In the name of Allah the most gracious and the most merciful

قُلْ إِنَّ صَلاتِي وَنُسُكِي وَمَحْيَايَ وَمَمَاتِي لِلَّهِ رَبِّ الْعَالَمِينَ

لاَ شَرِيكَ لَهُ وَبِذَلِكَ أُمِرْتُ وَأَنَاْ أَوَّلُ الْمُسْلِمِينَ

“Say my worship and my sacrifice and my living and my dying are for Allah, Lord of the Worlds. He hath no partner. This am I commanded, and I am first of those who surrender unto Him”

Holy Quran - 6 [162-163]

University of Alberta

Improvement of Thermal Heavy-Oil Recovery in Sandstone and Carbonate Reservoirs Using Hydrocarbon Solvents

by

Al Muatasim Mohammed Hamood Al Bahlani

A thesis submitted to the Faculty of Graduate Studies and Research
in partial fulfillment of the requirements for the degree of

Doctor of Philosophy
In

Petroleum Engineering

Department of Civil and Environmental Engineering

Fall 2011
Edmonton, Alberta

To:

Oman

Abstract

This thesis introduces a new approach for heavy-oil recovery from fractured reservoirs: Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR). The SOS-FR technique is a new technology proposed as an alternative method to the sole injection of steam or solvent and consists of three phases; Phase 1 produces heavy-oil by thermal expansion and conditions the oil for Phase 2, which is solvent injection, and Phase 3 is applied mainly to retrieve the solvent.

Extensive experimental evidence and analysis were provided through static and dynamic laboratory scale experiments. Static experiments were conducted to test four parameters: (1) Matrix wettability, (2) solvent type, (3) initial water saturation, and (4) matrix boundary conditions and size. This was followed by dynamic experiments to test the effect of solvent injection rate on the process. Experiments were conducted using heavy-crude oil samples obtained from a field in Alberta on either wettability-treated sandstone (to mimic oil-wet behavior), or cleaned carbonate cores.

Visualization experiments were also performed on 2.5 cmx7.5 cm Hele-Shaw cells with different boundary conditions to gain an insight into fluid-fluid interaction between oil in the matrix and solvent in the surrounding fracture. Interaction between oil saturated 2-D models and the hydrocarbon solvent surrounding it was analyzed qualitatively. Two new dimensionless numbers were introduced as functions of fluid

properties (viscosity, density, and diffusion coefficient) and matrix boundary conditions, and the numbers were correlated to oil recovery rate.

Finally, numerical simulations were conducted using a commercial software package for two main purposes; (1) history matching and obtaining an insight into the upscaling procedure from lab to larger scales, and (2) examining the efficiency of the process at the field scale (mainly large matrix sizes).

The importance of this work is that it provides a novel perspective on the interaction between steam/solvent and heavy oil in the matrix, and presents an alternative technique for heavy-oil recovery from deep natural fractured reservoirs with tight and oil-wet matrix.

Acknowledgements

Before I started my PhD work, I asked a friend who just finished his PhD in petroleum engineering “What is the most essential thing you need for a successful PhD?” he answered “A passionate supervisor”. At this moment, I can say that he was completely correct. Throughout my academic career, I have never seen a supervisor so passionate about research as Dr. Tayfun Babadagli, so I would like to thank him for all the time he spent with me through what I may call a wonderful research adventure. I would like to thank him for sleepless nights where he stayed with me in the university until 11:30 pm to finalize a paper, and for meeting me during snow storms, weekends and vacations so I can advance in my research and meet my deadlines. Most importantly, I would like to thank him for spending his time and thoughts to help me initiate and complete this research.

I would like to thank the committee members Dr. Ergun Kuru, Dr. Daoyong Yang, Dr. Ryosuke Okuno and Dr. Qingxia (Chad) Liu, for taking the time and effort to go through this thesis. I am also thankful to the candidacy committee members Dr. Ergun Kuru, Dr. Vivek Bindiganavile, Dr. Zaher Hashisho, and Dr. Zhenghe Xu for their constructive comments and suggestions on the research outline in its early stages. Thanks are also extended to Dr. Japan Trivedi for his fruitful comments on parts of my research and, before that, for being such a wonderful friend. Thanks are also due to the technicians of Civil and Environmental Engineering

Department, School of Mining and Petroleum for their continuous help and support in assembling my experimental setup.

This research was partly funded by Natural Science and Engineering Research Council of Canada (NSERC) Grant (No: G121210595). The funds for the equipment used in the experiments were obtained from the Canadian Foundation for Innovation (CFI) (Project # 7566) and the University of Alberta.Thanks are extended to all organisations.

I would like to thank Computer Modelling Group Co. (CMG) for providing their software package for academic research. Special thanks are extended Abe Doroudi for his unconditional support on the numerical modeling part of this research.

I would like to thank Petroleum Development of Oman Co. for financing this PhD scholarship. Specifically, I am thankful to Dr. Suliman Al Hinai, Dr. John van Wunnik, Dr. Mohammed Al Kindi, Hamed Al Hadhrami, Dr. Said Al Busaidi, Khalid Al Rawahi, Suad Al Battashi and Asaad Al Muherzi for their continuous support during the construction of this thesis.

Two things I need every morning in the university, a hot cup of coffee and my friend’s smile. Khosrow Naderi, to make my day with his lovely smile every morning, deserves special thanks for this. Thanks are also extended to all former and current members of the EOGRRC research group for their support.

I would like to thank my wife for her support during this period. I am so grateful to my cousin Said Al Bahlani for his great moral support during the course of this research. I would also like to extend thanks to my family members in Oman for their thoughts and prayers during the course of this research, specifically my sister Dr. Shadia Al Bahlani who supported me on my studies since I was in my fourth grade all the way to the moment of handing this thesis. I would like to take this opportunity to express my heartfelt appreciation for teaching me that knowledge is the only asset that never parishes.

Finally, I would like to extend my appreciation to my mother Alya Al Rashdi for teaching me a true meaning of sacrifice, and how to be a good parent and for simply being her son. Last but not least, I would like to thank my four little angels, Al Baljaa, Al Julanda, Al Taqwa and Mohammed for being the light of my life. I am so grateful to Al Baljaa and Al Julanda for coming with me to Canada without their mother and other two siblings, and Al Taqwa and Mohammed for being patient about leaving their father and other two siblings. I hope that this period has conveyed a very important message that will stay with them for the rest of their life; “Knowledge is so precious that it requires great sacrifices."

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Chapter 1: Introduction

1. Introduction

1.1. Preface

The challenges which are introduced by carbonate reservoirs are mainly due to their complex fabric nature (low matrix permeability, poor effective porosity, vugs and fractures) and unfavorable wettability. Such challenges are further hardened when combined with increased depth and low grade oil (low API and high viscosity). Vast amounts of heavy oil and bitumen are contained in such reservoirs without any technological breakthrough for improving the recovery efficiently.

Steam injection (in the form of flooding, huff-and-puff, or steam assisted gravity drainage) is the only proven and the most commonly applied technology to produce heavy-oil through thermal means in homogenous sandstone reservoirs. Typical reservoir engineering approach in these applications is based on mobility reduction by reducing oil viscosity through effective heating, and by producing oil through viscous and gravity displacement.

This may not be applicable in fractured reservoirs due to extreme permeability contrast between rock matrix and fracture network, which makes viscous displacement impossible. A great portion of fracture reservoirs are carbonates and this type of rocks exhibits unfavourable (oil-wet or weakly water wet) wettability character. Wettability is a very important feature which controls the location, flow and distribution of fluids in the reservoir (Anderson, 1986) and directly controls the rate of matrix drainage. When these two effects, i.e., heterogeneous rock (complexity at different scales, i.e., faults, fissures, micro fractures, vugs, poorly interconnected matrix pore structure) and unfavorable wettability, are combined with high oil viscosity, oil recovery from this type of reservoir becomes a real challenge and classic thermal application theories fail to define the displacement process.

The main target in fractured carbonates reservoirs is the matrix oil as a great portion of oil is stored in porous matrix. Oil recovery from this type of reservoirs relies on drainage capability of matrix. Wettability is a critical factor controlling this drainage process in both immiscible (water or steam flooding) and miscible (solvent injection) displacement. It is essential to have a water-wet medium to drain matrix oil in fractured carbonates in immiscible processes. Carbonates, however, usually fail to meet this criterion and therefore are not eligible for this type of application. Alteration of wettability from oil-wet to water-wet may introduce technical and practical difficulties and yet theoretical aspects of this process are not well understood.

If waterflooding is not responding due to unfavorable wettability and low grade gravity of oil, recovery can be improved by reducing oil viscosity to enhance matrix drainage. As the matrix is still not water-wet enough to cause recovery by capillary imbibition, gravity is expected to be the governing force to drain oil. Thermal Assisted Gas Oil Gravity Drainage process (TA-GOGD) provides a glimpse of “hope” on getting better recovery by improving matrix oil recovery. An effective matrix heating is essential to enhance matrix-fracture fluid interaction and drainage of matrix oil in this type of process, however, the project life is still too long. Operationally, on the other hand, such recovery techniques are totally water dependent. The challenges are then not due to water injection / production only, but also logistically in terms of water availability and disposal. Yet, the oil recoveries are below the economical limit as the drainage is a slow process and the ultimate recovery from the matrix is expected to be relatively low.

Although part of the water may be treated and re-injected as steam, water treatment to insure 0 ppm of oil is expensive and risky for water boilers. These theoretical and operational challenges urge for a different approach in tackling heavy-oil recovery from fractured carbonates; hence, a new approach in this thesis hoping to help unlock such giant fields is introduced. Results of series experiments designed to test whether alternating injection of steam/hot water and solvent may be the way forward for research studies are presented an analysed.

1.2. Problem statement

Intensive amount of research was conducted to investigate the effects of steam injection on the mechanics of heavy oil recovery from homogeneous high permeability sandstones (Pratts, 1982). In homogeneous sandstone reservoirs, the recovery mechanism is mainly through displacement of oil by steam or hot water. However, in NFRs[1], the recovery is mainly based on gravity drainage achieved by heat introduction into the system causing oil to expand and drain from the tight low permeable matrix to the highly permeable fracture (Briggs et al., 1988, 1992; Reis, 1990; Babadagli, 1996a; Babadagli 1996b; 2002a).

For oil wet and fractured carbonate reservoirs, the use of steam –strictly speaking– does not yield fluid viscosity reduction only, rather a more complex process is observed. Reis (1992) classified two categories for oil expulsion from matrix block during steam injection; low temperature, and high temperature. Typical recovery mechanisms in low temperature steam injection are; capillary imbibition (40%), gravity drainage (30%), pressure depletion (5%), solution-gas drive (25%) and rock compaction (25%). For elevated temperatures, thermal expansion (17%), gas generation (25%), alteration of oil (1%), in-situ steam generation (25%), oil generation (50%), distillation (5%) and to some extend capillary imbibition (5%) are the typical recovery mechanisms. However, these values –as stated by Reis– do not represent the cumulative recoveries when they are combined together, which explains why some numbers are very attractive. The above listed mechanisms and their potential contribution to the recovery, however, indicate the complexity of the process of heavy-oil recovery from fracture reservoirs.

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[1] Naturally fractured reservoirs

Figure 1 obtained from (Babadagli and Bemani, 2007) clearly emphasizes the existing problem. A 1”x3” size oil-wet carbonate sample taken from the fractured-carbonate Qarn Alam (QA) field was saturated with 3,000 cp oil and was heated at 200^{o}C in an oven. At this temperature 16% initial water saturation is expected to be flashed out (see the case of QA5 at T = 200^{o}C and atmospheric pressure). If this value is subtracted from the total weight change before and after the heating experiment, the recovery is estimated to be 31% even at very ideal laboratory conditions (especially very small size matrix).

This translates into much lower values at reservoir conditions with much larger matrix blocks. An optimistic estimate was given as 26% ultimate recovery by Shahin et al. (2006) for field application.

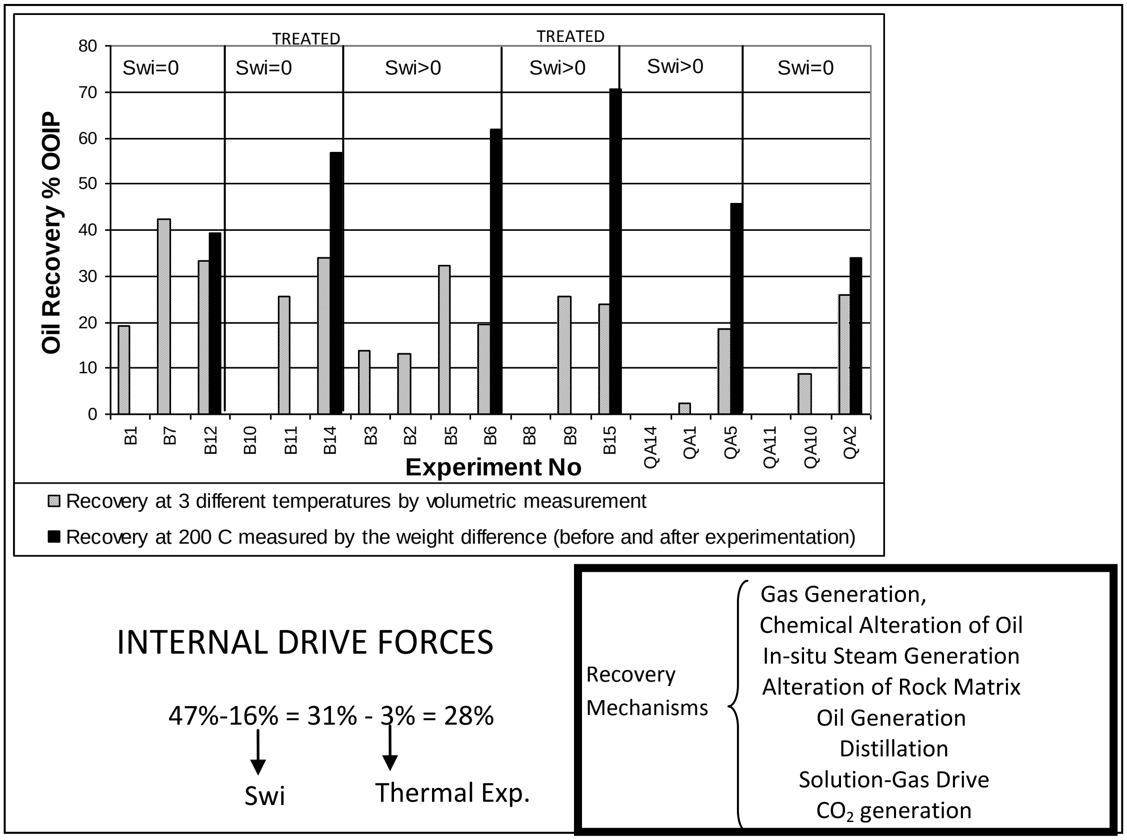

Figure 1: Experimental results on QA carbonate cores (Babadagli and Bemani 2007). B: Berea sandstone, QA: Qarn Alam carbonate cores. Method: Heating carbonate samples saturated with dead QA oil at different temperatures and observing positive recoveryby drainage and thermal expansion

These values for steam injection only in heavy-oil recovery from fractured carbonates are highly pessimistic to initiate any field scale applications even with high oil prices. Operations at less steam temperature and pressure and effective use of auxiliary materials (surfactants, polymers, solvents etc.) need to be studied to propose optimal conditions for heavy-oil/bitumen recovery from fractured carbonates or high permeability oil sands.

In conjunction with all these facts, steam injection in NFRs requires a massive amount of energy to heat large matrices which makes the efficiency of the process very low. Most –if not all– of the steam transfer occur in the highly permeable fracture network causing rapid steam movement within the reservoir. This may result in an early steam breakthrough and hence an extensive amount of energy consumed without efficient heating. This provides a substantial logistic challenge in terms of water availability, pre- and post- injection treatment, and disposal with minimal environmental impact. Also, gravity dominated process between immiscible fluids is very slow (low recovery that typically takes decades) which is very critical from an economic prospective. All these reasons make applying steam injection in NFR carbonates very rare.

In addition to the field scale applicability conditions, surface chemistry (wettability alteration) and thermodynamics of the process (phase behaviour of heavy-oil and solvents at elevated temperature and asphaltene precipitation) need to be identified and studied. The major issue is the complexity of the process as several different recovery mechanisms play a critical role during the hybrid application of heat and chemicals (surfactants, polymers or solvents) injection.

Chemicals (mainly surfactants) have been extensively tested as addition to steam but yet technically and economically they are still not viable. The current tendency is on solvents rather than IFT reducing agent to improve steam recovery efficiency in heavy-oil recovery. However, solvent injection cost and retrieval still remain as the main obstacles. Neither technique provides fully effective application with very low residual oil saturation and high recovery technique. Hybrid application of these two materials, heat and solvent, has been proposed for oil sands but, tests at the laboratory and field scales showed that it still required more research for the sake of optimization and selection of proper combination of solvent type and operational conditions.

The challenge is more severe when it comes to carbonates and fractured (low matrix permeability) system. Huge amount of heavy-oil /bitumen reserves are still waiting for an efficient technique for depletion of this oil. Reduced steam temperature and amount, less expensive solvent, high recovery rate and solvent retrieval are the main issues in this type of reservoirs. Especially, foe deep heavy oil reservoirs, one has to discover recovery techniques using low steam quality.

2. Proposed solution and methodology

In this thesis, we propose a hybrid application of steam (hot-water) and hydrocarbon injection to recover heavy-oil from oil-wet fractured reservoirs. This technique is called Steam-Over-Solvent injection in Fractured Reservoirs and patented in 2008 (Babadagli and Al-Bahlani, 2008). It relies on alternate injection of steam and selected hydrocarbon solvent. For applicability of the method in unfavorable conditions, especially deep and strongly oil-wet systems, low temperature (less than 100°C yielding hot-water) was used and experiments were applied on synthetically created strongly oil-wet outcrop sandstones or naturally oil-wet carbonates cores.

2.1. Hypothesis

The approach in constructing the method proposed was based on several hypotheses:

1) Oil can be produced from the matrix through thermal expansion and gravity drainage where substitution of oil by water may occur.
2) Water is considered as the non-wetting phase to the matrix, which reverses the role-play in water wet reservoirs where oil is the non-wetting phase. Hence, solvent introduction will lead to complex fluid flow behaviour of imbibition (solvent → water) and drainage (water → oil) which may boost the recovery process. In addition, the process will be enhanced through solvent diffusion into an oil saturated matrix improving the quality of oil.
3) Solvent diffusion into matrix can be enhanced by heating the matrix and then introducing cold solvent. This will cause solvent expansion resulting in solvent penetration into fracture which will cause oil to drain from matrix to fracture. Also, oil contraction will cause rapid solvent penetration into the matrix which may enhance solubility of oil and solvent.
4) After solvent diffuses into the matrix, matrix oil and fabric properties may alter which will make it possible to retrieve the solvent through another cycle of steam injection if the temperature of injected steam (or hot-water) is close to the boiling point of the solvent.

2.2. SOS-FR in brief

SOS-FR is a new approach, which was developed in early 2008 (Babadagli and Al-Bahlani, 2008; Al-Bahlani and Babadagli, 2008) for heavy oil production from fractured (especially oil-wet) reservoirs. It employs the advantage of both steam and solvent injection for efficient recovery of heavy-oil from fractured carbonate reservoirs. The main idea behind the technique is to create several thermal and chemical disturbances which will cause the system to readjust and hence expel oil from matrix to the fracture. Thus, an introduction of heat discrepancy between fracture and matrix will cause oil trapped in the matrix to thermally expand first. Depending on the wettability characteristics, a certain amount of water (condensed water from steam) will imbibe into matrix. Meanwhile, the reduced viscosity will accelerate the drainage of oil during this period and also condition the oil in the matrix for the next phase: Solvent injection.

After matrix heating to a certain degree, a chemical disturbance is created by introduction of light hydrocarbon solvent. This will cause solvent introduction into the matrix mainly by diffusion and interact with the conditioned oil in it, eventually causing several different process to displace and produce additional oil (mainly gravity drainage accelerated by density alteration due to diffusion and dispersion processes in the matrix).

Since the solvent is an expensive entity, it is very important to retrieve it. Thus, steam (or hot-water) is injected causing solvent to be expelled through thermal expansion and phase change (by boiling if the temperature is close to its boiling point) which will cause further oil and solvent to be produced.

Hence, the process is mainly divided into three main phases;

1) Phase 1: Steam (or hot-water) injection (for heating and thermal expansion mainly),
2) Phase 2: Solvent injection (for diluting the matrix oil by diffusion),
3) Phase 3: Steam (or hot-water) injection (for retrieving solvent penetrated into the matrix with some additional oil recovery).

3. Research objectives

- Clarify the applicability of alternating hot water and solvent injection on heavy-oil recovery from an oil wet matrix.
- Explore the main mechanisms involved in the process (imbibition, drainage, diffusion and dispersion).
- Examine the process in three scales; lab (experimental and numerical), field (numerical) and micro scale (visualization using Hele-Shaw cells).
- Study different solvent types and their effect on the rock and fluid properties.
- Study the effect of rock properties on the process (porosity, permeability and wettability).
- Identify fracture-matrix drainage through static and dynamic experiments.
- Examine the applicability of commercial computer modelling software to model the proposed method (SOS-FR).
- Wettability effect on overall recovery through thermal and non-thermal processes.
- Degree of solvent retrieval.
- Effect of initial water saturation on the production from oil wet cores.

4. Research methodology and organization of the thesis

To understand the physics of the proposed method and identify the critical parameters, a research methodology based on a series of experimental runs was developed. The whole program consists of two parts: (1) Static (no injection, only matrix behavior), and (2) dynamic experiments (injection through fractured samples).

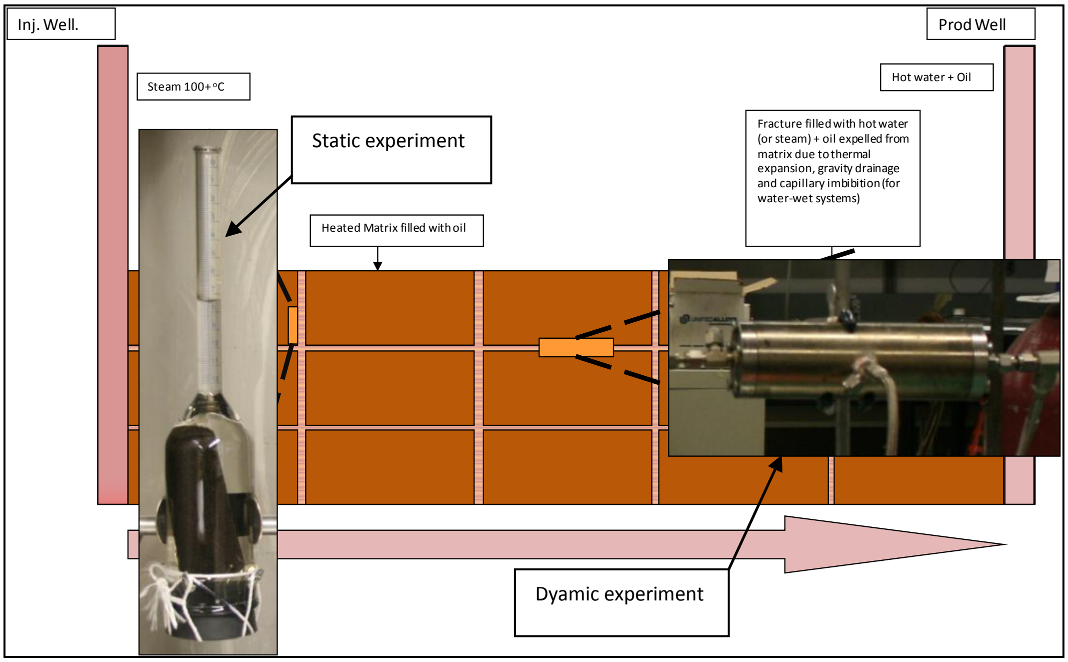

Figure 2: Experimental methodology using static and dynamic experiments and how they mimic the processes at reservoir conditions.

Figure 2 describes the process in naturally fracture reservoirs. As seen, the static experiments accounts for the matrix contribution to the recovery when it was exposed to fluid flowing in the fracture (steam, hot-water, solvent) without considering the effect of fracture parameters and injection rate. The dynamic experiments, on the other hand, are conducted to clarify the effects of injection rate and fracture properties, in a sense, yielding a more realistic picture of the process as a very small scale model of the field scale application. The experimental design and methodology are summarized below.

4.1. Static experiments

Static experiments refer to immersing a rock matrix element into the liquid that was expected to fill the fracture network to interact with the matrix oil. The main advantage of the static experiments is to study the physics of matrix-fracture interaction in its simplest form. This is a common and initial approach applied in the assessment of enhanced oil recovery potential of matrix element in naturally fracture reservoirs. Cores of different shape, size, wettability, and initial water saturation were subjected to the process composed of three distinct phases as listed above. The core plugs were immersed into hot water (90^{o}C) inside an imbibition cell to mimic Phase 1.

The reason for selecting this particular temperature range was twofold:

1) Experimental simplicity: For the initial tests, steam was avoided in order to run as many experiments as possible for different conditions and simplifications were needed. Steam experiments (temperature over 100^{o}C) require a special design of closed systems and this would limit the visual observations of the matrix behavior significantly.

2) It is safe to assume that most of the steam at deep naturally fractured reservoirs will have very poor quality once it arrives to the sandface. Therefore, designing a new recovery technique for pessimistic (low temperature – low steam quality) scenarios is critical. For shallow reservoirs, this also brings the advantage of low cost due to low quality steam. Note also that, as will be discussed later, the temperature range is critical in Phase 3 as it determines the solvent retrieval rate and should be near the boiling point of the solvent used. This reduces the high temperature needed in Phase 3 depending on solvent type.

Phase 1 was followed by Phase 2 in which the core plug was immersed into the selected solvent. The change in the color of solvent surrounded was monitored and refractometer readings were taken periodically to estimate the amount of oil recovered. Also, solvent was replenished periodically to mimic solvent supply during continuous injection of it at slow rates. After completing Phase 2, i.e., no significant color change occurred in the solvent surrounding the core, the core was placed into hot water at 90°C (the same apparatus as in Phase 1) in an attempt to retrieve the solvent diffused into the matrix.

In Chapter 2 preliminary static experiments were conducted to test the applicability of the designed experimental procedure on obtaining required objectives. Since wettability is one of the major issues which needs to be identified and tested before further proceeding with other experiments, several procedures to create oil-wet medium were compared: (1) Aging, (2) using synthetic wettability alteration agents, and (3) using original oil-wet cores from producing carbonate fields. All these cores were benchmarked against a water wet sandstone core plug. Also, the main hypothesis of solvent ability to improve oil production was also tested. The major question which this chapter answers is that whether the solvent used to improve oil recovery can be retrieved and how fast it would be.

In Chapters 2 and 3, more fine-tuned static experiments were reported. These experiments tested several different parameters: (1) solvent type, (2) different matrix sizes and boundary conditions, and (3) importance of prolonged Phase 1.

4.2. Dynamic experiments

For further numerical simulation studies to assess the process at field conditions, dynamic experiments are needed. Dynamic experiments were designed to examine the rate dependency effect on the process, mainly during the second phase. The injection rate controls both amount and time of contact between solvent in fracture and oil in matrix. More importantly, the dynamic tests provide a better control on injected/produced fluids and hence, a better insight into solvent recovery factor which is the most important factor considered in this process.

A core plug with an induced fracture in the middle was subjected to the three phases of the SOS-FR method. The variable in the dynamic experiment is the solvent injection rate. Dynamic experiments will also led to a good understanding of the solvent injection strategy at field conditions.

Chapters 3 and 4 provide a detailed procedure description and an in-depth analysis of the dynamic process. It also shows a quantitative analysis of the recovery in all three phases of the SOS-FR including solvent retrieval in Phase 3. Eventually, Chapter 4 correlates both static and dynamic experiments together and discusses the physics of the whole process as deduced from the core experiments.

4.3. Visualization experiments on Hele-Shaw cells

The objective of visualization Hele-Shaw models is to inspect the physics of the process visually. This includes visual examination of diffusion process between two fully miscible fluids and the effect of the presence of immiscible fluid on diffusion. The visualization models were also designed to examine the effect of boundary conditions on diffusive interaction between matrix and fracture, and to scrutinize the effect of gravity on the process, mainly by using vertically and horizontally situated models.

Chapter 5 provides a detailed visual analysis using Hele-Shaw cells of 2.5 cmx7.5 cm. After summarizing the details on model preparation and experimental procedure, the effects of orientation and matrix boundary conditions on the process were clarified and visually presented. One of the main aspects of this chapter is the visualization of solvent retrieval (Phase 3). Most of the hypotheses and observations obtained through core experiments were tested and confirmed/rejected visually.

4.4. Up-scaling and simulation model

Modelling such processes using existing available computer package software is not an easy task, especially with complexity of naturally fractured reservoir (dual porosity dual permeability model). Thus, the objective of the simulation model was to history match existing dynamic experiments and then upscale to field scale model to test the applicability of the process at reservoir conditions.

Chapter 6 provides a detailed procedure on how the dynamic experiments obtained in Chapter 3 were history matched. Numbers obtained through history matching exercise (pseudo dispersion coefficients) were used to further proceed for modelling larger matrices, i.e., field scale applications. In Chapter 7, field scale applications were tested for different injection schemes and an economic analysis was provided.

Figure 3 summarizes all these efforts and presents a summary of the research program followed in this thesis. This is a paper-based thesis and each chapter is a paper presented at a conference and/or submitted for publications. The papers are given in chronological order and each of them complements the preceding one(s). The specific research targets in each paper (or chapter) and its relation to the previous one(s) are shortly described in the beginning. Because this is a paper-based thesis, each chapter has its own introductions, references, conclusions, and nomenclature. However, a general "Introduction" section as well as a general literature survey to the whole thesis was provided in this Chapter. At the end of the dissertation, general contributions out of all these chapters (papers) and a discussion/future work were provided.

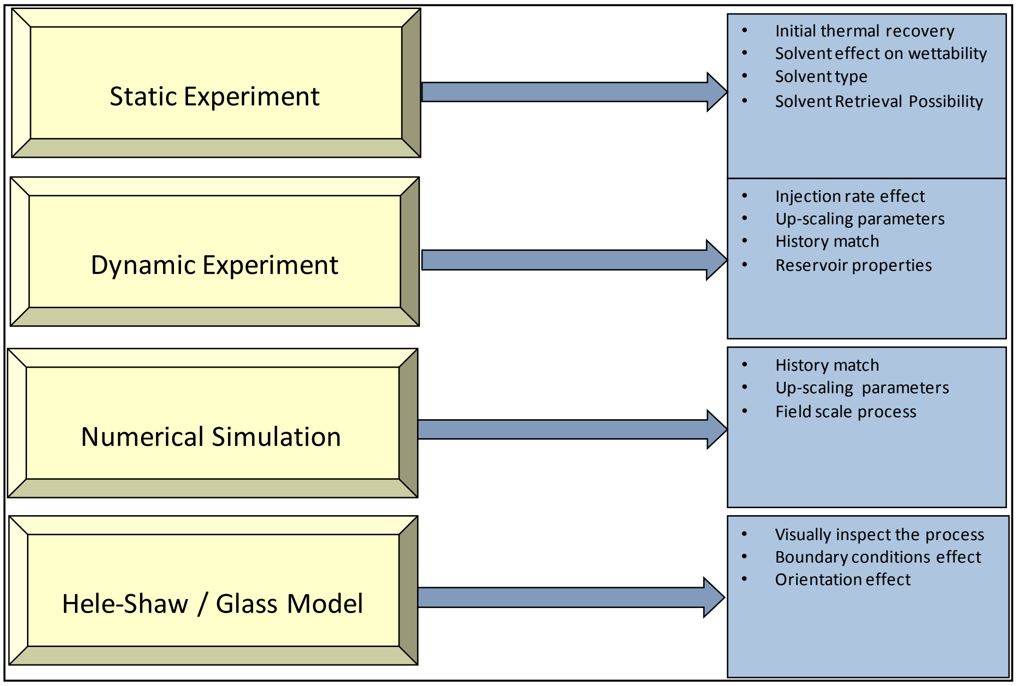

Figure 3: Schematic representation of the research program followed in this thesis.

5. Literature review

5.1. Field experience and related laboratory experiments

The applications of steam injection in fractured carbonates are very rare. To date, five published results of steam pilots in fractured carbonates: (1) The Lacq Superior field, France (Sahuquet and Ferrier, 1982), (2) The Ikiztepe field, Turkey (Nakamura et al., 1995), (3) The Yates field, USA (Snell and Close, 1999), (4) The Qarn Alam field, Oman (Al-Shizawi et al., 1997; Macaulay et al., 1995), and (5) The Bati Raman field, Turkey (Babadagli et al., 2008). Out of those, only the Qarn Alam project was switched to full field scale application (Penney et al., 2005; Rawnsley et al., 2005; Shahin et al., 2006). The main reason behind the limited number of projects initiated (and uncompleted) in the past is the inefficiency of the process, as the recovery is controlled by matrix drainage rather than by frontal displacement.

Pronounced amounts for matrix recovery in fractured carbonates based on laboratory scale experiments and field pilots are not very optimistic. For example, Babadagli and Bemani (2007) showed that the matrix drainage at very favorable laboratory conditions do not exceed 31% in challenging Qarn Alam cores containing heavy-oil. Obviously, this number will decrease too much lower values at field conditions. In fact, Shahin et al (2006) reported that the recovery only increases to 27% by steam injection through the process called TAGOGD (Thermal Assisted Gas Oil Gravity Drainage), and is only 4% without thermal assistance.

This recovery is with a very low cumulative Oil Steam Ratio OSR 0.2 over a period of 30 years. This implies that a significant amount of water, and hence an extreme amount of energy, is needed. The expected slow recovery rate was also reported by Macaulay (1995).

5.2. Wettability alteration

Alteration of wettability is one of the main problems in carbonates and water wetness is needed to enhance matrix drainage by gravity and capillary imbibition. It is importance rises from its effect on water imbibition as it is well documented in literature (Al-Hadrami and Blunt, 2001; Anderson 1987; Gupta and Mohanty, 2008; Motealleh et al. 2005; Rao, 1999; Seethepalli et al., 2004; Schembre et al., 2006; Zhou et al. 1996;). However, the issue of wettability is difficult to tackle without properly answering the question; what is wettability? Anderson (1986a) in his popular literature survey quotes the definition of wettability from Craig as "the tendency of one fluid to spread on or adhere to a solid surface in the presence of another immiscible fluid". Hirasaki (1991) tackles wettability from a thermodynamic prospective and examined the value of the contact angle as the water film collapse. He concluded that contact angle (representing wettability in this case) is strongly dependent on rock-fluid charges and water film thickness. Taking in consideration that wettability is much related to fluid-fluid and fluid-rock interfacial tension then it is fair to assume that incremental production from thermal production in carbonate reservoirs is due to reduction to interfacial tension more than the change in rock surface mineralogy. Through their experimental work, Zhou et al. (1996) showed that the rate of spontaneous imbibition is highly dependent on wettability. Motealleh et al. (2005) conducted lab experiments investigating wettability alteration due to steam injection. They aged carbonate rocks for 15 days and heated some with electrical heating to measure contribution due to thermal expansion. Other cores where then circulated with hot water and an increment in recovery was noticed. They concluded that this increment is due to wettability alteration; however, such increment may be due to other active steam injection mechanism such as gravity drainage.

5.3. Chemical attempts

Remarkable attempts were made to improve matrix recovery through chemical aids (mainly surfactants) in the past but finding the proper surfactant, as well the cost of the process limit the field application for carbonates (Austad and Standnes, 2003; Babadagli, 1996a; Babadagli, 2001; Babadagli 2002b; Babadagli, 2003a; Babadagli, 2003b; Babadagli, 2003c, Babadagli, 2005; Babadagli et al., 2005; Babadagli and Boluk, 2005; Babadagli, 2006; Chen et al., 2000; Hatiboglu and Babadagli, 2007; Michels et al., 1996; Spinler, 2000; Standnes and Austad, 2003; Standnes et al., 2002).

Surfactants (Standnes and Austad, 2003; Zhou et al, 1993) and steam heating (Al-Hadrami and Blunt, 2001; Gupta and Mohanty, 2008; Rao, 1999; Schembre et al., 2006; Seethepalli et al., 2004) were observed to achieve this to some extent. This, however, becomes more challenging as oil in the matrix gets heavier. In short, heavy-oil recovery from fractured carbonates (oil stored in the matrix) requires more sophisticated and efficient techniques. A very recent study showed that solvent diffusion (miscible flooding) into an oil-wet matrix could be used as an alternative to capillary imbibition (waterflooding) as the latter yields no recovery in economical time frames (Hatiboglu and Babadagli, 2008a-b). Both studies used light oil samples (up to 35 cp) and conducted experiments at ambient conditions. Heavier oil recovery would require additional heat energy to mobilize the oil.

5.4. SAGD for carbonate and fractured reservoirs

Unlike clastic reservoirs, very few attempts were made to explore the applicability of SAGD in carbonate reservoirs (Bahlani and Babadagli, 2008 and 2009). Yet, even those existing attempts are extremely simplified to the extent that jumping into “commercial conclusions” would be a fallacy. No study on any laboratory experiments investigating the physics of the SAGD process in carbonate reservoir (tight matrix with fractures or extremely heterogeneous structure with significant permeability change) has been notified in the literature. All presented attempts are of numerical simulation nature. However, there is no doubt that these attempts open a wide window for further investigations. Das (2007) conducted a 2D simulation model investigating Cyclic Steam Stimulation (CSS), conventional SAGD and Staggered SAGD in carbonate reservoirs. His model had an extreme heavy fractured reservoir with fracture spacing of 0.5 - 4 m. One of his interesting observations is that more steam went into the system with wider fracture spacing. He referred that to a higher fracture to matrix steam invasion. Beside this, larger matrix is present with wider spacing which implies the need for more energy to heat-up the matrix hence more steam would be injected. He then reported an average oil rate of 400 bbl/d and 34% recovery in 8 years which is very optimistic. He also reported an increase in SOR with higher fracture spacing. Sola et al. (2006) conducted a numerical simulation study on a field located in southern Iran. The model was directly transferred from GRID and from images provided a very coarse grid was used. Without showing production results, they concluded feasibility of SAGD application.

5.5. Application of SAGD with additional materials (solvents and non-condensable gases)

A novel approach, Expanding Solvent SAGD (ES-SAGD), was developed by Nasr et al (2003) at Alberta Research Council (ARC). Its main concept is the co-injection of hydrocarbon additive with steam at low concentrations. Solvent would condense with steam around the steam chamber interface causing oil dilution and viscosity reduction. A reduction was reported in steam oil ratio by up to 50% and solvent recovery of 95–99% in a 2D experiment. This process was tested by Suncor Energy in

Burnt Lake and Firebag. Petro-Canada is also planning to pilot solvent-SAGD in MacKay River.

2D experiments at ARC showed an improved oil recovery, enhanced non condensable gas production, lower residual oil saturation, and faster lateral advancement of heated zones. An important observation was reported by Nasr et al. 2003 where adding non condensable gases to live oil did not improve the process because of initial methane presence (Nasr et al. 2001, Nasr et al. 2003, Nasr and Ayodele 2006, Petro Canada website). From the images provided by Nasr and Ayodele (2006), we notice that ES-SAGD temperature was uniformly centred in the middle of the model compared to classical SAGD. This adds another point to the process where solvent may operate as insulator reducing heat losses and hence reducing the amount of gas needed. This solvent effect may have a greater role than viscosity reduction since at higher temperature further viscosity reduction may have only small effect. Such observation was also reported by Deng (2005). He pointed out that viscosity reduction was mainly from steam. He also noticed that higher addition of propane impedes heat transfer between steam and the oil zone. Deng (2005) conducted a 2D simulation model to experiment a steam/propane hybrid process. He observed that propane role was to maintain the reservoir pressure, which raises some questions about how solvent addition would affect reservoir geomechanics. Images provided from Deng (2005) simulation showed that addition of propane converted the steam growth shape from hand fan shape to a cupcake where better lateral movement was noticed compared to classical SAGD. However, one of the main issues unaddressed in ES-SAGD research is the effect of wettability and how would the process works in pore scale.

The theory of SAGD implies the condensation of solvent on steam chamber edges in sandstone reservoirs; however, due to hydrophilic nature of most clastic rocks condensed water will out-compete condensed solvent in terms of pore-scale mobility. One can thus expect a near wellbore effect of solvent rather than a full pair-scale. Also, papers suggesting the feasibility of ES-SAGD do not show solvent to original oil ratio. They only show the incremental oil production or reduced steam oil ratio. This can be very misleading if solvent recovered is not displayed. Also, the amount of solvent dissolved in oil due to diffusion/dispersion should also be addressed. Another concern with ES-SAGD is the possibility of water-emulsion creation on the interface. Such an emulsion can be very critical in fluid flow movement through a porous medium.

5.6. Steam alternating solvent

Steam Alternating Solvent (SAS) is a technique targeted towards replacing large amount of steam used in SAGD by solvent with the assumption that solvent can be recycled (Zhao et. al. 2005). Experimental tests were done to compare the effect of SAS on the process by injecting steam and solvent alternatively into a 2D high pressure, high temperature sand pack. The sand pack permeability was measured to be 115 Darcy and it has a porosity of 33%. The experiment concluded a 46% decrease in the consumption of energy per gram of produced oil with 96% of solvent retrieved (Zhao et. al. 2005). Simulation results showed that SAS can produce as high or higher than conventional SAGD. The authors attributed such performance to the further reduction of viscosity due to solvent injection along the chamber boundary (Zhao 2007). However, the question remains as to what extent solvent injection can reduce the viscosity at elevated temperature?

5.7. Liquid Addition to Steam for Enhanced Recovery (LASER)

Imperial Oil adopted the addition of liquid diluents (solvent) into some of their existing CSS[2] wells and named the technique as LASER (Liquid Addition to Steam for Enhanced Recovery). Their main objective is to improve the performance of CSS by the addition of a diluent that is already used to pipeline the produced bitumen. The pilot tests performed at Cold Lake reservoir showed an increase of 0.12 in Oil-Steam-Ratio (OSR) and this was attributed to the influence of LASER applied on 12 wells. The pilot also reported an 80% recovery of diluent from the first cycle where a large fraction was actually recovered from the venting facility (Leaute and Carey 2007).

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[2] Cyclic steam stimulation

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Chapter 2: Heavy-Oil Recovery in Naturally Fractured Reservoirs with Varying Wettability by Steam Solvent Co-Injection

This paper was presented at the 2008 SPE International Thermal Operations and Heavy Oil Symposium held in Calgary, Alberta, Canada, 20–23 October 2008.

1. Preface

In heavy-oil recovery, although steam injection has no alternative in many circumstances, it may not be an efficient process under certain reservoir conditions. These conditions include deep reservoirs, where steam injection may turn out to be ineffective hot-water flooding due to excessive heat loss, and oil-wet fractured carbonates, where steam channels through fractures without effectively sweeping the matrix oil.

Solutions for heavy oil recovery in consolidated/unconsolidated sandstones have been proposed and some of them are currently in the commercial phase, including steamflooding and its different versions. A more challenging case is heavy-oil fractured carbonates where the recovery is usually limited only to matrix oil drainage gravity due to unfavourable wettability or thermal expansion if heat is introduced during the process. Wettability alteration is usually thought to occur at elevated temperatures which are difficult to achieve in deep reservoirs. Thus, improvement of matrix oil recovery requires different methodologies. We propose a new approach to improve steam/hot-water injection effectiveness and efficiency for this type of reservoir.

Static imbibition experiments were run on Berea sandstone and carbonate cores with different wettabilities and for different oil viscosities ranging between 200 cp and 14,000 cP. For wettability alteration, cores were either aged or treated by a wettability altering agent. The experiments were conducted initially in imbibition cells in a 90 ^{o}C oven to mimic the matrix-fracture interaction in steam condensation zones. Due to its high boiling point, heptane was selected as the solvent and the core samples were exposed alternately to high temperature imbibition and solvent diffusion. The main ideas behind this process were to enhance capillary and gravity interaction by reducing viscosity (heat and solvent effect) and altering wettability (solvent effect). The results showed that further reduction in oil saturation due to solvent diffusion process preceded by hot water is remarkably fast and the ultimate recovery is high. The magnitude of recovery depends on wettability and the amount of water existing in the core. It was also observed that solvent retrieval is a very fast process and may increase to 85-90% depending on core type, wettability, and saturation history.

2. **Introduction**

Carbonate reservoirs introduce great challenges due to their complex fabric nature (low matrix permeability, poor effective porosity, fractures) and unfavorable wettability. These challenges are further displayed when combined with increased depth and low grade oil (low API and high viscosity). A huge amount of oil is contained in such reservoirs without any technological breakthrough for improving the recovery efficiently.

The main recovery mechanism in fractured carbonate reservoirs is matrix-fracture interaction. The most proven approach to produce heavy-oil reservoirs is through thermal means, specifically speaking steam injection. Yet, the typical reservoir engineering approach is based on mobility reduction by reducing oil viscosity through effective heating, and by producing oil through viscous and gravity displacement. This is valid in homogeneous sandstones. Carbonate systems, which are fractured in general, introduce rock complexity at different scales, i.e., faults, fissures, micro fractures, vugs, poorly interconnected matrix pore structure, etc. Wettability is also a very important feature which controls the location, flow and distribution of fluids in the reservoir (Anderson, 1986). When these two effects, i.e., inhomogeneous rock and unfavorable wettability, are combined with high oil viscosity, oil recovery from this type of reservoir becomes a real challenge and classic thermal application theories fail to define the displacement process.

Oil recovery from fractured carbonates relies on drainage of matrix where a great portion of oil is stored. Wettability is a critical factor controlling this drainage process in both immiscible (water or steam flooding) and miscible (solvent injection) displacement. It is essential to have a water-wet medium to drain matrix oil in fractured carbonates in immiscible processes. Carbonates, however, usually fail to meet this criterion and therefore are not eligible for this type of application. Alteration of wettability from oil-wet to water-wet may introduce technical and theoretical challenges if not well understood for specific cases. If wettability alteration occurs, it will occur mostly near the fracture and progress through the matrix as the elevated temperature front progresses through the matrix.

If waterflooding is not responding due to unfavorable wettability and low gravity of oil, recovery can be improved by reducing oil viscosity to enhance matrix drainage. As the matrix is still not water-wet enough to cause recovery by capillary imbibition, gravity is expected to be the governing force to drain oil. Thermal Assisted Gas Oil Gravity Drainage process (TA-GOGD) provides a glimpse of “hope” on getting better recovery by reducing matrix oil recovery. However, the project life is still long. Operationally, such recovery techniques are totally water dependent. The challenges are then not due to water injection / production only, but also on water availability and disposal. Yet, the oil recoveries are below the economical limit as the drainage is a slow process and the ultimate recovery from the matrix is expected to be relatively low.

Although part of the water may be treated and re-injected as steam, water treatment to insure 0 ppm of oil is expensive and risky for water boilers. These theoretical and operational challenges urge for a different approach in tackling heavy-oil recovery from fractured carbonates; hence, we introduce a new approach in this paper hoping to help unlock such giant fields. We present the results of preliminary experiments designed to test whether alternating injection of steam/hot water and solvent may be the way forward for research studies. The main hypothesis for such an approach depends on two major steps. First, oil can be produced from the matrix through thermal expansion and gravity drainage where substitution of oil by water may occur. Second, water in considered as the non-wetting phase to the matrix, which reverses the role-play in water wet reservoirs where oil is the non-wetting phase. Solvent introduction will lead to complex fluid flow behaviour of imbibition (solvent → water) and drainage (water → oil) which may boost the recovery process. In addition, the process will be enhanced through solvent diffusion into an oil saturated matrix improving the quality of oil.

2.1. Background and statement of the problem

As stated above, oil recovery from fractured carbonates is a challenging process. As the oil gravity goes down, heating becomes a necessity to mobilize the oil and steam injection is the only proven (end effective) thermal technique to achieve this. The mechanics of oil recovery by steam injection and displacement theories are well defined for homogeneous porous media (Pratts, 1982). The process and recovery mechanisms are totally different in fractured systems. The recovery is based on draining the matrix through heat introduced into the system rather than displacement by viscous or gravitational forces (Briggs et al., 1988, 1992; Reis, 1990; Babadagli, 1996a-b, 2002-a). Yet, this process is not well defined and the physics of it is not well understood. The efficiency of the process from the oil recovery time and economics points of view is also critical compared to homogeneous systems as the fracture network causes the rapid movement of steam resulting in early breakthrough without effectively heating the matrix.

For these reasons, the applications of steam injection in fractured carbonates are very rare. To date, we are aware of five published results of steam pilots in fractured carbonates: (1) The Lacq Superior field, France (Sahuquet and Ferrier, 1982), (2) The Ikiztepe field, Turkey (Nakamura et al., 1995), (3) The Yates field, USA (Snell and Close, 1999), (4) The Qarn Alam field, Oman (Macaulay et al., 1995, Al-Shizawi et al., 1997), and (5) The Bati Raman field, Turkey (Babadagli, et al., 2008). Out of those, only the Qarn Alam project has been switched to full field scale application (Rawnsley et al., 2005; Penney et al., 2005; Shahin et al., 2006). The main reason behind the limited number of projects initiated (and uncompleted) in the past is the inefficiency of the process, as the recovery is controlled by matrix drainage rather than by frontal displacement.

Pronounced amounts for matrix recovery in fractured carbonates based on laboratory scale experiments and field pilots are not very optimistic. For example, Babadagli and Bemani (2007) showed that the matrix drainage at very favorable laboratory conditions do not exceed 42% in challenging Qarn Alam cores containing heavy-oil. Obviously, this number will decrease to much lower values at field conditions. In fact, Shahin et al (2006) reported that the recovery only increases to 27% by steam injection through the process called TAGOGD, and is only 4% without thermal assistance. Note that the drainage process is rather slow (in the order of decades) as indicated by Macaulay (1995).

Those facts entail new methodologies to recover more oil at much faster rates. Remarkable attempts were made to improve matrix recovery through chemical aids (mainly surfactants) in the past but finding the proper surfactant, as well the cost of the process limit the field application for carbonates (Babadagli, 1996-a; Michels et al., 1996; Spinler, 2000; Chen et al., 2000; Babadagli, 2001; Babadagli 2002-b; Standnes et al., 2002; Babadagli, 2003a-b-c, Babadagli, 2005; Babadagli et al., 2005; Babadagli and Boluk, 2005; Austad and Standnes, 2003; Standnes and Austad, 2003; Babadagli, 2006; Hatiboglu and Babadagli, 2007).

Alteration of wettability is one of the main problems in carbonates and water wetness is needed to enhance matrix drainage by gravity and capillary imbibition. Surfactants (Zhou et al, 1993; Standnes and Austad, 2003) and steam heating (Rao, 1999; Al-Hadrami and Blunt, 2001; Seethepalli et al., 2004; Schembre et al., 2006; Gupta and Mohanty, 2008) were observed to achieve this to some extent. This, however, becomes more challenging as oil in the matrix gets heavier. In short, heavy-oil recovery from fractured carbonates (oil stored in the matrix) requires more sophisticated and efficient techniques. A very recent study showed that solvent diffusion (miscible flooding) into an oil-wet matrix could be used as an alternative to capillary imbibition (waterflooding) as the latter yields no recovery in economical time frames (Hatiboglu and Babadagli, 2008a-b). Both studies used light oil samples (up to 35 cp) and conducted experiments at ambient conditions. Heavier oil recovery would require additional heat energy to mobilize the oil. The main problem would then be the retention of the expensive solvent used.

This study focuses on this problem; heating the matrix to mobilize heavy-oil in an oil wet matrix, upgrading and then recovering it through the injection of solvent alternate to heating, and eventually retrieving the solvent from the matrix.

2.2. Methodology and objectives

To clarify whether injecting solvent alternately to steam to accelerate the recovery rate and improve the ultimate recovery is an efficient process, an experimental study was performed. A set of experiments were conducted and the objectives of the experimental work are listed as follows:

1) To clarify the applicability of alternating hot water and solvent injection on heavy-oil recovery from an oil wet matrix,

2) Wettability effect on overall recovery through thermal and non-thermal processes,
3) Possibility of solvent retention,
4) Effect of initial water saturation on the production from oil wet cores.

Meeting these objectives will provide clear insight on the next step towards tackling the challenging carbonate reservoirs (high viscosity, low permeability, fractured). Note that in the experiments, hot water was used instead of steam. The reasons behind this are two-fold: (1) To simplify experimental runs, so that more experiments could be run, and (2) to represent the worst case scenario as the steam will eventually turn to water phase in the reservoir and a great portion of the process in the project life will take place under hot water conditions. This more critical for deep reservoirs, which are not economically suitable for steam injection.

3. Experimental procedure

To achieve the goals outlined above, different combinations of experiments were designed. The procedure includes the following three phases:

Phase 1: Steam/hot-waterflooding phase (spontaneous imbibition): The core was immersed into 90^{o}C distilled water and left in a constant temperature oven until no change in the recovery was observed.

Phase 2: Miscible flooding phase (diffusion): The core was then left to cool to eliminate any heat left inside. For the oil wet case, this will cause the oil inside the core to contract and suck some water into the core. Next, the core was immersed into the solvent and the amount of oil matrix oil produced was recorded by both a refractometer and verified by weight measurements at the end of the experiment.

Phase 3: Steam/hot-waterflooding phase (spontaneous imbibition - solvent retention): The core was immersed again into hot water (90 ^{o}C) in an attempt to retrieve the solvent and/or recover of some portion of heavy-oil left inside the core.

4. Core preparation and saturation procedure

As seen in **Table 1**, ten experiments were carried out on different rock sample saturated with different oil viscosities. The combinations targeted testing of different viscosity oil, the importance of initial water saturation, and different wettabilities. Wettability was altered in two ways: (1) aging the cores for 6–8 weeks, and (2) using a wettability alteration chemical (Surfasil™ treatment, SST). The latter resulted in a very high degree of oil-wettability (strongly oil wet) whereas the former yielded relatively less wettability alteration (weakly-water wet).

The saturation procedure differed based upon initial water saturation type. If no initial water saturation was intended, the core was immersed into an oil-filled beaker placed in an oven and the system was attached to a vacuum pump. After full saturation was reached, which took a couple of days, the temperature was gradually decreased to the ambient conditions, keeping the vacuum pump on. If the core had initial water saturation, it was immersed into a 2% NaCl brine, and then connected to a vacuum. Once it was fully saturated with water, the core was flooded by around 10PV of brine followed by 10PV of heated oil. The saturation setup for the latter is shown in **Figure 1**.

Three different crude oil types were used at the viscosity range of 200 cp - 14,000 cp (**Table 1**). Heptane was used as the solvent phase. Brine used in the saturation of core is a 2% NaCl solution. The cores are Berea sandstone (20% average porosity and 350-550 mD average permeability). Each core was used only once to avoid any wettability change due to the cleaning process. The cores are assumed to have had similar petrophysical properties as they were plugged out from the same block. The carbonate sample used in only one experiment was a core sample of a producing formation. Its porosity and permeability are 29% and 10 mD, respectively. All cores are 3-in length and 1-in diameter.

5. Analysis and discussion

Snapshots taken during the three different phases are shown in **Figures 2** to **4**. The analyses of those phases for different experiments representing different core and oil types are given below.

Phase 1:

Four different cases representing Phase 1 only (hot water immersion) are compared in **Figure 5**. The cases represent Phase 1 (hot-water immersion). All water wet cores exhibited their expected behavior where water imbibed very fast into the cores causing a high recovery factor. The oil viscosity was the controlling parameters on the rate of recovery and residual oil saturation. Oil wet cores, however, displayed an expected behaviour where the ultimate recovery was very low and took a much longer time to reach the plateau. This recovery was mainly from thermal expansion and gravity drainage. As thermal expansion is not expected to exceed ~10% recovery for this temperature range and the total recoveries of for the oil wet cases are greater than this value, other mechanisms need to be considered to account for the additional recovery. The gravity drainage could be major cause as the alteration of wettability due to thermal effects was not expected in the case of Surfasil treated (SST) cores to cause a remarkable recovery by capillary imbibition.

Initial water is a critical factor not only in the capillary imbibition but also in the diffusion process. Existing water in the system could be a barrier to the transport of solvent in the system through diffusion. Therefore, the effect of initial water was also considered in the experimental program and the results of the four cases for Phase 1 are shown in **Figure 6**. Comparing the effect of initial water saturation presence, initially, the recovery is faster for the $S_{wi}=0$ cores. This observation is in disagreement with the isothermal imbibition experiments (Hatiboglu and Babadagli, 2007 and 2008-a; Naderi Babadagli, 2008). This could be attributed to the following processes occurring during the initial phase of the experiment: (1) oil is trying to leave the rock because of thermal expansion, and (2) water is trying to enter the rock through the initial water phase. Those two counter forces slows down the imbibition in the $S_{wi}>0$ cases. Eventually, ultimate recovery reaches higher values for the initial water experiments due to relatively stronger capillary imbibition. The graph given in **Figure 6** is included to give an idea about the level of initial matrix production for oil wet system under thermal effects.

When the strongly oil wet cores are left to cool at the end of Phase 1, oil tends to contract; hence, some amount of water intrudes into the system. The *tube model* shown in **Figure 7** illustrates this process. This assumption is made based on the non-occurrence of wettability alteration in both cases. It must be remembered here water in this case is not the wetting phase; hence, water drops are not attached to the grain. This notification is important since it will be needed to explain other behaviors in Phase 2. Note also that the cooling off period was intentional to consider the cooling period during switching operation from the thermal (steam/hot water injection) to the miscible (solvent injection) phase in the field.

Phase 2

Figure 8 compares different cores for the same viscosity oil (the highest viscosity -14,000 cp- used in the experiments). When the SST and the carbonate cores are compared, it can be seen that permeability has a profound effect on production. The carbonate core produced 10% oil in the Phase 1, which is approximately equal to the expected thermal expansion recovery at this temperature. The 10% addition recovery from the SST core in the same phase could be attributed to capillary imbibition and gravity drainage recovery, which is expected to be relatively faster than the carbonate case due to much higher permeability. Note that the oil density, which is very close to that of water at room temperature, will be reduced at 90 ^{o}C and this will accelerate the gravity drainage process. The amount of oil recovered by diffusion during Phase 2 for both SST and carbonate cases (the right side of the arrows in **Figure 8**) is almost the same for both cases. Likewise, the diffusion recoveries for the other two cases in the Phase 2 (water wet and aged) are almost the same indicating the independence of it on the wettability.

During Phase 2, several other observations were recorded. As indicated in **Figure 7**, some amount of water intrudes into the core during the cooling off period due to very weak capillary imbibition. When the core is exposed to solvent (Phase 2) solvent not only diffuses into the matrix to mix with oil, it also enters the matrix to displace this water by capillary imbibition as the core is strongly oil wet. This caused a small amount of water production. **Figure 9** shows water droplets in the solvent filled beaker coming out of the core. This process was schematically presented in **Figure 10**.

A similar behavior was observed when initial water exists in the system. As seen in **Figure 11**, oil wet cores with initial water saturation recovered the oil faster than the cores with no initial water saturation. This cannot be explained by considering diffusion only; rather, the process is much more complex. From the assumption made in analysing Phase 1, we postulate that three processes occur during Phase 2 in oil wet cores, namely diffusion, imbibition and drainage. The process can be de-coupled into two sections; (1) displacement of water in the system by solvent (capillary imbibition), and (2) displacement of oil by water. As the water is the non-wetting phase in this process, the rock grains favour the movement of an oleic phase. Thus solvent will imbibe into the rock, pushing the water out and this water will drain some amount of oil out of the core. This resulted in water droplets seen inside the solvent containers as shown in Fig. 9. However, when it comes to the water wet case, water will impede the transport of solvent, as can be inferred from **Figure 8**, resulting in a slow recovery of the residual oil developed after Phase 1 (around 27%). As water is the wetting phase in this case, and grains favour the attachment of water than oil, other displacement of oil by water is not expected. The recovery here is mainly diffusion controlled, which is a rather slow process.

In short, the main observation in Phase 2 is the high increment of oil production when the oil wet core is immersed into solvent (Figs. 8 and 11). This is highly promising for practical applications as the recovery time could be a critical factor in commercial applications. Note, however, that matrix size is one of the parameters controlling the rate of the diffusion process and the laboratory scale process should be up-scaled to the reservoir scale to determine the optimal application conditions. This part of the research is on-going.

Phase 3

The observations made through Phases 1 and 2 and analysis done so far suggest that the process proposed in this paper is highly promising to recover heavy matrix oil from oil wet fractured carbonates. Note, however, that valuable solvents are needed for this process to produce less valuable heavy-oil. Therefore, the retrieval of solvent is the next issue to deal with. Phase 3 was designated to retrieve solvent and extra oil left in the matrix. In this phase, the cores were placed in hot water (90 ^{o}C) again. It was interesting to observe that the recovery of solvent+matrix oil left was extremely fast, completed in the order of minutes (**Figure 4**). Within a few minutes a very fast bubbling was noticed with difference in the shapes/sizes and densities for different wettability samples. To compare the time scale of the process, one may compare this recovery rate with the recovery time given in **Figures 8** and **11**. The bubble size was much smaller in the water-wet case and the amount recovered was expectedly lower. In the oil-wet case, however, the bubbles were much bigger and the recovery was as fast as it was in the water wet case. In all experiments, a small amount of additional matrix oil was produced, indicated by the color of oil produced. A great portion of oil was recovered in the minute scale and the bubbling continued at a lower rate and fully stopped within a day.

Figure 12 illustrates the final recoveries after Phases 1 and 2. A great portion of heavy matrix oil was recovered during Phase 1 in the water wet cases. Though the process was longer compared to the oil wet cases, Phase 2 yielded considerable additional recovery. In the oil wet cases, however, most of the recovery was due to Phase 2. The average recovery for all cases at the end of Phase 2 was around 85-90%. During Phase 3, some portion of the oil left (indicated by yellow in **Figure 12**) was recovered along with the solvent. The solvent recovery at the end of Phase 3 was observed to be around 80-95% depending on the wettability of the sample. The solvent retention was surprisingly higher in the oil wet cases compared to the water wet ones.

Another interesting observation was made during experimentation, which seems to be a critical issue. Some form of powder like substance which we believe it is clay has formed during Phase 2 (**Figure 13**). Although a huge impact was not noticed on production, this may have further effects during field scale applications where it can block the pores or at least restrict the flow in the fracture. This may only be determined through dynamic tests and by understanding the nature of such substance (XRD and SEM tests). This is an on-going part of the research.

6. Conclusions and remarks

A new approach for heavy-oil recovery from oil-wet fractured carbonates was presented in this paper. Preliminary experimental results suggest that efficient oil recovery is possible using alternate injection of steam/hot water and solvent.

The following specific conclusions can be withdrawn from this research:

1) Steam alternating solvent may introduce a new path towards unlocking the carbonate oil wet deep reservoirs. Unfavorable wettability limits the matrix recovery to mainly thermal expansion in oil wet fractured reservoirs when only steam injected. Other processes are too slow to be economic. The use of solvent as an alternate to steam/hot-water injection results in a fast recovery with reasonably low residual oil saturation.
2) It would not be an overstatement to claim that the most exciting part of the observations was a very fast retrieval of solvent from the matrix when the sample contacted with hot water in the third phase of the process. This could be considered as motivation to further investigate the applicability of this method, as it has profound effect on the economic feasibility of the process.
3) In case of the existence of a two phase (oil and water) system inside the oil-wet rock matrix, a complex

imbibition-drainage process might be a governing recovery mechanism in addition to the recovery by diffusive (mass transfer) matrix-fracture interaction.

4) Fines may have a profound role in blocking pore throats when solvent is introduced into the matrix.
5) The results present the hot-water phase of steam injection and from this perspective, it could be considered as the worst case scenario for a steam injection application. This also implies that the methodology suggested could be a solution to ineffective steam injection in deep reservoirs where steam injection would eventually turn out to be hot water injection due to excessive heat loss.
6) A critical parameter that would affect both the recovery rate the ultimate recovery is the matrix size. The cores used in the experimentation were at the laboratory scale (3” in length and 1” in diameter) and they yielded very fast heavy-oil recovery and solvent retrieval. As the matrix size gets larger, the dynamics of the process will be influenced negatively and this effect should be quantified. This is the on-going part of the research.

The process suggested can open doors towards the efforts unlocking the large fractured heavy oil carbonates field and the preliminary experimental results provided the way forward for the further research in this area. The next step to further understand this process is through micro-model visual experiments and static/dynamic experiments on larger cores. The former will provide insight into the dynamics of the process, especially from wettability alteration and effective mechanisms points of view. The latter, on the other hand, will shed light on the application protocol in the field, i.e., single well (huff and puff) or multi well (continuous injection) development. Then the proper cycles or injection schemes could be determined based on oil and reservoir characteristics (more specifically matrix-fracture properties) to optimize the process.

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Table 1: Rock and fluid properties used in the experiments. SST: Surfasil treated.

Core	Wettability			Viscosity			Initial Water Saturation
	Oil Wet		Water wet	14000	2400	200	Swi
	SST	Aged					
V14000-S0-SST	x			x			0
V14000-S0-AG		x		x			0
V14000-S0-Car	Carbonate			x			0
V14000-S1-WW			x	x			15
V2400-S1-WW			x		x		9.4
V2400-S0-SST	x				x		0
V2400-S1-SST	x				x		7
V200-S0-SST	x					x	0
V200-S1-WW			x			x	11
V200-S1-SST	x					x	7.5

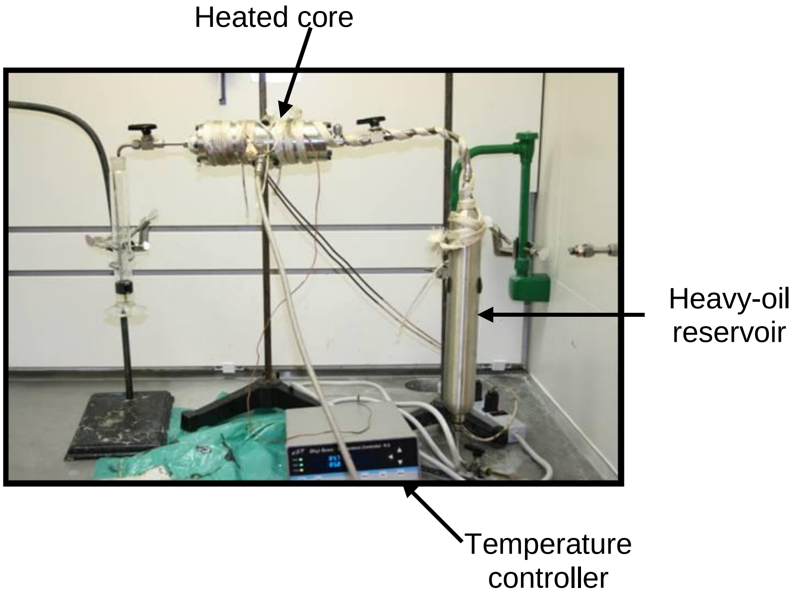

Figure 1: Saturation setup for the S_{wi}>0 cases.

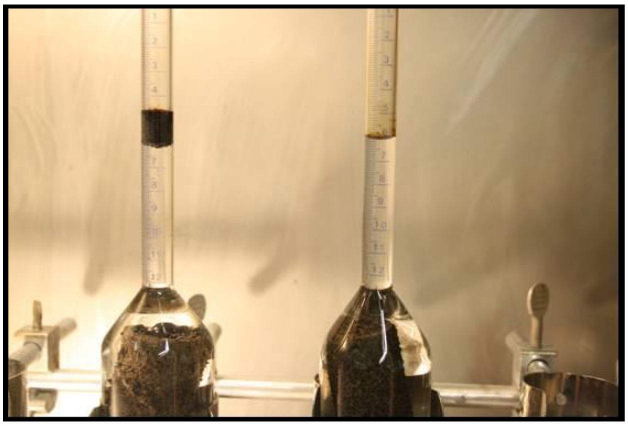

Figure 2: PHASE 1: Two cores in the imbibition cells located in a 90 °C oven. The core to the left is water wet and the core on the right side is oil wet. Notice the difference in production even though they were started at the same time. Even thermal expansion recovery was less than expected due to extremely high viscosity of oil.

Figure 3: PHASE 2: Two cores immersed into solvent. The core to the left is water wet; the core to the right is the oil wet. The difference in color intensity represents production of heavy matrix oil. The water wet sample yields less diffusion (and less recovery) due to existing water from Phase 1 compared to the oil wet case and therefore the color is lighter (left side) whereas the oil wet sample yields higher oil production indicated by much darker color (right side).

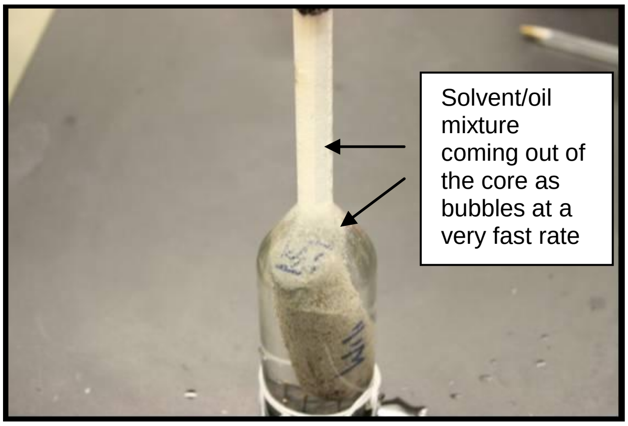

Figure 4: PHASE 3: Bubbles represent solvent leaving the core immediately upon contacting hot water at 90°C (water wet core). This process was observed to be faster and the bubbles were much bigger in size for the oil wet case.

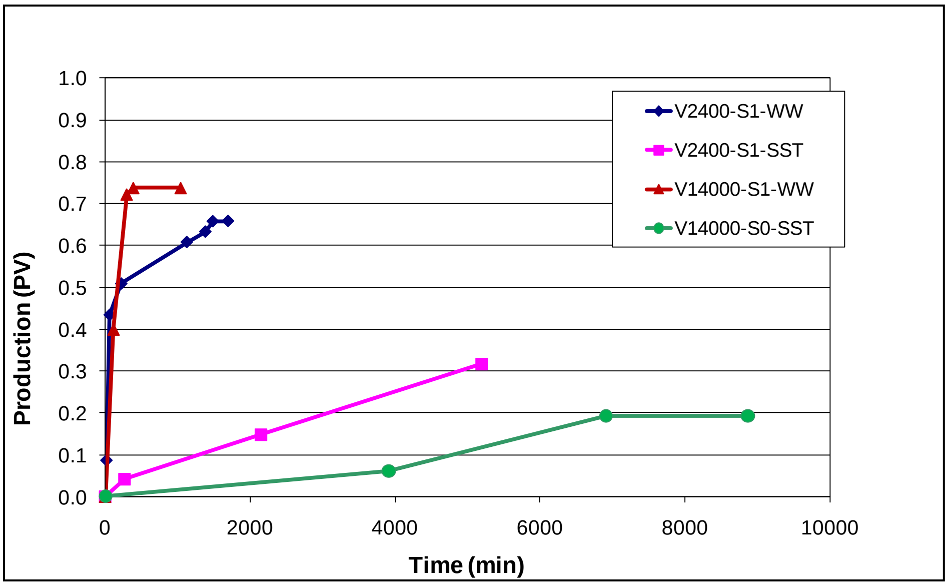

Figure 5: Effect of wettability on Phase 1; water wet cores produce mainly from capillary imbibition and oil wet cores produce due to thermal expansion and possibly gravity drainage.

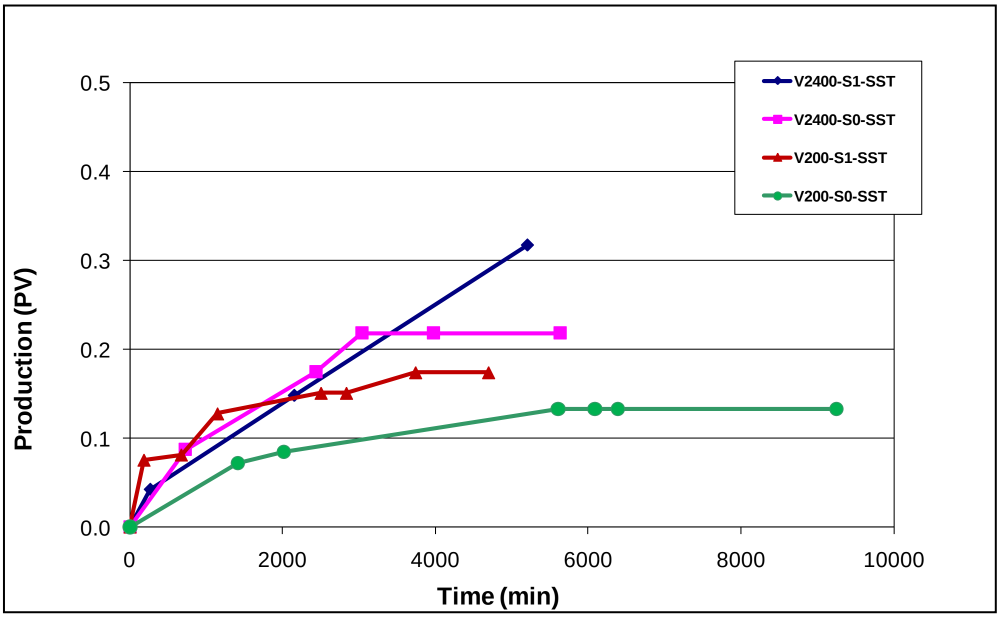

Figure 6: Effect of initial water saturation in oil wet cores for Phase 1.

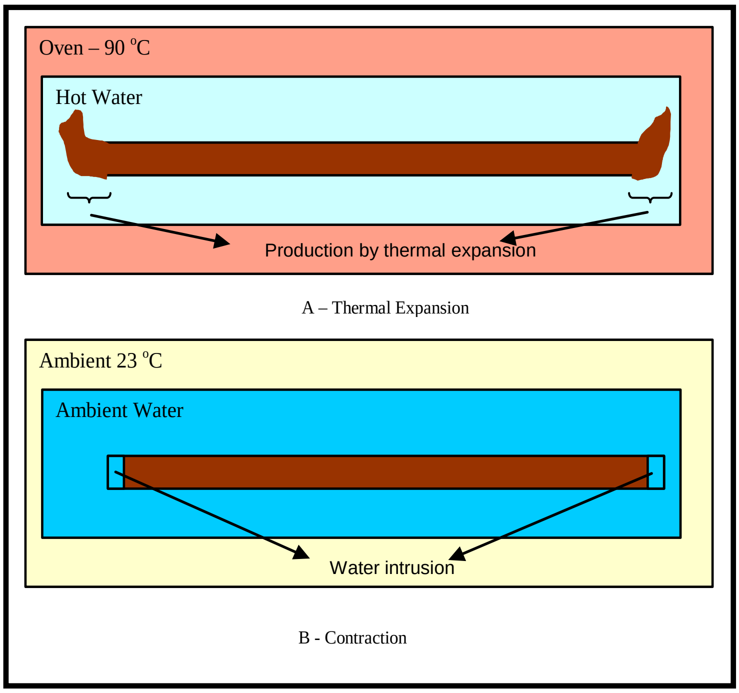

Figure 7: Sketches representing water intrusion into the system by oil contraction when the system is cooled from 90 °C to 23 °C.

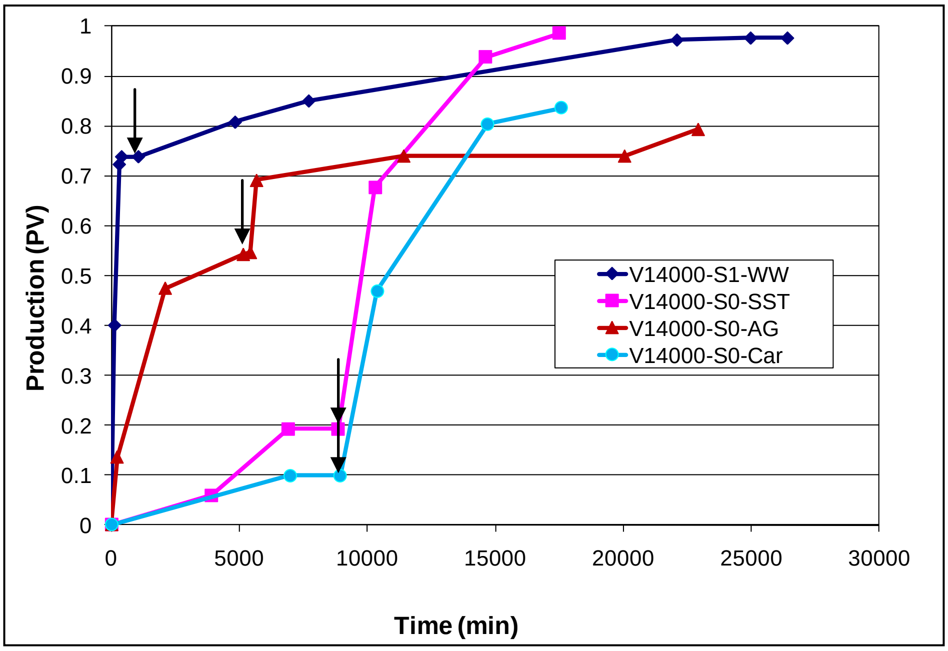

Figure 8: Comparison of oil wet and water wet cases for Phase 1 (hot water immersion) and Phase 2 (solvent immersion). Arrows indicate the starting point of Phase 2.

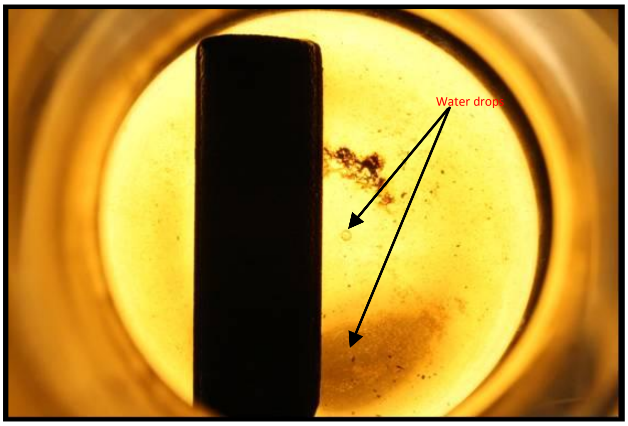

Figure 9: Water droplets coming out of core due to solvent imbibition into water filled pores during Phase 2.

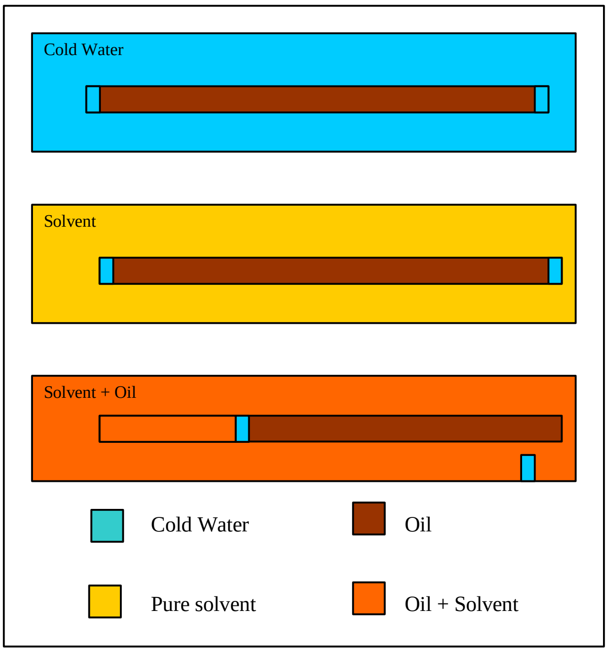

Figure 10: Sketch illustrates presumed solvent imbibition inside the oil wet core displacing water.

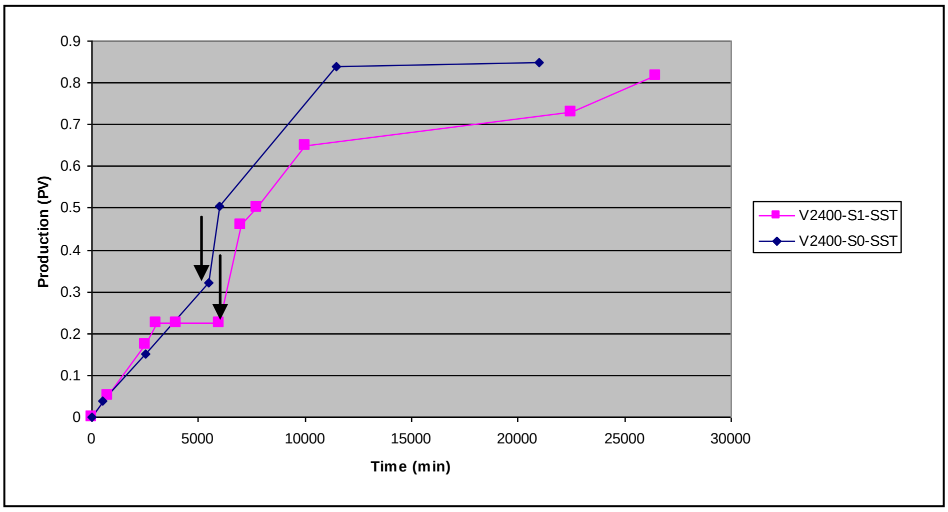

Figure 11: Comparison of the two oil wet cases, with and without initial water (Phases 1 and 2). Arrows indicate the starting point of Phase 2.

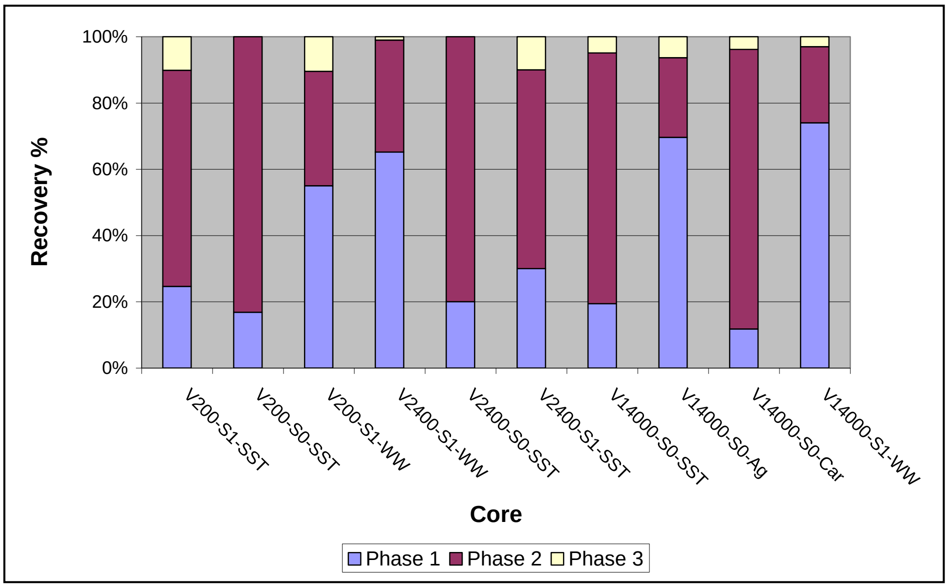

Figure 12: Final oil (heavy matrix oil) recoveries obtained through Phases 1, 2 and 3 for all experiments.

Figure 13: Powder like substance observed at the end of experiments. It is believed that it is clay+asphaltinic components formed during Phase 2.

Chapter 3: Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR) for Heavy-Oil Recovery: Experimental Analysis of the Mechanism

This paper was originally presented at the 2009 SPE Asia Pacific Oil and Gas Conference and Exhibition held in Jakarta, Indonesia, 4–6 August 2009. This version has been submitted to *SPE Reservoir Evaluation and Engineering*

1. Preface

Heavy oil trapped in fractured carbonate reservoirs possesses a great challenge to the petroleum industry due to high oil viscosity, low matrix permeability, and unfavorable wettability of the matrix. Thermal recovery methods (mainly steam injection) show a promising way forward to unlock these reserves. Yet, previous experiences revealed that heating the matrix to drain heavy-oil by gravity is a slow and inefficient process due to low matrix recovery caused by unfavorable matrix properties (oil wetness and low permeability). Acceleration of matrix-fracture interaction by changing the matrix and oil properties could be possible by injecting the proper hydrocarbon solvent alternately with steam as reported in our earlier work (SPE 117626). This process, called Solvent-Over-Steam injection in Fractured Reservoirs (SOS-FR), consists of several cycles, each having three phases: (1) steam/hot water injection, (2) solvent injection, and (3) steam/hot water injection.

This paper reports a detailed experimental analysis of this new method. Static and dynamic tests were conducted by exposing heavy-oil saturated fractured rocks to hot water and solvent alternately. Oil-wet sandstone and carbonate samples were saturated with heavy-crude oil and tested against different solvents, namely heptane, kerosene, decane and light crude. Fractured cores were tested under dynamic conditions with different solvent injection rates to explore the rate dependency of the process. The physics of the injection rate and the role of asphaltene as a bi-product were examined and discussed.

Understanding the physics of this new technique will contribute to the development of an alternative method at field conditions for unlocking trapped heavy matrix oil from oil-wet, fractured, and deep carbonate fields.

2. **Introduction**

Heavy oil/bitumen production from fractured reservoirs (especially oil-wet carbonates) is considered one of the greatest challenges to the petroleum industry. The combination of unfavorable flow and accumulative properties urged researchers to pursue novel and innovative methods to overcome these challenges. Yet, an acceptable solution is far from reach, and intensive research efforts are underway where several suggested solutions are in the developmental stage, but have not yet been proven.

In order to surmount these challenges, thermal methods were introduced to reduce the viscosity and hence enhance oil mobility. However, the main challenge in these methods of heavy oil /bitumen recovery is the efficiency of the process. Steam injection is the only proven way to achieve this technically but an enormous amount of energy is required to heat the reservoir and mobilize the matrix oil. Even with the cost effectiveness of steam injection due to high oil prices, the environmental effects posed by high amounts of CO2 emission, as well as operational problems, are still major challenges. All of these require more research effort to propose ways to reduce the amount and cost of steam and/or to improve recovery effectively for more efficient applications.

In heavy oil/bitumen recovery from sandstones, chemicals (mainly surfactants) have been tested as additions to steam but technically and economically, they are still not viable. The current tendency is for solvent, rather than the IFT reducing agents, to improve steam recovery efficiency in heavy-oil/bitumen recovery. In carbonates which are generally oil wet, wettability alteration is a critical problem as matrix oil recovery through capillary imbibition and gravity drainage is controlled mainly by its wettability. Wettability alteration in such reservoirs was studied at elevated temperatures (Anderson 1986; Zhou et al., 1996; Motealleh et al., 2005; Rao, 1999; Al-Hadrami and Blunt, 2001; Seethepalli et al., 2004; Schembre et al., 2006; Gupta and Mohanty, 2008; Zhou et al., 1993). High temperatures will break the bond between organic matters attached to the rock surface and alter the wettability to water-wet which will promote water imbibition and hence a sandstone-like thermal production. However, wettability alteration by the latter means can only be achieved at elevated temperatures, which bring us to the same initial issues: a high amount of steam and a large carbon foot print.

Reis (1992) classified two categories for heavy oil expulsion from sandstone and carbonate matrix block during steam injection: (1) low temperature and (2) high temperature. Typical recovery mechanisms in low temperature steam injection are: capillary imbibition, gravity drainage, pressure depletion, solution-gas drive and rock compaction. At elevated temperatures, thermal expansion, gas generation, alteration of oil properties, in-situ steam generation, oil generation, distillation and to some extent capillary imbibition are typical recovery mechanisms.

Babadagli and Al Bemani (2007) reported experimental evidence as to the recovery mechanisms from carbonates at high temperatures. They conducted experiments using 3,000 cp oil in an oil-wet carbonate matrix (3” in length and 1” in diameter) taken from the fractured-carbonate Qarn Alam field. They subjected the rock to heat and measured the oil release capability. The recovery potential was observed to be 47% OOIP at very ideal laboratory conditions (200oC and atmospheric pressure). An estimation of matrix recovery in the same field was given as 26% ultimate recovery by Shahin et al. (2006) based on their field pilot test observations and numerical model results. These values for steam injection only in heavy-oil recovery from fractured carbonates are promising but they translate into much lower values at reservoir conditions with much larger matrix blocks. New efficient methods need to be tested for heavy-oil/bitumen recovery in fractured carbonates.

As such, the challenge is more severe when it comes to carbonates and fractured (low permeability) systems. Huge amounts of heavy-oil/bitumen reserves are still waiting for efficient techniques for depletion of this oil. Reduced steam temperature and amount, less expensive solvent, high recovery rate and solvent retrieval are the main issues in this type of reservoir. Due to their depth, for marginal reservoirs for steam injection especially, one has to discover recovery techniques using low steam quality.

Solvent has been used in the petroleum industry for stimulation purposes in low gravity oil recovery for a long time. The main purpose was initially to (1) wash out particulate matter, (2) dissolve viscous deposits, (3) dilute the viscous crude and (4) demulsify (Harris and Coppel, 1969). Solvent injection as a mean of recovery was discussed earlier by Doscher (1967) for the Athabasca tar sands. He outlined several issues that the industry encountered with in-situ recovery by means of solvent injection that can be classified as (1) viscous fingering and gravity overlay and (2) high cost of solvent. For hydrocarbon solvents, Farouq Ali (1976) noted two important impediments of solvent injection: (1) a large volume of solvent must be employed and (2) formation plug due to asphaltene flocculation.

The hybrid application of heat and solvent was proposed more recently for oil sands but tests at the laboratory and field scale revealed that more research is required for the sake of optimization and the selection of a proper combination of solvent type and operational conditions. The use of solvent for heavy oil production was tested earlier at both lab and field scale (Miller et al., 2003; Zhao 2007). Jurinak and Soni (1987) conducted a numerical simulation to show the effect of solvent co-injection with steam in fractured assisted steam flood technology. They showed significant improvement in oil recovery (an increase from 31% to 54 %) and reduction in steam oil ratio (a drop from 7.06 to 4.03) during the steamflood process after injecting 1PV of solvent with 4PV of water.

This paper focuses on a new approach in producing heavy oil from fractured carbonate (oil-wet) reservoirs. It presents a combination of thermal (steam/hot water) and solvent injection into the reservoir which presents a complicated yet effective process in improving heavy oil recovery. The experimentation of such a hybrid technique is a difficult task especially under dynamic (injection) conditions and requires significant care for accurate data collection (mainly due to changing oil properties through heating and solvent mixing). To our knowledge, this is the first attempt of dynamic experiments at elevated -constant- temperature with involvement of solvent on fractured rock samples. Previous experimental experiences were on sizable sandpack or glassbeads models. Due to these facts, several challenging experimental obstacles were faced and the way they were overcome is also reported in this paper.

2.1. Objective of the study

In our previous attempt (Al-Bahlani and Babadagli, 2008; Babadagli and Al-Bahlani, 2008), we introduced a new method called Steam-Over-Solvent injection from Fracture Reservoirs (SOS-FR) to produce heavy-oil from fractured reservoirs. The initial results obtained from the static experiments showed the viability of this technique. Our first objective is to extend this work for more detailed experiments under static conditions to mimic heavy-oil recovery from the matrix portion of a naturally fractured reservoir. Static experiments are relatively easier to conduct and play a critical role in identifying the enhanced oil recovery (EOR) mechanisms and are useful in obtaining initial information about any EOR process (ultimate recoveries, dynamics of matrix oil recovery, etc.). They reveal valuable initial information about the viability of the process but they are run under an “infinite supply” of injectants like water, steam, or solvent, as the samples were soaked into the cells filled with these fluids. A more realistic approach would be the dynamic version of these experiments, i.e., injecting the fluids (water, steam, or solvent) at a certain rate through the fracture to recover matrix oil. This will also enlighten the way this process can be run in the field, the continuous injection or cyclic injection and the economics of the process. Soaking time is important for the solvent injection phase especially (called Phase 2 in the SOS-FR technique in the earlier study by Al-Bahlani and Babadagli, 2008) as the solvent diffusion into the matrix is a rather slow process. This can be achieved through cyclic injection but enough solvent may not be supplied through this method as needed. Then, dynamic injection accelerates the process, but optimal injection rate range should be selected for the efficiency of the process. Hence, dynamic experiments were designed to compare the results in terms of the process time and the amount of solvent injected to finally make a decision about the field scale applications.

The procedure followed in the reported research is as follows:

- Examine the effect of different types of hydrocarbon as solvent: Different paraffinic solvents were tested for the cost (and the efficiency) of the process (static experiments).
- Run experiments under different matrix boundary conditions and identify the contribution of different recovery mechanisms, especially gravity drainage.
- Identify the effect of solvent rate injection on the process.
- Examine and understand the physics behind the process and explain the high recovery noticed in previous experiments.
- Examine the possibility of solvent retrieval and what may impede it.

Obviously, one of the questions at this stage of a new heavy-oil recovery approach will come out as the possibility of field scale application. This paper presents the initial experiments and provides the results as to the applicability of the proposed approach. The results are promising for further investment of research time. In a series of studies conducted parallel to the present work, the SOS-FR technique was tested numerically at laboratory (Singh and Babadagli, 2010) and field scale (Al-Bahlani and Babadagli, 2010) conditions. Both studies were based on the experimental results presented here (matching exercises to determine unknowns such as diffusion/dispersion coefficients) and the latter especially proved that field scale application is possible but it is imperative to perform a study to determine the application conditions, depending on reservoir conditions and most critically on the matrix size. Therefore, the data presented in this paper should be taken as reference for further field scale numerical simulation and up-scaling exercises.

3. Core preparation

The cores used for these experiments were Berea sandstone plugs and carbonate cores from a producing oilfield. Sandstone samples were treated initially with a siliconizing wettability alteration agent to alter the wettability from water wet to strongly oil wet. This agent is a short chain, clear polymeric silicone fluid consisting primarily of dichlorooctamethyltetrasiloxane. When applied to glass, quartz or similar materials, the unhydrolyzed chlorines present on the chain react with surface silanols to form a neutral, hydrophobic and tightly bonded film over the entire surface (Surfasil™ product website June 2009). In this process, the core was placed inside a core holder. Then, a solution of Toluene + 10% siliconizing fluid was introduced into the core via a syringe pump. The process was repeated until around 4 PV of fluid was passed through the core. The core was then flushed with pure solvent to remove any excess siliconizing fluid that did not adhere onto the rock surface. A flush of another 4 PV of Methanol was then passed through the core to allow for siliconization of the siliconizing fluid on the grain surface. The core was then placed inside the oven for 24 hours to allow for evaporation of excess fluid and to cure the siliconizing fluid.

All cores were then saturated under a vacuum in a hot medium (90 oC) for one week and allowed to age in ambient conditions for at least another 14 days to ensure complete oil-wetness.

In the preparation of the carbonate samples, plugs were extracted from the original cores and then cleaned with toluene for one week followed by a mixture of toluene and methanol for 4 days to ensure the removal of any existing initial water saturation. The cores were then saturated in heavy crude oil under a vacuum and inside an oven at 90 oC for one week and then left to age for at least 14 days.

Cores which underwent counter-current experiments were covered by thermal and solvent resistive epoxy after they were fully saturated. All cores were weighed before and after they were saturated for OIIP measurements.

4. Experimental apparatus and procedure

In order to mimic the conditions in deep naturally fractured reservoirs, all experiments were conducted using hot water. It is reasonable to assume that steam quality arriving to the sand face in deep naturally fractured reservoirs is extremely low. Hence, hot water of 90^oC was used for both static and dynamic experiments. All experiments were conducted at ambient pressure and 90^oC temperature.

Static experiments' apparatus

The apparatus and materials used for static experiments were: (1) graduated imbibition cylinders for Phase 1 and Phase 3 (**Figure 1**), (2) 250 ml graduated cylinders filled with 50 ml of selected solvent for Phase 2, (3) gas condenser and hot water bath for Phase 3, (4) a sensitive scale, (5) heptane, decane, kerosene, and light crude oil mixed with heptane.

5. Static experiments' procedure

The procedure for the static experiments was as follows:

Phase 1

The cores were placed inside an imbibition cell and immersed into 90 ^{o}C distilled water. They were then placed inside a convection oven with 90 ^{o}C ambient temperature. Readings were initially taken on daily basis; however, as the cores reached near plateau they were allowed further time to ensure total plateau from the first phase. Once they reached their plateau, they were taken out and allowed to cool down before initiating the second phase.

Phase 2

The cores were then placed into 250 ml graduated cylinders and filled with 50 ml of solvent per cycle. After each cycle, a solvent reading was taken through a digital refractometer and the amount of oil produced was calculated through oil/solvent refractometer correlation. Weight, volume and density measurements of the core and the solvent were also taken. The core was then immersed in a new 50 ml of solvent. The solvent was changed with "fresh" solvent every time a reading was taken. This allowed the rock to further expel oil from the matrix through diffusion and gravity difference as fracture solvent efficiency drops with higher ends diffusing into it. In a sense, this mimics very slow rate solvent injection or solvent injection cycles (inject-shut down-produce). The initial target was to leave the cores in the solvent for nine days total. Depending on solvent type, which has a lower diffusion coefficient, some cores were allowed longer time in the solvent.

Phase 3

After final measurements (weight, refractive index) of Phase 2 were taken, the cores were immersed into hot distilled water. The temperature ranged from 90 to 95 ^{o}C depending on the type of solvent. The imbibition cell was connected to a gas condenser in an attempt to collect and analyze the type of gas coming out of the core during this phase.

6. Dynamic Experiments

The purpose of the dynamic experiments was primarily to test the rate effect of solvent injection into the fracture on the total production and to gain insight into the efficiency of the process. The experiments were done in two stages: (1) Pilot, and (2) conclusive tests.

The complexity of this type of experiment is due to the quality of the gathered data. It is a steam and solvent experiment at variable temperatures (the solvent is injected at isothermal conditions but on already heated model) on a fractured sample. Collection of the mixture and the separation of phase (oil and solvent) volumes under dynamic conditions are typical problems. Therefore, we begin with commissioning a pilot stage to run the initial tests and describe the system flaws and possible experimental and procedural problems. The second stage (conclusive stage) experiments have certain modifications based on these observations.

For this purpose, a core holder with a rubber sleeve was used to place the rock piece that was artificially fractured by cutting it in the middle and saturating it with oil. Cylindrical Berea sandstone cores of 3”x1” size were treated with an oil wet alteration wettability agent and saturated with heavy crude oil. Hot water and heptane were alternatively injected through two constant rate syringe pumps. A heating unit consisting of a coil-tube immersed in an oil bath and temperature controller was used to generate hot water. Temperatures were measured at the inlet and outlets through two thermocouples and a data acquisition system. To compensate for the heat losses, a heating tape was used to keep the temperature inside the core holder, which was insulated by glass wool. An overburden pressure of 100 psi was applied to prevent injected fluid from flowing through the gap between the rubber sleeve and the core sample (**Figure 2**).

Initially, a large amount of hot water was injected at a rate of 2 cc/min (CWE) to produce some oil and to reach uniform heating of the core. The system was then left to cool with a minimal cold water injection of 0.25 cc/min (CWE). The main reason behind this was to observe cold solvent recovery behavior at minimal temperature representing lowered steam cost conditions. Subsequently, solvent was injected at three different rates: 0.1, 0.3, and 0.5 cc/min. The injection was stopped either after reaching a plateau or completion of nine hours. The third phase was then initiated where steam was injected at a rate of 2 cc/min. For the third phase, a tower was attached to the production line in an attempt to allow any gas to condense and drop down. Weight measurements and refractometer readings were taken to quantify the production.

Several experimental issues were explored from the initial (pilot) stage dynamic experiments which were avoided in the succeeding conclusive experiments. The first issue was the core size. It was increased to a larger dimension (5”x1.5”) with the same saturation procedure. This was done mainly to have a larger pore volume (to improve the accuracy of oil produced from the different phases during the experiments) and to compare two different core lengths for identification of breakthrough time effects on the process.

The temperature control system was also changed in the conclusive experiments. In the pilot experiments, the injection temperature was controlled via thermocouples immersed into the coil in the oil bath which was connected to a heating unit. This resulted in fluctuations of temperature and injection temperature was not well controlled. Also, it was observed that the ambient temperature was not well controlled for the core and having the core outside resulted in heat losses even with insulation with fiberglass wool. These were critical problems faced especially in Phase 1. To avoid such heat loss problems, the experiments were run at a constant temperature oven (set at 90 ^oC) in the conclusive experiments.

During Phase 2 (solvent injection) in the pilot experiments, the core was allowed to fully cool down (to room temperature) and then the solvent was injected. The main reason behind this was to create a “worst case scenario” and to observe the recovery for minimal heating conditions. To represent the field scale applications more realistically, the cooling down period was avoided and the core was left to cool by itself during -cold- solvent injection. Note that experience on static experiments showed that the recovery from a hot core during Phase 2 was higher than a cold solvent due to a faster diffusion at higher temperatures. All of these encouraged the injection of cold solvent (Phase 2) immediately after Phase 1 without a cooling period in the conclusive experiments.

The solvent was injected at four different injection rates in the conclusive experiments: 0.15 cc/min, 0.5 cc/min, 1 cc/min, and 5 cc/min. A temperature controlled digital refractometer was used in the conclusive experiments to improve the accuracy of readings.

During the final phase (Phase 3, solvent retrieval), the core holder was replaced inside the oven (a closed system like the reservoir); however, all fluids were recovered outside the oven at atmospheric conditions (an open system like the well head) to mimic the field application of the process. The amount of solvent retrieved during Phase 3 was a crucial part of the experiments. To avoid any solvent loss due to vapour generation and for an accurate estimation of the solvent retrieved, the outlet was attached to a gas condenser. The experimental set-up for conclusive experiments are shown in **Figures 3-a** and **b.** Due to safety precautions related to the convection oven design, solvent injection was made outside the oven with an ambient temperature of 25 ^{o}C. This was also to allow the solvent to be heated mainly via the energy stored in the rock.

7. Results and discussion

7.1. Static experiments

As was initially stated, one of the objectives of static experiments was to test the effects of solvent type on the process. Solvent cost is a critical issue in this process and as the carbon number increases the solvent cost decreases. Also, as the molecular weight of the solvent increases, the amount of oil recovery decreases (Riazi and Whitson, 1993).

We begin this section with an analysis of Phase 1. Then, we continue with the other two phases (Phase 2 and 3, solvent and hot water injection, respectively).

Phase 1

As can be seen in **Figure 4**, different recovery mechanisms are expected in Phase 1. For all cases, an initial plateau was reached at around 12 % OOIP and then it increased again until it reached a plateau around 20 % OOIP. It is apparent that the initial recovery mechanism is thermal expansion and it was followed by gravity drainage accelerated by the reduced viscosity under elevated temperature. The durations of each mechanism are in agreement with previous observations (Reis, 1992; Briggs et al., 1992; Babadagli, 1996a and 1996b), i.e., thermal expansion was very fast but the gravity drainage was at much slower rates. No capillary imbibition is expected with this oil as the system wettability was changed to strongly oil-wet, as assured by additional wettability tests.

Note that Phase 1 is critical as it determines whether further phases (solvent and then hot water) are needed. This is controlled by the wettability of the rock; for strong water-wet cases the recovery during Phase 1 may go up to ~70% OOIP, as reported by Al-Bahlani and Babadagli (2008) due to the capillary imbibition contribution, which does not necessitate further applications of solvent. Hence, we paid attention to Phase 1 for strongly oil-wet systems and detailed analyses for different conditions (rock samples and interaction type) were performed. **Figure 5** compares different rocks and matrix boundary conditions. The samples coded as S, T, B, and O are Berea sandstone cores treated with the wettability alteration agent. The rest are two carbonate cores: the first one is open from all sides (co-current) and the second one is open only from one side (counter-current). **Figure 6** shows the cores used for co- and counter-current experiments. The counter-current carbonate case in **Figure 5** is situated as “open-side down” as shown in **Figure 6** (sample at left).

It is evident that up to 5800 minutes (indicated by the red line in **Figure 5**), the total recovery from all cores is almost equal and this corresponds to recovery by thermal expansion (**Figure 5**). This suggests that the recovery mechanism is independent of rock property, and is only affected by fluid property during the thermal expansion portion of Phase 1. The thermal expansion recoveries varying between 7 and 13% are in agreement with the numbers suggested by Reis (1992) and Babadagli (1996a). The later increment in recovery is expected to be by gravity drainage which can go up to 30%, as also suggested by Reis (1992).

It can also be observed that the co-current carbonate core produced the least amount of oil (less than 10%) over a long period compared to over 20% in the counter-current core (**Figure 6**). This was an interesting observation and a repetition of the experiment “Carbonate counter-current” in **Figure 6** was made on a different core from the same block. The rock sample (sample Car2) was saturated with the same oil under the same core preparation procedure, yet it (Car2) yielded the same trend as the sample “Car1” (**Figure 7**). The observation of higher recovery in Phase 1 for the counter-current case than that of the co-current one can be attributed to the following possible reasons:

The pore structure of the carbonate cores allows the oil to be produced via gravity faster. Hamida and Babadagli (2006) observed that counter-current air-water capillary imbibition tests on carbonates yielded much higher ultimate recovery than that of the co-current one, which was also attributed to the pore structure (**Figures 3** and **4** of this reference). They reached this conclusion as more water-wet and permeable Berea sandstone resulted in lower recovery (or more residual non-wetting phase entrapment) than that of carbonates (Indiana limestone) under counter-current interaction.

The counter-current movement created a stronger gravity drive inside the matrix than that of the co-current one. In their specific case of air-water and oil-water imbibition experiments, Babadagli et al. (2009) observed that the higher density fluid pushed the lower density one downward more strongly compared to the gravity push in the co-current (all sides open matrix) case. A similar effect is expected in the cases shown in **Figure 7**.

A snap-shot obtained during the experiments (**Figure 8**) revealed that oil droplets from all sides of the open core (co-current interaction) are too small to coalesce. This makes it difficult to create a buoyancy force between the droplets and the water to overcome the adhesion force between the oil droplets and the oil wet core surface. On the counter-current core during thermal expansion, there is a limited area for the oil to exit the core. This helps tiny droplets coalesce and form a larger bubble which can overcome the adhesion force and create more buoyancy force down to the open part of the core.

Based on the above observations and for the sake of consistency, the same experiment was repeated on a sandstone core treated with wettability alteration agent to make it strongly oil-wet. But the core size was kept larger and taller (5”x1.5”, Sample SS-Treated in **Figure 7**). Obviously, due to the size of the sample compared to the other samples (given in **Figures 5** and **7**), the process was much slower in the beginning. But at the end, a similar Phase 1 recovery value (~20%) to the one for the oil-wet sandstone in **Figure 5** was reached. The delay was due to the size and counter-current nature of the process. In all of these experiments, no significant capillary imbibition was observed from any of these cores, especially the carbonate rocks, indicating strong oil wetness of the cores.

Phase 2

In Phase 2, the cores were immersed into different solvents. The results were as expected: the lower the carbon number, the higher the heavy-oil recovery (**Figure 4**). But the cost of the solvent increases as the carbon number decreases. It would be prudent to test the optimal mixture of the crude oil and an additional lighter solvent for a cost effective process. Also, it was visually observed that asphaltene precipitation and deposition on the core surface was much less with higher molecular weight solvents which are yet present, as also expected. Another interesting observation was that the refractometer showed no change in the core immersed in the light crude oil, which suggests that there is no recovery by using light crude oil. This is due to s much lower diffusion coefficient between the solvent and oil, compared to lower carbon solvent cases.

Specific attention was paid to the carbonate cores as they are commonly encountered matrix types in naturally fractured reservoirs. Phase 2 of the counter- and co-current cases was compared in **Figure 9a.** It is should be mentioned that the open face in the counter-current core is facing upward in this case to avoid any production due to gravity segregation, which might also have a negative effect on the production of oil. This kind of configuration was chosen deliberately to test whether diffusion itself can be a drive mechanism in the absence of gravity (with the bottom part and all sides closed to flow). This can be considered as the worst case scenario since the gravity effect is nil. As seen in **Figure 9**, although the counter-current case yielded a better recovery during Phase 1 (as explained in the earlier section), Phase 2 (started after ~73,000 minutes), showed very little recovery. The co-current case (all sides open) responded very well to Phase 2 due to a faster diffusion of solvent and the accelerated effect of gravity. In order to further study the effect of gravity on the process three sandstone oil-wet cores treated with wettability alteration agent and aged in heavy oil were immersed in n-Heptane solvent. The first core represents the best case scenario where the core sees the solvent from all sides, the second core has the upper side of the core only open and exposed to solvent to eliminate the gravity effect, and the third core has the lower side open and exposed to solvent to test for gravity drainage. Readings of oil concentration were taken after 24 hours and after 10 days without changing the solvent. It can be seen from **Figure 9b** that with the best case scenario the oil concentration is much higher than the other two cases while the other counter-current cores produced after 24 hours almost the same result. After 10 days the all sides open core rapidly changed while the other cores did not change significantly. However, a slight change in the core where the open side is facing downward was noticed, which indicates a slow contribution of gravity difference on the process.

Numerical modelling of the SOS-FR process at laboratory (Singh and Babadagli, 2010) scales contradicts this observation. The previous study showed that the main drive mechanism for heavy-oil recovery during Phase 2 is gravity drainage and solvent diffusion accelerates it by creating a density gradient inside the matrix through a diffusive mixing process. In order to understand the process, the experiment was analyzed visually as it can be seen in **Figure 9c**. Gravity segregation between oil and solvent is quite evident in the tube where the open side of the core is facing down. This implies that gravity drainage is actually taking place and reduces the concentration (density) difference between the solvent in the fracture and the oil inside the matrix which reduces the efficiency of the process. While with the open side up, solvent as oil is produced through diffusion it mixes with the solvent uniformly as it can be seen from **Figure 9c,** which makes the quality of the solvent much better than the previous case. Thus, we can conclude that gravity drainage due to density difference takes place; however, under static conditions this may downgrade the quality of the solvent which is unfavorable for this process.

Phase 3

Finally, all cores were subjected to hot water at 90°C as similar to Phase 1. This is a critical stage of the whole process as solvent retrieval occurs during this phase and additional oil recovery is also expected during this period. When the sample was immersed into the hot water after solvent exposure (Phase 2), a significant solvent (heptane) bubbling occurred and, depending on rock type, around 80-90% of solvent was recovered within a few minutes in the form of gas. This amount is in agreement with our previous observations (Al-Bahlani and Babadagli, 2008). Kerosene and decane did not show any solvent retrieval due to their higher boiling temperature. Additional oil recovery (~8-10%) during Phase 3 was observed for light solvent (heptane) only, as indicated in **Figure 4**. Heavier solvents did not yield any additional oil recovery (**Figure 4**). The qualitative and quantitative analyses of solvent retrieval are given in detail in the next section for dynamic experiments.

Note that the main driving factor of solvent retrieval is believed to be thermodynamic reasons, i.e., boiling out of heptane (the temperature applied in Phase 3 is close to the boiling temperature of heptane at atmospheric pressure). Another possible reason for solvent retrieval could be wettability alteration (all samples used in the experiments are strongly oil-wet) that allows hot water in by capillary imbibition, expelling out the oleic phase (solvent and original crude oil). Although this is not expected to be the case (even if it can be enhanced by increased temperature), the possibility of wettability alteration after solvent exposure (Phase 2) was tested by immersing an all-sides open core into distilled water at ambient conditions (20 ^{o}C) after Phase 2 over a one month period. The recovery (expected to be mainly by capillary imbibition) was negligible to null, which suggests that wettability alteration was not apparent at ambient conditions even after long exposure to solvent. This can also be attributed to the incapability of heptane to dissolve heavier components deposited on the pore surface. The same sample was exposed to a higher temperature (90 ^{o}C) after this and significant oil recovery was observed with heptane production in the form of gas bubbles.

Note that static experiments are good indicators of matrix recovery capability of naturally fractured reservoirs. Traditionally, they are used to understand the rock-fluid interactions and possible recovery mechanisms when the matrix is exposed to injectant flowing in fractures. Next, dynamic experiments are conducted to gain more insight into the applicability of the process under more realistic conditions. Both experimental data are useful for further numerical simulation studies, initially lab scale and then field scale.

7.2. Dynamic experiments

The proposed -SOS-FR- method can be applied in the field as cyclic or continuous injection each having advantages and disadvantages. Plenty of solvent supply is needed in Phase 2 and this may not be achieved through a cyclic (huff and puff) type injection. Also needed is sufficient exposure time between the rock matrix and the solvent, and this might be possible if the solvent is injected at optimal rates. For the hot water/steam phases (Phase 1 and 3), the supply of an aqueous phase (and heat) is also critical and a high permeability fracture effect needs to be considered as the early breakthrough of how water/steam would reduce the efficiency of the process. Hence, more realistic dynamic experiments were conducted to test these effects after promising static experiments, to eventually collect enough information that might be useful towards decision making regarding field scale application strategies.

7.3. Pilot experiments

The main purpose of the dynamic experiments was to test the solvent injection rate effect during the second phase. The results are shown in **Figure 10**. During the first phase, several pore volumes of hot water/steam were injected to recover oil and to heat the system. The injection rate was 2 cc/min. This rate of injection was needed to provide sufficient heating of the sample in a short period of time. This, however, caused a quick breakthrough of hot water as the core length was limited to 3”. Recoveries went as high as 45%, which suggests different recovery mechanisms acting at the same time in addition to thermal expansion due to a high rate of injection compared to the core size.

During Phase 2, three different solvent injection rates were tested: 0.1, 0.3 and 0.5 cc/min. The highest recovery was obtained at the rate of 0.3cc/min. The 0.5 cc/min case showed minimal recovery due to insufficient contact time with the matrix in order for the diffusion transfer to take place. A better contact time was achieved at 0.1cc/min, but the process turned out to be too slow. As expected through previous experiences and literature (Babadagli, 1996b; Farouq Ali et al. 1979; Trivedi and Babadagli, 2008) the process was rate dependent. For a better view, only the oil recovered through Phase 2 (solvent injection) is given in **Figure 11**.

Two other plots were provided to clarify the efficiency of the process. **Figures 12** shows the solvent produced against the recovery during Phase 2 and the cumulative solvent injected against oil recovery, respectively. The plot suggests that lower rates are more efficient in terms of solvent use. The high rate case (0.5 cc/min) yielded a very inefficient process with low recovery (due to ineffective diffusion transfer between the matrix and fracture) and an excessive amount of solvent injection. When time constraints are considered, the 0.3 cc/min rate turned out to be an optimal value. All these observations suggest that there exists an optimal rate to be determined on the basis of solvent, oil, and rock properties.

The most critical part after oil recovery was solvent retrieval from the system. The amount of solvent in the produced oil was calculated using a refractometer and weight/volume readings during Phase 2. It is desirable to produce the injected solvent for an efficient process and some amount of solvent was recovered during Phase 2. Based on the observations during static experiments, a great amount of solvent is expected to be retrieved in Phase 3 (hot water/steam injection). For this purpose, the third phase was initiated by injecting hot water/steam (90 ^{o}C) at 2 cc/min rates. Within less than one hour, the whole process was completed and a great portion of solvent was retrieved at a very high rate. Note that this temperature is very close to the boiling point of heptane and the main mechanism driving solvent out of the rock matrix is boiling of the solvent. Capillary imbibition recovery is also a possibility. Although the core was originally oil-wet, as hot aqueous phase flows in the fracture it might imbibe into the matrix and expel oil out due to possible changes in the interfacial properties (interfacial tension and wettability making the sample more water wet) by changing properties of the oil through the mixing process and the solvent removal of polar groups from the surface of the rock at a higher temperature. Assessment of wettability alteration was beyond the scope of this work and, as discussed in the previous section, its effects on the recovery of extra oil and solvent retrieval were observed to be much smaller compared to the solvent boiling mechanism. An accurate estimate of solvent recovered during Phase 3 was a difficult task as most of the solvent came out as gas at this temperature at a very high rate during this type experimentation.

The amount of solvent and original crude oil in the produced oil was calculated. Some additional crude oil recovery is seen in Figure 10 (Phase 3 portion). The 0.3 and 0.5 cc/min rates yielded additional oil recovery around 3-6 % in Phase 3. This amount is slightly lower in the 0.1 cc/min case. Once again, most of the recovery was boiling heptane and oil produced by its pushing force. The mixture produced 60-70% solvent on average for three rates. It was possible to detect the amount of original crude oil and solvent produced through refractometer analysis. It was, however, difficult to quantify the solvent produced in the form of gas bubbles, mainly due to its high volatility. It is worth mentioning that this process was extremely quickly completed (in the order of minutes) for both the static and dynamic conditions. This is the most promising outcome of the experiments conducted as solvent retrieval is a crucial issue in this type of process.

7.4. Conclusive experiments

As can be realized, laboratory scale experimentation of such a complex heavy-oil recovery process (alternate injection of hot water and solvent) in complex (fractured) structures and a realistic representation of field scale application are not simple. On the other hand, no such experimentation is available in the literature so that a routine procedure can be adapted. Therefore, we first conducted pilot experiments to identify the experimental difficulties and possible problems. They include accurate monitoring of oil and solvent recovered at elevated temperature, insulation required to prevent any heat loss during constant temperature experiments, and determination of realistic injection rates based on the core size/pore volume to prevent early breakthroughs. The pilot experiments help clarify these effects and a new experimental system was designed as shown in Figure 3 in the conclusive experiments. Experiments were conducted in a constant temperature oven and larger core samples (or larger oil volumes) were used to overcome the difficulties listed above. Pilot experiment injection rates were also useful to determine scaled injection rates for given core lengths and pore volumes. To quantify solvent retrieval in Phase 3, a condensing system was designed to collect heptanes in gas form and convert it into liquid.

As observed in the pilot tests, it is quite apparent that hot water injection lacks efficiency in highly fractured oil-wet cores. The purpose of Phase 1 was to heat the core and improve the quality of oil to some extent to allow a better diffusion between the oil and solvent. However, the steam oil ratio was very high and continuation of injection was considered uneconomic. The first thing done in the conclusive experiments, which were run in a closed system (a constant temperature oven to represent a reservoir), was to check the temperature difference between the injection and production port to make sure that it was nearly zero. The injection was continued for few more pore volumes just to ensure uniform core heating. The temperature measurements confirming its uniform distribution and the time required to achieve this are given in **Figure 13**. It was observed that the desired temperature throughout the core was reached in a short period of time without any significant oil production (mainly by thermal expansion).

Figure 14 shows the total oil recovery of all three phases in the conclusive experiments. The rates applied are different from the pilot experiments as the core sizes were changed. It can be seen that, during Phase 1, all cores achieve around 20% recovery when the core was uniformly heated to 90^{o}C. However, the injection rate is high resulting in high steam-oil-ratio (SOR). With this application condition, we achieved uniform core heating via hot-water injection but one should pay attention to find optimal injection rates to minimize the SOR for practical applications, which is beyond the scope of this paper.

Phase 2 (solvent injection) was initiated immediately without cooling the core (unlike the pilot case); however the injection procedure was conducted outside the oven to mimic cold solvent injection in the field conditions. Different injection rates yielded different oil and solvent recoveries. Systematically, high recoveries were obtained with high injection rates. However, as the core cooled down over time, the lower injection rates yielded higher recoveries as seen in **Figure 15**. The high recoveries come at an expense of high cumulative solvent oil ratio (cum SoOR) as can be inferred from **Figure 16**. It is interesting that the highest cum SoOR was obtained for the 0.5cc/min rate and that it does not follow a systematic pattern but rather there is an optimum cum SoOR. However, when solvent recovery during Phase 2 was plotted (**Figure 17**), it was noticed that the least cumulative solvent recovered was from the 0.5 cc/min rate, which explains the high cum SoOR. This complex production behavior of oil during Phase 2 can be attributed to several physical aspects that may have occurred during the course of solvent injection as explained below:

Diffusion in its main essence is the movement of particles from high concentration side to low concentration side. In the case of miscible fluids, particles move from the higher concentration medium to the lower concentration medium driven by the Brownian motion. For this case specifically, hydrocarbon particles are highly excited by thermal energy stored during their exposure to hot water. Once they are exposed to a cooler medium with lower concentration they tend to move towards it. The higher the amount of solvent they are exposed to, the faster they transfer from a hot to a cold medium to reach equilibrium. Hence, diffusion is enhanced by thermal effect. Also, the solubility of solid heavy oil particles in liquid solvent increases with high temperature.

As solvent is injected at lower rates, beside the enhancement of diffusion of solvent into the matrix, part of the solvent converts to vapor. The penetration of vapor solvent into the matrix is relatively faster and this results in an improved gravity drainage between vapor solvent and oil and thereby a faster expulsion of heavy oil from matrix to fracture. **Figures 18** and **19** show the liquid produced to the liquid injected ratio and the cumulative solvent injected to the cumulative solvent produced, respectively. The significance of these graphs is that they show how much fluid is lost either due to solvent oil mixing or due to vapor generation. Higher loss is seen at lower rates, while the ratio is almost unity at higher rates.

The solvent injected at room temperature causes the oil to cool down and, thereby, the oil contracts back to the matrix. This promotes the entrance of solvent into the matrix, which causes counter-current fluid movement that enhances oil recovery as also noticed visually by Hatiboglu and Babadagli (2007 and 2010).

The flocculation of asphaltene and its role in blocking some of the pore throats near the fracture may be considered as a factor affecting oil production. In the case of high rates – or high velocities – the time taken for asphaltene to flocculate in or near the fracture is much lower than at the lower rates. The high inertia forces due to high velocities work as a mechanical cleanser for any asphaltene deposits that may occur. **Figures 20** and **21** show the asphaltene deposition in an oil sample taken from the outlet during Phase 2. Here, it can be clearly seen that asphaltene flocculates during this process.

It is obvious that there are different complex mechanisms effective during the solvent injection phase. We can, however, divide this process simply into two main phases: (1) thermal and (2) post-thermal phase. When the volume of cumulative solvent injected is plotted against the cumulative volume of solvent produced (**Figure 19**), one may observe that the slope is almost identical at the thermal phase, where a small deviation is noticed during the post thermal phase. The physics of the thermal stage includes enhancement of solubility and diffusion between oil and solvent. This is in line with the effect of solubility as presented by Deng et. al. (2010) on the ES-SAGD process applied on an Athabasca oil. Their simulation showed that increasing the K-value of the solvent component in the simulation reduces the production; hence it is evident that solvent solubility has an effect on the solvent process. Another study of the effects of temperature on solvent injection was shown by Rezaei and Mohammedzadeh (2010) where they investigated the performance of warm VAPEX process by injecting a superheated hydrocarbon solvent. They noticed an increment in oil production with a decrease of solvent concentration in produced oil due to increased solvent temperature. Er and Babadagli (2010) discussed the mechanism of oil production during miscible CO_2 (solvent) injection and showed that when solvent is injected downward, it tends to rise up due to gravity segregation and literally push the oil down. Hatiboglu and Babadagli (2007 and 2010) showed the counter current movement of a 2D sand pack saturated with oil when exposed to a lower density solvent. They concluded that the gravity effect eventually causes a counter-current (and convective) movement inside the matrix where solvent rises to the top of the model causing heavier oil to be expelled to the fracture at the bottom.

To clarify this effect and to picture the displacement (or residual oil) profile in our dynamic (conclusive) experiments, photos of the two matrix blocks were taken after each experiment. There was a distinct shape difference between the high and low rate experiments. At a high rate (5 cc/min), a visible vertical line was noticeable between the swept and unswept (residual oil) area while at lower rates the line between the swept and residual area was almost horizontal (**Figures 22** through **25)**. It is true that solvent tends to rise up in all cases causing the oil to be expelled vertically into the fracture. However, on the other side, as the solvent reaches the other boundary of the core it tends to push the oil horizontally from the boundary to the fracture. This was also observed by Er and Babadagli (2010) in a 2D sand pack model with CO_2 injection into light mineral oil. Thus, we conclude that the sweep efficiency with higher rates is much better than with lower rates, which is mainly due to the higher volume available of fresh solvent compared to lower rates. Economics of this should be evaluated through further optimization studies. The cores were then immersed into hot water and bubbling areas were monitored, which identify the solvent penetration into the matrix.

During Phase 3, the core holder was placed in the high temperature oven and hot water was injected to retrieve the solvent penetrated into the matrix during Phase 2. Additional -small- amounts of oil (**Figure 26**) and solvent (**Figure 27**) were recovered during this phase. It was noticed that the amount of oil recovered from lower rate experiments was insignificantly higher than that of the higher rate experiments. It was also observed that the higher rates did not produce as much solvent as at the lower rates mainly because of these reasons: (1) due to lower velocity, solvent gained enough energy to convert into vapor, (2) the amount of solvent to the amount of oil caused an upgrade of the oil with rates low enough for it to be produced during Phase 3, and (3) possible experimental reading error since with lower rates the oil solvent production was more emulsive (**Figure 28**) compared to the higher rates (**Figure 29**). This made it quite challenging to obtain a highly accurate estimate of solvent recovery with all precautions taken not to lose oil due to evaporation. At high rates, the emulsion effect was lower and, until the last very few readings, solvent production was very clear.

Upon completion of all three phases, as a final step, the cores were taken out of the core holder and immersed into hot water (90 ^{o}C) to observe if there was any more solvent retrieval possible. The reason behind this experimentation is that injected hot water in Phase 3 contacts (or heat) only through the fracture surface and any solvent penetrated into deeper parts of the matrix may not be recoverable due to unfavorable boundary conditions. The boundary conditions created due to the experimental design may allow for heating the matrix effectively but this may not be sufficient to retrieve solvent caused by restricted flow conditions, which are limited only through the fracture surface. To create more area for flow (or open boundaries), the samples were immersed into hot water as shown in **Figure 30.** Solvent bubbling was observed as seen in this snap-shot and more solvent was retrieved during this experimentation. This shows that solvent retrieval is strongly controlled not only by temperature (and pressure) but also by existing boundary conditions (mainly matrix size and contact area). If they are favorable (small matrix sizes) and suitable pressure-temperature conditions (for the solvent to boil and for phase change from liquid to vapor) are applied, a great potion of the solvent (80-90%)

is retrieved regardless the permeability or wettability of the sample making the suggested enhanced heavy-oil recovery technique suitable for heavy oil recovery.

8. Conclusions and remarks

In agreement with our previous work (Al-Bahlani and Babadagli, 2008 and Babadagli and Al-Bahlani, 2008), the proposed method (SOS-FR) shows potential for heavy oil/bitumen recovery from fractured carbonate reservoirs. The following specific conclusions can be drawn from this detailed experimental work:

A new technique called Steam-Over-Solvent Injection in Fractured Reservoir (SOS-FR) was tested extensively for static and dynamic conditions. Different solvents were tested and solvents with lighter molecular weight produced a higher amount of oil but with a higher amount of asphaltene precipitation and deposition.

Co-current and counter current experiments showed that the process is highly affected by the nature of interaction, i.e., co- or counter-current. More favourable interaction was observed in Phase 1 for the counter-current case whereas the solvent interaction was negatively affected in the case of counter-current interaction due to a limited solvent contact area.

Dynamic experiments show a rate / velocity dependency of the process. There exists an optimal rate and the process can be efficient in terms of recovery time and solvent use. This might lead to the conclusion that a high rate injection of water/steam in Phases 1 and 3 and an injection of solvent at an optimal rate (to be determined based on the rock and oil, and solvent characteristics) would be more efficient than injection in the cyclic (huff and puff) form.

Dynamic experiments showed that higher injection rates cause faster oil recovery but with a high solvent to oil ratio, while lower recoveries were obtained at lower rates. This leads us not only to the possibility of an optimal injection rate, but also to an optimal injection scheme that may yield an optimal recovery throughout the lifecycle of the core.

Solvent penetration into the matrix can happen through contraction of oil causing solvent to penetrate faster into the matrix. Once solvent enters the matrix, it creates a counter-current (or convective) movement driven by gravity difference, which enhances oil recovery.

Larger cores may yield a different set of recovery results with the same physics acting in place as in the smaller cores. This indicates the importance of the boundary conditions and sample size on the process, especially from the up-scaling of the process point of view.

Asphaltene precipitation and deposition may have a great impact on the process. At higher rates/velocities, the displacement (and diffusion) process is so fast that asphaltene flocculation and deposition cannot occur (or be delayed). This eventually yields a better recovery. On the other hand, at low rates/velocities, the possibility of asphaltene deposition in the matrix is higher, which leads to a blockage near the matrix area causing reduced permeability and lower recoveries.

It was difficult to quantify the solvent produced in the form of gas bubbles, mainly due to its high volatility and foam emulsion-like production. It is worth mentioning that this process was extremely fast; it was completed in an order of minutes for both the static and dynamic cases, as can be inferred from Figures 4 and 9. This is the most promising outcome of the experiments conducted as solvent retrieval is a crucial issue in this type of process.

As similar to previous experiences (Babadagli, 1996b; Farouq Ali et al., 1979; Trivedi and Babadagli, 2008) focused only on single material (steam, water, solvent, or CO_2 only) injection, the SOS-FR process turned out to be highly injection rate dependent.

Obviously, one of the questions at this stage of a new heavy-oil recovery approach will be the possibility of field scale application. This paper presents the initial experiments and provides the results as to the applicability of the proposed approach. The results are promising for further investment of research time. In a series of studies conducted parallel to the present work, the SOS-FR technique was tested numerically at laboratory (Singh and Babadagli, 2010) and field scale (Al-Bahlani and Babadagli, 2010) conditions. Both studies were based on the experimental results presented here (matching exercises to determine unknowns such as diffusion/dispersion coefficients) and especially, the latter proved that field scale application is possible but it is imperative to perform a study to determine the application conditions depending on reservoir conditions and most critically the matrix size. Therefore, the data presented in this paper should be taken as a reference for further field scale numerical simulation and up-scaling exercises.

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Table 1 : List of experiments and corresponding rock properties.

Core	Size	Type	Solvent used	Permeability	Porosity
S	3" x 1"	Sandstone oil wet	Heptane	500 mD	16-17
T		Sandstone oil wet	Kerosene		16-17
B		Sandstone oil wet	Decane		16-17
O		Sandstone oil wet	Light oil		16-17
C1		Carbonate	Heptane	7 – 11 mD	23
C2		Carbonate	Heptane	7 – 11 mD	23
Car2		Carbonate	Heptane	7 – 11 mD	23
SS-treated	5” x 1”	Sandstone oil wet	Heptane	500 mD	20

Table 2: Properties of oil used.

Oil Type	Heavy Oil – Dead
Viscosity @ 15 ^{o}C	4439
API	14.76
Asphaltene wt% (Heptane)	18%
Asphaltene wt% (Decane)	12%
Asphaltene wt% (Kerosene)	8%

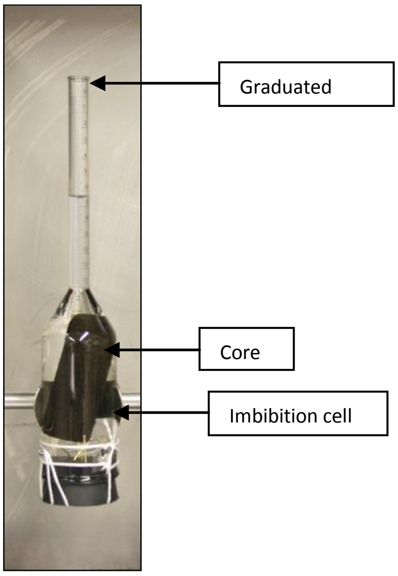

Figure 1: Imbibition cell used for Phases 1 and 3 of static experiments.

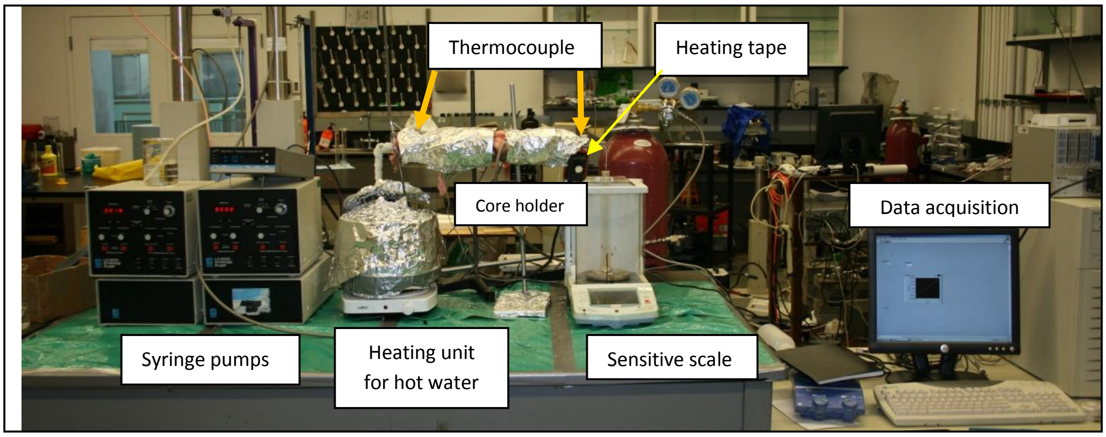

Figure 2: Experimental set-up used for dynamic (pilot) experiments.

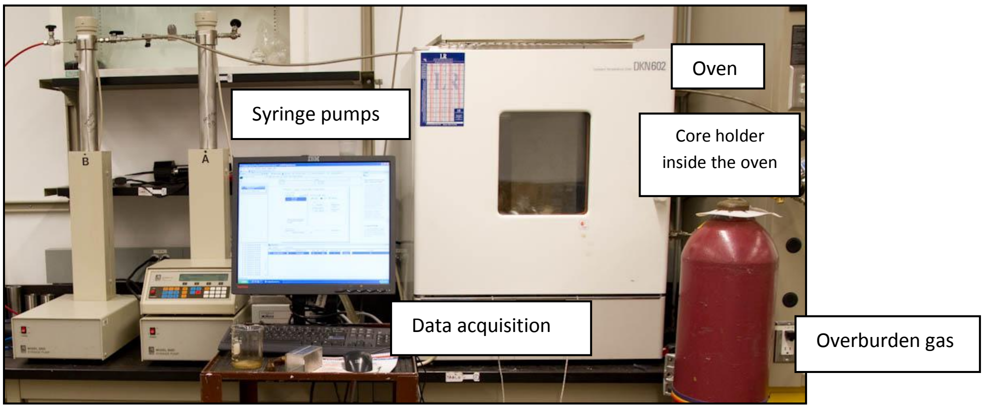

Figure 3-a: Experimental set-up used for dynamic (conclusive) experiments.

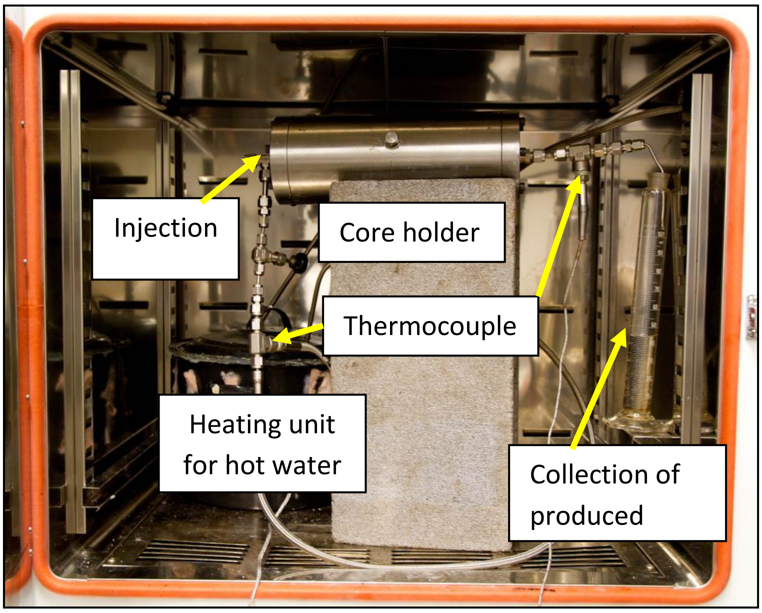

Figure 3-b: Dynamic experiment set-up for conclusive experiments: Inside the oven.

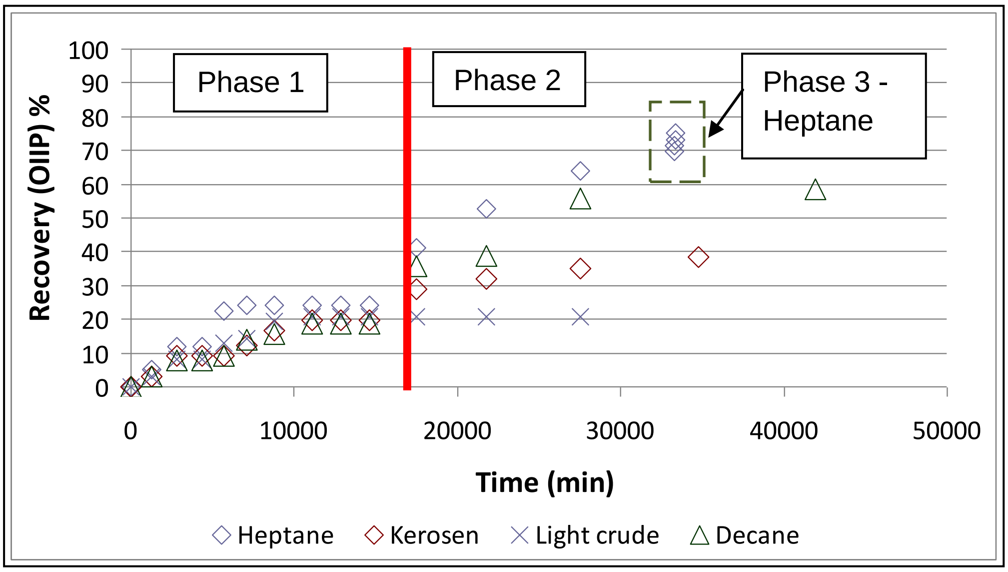

Figure 4: Oil recovery with different types of solvents. The higher the molecular weight the lower the production.

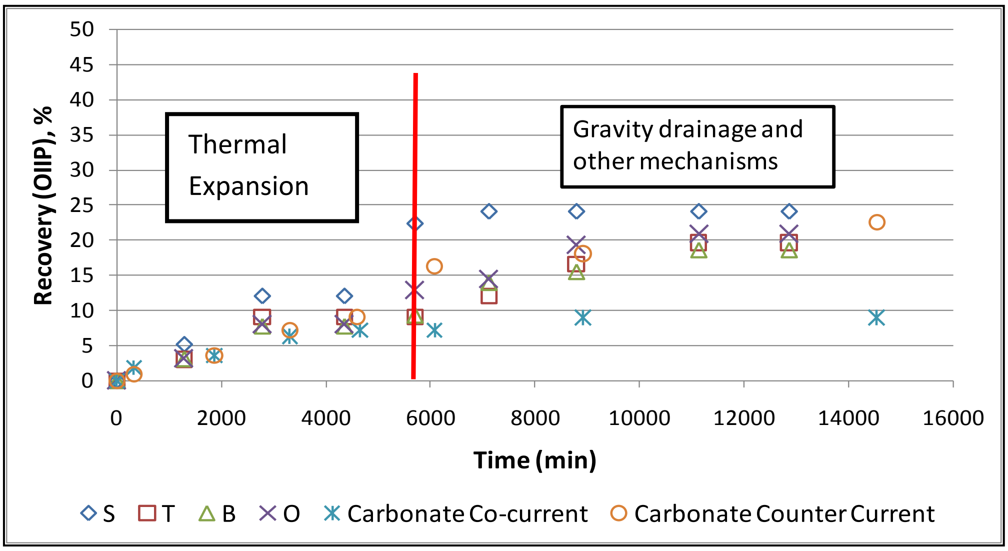

Figure 5: Oil expulsion from matrix under static conditions for different matrix types and configurations.

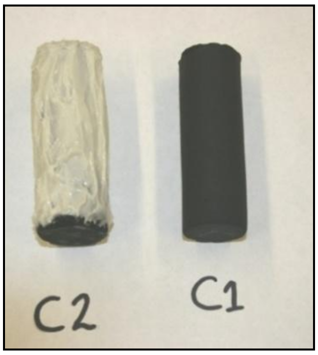

Figure 6: Sample C2: Counter current case (all sides sealed except the bottom face). Sample C1: Co-current case (all sides open to flow).

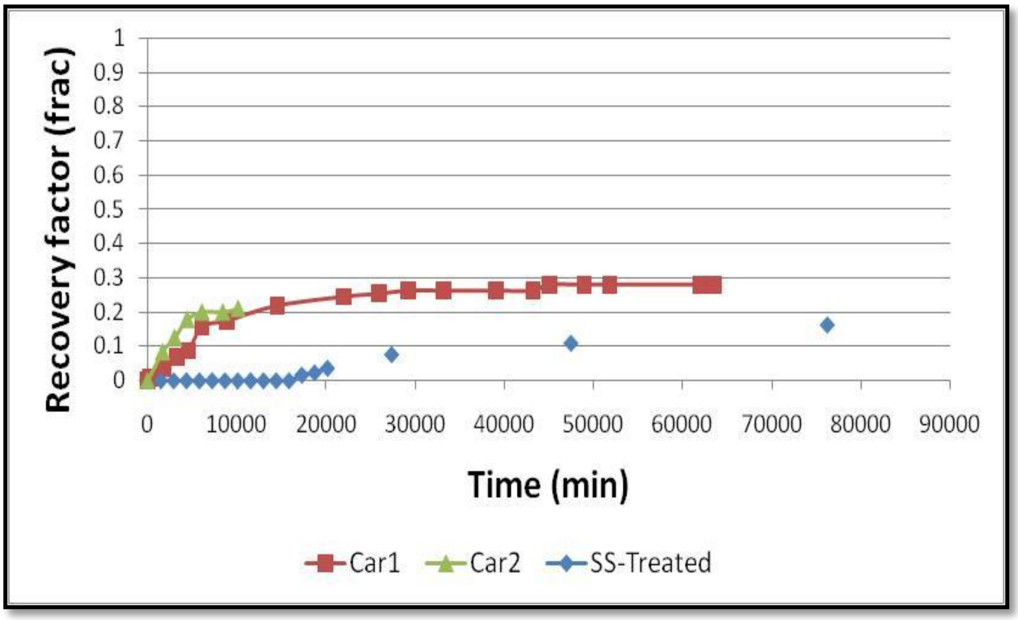

Figure 7: Oil expulsion from matrix under static condition for counter-current cores of both carbonate (Car1 and Car2) and oil wet treated sandstone cores (SS-treated). Experiment "Car2" is a repetition of "Car1" to test the reproducibility.

Figure 8: Tiny droplets of oil adhere to the surface of the rock; they are too small to coalesce and overcome adhesion forces.

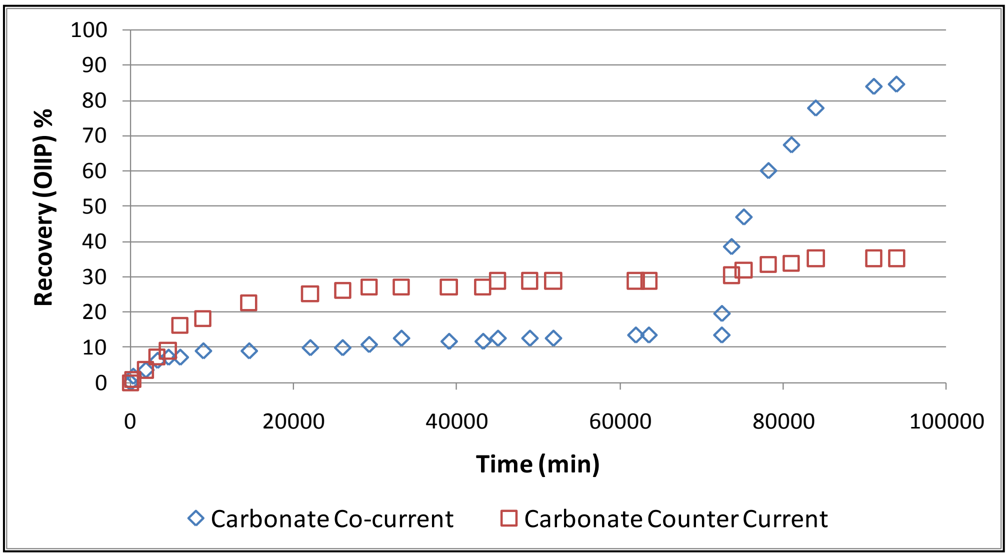

Figure 9a: Comparison of co-current and counter-current cases for Phases 1 and 2.

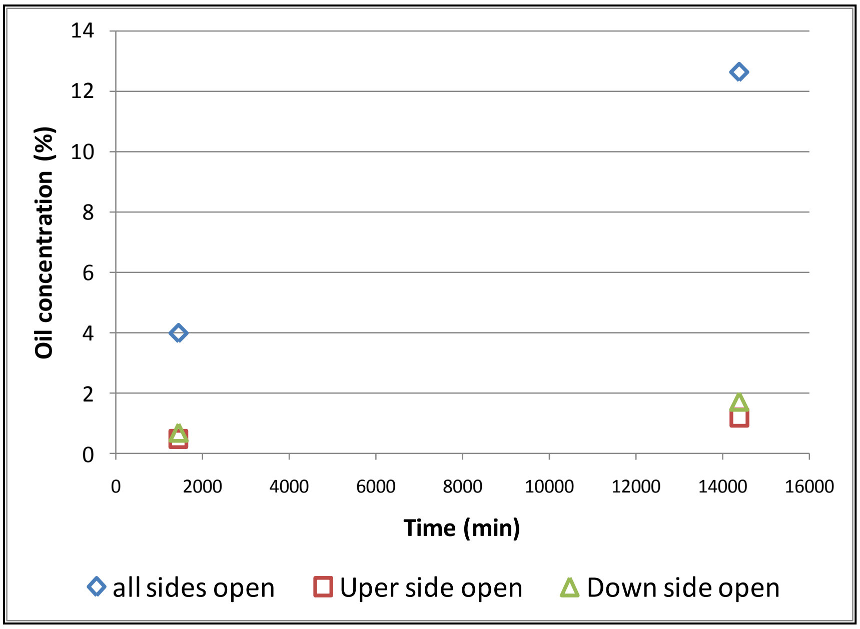

Figure 9b: Study of the effect of gravity and surface area on solvent process.

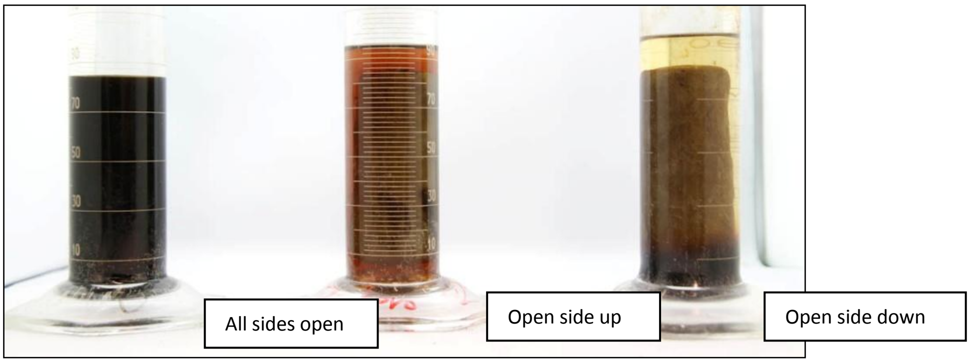

Figure 9c: Visual inspection of the effect of gravity on SOS-FR process during Phase 2.

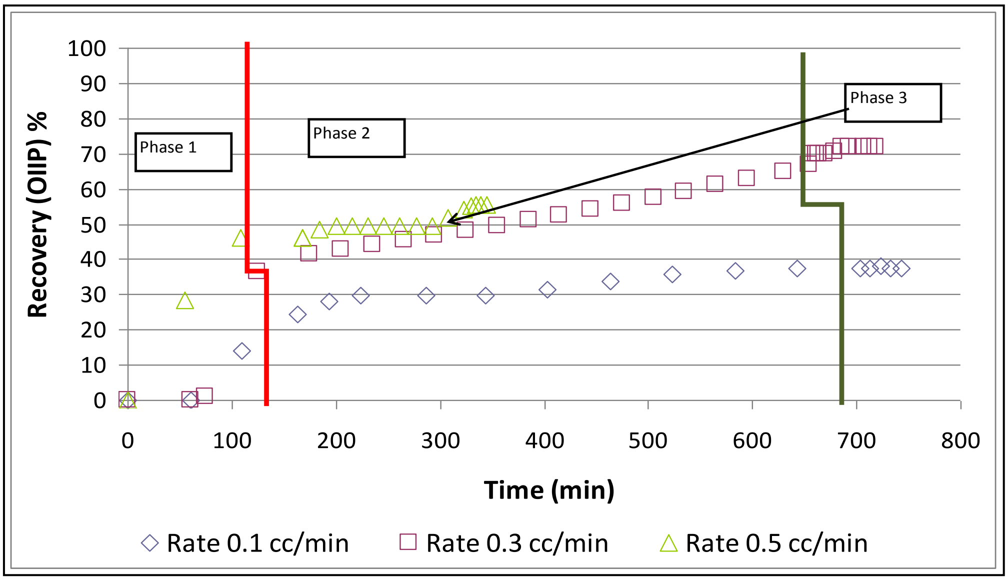

Figure 10: Results of dynamic experiments. Beginning of Phase 3 for 0.5 cc/min case was indicated by an arrow.

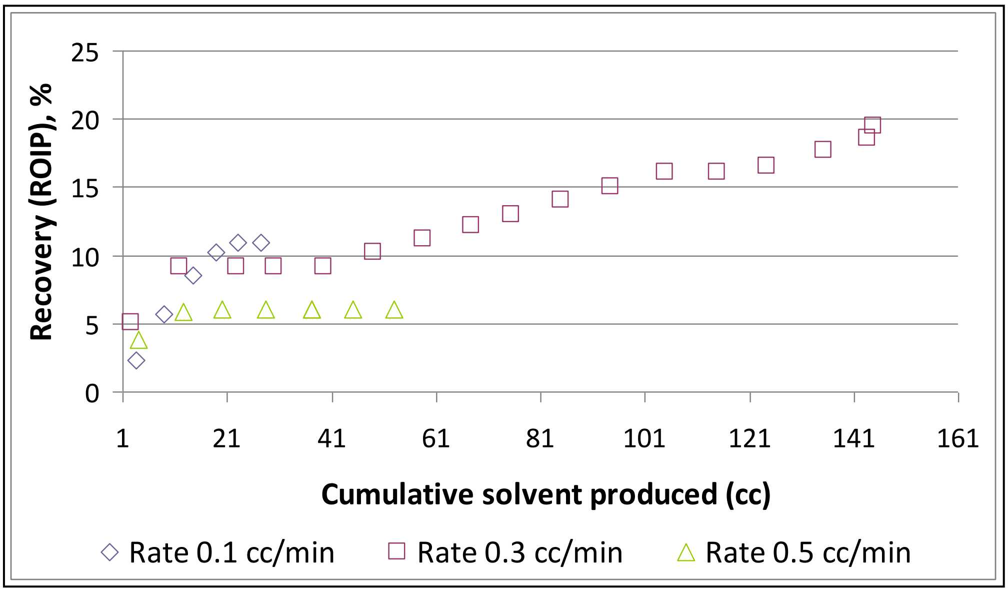

Figure 11: Solvent produced (or retrieved) against oil recovery during Phase 2.

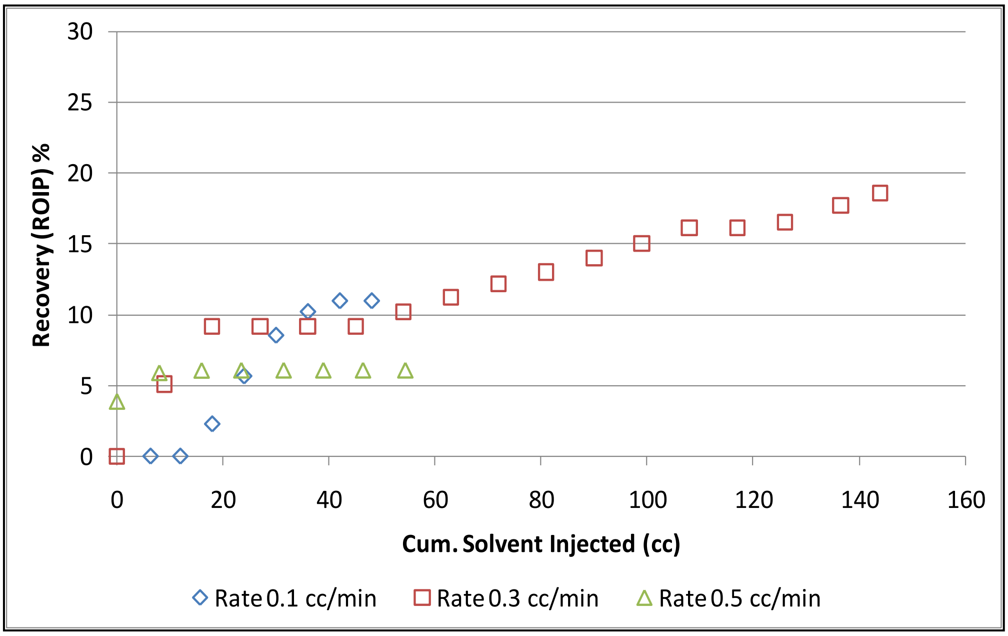

Figure 12: Amount of solvent injected against oil recovery during Phase 2.

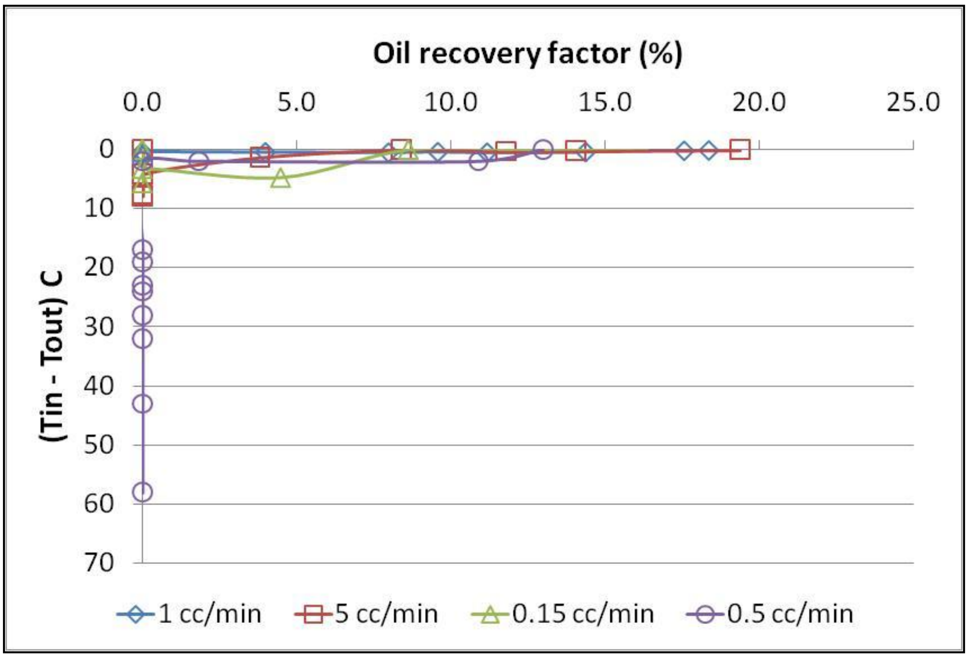

Figure 13: Thermocouple data shows that the cores are well heated during Phase 1 and temperature difference is zero and recovery is factor is around +/- 18% for all cases.

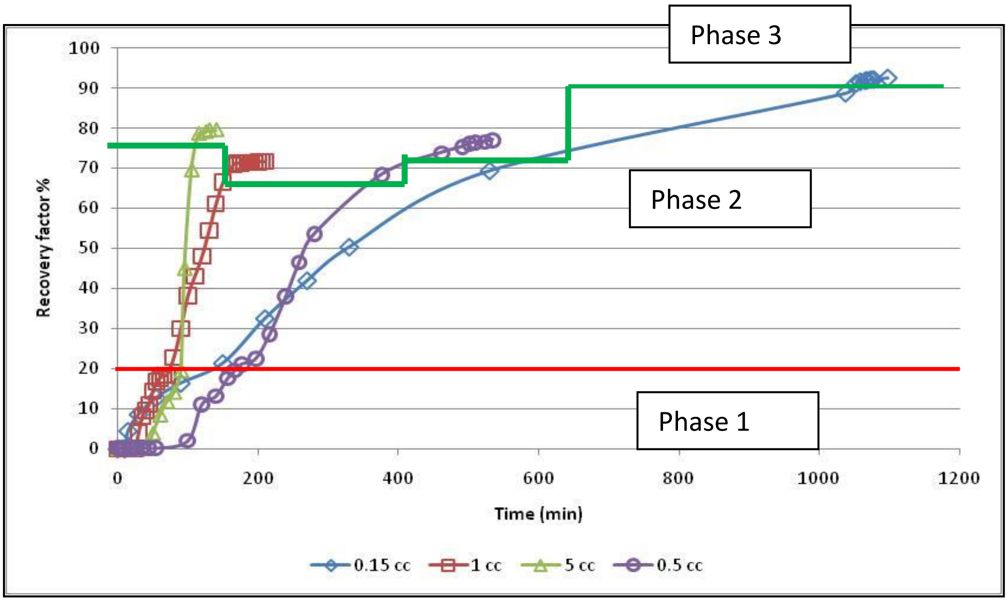

Figure 14: Oil recovery factor of conclusive experiments for all three phases (hot-water, solvent, hot-water) at different rates.

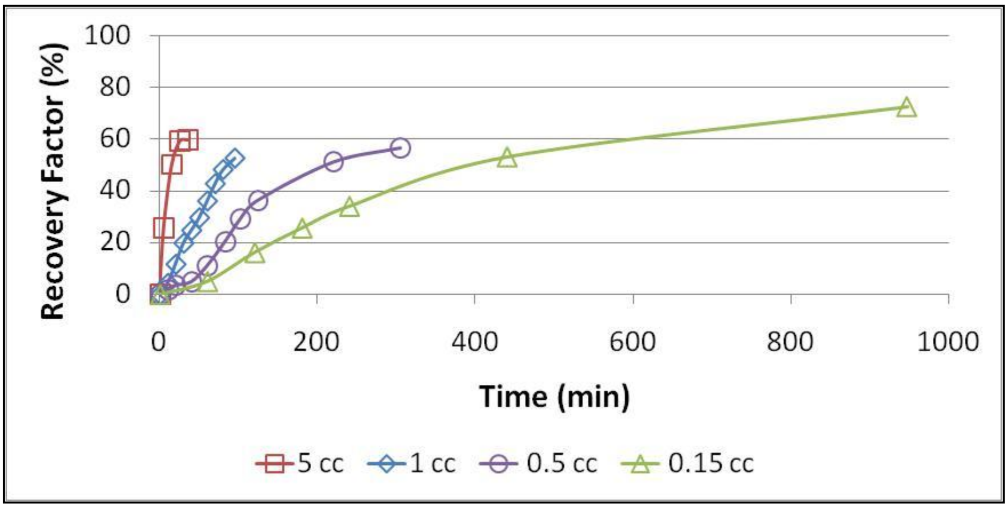

Figure 15: Oil recovery factor of conclusive dynamic experiments during Phase 2 only. Faster rates yield faster recoveries.

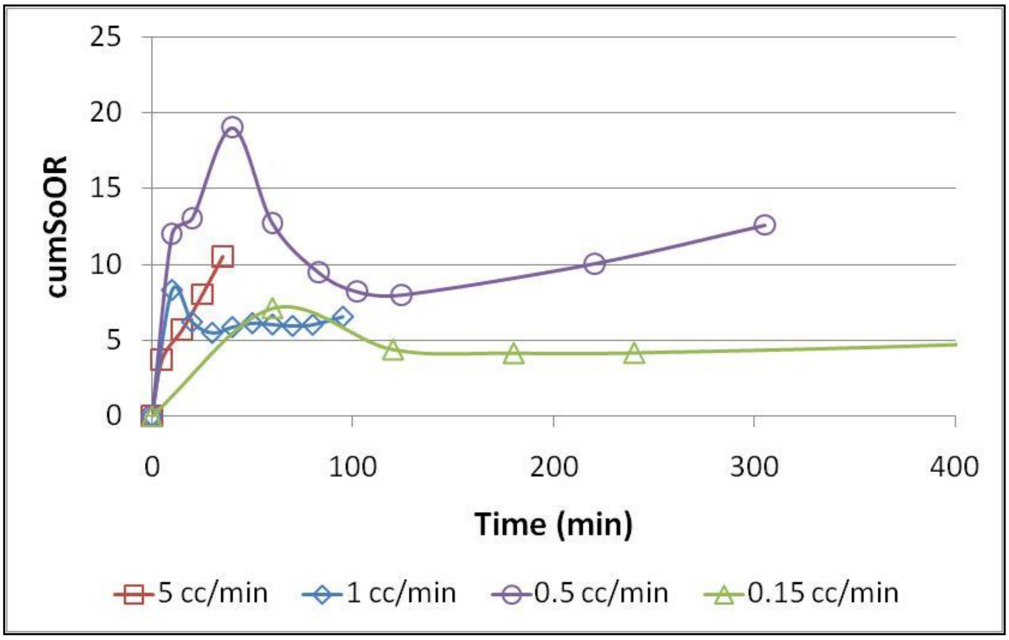

Figure 16: Cumulative Solvent Oil Ratio (cumSoOR) during Phase 2.

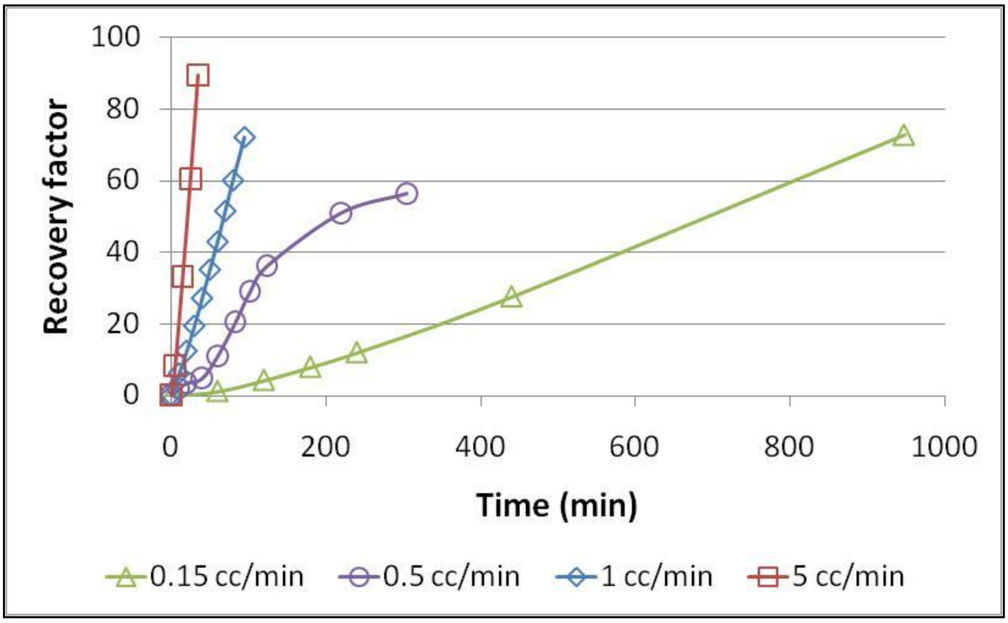

Figure 17: Solvent recovery factor during Phase 2.

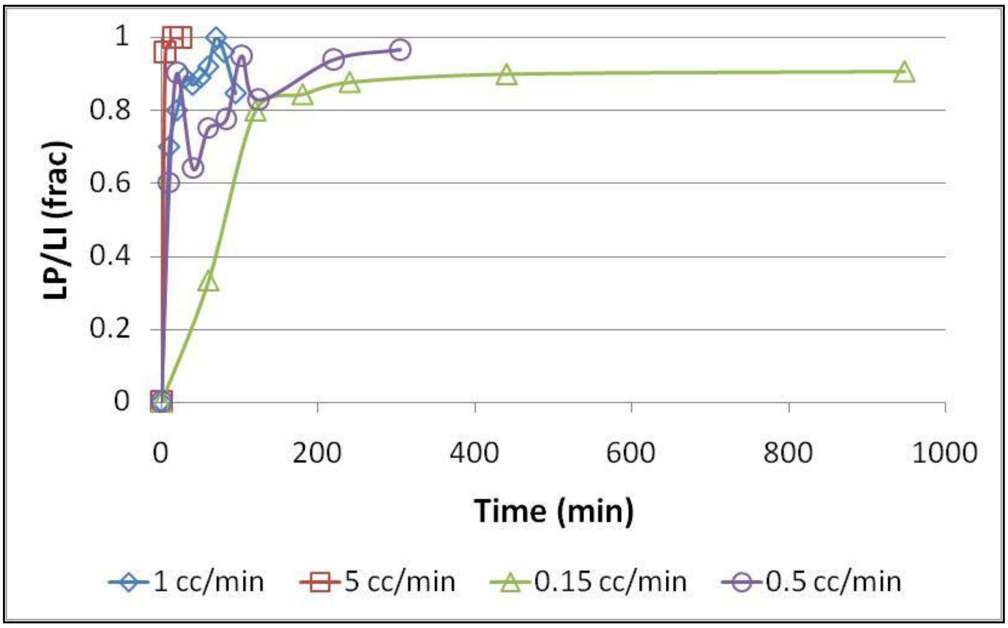

Figure 18: Liquid produced / liquid injected during Phase 2 for all dynamic –conclusive- experiments.

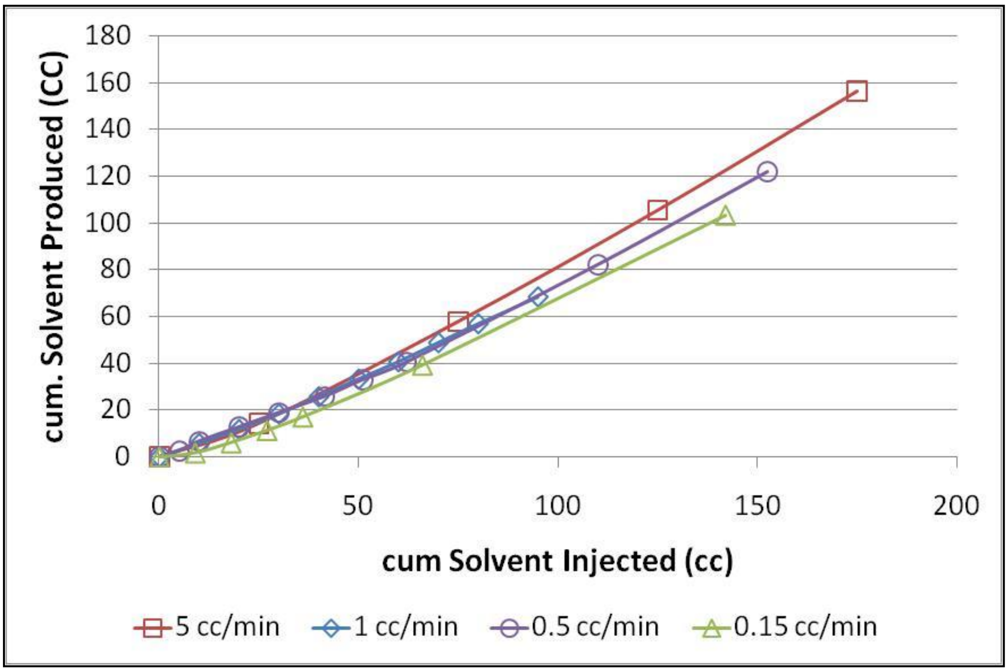

Figure 19: Cumulative solvent injected vs. cumulative solvent produced at different rates.

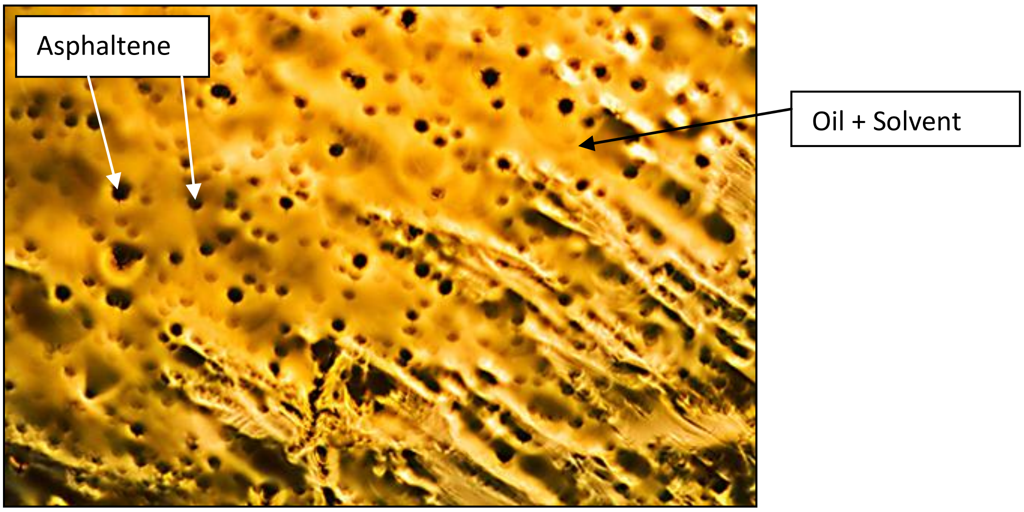

Figure 20: Asphaltene precipitation on a produced oil + solvent sample seen under microscope.

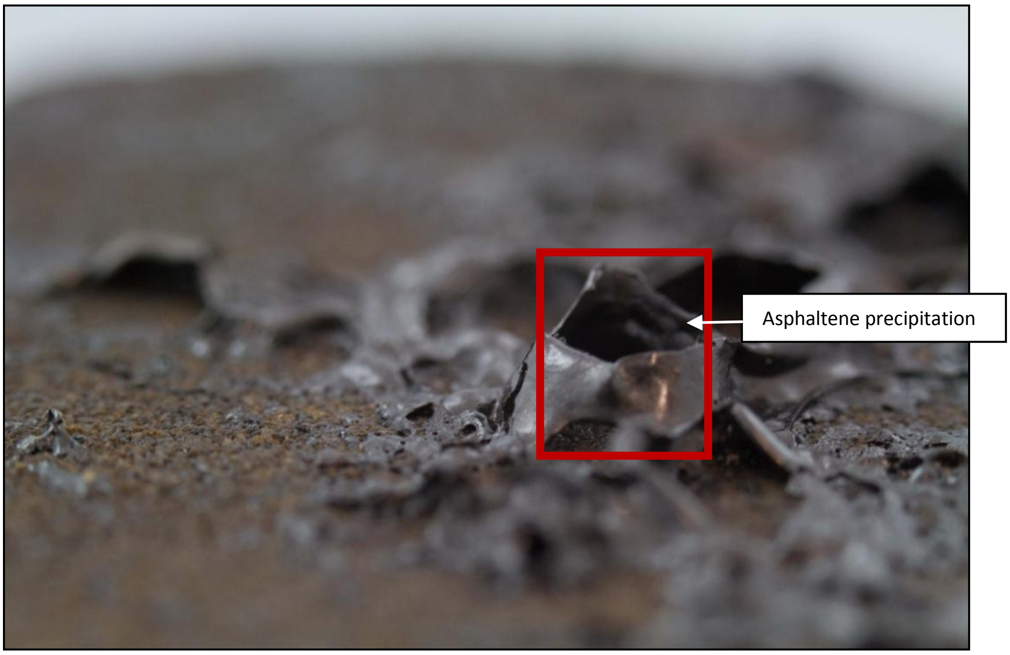

Figure 21: Asphaltene precipitation after long exposure to solvent.

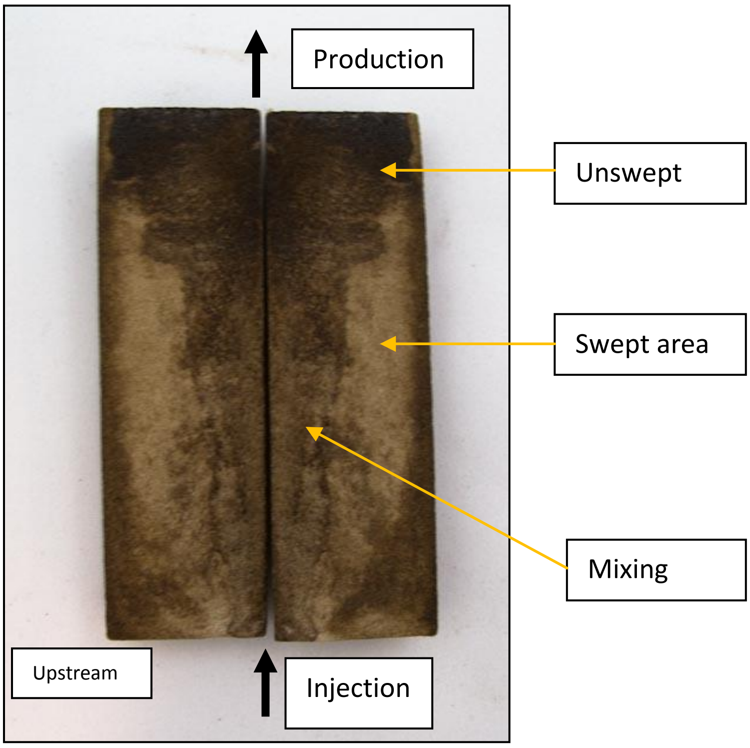

Figure 22: Residual oil in the matrix after the whole experiment was conducted (1 cc/min solvent injection rate).

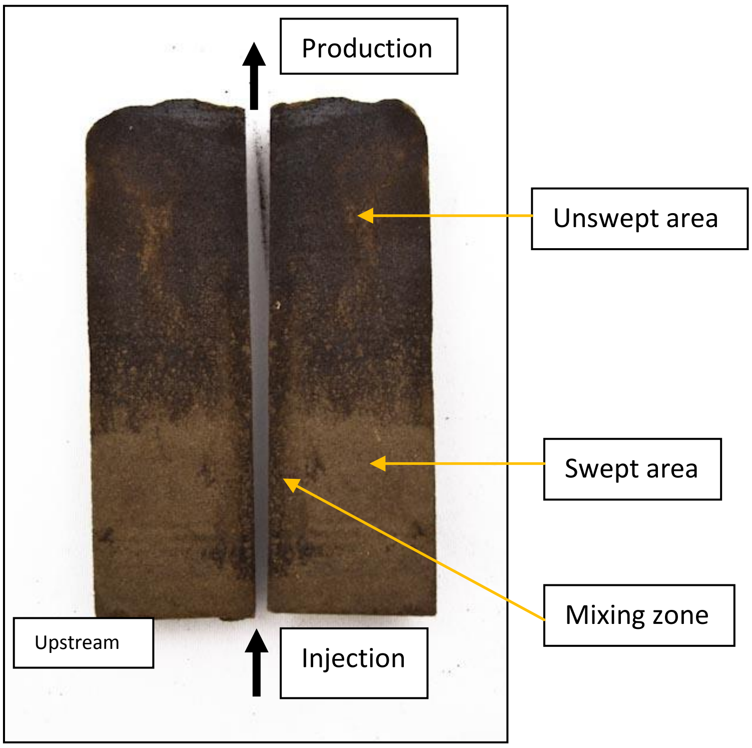

Figure 23: Residual oil in core after the whole experiment was conducted (5 cc/min solvent injection rate).

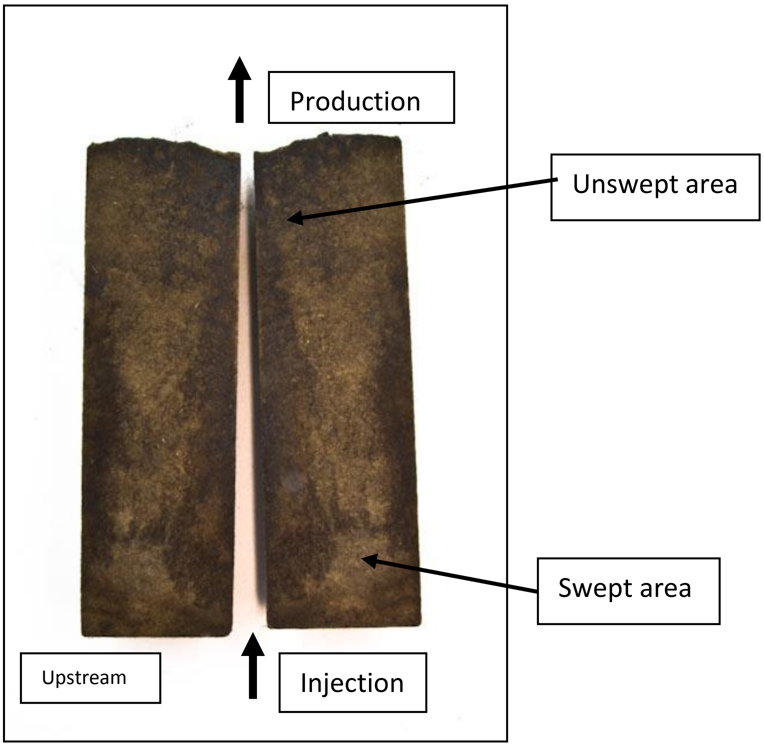

Figure 24: Residual oil in the core after the whole experiment was conducted (0.15 cc/min solvent injection rate).

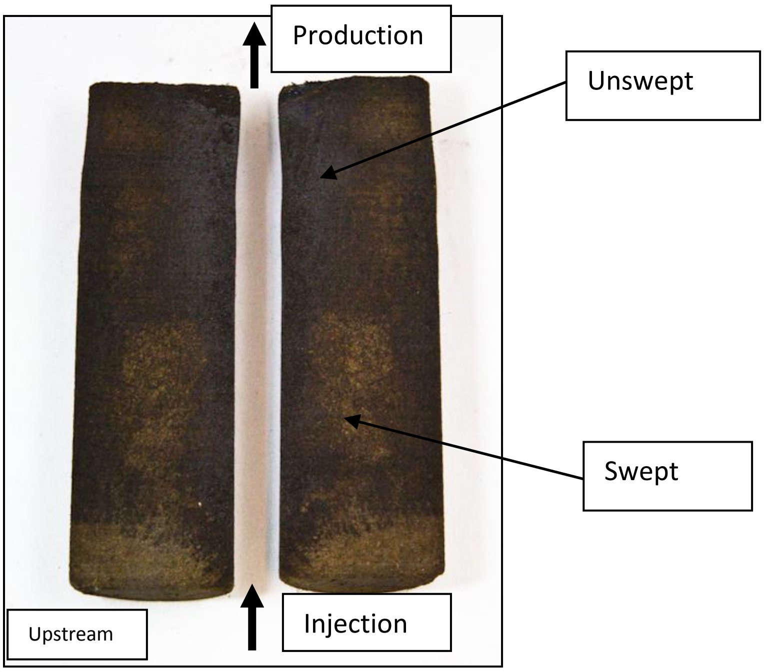

Figure 25: Residual oil in the core after the whole experiment was conducted (0.5 cc/min solvent injection rate).

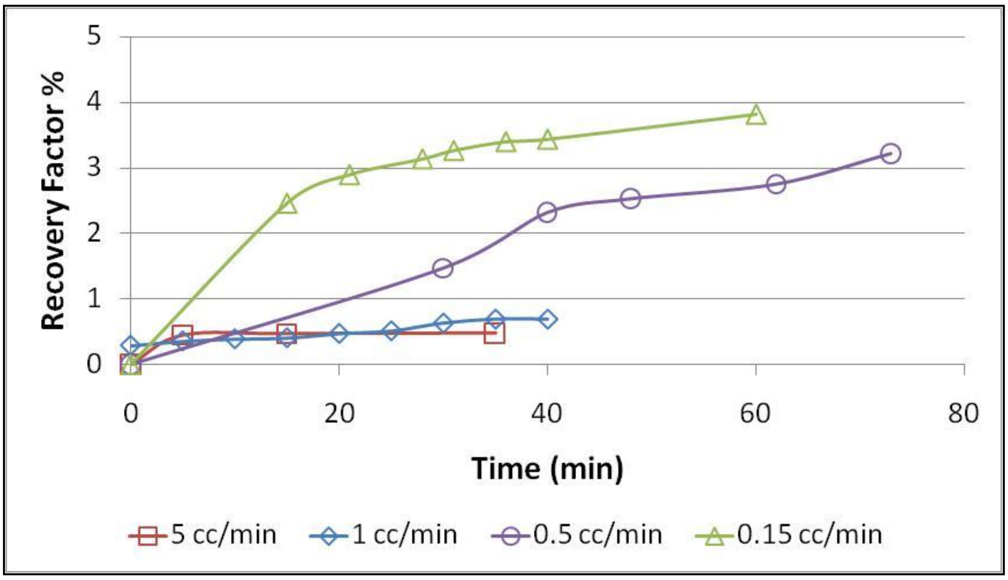

Figure 26: Oil recovery factor during Phase 3 for different solvent injection rate cases (Phase 2).

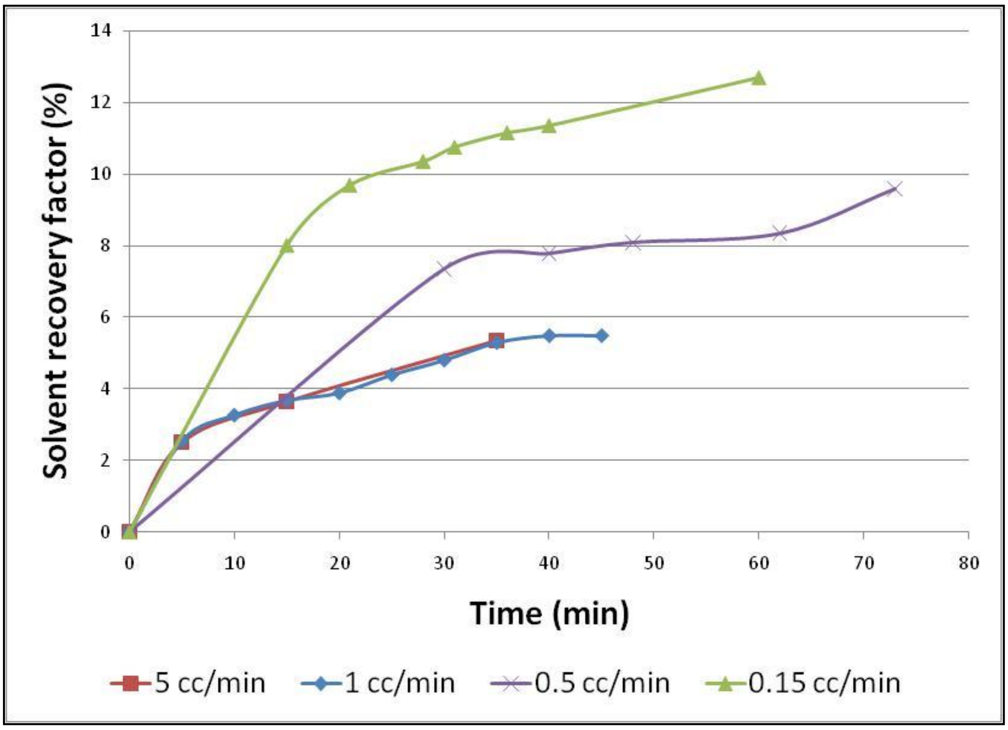

Figure 27: Solvent recovery during Phase 3 for different solvent injection rate cases (Phase 2).

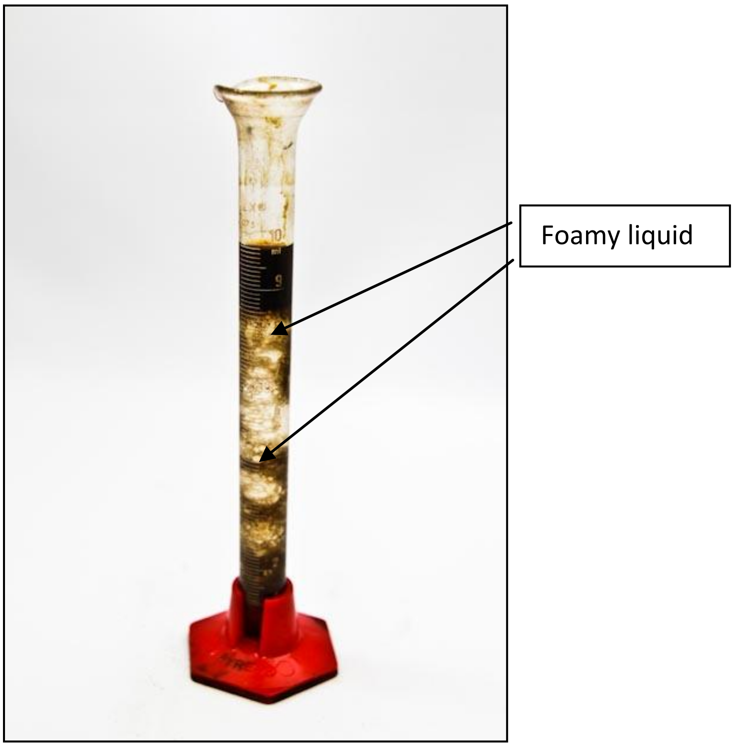

Figure 28: Solvent+oil production during Phase 3 for low injection rate, 0.15 cc/min (at initial stages).

Figure 29: Solvent+oil production during Phase 3 for high injection rate, 5 cc/min (at later stages).

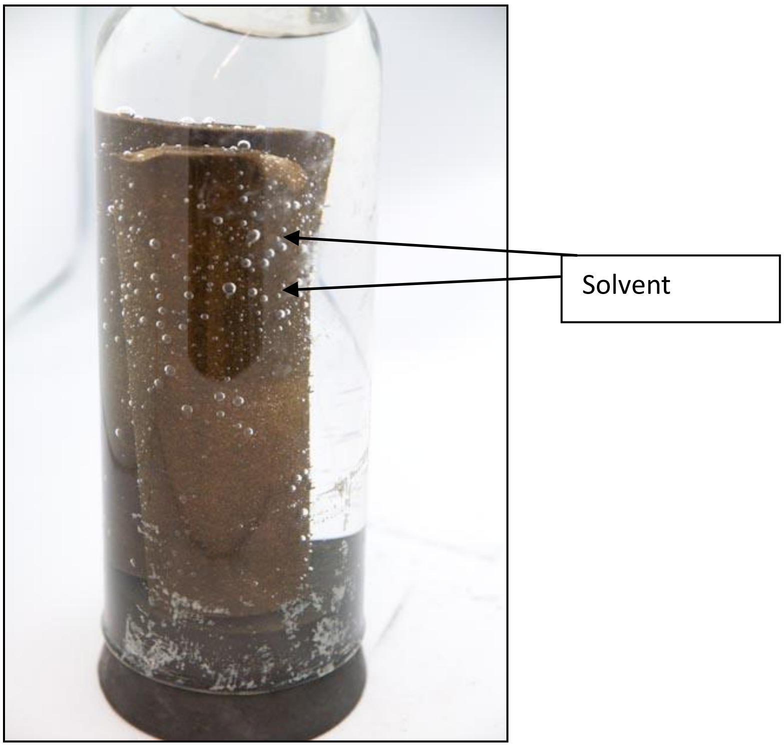

Figure 30: Solvent bubbles when the core was subjected to 90^{o} C distilled water after the completion of all three phases (for 5 cc/min solvent injection rate) at dynamic conditions. It shows that most of the solvent which was in the swept area was actually produced during Phase 3 and only a small amount of it, as seen in the picture, was removed under static conditions.

Chapter 4: 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

This paper has been submitted to Energy and Fuels for publication

1. **Preface**

Heavy oil recovery from tight naturally fractured carbonate reservoirs is a great challenge to the oil industry and yet no well-established recovery technique has been adopted by the oil industry. Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR) is a new technology proposed as an alternative method to the sole injection of steam or solvent and this paper introduces this method through extensive experimental evidence and analysis. The method consists of three phases: (1) steam (or hot-water), (2) solvent, and (3) steam (hot water) injection. Phase 1 produces heavy-oil by thermal expansion and conditions the oil for Phase 2, which is solvent injection. Phase 3 is applied mainly to retrieve the solvent.

Several static experiments were conducted to mainly test four critical parameters: (1) Wettability of the matrix, (2) solvent type, (3) initial water saturation, and (4) matrix boundary conditions. This was followed by several dynamic experiments, which were aimed at testing the effect of solvent injection rate on the process.All three phases yielded above 90% recovery with 85-90% solvent retrieval if matrix boundary conditions were favourable (large surface area per volume for effective solvent diffusion) when heptane was used as the solvent, regardless of the wettability of the matrix.

After provision of the experimental results, we discuss the upside and downside of the technology and suggests ways to improve it. The importance of this work is that it provides a novel perspective on the interaction between steam/solvent and heavy oil in the matrix, and presents an alternative technique for heavy-oil recovery from deep naturally fractured reservoirs with tight and oil-wet matrix.

2. Introduction

It is an inevitable fact that global energy demand is in an increasing trend and will remain so for the next few decades. Heavy-oil and bitumen resources have a significant impact on meeting this demand due to their huge but almost untouched volume. With around 7 trillion barrels of heavy oil available globally, lack of an efficient, feasible and environmentally friendly heavy oil production technology is eminent. Several methods were considered to produce heavy oil with one main concept in mind: viscosity reduction. The proposed methods can be categorized under three main categories: (1) thermal, (2) solvent, (3) and the hybrid application of these.

Several options of the thermal methods were proposed to reduce the viscosity of heavy oil. Such methods include steam injection, air injection, and electrical heating. Among these, steam injection has been most widely used and different versions of this method have been proposed and field-tested (steamflooding, cyclic steam stimulation, steam assisted gravity drainage (SAGD), and thermally assisted gas-oil gravity drainage -TAGOGD). The main disadvantage of steam injection is the amount of energy needed to generate enough steam to effectively reduce oil viscosity and hence to mobilize the oil. With thin reservoirs, heat losses to the over and underburden of the reservoir make production through thermal methods generally, and steam injection particularly, inefficient and uneconomic. This also is applicable to heavy oil trapped in fractured carbonate (oil wet) reservoirs where the matrix is too tight to mobilize heavy oil. Even with viscosity reduction of heavy oil in the matrix, the oil wetness of the reservoir introduces a great challenge for the water to imbibe into the matrix draining oil. Other researchers suggested that a high temperature injection of steam would actually cause the matrix to become water wet. Even with such consideration, to elevate the matrix temperature to the extreme where it reverses wettability is considered to be a huge energy sink. This has urged researchers to find alternative methods to reduce viscosity through other means, which has led to the introduction of chemical methods for heavy oil production.

The VAPEX (vapour extraction) technique was suggested for heavy-oil recovery as an alternate to steam injection for thin, clean, and clastic heavy oil reservoirs (Butler and Mokrys, 1991) and is the most widely known solvent injection technique for heavy-oil/bitumen recovery. Its economics and applicability at the field scale, however, have not been proven yet. The main hurdle with solvent injection is its tendency to disturb the oil chemical system negatively causing asphaltene to precipitate and deposit and clog pore throats.

Another method to tackle the challenge of heavy oil production is the employment of both steam and light hydrocarbon (solvent) injection in a hybrid manner. These methods can be categorised under two main categories: (1) solvent addition to steam (Expanding Solvent-SAGD (Nasr et al., 2003)), Liquid Addition to Steam for Enhancing Recovery (LASER) (Leaute and Carey, 2007) and (2) steam alternating solvent (SAS) (Zhao et al., 2005, Zhao, 2007).Both methods are targeted towards production for clean and highly permeable clastic reservoirs.

On the other hand, huge quantities of heavy oil are trapped in tight but fractured carbonate reservoirs. Until recently, except for limited efforts in the applicability of steam injection at a field pilot scale, there was no method introduced to produce heavy oil from fractured carbonate reservoirs. This has urged us to find a novel technology to target specifically tight fractured carbonate reservoirs, and a new approach named Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR)was introduced in 2008 (Al Bahlani and Babadagli, 2008) for efficient recovery of heavy-oil from fractured reservoirs.

2.1. Problem statement

An intensive amount of research was conducted to investigate the effects of steam injection on the mechanics of heavy oil recovery from homogeneous high permeability sandstones (Pratts, 1982). In homogeneous sandstone reservoirs, the recovery mechanism is mainly through the displacement of oil by steam or hot water. However, in NFRs, the recovery is mainly based on gravity drainage achieved by heat introduction into the system causing oil to expand and drain from the tight low permeable matrix to the highly permeable fracture(Briggs et al., 1988, 1992; Reis, 1992; Babadagli, 1996a-b, 2002-a). As mentioned earlier, this is a complex process and yet a big challenge. Low oil gravity makes heating a necessity for oil mobilization. The only proven and relatively effective thermal technique to provide such necessary heat is through steam injection and yet this process is not well defined.

In conjunction with all of these facts, steam injection in NFRs requires a massive amount of energy to heat large matrixes, which makes the efficiency of the process very low. Most –if not all– of the steam transfer occurs in the highly permeable fracture network causing rapid steam movement within the reservoir. This may result in an early steam breakthrough and hence an extensive amount of energy is consumed without efficient heating. This provides a substantial logistical challenge in terms of water availability, pre- and post- injection treatment, and disposal with minimal environmental impact. Also, a gravity dominated process between immiscible fluids is very slow (low recovery that might take decades) which is very critical from an economic prospective. All these reasons make applying steam injection in NFR carbonates very rare.

Until the publication of this paper, only five steam pilots in fractured carbonates were reported: (1) The Lacq Superior field, France (Sahuquet and Ferrier, 1982), (2) The Ikiztepe field, Turkey (Nakamura et al., 1995), (3) The Qarn Alam field, Oman (Macaulay et al., 1995;Al-Shizawi et al., 1997), (4) The Yates field, USA (Snell and Close, 1999), and (5) The Bati Raman field, Turkey (Babadagli et al., 2008). The decision to go for a full field application was only made for the Qarn Alam project (Rawnsley et al., 2005; Penney et al., 2005; Shahin et al., 2006) and conversion to full field application is still in progress.

In addition to the field scale pilots listed above, a limited number of lab scale experiments were conducted to investigate oil production from naturally fractured carbonate reservoirs. Pronounced amounts for matrix recovery in fractured carbonates based on laboratory scale experiments and field pilots were not very optimistic. Babadagli and Al-Bemani (2007) conducted several matrix heating experiments on the Qarn Alam cores containing heavy-oil. They demonstrated at very favorable laboratory conditions that matrix oil drainage does not exceed 31%. Obviously, once this number is upscaled to the field scale, then it will decrease to a much lower value. Shahin et al. (2006) reported that for the Qarn Alam field, production without thermal assistance is only 4% and the increase in recovery is only 27% by steam injection through TA-GOGD. Note that as reported by Macaulay et al. (1995), the drainage process is very slow and it is in the order of decades.

Those clear facts entail that new methodologies to recover more oil at much faster rates are critically needed. Several attempts were made in order to improve matrix recovery through surfactants in the past. However, finding the suitable surfactant, and the high cost of the process limits the field application for fractured carbonates (Babadagli, 1996-a; Spinler, 2000; Chen et al., 2000; Babadagli, 2001; Babadagli 2002-b; Standnes et al., 2002; Babadagli, 2003a-b-c, Babadagli, 2005; Babadagli et al., 2005; Babadagli and Boluk, 2005; Standnes and Austad, 2003; Babadagli, 2006; Hatiboglu and Babadagli, 2007).

Wettability alteration is one of the main problems in carbonates since most of these reservoirs are oil wet while water wetness is needed to enhance matrix drainage by gravity and capillary imbibition. Surfactants (Zhou et al., 1993; Standnes and Austad, 2003) and steam heating (Rao, 1999; Al-Hadrami and Blunt, 2001; Seethepalli et al., 2004; Schembre et al., 2006; Gupta and Mohanty, 2008) have a certain effect on wettability alteration to some extent. However, as the oil in the matrix becomes heavier, the success of these processes becomes more questionable.

All of these challenges and proposed solutions suggest that more sophisticated and efficient techniques are required for heavy-oil recovery from fractured carbonates (oil stored in the matrix). Hatiboglu and

Babadagli (2008 a-b) showed that even light oil samples (around 35 cp) in a weakly water wet matrix yielded no recovery by capillary imbibition in an economical time frame. They suggested and tested solvent diffusion into an oil-wet matrix as an alternate to waterflooding (recovery mainly by capillary imbibition). In this case, the main challenge would be the retention of the solvent diffuse into the matrix used which is a challenge in fracture systems. As oil becomes heavier, oil recovery would require additional heat energy to mobilize the oil in addition to the solvent, which might also result in asphaltene deposition.

Recent studies conducted by Al-Bahlani and Babadagli (2008, 2009a-b, 2010, 2011) led to the introduction of a new technique to recover heavy oil from fractured carbonate oil wet reservoirs by combining steam (hot water) and hydrocarbon solvents. Their work focused on the initial mobilization of oil through steam injection, recovery improvement by solvent (miscible) injection, and retrieval of the expensive solvent injected. This process, called Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR), was observed to be efficient due to high recovery but needs further clarification in terms of its economics controlled by the recovery time of oil and the retrieval of solvent injected (Al-Bahlani and Babadagli, 2010) and up-scaling to field conditions (Al-Bahlani and Babadagli, 2009a; Singh and Babadagli, 2011). In this paper a detailed description and analysis of this method was reported with experimental and numerical model results. Main parameters studies as to the efficiency of the process are the matrix properties (rock type, permeability and wettability), solvent type, injection rate, and matrix drainage capacity, mainly controlled by its size and boundary conditions.

2.2. Description of the SOS-FR technique

SOS-FR is a new approach, which was developed in early 2008 (Babadagli and Al-Bahlani, 2008) for heavy oil production from fractured (especially oil wet) reservoirs. It employs the advantage of both steam and solvent injection into fractured reservoirs for the efficient recovery of heavy-oil from fractured carbonate reservoirs. The main idea behind the technique is to create several thermal and chemical disturbances that will cause the system to readjust and hence expel the oil from the matrix to the fracture. Thus, an introduction of heat discrepancy between the fracture and the matrix will cause oil trapped in the matrix to thermally expand first. Depending on the wettability characteristics, a certain amount of water (condensed water from steam) will imbibe into the matrix. Meanwhile, reduced viscosity will accelerate the drainage of oil during this period and also condition the oil in the matrix for the next phase: solvent injection.

Once the matrix is relatively heated, a chemical disturbance is created by the introduction of a light hydrocarbon solvent. This will cause solvent introduction into the matrix mainly by diffusion and will interact with the conditioned oil in it, eventually causing several different processes to displace and produce it (mainly gravity drainage accelerated by density alteration due to diffusion and a dispersion process in the matrix).

Since, the solvent is an expensive entity, it is very important to retrieve it. Thus, steam (or hot-water) is injected causing the solvent to be expelled through thermal expansion and phase change (by boiling if the temperature is close to its boiling point),which will cause further oil and solvent to be produced.

Hence, the process is mainly divided into three main phases:

1) Phase 1: Steam (or hot-water) injection (mainly for heating and thermal expansion),
2) Phase 2:Solvent injection (for diluting the matrix oil by diffusion),
3) Phase 3: Steam (or hot-water) injection (for retrieving the solvent penetrated into the matrix with some additional oil recovery).
4) Research methodology

To understand the physics of the proposed method and to identify the critical parameters, a research methodology based on a series of experimental runs was developed. The whole program consists of two parts: (1) static (no injection, only matrix behavior), and (2) dynamic experiments (injection through fractured samples).

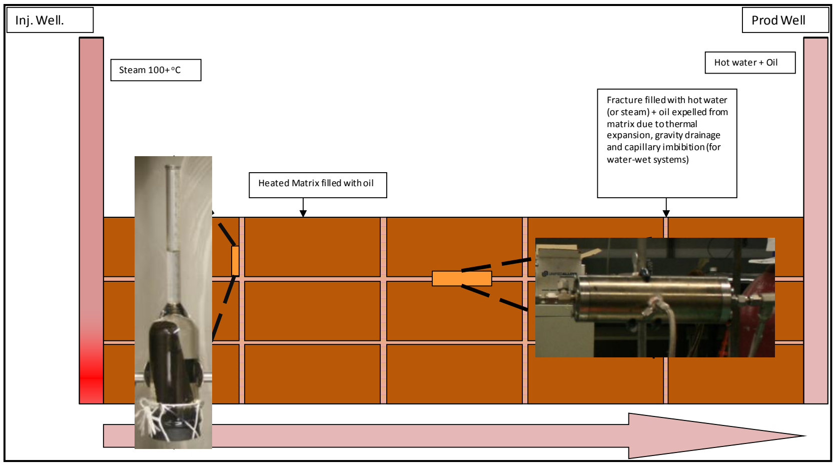

Figure 1: Experimental methodology using static and dynamic experiments and how they mimic the processes at reservoir conditions.

Figure 1 describes the process in naturally fractured reservoirs. As seen, the static experiments account for the matrix contribution to the recovery when it was exposed to fluid flowing in the fracture (steam, hot-water, solvent) without considering the effect of fracture parameters and injection rate. The dynamic experiments, on the other hand, are conducted to clarify the effects of injection rate and fracture properties, in a sense yielding a more realistic picture of the process as a very small scale model of the field scale application. The experimental design and results are summarized below:

3. Experimental design and procedure

3.1. Static core experiments

Static experiments refer to immersing a rock matrix element into the liquid that was expected to fill the fracture network to interact with the matrix oil. The main advantage of the static experiments is to study the physics of the matrix-fracture interaction in its simplest form. This is a common and initial approach applied in the assessment of the enhanced oil recovery potential of a matrix element in naturally fractured reservoirs. Cores of different shape, size, wettability, and initial water saturation were subjected to the process composed of three distinct phases as listed above. The core plugs were immersed into hot water (90 ^{o}C) inside an imbibition cell to mimic Phase 1.

1) The reason for selecting this particular temperature range was twofold:
2) Experimental simplicity: For the initial tests, steam was avoided in order to run as many experiments as possible for different conditions and simplifications were needed. Steam experiments (temperature over 100^{o}C) require a special design of closed systems and this would limit the visual observations of the matrix behavior significantly.
3) It is safe to assume that most of the steam at deep naturally fractured reservoirs will have very poor quality once it arrives to the sandface. Therefore, designing a new recovery technique for pessimistic (low temperature – low steam quality) scenarios are critical. For shallow, reservoirs, that also brings the advantage of low cost due to low quality steam. Note, however, that as will be discussed later, the

temperature range is critical in Phase 3 as it determines the solvent retrieval rate and should be near the boiling point of the solvent used.

Phase 1 was followed by Phase 2 in which the core plug was immersed into the selected solvent. The change in the color of the solvent surrounded was monitored and refractometer readings were taken periodically to estimate the amount of oil recovered. Also, solvent was replenished periodically to mimic solvent supply during continuous injection of it at slow rates. After completing Phase 2, i.e., no significant color change occurred in the solvent surrounding the core and the core was placed into hot water at 90^{o}C (the same apparatus as in Phase 1) in an attempt to retrieve the solvent diffused into the matrix.

3.2. Dynamic experiments

For further numerical simulation studies to assess the process at field conditions, dynamic experiments are needed. Dynamic experiments were designed to examine the rate dependency effect on the process, mainly during the second phase. The injection rate controls both the amount and time of contact between the solvent in the fracture and the oil in the matrix. A core plug with an induced fracture in the middle is subjected to the three phases of the SOS-FR method. The variable in the dynamic experiment is the solvent injection rate. Dynamic experiments will also lead to a good understanding of the solvent injection strategy at field conditions.

4. Core preparation for static and dynamic experiments

Two different types of cores are used for these experiments: (1) Berea sandstone (outcrop) and (2) carbonate limestone (obtained from a producing formation) cores (**Table 1**). The wettability of the Berea sandstone cores was altered from water wet to oil wet using a wettability alteration agent. The wettability alteration process is as follows:

1. A clean core is placed inside a core holder with a rubber sleeve and an overburden pressure to hold the core in place. The core is placed vertically and fluid is injected from bottom to top using a syringe pump.
2. The wettability alteration fluid is prepared by adding 3% of the active agent with 97% of Toluene. Four pore volumes of the mixture are then injected in the core at a rate of 5 cc/min.
3. The mixture is then followed by equal pore volumes of pure toluene to remove any active agents that didn't stick to the rock surface.
4. Four pore volumes of methanol are then injected to complete the wettability alteration process.
5. The samples are then placed in an oven at 100^{o}C for 24 hours.

Once the wettability alteration process is completed, for the dynamic experiments, fractures were induced in the middle of the core using a saw machine in order to use them for dynamic experiments. For carbonate limestone cores, no wettability alteration was applied, as they are naturally oil-wet. The carbonate cores were cleaned using the Soxhlet device before saturation.

With some exceptions (cores prepared with initial water saturation), all cores were saturated with 100% oil. The cores were then placed inside a sealed container filled with heavy oil (15 ^{o}API, 8,000 m.Pa.s @ 25^{o} C, 0.97 g/cc). The whole system was placed inside a convection oven of 80^{o}C. The container was then connected to a high pressure vacuum for 7-10 days for saturation. The process continued until all air was removed. Once all air was sucked away from the cores, the oven was shut down and the cores were left to cool under a vacuum to account for the oil thermal contraction. The vacuum pressure was then gradually reduced. The cores were left to age at ambient temperature for another 10 - 14 days. Next, the results for static and dynamic experiments were summarized and analyzed as given in the next section.

5. **Results**

5.1. Static experiments

As mentioned earlier, the motive behind static experiments was to understand the physics of the interaction between the fracture and the matrix without any intrusion of induced mechanical forces such as fluid flow. The static experiments examine three different elements of the process:(1) solvent type, (2) matrix wettability, and (3) matrix boundary condition and orientation effect. All the cores tested under static conditions were subjected to the three phases as follows:

1) Phase 1: To resemble steam/hot-water injection into a reservoir, the core was placed into an imbibition cell and then immersed into 90^{o}C hot distilled water. The core was then placed inside a convection oven preheated to the same temperature (90^{o}C). The oil produced was collected and measured at the top of the cell. This procedure is considered common practice for enhanced oil recovery in naturally fractured reservoirs named as imbibition experiments. **Figure 2** shows a producing core through thermal expansion inside an imbibition cell.

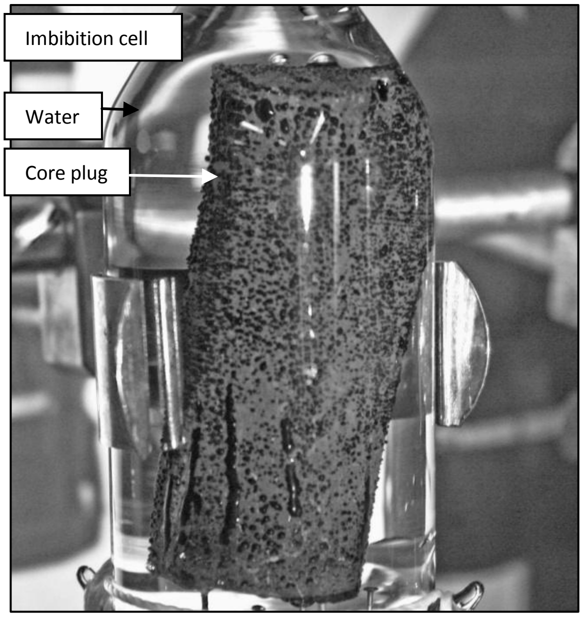

Figure 2: Core plug immersed in hot water inside an imbibition cell which is placed inside a 90 ^{o}C oven to conduct Phase 1 of the SOS-FR technique.

2) Phase 2: The cores were removed from the hot water and their weight was measured after the first phase. Then, the cores were placed in an ambient temperature solvent **(Figure 3)**. The concentration of oil in the solvent was measured using a digital refractometer.

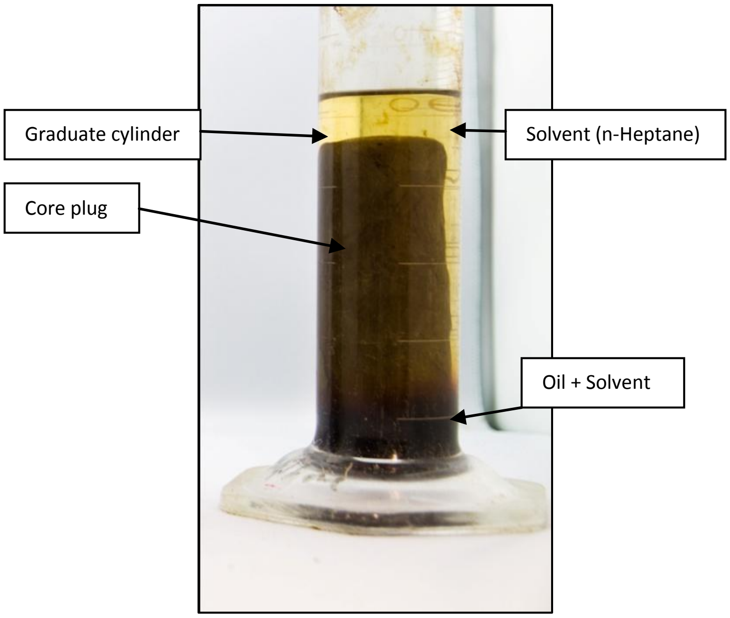

Figure 3: Phase 2: Core plug immersed in n-heptane solvent at ambient temperature. The core plug is covered in epoxy and only the upper part is open to solvent. The photo clearly shows the gravity segregation between the solvent (top part) and the oil/oil-solvent mixture.

3) Phase 3: The core is replaced in an imbibition cell filled with distilled water and then placed in a hot water bath of 90 ^{o}C **(Figure 4-a)** in an attempt to retrieve the solvent and some extra oil **(Figure 4-b)**.

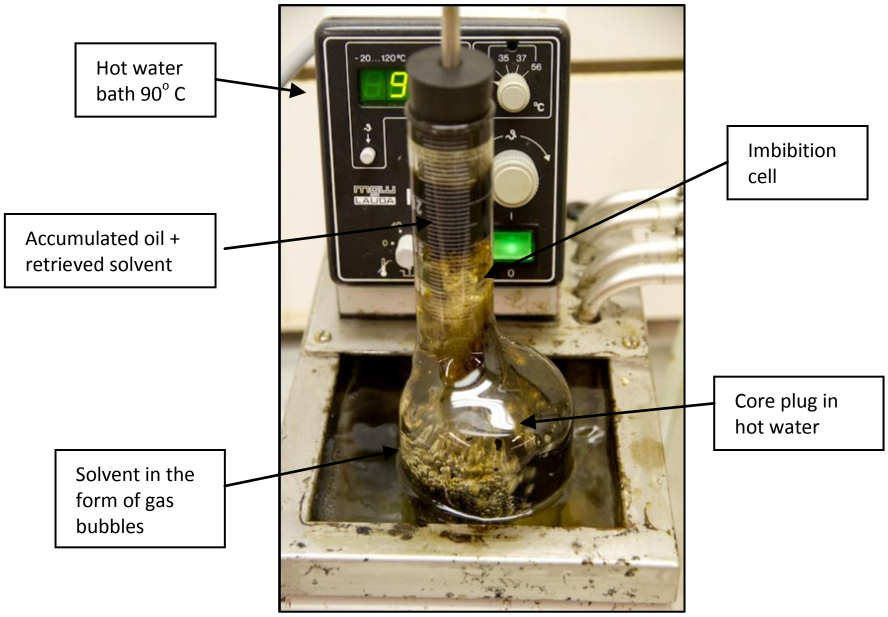

Figure 4-a: Phase 3: Core plug is immersed into an imbibition cell placed inside a water bath. The figure shows intense bubbling of the solvent and accumulation of light oil on top and the recovered solvent.

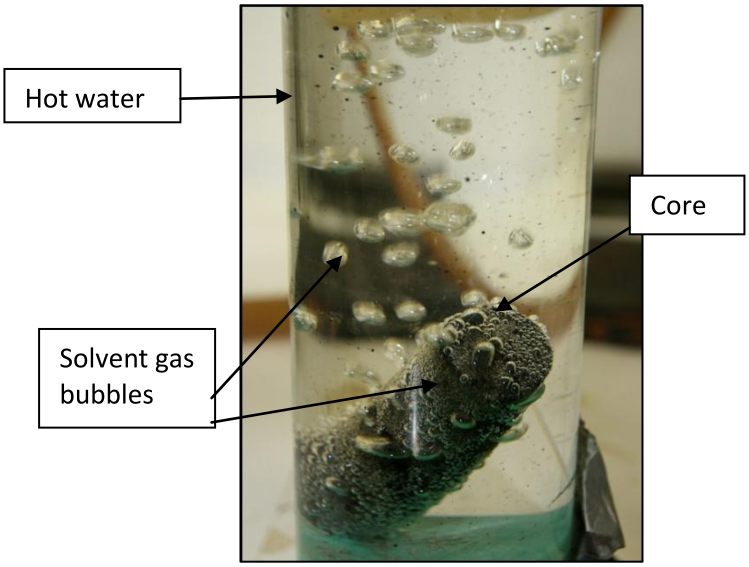

Figure 4-b: Core immersed into hot water at Phase 3 after a long exposure to solvent. It can be clearly seen that core is bubbling the diffused solvent out at a very fast rate as the temperature is close to the boiling point of the solvent.

5.1.1 Effect of solvent type on the process

Three different molecular weight solvents were used to investigate the effect of solvent type on the recovery process. Different types of solvent will have different effects on the process (recovery and asphaltene precipitation) due to different diffusion capability to the oil in the matrix (the higher the molecular weight and the lower the diffusion rate).The solvents tested are, in the increasing order of the carbon number and molecular weight: heptane, decane, kerosene, and light crude oil. As seen in **Figure 5**, the production of oil becomes higher with decreasing molecular weight solvent of the solvent. The diffusion into the matrix was so slow with higher molecular weight solvents that the production lessened to the extent that light crude oil did not produce any oil during Phase 2. This is because the process is also dominated by a gravity difference between the oil and the solvent, which is much lower in the case of crude oil and heavy crude oil. However, it was also noticed that asphaltene precipitation was much higher with a lower molecular weight (**Figure 6)**.

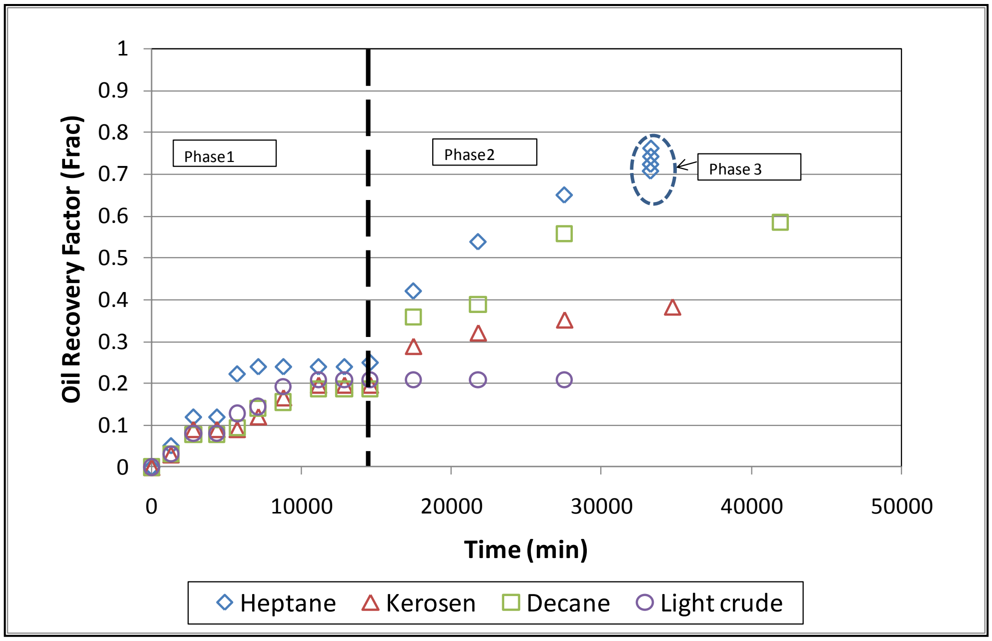

Figure 5: Comparison of different solvent types used to improve recovery from oil wet Berea sandstone core plugs. Only core treated with n-heptane was able to retrieve the solvents by 90^{o} C hot water at Phase 3. (Data adapted from Al Bahlani and Babadagli 2009b).

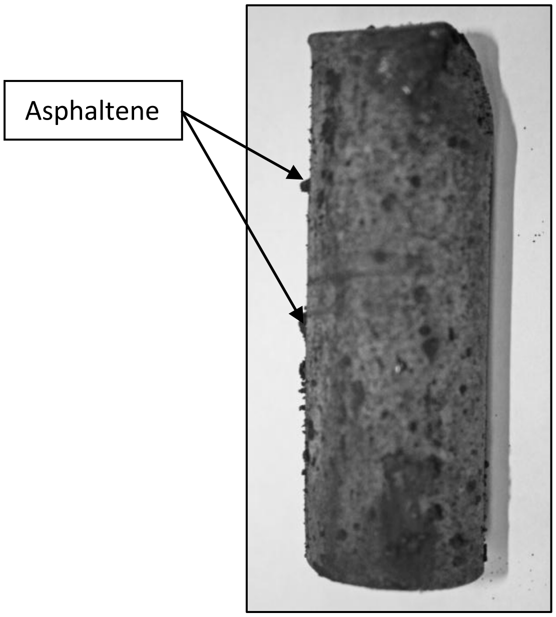

Figure 6: Asphaltene precipitation on a core immersed into n-heptane.

When the cores were immersed into the solvent to attempt of diffusion of solvent recovery by immersing the solvent in a hot water bath, only cores immersed into n-heptane recovered some amount of solvent. The reason for that is that the temperature was close to the boiling point of the solvent (heptane) at atmospheric pressure and the solvent boiling was the main retrieval mechanism. The other cores saturated with heavier solvents did not show any recovery at 90^oC as this temperature is way below the boiling temperature of other solvents used: Decane (174 ^oC) and kerosene (150 ^oC).

5.1.2 Effect of matrix wettability on the process

Cores with different wettabilities were subjected to the same process. Figure 7 compares three cases: (1) Water wet sandstone, (2) sandstone, wettability altered chemically (as described in section 4.1.3), and (3) carbonate cores. In each experiment, the cores were left to cool down to the room temperature after Phase 1.

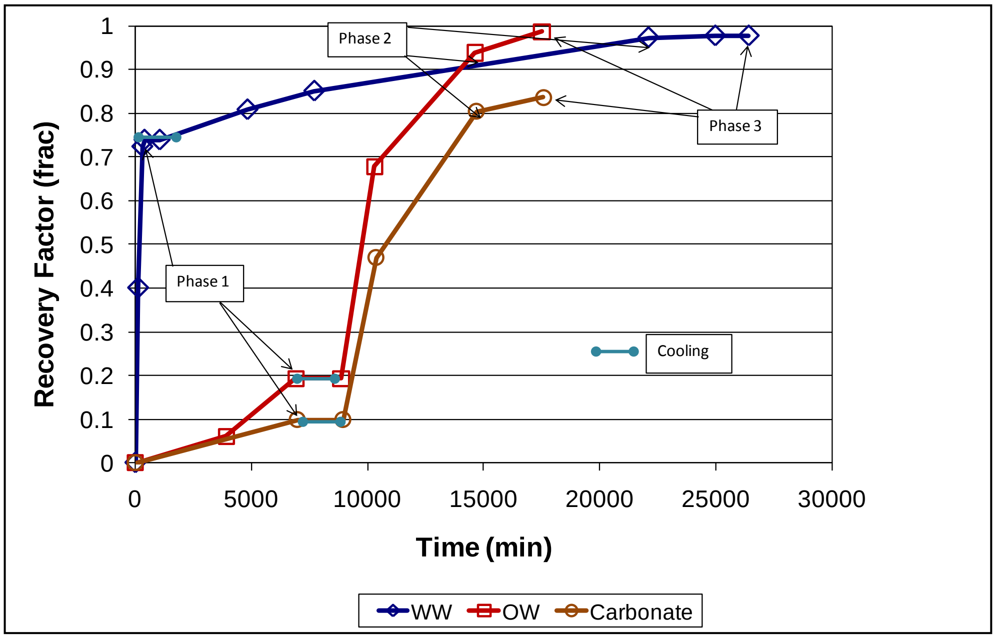

Figure 7: Comparison of different wettability profiles, water wet (WW), oil wet (OW) and carbonate (carb) (data adapted from Al-Bahlani and Babadagli (2008). Ending times of each phase are indicated by arrows. The samples were exposed to a cooling period after Phase 1 for a short period of time.

It can be clearly seen in **Figure 7** that water wet cores did produce much more by capillary imbibition and accelerated gravity drainage during Phase 1 due to favorable wettability. As expected, however, their performance during Phase 2 was not as good as the oil wet and carbonate cores. Thus, the role of wettability type shows that it may have a profound effect on the whole process: this is mainly because oleophilic surfaces promote the advance of solvent in the medium while hydrophilic surfaces adhere to water which makes it difficult for solvent to drain any water that intruded into the system.

5.1.3 Effect of matrix boundary condition and orientation

Four different cases with different boundary conditions were tested using carbonate limestone cores saturated with heavy oil. Three cores were covered with epoxy from all boundaries except one of the flat surfaces of the cylindrical cores, and then placed into the imbibition cells in three different positions: (1) open part facing upwards (vertical positioning), (2) open part facing downwards (vertical positioning), and (3) horizontal positioning (open part facing E-W direction) **(Figure 8)**.

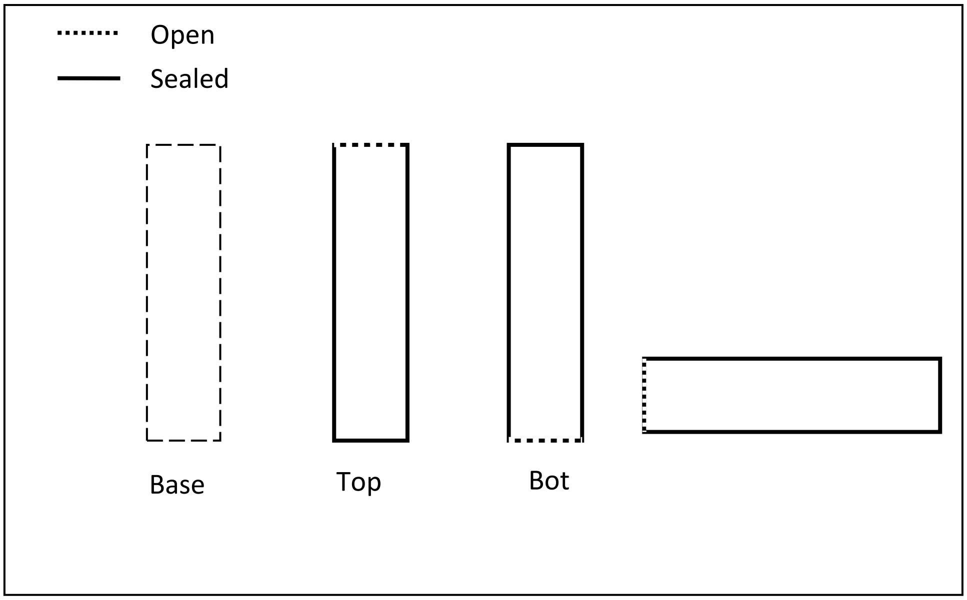

Figure 8: Schematic representation of the boundary conditions of the cores and corresponding abbreviations used in the graphs to represent the experiments.

In order to have a good benchmark for the process, the fourth core was not covered with epoxy (all sides open): This will resemble the best case scenario. Unlike the previous cases, after Phase 1, the cores were not left to cool down and Phase 2 was initiated immediately in order to take advantage of the thermal effects on enhancing diffusion.

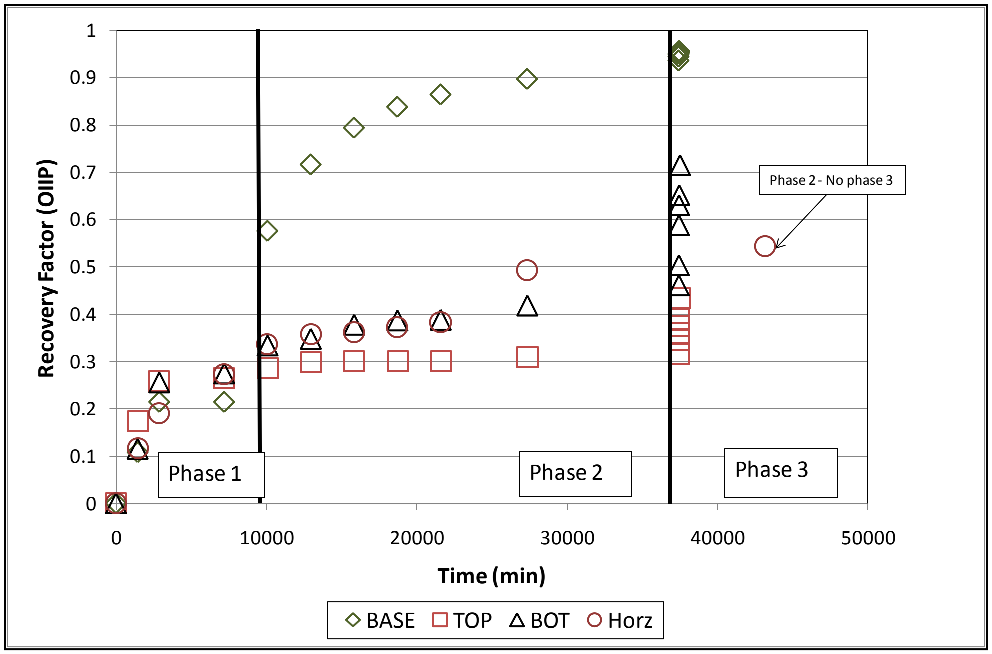

Figure 9: Comparison of different boundary conditions. Base: No epoxy, Top: Top part of the core is open, Bot: Bottom part of the core is open, Horz: One side is open and the core is placed horizontally. OOIP: Original Oil In-Place (fraction).

Figure 9 clearly marks the three phases of different boundary conditions used for this experiment. During Phase 1, all four cores produced more or less the same amount of oil due to initial oil thermal expansion and possible gravity drainage. Once the cores reached a clear plateau, the cores were immediately immersed in solvent without cooling which usually results in an enhanced diffusion and solubility between solvent and oil.

This caused the initial bump in recovery for all three cases (Top, Bot, and Horz) with a limited exposure area. For the case “Base” where no epoxy was used to cover the core, production is much higher and rapid than that of the others, which shows that several mechanisms are acting to produce oil other than diffusion which is very slow. The worst case scenario here can be considered when the open face is placed upward “TOP”; we can see an initial bump of recovery due to thermal effects, but production then seizes to almost zero. This is mainly because diffusion of solvent into the oil is very slow, causing oil swelling and expulsion from the matrix to the fracture in a very time consuming manner. However, we can see a very high increment of oil recovery (10% in one hour) during phase 3 in a very short time. This can be attributed to solvent diffusion although it is a very slow process, but it can change heavy oil property to less viscous oil and lower density oil.

For the cases “BOT” and “Horz”, where the cores are placed open face downward and open face horizontal respectively, the production is much better than the case “TOP”. This increment in production is mainly due to the effect of gravity (density difference) between the oil and the solvent. After approximately 22,000 minutes, the “Horz” core was rotated 90^o along the x-axis, this will make any solvent which entered the matrix and settled on top of the core to be below the heavy oil up. It can be seen that this created a large increment in recovery of around 10%. During Phase 3 the core with bottom side open “Bot” produced a huge increment in oil recovery in a very short period of time (25% in 75 minutes). The main reason for this recovery is the mechanism by which oil was produced during Phase 2. Since the core is placed open side downward, heavy oil drains from the core mainly due to gravity causing oil to drain much faster as can be inferred from **Figure 10** (oil accumulated at the bottom of the experiment cell)**.** Note that Phase 3 result for “Horz” case were not included mainly due to experimental setup challenges in collecting and analyzing samples for horizontally situated cores. An attempt was made and Phase 3 was run for the “Horz” case and a large amount of solvent gas was released quickly during experimentation but reliable quantification of the amount was not possible.

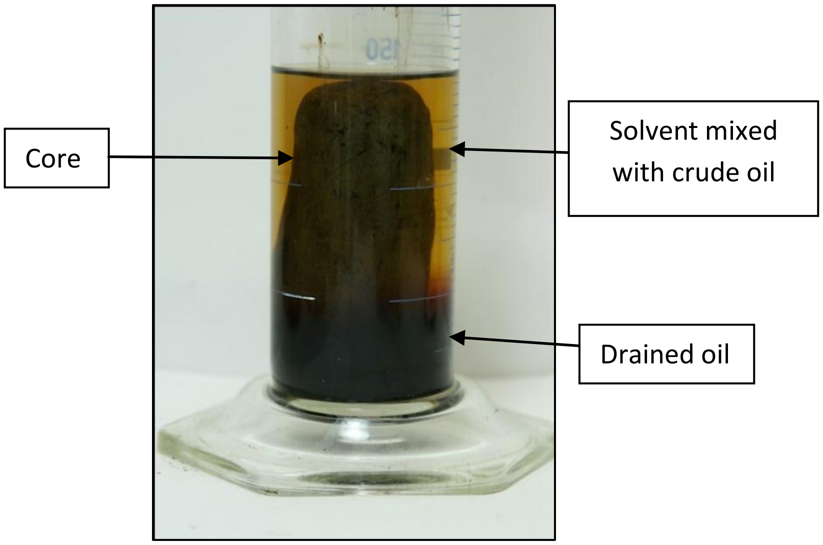

Figure 10: Effect of boundary condition on solvent recovery Phase 2. Oil is draining by gravity from the bottom of the core causing gravity segregation between oil and solvent as can be seen from the discoloration of the fluid.

Also, Al-Bahlani and Babadagli (2011) showed that fingering from bottom to top creates a counter current movement inside the matrix, which allows for better mixing between the solvent and hence lighter oil. As solvent enters the matrix during Phase 2 it tends to settle on top of the matrix, and when heat is introduced, it tends to thermally expand rapidly causing oil to be pushed out of the matrix.

5.1.4 Initial water saturation

For this experiment, the cores used were Berea sandstone of which wettability was altered as described earlier. One core was then saturated with synthetic 3% brine under a vacuum. The core was then placed inside a core holder and injected with around 5 pore volumes of oil. For injectivity purposes, the viscosity of oil was reduced by adding light crude oil to the heavy oil used on the other cores. The other core was immersed in the mixed oil and it was saturated under vacuum without heating. Only Phases 1 and 2 were conducted for this experiment to examine the effects of fluid distribution on the process.

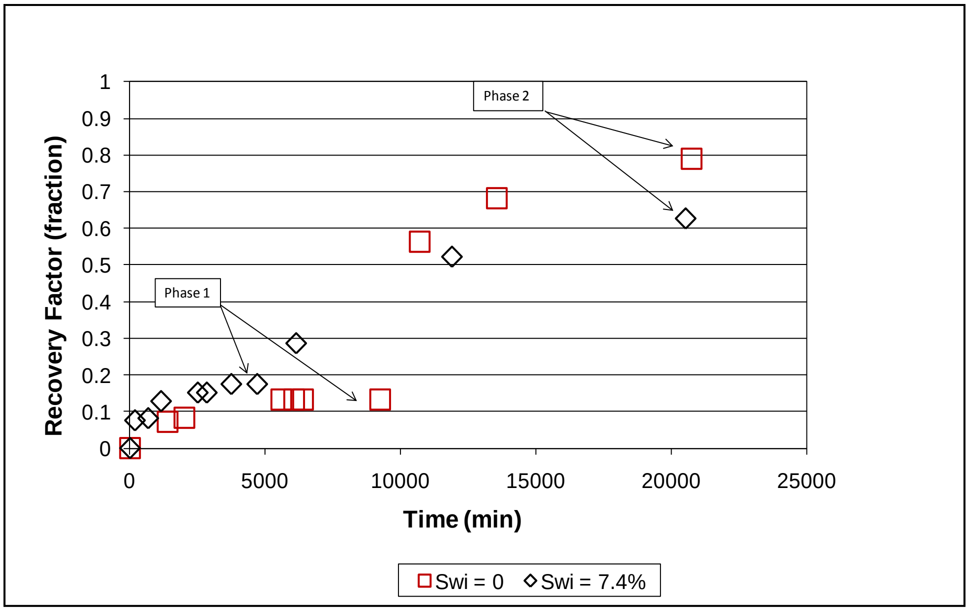

Figure 11: Effect of initial water saturation on the process between two cores, one saturated with light crude oil. The ending times for the phases are indicated by arrows.

Figure 11 shows that the effect of initial water saturation has quite an impact on the recovery. We can see that during Phase 1, both cores produced almost the same amount of oil; however, the core without initial water saturation reached the ultimate recovery (plateau) later. During Phase 2, the core without initial water saturation recovered a much higher amount of oil than that with initial water saturation. This is mainly due to possible blockage of water drops to the pore throats, which seizes diffusion or any counter current movement from happening. However, some water was noticed to drip out of the core during Phase 2 as it can be seen from **Figure 12.**

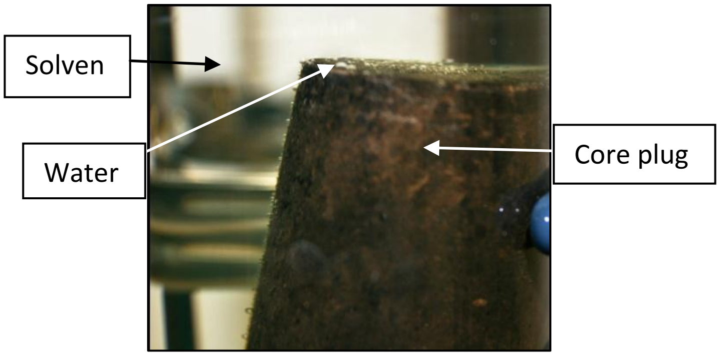

Figure 12: Oil wet core immersed in solvent showing water drops leaving the core and as solvent imbibes into the system during Phase 2. Capillary imbibition is not expected to be critical as the amount of water in the system after Phase 1 is trivial and gravity drainage dominated by diffusion controls the process.

To further understand the process a simple tube experiment was done where the tube was wettability altered the same way as the cores and then saturated with crude oil (**Figure 13**). The tube was subjected to hot water for thermal expansion and then it was cooled down in water for thermal contraction so that some amount of water intruded into the system. The tube was then immersed horizontally into the solvent. Although solvent wets the surface and enters the tube by capillary suction (the left end of the tube), water does not allow any solvent diffusion into the oil or create a form of counter-current movement (solvent in-water out). Hence, pore structures in cores are neither perfectly horizontal nor vertical and this may cause movement of several water drops, causing water to drain from the matrix. This explains the reason for water production during Phase 2 in some experiments.

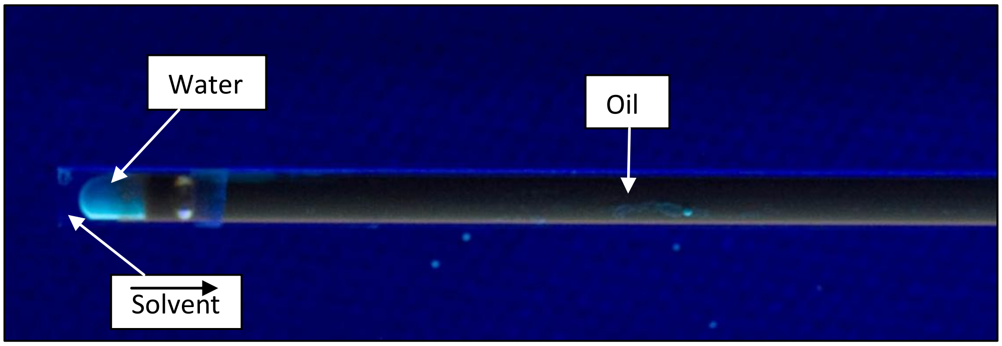

Figure 13: Tube experiment presenting visually the effect of water saturation on the process. It can be seen that water obstructs the solvent from entering into the system even though solvent is the wetting phase.

5.2. Dynamic experiments

The objective behind conducting dynamic experiments was to mainly understand the rate dependency effect on the process and to obtain a more realistic insight into the physics (matrix-fracture interaction) of the process. Four oil wet (5" x 1.5") cores Berea sandstone cores were prepared for dynamic experiments. The samples were placed inside a rubber sleeve and then located in a core holder. An overburden pressure of 100 psi was applied on the core using compressed air. The inlet of the core was connected to a heating loop immersed inside an oil bath to heat up the distilled water supplied through a syringe pump. The core holder and the oil-bath were placed inside an oven set to 90^{o}C. Two thermocouples were connected to the inlet and outlet of the core holder to measure the temperature since it was quite essential to achieve a uniform 90^{o}C throughout the core. The thermocouples were connected to an automatic data acquisition system. The dynamic testing process was initiated following these steps:

1) Phase 1: Hot water was injected at 90^{o}C at a rate of 2 cc/min (CWE). This rate is quite high for the core (or matrix) size used; however, such a rate is needed to heat the model efficiently, which was the main purpose in Phase 1. Thermocouples readings were monitored until the temperature difference throughout the core reached a value of zero. The water injection was stopped once no more oil was produced.
2) Phase 2: The core was taken out of the oven and connected to a solvent injection inlet from a syringe pump. The solvent injection rate varied depending upon the desired experimental rate, which were 0.15, 0.5, 1.0, and 5.0 cc/min. The oil solvent mixture was collected and the oil and solvent concentration was measured using a digital refractometer.
3) Phase 3: The core holder was replaced inside the oven and the outlet was connected to a T-junction outlet where one part was connected to a gas condenser, and the second part was connected to a collection point. Hot distilled water was injected at 2 cc/min (as similar to Phase 1) in an attempt to retrieve the injected solvent.

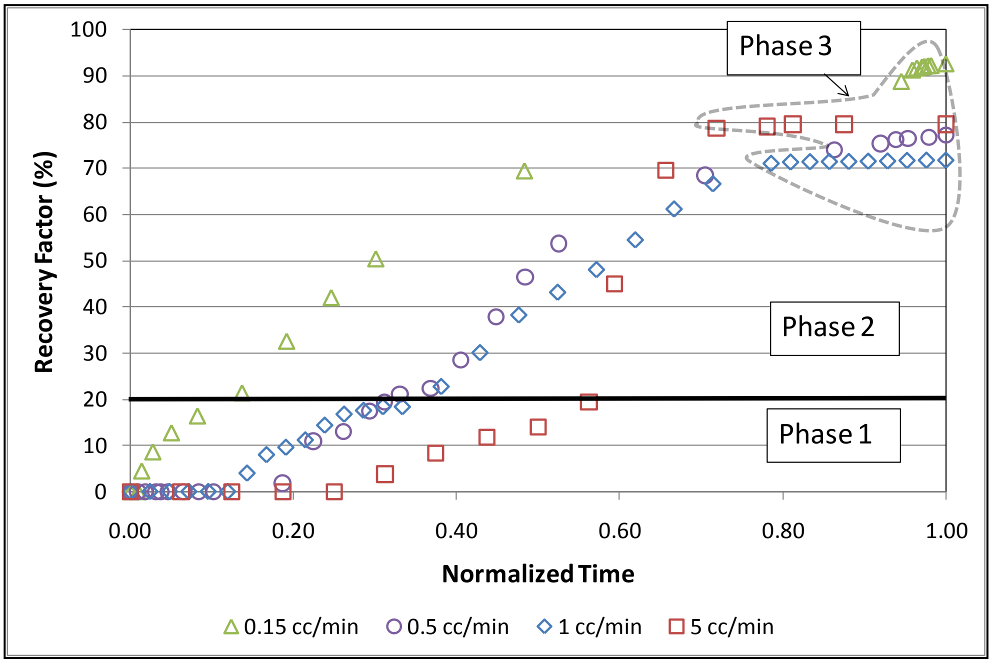

Figure 14: Recovery factor of the dynamic experiment of four different solvent injection rates showing the three phases: Phase 1; hot water injection, Phase (2); Solvent injection with four different rates and Phase 3; Solvent retrieval by hot water injection.(Data adapted from Al-Bahlani and Babadagli 2009b).

Figure 14 shows the percentage of recovery plotted against the time normalized to the total time of the experiment. It can be seen that during Phase 1 the matrix expelled almost an equal amount of oil for all rates, which is primarily due to thermal expansion. Gravity drainage or some amount of capillary imbibition (the matrix might still show some degree of water wettability as being a sandstone core) are possibly the reason for production at this stage. Phase 2 shows interesting, but expected results. The recovery rate in Phase 2 was inversely proportional to the rate of injection but the ultimate total recovery was almost the same for all rates and varies within the range of an 18% span. The recovery was very high initially and dropped down quickly. This was mainly due to the initial contact between the cold solvent and the hot matrix, since the thermal effect enhanced the diffusion of oil into the system.

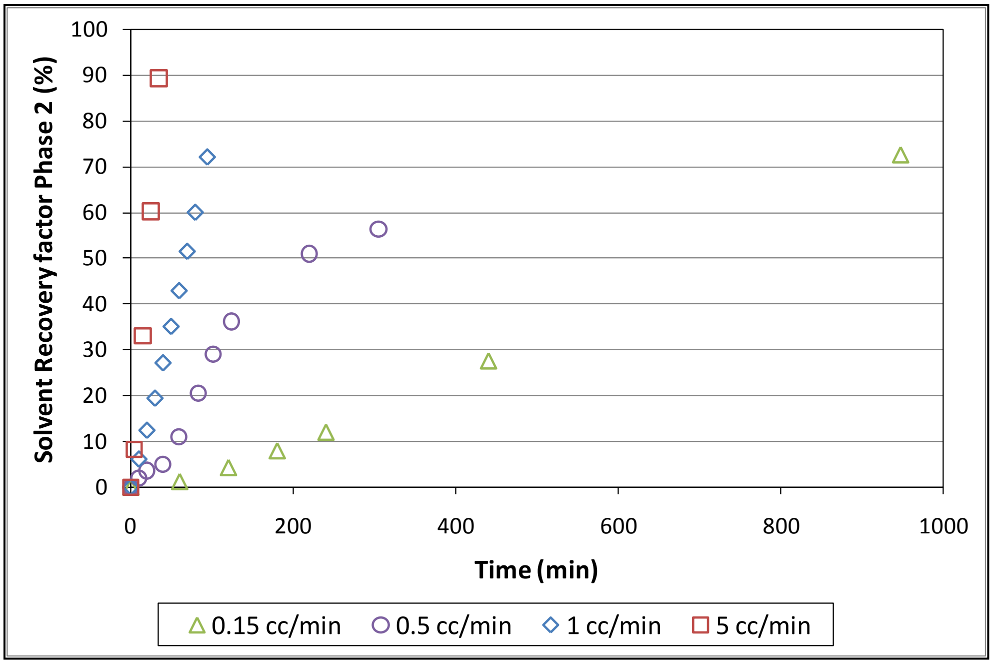

Figure 15: Solvent recovery factor during Phase 2 for four different injection rates. (Data adapted from Al-Bahlani and Babadagli 2009b).

Figure15 shows the solvent recovery factor during Phase 2. As seen, the higher the rate of injection, the higher the amount of solvent recovered. For very low rates, the amount of solvent recovered was minimal. This can be attributed to the conversion of a small amount of solvent to gas when meeting a hot temperature surface (fracture face). However, an additional amount of solvent was recovered during Phase 3 as can be seen in **Figure 16**. The total amount of solvent retrieved from Phase 2 (coming with oil) and Phase 3 is almost the same for all three phases.

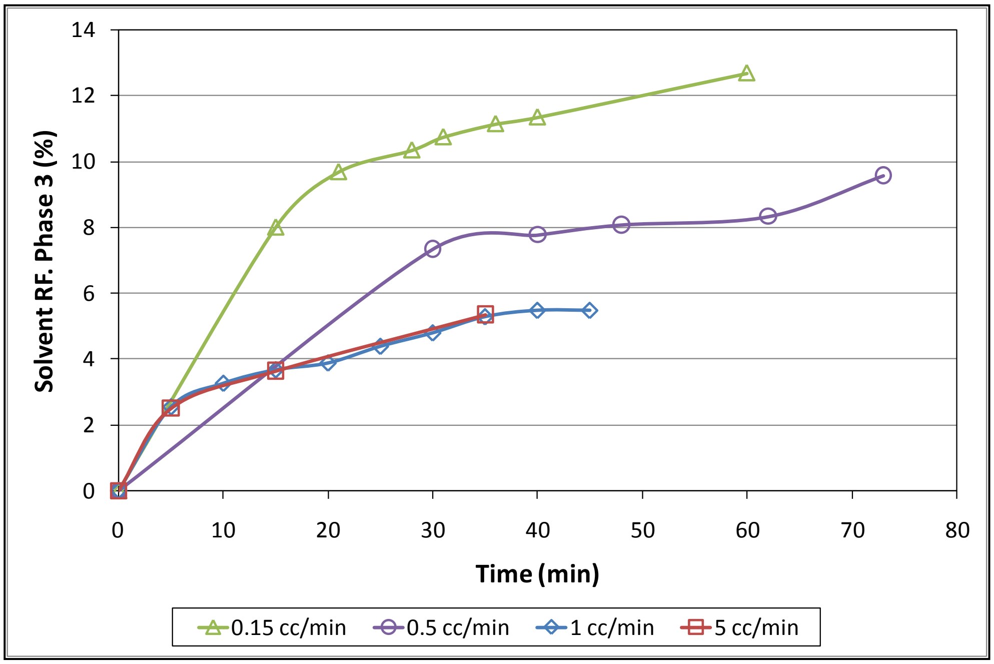

Figure 16: Solvent recovery factor during Phase 3 for cores identified by their solvent injection rate. (Data adapted from Al-Bahlani and Babadagli 2009b).

5.3. Solvent retrieval

Retrieval of solvent is the most critical part of the SOS-FR technique as it determines the economic feasibility (or efficiency) of the process. As explained above and seen in **Table** 1, solvent retrieval is very fast as long as the temperature during Phase 3 is near the boiling point of the solvent and boundary condition (solvent-matrix interaction area) is favorable. In this case, solvent retrieval is very fast and the recovered amount can be as high as 80-90% of the injected value. This process is strictly controlled by the boundary condition of the matrix. Al-Bahlani and Babadagli (2011) investigated this effect using small scale Hele-Shaw cells of 1”x3” size (a layer of crude oil sandwiched between two glass sheets). The models were exposed to Phase 2 and Phase 3.The details can be found in the relevant reference as to the dynamics of the process and its visual analysis. Here, we consider only one case: Solvent retrieval during Phase 3. Although the models possess the same characteristics, one model was situated in longer side in vertical direction (**Figure 17**) and the other one shorter side in vertical direction (**Figure 18**). Due to boundary condition that control the gravity drainage (three sides open, only one vertical side is open), both models yielded different solvent intrusion by diffusion (see the first image representing the situation just after Phase 2 and very beginning of Phase 3 after long exposure to solvent). When the solvent exposed model (Phase 2) was immersed into 90^{o}C hot water, the solvent started boiling and expand and recovered mainly by expansion and gravitational drive. A seen in the second images of both figures, no solvent entrapment was observed in the favorable case (**Figure 17**) but some amount of solvent in the form of gas (at this temperature it is in the gas phase) entrapped in the model. This is due to weaker gravity drainage in the second case (**Figure 18**), created by unfavorable matrix boundary condition, compared to the vertical case given ion **Figure 17**.

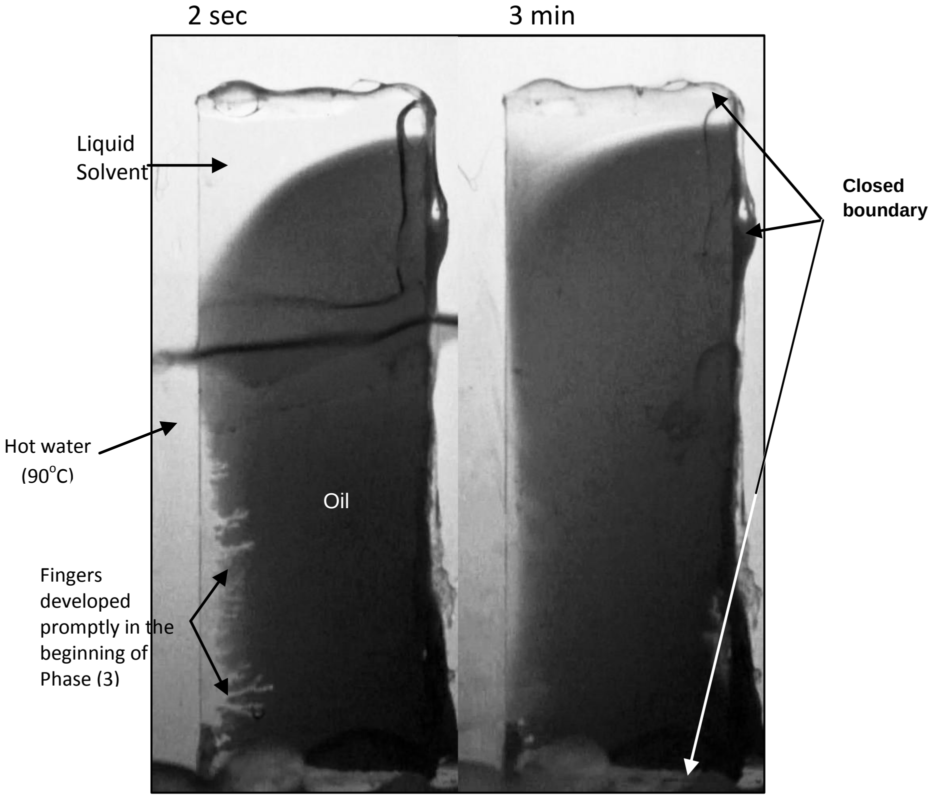

Figure 17: Phase 3 for solvent retrieval by introduction of hot water at 90^{o} C (three sides closed model, vertically situated sample–longer side is in vertical position).

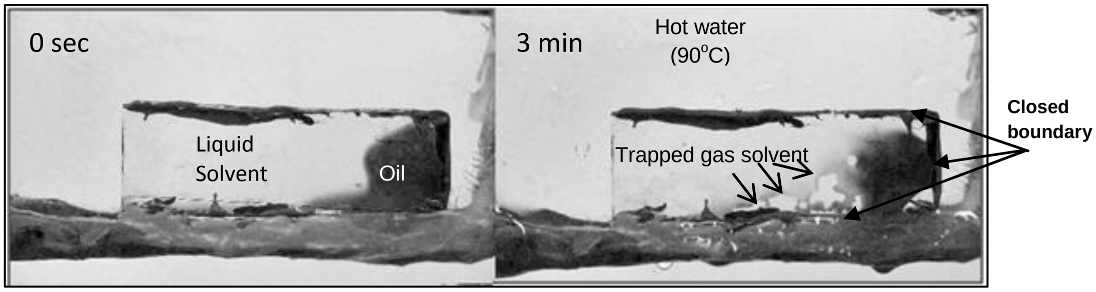

Figure 18: Phase 3 for solvent retrieval by introduction of hot water at 90^{o} C (three sides closed model, horizontally situated sample –shorter side is in vertical position).

6. Conclusions

- A new process for heavy oil recovery from fractured carbonate reservoirs was successfully tested experimentally. The results showed high incremental oil recovery which gives a promising way forward to unlock vast amounts of oil initially in place in tight carbonate reservoirs.
- The process is controlled by the solvent type, matrix wettability, matrix size and boundary conditions (which result in co- or counter-current type interaction and control the gravity drainage capability), initial water saturation, and solvent injection rate. Favorable combination of these might yield an oil recovery up to 95% and solvent retrieval of 80-90%.
- The physics of the process is far more complicated than simple diffusion and dispersion behavior. It is mainly dependent on the gravity difference between heavy oil and the hydrocarbon solvent as well as the injection rate and injection strategies.
- SOS-FR is more efficient than continuous steam injection as it requires lower amount and temperature of steam and thereby it has less impact on environment.
- Solvent retrieval is quick and recovered amounts are as high as 90% if proper solvent type and steam temperature are selected. The temperature in the final phase to retrieve the solvent should be close to the boiling point of the solvent for the given pressure. This

is the most critical part of the SOS-FR technique, which makes it an efficient process.

- This process can be adapted to design an enhanced oil recovery application in deep naturally fracture reservoirs with tight and oil-wet matrix containing heavy-oil.

Nomenclature

SOS-FR = Steam-Over-Solvent Injection in Fractured Reservoir

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Table 1: Core/fluid properties used in the experiments and summary of the results.

Abbreviationor title used todescribe experiment in the graphs	Experiment Type	Figure Number	Core Type	Wettability	Porosity	Permeability (mD)	OIIP (cc)	Parameter tested	Solvent Type	Recovery (%)	Solventvolume recoveredin Phase 3 (cc)	Solvent Recovery Factor (%) (retrieved percentage of solvent)
Heptane	Static	5	Sandstone	Oil wet	20%	550	6	Solvent type	n-Heptane	70	3.58	
Kerosene					20%	550	6.4		Kerosene	38	No recovery	
Decane					20%	550	6.4		Decane	58		
Light Crude					20%	550	6.2		Light crude	20		
WW		7	Sandstone	water wet	20%	550	7.11	Wettability	n-Heptane	97	0.8	
OW				Oil wet	20%	550	8.5			96	4.55	
Carb			Limestone	Oil wet	22%	11	8.35			81	4.74	
Base		9	Limestone	Oil wet	23%	11	9.3	Boundary	n-Heptane	95	4.8	
Top					23%	11	9.4			46	1.37	
Bot					21%	11	8.5			71	2.83	
Horz					20%	11	7.1			55	Unquantifiable	
S_{wi} = 0		12	Sandstone	Oil wet	23%	550	8.29	Initial water saturation	n-Heptane	79	No Phase 3	
S_{wi} = 7.4					23%	550	7.5			63		
0.15 cc/min	Dynamic	14	Sandstone	Oil wet	21%	550	25.3	Solvent Injection rate	n-Heptane	91	18	84.12
0.5 cc/min					19%	550	22			77	14.6	89.8
1 cc/min					21%	550	27.5			71	5.2	77.6
5 cc/min					20%	550	26.1			79.5	9.37	94.75

Chapter 5: Visual Analysis of Diffusion Process During Oil Recovery Using Hydrocarbon Solvents and Thermal Methods

This paper has been submitted to AIChE for publication

1. **Preface**

This chapter focuses on the diffusion process between two fully miscible liquids in fractured porous media, more specifically, the interaction between fluid in a fracture (solvent) and fluid in a porous matrix (solute). This type of process is encountered in many different applications including enhanced oil (or heavy-oil) recovery and groundwater contamination. Experiments were performed on vertical and horizontal orientations of 2.5cmx7.5cm Hele-Shaw models with different boundary conditions. Oil recovery from a unit element reservoir by solvent injection was simulated on these models, mimicking solvent injection into fractured oil reservoirs. Despite tremendous efforts on injection controlled miscible displacement experiments (dispersion dominated),purely Fickian-diffusion controlled static experiments (no fluid injection) in Hele-Shaw models are very limited. This type of experimentation gives clear understanding of the fluid-fluid interaction between oil in the rock matrix and solvent in the surrounding fracture.

We first analyzed the interaction between oil saturated 2-D models and the hydrocarbon solvent surrounding it qualitatively. Also provided was an analysis of high temperature water injection following this process to retrieve the solvent diffuse into the oil saturated model. We mainly explored the effects of the model (matrix) boundary conditions controlled by the aspect ratio and solvent oil interaction area on the process, using the images acquired during the experiments. Results were then analyzed quantitatively and two new dimensionless numbers were defined as functions of fluid properties and matrix boundary conditions. The work concluded that, under a fully static interaction between the solvent and oil, the process is strongly controlled by the boundary conditions that determined the relative contribution of the gravity and diffusion on the interaction process.

2. Introduction

Heavy-oil recovery requires two important applications: (1) Solvent injection and (2) thermal applications to reduce the viscosity of oil and accelerate its flow rate toward the production wells.

The use of solvent to promote production from heavy oil reservoirs has been proposed as an alternative to steam injection to reduce the excessive cost and environmental problems (waste water and CO_2 emission) caused by this method. It is well known that neither hydrocarbon solvent nor steam injection results in a sufficiently efficient process and that their hybrid applications have been proposed, such as Steam alternating solvent (Zhao et al. 2005, Zhao 2007), Expanding solvent steam assisted gravity drainage (ES-SAGD) (Nasr et al. 2003), and Liquid Addition to Steam for Enhancing Recovery (LASER) (Leaute and Cary 2007). The experimental (lab scale) and numerical (field scale) simulations of these methods, all designed for clean permeable clastic reservoirs, showed promising results. However, no applications at the field scale have yet been reported, even at pilot scale.

The heavy-oil trapped in fractured tight rocks is more problematic and has rarely been targeted with such technologies despite huge reserves existing all around the world. In a recent attempt, Al-Bahlani and Babadagli (2008) developed a new technology targeting heavy oil production from fractured carbonate reservoirs. The technique named SOS-FR (Steam-over-solvent injection fractured reservoirs) utilizes both steam and solvent to promote high oil production from fractured carbonate reservoirs. It consists of three main phases; Phase 1: Steam is injected through fractures to heat the matrix for recovery by thermal expansion and to condition the oil for the next phase; Phase 2: Solvent is injected to produce a higher amount of oil by dissolving the matrix heavy oil in the solvent flowing in the fracture; Phase 3: Steam is injected mainly to retrieve the solvent diffusion into oil in the matrix and to produce extra -upgraded- oil by this kind of expansion.

The SOS-FR technique employs both the ability of steam to heat and reduce the viscosity of the oil and the solubility of the solvent into the oil causing it to drain from the tight matrix into the fracture by gravity. Several lab experiments and computer simulations were conducted during the past four years. The research focused initially on a static experiment, where oil wet core plugs saturated with heavy oil were soaked in hot water, solvent, and then hot water again to mimic the described process (Al-Bahlani and Babadagli 2008). Analyzing the static experiment showed a high increment of heavy oil production during the solvent soaking period. This entailed a further need for dynamic experiments in which steam and solvent were injected into an induced fracture in a core plug (Al-Bahlani and Babadagli 2009a).

Solvent injection rate effect was extensively studied and showed several recovery behaviors which led to a new hypothesis on the relationship between the matrix oil and the fracture solvent (Al-Bahlani and Babadagli 2009b). The dynamic experiments were then modelled in a simulation and history matched. The model was then expanded to explore the process behavior at a field scale (Al-Bahlani and Babadagli 2010).

This extensive research highlighted some critical questions on the physics of the process, mainly the way solvent and heavy oil interact under such circumstances, and urged the need for conducting an experiment to visually asses and analyze the physics of the process. Hele-Shaw models provide a good visualization on fluid-fluid interaction which is analogous to the flow in porous media (Hamida and Babadagli, 2008). Nagatsu et al. (2009) categorized the viscous fingers in Hele-Shaw models into two main categories depending on the miscibility state (miscible and immiscible). They stated that for immiscible conditions, surface tension has a major role in the shaping the fingers, while in miscible conditions, convective and diffusive effects are important. A different categorization was suggested by Logvinov et al. (2010); however, they stated that for miscible displacement, the shape of the front is controlled by diffusion of the fluid, the Peclet number and the viscosity ratio.

However, in all these cases fluid flow is mainly studied through fluid injection means, while this study concentrates on static conditions. In this situation, the entry of fluid into the matrix by diffusion and its progress mainly by gravity and dispersion need clarification to account for the rate and amount of oil recovery. Studies of this kind in the literature are very rare (Hatiboglu and Babadagli, 2008 and 2010). This paper focuses on the physics involved in this process through 2-D visual (Hele-Shaw type) cells with a very small aperture. The main focus is to understand the solvent oil interaction caused mainly by diffusion and controlled by gravity under purely static conditions. This refers to Phase 2 of the SOS-FR technique as described above. The third phase of this technique (Phase 3), which mainly targets retrieving the solvent back by injection of hot water or steam (depending on the boiling point of the solvent used) with some additional oil recovery, was also included in the visual experiments.

3. Experimental concept and setup

As mentioned earlier, studies on the modelling of miscible displacement using Hele-Shaw cells focused mainly on viscous flow dominated (high Peclet numbers) displacement without considering the gravity effect (horizontal models). A commonly encountered case in practice, like flow in fractured porous media, is purely diffusion controlled (mass transfer between fluid flowing in the fracture and fluid in a porous matrix) under the effect of gravity. In laboratory conditions, this represents a static case, i.e., matrix saturation with one fluid surrounded by fracture fluid, which are oil and solvent, respectively, in our cases). This process is encountered in miscible (the Fickian diffusion dominates under static conditions) and immiscible (capillarity will dominate under static conditions) transfer. However, in both cases (miscible and immiscible), hydrostatic forces cannot be ignored and depending on the size of the rock matrix, the transfer rate can be predominantly controlled by the gravity forces. In such cases, the matrix-fracture interaction area, i.e., matrix boundary conditions, becomes critical also, as the diffusion rate is directly proportional to the oil-solvent contact area.

For the experimental part of the study, Hele-Shaw models representing the matrix were created. The surrounding area corresponds to the fracture filled with solvent. The Hele-Shaw model (i.e., matrix) consists of a 75 mm x 25 mm glass slide (Figure 1-a). The wettability of the glass slides was altered from water wet to oil wet using a wettability alteration agent called Surfasil® to represent a typical carbonate rock, which is the sedimentary rock type most commonly encountered in fractured reservoirs. The model consisting of two glass sheets was sealed using a temperature and solvent resistant epoxy depending on the desired boundary condition, i.e., the contact area between the oil and (in the model) solvent as seen in **Figure 1-a**.The aperture of the model is 0.038 mm. The slides were saturated with light crude oil of 33 cp viscosity and 0.87 g/cc density, and the solvent used was n-Heptane. The snapshots were taken using a Canon 7D camera with a 100 mm L type macro lens. Most of the images were taken under florescent light and then processed for better image representation. A photo of the whole set up is shown in **Figure 1-b**.

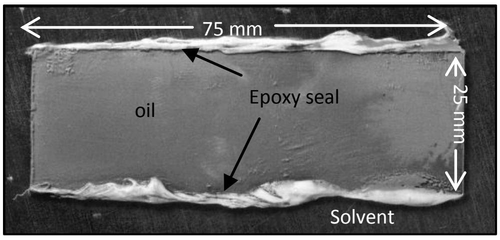

Figure 1-a: Hele Shaw model used for experiments.

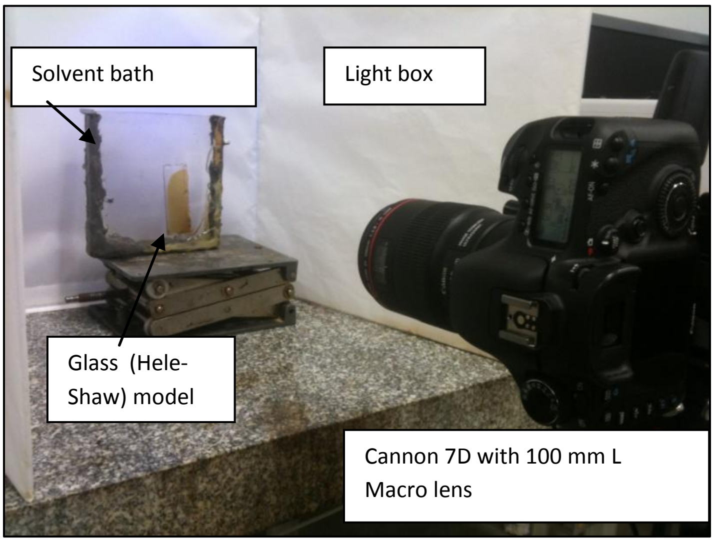

Figure 1-b: Experimental setup.

4. **Qualitative analysis**

The images obtained from the experiments were processed to clarify the displacement of the oil and the diffusion front. Then, a qualitative analysis of the images was provided. In this analysis, the main focus was the effect of the boundary condition on the process and the oil and solvent types were kept the same throughout the study.

4.1. Observations and discussions

We started with the base case, which is a model with all sides open. The slides were glued at the corners of the model only to hold the pieces together and then saturated with light crude oil. As the model was immersed into solvent (n-heptane), root shape fingers grew towards the model (**Figure 2**). Fingers entered symmetrically almost from the same point across the longer sides of the model. They then grew very fast into the model with a differing concentration profile. The fingers did not grow from the short and long sides equally even though they showed a line of symmetry. They tended to change the shape in such a way that growing fingers from the shorter sides of the model started shrinking after 90 minutes. In 120 minutes, fingers from the side grew further inside and fingers from the long side began shrinking. This is likely because of the swelling of the oil due to diffusion effect and to the further growth of fingers from the other sides (shorter sides) of the model. The model reaches quasi equilibrium (no change in fingers' shape) as the solvent diffusion is completed (see image at 120 min).

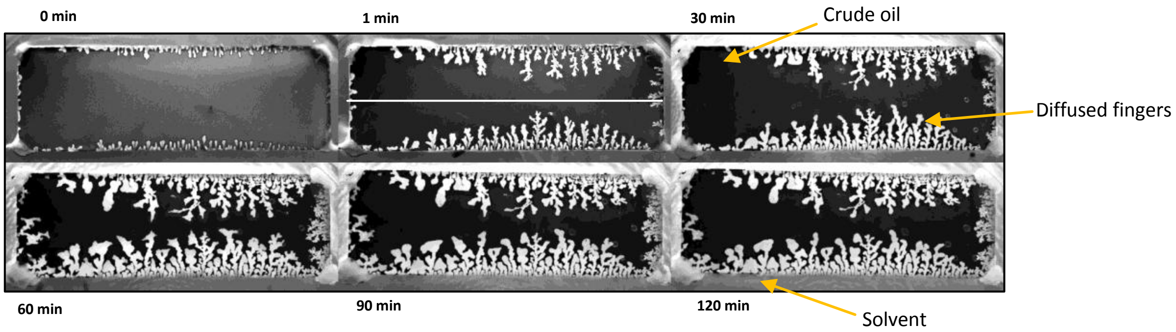

Figure 2 : Horizontal:All sides open (base) case. The line in the middle was placed to show the symmetry in the model.

Another model with the same boundary conditions (all sides open) was then immersed vertically into the solvent bath (**Figure 3**). Initially, root shape fingers appeared from the longer sides and they later blended into the oil (10 min) and started moving downwards (30 min).Gravity dominated the further flow of crude oil in this case; however, we can see solvent entering the model from the bottom side with pear shape fingers indicating counter-current flow of the solvent. The oil was purely displaced by solvent in 115 minutes.

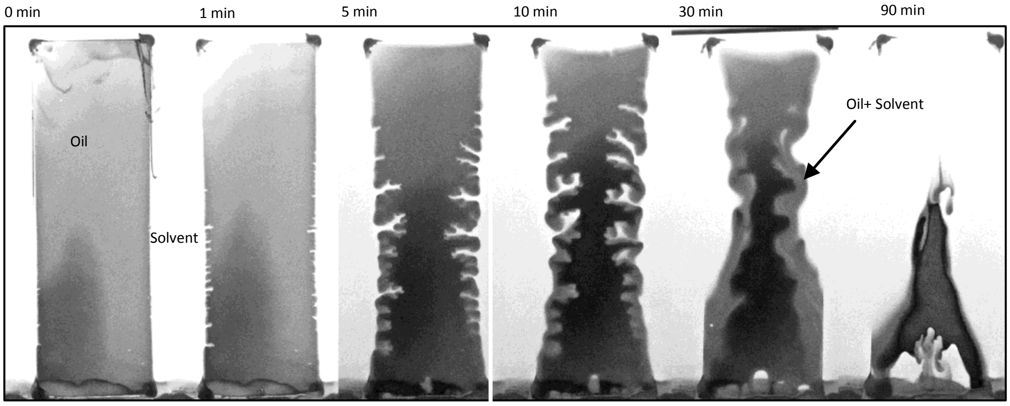

Figure 3:Vertical: All sides open vertically, the white line in the image of the 3 minutes case shows the line of symmetry.

This configuration is the strongly gravity dominated cases, thus for further understanding of the effect between gravity and hydrostatic pressure of the solvent column on top of the model, a new matrix boundary condition was created with the upper boundary closed (**Figure 4**).

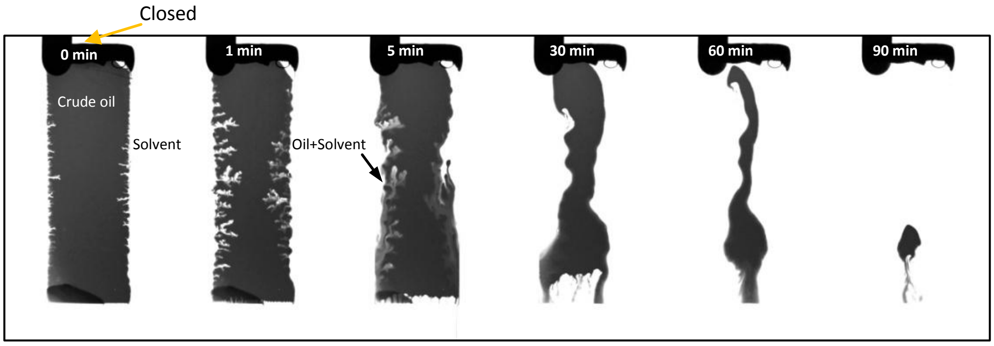

Figure 4: Vertical: Top side closed vertical model testing no top hydrostatic effect on the model.

Compared with the same time lapsed photos from the experiment with no boundary conditions (Figure 3), we observed that fingering grow this interestingly much faster within the model (Figure 4). The shape is almost symmetrical. It can also be noticed that most of the gravity drainage happened from the longer sides until the oil became a thin stream (image for 60 minutes), where it dropped much faster than in the previous model. Thus, it can be seen that the top hydrostatic effect had a negative impact on oil drainage, while the higher drainage area (two long sides) can contribute to oil production much better. To clarify this effect, another boundary condition (**Figure 5**) was applied and the importance of the gravity forces acting from the top side of the model was tested. This model differs from the others given in **Figure 3** and **4** with its asymmetric boundary condition. The model showed a very slow process and it was observed that counter-current flow from the bottom of the model counteracts against gravity, which was weakened due to the sealing of one of the longer sides.

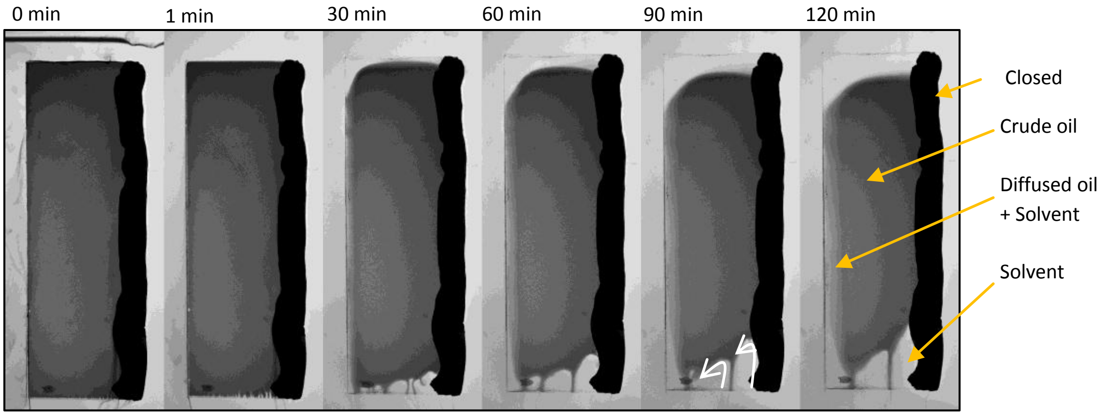

Figure 5: Vertical: Long -right- side closed boundary condition. Arrows (image for 90 minutes case)indicate the flow of solvent in a counter-current manner.

It can be seen that, with only three sides open and one of the long sides closed in the vertically situated case, the process becomes extremely slow compared to other vertical models. The main physical recovery mechanisms acting here are; (1) the effect of gravity taking place from only one side, (2) counter current flow of solvent fingers from the lower side, and (3) hydrostatic pressure exerted on the model from the top. All of these became effective after 30 minutes at the same time. It is obvious that, on the right side edge of the model (closed side), the oil column is shorter than on the opposite side where the counter-current flow acts much faster. This is because the counter-current flow exerted from the bottom of the model acted against gravity without any countering diffusion effect from the -closed- side. On the opposite side (long side open), solvent diffused into the matrix oil and then drained down to the bottom due to gravity. It can be seen that there is no diffusing front on the closed side while in the open long side the diffusion front is very evident. This is a very interesting observation caused by boundary conditions on the relation between diffusion and gravity and they may counter-affect each other.

In order to eliminate both the hydrostatic forces and the gravity acting on the long sides, a model was made with only two shorter sides open. One side was immersed into oil (bottom) and the other side was exposed to air as shown in **Figure 6.**Hence, the diffusion process acted as a counter-current.

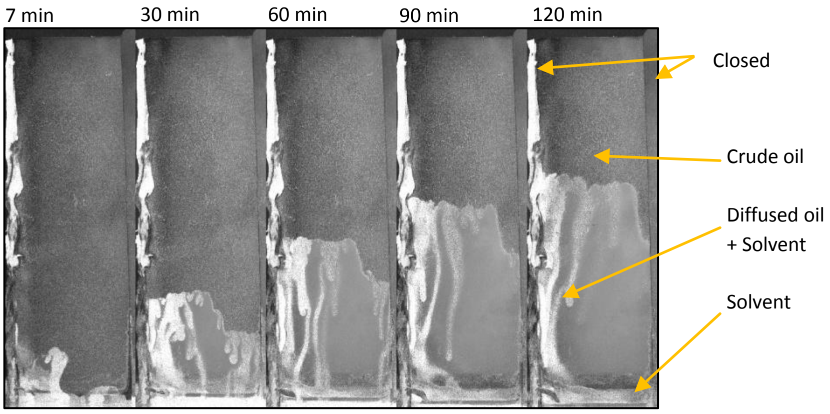

Figure 6: Vertical: Hele-Shaw model with only bottom side immersed into solvent.

Pear-shaped fingering occurred from the lower side towards a pear shape (the gray areas at the bottom of the images in Figure 6). Meanwhile, oil diffused with solvent moved downward counter-currently (the lightest color-thin fingers in the images). We observed a clear and sharp front between the solvent and oil.

To further analyze and understand how diffusion and gravity act together on the oil recovery process, the gravity effect was eliminated and only diffusion was allowed to act by placing the models(saturated with light crude oil) horizontally. **Figure7** shows the model (both short sides of the slides are open and exposed to the solvent.

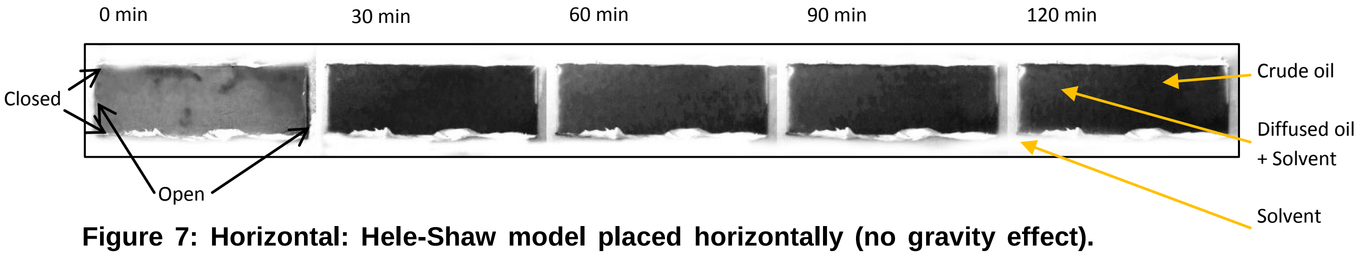

Figure 7: Horizontal: Hele-Shaw model placed horizontally (no gravity effect). Very slow diffusion.

As expected, solvent diffusion takes place through both sides; however, the diffusion is too slow to the extent that, after more than 3 hours of solvent soaking, only a few millimetres of solvent intruded into the oil. We can also deduce that there are two forces acting against each other. These forces counteract each other due to equal sizes of the diffusion area of the sides and hence, with diffusion being the only driving force in the absence of gravity, turn out to be extremely slow.

Next, the long sides were kept open and the shorter sides were sealed to further clarify the boundary condition effect in such processes (**Figure 8**).

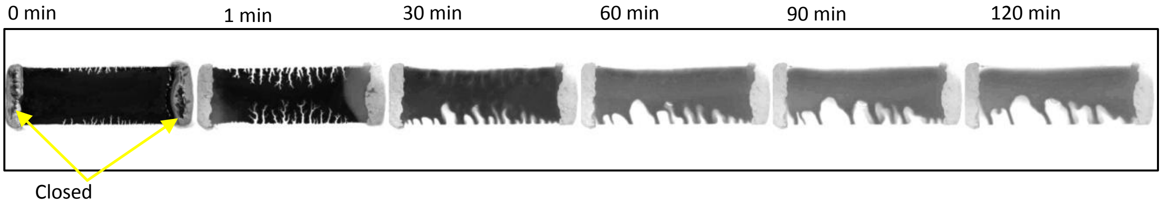

Figure 8: Horizontal: Hele-Shaw model with two short sides closed.

In this case, fingers occurred symmetrically initially and progressed inwards for a few seconds creating root shape fingers.

Later, fingering from two long sides differed in shape and generated thick and pear-shaped fingers. At first sight, one might be suspicious of an additional gravity effect created by the imbalanced model due to a very slightly tilted model that adds a degree of gravity. Although utmost attention was paid to locate the model into a solvent filled container in a flat position, some degree of tilting is still possible, but it is questionable to have such a heterogeneous finger growth process with a small degree of gravity in 30 min.

Another explanation to the asymmetrical growth of the finger in this type of symmetrical model is that the solvent flows counter-currently causing the fingers to expand laterally and to eventually merge inside of each pear-shaped finger. Once a perturbation from one side is created randomly for any possible reason, the merge of the fingers creates a stable front of solvent which makes diffusion the dominating physical process. While zooming into each pear-shaped fingers, a counter-current flow of solvent solvet+oil mixture was observed. To clarify the mechanics of the counter-current flow inside the fingers, three sides of the model were exposed to solvent and only one side was closed (**Figure9**).

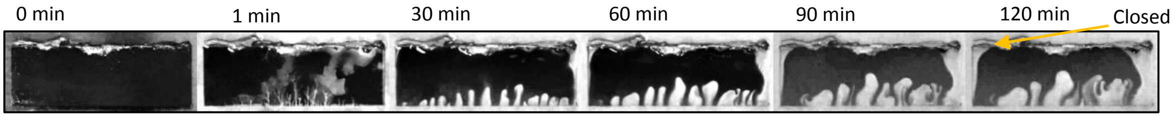

Figure 9:Horizontal:Hele-Shaw model with only one long side sealed.

As the model was immersed into solvent, symmetrical fingering occurred immediately from the long side. Fingering behavior was similar to that seen with the previous model (two longer sides open in **Figure 8**). The fingers initially had a root shape (image for 1 min); however, later on, it started to thicken and take a pear shape. The fingers merged faster and created thicker fingers. This indicates that oil production happened only through the advancement of these fingers. In other words, the crude oil was counter-currently produced and this resulted in thickening of the fingers as oil production slowed down. Once these fingers merged and became a stable front, the process slowed down. Another interesting observation throghout the experiment was the kinematics of a single finger. A series of closeup time lapse images on the finger show a counter-current flow inside the fingers as shown in**Figures 10**and **11**.

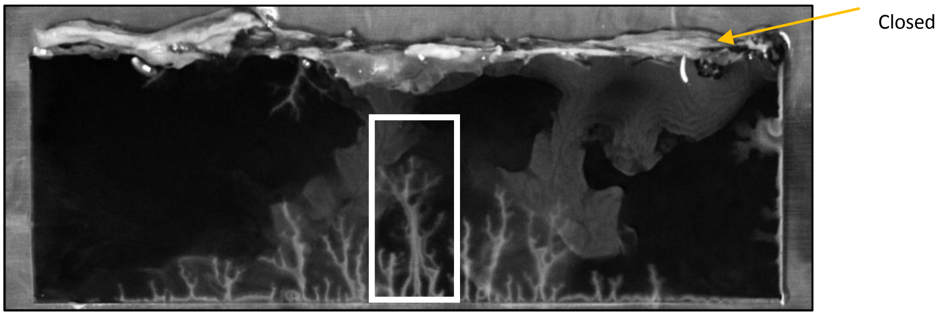

Figure 10: Horizontal: Hele-Shaw model with three sides open at 1 minute showing fingers development into the model.

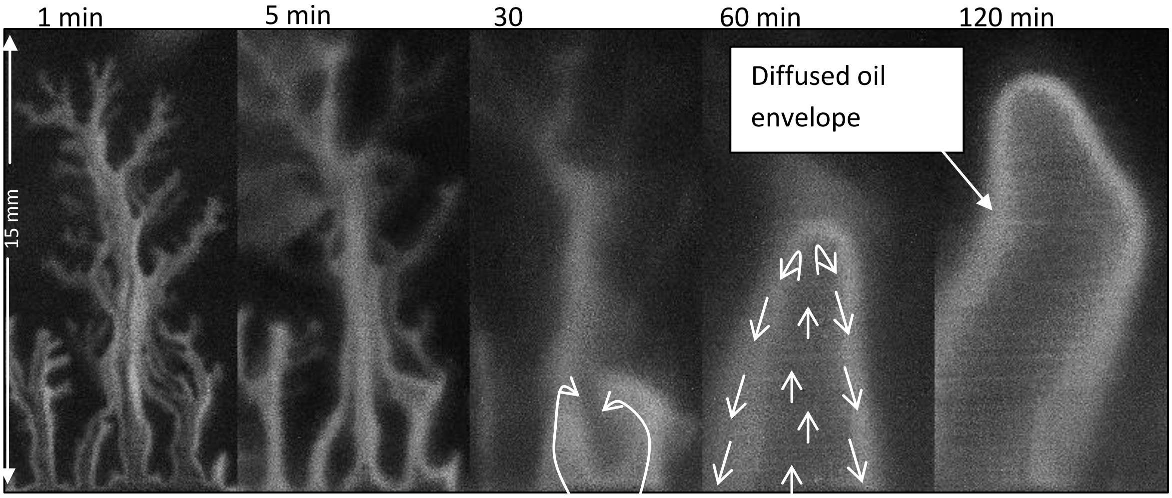

Figure 11: Close up on fingering behaviour inside the model.

Figure 10 shows the original size of the finger while **Figure 11** presents its chromatographic change at a smaller scale. It can be seen that it merges several fingers together, pushing the oil between them outside of the model with the conversion of the finger from root-shaped to pear-shaped. As the finger progresses, the solvent enters the finger from the middle, reaches the diffused oil envelope interface, diffuses into the oil and then leaves the matrix (see the arrow in the image for 60min).

A vertical model with the same boundary condition was tested earlier as seen in **Figure 5** and this form of fingering and physical behaviour was not observed. This is because of the fact that, in a vertical model, gravity drainage is the dominating recovery method which overrides recovery through diffusion only.

Solvent fingering with gravity has a favourable effect on oil production. However, solvent interaction between solvent (in fracture) and oil (in matrix) may not be uniform. For example, the whole fracture surrounding the media may not be filled with solvent or the surface of the matrix might be coated with impermeable material due to mineral scaling. Hence, a partially open model was created with a random opening in **Figure 12**. Interestingly, no characteristic fingers occurred as observed before and a stable front of solvent diffused from the longest open side (the short side on the right), and advancing towards the rest of the model was observed (**Figure 13**).

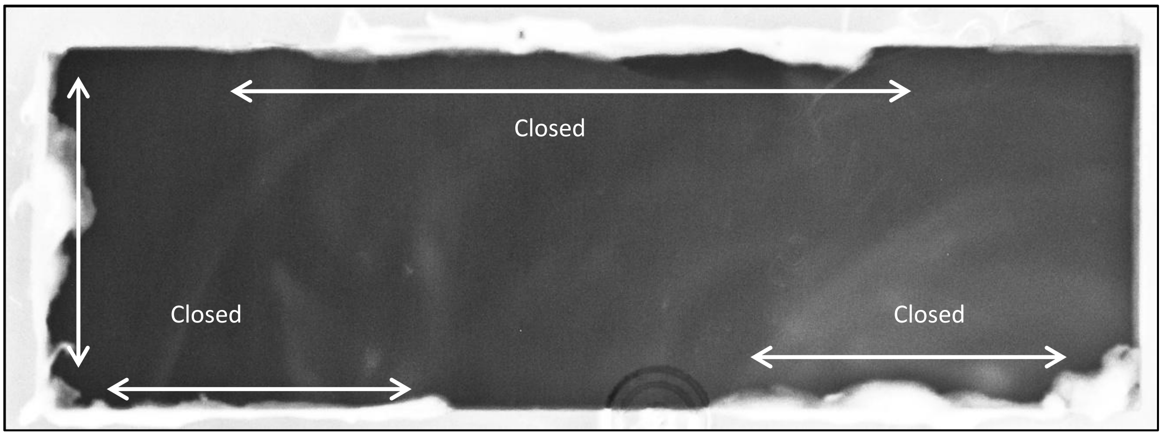

Figure 12: Horizontal: A general look of a partially pinhole-Shaw model.

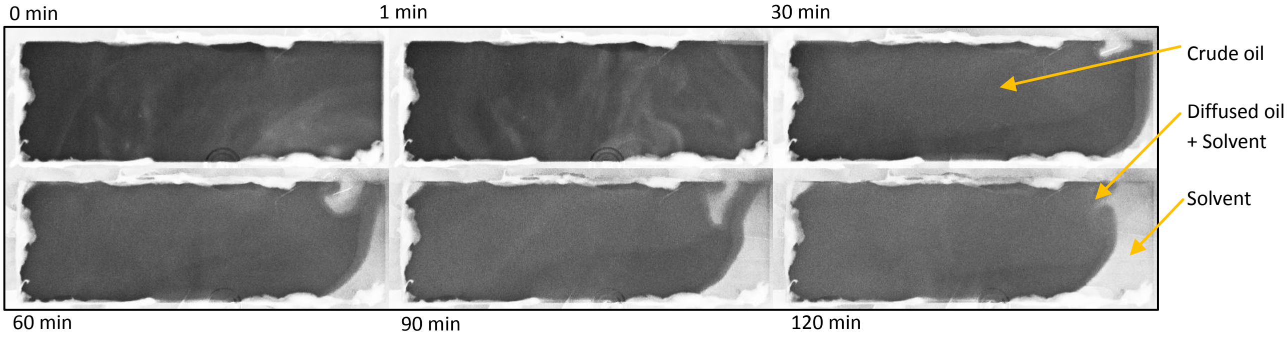

Figure 13: Horizontal: Diffusion process on partially open Hele-Shaw model.

4.2. Initial water saturation effect

The experiments discussed above, i.e., solvent exposure, describe the process that corresponds to the second phase of the SOS-FR method (Al-Bahlani and Babadagli 2008, 2009a-b, 2010;

Babadagli and Al Bahlani 2008). This phase proceeds with steam or hot-water injection to produce some initial oil by thermal expansion and to condition the oil for the next phase (solvent injection discussed so far). During this phase, called Phase 1, some amount of water may intrude into the system due to capillary imbibition or the contraction of oil after Phase 1 (Al-Bahlani and Babadagli 2008) as the system cools down before starting Phase 2. The existence of some amount of water accumulated near the boundary of the model (or rock matrix) may cause remarkable changes in the solvent diffusion process.

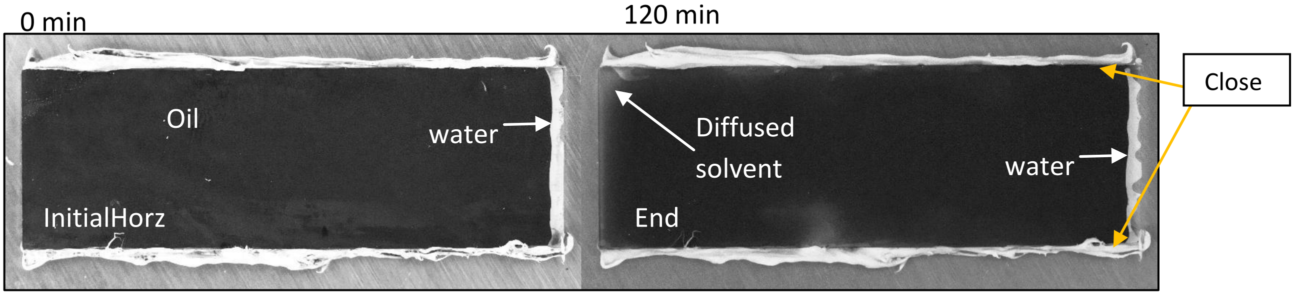

Figure 14: Effect of initial water saturation in Thiele-Shaw model where water entered from one side only.

In previous experiments, there was no initial water in the system before the solvent exposure. In this part of the work, the model was subjected initially to hot water at 90°C for around two hours, then it was left to cool down to normal room temperature. The water phase was mixed with florescent dye in order to track it is movement within the model. As the model cooled down, the oil contracted causing some of the water to enter the model. When the model was introduced to the solvent, the water acted as an obstacle to diffusion when it was placed horizontally. As seen in Figure 14, a trivial amount of solvent diffused from the top portion of the open side after a long exposure (see the image for 120 min). The water blocking the opposing direction also created a “closed boundary” effect, reducing the diffusion from the open side (the left short side).

Next, water was introduced from both sides by locating the sample in a tilted position to introduce an unequal amount of water intrusion from both sides. As seen in Figure 15, solvent diffusion was not possible even after a long exposure time.

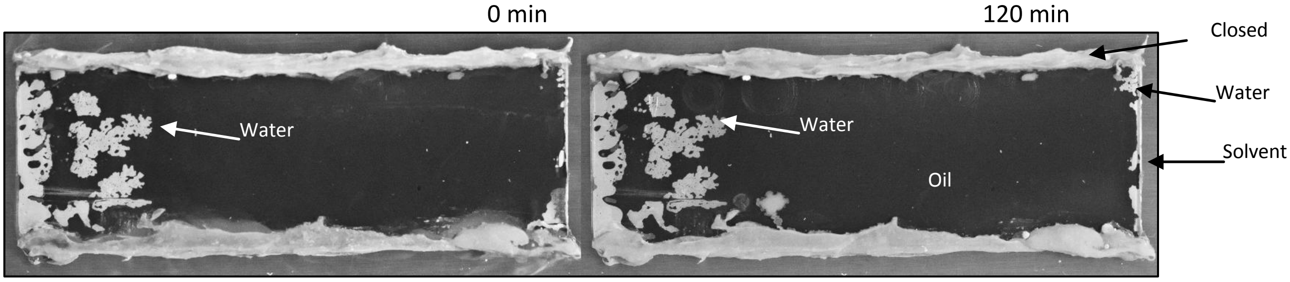

Figure 15: Horizontal: Effect of initial water saturation where water entered from both sides of the model.

4.3. Effect of temperature

If Phase 2 is started immediately after Phase 1 without any cooling period, the solvent diffusion takes places under a higher temperature for a while. To clarify the diffusion process at higher temperatures, the model was heated inside an oven of 90^{o} C and then immersed immediately into room temperature solvent. The model used had two short sides open and two long sides closed. This scenario was seen in **Figure 7** to have no fingering effect when the model was immersed into cold solvent. However, when the model was heated and then solvent was introduced, fingers appeared and entered the model immediately at contact **(Figure 16).**

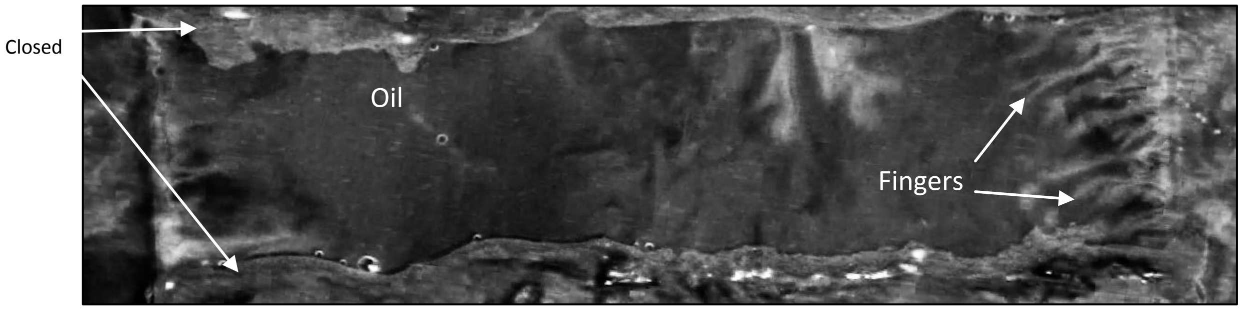

Figure 16:Horizontal: Immediate fingering of solvent (order of seconds) into the model due to high temperature of oil.

Once the model cooled down, the fingering effect disappeared and it was replaced by a frontal progress of the diffusion process**(Figure 17)**.

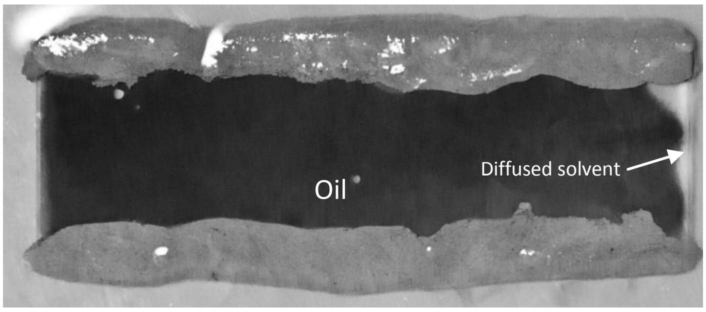

Figure 17: Hele-Shaw model seen in Figure 16 after it cooled down and solvent diffusion took place.

4.4. Matrix shape factor (MSF) effect

One of the main issues affecting the relative contribution of solvent diffusion and gravity drive is the shape of the matrix (matrix shape factor, MSF, corresponding to aspect ratio).Two models were made one with 1/3 MSF and another with 3/1 MSF. They were then immersed in a bath of solvent vertically. The images in **Figures 18** and **19** show a time lapse of the process.

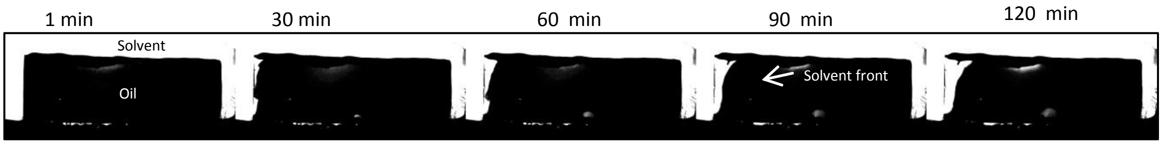

Figure 18: Hele-Shaw model with 1/3 MSF.

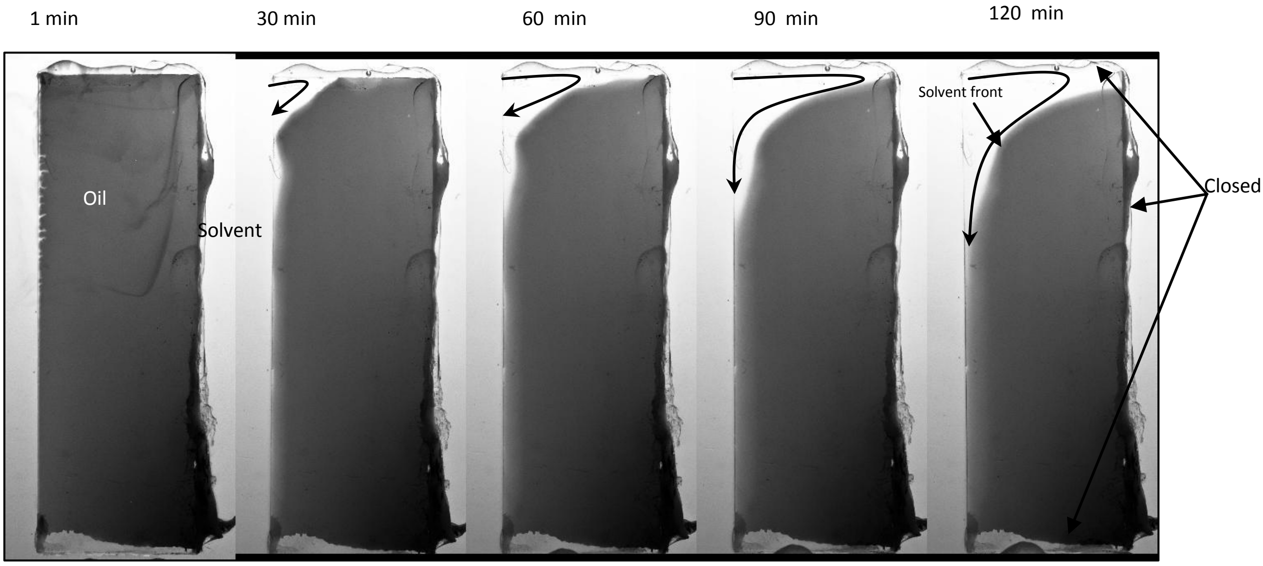

Figure 19: Hele Shaw model with 3/1 MSF.

As seen in these images**,** with low MSF, solvent takes a much longer time to drain the oil leaving much of the oil undrained. However, with high MSF, the solvent is able to drain the oil much faster. This is mainly due to the boundary on the horizontal side being much closer. If we assume that the development of the solvent envelope is due to counter current movement of solvent inside the model, then once the pure solvent reaches the boundary, it will force the diffused solvent + oil to drain much faster. This combined with gravity accelerates the process.

4.5. Phase 3 and solvent retention

Solvent retrieval during any enhanced oil recovery application is one of the main concerns in solvent based processes due to its high cost. It is more critical in fracture reservoirs, as the solvent and solvent mixed oil cannot be easily retrieved by successive water injection as in the homogeneous reservoirs. The third phase in SOS-FR (called Phase 3 throughout the text) is applied mainly to retrieve the solvent (Al-Bahlani and Babadagli 2008; Babadagli and Al-Bahlani 2008). The main mechanism to retrieve solvent is to inject steam or hot water around the boiling temperature of the solvent for a given pressure (Al-Bahlani and Babadagli 2009a). This was observed to be a fast process and as much as 80-90% of solvent in the system can be recovered (with some additional oil) in the gas phase. Hot water of $90^oC$was introduced to the system in Phase 3 and the solvent retrieval and additional oil recovery was observed. This temperature is close to the boiling point of heptane at atmospheric pressure.

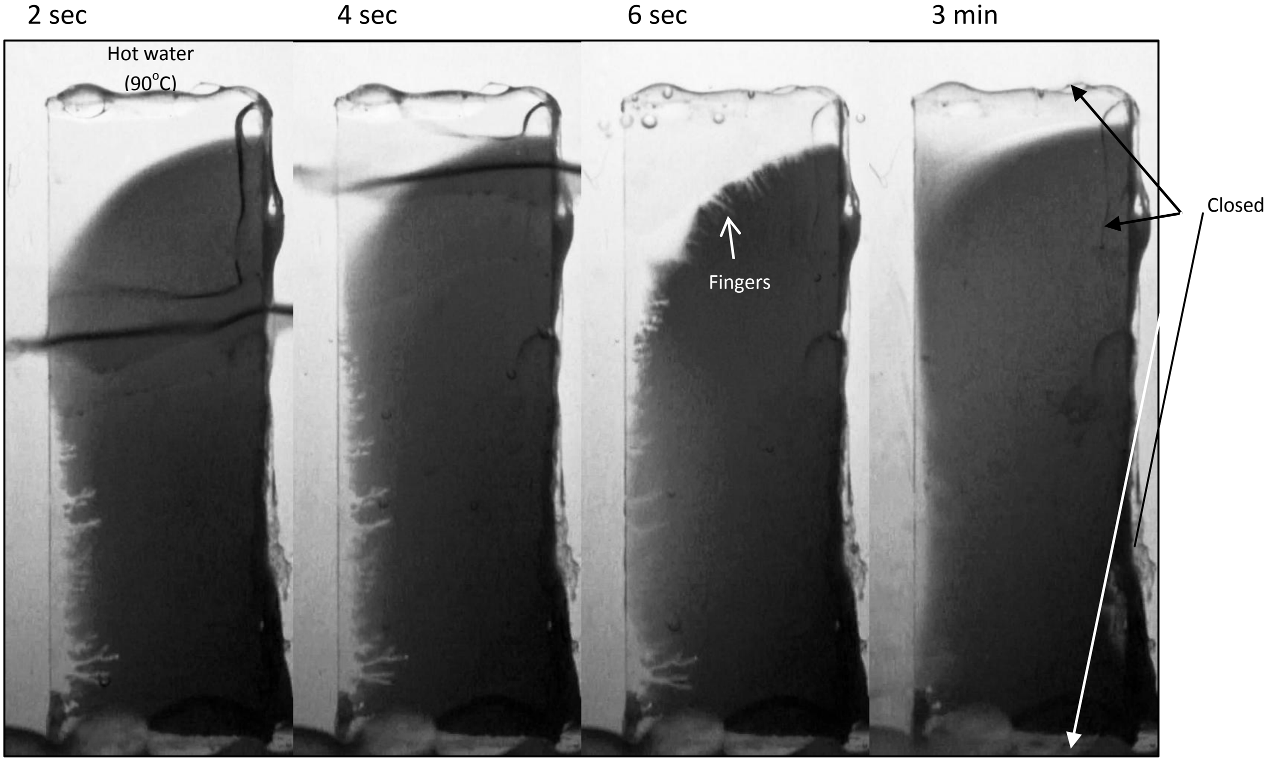

Figure 20: Vertical: Phase 3 for solvent retrieval by introduction of hot water at 90^{o} C on a high MSF model (three sides closed).

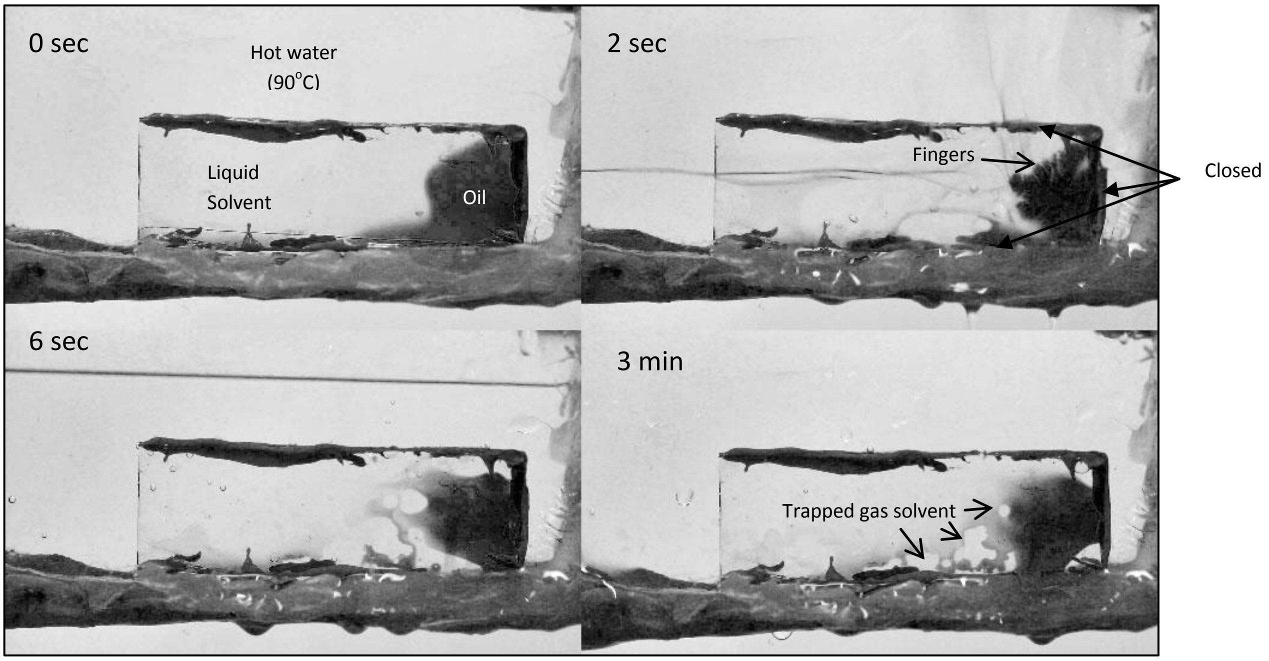

Figure 21:Vertical (low MSF): Phase 3 for solvent retrieval by introduction of hot water at 90^{o} C on a low MSF model (three sides closed).

Figures 20 and **21** show two different matrix configurations (or MSFs). In these figures, the model was immersed into 90^{c}C water after solvent exposure (Phase 2). An immediate reaction causing initial fingering of solvent into the oil, followed by thermal expansion of both pure solvent and oil, was observed. These fingers were indicated by arrows in **Figures 21** (image for 6 seconds) and **22** (image for 2 seconds). At later stages, the solvent started boiling and was converted into a gas phase due to its high temperature. It can be clearly seen that a high amount of gas got trapped in the low MSF model (**Figure 21**), while the gas escaped easily out of the high MSF model (**Figure 20**) due to a more favourable gravity effect. This is critical, as trapped gas is undesirable in the process and all the solvent in the system is desired to be converted into gas and to flow out of the matrix quickly. Additional oil recovery can also be observed during the process but this is strongly controlled by the matrix boundary condition. One may observe oil accumulation at the bottom of the model for the low MSF case (**Figure 21**). We did not observe any water intrusion into the model to displace the solvent at the water solvent interface (the open part of the matrix). This indicates that model is still strongly water-wet despite an increase in temperature, and the capillary imbibition of water was not a possible drive mechanism.

5. Remarks on the fingering process

We can classify the shape of the fingers developed when the Hele-Shaw model was immersed into the solvent in two main categories: (1) Root shape, and (2) pear shape. The root shape can be noticed in three cases:

- Horizontal models with large open areas (Figures 2, 8 and 9)
- Heated horizontal models with small open areas (Figure 16)
- Whenever the models with solvent and oil in the matrix are immersed in hot water (Phase 3) (Figures 21 and 21).

Once “pure” diffusion seen in the horizontal cases (all images in **Figure 2** or images for 0th and 1st minutes in **Figures 3, 4 and 9**) is disturbed by the effect of gravity, the finger shapes change and develop pear-shaped fingers (images for the 5th minutes in **Figures 3** and 4 and images after the 30th minute in **Figure 9** or all images in **Figure 5**). The formation of pear-shaped fingers is due to counter forces acting against the diffusion front and these two forces (diffusion in one direction and gravity in the opposite direction) creating a counter-current type flow within the finger as pictured in Figure 12. The flow of solvent inside the finger upwards was affected greatly by the boundary conditions of the model that controlled the degree of the gravity force.

The symmetrical shape we see in **Figures 2, 3, 4, 8,** and **9** suggests that the balance is not distributed evenly around the model; rather, there is a contour of interfacial tension enforcing the stabilization of the fluid in the model. However, in a model with a high [closed side/open side] ratio, we see no fingers at all. This is because the area exposed to air is much lower compared to models with a low sealed/open ratio.

In the heated model case (**Figure 16**), a model with a high sealed/open ratio was made similar to the case where no fingering occurred (two short sides open). Fingering from solvent to oil was immediately noticed to take place in few seconds and at lower time, diffusion started. This can be attributed to the oil contraction, and solvent expansion enhanced the entrance of the solvent to the oil.

In the solvent retention case (**Figures 20 and 21**),the models were immersed into the solvent for a certain period and then immersed in a hot water bath. It was noticed that root-shaped fingering also occurred inside the model from the solvent filled areas to the oil filled areas. This happens instantaneously and dissipates quickly; however, this time there was no clear diffusion area, but rather an expansion of oil pushing the solvent outside the matrix.

6. Quantitative analysis

From previous qualitative analysis of the results, it is evident that boundary conditions have a profound effect on the behaviour of solvent diffusion into oil during Phase 2 (the solvent interaction period). The boundary condition controls the effective diffusion coefficient and gravity drainage process, and thereby, the recovery of oil. However, to deepen our understanding of the physics of the process, it is important to further analyze the results quantitatively. In order to achieve such an analysis, an image analysis program called ImageJ (Rasband, 1997-2005) was used to convert the images into binary images and hence, to use them to measure the recovery factor. The experiments were categorized into two main categories: vertical (gravity involved) and horizontal (no gravity force, flat model).

6.1. Horizontal analysis

Each model was characterized by its boundary conditions and the area swept by solvent in three characteristic times (1 min, 60 min, and 120 min). Since this is a horizontal (flatly laid model) model, gravity effect is eliminated. Thus, diffusion is the only acting mechanism and hence, oil recovery was greatly affected by the contact area between the solvent and the oil in the model. To characterize the boundary condition quantitatively for this type of model, the ratio between the open length (L_o) to the total length (L_t) was measured for each model. Since the process is also dependent on the viscosity and density of the solvent, relative viscosity and density between solute (oil) and solvent were calculated and incorporated in the analysis. Another important number to be added to this analysis is the diffusion coefficient (Fickian) of solvent into oil , D, a capillary tube was saturated with oil and then one end was sealed while the other end was immersed into the solvent horizontally (**Figure 22**).

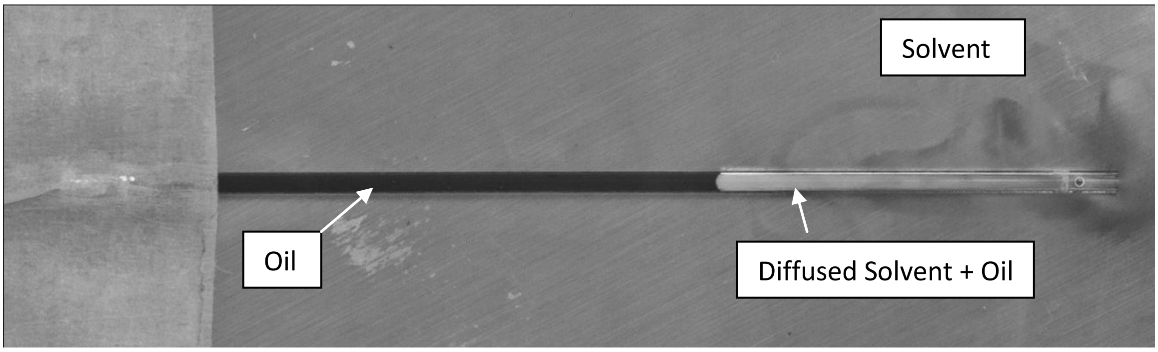

Figure 22: Capillary tube filled with oil and immersed in solvent.

With time lapse imaging, the concentration profile was detected and a diffusion coefficient (D, m^2/s) was calculated. **Table 1** shows the details of the above described characteristics.

In the previous qualitative analysis, it was concluded that diffusion is the main recovery mechanism for the horizontal case and it is controlled by the boundary condition. Thus, it is needed to introduce an effective diffusion coefficient as a function of boundary conditions. Combining the factors affecting the process, i.e., viscosity and density ratios of oil and solvent, characteristic length, and the diffusion coefficient, one may define the boundary condition controlled effective diffusion coefficient, D_{eb}, as follows:

$$D_{eb} = \left(\frac{\mu_s}{\mu_o}\right)\left(\frac{\rho_o}{\rho_s}\right)\left(\frac{L_o}{L_t}\right)D \qquad (1)$$

The values of D_{eb} for each experiment for different times are given in **Table 1**. The oil recovery was plotted against calculated D_{eb} values in **Figure 23-a** and a relationship was derived between the recovery factor at three different time values: t=1 minute (t_d= 0.01), t = 60 minutes (t_d= 0.5) and t = 120 minutes (t_d= 1).Note that 120min was taken as the base case and the dimensionless time values were calculated by dividing the time by this value. As seen, the correlation that was observed at low time values differs from that of late times but they are both linear. 1-min data corresponds to the very early stage which represents the unstable region, typically yielding instantaneous root-shaped fingers. 60 min and 120 min values yielded a good overlap and they are close to the end of process. Hence, this can be considered as the ultimate recovery. The relationship for the data excluding very early time values is linear as given below:

$$RF = 9 \times 10^{7} D_{eb} \tag{2}$$

This observation suggests that a more general correlation can be obtained if D_{eb} is plotted against recovery (area swept by solvent) per time, i.e., recovery rate. This, in a sense, describes an effective diffusion coefficient as its unit corresponds to L^2/T. **Figure 23-b** illustrates the plot of D_{eb} vs. recovery rate (area swept (or oil recovered) per unit time). This plot shows that all data (which was normalized using the time values) overlaps and yields a general correlation for the oil recovery rate as given below:

$$Recovery\ Rate = 1 \times 10^{10} D_{eb}^{1.588} \tag{3}$$

This can be also interpreted as an effective diffusion term or coefficient (L^2/T), describing the rate of solvent-oil displacement purely by diffusion (the horizontally placed -flat- sample).

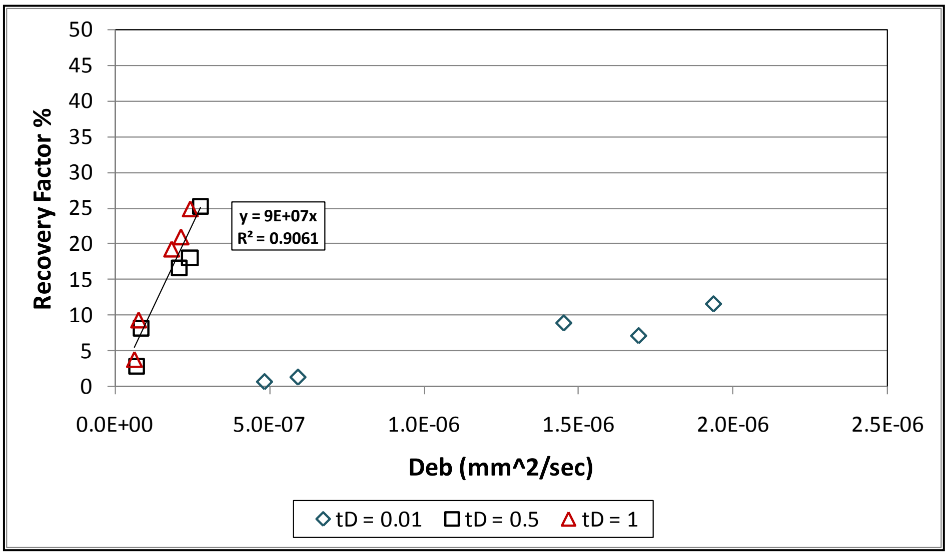

Figure 23-a: Relationship between modified diffusion coefficient given in Eq. 1 and oil recovery factor.

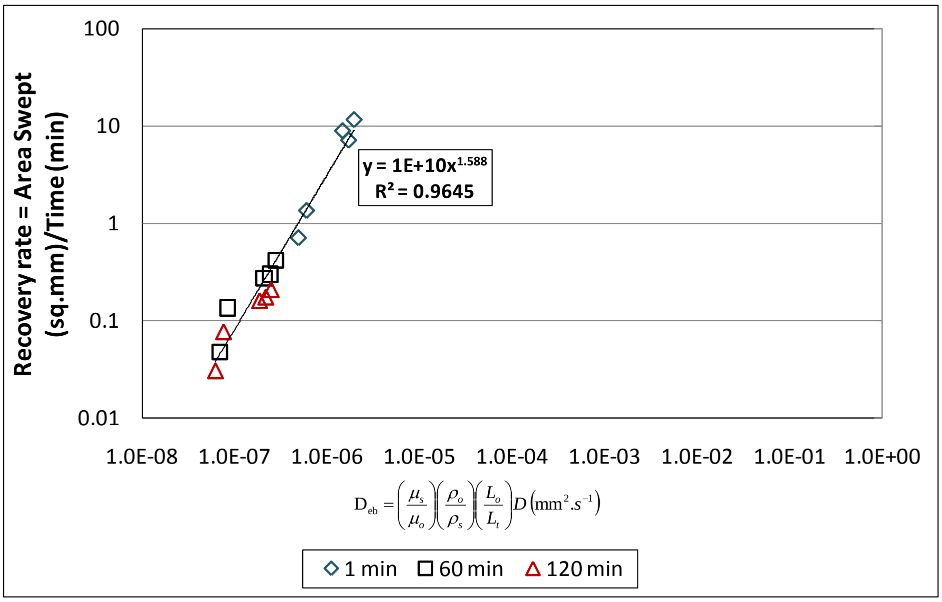

Figure 23-b: Swept area by solvent per time vs. modified diffusion by boundary condition given in Eq. 1.

6.2. Vertical analysis

As was noticed in the qualitative analysis, when the Hele-Shaw model is placed vertically, the dominating process becomes gravity drainage where it overrides the effect of diffusion. The recovery factor of each model was measured as the area swept divided by the total area, as done in the horizontal case in the previous section. In this exercise, the results for the two-short-sides-open case (**Figure 6**) were not included because only the lower part was immersed into solvent while the upper side was facing to air unlike all other vertical cases in which the all open sides were in contact with solvent. The results are shown in **Table 3**. Note, however, that the characteristic length is more complicated as the gravity plays a role in addition to diffusion in the vertical cases. Hence, a new characteristic length was introduced as described in **Figure 24**.

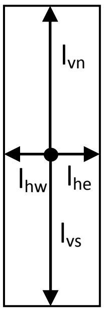

Figure 24: Representation of parameters used to define a characteristic length for vertical models.

If an arrow oriented in one direction from the centre of the model meets an open side of the model, then the percentage of the open part on that face of the model was calculated**.** However, it was qualitatively observed in the experiments that vertical distances, l_{vn} and l_{vs} control the gravity drainage process which is a function of density and viscosity values. Thus, the l_{vn} and l_{vs} values were modified, incorporating the gravity and viscosity effect. After an intensive trial and error exercise and analysis of the experimental data given above, the contribution of density difference and viscosity ratio and their relative -vectoral- effects with respect to the direction of the flow (downward dominated by gravity) were described. A gravity component is added to the l_{vs} by subtracting the specific gravity (dimensionless) of solvent from the specific gravity of the oil (δ_o–δ_σ), and a viscosity component is added to the l_{vn} by incorporating the square root of the mobility ratio (dimensionless). The characteristic length (l_c) was obtained by adding each term and the values obtained were listed in **Table 4**.

$$\mathbf{l_c = l_{he} + l_{hw} + \left(\frac{l_{vs}}{\delta_o - \delta_s}\right) - \left(l_{vn} \times \sqrt{{\mu_s}/{\mu_o}}\right)} \tag{4}$$

where μ is the viscosity and *s* and *o* denote solvent and oil, respectively. When this number is plotted against the recovery factor at different times, an exponential relationship, with minor differences in the coefficients, was observed (**Figure 25-a**):

$$RF_{tD=0.25} = 1.3312e^{0.0127l_c} \tag{5-a}$$

$$RF_{tD=0.5} = 2.3308e^{0.0123l_c} \tag{5-b}$$

$$RF_{tD=0.75} = 3.5512e^{0.0116l_c} \tag{5-c}$$

$$RF_{tD=1.0} = 5.3511e^{0.0106l_c} \tag{5-d}$$

A systematic change in the recovery rate was observed for all data except very early (first minute) data. As similar to the horizontal case, the very early data corresponds to the unstable region represented by instantaneously developed root-shaped fingers. To define a more universal relationship, the recovery rate as described before (area swept (or oil recovered) per unit time) was plotted against the characteristic length (**Figure 25-b**) and the following relationship was obtained:

$$Recovery\ Rate = 0.7825e^{0.0118l_c} \qquad (6)$$

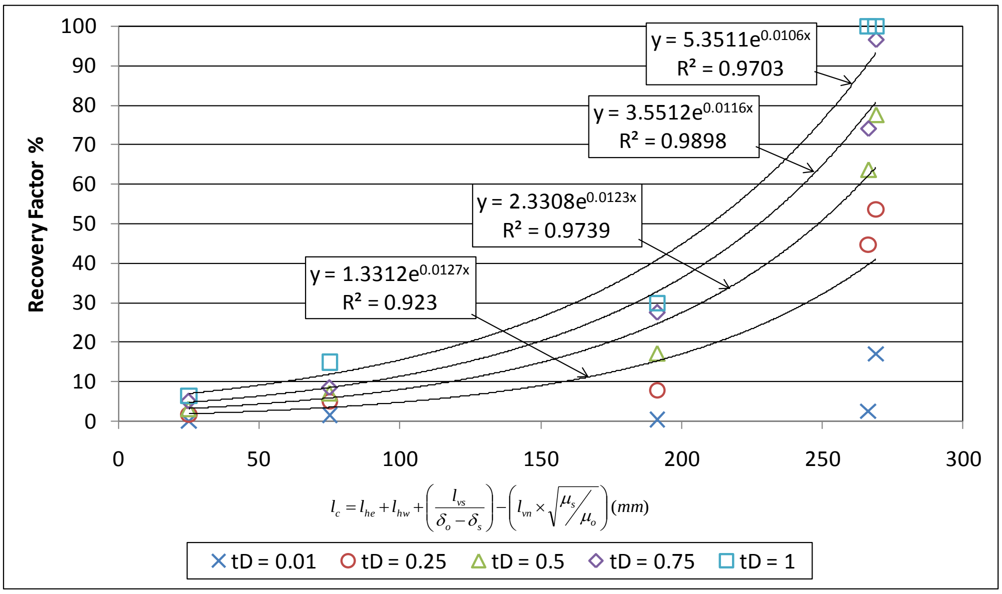

Figure 25-a: Relationship between characteristic length (Eq. 4) and recovery factor for different dimensionless times.

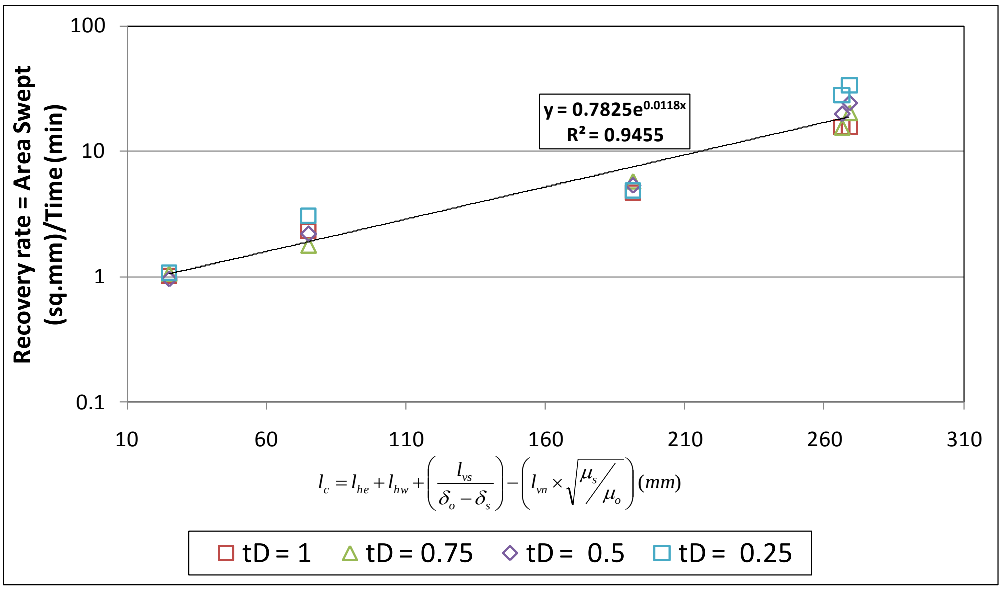

Figure 25-b: Swept area vs. characteristic length given in Eq. 4.

7. Conclusions

Interaction between the oil saturated matrix and the solvent surrounding it was studied for different boundary conditions of the matrix using Hele-Shaw models under fully static conditions (no injection was involved). This represents a portion of an alternative injection of steam-solvent in fractured heavy-oil reservoirs. The results were analysed qualitatively and quantitatively and the following conclusions were drawn:

In a horizontal (flat) Hele-Shaw model, solvent tends to diffuse into the oil in two main manners: (1) Root-shaped fingering caused by instantaneous instability in the system which drives the solvent by diffusion into the model very slowly, and (2) pear-shaped fingering caused counter gravity forces on the diffusion front that eventually yielded a counter-current flow solvent (inner part) and an oil/solvent mixture (outer part) inside the fingers.

In a vertical 2D Hele-Shaw model, gravity may override the diffusion effect depending on the boundary condition. This representation of the model yields much higher and faster recoveries.

Boundary conditions have a profound effect on the recovery process on both the horizontal and the vertical models. With the horizontal models, higher recoveries were noticed with a higher open length to total length ratio. With the vertical models, the gravity override of the solvent on the oil decelerates the production of oil from the matrix.

Temperature accelerates the diffusion process of solvent into the matrix, and thereby, can decrease the time needed for oil recovery.

Solvent retrieval by succeeding hot water (or steam) injection is possible once the temperature reaches the boiling point of the solvent. As the gravity effects are eliminated, i.e., in the case of low matrix shape factor (MSF) values, solvent tends to travel further into the matrix during its expansion, causing solvent gas to be trapped inside the matrix towards the closed boundary parts.

A modified effective diffusion coefficient was introduced for horizontal orientation and was related to the oil recovery rate and amount. The modification was based on boundary conditions, relative solvent viscosity and relative solvent density.

A prediction of oil recovery for the vertical model (with the effect of gravity) was also presented based on the boundary conditions. A new definition of characteristic length was introduced to account for the boundary condition effect. The characteristic length was introduced based on open length from the centre of the model, the difference in the specific gravity between the oil and the solvent, and relative viscosity. The characteristic length was also related to the oil production rate and amount. The relationship between the characteristic length and the recovery rate (or area swept per unit time) yielded a general correlation to account for the effect of the boundary condition on the solvent diffusion process. This study was focused mainly on the effect of the boundary condition for the same type of fluid (solvent and oil) pair. The equations proposed (Eqs. 1 and 2) should be tested for different solvent and oil (with different densities and viscosities) types.

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Table 1: Recovery factor of the horizontal Hele-Shaw model, characteristic length, and oil/solvent viscosity and density ratios.

	Recovery Factor %			L_o/L_t	$\frac{\mu_s}{\mu_o}$	$\frac{\rho_o}{\rho_s}$	Figure Number
Model Type	**1 min**	**60 min**	**120 min**				
Two long side open	12.50	23.26	27.00	0.75	0.117	1.32	8
Threesides open	10.00	25.00	29.39	0.87	0.117	1.32	9
Two short sides open	1.00	4.00	5.20	0.25	0.117	1.32	7
Partially open	1.90	11.471	13.00	0.31	0.117	1.32	13
All sides open	16.23	35.434	34.94	1.00	0.117	1.32	2

Table 2: Boundary condition controlled effective diffusion coefficient at different times.

	D_{eb} (mm^2/sec)			Figure Number
Model type	**1 min**	**60 min**	**120 min**	
Two long side open	1.45E-06	2.07E-07	1.83E-07	8
Three sides open	1.70E-06	2.41E-07	2.13E-07	9
Two sides short open	4.84E-07	6.90E-08	6.10E-08	7
Partially open	5.93E-07	8.44E-08	7.46E-08	13
All side open	1.94E-06	2.76E-07	2.44E-07	2

Table 3: Oil recovery factors obtained forthe vertical 2D Hele-Shaw model.

	Oil Recovery Factor %					Figure Number
Model Type	**1 min**	**30 min**	**60 min**	**90 min**	**120 min**	
Three sides open- long closed	0.38	7.759	17.148	27.5	29.829	5
Three sides open top closed	17.02	53.679	77.523	96.506	100	4
Three sides closed long open	1.5	4.917	7.054	8.46	14.87	19
Three sides closed short open	0	1.714	3.079	5.037	6.44	18
All sides open	2.426	44.649	63.635	74	100	3

Table 4: Relation between vertical length and calculated characteristic length.

	L_{he}	L_{hw}	L_{vn}	L_{vs}	**Hor**	**Ver**	l_c	**Figure Number**
Three sides open- long closed	75	0	25	25	75	116	191	5
Three sides open top closed	75	75	0	25	150	119	269	4
Three sides closed long open	75	0	0	0	75	0	75	19
Three sides closed short open	25	0	0	0	25	0	25	18
All sides open	75	75	25	25	150	116	266	3

Chapter 6: Laboratory and Field Scale Analysis of Steam Over Solvent Injection in Fractured Reservoirs (SOS-FR) for Heavy-Oil Recovery

This paper was presented at the 2009 SPE Annual Technical Conference and Exhibition held in New Orleans, Louisiana, USA, 4–7 October 2009.

1. Preface

Tapping heavy-oil from fractured carbonates is a real challenge due to unfavorable rock and reservoir characteristics. We introduced a new technique called Steam-Over-Solvent in Fractured Reservoirs (SOS-FR) for efficient heavy-oil recovery from fractured reservoirs, more specifically carbonates. The process consists of cyclical injection of steam and solvent in the following manner: Phase 1: Steam injection to heat up the matrix and recover oil mainly by thermal expansion, Phase 2: Solvent injection to produce matrix oil through diffusion-imbibition-drainage processes, and Phase 3: Steam injection to retrieve injected solvent and recover more heavy-oil. Our preliminary experiments under static (SPE 117626) and dynamic (SPE 123568) conditions showed that, under very unfavorable conditions (oil-wet carbonate, ~4,500 cp crude), oil recovery at the end of Phase 3 could be as high as 85-90% OOIP with 80-85% solvent retrieval.

This paper presents numerical modelling of the dynamic experiments and an upscaling study for reservoir size matrix. Heptane was selected as the solvent to inject through single-fracture oil-wet Berea sandstones saturated with ~4,500 cp oil. The experimental results were matched to a single matrix/single fracture numerical model and parameters needed for larger scale simulation (matrix-fracture interaction parameters such as thermal diffusion, solvent diffusion and dispersion coefficients) were obtained. The main focus was the matrix size and first an up-scaling study to field conditions was performed.

Specific observations and conclusions as to the applicability of this technique in the field effectively were reported. It is hoped this new technique will be an alternative for tapping heavy matrix oil from oil-wet, fractured, deep, carbonate fields.

2. Introduction

Finding an efficient way to produce heavy oil / bitumen production from tight naturally fractured carbonate reservoirs is one of the most challenging tasks the petroleum industry. Due to geological constraints, i.e., discontinuous structure of reservoir caused by fractures, steam injection can only be applied to heat matrix rather than conventional steam displacement (Briggs et al., 1988, 1992; Reis, 1990; Babadagli, 1996a-b, 2002). Therefore, steam injection applications in fractured reservoirs are not abundant and have been limited to a few pilot applications (Sahuquet and Ferrier, 1982; Nakamura et al., 1995; Snell and Close, 1999; Macaulay et al., 1995; Al-Shizawi et al., 1997; Babadagli, et al., 2008). The common observation in all these pilot attempts was the inefficiency of the process that was caused by the rapid movement of steam resulting in early breakthrough without effectively heating the matrix.

Out of these pilot tests, only the Qarn Alam project has been switched to a full field scale application (Rawnsley et al., 2005; Penney et al., 2005; Shahin et al., 2006). Babadagli and Bemani (2007) reported that the matrix drainage at relatively favorable laboratory conditions do not exceed 42% for challenging Qarn Alam cores containing ~3,000 cp dead oil. It is expected that this number will be reduced to lower values at field conditions. Shahin et al (2006) reported that the recovery only increases to 26% by steam injection through the process called thermally assisted gas oil gravity drainage (TA-GOGD), which was expected to be only 4% without thermal assistance. Note that the drainage process is rather slow as pointed out by Macaulay (1995).

With huge amounts of oil locked in fracture reservoirs, the need for a novel approach for efficient recovery is eminent. Very recently, Al Bahlani and Babadagli (2008; 2009) proposed a new technique called steam-over-solvent injection in fractured reservoirs (SOS-FR). They showed that starting with hot-water injection followed by solvent injection and completing the process with how-water injection, up to 85-90% OOIP recovery for static conditions and 70% recovery under dynamic conditions with 80-85% solvent retrieval can be achieved. In this paper, we present the numerical modeling of the dynamic experiments and an upscaling exercise for field scale matrix conditions

3. **Experimental Procedure**

Three symmetrically fractured sandstone cores (cylindrical core with an induced fracture in the middle) were used to conduct the experiment. Their wettability was altered from water to oil wet using a siliconizing wettability alteration agent. This agent is a short chain, clear polymeric silicone fluid consisting primarily of dichlorooctamethyltetrasiloxane. They were then saturated with ~4,500 cp dead crude oil under vacuum at high temperature and left for a few weeks in oil for aging. The core was placed into a core holder with an overburden pressure of 180 psi. Hot water was injected at ambient pressure and fluids were collected and measured at the production end. The process consists of three phases as described before (Al Bahlani and Babadagli, 2008; Al Bahlani and Babadagli, 2009). It starts with hot water injection (Phase 1) continued with solvent injection (Phase 2). Finally, how water was injected (Phase 3) to retrieve the solvent injected and recover some more extra oil. After Phase 1 was completed; the core was left to cool for a certain period until it reaches room temperature. Solvent (Heptane) was then injected at ambient pressure. Three experiments were run for three different solvent injection rates (0.1, 0.3, and 0.5 cc/min). The hot water injection experiments were conducted at a constant rate of 2.0 cc/min and at 90 ^{o}C. The experimental set-up is demonstrated in **Figure 1** (Al Bahlani and Babadagli, 2009). Details of the experimental work can be found in the same reference.

4. Numerical modelling of the experiments

4.1. Model description

The simulator used to run the experiments is a semi-compositional -commercial- simulator. The PVT values of the solute (heavy oil) characteristics were calculated using another commercial simulator. First contact miscible tests were also performed for the solvent (heptane) and the solute (heavy crude oil).

The model is a single porosity cartesian model (**Figure 2**). The model length was fixed to the exact core length and sensitivity runs were applied on the width and thickness to approximate the original amount of initial oil in place in the cylindrical experimental sample. Two additional grid blocks at the inlet and outlet were included to act as a buffer zone and mimic heat losses at the experimental connection points. A fracture was assigned in the middle of the model and the perforations were created to allow the injected fluid flow through the fracture. This representation corresponds to the fracture blocks creating a source / sink well model. The units used in the model were lab units. The IJK blocks for the 3D model were 16x21x12 with the dimensions of 9.62 x 2.248 x 2.238 cm representing the exact volume of the experimental system. The matrix properties used in the simulation study are given in **Table 1**.

The main objective of this numerical simulation is to history match the experiments and obtain immeasurable parameters for the upscaling exercises.

4.2. History matching

A 2D model was first initiated to study the factors affecting the controlling the process at all three phases. For Phase 1 (hot water injection), the factors affecting the process are mainly (a) the first coefficient of thermal expansion (CT1), (b) injection temperature, (c) relative permeability curves, and (d) heat loss parameters. Impacts of other parameters such as rock heat capacity, and fluids thermal conductivities (oil, gas and water) were less pronounced. Therefore, the values from a producing heavy oil field with the similar properties were used. For Phase 2 (solvent injection), the main parameters affecting the process are (a) matrix molecular diffusion, and (b) matrix-fracture mechanical dispersion. For Phase 3, the only tuning parameter left was the injection temperature as others were already set in the previous phases.

A 3D model was then built and a grid sensitivity analysis was made first. Fine grids seemed to have no major effect on the process and the ultimate grid size was obtained to optimize the run time. The thermal oil expansion coefficient was estimated from the previous static experiments (Al Bahlani and Babadagli, 2008). During the initial phase of the static experiment oil was produced mainly from thermal expansion. The coefficient was obtained from the following equation:

$$c = \frac{\Delta V}{\Delta T}\frac{1}{V_i} \qquad (1)$$

where ΔV is the difference in volume, V_i initial volume, and ΔT is the difference in temperature. After employing the thermal expansion coefficient obtained from the experimental work and applying different sensitivity runs, the optimal number was specified and used for all other models. A typical oil wet relative permeability table was created and a sensitivity analysis on the relative permeability parameters was performed. The most critical uncertainty was in the injection temperature as the temperature control due to heat loss during experiments was not stable. The temperature hardly stabilized at later stages in the experiment and to achieve this, a heating tape was used. Thus, injection temperature was the last tuning parameter employed and a single injection temperature for each experimental phase was specified.

In order to initiate Phase 2 (solvent injection) the model temperature was desired to be at ambient conditions. To model that, a new model with the same dimensions and perforations were built. The saturation profiles (water saturation and oil saturation) from the last time step were then imported from the previous model. Subsequently, solvent injection started at the desired rates (0.1, 0.3, 0.5 cc/min) with three different models each with matched saturation profile from Phase 1. The dominating process in the fracture was assumed to be dispersion based on previous experience (Trivedi and Babadagli, 2008, 2009; Er and Babadagli, 2009). Hence, there was no molecular diffusion coefficient parameter employed for the fracture. The representation of flux J_{ijk} of component i in phase j in direction k due to diffusion is given by:

$$J_{ijk} = -(\varphi S_j D *_{ij} / F_{jk}) \nabla_{\mathrm{k}} (\rho_{\mathrm{j}} \mathrm{X}_{\mathrm{i,j}})$$

φ, S_j = Porosity, Saturation of phase j

D*ij = molecular diffusion of component in phase j

F_{jk} = tortuosity for phase j in direction k

$\nabla_k\left(\rho_j x_{i,j}\right)$ = concentration gradient of component i in phase j in direction k

The dispersion coefficient was assigned for both matrix and fracture, bearing in mind that mechanical dispersion is modelled explicitly in this model, unlike total dispersion which models implicitly both molecular diffusion and mechanical dispersion coefficient lumped in total dispersion coefficient. The simulation package represents the mechanical dispersive flux J_{ijk} of component i in phase j in direction k by the following equation

$$J_{ijk} = -\varphi S_j \alpha_{jk} \left|u_j\right| \nabla_k\left(\rho_j X_{i,j}\right)$$

φ, S_j = Porosity, Saturation of phase j

α_{jk} = dispersivity for phase j in direction k

$\left|u_j\right|$ = magnitude of interstitial velocity of phase j

$\nabla_k\left(\rho_j X_{i,j}\right)$ = concentration gradient of component i in phase j in direction k

The matching parameter for Phase 2 was the recovery factor. For Phase 3, hot water was injected at the same rate in the experiment (2 cc/min) and the match parameters that yielded the best match were used in the upscaling study.

4.3. *Upscaling process*

Scale dependency of the molecular diffusion and dispersion coefficients during miscible displacement and the upscaling of this process have been critically discussed previously, especially in terms of heterogeneity (Arya et al. 1988). To define the upscaling parameters, the production from Phase 3 of the models were matched with the lab experiments. One model gave the closest match and its saturation profile was used for upscaling purposes. The upscaling methodology included enlarging the grid size by three factors; x2 x5 and x10 of the lab scale size with a constant block density. The matching parameter was the recovery factor over a certain time. The first upscaled parameter was the solvent injection rate. Since the fracture spacing (or matrix size) was also doubled (x2), it was assumed that fluid velocity in both experimental and larger scales should be the same. Thus, the rate was estimated by the following equation

$$v = \frac{Q}{Wb} = \frac{0.1}{2.238 \times 0.01} \frac{cm^3/\min}{cm \cdot cm} = 4.47 cm/\min$$

$$Q = 4.47Wb \text{ cc/min}$$

Note that this was only a rough initial estimate and the actual upscaling method will be introduced later.

The solvent and solute diffusion coefficients were considered to be the same in all cases but the dispersion coefficients were the tuning parameters used to obtain the recovery factor match at a certain time.

After all three models gave a satisfactory recovery factor matches at a specified time, the relationship between the three models was identified and tuning parameters were introduced.

5. Results and discussion

The SOS-FR process is a complicated process. The first phase (steam/hot-water injection) is commonly tested in labs. However, the miscible displacement in fractured porous media filled with heavy-crude and some amount of immiscible fluid has not been studied in detail. Its importance captured the attention of many researchers in the fields of CO2 sequestration in waterflooded oil reservoirs, and in Expanding Solvent SAGD (ES-SAGD) process. Yet, the physics of the process was mainly studied implicitly through total dispersion coefficient where diffusion coefficients were to be modelled explicitly. Reasons for that are mainly due to tortuosity introduced in the matrix and its effect on the diffusion process. The effect of diffusion on dispersion is likely to appear at low rates (laminar flow).

To test the effect of diffusion and dispersion coefficients on model, three runs were conducted: (a) both diffusion and dispersion coefficients are present, (b) without dispersion coefficient, and (c) without diffusion coefficient. The results are shown in **Figure 3**. By conducting these runs, we can estimate what controls the recovery process using the output curve shape. When the diffusion coefficient is eliminated immediate increase in recovery is seen, and when dispersion coefficient is eliminated a long time with constant low recovery is obtained as seen in Figure 3. This helped in tuning the model in history match. It was also useful in clarifying some experimental observations.

Figures 4 through **6** show the history matches for Phase 1. After obtaining satisfactory history match, Phase 2 was then initiated with different temperature (ambient). In order to reduce the run time to achieve ambient temperatures, new models were created with saturation profiles imported from the last run of Phase 1. **Figure 7** shows the saturation distribution after Phase 1 for the core used for 0.1 cc/min solvent injection rate. By tuning both dispersion and diffusion coefficient parameters, a match for the recovery factor was achieved for all three rates. The results are shown in **Figures 8** through **10**.

Figure 11 implies that the solvent injection process undergoes three phases: (a) the first phase where a small but similar amounts for all rates were observed, (b) the second phase where a constant rate recovery was achieved, and (c) the third phase where very fast recovery was noticed. To explain this behaviour we refer back to **Figure 3** where we can see the effect of dispersion and diffusion on the process. For the first phase, oil seems to be produced mainly from the residual oil in the fracture which is a very small amount. In the second phase, the dominant recovery mechanism is through diffusion into the matrix which is a very slow process as indicated by a “plateau like” recovery curve. As solvent diffusion into the matrix is completed and the stable volume (or density of mixture) is reached, the dispersion in the fracture starts dominating the recovery process represented by thirds phase in **Figure 11.** The diffusion and dispersion coefficients obtained from history matching Phase 2 are presented in **Table 2.**

Finally, to simulate Phase 3, we selected the semi-compositional model option for the sake of simplicity. It has certain drawbacks as this type of model (not fully compositional) does not represent bi-products of the process, mainly asphaltene precipitation. During the lab experiments, gas (heptane) was produced at very high rates initially during Phase 3 (Al Bahlani and Babadagli, 2008). What we noticed in the very beginning of Phase 3 is a sharp oil peak (first few minutes of Phase 3) as shown in **Figure 12**. This sharp peak is highly likely the amount of gas (heptane) observed during lab experiments. Note that the temperature (90 ^{o}C) is very close to the boiling point of heptane and when Phase 3 is started, heptane in the matrix starts boiling and produced as gas bubbles. The produced amount during this stage is in good agreement with the experimental observation. The rest of the recovery profile shows also a good match with the experimental results.

For the upscaling, three upsized grid blocks of the initial matrix size were tested (x2, x5, and x10). The initial guesstimate of the oil rate was close to some extent, however, with tuning, it was found that there is an exponential relation between the rate upscaling methodology and rates obtained from tuning. Thus, a power relation was obtained as it can be seen from **Figure 13**. The results were employed to obtain an upscaling equation for the oil rate with respect to fracture dimensions.

Figure 14 gives a good estimation of weather the upscaling parameters in hand are applicable or not. If the oil recovery reaches the same recovery factor of what is reached in the lab then parameters in hand are applicable. Thus, upscaled model can be tuned to design efficient solvent rate injection, well placement or any desired injection strategy. It is also apparent from **Figure 14** can be seen that the three phases seen in both lab experiments and simulation are apparent as explained earlier (oil fracture depletion, diffusion dominated phase and dispersion dominated phase). The diffusion and dispersion coefficients for tuned upscaled model are presented in **Table 3** and the equations used to initially estimate them are presented in **Table 4**. After Phase 2 in the upscaled matrices, hot water was injected again. As it can be noticed again, the recovery is inversely proportional to the grid block size. This is because the recovery in this case is mainly due to thermal means and higher energy injection rates are required as it can be seen from **Figure 15.** A peak is also noticed at the solvent production rate at this phase as it can be seen from **Figure 16**. This, to some extent, strengthened the hypotheses that as solvent is heated and escapes the matrix (gas phase in case of lab experiment) it pushes a good amount of oil with it causing a high initial recovery factor. The solvent recovery factor is calculated and results are presented in **Table 5**. It can be clearly seen that solvent recovery factor is quite high at very low time ranging between 51 and 70% OOIP (the smaller the matrix block size, the higher the solvent retrieval). The decrease with enlarging grid size maybe explained in terms of rock properties, since heating a larger matrix block takes larger energy which delays the solvent production from inner matrix. It should be emphasized that simulator package in hand is a semi-compositional and results may vary when fully compositional simulator is used.

6. **Conclusions**

- The process of SOS-FR introduced in two previous papers (Al Bahlani and Babadagli, 2008 and 2009) with experimental evidence was highly promising for heavy-oil/bitumen recovery from fractured reservoirs. The numerical model study presented in this paper also showed that it is applicable at larger matrix sizes especially when the time scale to reach the ultimate recovery was considered.
- A new methodology was proposed for upscaling lab data to field data by employing a dimensionless equation, rate and dispersion coefficient provided in Table 4. These equations were obtained by employing fracture dimensions of both lab experiments and upscaled model, and assuming the fact that the velocity at all scales are the same.
- A relationship between mechanical dispersion and molecular diffusion at low rates was introduced and studied to understand and maintain reasonable tuning for the lab experiment history match.
- During solvent injection, three phases were observed; (1) fracture oil depletion phase, (2) diffusion dominant phase,

and (3) dispersion dominant phase. This indicates that diffusion and dispersion process in highly water saturated porous media is more distinctive than diffusion-dispersion process in oil saturated porous media.

- Large block sizes need larger solvent injection rate because of fluid velocity dispersion dependency.
- High and fast initial solvent rate is observed during the third phase, this coincides with the high gas bubbling seen during phase three in lab experiments (Figure 16). This strongly suggests that gas retrieved is mainly heptane.
- Even for large matrices, solvent retrieval seems to be very high ranging 50 % to 70 %.
- The next step towards understanding this process is to up-scale to field scale and test the efficiency of the process.

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Table 1: Matrix properties

Matrix blocks in IJK direction	16x21x12
Fracture spacing	0.01 cm
Matrix porosity	0.147
Fracture porosity	1
Matrix permeability	550 mD
Fracture permeability	55 D
Heavy oil gravity	14 API
First thermal expansion coefficient CT1	0.0015

Table 2: Parameters obtained from the history matching of Phase 2

Rate	**Solvent diffusion coefficient (cm^2/min)**	**Solute diffusion coefficient (cm^2/min)**	**Matrix dispersion coefficient (cm)**	**Fracture dispersion coefficient (cm)**
0.1 cc/min	0.0002	0.000535	0.039	0.000888
0.3 cc/min	0.002	0.00535	1.7e-6	0.098
0.5 cc/min	0.0002	0.000535	0.0	0.00088

Table 3: Parameters obtained from upscaling at certain recovery factor (10 %) and at a certain time (480 min).

Upscaled model	**Solvent diffusion coefficient (cm^2/min)**	**Solute diffusion coefficient (cm^2/min)**	**Matrix dispersion coefficient (cm)**	**Fracture dispersion coefficient (cm)**
X 2	0.0002	0.000535	0.078	0.003552
X 5	0.0002	0.000535	0.159	0.0222
X 10	0.0002	0.000535	0.39	0.0888

Table 4: Upscaling equations for key parameters

Upscaling number	$N = \frac{l}{3.07W}$
Matrix dispersion coefficient upscale equation	$D_i \times N$
Fracture dispersion coefficient upscale equation	$D_i \times N^2$
Rate upscale equation	$1.4196(4.4683Wb)^{1.3886}$

D_i : *Dispersion coefficient obtained from the original model.*
N : *Upscaling number*
W : *Fracture width of the upscaled model.*
b : *Fracture spacing of the upscaled model.*
l : *Fracture length of the upscaled model*

Table 5: Solvent injection and recovery in the upscaled models.

	x2	**x5**	**x10**
Total solvent injected (cm^3)	191.988	2399.98	16799.8
Total solvent produced @ 480 min (cm^3)	186.993	2305.89	16112.6
Total solvent produced @ 540 min (cm^3)	190.499	2363.92	16463.8
Amount of solvent diffused in matrix (cm^3)	4.995	94.11	687.2
Amount of solvent produced in Phase 3 (cm^3)	3.506	58.05	351.2
Solvent recovery factor from Phase 3 (%)	70	62	51

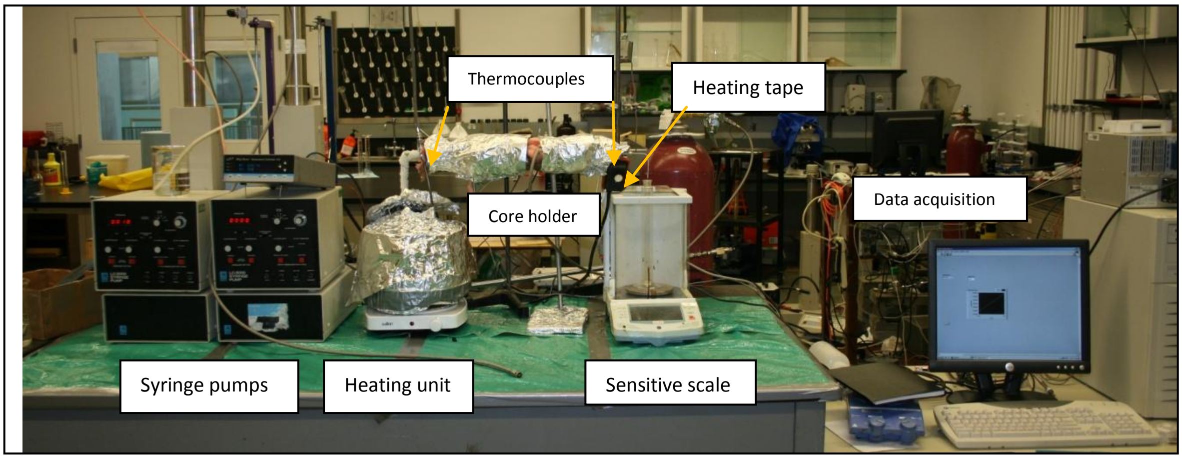

Figure 1: Experimental set-up for three different solvent injection rates (Al Bahlani and Babadagli, 2009).

Figure 2: Single porosity cartesian model used to history match lab experiment dynamic results.

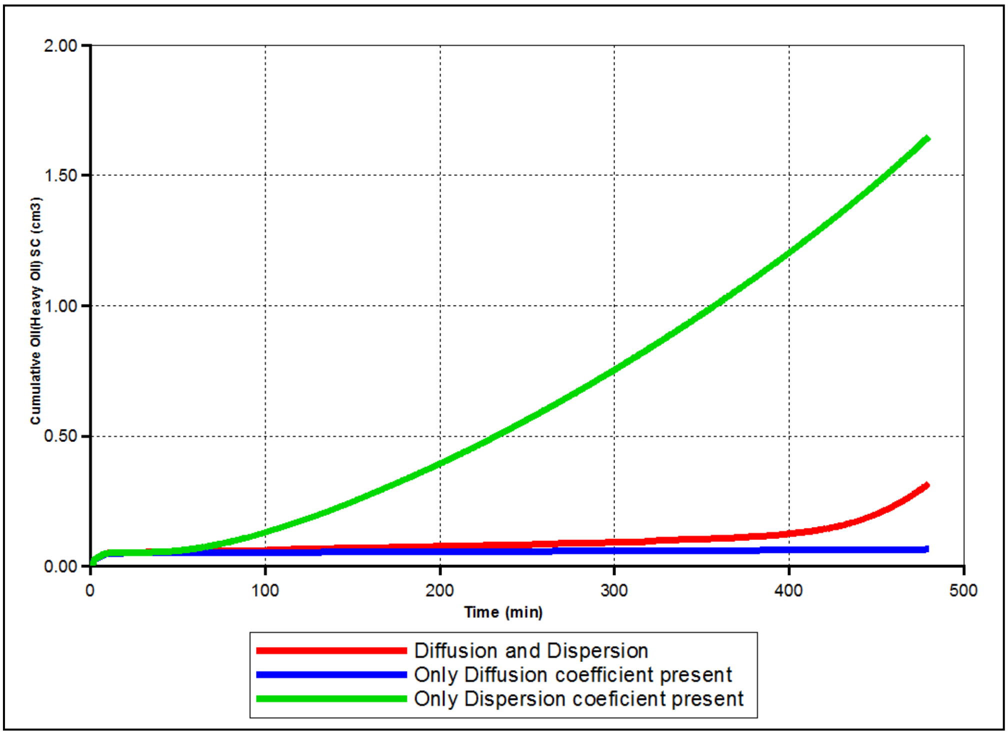

Figure 3: Three runs testing the effect of dispersion and diffusion coefficient on the simulation model.

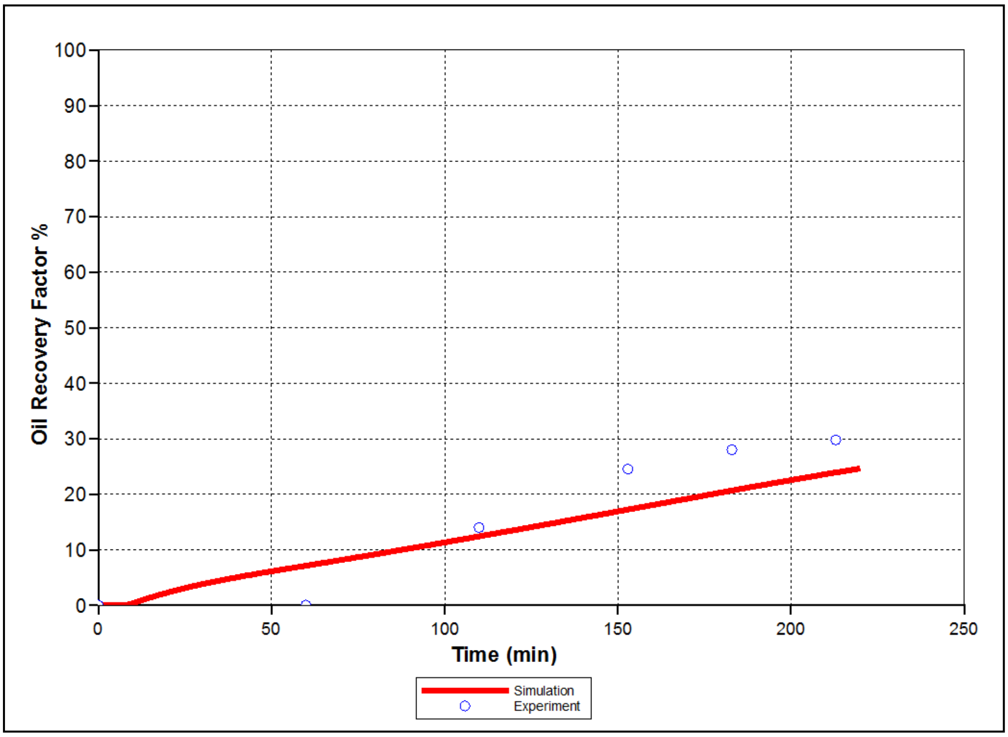

Figure 4: History match of Phase 1 on the core sample later used for 0.1 cc/min solvent injection rate.

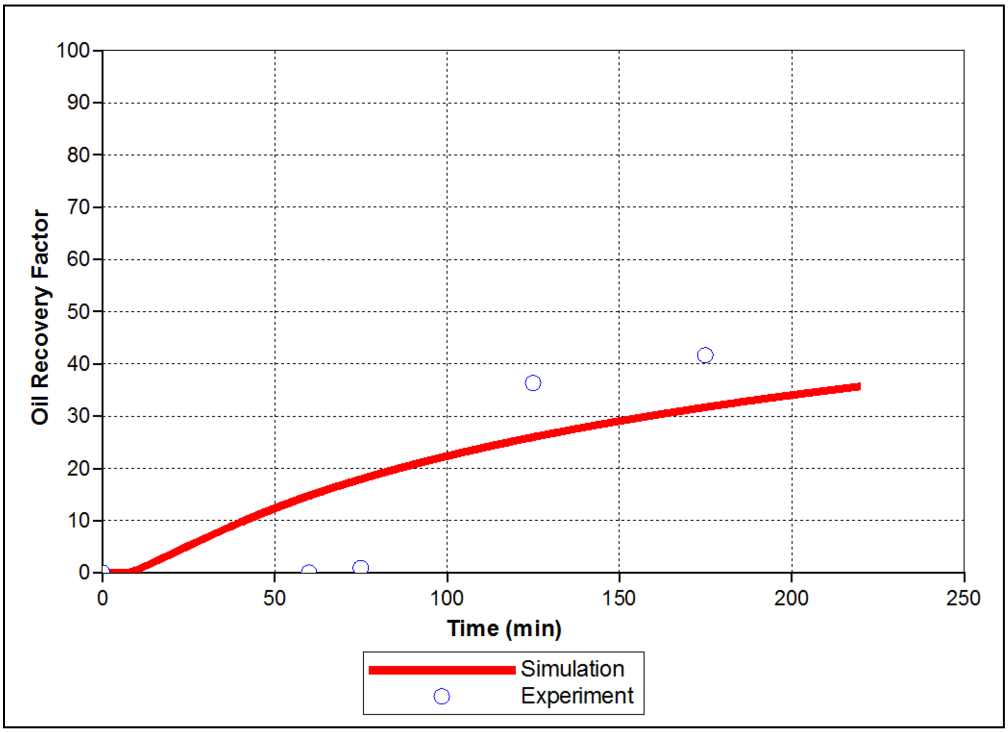

Figure 5: History match of Phase 1 on the core sample later used for 0.3 cc/min solvent injection rate.

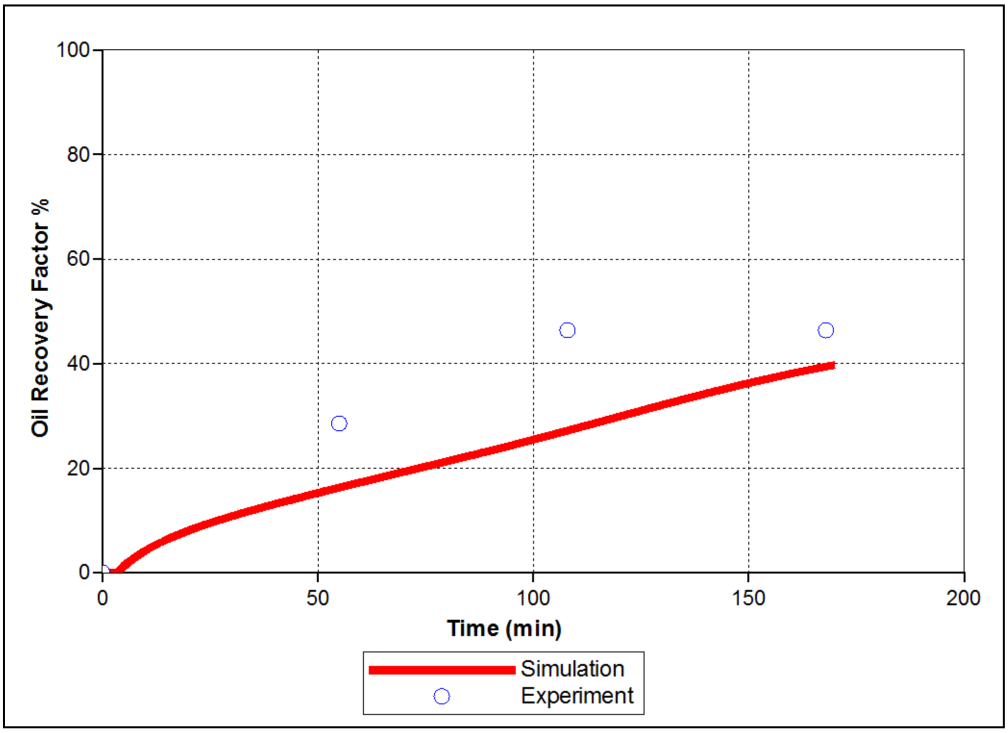

Figure 6: History match of Phase 1 on the core sample later used for 0.5 cc/min solvent injection rate.

Figure 7: Oil saturation at the last time step of Phase 1 for the core used in 0.1 cc/min solvent injection rate. This saturation distribution was imported to the model for Phase 2.

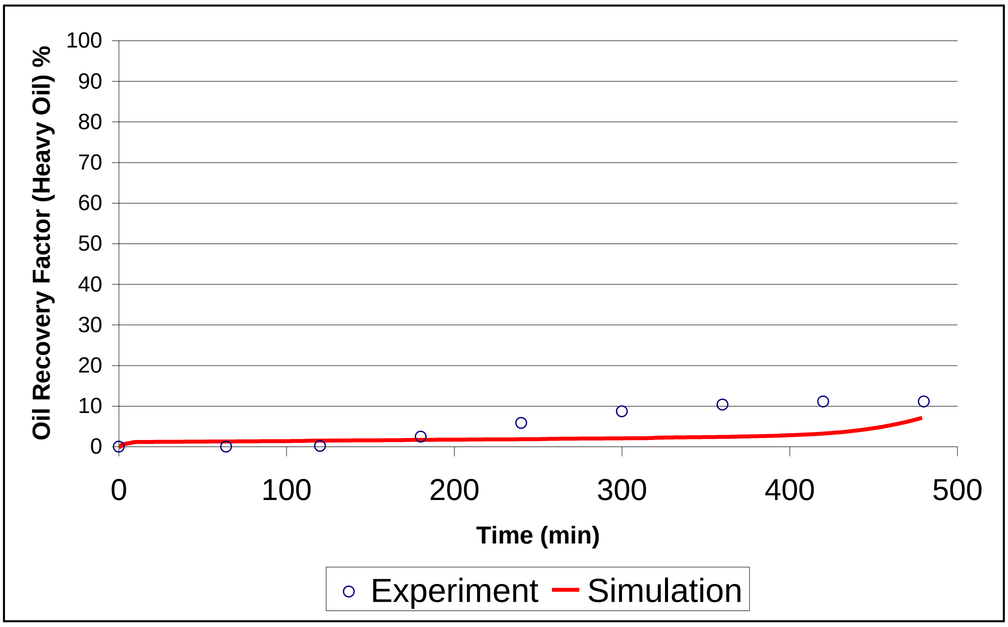

Figure 8: History matching of Phase 2 for 0.1 cc/min injection rate.

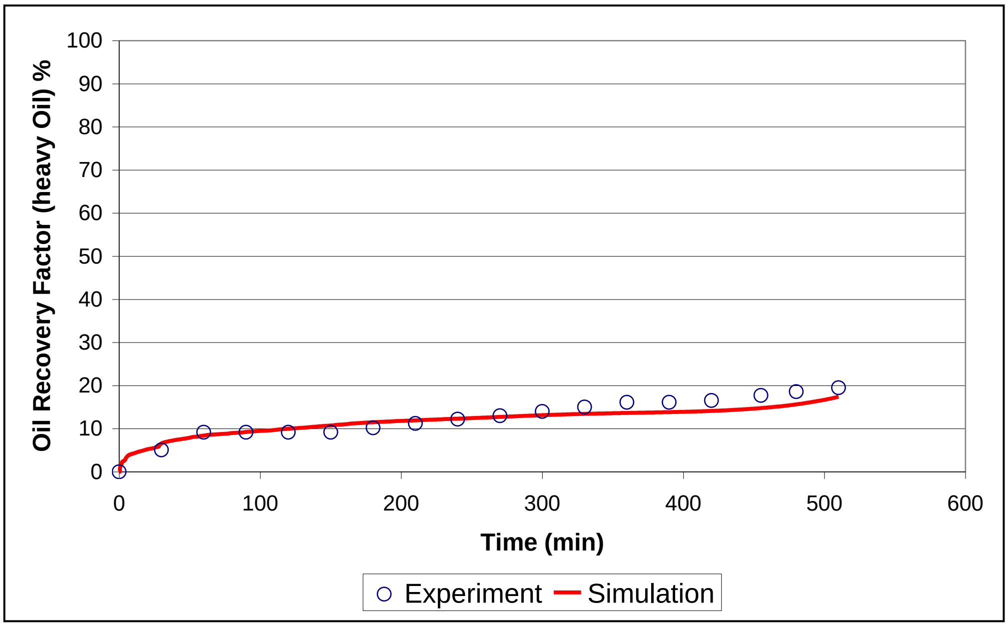

Figure 9: History matching of Phase 2 for 0.3 cc/min injection rate.

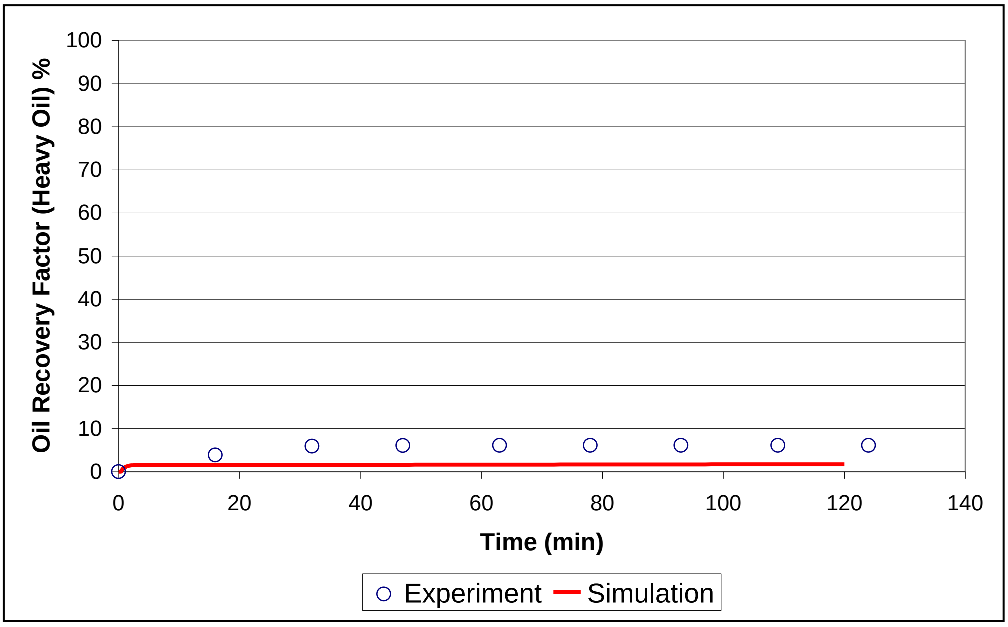

Figure 10: History matching of Phase 2 for 0.5 cc/min injection rate.

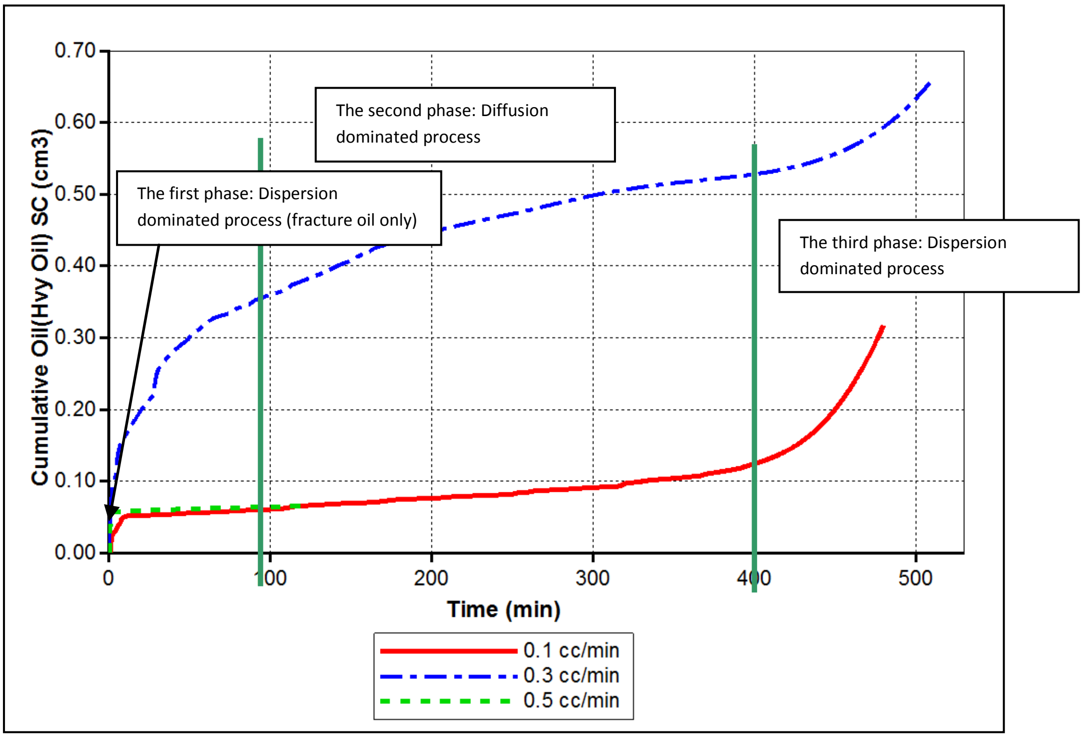

Figure 11: Demonstration of three distinctive phases during solvent injection process (Phase 2).

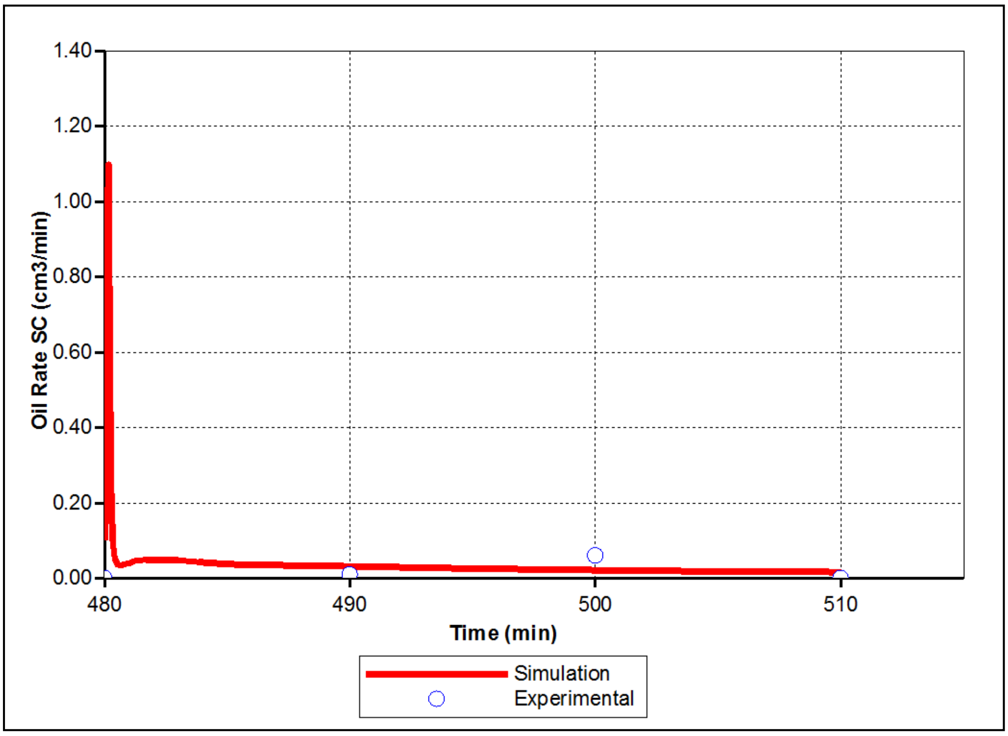

Figure 12: History match of Phase 3 for 0.1 cc/min solvent injection core.

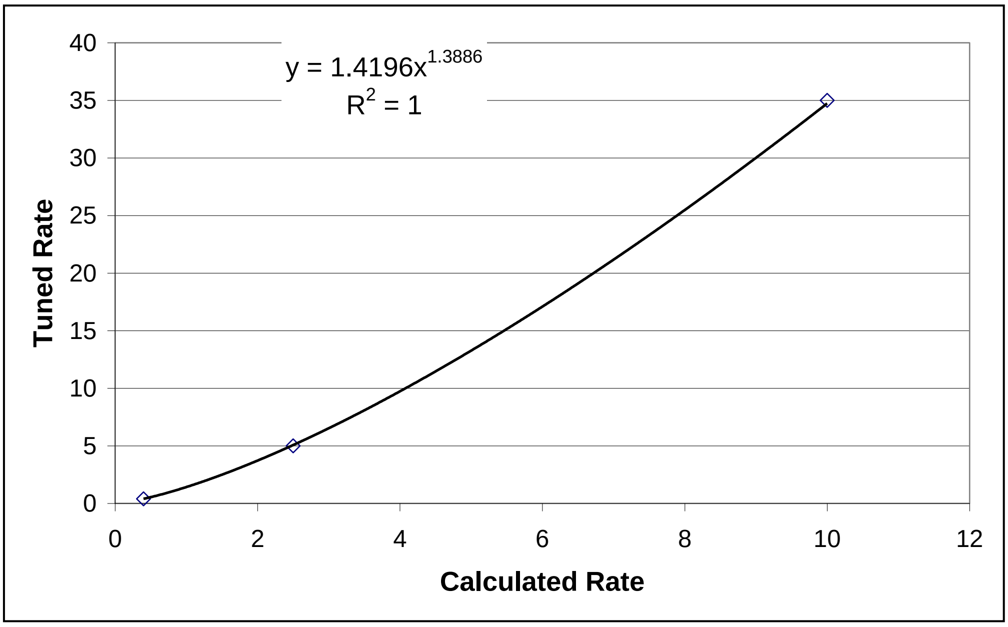

Figure 13: Relationship between the calculated upscaled solvent injection rate and tuned rate to obtain desired recovery factor.

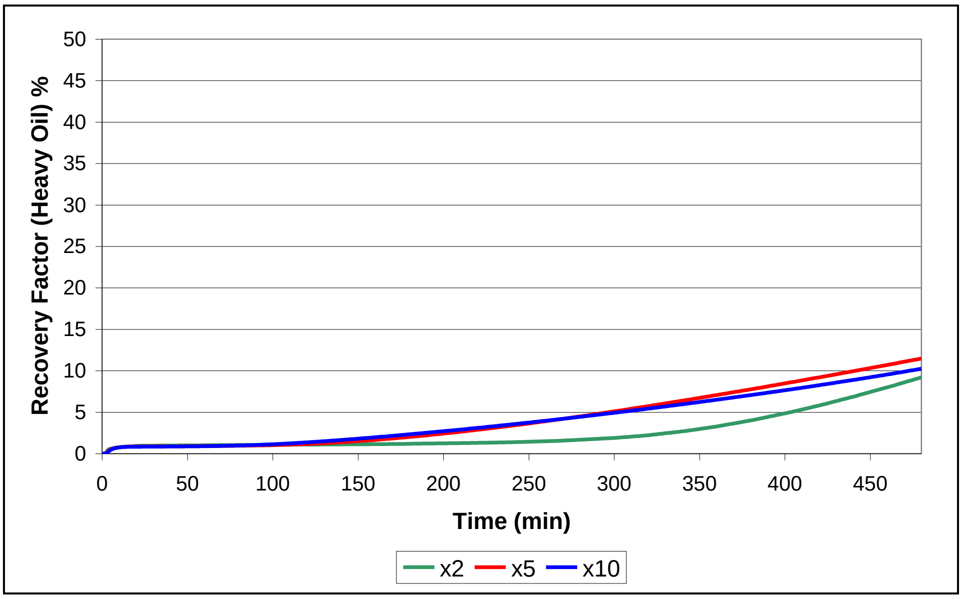

Figure 14: Recovery factor for three upscaled grid blocks sizes all reaching the same recovery factor at the same time.

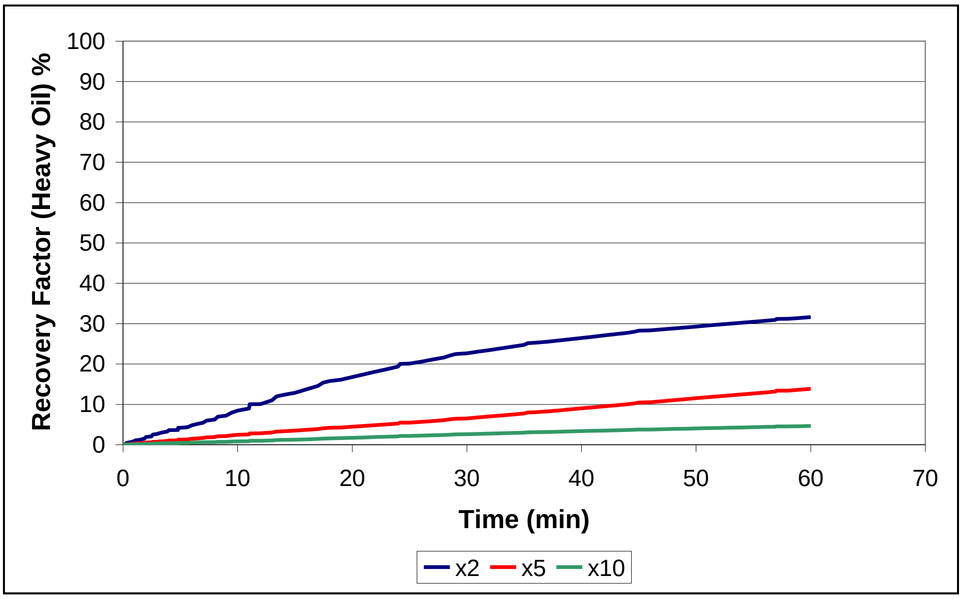

Figure 15: Incremental recovery factor at Phase 3 from upsized models. Smaller models produced higher recovery.

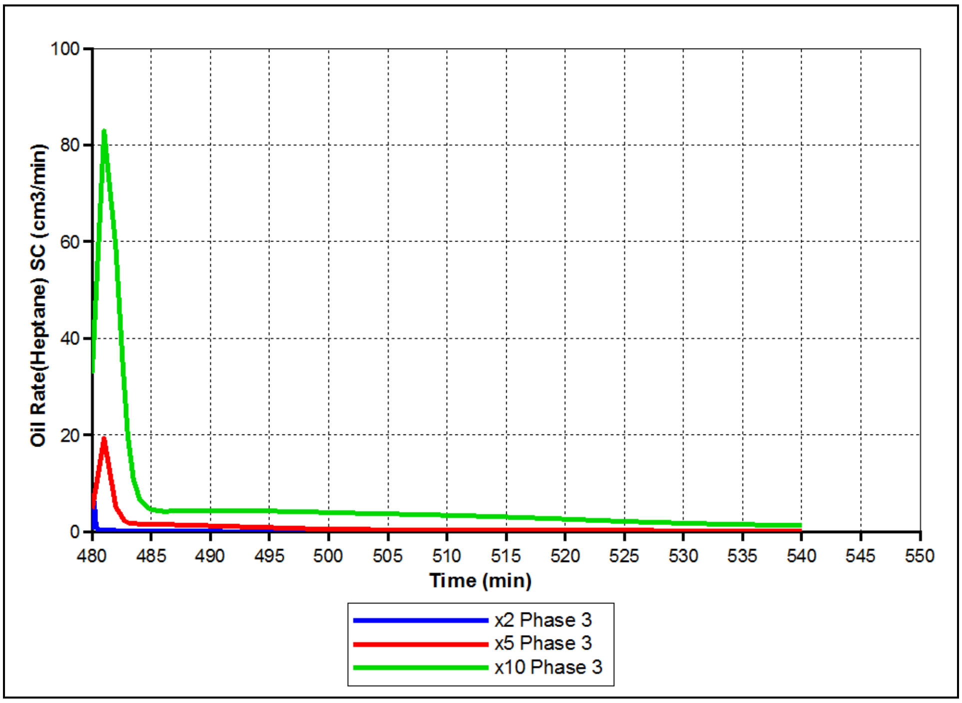

Figure 16: Oil rate during Phase 3 for the upscaled grid blocks.

Chapter 7: Field Scale Applicability and Efficiency Analysis of Steam-Over-Solvent Injection in Fractured Reservoirs (SOS-FR) Method for Heavy-Oil Recovery

Submitted to Journal of Petroleum Science and Engineering for publication

1. Preface

Heavy-oil recovery from fractured carbonates is a real challenge, yet no proven technology exists as an efficient solution. Reservoir heating is generally inevitable and steam injection is the only effective way to heat heavy-matrix oil in such reservoirs using the steam distributed through fracture network. We propose a new method minimizing heat needed for efficient heavy-oil recovery from oil-wet fractured rocks by adding solvent component. Efficiency is a critical issue in this process due to potentially high cost of the process.

A new technique we proposed previously called Steam-Over-Solvent in Fractured Reservoirs (SOS-FR) consists of a cyclic injection of steam and solvent in the following manner: Phase 1: Steam injection to heat up the matrix and recover oil mainly by thermal expansion, Phase 2: Solvent injection to produce matrix oil through diffusion-imbibition-drainage processes, and Phase 3: Steam injection to retrieve the injected solvent and recover more heavy-oil. Laboratory scale static and dynamic experiments had shown that, under very unfavorable conditions (oil-wet matrix, 4,000cp crude), oil recovery at the end of Phase 3 was around 85-90% OOIP with 80-85% solvent retrieval (Al Bahlani and Babadagli, 2008 and 2009a).

In this paper, the experimental results obtained earlier were matched to a single matrix/single fracture numerical model and parameters needed for field scale simulation (matrix-fracture thermal diffusion, solvent diffusion and dispersion coefficients) were obtained (Al Bahlani and Babadagli, 2009b). Using the data obtained through matching, field scale simulations were performed for efficiency analysis and to identify the optimal injection schemes (soaking time for cyclic and injection rate for continuous injection) and durations, and surface steam quality. Specific conclusions as to how to apply this technique efficiently in the field considering the cost of the process were reported.

2. Introduction

2.1. Problem description

The production of heavy oil from tight carbonate reservoirs imposes a great challenge which needs unconventional solutions to overcome. The orthodox method of steam injection has shown acceptable production through different mechanisms including thermally assisted gas oil gravity drainage known as TA-GOGD (Shahin et al. 2006; Babadagli and Al-Bemani, 2007). Wettability alteration from oil wet to water wet due to steam injection can play a major role in promoting heavy oil production (Zhou et al. 1993; Motealleh et al. 2005; Rao, 1999; Al-Hadrami and Blunt, 2001; Schembre et al., 2006; Gupta and Mohanty, 2008). However, wettability alteration has a very narrow effect, which may only occur in a limited -heated- matrix-fracture contact area. This is mainly due to high temperature requirement to create wettability alteration in the sense of changing rock property. Wettability alteration cannot be considered as a very reliable form of EOR technique, rather it can be thought of as a side effect to steam injection that may or may not occur. Wettability alteration can be in the form of changing the contact angle between two fluids and solid adhesive medium, and can be in the form of fluid rock adhesive forces. The earlier form can occur immediately as steam is injected, however, it has a minor effect on the process. The second form which is to break the bonds between heavier components of hydrocarbon molecules and the pore surface require elevated temperatures depending on rock and fluid type.

With all the beauty steam injection exhibits, its impracticality surfaces during the execution of the process, where vast amount of water has to be made available, processed, injected, produced, treated, and then contained in an environment friendly manner. In other words, it requires a huge water management effort combined. This becomes a major challenge in remote areas with limited water accessibility.

The vast amount of heavy oil locked in extreme challenging reservoirs enforces the immanency for new methods which facilitate enhanced oil recovery from such reservoirs. The use of solvent for heavy oil recovery in thin and high permeability sandstones has shown promising results in laboratory scales (Al Bahlani and Babadagli, 2008; Al Bahlani and Babadagli 2009a, Al Bahlani and Babadagli 2009b). Mainly VAPEX and ES-SAGD (Nasr et al. 2003) were developed to overcome or minimize the use of steam for heavy oil production. Such processes show attractive results in labs and simulations, yet, no field pilots proved the efficiency of the methods. No reliable proven results of solvent injection have shown an established applicability on tight and fractured sandstones and carbonates containing heavy oil.

The main issue with solvent processes in fractured reservoir is the ability of solvent to penetrate into the matrix. This penetration of solvent to matrix oil is observed through different physical process such as diffusion, dispersion or gravity drainage.

2.2. Proposed solution

Steam-Over-Solvent Injection for Fractured Reservoirs (SOS-FR) has been recently proposed as an attempt to utilize the goodness of both steam and solvent to exploit carbonate reservoirs (Al Bahlani and Babadagli 2008; Al Bahlani and Babadagli 2009a). Steam injection will provide viscosity reduction, heating up the reservoir and producing fast-oil through thermal expansion. Solvent injection will penetrate the matrix easier through imbibition and will create counter current effect which will help further expel oil from matrix to fracture. The method relies on two main key reservoir characteristics; Fracture density and oil wetness. The high fracture density introduces a higher steam/solvent exposure to matrix which allows heavy oil production by gravity in both steam and solvent soaking phase. Oil wetness allows for faster solvent imbibitions into the matrix which creates inner matrix convective movement due to gravity difference between heavy oil and solvent. Although diffusion plays a role in production, yet it is not considered as the main working mechanism.

2.3. Process description

The main idea of the process is to take advantage of the fast recovery from thermal expansion by steam injection, followed by a cooling period where water is "sucked" into the oil wet matrix by oil thermal contraction, subsequent introduction of the solvent, and retrieving the solvent by steam injection. As solvent is introduced into the fracture, water drains from the oil wet matrix while solvent is imbibed due to oil wetness. This process showed improved oil recovery both at lab scale experiments (Al Bahlani and Babadagli 2008; Al Bahlani and Babadagli 2009a) and simulations (Al Bahlani and Babadagli 2009b), and field scale simulations (Al Bahlani and Babadagli 2009c). The process consists mainly of three phases:

- Phase 1: Steam (hot-water) is injected to promote early high production by oil thermal expansion (~10%). This is followed by a cooling period to allow for thermal contraction.
- Phase 2: Solvent is injected as a wetting phase. This will allow solvent to enter the matrix portion invaded by water previously to displace oil by capillary imbibition and interact with oil by molecular diffusion. Solvent will mix with oil by diffusion creating a new type of oil with different components.
- Phase 3: Steam (hot-water) is injected to retrieve solvent diffused into matrix and more recover more oil. This causes a rapid thermal expansion of solvent forcing it to depart the matrix with a further production of oil.

This paper attempts to explore through means of computer software simulation package the practical aspect of the proposed method (SOS-FR). The paper focuses mainly on the second phase (solvent injection) as the recovery by solvent injection and solvent retrieval are the critical parts for a successful application of any solvent injection project. Sensitivity analyses were performed on solvent injection rate, fracture density and soaking period for huff and puff application.

3. **Modelling concept**

3.1. Modeling essentials

Modeling solvent injection processes using a commercial software package has never been a straight forward application, especially if the process is non-isothermal. This is mainly due to lack of reliable analytical modeling of such complex phenomenon more than software behavior. Solvent process modelling is very sensitive to several characteristics which include grid size, grid orientation, and grid properties. The main property, which solvent processes are heavily dependent on, is its solvent diffusion coefficient and this is obtained from experimental data. The main way to measure the diffusion coefficient is to introduce the solvent to the solute and then measure the concentration at a specific point with time. The slope between concentrations and time will give the diffusion coefficient. The application of this method into porous media and to petroleum industry particularly may not be very accurate, since other factors affect the flow of solvent from one end to the other. Such factors include permeability, concentration and asphaltene precipitation which may introduce an obstacle to the solvent flow into the porous medium. Such factors need to be represented in a certain fashion that the simulator can understand and digest in order to replicate field scale results. The best way to achieve this target is by introduction of pseudo effective diffusion coefficient.

To obtain this number a series of dynamic experiment mimicking field case scenario were made on 3” x 1” fractured cores, the experiments were then history matched and the pseudo effective diffusion coefficient was obtained. The experiment and history matching are extensively discussed in previous work by authors (Al Bahlani and Babadagli 2009 a-b). **Figure 1** shows a history match for one of the cases where solvent was injected at a rate of 0.3 cc/min.

3.2. The simulator

The simulator used for this model is a semi-compositional commercial simulator (CMG STARS). The model used is an IK Cartesian 2D Model with single porosity and single permeability. A 2D Model was preferred because of the convergence periods encountered with a 3D model. It was observed that standard PCs are incapable of running such simulations in 3D hence a 2D model was adapted. The representation of 2D model for such purpose is acceptable for the stated objective as the main purpose is to compare different scenarios to test the applicability of the technique at the field scale.

3.3. Simulation assumptions

The base case used to benchmark all cases is 20x30x15m block. The model contains a single fracture of 1cm aperture. The size was selected as the optimal number not to encounter a convergence problem. **Table 1** provides details on geological features of the model and **Table 2** shows the injection periods for all continuous injection cases. Other model variations include matrix size variation and fracture density. The representations of the numerical models used are given in **Figures 2a** and **2b** for a single and multiple matrix cases, respectively. In the model, we assume that there is no asphaltene precipitation and deposition which may reduce permeability.

3.4. Simulation procedure

The main theme of this paper is to investigate the efficiency of SOS-FR process at field scale and to exercise a comparison between continuous and cyclic (huff and puff) injection. For Phase 1 (steam injection) all models were run for the same period with the same amount of steam injected; 20 Tons/day CWE (cold water equivalent). Steam was injected at elevated temperature with a well head steam quality of unity. Before Phase 2 was initiated, cold water at 20^{o}C was injected in order to speed up the cooling process. The cooling period was suggested to introduce some amount of water into the system in the experimental work (Al Bahlani and Babadagli, 2008), which would add to the economics of the process due to reduced heating time and improve oil recovery by the spontaneous imbibition of solvent displacing water in the system during Phase 2. The cooling stage also represents the time period to switch from steam to solvent injection in practice.

Solvent was then injected at different rates (5, 10, and 50 m^3/day) for the same period of time for all models. For multiple fractured models the wells were placed within the horizontal fracture layer while with single matrix wells are placed within the vertical fracture. Three soaking periods were trialed (2 weeks, 1 month and 2 months) and the injection and production periods were 14 and 7 days, respectively. Phase 3 was then initiated with the injection of 0.75 quality steam at wellhead for all cases. A total of eighteen scenarios were tested as shown in **Table 3**.

4. Results and discussion

In order to introduce a relevant comparison, two extreme cases where used to benchmark the proposed process, which were solely steam or solvent injection for the whole simulation period.

4.1. Continuous injection

For a single matrix, several sensitivity runs were conducted for different matrix size and solvent injection rates. The SOS-FR was then benchmarked to continuous solvent and continuous steam injection to construct an image of how this process compares to the other established injection scenarios as a combination of steam and solvent injection. **Figure 3** shows the effect of matrix size on the process. As expected, the larger the matrix, the lower the recovery. However, solvent saturation profiles show that with a large matrix, the saturation near the wellbore is much lower than that of the small matrix. This can be attributed to the fact that larger matrix blocks maintain higher average block pressure, which obstructs the movement of solvent into the matrix. **Figures 4** and **5** show solvent saturation profiles at the end of Phase 2 and average block pressures for different block sizes, respectively. It can be seen that with smaller matrix size pressure drops to around 1000 kPa while with large matrix it remains around 2500 kPa.

When the SOS-FR method was compared to continuous steam-only injection and continuous solvent-only injection cases, one may observe that a higher recovery factor can be obtained for continuous steam injection. **Figures 6** and **7** show the recovery factor sensitivity of both single matrix and multiple matrix cases for a 20 m block size. As seen, the oil recovery from steam injection is slightly higher than that of the SOS-FR. However, it was observed that the SOS-FR is more economic than continuous steam injection as will be pointed out later. This is mainly due to high negative impact factor of the steam injection on the economics of the project due to its high cost.

For the rate dependency sensitivities, three different rates (5, 10, and 50 m3/day) were used. The results show that, for a single matrix rate case, the rate has a very minimal effect on the recovery factor as can be seen in **Figure 8**. The solvent injection rate is more critical for the multiple matrix case as can be inferred from **Figure 9**. This does not only appear in the oil recovery factor but also in the cumulative solvent oil ratio (SoOR). **Figure 10** shows a much lower SoOR for higher fracture density blocks. This is mainly due to larger matrix exposure area created by higher fracture density. This implies that fracture density is a predominant factor in this application.

For the third phase, most of the solvent injected was retrieved. **Figure 11** shows that, by the end of Phase 3, the total solvent produced (Sp) to total solvent injected (Si) ratio is around unity. We also observed that as the injection rate is increased (50 m3/day), the Sp/Si becomes much higher at earlier stages. This implies that the solvent interaction time with matrix becomes lower. However, we also noticed that oil production from this case is significantly higher in the multi-matrix model (+10%), which implies that the process is controlled by two main factors; diffusion and gravity drainage. Apparently, gravity drainage dominates the process since the diffusion process is quite slow indicated by a fairly small value (2.88E-5 m^2/day).

4.2. Cyclic solvent stimulation (CSoS)

Another method tested for the SOS-FR was to conduct cyclic solvent stimulation. After Phase 1 is completed, solvent was injected for a period of 14 days followed by a solvent soaking for three different periods (two weeks, one month, two months). The production well was then opened for seven days only as all production would happen from the fracture. Steam was then injected to retrieve the solvent left in the matrix.

Results show little improvement for a single matrix (an increase from 14% for SOS-FR to 19% for a soak period of two weeks). Longer soak periods did not show significant improvement in the recovery factor for a single matrix. In fact, for two months soaking period time, the recovery was less than standard SOS-FR. However, a significant improvement was seen in the solvent to oil ratio (SoOR). This can be seen in **Figures 12** and **13** show the recovery factor for a single matrix and multi matrix (20m block) where we can see the little to no improvement to recovery factor. However, the solvent oil ratio drops significantly with CSoS as shown in **Figure 14**. This emphasizes the relationship between diffusion and gravity drainage; while oil is drained into the fracture, solvent rises in the matrix. This can be clearly seen in **Figure 15,** which shows the solvent mole fraction saturation profile for the CSoS. The solvent rises to higher layers of the reservoir and oil drains into the lower parts of the matrix. Limited solvent penetration is seen on the lower part of the reservoir as it is mainly controlled by diffusion and/or solvent imbibition and water drainage.

4.3. Economic Indicators

The economic indicator is the key objective of this paper since the efficiency of any EOR process is assessed by its ability to create revenue. This efficiency is to be tested by processing it into an economic indicator, which will give a preliminary overview on the cases that need to be further studied to eventually obtain an ultimate economic profile. It must be emphasized the economic indicator is not conclusive, rather it takes into account key common elements (such as steam and solvent cost) and omits other factors which may greatly vary from a location to another. The indicator takes into account the gross profit, economic impact factor (EIF) of certain elements and the money recovery factor (MRF). All these depend on initial asset value (IAV), which is the amount of money we have in-place. It is obtained by multiplying the STOIIP by the price of oil.

$$IAV = (STOIIP)x(\$_{oil}) \tag{1}$$

We also identify three elements that cause an economic impact on the project; (1) steam, (2) solvent, and (3) oil. Each of these elements may directly generate revenue, cost or a combination of both. The total effect on the initial asset value IAV is explored by the following:

$$EIF_i = \frac{\mathrm{Re}venue_i - Cost_i}{IAV} \tag{2}$$

where (i) is the tested element. Then, the MRF is defined as follows:

$$MRF = \frac{Gross\mathrm{Pr}ofit}{IAV} \tag{3}$$

The three elements mentioned above have the following impacts on the process:

(1) For steam, revenue is considered to be null since no steam is treated and re-used for injection. It is not a common practice to re-

treat the produced water and re-inject it into the reservoir as steam. This is mainly due to high treatment cost and high risk of untreated hydrocarbon residue that may harm the boilers. Thus, we expect to have only negative impact on the project.

(2) Solvent, however, is considered to have both revenue and cost with the same price. Even if oil is not treated to extract the solvent, it upgrades the oil which reduces the need to add solvent for pipeline transportation. Also, most of this solvent is recovered in the distillation tower. Thus, we expect to either have a low negative impact on the project.

(3) As for the oil, it is considered to only have revenue and no cost associated with it as a single element since it is in in-place, thus, it will only have a positive impact on the project.

If the sum of EIF is positive, then the proposed scheme has an economic value. The negative value suggests an uneconomic application. The prices for steam solvent and oil are shown in **Table 5.** The CAPEX due to the development of the infrastructure (injection facilities, steam generation, treatment plants etc.) was not included in this comparison analysis as it would possibly be the same for all cases.

A full economic analysis is generated and presented in **Table 6**. **Figure 16** shows the MRF values for all cases. This economic indicator shows that all cases in a single matrix yield an uneconomic recovery. It also indicates a high impact factor for steam, which is considered as money sink. It is easily predictable that, for such unfavorable matrix characteristics (oil-wet, tight, and large), high fracture density can improve the recovery through different means of injection. The multiple fracture cases showed significant improvements in the economics. The only case for the multiple-matrix, which did not yield a positive MRF was the continuous solvent injection at the rate of 5 m3/day. It is close to nil and the SOR turned out to be the highest value of the all cases (**Figure 17**). It also shows that, due to minimized usage of solvent in cyclic solvent stimulation, the MRF is much higher than the other SM cases. In practice, this might be questionable as the fracture volume is very low and unless forced imbibition from fracture to matrix is achieved, the solvent volume injected will be very small resulting in a very ineffective use of solvent during Phase 2.

5. Carbon dioxide emission reduction

With the tendency of carbon taxation in many countries in the near future, the knowledge of the carbon footprint becomes a crucial criterion not only for environmental related issues but also for economical decision making. The main emission source of CO_2 in this kind of heavy-oil recovery will be steam generation. It is represented here in terms of enthalpy of the injected fluid. Thus, the carbon dioxide foot print of SOS-FR compared to continuous steam injection and continuous solvent injection is tested. The enthalpy injected is multiplied by a factor of 14.4 metric ton of carbon/TJ to calculate the carbon produced per amount of heat generated (www.bioenergy.ornl.com) As seen in **Figure 18,** when the SOS-FR technique is applied, the reduction of carbon dioxide produced from the steam injection only case is 50%. This significant reduction without sacrificing any oil recovery can be considered as an advantage of the process over steam injection alone.

6. Conclusions

1) The efficiency of the Steam-Over-Solvent for Fractured Reservoir (SOS-FR) method was tested for field scale conditions, i.e., large matrix sizes, for different application types including continuous injection and cyclic injection.
2) Compared to the continuous injection of only steam or only solvent, the SOS-FR shows a much better overall efficiency with a lower steam/oil ratio and solvent/oil ratio, and hence a more economic process.
3) The carbon foot print of SOS-FR is 50% lower than continuous steam injection with overall recovery close to it.
4) It was observed that the fracture density is a key parameter in the success of this project. Depending on the fracture density (or matrix size) the application scheme should be determined. For highly fractured reservoirs, both continuous and cyclic injection will work and the selection depends on the economics of the

process, which will be controlled by the injection rate and soaking times, respectively.

5) Two major parameters controlling the physics of the recovery process from a single matrix are diffusion and gravity drainage. Gravity drainage is the dominant parameter and is improved through the density change accelerated by the diffusion of solvent into the matrix.
6) Cyclic solvent stimulation following a period of continuous steam injection yields a higher recovery factor and hence, more economic process indicated by an increasing MRF.

Nomenclature

CSoS = Cyclic Solvent Stimulation

EIF = Economic Impact Factor

HnP = Huff and Puff

IAV = Initial Asset Value

MM = Multiple Matrix

MRF = Money Recovery Factor

mth = Month

P1 = Phase 1

P2 = Phase 2

P3 = Phase 3

RF = Recovery Factor

Si = Cumulative solvent injected

SM = Single Matrix

Sok = Soak

SoOR = Solvetn Oil Ratio

SOS-FR= Steam-Over-Solvent for Fractured Reservoirs

Sp = Cumulative solvent produced

STOIIP = Stock Tank Oil Initially In Place

StOR , SOR = Steam Oil Ratio

USD = United States Dollar

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Table 1 : Reservoir properties used in the simulations.

Reservoir depth	500 m
Matrix porosity	0.30
Fracture porosity	0.99
Matrix permeability	10 mD
Fracture permeability	550 D
Initial reservoir pressure	8 MPa
Initial reservoir temperature	50° C
Oil density SC	965
Solvent type	Heptane
Initial water saturation	0.00
Solvent diffusion coefficient	2.88e-5 m^2/day
Wettability	Oil wet

Table 2 : Injection strategy for the continuous injection case.

Time range (days)	**Action**
0 – 395	Steam injection
395 – 570	Cold water injection
570 – 575	Well Shut in
575 – 1085	Solvent injection
1085 – 1264	Steam injection

Table 3 : Performances of the eighteen cases considered.

Case	Sol. Inj. Rate	Soaking Period	Cum. St. Inj	Cum. So. Inj	Cum. So. Rec.	Cum StOR	Cum. SoOR	Ph.2 Cum SoOR
	(m3/day)	days	(m3) CWE	(m3)	(m3)	-	-	-
Single Matrix	5	-	12355	2550	2536	31	6	116
	10	-	12355	5100	5079	30	12	207
	50	-	12355	25500	25456	27	55	405
	0	-	25278	0	0	52	0	0
	5	-	0	6320	6272	0	122	122
Single Matrix (5 m Block)	5	-	12355	2550	2550	451	93	3102
Single Matrix (40 m Block)	5	-	12355	2550	2550	30	6	233
Multiple Matrix	5	-	12355	2550	2502	13	3	42
	10	-	12355	5100	5046	13	5	83
	50	-	12355	25500	25436	11	23	92
	0	-	25278	0	0	25	0	0
	5	-	0	6320	6211	0	62	5
Multi Matrix Solvent Huff n Puff	5	14	12355	990	952	11	1	7
	5	30	12355	710	666	12	1	8
	5	60	12355	390	367	12	0	21
Single Matrix Huff n Puff	5	14	12355	990	940	24	2	10
	5	30	12355	710	668	26	1	11
	5	60	12355	390	367	28	1	11

Table 4 : Recovery factor (RF) obtained for the eighteen cases considered. P1: Phase 1, P2: Phase 2, P3: Phase3.

Case No.	Case	STOIIP	RF. P1	RF. P2	RF. P3	Total RF
		(m3)	(%)	(%)	(%)	(%)
1	Single Matrix	2740	12	1	2	15
2		2740	12	1	3	15
3		2740	12	2	3	17
4		2740	18	0	0	18
5		2740	0	2	0	2
6	Single Matrix (5 m Block)	69	29	1	10	40
7	Single Matrix (40 m Block)	5480	6	0	2	8
8	Multiple Matrix	2046	33	3	12	48
9		2046	33	3	12	48
10		2046	33	14	9	55
11		2046	50	0	0	50
12		2046	0	5	0	5
13	Multi Matrix Solvent Huff n Puff	2046	33	7	14	54
14		2046	33	4	15	52
15		2046	33	1	17	51
16	Single Matrix Huff n Puff	2740	12	4	4	19
17		2740	12	2	4	17
18		2740	12	1	3	16

Table 5: Element prices.

Element	**Price**
Steam	18 $\$/m^3$
Solvent	1000 $\$/m^3$
Oil	80 $/bbl

Table 6 : Economy analysis for the eighteen cases considered.

Case No.	Case	STOIIP	Initial Asset Value	EIF	EIF	EIF	Cum.EIF	Gross Coast	Gross Rev.	Gross Profit	Gross Money RF (%)
		(m3)	Million USD	Steam	Solvent	Oil	0	million USD	million USD	Million USD	Money Recovery Factor
1	Single Matrix	2740	1.38	-0.16	-0.01	0.15	-0.03	2.77	2.74	-0.03	-2.52
2		2740	1.38	-0.16	-0.02	0.15	-0.03	5.32	5.28	-0.04	-2.72
3		2740	1.38	-0.16	-0.03	0.17	-0.02	25.72	25.69	-0.03	-2.49
4		2740	1.38	-0.33	0.00	0.18	-0.15	0.46	0.24	-0.21	-15.27
5		2740	1.38	0.00	-0.03	0.02	-0.02	6.32	6.30	-0.02	-1.59
6	Single Matrix (5 m Block)	68.5	0.03	-6.44	0.00	0.40	-6.04	2.77	2.56	-0.21	0.00
7	Single Matrix (40 m Block)	5480	2.76	-0.08	0.00	0.08	0.00	2.77	2.76	-0.01	-0.45
8	Multiple Matrix	2046	1.03	-0.22	-0.05	0.48	0.21	2.77	2.99	0.22	21.28
9		2046	1.03	-0.22	-0.05	0.48	0.21	5.32	5.54	0.21	20.70
10		2046	1.03	-0.22	-0.06	0.55	0.27	25.72	26.00	0.28	27.23
11		2046	1.03	-0.44	0.00	0.50	0.06	0.46	0.52	0.06	5.98
12		2046	1.03	0.00	-0.11	0.05	-0.05	6.32	6.26	-0.06	-5.57
13	Multi Matrix Solvent Huff n Puff	2046	1.03	-0.22	-0.04	0.54	0.28	1.21	1.51	0.29	28.45
14		2046	1.03	-0.22	-0.04	0.52	0.26	0.93	1.20	0.27	26.07
15		2046	1.03	-0.22	-0.02	0.51	0.27	0.61	0.89	0.28	26.90
16	Single Matrix Huff n Puff	2740	1.38	-0.16	-0.04	0.19	-0.01	1.21	1.20	-0.01	-0.72
17		2740	1.38	-0.16	-0.03	0.17	-0.02	0.93	0.91	-0.02	-1.75
18		2740	1.38	-0.16	-0.02	0.16	-0.02	0.61	0.59	-0.02	-1.77

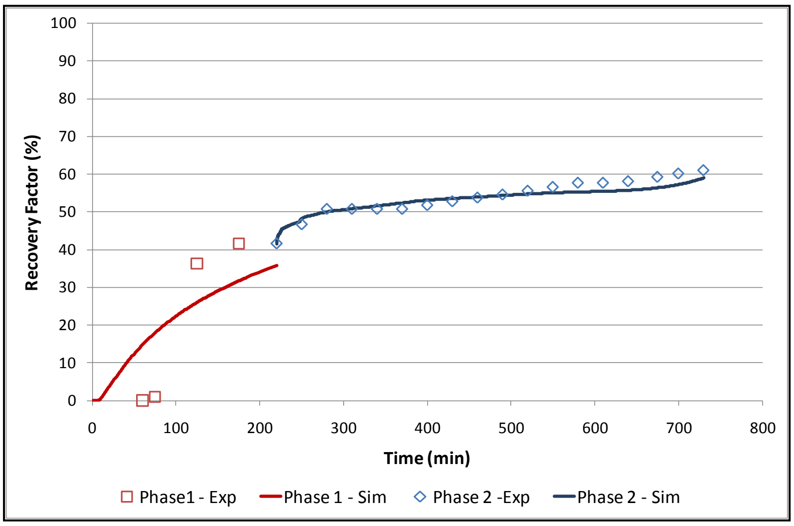

Figure 1: History match of experimental and numerical models (lab scale) for Phases 1 and 2 of 0.3 cc/min solvent injection.

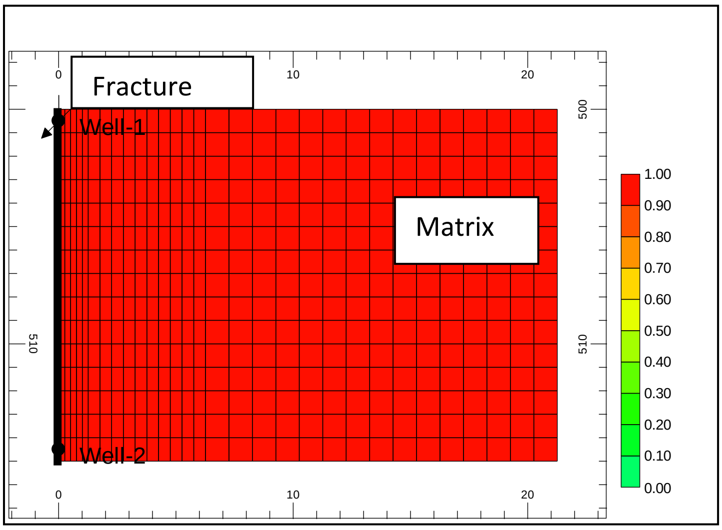

Figure 2-a: Numerical representation of single matrix block with unity oil saturation.

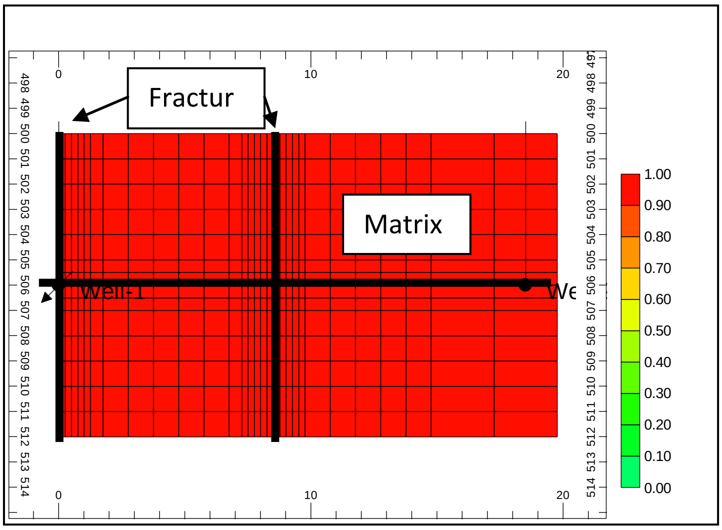

Figure 2-b: Numerical representation of multiple matrix block with unity oil saturation.

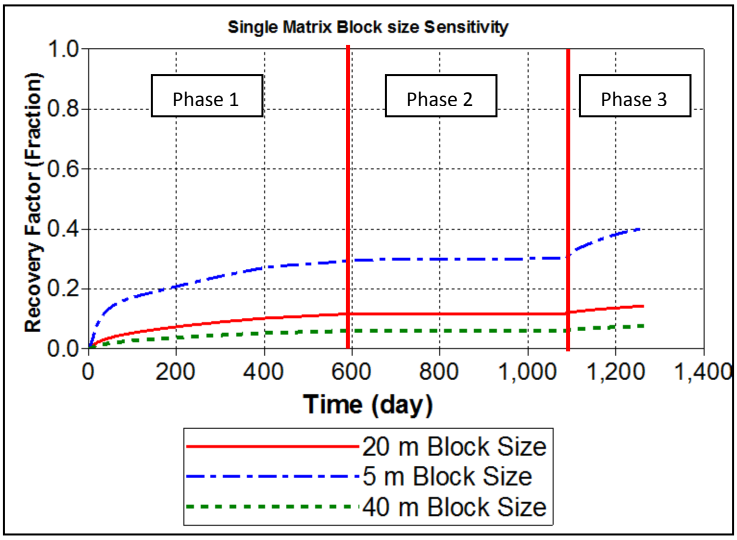

Figure 3: Recovery factor for with fixed solvent injection rate (5 m^3/day).

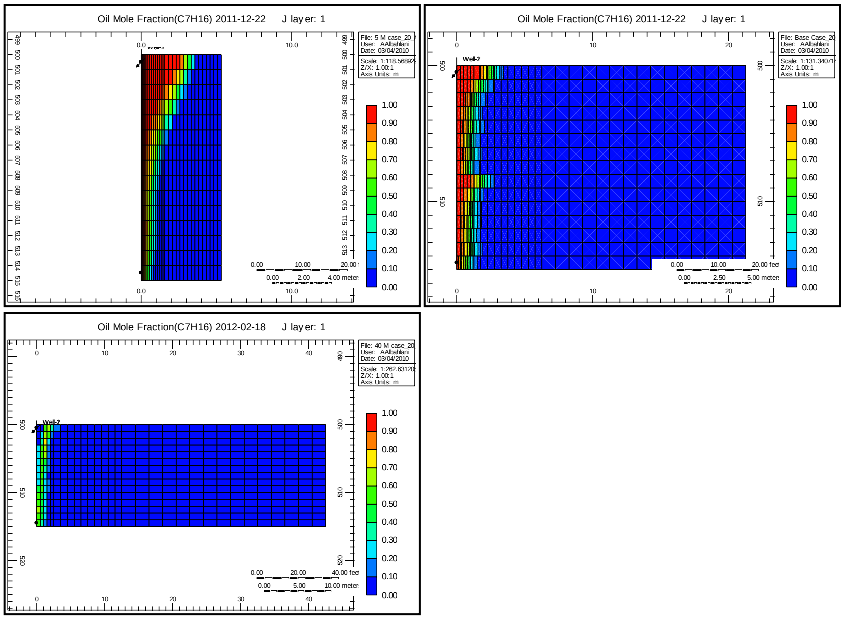

Figure 4: Solvent saturation profiles with different matrix sizes.

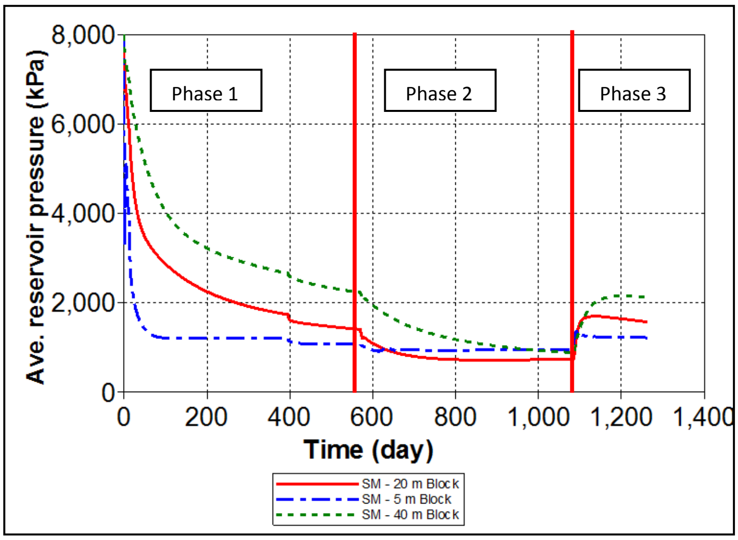

Figure 5: Average reservoir pressure for different single matrix (SM) block size.

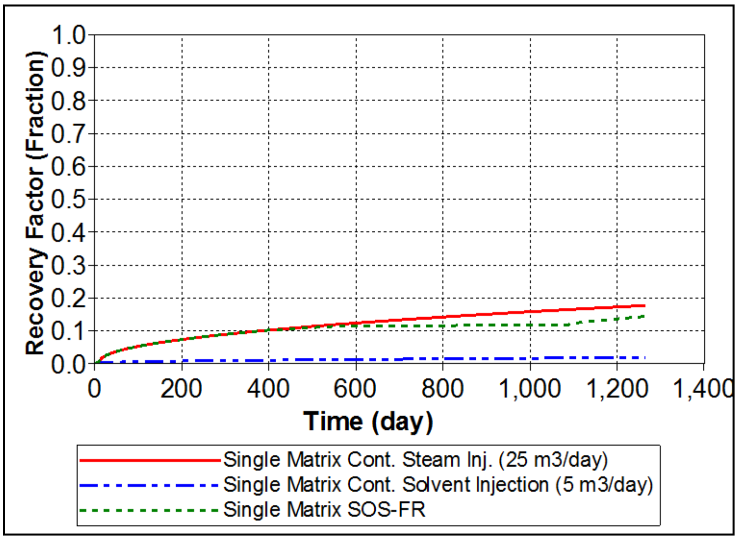

Figure 6: Comparison of the recovery factors for continuous steam injection, continuous solvent injection and the SOS-FR for a single matrix.

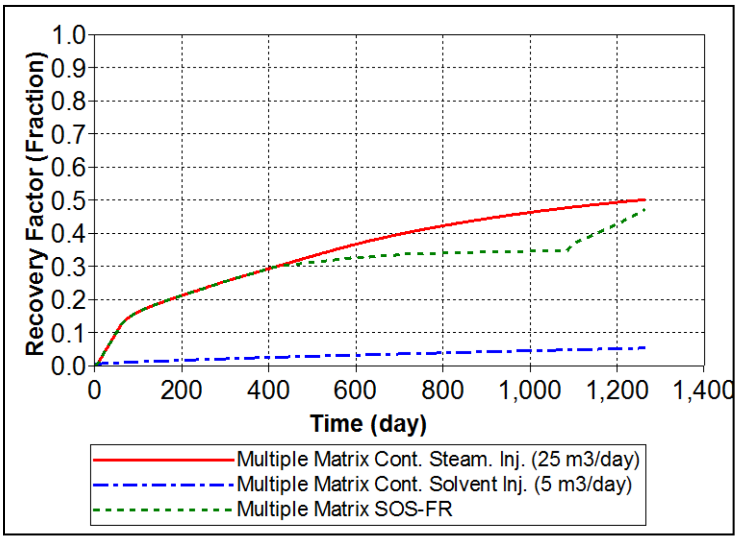

Figure 7: Comparison of the recovery factor for continuous steam injection, continuous solvent injection and the SOS-FR for a multiple matrix.

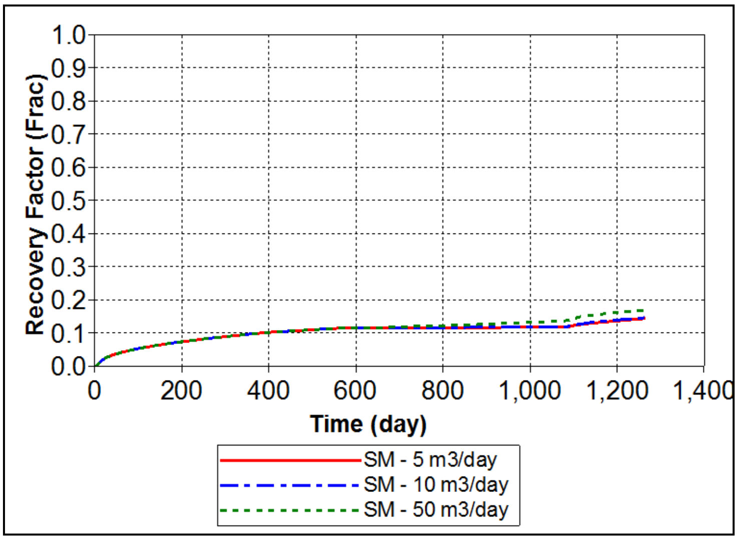

Figure 8: Comparison of different solvent injection rates for a single matrix block of 20 m.

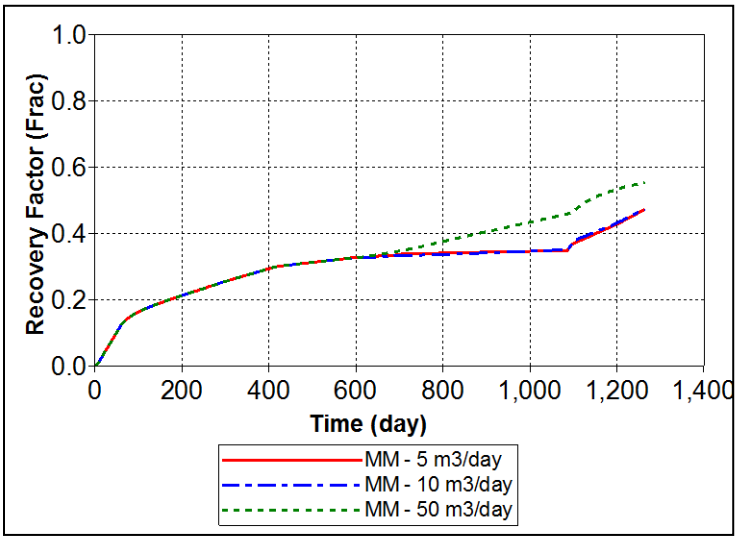

Figure 9: Comparison of different solvent injection rates for a multiple matrix block of 20 m.

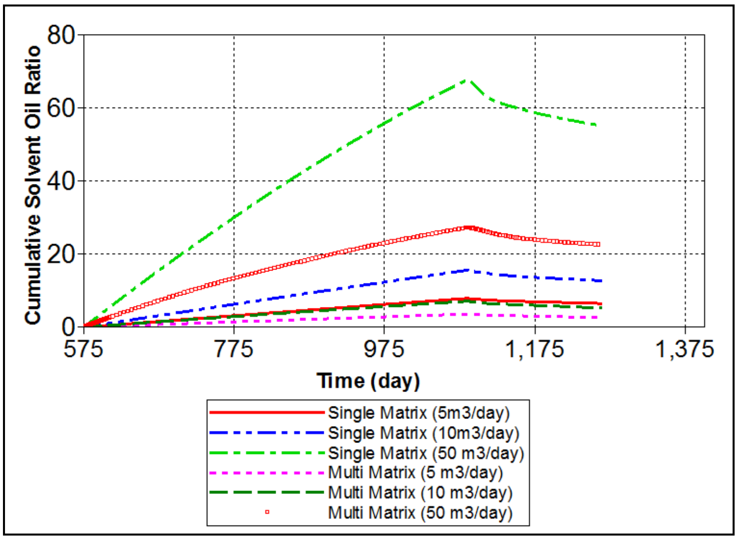

Figure 10: Cumulative Solvent Oil Ratio (SoOR) for different injection rates.

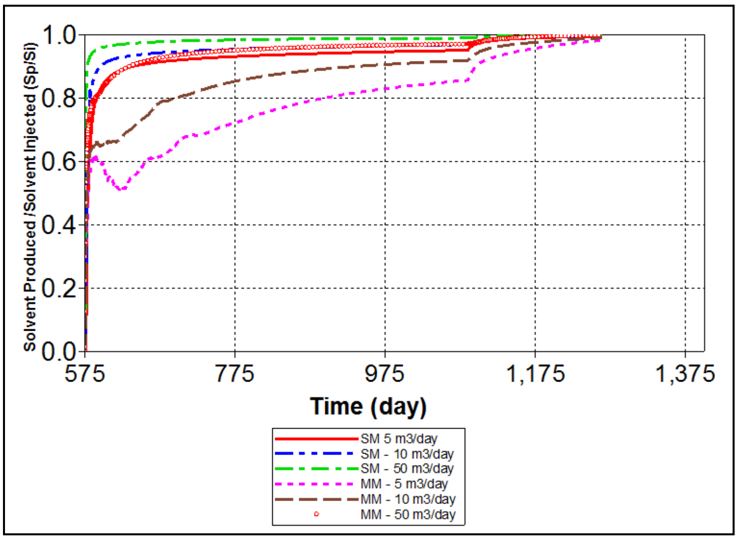

Figure 11: Total Solvent Produced / Total Solvent Injected for different rates.

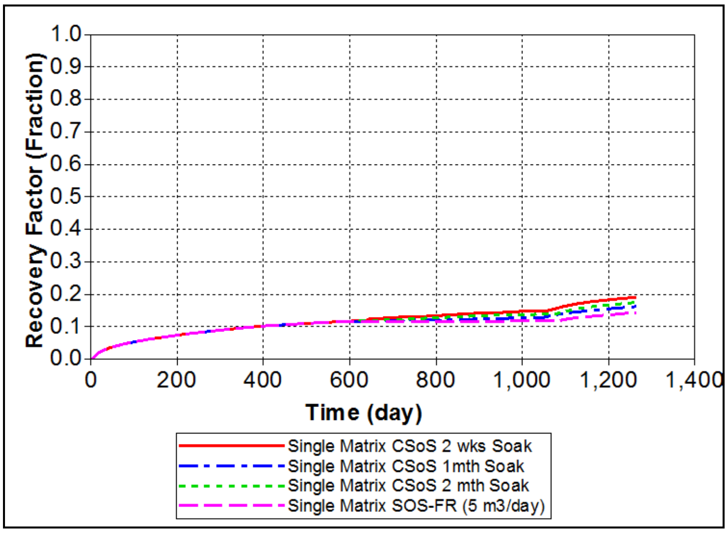

Figure 12: Comparison of the recovery factors of the SOS-FR and Cyclic Solvent Stimulation for a single matrix 20 m block.

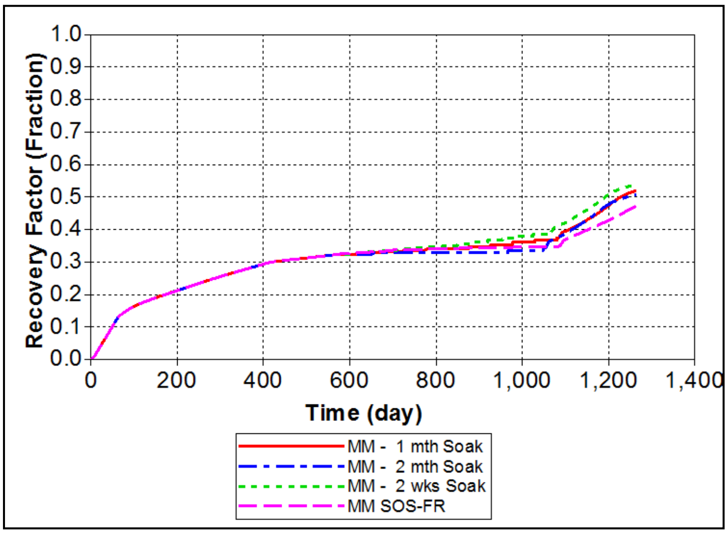

Figure 13: Comparison of the recovery factors for the SOS-FR and Cyclic Solvent Stimulation for a multi matrix 20 m block.

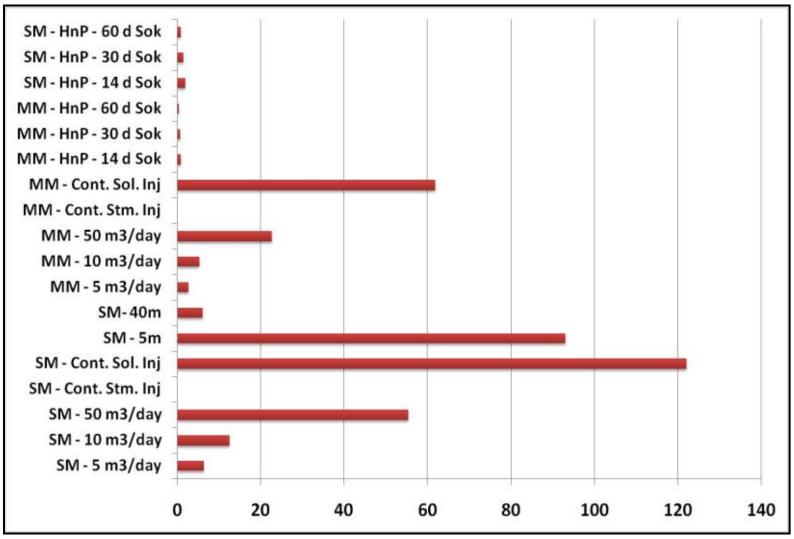

Figure 14: Cumulative Solvent Oil Ratio (SoOR) for all cases.

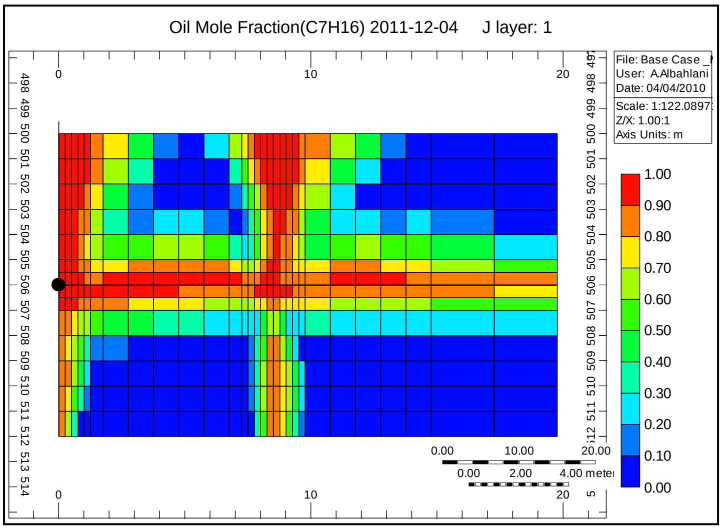

Figure 15: Saturation profile for solvent (Heptane) in the last cycle of Cyclic Solvent Stimulation (CSoS).

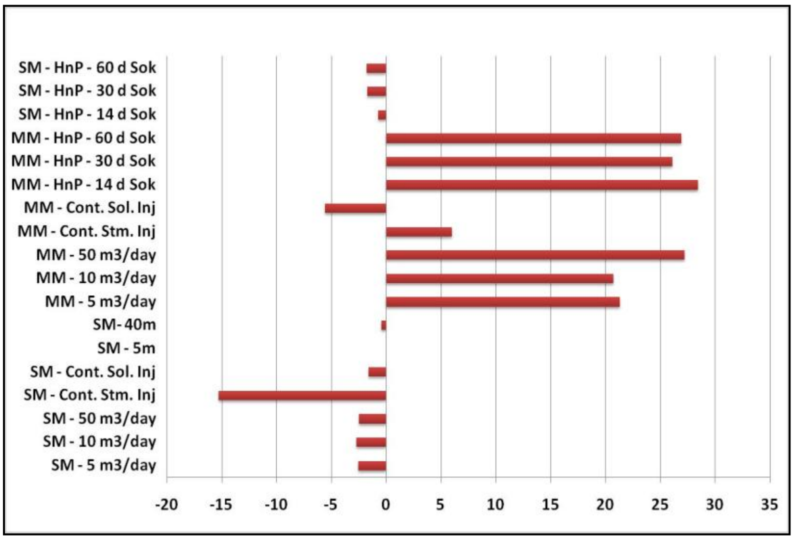

Figure 16: Money recovery factor (MRF) for all cases shown in Table 6.

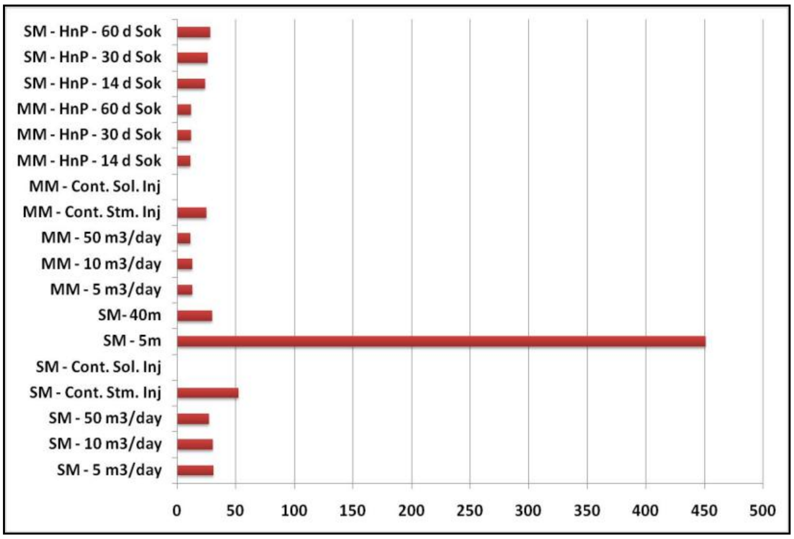

Figure 17: Cumulative Steam Oil Ratio (SOR) for all cases shown in Table 6.

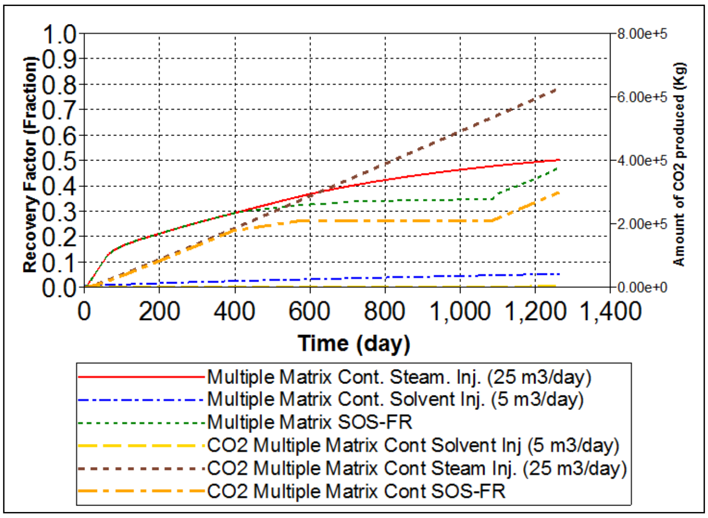

Figure 18: Comparison of CO_2 productions for different injection scenarios of continuous steam injection, solvent injection and SOS-FR.

Chapter 8: General Discussion and Contributions

1. General discussion

The experimental evidences and results obtained from numerical simulations at different scales indicate that the technique proposed in this thesis (SOS-FR) can be an alternate solution to heavy oil from fractured carbonate reservoirs. Static experiments presented in Chapters 1, 2, and 3 were preliminary tests, however, they were able to steer into a good direction where the research should be directed to. The major findings were the confirmation of the possibility of solvent retrieval through introduction of heat by steam and or hot water. It also showed a discernible interaction phenomenon between oil and water in an oil-wet medium which is the drainage of water which can be replaced by solvent. This can be considered as another mean of solvent introduction into the matrix other than diffusion. The importance of solvent penetration into the matrix is not to create a solely diffusion interaction between oil and solvent, rather to create a movement inside the matrix, which will allow for mixing and hence, the possibility of oil expulsion from matrix to fracture to increase oil recovery substantially.

This movement was visually inspected and proved through several Hele-Shaw model experiments. Although the Hele-Shaw experiments were conducted using a less viscous oil than that can be found in extreme heavy oil carbonate fields (due to technical difficulties in visualizing very viscous oil), it served its main purpose, which was the examination of the dynamics of recovery. Also, the Hele-Shaw models gave a good insight into fluid-fluid interaction inside the matrix when hot water is reintroduced for solvent retrieval (Phase 3).

Through lab experiments (both static and dynamic), Hele-Shaw experiments, and numerical modelling, it can be concluded that matrix size and fracture density play a major role in accelerating the recovery of the process. This brings the attention to the ability of the technique to yield positive results at the field scale.

One of the major hurdles faced during this research was the ability to have an acceptable PVT data for numerical simulations. The main issue in this regard is that the oil properties change during saturation and experimental runs rapidly with any disturbance of heat. This can happen mainly in two ways; (1) loss of light component due to evaporation while saturating the core and (2) asphaltene precipitation which can dramatically change the viscosity of the oil. Hence, every experiment presented in different chapters (or papers) may have different oil properties even if the same oil was used throughout this research. That is why, for each experimental program, the viscosity and density of oil were measured before and after the saturation procedure. But, certain approximations and correlations had to be used to model the PVT behaviour in numerical simulation studies as data required for this type of heavy-oils are experimentally unavailable.

A good understanding of the modelling requires further clarifications on the physics of this type of complex process in which both mass and heat transfer phenomena were heavily involved. For example, as observed in the Hele-Shaw experiments, a counter-current fluid movement inside the core was observed to be a major recovery mechanism for both vertical and horizontal orientations. This type of behavior was not included in the numerical model and can only be accounted for using “pseudo dispersion coefficients” which can be obtained through matching of numerical/experimental model results. Note that, physically, there is no dispersion actually occurring in the matrix and the recovery process is based on diffusion between oil and solvent and gravity drainage created by density difference between oil and solvent mixed oil in the matrix. That is why, the use of the simulator was limited in exploring the applicability of the process in large matrices with wide assumptions.

In general, all experiments (laboratory and numerical simulations) complemented each other and we can draw certain specific conclusions and general contributions to both academia and industry as listed below.

2. **General contributions**

This thesis introduced a solution to a challenging problem by proposing a new technique. Academic and scientific contributions are listed in the succeeding section and it is worth emphasising the practical contributions for industry first.

The foremost contribution is the invention of new technology that promises unlocking of vast major heavy oil carbonate oil fields. This technology (Steam-Over-Solvent Injection in Fractured Reservoirs, SOS-FR) combines the ability of steam or hot-water to deliver high temperature to the matrix, and the ability of solvent to dissolve and drain matrix oil. The validation and applicability of the model was tested through an intensive experimental program first. Rock-oil-solvent interactions at high temperature were investigated for many different applications conditions and reservoir/rock/fluid properties. The efficiency (technical and economic) of the process was also shown at laboratory and field scale conditions with significant parametric analysis.

The proposed method (SOS-FR) can be a solution to deplete heavy oil reservoirs in deep fractured reservoirs where steam injection may not possibly yield an efficient process. The field scale application was tested numerically and optimal application strategies were defined for different rock and reservoir properties, especially the matrix size.

With ample amount of experimental and numerical evidences and extensive analyses provided in this thesis, further attempts for the application of the technique in specific reservoir conditions can easily be made.

3. Specific contributions

3.1. Static experiments

- It would not be an overstatement to claim that the most exciting part of the observations was a very fast retrieval of solvent from the matrix when the sample contacted with hot water in the third phase of the process. This could be considered as motivation to further investigate the applicability of this method, as it has profound effect on the economic feasibility of the process.
- In case of the existence of a two phase (oil and water) system inside the oil-wet rock matrix, a complex imbibition-drainage process might be a governing recovery mechanism in addition to the recovery by diffusive (mass transfer) matrix-fracture interaction.
- Fine particles (mainly asphaltene) may have a profound role in blocking pore throats when solvent is introduced into the matrix. Subsequently, asphaltene precipitation and deposition can cause reduction in permeability to drain oil and retrieve solvent in Phase 3.

- The physics of the process is far more complicated than simple diffusion and dispersion behaviour. It is mainly dependent on the gravity difference between heavy oil and the hydrocarbon solvent.
- Water-wet core showed unfavourable increment in oil production which strongly suggests that solvent aided processes in water-wet cores may not be as feasible as expected since the existing of water in the system would act as a physical barrier preventing solvent diffusion into oil.
- In the event of two phase existence in an oil-wet matrix (oil and water), water can act as an obstacle to diffusion, however, its drainage from matrix can promote solvent intrusion (by capillary imbibition) and hence oil expulsion into the fracture.
- Co-current and counter current experiments showed that the process is highly affected by the nature of interaction. More favourable interaction was observed in Phase 1 for the counter-current case whereas the solvent interaction was negatively affected in the case of counter-current interaction due to a limited solvent contact area.
- Orientation of matrix is very critical for recovery process since it controls the rate of the gravity drainage. Residual oil and solvent are critically affected by the boundary condition

of matrix that also determines the strength of gravity drainage.

3.2. Dynamic experiments

- Dynamic experiments showed a rate/velocity dependency of the process. There exists an optimal rate and the process can be efficient in terms of recovery time and solvent use. This might lead to the conclusion that a high rate injection of water/steam in Phases 1 and 3 and an injection of solvent at an optimal rate (to be determined based on the rock and oil, and solvent characteristics) would be more efficient than injection in the cyclic (huff and puff) form.
- Dynamic experiments showed that higher injection rates cause faster oil recovery but yield a high solvent to oil ratio. This leads us not only to the possibility of an optimal injection rate, but also to an optimal injection scheme (duration of solvent injection and steam injection phases) that may yield an optimal recovery throughout the lifecycle of the core.
- Solvent penetration into the matrix can happen through contraction of oil causing solvent to penetrate faster into the matrix. Once solvent enters the matrix, it creates a counter-current (or convective) movement driven by gravity difference, which enhances oil drainage rate.

- Larger cores may yield a different set of recovery results with the same physics acting in place as in the smaller cores. This indicates the importance of the boundary conditions and sample size on the process, especially from the up-scaling of the process point of view.
- Asphaltene precipitation and deposition may have a great impact on the process. At higher rates/velocities, the displacement (and diffusion) process is so fast that asphaltene flocculation and deposition cannot occur (or delayed). This eventually yields a better recovery. On the other hand, at low rates/velocities, the possibility of asphaltene deposition in the matrix is higher, which leads to a blockage near the matrix area causing reduced permeability and lower recoveries.
- It was difficult to quantify the solvent produced in the form of gas bubbles, mainly due to its high volatility and foam emulsion-like production. It is worth mentioning, however, that this process was extremely fast; it was completed in an order of minutes for both the static and dynamic cases. This is the most promising outcome of the experiments conducted as solvent retrieval is a crucial issue in this type of process.

3.3. Visualization (Hele-Shaw) experiments

- In a horizontal (flat) Hele-Shaw model, solvent tends to diffuse into the oil in two main manners: (1) Root-shaped fingering caused by instantaneous instability in the system which drives the solvent by diffusion into the model very slowly, and (2) pear-shaped fingering caused counter gravity forces on the diffusion front that eventually yielded a counter-current flow solvent (inner part) and an oil/solvent mixture (outer part) inside the fingers.
- In a vertical 2D Hele-Shaw model, gravity may override the diffusion effect depending on the boundary condition. This representation of the model yields much higher and faster recoveries.
- Boundary conditions have a profound effect on the recovery process on both the horizontal and the vertical models. With the horizontal models, higher recoveries were noticed with a higher open length to total length ratio. With the vertical models, the gravity override of the solvent on the oil decelerates the production of oil from the matrix.
- Temperature accelerates the diffusion process of solvent into the matrix, and thereby, can decrease the time needed for oil recovery.

- Solvent retrieval by succeeding hot water (or steam) injection is possible once the temperature reaches the boiling point of the solvent. As the gravity effects are eliminated, i.e., in the case of low matrix shape factor (MSF) values, solvent tends to travel further into the matrix during its expansion, causing solvent gas to be trapped inside the matrix towards the closed boundary parts.
- A modified effective diffusion coefficient was introduced for horizontal orientation and was related to the oil recovery rate and amount. The modification was based on boundary conditions, relative solvent viscosity and relative solvent density.
- A prediction of oil recovery for the vertical model (with the effect of gravity) was also presented based on the boundary conditions. A new definition of characteristic length was introduced to account for the boundary condition effect. The characteristic length was introduced based on open length from the centre of the model, the difference in the specific gravity between the oil and the solvent, and relative viscosity. The characteristic length was also related to the oil production rate and amount.

3.4. Numerical simulation

Upscaling

- A new methodology was proposed for upscaling lab data to field data by employing a dimensionless equation, rate and dispersion coefficient. These equations were obtained by employing fracture dimensions of both lab experiments and upscaled model, and assuming the fact that the velocity at all scales are the same.
- The numerical model study showed that the SOS-FR method is applicable at larger matrix sizes especially when the time scale to reach the ultimate recovery was considered.
- A relationship between mechanical dispersion and molecular diffusion at low rates was introduced and studied to understand and maintain reasonable tuning for the lab experiment history match.
- Large block sizes need larger solvent injection rate because of fluid velocity dispersion dependency.
- High and fast initial solvent rate is observed during the third phase, this coincides with the high gas bubbling seen during phase three in lab experiments.
- Even for large matrices, solvent retrieval seems to be very high ranging 50 % to 70 %.

Matrix size (field scale applications)

- The efficiency of the SOS-FR method was tested for field scale conditions, i.e., large matrix sizes, for different application types including continuous injection and cyclic injection. Compared to the continuous injection of only steam or only solvent, the SOS-FR shows a much better overall efficiency with a lower steam/oil ratio and solvent/oil ratio, and hence a more economic process.
- The carbon foot print of SOS-FR is 50% lower than continuous steam injection with overall recovery close to it.
- It was observed that the fracture density is a key parameter in the success of this project. Depending on the fracture density (or matrix size) the application scheme should be determined. For highly fractured reservoirs, both continuous and cyclic injection will work and the selection depends on the economics of the process, which will be controlled by the injection rate and soaking times, respectively.
- Two major parameters controlling the physics of the recovery process from a single matrix are diffusion and gravity drainage. Gravity drainage is the dominant parameter and is improved through the density change accelerated by the diffusion of solvent into the matrix.

- Cyclic solvent stimulation following a period of continuous steam injection yields a higher recovery factor and hence, more economic process indicated by an increasing MRF.

Provisional work

- High temperature and high pressure experiments should be conducted to give a realistic approach for field scale applications. This applies for static, dynamic, and visualization experiments.
- It is quite difficult to find a universal solvent for all types of heavy oil, however, a specific formula depending on oil composition is needed. The formula should take into account dissolving capability of high ends and economics. One suggested way is to mix pure solvents with light (condensate) oil readily available to reduce the cost.
- Introduction of solvent into the reservoir may change petrophyscial and geochemical properties of rock matrix which will eventually affect the geomechanical behaviour of the reservoir. This kind of reaction should be clarified for different solvents and rock types.
- Hele-Shaw experiments showed different dynamics of oil drainage (counter current flow of oil and solvent). Numerical simulation of this process through continuum or pore scale models are recommended.

Appendices

1. Input data file for history match of phase 2 of 0.3 cc/min case (Chapter 6 Figure 9)

```
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INUNIT LAB
WSRF WELL 1
WSRF GRID 10
WSRF SECTOR 10
OUTSRF  GRID  CMPVISO  MASDENO  OILFRFL  PRES  SO  SW  TEMP  THCONDUCT  VISO  W
WATFRFL
      X
OUTSRF WELL DOWNHOLE
OUTSRF WELL COMPONENT ALL
OUTSRF SPECIAL MOLEFRAC  'Injector' 'Hvy Oil' OIL
        PHWELL 'Well-2' TEMP SURFACE
OUTSRF WELL DOWNHOLE
PARTCLSIZE 1e-011
WPRN GRID 0
OUTPRN GRID ALL
OUTPRN RES ALL
OUTPRN WELL LAYPHASE
**$  Distance units: cm
RESULTS XOFFSET           0.0000
RESULTS YOFFSET           0.0000
RESULTS ROTATION           0.0000  **$  (DEGREES)
RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0
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**$ Definition of fundamental corner point grid
**$ ****************************************************************************
GRID VARI 16 21 12
KDIR DOWN
DI IVAR
 1 14*0.544285714 1
DJ JVAR
 3*0.1 7*0.117038 0.01 7*0.117038 3*0.1
DK ALL
 4032*0.186544022
DTOP
 336*1
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          1          12:21      1:12                 0
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          2:15       11         1:12                 1
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          16         12:21      1:12                 0
```

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        2:15    11      1:12            55000
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PERMK   IJK

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        2:15    11      1:12            55000
        2:15    12:21   1:12            550
        16      1:10    1:12            0
        16      11      1:12            55000
        16      12:21   1:12            0



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**$  0 = pinched block, 1 = active block
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END-GRID



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**rock heat capacity
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*THCONR     4.583
*THCONW     0.347
*THCONO   1.375
THCONG 0.027778
THCONMIX SIMPLE
*HLOSSPROP         *OVERBUR  1.8   0.5556
                *UNDERBUR 1.8   0.5556
**$ Model and number of components
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CMM
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PCRIT
0 261 2736
TCRIT
0 666.85 267.05
MASSDEN
0 0.000969 0.00068
```

```
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CT1
0 0.0015 0
CT2
0 0.00002 0
CPT
0 0 0
VISCTABLE
**$      temp
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          21        0      2457      0.38
          25        0      1699      0.38
          30        0      1213      0.38
          40        0       704      0.38
          80        0       192      0.38
          90        0       156      0.38
         150        0        66      0.38
ROCKFLUID
RPT 1 LININTERP WATWET
SWT
 SMOOTHEND LINEAR
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0.08000   0.00001   0.65610
0.16000   0.00016   0.40960
0.24000   0.00081   0.24010
0.32000   0.00256   0.12960
0.40000   0.00625   0.06250
0.48000   0.01296   0.02560
0.56000   0.02401   0.00810
0.64000   0.04096   0.00160
0.72000   0.06561   0.00010
0.80000   0.10000   0.00000



SLT NOSWC
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       0.386  0.699751727  0.064826264
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        0.59  0.329876978  0.307786103
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RPT 2 WATWET

SWT
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SLT
**$       Sl      krg      krog
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           1        0        1

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               1            11           1:12                      2
               1            12:21        1:12                      1
               2:15         1:10         1:12                      1
               2:15         11           1:12                      2
               2:15         12:21        1:12                      1
```

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             16          11          1:12                    2
             16          12:21       1:12                    1
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             *MOD
                         1:16        11          1:12        =           0.00088
 MDSPJ_OIL               CON         0.000001
             *MOD
                         1:16        11          1:12        =           0.00088
 MDSPK_OIL               CON         0.000001
             *MOD
                         1:16        11          1:12        =           0.00088

 *DIFFI_OIL 'C7H16' *CON 0.0002
             *MOD
                         1:16        11          1:12        =           0.0000

 *DIFFJ_OIL 'C7H16' *CON 0.0002

             *MOD
                         1:16        11          1:12        =           0.0000

 *DIFFK_OIL 'C7H16' *CON 0.0002

             *MOD
                         1:16        11          1:12        =           0.0000


 *DIFFI_OIL 'Hvy Oil' *CON 0.00535

             *MOD
                         1:16        11          1:12        =           0.0000

 *DIFFJ_OIL 'Hvy Oil' *CON 0.00535
             *MOD
                         1:16        11          1:12        =           0.0000

 *DIFFK_OIL 'Hvy Oil' *CON 0.00535

             *MOD
                         1:16        11          1:12        =           0.0000

 INITIAL
 VERTICAL OFF

 MFRAC_OIL 'C7H16' con       0
 SG con 0

 INITREGION 1
 REFPRES 101
 REFDEPTH 1
 **$ Property: Pressure (kPa)   Max: 101  Min: 101
 PRES CON         101
 **$ Property: Temperature (C)   Max: 22  Min: 22
 TEMP CON          20
 **$ Property: Water Saturation  Max: 1  Min: 0
 SW ALL
 (Saturation profile imported from phase 1 history match)
SO ALL

 (Saturation profile imported from phase 1 history match)
 NUMERICAL
 NORTH 100
 ITERMAX 70
 SMALL-RATES ON
 RUN
```

```
DATE 2009 1 1
DTWELL 0.0001


**$
WELL  'Well-2'
PRODUCER 'Well-2'
OPERATE  MAX  BHO  0.3  CONT
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.0099  0.235  1.  0.
PERF  TUBE-END  'Well-2'
**$ UBA     ff  Status  Connection
    1 11 5  1.  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    1 11 6  1.  OPEN    FLOW-TO  1
    1 11 7  1.  OPEN    FLOW-TO  2
    1 11 8  1.  OPEN    FLOW-TO  3
**$
WELL  'Injector'
INJECTOR MOBWEIGHT EXPLICIT 'Injector'
INCOMP  OIL  0.  0.  1.
TINJW  20.
PINJW  101.
OPERATE  MAX  STO  0.3  CONT
**$          rad  geofac  wfrac  skin
GEOMETRY  K  0.0099  0.235  1.  0.
PERF  TUBE-END  'Injector'
**$ UBA      ff  Status  Connection
    16 11 5  1.  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
    16 11 6  1.  OPEN    FLOW-FROM  1
    16 11 7  1.  OPEN    FLOW-FROM  2
    16 11 8  1.  OPEN    FLOW-FROM  3

DATE 2009 1  1.00069
```

2. Input data file for multiple matrix SOS-FR case (Chapter 7 - Figure 7)

```
RESULTS SIMULATOR STARS 200800
INUNIT SI
WSRF WELL 1
WSRF GRID TIME
WSRF SECTOR TIME
OUTSRF GRID CMPVISO MASDENO OILFRFL PRES SO SW TEMP THCONDUCT VISO WATFRFL X    Y

REWIND 20
OUTSRF SPECIAL MOLEFRAC  'Well-1' 'Hvy Oil' OIL
            PHWELL 'Well-2' TEMP SURFACE
OUTSRF SPECIAL STMQUAL  'Well-1'
            PHWELL 'Well-1' STQUAL DOWNHOLE
            PHWELL 'Well-1' TEMP DOWNHOLE
            PHWELL 'Well-1' PRES DOWNHOLE
OUTSRF GRID FLUIDH PRES QUALBLK SG SO SORG STEAMQUAL SW TEMP VISO
OUTSRF WELL DOWNHOLE
OUTSRF WELL COMPONENT ALL
OUTSRF WELL COMPONENT 'H2O' 'Hvy Oil'
OUTSRF WELL DOWNHOLE
OUTSRF WELL COMPONENT ALL
OUTSRF WELL COMPONENT 'H2O' 'Hvy Oil'
PARTCLSIZE 1e-011
WPRN GRID 0
OUTPRN GRID ALL
OUTPRN RES ALL
OUTPRN WELL LAYPHASE
**$  Distance units: cm
RESULTS XOFFSET          0.0000
RESULTS YOFFSET          0.0000
RESULTS ROTATION          0.0000  **$  (DEGREES)
```

```
RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0

**$ ****************************************************************************

**$ Definition of fundamental cartesian grid

**$ ****************************************************************************

GRID VARI 31 1 15

KDIR DOWN

DI IVAR

1*0.01 5*0.25 1*0.5 5*1 1*0.5 5*0.25 1*0.01 5*0.25 5*1 2*2.5

DJ JVAR

30

DK KVAR

5*1       2*0.5     1*0.01    2*0.5     5*1

DTOP

31*500

**$ Property: NULL Blocks  Max: 1  Min: 1

**$  0 = null block, 1 = active block

NULL CON       1



**variable porosity nr of layers x porosity value

POR       CON       0.30

          MOD

                    1         1         1:15      =         0.99

                    19        1         1:15      =         0.99

                    1:31      1         8         =         0.99


PERMI     CON       10

          MOD

                    1         1         1:15      =         55000

                    19        1         1:15      =         55000

                    1:31      1         8         =         55000

PERMJ     CON       10

          MOD
```

```
                    1       1       1:15    =       55000
                    19      1       1:15    =       55000
                    1:31    1       8       =       55000
PERMK   CON         10
        MOD
                    1       1       1:15    =       55000
                    19      1       1:15    =       55000
                    1:31    1       8       =       55000


**$ Property: Pinchout Array  Max: 1  Min: 1
**$  0 = pinched block, 1 = active block
PINCHOUTARRAY CON        1

END-GRID

*ROCKTYPE         1
*CPOR     0.29E-6      **formation compressibility
*ROCKCP   1.5E6        **rock heat capacity
*THCONR    6.6E5
*THCONW     5E4
*THCONO   1.98E5
THCONG 4000
THCONMIX SIMPLE
*HLOSSPROP       *OVERBUR  1.0E6   8.0E4
        *UNDERBUR 1.0E6   8.0E4
**$ Model and number of components
MODEL 3 3 3 1
COMPNAME 'H2O' 'Hvy Oil' 'C7H16'
CMM
0 0.395 0.100205
PCRIT
0 261 2736
```

```
TCRIT

0 666.85 267.05

KV1

0 0 1.0442e6

KV4

0 0 -2911.32

KV5

0 0 -216.64

MASSDEN

0 969 684

CP

0 0.48e-6 0

CT1

0 0.0015 0

CT2

0 0.00000 0

CPT

0 0 0

VISCTABLE

**$    temp

       15     0    4493    0.435

       21     0    2457    0.405

       25     0    1699    0.386

       30     0    1213    0.365

       40     0     704    0.329

       80     0     192    0.228

       90     0     156    0.211

      150     0      66   0.1426

      175     0      19   0.1249

      360     0       2  0.0648

      400     0     1.6   0.0589

      500     0     1.4   0.0486

ROCKFLUID
```

```
RPT 1 STONE2 OILWET

SWT

 SMOOTHEND CUBIC

**$       Sw       krw      krow

          0   0.00000   1.00000

        0.1   0.01796   0.65610

        0.2   0.05834   0.40960

        0.3   0.11624   0.24010

        0.4   0.18956   0.12960

        0.5   0.27701   0.06250

        0.6   0.37766   0.02560

        0.7   0.49081   0.00810

        0.8   0.61588   0.00160

        0.9   0.75241   0.00010

          1   0.90000   0.00000

SLT

**$       Sl       krg      krog

          0   1.00000   0.00000

        0.1   0.83601   0.02504

        0.2   0.68431   0.07592

        0.3   0.54534   0.14524

        0.4   0.41962   0.23014

        0.5   0.30779   0.32889

        0.6   0.21062   0.44029

        0.7   0.12915   0.56345

        0.8   0.06483   0.69765

        0.9   0.01995   0.84233

          1   0.00000    0.9000
```

```
RPT 2 WATWET
SWT
**$          Sw     krw     krow
             0      0       1
             1      1       0
SLT
**$           Sl     krg     krog
               0      1       0
              1      0       1

KRTYPE CON           1
            MOD
                        1           1           1:15        =           2
                        19          1           1:15        =           2
                        1:31        1           8           =           2
**$ Property: Water Connate Saturation  Max: 0  Min: 0
BSWCON CON        0

**$ Property: Oil Effective Molecular Diffusion Coef. I(C7H16) ((m*m)/day)   Max: 2.88e-5  Min: 2.88e-5
DIFFI_OIL 'C7H16' CON       2.88e-5

**$ Property: Oil Effective Molecular Diffusion Coef. J(C7H16) ((m*m)/day)   Max: 2.88e-5  Min: 2.88e-5
DIFFJ_OIL 'C7H16' CON       2.88e-5

**$ Property: Oil Effective Molecular Diffusion Coef. K(C7H16) ((m*m)/day)   Max: 2.88e-5  Min: 2.88e-5
DIFFK_OIL 'C7H16' CON       2.88e-5
INITIAL
VERTICAL OFF
MFRAC_OIL            'Hvy Oil'    con         1
INITREGION 1
REFPRES 8000
REFDEPTH 500
**$ Property: Pressure (kPa)   Max: 8000  Min: 1000
```

```
PRES CON        8000
temp con 50
SW          CON         0
            MOD
            1           1           1:15        =           1
NUMERICAL
DTMIN 1e-15
**NORM PRESS 100 SATUR 0.1 TEMP 5 Y 0.1 X 0.1 W 0.1 ZO 0.1 ZNCG 0.1 ZAQ 0.1
NORTH 300
ITERMAX 100
NCUTS 14
SMALL-RATES ON
RUN
DATE 2009 1 1
DTWELL 1e-3
**$
WELL  'Well-1'  FRAC  1
INJECTOR MOBWEIGHT IMPLICIT 'Well-1'
PHWELLBORE  SAMODEL
 DEPTH              514.       **$ (m)
 WLENGTH              514.       **$ (m)
 CASLENGTH            514.       **$ (m)
 RTUBIN             0.062      **$ (m)
 RTUBOUT              0.073      **$ (m)
 RCASIN             0.1594     **$ (m)
 RCASOUT              0.1778     **$ (m)
 RHOLE              0.28       **$ (m)
 CONDTUB              3.738e+006  **$ (J/(m*day*C))
 CONDCAS              3.738e+006  **$ (J/(m*day*C))
 CONDCEM              75000.      **$ (J/(m*day*C))
 CONDFORM               209000.     **$ (J/(m*day*C))
 HCAPFORM              2.347e+006  **$ (J/(m3*C))
 GEOGRAD              0.025      **$ (C/m)
```

```
 SURFACE_TEMP       35.       **$ (C)
INCOMP  WATER  1.  0.  0.
TINJW  260.
QUAL  1.
PINJW  4500.
OPERATE  MAX  STW  20.  CONT
**$         rad  geofac  wfrac  skin
GEOMETRY  I  0.086  0.249  1.  0.
PERF  TUBE-END  'Well-1'
**$ UBA    ff  Status  Connection
   1 1 8  1.  OPEN    FLOW-FROM  'SURFACE'
**$
***********
** Phase 1 **
***********
WELL  'Well-2'  FRAC  1
PRODUCER 'Well-2'
OPERATE  MAX  BHL  500.  CONT
OPERATE  MIN  BHP  1000.  CONT
**$         rad  geofac  wfrac  skin
GEOMETRY  I  0.086  0.249  1.  0.
PERF  TUBE-END  'Well-2'
**$ UBA     ff  Status  Connection
   31 1 8  1.  OPEN    FLOW-TO  'SURFACE'

DATE 2009 1  1.15972
DATE 2010 1 31.00000
**$
***********
** Cooling **
***********
WELL  'Well-1'  FRAC  1
INJECTOR MOBWEIGHT IMPLICIT 'Well-1'
```

```
INCOMP  WATER  1.  0.  0.
TINJW  20.
OPERATE  MAX  STW  5.  CONT
OPERATE  MAX  BHP  15000.  CONT

DATE 2010 2  1.00000
DATE 2010 7 25.00000
**$
WELL  'Well-1'  FRAC 1
SHUTIN 'Well-1'
DATE 2010 7 26.00000
DATE 2010 7 27.00000
DATE 2010 7 28.00000
DATE 2010 7 29.00000
DATE 2010 7 30.00000
**$
***********
** Phase 2 **
***********
WELL  'Well-1'  FRAC  1
INJECTOR MOBWEIGHT IMPLICIT 'Well-1'
INCOMP  OIL  0.  0.  1.
TINJW  50.
OPERATE  MAX  STO  5.  CONT
**$
WELL  'Well-2'  FRAC  1
PRODUCER 'Well-2'
OPERATE  MAX  BHL  500.  CONT
OPERATE  MIN  BHP  1000.  CONT
DATE 2010 7 31.00000
DATE 2011 12 22.00000
**$
```

```
***********
** Phase 3 **
***********
WELL  'Well-1'  FRAC  1
INJECTOR MOBWEIGHT IMPLICIT 'Well-1'
INCOMP  WATER  1.  0.  0.
TINJW  100.
QUAL  0.75
PINJW  3500.
OPERATE  MAX  STW  20.  CONT
DATE 2011 12 23.00000
DATE 2012 6 18.00000
STOP
```