability of these techniques is given in each chapter. The following is a brief overview of steam and solvent applications as well as their hybrid applications.

Steam Injection

Steam is injected into a reservoir to introduce the heat and make the oil less viscous. This is achieved through two methods: (1) Steam stimulation (cyclic injection of steam from a single well) and (2) steamflooding. In the steam stimulation process (aka steam soaking or huff and puff), there are consecutive periods of steam injection, whereas in steamflooding, steam is continuously injected from injection wells and oil is produced from production wells. Sometimes they are simultaneously applied once cyclic steam stimulation loses its efficiency by converting the process into steamflooding gradually.

A special form of steamflooding is steam-assisted gravity drainage (SAGD) in which the production is based on gravity instead of viscous displacement. In this process, steam is injected through a horizontal well located with a small gap above the production well. Steam rises up and creates a steam chamber which heats the oil inside and makes it flow at the interface of chamber downward towards the production well. This method was proposed by Roger Butler at Imperial Oil in the late 1970s and well described in Butler (1998). It was then commercialized and widely employed over the 30 years for thermal recovery of heavy oil and bitumen. An extensive review on SAGD has been performed by Al-Bahlani and Babadagli (2008a).

Despite the vast amount of work mainly in unconsolidated reservoirs, SAGD applications in carbonate reservoirs have not yet been investigated, though there are few numerical studies of this kind. For example, Sedaee Sola and Rashidi (2006) investigated the application of SAGD to an Iranian heavy-oil carbonate reservoir with low matrix permeability by field-scale 3-D simulation models and showed that SAGD is feasible for that reservoir and there is an optimum steam injection pressure of 1300 psia. Das (2007) performed simulations on production rates for CSS (cyclic steam stimulation) and SAGD in fractured carbonate reservoirs with high pay thickness and found that the most significant parameters are wettability and oil viscosity. He concluded that SAGD performs better than CSS for higher viscosity heavy oils.

Solvent and CO_2

Solvent usually refers to hydrocarbon solvents and there is ample amount of work in the literature on solvent use in heavy-oil recovery. The most typical application of solvent injection in heavy-oil and bitumen recovery refers to the process called VAPEX (vapor extraction), in which vaporized solvent is injected from a horizontal well to dilute and drain the oil towards to another horizontal well located a few meters lower than the injector. This method was proposed for unconsolidated heavy-oil and bitumen reservoirs by Roger Butler (Butler and Mokrys 1991), yet no commercial application has been reported.

On the other hand, solvent applications in fractured reservoirs are very rare; almost limited to the SOS-FR (steam-over-solvent injection in fractured reservoir) technique proposed by Al-Bahlani and Babadagli (2008a). They tested liquid solvents at the ambient conditions injected alternatively with hot-water and observed remarkable recovery of heavy-oil while retrieving the solvent efficiently by applying a final hot-water injection cycle.

CO_2 can also act as solvent and its injection for EOR and storage is more common in fractured and carbonate systems. However, the miscibility of CO_2 is an issue in its use as solvent. A comparison of hydrocarbon solvents with CO_2 is a critical task especially for extra heavy oil and bitumen recovery as the former is more expensive and the latter brings the advantage of permanent storability.

Injection of different solvents such as hydrocarbon gases (methane, ethane, propane and butane), nitrogen or CO_2 makes a mixture of oil-solvent after their dissolution into oil phase. The efficiency of the dissolving process depends on pressure and advection-diffusion characteristics. Different mechanisms are believed to contribute to the improved oil recovery in the CO_2 displacement process such as oil viscosity reduction, oil swelling, interfacial tension (IFT) reduction, emulsification, etc. (Jha 1986). Hence, it should be investigated if these types of mechanisms are dominant or others such as gravity drainage or diffusion. In a fractured reservoir, oil recovery depends on matrix-fracture interaction and this is achieved primarily by diffusive mass transfer. When CO_2 is used as solvent, oil in the matrix is drained by gravity and CO_2 dissolution into the oil and some portion of CO_2 is stored in the matrix. This process should be optimized so that the maximum amount of CO_2 can be stored into the matrix while maximum amount of oil can be recovered from the matrix simultaneously. In this optimization process, optimal injection rate and pressure as well as the abandonment pressure should be estimated.

A limited number of studies have focused on matrix-fracture diffusive mass transport phenomenon. da Silva and Belery (1989) showed that molecular diffusion is a rapid phenomenon in naturally fractured reservoirs and may override other hydrocarbon displacement mechanisms. Morel et al. (1990) performed methane and nitrogen flooding experiments with horizontal outcrop chalk cores and showed that the recovery process is not a pure diffusion mechanism. Hu et al. (1991) conducted simulation works based on nitrogen diffusion experiments and showed the importance of both diffusion calculation and capillary pressure curve correction on the IFT change due to compositional variation. They also noted that hydrocarbon production depends on molecular diffusion and stream velocity in the fracture. Zakirov et al. (1991) investigated the effect of displacement rate and pressure on recovery performance in miscible displacement in fractured reservoirs.

Firoozabadi and Markeset (1994) showed that the capillary pressure contrast between matrix and fracture could be the major parameter that causes low recovery efficiency in fractured reservoirs. If the capillary pressure of the fractured and layered reservoirs are reduced or eliminated, in case of miscibility or near-miscibility, gravity drainage performance can be improved. Furthermore, they studied the effect of matrix/fracture configuration and fracture aperture on first contact miscible efficiency. Burger et al. (1996) performed experiments on bypassing during gasfloods and concluded that the mass transfer from a bypassed region to a flowing region is a function of the solvent phase behavior and the capillary does not contribute significantly to mass transfer as in the contrary liquid phase diffusion and gravity does in vertical and horizontal orientations, respectively. Burger and Mohanty (1997) showed that the mass transfer is the least for the vertical orientation and the highest for the horizontal orientation.

A number of experimental works were carried out for the purpose of oil recovery from naturally fractured reservoir using carbon dioxide as a solvent. A few of these also focused on CO_2 sequestration. Darvish et al. (2006a, 2006b) used saturated chalk cores and injected CO_2 to displace the oil. They concluded that CO_2 injection could be an effective EOR method for fracture reservoirs after water injection. Variable oil composition confirmed that the main oil recovery mechanism in their experiment was diffusion. Karimaie et al. (2008) performed experiments for secondary and tertiary injection of CO_2 and N_2 in a fractured carbonate rock in reservoir conditions. They used binary mixture of C1-C7 as solute. CO_2 turned out to be very efficient when 73.0% of oil was recovered after a secondary CO_2 injection. Tertiary injection increased the recovery by 15.7% of OOIP. The recovery by nitrogen was quite low.

Trivedi and Babadagli (2008a) performed experiments to study the diffusion process between matrix and fracture. Heptane was used as miscible solvent. The process efficiency was investigated in terms of recovery time and solvent amount. They showed that diffusion is dominant over viscous flow and lower rate of solvent injection gives more production contribution from the matrix as the solvent has more time to diffuse into the matrix before breakthrough.

CO_2 sequestration was also investigated by Trivedi and Babadagli (2008b) where they defined a dimensionless term as the global effectiveness factor in order to optimize both oil (solute) recovery and CO_2 (solvent) storage. They also analyzed CO_2 sequestration efficiency by experiments of CO_2 injection at constant rates into fracture under high pressure (Trivedi and Babadagli 2008c). The shutdown after slower rate showed a better recovery followed by blowdown compared to the faster injection cases. Beneficial pressure range for the sake of recovery and sequestration were measured for different core types. In a subsequent work, Trivedi and Babadagli (2009) combined laboratory experiments and numerical simulations to evaluate the mass transfer between matrix and fracture. Their results showed that the recovery through fracture is dominant by the dispersion effect and mass transfer rate. The length of the matrix was observed to be an important parameter; the longer the core, the later the breakthrough time and the higher the solute recovery. The effects of miscibility and injection rate on oil recovery and CO_2 sequestration were studied by Trivedi and Babadagli (2010). They observed that a certain rate was the most effective rate for both storage and recovery. Near-miscible pressure condition was shown to be the most effective for oil recovery.

Combination of Steam-Solvent

In one of the earliest attempt on the hybrid application of steam and solvent injections, Orlando and Farouq Ali (1972) performed miscible solvent and thermal steamfloods to determine the bitumen recovery from tar sands. Their results showed that bitumen recovery was lower at high rates of solvent floods. Recirculation of solvent was suggested by them to reduce the amount and hence the cost of solvent. They also observed that steamflood might give lower recovery if the core was pre-flooded by solvent.

Nasr et al. (2003) introduced a novel SAGD variation called Expanding Solvent SAGD (ES-SAGD) in which hydrocarbon additive is injected with steam at low concentrations. The solvent would condense with the steam at the boundary of the steam chamber. Condensed solvent around the interface dilutes the oil and helps the viscosity reduction together with oil.

Steam Alternating Solvent (SAS) was introduced and studied numerically by Zhao (2004) in an attempt to combine the advantages of SAGD and VAPEX. In this method steam and solvent are injected alternatively. His simulations showed that SAS might save 18% of the energy input for the same oil production as SAGD.

Horizontal well cyclic steam stimulation with solvent was simulated by Chang et al. (2009). Their results showed that if steam and solvent are to be injected separately in a cycle, it is best to inject the solvent before the steam. However this results in solvent losses in the reservoir which may be recovered by steamflood.

Hosseininejad Mohebati et al. (2010) numerically investigated the effects of hydrocarbon additives to steam in SAGD. Their results suggested that solvent injection could be more effective at lower injection pressure. There is also an optimum solvent concentration above which oil recovery does not improve significantly.

Al-Bahlani and Babadagli (2008b) studied the recovery of heavy oil in fractured reservoirs by alternative injection of steam and solvent and observed fast retrieval of solvent at the end by applying high temperature water injection. They called this method steam-over-solvent injection in fractured reservoir (SOS-FR) and investigated the effect of critical parameters on the efficiency of the process through a series of laboratory (Al-Bahlani and Babadagli 2009a) and field scale analyses (Al-Bahlani and Babadagli 2009b). They observed that lighter solvents produced a higher amount of oil but with a higher amount of asphaltene precipitation. Dynamic experiments confirmed the existence of an optimum rate in terms of recovery time and solvent use. Their numerical model studies showed that this method is applicable at field conditions with much larger matrix sizes (Al-Bahlani and Babadagli 2010). Finally they showed the importance of gravity drainage in the process through 2-D visual experiments using small size Hele-Shaw cells (Al-Bahlani and Babadagli 2012).

Statement of the Problem

The main obstacle for heavy oil recovery is its high viscosity and hence its resistance to flow. The usual means to overcome this issue has been heating the oil in order to mobilize it. Steam injection is the most viable method to introduce the heat into the reservoir but it has its own operational costs and environmental issues. Solvent injection has been proposed as an alternative which has a cost problem. In this process, the solvent retrieval and asphaltene deposition rise as two major concerns. Combined injection of steam and solvent components has been also proposed. These methods need to be investigated deeply in laboratory and field scale to provide a reliable optimized solution.

New techniques should be implemented to increase oil recovery and to decrease the cost due to heating (by operating at a lower temperature) and the use of expensive solvents by increasing its retrieval factor.

Naturally fractured reservoirs (NFR) bring more challenges into this problem. One of these challenges is the effective heating of the reservoir. The fracture system controls the flow of injected steam and it may cause uneven distribution of heat in the reservoir, which yields inefficient heating of oil containing matrix. Another challenge is the unfavorable wettability (oil-wet) of the matrix, assuming that most of the NFRs are made of tight carbonates. This limits capillary imbibition type interaction as opposed to favorable (water-wet) matrixes.

The graph shown in **Fig. 1-2** clearly points out this problem in fractured carbonate reservoirs. The fluid (oil and flashed out initial water) recovery from an oil-wet core (3 cm in height and 1 cm in diameter) from the Qarn Alam field is 47% at fine laboratory conditions (QA5 at 200 ºC with initial water saturation). Assuming the whole initial water flashes out, the oil recovery would be 30.5% only. This recovery becomes lower at reservoir conditions with large matrix blocks.

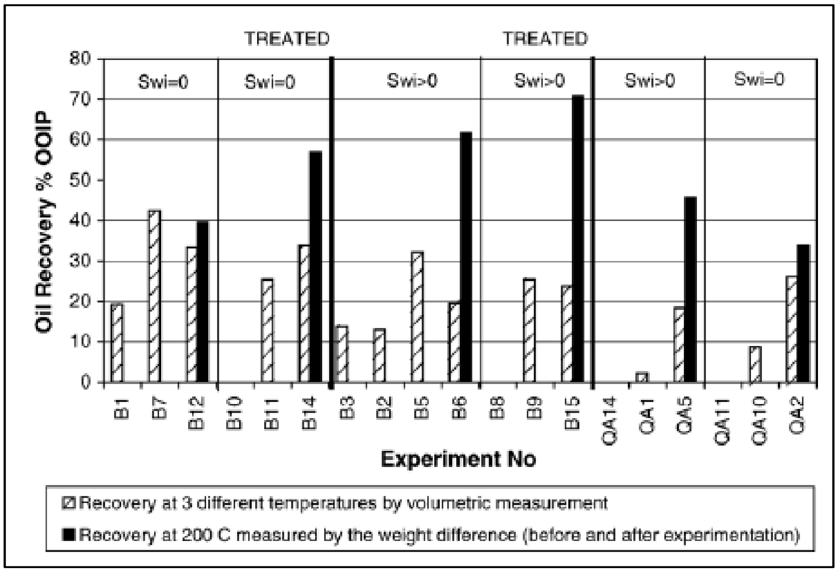

Figure 1-2: Static experiments recoveries at different temperatures (Babadagli and Al-Bemani 2007).

Another similar situation is observed in unconsolidated sands. Heavy-oil recovery after CHOPS (cold heavy oil production with sands) leaves a huge amount of original oil-in-place (~90% of OOIP) in an environment with wormholes. Recovery of this oil is a critical task and represents similarities to oil recovery from fractured reservoirs. Thermal and solvent injection techniques are not easily applicable in this type of reservoir due to huge transmissibility of wormholes.

Under these circumstances, more efficient methods are needed and using solvent is one of the options. Sole injection solvent is restricted due to excessive cost and retrieval problem, especially in fracture carbonates. On the other hand, the diffusion of solvent into matrix oil is rather slow process. One option is to combine it with steam (or hot water) injection but this type of applications requires substantial research to experimentally prove the viability of the method and optimization studies to propose optimal injection conditions for economical feasibility.

The efficiency of solvent applications depends on solvent type, the time available for diffusion, and the amount of solvent injected. Another important issue is the value of injected solvent. Hydrocarbon solvents are usually more effective than CO_2 but more expensive; hence, the solvent retrieval rate becomes a vital matter influencing the applicability of solvent injection. This requires a rigorous optimization study considering the profit obtained by oil recovery and solvent retrieval.

If available, CO_2 can be an alternative to hydrocarbon solvent in heavy-oil recovery from NFRs. This might also add a value to the project if certain amount of CO_2 is permanently stored in the reservoir. The works investigating this matter showed promising results for light oil cases as discussed above, yet it needs to be more thoroughly investigated and optimized, especially heavy-oil applications. Fractured reservoirs display an additional challenge as the breakthrough of injected CO_2 flow might occur and bypass the matrix and leave oil behind. The substitution of CO_2 and oil from fracture to matrix and reverse is the main problem to be considered. A good understanding of matrix-fracture mass transfer, the role of injection rate, pressure conditions, and the gravity effect is required.

In short, a comprehensive solution for the recovery of heavy oil from fractured carbonate reservoirs and after the CHOPS method by means of steam/CO_2 having the side goal of sequestration is needed to be investigated from laboratory to field scale. This work is intended to create a base frame for such solution and investigate the various ways that it may take in order to discover the paths and parameters for further concentrations and developments.

Methodology

The first step in proposing solutions to the above described problem is to clarify the mechanics of oil recovery by the combined injection of steam (or hot-water) and solvent experimentally. The SOS-FR method was adapted and tested for different solvents including primarily CO_2 at different pressure and temperature conditions. This method consists of three phases of injection cycles as proposed by Al-Bahlani and Babadagli (2008a, 2008b, 2011):

(1) Phase-I: Thermal; heating the core with steam or hot water to reduce the viscosity and produce oil by gravity drainage and thermal expansion,

(2) Phase-II: Solvent (Hydrocarbon solvent or CO_2); exposing the core to solvent to dilute the oil by diffusion,

(3) Phase-III: Thermal; normally heating by hot water to recover more oil and retrieve solvent.

The same protocol was applied on different porous media containing different types of heavy-oil and bitumen for different solvents including CO_2.

Unlike the inventors of the method (Babadagli and Al-Bahlani 2008), different pressure and different temperature conditions were tested.

For this purpose, a design of static experiments was developed and different types of cores (sand and carbonate samples) were tested at various reservoir conditions (mainly pressure and temperature). Solvent diffusion into matrix and its retrieval rate as well as the effect of different steam conditions (mainly temperature) on the process were explored during experimentation. Experiments were conducted at static conditions to clarify the matrix-fracture interaction during thermal and solvent applications. Special attention was given to ultimate oil recovery due to the static (closed system) nature of the process as well as solvent retrieval and CO_2 storage. Finally, a numerical model was employed to obtain the necessary parameters such as diffusion coefficients for field scale applications by history matching. Next, the feasibility of the SOS-FR method for hydrocarbon solvents and CO_2 at the field scale was analyzed using the numerical model.

Outline

This is a paper-based thesis. After a short introduction section (Chapter 1) that includes a general overview, problem statement and methodology, five papers which were presented at different conferences and under revision for journal publications are given in Chapters 2 through 6. Each chapter has its own abstract, introduction, literature survey and references.

Chapter 2 deals with low temperature and low pressure SOS-FR application with hydrocarbon solvents and hot water on unconsolidated original oilsands. Chapter 3 applies similar condition of SOS-FR on a specific carbonates reservoir containing bitumen (the Grosmont unit in Alberta). These are purely experimental studies in which original -preserved- cores from the fields were used in the experiments. Liquid hydrocarbons were used as solvent.

In Chapter 4, CO_2 was introduced as a substitute to hydrocarbon solvent and experiments were conducted at high temperature and high pressure conditions on unconsolidated sandpacks. This was to mimic the application of the SOS-FR method in oilsands. Chapter 5 covers experimental works conducted at high temperature and high pressure conditions on both oil-wet and water-wet sandstones and carbonates.

Chapter 6 reports a numerical modeling study at laboratory and field scale. The former is conducted to match the experimental data to obtain diffusion and dispersion parameters. The latter uses this data at the field scale and reports an economic analysis of the method.

The final chapter (Chapter 7) gives the main contributions to the literature and industry as well as suggested future work.

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Chapter 2 : An Enhanced Oil Recovery Technology as a Follow Up to Cold Heavy Oil Production with Sand

A version of this chapter is accepted for presentation at the SPE Heavy Oil Conference Canada held in Calgary, Alberta, Canada, 11–13 June 2013 and is also submitted to SPE Reservoir Evaluation & Engineering.

Introduction

Lloydminster area that straddles Alberta and Saskatchewan border contains vast amounts of heavy oil deposits in thin unconsolidated formations. The amount of heavy oil in place is estimated to be 5.2 E9 m^3 (33 billion bbl) (Brice and Renouf 2008). The oil occurrence consists of multiple zones of thin unconsolidated sandstones with high oil saturations mostly found at a depth of 400 to 600 m. Most of the oil is found in the Lower Cretaceous Mannville Formation. Cyclic bedding typically includes coal capped, upward coarsening units that grade from basal shale through sandy mudstone to sandstone, and upward fining units that grade from basal sandstone to mudstone and shale. Maximum bedding cycle thickness in cores of the offshore and shoreline deposits of the Manville is about 20 m. (Christopher 2002). However, 80% of the oil is found in sands less than 5 m thick. (Adams 1982) These reservoirs have been defined as fine to very fine grained quartzose sand zones with porosities of around 30%, average connate water saturation of around 25% and permeabilities in the 0.5 to 10 Darcy range. Most reservoirs have an average permeability of 1 - 4 Darcy (Dusseault 2002). Oil viscosity ranges between 500 to 50,000 cP and the oil gravity is between 10 to 16 °API. Reservoirs are typically underpressured at initial pressures of 3000 to 4000 kPa and the reservoir temperature ranges from 20 to 30 °C (Carlson et al. 1995)

Cold Heavy Oil Production with Sand (CHOPS) has been successfully implemented in many of these reservoirs, particularly since mid-1980s with the large scale implementation of progressing cavity pumps with which continuous sand production is encouraged. CHOPS comprises the deliberate initiation of sand influx during the completion procedure, maintenance of sand influx during the productive life of the well without any sand exclusion devices such as screens or liners. High permeability channels called wormholes are created as a result which provide a conduit for the flow. Foamy oil behavior, where solution gas stays as bubbles and a continuous gas phase does not form, contributes to flow enhancement (Sawatzky et al. 2002). Because of these unique characteristics of unconsolidated heavy oil reservoirs, well productivity may be 10 – 20 times higher in CHOPS wells than predicted by conventional Darcy's law flow equations (Smith 1988; Han et al. 2007). Therefore, commercial production rates can be attained through this process. However, high heavy oil viscosity, low solution gas oil ratio (generally 8-10 m^3/m^3), and low initial reservoir pressures result in primary recovery efficiencies that are typically below 10% (Dusseault 2002; Guiterrez et al. 2011).

After operating in Lloydminster area for almost 70 years, Husky's experience for the primary CHOPS recovery on average is 8% of the original oil in place. This means that at the end of the primary recovery process, there will still be a very significant amount of oil left behind. How to economically recover this remaining oil in place is still a challenge. Because most of the oil is found in thin oil reservoirs, steam based thermal recovery technologies have a disadvantage due to large heat losses to surrounding formations. In addition, highly adverse mobility ratios limit additional oil that can be economically recovered by waterflooding (Miller 2006). Therefore, an effective follow up recovery process is required.

Steam and solvent injection in fractured reservoirs is a recently proposed method which consists of alternate injection of steam and hydrocarbon solvents to improve oil recovery compared to steam injection alone (Al-Bahlani and Babadagli 2008, 2009a, 2009b). Initial tests were done with hot water instead of steam and liquid solvents for simplicity. However, it was found that even at these relatively low temperatures compared to steam injection significant oil recoveries were obtained. An added advantage of this methodology is that a final injection stage of hot water tends to recover solvent in the reservoir fairly rapidly along with additional oil. It is surmised that wormholes generated during the CHOPS process can act as conduits, similar to fractures in carbonates, to distribute injected fluids into the reservoir and to produce the mobilized oil in return. Therefore, it was decided to carry out similar experiments with preserved, unconsolidated heavy oil cores to see if the hot water and solvent injection can be a viable process in the Lloydminster heavy oil reservoirs.

Experimental Procedure

A series of experiments were designed to investigate the interaction between the fluids in the wormholes and the undisturbed reservoir. The hot water and solvent technique includes three phases. *Phase-I*: This is the initial thermal conditioning phase where the 90 ºC hot water is injected into the reservoir to heat the oil. There may be added benefits of producing some oil due to thermal expansion at this stage. Using hot water delivers less heat but reduces the operating cost significantly compared to steam. At the end of this phase, the reservoir is conditioned for the solvent injection which is conducted in the next stage. *Phase-II*: This is the solvent injection phase where heptane or distillate displaces the hot water and diffuses into the core and dissolves in heavy oil. Solvent experiments were conducted at room temperature in this study. *Phase-III*: This is the final thermal phase where hot water is injected again to recover the solvent in the wormholes as well as the solvent diffused into the matrix. Additional oil can also be produced during this last phase.

The injection of different fluids into the wormholes was simulated by immersing the core into hot water first, solvent next and hot water finally again. The average water saturation is 20 to 25 % in the Sparky formation of Dee Valley area near Lloydminster, Saskatchewan where the preserved core was obtained. The dead oil viscosity is 14,000 cP and the reservoir temperature is 20 ºC at a depth of 475 m. In order to calculate porosity, the differences in the initial core weight and the weight after the final cleaning was used assuming that the core was initially saturated with oil only. Therefore, if one ignores the experimental errors, the recovery numbers reported in this study are conservative values and that they should be higher with some connate water in the system (i.e. lower initial oil volume).

Mass of asphaltene precipitated in the core at the end of an experiment was measured by cleaning the core with heptane first, which does not dissolve asphaltenes, and toluene next, which dissolves asphaltenes. The oil recovery was calculated by measuring directly the volume of oil recovered in the first phase and by calculating oil fraction in the mixture in the solvent phase using refractometer in Phases II and III. The ultimate oil recovery was also calculated by taking the difference in the weight of the core before and after the experiment and this value was compared to the volumetric numbers for quality assurance.

Core plugs of 1.5 inches in diameter were taken from the full size core while it was frozen. These plugs were shipped to the laboratory inside a Teflon casing. The frozen sample was carefully removed from the Teflon casing and wrapped with a permeable material while making sure that the original pore structure is disturbed minimally. This arrangement preserved the core integrity while providing a medium for fluid exchange with the core. The solvent interaction with the oil is visually observed as illustrated in **Fig. 2-1** where the images show how the solvent color changes daily over an 18 day period. The amount of oil in the solvent is calculated with a refractometer which was calibrated using the solvent and the oil from the core.

Results and Discussion

Fig. 2-2 shows the core in Phase-III where the core is now placed in hot water and the temperature is kept constant by placing the whole apparatus inside an oven. The bubbles observed in this figure are those of the boiling solvent expelled from the core as the boiling point of heptane is very close to the water temperature of 90 ^{o}C at atmospheric pressure. This process happens quite vigorously and quickly. It is interesting to note that the initial hot water exposure (Phase-I) only produced negligible amount of oil as there was minimal thermal expansion at these temperatures, with no water imbibition into the core providing support that the core is oil wet. If the core was water wet, one can expect that this phase would provide some oil recovery through water imbibition (Al Bahlani and Babadagli

2008). However, after solvent exposure, hot water does imbibe into the core quite readily recovering additional oil and more importantly recovering a significant portion of the diffused solvent. Additional oil recovery seen during Phase-III in these experiments is partly due to oil being displaced by the boiling solvent and partly due to hot water imbibition replacing some oil solvent mixture in the core. The produced oil is seen as a thin black rim at the top of the hot water in **Fig. 2-2**. While the first two phases take days in the experiments reported here, most of the solvent recovery in Phase-III takes hours mainly because the imbibition of water while solvent is boiling happens quickly.

A series of 10 experiments were conducted using different solvents, different boundary conditions, by repeating some of the steps, by placing the core horizontally and vertically, and by varying solvent exposure time. These experiments are shown in **Figs. 2-3 to 2-12**. In some of the experiments slow continuous injection of solvent is simulated by replacing the oil "contaminated" solvent with fresh solvent several times. In others, a cyclic injection is simulated by repeating Phase-II and III a number of times. The details of each experiment and results are summarized in **Table 2-1** where it is observed that the recovery ranges from 42 to 88% of the original oil in the core. Considering that the original wormholes reach out to the reservoir enough to recover on average 8% of the oil in place in a typical CHOPS well, then it can be speculated that the technique suggested in this chapter could provide an additional 3 to 7% recovery if it can be implemented economically.

Asphaltene precipitated in the core as a percentage of original oil in place (OOIP) was measured between 2.5 to 11.7 weight%. Note that the highest asphaltene precipitation happened in the experiment where the initial thermal conditioning phase was skipped. Higher molecular weight distillate has better asphaltene dissolving capacity and, thus, yields lower asphaltene precipitation compared to heptane. Given the high initial permeability of these unconsolidated formations and very permeable pathways in the reservoir of wormholes, the risk of permeability impairment due to asphaltene precipitation is expected to be low. This would be in line with the current operations as asphaltene precipitation problems are rarely encountered during the primary CHOPS operations.

A number of experiments (1, 2 and 3) were done by changing the hot water and solvent exposure time. It is seen that the initial hot water phase does not produce any appreciable amount of oil regardless of the exposure time. Furthermore, it is seen that the recovery at the end of the solvent phase of 23 to 35 days is in the 40 to 55% range. This recovery can be increased by repeating the solvent and hot water exposure a number of times as seen in experiment 3 where the recovery at the end of the initial solvent exposure of 30 days is 56%, in line with the previous experiments. However, if one repeats the solvent phase one more time briefly for 10 days, the recovery can reach as high as 74%. A similar trend is observed in experiment 4 (counter current experiment) where the recovery at end of the initial 40 day solvent exposure is 52%, in the range of previous experiments. Again if one repeats the hot water and solvent phases twice, for 20 days the first time and for 10 days the second time for the solvent exposure, the oil recovery can be as high as 88%.

It should be noted that cores in all the experiments reported here had all their sides open for interaction with the exception of experiments 4 (vertical) and 5 (horizontal) where only one circular end of the cylindrical core was open. Therefore, these two experiments simulated counter current flow at the faces of the wormholes. The oil recovery at the end of the first solvent phase for these two experiments is the same (52%) even though the exposure time changes between 40 to 65 days. It is likely that the intermediate data points have some error and they should probably look more like the second phase of experiments 1 to 3. If this was the case then the change in the recovery from 40 to 60 days would be small and within the experimental measurement error. One can conclude that the counter current experiments are as efficient as the experiments with cores where all the sides are open for fluid interaction.

Two experiments (6 and 7) were conducted to simulate continuous and slow solvent injection where the oil saturated reservoir is exposed to fresh solvent during the solvent injection phase. In experiment 7 the solvent phase lasted for 30 days during which fresh solvent was provided to the core for 4 times in 8 day intervals including the initial solvent injection. The recovery at the end of the solvent phase was over 70% with small additional recovery during the last phase. In experiment 6, the solvent was replenished 6 times at 7 day intervals and the last batch of solvent was allowed to stay in contact with the core for 45 days for a total of approximately 80 days of solvent exposure. The resulting recovery in experiment 6 at the end of the first 4 solvent batches which took about 30 days is 58% and the ultimate recovery is over 80% showing the effect of additional fresh solvent exposure as well as the additional exposure time.

As there is no oil produced during the first thermal conditioning phase, one experiment (8) was conducted to observe how sensitive the process is to this initial phase. While in the reservoir the volume of rock heated will be significant and the heat can be retained longer than these experiments, this experiment still provides some indication as to the effect of this initial phase. Experiment 8 did not have any initial hot water exposure and started with the solvent phase from the start for 80 days. The oil recovery at 40 days of solvent exposure is 42% which is at the low end of the range of experiments where there was initial hot water exposure. In fact the average recovery at the end of a 30 to 40 day solvent exposure phase for experiments 1 to 5 is 51% and if one neglects experiment 1, it is 54%. Therefore, the initial thermal conditioning phase does have a significant impact on the oil recovery during the solvent phase. Experiment 8 continued for another 40 days with an ultimate recovery of 48% which is still below the average.

In Lloydminster, a distillate from Husky's heavy oil upgrader is used to reduce the viscosity of the produced heavy oil so that the oil can be transported to the upgrader through pipelines. Considering the availability and relatively lower cost of it compared to liquid alkane solvents, two experiments (9 and 10) were conducted with this distillate as solvent. During the first experiment (9), the core was exposed to the distillate for 80 days with an ultimate recovery of 80%. If the solvent exposure time is reduced to 30 days as in experiment 10, the ultimate recovery decreases to 64% which is not unexpected. In general, oil recovery with distillate is better than that obtained by heptane. Again this is not unexpected as higher molecular weight aromatic distillate (C11+) should be more miscible with heavier ends even though the diffusion rate is slower than the lower carbon number heptane (C7).

Fig. 2-13 summarizes the main parameters of the experiments including porosity, asphaltene precipitation and recovery factor. Exp. 4 has the highest recovery factor, which is a result of two times repetition of solvent and thermal phases. Replenishing solvent also increases the recovery factor and it gets higher with increasing number of replenishment cycles (Exp. 6). The comparison between these two cases, i.e. repetition or replenishment, depends on how many cycle rounds and how long each cycle takes, as repeating Phases-II and III just once (Exp. 3) yields to a similar recovery as replenishing solvent for four one-week cycles (Exp. 7). Comparing similar experiments with different solvents (Exp. 1 vs. Exp. 10 and Exp. 2 vs. Exp. 9) shows that distillate performs better as solvent in terms of increasing total recovery and also decreasing asphaltene precipitation in the cores. Having no initial thermal phase (Exp. 8) affects negatively on recovery and also increases the asphaltene precipitation, hence initial heating is important in such oilsand samples in order for the whole process to be effective through improving oil recovery and leaving less asphaltene behind. Interestingly, initial heating phase was suggested to be avoided and direct solvent injection followed by hot-water yielded better recovery in case of bitumen carbonates (Naderi et al. 2013).

Although there is no direct correlation between the recovery and porosity, and each case represents different experimental systematic or solvent, the porosities measured were provided as reference in **Fig. 2-13**. Also provided is asphaltene precipitation (and deposition in the core) values (except Exp. #1). Low asphaltene precipitation is obvious for Exps. #9 and 10 due to aromatic content of the solvent.

Finally, the solvent recovery is economically a critical part of the process. This was the main objective in Phase-III, the final hot water phase of the process. As mentioned above, the solvent was recovered fairly quickly during this final hot water phase of the process through boiling off of the solvent from the core as well as imbibition of the hot water into the core. The calculation of the solvent recovered during the final phase is difficult because the system is not completely air tight (**Fig.2-2**). As a result, some air gets mixed with the produced solvent vapors and potentially some solvent escapes from the system. The solvent vapor is condensed and weighted to calculate the amount of solvent recovered. Even during the weighing process, some solvent may evaporate again. Keeping this in mind, in two experiments (3 and 7) solvent recovery calculations were attempted where 45 to 55% of the solvent was calculated to be recovered during Phase-III (**Fig. 2-14**). Given the opportunity for solvent to escape from the system, these numbers are probably low. In a separate series of similar experiments conducted with carbonate cores solvent recoveries of 60 to 80% are observed (Naderi et al. 2013). A more extensive study by Mohammed and Babadagli (2013) focused on solvent retrieval in a similar process on consolidated sandstone cores with different wettabilities using different solvents. The methodology followed was very similar to the present study but they started the process with solvent injection (Phase-II in the present study) and heated applying a similar range of temperature in the following phase. After testing different combinations of injection cycles and solvents, they observed solvent retrieval varying between 72% and 91% for both heptane and the distillate used in our study (Fig. 14 of Mohammed and Babadagli 2013).

Conclusions

Hot water and solvent injection as a post CHOPS recovery technique was investigated in preserved heavy oil cores by conducting a number of experiments with different solvents, different boundary conditions, by repeating some of the steps, by placing the core horizontally and vertically, and by varying solvent exposure time. The oil recovery ranged between 42 to 88%.

The initial hot water phase does not produce any appreciable amount of oil regardless of the exposure time pointing to the fact that these cores are oil wet and that the thermal expansion of the oil is negligible. However, it was found that this Phase-I was necessary to condition the reservoir so that the oil recovery can be maximized.

Higher molecular weight aromatic distillate is more miscible with heavy oil and, therefore, yields higher oil recovery when compared to a lower molecular weight solvent like heptane.

Solvent recovery is an important factor in the economics of this process. Although the current experiments resulted in a solvent recovery factor of 45 to 55%, this number is quite possibly low and the expected recovery should be better than 70% based on other experiments reported separately.

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Table 2-1: Summary of Results.

Exp.#	Solvent	Porosity (%)	Asphaltene Precipitation (% OOIP)	Ultimate Oil Recovery (% OOIP)
1	Heptane	35.5	-	42.2
2	Heptane	33.9	7.3	58.7
3	Heptane	36.2	8.7	74.5
4	Heptane	35.6	5.9	87.9
5	Heptane	55.6	3.9	52.2
6	Heptane	36.5	7.5	81.8
7	Heptane	22.7	7.1	73.9
8	Heptane	46.7	11.7	47.6
9	Distillate	31.6	2.5	80.5
10	Distillate	25.6	6.8	64.5

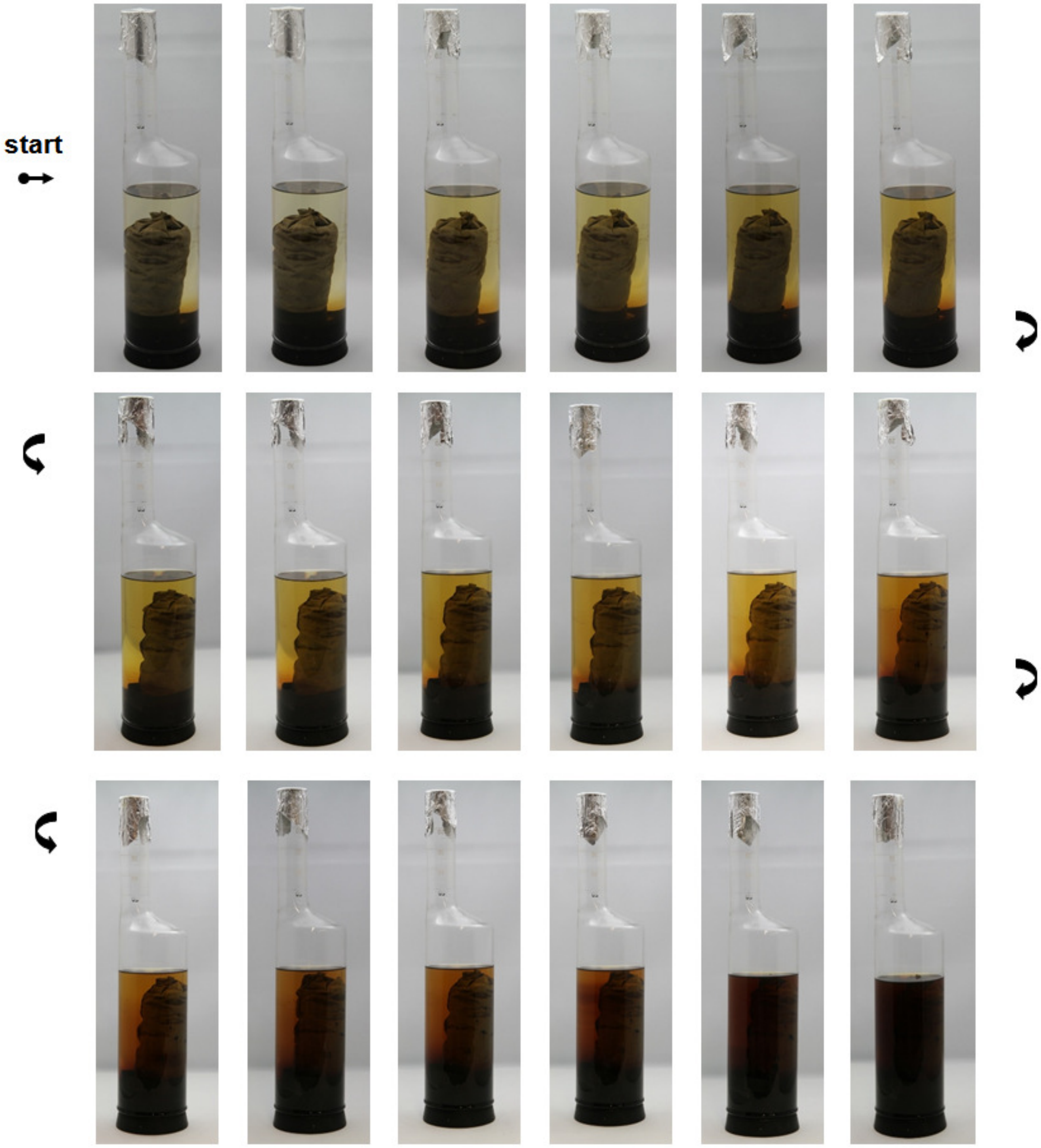

Figure 2-1: Phase-II – solvent phase. Photographs are taken in 1 day intervals.

Figure 2-2: Phase-III in oven.

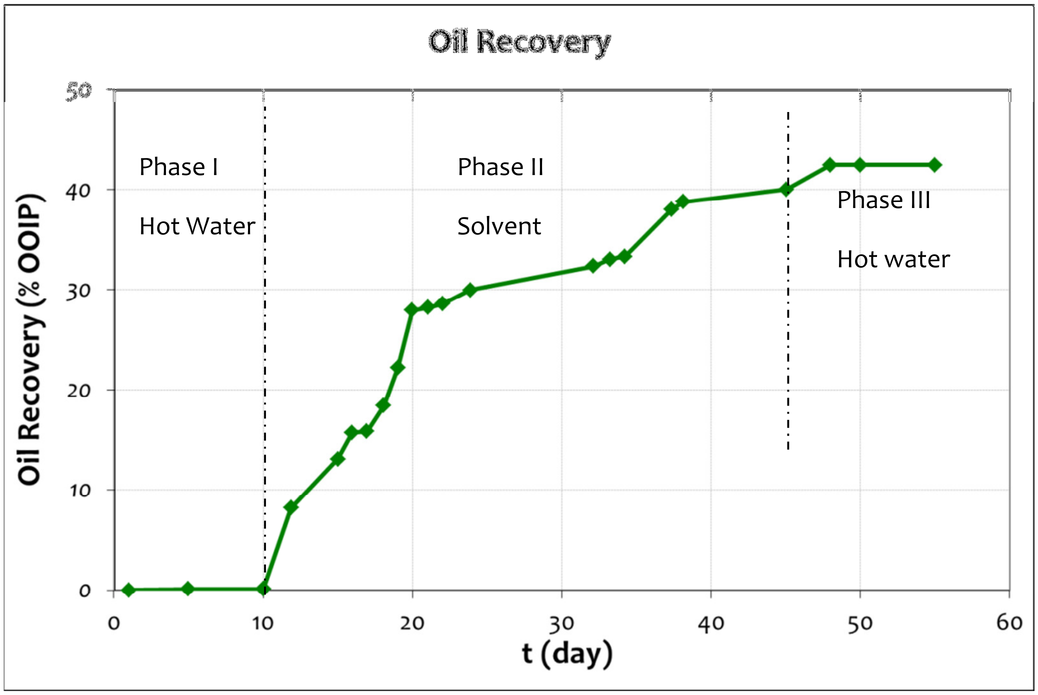

Figure 2-3: Recovery graph for Exp.1.

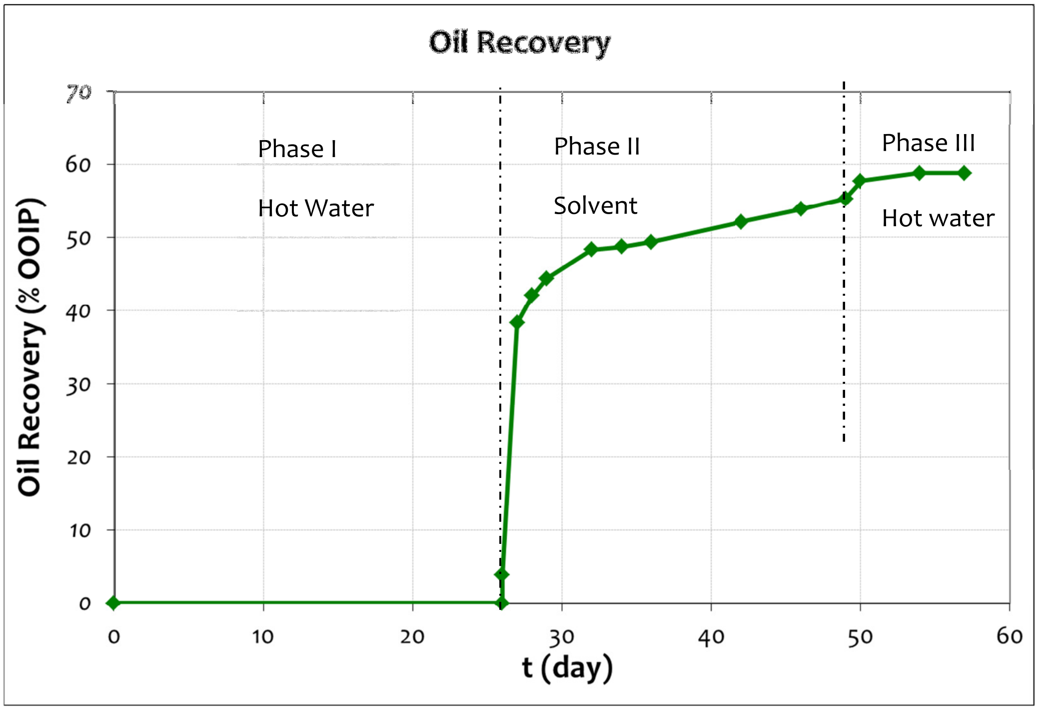

Figure 2-4: Recovery graph for Exp.2.

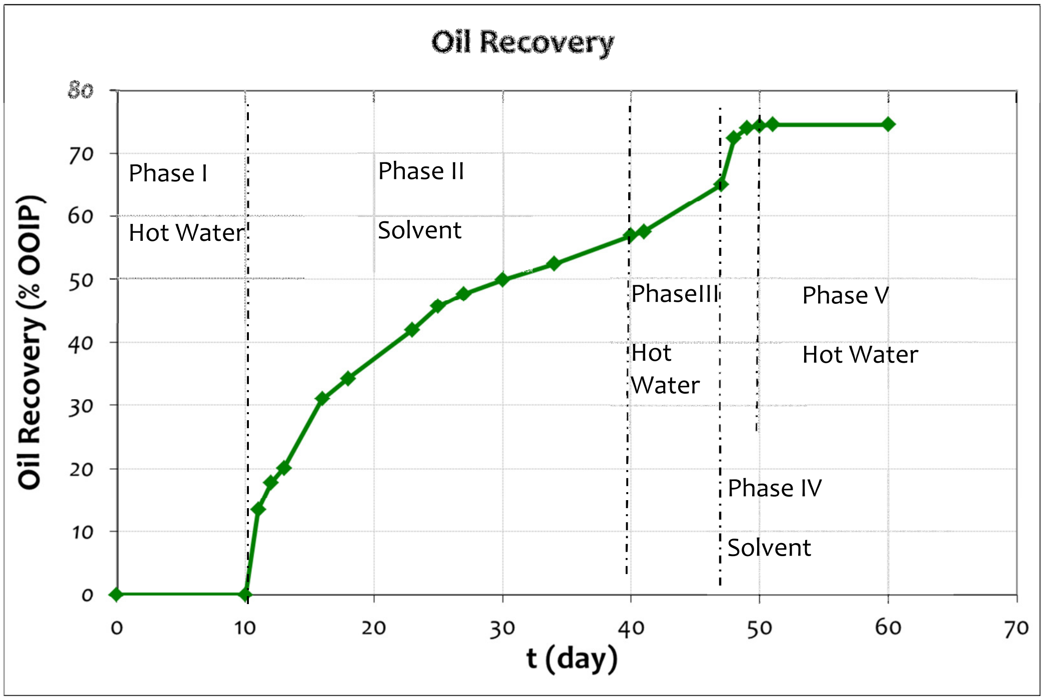

Figure 2-5: Recovery graph for Exp.3.

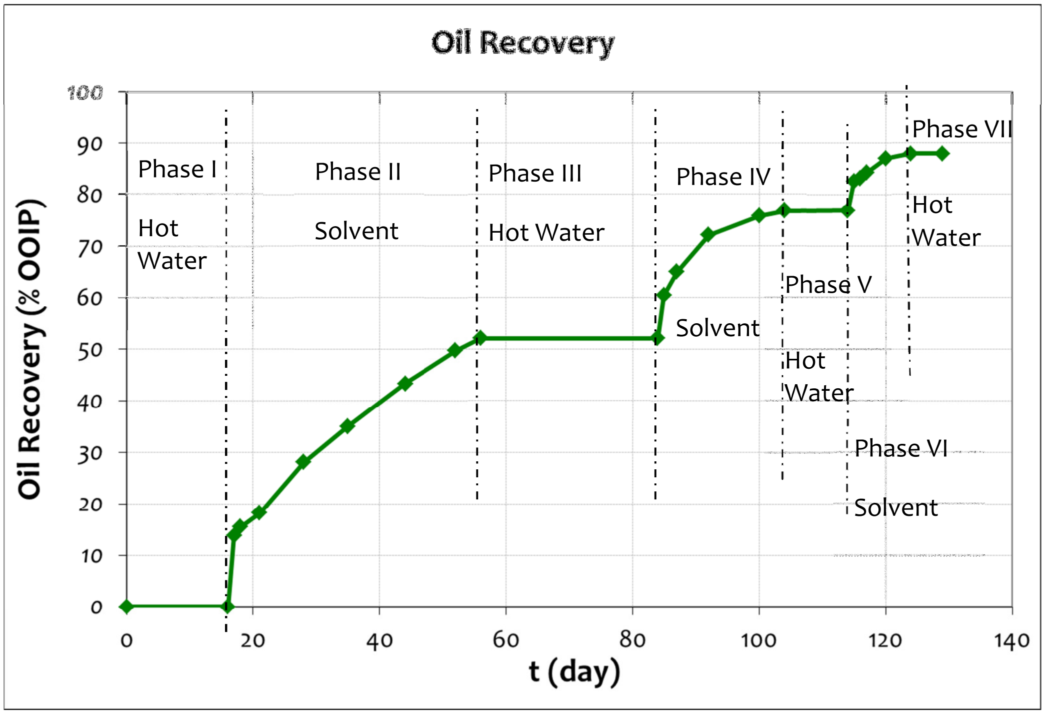

Figure 2-6: Recovery graph for Exp.4.

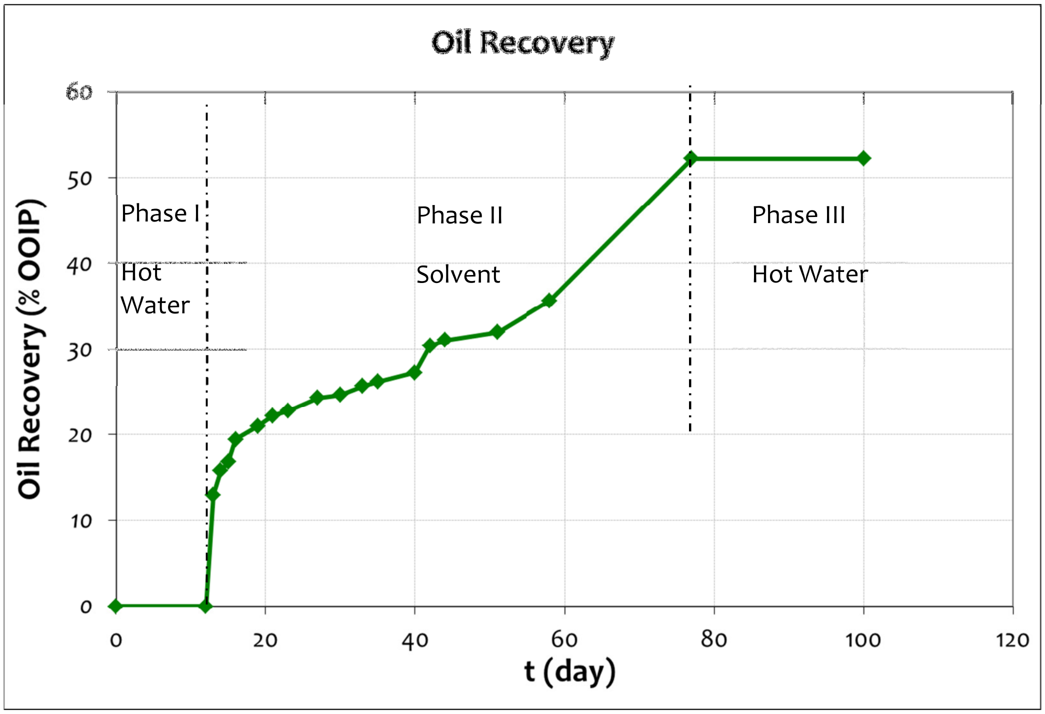

Figure 2-7: Recovery graph for Exp.5.

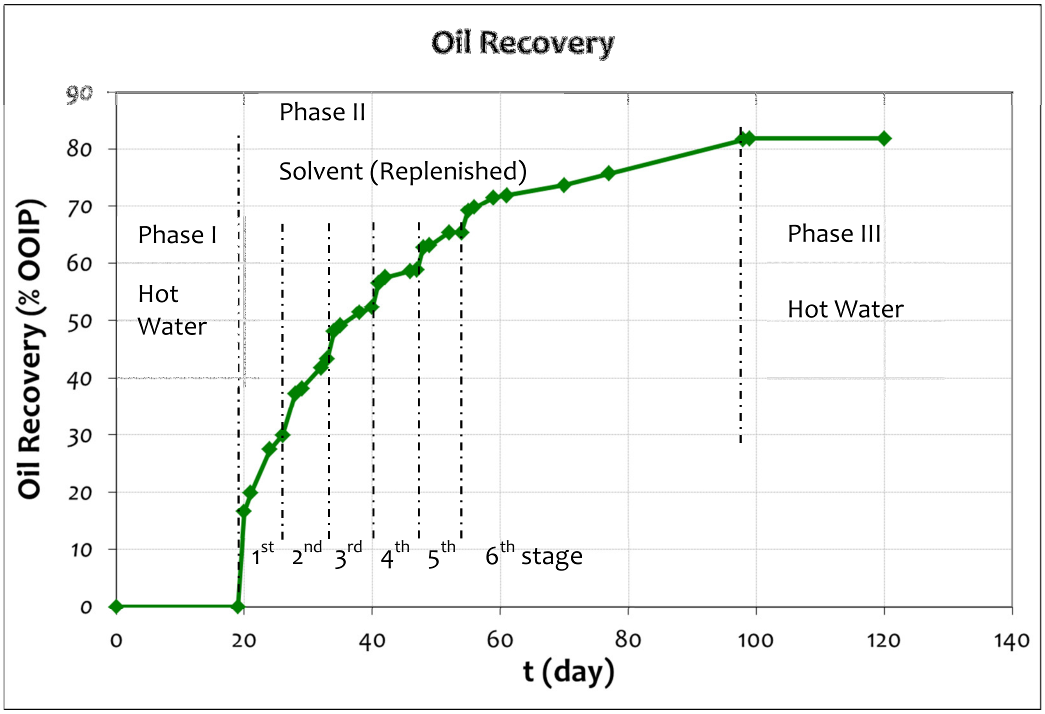

Figure 2-8: Recovery graph for Exp.6.

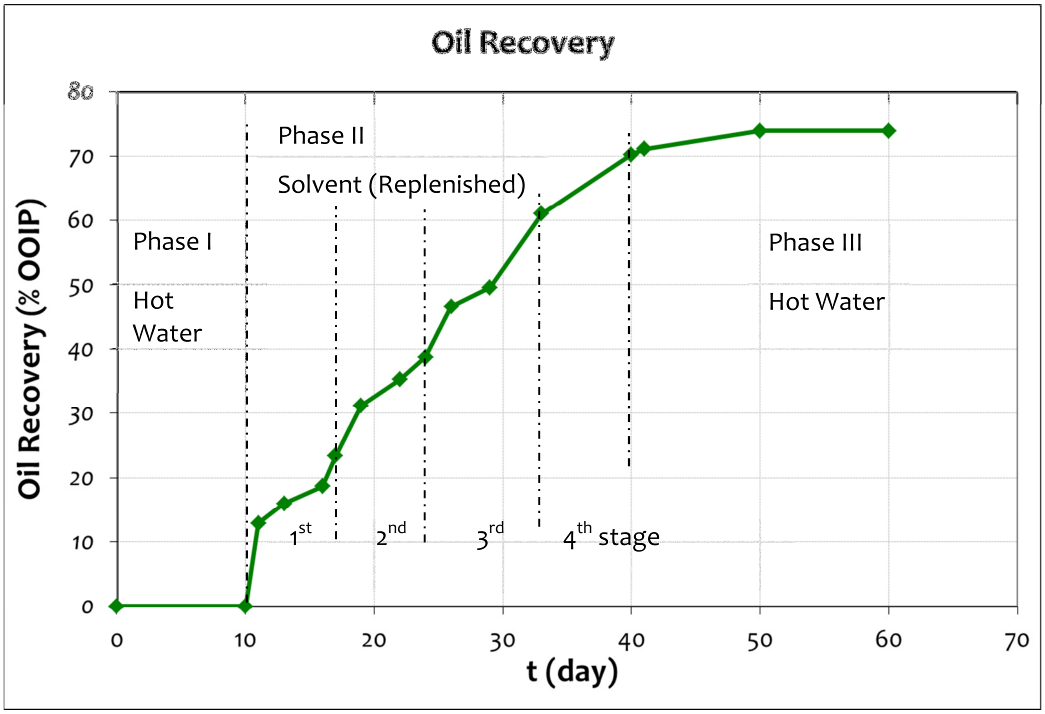

Figure 2-9: Recovery graph for Exp.7.

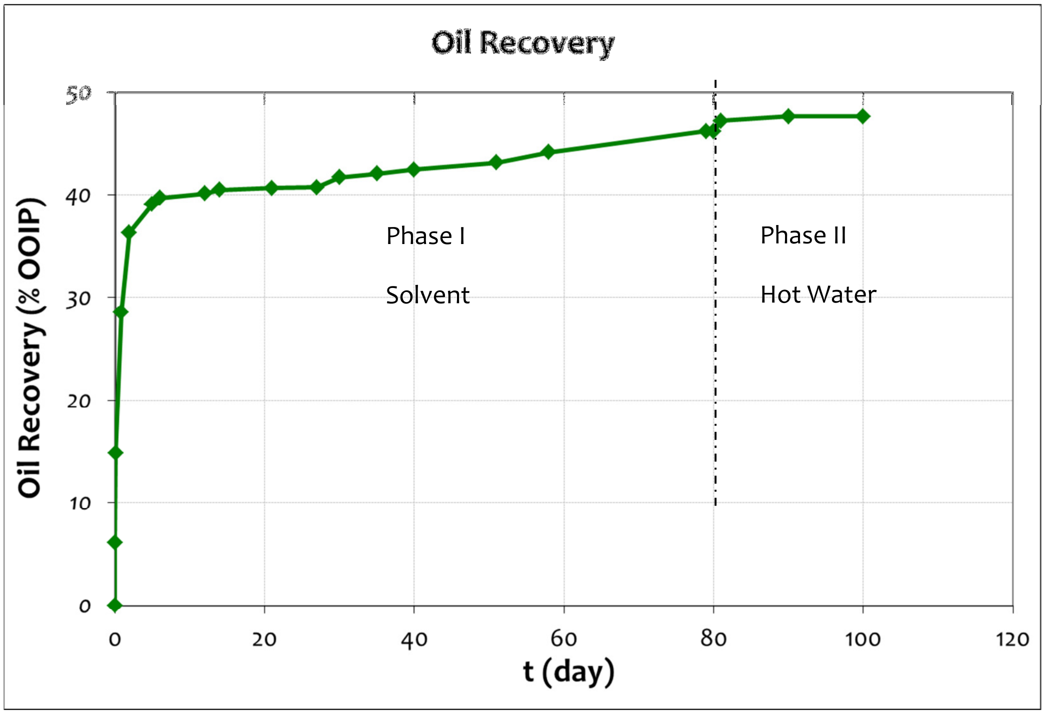

Figure 2-10: Recovery graph for Exp.8.

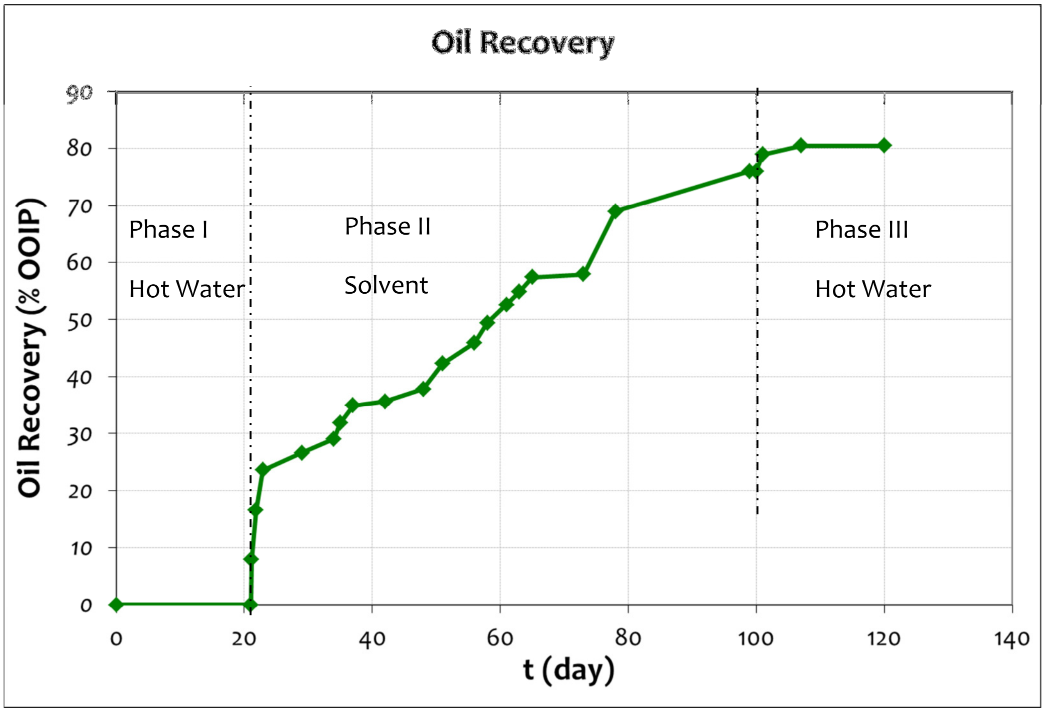

Figure 2-11: Recovery graph for Exp.9.

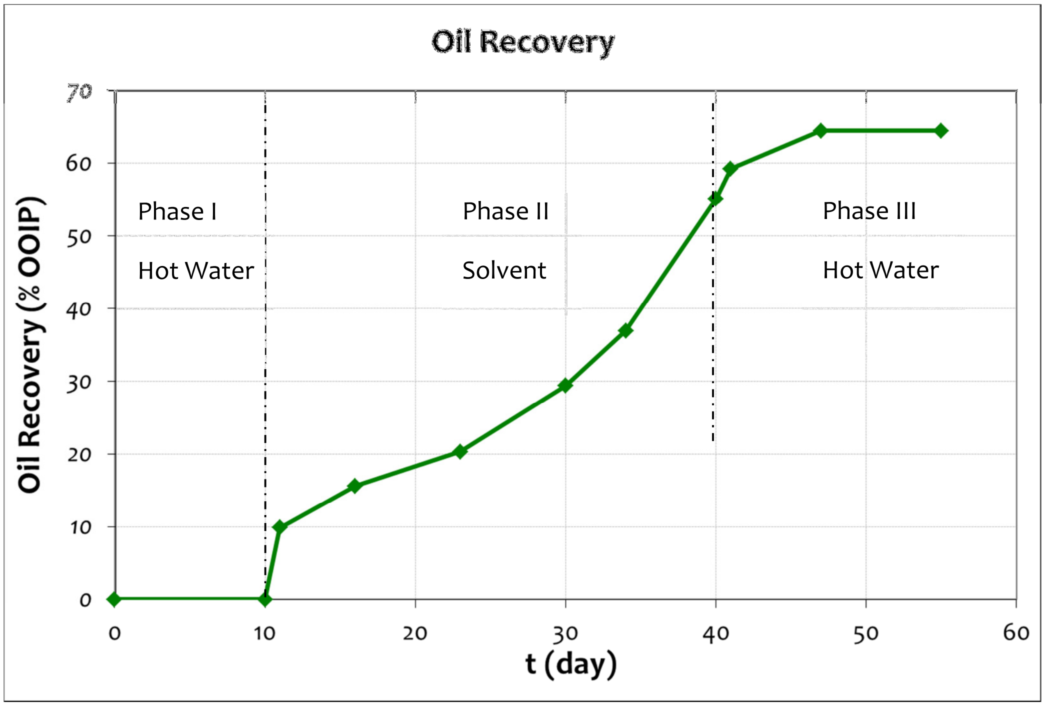

Figure 2-12: Recovery graph for Exp.10.

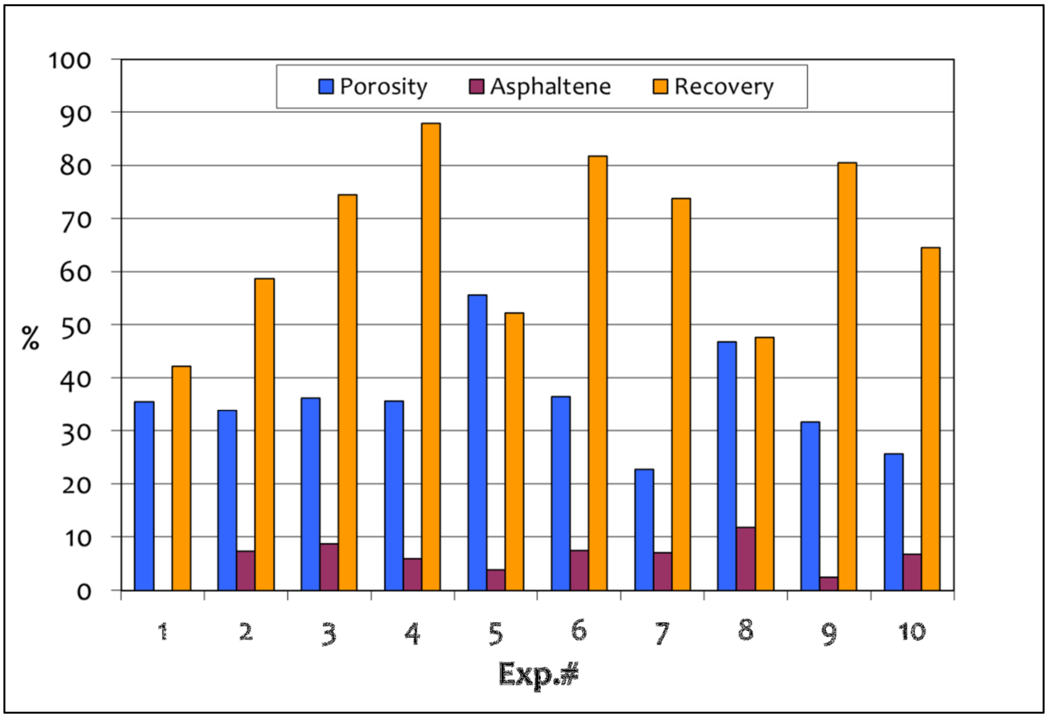

Figure 2-13: Summary of all experiments.

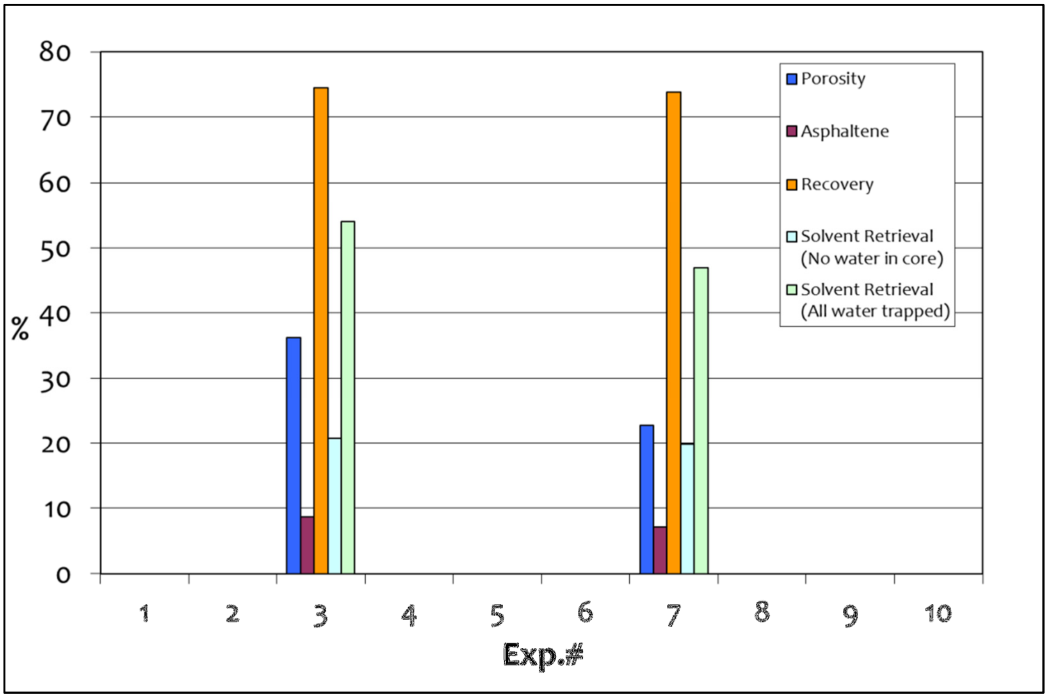

Figure 2-14: Solvent retrieval for two experiments.

Chapter 3 : Bitumen Recovery by the SOS-FR (Steam-Over-Solvent Injection in Fractured Reservoirs) Method: An Experimental Study on Grosmont Carbonates

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Introduction

Heavy oil recovery from carbonate reservoirs is a challenge due to the heterogeneity at different scales such as sub-seismic fractures, micro fractures, vugs, and regional variations of these occurrences. In naturally fractured carbonate reservoirs, a great portion of oil is stored in the matrix and, therefore, the mobilization of this oil into the fracture network is the main target. But, if the matrix is not water-wet as typically observed in this type of reservoir containing high viscosity oil, this may not be a simple task.

An extensive review of enhanced oil recovery (EOR) applications in carbonate reservoirs was conducted by Alvarado and Manrique (2010). They observed that gas injection is the most common EOR method in carbonates, but that dealing with heavy oil is different and limits the options. At first sight, steam injection appears to be the first choice in heavy oil containing carbonates but a routine design of steam injection based on pattern displacement may not be as effective to produce a sufficient amount of oil to offset the cost. Heterogeneity commonly encountered in this type of reservoirs is a restriction for efficient application of cyclic steam or SAGD applications. All these require special designs or modifications to standard steam injection applications.

Applications of steam injection into fractured carbonate reservoirs are rare. The limited number of field pilots include the Lacq Superior field in France (Sahuquet and Ferrier 1982; Sahuquet et al. 1990), the Ikiztepe field in Turkey (Nakamura et al. 1995), the Yates field in the USA (Snell and Close 1999), the Bati Raman field in Turkey (Babadagli et al. 2008), the Wafra field in the Partitioned Zone between Saudi Arabia and Kuwait (Brown et al. 2011), the Oudeh field in Syria (Li et al. 2010), and the Qarn Alam field in Oman.

The Qarn Alam pilot is the only field further extended to a full field scale application. Macaulay et al. (1995) reported that a small primary recovery of 2% of oil initially in place from this field can be raised to 20% by means of thermally assisted gas-oil gravity drainage (TA-GOGD) process through steam injection. This estimation was given from experimental and simulation work prior to the pilot test. Al-Shizawi et al. (1997) discussed the methods of heat monitoring in the same field for the same pilot project. Later studies on Qarn Alam showed the field application possibility and the physics of steam injection (Penney et al. 2005; Shahin et al. 2006; Penney et al. 2007).

Matrix recovery from intensively fractured carbonates like the Qarn Alam field is the most critical part of recovery by steam injection. The matrix should be heated effectively to reduce the viscosity of its oil and drain this oil by gravity more effectively while the injected steam flows into the fracture network. Babadagli and Al-Bemani (2007) performed drainage experiments on Qarn Alam core samples and observed that the recovery can go up to 33% OOIP at 200 ºC. However, this recovery is expected to be lower at the field conditions. Based on their pilot and numerical modeling experience, Shahin et al. (2006) suggested that recovery might go up to 27% OOIP in the Qarn Alam field. They also pointed out that gravity drainage is a slow process and reaching this level of ultimate recovery through this process could take several decades.

A vast amount of heavy oil deposited in carbonate reservoirs around the world is a motivation for more in-depth research to investigate new recovery methods pertinent to carbonate reservoirs to accelerate the recovery rate and improve ultimate recovery. To assist the steam interaction with the reservoir fluid in heavy oil reservoirs, some solvent-aided methods could be considered in order to accelerate the drainage process. One example of such method is steam-over-solvent injection in fractured reservoirs (SOS-FR) presented by Al-Bahlani and Babadagli (2009a, 2012). This method consists of three consecutive phases of hot water, solvent, and hot water injection that enhances the oil recovery overall by steam and solvent alternate injection rather than a co-injection of both. In this study, we applied this method to Grosmont carbonate rock samples containing immobile bitumen and as such possess a bigger challenge to the oil recovery process compared to geologically similar fields mentioned above.

Grosmont Unit

Characteristics

The Grosmont unit is an Upper Devonian carbonate reservoir extending widely in northern Alberta, Canada. The unit contains very large amount of bitumen reserves about 400 billion barrels (Zhao and Machel 2012), and with the current trend in increasing oil prices, these reservoirs are becoming more economically attractive. The recovery of 1,600,000 cP bitumen from the Grosmont carbonates; however, is a great challenge not only because of unfavorable oil properties but also because of the severe heterogeneity. Although several steam and air injection pilots in the 1970s, 1980s and an on-going steam injection pilot showed promising results, currently there is no commercially proven recovery technology.

Past Experience in Grosmont

Steam and air injection pilot tests were conducted in the 1970s, and a solvent injection pilot was performed very recently (Buschkuehle 2007). The results were found to be technically promising but economically unsuccessful. Such efforts resumed recently due to advancements in new technologies and higher oil prices. A review by Edmunds et al. (2009) showed that the high bulk permeability of fractured and vugular Grosmont Unit makes it an attractive target for steam recovery as well as non-thermal solvent technology based on gravity drainage. Warm solvent soak tests in laboratory on Grosmont cores, performed by Jiang et al. (2010), showed nearly 50% bitumen recovery. A comparison of cyclic steam stimulation (CSS) in both Clearwater oilsands and Grosmont carbonates by Ezeuko et al. (2012) indicated that the response of carbonates is completely different than that of oilsands and is very sensitive to the fracture network and steam injection pressure. Jiang et al. (2012) also compared McMurray oilsands and Grosmont carbonates through laboratory tests and field pilot results and proved that both steam- and solvent-based recovery processes are efficient in producing bitumen; however, the Grosmont C reservoir could potentially attain a higher productivity than McMurray oilsands reservoir under optimal operating conditions.

Modeling the Grosmont reservoir faces a big problem of effective permeability estimation as the effect of large vugs and long fractures makes it difficult to rely only on the core samples permeability results. Hence, a successful numerical model should have a diverse permeability distribution while an automated history matching process using a genetic algorithm helps the model be more accurate (Novak et al. 2007). The results of a numerical model created by Yuan et al. (2010) demonstrated that SAGD would be a commercially viable recovery process for Grosmont carbonate with a low pressure injection. The laboratory tests confirmed those results and also showed the enhancement of recovery due to the addition of solvent.

Other challenge in the simulation of bitumen recovery from the Grosmont unit is the fluid properties. A study by Zhao and Machel (2012) reported that Grosmont bitumen is a non-Newtonian fluid at low temperatures (less than 40 °C), but exhibits a shear-thinning behavior at higher temperatures and changes to a Newtonian fluid.

Current Experience in Grosmont

Thermal methods are the first ones called upon to mobilize 1,600,000 cP bitumen. Steam injection is the most common thermal methodology; however, any plan for carbonates should consider the specific conditions of the particular reservoir to utilize the fractures in a certain way to both minimize the heat loss and maximize the thermal energy distribution into the matrix. Early pilot attempts (70's and 80's) on the development of the Grosmont unit were on thermal applications (Edmunds et al. 2009; Jiang et al. 2010; Yuan et al. 2010; Ezeuko et al. 2012). More recently solvent injection was thought to be applicable (Edmunds et al. 2009; Pathak et al. 2012a, 2012b; ERCB Application 1707256 2012).

Solvent processes are beneficial to dilute and drain the heavy oil but the loss of expensive solvent becomes a critical issue in determining the efficiency of this method. Cold solvent laboratory tests showed up to 60% OOIP recovery (Edmunds et al. 2009). A combination of thermal and solvent could be more efficient if it reduces the required steam temperature and thereby the cost of the project. In fact, Pathak et al. (2012b) experimentally showed that butane results in 60% recovery from the preserved Grosmont cores when it is applied at relatively low temperatures (~115 °C) while only 22% OOIP is produced when propane is used at relatively low temperatures (~53°C). Hence, a careful optimization of a hot solvent injection method could yield better recoveries at lower costs.

Another technique recently introduced by Al-Bahlani and Babadagli (2009a, 2012) called steam-over-solvent injection in fractured reservoirs (SOS-FR) suggested an alternate injection of steam and solvent to improve the recovery and retrieve the solvent injected efficiently. A recent optimization study showed that this process could be feasible if properly designed (Al-Bahlani and Babadagli 2011; Al-Gosayir et al. 2011, 2012). In the following sections, the application of this method for the Grosmont carbonates is described and the results are summarized.

Experimental Procedure

The generic experiment to simulate the SOS-FR technique includes three phases, as suggested by Al-Bahlani and Babadagli (2009a, 2012):

- Phase-I: First thermal phase (with hot water in our set of experiments),
- Phase-II: Solvent phase (with heptane or distillate) at room temperature, and
- Phase -III: Final thermal phase (with hot water).

Hot water injected at around 90 ºC reduces the cost compared to standard steam injection at much higher temperatures significantly. Phase-I produces heavy oil by thermal expansion (and capillary imbibition, depending on the wettability of the core) and conditions the reservoir for Phase-II; solvent exposure. Phase-III is applied mainly to retrieve the solvent and to recover additional oil. This process was applied by immersing the core samples into the respective fluids and the recovery was monitored under purely static conditions. Porosity values were calculated as the ratio of the volume of oil to the volume of the preserved rock assuming that the whole pore volume is filled completely with only oil. Asphaltene precipitation in the core after the experiment was measured by the weight difference of the core after heptane and toluene cleaning stages. Asphaltene was cleaned out with toluene but not heptane.

The ultimate bitumen recovery was calculated in two different ways: (a) By adding up the volumetric recoveries from each phase (when the sample was exposed to hot water - Phases I and III) and using refractometer (when the sample was exposed to solvent; Phase-II), and (b) by weighing the core at the initial and final stages (in all three phases). The latter gave a more accurate recovery, while the former was used for cross-checking and finding the recovery values during solvent phase by converting the refracting index of mixture into the amount of oil dissolved in the solvent through a linear correlation assumed between pure solvent and pure oil refractive indexes. These recovery values were also corrected based on weight measurement at the end of solvent phase. Hence, the recovery points in the graphs during the solvent phase show such corrected values while the end points (initial and final recoveries during the solvent phase) were taken from weight measurements directly.

The carbonate cores were drilled out of a full size core from the Grosmont unit (carbonate core obtained from a Saleski well in lower UG2 - C2 geological unit). The detailed description of the Grosmont formation stratigraphic units can be found in Zhao and Machel (2012). Twelve experiments were performed in various combinations of the phases under different conditions. The experiments and results are summarized in **Table 3-1**. Experiments were conducted under static conditions, i.e., the samples were immersed into the injectant (hot water or solvent) to mimic the matrix recovery in naturally fractured reservoirs.

The original preserved core before cutting the plugs for experiments is illustrated in **Fig. 3-1**. It was cut into shorter cylinders and then the cores were drilled out of each portion. **Fig. 3-2** shows the sample G1 after it was prepared for the experiment with a length of 7 cm and a diameter of 3.5 cm. The experimental procedure began by putting the core inside the glass cell exposed to hot water and inside an oven set at a constant temperature (**Fig. 3-3**). **Fig. 3-4** illustrates Phase-II when the core was exposed to the hydrocarbon solvent (heptane or distillate) at room temperature. The solvent gradually diffused into matrix and mixed with the bitumen. The oil then drained by gravity made the color of the solvent in the cell darker (**Fig. 3-4**). The core and asphaltene precipitated and deposited on its outer surface at the end of Phase-II is shown in **Fig. 3-5.**

Fig. 3-6-a illustrates the oil produced and asphaltene deposited on the glass cell, in which the core was placed into, in the beginning of Phase-III (90 ^{o}C hot water). The imbibition cell was kept in an oven for one week at this temperature and then was taken out of the oven at the end of this phase. The oil recovery and asphaltene deposited on the glass cell are demonstrated in **Fig. 3-6-b.**

Fig. 3-7 shows the core out of that cell at the end of Phase-II. As seen, oil is produced out of the core during this phase, sticking to the surface of the rock indicating its oil-wet nature. Then the core was cleaned with toluene (the cleaned core is shown in **Fig. 3-8)**.

At the start of Phase-III, when the core was brought into contact with hot water, the diffused solvent inside the core started to come out due to buoyancy and expansion in the form of bubbles. (Note that to achieve this, the temperature should be around the boiling point of the solvent) This temperature was around 90-95 ^{o}C for heptane (at atmospheric pressure). The rate and amount of solvent retrieved (in the form of gas bubbled) depends on the time of exposure to solvent and therefore to the amount of solvent that diffused into the core. **Fig. 3-9** illustrates the bubbling of solvent in the beginning of Phase-III and **Fig. 3-10** shows the same experiment (G4) after a few minutes. As seen in **Fig. 3-10** bubbling was almost finished also resulting in the recovery of extra amount of oil (almost 2 ml) collected at the graduated part of the cell. The asphaltene precipitated and deposited on the surface of the core after the period of solvent exposure (Phase-II) is seen in **Fig. 3-11** for sample G7.

Results and Analysis

The oil recovery and asphaltene precipitation depended on the solvent type, solvent exposure duration, the situation of the matrix sample (horizontal or vertical), and the temperature applied. The set of experiments investigating the effect of these parameters are listed in **Table 3-1** and the recovery graphs for all experiments are demonstrated in **Figs. 3-12** through **3-23**. A summary of all experiments including porosity, asphaltene and recovery are illustrated in **Fig. 3-24**. **Fig. 3-25** compares the solvent retrieval calculations for three experiments. As seen, the recovery values vary between 40% and 90% OOIP depending on the experimental conditions given in **Table 3-1** (matrix boundary conditions (horizontal or vertical placement), solvent type, and duration of the cycles). The average recovery of the twelve experiments was 68% OOIP. Most importantly, the last phase (hot water immersion) yielded substantial retrieval of solvent diffused into matrix oil with an applied temperature value close to the boiling point of the solvent. The solvent retrieval was extremely fast fully completed within several minutes and varied between 62% and 82% of the solvent diffused into the core during solvent exposure.

Asphaltene precipitated in the core as a percentage of OOIP was measured between 6.5 weight% and 33 weight%. A distillate obtained from Husky's Lloydminster Heavy Oil Upgrader was also used in these experiments. The distillate hydrocarbon was more effective than heptane as it leaves the least asphaltene in the core (G9 and G11). This is attributed to better asphaltene dissolving capacity of higher carbon number solvents (like the distillate used) compared to lower carbon number solvents (heptane) as also observed by Pathak et al. (2012a, 2012b) and Arciniegas and Babadagli (2013). Moreover, the distillate is a naphta mixture that contains aromatic hydrocarbons and its molecular structure makes it more capable of solving heavier ends such as asphaltenes. The GC result for the distillate used in these experiments is given in **Fig. 3-26**. The distillate is mainly composed of C12 (47 mass %) and C13 (21 mass %) molecules. The rest was C11 and lower carbon numbers (19 mass%) and C14+C15 (13 mass%). Heavier molecules make the diffusion slower but being aromatic and carbon structure closer to the oil yields a better ultimate recovery and lower asphaltene precipitation in the long run. The highest asphaltene precipitation in the core at the end of experiment happened in G3 where there was no initial thermal phase and the solvent phase was shorter.

The difference in the ultimate recoveries and the deviation from the average value indicated that the selection of proper injection scheme, depending on the existing conditions, was highly critical. Solvent type also affects the recovery and asphaltene deposition. In fact, the distillate experiments (G9 and G11) yielded much better recoveries compared to the other experiments conducted using heptane. The best recoveries were obtained in the cases with distillate as the solvent in Phase-II. This was a good sign that such fluid from the upgraders could be directly used into the reservoir in such a process instead of injecting refined hydrocarbon solvents such as heptane. Even the horizontal core with the distillate showed a very strong recovery though it was less than the similar case with a vertical core, where the gravity drainage helped the recovery improve (compare G11 with G9 in **Figs. 3-22** and **3-20,** respectively).

The cores in the second set of experiments (G7-G12) were relatively larger in size (20 to 30% larger) than the cores of the first set of experiments (G1-G6). Having that in mind, the first six experiments showed an agreement between recovery and porosity while the second half did not. While the nature, conditions, and sequence of phases in all experiments are different, this gives a general idea that, in smaller cores, the capillary forces are more important while in the larger cores, the effect of fractures and large vugs are more prominent (even though it changes from core to core) and the gravity force is higher and capillary effects are less sensible. Also, more surface area was available for the solvent to diffuse into the matrix which caused increases in the diffused amount as more fluid is available for solvent-oil interaction. Although it had to travel deeper in a larger core, having larger surface area would prevail and improve the diffusion rate.

It was earlier observed that initial thermal phase for heavy-oil containing oil-wet sandstones and carbonates (Al-Bahlani and Babadagli 2009a, 2009b, 2011) and oil-wet and water-wet sandpacks (Naderi and Babadagli 2012a, 2012b) could be useful in conditioning oil for the next -solvent- phase (Phase-II). However, our observations, as summarized above, suggest that when there is no initial thermal phase (Phase-I) and the experiment starts with direct exposure of the core to the solvent (Phase-II) at room temperature, the ultimate recovery is higher (from both Phase-II: solvent, and Phase-III: thermal recovery phase) compared to the similar cases which include Phase-I (and go through all three phases). This can be seen by comparing G3 and G4 with G1 and G2 or a comparison of G8 and G7. Note that a small amount of water might penetrate into the core by capillary imbibition during Phase-I even if the cores are not water-wet. This much water could make a non-wetting free phase in oil-wet carbonate cores that eventually reduces the interaction time and contact surface of the solvent in Phase-II with the remaining oil in the cores, and thereby decreases the diluted amount of bitumen. In this case, Phase-I could be avoided if there is a chance of water penetration into the core even if viscosity reduction effect is critical for the following solvent phase (Phase-II). It should be emphasized that the Exps. G3 and G4 were the very first experiments without Phase-I and the purpose was to obtain an idea about solvent diffusion behavior. During these two experiments, no continuous monitoring of recovery through refractometer was performed, instead, only the final recovery was recorded (red points in **Figs. 3-14** and **3-15**) and the initial and final saturation values were connected by a dashed line to indicate this.

Also observed through **Figs. 3-12 to 3-23** was that the first thermal phase (Phase-I) did not produce oil out of smaller cores for the given time period but contributed directly to the oil recovery on larger cores. Longer cores exert higher gravitational drive on the oil resulting in higher recoveries for these cores compared to shorter ones. While hot water acts within a certain period of time to heat the matrix and condition the oil, it also produced some amount by thermal expansion quickly, and therefore there was no point in keeping the core in the thermal phase any longer. Note also that the thermal expansion effect is better sensed in some cores. That could be attributed to the heterogeneous nature of the cores that might vary sample by sample. Cores with visibly large size vugs yield faster recovery of oil in Phase-I by thermal expansion. This was commonly seen in all experiments except Exps. 1, 2, 5, and 6. These four samples are relatively smaller in size and having relatively large size vugs (especially their connectivity to each other) may not be as abundant as the larger size samples.

Keeping the core in thermal phase for a very long time might have a negative effect on the overall recovery as it would likely thicken the oil by vaporizing the lighter components. This eventually makes the oil-solvent interaction less effective. Thus, it was beneficial to move to the solvent phase (Phase-II) that required a longer period of time due to a much lower diffusivity of solvent into the matrix than heat. This switch time was a parameter for further optimization studies as also indicated by Al-Gosayir et al. (2011, 2012) for heavy-oil recovery form fracture carbonates through the SOS-FR method. There was also an optimal time period for the solvent phase (Phase-II): when the core was immersed into solvent, the solvent started diffusing into matrix oil and its concentration inside the core gradually decreased. This resulted in the reduction of the diffusion rate, and thereby decreased the recovery rate.

Phase-II is of particular importance in this process as most of the oil is recovered during this period. Considering the facts that, solvent diffusion is a rather slow process and it is a costly application, determination of the optimal duration time for Phase-II is very critical. To clarify this, different experiments were compared. As seen in **Figs. 3-12, 3-13, 3-18, 3-19, 3-21,** and **3-23**, most of the recovery was obtained within first ~5 days. Then the recovery rate decreased and elongated solvent exposure did not contribute significantly. Note that solvent was not replenished in some of those experiments and the concentration difference between the mixture surrounding the core (solvent and oil recovered from the core) and the oil inside the core decreased gradually as the more oil is mixed with the solvent.

Solvent replenishment (**Fig. 3-21**) improved the ultimate recovery (mimicking cyclic injection or slow but continuous injection of solvent) compared to the other equivalent cases without replenishment (**Figs. 3-12, 3-13, 3-18** and **3-19**). After a certain period of time (for example, nine weeks in heptane for G2), the solvent was "saturated" with oil and could no longer produce oil by diffusion. Replenishing the solvent overcame this issue as fresh solvent reestablished the concentration difference and hence made the diffusion faster. For example, the recovery due to solvent (Phase-II) was higher when four cycles of replenished solvent, each for only a week, was applied (G10) rather than a very long exposure of the same solvent that is not refreshed during the entire solvent phase (G2). This becomes a critical issue in determining the injection rate of a continuous injection type application or the duration of solvent cycles in huff and puff type applications.

History, i.e., Phase-I, may also impact the performance of Phase-II. Longer exposure to Phase-I delayed the diffusion of solvent in Phase-II. G5 (**Fig. 3-16**) and G6 (**Fig. 3-17**) are good examples for this. 50-day exposure to hot water might have caused some amount of water intrusion into the core by capillary imbibition and this water near the surface of the core, might have created a barrier to solvent diffusion. Hence, one has to pay attention to the use of Phase-I depending on the rock and oil type as well as wettability. As mentioned earlier, in certain circumstances, Phase-I was shown to be useful for different reservoir types (Al-Bahlani and Babadagli 2009a, 2009b; Naderi and Babadagli 2012a, 2012b). As shown in the present study, skipping Phase-I and starting Phase-II directly could be more feasible.

Distillate, on the other hand, showed a slower diffusion rate at first and a different recovery trend compared to the heptane cases. As seen in **Figs. 3-20** (Exp. G9) and **3-22** (Exp. G11), to recover ~40% OOIP in solvent phase it takes more time for the distillate cases (~7 days for the vertical case -G9- and ~13 days for the horizontal case -G11) compared to ~3 days for the heptane ones (Exps. G7 and G8). In general, the distillate recovery curves tend to reach a plateau in a later time than that of the heptane cases. Due to its higher carbon number (predominantly C11-13) as reported by Coskuner et al. (2013) diffusion rate is expected to be slower than that of heptane (Al-Bahlani and Babadagli 2009a, 2012). However, the ultimate recovery by distillate is significantly higher compared to the heptane cases due to its 20% aromatic content (saturates is 80% and resins and asphaltenes are 0%), which dissolves heavier components compared to heptane (100% saturates).

Solvent retrieval was another critical part of this technique and Phase-III was run mainly for this purpose. Quick recovery of solvent (order of minutes) during this thermal phase was expected as the solvent boiling point is very close to the experimental temperature (hot water temperature) helping recover solvent by boiling it (**Fig. 3-9**). The vapor mixture that is generated quickly right after starting this phase is indeed a mixture of heptane (67 volume%) and air (33 volume%). Obviously, the air mixing with produced heptane (in the form of gas) during the collection of the gas produced was unavoidable. The corresponding GC graph showing the composition of a sample of this mixture is shown in **Fig. 3-27**. Capturing the solvent as liquid while it was coming out of the core in vapor phase and measuring the amount retrieved was not a simple process. In three experiments, we managed to collect the solvent produced (or retrieved) during Phase-III. We tested different methods to achieve this. The most efficient method was to transport the produced gas through a tube to a graduated cylinder placed inversely inside a cold water tank. Because the system was not fully closed, it is possible that some amount of solvent escaped in the form of gas and some amount of solvent evaporated within a short period of time during weight measurement and transfer between the phases.

The amount of recovered solvent was calculated from the volumetric measurement of oil-solvent mixture on top of the main cell as well as pure solvent collected in that graduated cylinder. Therefore, the calculation, which was based on solvent recovery in liquid form, showed a pessimistic estimation of recovered solvent since some of the recovered solvent might have escaped in the form of vapor as explained before. The amount of solvent diffused in the core during Phase-II was measured through a simplified material balance as described in the Appendix and it was dependent on the amount of water that remained inside the core. Two sets of calculations were performed assuming extreme cases of: (1) No water left in the core (either all water came out of the core during Phases II and III or it never went into the core in Phase-I, which was the likely case for oil-wet carbonate cores), and (2) the whole water, taken up by the core in Phase-I, remained there during subsequent phases. Both estimations are shown in **Fig.3-25**. Even with the pessimistic approach, a fair amount of solvent (between 62% and 82%) was retrieved. This is a good indication of how Phase-III is efficient in retrieving the diffused solvent back. The retrieved solvent can be recycled back to the reservoir in consecutive solvent cycles to improve the recovery as much as possible. This recycling of the solvent can be performed as a re-injection of solvent; hence there would be consecutive replenished solvent phases. Alternatively, the recycling of the solvent can be done after the second thermal phase (Phase-III), hence there would be a repetition of the solvent-thermal cycles (Phases II and III). The experimental results outlined in this study show that repeating the solvent phase after the thermal phase makes no big change in the recovery (compare G12 with G7) while replenishing the solvent increases the final recovery (compare G10 with G7).

Conclusions and Remarks

The SOS-FR (steam-over-solvent injection in fractured reservoirs) method yielded ultimate recoveries between 40% and 90% OOIP with a mean value of 68% for different solvent types, matrix boundary conditions, and the cycle durations and number of cycles.

Asphaltene precipitation in the core after the experiment was measured between 6.5 weight% and 33 weight%. The oil recovery and asphaltene precipitation depends on the solvent type, solvent exposure time, and matrix boundary conditions (horizontal or vertical placement).

The last phase (hot water immersion) yielded substantial retrieval of solvent diffused into the matrix oil through applied temperature value close to the boiling point of the solvent. The solvent retrieval was extremely fast and varied between 62% and 82% of the solvent diffused into the core during solvent exposure.

Using distillate rather than pure hydrocarbon solvent (heptane) resulted in a better recovery. This could be attributed to higher carbon molecules yielding a lower asphaltene precipitation value. Also note that the distillate is closer in molecular structure to oil than heptane and this might yield a slower diffusion rate (lower diffusion coefficient) but a better mixing in long run. Also note that the distillate contains certain amount of aromatic that might help dissolving and recovering asphaltinic components. Further investigation is required to understand this phenomenon better. In practice, this type of solvent is more readily available at a relatively cheaper cost than processes involving solvent-like heptane and, therefore, is a more promising application.

Timing of the phases is also important, especially in the solvent phase (Phase-II). Selection of cycle durations, and especially how many solvent cycles are needed (solvent injection-solvent soaking-production) is crucial as Phase-II is critical. This can be optimized using a numerical simulation as applied by Al-Gosayir et al. (2011, 2012). Another critical issue is the way Phases II and III are applied. One may consider applying Phases-II and III alternately in several cycles or having repetitive cycles of Phase-II (solvent injection-soaking-production) followed by a single shot of Phase-III for solvent retrieval. The experimental results of this study suggest that repetitive solvent cycles assisted by one thermal phase at the end will yield a better recovery outcome. This; however, requires further experimental support as well as numerical modeling combined with an optimization scheme. Obviously, the first option (repetitive Phase-II-Phase-III cycles) may yield water intrusion in the matrix while applying Phase-III and this water phase may result in a blockage to the solvent diffusion in the next solvent cycle.

Skipping Phase-I and starting the experiments with the solvent phase (Phase-II) in oil-wet Grosmont rocks yields a higher ultimate recovery at the end. Although Phase-I might have significant effects on conditioning the oil for the next solvent phase and contributing to recovery by thermal expansion and viscosity reduction (accelerated gravity drainage and even capillary imbibition), starting the recovery process with solvent could be considered as a better choice.

Replenishing solvent is more efficient than repeating the solvent phase after the final thermal phase recovery as the fresh solvent creates the high concentration difference again and makes the diffusion faster. This implies that the huff and puff type of injection is an option as well as very slow rate continuous injection. A detailed analysis of these options was presented in Al-Bahlani and Babadagli (2011) and Naderi and Babadagli (2012c) for field scale application of the methodology for heavy-oil (~4,000-8,000 cp) using hydrocarbon solvents and CO_2, respectively. The same procedure can be applied to the Grosmont case after matching the laboratory experiments to the numerical models to obtain the data for field scale applications. This will also provide a systematic approach to upscale the process to the field scale, especially considering the matrix size. Different approaches were applied for upscaling the process of heavy-oil recovery from naturally fractured reservoirs with a relatively high permeability matrix (Al-Bahlani and Babadagli 2009b; Singh and Babadagli 2010).

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Appendix: Solvent Retrieval Calculations

Liquid solvent recovered during Phase-III is measured volumetrically either in a mixture with oil or in pure solvent form. The amount of solvent in core at the end of Phase-II is calculated based on the following equations:

Original state

Core weight = W_{core0}

After Phase-I

Core weight = W_{core1}

Produced oil weight = W_{oil1}

Imbibed water weight = $W_{water1} = W_{core1} - W_{core0} + W_{oil1}$

After Phase-II

Core weight = W_{core2}

Produced oil weight = W_{oil2}

Produced water weight = W_{water2}

Diffused solvent weight = $W_{solvent.in.core} = W_{core2} - W_{core1} + W_{oil2} + W_{water2}$

To make it simpler we assumed two scenarios:

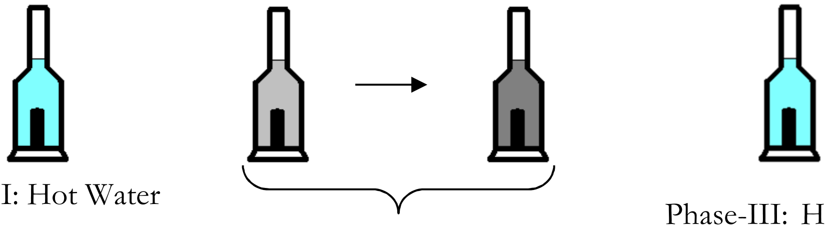
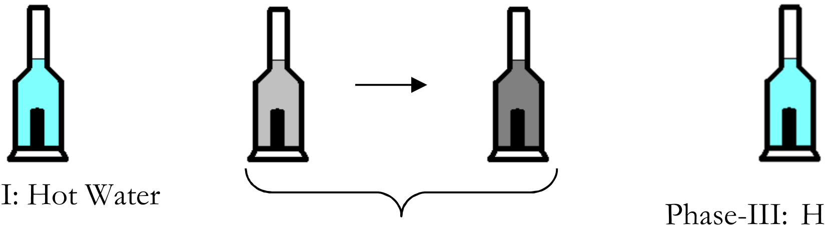
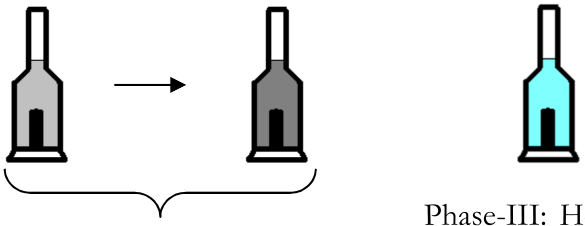
a) All water comes out in Phase-II or $W_{water2} = W_{water1}$,Then:

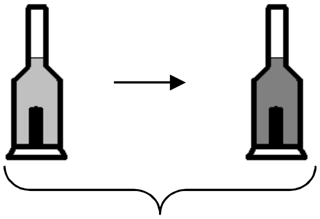
$$W_{solvent.in.core} = W_{core2} - W_{core0} + W_{oil1} + W_{oil2}$$

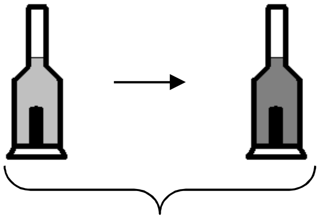
b) No water comes out in Phase-II or $W_{water2} = 0$, Then:

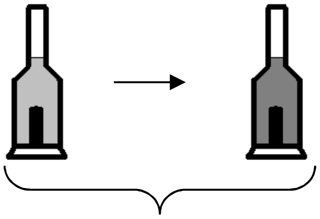
$$W_{solvent.in.core} = W_{core2} - W_{core1} + W_{oil2}$$

Table 3-1: Summary of experiments and results.

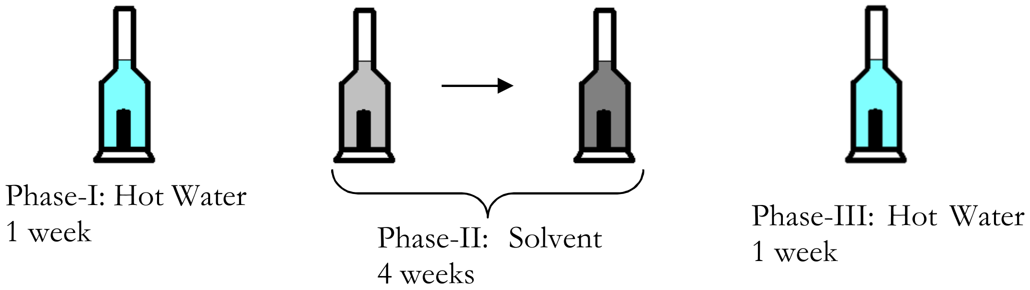
Exp.#	**Solvent**	**OOIP (ml)**	**Porosity (%)**	**Asphaltene (% OOIP)**	**Recovery (%OOIP)**
G1	Heptane	17.7	20.8	15.5	52.2
 Phase-I: Hot Water 2 weeks Phase-II: Solvent 1 week Phase-III: Hot Water 1 week					
G2	Heptane	19.5	22.7	18.7	57.3
 Phase-I: Hot Water 3 weeks Phase-II: Solvent 18 weeks Phase-III: Hot Water 1 week					
G3	Heptane	16.3	32.7	32.5	68.5
 Phase-II: Solvent 2 weeks Phase-III: Hot Water 1 week					

<table>
<tr><th>Exp.#</th><th>Solvent</th><th>OOIP (ml)</th><th>Porosity (%)</th><th>Asphaltene (% OOIP)</th><th>Recovery (%OOIP)</th></tr>
<tr><td>G4</td><td>Heptane</td><td>22</td><td>43.4</td><td>26</td><td>70.9</td></tr>
<tr><td colspan="6">
Phase-II: Solvent
2 weeks

Phase-III: Hot Water
1 week</td></tr>
<tr><td>G5</td><td>Heptane</td><td>13.4</td><td>34.6</td><td>10.8</td><td>50.4</td></tr>
<tr><td colspan="6">
Phase-I: Hot Water
7 weeks

Phase-II: Solvent
7 weeks

Phase-III: Hot Water
1 week</td></tr>
<tr><td>G6</td><td>Heptane</td><td>12.8</td><td>26.1</td><td>12.5</td><td>39.2</td></tr>
<tr><td colspan="6">
Phase-I: Hot Water
7 weeks

Phase-II: Solvent
6 weeks

Phase-III: Hot Water
1 week</td></tr>
</table>

<table>
<tr><th>Exp.#</th><th>Solvent</th><th>OOIP (ml)</th><th>Porosity (%)</th><th>Asphaltene (% OOIP)</th><th>Recovery (%OOIP)</th></tr>
<tr><td>G7</td><td>Heptane</td><td>16.2</td><td>20.1</td><td>15.4</td><td>70.3</td></tr>
<tr><td colspan="6">
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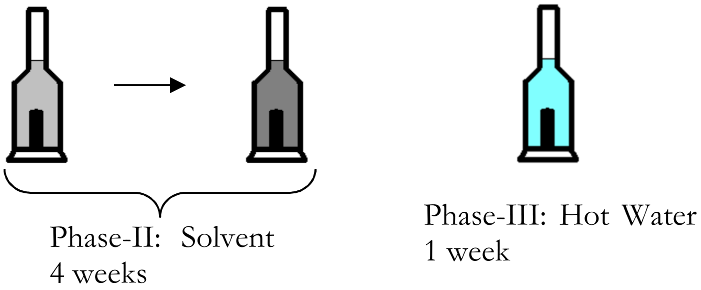
<tr><td>G8</td><td>Heptane</td><td>16.8</td><td>18.1</td><td>13.2</td><td>78.7</td></tr>
<tr><td colspan="6">
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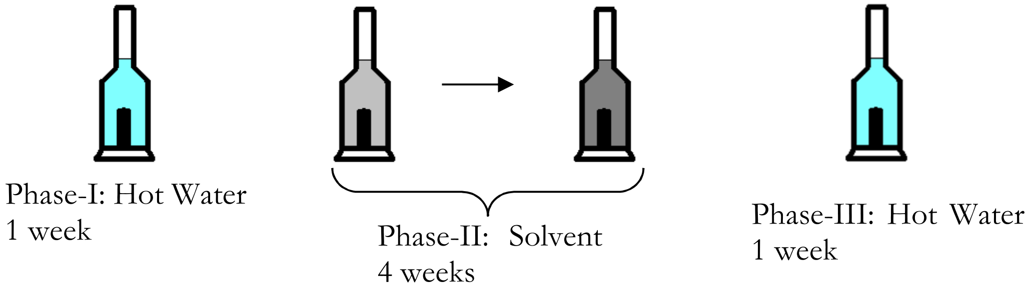
<tr><td>G9</td><td>Distillate</td><td>10.3</td><td>11.8</td><td>6.5</td><td>90.6</td></tr>
<tr><td colspan="6">
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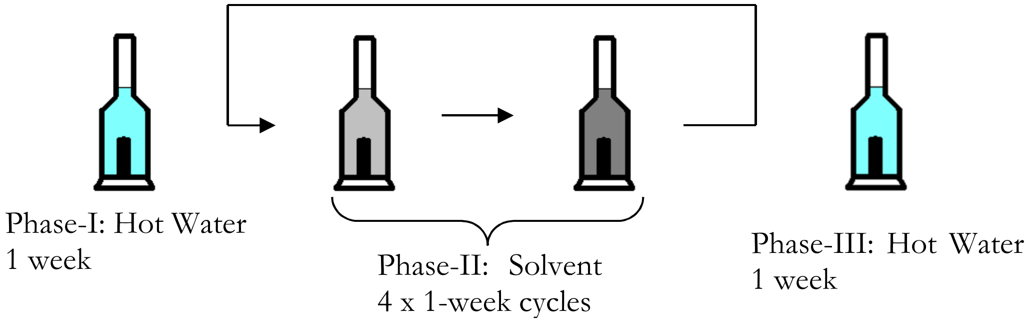
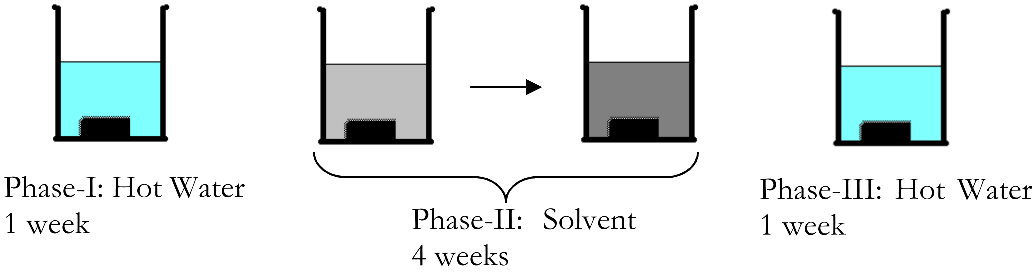
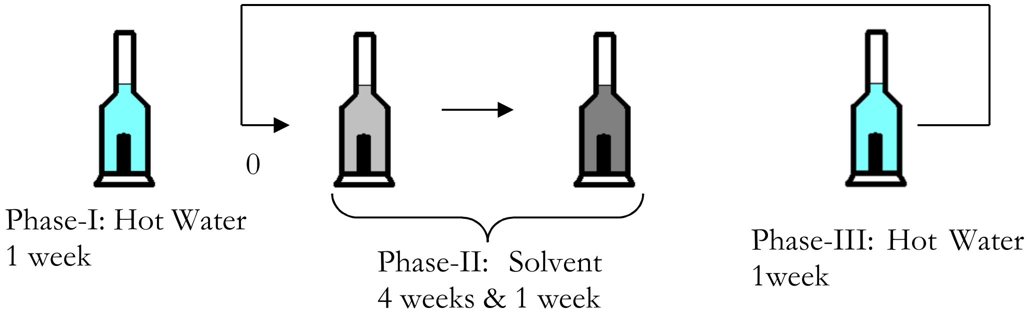
<table>
<tr><th>Exp.#</th><th>Solvent</th><th>OOIP (ml)</th><th>Porosity (%)</th><th>Asphaltene (% OOIP)</th><th>Recovery (%OOIP)</th></tr>
<tr><td>G10</td><td>Heptane</td><td>14.8</td><td>15.9</td><td>16.1</td><td>76.3</td></tr>
<tr><td colspan="6"> </td></tr>
<tr><td>G11</td><td>Distillate</td><td>32.2</td><td>21.5</td><td>8.3</td><td>88.4</td></tr>
<tr><td colspan="6"> </td></tr>
<tr><td>G12</td><td>Heptane</td><td>29.2</td><td>24.9</td><td>22.1</td><td>70.3</td></tr>
<tr><td colspan="6"> </td></tr>
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Figure 3-1: Original carbonate core (diameter is ~10 cm).

Figure 3-2: Core G1, (top) side view,

(bottom) top view (diameter is nearly 3.5 cm).

Figure 3-3: Samples G1 and G2 inside oven in Phase-I.

Figure 3-4: Samples G1 in solvent in Phase-II. (a) t=1 min, (b) t=30 min, (c) t=60 min.

Figure 3-5: Samples G1 after the solvent phase (Phase-II).

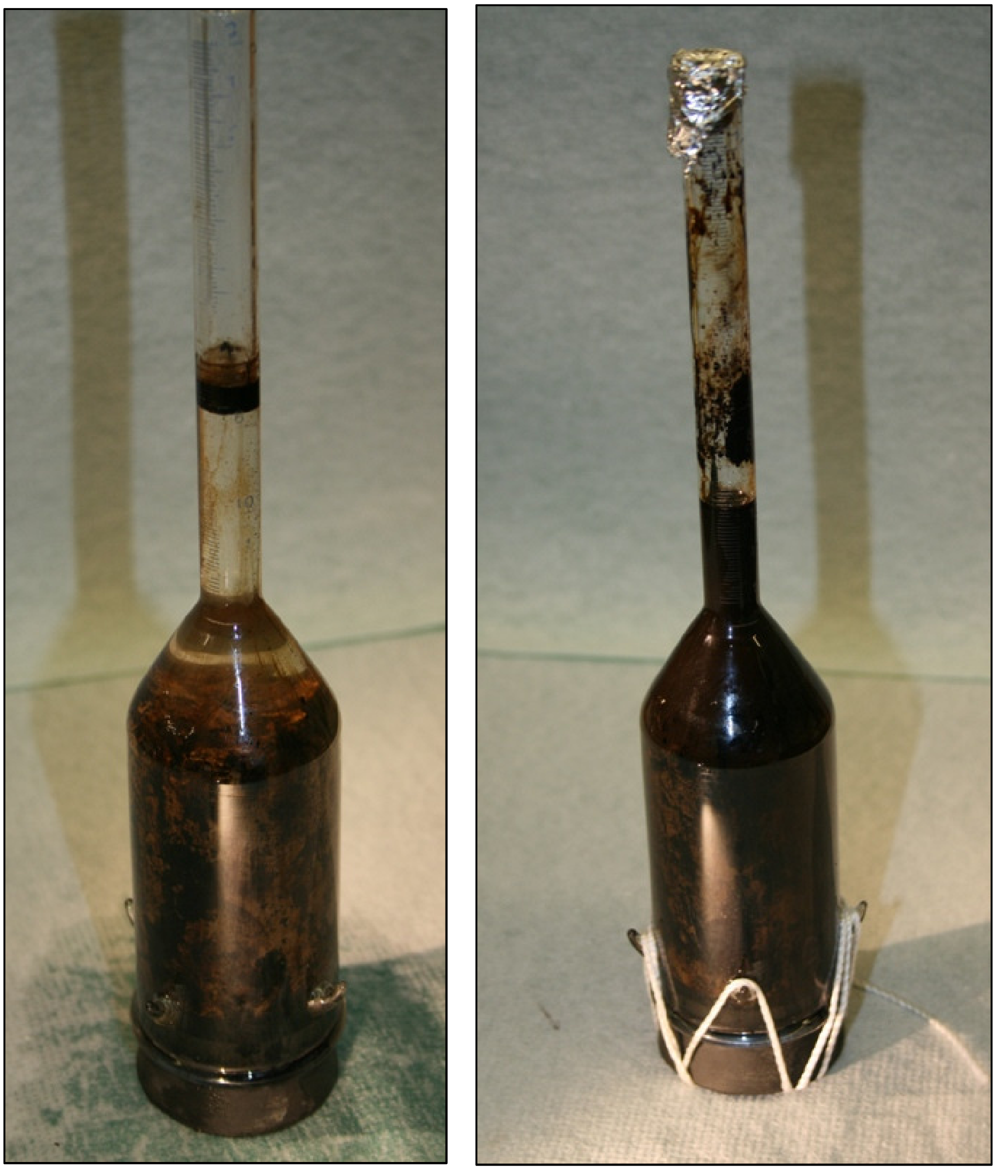

Figure 3-6: Samples G1 in hot water. (a) starting Phase-III, (b) after one week in Phase-III (out of oven).

Figure 3-7: Samples G1 after Phase-III (out of hot water).

Figure 3-8: Samples G1 after cleaning.

Figure 3-9: Bubbling occurs when sample G4 (the shape is not cylindrical but amorphous) is at the start of Phase-III.

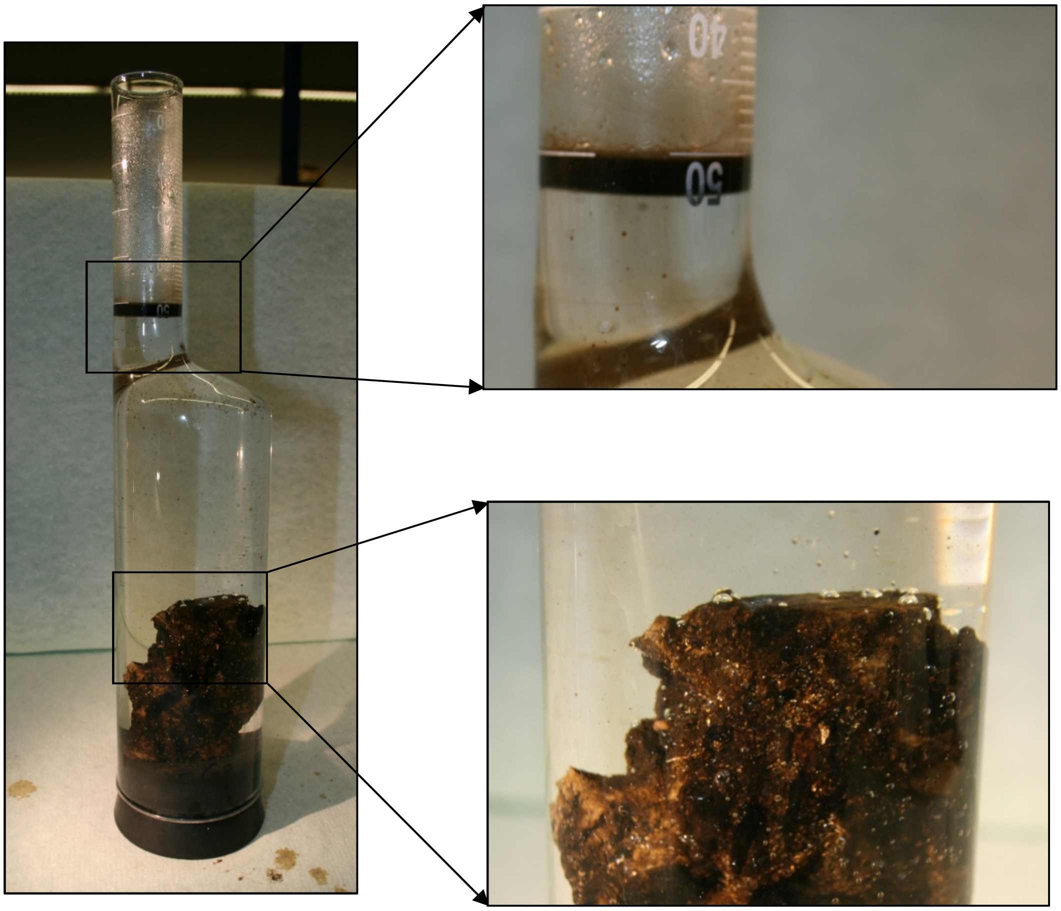

Figure 3-10: Samples G4 (the shape is not cylindrical but amorphous) after a few minutes in Phase-III. Bubbling is still going on and a layer of recovered oil is accumulated on top.

Figure 3-11: Sample G12 after solvent phase with asphaltene precipitation and deposition.

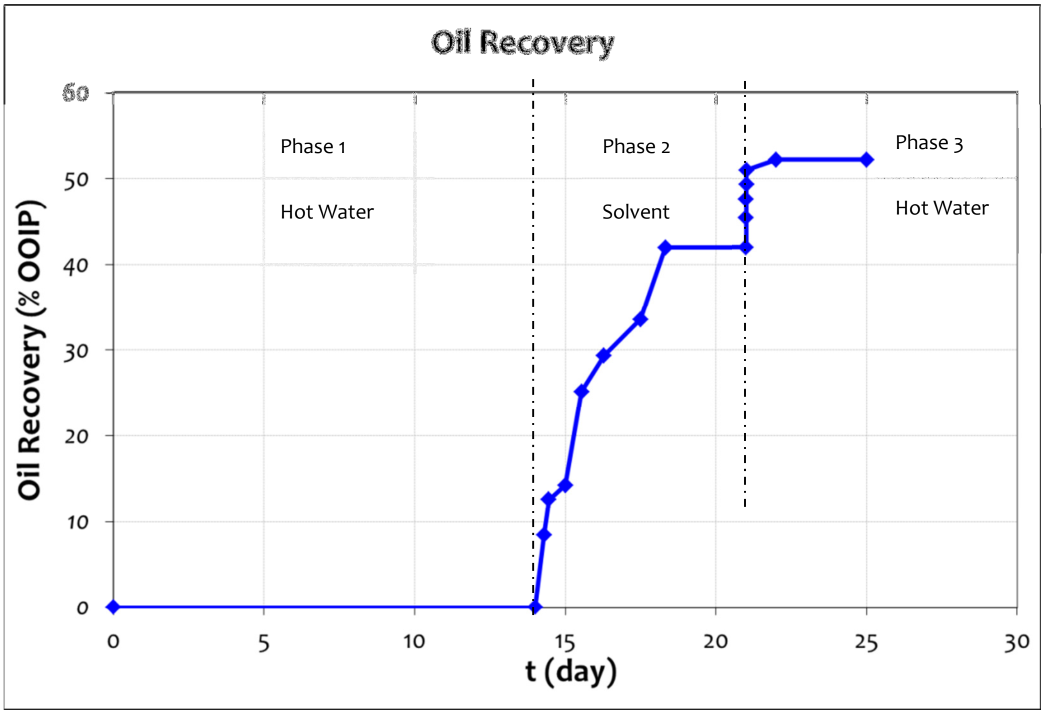

Figure 3-12: Recovery graph for G1.

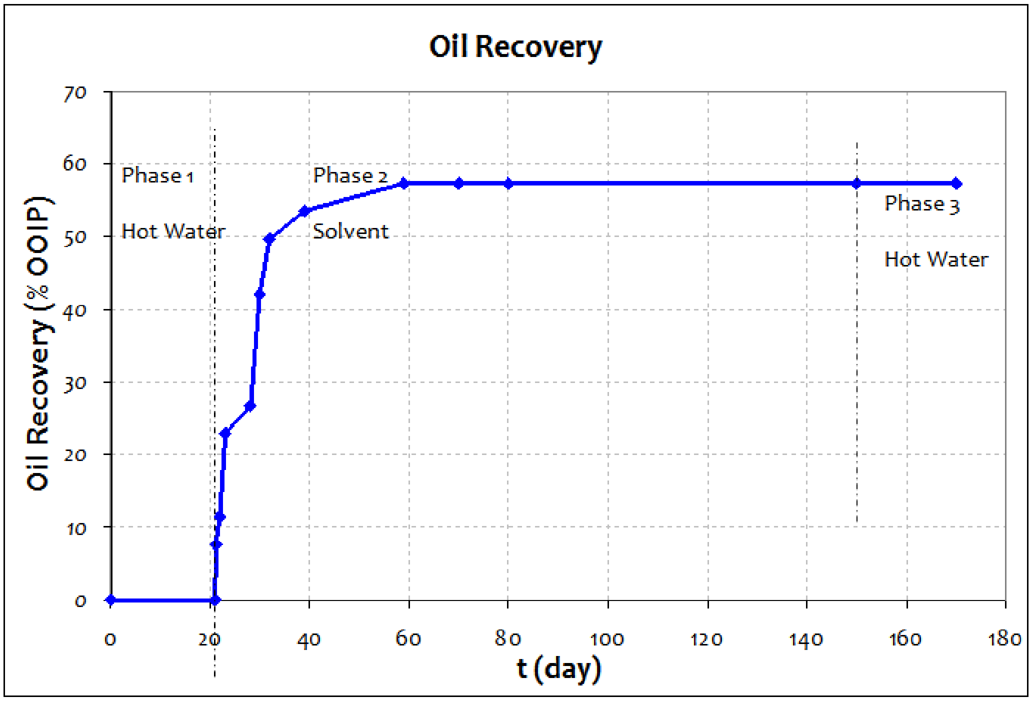

Figure 3-13: Recovery graph for G2.

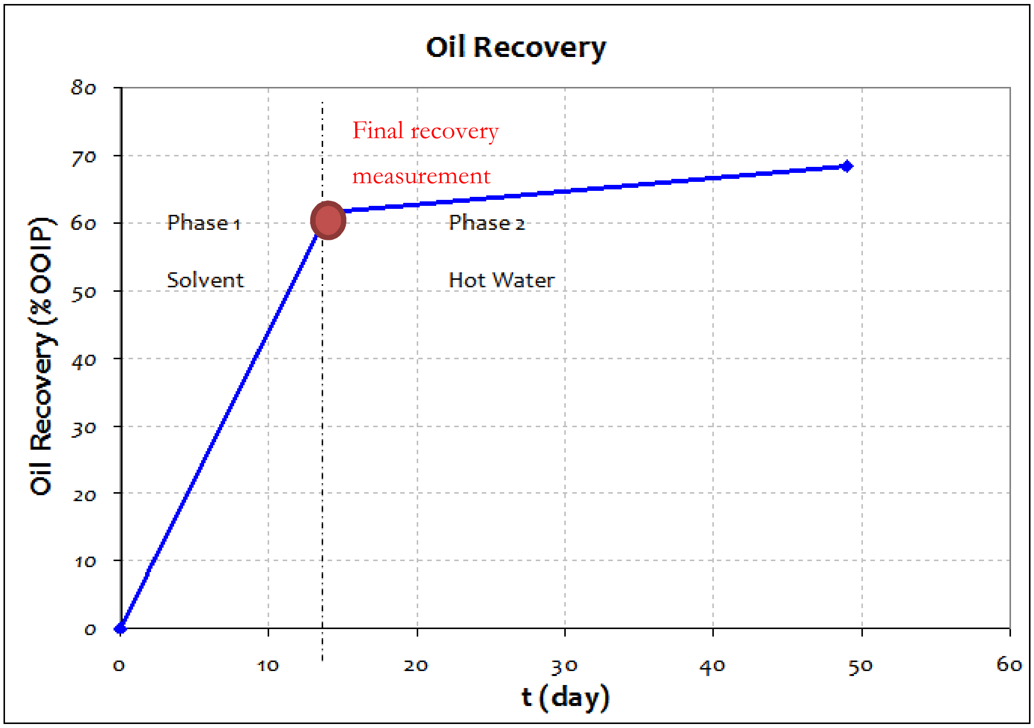

Figure 3-14: Recovery graph for G3.

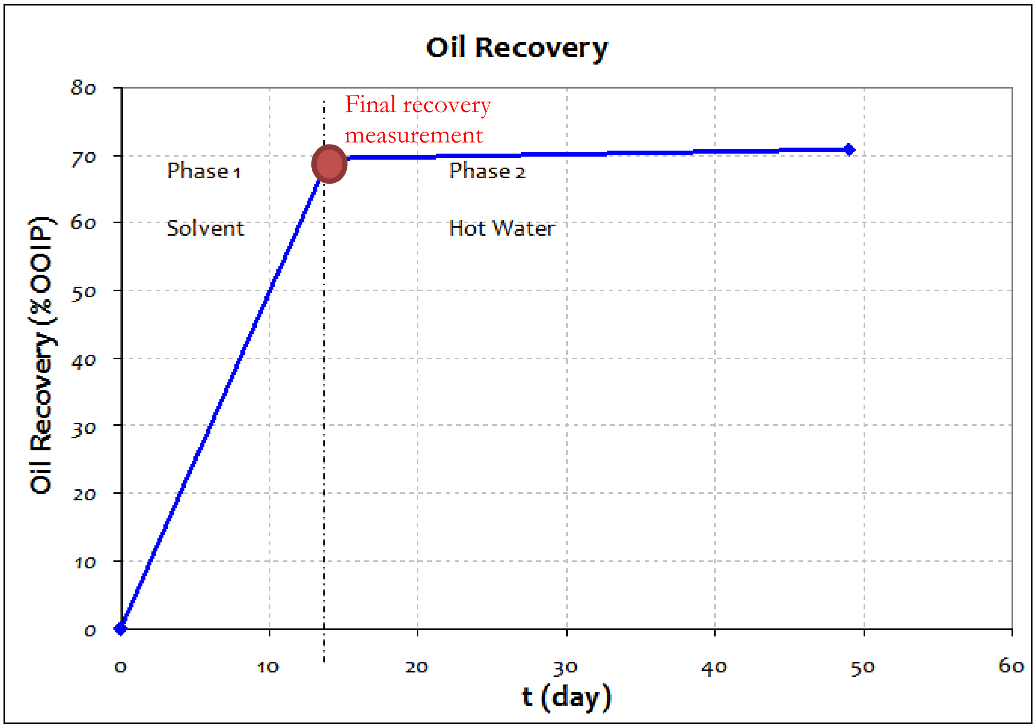

Figure 3-15: Recovery graph for G4.

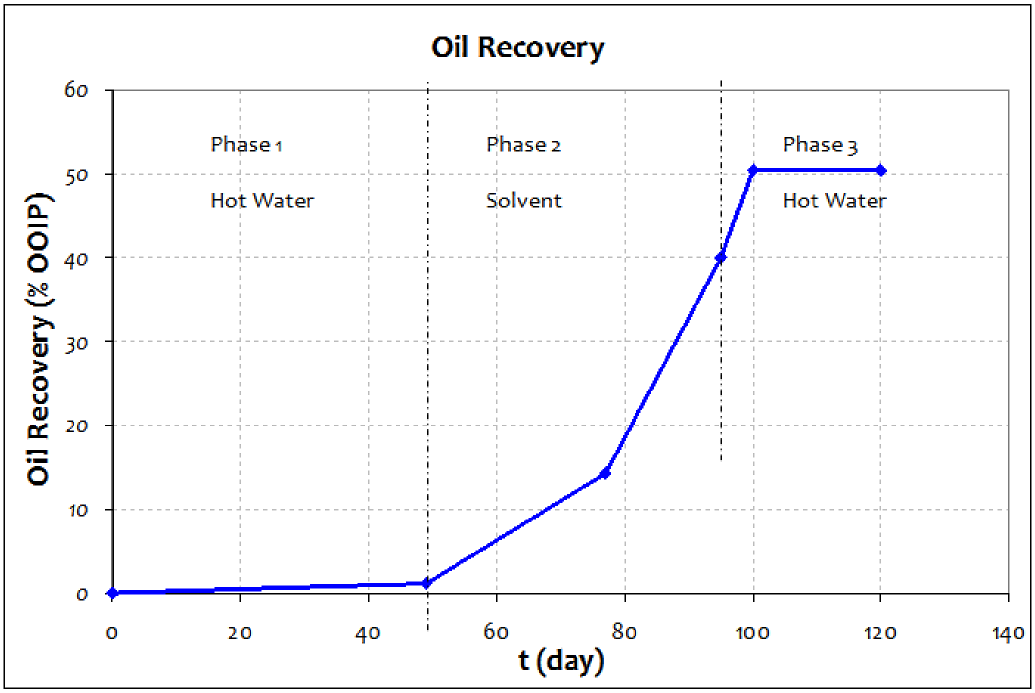

Figure 3-16: Recovery graph for G5.

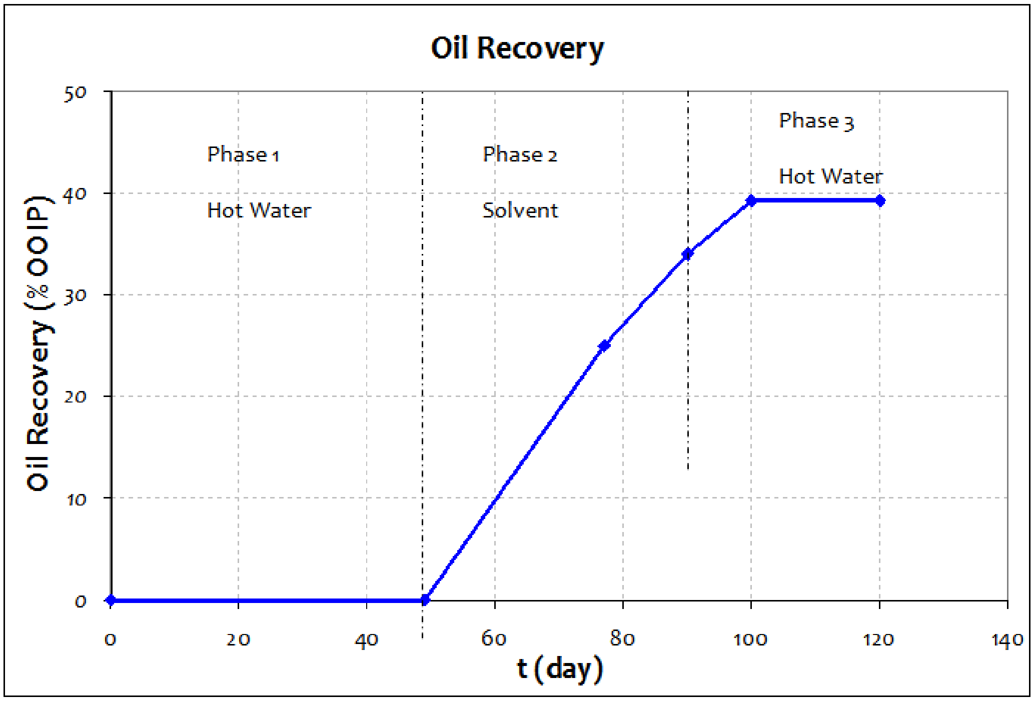

Figure 3-17: Recovery graph for G6.

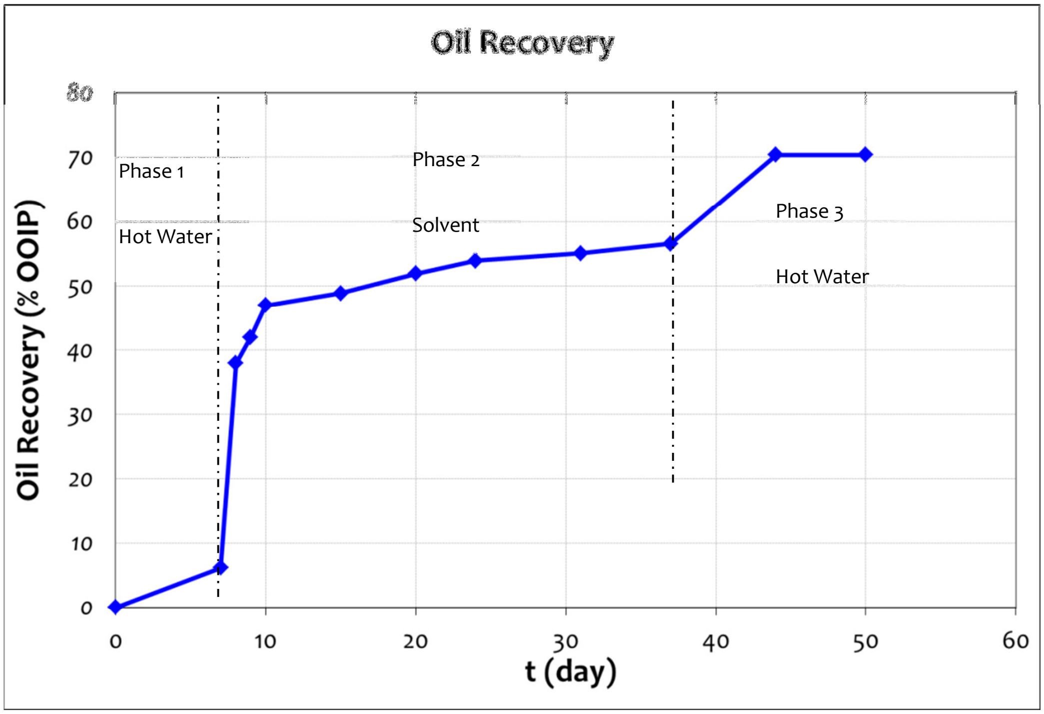

Figure 3-18: Recovery graph for G7.

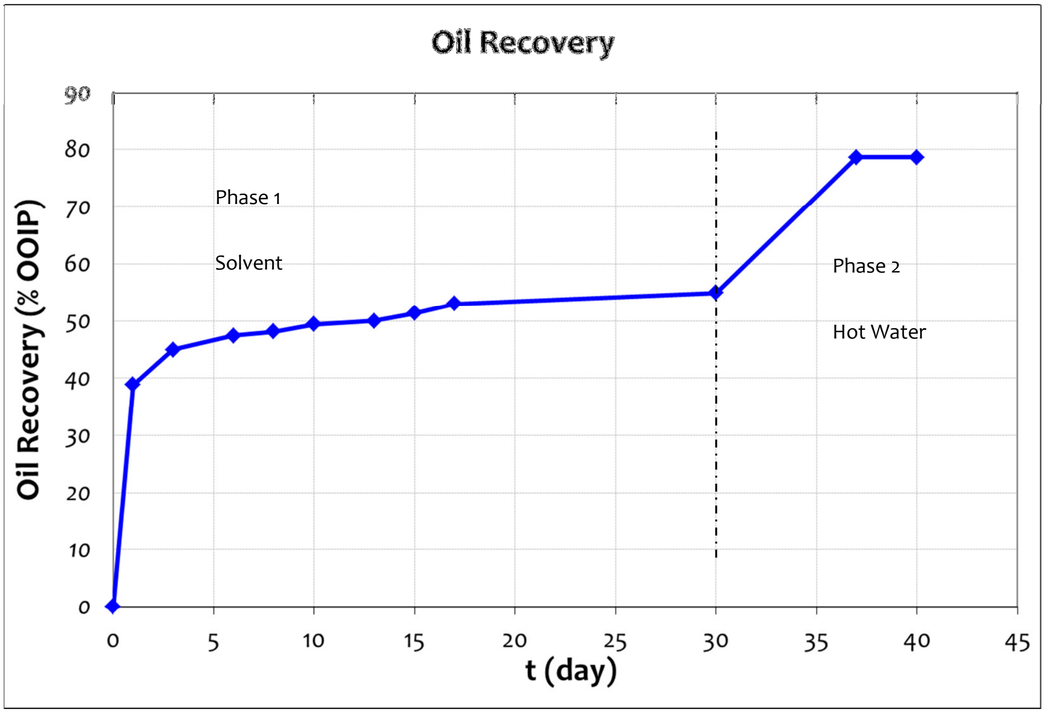

Figure 3-19: Recovery graph for G8.

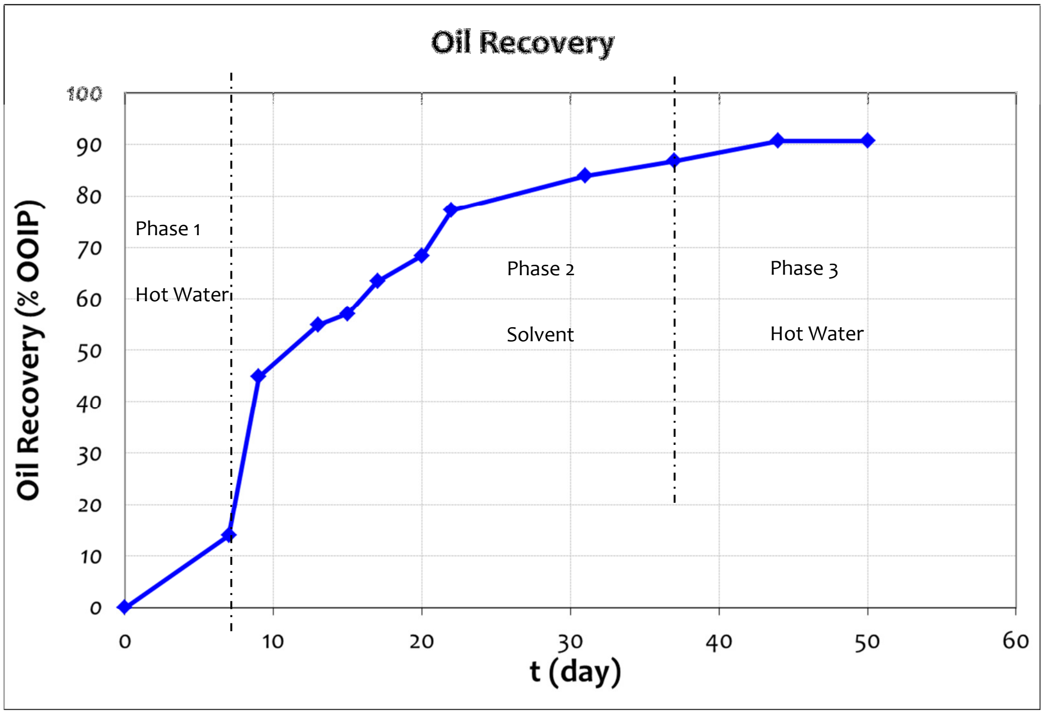

Figure 3-20: Recovery graph for G9.

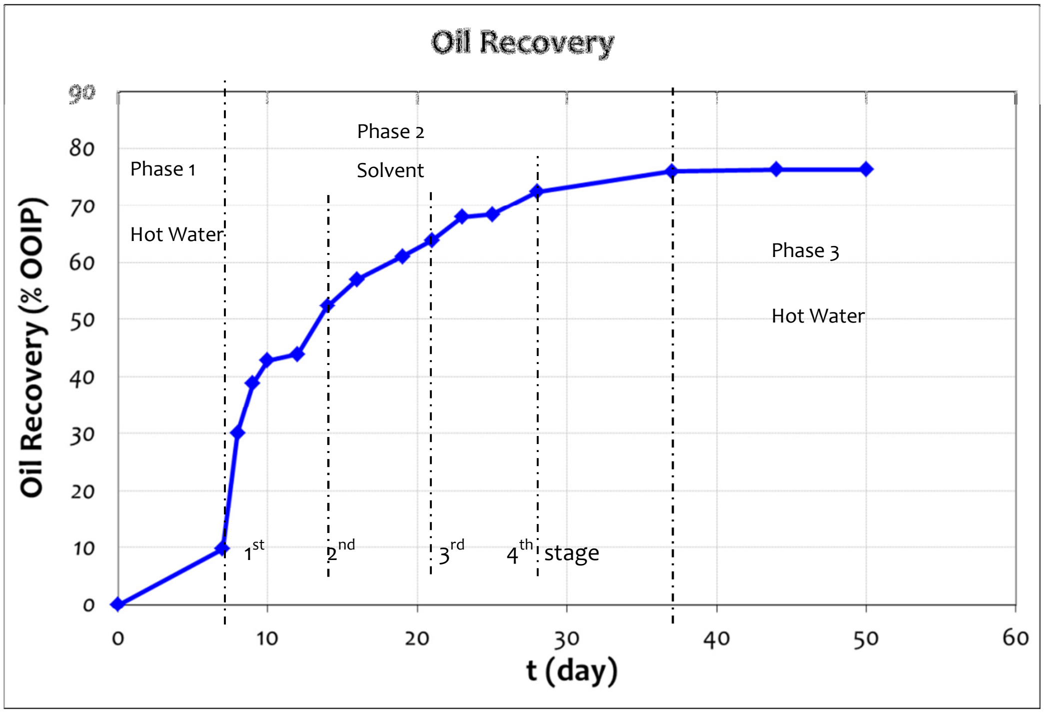

Figure 3-21: Recovery graph for G10.

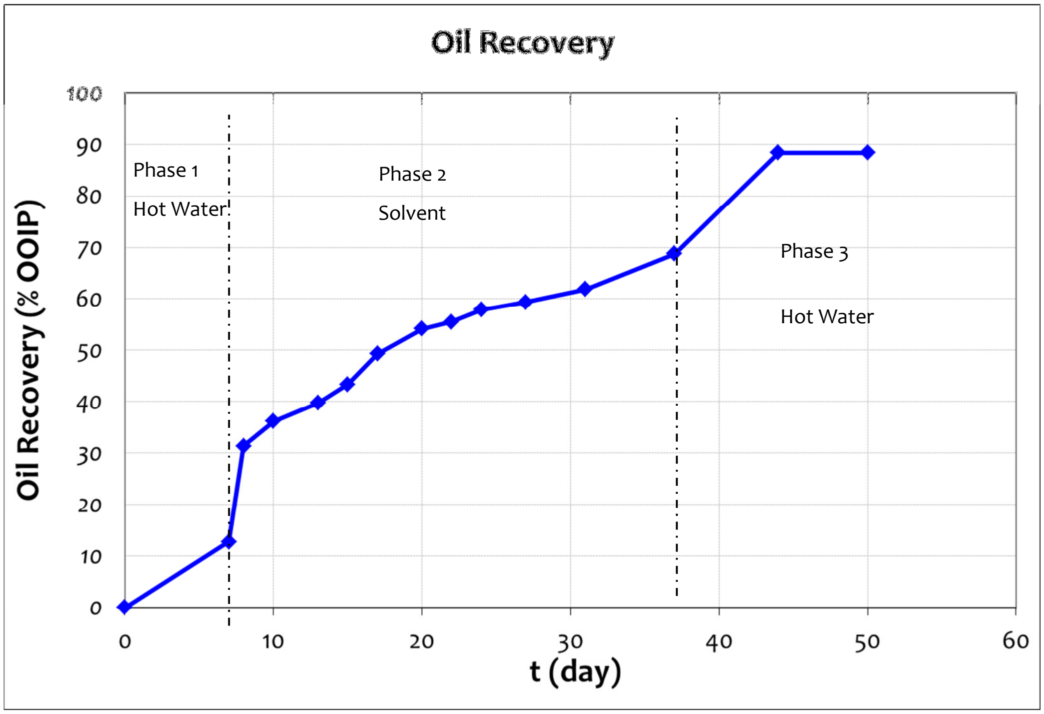

Figure 3-22: Recovery graph for G11.

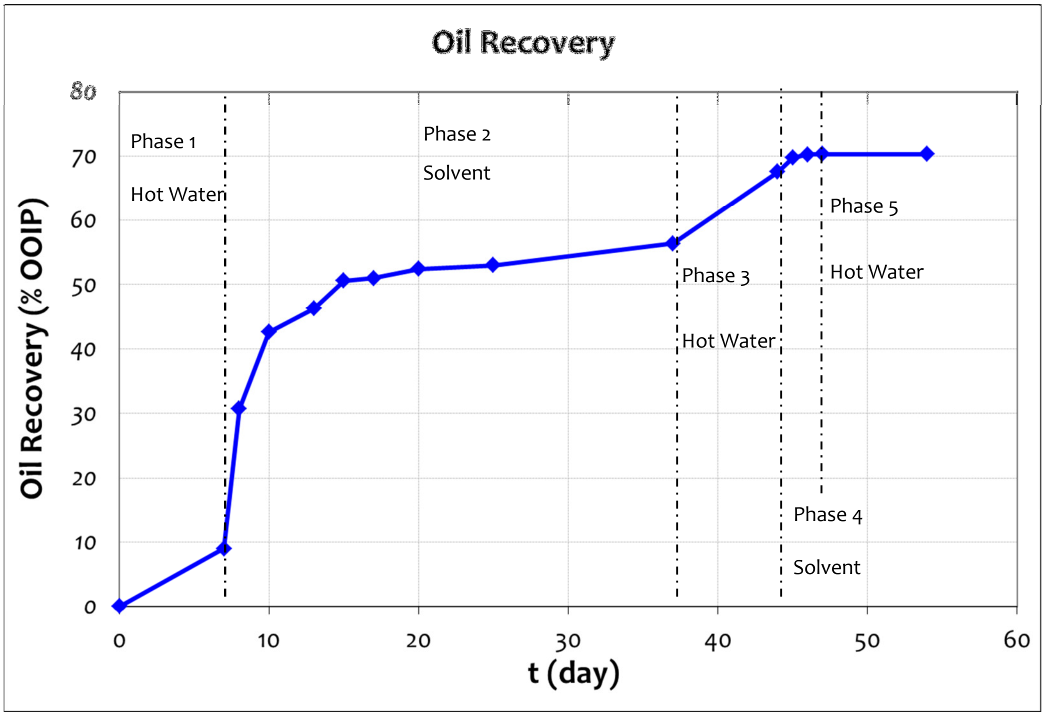

Figure 3-23: Recovery graph for G12.

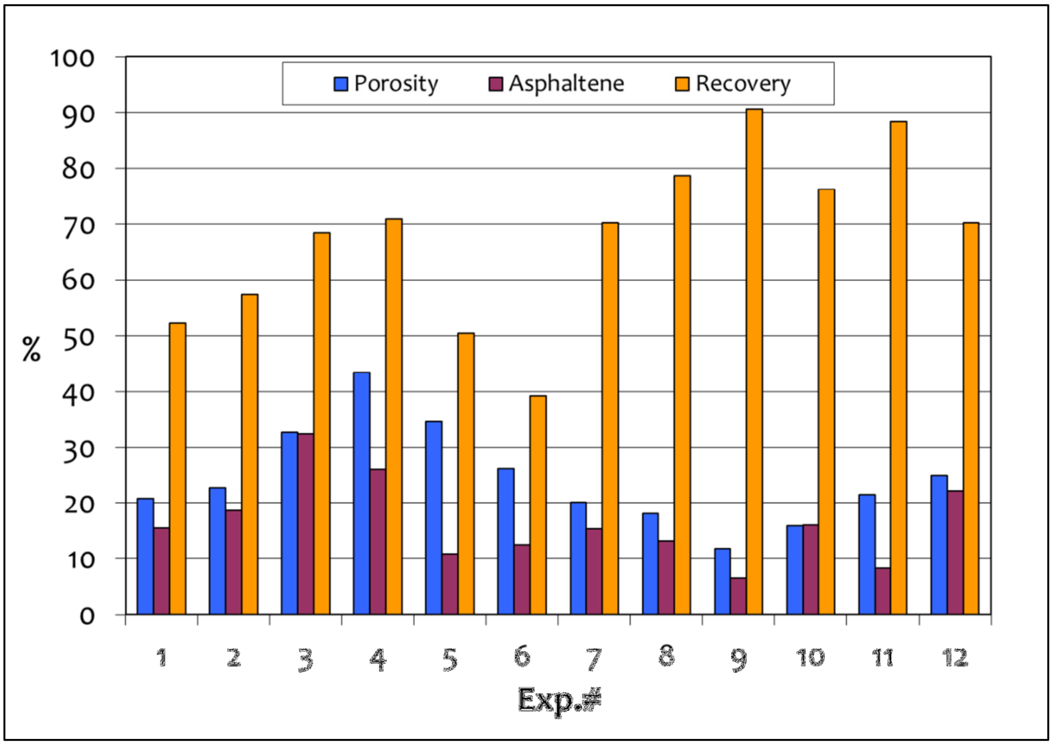

Figure 3-24: Summary of all experiments.

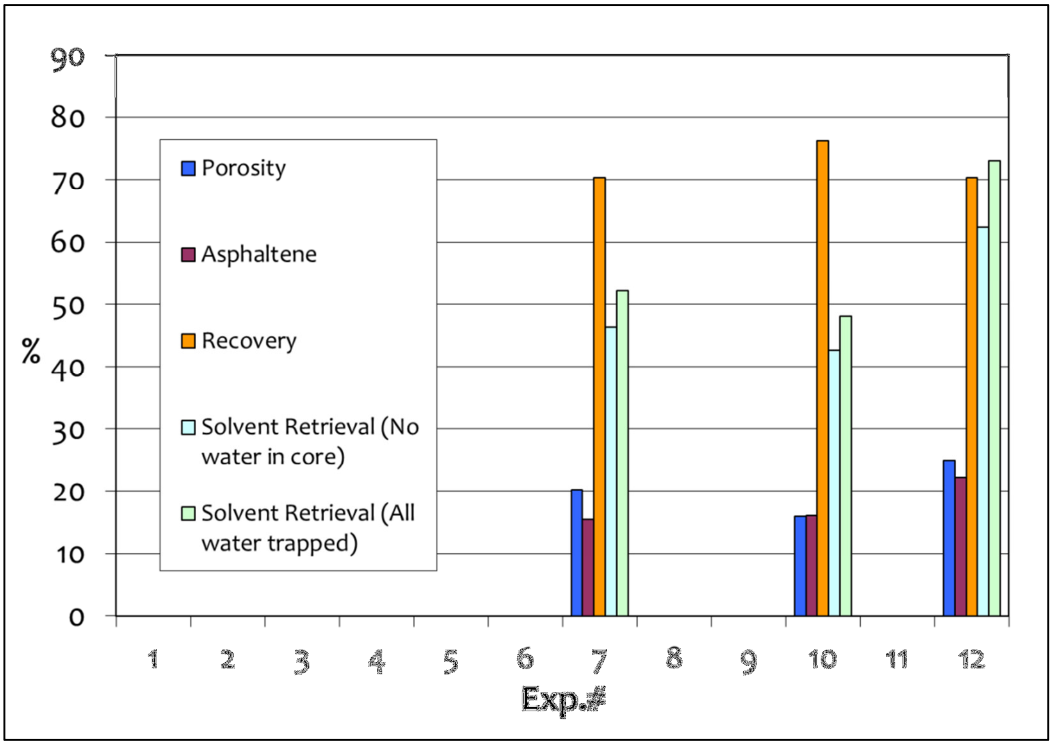

Figure 3-25: Solvent retrieval for three experiments.

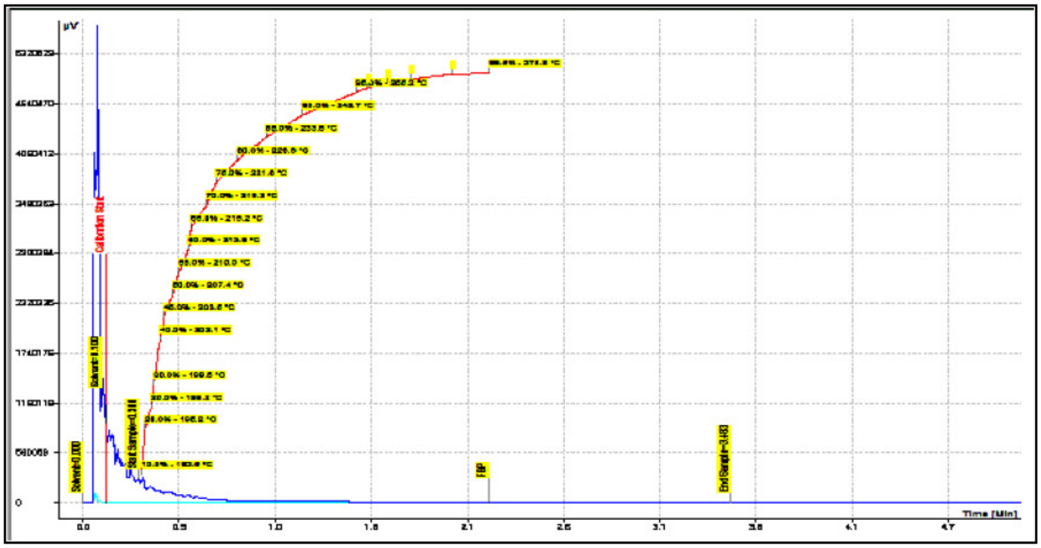

Figure 3-26: GC results for distillate.

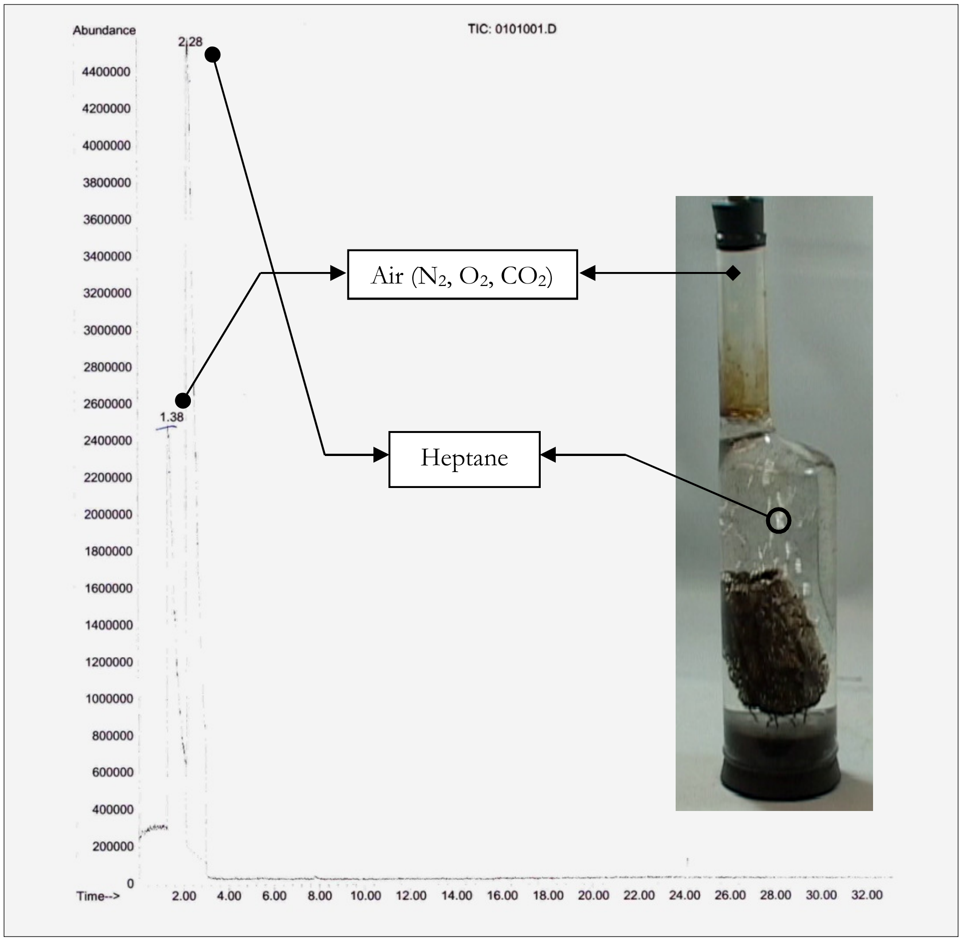

Figure 3-27: GC results for vapor mixture produced in Phase-III.

Chapter 4 : Experimental Analysis of Heavy Oil Recovery by Alternate Injection of Steam and Solvent (Hydrocarbon/CO_2) in Unconsolidated Sand Reservoir

A version of this chapter is presented at the SPE Heavy Oil Conference Canada held in Calgary, Alberta, Canada, 12–14 June 2012 and is also submitted to Journal of Canadian Petroleum Technology.

Introduction

Heavy oil reserves have been receiving more attention recently as oil prices are steadily high enough to surmount the associated expenses of oil production. In conjunction with this, technological advancements to improve heavy-oil recovery have been reported but laboratory scale experiments are critically needed in the optimal design of field tests.

Contrary to conventional oil reservoirs, heavy oil reserves lack standardized methods. In addition to this, when the reservoirs show geological constraints, special methods are needed to take into account the diverse medium and fluid properties of such reservoirs. Specifically, in the case of fractured reservoirs, the main problems are to mobilize the oil out of the tight matrix into fractures and to distribute the heat uniformly to heat the matrix in order for this process to occur. A similar situation is encountered in unconsolidated sand reservoirs continuing heavy-oil after the primary cold production with sands (CHOPS). In these reservoirs, sand production creates a network of wormholes acting as a high permeability medium similar to fractures and heavy-oil left in the "matrix" part is a critical task.

The common practice to reduce the heavy oil's reluctance to flow is to decrease its viscosity by providing heat and the most common way to do that is by steam injection. This method, on the other hand, has its own restrictions due to the high generation cost and heat losses if the reservoir is deep. Different forms of thermal applications were suggested and applied such as steamflood, cyclic steam injection (CSS), and steam-assisted gravity drainage (SAGD) mainly for sandstones or oilsands. Carbonate reservoirs have not been under such applications widely. One example out of a few is the Qarn Alam field in Oman in which steam injection has been applied field-wide. Macaulay et al. (1995) reported that a small recovery of 2% of OOIP during the primary recovery can be raised to 20% by means of gas-oil gravity drainage thermally-accelerated by steam injection. Al-Shizawi et al. (1997) reviewed the methods of heat monitoring in the same field for the same pilot project. An analysis of the pilot test and an additional understanding of the physics of the process are available in works by Penney et al. (2005), Shahin et al. (2006), and Penney et al. (2007).

The problem with carbonate reservoirs is that the matrix recovery is typically in the low range due to low permeability and unfavorable wettability of the matrix, and also the high viscosity of oil. For the above mentioned Qarn Alam field, Babadagli and Al-Bemani (2007) conducted an experimental analysis on core samples and observed that the recovery goes up to 47% OOIP for the case with initial water saturation at 200 ºC. This recovery is expected to be as low as 27% in field conditions, as reported by Shahin et al. (2006).

In unconsolidated sand reservoirs, CHOPS (Cold Heavy Oil Production with Sand) is commonly applied. In this method, sand is allowed to be produced with heavy oil that makes it economical due to avoided cost of any injection. However, the ultimate recovery by CHOPS is limited to 8-12%. As a result of such method of production, a high permeability wormhole network is created in the reservoir reminiscent of fluid conduits similar to a fracture network in naturally fractured reservoirs. McCaffrey and Bowman (1991) discussed how the sand production through the cold production method generates high permeability channels and improves overall permeability and porosity. Field scale applications were also reviewed using the observations from the Frog Lake Field by Huang et al. (1998). The generated wormholes make a network to access different parts of the reservoirs for possible applications of post-CHOPS productions through thermal or solvent methods.

As an alternative to thermal methods, a limited number of solvent applications were also proposed in sandstones to dilute the oil and produce it by gravity. The vapor extraction (VAPEX) method is the usual solvent method, which uses two horizontal wells to inject solvent and produce the oil (Butler and Mokrys

1989; Das 2002). Hydrocarbon solvents are costly and hence solvent retrieval is a major concern. Particularly in fractured systems, the retrieval problem makes solvent applications limited (Hatiboglu and Babadagli 2008a, 2008b). Substituting hydrocarbon solvents with CO_2 could be an economically and environmentally viable approach. CO_2 is the major greenhouse gas and has recently received more attention from an environmental point in terms of storage in oil reservoirs. Environmental concerns aside, CO_2 can enhance oil production as a solvent depending on the reservoir conditions and fluid interactions, which determine the miscibility and solubility of CO_2 into oil.

Operation conditions such as timing are also important. For example, a study by Trivedi and Babadagli (2009a) showed that CO_2 can extract heavier ends of the light oil sample tested provided that a certain time is given for the CO_2 to interact with the oil. In this process, a significant factor is the injection rate controlled by the fracture system; i.e., aperture, density, and orientation. Barkve and Firoozabadi (1992) proposed a gravity drainage rate in homogeneous porous media as a function of injection rate. To indicate the strength of the matrix-fracture transfer as a function of the injection rate, Babadagli and Ershaghi (1993) and Babadagli (2000) introduced a dimensionless group called imbibition index. The inverse of this index resembles the fracture capillary number which is the ratio of the viscous forces that are effective in the fractures to the capillary forces that are effective in the matrix.

In a similar attempt, Darvish et al. (2006a, 2006b) injected CO_2 into saturated chalk cores to displace the oil and concluded that CO_2 injection could be an effective EOR method for fracture reservoirs after water injection. Diffusion was the main oil recovery mechanism in their experiment. Karimaie et al. (2008) used a binary mixture of C1-C7 as the solute and investigated the secondary and tertiary injection of CO_2 and N_2 in a fractured carbonate rock. Contrary to nitrogen with low recovery values, CO_2 efficiently recovered 73.0% of the oil after a secondary CO_2 injection. Tertiary injection increased the recovery by 15.7%.

CO_2 huff-and-puff was studied by Torabi and Asghari (2007) at the laboratory scale. They injected CO_2 at different pressure steps into a 0.5 cm annular space between a sandstone core and a core holder acting as a fracture. An increase in the recovery factor from immiscible to near miscible/miscible conditions was observed. At miscible conditions, the permeability did not show a major impact on the recovery factor while at below miscible conditions, the production rate and recovery factor were higher in high permeable cores. Similar experiments focusing on gravity drainage by Asghari and Torabi (2007) showed that miscibility could highly increase the production. They also found that CO_2 injection at pressures below the minimum miscibility pressure (MMP) could recover up to 19% of OOIP, which increased to more than 50% at miscible conditions. But going much above the MMP might have a negative effect on ultimate recovery due to the presence of denser fluid in the fracture.

An experimental study by Trivedi and Babadagli (2008a) on miscible displacement in fractured porous media using heptane showed that diffusion is dominant over viscous flow. Also, a lower rate solvent injection provides more time for the solvent to diffuse into the matrix before breakthrough, which leads to more recovery contribution from the matrix. They also investigated CO_2 sequestration (Trivedi and Babadagli 2008b) by defining a dimensionless term as the global effectiveness factor in order to optimize both oil recovery and CO_2 storage. Later, Trivedi and Babadagli (2008c) analyzed CO_2 sequestration efficiency by experiments of CO_2 injection at constant rates into the fracture under high pressure. Lower rates showed a better recovery after a blowdown and shut-in compared with higher injection rates. For different core types, favorable pressure ranges for recovery and sequestration were measured. Numerical simulations were taken together with experimental analysis in another study (Trivedi and Babadagli 2009b) to evaluate the mass transfer between the matrix and the fracture. The dispersion effect and mass transfer rate were shown to be dominant factors on recovery. Another effective parameter was the length of the matrix as a longer core resulted in delayed breakthrough and yielded higher oil recovery.

More recently, Trivedi and Babadagli (2010) tested the effect of injection rate and reported optimal rates maximizing both storage and recovery. As for pressure conditions, near-miscible pressure was the most effective condition for oil recovery.

As seen, a combination of thermal and solvent methods for heavy-oil recovery from fractured reservoirs is plausible with certain constraints such as the availability of injectants, geological uncertainty, reservoir depth, and oil type. SOS-FR (steam-over-solvent injection in fractured reservoir) is one of these combined techniques proposed by Al-Bahlani and Babadagli (2008) as being one of the rare applications of solvent injection in fractured porous media. The method consists of cyclic injection of hot water and hydrocarbon solvent with a final thermal phase aimed at retrieving solvent from the matrix. They studied the recovery of heavy oil in fractured reservoirs by a cyclic injection of steam and solvent and gained high recovery up to 90% at laboratory conditions. The retrieval of solvent from the core using hot water showed a fast trend but was controlled by the matrix size (Al-Bahlani and Babadagli 2009a, 2009b). Later, Al-Bahlani and Babadagli (2010) showed promising applicability of the SOS-FR method in larger matrix sizes through field scale numerical modeling. They concluded that this combination yields a better efficiency compared with the sole injection of either solvent or steam. They also observed higher oil recovery as well as higher asphaltene precipitation when using lighter solvents.

In order to investigate the applicability of the SOS-FR method in a broader range, Naderi and Babadagli (2012a) tested steam in addition to hot water and replaced the hydrocarbon solvents with CO_2. Numerical modeling of the same method for the field scale was also reported by Naderi and Babadagli (2012b), showing the applicable conditions for larger matrix sizes, i.e., field conditions.

In the present work, we performed a further experimental investigation of the SOS-FR method. The use of CO_2 as a solvent was compared with a hydrocarbon solvent (propane) on unconsolidated porous media. The temperatures applied during experimentation were selected conservatively to reduce the generation cost of steam and instead make a combination with solvent methods to recover the oil. In a sense, this process represents heavy oil recovery from unconsolidated sands after CHOPS through low temperature thermal methods combined with solvent injection. The observations could also be useful in the assessment of gravity drainage dominated heavy-oil recovery potential of oilsands through the same methods.

Methodology

The SOS-FR method consists of three stages. It begins with the injection of steam (or hot-water) to produce the initial oil by thermal expansion (Phase-I) and to condition the matrix oil for the next phase, which is solvent injection (Phase-II). After the injection of solvent, the third phase (Phase-III) is conducted by injecting hot water (or steam) mainly to retrieve the solvent and to recover additional -upgraded- heavy-oil.

The earlier studies on the SOS-FR method (Al-Bahlani and Babadagli 2008, 2009a, 2009b, 2010) considered lower temperatures in Phases-I and III of less than 100 ^{o}C (practically hot water injection). They mainly used heptane as their solvent in those experiments.

In our previous experimental work (Naderi and Babadagli 2012a), we replaced hydrocarbon solvents with CO_2 and conducted Phases-I and III at higher pressures and temperatures considering more realistic reservoir conditions. In those experiments, high permeability Berea sandstone cores were used. In the present chapter, we extended this experimental program by taking into account another type of porous media (unconsolidated sandpacks). We also compared the CO_2 performance as the solvent with that of propane at higher pressures than applied by Al-Bahlani and Babadagli (2008, 2009a, 2009b, 2010). A heavy-oil with a viscosity of 6100 cP and density of 0.9639 gr/ml (at ambient conditions) was used to saturate the unconsolidated sands (glassbead packs). To make the cores oil wet, a wettability alteration agent was used as suggested by Al-Bahlani (2008, 2009a, 2009b) and Naderi and Babadagli (2012a), so the glassbeads were first undergone through the wettability alteration method and then used for saturation.

The experiments consist of three phases: Phase-I: Thermal, Phase-II: Solvent, and Phase-III: Thermal. In Phase-I, the core was either immersed into hot water (at 90 ºC) or soaked by steam (at 120 ºC) in a specially designed setup (**Fig. 4-1**). In Phase-II, the core was placed into another setup that was designed for solvent soaking (**Fig. 4-2**). The solvent conditions were chosen in such a way as to keep them in gaseous phase. Phase-III was the same as Phase-I (i.e., thermal) but hot water was mainly used at this stage. For the thermal stage, hot water at 90 ºC and steam at two different temperatures and pressures were used. At the end, the total recoveries of oil were determined by volumetric and then weight measurements of the core. **Fig. 4-3-a** displays a sandpack container used for experiments. It has 1.75 inch diameter and 11 inch length. The sandpack mixture of glassbeads and oil is shown in **Fig. 4-3-b**. Glassbeads are round spheres with an average diameter of 0.65 mm. The heavy oil is added to the glassbead in a ratio to almost fill the void space considering a rhombohedral arrangement that gives a porosity of 25% (Cooke and Rowe 1999). This packing configuration is more likely to happen and also leaves room for a conservative porosity assumption that does not lead to excessive oil out of pore volume. The mixture is placed in the container with no extra force to change the compactness; however, samples might be slightly different due to the deliberate difference in height for some experiment and also due to unsystematic difference in packing. **Table 4-1** lists sandpack experiments, including the corresponding pressure and temperature conditions. **Table 4-2** lists the control experiments that were run mainly to see the effect of gravity at different conditions. These experiments were run under ambient conditions or at elevated temperature without pressurizing.

Analysis of the Results

Except for a short cooling duration after Phase-I, the consequent phases were done immediately after one another; hence, the transition times were very short. This resembles the actual process in field tests. Due to the complex nature of the process and the interaction of a considerable number of phases (oil, solvent and water in vapor and liquid phases), certain assumptions needed to be made to enable recovery calculations at the end of each phase. We relied on weight measurements, which were made before and after the experiments, when the cores were in equilibrium conditions. To reduce the risk of miscalculation of recovery factors, we reported the recoveries for Phase-II and III as a whole and the main assumption was that there was no condensed water (from steam) trapped in the core at the end of Phase-I.

The solvent (CO_2 or propane) diffused into core during Phase-II and oil is produced by gravity drainage from the core gradually, which can be seen by the pressure reduction in the cell. **Fig. 4-4** shows two graphs of pressure decline in Phase-II for CO_2 and propane, respectively. CO_2 pressure declined form 3400 kPa (gauge pressure) to 3300 kPa (**Fig 4-4-a**) and propane pressure decreased to 580 kPa from 750 kPa (**Fig 4-4-b**), both in one day. The CO_2 process is not miscible considering the pressure applied and the gravity of oil, as indicated by lower pressure drop, which means lower diffusion than the propane case that has higher mixing capability. After this phase, when the core was removed from the cell, gas bubbles were observed coming out of the core. This process was accelerated by hot water exposure in Phase-III which caused more oil to be produced with more CO_2 bubbles out of the core. Thus, the high temperature of water (90 ºC versus an ambient temperature of 25 ºC) accelerated the oil production in the early times of Phase-III not only by the thermal expansion of oil but also with the help of CO_2 bubbles coming off out of the core. The bubbling rate is not high in sandpack models as it was released easier in the transit time between Phases II and III, but similar experiments on rocks made it more visible than this sort of bubbling in the beginning of Phase-III happens with various rates depending on the conditions. **Fig. 4-3-c** shows one of such cases on consolidated sandstone cores when, at the start of Phase-III, hot water makes the stored CO_2 in the core come off with a high rate (Naderi and Babadagli 2012a).

Figs. 4-5 to 4-13 demonstrate the recovery charts for the different phases of the sandpack experiments. In a sense, this mimics a case of steam-solvent application after the CHOPS process in which the wormholes created may act like the main conduit to transfer (and contain) the injected steam and solvent. Phase-I results show that most of the oil -more than 60%- was produced during the initial thermal phase due to the loose structure of the sandpacks by gravity drainage which is assisted by thermal expansion and accelerated by reduced viscosity (**Figs. 4-5** and **4-6**). The gravity drainage seems to be the main mechanism here. The control experiments were performed to verify this effect. **Table 4-2** shows the list of control experiments and **Fig. 4-13** exhibits the results.

First of all, the effect of pressure should be evaluated by taking experiments CT1 and CT2, which are at high temperature in oven but not under steam pressure (they are at atmospheric pressure), against the similar experiments that are exposed to steam at the same temperature but with a surrounding pressure around 200 kPa (GB1, GB6, GB9, GB10 and GB15). The average recovery is 71.9% for the former group and 75.5% for the latter group. Hence, the main effect is of temperature as it reduces the viscosity of heavy oil and also makes it thermally expand. As the pressure around the core is very low in the pressurized cases (GB experiments), it is not expected to have any significant recovery by its drive.

The effect of temperature is not only seen in the final recovery, but also in the recovery rate. Comparing experiments CG1 and GB3, one observes that in a short period of time (6 hours), increasing temperature from 25 ºC to 120 ºC yields a recovery improvement from 2.6% to 64.4%. After 24 hours, we obtain an average of 21.4% oil recovery at room temperature (CG2 and CG3); while at steam conditions (120 ºC) the average recovery after 24 hours is 75.5% (GB1, GB6, GB9, GB10 and GB15). Note that experiment GB11 gives a recovery of 30.8% at only 2 hours under steam conditions. Room temperature experiments yield a very minimal recovery, which is controlled only by the drainage capability of the sample by gravity and this is also quite ineffective due to the high viscosity of oil.

While the rate is high in the beginning (recovery becomes double from 2 to 6 hours; GB3 vs. GB11) in the high temperature experiments, it slows down when it drains most of the oil and advances to an average of 75.5% (GB1, GB6, GB9, GB10, GB15) for a 24-hour period and 80.7% after 48 hours (GB12). Note that leaving the core at ambient conditions (control experiments) for a very long period of time (1 month) gives a final 64.7% recovery (CG4), which was attainable with steam in only 6 hours.

The surrounding fluid and its temperature are also important. Exposing the core to hot water at 90 ºC for 24 hours (GB14) results in a low recovery of 37.4% despite possible recovery by capillary imbibition due to the water-wet nature of sandpacks. However, temperature is not high enough to obtain a high value of recovery. Increasing the temperature to 120 ºC prompts a phase change and requires a larger amount of heat but almost doubles the recovery (75.5% on average for GB1, GB6, GB9, GB10, and GB15).

Two experiments were performed with different heights of the core column inside the cage: (1) GB4 with 6 inch, and (2) GB13 with 2 inch height, compared with the 4 inch average height for the rest of the experiments. Although increasing the height from 4 to 6 inch does not seem critical, but very short core (2 inch tall) leads to a significantly lower recovery (45.3%) that shows the degree of the importance of sample height to provide enough gravity force for recovery.

Wettability does not show a critical effect in Phase-I. On average, oil-wet cores yielded 64.8% recovery (GB2, GB7 and GB16), which is slightly lower than the average recovery of equivalent water-wet experiments (GB1, GB6, GB9, GB10, GB15), which is 75.5%. The effect of wettability on the gravity drainage recovery is well known and oil-wet samples characteristically yield lower recovery than that of water-wet samples at ambient conditions (Nabipour et al. 2007), and we observed the same at 120 ºC.

In Phases II and III, the cases with no initial thermal phase (Exps. GB5 and GB8) showed a very high recovery (**Figs. 4-7** and **4-8**). GB5 was exposed to CO_2 at 3500 kPa pressure (absolute) while GB8 was under propane with a pressure of 850 kPa (absolute). A major fraction of this high recovery was due to gravity drainage enhanced by the diffusion of the solvent; the rest was by a hot water effect in the following phase. Propane, with a much lower pressure, still showed a better recovery compared with CO_2, yet CO_2 showed promising results when followed by hot water injection (GB5). Experiments GB11 and GB14 gave the next best recoveries as they had also relatively low recoveries in Phase-I. The lowest recoveries in Phases II and III combined were obtained with the experiments that performed better in Phase-I; GB6, GB7 and GB12.

We reported the recoveries from Phases II and III as a whole and this gave a relatively accurate measurement due to limited number of assumptions made in the calculation of the oil recoveries using measured weight differences before and after the experiments. If we are interested in the separate recoveries from Phase-II and Phase-III, some additional assumptions are needed for calculations. Although such assumptions might reduce the uncertainty, they provide an insight into the contribution from each phase. Supposing that there is no condensed water blocked in the core after Phase-I (in steam cases) and also neglecting the solvent weight inside the core after Phase-II, and assuming that all water and solvent were out of the core during the drying period after the experiments, we can present the corresponding recoveries for Phase-II and III as shown in **Figs. 4-9 and 4-10**. This shows how different solvents react with oil in Phase-II. When there is no initial thermal phase (GB5 and GB8), the propane is in charge of the most recovery (GB8), while the production due to CO_2 exposure (GB5) is not that high.

However, Phase-III helps GB5 to acquire fair -overall- recovery. Experiments GB11 and GB14 are the ones showing the lowest recovery in Phase-I. GB11 yields 17% recovery under CO_2 (as Phase-II), while this amount in GB14 is 3.8% under CO_2 with the same conditions because GB14 was previously in contact with hot water. The hot water penetrated into the sandpack core in Phase-I by capillary imbibition, and then in the following phase gravity produced both water and oil yielding lower amounts of oil in the effluent.

Pressure in Phase-II is a critical factor in recovery. Lowering CO_2 pressure in the second phase from 3500 kPa to 1800 kPa for similar cores reduced the recovery in this phase from 6% to 0.4% (GB9 and GB10). Even though hydrocarbon solvents (propane and butane) are generally more efficient solvents, low pressure causes slower diffusion and therefore the recovery due to such solvent (Phase-II) after the thermal phase (Phase-I) in low pressures is not high (GB6, GB7, GB15 and GB16). On the other hand, propane application to an original core with the whole initial oil available to solvent (not gone through thermal phase before) gave a very high recovery in solvent phase as a result of solvent diffusion and gravity effects combined (GB8). The pressures of propane and butane in Phase-II are chosen in a way to keep them in gas phase close to the vapor pressure point as suggested by Pathak et al. (2011, 2012). CO_2 is also in gaseous phase.

The best Phase-III (hot water) performance was obtained for GB14 where the sandpack core has been exposed to hot water instead of steam in Phase-I. Water penetration into the core took place due to capillary imbibition as hot water was exposed to the sample in Phases I and III. This results in higher recovery in Phase-III due to the reduced viscosity of oil during Phase-II by solvent dilution. The remaining water in the sand from Phase-I can also improve the imbibition in Phase-III. This case aside, hot water gives better recovery when more oil is available to Phase-III (GB11, GB5 and GB13). The least recovery due to hot water is of GB12 where most of the oil has already been produced in the long exposure (48 hours) previous phases. Long initial thermal phase might have also changed the remaining oil properties by taking the lighter ends out and making it more viscous so that in Phases II and III the recoveries are very low even with long-time exposures of solvent and hot water. Using steam in the third phase (GB9) is not as helpful as hot water (GB1) since the water in the final phase (Phase-III) helps to produce oil and solvent together by imbibition and buoyancy.

The total recoveries of the sandpacks are typically high due to their unconsolidated nature as shown in **Figs. 4-11 and 4-12.** The best case was GB4 which was a longer sandpack with an almost 50% increase in the height. This shows the contribution of gravity drainage for the sandpack models. On the other hand, the core with a 2 inch height (half of the original height used) yields one of the lowest recoveries (GB13). The next best performance after GB4 was from GB8 in which the sandpack went through propane exposure during Phase-II without an initial thermal phase (Phase-I). This suggests that if a hydrocarbon solvent is used, it is more efficient to introduce the solvent first rather than injecting steam (or any other processes that lead to a high fraction production and change the characteristics of the oil) in the initial phase (compare GB8 and GB6). On the other hand, this is not true for CO_2, as a combination of thermal-solvent-thermal stages works better than only a solvent-thermal stage (compare experiments GB1 and GB5). Even if the difference in the ultimate recoveries of these two experiments is not high, the recovery rate for GB1 is expected to be faster due to inclusion of Phase-I.

The time scale used in this experimental program did not show a significant difference in total recovery. For example, 6-hour and 24-hour exposure times (for each phase) were not critically different in the overall performance for this size of sandpack when CO_2 was used as a solvent. On the other hand, 2-hour phases seem too short and 48-hour phases seem too long when looking at the overall recovery, as both yielded low final recoveries (GB11: 2 hours, and GB12: 48 hours, each phase). The former did not provide enough time for the soaking process and the latter makes most of its recovery in the first phase changing the oil properties and likely resulting in a certain amount of water intrusion into the core so that the performance of the consequent phases (especially solvent diffusion during Phase-II) declines.

Wettability showed its effect more in the CO_2 and butane cases compared to the propane case. The oil wet cases (GB2 and GB16) had lower recoveries than the water-wet equivalent cases (GB1 and GB15), respectively. But, for the propane cases, there is no difference between the total recoveries of water-wet and oil-wet cases (GB6 and GB7). The hydrocarbon solvents are expected to be more efficient and overcome the wettability issue better. This occurred in the propane cases but not with butane, since the propane pressure was enough for effective diffusion; however, the butane pressure was at a much lower value. The pressures for solvents are selected to keep them in gas phase at the given temperature conditions.

Overall, the initial thermal phase (Phase-I) is critical as it produces most of the oil and leaves less in the core for the subsequent phases. These phases (Phase-II and III) help towards the overall recovery when using a solvent like CO_2 which is not miscible with the heavy oil due to low pressure. On the other hand, having the initial thermal phase for a hydrocarbon solvent like propane reduces the effectiveness of solvent by providing a small fraction of oil to the solvent phase which decreases the total recovery and the efficiency of the process. Also, steam is more efficient in the first phase than hot-water towards the overall production, while hot water is more effective in Phase-III than steam due to its imbibition ability.

The specific SOS-FR method applied in this work, which employed CO_2 as a solvent, showed that although it is not miscible with the oil, CO_2 is capable of improving heavy oil recovery when used with steam (or hot-water) properly. Note that the proposed scheme is a soaking process that resembles the huff-and-puff type application more than routine injection for displacement. Hence, the timing for soaking in larger matrix sizes becomes critically important, especially in Phase-II, for an efficient solvent-oil interaction by diffusion. Wormhole network distribution after CHOPS is also of importance as it determines the capability of matrix-wormhole fluid interaction.

Solvent Retrieval

As the hydrocarbon solvents are costly, the retrieval of such solvents at Phase-III is of importance. On the other hand, although retrieval of CO_2 is also critical as it can be recycled for the next phases of the project, its permanent storage at the end of the project is also desired, unlike hydrocarbon solvents. Hence, these two different types of solvents should be evaluated from the retrieval point of view.

It was shown earlier that, when using liquid hydrocarbon solvents, the rate (and ultimate recovery) of solvent retrieval during Phase-III can be controlled by the temperature of the water used (Al-Bahlani and Babadagli 2008, 2009a, 2009b, 2010; Naderi et al. 2013). If the temperature of the water injected is near the boiling point of the solvent, the solvent can be retrieved as vapor due to its boiling eventually condensing as it is produced through a lower temperature system (Naderi et al. 2013). This is experimentally doable through a vapor collection and condensation system and the amount of liquid solvent retrieved can be measured as it is in liquid form (Mohammed and Babadagli 2013). In the present study, where we use gas solvents, this application is more difficult as the solvent is only comes out in the form of gas and the condensation requires much lower temperatures as the boiling points of these solvents (propane, butane and CO_2) are very low. Separation facilities can be designed when using this method in field scale for the sake of hydrocarbon solvent retrieval. However, earlier attempts showed that solvent penetrated into the core can be retrieved during even cold production during Phase-III and this amount is maximize at the boiling point of the solvent

(Naderi and Babadagli 2012a), reaching values between 70% and 90% (Naderi et al. 2013; Coskuner et al. 2013; Mohammed and Babadagli 2013).

As mentioned above, CO_2 may be injected for a dual-goal purpose: (1) Heavy oil recovery improvement, and (2) CO_2 sequestration. In case of sequestration, the solvent retrieval is not an issue, instead it is important to leave the injected CO_2 in the reservoir permanently. This would happen by omitting Phase-III, which is a thermal phase that helps oil and solvent production together, but is conducted primarily for solvent recovery. If only drawdown production is allowed without another round of steam or hot water injection after solvent soaking, more CO_2 is left inside reservoir and also less oil is produced overall. Thus, an optimized scheme for this dual-goal program, i.e., maximized oil recovery with maximized CO_2 storage, is needed to increase the combined benefits of oil production and CO_2 sequestration (Naderi and Babadagli 2012b; Trivedi and Babadagli 2010).

Conclusions

Using CO_2 in SOS-FR method on unconsolidated medium shows promising results, close enough to hydrocarbon solvents' performance to be considered as a substitution.

CO_2 and hydrocarbon solvents were compared as the solvent used in Phase-II. Phase-I resulted in similar recovery for different wettabilities. Phases-II and III recoveries were more prominent for the cases without initial thermal stages. Propane led to a better recovery when it was applied without Phase-I. CO_2, not a very effective solvent on its own at these conditions, performed well with the help of thermal phases before and after solvent exposure.

Total recovery performance (oil recovery through Phases-I, II, and III) was better for longer cores.

The time period of phases can be optimized for different matrix sizes to present the best overall recovery. At this level of laboratory scale, the total production is maximized when a time slot of 6-24 hours is selected for each phase (shorter phases such as 2 hours or longer phases like 48 hours affect the recovery negatively).

The hindering effect of wettability was more prominent in the CO_2 case than in propane, which is related to solvents diffusion capability. A similar effect was observed in the butane case but this time the reason is the low pressure of butane that was chosen to keep it at the gas phase.

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Table 4-1: Sandpack experiments.

Exp.#	Wettability	Phase-I	Phase-II	Phase-III	Comment
GB1	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.	4", 24 hrs
GB2	Oil Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.	4", 24 hrs
GB3	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.	4", 6 hrs
GB4	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.	6", 24 hrs
GB5	Water Wet	-	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.	4", 24 hrs
GB6	Water Wet	Steam 120 °C 200 kPa	C3 24 °C 850 kPa	Hot Water 90 °C Ambient P.	4", 24 hrs
GB7	Oil Wet	Steam 120 °C 200 kPa	C3 24 °C 850 kPa	Hot Water 90 °C Ambient P.	4", 24 hrs
GB8	Water Wet	-	C3 24 °C 850 kPa	Hot Water 90 °C Ambient P.	4", 24 hrs
GB9	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Steam 120 °C 200 kPa	4", 24 hrs
GB10	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 1800 kPa	Hot Water 90 °C Ambient P.	4", 24 hrs

Exp.#	Wettability	Phase-I	Phase-II	Phase-III	Comment
GB11	Water Wet	Steam 120 ºC 200 kPa	CO_2 24 ºC 3500 kPa	Hot Water 90 ºC Ambient P.	4", 2 hrs
GB12	Water Wet	Steam 120 ºC 200 kPa	CO_2 24 ºC 3500 kPa	Hot Water 90 ºC Ambient P.	4", 48 hrs
GB13	Water Wet	Steam 120 ºC 200 kPa	CO_2 24 ºC 3500 kPa	Hot Water 90 ºC Ambient P.	2", 24 hrs
GB14	Water Wet	Hot Water 90 ºC Ambient P.	CO_2 24 ºC 3500 kPa	Hot Water 90 ºC Ambient P.	4", 24 hrs
GB15	Water Wet	Steam 120 ºC 200 kPa	C4 24 ºC 110 kPa	Hot Water 90 ºC Ambient P.	4", 24 hrs
GB16	Oil Wet	Steam 120 ºC 200 kPa	C4 24 ºC 110 kPa	Hot Water 90 ºC Ambient P.	4", 24 hrs

C3: Propane, C4: Butane, All experiments are sandpacks with heavy oil.

Table 4-2: Control experiments.

Exp.#	Wettability	Control Type	Condition	Comment
CG1	Water Wet	Gravity Drainage	Ambient	4", 6 hrs
CG2	Water Wet	Gravity Drainage	Ambient	4", 24 hrs
CG3	Water Wet	Gravity Drainage	Ambient	5", 24 hrs
CG4	Water Wet	Gravity Drainage	Ambient	5", 1 month
CT1	Water Wet	Thermally Assisted Gravity Drainage	Ambient	5", 24 hrs
CT2	Water Wet	Thermally Assisted Gravity Drainage	Ambient	5", 24 hrs

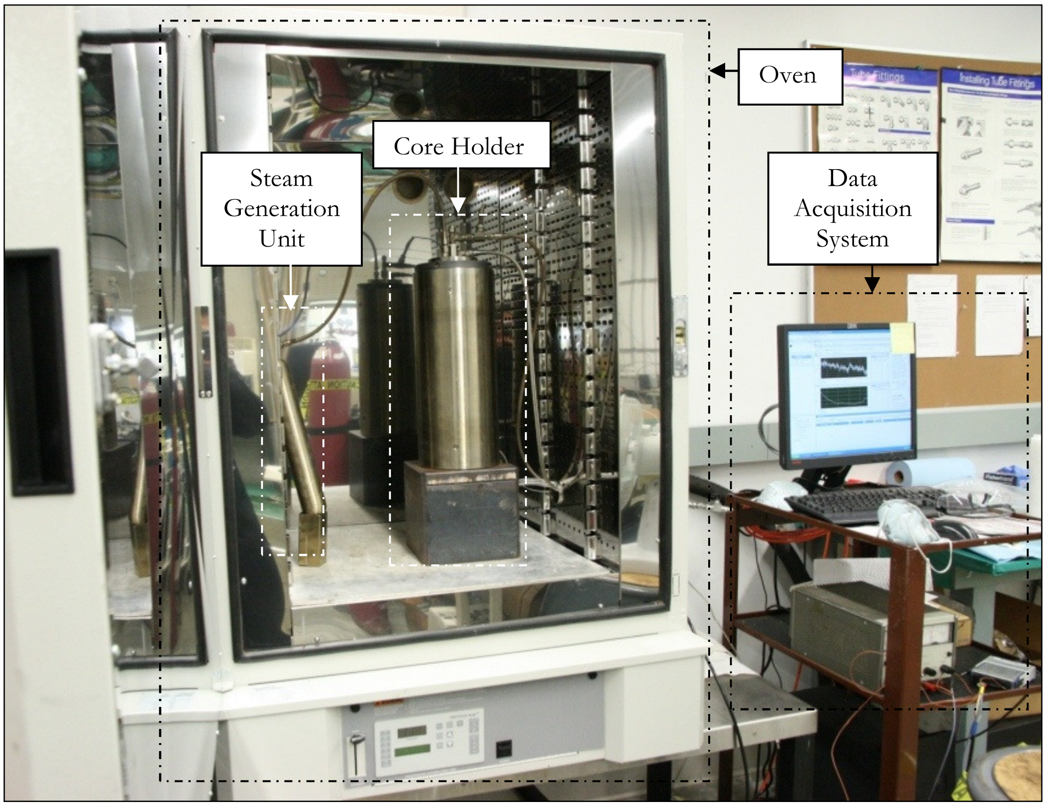


Figure 4-1: Steam soaking setup used for Phase-I and III (from Naderi and Babadagli 2012a).

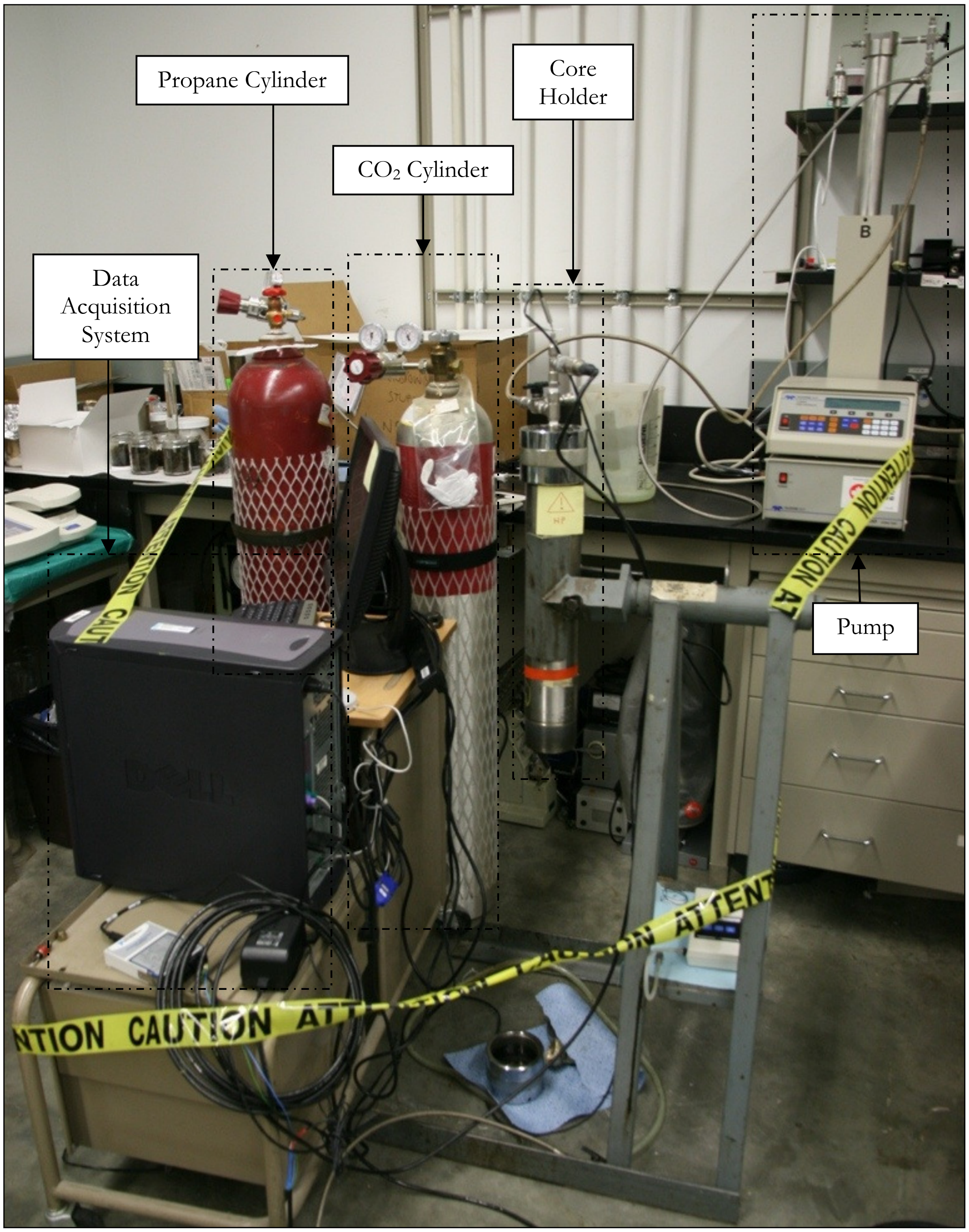
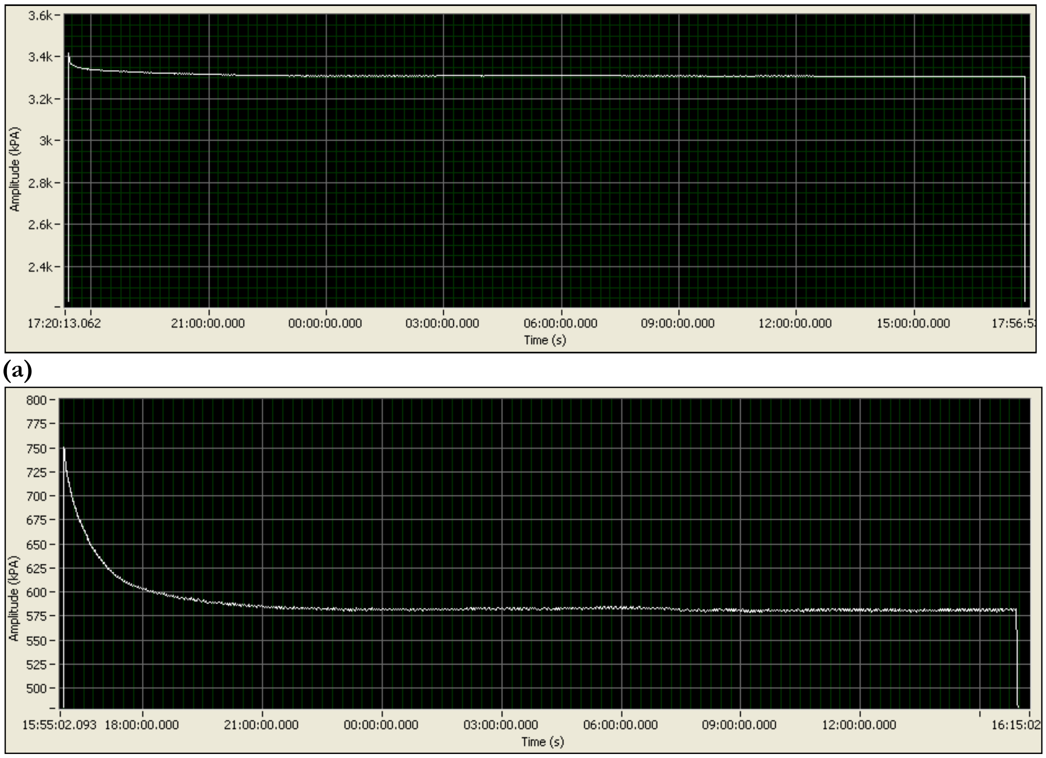


Figure 4-2: Solvent soaking setup (Phase-II experiments).

(a) **(b)** **(c)**

Figure 4-3-a: Sandpack container, b: Sandpack mixture, c: CO_2 bubbling from a sandstone core in Phase-III.



(a)

(b)

Figure 4-4: Pressure decline in Phase-II for: (a) CO_2, (b) propane.

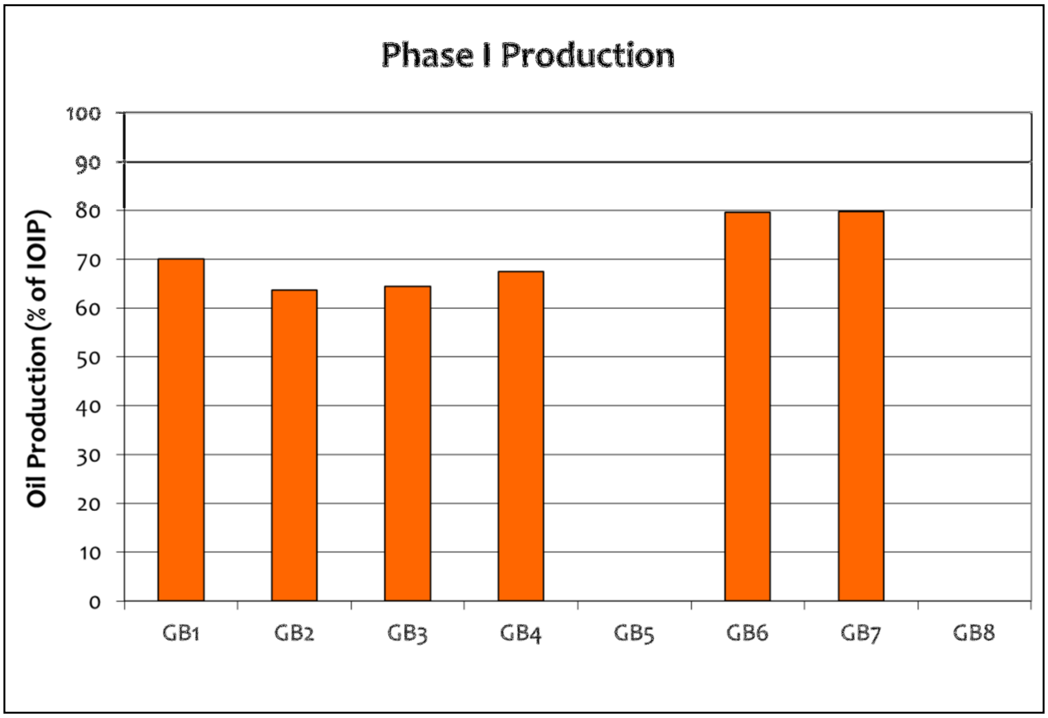


Figure 4-5: Phase-I recoveries (first batch).

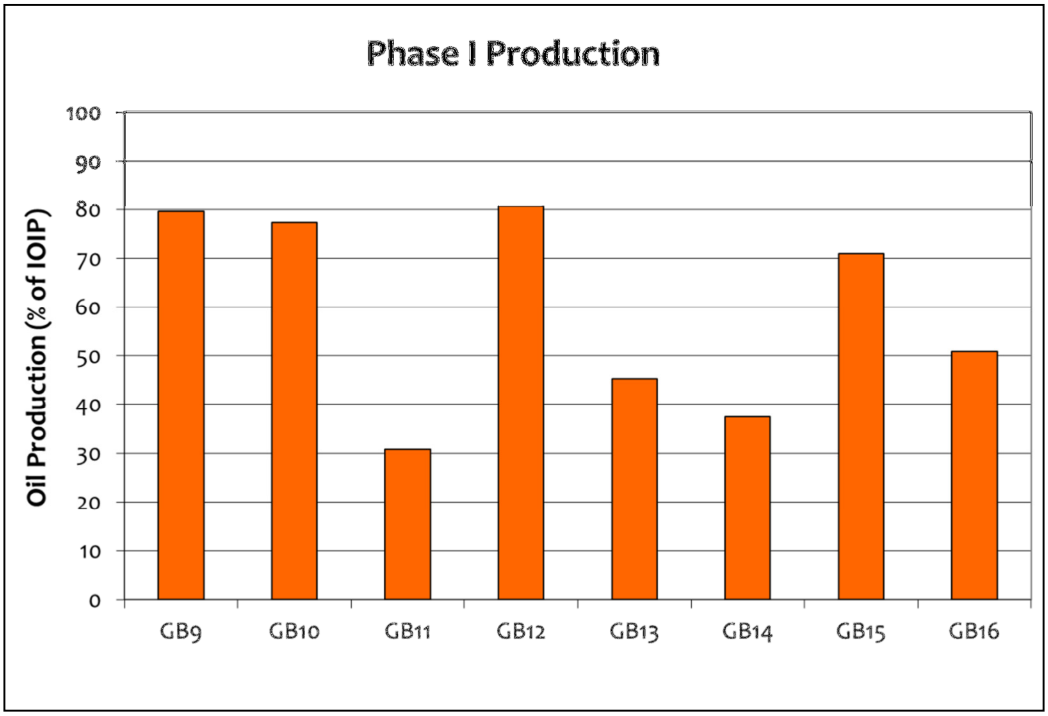


Figure 4-6: Phase-I recoveries (second batch).

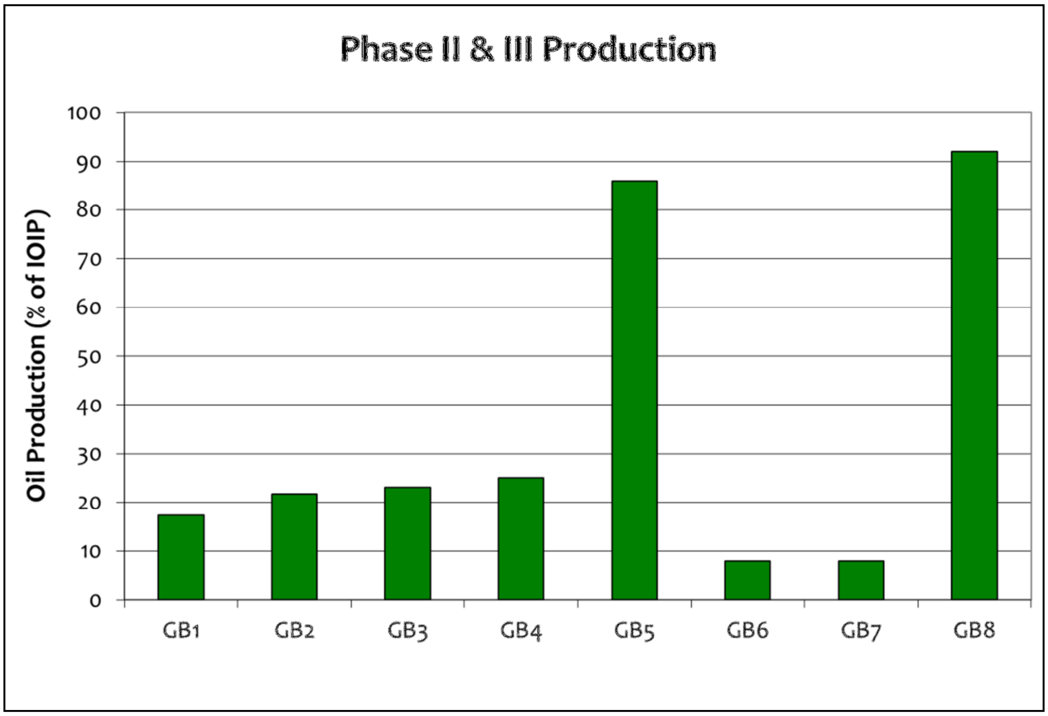


Figure 4-7: Phase-II & III recovery (first batch).

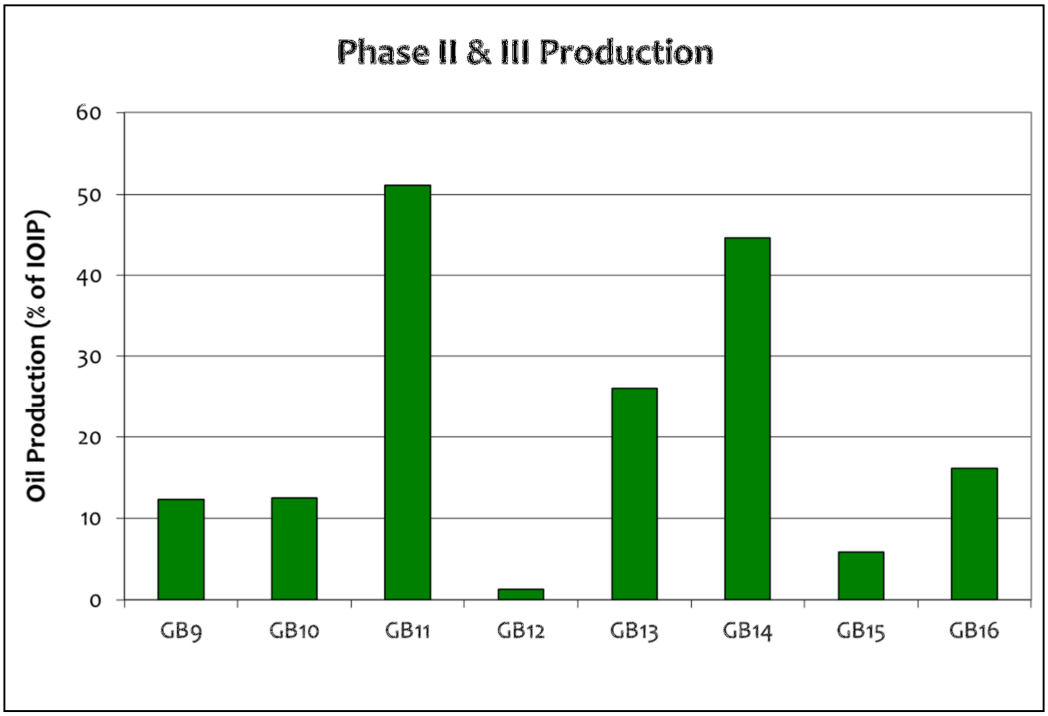


Figure 4-8: Phase-II & III recovery (second batch).

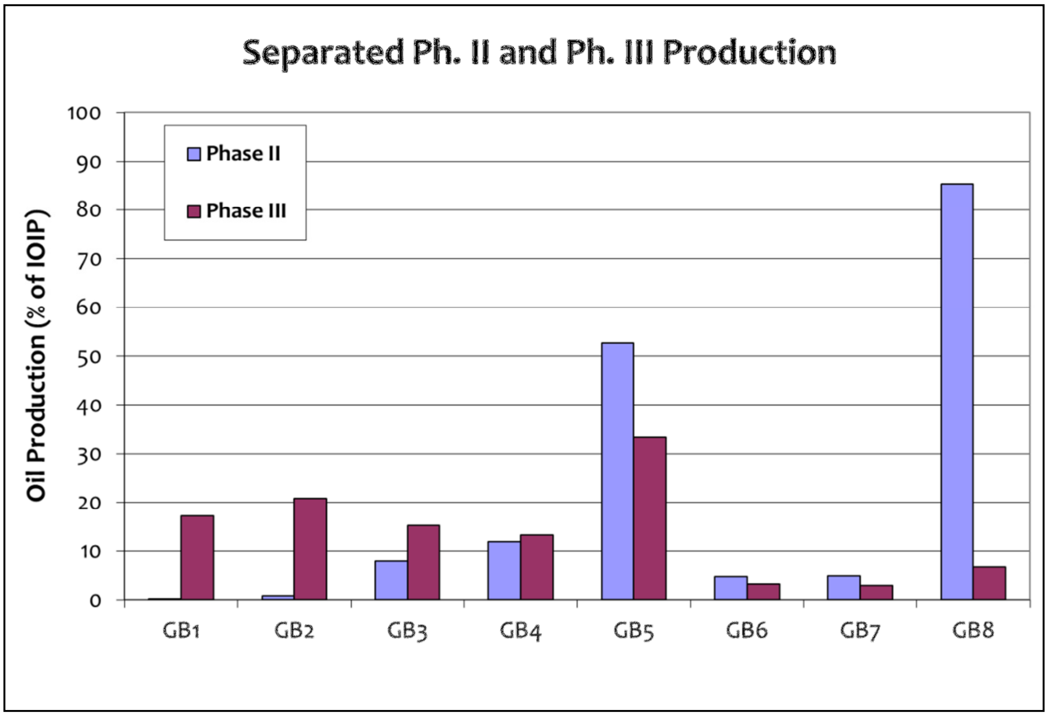


Figure 4-9: Separate Phase-II & III recovery (first batch).

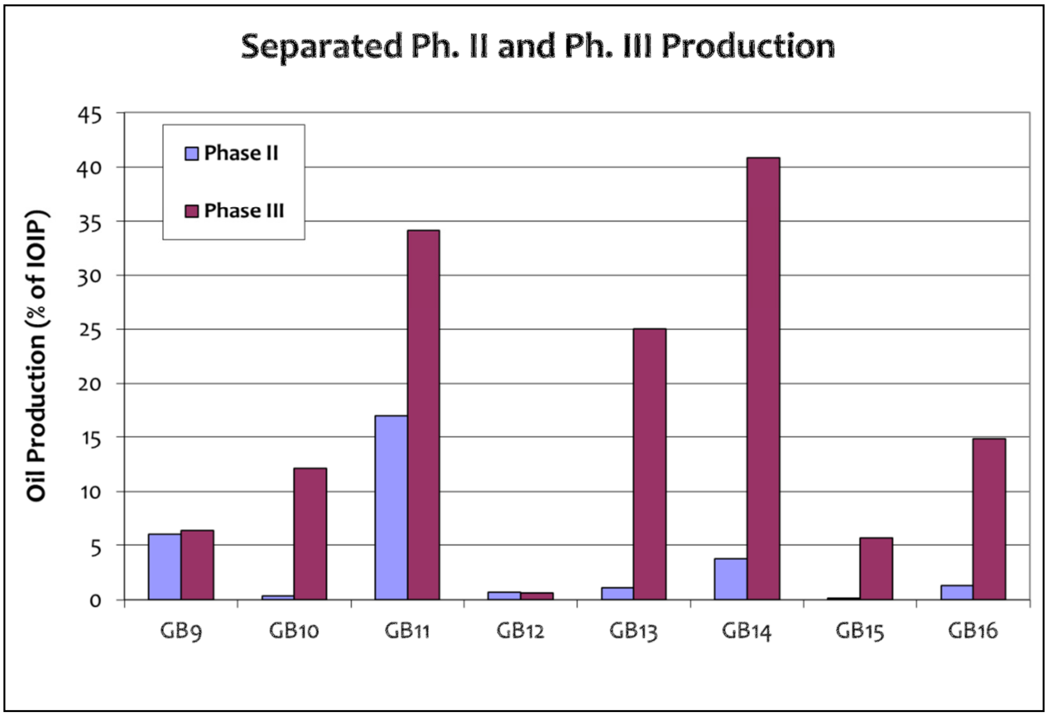


Figure 4-10: Separate Phase-II & III recovery (second batch).

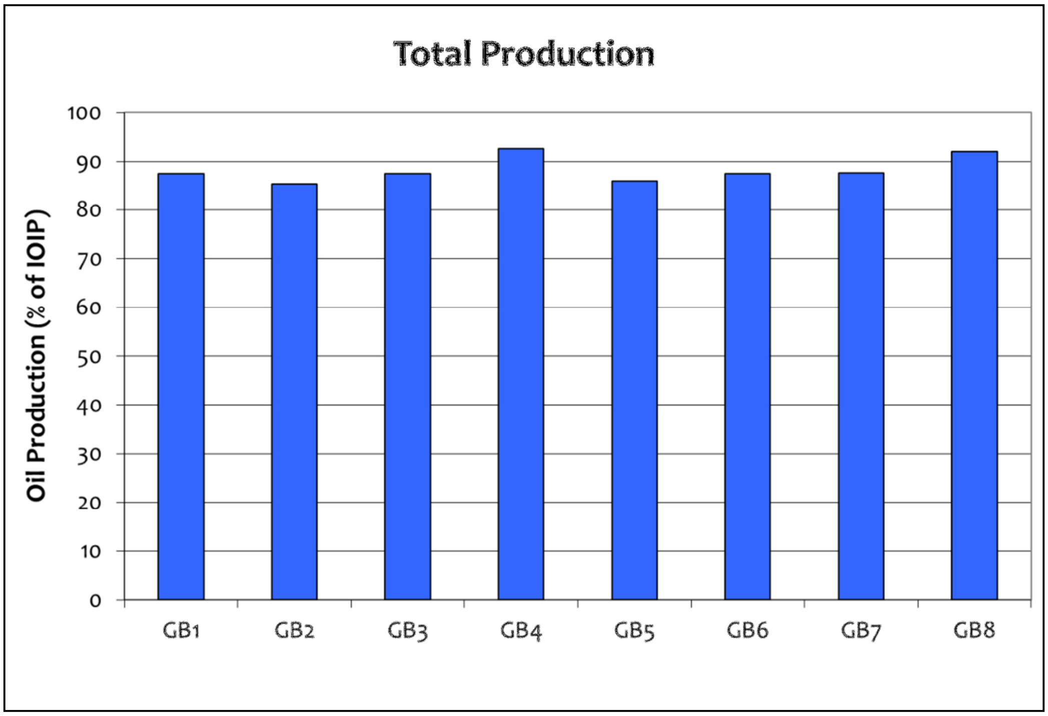


Figure 4-11: Total production (first batch).

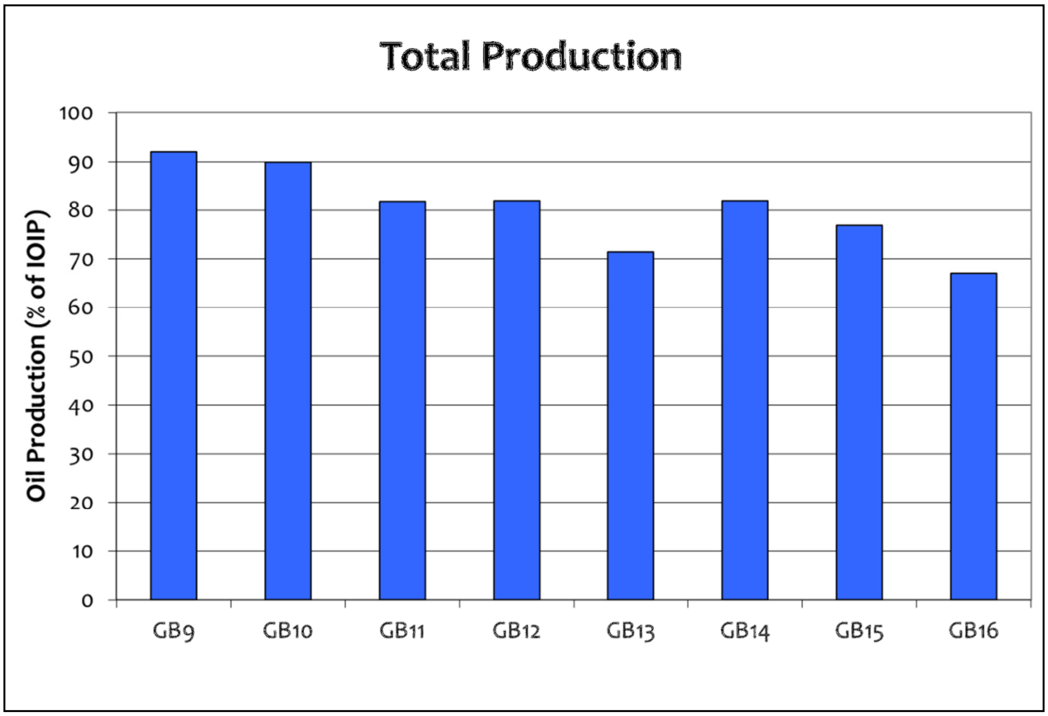


Figure 4-12: Total production (second batch).

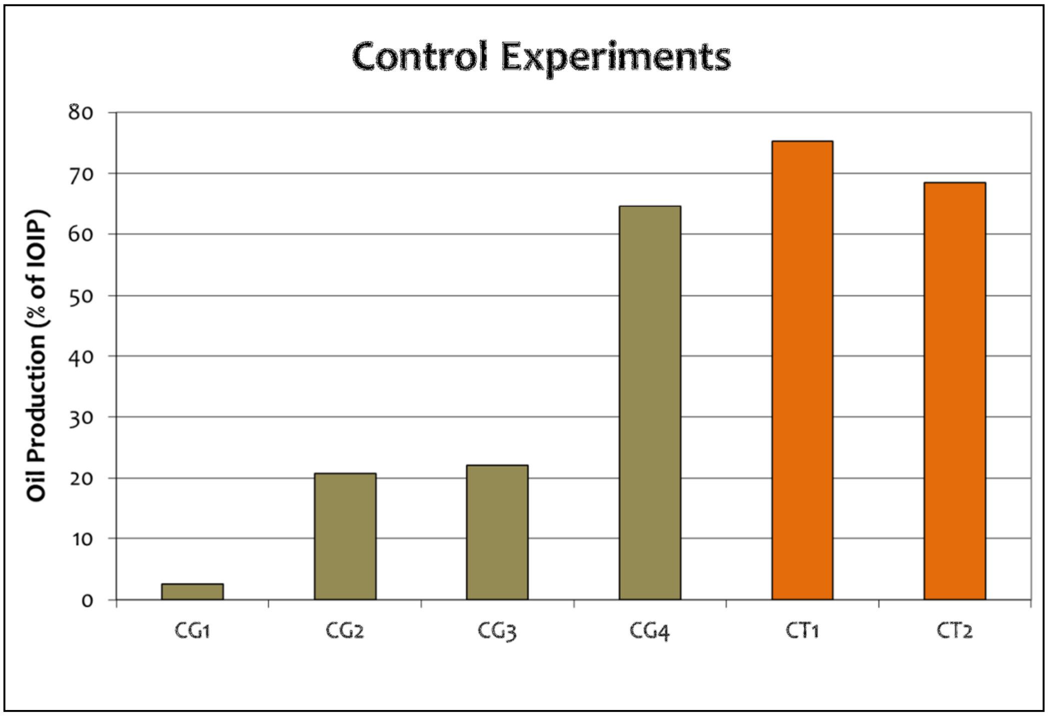


Figure 4-13: Control experiments.

Chapter 5 : Use of CO_2 and Hydrocarbon Solvents during Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR) Method for Heavy-Oil Recovery from Sandstones and Carbonates

A version of this chapter is presented at the International Petroleum Technology Conference held in Bangkok, Thailand, 15–17 November 2011 and is also submitted to SPE Reservoir Evaluation & Engineering.

Introduction

Excessive need and increasing oil prices forced the industry to focus heavily on unconventional resources. Heavy oil reserves, in particular, gained specific attention as an alternative hydrocarbon resource, yet they are still challenging cases and more research is required to ease the recovery from this type of reserve. A specific challenge is fractured and deep carbonate reservoirs containing heavy-oil, where the main problem is to mobilize the heavy-oil in a tight matrix towards a high permeable fracture network. This requires the reduction of oil viscosity and interfacial tension and the best possible way to achieve this is by steam injection. Heat loss and generation costs are the main issues with thermal approaches.

Although different forms of steam injection such as cyclic steam injection, steamflooding, and steam-assisted gravity drainage (SAGD) have been successfully applied in sandstones worldwide, carbonates have very limited field scale steam injection projects (Babadagli et al. 2009). In one of the rare applications, steam was injected from the crest to heat the matrix and collect the oil drained by gravity in the Qarn Alam field in Oman. Macaulay et al. (1995) reported a small primary recovery of 2% of stock-tank oil initially in place during the primary recovery, which can be raised to 20% by means of gas-oil gravity drainage, which is thermally-accelerated by steam injection. This estimation is based on experimental and simulation works prior to the pilot test. Al-Shizawi et al. (1997) discussed the methods of heat monitoring in the same field for the same pilot project. Later studies reported an analysis of pilot test and further understanding of the physics of the process (Penney et al. 2005; Shahin et al. 2006; Penney et al. 2007)

Matrix recoveries from fractured carbonates do not show very high amounts, typically due to low permeability, unfavorable wettability, and high viscosity. Babadagli and Al-Bemani (2007) performed an experimental analysis on Qarn Alam core samples and observed that the recovery can go up to 47% OOIP for the case with initial water saturation at 200 ºC. This recovery is expected to be lower in field conditions (27% in the Qarn Alam field), as reported by Shahin et al. (2006). Beyond this, the production rate is very slow in cases of gravity drainage, even if it is thermally accelerated.

A great portion of the published work on heavy-oil recovery from fractured carbonates cover either pilot tests (only five pilot test results were documented as reported by Babadagli et al. 2009) or from numerical simulation attempts (Sedaee Sola and Rashidi 2006).

Solvent applications were also proposed as an alternative to thermal methods in sandstones, with the vapor extraction (VAPEX) method being the most popular one employed to dilute and drain the oil by gravity using two horizontal wells (Butler and Mokrys 1989; Das 2002). Cost and solvent retrieval are the two main concerns, in addition to asphaltene precipitation, in this type of application. Solvent applications in fractured porous media are very rare; they are almost limited to the SOS-FR (steam-over-solvent injection in fractured reservoir, SOS-FR) technique proposed by Al-Bahlani and Babadagli (2008). They studied the recovery of heavy-oil in fractured reservoirs by a cyclic injection of steam and solvent and observed recovery at laboratory conditions as high as 85-90% OOIP and a fast retrieval of solvent when the sample contacted hot water after a long period of solvent exposure. They further analyzed this method experimentally (Al-Bahlani and Babadagli 2009a, 2009b) and concluded that the process is strongly controlled by the matrix size and that lighter solvents produced a higher amount of oil but with a higher amount of asphaltene precipitation. Dynamic experiments confirmed the existence of an optimum rate in terms of recovery time and solvent use (Al-Bahlani and Babadagli 2009a). Field scale numerical model results showed that this method is applicable at larger matrix sizes with a high rate of solvent retrieval with a proper injection design (Al-Bahlani and Babadagli 2010). They also concluded that the efficiency of the SOS-FR method yields a better efficiency compared with the sole injection of solvent or steam. Gravity drainage is the dominant parameter controlling the physics of the recovery.

Using CO_2 as an alternative to more expensive hydrocarbon solvents brings the advantage of disposing of a greenhouse gas. Therefore, it is preferred from an environmental point of view as well and makes a second benefit to oil production. The co-optimization of these goals needs to be understood through the study of solvent-oil interaction under different conditions of reservoir and operation.

The use of CO_2 as solvent in this type of process was considered and tested in this chapter. Several issues are highly critical in this process. Like hydrocarbon solvents used under non-isothermal conditions, the recovery process is highly sensitive to pressure and temperature as they determine the miscibility level. Also important is the capability of CO_2 to extract the matrix oil. Our earlier studies with light oil showed that heavier ends can be extracted if enough time is allowed for CO_2 to interact with matrix oil (Trivedi and Babadagli 2009a). The same needs to be investigated for heavy-oils. Another dilemma was inverse proportionality of CO_2 solubility with temperature. Steam (or heating) is inevitable to condition oil and decrease its viscosity before CO_2 injection but temperature should be critically adjusted so as not to sacrifice the CO_2 solubility of oil.

A number of experimental works were performed to test light oil recovery from naturally fractured reservoirs using carbon dioxide as a solvent. Some of them also focus on CO_2 sequestration during the enhanced oil recovery process (Trivedi and Babadagli 2008a, 2008b). Darvish et al. (2006a, 2006b) used saturated chalk cores and injected CO_2 to displace the oil. They concluded that CO_2 injection could be an effective EOR method for fracture reservoirs after water injection. Variable oil composition confirmed that the main oil recovery mechanism in their experiment was diffusion. Karimaie et al. (2008) performed experiments for secondary and tertiary injection of CO_2 and N_2 in a fractured carbonate rock in reservoir conditions. They used a binary mixture of C1-C7 as the solute. CO_2 turned out to be very efficient when 73.0% of oil was recovered after a secondary

CO_2 injection. Tertiary injection increased the recovery by 15.7% of OOIP. The recovery by nitrogen was quite low.

Torabi and Asghari (2007) studied CO_2 huff-and-puff performance on two Berea sandstone cores. CO_2 was injected into a 0.5 cm annular space between the core and a core holder acting as a fracture. In their experiments, they injected CO_2 at six different pressure steps of constant pressure into a saturated core. They observed a drastic increase in the recovery factor from immiscible to near miscible/miscible conditions. Below miscible conditions, the production rate and recovery factor were higher in high permeable cores, while at miscible conditions, the permeability does not show a significant impact on the recovery factor. Asghari and Torabi (2007) performed gravity drainage experiments in sandstone core samples with a fracture at the annular space and concluded that miscibility can increase the production substantially. They also found that CO_2 injection at pressures below the minimum miscibility pressure (MMP) could recover up to 19% of OOIP which increases to more than 50% at miscible conditions. However, at a pressure far above the MMP, the ultimate recovery might decrease due to the presence of denser fluid in the fracture.

Trivedi and Babadagli (2008a) performed experiments to study the diffusion process between the matrix and the fracture. Heptane was used as a miscible solvent to mimic miscible displacement in fractured porous media. The process efficiency was investigated in terms of recovery time and solvent amount. They showed that diffusion is dominant over viscous flow and a lower rate of solvent injection gives more production contribution from the matrix as the solvent has more time to diffuse into the matrix before breakthrough.

CO_2 sequestration was also investigated by Trivedi and Babadagli (2008b) where they defined a dimensionless term as the global effectiveness factor in order to optimize both oil (solute) recovery and CO_2 (solvent) storage. They also analyzed CO_2 sequestration efficiency by experiments of CO_2 injection at constant rates into the fracture under high pressure (Trivedi and Babadagli 2008c). The shutdown after a slower rate showed a better recovery after the first blowdown compared to the faster rate. Beneficial pressure ranges for the sake of recovery and sequestration were measured for different core types. In another work by Trivedi and Babadagli (2009b), their combination of laboratory experiments and numerical simulations were employed to evaluate the mass transfer between the matrix and the fracture. Their results showed that the recovery through the fracture is dominant by the dispersion effect and mass transfer rate. Length of the matrix is an important parameter, and the longer the core, the later the breakthrough time and the higher the solute recovery.

The effects of miscibility and injection rate on oil recovery and CO_2 sequestration were also studied by Trivedi and Babadagli (2010). They observed that a certain rate was the most effective rate for both storage and recovery. A near-miscible pressure condition was shown to be the most effective for oil recovery.

The current experience in heavy-oil recovery, especially from fractured systems, leads to a focus on a combination of thermal and solvent methods. The application strategy may vary depending on the geological constraint, availability of injectants, depth and oil type, but alternate injection could be a possibility as reported by the studies listed above. Injection of CO_2 only into light oil-containing reservoirs might be feasible (Beliveau et al. 1993) but its application in naturally fractured heavy-oil reservoirs is not efficient and requires further improvements.

This chapter reports an experimental study on using CO_2 as a solvent during the application of the SOS-FR method. Indirect cost benefits due to a CO_2 storage option is thought to be an asset as long as the method yields substantial oil recovery.

Methodology

The steam-over-solvent injection in the fractured reservoir (SOS-FR) method comprises three steps (Al-Bahlani and Babadagli 2008, 2009a, 2009b, 2010; Babadagli and Al-Bahlani 2008):

(1) Injection of steam (or hot-water) to produce the initial oil (usually by thermal expansion if wettability is unfavorable) and to condition the heavy-oil in the matrix for succeeding solvent injection.

(2) Hydrocarbon solvent injection.

(3) Injection of steam to mainly retrieve solvent and to recover additional oil.

The reported studies on the SOS-FR method (Al-Bahlani and Babadagli 2008, 2009a, 2009b, 2010) considered pessimistic conditions (mainly deep reservoirs) so that the temperature in Phases I and III were not very high. In fact, in their experiments, it was kept under 100 °C (hot water conditions). This temperature value was particularly critical in Phase-III as it should be above the boiling point of the solvent for the given pressure to maintain suitable thermodynamic conditions for efficient retrieval. The aforementioned papers by Al-Bahlani and Babadagli mainly tested heptane as a solvent, even though they used higher carbon solvents for comparison.

The effects of alternating the injection of steam and solvent for heavy oil recovery were investigated experimentally, in which CO_2 was selected as the solvent in comparison to hydrocarbon solvents (propane and butane). 100% heavy-oil saturated cores were tested at various reservoir conditions. For the thermal stage, hot water at 90 ºC and steam at two different temperatures and pressures were used.

The experiments consisted of three phases: (1) Phase-I: Thermal, (2) Phase-II: Solvent and (3) Phase-III: Thermal. In Phase-I, the core was either immersed into hot water (at 90 ºC) or soaked by steam (at 120 or 150 ºC) in a special setup (**Fig. 5-1**), and then, in both cases, it was left in the oven at the same temperature for one day. In Phase-II, the core was taken out of the oven and placed into another setup that was designed for solvent soaking (**Fig. 5-2**). This stage took one day. Phase-III was the same as Phase-I, i.e., thermal. At the end, the total recoveries of oil were determined by volumetric and then weight measurements. **Tables 5-1** and **5-2** list the experiments and their corresponding pressure and temperature conditions for sandstone and carbonates, respectively.

The heavy-oil used in these experiments had a viscosity of 6,100 cP and a density of 0.9639 gr/cm^3 at room temperature. To saturate the cores better, the cores were placed into an oil bath inside the oven at 60 ºC for a week under vacuum. The saturation process changes the oil properties to a viscosity of 6,400 cP and a density of 0.9738 gr/cm^3 at the same temperature (25 ºC) due to evaporation of a certain amount of lighter ends.

Wettability alteration of sandstone cores was achieved through the application of a siliconizing liquid named Surfasil (dichlorooctamethyltetrasiloxane) in a certain amount mixed with a solvent succeeding by same solvent flood and a stabilization agent flood to obtain oil wet cores.

Analysis of the Results

The oil production after each stage was measured. Visual analysis showed that the first thermal phase always gave a core with a fairly clean surface (**Fig. 5-3-a and Fig. 5-4-a**), whereas the core coming out of the solvent phase had a certain amount of sticky oil outside and usually CO_2 or propane bubbles on the core were also eminent (**Fig. 5-3-b** and **Fig. 5-4-b**). Due to the nature of the process and thereby the experimental design, the cores had to be put immediately into the next phase after Phase-II to prevent any solvent release that might cause errors in recovery calculations. Thus, the distinction between the productions of Phase-II and Phase-III was not exact and the production for these two phases is given together. **Fig. 5-3-c** and **Fig. 5-4-c** show the cores in third phase inside hot water for two different sandstone and carbonate experiments.

Sandstone Experiments

Overall recoveries of different phases for sandstone experiments are given in **Figs. 5-5** through **5-10**. In Phase-I, thermally assisted gravity drainage results in a higher recovery from water-wet cores than oil-wet cases (Exp. 1 versus Exps. 2, 3 and 4). The base temperature in Phase-I is steam at 120 ºC. Using hot water at lower temperature decreases the production slightly (Exp. 3 in **Fig.5-5**), while using steam at higher temperature (150 ºC) makes a large positive difference in recovery (Exps. B1 and B2). The steam is at saturated condition and the saturated steam pressure increases severely by slight changes in temperature, going up from 200 kPa to 550 kPa by increasing the temperature from 120 ºC to 150 ºC. Therefore, there is also a pressure effect in addition to temperature effect at elevated conditions for Exps. B1 and B2 to drive oil out of the core.

Exps. R1, R2, RB1 are the repeated versions of Exps. 1, 2 and B1 and they show a similar trend (**Fig. 5-5**). However the repeated version of Exp. B2, which is Exp. RB2, deviates from the original experiment because it was an oil-wet case that had been left in the oil after saturation for a longer time, which might have changed the wettability (which was already altered by chemical processing) through extra aging time. The results from this phase show that a sole steam injection could not be an effective process, specifically for oil-wet cases. This becomes important when considering the heat loss for deep reservoirs. Thus a combination of steam and solvent injection is introduced in this work and the SOS-FR method was applied as described in section "Methodology." Note that previous applications of this method were performed under atmospheric pressure using hot water in Phase-I (Al-Bahlani and Babadagli 2008, 2009a, 2009b, 2010; Babadagli and Al-Bahlani 2008), whereas we used steam (temperature above 100 ºC and at corresponding saturation pressure). This first batch of Berea sandstone experiments was discussed by also comparing them with other unconsolidated sandpack experiments by Naderi and Babadagli (2012b).

The second batch of experiments have similar Phase-I conditions and their recovery from this phase (given in **Fig. 5-6**) is in a close range (between 5 to 12%). On average, the three cores that are smaller (S5, S6, S7) showed a slightly better recovery in the first thermal phase. These three cores are 3½-4 inch tall while all other cores have a height between 5½ to 6½ inches. All cores have a diameter of 1½ inch.

In Phase-II, solvents (CO_2, propane, butane) gradually penetrate into the core by diffusion and also due to the pressure applied in the system. At the current pressure-temperature conditions the CO_2 process is not miscible with the heavy-oil, while propane and butane have more mixing capability and faster diffusion. The pressures were chosen in a way to keep the solvents in gas phase close to the vapor pressure line (in P-T diagram) because Pathak et al. (2011, 2012, 2013) suggested that solvent should be in the gas phase just below the saturation line to obtain maximum recovery. At the end of this phase (Phase-II), when the pressure was released to the atmospheric pressure to remove the core from the core holder, the gas bubbles were seen coming out of the core. By putting the cores into hot water for Phase-III and increasing the temperature to 90 ºC, the solvent bubbles came out in an accelerated rate leading to more oil recovery by its drive. Solvent retrieval through Phase-III is also a function of temperature and becomes faster as the temperature reaches the boiling point of the solvent. **Figs. 5-7** and **5-8** demonstrate these oil and solvent recovery processes for Phases-II and III.

The water-wet cases that produced less oil in Phase-I because of lower temperature steam, showed a better recovery in the consequent phases on average (see Exps. 1, R1, 5, S5 and R5). The water-wet experiments with high recovery in Phase-I as a result of high temperature (Exps. B1 and RB1) had less production in Phases-II and III compared with similar oil-wet cases (Exp. B2 and RB2) (**Fig. 5-7**). Thus, the earlier application in first phase critically changes the performance in the subsequent phases. In Phase-III hot water was more effective than steam as thermal effects are accompanied by imbibition and buoyancy of hot liquid phase compared to vapor (Exp. 4).

Comparing Exp. 5 with Exps. 6 and 7 and also Exp. S5 with Exps. S6 and S7 in **Fig. 5-8**, one may conclude that CO_2 and propane perform similarly and better than butane. The reason for this is that the CO_2 pressure in solvent phase is high (3500 kPa), propane pressure is medium (850 kPa), and butane pressure is low (110 kPa). As mentioned above, these ranges were selected so as to keep the solvents in gaseous phase to maximize the diffusion capability and thereby the oil recovery. Although CO_2 has no high mixing capability as the hydrocarbon solvents in such conditions, its relatively higher pressure contributes to diffusion. Even if the CO_2 acts more like a swelling agent rather than mixing solvent, because of relatively high pressure difference when the pressure is reduced to ambient pressure at the end of the solvent phase, it expands significantly. This drive may result in additional oil production as well.

Using the generalized equation of state below (**Eq. 5-1**) and the corresponding graphs to determine the compressibility factor z (McCain 1990; Himmelblau 1989), one may find that CO_2 expands by a factor of 42.7 coming from Phase-II (under 3500 kPa pressure) to ambient pressure (**Eq. 5-2**). This factor is 12.2 (when it comes from 850 kPa to ambient pressure) and 1.3 for propane and butane, respectively (from 110 kPa to ambient pressure) in our experiments.

$$PV = znRT \tag{5-1}$$

$$\frac{V_2}{V_1} = \frac{P_1 T_2 z_2}{P_2 T_1 z_1} \tag{5-2}$$

This much solvent that goes into the pores at given pressures without diffusing into the oil is still in the gas phase and expands when the pressure is released. This effect is better seen in larger cores in **Fig. 5-8** (Exps. 5, 6 and 7), while the diffusion acts slower in larger cores than in smaller cores (Exps. S5, S6 and S7) due to increased surface area. Hence, the recovery due to hydrocarbon solvents diffusion (propane and butane) is somewhat higher in smaller cores (higher in Exps. S6 and S7 than in Exps. 6 and 7) but remains almost the same in the CO_2 cases (Exps. 5 and S5).

Gas expansion also takes place when we start Phase-III in hot water as the temperature rises from ambient to 90 ºC. Phase-III also helps oil recovery by thermal expansion of oil, viscosity reduction, imbibition and buoyancy. Using **Eq. 5-2**, gas expansion factor is estimated to be 1.2 in Phase-III when temperature goes up to 90 ºC from ambient conditions.

The total recovery graphs given in **Figs. 5-9** and **5-10** show that the whole process is more effective in terms of recovery when the core is water-wet and Phase-I is run at low temperatures so that more oil remained in the core to be exposed to solvent phase (Phase-II) and the following thermal phase (Phase-III) (Exps. 1 and R1). Therefore, one may conclude that the SOS-FR method is more efficient in all three phases combined for the cases with lower steam temperature in Phase-I, as Phases-II and III compensate for the low recovery of Phase-I. High temperature in Phase-I produces more oil in this thermal phase but leaves an upgraded oil in lesser amount to the rest of the process which negatively affects the overall performance. For instance, Exps. B1 and RB1 which had a high recovery under high temperature steam in Phase-I, yield to a lower total recovery than Exps. 1 and R1. Similarly, in Phase-III, steam is not as effective as hot water (Exp.4). Hence, lower temperature steam in Phase-I and hot water in Phase-III increases the heavy-oil recovery of the whole process and also reduces the steam generation costs by lowering the temperature needed in thermal phases.

High pressure CO_2 and medium pressure propane yields to similar recoveries which are higher than recovery of low pressure butane as solvent in Phase-II. Hydrocarbon solvents performance is better in smaller cores as they interact with a higher fraction of oil in a fixed time period. Exp. R5 is a repetition of Exp. 5 and shows a very close repeatability.

Carbonate Experiments

Table 5-2 lists the carbonate experiments and **Figs. 5-11** to **5-13** show the ultimate recovery values of such experiments for different phases. The carbonate cores' diameters are 1-1½ inch and their height is 3-3¼ inch. The cores were obtained from a producing formation and were saturated with the oil used throughout the experiments after the cleaning procedure. They were observed to be oil-wet with a permeability value in the range of 1-10 mD.

The first phase is similar for all experiments: Steam at 120 °C. Phase-I recovery is given in **Fig. 5-11**. The recoveries are in a range between 3 to 7%, which is on average lower than thermal recovery of oil-wet sandstone cores in Phase-I. This is attributed to the different medium properties of carbonates, especially permeability.

Consequent solvent and thermal phases (**Fig. 5-12**) demonstrate that hydrocarbon gas solvents act better in terms of heavy-oil recovery from carbonates.

The medium is oil-wet and also less pore volume is available for CO_2 to penetrate into the core under pressure. Hence, it would be the diffusion effect that is more prominent in carbonates than sandstones. Therefore, the hydrocarbon solvents that diffuse more effectively than carbon dioxide perform better on oil dilution and recovery. Propane with medium pressure improves the heavy-oil recovery better than butane in low pressure. Exp. 4 has gone under CO_2 with different pressures for a longer period of time (with the same thermal phases as others), which improves the solvent phase recovery but not as efficiently as hydrocarbon solvents.

The overall recovery is following the trends in Phases-II and III as the Phase-I recoveries are more or less in the same range. Similar experiments were performed on Grosmont carbonates at low pressure and low temperature conditions with different hydrocarbon solvents by Naderi et al. (2013). They showed that the recovery is dependent on the selection of the experimental conditions including solvent type and timing.

Change in the Rock Properties: Carbonate Mineralization

Carbonate minerals are usually rich in metallic elements such as calcium, magnesium and iron which are reactive when in contact with a mixture of CO_2 and water. Depending on pressure and temperature conditions of CO_2 injection for enhanced oil recovery or sequestration, this rock-fluid chemical reaction yields carbonate mineral precipitation. The process of CO_2 dissolution in formation water, its reaction with in situ minerals and ions and its precipitation as carbonate minerals is called CO_2 mineralization (Thibeau et al. 2007). Mineralization of CO_2 into carbonate minerals occurs when water-CO_2 mixture combines with divalent metal cations such as Ca^{2+}, Mg^{2+} and Fe^{2+} that are present in formation water or become available as a result of dissolution of the rocks rich in such metals. Carbon dioxide in the presence of water creates carbonate acid (**Eq. 5-3**) which can dissociate into bicarbonate and hydrogen ions (**Eq. 5-4**). Metal cations in the water can then precipitate (**Eq. 5-5**) if there are different reactions that consume hydrogen ions such as fosterite reacting with hydrogen ions (**Eq. 5-6**) (Adam et al. 2011).

$$CO_2 + H_2O \leftrightarrow H_2CO_3 \tag{5-3}$$

$$H_2CO_3 \leftrightarrow HCO_3^- + H^+ \tag{5-4}$$

$$(Ca, Mg, Fe)^{2+} + H_2CO_3 \rightarrow (Ca, Mg, Fe)CO_3 + 2H^+ \tag{5-5}$$

$$Mg_2SiO_4 + 4H^+ \rightarrow 2Mg^{2+} + H_2O + SiO_{2(aq)} \tag{5-6}$$

The required time for this reactions and precipitation depends on pressure and temperature conditions, solution composition, pore structure and availability of metal cations which is related to the rate of the mineral dissolution (Adam et al. 2011). The injection strategy of CO_2 and brine also makes changes of solubility, transport mechanism and porosity of different rocks (Mathis and Sears 1984). Dissolution and deposition both occur during co-injection of CO_2 and brine into limestone at different stages and compositions (Grigg and Svec 2003). Conditioning the carbonate rock with high temperature (above 300 ºF or 150 ºC) steam flooding (without CO_2 injection) also makes carbonate dissolution and some minerals precipitation occur which may result in wettability alteration (Tang et al. 2011; Tang et al. 2012).

All these effects may contribute to the recovery through wettability change and permeability improvement. Therefore, we studied these phenomena through SEM imaging and energy-dispersive X-ray spectroscopy of some carbonate rock samples used in the experiments. **Table 5-3** lists these rock samples. **Fig. 5-14** shows the mineralogy of carbonate rock samples based on the EDS (energy dispersive spectroscopy) analysis. Sole steam application on the samples (Sample 2) increases the atom counts of calcium and reduces that of carbon compared to the original rock (Sample 1). Note that these are the normalized numbers of atoms, meaning that some compounds containing carbon and oxygen are dissolved increasing the ratio of calcium atoms in the overall atom count. This could be attributed to the high temperature effects mentioned above. The consequent phases of hydrocarbon solvents and hot water application restore carbon and calcium back but reduce oxygen atoms (Samples 3 and 4). This implies that a combination of oxygen and calcium is dissolved. CO_2 reacts differently based on its pressure: the higher the pressure, the higher the atoms of oxygen, calcium and magnesium and the lower atoms of carbon (Sample 5). At lower pressures more carbon compounds are deposited on the surface.

The SEM microscopic images demonstrate this better. **Figs. 5-15** through **5-21** show the SEM images of samples at 500x. **Figs. 5-22** through **5-28** display the similar images at 1500x, and **Figs. 5-29** through **5-35** demonstrate such images taken at 3000x. The original rock (**Figs. 5-15, 5-22** and **5-29**) has a mixed pattern of fine and coarse mineral blocks. When heated in the first phase (steam), much finer particles are observed (see circled parts in **Figs. 5-16, 5-23** and **5-30**) which can be due to rock expansion and dissociation. Consequent phases of hydrocarbon solvent and hot water remove very fine particles and in some spots make a degree of deposition or layering of rock (**Figs. 5-17, 5-24** and **5-31** for propane and **Figs. 5-18, 5-25** and **5-32** for butane). The areas with possible deposition are shown in circles in those figures. CO_2 together with hot water changes the pore features depending on the gas pressure range. At high pressure, the deposition is visible on scattered spots (circled areas in **Figs. 5-19, 5-26** and **5-33**) while at mixed range of pressure, the deposition is wider in a form of sponge-like porous layer (areas circled in **Figs. 5-20, 5-27** and **5-34**). At medium pressure range the CO_2 has changed the appearance of rock significantly with clear folded layers of mineral deposition (circled parts in **Figs. 5-21, 5-28** and **5-35**).

Effective mineralization occurs when there are both CO_2 and water in place. If we assume that the remaining condensed steam in the core is negligible, this happens mainly in the third phase in which hot water may react with CO_2. Although most of the CO_2 is drained by drawdown at the end of Phase-II, the remaining CO_2 can be sufficient to contribute to this reaction. Note that the remaining CO_2 is inversely proportional to the phase pressure, hence at given medium pressure, enough amount of CO_2 is available for such reaction.

Mineral deposition does not affect permeability of fractured carbonates negatively if the high pressure gas injection is able to induce more fractures. This depends on the injection conditions as well as medium properties. In this laboratory work, when the experimental pressure was 3500 kPa for Phase-II with CO_2 as solvent, the core became visibly fractured due to this pressure and also the consequent thermal expansion. Hence, the permeability increased from 2.6 mD to 28.6 mD. For the other core in the lower CO_2 pressure, such new fractures were not visible and the final permeability was 3.0 mD. The permeability values were calculated by the Darcy's law using the data obtained from a standard water injection test at different injection rates.

Change in the Fluid Properties

Original heavy-oil had a viscosity of 6,100 cP and a density of 0.9639 gr/cm^3, both at 25 ºC. The saturation process involves putting the core inside a desiccator under vacuum at higher temperature (inside the oven at 60 ºC) for a week which facilitates the saturation. The saturation oil under this condition had a slightly higher viscosity (6,400 cp) and density (0.9738 gr/cm^3) at the same temperature (25 ºC) due to removal of some portion of lighter phases. Thermal phase (Phase-I) also removed some lighter hydrocarbon from the heavy oil and increased the viscosity and density of the produced oil at the end of Phase-I. On average, the samples taken out of Phase-I production after being exposed to steam at 120 ºC, had a viscosity of 13,300 cP and a density of 0.9817 gr/cm^3. This is also observable in **Fig. 5-36** which is the hydrocarbon distribution of oil at different stages taken out of chromatography tests. Light components (C12$^-$ and C13-C15) are less after the first thermal phase (Phase-I). The consequent CO_2 and hot water phases made the oil a little lighter again, as CO_2 extracted some medium hydrocarbons. This change; however, is not so critical because the CO_2 is not in supercritical conditions, which yields to more extraction (Trivedi and Babadagli 2009a). Hot water at Phase-III again reduced the lower end hydrocarbons in overall distribution but not as high as steam because the temperature is lower and oil is already upgraded to some degree (**Fig. 5-36**). For this combination of steam, high-pressure CO_2 and hot water, the produced oil at the end of experiment has an average viscosity of 9,500 cP and density of 0.9765 gr/cm^3 which are respectively lower than those of the steam-exposed oil and higher than original oil properties. Therefore, the produced oil from the SOS-FR method would be slightly lighter than that of a steam injection.

The asphaltene content of oil follows a similar trend. The asphaltene content of the saturation oil was 18.0 weight% and increased to 19.0 weight% after Phase-I as the lighter hydrocarbon components are removed by high temperature process. At the end of experiment, the amount of asphaltene measured in the produced oil was reduced to 15.7 weight% meaning that an amount of asphaltene is precipitated inside the core or some of asphaltene molecules were dissociated by CO_2 through its solvent effect (Phase-II) and hot water (Phase-III), thus the produced oil now contains less asphaltene.

Solvent Retrieval and Storage

Solvent retrieval is the most critical part of solvent based recovery methods as it is more expensive than the recovered heavy-oil. In this version of the SOS-FR method proposed here, CO_2 substitutes hydrocarbon solvents which are expensive and whose retrieval is a major issue while CO_2 is cheaper, if easily available, and also required to be disposed from an environmental point of view. Thus, the retrieval of hydrocarbon solvents at the end of the process is critical. The same can be said for CO_2 as it could be recycled for the subsequent injection runs in the field. Permanent storage of CO_2 at the end of the process is also critical unlike the hydrocarbon solvents and this should also be taken into account in designing this kind of heavy-oil recovery processes.

The amount of solvent which is stored in the core at the end of Phase-II can be determined from **Eq. 5-7** which is derived from **Eq. 5-1**:

$$Solvent\ stored\ fraction = 1 - \frac{n_2}{n_1} = 1 - \frac{P_2 V_2 T_1 z_1}{P_1 V_1 T_2 z_2} \tag{5-7}$$

where *n* is the amount of gas available in the vessel out of the core with pressure, volume and temperature conditions of *P, V, T* and corresponding compressibility factor *z*. The indices 1 and 2 correspond to the initial and final conditions of the solvent phase (its beginning and end). The pressure in this phase gradually declines showing a continuing intrusion of solvent into the core. **Fig. 5-37** displays the typical pressure graphs for three cases with different solvents in the second phase.

For the larger sandstone cores (Exps. 1, 2, 3, 4, B1, B2, R1, R2, RB1, RB2, 5 and R5) between 0.76 to 2.30% of initial injected CO_2 went into the core during Phase-II with an average of 1.47%. This amount is 10.30% for propane (Exp. 6) and 7.07% for butane (Exp. 7). For the smaller sandstone core (Exp. S5) the stored fraction of CO_2 is 2.06% (which is still in the same range of larger cores, but greater than their average). The corresponding values for propane and butane storage in small cores (Exps. S6 and S7) are 5.67% and 0.07%, respectively. This shows that diffusion of hydrocarbons are more prominent, and it is related to the amount of oil (size of the matrix containing this oil) available to the solvent as well as pressure. But in the case of CO_2, the reduction in pressure could be partly due to diffusion and partly because of swelling or simple storage (as a result of high pressure). For carbonate cores the storage ratio is 0.67% for CO_2 (Exps. 1 and 4), 4.41% for propane (Exp.2) and 1.15% for butane (Exp.3). **Table 5-4** summarizes the values given above for a variety of experiments.

The "solvent stored fraction" values show the amount of diffused solvent into core during Phase-II while the core is still under pressure. When this phase is finished and the core is taken out of pressurized cell some of the diffused gas may come off the core due to de-pressurizing. Some other portion of the diffused solvent into the core is also released in Phase-III when the core is put inside hot water which provides a rapid temperature increase. The released solvent comes as gas bubble out of the core. **Fig. 5-3-c** and **Fig. 5-4-c** are two examples of Phase-III which show this process visually.

We examined the produced gas at this later phase through a GC analysis to obtain a semi-qualitative idea about the degree of solvent retrieval. For Exp.5 (sandstone) which was under CO_2 at 3500 kPa, the amount of CO_2 in the produced gas right after starting Phase-III was 1.49%. This means that almost 1.5% of the produced gas in the beginning of Phase-III was carbon dioxide. Normally the amount of CO_2 in air is 0.04-0.05%, hence the increase in CO_2 amount is due to recovering solvent through bubbling in this phase. The amount of CO_2 in produced gas in Phase-III of Exp. S5 is 1.13% for which was at similar conditions but with a lower pore volume as the core was smaller. Exp. 6 was under propane in second phase and it produced 22.51% propane in the gas sample taken. This value was 4.76% for Exp. S6 which is in similar condition but smaller in size. Exp. S7 which had butane as solvent gave a fraction of 0.10% butane in the gas sample taken.

For the carbonate cores, the first experiment (Exp.1) under high pressure CO_2 produced 2.03% CO_2 in the gas sample that was reduced to 0.61% in the lower pressure test (Exp.4). The experiment under propane (Exp.2) yielded 9.40% propane and the one with butane (Exp.3) showed a 0.01% fraction of butane in the gas sample. The carbonate cores are relatively much smaller than sandstone cores. Hence, the amount of gas stored and released depends on the matrix size, the gas pressure and the type of solvent. **Table 5-5** lists the gas sample compositions for the mentioned experiments.

Gas samples results given above are a qualitative measure of how solvents are recovered; however calculating the total amount of retrieved solvent is not easy when using gas solvents instead of liquid solvents. When liquid solvents are employed the solvent retrieval measurement is relatively simpler as the liquid collection is better feasible in laboratory conditions (Naderi et al. 2013; Mohammed and Babadagli 2013). In the applications where all the solvents are in gas phase, collecting the recovered gas in Phase-III requires a sophisticated setup that provides a closed system. However, our previous experience showed that solvent retrieval rate for liquid hydrocarbons typically vary between 70% and 90% (Naderi et al. 2013; Coskuner et al. 2013; Mohammed and Babadagli 2013). We expect a similar solvent retrieval rates for gas hydrocarbons and CO_2. This; however, will be controlled by temperature and the selection of optimal temperature depending on the bubble point of the solvent at given pressure is critical for maximal solvent retrieval as discussed above and elsewhere (Naderi and Babadagli 2012b). In fact, during the experiment, most of the solvent was observed to be retrieved during the pressure depletion at the end of Phase-II unlike liquid solvent cases reported in Naderi et al. (2013), Coskuner et al. (2013), and Mohammed and Babadagli (2013). Note that Phase-III is a must to retrieve the liquid solvent as they require temperatures around the bubble point of the solvent to be bubbled out as gas. This is an advantage of using gas solvent and even without Phase-III a great amount of solvent may be retrieved during the pressure depletion after Phase-II (i.e., production cycle).

CO_2 sequestration has recently gained interest as it is a greenhouse gas and is desired to be removed from the atmosphere for environmental purposes. One way of such process is to sequester the CO_2 in underground reservoirs; thus, a double-purpose injection program can be designed to sequester the CO_2 and to enhance oil recovery at the same time. Naderi and Babadagli (2012a) performed a field scale analysis and showed that SOS-FR method by having CO_2 as solvent can be adjusted so that both goals are met. Phase-III plays an important role here as it improves oil recovery in the last phase but also recovers solvent. This is vital in case there is hydrocarbon solvent used in second phase; however having CO_2, one may be interested in sequestration then a simple drawdown at the last stage with no steam injection helps more CO_2 remain in the reservoir. An optimization should be taken into account for each case based on the importance and benefits of such dual goals of the process.

In addition to sequestration, CO_2 also serves its main goal in this design, which is additional heavy-oil recovery. Although we see a large gap between productions of lower (Exps. 1, 2, 3, and 4) and higher (Exps. B1 and B2) temperature cases during Phase-I, the solvent phase (Phase-II), together with the succeeding thermal phase (Phase-III), helps improve the lacking productions. Therefore, a general conclusion can be reached as follows: CO_2, which already removed the high costs of the hydrocarbon solvent, can also help reduce the thermal stage temperature (with a much lower decrease in production) and hence reduce the steam generation costs.

The final issue to discuss is the injection strategy. The experiments were designed for static conditions for all phases. This corresponds to the huff-and-puff type injection strategy. This is critical, due especially to the CO_2 injection phase

(Phase-II), as certain time is needed for the efficient transfer of CO_2 injection into the matrix. Earlier works showed that additional time would be useful for CO_2 interaction with oil to further upgrade it (Trivedi and Babadagli 2009a). This can be achieved as a continuous injection of CO_2 followed by a soaking period, as suggested by another group of work by Trivedi and Babadagli (2008c, 2009b, 2010). Thermal phases (Phases-I and III) can be done in either way (continuous or soaking), depending on the reservoir type and the fracture network structure, as long as efficient matrix heating has been achieved. Further, experimental and numerical modeling studies are needed for solid suggestions of injection strategy. This chapter was limited to applicability of the method suggested for different reservoir (mainly matrix wettability) and injection conditions (mainly temperature).

Conclusions

A new approach in the SOS-FR method is proposed in which CO_2 takes the place of hydrocarbon solvents.

Higher temperature (and pressure) in Phase-I results in higher oil production regardless of the wettability of the matrix.

CO_2 in Phase-II increases the production in oil-rich cores, especially in the water-wet case.

On the basis of the wettability conditions, one may choose the optimal injection temperature in Phases-I and III.

Mass transfer between CO_2 and conditioned heavy-oil after Phase-I was observed to be efficient after a period of heating but it is dependent on the oil type and matrix size. The injection pressure, temperature (pre-heating period) and soaking time are to be determined for each specific reservoir case.

Although higher temperature steam leads to higher recovery in Phase-I, the overall recovery of the SOS-FR process for such cases reduces at the end. This could be attributed to the effects of high temperature on oil properties—i.e., the lighter components are removed by heating and this makes the following solvent phase less effective. A lower temperature steam in Phase-I is more effective in terms of the ultimate recovery reached at the end of the whole cycles. Hot-water performs better than steam in Phase-III in recovery improvement as well as solvent retrieval. In conclusion, the temperature requirements and thereby, the steam generation cost is reduced through the SOS-FR method.

Carbonate mineralization occurs due to the interaction of CO_2-water with the carbonate minerals as a result of chemical reaction of carbonic acid with dissolved cations in the place. Such changes are qualitatively observable at SEM images; however, a quantitative analysis by measuring permeability does not show a reduction in permeability because the effect of fracturing in core scale overcomes the deposition in pores.

The whole three-phase process of the SOS-FR method produces an oil heavier than the oil in place but lighter than what can be expected from the sole steam application.

The solvent storage and retrieval rates depend on the matrix size, the lithology of the core, solvent type, temperature and the pressure applied during the solvent phase. Under experimental conditions, approximately 1-2% of CO_2, 5-10% of propane and 1-7% of butane is stored in the core during Phase-II. A fraction of this diffused amount is expected to be released by depressurizing at the end of Phase-II and also thermal application of Phase-III which recovers the solvent in form of gas bubbles. The samplings of such produced gas in Phase-III show 1-2% of CO_2, 5-22% of propane and 0-0.1% of butane in the gas samples of related experiments.

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Table 5-1: Sandstone experiments.

Exp.#	Rock Type	Wettability	Phase-I	Phase-II	Phase-III
1	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
2	Berea Sandstone	Oil Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
3	Berea Sandstone	Oil Wet	Hot Water 90 °C Ambient P.	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
4	Berea Sandstone	Oil Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Steam 120 °C 200 kPa
B1	Berea Sandstone	Water Wet	Steam 150 °C 550 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
B2	Berea Sandstone	Oil Wet	Steam 150 °C 550 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
R1	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
R2	Berea Sandstone	Oil Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
RB1	Berea Sandstone	Water Wet	Steam 150 °C 550 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
RB2	Berea Sandstone	Oil Wet	Steam 150 °C 550 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.

Exp.#	Rock Type	Wettability	Phase-I	Phase-II	Phase-III
5	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
6	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	C3 24 °C 850 kPa	Hot Water 90 °C Ambient P.
7	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	C4 24 °C 110 kPa	Hot Water 90 °C Ambient P.
S5	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
S6	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	C3 24 °C 850 kPa	Hot Water 90 °C Ambient P.
S7	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	C4 24 °C 110 kPa	Hot Water 90 °C Ambient P.
R5	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.

Table 5-2: Carbonate experiments.

Exp.#	Rock Type	Wettability	Phase-I	Phase-II	Phase-III
1	Carbonate	Oil Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
2	Carbonate	Oil Wet	Steam 120 °C 200 kPa	C3 24 °C 850 kPa	Hot Water 90 °C Ambient P.
3	Carbonate	Oil Wet	Steam 120 °C 200 kPa	C4 24 °C 110 kPa	Hot Water 90 °C Ambient P.
4	Carbonate	Oil Wet	Steam 120 °C 200 kPa	CO_2 24 °C 850-3500 kPa	Hot Water 90 °C Ambient P.

Table 5-3: Carbonate rock samples taken for SEM and EDS analysis.

Exp.#	**Rock Type**	**Phase-I**	**Phase-II**	**Phase-III**	**Remark**
1	Carbonate	-	-	-	Original rock cleaned
2	Carbonate	Steam 120 °C 200 kPa		-	Original rock heated
3	Carbonate	Steam 120 °C 200 kPa	C3 24 °C 850 kPa	Hot Water 90 °C Ambient P.	Full experiment with propane as solvent
4	Carbonate	Steam 120 °C 200 kPa	C4 24 °C 110 kPa	Hot Water 90 °C Ambient P.	Full experiment with butane as solvent
5	Carbonate	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.	Full experiment with high pressure CO_2 as solvent
6	Carbonate	Steam 120 °C 200 kPa	CO_2 24 °C 850-3500 kPa	Hot Water 90 °C Ambient P.	Full experiment with mixed pressure CO_2 as solvent
7	Carbonate	Steam 120 °C 200 kPa	CO_2 24 °C 850 kPa	Hot Water 90 °C Ambient P.	Full experiment with medium pressure CO_2 as solvent

Table 5-4: Gas storage in cores before the end of Phase-II.

Exp.#	**Rock Type**	**Solvent Type**	**Solvent storage as of solvent injected (%)**
1	Sandstone	CO_2	1.32
6	Sandstone	Propane	10.30
7	Sandstone	Butane	7.07
S5	Sandstone	CO_2	2.06
S6	Sandstone	Propane	5.67
S7	Sandstone	Butane	0.07
1	Carbonate	CO_2	0.68
2	Carbonate	Propane	4.41
3	Carbonate	Butane	1.15

Table 5-5: Gas sample composition in Phase-III.

Exp.#	**Rock Type**	**Solvent Type**	**Solvent % in gas sample**	**Water vapor % in sample**	**Oxygen % in gas sample**	**Nitrogen % in gas sample**
5	Sandstone	CO_2	1.49	1.13	17.86	70.16
S5	Sandstone	CO_2	1.13	1.29	17.80	69.95
6	Sandstone	Propane	22.51	1.04	13.31	52.48
S6	Sandstone	Propane	4.76	1.67	16.80	65.07
S7	Sandstone	Butane	0.10	1.28	17.94	69.80
1	Carbonate	CO_2	2.03	1.70	17.45	67.90
2	Carbonate	Propane	9.40	1.00	15.86	61.42
3	Carbonate	Butane	0.01	1.46	17.89	69.49
4	Carbonate	CO_2	0.61	1.43	18.38	73.06

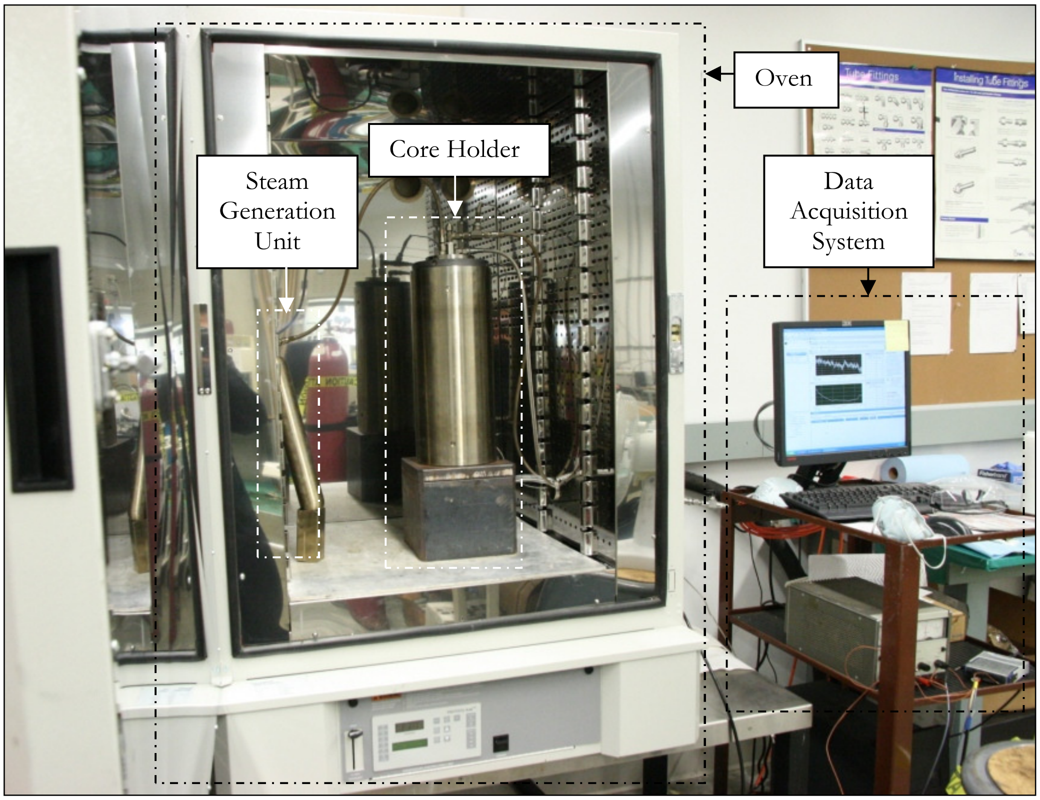


Figure 5-1: Steam setup.

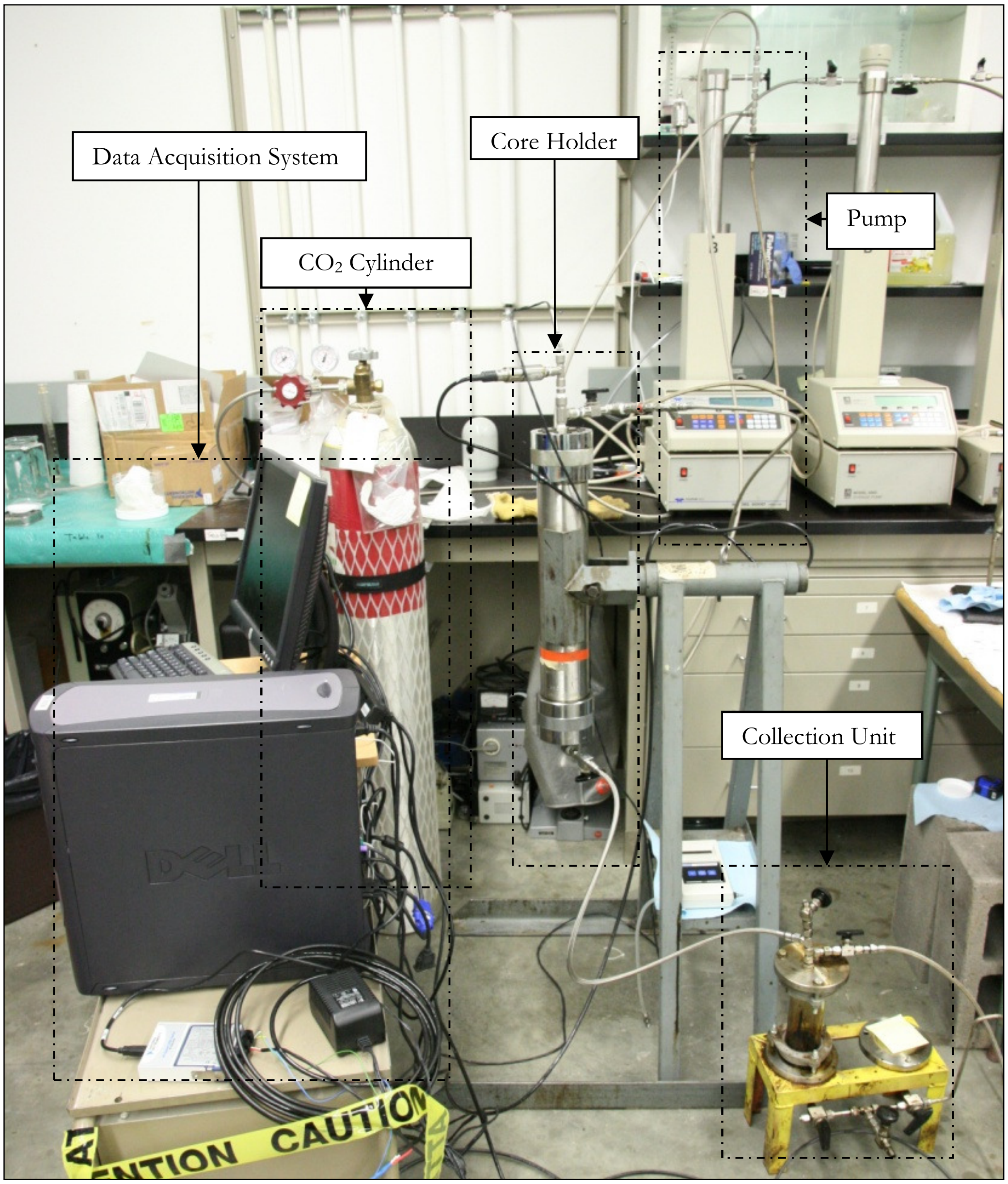
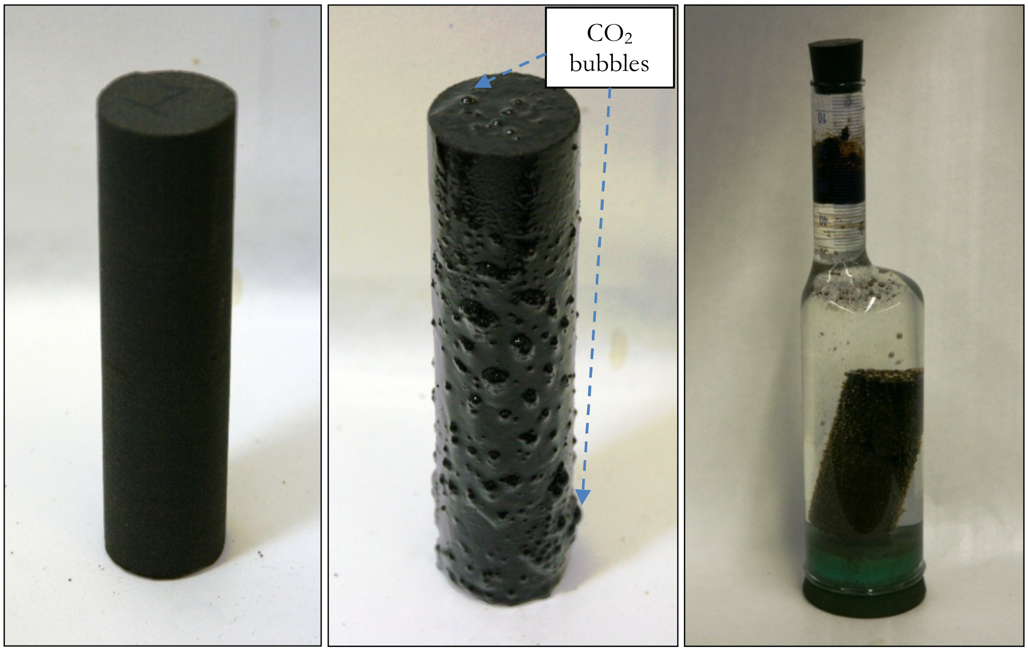
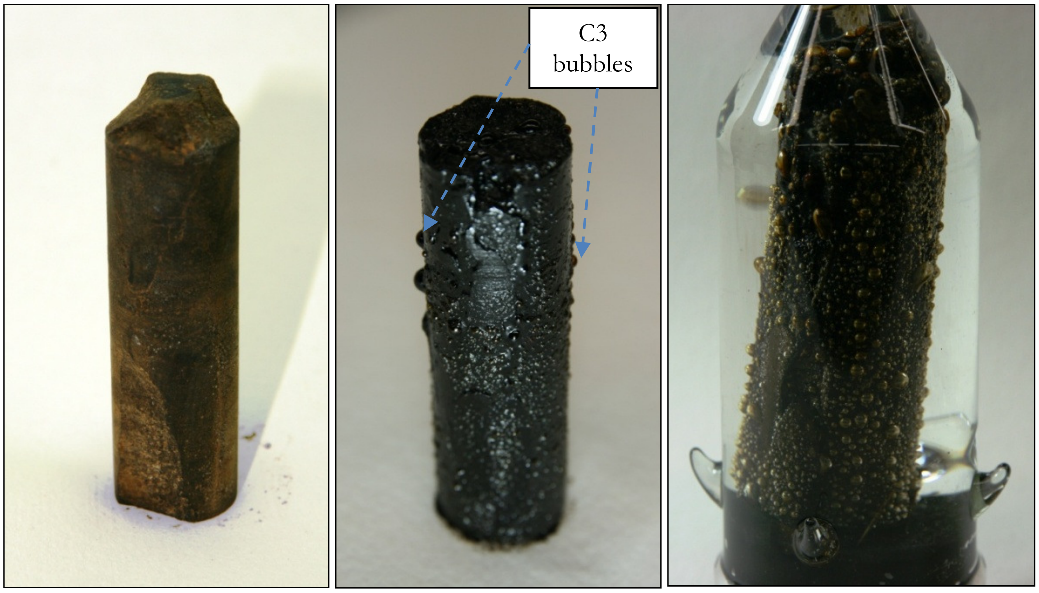


Figure 5-2: Solvent setup.



(a) **(b)** **(c)**

Figure 5-3: (a) Sandstone core after thermal phase (Phase-I), (b) Sandstone core after solvent phase (Phase-II), (c) Inside hot water (Phase-III).



(a) **(b)** **(c)**

Figure 5-4: (a) Carbonate core after thermal phase (Phase-I), (b) Carbonate core after solvent phase (Phase-II), (c) Inside hot water (Phase-III).

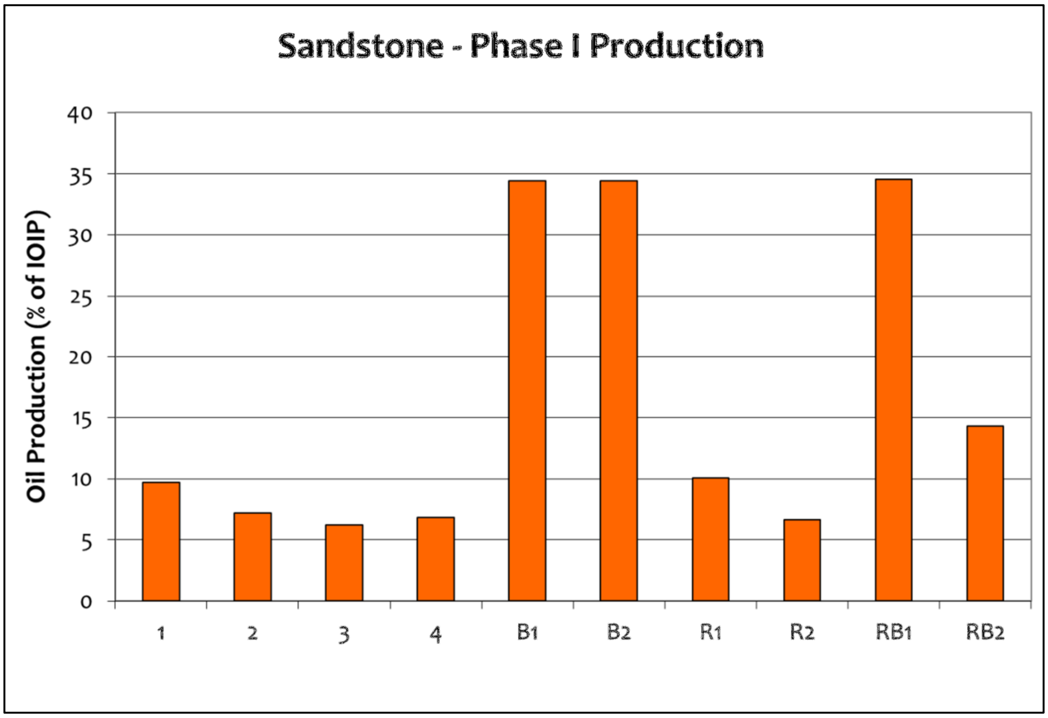


Figure 5-5: Phase-I production of sandstone experiments – batch 1.

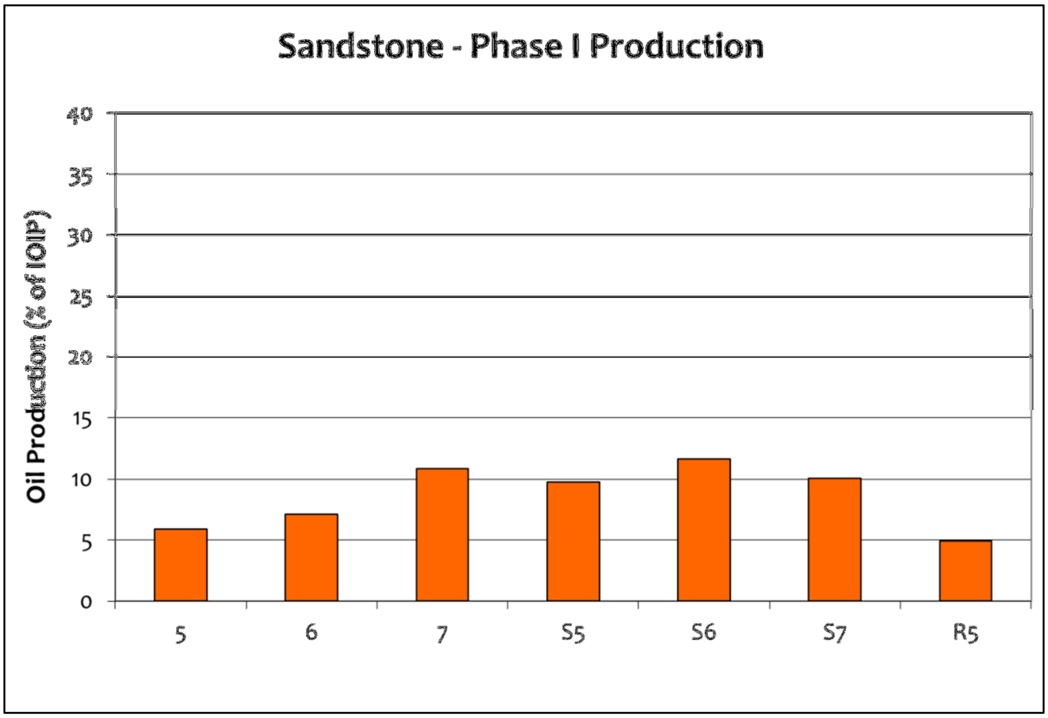


Figure 5-6: Phase-I production of sandstone experiments – batch 2.

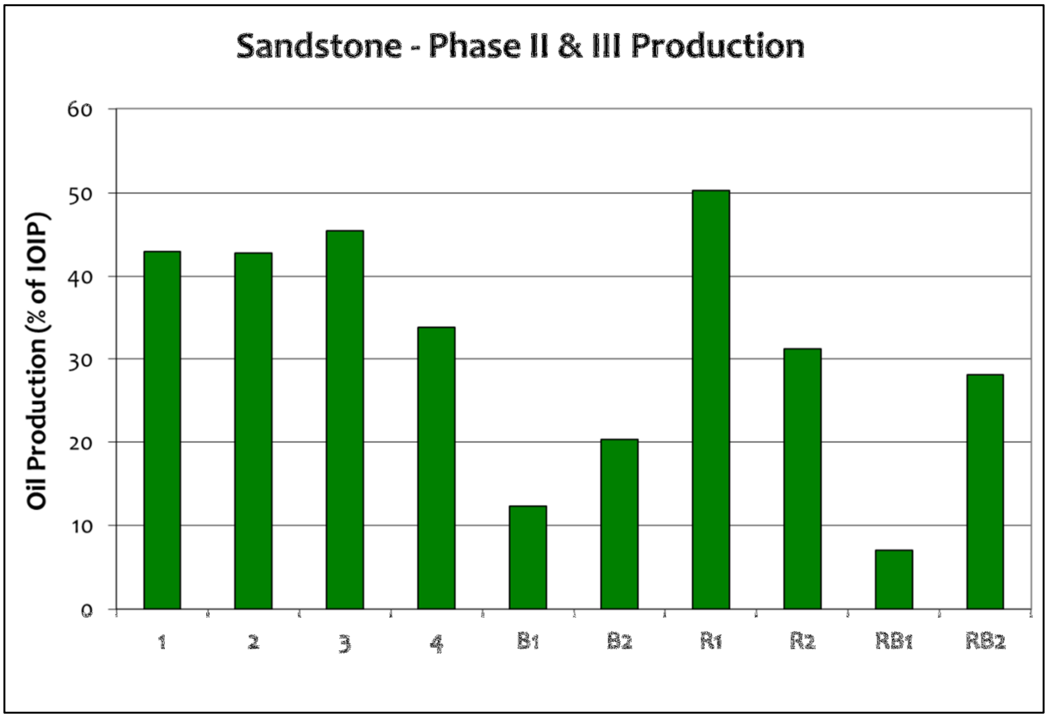


Figure 5-7: Phases-II and III production of sandstone experiments – batch 1.

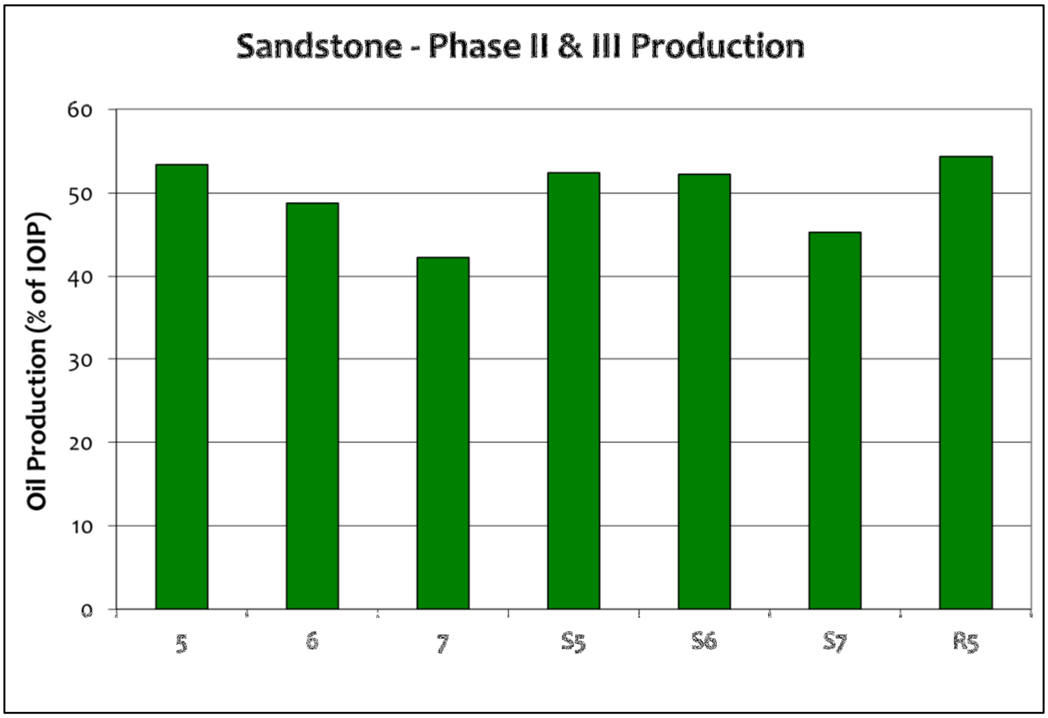


Figure 5-8: Phases-II and III production of sandstone experiments – batch 2.

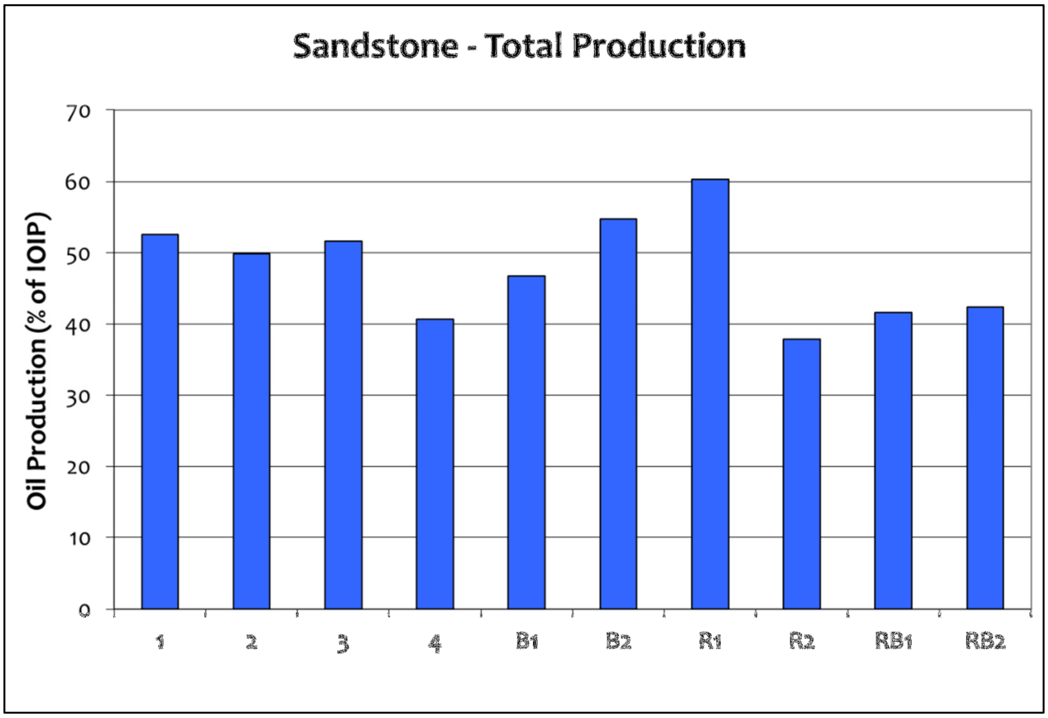


Figure 5-9: Total oil production from all three phases of sandstone experiments – batch 1.

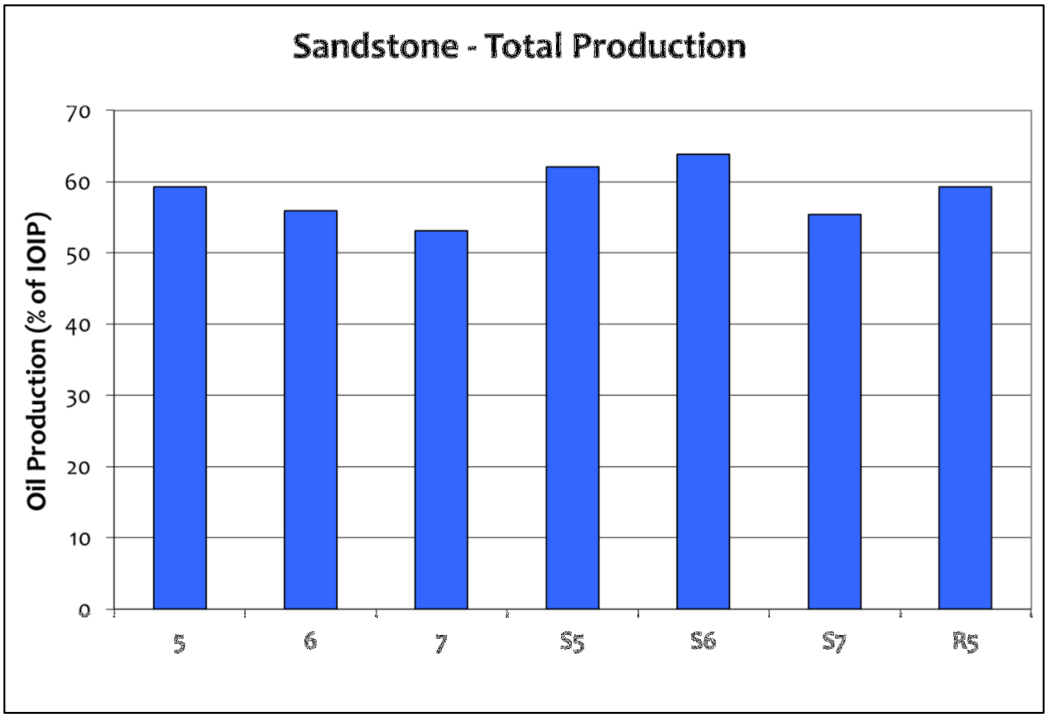


Figure 5-10: Total oil production from all three phases of sandstone experiments – batch 2.

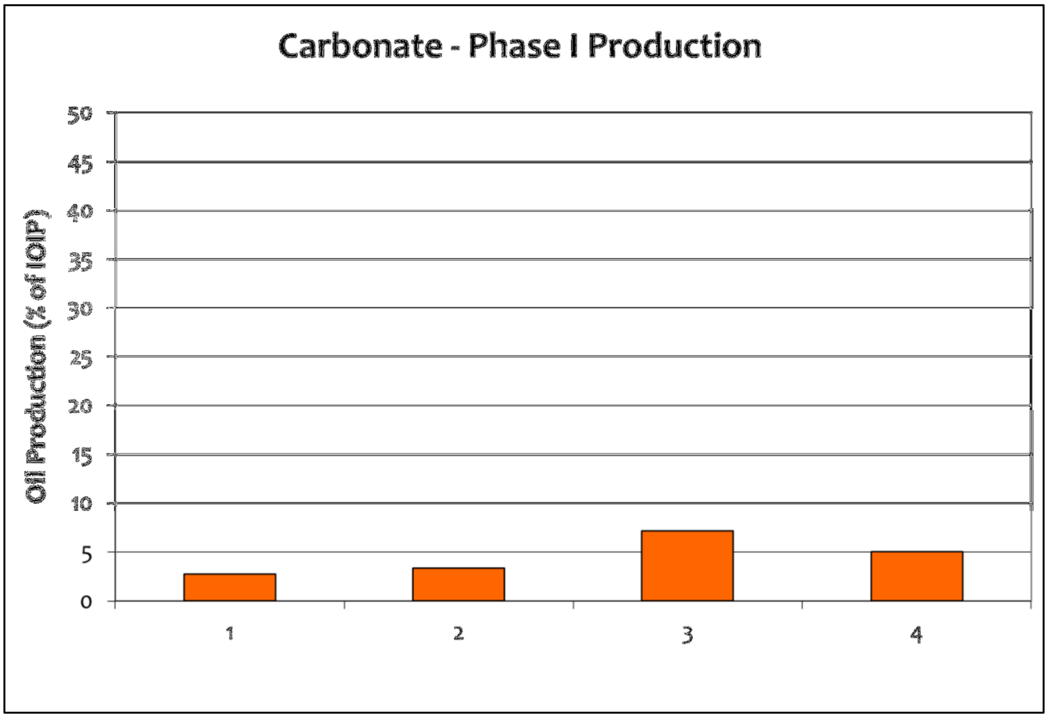


Figure 5-11: Phase-I production of carbonate experiments.

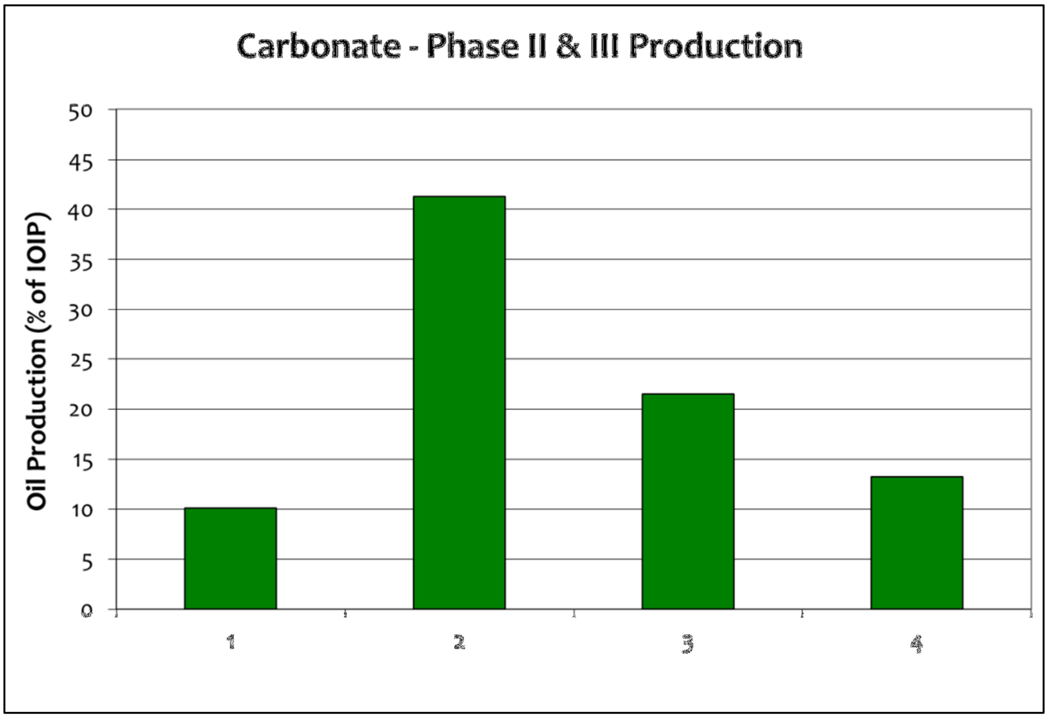


Figure 5-12: Phase-II and III production of carbonate experiments.

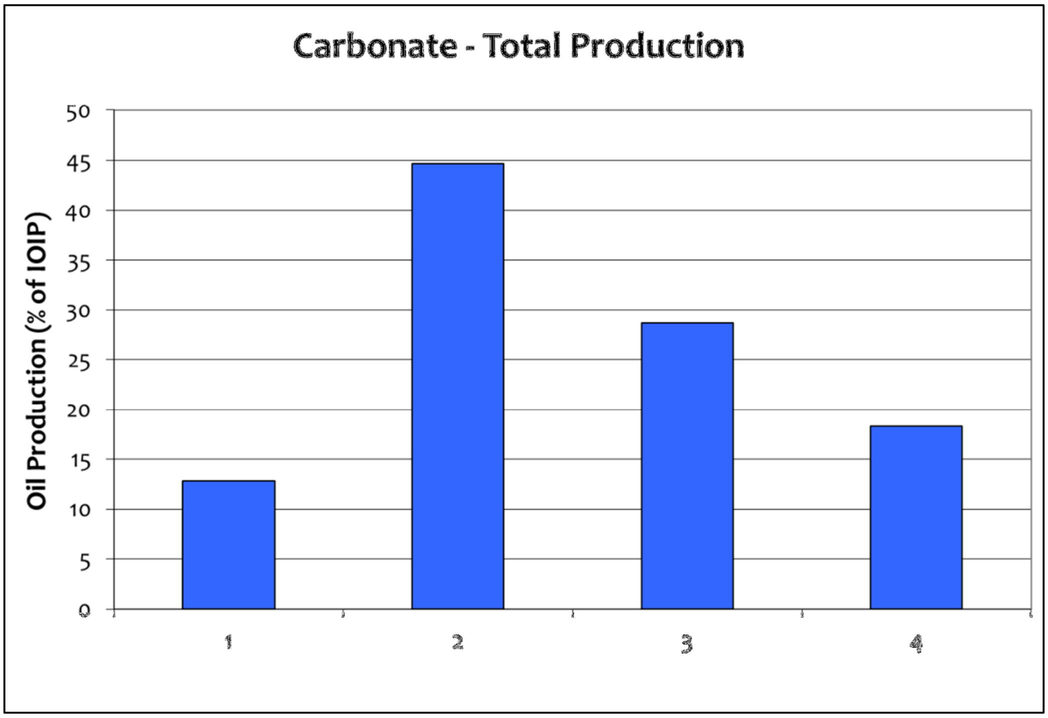


Figure 5-13: Total production of carbonate experiments.

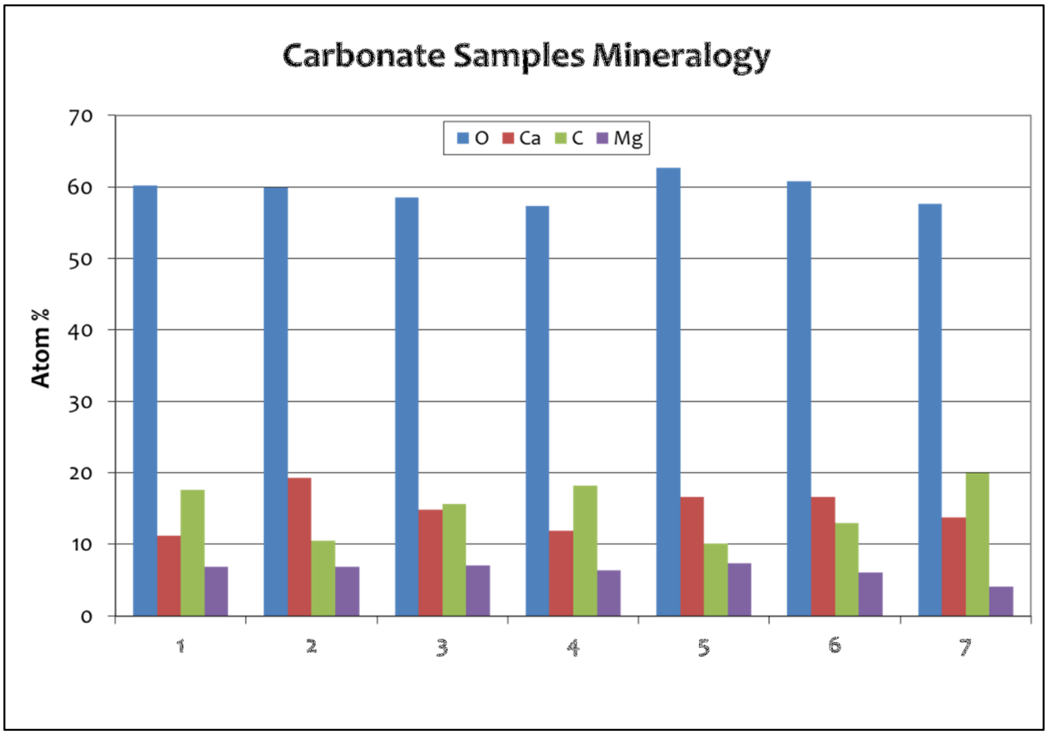


Figure 5-14: Carbonate rock samples mineralogy based on EDS analysis (refer to Table 5-3).

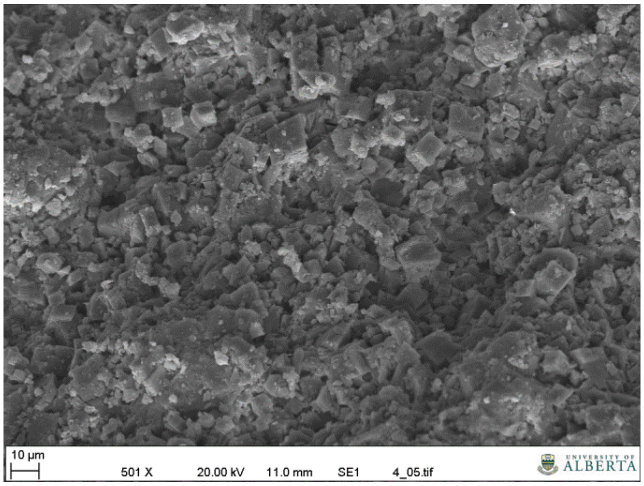


Figure 5-15: SEM image of sample 1 (original rock) at 500x.

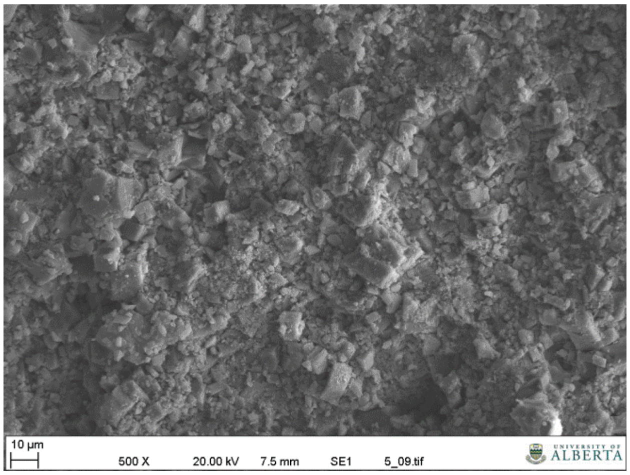


Figure 5-16: SEM image of sample 2 (heated rock) at 500x.

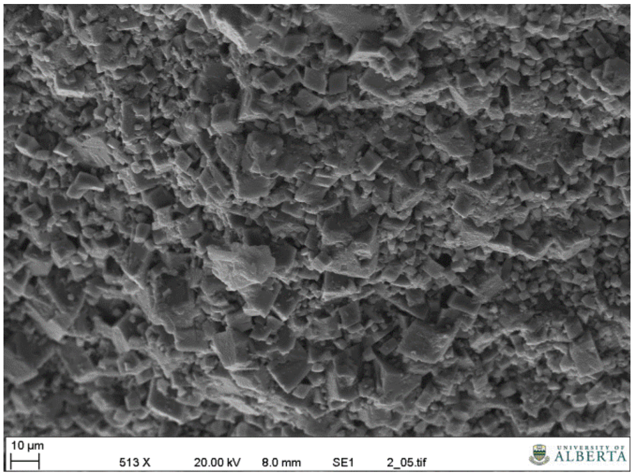


Figure 5-17: SEM image of sample 3 (exposed to propane) at 500x

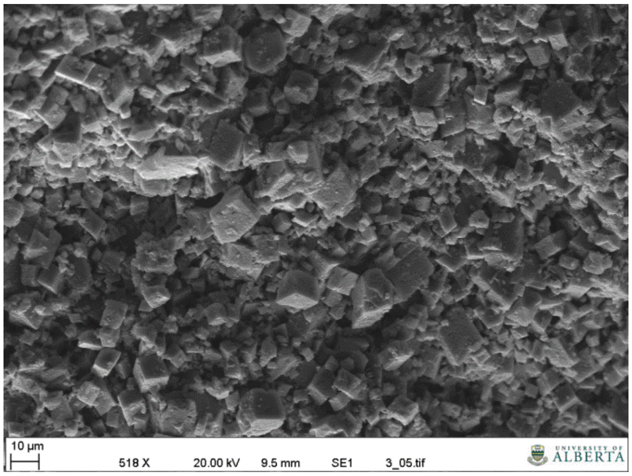


Figure 5-18: SEM image of sample 4 (exposed to butane) at 500x.

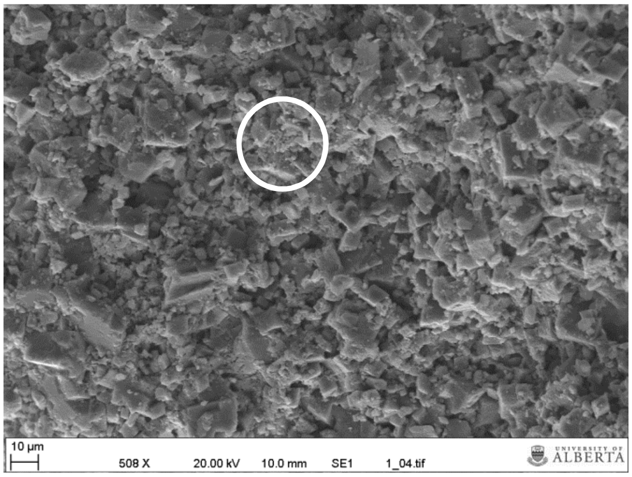


Figure 5-19: SEM image of sample 5 (CO_2 at 3500kPa) at 500x.

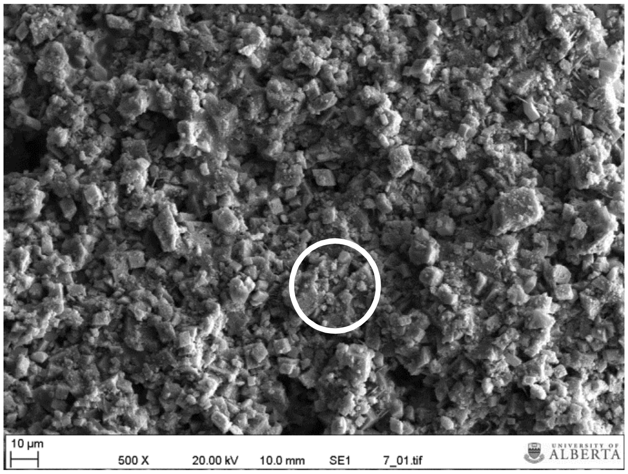


Figure 5-20: SEM image of sample 6 (CO_2 at 850-3500kPa) at 500x.

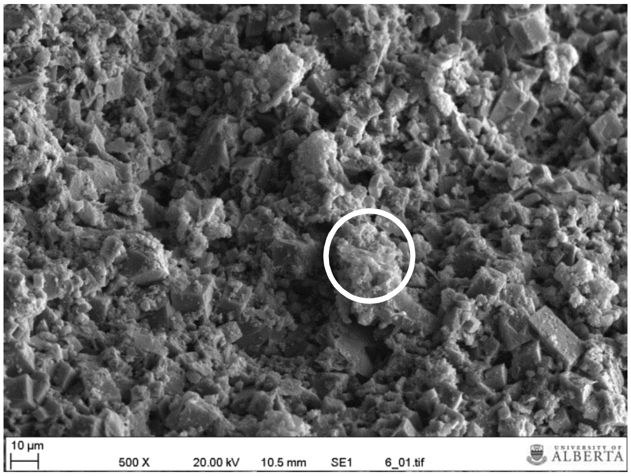


Figure 5-21: SEM image of sample 7 (rock exposed to CO_2 at 850kPa) at 500x.

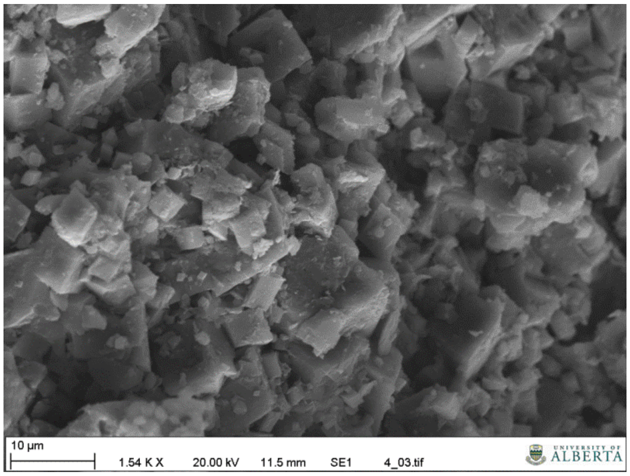


Figure 5-22: SEM image of sample 1 (original rock) at 1500x.

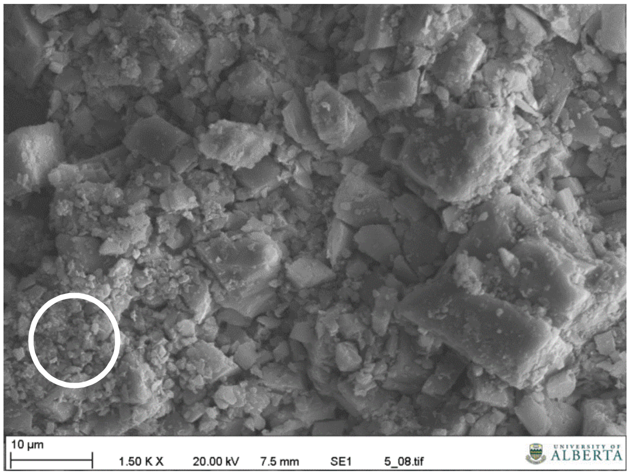


Figure 5-23: SEM image of sample 2 (heated rock) at 1500x.

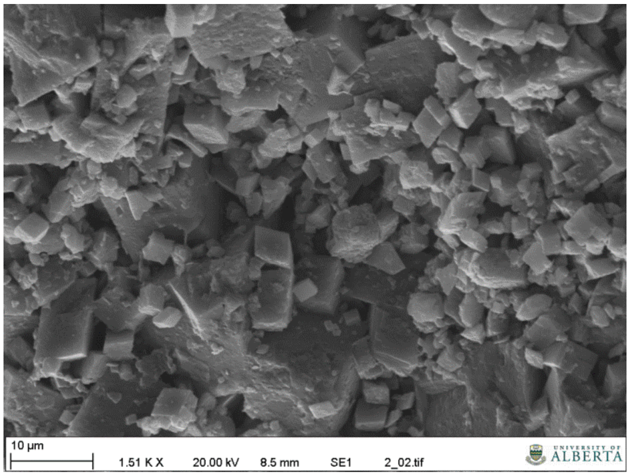


Figure 5-24: SEM image of sample 3 (exposed to propane) at 1500x.

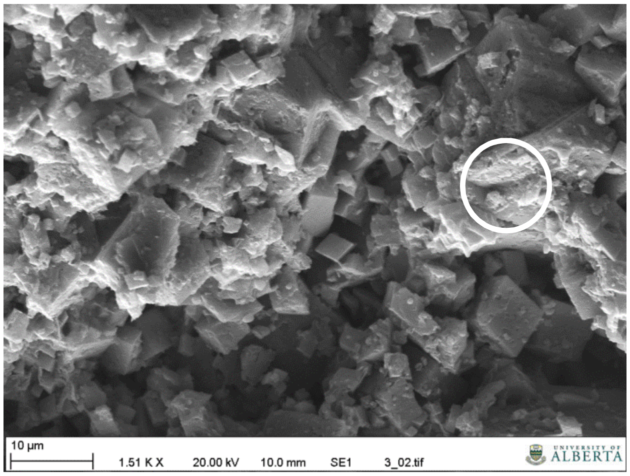


Figure 5-25: SEM image of sample 4 (exposed to butane) at 1500x.

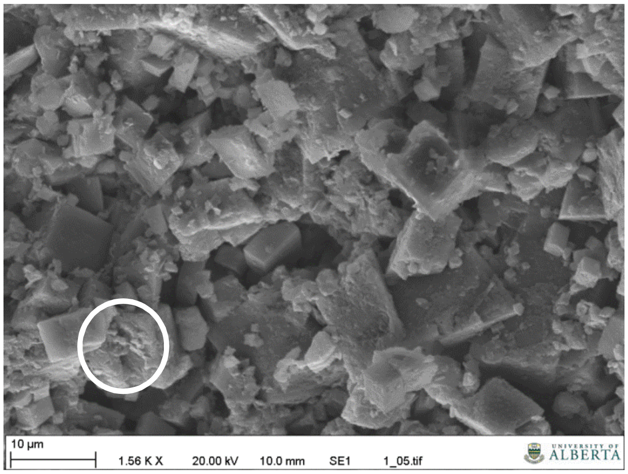


Figure 5-26: SEM image of sample 5 (CO_2 at 3500kPa) at 1500x.

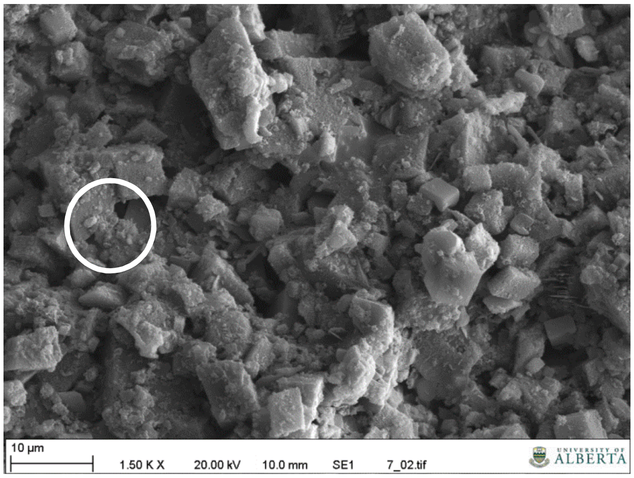


Figure 5-27: SEM image of sample 6 (CO_2 at 850-3500kPa) at 1500x.

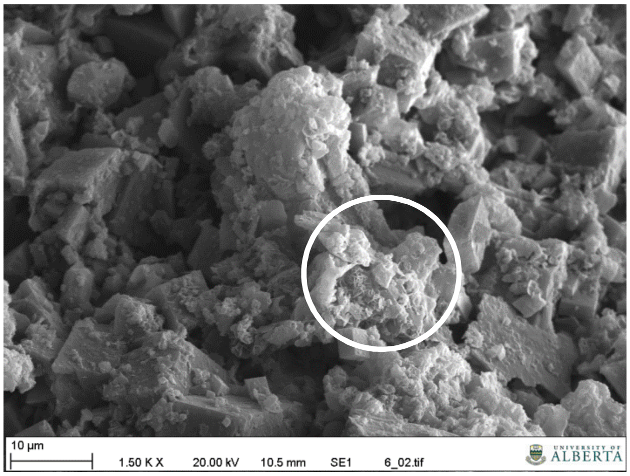


Figure 5-28: SEM image of sample 7 (rock exposed to CO_2 at 850kPa) at 1500x.

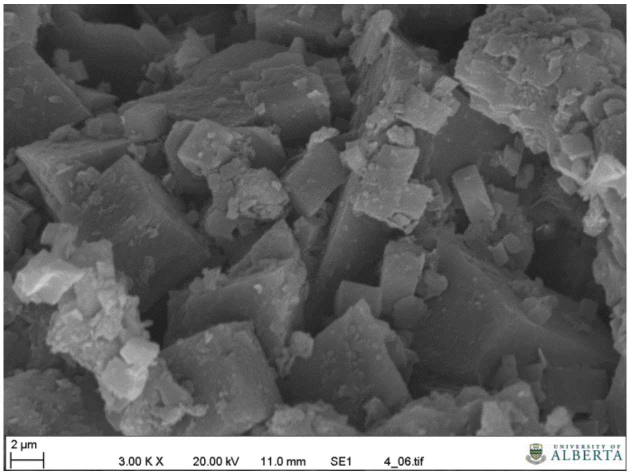


Figure 5-29: SEM image of sample 1 (original rock) at 3000x.

Figure 5-30: SEM image of sample 2 (heated rock) at 3000x.

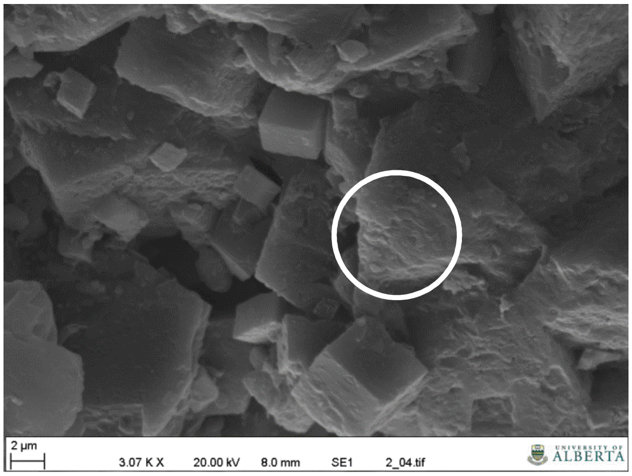


Figure 5-31: SEM image of sample 3 (exposed to propane) at 3000x.

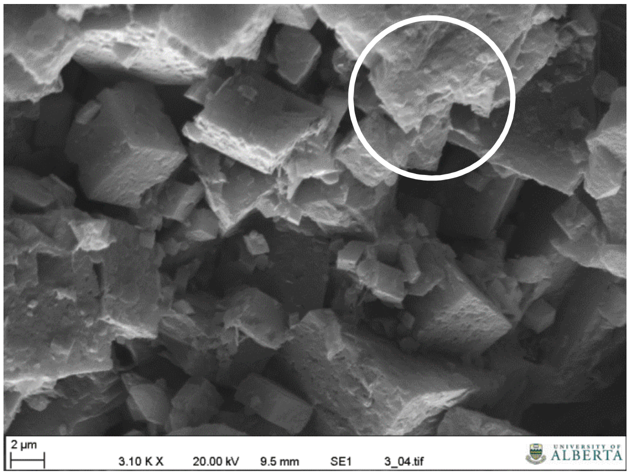


Figure 5-32:SEM image of sample 4 (exposed to butane) at 3000x.

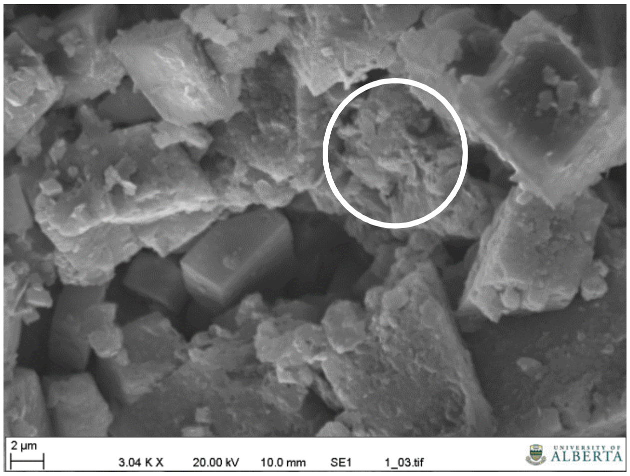


Figure 5-33: SEM image of sample 5 (CO_2 at 3500kPa) at 3000x.

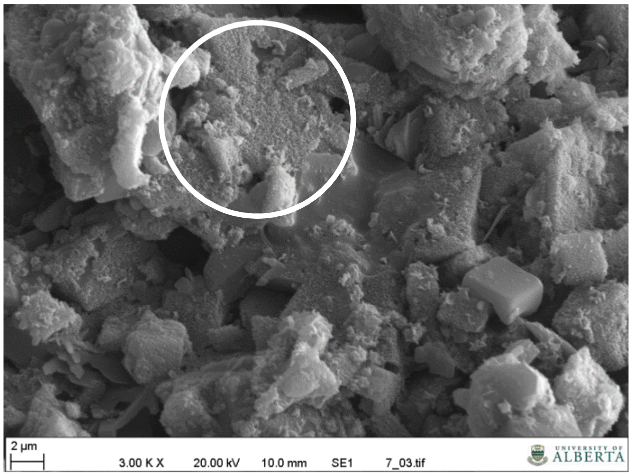


Figure 5-34: SEM image of sample 6 (CO_2 at 850-3500kPa) at 3000x.

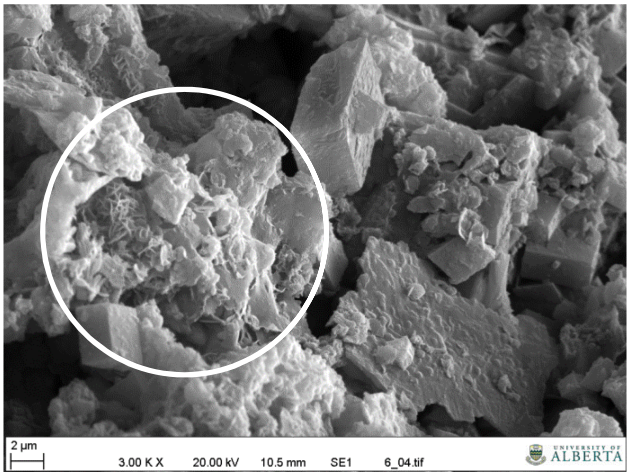


Figure 5-35: SEM image of sample 7 (rock exposed to CO_2 at 850kPa) at 3000x.

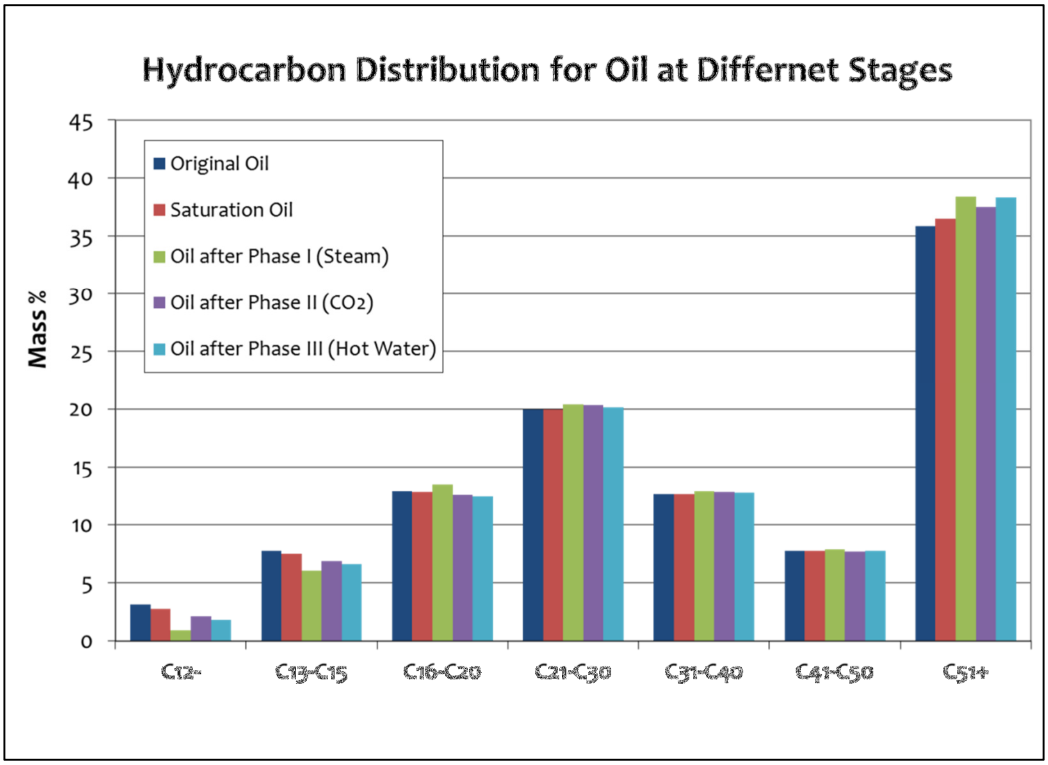


Figure 5-36: Hydrocarbon distribution of oil samples at different stages.

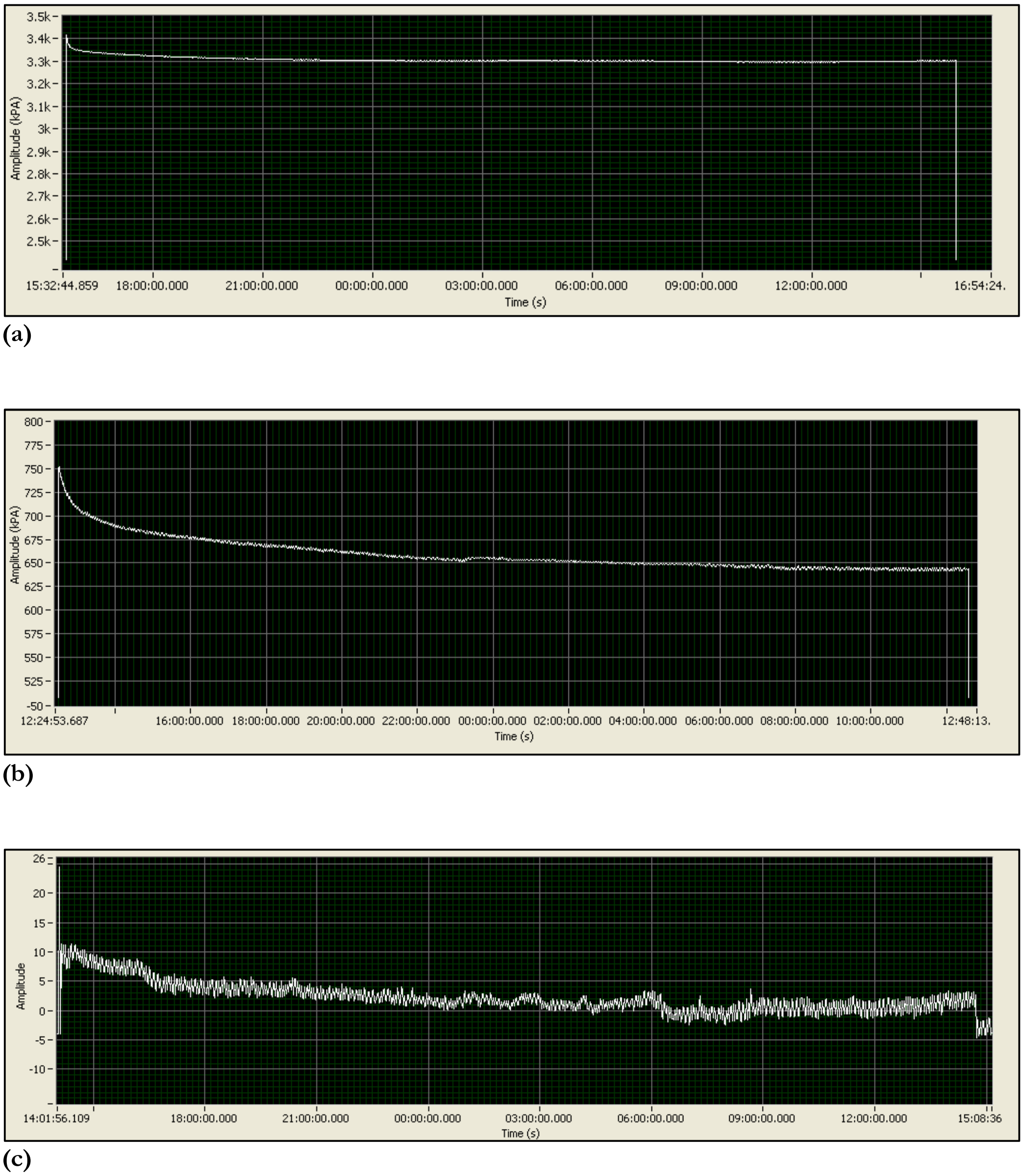


Figure 5-37: Pressure decline in Phase-II for: (a) CO_2, (b) propane, and (c) butane.

Chapter 6 : Field Scale Application of the SOS-FR (Steam-Over-Solvent Injection in Fractured Reservoirs) Method: Optimal Operating Conditions

A version of this chapter is presented at the Eighteenth SPE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, USA, 14–18 April 2012 and is also submitted to Journal of Canadian Petroleum Technology.

Introduction

Recent trends in upstream oil industries have shown an increasing interest in heavy oils resulting in new ideas and innovative methods tested at the laboratory scale to suggest economically and environmentally feasible recovery techniques. In order to check the applicability of such methods, field tests are required. However, before these field tests, a series of numerical modeling exercises should be performed to determine the optimal application conditions. Performing simulations makes it more feasible to run many possible combinations which could be very difficult in terms of resources and time. On the other hand, field scale modeling of complex recovery processes such as heavy-oil recovery through thermal and solvent injections has its own drawbacks, as the existing simulators may not be capable of fully representing the real physics. Data for simulators, such as relative permeability and solvent diffusion/dispersion characteristics, is also needed. All of these require a solid experimental foundation to virtually support the field scale numerical simulation exercises.

The main aim of the method considered in this study (SOS-FR) is to improve heavy oil recovery by introducing heat and then solvent to the matrix of fractured reservoirs to reduce the viscosity of oil and improve gravity drainage. Steam is a reasonable candidate to deliver this heat down to the reservoir and there are some working methods to employ steam in this manner, such as cyclic steam stimulation (CSS), steamflooding, and steam-assisted gravity drainage (SAGD) (Butler 1998). Das (2007) performed simulations for CSS and SAGD in fractured carbonate reservoirs with large pay thickness and found that wettability and oil viscosity were the main parameters of significance and that SAGD worked better for higher viscosity heavy oils than the CSS.

There are also proposed solvent applications for heavy oil recovery such as the vapor extraction (VAPEX) method applied to dilute the oil and help it drain by gravity using two horizontal wells (Butler and Mokrys 1989). The main concern for solvent applications is its high cost, which makes solvent retrieval an important issue. Solvent applications in fractured systems are limited due to retrieval problems (Hatiboglu and Babadagli 2008a, 2008b).

A combination of thermal and solvent methods was also introduced for naturally fractured reservoirs, mainly of a carbonate (oil-wet) origin, by Al-Bahlani and Babadagli (2008, 2009a, 2009b, 2011b). The technique called steam-over-solvent injection in fractured reservoirs (SOS-FR) consists of a cyclic injection of steam (or hot water) and hydrocarbon solvent; this technique showed a high recovery of oil in laboratory conditions which are controlled by the matrix size and injection rate (Al-Bahlani and Babadagli 2009a, 2009b, 2011b). In addition to two thermal and solvent cycles, this method suggests a third stage of the thermal phase, which is aimed to retrieve as much solvent as possible from the matrix. Numerical modeling of the same method for the field scale showed that this method is applicable at larger matrix sizes with a high rate of solvent retrieval that also gives a better efficiency rather than injecting only steam or solvent (Al-Bahlani and Babadagli 2010, 2011a).

CO_2 can be used as an alternative to expensive hydrocarbon solvents. Also, from an environmental point of view, this can help permanently sequester that type of greenhouse gas in underground reservoirs. Nevertheless, the impact of CO_2 injection on heavy-oil recovery needs to be clarified to find the optimal application conditions. The critical injection rate of CO_2 was discussed by various authors. Slobod and Howlett (1964) gave a critical rate of front stability in gravity segregation. Thompson and Mungan (1969) compared displacement velocity to critical velocity and showed that oil recovery under miscible gravity drainage conditions is more efficient in non-fractured systems than in fractured ones. They also noted that when a fluid miscibly displaces a more viscous fluid, the fingering behavior depends on the critical velocity.

The critical injection rate was also considered to a crucial factor in immiscible displacement in fractured systems. Barkve and Firoozabadi (1992) proposed a gravity drainage rate in homogeneous porous media. Babadagli and Ershaghi (1993) and Babadagli (2000) introduced an imbibition index in fractured systems, which indicates the strength of the capillary imbibition transfer in those systems. The inverse of this index resembles the fracture capillary number which is the ratio of the viscous forces that are effective in the fractures to the capillary forces that are effective in the matrix.

The diffusion process between the matrix and the fracture was experimentally studied by Trivedi and Babadagli (2008) while heptane was injected through a fracture as the miscible solvent. Their results showed that diffusion (into the matrix) is the dominant mechanism and that a lower rate of solvent injection gives more recovery from the matrix by allowing the solvent more time to contact and diffuse into the matrix oil. Another of their studies uses CO_2 as a solvent for light oil reservoirs and showed that giving enough time for CO_2 interaction with oil would extract heavier ends of oil (Trivedi and Babadagli 2009a, 2009b). They also investigated the effects of miscibility and injection rate on oil recovery and CO_2 sequestration and found an optimum rate that provided the most efficiency for both recovery and storage (Trivedi and Babadagli 2010).

Numerical Modeling

History Match of Experimental Data

In our previous work (Naderi and Babadagli 2012a, 2012b), we studied the effects of the alternate injection of steam and solvent for heavy oil recovery through an experimental program which was a form of the SOS-FR method in which CO_2 was selected as the solvent. Saturated sandstone cores with heavy-oil (3,500 cP at ambient conditions) were tested at various reservoir conditions. The experiments consisted of three phases: (1) Phase-I: Thermal, (2) Phase-II: Solvent (CO_2) and (3) Phase-III: Thermal. In Phase-I, the core was either immersed into hot water (at 90 ºC) or soaked by steam (at 120 or 150 ºC) in a thermal setup for one day. In Phase-II, the core was taken out of the oven and placed into another setup which was designed for solvent soaking. This stage also took one day. Phase-III was similar to Phase-I (thermal), mainly using hot water or low-temperature steam. **Table 6-1** lists the selected experiments (from Naderi and Babadagli 2012b) and their pressure and temperature conditions. Note that at this given pressure and temperature range, CO_2 is not miscible with the heavy-oil and its contribution is to just swell oil by diffusive mass transfer to the matrix.

In this work, we first modeled these experiments using a commercial simulator (CMG – STARS). A cylindrical model was used to represent the core, the core holder and the oven, and is illustrated in **Fig 6-1**. The grid sizes range from 2.5 mm (inner core) to 0.5 m (oven).

The same grid system and model was used for Phases II and III. The parameters subject to change during the history match process are the matrix relative permeabilities, thermal expansion and the diffusion coefficients. The simulation schedule was prepared in a way to best fit the experimental methods. For Phase-I, the oven was heated up to produce steam inside the core holder and at the end of this phase; it was shut down to cool down the core. Then the saturations were taken for the next phase which was Phase-II with solvent injection and soaking periods. At the end of this phase, the saturations were taken and used for Phase-III (the final -thermal- phase).

The best matches are shown in **Figs. 6-2** to **6-4**. The first phase matches were accomplished mainly by tuning the relative permeabilities and the thermal expansion coefficient (**Table 6-2**). The diffusion coefficient for Phases-II and III was taken as $9x10^{-5}$ m^2/day for the oil, which was first treated at a higher temperature in Phase-I and as 8x10^{-5} m^2/day for the oil, which was under lower temperature steam injection in Phase-II. The relative permeability curves were based on typical curves depending on wettability of the cores and the end points were changed during the matching process.

Field Scale Modeling

Up-scaling from small-scale laboratory results to large-scale field results is regularly done through analytical modeling, such as dimensionless groups or scaling parameters. Since we do not deal with real field scale numerical modeling, we did not use such analytical approaches and instead performed numerical studies on simpler matrix-fracture models described below using the rock and fluid properties obtained through either laboratory measurements or history matching that was previously discussed. In this regard, the fluid and rock parameters obtained in the experimental history match were transferred to a large scale model. A 2D model with 20 x 30 x 15 m blocks was created for this purpose. The fractures have 1 cm aperture. The grid sizes differ from smaller sizes (25 cm) close to the fractures up to larger sizes (2.5 m) far from the fractures. The structural properties of this model were chosen to be similar to the multi-matrix model given in Al-Bahlani and Babadagli (2011a) for comparison of the CO_2 and hydrocarbon solvent. This particular matrix-fracture system (multi matrix) yielded the best performance in their study, where they used light hydrocarbons as the solvent. **Table 6-3** summarizes the reservoir properties. Rock and fluid properties are the same as the history match parameters (**Table 6-2**).

Fig. 6-5 shows an *IK* cross section of the model. Three fractures were defined vertically and horizontally with a 1 cm aperture. Two wells injected and produced from the fractures.

Results

Comparable Runs with Hydrocarbon Solvent Case

Two main injection schemes were considered: (1) continuous and (2) cyclic. In the continuous case, steam was injected for 395 days in Phase-I. Then, cold water was injected for 175 days to cool the reservoir, similar to the study by Al-Bahlani and Babadagli (2011a). Note that they used this option to be consistent with their experimental scheme that involves a cooling period between Phase-I and Phase-II. This cooling period also provides similarity between what was actually done in laboratory tests as the core was cooled down after the first thermal phase before being exposed to solvent. The injection of CO_2 in Phase-II took 510 days with three different rates of 5, 10 and 50 m^3/day. In Phase-III, steam at a lower temperature was injected for 180 days.

In the cyclic injection, after a period of steam injection (Phase-I), in the following phase the solvent (CO_2) was injected for 14 days, and then there was a soaking period with different durations (14, 30 and 60 days). The production period took seven days. This trend (CO_2 injection, soaking and production) was repeated several times to fill the complete fixed project period of Phase-II for all runs. Then, another steam injection period was started as Phase-III. The injection schedules were selected as the same as those chosen by Al-Bahlani and Babadagli (2011a) to be able to compare our results with theirs.

Looking at the CO_2 saturation at the end of the solvent phase, we observed that, in continuous injection, the majority of CO_2 accumulates on top of the formation along the vertical fractures (with a higher concentration at a higher rate) due to its lower gravity, while cyclic injection makes it also diffuse along the horizontal fracture and have a better concentration in the middle of the matrix. This is better achieved in shorter soaking periods as the number of injections is reversely higher. **Figs. 6-6** to **6-11** show six cases of solvent mole fraction (four cases of CO_2 and two cases of propane) at the end of last solvent injection period. In the continuous cases (**Figs. 6-6, 6-7** and **6-10**), the solvent tends to go upward because of its lower density through the two vertical fractures. Solvent diffusion to the matrix takes place from these fractures as well as the horizontal fractures. The strongest diffusion into matrix was observed on the top of the matrix due to solvent accumulation at the top of the vertical fractures. The diffusion is higher in propane case (**Fig. 6-10**).

In the cyclic cases (**Figs. 6-8, 6-9** and **6-11**), the soaking effect is visually seen where the solvent diffuses better along all fractures even the horizontal one and it also has enough time to go deeper in the lower half of reservoir. Thus, we observe matrix diffusion occurring along the vertical fractures in the lower parts as well. As similar to the continuous injection cases, the solvent fraction diffused into the matrix blocks is higher when propane was used as solvent (**Fig. 6-11**).

As displayed in **Fig. 6-12**, the injection rate does not change recovery considerably for the continuous injection of CO_2. **Fig.6-13** shows recovery curves for cyclic injection with different soaking periods. For cyclic injections, shorter soaking times give slightly better recoveries. Note that the total solvent injection phase is the same. Therefore, the shorter soaking period means more number of solvent injection intervals during the whole solvent phase. Both set of results comply with Al-Bahlani and Babadagli's results (2011a) for a hydrocarbon solvent. In their continuous injection, the recovery for the highest rate (50 m^3/day) stands a little above the other two rates, which almost coincided, while in our models all three rates give a very close recovery. In cyclic injection, both their results and ours showed a better recovery for shorter soaking time (14 days) periods. **Fig. 6-14** is a diagram comprising recovery factor curves of selected scenarios for the two different solvents used: carbon dioxide and propane. In continuous injection, both solvents act in a similar manner, while in cyclic injection, propane acts better as it has a higher diffusion capability and yields higher recovery than CO_2. **Fig. 6-15** displays the cumulative solvent (CO_2) produced over the cumulative solvent injected. When injection occurs at higher rates, the solvent has less time to interact and diffuse into the matrix, hence most of it will be produced. As shown, the performance (produced solvent / injected solvent) is not critically sensitive to the injection rate.

Drawdown Runs

In addition to the previous cases which were similarly chosen for comparison to Al-Bahlani and Babadagli's results (2011a), we also conducted new cases considering drawdown after CO_2 injection with no Phase-III, with steam injection as suggested by Trivedi and Babadagli (2009b). One case of each group that yielded the best performance was selected (continuous injection at 50 m^3/day and cyclic injection with 14 days soaking). The drawdown pressure was set to 3000 kPa. Recovery changes are shown in **Fig. 6-16** and the CO_2 production factor (of the total injected CO_2) is displayed in **Fig. 6-17**. The drawdown cases showed a little lower recovery and a CO_2 production ratio at the end which is more prominent for the cyclic case. But, economically, these cases would be more favorable as they reduced the cost of steam (or hot water) in Phase-III and might add value to the project due to CO_2 storage in the matrix.

Economic Analysis

Al-Bahlani and Babadagli (2011a) introduced a general method to describe the economic analysis of the SOS-FR. A simple statement of that analysis is that we evaluate the cost of steam injection, the price of solvent lost and the revenue for produced oil which all sum up to the gross profit. The "money recovery factor"

(MRF) is the fraction that gross profit makes out of the "initial asset value" (IAV) which is basically the value for underground oil:

$$IAV = OIIP \times Oil.price \tag{6-1}$$

$$MRF = \frac{Gross.profit}{IAV} \tag{6-2}$$

The base prices used to make these calculations are given in **Table 6-4. Fig. 6-18** shows a bar chart of the MRF for different cases.

Although the values cannot be directly compared with Al-Bahlani and Babadagli's results (2011a) due to differences in estimates and the nature of the processes, the general trends give insight into the selection of the optimal method. To do so, we re-generated a graph with their reported MRF values for the six similar cases (Fig. 16 of Al-Bahlani and Babadagli 2011a) as shown in **Fig.6-19**. In continuous injection, the CO_2 case with higher rates results in a lower MRF (**Fig. 6-15**), while it is higher in their results of the same case (**Fig. 6-16**). In cyclic injection; however, both results show a favorable MRF for cyclic injection with a shorter soaking period (14 days). When we substitute the hydrocarbon solvent with CO_2, we may add a value to the project for the sequestered CO_2 in the reservoir. This was not considered in these simulation exercises but this credit may positively affect the MRF for larger scale field applications in the long run.

Conclusions

Numerical modeling was performed to history match the core scale experimental data for the SOS-FR method using CO_2 as the solvent. The match provided some fluid and rock properties which were employed to model large matrix applications (field scale) of the same method for longer times. Rock and fluid properties were changed to obtain the best match including relative permeability parameters (end points and residual oil saturation values) and the diffusion coefficient.

Two methods were studied for the field scale: (1) continuous and (2) cyclic injection. CO_2 was observed to be a light solvent which accumulates on top of the formation for continuous injection as the cyclic trend helps CO_2 stay in the middle fracture-matrix area. In continuous schemes, the recovery is not sensitive to the solvent injection rate while at cyclic ones, the soaking period plays a role in discriminating the recovery factors (higher for a shorter soaking period). The fraction of solvent recovered to the injected solvent is high and tends toward unity as time passes.

Our modeling yields a better recovery in cyclic injection and the best one is with 14 day soaking periods. Also, in terms of CO_2 sequestration, cyclic injection is more useful as it leaves more CO_2 behind in the reservoir in contrast to hydrocarbon solvent injection in which the solvent needs to be retrieved. Hence, one may suggest continuous injection for hydrocarbon solvent injection for the sake of its retrieval, whereas cyclic injection is a better option for cases in which CO_2 is used as the solvent.

In a scheme of the process without Phase-III, or as it is called in this chapter, the drawdown case, the recovery of both oil and CO_2 is reduced in cyclic injection which reduces the revenue although it enhances the sequestration. The highest revenue was obtained with cyclic injection of a 14-day soaking period.

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Table 6-1: Core scale experiments considered in the numerical modeling for history matching (from Naderi and Babadagli 2012b).

Exp.#	**Rock Type**	**Wettability**	**Phase-I**	**Phase-II**	**Phase-III**
1	Berea Sandstone	Water Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
2	Berea Sandstone	Oil Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
3	Berea Sandstone	Oil Wet	Hot Water 90 °C Ambient P.	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
4	Berea Sandstone	Oil Wet	Steam 120 °C 200 kPa	CO_2 24 °C 3500 kPa	Steam 120 °C 200 kPa
B1	Berea Sandstone	Water Wet	Steam 150 °C 550 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.
B2	Berea Sandstone	Oil Wet	Steam 150 °C 550 kPa	CO_2 24 °C 3500 kPa	Hot Water 90 °C Ambient P.

Table 6-2: Matching parameters used for numerical simulation of experiments.

Connate Water Saturation	0
Residual Oil for Water-Oil Table	0.2 (WW) , 0.3 (OW)
Residual Oil for Gas-Liquid Table	0.4 (WW) , 0.5 (OW)
K_{rw} at Irreducible Oil	0.4 (WW) , 0.7 (OW)
K_{rg} at Connate Liquid	0.3 (WW) , 0.4 (OW)
CO_2 Diffusion Coefficient in Oil*	8.5×10^{-5} (m^2/day)
Water 1st Thermal Expansion Coefficient	1.9×10^{-4} (1/C)
CO_2 1st Thermal Expansion Coefficient	7.25×10^{-3} (1/C)
Oil 1st Thermal Expansion Coefficient	5.6×10^{-4} (1/C)

* Diffusion coefficient for Phase-II and III was taken as 9×10^{-5} m^2/day for the oil which was first treated in a higher temperature in Phase-I (and presumably became more viscous) and as 8×10^{-5} m^2/day for the oil which was under lower temperature steam injection in Phase-II.

Table 6-3: Reservoir properties used in field scale simulations.

Depth	500 m
Pressure	8000 kPa
Temperature	50 ^{o}C
Matrix Porosity	0.3
Matrix Permeability	10 mD
Fracture Porosity	0.99
Fracture Permeability	550 D
Oil Density	959 Kg/m^3
Wettability	Oil Wet

Table 6-4: Base prices used in economic analysis.

Steam	18 $/m^3
CO_2	50 $/m^3
Oil	100 $/bbl
Initial Asset Value (Oil in Place Value)	1.3 m$

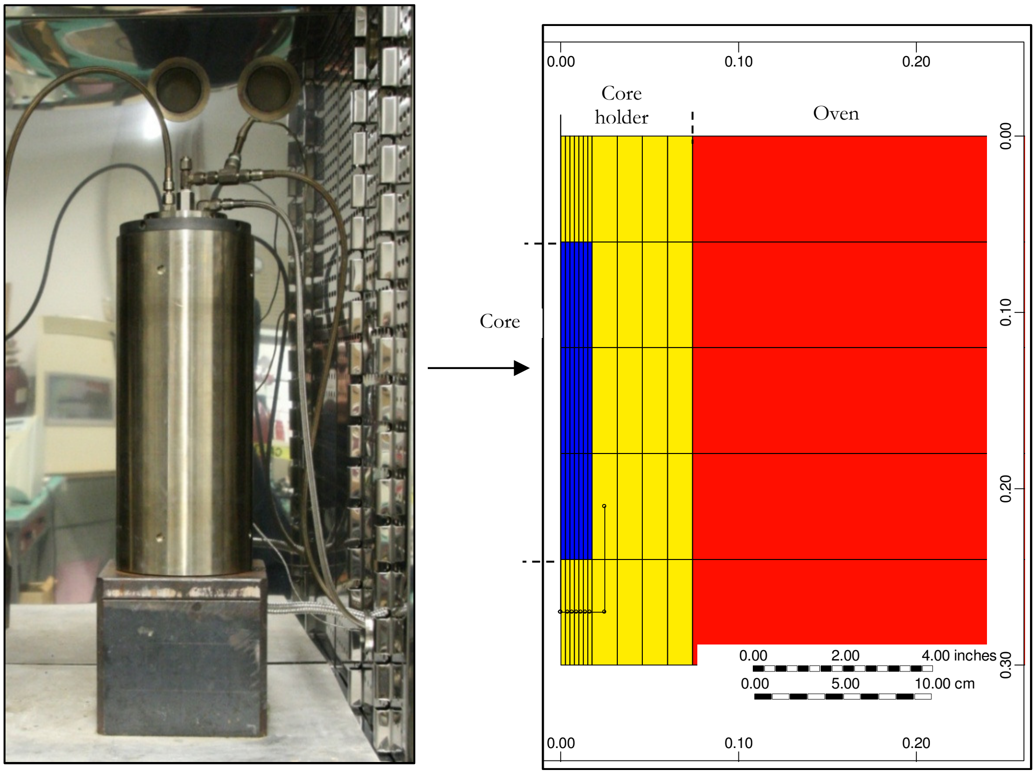

Figure 6-1: The thermal setup and its model in the simulator.

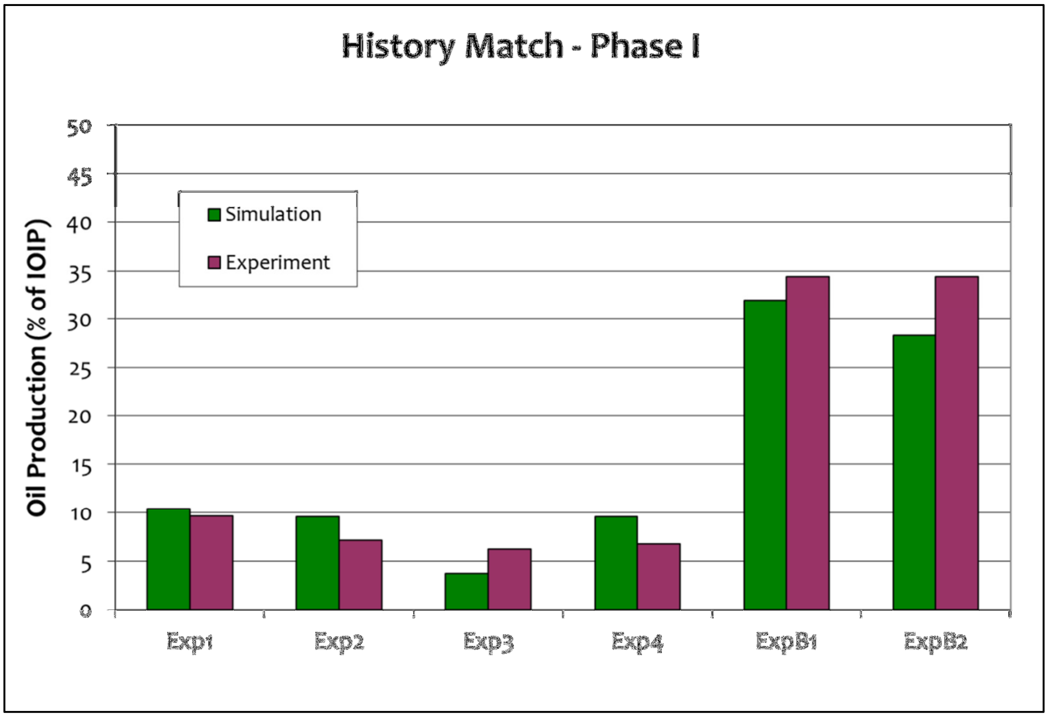

Figure 6-2: History Match for Phase-I.

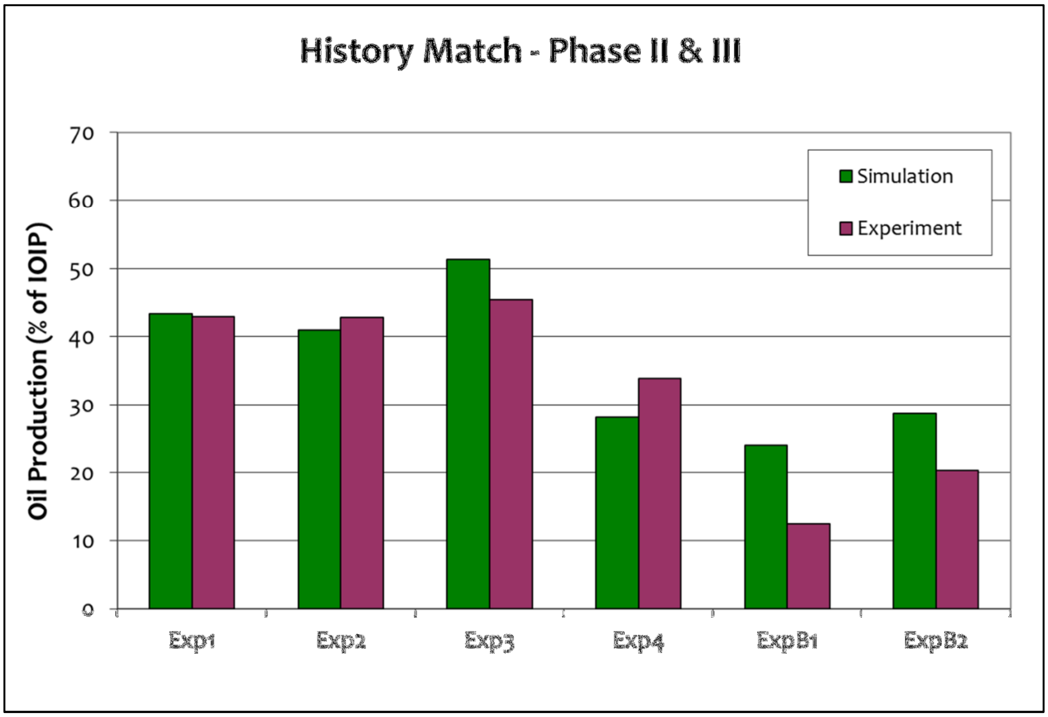

Figure 6-3: History Match for Phase-II and III.

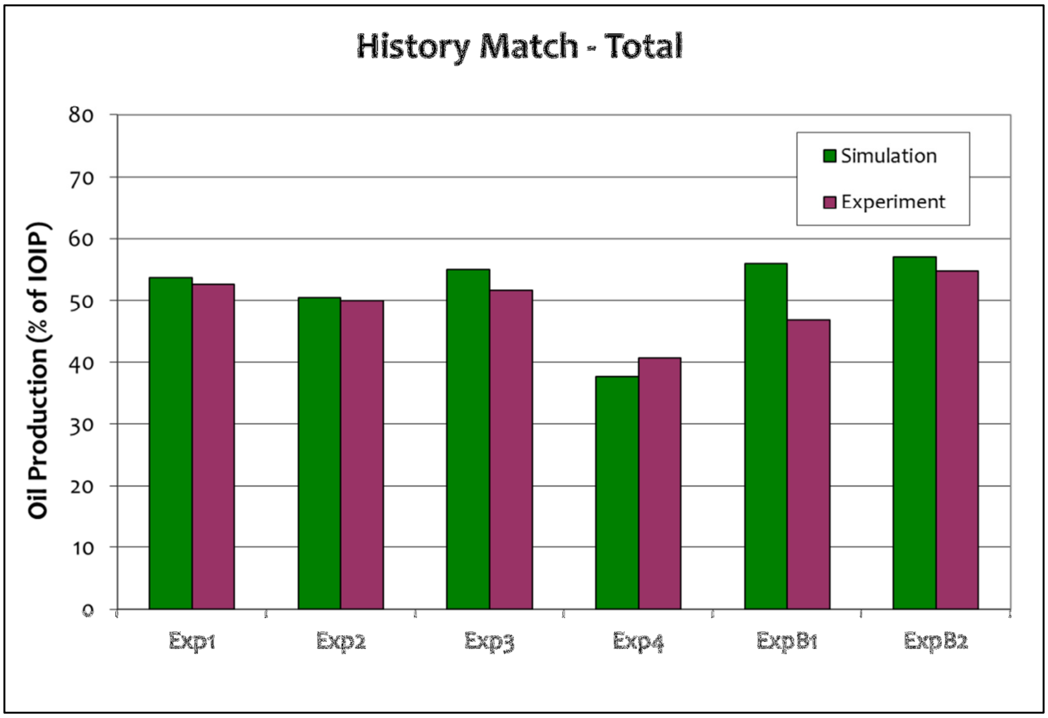

Figure 6-4: History Match for Total Process.

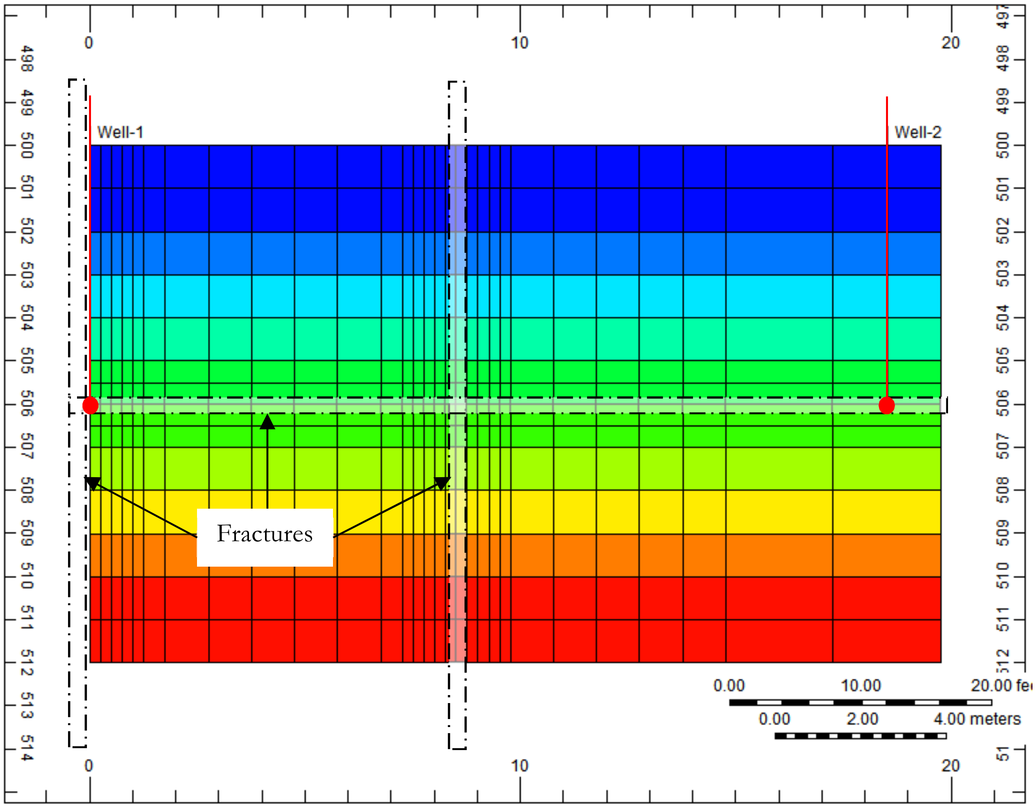

Figure 6-5: Matrix blocks IK cross section.

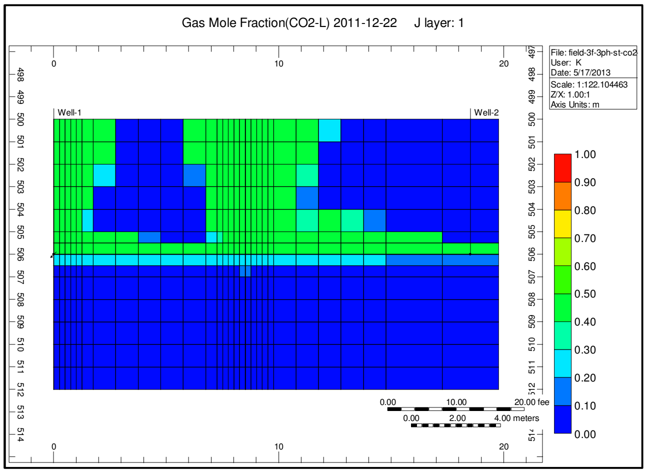

Figure 6-6: CO_2 gas mole fraction at the end of continuous injection, rate: 5 m^3/d.

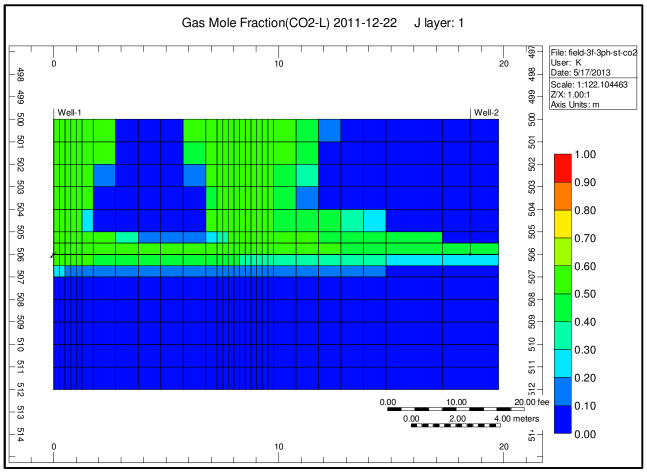

Figure 6-7: CO_2 gas mole fraction at the end of continuous injection, rate: 50 m^3/d.

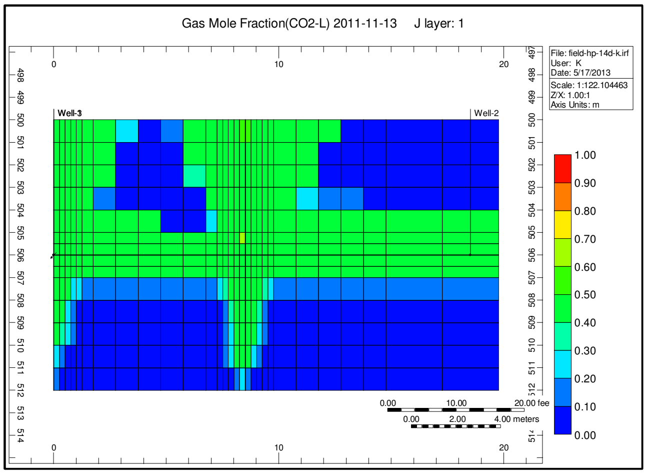

Figure 6-8: CO_2 gas mole fraction at the end of cyclic injection, each soaking: 14 d.

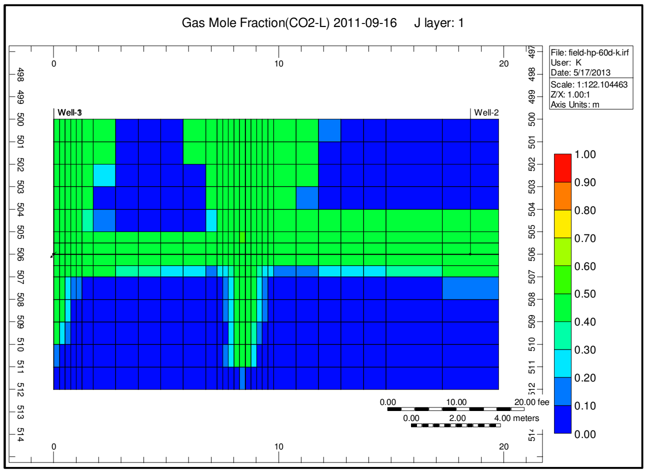

Figure 6-9: CO_2 gas mole fraction at the end of cyclic injection, each soaking: 60 d.

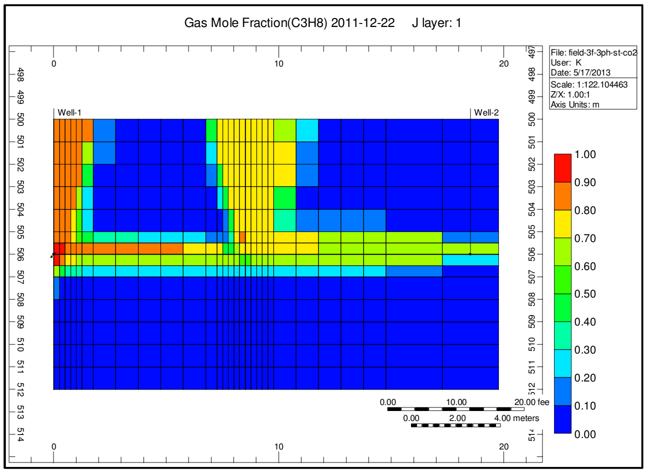

Figure 6-10: C3 gas mole fraction at the end of continuous injection, rate: 5 m^3/d.

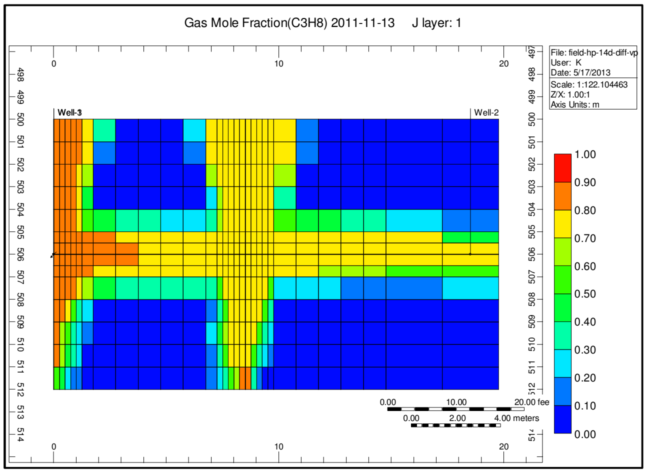

Figure 6-11: C3 gas mole fraction at the end of cyclic injection, each soaking: 14 d.

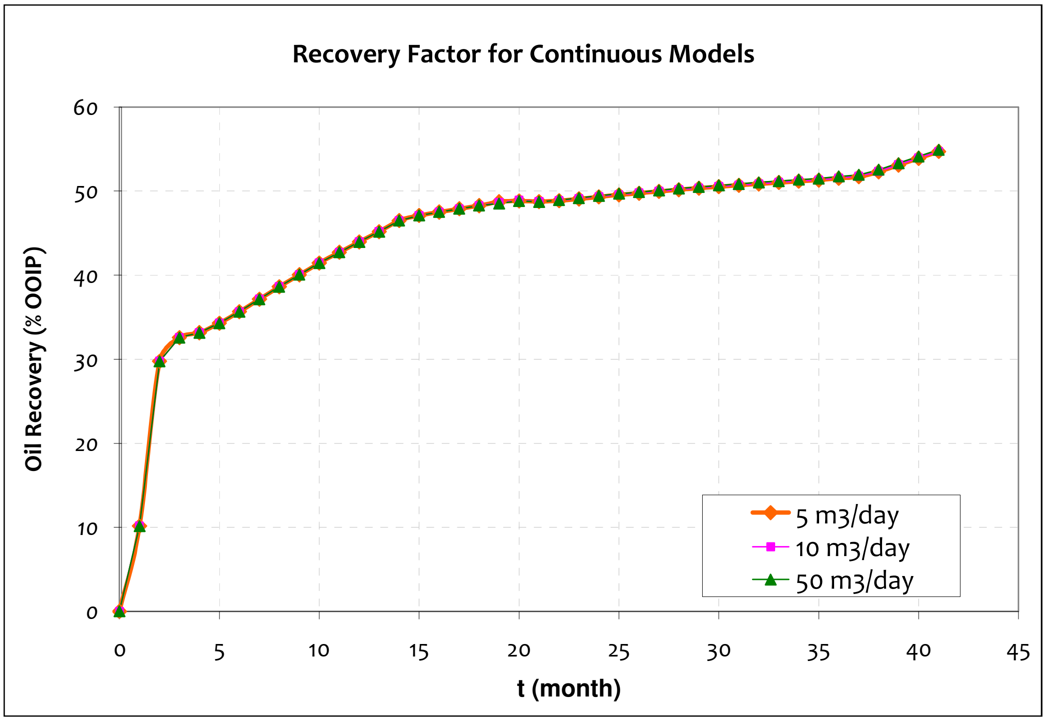

Figure 6-12: Recovery factor for continuous models.

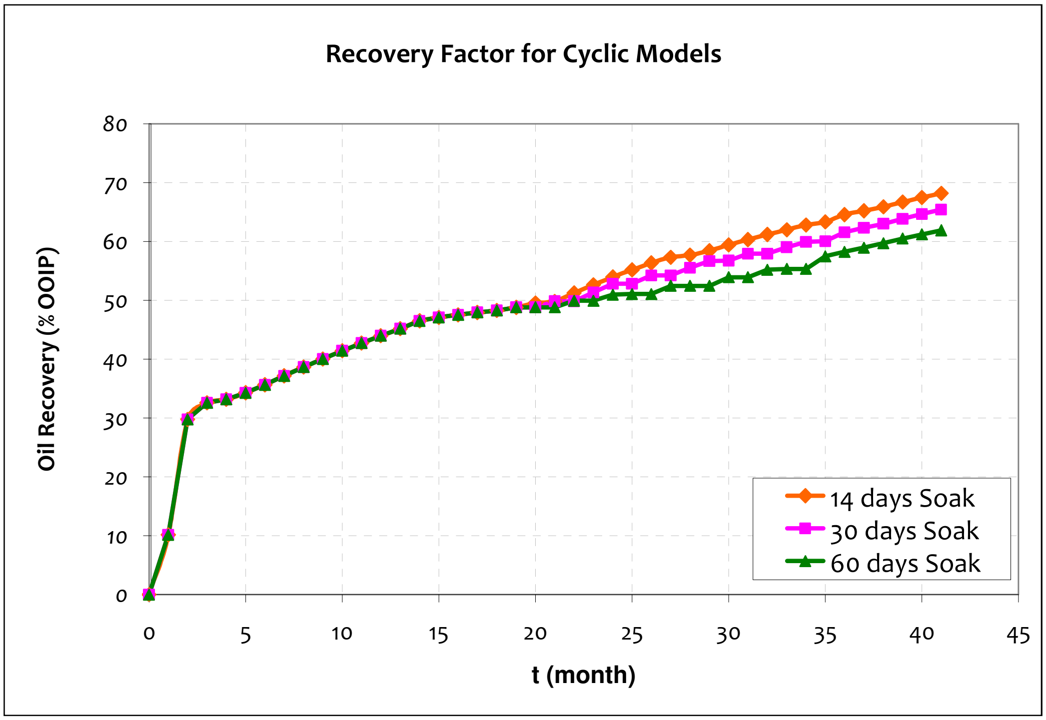

Figure 6-13: Recovery factor for cyclic models.

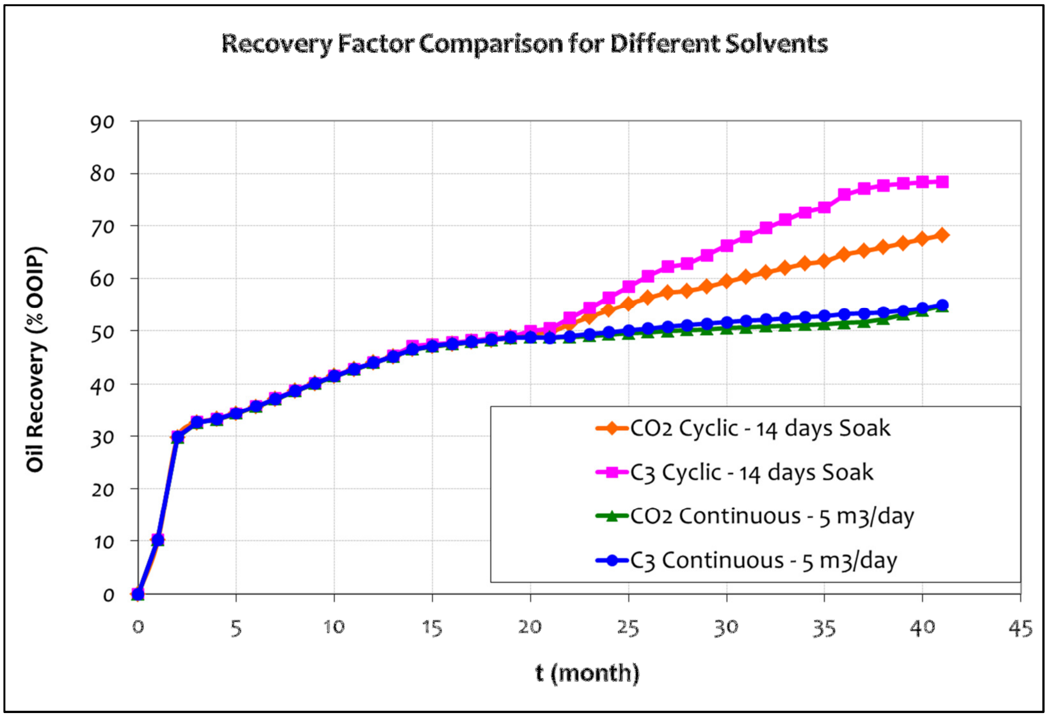

Figure 6-14: Recovery factor comparison for different solvents.

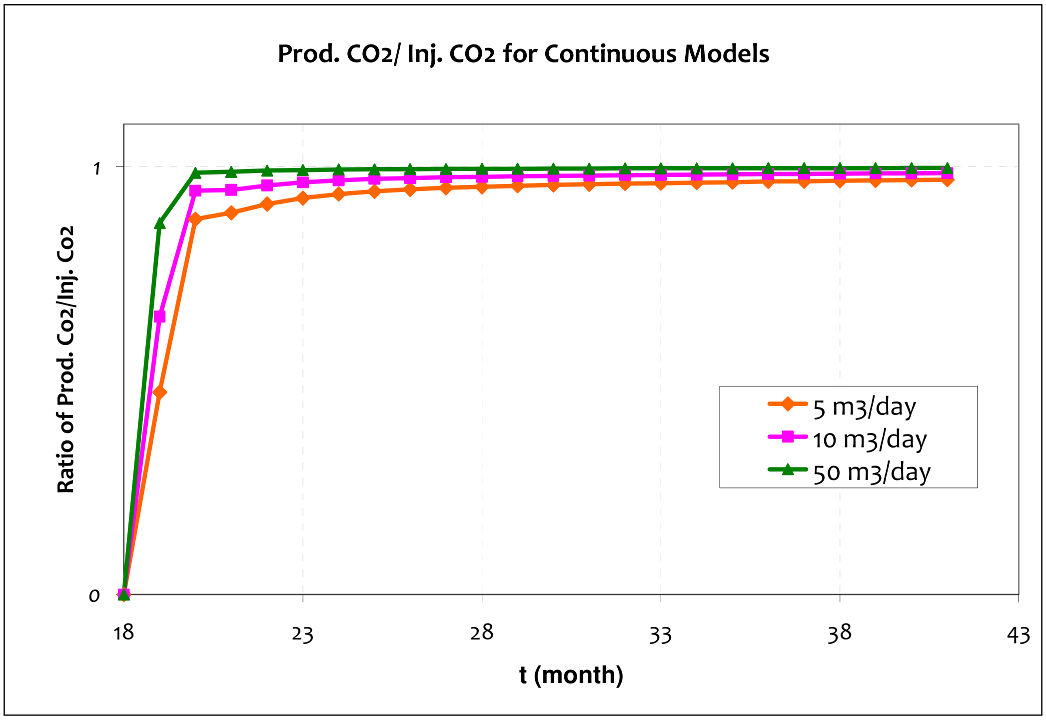

Figure 6-15: Production solvent over injected solvent for continuous models.

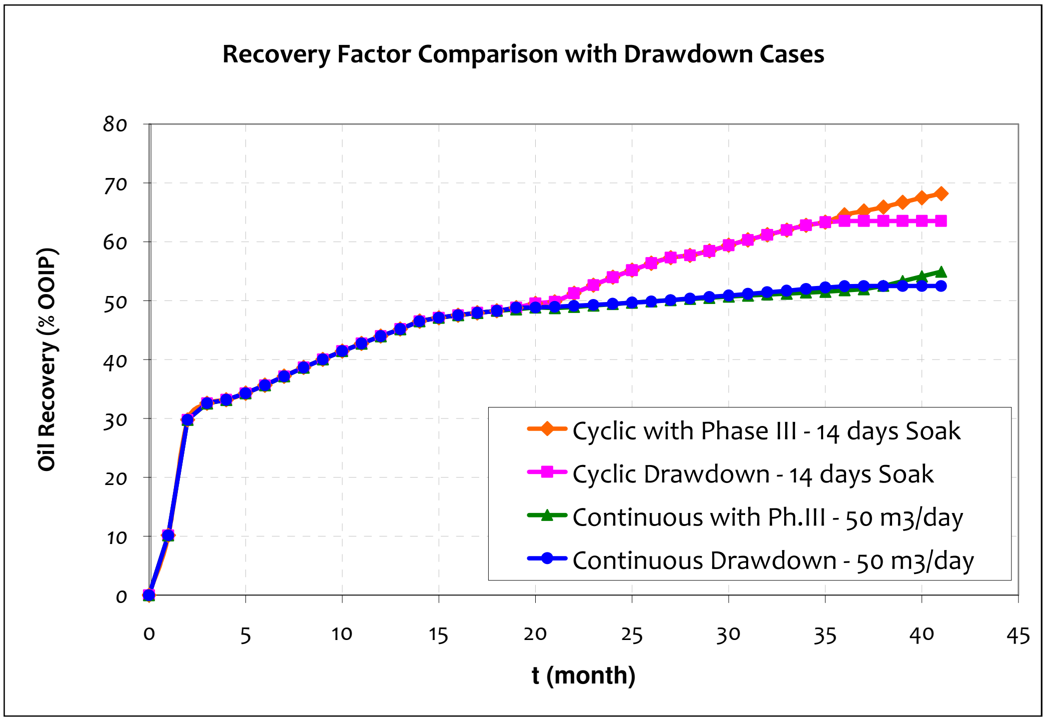

Figure 6-16: Recovery factor for drawdown models.

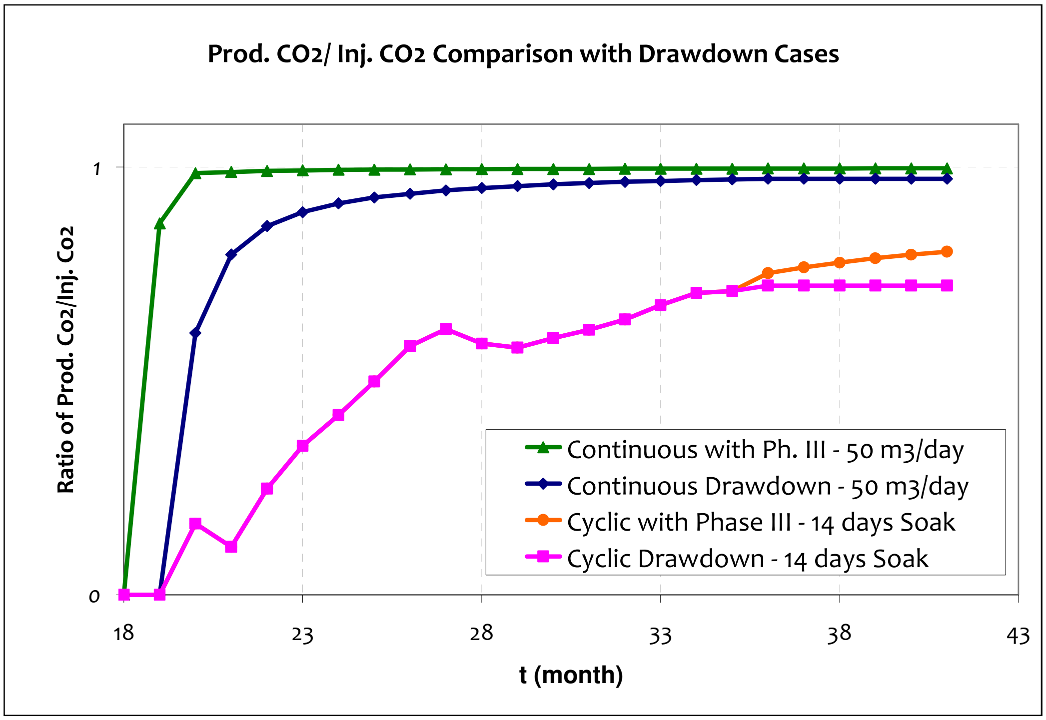

Figure 6-17: Production solvent over injected solvent for drawdown models.

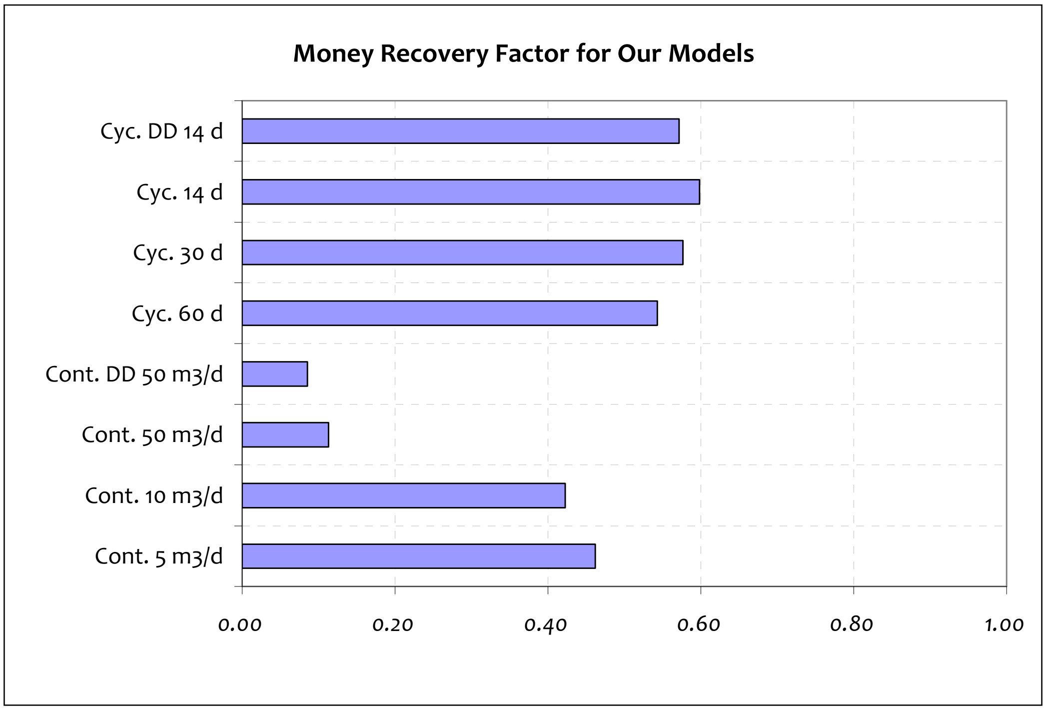

Figure 6-18: Money recovery factor. (Cont.: Continuous; Cyc.: Cyclic; DD: Drawdown).

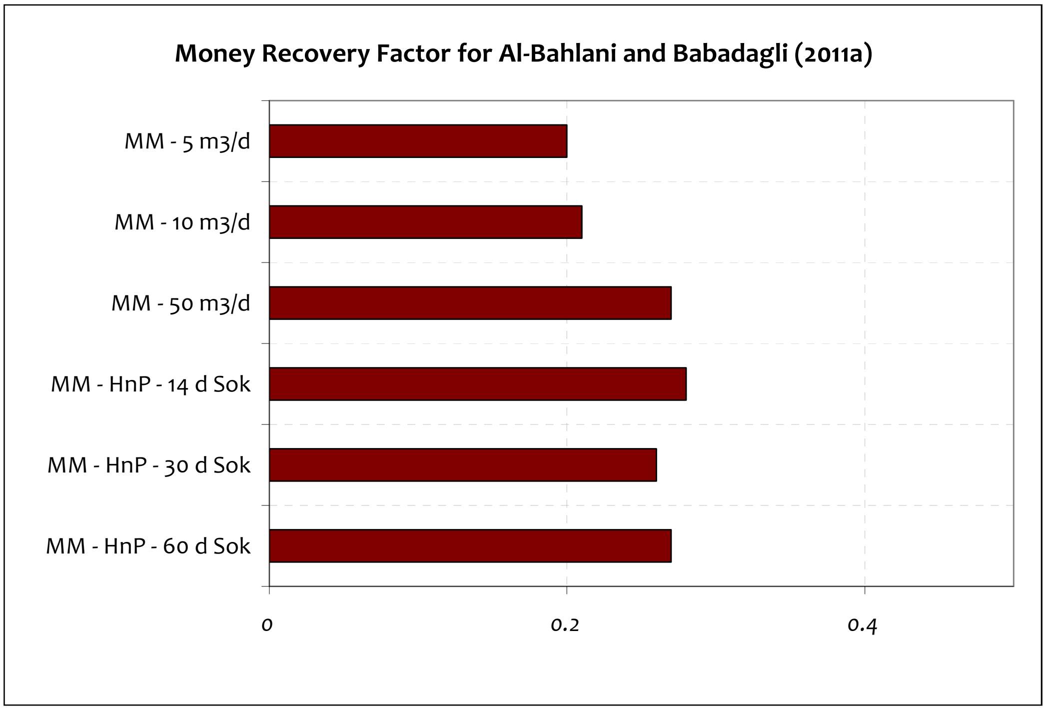

Figure 6-19: Money recovery factor for Al-Bahlani and Babadagli (2011a) models compared with our cases given in Fig. 6-18. Values were obtained from Fig. 16 of the reference. (MM: Multiple Matrixes, Hnp: Huff and Puff, Sok: Soaking).

Chapter 7 : Contributions and Recommendations

Conclusions, Remarks and Contributions

In this chapter, a general overview of the research was provided and some interesting observations were highlighted. Also covered were the specific contributions to literature and industry.

The SOS-FR (steam-over-solvent injection in fractured reservoirs) method is recently introduced to bring a new horizon for heavy oil recovery from naturally fractured reservoirs. This method associates the effects of thermal recovery processes which deliver heat and reduce the oil viscosity with the effects of solvent injection processes that dissolve and dilute the oil. The thermal and solvent phases interact with each other as well by conditioning the oil and changing the fluid and medium properties.

The research on this method was initiated by conducting experiments at low temperature (hot water) and low pressure (ambient pressure) conditions (Al-Bahlani and Babadagli 2011). In this thesis, the research has been elevated to another level and a broader coverage. High pressure and high temperature processes were tested on various samples of both unconsolidated (original sandstone cores and synthetic sandpacks) and consolidated (sandstones, different carbonates) with different oil types (bitumen, original heavy oil in core, and a different heavy oil for saturation of non-preserved cores). Solvent type was of significant importance too. In addition to liquid solvents (ranging between the carbon numbers of C7 and C12) used during initial attempts by Al-Bahlani and Babadagli (2011), gas (propane and butane) and solvents with high aromatic content as well as CO_2 were also tested alternatively.

In Chapter 2, the lower pressure and temperature conditions with liquid hydrocarbon solvents were selected for the process on original oilsand samples. Then interaction of the surrounding phase (hot water and solvent) with the matrix fluid was investigated which resembled the process occurring in post-CHOPS (cold heavy oil production with sands) enhanced oil recovery applications. The effects of time and placement of cores on the process were studied by selecting different programs of employing this method. The initial hot water phase did not produce any appreciable amount of oil as the cores were oil-wet, temperature was not very high, and oil was heavy so that the thermal expansion of the oil was negligible. However, it was found that this phase was necessary to condition the oil for the consequent phases. Aromatic distillate was more miscible with heavy oil and hence yielded higher oil recovery when compared to a lower molecular weight solvent like heptane. Note that the diffusion took more time for this type of solvent compared to lower carbon number single component alkanes.

Chapter 3 studied similar conditions on carbonates. Distillate solvent resulted in a better recovery than pure lighter hydrocarbon solvent. Timing of the phases is important as well as the program scheme. Cycle durations in solvent phase and the number of solvent cycles are crucial and can be optimized to obtain the highest oil recovery and least solvent loss. Replenishing solvent was more efficient than repeating the solvent phase after the final thermal phase recovery. This implies that cyclic- (huff and puff) type injection schemes are more applicable if there is enough fracture volume to fill with solvents. Although the initial thermal phase showed contribution to oil recovery by thermal expansion, skipping this phase and starting the experiments with the solvent phase in such carbonate rocks yielded a higher ultimate recovery.

High pressure and high temperature conditions along with the introduction of carbon dioxide as solvent on unconsolidated sandpack medium were discussed in Chapter 4, where CO_2 performance showed promising results close to hydrocarbon solvents. Hydrocarbon solvents (specifically propane) gave better results without initial thermal phase as the high permeability of the medium made it more efficient for the solvent interaction with the heavy oil, while CO_2 worked better together with initial and final thermal stages. Wettability, size, and time were also important factors. Oil-wet medium affected CO_2 cases more than propane. Longer cores proposed a better gravity drainage and total oil recovery. At the laboratory scale, the total production was maximized when a time slot of 6-24 hours was selected for each phase. Shorter phases such as 2 hours or longer phases like 48 hours reduced the ultimate recovery.

Similar high end conditions were applied on consolidated medium, i.e., sandstone and carbonates, as given in Chapter 5. The direct effects of temperature in Phase-I on oil production were shown, but overall recovery depended on the whole process. Having a very high temperature in the first phase increased the recovery of Phase-I but reduced the recoveries in the consequent phases and ultimate recovery, too. High temperature removed the lighter components and thereby affected oil properties which made the following solvent phase less effective. A lower temperature steam in Phase-I was more effective in terms of the ultimate recovery of the whole SOS-FR process. Hot-water performed better than steam in Phase-III in recovery improvement as well as solvent retrieval. Thus, having these two observations for thermal phases, the temperature requirements and hence the steam generation cost were reduced through the SOS-FR method.

Another phenomenon that occurred on carbonate rocks is carbonate mineralization due to the interaction of CO_2 with carbonate minerals in the presence of water. This type of interaction yielded chemical reactions of carbonic acid with dissolved cations in the place. This was qualitatively presented using SEM images.

Solvent recovery is an important factor in the economics of this process. The solvent storage and retrieval rates depend on the matrix size, the lithology of the core, solvent type, temperature and pressure applied during the solvent phase. Under experimental conditions discussed in Chapter 5, approximately 1-2% of CO_2, 5-10% of propane and 1-7% of butane were stored in the core during Phase-II. A fraction of this diffused amount is expected to be released by depressurizing at the end of Phase-II and also thermal application of Phase-III which recovers the solvent in the form of gas bubbles. The samplings of such produced gas in Phase-III showed 1-2% of CO_2, 5-22% of propane and 0-0.1% of butane in the gas samples of related experiments.

In Chapter 6 a numerical study of the SOS-FR method using CO_2 was performed that included history matching of the laboratory scale experiments to obtain the parameters needed for larger (field) scale simulations. Two methods were numerically modeled and studied for field scale applications: (1) continuous and (2) cyclic injection. In the continuous schemes the recovery was not sensitive to the solvent injection rate while in the cyclic schemes the soaking period played a role in the recovery factor and made it higher when there were shorter soaking periods in a fixed solvent injection time slot that gave more number stages of huff and puff. This scheme also left more CO_2 inside the reservoir, hence it was desirable for sequestration goals. The sequestration was even enhanced when the last thermal stage was removed from the program, but it also reduced the recovery. In an example of placing a higher significance on oil recovery, the highest revenue was obtained with cyclic injection of a 14-day soaking period. Eventually, an optimization study is needed to maximize both oil recovery and CO_2 sequestration.

This study is the first one of its kind that deals with co-injection of CO_2 -steam in heavy oil and bitumen recovery. Core-scale investigations of water and solvent phases in various porous mediums were done as well as the numerical study of the applicability of SOS-FR method with CO_2 at the field scale. This approach showed promising results of substituting hydrocarbon solvents with CO_2 and gaining similar recovery factors together with the possibility of CO_2 storage for environmental purposes. This method can be used on fractured carbonate reservoirs or on oilsands with a developed wormhole network after CHOPS.

The applicability of this method is highly dependent on reservoir conditions; mainly fracture network structure and matrix size. Therefore, an optimization exercise, taking into account all the available reservoir data for each specific case, is needed and then an optimal design should be proposed with modifications on injection rate, phase (cycle) durations, pressure-temperature conditions and even solvent composition.

The first phase of the SOS-FR method is the initial thermal phase which is intended to condition the oil for the consequent phases; however, the importance of this phase depends on the type of porous medium under application. For example, initial thermal phase did not produce an appreciable amount of oil directly but is very essential for the upcoming solvent and thermal phases to improve the oil recovery in case of unconsolidated oilsands (Chapter 2). However, in Grosmont carbonates, the initial thermal phase reduces the effectiveness of the following phases and eventually the efficiency of the whole process (Chapter 3) even if it produces some amount of oil during its own period.

Wettability effects on the overall process are more critical in Phases-II and III when solvent and water are in contact with the oil. Oil wet cores generally yield lower recoveries. This negative effect is better seen when CO_2 is used as solvent rather than hydrocarbons. In case of very heavy oil, solvent could “imbibe” into oil-wet matrix in the beginning of Phase-II before mixing by diffusion starts. This needs to be investigated.

Choosing the proper solvent depends on few parameters. Hydrocarbon solvent usually perform better in Phase-II alone but when it comes to the overall three-phase process, CO_2 cases also provide comparable recoveries. An economic analysis taking into account the injected solvent costs, produced oil revenue, value of recycled solvent and CO_2 sequestration benefits is required for each field application case. Pressure-temperature condition of injected solvent is a ruling factor of solvent diffusion and its effectiveness to dilute and produce oil and it also affects the injection cost directly. As mentioned iteratively throughout the thesis, the solvent retrieval ratio is very critical in all solvent applications. The results given for different porous media at pessimistic laboratory conditions show at least half of the solvent is readily recoverable in the SOS-FR method. It goes up to 80% depending on the matrix and oil type. Interestingly, the retrieval rate was mush higher in case of bitumen contacting vuggy carbonates (Grosmont) than loose oilsands containing heavy-oil. In a recent study, Mohammed and Babadagli (2013) designed a special system to accurately measure the solvent retrieved during Phase-III of the SOS-FR method. After testing different combinations of injection cycles and solvents, they observed solvent retrieval varying between 72% and 91% for both heptane and the distillate used in our experiments as well (Chapters 2 and 3). This is highly promising to continue research on the subject and field trials.

Timing is also very important in designing the field scale application of the method. The results of laboratory works presented in this thesis showed that the heating time should be enough for the oil to flow and be produced but longer times may not be beneficial as it changes the oil properties and reduces the solvent effectiveness in the following phase even though it may increase the thermal phase productivity in thermal phase itself. Therefore, there are optimal times for each application in which the most oil is recovered as a combination of produced oil of all phases.

The SOS-FR method was also successful in reducing the costs associated with both thermal and solvent injections and increasing the revenue by providing a method to use carbon dioxide instead of hydrocarbon solvents and also by reducing the temperature requirements for both initial and final thermal phases.

Suggested Future Work

1) More research is suggested to be done on solvent recovery. This can include an experimental work on a sealed setup that provides a means of measuring the pressure, solvent production rate, and continuous gas sampling that can be used for accurate calculations of solvent retrieval.

2) The effects of such a method on rock properties can also be a point of interest. A research topic can cover the chemical reactions occurring through different stages of the SOS-FR method, containing the changes on wettability, depositions and dissolutions.

3) This thesis contained only static experiments. Dynamic versions of selected experiments at different injection, pressure, and temperature conditions will be useful in identifying the effect of injection rates and soaking times. Although this would not be a simple practice, inclusion of the effect of matrix size on solvent diffusion into matrix, oil recovery and solvent retrieval rates would be extremely beneficial for further numerical applications and up-scaling exercises to field scale simulations.

4) Visual analysis in micro scale may provide a clear insight into what actually happens in pore scale during different phases, especially the final phase where all phases are available and interact with each other.

5) Finally, pilot field tests are encouraged to make preliminary field data available for numerical analysis to modify the method and optimize its applicability for specific cases.

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Al-Bahlani, A.M. and Babadagli, T. 2011. SOS-FR (Solvent-Over-Steam Injection in Fractured Reservoir) Technique as a New Approach for Heavy-Oil and Bitumen Recovery: An Overview of the Method. *Energy and Fuels* **25** (10): 4528-4539.

Mohammed, M.A. and Babadagli, T. 2013. Efficiency of Solvent Retrieval during Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR) Method: Core Scale Experimentation. Paper SPE 165528 presented at SPE Heavy Oil Conference, Calgary, Alberta, Canada, 11-13 June.