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Experimental Study of Heavy Oil Recovery Mechanisms during Cyclic Solvent Injection Processes

Plata Sanchez, Maria Alejandra

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Experimental Study of Heavy Oil Recovery Mechanisms during Cyclic Solvent Injection
Processes

by

Maria Alejandra Plata Sanchez

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES
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Abstract

In recent years, the Cyclic Solvent Injection (CSI) process has shown to be a promising method for enhanced heavy oil recovery in Canada. CSI laboratory studies work for only 2 to 3 cycles due to low incremental oil in subsequent cycles whereas field pilots continue for years over multiple cycles. This experimental study is intended to capture the production mechanisms responsible for heavy oil production in CSI.

Primary production and CSI tests were conducted using physical sandpack models saturated with live heavy oil of 9,530 mPa.s viscosity. The experiments were conducted in horizontal and vertical mode injection at high and low-pressure depletion rates using two solvent mixtures of CH_4 and C_3H_8 . The sandpack was Computed Tomography scanned after every cycle to analyze the evolution of gas and oil saturations. Three cores were used to study the effect of gravity forces, depletion rate, solvent composition, and initial oil saturation (dead/live oil systems) on the performance of CSI processes.

CSI after primary in horizontal systems produced negligible incremental oil for both slow and fast drawdown rates due to the large void space and high free gas saturation inhibiting the pressure build up to push the solvent-diluted oil. These CSI experiments were only successful in dead oil systems, where the initial oil saturation was high and pressure gradient was generated through fast depletion rates until conditions of high void space and gas channels were reached.

When the sandpack was flipped vertically, CSI cycles exhibited higher incremental oil recovery per cycle. Slow depletion cycles were more efficient in terms of pressure and incremental recovery per cycle, however faster depletion cycles performed better as a function of time. The higher C_3H_8 content solvent mixture exhibited better performance in comparison to the lower C_3H_8 content as higher volume of diluted oil was drained out of the core.

These results demonstrate the importance of gravity drainage in the CSI process, and its significance on successful oil recovery rates. This study illustrates the limitations of previous horizontal laboratory tests and shows an improved test configuration for modeling and prediction of the improved response observed in CSI pilots.

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Dedication

To God, for fulfilling all of my dreams and for always putting angels on my path. For
granting me health, strength, and thousands of blessings.

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List of Symbols, Abbreviations and Nomenclature

Upper Case Symbols

A	Amplitude of the signal
A	Cross-sectional area of core [cm ²]
AI	NMR amplitude index (i.e. the NMR amplitude per unit mass of fluid)
D	Diffusion coefficient (m ² /s)
DP	Delta pressure [kPa]
H	Horizontal core alignment
L	Length of core [cm]
MW	Molecular weight [g/mol]
OD	External diameter [cm]
P	Pressure [kPa]
PV	Pore volume [cm ³]
R	Ideal gas constant [J/mol.°K]
RHI	Relative hydrogen index
S_g	Gas saturation
S_o	Oil saturation
S_{oi}	Initial oil saturation at each cycle
S_{or}	Residual oil saturation
S_{wc}	Connate water saturation
S_{wi}	Initial water saturation
S_{wirr}	Irreducible water saturation
SD	Standard deviation
T	Temperature [°C]
T_2	NMR transverse relaxation time for a fluid [ms]
T_{2B}	T ₂ relaxation time of a bulk fluid [ms]
T_{2gm}	Geometric mean T ₂ value [ms]
V	Convection velocity [m/s]
V	Volume [cm ³]
V	Vertical core alignment
V_{bulk}	Bulk volume [cm ³]

V_{oil}	Volume of oil [cm ³]
V_{water}	Volume of water [cm ³]
X	Solubility of solvent

Lower Case Symbols

c	Concentration of the gradient [m ⁻³]
g	Gravity acceleration [m ² /s]
j	Diffusion flux of the diffusing fluid [m ⁻² s ⁻¹]
k	Effective permeability [D]
m	Mass [g]
n	Moles
s	Standard deviation

Greek Symbols

μ	Fluid viscosity [mPa·s]
μ_o	Viscosity of oil [mPa·s]
μ_w	Viscosity of water [mPa·s]
ΔP	Pressure difference [kPa]
ρ	Fluid density [kg/m ³]
ρ_b	Bulk density [kg/m ³]
ρ_o	Oil density [kg/m ³]
φ	Porosity of the porous media

Abbreviations

ASP	Alkaline surfactant polymer
BPR	Back pressure regulator
CHOPS	Cold heavy oil production with sand
CPCSI	Cyclic production with continuous injection
CPMG	Car-Purcell-Meiboom-Gill echo train acquisition
CPT	Constant-pressure technique
CSI	Cyclic Solvent Injection
CSP	Cyclic solvent process
CSS	Cyclic Steam Stimulation
CT	Computed Tomography

<i>DAS</i>	Data acquisition system
<i>DPDVA</i>	Dynamic Pendant Drop Volume Analysis
<i>ECSP</i>	Enhanced cyclic process
<i>EOS</i>	Equation of State
<i>EOR</i>	Enhanced oil recovery
<i>GC</i>	Gas chromatography
<i>GOR</i>	Gas oil ratio [scm^3/cm^3]
<i>JIVE</i>	Joint Implementation of Vapour Extraction
<i>LNG</i>	Liquified natural gas
<i>LPG</i>	Condensed petroleum gas
<i>MPC</i>	Methane pressure-cycling
<i>NMR</i>	Nuclear Magnetic Resonance
<i>OOIP</i>	Original oil in place [cm^3]
<i>OSR</i>	Oil steam ratio [cm^3/scm^3]
<i>PT</i>	Pressure transducer
<i>RF</i>	Radio-frequency
<i>RF</i>	Recovery factor [%]
<i>SAGD</i>	Steam Assisted Gravity Drainage
<i>SOR</i>	Solvent-oil ratio
<i>VAPEX</i>	Vapor Extraction

1. CHAPTER ONE: INTRODUCTION

1.1. Background

Approximately 55% of Canada's heavy oil reserves are contained in reservoirs less than 5 m thick (Adams, 1982), and only 5 to 10 % of their OOIP is recovered under primary depletion. Many thin reservoirs in Cold Lake, AB and Lloydminster, AB are primarily produced by Cold Heavy Oil Production with Sand (CHOPS). Through this approach, heavy oil production reaches rates 10 to 20 times greater than conventional cold production (Maini, 1999). Moreover, sand production leads to the formation of a high permeable network of flow paths called "wormholes" that extend within formations and become channels of access for injection fluids in following EOR processes (Du *et al.*, 2013).

Thermal recovery methods such as Cyclic Steam Simulation (CSS), Steam Assisted Gravity Drainage (SAGD), and Steam Flooding are well known for their optimum impact in heavy oil viscosity reduction. However, most of these techniques are not economically viable for thin Canadian heavy oil reservoirs due to the extensive heat or steam losses to surroundings. On the other hand, non-thermal recovery methods such as hydrocarbon-solvent based processes have become a feasible choice for these depleted reservoirs since they utilize solvent dissolution instead of heat to lower oil viscosity. Examples of these techniques are Vapor Extraction (VAPEX) and Cyclic Solvent Injection (CSI). The slow mass transfer rates of solvent into the oil during VAPEX causes a very low production rates mostly during its early stages (Zhang *et al.*, 2000). Moreover, during conventional VAPEX the solvent is injected at pressures close to its dew point to maximize the contact between the heavy oil and the solvent. This approach limits the applicability of different solvents and operative conditions in shallow reservoirs in Western Canada, where low initial

pressures range between 2,000 – 3,500 kPa (Bryan *et al.*, 2016). Gas-phase solvent injection in a cyclic mode, known as the cyclic solvent injection (CSI), have shown to be a faster process in terms of production rates due to solvent convection into the oil during the pressurization stage, and drainage of the diluted oil during production. Besides, the presence of wormholes may increase the contact between the injected solvent and crude oil when they are cyclic injected (Du *et al.*, 2013).

Through the CSI or Huff-n-Puff method, different solvents such as methane, ethane, propane, CO₂ or mixtures of them are injected into a well to re-pressurize the reservoir. They are then left to soak for a specific time to allow for the oil viscosity to be reduced by mass transfer, and finally, the same well is put back on production.

Previous experimental studies have shown that the CSI process is potentially affected by different variables such as pressure depletion rate (Du *et al.*, 2014), foamy oil flow (Bjorndalen *et al.*, 2012), the effect of wormholes (Du *et al.*, 2013), type of solvent (Qazvini Firouz and Torabi, 2012) (Qasvini Firouz and Torabi, 2014) (Qi, 2005) and solvent injection sequence (Jamaloei *et al.*, 2013) (Jamaloei *et al.*, 2012). However, experimental results associated with heavy oil recovery obtained by different authors vary when compared to each other and field applications.

Operator companies such as Husky and Nexen-CNOOC have carried out some field-scale CSI pilot tests in post-CHOPS Canadian reservoirs. A recent pilot field known as the Mervin Cold Solvent EOR tested the effect of injecting a CO₂ and C₃H₈ mixture during two cycles in two different wells. The cumulative oil achieved through this process was 2,810 m³ in a production period of 17 months (Husky Energy, 2011). Another Huff-n-Puff pilot test was conducted in two wells of Plover Lake. The results of injecting C₃H₈ and C₄H₁₀ along with CH₄ indicated successful heavy oil recovery for a three-cycle CSI process (Nexen Inc., 2006). On the contrary, some

laboratory studies (Zhang and Kantzas, 2014) (Alshmakhy and Maini, 2012) conducted in horizontally aligned cores at rapid depletion rates (112 kPa/h – 140 kPa/h) have shown a very low heavy oil production per cycle and a challenge to achieve oil recovery after two production cycles. In contrast, Ivory *et al.* (2010) conducted a 6-injection cycle of a 28% C_3H_8 - 72% CO_2 solvent mixture for long production times (roughly 60 days) and slow depletion rates (5 kPa/h). Instead of running horizontal models like other researchers, they used a stepped cone sandpack model vertically configured. Under these conditions, they obtained repeatable oil recovery from all of the CSI cycles, different to other works where oil recovery significantly dropped after each cycle even under greater depletion rates.

Wu and Kantzas (2008) investigated C_3H_8 and mixtures of CH_4 and C_3H_8 flooding efficiency in horizontal and vertical mode injections. They found that during the vertical mode, the model yielded much more incremental oil recovery under all operation pressures compared to horizontal tests. These results along with Ivory *et al.*'s suggest that gravity segregation at moderate flow rates could be playing an important role in the heavy oil displacement and oil recovery factor efficiency during the CSI field application processes.

Therefore, the main objective of this work is to assess the role of gravitational forces on heavy oil recovery by conducting CSI experiments at very slow depletion rates (close to what is achieved in the field) in both a vertically and horizontally aligned 1-D sandpacks. It is intended to determine whether gravity forces contribute to some extent on the production from repeat CSI cycles observed in the field, and therefore being able to closely relate laboratory results to the field.

CSI cycles will also be run using two different mixture solvents under more realistic laboratory conditions in terms of fluid and porous media properties, pressure ranges and overburden pressure that allow for a better representation of reservoir parameters.

1.2. Research Objectives

This research aims to provide a better understanding of further heavy oil recovery mechanisms involved in the CSI process to closely relate laboratory results to the field. Very fast depletion rates are usually required in the experimental CSI laboratory tests to get incremental oil production. However, in the field, oil is continuously recovered under much slower drawdown rates from multiples cycles. This suggests that there are some mechanisms present in the field that need to be investigated in order to better represent the CSI field response in the lab physical models.

Therefore, the general objective of this thesis is to investigate the effect of gravity during CSI production. For this purpose, sandpack depletion and CSI experiments are conducted at the laboratory scale to accomplish the following specific objectives:

1. Study the role of gravity forces by comparing the performance of the CSI process in multiple cycles, in vertical and horizontal aligned sandpack models. CT scanning will be used to analyze the fluids saturation in the cores after primary depletion and each CSI cycle. The final core will also be tested via Dean-Stark extraction to obtain a profile of residual oil saturation in the core after multiple CSI cycles.
2. Assess the effect of the depletion rate on CSI processes under the influence of the viscous forces and/or gravity forces. CSI cycles are run at a fast and a slow drawdown rate (close to the field rates) for both sandpack configurations.
3. Evaluate the performance of two different ratios of propane and methane on the heavy oil recovery under the effect of gravity and viscous forces, and different pressure depletion rates.

4. Study the impact of vertical vs. horizontal core CSI responses on systems that do not begin with large void space. For this, CSI cycles are run on a core containing high initial oil saturation by omitting the primary production step.
5. Assess the impact of solvent composition in the quality of the produced oil by measuring the viscosity and asphaltene content after the CSI.

1.3. Thesis Structure

This thesis is divided into seven remaining chapters, as outlined below.

- *Chapter 2* provides an updated literature review of the heavy oil and oil sands in Canada, followed by a general overview of EOR methods for heavy oil recovery. A more in-depth background of the Cyclic Solvent Injection (CSI) process, important recovery mechanisms behind this technique, and pilot/field applications in Canada. At the end of this chapter, a summary of the most important aspects of CSI found in the literature and motivations for the development of this work are included.
- *Chapter 3* describes the laboratory preparation and measurement of properties along with the experimental design, setup, and procedures used for primary depletion and CSI cycles. This chapter also discusses CT scanning, NMR and Dean-Stark techniques used to measure fluid properties and residual oil saturation.
- *Chapter 4, chapter 5, and chapter 6* present and describe the procedures and results from CSI tests conducted in three different sandpack models.
- *Chapter 7* summarizes and compares the results from all CSI experiments conducted in the three cores with previous works from the literature. The effect of gravity forces, depletion rate, solvent composition, and initial oil saturation are discussed.

- *Chapter 8* summarizes the major results and conclusions from this thesis and provides recommendations for future work in this area.

1.4. Novelty and Contributions

This study evaluated the impact of the gravity mechanism on the recovery factor during CSI processes. The results of this work showed that gravity forces can relate laboratory results to favorable field CSI performance when reservoir conditions such as large void space (post-primary production) and slow drawdown rates are modeled in the physical laboratory models.

This study produced experimental results for horizontal and vertical CSI tests using different solvent composition mixtures at different depletion rates which have been compared and fit to identify trends in works from the literature.

The analysis of the impact of various parameters on the CSI process illustrates the limitations of previous horizontal laboratory tests and provides an enhanced test configuration for further modeling and prediction of the field response observed in CSI pilots.

2. CHAPTER TWO: LITERATURE REVIEW

2.1. Heavy Oil and Oil Sands in Canada

Heavy oil is an abundant source of energy. According to the NEB (2017), the recoverable heavy oil and bitumen resources are estimated at 5.6 trillion barrels compared to the remaining conventional oil reserves of 1 trillion barrels. Canada is the world's third-largest proven oil reserves with 171 billion barrels, of which 96% corresponds to oil sands located in Western Canadian Sedimentary Basin.

The oil sands and heavy oil can be defined as either semi-consolidated sandstones or carbonates containing water and extremely viscous petroleum. In terms of fluid properties, heavy oil viscosity in Canadian reservoirs ranges between 1,000 to 10,000 mPa·s with a gravity of 10° to 20° API. On the other hand, the crude bitumen contained in oil sands have a viscosity of more than 10,000 mPa·s and a gravity higher than 10° API (Farouq Ali, 1995).

The main oil sand deposits are found in the provinces of Alberta and Saskatchewan (see Figure 2-1), specifically in the Athabasca (McMurray Formation), Cold Lake (Clearwater Formation), Peace River (Blue sky/ Gething Formation) and Wabasca (Grand Rapids Formation) areas. Most of these reservoirs are characterized for being shallow (800 – 1,000 m) with high permeability values ranging from 1–5 D, effective porosity from 26 – 32% and average liquid saturation of 75% (Dusseault, 2001).

Reservoir temperatures range from 4 to 40°C and oil's viscosity goes from 500 mPa·s to greater than one million (Yan *et al.*, 2015; James *et al.*, 2008).

Conventional heavy oil is found along the Alberta-Saskatchewan border (Lloydminster) with approximately 1.3 billion barrels of reserves (NEB, 2017), is the “Heavy Oil Belt” deposit the area of major exploitation and development for its considerable lower oil viscosity as compared to the main oil sand reservoirs.

For oil sands recovery, two main techniques are currently used depending on the depth of the pay zone: mining and drilling (in-situ). As 80% of oil sand reserves are too deep to be mined (greater than 100 m deep), most of the oil sand reserves are recovered by drilling followed by thermal recovery processes such as Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage (SAGD). However, extensive improvement and innovative technology has been developed in the last three decades resulting in new in-situ alternatives to thermal processes such as Cold Heavy Oil Production with sand (CHOPS) and solvent-based methods to exploit reservoirs in Canada (Nasr *et al.*, 2002).

Figure 2-1: Oil sands and Heavy oil regions in Alberta and Saskatchewan. Adapted from (Dusseault, 2001).

In the Heavy Oil Belt and certain areas of the Cold Lake and Wabasca deposits, heavy oil is recovered by primary or “cold production” using two different methods: (1) Cold Heavy Oil Production without Sand and (2) Cold Heavy Oil Production with Sand (CHOPS). In the first method, fluids are produced without sand by implementing sand exclusion devices during the completion of the wellbores. In the latter one, the sand is produced along fluids and separated from oil at the surface. Through the CHOPS approach, heavy oil production reaches rates 10 to 20 times greater than the expected value, with increments from 10% to 15% in recovery factors, and oil production in the form of oil continuous foam (Maini, 1999). The CHOPS technique has been used for the past 15 -20 years in Alberta and Saskatchewan due to its economic success. However, oil production from these methods has been declining, leaving tens of thousands of CHOPS wells inactive and lots of available infrastructure for enhanced oil recovery (EOR) processes.

2.2. In-situ Heavy Oil Recovery Methods

Lloydminster and Cold Lake heavy oil reservoirs are characterized for being unconsolidated, shallow (less than 500 m deep), and thin (2 – 10 m thick) formations and for containing mobile heavy oil with low initial gas-oil ratio (GOR) (Nasr *et al.*, 2002). Because of the poorly consolidation nature of the sands and oil mobility, CHOPS is currently the primary method used to increase heavy oil rates in these reservoirs.

At the end of the CHOPS process, the reservoir pressure is already depleted, and the void space left by the produced oil and sand remains occupied by the gas. Also, as a result of sand production, high permeability network of flow paths known as “wormholes” are developed and extended along the reservoirs. To produce part of the remaining oil, it is required to apply a recovery technique that can re-pressurize the reservoir, reduce oil viscosity, and mobilize oil within the network of

wormholes towards the wellbore. Therefore, different enhanced oil recovery techniques (EOR) such as thermal methods, chemical flooding, and solvent-based processes have been studied and implemented to produce heavy oil reserves.

2.2.1. Thermal-based Methods

In thermal processes, heat is supplied to the reservoir to reduce oil viscosity, expand the oil phase and improve the mobility ratio, which lastly results in a decrease in the water cut and higher recovery factors. During this process, additional mechanisms such as rock and fluid expansion, and compaction may occur (Zhao *et al.*, 2014).

Thermal methods have been successfully applied in countries such as Canada, United States, and Venezuela. Among the most used techniques in Canada are CSS, Steam Flooding, and SAGD.

2.2.1.1. Cyclic Steam Stimulation (CSS)

In the Cyclic Steam Stimulation (CSS) method, steam is injected at high pressure (typically 10 MPa) into a single well, for some time to heat the oil until 200 ~ 300°C (Alvarez and Han, 2013). Then, this well is shut-in for a specific time to allow for uniform heat distribution into the formation. Finally, the same well is put back on production to allow the mobilized bitumen, condensate steam, and gas to be produced to the surface. The production is continued until the oil production rate drops below an economic limit, and then a new cycle of injection, soaking, and production is repeated. The cycles, in turn, are repeated until the ratio of produced oil to injected steam reaches the level that is considered uneconomic.

A typical CSS process is efficiently applicable for reservoirs of less than 1,000 m depth and more than 9 m net thickness, with porosity and oil saturation greater than 40% and 30% respectively,

and permeability higher or equal than 100 mD. Furthermore, oil viscosity should be from 1,000 – 4,000 mPa·s and a low presence of fine grains are appropriate (Akhondzadeh and Fattahi, 2015). Recovery factors for the CSS process are between 10 – 40% OOIP. Although ultimate oil recoveries are low, this method is widely used because it has quick payout (Kamari, and Mohammadi, 2015).

2.2.1.2.Steam Flooding

During steam flooding, steam is continuously injected using multiple injectors and producer wells often arranged in a pattern. Through this method, recovery factors of 50% or higher can be achieved. However, an excessive steam volume is required due to extensive heat losses to the surroundings (Farouq Ali, 1995). According to this, the OSR (Oil-steam ratio) obtained with steam flooding is lower in comparison to the CSS process but the final oil recovery is greater.

2.2.1.3.Steam Assisted Gravity Drainage (SAGD)

The Steam Assisted Gravity Drainage (SAGD) process was developed by Butler (1985) and initially piloted at Cold Lake. Nowadays, this process represents one of the most used thermal techniques for in situ bitumen recovery in Athabasca. Contrary to steam flooding, this method works for very viscous bitumen. This process consists of two horizontal wells, one above the other, separated about 4 – 7 m in the vertical plane. Figure 2-2 shows a diagram of the SAGD process. The steam is injected into the top well, creating a steam chamber around the injector that expands both upwards and laterally as steam is continuously injecting. The heat from the steam reduces the bitumen viscosity, which drains downwards along with the condensed steam towards the producer well below. The main mechanism of this process is gravity drainage; therefore, it should

be applied in reservoirs of thick net pay zones (> 15 m), high vertical permeability, and without the presence of thief zones (Butler and Mokrys, 1993).

Figure 2-2: A conceptual illustration of the SAGD process. Adapted from (Kim, 2017).

About two-third of heavy oil reserves in Canada are contained in Saskatchewan (NEB, 2017), and 75% of these reserves are found in formations of less than 4 m (Farouq Ali, 1995) as Figure 2-3 shows. Bottom water and edge water are other typical characteristics of these reservoirs (Miller, 2001). This implies that steam-based methods can recover just a small fraction of these reserves. The CSS and SAGD techniques become energy inefficient and uneconomic due to significant heat losses to overburden and underburden when pay zones are less than 10 m (Dong *et al.*, 2006). In addition, the presence of aquifers greatly affects the performance of these methods as steam rapidly channels into the water layer, which results in low OSR and oil production rates (Lim, *et al.*, 1995). Furthermore, environmental concerns related to feeding water availability and produced water disposal put the steam-based processes in a less attractive position when it comes to thin pay zones.

Figure 2-3: Saskatchewan heavy oil resources distribution in terms of sand thickness. Modified from (Farouq Ali, 1995).

Most of the heavy oil recovery in the Lloydminster region comes from cold production, and about 80 to 95% of the OOIP is left after the economic limit is reached (Miller, 2005). As the steam-based process are not suitable for this type of reservoir, it is essential to develop and implement techniques that suit the reservoir characteristics and allow for enhanced oil recovery fulfilling both economic and environmental conditions.

2.2.2. Non-Thermal Methods

Non-thermal methods can be classified into three main categories: miscible displacements, chemical flooding, and immiscible displacements. Miscible displacement processes involve the injection of fluids that dissolve into the oil at first contact or multiple contacts to reduce the interfacial tension and increase the oil displacement.

The displacing fluid forms a transition zone or mixing zone with the displaced fluid (oil and water) that spreads out as the flood advances. (Shah *et al.*, 2010). The production mechanisms responsible

of oil recovery during miscible floods are mainly: extraction, dissolution, vaporization, solubilization, condensation, which in turns leads to oil phase behavior changes such as viscosity reduction, oil swelling and solution gas drive (Lake, 1989).

Several gases and liquids can be used as displacement agents. These include high-pressure nitrogen, carbon dioxide, air, flue gas, methane, organic alcohols, condensed petroleum gas (LPG), liquified natural gas (LNG), among others. The success of these method depends on achieving miscibility between the displacing and displaced fluids at the reservoir pressure and prevention from fingering and early breakthrough of the displacing agent.

In chemical flooding processes, chemicals such as alkalines, surfactants, polymers, or combination of them (ASP) are injected into the reservoir to increase the viscosity of displacing fluid and/or reduce the interfacial tension to enhance the reservoir sweep. This type of process is restricted to reservoirs with presence of clays or carbonates as chemicals are absorbed for this type of formations. Chemical flooding is considered suitable for oil viscosities lower than 100 or 200 mPa·s, however, some chemical EOR pilots conducted in Canada has shown successful results in formations with heavy oils up to 10,000 mPa·s (Wilson, 2016). Although this recovery method can achieve recovery factors up to 40%, the high concentrations and cost of polymers and surfactants, has limited its use (Shah *et al.*, 2010).

Through immiscible flooding or also known as reinjection process, gas is injected into the reservoir to increase the pore pressure, dissolve into the crude oil and reduce its viscosity to allow the oil flow to the wellbore. Carbon dioxide (CO₂) is one of the most popular gases used for heavy oil

recovery for its high dissolution into heavy oil, which leads to oil swelling, viscosity reduction, and oil mobility. According to simulation and laboratory studies, the CO₂ has shown to be efficient for moderately viscous oil of about 1,000 mPa·s (Qazvini Firouz and Torabi, 2012).

2.2.3. Solvent-based Methods

Among different non-thermal methods, solvent processes have been proposed as a promising alternative to thermal methods for its advantages in: (1) Energy efficiency. The energy required to produce at a specific rate through solvent processes is about 3 % of the energy needed for SAGD (Singhal *et al.*, 1996). (2) Cost-effectiveness. Several expenses related to steam processes, such as extensive infrastructure, steam generators, fuel, source water, treatment and disposal of produced water are avoided during the application of solvent techniques. (3) Oil in-situ upgrading. The dissolution of solvents into the oil may generate in-situ precipitation of asphaltenes (heavier components), which allows the production of lighter density oil crude to the surface conditions. (4) Environmental pollution. Over 80% of greenhouse gases emissions are minimized through solvent processes as they can be recovered in the produced fluids and be reinjected (Jia, 2014). On the other hand, these techniques present some drawbacks related to low oil production rates as a consequence of low gas dissolution and mass transfer rate of solvent into the heavy oil (Lim *et al.*, 1995).

Solvent-based EOR methods are well known for their ability to reduce oil viscosity and increase oil mobility through dissolution and diffusion into the oil. Examples of these techniques are Cyclic Solvent Injection (CSI), and Vapor Extraction (VAPEX).

2.3. Cyclic Solvent Injection (CSI)

In the Cyclic Solvent Injection process different solvents such as CH_4 , C_2H_6 , C_3H_8 and CO_2 or their mixtures are injected into a well to re-pressurize the reservoir; they are then left to soak for a specific time to allow for the oil viscosity to be reduced by mass transfer and convective dispersion, and finally the same well is put back on production to allow for the diluted oil to flow to the wellbore (Chang *et al.*, 2013). The injection, soaking, and production stages of this process conform a CSI cycle as is shown in Figure 2-4.

Figure 2-4: A conceptual illustration of the CSI Process.

In recent years, CSI appears as an attractive EOR method for Post-CHOPS due to its applicability to thin and shaley reservoirs with the presence of aquifers. As CSI requires a single well for the injection and production, the well infrastructure left after CHOPS remains available for CSI applications. This and the economic advantages associated to solvent-based processes have led to developing field CSI-pilot projects by Husky (Husky Energy, 2011) and Nexen-CNOOC (Nexen Inc., 2006).

After cold production or CHOPS, the reservoirs have been pressure depleted and left with void space. Therefore, the goal of CSI is to drive gas into solution by reinjecting solvents in vapour phase until bringing the reservoir pressure close to its initial pressure. Solvent composition is chosen based on reservoirs pressure so that solvents remain in the vapour phase during the injection and can greatly dissolve into the oil to reduce its viscosity (see Figure 2-5). Then, production is initiated from the soaking pressure (system pressure when the solvent is already dissolved into the oil) to a defined final pressure. As Figure 2-5 shows, the reservoir pressure slowly decreases when the well is put back on production, this is attributed to the expansion of solvent (gas phase) that occupies the depleted pores.

Figure 2-5: Reservoir behavior during CSI. Adapted from (Chang *et al.*, 2013).

The cyclic solvent injection process was first introduced by Shelton and Morris (1973) through the injection of rich gas in an oil-viscous reservoir using a single well as injector and producer. Allen (1974) patented a CSI type process with propane, butane or solvent mixture for heavy oil recovery. In the '80s, several field studies were conducted to evaluate the efficiency of cyclic CO₂ injection.

Bardon *et al.* (1986) conducted a CSI pilot with CO₂ in the Camurlu oilfield in Turkey. The reservoir had an average porosity of 13%, a permeability of 5 mD, oil viscosity of 284 mPa·s and presence of a gas cap. They run three consecutive cycles in two different wells applying soaking periods between 10 and 15 days. The production responses for the first two cycles were initially good but short. Hence, for the third cycles, CO₂ injection was increased 10 times and production responses improved. This was attributed to the enhancement of pressure build up. Taking into account the injection and soaking times the cyclic CO₂ injection produced almost at the same rate as that during primary production, 11.5 bbl/d and 11 bbl/d respectively.

Olenick *et al.* (1992) described the immiscible CO₂ project carried out at the laboratory and field scale (Halfmoon oil field, Wyoming). In the laboratory, they evaluated the injection of CO₂ in three different modes: continuous flooding, cyclic injection, and cyclic injection followed-up by water flooding. From their results, they concluded that CO₂ flooding achieved more incremental oil while cyclic CO₂ was more favorable in terms of CO₂ utilization. Viscosity reduction was identified as one of the main mechanisms behind oil recovery. Although a final recovery of 27 % was obtained from the laboratory study, field results were less optimistic, as effects of natural fractures and other reservoir heterogeneities were absent in the laboratory tests. The huff-n-puff pilot showed that the incremental oil produced from each well was proportional to the amount of injected gas produced back. Also, during both studies, there was no evidence of asphaltene precipitation. Due to drops in the oil price at that time, the CO₂ injection was ended due to economic viability.

Along the investigation of CSI, different hydrocarbon-solvents have been evaluated for their effectiveness in heavy oil recovery. Lim *et al.* (1995) first experimentally studied the cyclic

injection of ethane in a 3-D physical model saturated with Cold Lake bitumen. They showed that by solubilization of solvent gas at 4 MPa and ambient temperature, the viscosity of the bitumen could be reduced from 100,000 mPa.s to 100 mPa.s. Furthermore, they evidenced a decline in oil production rate at early stages, which was attributed to the wellbore inflow mechanism. On the other hand, the increment in oil production rate in subsequent cycles was explained by the effect of the gravity drainage as a further production mechanism.

Mokrys and Butler (1993) introduced the concept of VAPEX, a non-thermal analog of SAGD, in which gaseous condensable solvents (i.e. ethane, propane and butane) along with non-condensable carrier gases (i.e. methane and carbon dioxide) are injected into the reservoir. The condensable gas is injected in the vapour phase and the carrier gas is used to raise the dew point of the gas solvent to assure its vapour phase at the reservoir conditions, thus higher dissolution into the oil. Similar to SAGD, the vapour solvent forms a chamber which propagates upwards and laterally. The main heavy oil recovery mechanisms are: solvent dissolution, diffusion of solvent molecules in the bulk heavy oil, viscosity reduction, in situ oil upgrading by asphaltene precipitation above critical solvent concentration, and gravity drainage of the solvent-diluted heavy oil (Jia, 2014).

Several authors have experimentally studied this technique as an option for heavy oil recovery in thin reservoirs (Das and Butler, 1996; Boustani and Maini, 2001; Yazdani and Maini, 2005; Moghadam *et al.*, 2008). However, one of the major disadvantages of VAPEX is related to the slow diffusion and dispersion of solvent into the oil which leads to very low production rates especially at early stages (Zhang *et al.*, 2000). Moreover, gravity drainage is not very efficient in thin reservoirs. Besides, solvents have to be injected at pressures close to their dew point to

maximize the dissolution into the heavy oil. This restricts the use of solvents such as propane in shallow reservoirs of Western Canada, as the reservoir pressures are higher than propane's dew point (2,000 – 3,500 kPa) (Bryan *et al.*, 2016). On the other hand, the CSI process has shown some advantages over VAPEX in terms of production rates. As reservoir pressure is increased and decreased during the injection and production stages, the solvents disperse faster due to the presence of a pressure gradient and the diluted oil is produced at higher rates (Jamaloei *et al.*, 2012). Also, the presence of wormholes may increase the contact between the injected solvent and crude oil when they are cyclic injected (Du *et al.*, 2015).

Ivory *et al.* (2010) investigated the CSI efficiency as a follow-up process of cold production processes by using a mixture of 28% vol. % C_3H_8 + 72 vol. % CH_4 . The experiment comprised a stepped cone sandpack saturated with Rush Lake oil of 39,000 mPa·s with a mimic wormhole of 6 cm diameter. The core was first primary produced followed by 6 solvent injection cycles conducted at a very slow depletion rate. After about two years of testing, they reported a final oil recovery of 43.6 % from the CSI process. Contrary to other CSI experimental works in the literature, repeatable oil recovery was obtained after each CSI cycle. Although the authors did not look at the effect of gravity, the cone shape pack and the vertical displacement seemed to respond differently than other systems.

Furthermore, they conducted a history match to validate the CSI numerical model. These results showed the potential viability of the CSI process in a post-cold production process and the importance of different mechanisms such as foamy oil flow and wormholes presence in the performance of the process.

Du *et al.* (2015) studied the feasibility of the CSI as a Post-CHOPS process by considering the effect of wormholes and their properties in different sized sandpack models. They found that wormholes position and size enhance the CSI performance. When wormholes are located at the bottom of the sandpack and they have larger coverage, higher oil recovery factors and oil production rates are achieved.

Dong *et al.* (2006) adapted the cyclic flow interruption technique proposed by Adamache *et al.* (1994). This technique was adapted for thin reservoirs depleted either under cold production or waterflood production, in which 90 – 95% of the OOIP remained available. The aim of this method called methane pressure-cycling (MPC) was to restore the solution-gas drive mechanisms by saturating heavy oil through gas injection (methane) followed by injection of water to bring the reservoir pressure close to its original value. They conducted MPC tests in saturated sandpacks of 30.5-cm length and 5-cm diameter with oil viscosities from 1,700 to 5,400 mPa·s. The experimental results indicated that MPC provides favorable conditions for contact between methane and the remaining viscous oil within the reservoir. On the other hand, the efficiency of the methane gas cycling process is greatly affected by mobile-water saturation.

CSI variations have also been proposed to enhance oil recovery. Jamaloei *et al.* (2012) developed an enhanced cyclic solvent process (ECSP) for thin reservoirs in which two hydrocarbon solvents of different solubility are sequence injected. The essence of this method consists of injecting a volatile gas (methane) that fingers into the oil followed by a more soluble gas solvent (propane) that take these paths to dissolve into the oil. The results from six ECSP cycles showed a successful incremental oil recovery of 34.3% against 4.27% oil recovered during one-slug pure methane. However, to obtain oil production from all 6 cycles, they applied different strategies such as

injecting the methane at higher pressures and increasing the size of the propane slug. They observed that when the available residual oil saturation decreased significantly after each cycle, the recovery factor decreased abruptly even when the volume of injecting propane was increased. The production mechanisms identified in this process were the solution-gas drive energy generated by methane expansion and viscosity reduction by propane dissolution. Based on the optimal injection sequence, they run field-scale simulations that indicated high efficiency of the ECSP in heavy oil recovery.

Jiang *et al.* (2014) introduced another variation of the CSI process: cyclic production with continuous injection (CPCSI). In this method, a solvent in vapour phase is continuously injected through an injector to maintain the pressure in the reservoir, while the solvent-diluted oil is cyclic produced in another well. This method aims to overcome one drawback of CSI related to solvent exsolution and regain of oil viscosity as pressure drops. Jian *et al.* evaluated the CPCSI process in 1-D and 2-D sandpack models and found that oil recovery could reach values up to 85% through this method.

Although CSI is not a new concept for EOR, limited studies have been developed to investigate the performance of CSI on heavy oil recovery. Table 2-1 summarizes most CSI experimental studies published in the literature. It is observed that the final oil RF from all works greatly vary. These differences are attributed mostly to the pressure depletion rate applied during the production stage of the CSI. High RFs are associated with high-pressure gradients across the core, when large drawdown pressures are applied. This is evidenced in Table 2-1, where the shortest production times, mostly show oil ultimate RFs over 50%. Other factors such as gravity forces (in vertical cores), mobility ratio (k/μ), core properties (length, porosity), type of solvent, and wormholes presence have an impact on the CSI performance.

Table 2-1: CSI experimental studies in the literature

Reference	Heavy oil	Model					Injection		Production	
	Oil source / μ_o (mPa·s)	Type/ Shape	Size (cm)	ϕ (%)	k (D)	Inj/Prod mode	solvent	P (MPa)	Time	RF (%)
Lim <i>et al.</i> (1995)	Cold Lake 100,000 @ 20°C	Cube Sandpack	L ₁ = 47 L ₂ = 40 L ₃ = 27	32.8 35 35	80 20 110	Horiz.	C ₂ C ₂ C ₂	1	1 -3 h 3/13/15 cycles	40-50
Dong <i>et al.</i> (2006)	Senlac, Cactus and Plover Lake 1,700–5,400 @ 22°C	Cylindrical Sandpack	L= 30.5 D = 5	35.5 - 32.8	6.58 9.70	Horiz.	C ₁	Init: 4.5 Final: 0.5	5–17 h 8 cycles	23.3- 28.8
Shi and Kantzas (2008)	Lloydminster 10,700 @ 23°C	Cylindrical Sandpack/ Glassbeads	L = 18.5 D = 0.95	36.4 37.8	1.9 11.8	Horiz.	C ₁ CO ₂	4.85 6.5	20 d / 2 cycles 15 d / 2 cycles	4.8-5.2 2.7-4.2
Ivory <i>et al.</i> (2010)	Rush Lake 39,320 @ 15- 25°C	Cone sandpack	H = 300 D _{top} = 9.7 D _{btm} = 1	38	4.5	Vertical	C ₃ +CO ₂	Init: 2.2- 3.4 Final: 0.5-1	Inj: 63-80 d Prod: 17-26 d 6 cycles	52
Bjorndalen <i>et al.</i> (2012)	Rush Lake 61,495 @ 21°C	Ball-stick pattern Micromodel	Pore: D=265um H = 75um	-	-	Lateral	C ₁ /C ₃ /CO ₂ C ₃ +CO ₂	4.4	-	-
Alshmakhy and Maini (2012)	Mineral oil 1,900 @	Cylindrical Sandpack	L = 198 D = 2.6	36.2	24.1	Vertical	CO ₂	3.56- 3.68	1 d 2 cycles	28
Du <i>et al.</i> (2014)	Western Canada Heavy oil 4,330 @ 21°C	Cylindrical Sandpack	3 models: L = 30.48- 60.96 D = 3.81 - 15.24	33- 36	35.5- 32.8	Vertical and Horiz.	C ₃	0.8	Inj: 45 min Soak: 10 min Prod: 5 min 6 cycles	21-65.4

Table 2-1: CSI experimental studies in the literature

Reference	Heavy oil	Model					Injection		Production	
	Oil source / μ_o (mPa·s)	Type/ Shape	Size (cm)	ϕ (%)	k (D)	Inj/Prod mode	solvent	P (MPa)	Time	RF (%)
Qazvini Firouz and Toravi (2012)	Saskatchewan heavy oil 1,420 @ 28°C	Cylindrical Sandpack	L= 30.8 D= 5.08	24	1.8	Horiz.	C ₁ /C ₃ / C ₄ / CO ₂	Init: 1.7- 6.8 Final: 0.276	Soak: 24 h 7–10 cycles	58-73
Jamaloei <i>et al.</i> (2012)	South Britnell 1,080 @ 22°C	Cylindrical Sandpack	L = 101.3 D = 4.9, 3.2	38	41.8	Horiz.	C ₁ C ₃	Init: 3 Final: 0.5	Soak: 22 h Prod: 0.5 h 6 cycles	34.3
Zhang and Kantzas (2014)	Lloydminster 10,700 - 11,200 @ 23°C	Cylindrical Glassbeads Sandpack	L= 18 D = 0.95 L= 18/1.5 D = 0.95	37.8	11.8 1.9	Horiz.	CO ₂ +C ₃ H ₈	6.6	-	10
Jia <i>et al.</i> (2014)	Lloydminster 5,875 @ 21°C	Rectangular Sandpack	L ₁ = 40, L ₂ = 10, L ₃ = 2	36	4.7	Horiz.	C ₃	0.8	Soak: 55 min Prod: 5 min	60
Li <i>et al.</i> (2016)	14488 @ 54°C	Cylindrical Sandpack	L= 60 D=2.5	37- 39	8.3 - 9.4	Horiz.	CO ₂ + C ₁ + C ₃ + surf. + μ red.	4	Soak: 48 h Prod: 13 h	29.7
Sun <i>et al.</i> (2016)	Britnell 1,081 @ 22°C	Rectangular Sandpack	L ₁ = 101.3 L ₂ =4.9 L ₃ = 3.2	35	32	Horiz.	C ₁ + foaming agent	4.5	-	43.29
Ahadi and Torabi (2018)	6430 @ 20°C	Cylindrical Sandpack	L=33.5 D=4.1	32- 35	8.4 - 10.2	Horiz.	C ₁ +C ₃ C ₁ +C ₃ +CO ₂	1.7	Inj: 1 h Soak: 24 h Prod: 1 h	44-50
Horiz. = Horizontal / Init = Initial / Inj = Injection / Soak = Soaking / Prod = Production / RF = Recovery Factor / Surf. = Surfactant / μ red. = Viscosity reducer										

2.4. CSI Production Mechanisms

2.4.1. Diffusion and Convection

In solvent-based heavy oil recovery methods, when solvents are injected into the reservoir and contact the viscous heavy oil, mass transfer between fluids occurs. The mixing of the solvent and heavy oil is the result of molecular diffusion (concentration gradient) and/or convective dispersion or bulk motion (pressure gradient) (Cuthiell *et al.*, 2006). Molecular diffusion between two fluids can be modeled by using Fick's First Law of diffusion:

$$j = -D \frac{\partial c}{\partial x} \quad (2.4-1)$$

Where, j is the diffusion flux of the diffusing fluid (m^2s^{-1}), D is the diffusion coefficient (m^2/s), x is the distance in the direction of diffusion (m), c is the concentration of the gradient (m^{-3}), and the negative sign indicates that the concentration gradient is decreasing in the direction of increasing x .

When concentration changes both with time and distance, the mass-transfer process is described by the convection-diffusion equation derived from the continuity equation in one dimension:

$$\frac{\partial c}{\partial t} = \frac{\partial}{\partial x} \left(D \frac{\partial c}{\partial x} - cV \right) + S' \quad (2.4-2)$$

$$V = -\frac{k}{\mu} \left(\frac{dP}{dx} - \Delta \rho g \right) \quad (2.4-3)$$

Where, V is the convection velocity (m/s) that describes the bulk motion between the solvent and heavy oil as a function of distance and time, and S' represents the source or sink of the quantity c .

Equation (2.4-3) describes the convection velocity in a porous media expressed in terms of pressure gradient, $\frac{dP}{dx}$ (kPa/m), and gravity force, g (m²/s) using Darcy's law. $\Delta\rho$ represents the difference in density between the solvent-diluted oil and the liquid solvent, (kg/m³). The density of diluted oil mixture can be calculated by applying the mixture rule for an ideal solution:

$$\rho = \frac{1}{\frac{1-c}{\rho_o} + \frac{c}{\rho_s}} \quad (2.4-4)$$

Where, ρ_o (kg/m³) is the heavy oil density and ρ_s is the solvent density. In this equation, the solvent is assumed to be in liquid phase at the moment of dissolution with oil, and it can be only applied if the change of volume after solvent dissolution into the oil is negligible (Jiang *et al.*, 2014).

The diffusion coefficient of hydrocarbon-solvents in heavy oil and bitumen varies from 10⁻¹² to 10⁻⁸ m²/s and it is dependent on oil viscosity and operative conditions such as pressure and temperature (Jamaloei, 2013).

As diffusion coefficients are very low in heavy oil, processes such as VAPEX which works mainly through solvent diffusion, produces at very slow rates in field applications. The solvent diffusion coefficient in heavy oil has been measured by using different methods (see Table 2-2): the pressure decay method (Schmidt, 1985; Upreti and Mehrotra, 2002; Tharanivasan *et al.*, 2006), the dynamic pendant drop volume analysis method (DPDVA) (Yang and Gu, 2006), and the constant-pressure technique (CPT) (Etminan *et al.*, 2010).

Table 2-2: Diffusion coefficient measurements in different heavy oil and bitumen samples

Solvent	Oil	Pressure	Temp.	Viscosity	Diffusivity	Reference
		(Mpa)	(°C)	(mPa·s)	(10 ⁻⁹ m ² /s)	
CO ₂	Athabasca	3.1-4.1	25	767 @ 80°C	0.16-0.22	Upreti and Mehrotra (2002)
	Athabasca	4	25	821,000 @ 25°C	0.12-0.2	Upreti and Mehrotra (2002)
	Lloydminster	3.5-4.2	23.9	20,267 @ 23.9°C	0.46-0.53	Tharanivasan <i>et al.</i> , (2004)
	Athabasca	4	75 90	106,000 @ 40°C	0.46-0.51 0.76-0.79	Sheikha <i>et al.</i> , (2005)
	Lloydminster	2-6	90	23,000 @ 23.9°C	0.22-0.55	Yang and Gu (2006)
CH ₄	Athabasca	4	25	224,500 @ 25°C	0.08-0.11	Upreti and Mehrotra (2002)
	Athabasca	4-8	25	821,000 @ 25°C	0.06-0.08	Upreti and Mehrotra (2002)
	Lloydminster	4.9-5	23.9	20,267 @ 23°C	0.21-0.22	Tharanivasan <i>et al.</i> , (2004)
	Athabasca	4	75 90	35,000 & 106,000 @ 40°C	0.39 0.55-0.73	Sheikha <i>et al.</i> , (2005)
	Lloydminster	6-14	23.9	23,000 @ 23.9°C	0.12-0.19	Yang and Gu (2006)
C ₂ H ₆	Athabasca	4	25	821,000 @ 25°C	0.21-0.38	Upreti and Mehrotra (2002)
	Lloydminster	1.5-3.5	23.9	23,000 @ 23.9°C	0.13-0.77	Yang and Gu (2006)
C ₃ H ₈	Lloydminster	0.4-0.8	23.9	20,267 @ 23°C	0.49-0.79	Tharanivasan <i>et al.</i> , (2004)
	Lloydminster	0.4-0.9	23.9	23,000 @ 23.9°C	0.09-0.68	Yang and Gu (2006)
	Peace River Bitumen	0.7	22	55,000 @ 22°C	0.0011	Diedro <i>et al.</i> , (2015)
	Heavy oil	0.9	35	43,597 @ 15°C	0.002	Fayazi <i>et al.</i> , (2019)
N ₂	Athabasca	4	75 90	35,000 & 106,000 @ 40°C	0.25-0.26 0.28-0.4	Sheikha <i>et al.</i> , (2005)

Temp. = Temperature

2.4.1. Vapour Solvent Solubility in Heavy Oil

The solubility of a gas in a liquid may be expressed as the amount of free gas that can go into solution. This thermodynamic property is dependent on the temperature, pressure, type of gas, and the fluid composition. Zhou and Zhou (2001) introduced an equation derived from the EOS for a real gas and the mass conservation law to determine the amount of solvent dissolved into the heavy oil.

$$X = \frac{MW_{solvent}}{Rm_{oil}} \left(\frac{P_i V_i}{Z_i(P_i V_i) T_i} - \frac{P_f V_f}{Z_f(P_f V_f) T_f} \right) * 100 \quad (2.4-5)$$

Equation (2.4-5) describes the solubility of solvent into the oil phase, where, $MW_{solvent}$ is the solvent molecular weight, m_{oil} is the oil mass. T_i , P_i and V_i are the initial temperature, pressure and initial volume of the solvent respectively, and $Z_i(P_i V_i)$ corresponds to the compressibility factor at the initial conditions. T_f , P_f , V_f , and $Z_f(P_f V_f)$ are the final temperature, pressure, volume, and compressibility of the solvent. The initial and final parameters are experimentally measured before the solvent injection and after the soaking time.

Sayegh and Maini (1984) conducted a CSI process using a Lloydminster heavy oil of 11,996 mPa·s at 22°C. They performed two sets of experiments using pure CO₂ and a mixture of CO₂/CH₄ (3:1 mole ratio). They observed that injection of pure CO₂ at high pressures (6.55 MPa), caused oil swelling and significant viscosity reduction (from 6,822 to 226 mPa·s). For the solvent mixture, they found that CH₄ affected the CO₂ performance because of its lower solubility in oil. They also identified that rapid CO₂ injection led to an early gas breakthrough, which led to an ineffective reduction of oil viscosity.

Gu *et al.* (2015) measured the solvent diffusion coefficient of CO₂ vs CH₄ in a heavy oil sample from Saskatchewan. They conducted a PVT study where compared the solubility of both solvents. From this experimental work, CO₂ was found to have a much higher solubility than CH₄ represented in greater efficiency in oil viscosity reduction.

Shi and Kantzas (2008) and Jamaloei *et al.* (2012) studied the performance of CH₄ in laboratory cyclic injection processes. It was found that methane can efficiently re-pressurize depleted systems. However, due to its low solubility in the heavy oil, during the production stages, it quickly releases from solution, oil regains its viscosity, and low oil recovery factors are achieved after the first production cycle.

Qazvini Firouz and Torabi (2014) studied the feasibility of CO₂ in the CSI process at different injection pressures. They saturated a core of 1.7 D-permeability and 24%-porosity with a dead (gas-free) heavy oil of 952 mPa·s viscosity at 28°C. Figure 2-6 and Figure 2-7 show the cumulative oil recovery and viscosity reduction respectively for over 10 CSI cycles. It is observed that at the highest injection pressure (7,239 kPa), the oil recovery factor was significantly high (71%), and the viscosity of the produced oil was greatly reduced to 62 mPa·s.

They attributed these results to the higher diffusion coefficient and solubility of CO₂ at high pressures near supercritical conditions. These results indicate how gaseous solvent mixing pressures are essential in the performance of the CSI process. In order to efficiently increase oil recovery and mobilize the heavy oil, gaseous solvents need to greatly dissolve in the oil to be able to modify its properties and not only bring energy back to the system.

Figure 2-6: Recovery factor from CSI tests using CO₂ solvent. Adapted from (Qazvini Firouz and Torabi, 2014).

Figure 2-7: Produced oil viscosity after each CSI cycle using CO₂ solvent. Adapted from (Qazvini Firouz and Torabi, 2014).

Freitag (2012) studied the solubility and ability of oil viscosity reduction of CH₄, CO₂, and C₃H₈. His results indicated that propane had the greatest effect in oil viscosity reduction due to its high solubility into the oil in comparison with CO₂ and CH₄. Methane solubility in heavy oil was found to be lower than that of CO₂.

The ability of a solvent to dissolve in heavy oil is associated with the critical temperature and normal boiling point of the solvent. High values of these parameters translate into greater solubility of the solvent into the oil phase. Propane critical temperature and normal boiling point are higher than CO₂ and CH₄ values, and propane solubility is also greater. (Nguyen and Farouq Ali, 1988). Although propane can greatly reduce oil viscosity, the injection of this solvent alone is constrained in CSI applications due to Canadian reservoir properties. Typical reservoir temperatures are about 20°C or lower. Propane dew point at this temperature is about 800 kPa, which means that to keep the propane in a vapour phase, reservoirs should be pressurized at very low pressures (<800 kPa) leading to poor pressure gradients during the production stage in the CSI cycle. If propane is injected at pressures over its dew point, it will condense, and significant volumes will be required to re-energize the reservoir.

The utilization of CO₂ as a gas solvent for CSI is also restricted in shallow reservoirs in Western Canada where reservoir pressures ranging between 2,000 – 3,500 kPa (Bryan *et al.*, 2016). Due to safety concerns, during reservoir pressurization with gas, it is recommended to apply pressures below the initial reservoir pressure. This means that in this type of reservoirs solvents such as CO₂ have to be injected at low pressures, which in some extension would affect the ultimate oil recovery factor. This is because CO₂ higher dissolves into heavy oil and reduces oil viscosity at high pressures.

According to these facts, different authors have studied the combination of different solvents, in different mixtures ratios, in the way that the mixture solvent fulfills the required saturation pressure, reasonable solubility, and economic viability.

Qazvini Firouz and Torabi, (2012) investigated the performance of solvent mixtures by adding propane and butane to the CO₂ gas. They found that mixing CO₂ with a hydrocarbon solvent could yield equal or higher oil recovery factors than using pure CO₂ at similar pressures. Figure 2-8 shows that higher recovery factors were obtained with CO₂ and propane mixtures in comparison to mixtures with butane. This illustrates the importance of the solvent-mixture selection and on the CSI performance.

Figure 2-8: Incremental oil recovery factor for CSI experiments using solvent mixtures. Adapted from (Qazvini Firouz and Torabi, 2012).

Different authors have investigated the performance of the CSI using solvent mixtures of propane with CO₂ and CH₄ (Ivory *et al.*, 2010; Li *et al.*, 2016). Ahadi and Torabi (2018) studied the effect

of solvent concentration by using different ratios of propane with methane and CO₂ during CSI laboratory tests. Their results indicated that oil recovery with mixtures of propane and methane was enhanced from 24.3% to 33.4% when the concentration of propane was increased from 15 to 50 mole % in the mixture. They also observed that a lesser number of cycles and a lower amount of solvent was required to recover oil when propane concentrations were higher. The partial replacement of CH₄ with CO₂ in the mixture not just improved the solvent apparent solubility of solvent but also the foaminess of heavy oil. This study indicated the ability of propane to dissolve into the oil, and the importance of selecting optimum solvent mixing concentrations on the heavy oil recovery during CSI processes.

2.4.2. Pressure Drawdown

Solvent solubility in oil is a function of pressure. Du *et al.* (2015) conducted an experimental study to evaluate the effects of pressure declination in the CSI for Post-CHOPS reservoir conditions. For this, they included a 0.32 cm diameter tube to mimic a wormhole inside a cylindrical sandpack of 6 D permeability, 30.48 cm length and 15.24 cm diameter. Propane was injected into the sandpack at 800 kPa for 45 minutes and left to soak for 10 minutes. Then, the core was produced at three different drawdown rates: 500 kPa/5 min, 100 kPa/4 min, and 50 kPa/4 min. They observed that fast depletion rates lead to higher production rates due to the presence of a greater pressure gradient in the core that promotes the foamy oil flow and low gas mobility under solution gas drive. On the other hand, at slower drawdown rates, ultimate oil recovery factors were obtained due to larger drainage areas. Their results showed that the wormhole coverage had positive effects on the CSI performance and that pressure decline rate could be optimized to achieve reasonable average oil production rates and ultimate recovery factors.

The solvent dissolution and exsolution during the injection and production stages are not an equilibrium process. Zeng (2016) studied the non-equilibrium release of methane and propane from the oil phase during the depletion of live-oil saturated sand packs at different drawdown rates. Results from methane tests indicated that during fast drawdown rates, the pressure at the production port drops so fast that methane cannot leave solution with the oil (supersaturation) and a pressure gradient across the core is generated. Methane mobility remains low as it is trapped and dispersed into the oil (foamy oil), this helps to slow down the system pressure declination, and the overall recovery becomes high. This phenomenon known as foamy oil is one of the main mechanisms behind oil production during CHOPS. In the case of propane, Zeng (2016) observed that during high drawdowns, propane does not evolve until very low production pressures, thus oil does not expand, and oil production is not very effective.

As depletion rates in the field are usually much slower (about 200 kPa/day) than the experimental values used in laboratory tests, it is likely that the foamy oil mechanism is also present during CSI processes with pure propane. However, it is important to note that after CHOPS, methane always remains in the reservoir. So, the true solvent solubility and non-equilibrium release will be a mixture of the injection solvent and the methane present in the reservoir. This means that the rate of release should be slow enough to keep propane into solution but fast enough to allow CH₄ to expand and provide solution gas drive. Previous works had been run with pure solvents or mixtures of propane with CO₂, therefore, it is necessary to conduct additional laboratory investigation to study the effect of drawdown rates for solvent mixtures with methane.

2.4.3. Solution Gas Drive and Foamy Oil

One of the main production mechanisms during CSI processes in heavy oil systems is solution gas drive, which depends on different parameters such as pressure, temperature, oil viscosity, and solvent solubility (Qazvini Firouz and Torabi, 2012). Gaseous solvents such as methane and CO₂ are mainly injected to restore the reservoir energy after either primary production or waterflooding in heavy oil reservoirs. The purpose of the gas injection is to restore the solution gas drive by repressurizing the gas back into solution until reach the initial reservoir pressure.

Foamy oil is generated during the depressurization of heavy oil reservoirs under gas solution: the evolved gas bubbles start to move while being dispersed in the oil phase, because of the stably dispersed bubbles, the gas mobility and the GOR remains low, the pressure decline slower and the oil recovery becomes high (Alshmakhy and Maini, 2012). This type of flow is typical in primary production of live oil. However, it has also been identified in cyclic solvent injection processes (Qazvini Firouz and Torabi, 2012; Bjorndalen *et al.*, 2012; Jamaloei, 2013; Sun *et al.*, 2016).

2.4.4. Oil Swelling

Oil swelling occurs due to solvent dissolution to the heavy oil, which can increase the oil mobility, oil saturation and therefore improve the oil relative permeability (Tharanivasan *et al.*, 2006). The ratio of the volume of the solvent-saturated heavy oil to the volume of the original heavy oil is known as the oil swelling factor. This mechanism is proportional to the solubility of the solvent and therefore dependent on pressure.

Yang and Gu (2006) measured the solvent diffusion and oil swelling factors of different solvents and mixtures of them. They found that solvent diffusion and oil swelling factors of both pure

solvents and mixtures increased with pressure. Among the considered solvents, propane was found to have the largest oil swelling factor of 1.502 at 0.9 MPa.

2.4.5. Gravity Drainage

Gravity drainage was recognized as being one production mechanism during the cyclic stimulation of Cold Lake heavy oil with supercritical ethane. In this study, (Lim *et al.*, 1995) injected ethane at 4.9 MPa into a horizontal injector-producer well located at the base of a three-dimensional physical model. At early times of the production phase, oil production was dominated by the near well inflow mechanism. When the bitumen around the wellbore was mostly produced, the flow rates rapidly declined. Subsequently, the bitumen rate increased as an effect of the growing solvent chamber and gravity forces on draining the diluted oil.

Wu and Kantzas (2008) conducted horizontal and vertical mode injections of pure propane and a solvent mixture of 40% CH₄ and 60% C₃H₈ in cylindrical sandpacks of 38% porosity and 19 D permeability. Horizontal and vertical flooding tests were both conducted at different operating pressures to evaluate the effect of gravity and viscous forces in oil recovery. From all horizontal tests, they obtained low oil recovery factors along with high solvent-oil ratios (SOR).

CT images from the core at the end of the horizontal tests are shown in Figure 2-9. The color legend represents the density, where red and blue are high and low density respectively. These images show how gas fingered through the upper part of the model (green zone) due to gravity segregation of gas, leaving large upswept areas along the core (red regions). The gravity segregation occurred due to the lower density of the displacing solvent compared to the heavy oil. This led the displacing solvent to move preferentially towards the top of the core. During vertical

flooding, much more cumulative oil was obtained for all operation pressures, and the SOR considerably dropped. Figure 2-10 shows the CT images of the core after vertical tests. It is evident that significant improvement of the sweep efficiency compared to horizontal tests, which indicates the beneficial role of gravity forces on the crossflow mixing between solvent gas and heavy oil in the un-swept area and the stabilization of the displacement. They concluded that during solvent gas flooding, gravitational forces play a more important role than viscous forces and assuring a gravity-stable front is essential for the success of these type of processes. These results were in agreement with the core flooding results obtained by Salama and Kantzas (2005), which stated that vertical solvent floods were more efficient in terms of heavy oil recovery and amount of solvent required than horizontal floods even in a small (30 cm length) linear core.

Figure 2-9: CT images after last horizontal test. Adapted from (Wu and Kantzas, 2008).

Figure 2-10: CT images after last vertical test. Adapted from (Wu and Kantzas, 2008).

Ivory *et al.* (2010) conducted a 6-injection cycle of a 28% C₃H₈ – 72% CO₂ solvent mixture for long production times (roughly 60 days) and slow depletion rates (5 kPa/h). They used a stepped cone sandpack model vertically configured which successfully produced 43.6% OOIP. Even though Ivory *et al.* obtained favorable oil recovery through these operative conditions, they did not conduct a comparison discussion with CSI tests run with the model horizontally positioned.

2.5. Pilot/Field CSI Applications in Canada

The Joint Implementation of Vapour Extraction (JIVE) solvent pilot project ran from 2006 through 2010 was the first large-scale field trial of CSI in post-CHOPS Canadian reservoirs. This project was conducted with a consortium of operators such as Nexen-CNOOC, Husky and Canadian Natural Resources Limited (CNRL) (Kristoff *et al.*, 2008).

The Mervin Cold Solvent EOR pilot was conducted in 2010 by Husky in the province of Saskatchewan to test CSI and solvent flooding processes in three separate reservoirs (Husky Energy, 2011). The CSI method was applied to two wells to the Colony formation with a 3.5 m thickness, 31% porosity, and 20% initial water saturation. Pure CO₂ and a mixture of CO₂ and C₃H₈ were injected at pressures ranging between 3,100 to 3,570 kPa. The cumulative solvent injection from 2 cycles for one of the wells was 7,390 e³sm³ in a period of 14 months (injection and soaking). The cumulative oil production at the end of the second cycle was 2,810 m³ in a production period of 17 months. The percentage of solvent injected recovered during the production of the first cycle was 85 %. Results from well # 2 to date are not fully reported (Husky Energy, 2011). Although the results are not available, the field pilot seems to be successful as field trials are being expanded to commercial cyclic CO₂ injection schemes. (Husky Energy, 2011).

Another Huff and Puff pilot was conducted in two vertical wells of Plover Lake by Nexen-CNOOC. Three solvent injection and production cycles were run using three different solvent compositions: 95 % C_3H_8 – 5 % CH_4 , 80 % C_4H_{10} – 20 % CH_4 , and 71 % CH_4 – 29% C_4H_{10} . The results obtained from the CSI pilot test described the presence of different physics and mechanisms: 1) Gravity drainage of lighter oil was occurring. 2) Solvent diffuses into oil and creates a solvent/oil layer. 3) Solvent injected is contained near wellbore. 4) Water production was reduced from 9 m³/d to less than 0.8 m³/d. 5) Wormholes enhanced solvent contact with heavy oil. 6) Oil rates of 1.4 – 1.9 m³/d. 7) Oil viscosity reduced from 3,868 mPa·s to 1,781 mPa·s. The vertical CSI pilot was found to be not effective due to limitations in the growth of the gas chamber and rapid declination of oil production rates. However, the results were very encouraging to conduct a follow up pilot with horizontal wells (Nexen Inc., 2006).

Imperial Oil Resources is conducting a CSI pilot at Cold Lake in the Clearwater formation to evaluate the effectiveness of injecting propane and other solvent mixtures in horizontal wells for heavy oil recovery. Results from this pilot have not been released since 2012, when the project was still in its construction phase (Imperial Oil Resources, 2012).

2.6. Summary and Future Work

Recently, the cyclic solvent injection process has received a great deal of attention because of its relative ease of implementation, cost-effectiveness, and applicability in thin post-CHOPS reservoirs. This process has been field-piloted by operators such as Nexen-CNOOC, Husky, Canadian Natural Resources Limited (CNRL) and Imperial Oil Resources in different assets located in Saskatchewan and Alberta. Although updated production data from these pilots is not

available, it seems that some of these CSI pilot schemes have been promising as they are being extended to commercial cyclic CO₂ applications. (Husky Energy, 2011).

Previous experimental studies have shown that heavy oil recovery during the CSI process is affected by different variables such as diffusion and convection (Ahadi and Torabi, 2018), gravity drainage (Ivory *et al.*, 2010), pressure depletion rate (Du, *et al.*, 2014), foamy oil flow (Bjorndalen, *et al.*, 2012), the presence of wormholes (Du *et al.*, 2015), type of solvent (Qazvini Firouz and Torabi, 2014; Qi, 2005) and solvent injection sequence (Jamaloei *et al.*, 2012; 2013). However, experimental results associated with heavy oil recovery obtained by different authors vary when compared to each other and to field applications.

In the field, CSI is run at much slower pressure gradients than in the laboratory, and it is possible to get continued production of oil out of multiple cycles. On the contrary, some laboratory studies (Zhang and Kantzas, 2014; Alshmakhy and Maini, 2012) conducted in horizontally aligned cores (gravity drainage was neglected) at rapid depletion rates (112 kPa/h – 140 kPa/h) did not get significant oil recovery after two production cycles.

This indicates that there are different mechanisms present between the laboratory and the field that need to be further investigated to be able to properly model CSI in small physical models. Although gravity drainage has been suggested as an important aspect in the success of previous solvent flooding field experiences (Fred and Stalkup, 1983), none of the previous laboratory works have investigated the effect of gravity drainage in CSI process for heavy oil reservoirs. Therefore, one of the main objectives of this study is to evaluate the gravity drainage as a possible mechanism for obtaining repeatable CSI cycles in the field.

On the other hand, another parameter that needs to be understood is the effect of solvent concentration. Different studies have indicated the ability of C_3H_8 over CH_4 and CO_2 to dissolve into the oil and reduce its viscosity especially when propane is injected in gaseous phase (pressures below its dew point). However, in Western Canada, where reservoir pressures range between 2,000 to 3,500 kPa, propane mixtures with carrier gases such as CO_2 and CH_4 are preferentially used to guarantee that the saturation pressure of the injected solvent is higher than the reservoir pressure. An important parameter in the use of solvent mixtures is the release rate of the solvent from solution. The slow release of solvent leads to oil viscosity remaining close to its live oil value during depletion. Hence, an optimal solvent mixture will be a balance between a slow release of solvent and re-pressurization of the system.

As most current CSI lab works have been done mainly with pure solvents, this study also intends to investigate the effect of two different $C_3H_8 - CH_4$ solvent concentrations in the recovery of heavy oil under slow and fast depletion rates.

CSI cycles will be run at different depletion rates to: 1) Evaluate the rate of release of solvent during the depletion. 2) Investigate how the effects of gravity can be enhanced when drawdown rates are similar to the rates achieved in the field.

Therefore, this experimental approach will involve the investigation of several mechanisms behind the CSI such as gravity drainage, depletion rate, solvent concentration and initial oil saturation responsible for enhancing oil recovery in field applications.

3. CHAPTER THREE: EXPERIMENTAL METHODOLOGY

3.1. Introduction

Laboratory studies and numerical simulation studies are essential to understand the main mechanisms behind EOR processes and evaluate uncertainties and optimization strategies to achieve maximum efficiency during field applications. In order to appropriately reproduce the field conditions and predict field data, laboratory experiments have to consider more realistic conditions. Researches vary several parameters such as fluid properties (viscosity and GOR), physical model properties (porosity, permeability, pore pressure, initial fluid saturations) and drawdown rate to evaluate the CSI applicability.

This study aims to conduct CSI experiments in primary depleted physical models (sandpacks), considering pressure ranges, sandpack and fluid properties that allow for a better representation of post-CHOPS reservoir parameters. Three different sandpacks saturated with heavy oil were used to study the effect of gravity, depletion rate, solvent composition, and initial oil saturation on the performance of the CSI process.

3.2. Experimental Preparation

The preparation of the sandpack involved the use of a core holder, a sand packing process, and packing assess through CT (Computed Tomography) scanning. For the saturation process, fluids were prepared, and their properties were posteriorly measured.

3.2.1. Core Holder

In order to CT scan the sandpack for the experimental purposes, an x-ray transparent Fibreglas core holder of 65 cm length and 9.5 cm inner diameter was used (Figure 3-1).

To prevent chemical reactions between the core holder and solvents for the injection process, a shrink tube of 8.9 cm diameter and 45.7 cm length and a rubber sleeve of 8.9 cm inner diameter and same length were used. Instead of pouring the sand directly inside the core holder, the shrink tube was packed, then placed inside the rubber sleeve, and finally positioned into the Fibreglas core holder.

Overburden pressure was added by filling the gap between the core holder and the rubber sleeve with water. Apart from transmitting the overburden pressure to the system, the rubber sleeve helped to isolate water in the overburden from leaking into the sandpack.

Figure 3-1: Fibreglas core holder.

3.2.2. Core Packing

Lane Mountain (LM) silica sand 50 and 70 were mixed and sieved in a proportion of 50-50% to build the sandpack model. The particle size distribution is plotted in (Figure 3-2). The LM 50 and LM 70 sand has a mean particle size of 255 μm and 177 μm respectively.

For the sand packing process, the shrink tube was shrunk with heating to wrap around a steel tube of 8.9 cm. Then, the sand was poured into the shrink tube until reach 38 cm height. The pore volume was estimated with the bulk volume of the tube and the weight of the sand used to fill it. The shrink tube was positioned inside the rubber sleeve to be posteriorly attached to a vibrating device for 1 hour to obtain a more settled sandpack and uniform sand distribution. Two 325 mesh size sieves were positioned at the inlet and outlet mandrels to avoid sand production.

Figure 3-2: Particle size distribution of sand used in packed core.

3.2.3. Leaking Test

Once the sleeve was placed inside the core holder, nitrogen was injected at 6,894 kPa (1,000 psi) through the overburden port to pressurize the sandpack. To test for possible leakages, the pressure was monitored for several days. No pressure drops at constant temperature were an indication of proper sealing of the sandpack.

3.2.4. Overburden Pressure

After confirming no communication between the overburden and the sandpack, the nitrogen gas was released, and water was injected into the annulus (overburden) at 6,894 kPa. By applying hydraulic pressure in the annulus of the core holder, the confining pressure present in oil and gas reservoirs was simulated in the laboratory. Same as the leak test, the pressure and temperature were monitored.

3.2.5. Vacuum Saturation

Before starting the saturation of the sandpack with water, it was very important to remove all the air that could be trapped into the system. Displacement of air with CO₂ is a very effective technique to easily eliminate all the air present in the system. Therefore, the core holder was first flushed with CO₂ and then connected to a vacuum pump for 9 hours to assure free-gas conditions in the sandpack.

3.2.6. Computed Tomography (CT) Scanning

3.2.6.1. Calibration curve

To verify the uniformity and tightness of the sandpack, Computed Tomography (CT) was employed before carrying out the saturation process. This technique uses X-ray technology to visualize cross-sectional slices of the sample. The CT scanner employed in this study corresponds to a third generation General Electric CT/i scanner. This means that the X-ray source rotates along the detectors around the sample. The CT images are generated by measuring the attenuation of x-rays after passing through the sample. For high-density objects, the attenuation of the X-rays is greater as the object absorb more photons.

Since experimental conditions, such as atmospheric pressure, temperature, and humidity affect the average CT numbers, a calibration curve was built for every scan. Six standards (materials of known density) were positioned inside the Fibreglas core holder to be CT scanned and measure their average CT numbers (Figure 3-3).

Figure 3-3: Standards used for calibration of the CT scanner.

Then, the density and CT numbers were plotted to obtain an equation in function of both variables as Equation (3.2-1) and Figure 3-4 show:

$$\text{Density} = m * \text{CT number} + b \quad (3.2-1)$$

Where m corresponds to the slope of the line, and b to the y-intercept.

Figure 3-4: Calibration of CT scanner using real density.

Note that for all the scanning processes, the same voltage of 120 kV and amperage of 80 mA were applied. In addition, the image thickness was defined as 3 mm with an interval of 5 mm per image. After calibration of the CT, the sandpack was positioned inside the core holder to be axially scanned at intervals of 5 mm. By plotting the density versus the sandpack length, it was possible to recognize the presence of cracks, patterns or sand layers. As shown in Figure 3-5, sandpack # 1 was evenly packed except by its inlet. The low density at the inlet was attributed to a shorter time of the poured volume of sand on the vibrator machine. The low peaks observed in the plot indicated the presence of bottom sand layers created during short interruptions in the sand pouring. These pauses caused trapping of air, and therefore looser packing in these zones.

The CT numbers obtained from the scanning of the dry sandpack indicated that the average porosity of the medium was 37.3%.

Figure 3-5: Porosity vs. depth profile of dry core # 1.

3.2.6.2. Porosity Estimation

The absolute porosity corresponds to the ratio of the pore space to the bulk volume of the core.

This rock property can be estimated using the following equation:

$$\varphi = \frac{(\rho_g - \rho_b)}{(\rho_g - \rho_f)} \quad (3.2-2)$$

Where, φ is the porosity, ρ_g is the grain density, ρ_b is the measured density through the CT, and ρ_f is the fluid density.

A grain density of 2,650 kg/m³ was assumed for the porosity calculation which is roughly the grain density of the sand employed for the packing. The measured density corresponds to the density values obtained from the CT images processing. The fluid density refers to the fluid inside the pores. For the dry and water saturated core, the porosity was determined with the density of air and water respectively.

3.2.6.3. Gas Saturation

CT scanning is also employed to estimate the gas volume fraction that remains in the porous media after the primary production and the cyclic solvent injection. For this purpose, the profile gas saturation was estimated with the CT numbers from each stage of the process (i.e. primary depletion and CSI cycles) using Equation (3.2-3):

$$S_g = \frac{CTn_{brine} - CTn_{fluid}}{CTn_{brine} - CTn_{dry}} \quad (3.2-3)$$

Where, CTn_{dry} —CT numbers when core is dry, CTn_{brine} —CT numbers when core is saturated with water, CTn_{fluid} —CT numbers after the end of primary production or CSI cycles.

3.2.7. Fluid Preparation

3.2.7.1.Brine.

The brine was prepared by mixing NaCl with deionized water at 2wt. % solution concentration. using a magnetic mixer. After pouring the brine into a piston cylinder, a vacuum pump was connected to the top of the vessel for 3 hours to remove the trapped air. From this procedure, the brine was considered free of air, and ready to saturate the sandpack.

3.2.7.2.Dead Oil.

The dead oil used for all experiments came from the Colony formation of Cold Lake, Alberta. The oil buckets contained sand on the bottom, thus the oil was transferred to new containers using a tablespoon to avoid sand lifting. As the oil contained water, Nuclear Magnetic Resonance (NMR) relaxometry was employed to measure the water cut. The percentage of water in the oil was found to be 9.6%. Water was not removed by heating since it was desired to keep the light components in the oil. On the other hand, given the large amounts of oil required for the current experiments, centrifugation could not be carried out. Therefore, dead oil samples were kept with 9.6% of water cut.

3.2.7.3.Live Oil.

Live oil was prepared by mixing methane with dead oil at 2,413 kPa (350 psi). Dead heavy oil was poured into a 6 L piston cylinder which was connected to a driver mixer controlled by an air pump

(see Figure 3-6). A stainless-steel ball was put into the mixing cylinder to roll and help gas and oil to mix during the rocking of the vessel. Then, a pressured methane cylinder was connected to the top of the mixing cylinder to inject the gas at the desired bubble pressure, which was set at 2,413 kPa (350 psi). After disconnecting the gas supply, the bottom part of the mixing cylinder was connected to an ISCO pump to keep the pressure inside the vessel. The pressure was monitored with two pressure transducers connected at the top and the bottom of the cylinder. When the pressure was stable and the pump rate in the ISCO pump was approximately zero, the cylinder was shut in and the pump was disconnected. If pressure dropped after the cylinder had been isolated, it meant that oil was not saturated. Therefore, methane supply was recharged in and the mixing process continued until no pressure changes were recorded. This process took around 2 weeks to be completed.

Figure 3-6: Live oil mixer unit.

3.2.7.1.Solvent Mixture

Two different sets of CSI tests were conducted using two different solvent mixtures of methane and propane: 70% CH₄ – 30% C₃H₈ (mixture # 1) and 85% CH₄ – 15% C₃H₈ (mixture # 2). Using VMG software, a phase envelope was generated for the mixtures to determine the range of pressure and temperature at which both mixtures were in vapor phase (see Figure 3-7).

To prepare a volume of 3,500 cm³ (equivalent volume of transfer cylinder at atmospheric pressure and room temperature), the total number of moles was calculated using a mixing pressure of 2,758 kPa and 23°C. Then, according to the pre-specified mole percent of each gas mixture, the mole number of propane and methane was calculated. Using propane density at 2,820 kPa and 23°C, the liquid volume of propane required to achieve the desired mixture was determined. Then, methane was transferred into a transfer cylinder at 2,758 kPa until occupying a volume of 3,500 cm³. This was verified by collecting 3,500 cm³ of water from the transfer cylinder outlet. After that, the previously calculated volume of propane was added to the transfer cylinder at 2,820 kPa while another pump was connected to the bottom part of the transfer cylinder to drain water and keep a constant pressure.

Table 3-1 shows the properties of each solvent mixture. The mixture was considered ready when no more changes in the pump volume were seen. Finally, to verify the mole percent of each mixture, a sample of gas was taken from the transfer cylinder and defined using gas chromatography analysis (Varian CP-4900 Micro-GC). The purities of methane and propane (Praxair, Canada) used in this study were equal to 99.97 mol.% and 99.5 wt.%, respectively.

Figure 3-7: Solvent phase behavior during CSI for mixture # 1.

Table 3-1: Properties of the solvent mixtures of methane and propane.

Solvent mixture	Mole ratio	P_{mix} (kPa)	T_{mix} (°C)	V_{mix} (cm ³)	n_{mix}	$n_{propane}$	$n_{methane}$
1	70% CH ₄ – 30% C ₃ H ₈	2,758	23	3,500	5.87	1.75	4.12
2	85% CH ₄ – 15% C ₃ H ₈	2,758	23	3,500	4.85	0.73	4.12

3.3. Measurement of Fluids and Sandpack Properties

3.3.1. Dead Oil density

Dead oil density was measured with an Anton Parr DMA 4100 densitometer. This apparatus measures the density based on the frequency of oscillation of a U-tube mounted on a counter mass. The densitometer was first calibrated with air and water at 15°C. Then, oil density was measured at different temperatures within a range of 15°C up to 80°C. Measurements were started from the highest temperature (80°C) to eliminate air bubbles in the sample. The dead oil density at 21°C

was determined to be 989.5 kg/m^3 . Table 3-2 and Figure 3-8 show the obtained density values at different temperatures.

Figure 3-8: Dead oil density at multiples temperatures.

Table 3-2: Dead oil density measurements.

Temperature (°C)	ρ (g/cm³)
15	0.9925
20	0.9898
21	0.9895
25	0.9866
40	0.9765
60	0.9560
80	0.9388

3.3.2. Dead Oil Viscosity

To determine the dead oil viscosity at multiple temperatures, a LVDV-III Ultra Programmable Rheometer and a HBDV-II+ Pro viscometer with cone spindle/sample cup design were employed for low and high viscous oil samples measurements.

The oil viscosity was measured with the HBDV-II+ Pro viscometer for temperatures from 20°C to 40°C. At temperatures over 40°C, the viscosity measurements were done by using the LVDV-III Ultra Programmable Rheometer. The viscometer has a measurement accuracy of 1% of the full-scale range. During the viscosity measurements, the temperature is kept constant with heating circulating water bath with an accuracy of ± 0.1 °C. These viscometers work by measuring the shear stress exerted by the fluid when a spindle rotates in the sample at given shear rates. The viscosity of the oil is then obtained from the ratio between the applied shear stress (torque) and rate of shear (rpm) of the oil, including specific constants related to the viscometer reference and type of spindle.

Before measuring the sample oil viscosity, the viscometer was calibrated with a standard fluid at 3 rotational speeds to verify the apparatus response for low, medium, and high % torques. To measure the viscosity from 20°C to 80°C, the viscometer was connected to a temperature-controlled bath. Then, the spindle was rotated at 5 different rpm and the respective torque was recorded.

Figure 3-9 and Table 3-3 shows the exponential dependence between temperature and oil viscosity measured data.

Figure 3-9: Dead oil viscosity at multiple temperatures.

Table 3-3: Dead oil viscosity measurements.

Temperature (°C)	Viscosity (mPa·s)
20	30,365
21	27,190
25	16,325
40	3,550
60	634
80	181

3.3.3. Live Oil Density

To calculate the live oil density, a vessel of known volume was weighted when was empty, filled with water, and filled with live oil. The mass difference of the filled (water) and empty vessel was calculated and using the water density at the ambient temperature, the volume of the vessel was determined. Then, the mass difference was again estimated, but this time with the vessel filled with live oil. Finally, dividing the mass of live oil by the calculated volume of the vessel, the measured density of live oil is 984 kg/m^3 at 21°C . Figure 3-10 shows the set-up used to measure the live oil density.

Figure 3-10: Set-up for live oi density measurement.

3.3.4. Live Oil Viscosity

Live oil viscosity is measured with a capillary tube viscometer using the Hagen-Poiseuille equation. A capillary tube of 0.32 cm (1/8 inch) OD is connected to two high-pressure piston cylinders. One contains the mixed live oil to be injected at the inlet of the capillary tube, and the other one is used to receive the oil at the outlet of it. Each cylinder is connected to an ISCO pump so that a constant flow rate and a static system pressure (equal to the bubble point) are set at the upstream and downstream of the capillary tube respectively. A series of differential pressure

transducers monitor the pressure drop across the stainless-steel tube, and a controlled oven is used to keep the desired temperature (Figure 3-11). The procedure consisted of injecting live oil at different constant flow rates and reading the stabilized differential pressure at each rate. Then, the live oil viscosity is calculated from the slope of the differential pressure versus flow rate plot using the Hagen-Poiseuille equation. The measured live oil viscosity at 21°C is 9,530 mPa·s.

Figure 3-11: Set-up for live oil viscosity measurement.

3.3.5. Gas Oil Ratio

The gas oil ratio (GOR) measurement required the use of a piston cylinder, an ISCO pump, a graduated cylinder, and a sampler vial. The piston cylinder that contains the live oil above the bubble-point pressure is connected to an empty vial of known weight which in turn is connected to an inverted graduated cylinder submerged in water (Figure 3-12). The live oil is pumped at constant pressure (2,413 kPa) until reach approximately 2 ml in the vial. As the water is initially vacuumed to a determined level on the graduated cylinder, the released gas on the vial expands

through the line that connects to the submerged inverted cylinder. Therefore, as the gas expands inside the cylinder, the water level decreases. When the pump is stopped, the vial is weighted again to determine the dead oil volume, and the level on the graduated cylinder is recorded to calculate the volume of gas. This procedure is repeated several times to assure the repeatability of the results. The measured gas-oil ratio obtained was 7 scm³/cm³. Table 3-4 summarizes the dead oil and live oil density properties.

Figure 3-12: Set-up for gas oil ratio measurement.

The characterization of the sandpack consisted of measuring its pore volume, porosity, absolute and effective permeability, and the connate water saturation. The CT scanner was employed to have an additional estimation of some of the properties such as porosity and fluid saturations.

Table 3-4: Dead oil and live oil density properties.

	Dead Oil	Live Oil
Density (g/cm ³) at 21° C	0.9895	0.9840
Viscosity (mPa·s) at 21° C	30,365	9,530
GOR (cm ³ /cm ³) at 21° C	-	7.07
P_b (kPa)	-	2,413

3.3.6. Pore Volume and Porosity

Before conducting the brine saturation, it was necessary to measure the dead volumes in the system. This volume considered the dead volume of lines and mandrels. For their calculation, water was used to fill the empty volume and from weight difference, the volume was obtained. As mentioned above, the sandpack and lines were previously vacuumed before to start the saturation with brine. A piston-cylinder filled with brine was connected to the pump, and brine injection was initiated into the horizontally positioned sandpack at a constant pressure of 552 kPa (80 psi).

The initial volume of water in the pump was recorded, and when the pressure at the sandpack stabilized at 552 kPa, the final volume in the pump was also recorded. For the pore volume estimation, the dead line volume was subtracted from the total volume of the injected water. To calculate the porosity of the sandpack, the volume of brine was divided by the core bulk volume previously determined with its dimensions. To verify the full saturation of the physical model, CT scan was conducted after brine saturation.

3.3.7. Absolute Permeability

The absolute permeability was measured using two different methods. The first one consisted of recording the stabilized differential pressure between the inlet and outlet of the sandpack at 4

different brine flow rates. Using Darcy's Law, the flow rate vs. differential pressure was plotted for the four measurements, and the slope of the line produced the brine absolute permeability.

In the second method, a constant water head pressure was kept at the inlet of the core. Brine was flowed through the sandpack and the flow rate was calculated by recording the weight of the produced water per unit of time. This procedure was repeated at 4 different heights of brine head. Same as the first method, the pressure drop was plotted against the measured flow rates, and the absolute permeability was obtained from the slope of the line using Darcy's Law (see Appendix B). This technique was employed when the transducer sensibility was not appropriate for low differential pressures.

3.3.8. Connate Water Saturation and OOIP

After the brine permeability measurement, a piston-cylinder filled with water was connected from the top to the outlet of the core holder and from the bottom to the back-pressure regulator (BPR). This set-up was done to avoid the plugging of the BPR due to the direct flowing of heavy oil from the core holder to the BPR. Then, the sandpack was pressurized with water above the bubble point pressure. The piston cylinder and BPR were also set at this pressure. The core holder was vertically positioned to start the live oil saturation from the top to the bottom. An ISCO pump was used to inject the live oil at a constant rate of 10 ml/h. The produced water coming out from the piston cylinder was measured with a balance positioned at the outlet of the BPR. To measure the volume of water, oil, and gas coming out from the core, several samples were taken during the progress of the test to then being measured using the NMR and the gas chromatographer. The connate water saturation was estimated from the difference between the pore volume and the total produced water. Similarly, the original live oil in place was calculated as the difference between the pore

volume and the connate water saturation. The sandpack saturation with live oil was ended after injecting between 1.2 to 1.8 PV. When the water cut and GOR measurements from samples were constant, the core was considered completely saturated. CT scanning was conducted after live oil saturation. The CT density-depth profile plots after live oil saturation are shown in the following chapters.

3.3.9. NMR Testing

The low field Nuclear Magnetic Resonance (NMR) was used to measure the mass fraction of the produced oil and water during the primary production and cyclic solvent injection. The NMR measurements were obtained with an Ecotek low field relaxometer, which operates at a frequency of around 1.2 MHz.

Low field NMR records the response of hydrogen protons in the presence of an imposed magnetic field. Protons are present in oil and water, thus NMR signals come only from these fluids, and not from the surrounding rock. During NMR tests, protons align in the direction of the external magnetic field lines. Then, radio-frequency (RF) pulses are sent to the protons, which make them to tip onto a transverse plane. Protons bang into other protons and with the surrounding medium, giving off energy while they return to its original position in the longitudinal plane. An inversion software converts the measured signal loss on the transverse plane (decay data) into a distribution of amplitudes and their associated relaxation time (T_2) (Coates *et al.*, 1999).

Fluids can relax due to different mechanisms. For liquids not contained in porous media, relaxation occurs by protons banging into other protons, this process is called “bulk relaxation”. When it comes to multi-component mixtures, a distribution of T_2 values is obtained instead of a single one. A T_2 distribution can be represented by a mean T_2 known as the “geometric mean relaxation time”

(T_{2gm}). In bulk liquid systems, relaxation is controlled by bulk relaxation (T_{2B}), which is inversely proportional to viscosity (Bryan *et al.*, 2005). In viscous fluids, the NMR bulk relaxation occurs quickly. As flow in the liquid molecules is restricted, energy supplied by the NMR can be quickly transferred between protons and, therefore they relaxed faster.

To determine the water cut of a sample, a cut off is used to separate the signals from oil and water. The relaxation time for water is around 2,500 ms whereas for viscous oil is around 10 ms (Coates *et al.*, 1999).

Figure 3-13 shows the NMR measured relaxation time of the heavy oil used in this study converted into a T_2 distribution using on in-house inversion software. For all the NMR measurements of the present work, the parameters were defined at an echo spacing of 0.34 ms, 7,395 echoes, 32 trains and a 12s of repolarization time.

Figure 3-13: NMR signal of heavy oil.

As the signal amplitude is directly proportional to the number of protons present in a sample, then it is also proportional to the mass of fluid (Coates *et al.*, 1999). Hence, the amount of water can be related to the amplitude of the water signal and quantitatively calculated with Equation (3.3-1):

$$m_{water} = \frac{A_w}{AI_w} \quad (3.3-1)$$

Where, m_{water} is the mass of water, A_w is the amplitude of water signal and AI_w is the water amplitude index. The term AI_w can be obtained by measuring the water amplitude, A_w , of several water samples with a known mass. Then, the water mass is plotted against the measured amplitude with the NMR, and the AI_w is obtained from the slope of the line. After substituting AI_w in Equation (3.3-1) and obtaining the mass of water, the oil mass can be calculated by mass balance. Figure 3-14 shows that the amplitude index for the measured water samples was 19,259. Then, using this value, the mass of water is calculated. By calculating the error between the measured and calculated mass of water, the accuracy of NMR was determined to be 2.6%.

Figure 3-14: Amplitude index for water.

As NMR machines operate at different signal gain, the oil amplitude index obtained from one to another could vary. Then, a parameter called “relative hydrogen index” (RHI) is used to normalize the measured amplitude index. This term corresponds to the normalized oil amplitude per unit mass, referenced to the amplitude per unit mass of water at the same temperature as shown in Equation (3.3-2).

$$RHI = \frac{AI_{oil}}{AI_{water}} \quad (3.3-2)$$

Water has an RHI=1 and conventional oils will generally have $RHI \approx 1$. RHI and T_{2gm} are related to one another, and both are related to viscosity. When oil viscosity is high, part of the oil signal is lost. This translates into short oil T_{2gm} and low oil RHI ($RHI < 1$). For oil viscosities above 10,000 mPa·s, changes in the (T_{2gm}) are insignificant, therefore the RHI is used as an indicator for viscosity prediction.

3.3.10. Dean-Stark Extraction

After completing all CSI cycles in each core, the core was removed from the core holder, and several sample cuts were taken at different lengths to measure the residual fluid saturations directly through Dean-Stark. A weighted sample is located in the Dean-Stark Soxhlet extraction apparatus (see Figure 3-15) in which water in the sample is vaporized by boiling toluene. Condensed solvent and co-distilled water are continuously separated in a trap designed to recycle the toluene through the extraction thimble, dissolving the bitumen present in the sample, while the water is retained in the trap for volume determination. Extraction continues for about 24 hours until the extracted solvent is clear. Then, the collected samples are heated in an oven at 100°C for one hour to ensure

that irreducible water is completely evaporated. Then, the washed solids that are retained in the thimble are dried and weighed. Finally, the volume of oil is calculated from the weight difference between the initial and dry sample minus the weight of the water removed from it. Lastly, fluid saturations are calculated from the volumes and are plotted vs. length along the core. These results are then plotted against the CT-predicted gas saturation profile to validate observations.

Figure 3-15: Dean-Stark Soxhlet apparatus.

3.4. Experimental Design and Setup

3.4.1. Experimental Design

A series of CSI procedures were designed in this study to evaluate different mechanisms: gravity drainage, depletion rate, and solvent composition. Three sandpack models were used to conduct these experiments. Two of them were first primary depleted and then seven CSI cycles were run. Solvent mixtures of 70% CH_4 – 30% C_3H_8 and 85% CH_4 – 15% C_3H_8 were tested in core #1 and # 2 respectively. In the third core, six CSI cycles were conducted using a solvent mixture of 70% CH_4 – 30% C_3H_8 and primary depletion was not considered. Figure 3-16 and Figure 3-17 shows the experiment methodology used in cores 1-2 and 3 respectively.

Figure 3-16: Experimental procedure for core # 1 and core # 2.

Figure 3-17: Experimental procedure for core # 3.

3.4.2. Experimental Set-up

The experimental rig is comprised of an oil and gas solvent injection system, a core holder containing a sand pack under overburden pressure, and fluids collection system.

A schematic diagram of the CSI experimental set-up is shown in Figure 3-18. The oil and gas injection system consist of an ISCO pump equipped with two piston cylinders in which the live oil (dead oil saturated with methane) and solvent mixture are separate storage at 2,760 kPa (400 psi). During the sandpack saturation step, the live oil is pumped into the top of the model at a constant rate, and water/oil are collected from the bottom of the core.

For the CSI cycles the solvent is injected to the bottom of the pack at a constant pressure, and production is also from the bottom of the pack. The sandpack model is confined in a Fiberglas core-holder. The annulus space contains pressurized water to keep a confining pressure of 6,900 kPa (1,000 psi) on the model. Three pressure transducers are directly connected to the inlet, outlet, and top of the core-holder to record the core pressures (injection, production, and overburden) during the tests. The produced fluids are collected in a piston-cylinder where the pressure is controlled by an ISCO pump connected to the outlet of the cylinder. A digital scale is used to measure the weight of produced oil samples. Gas effluent from the cylinder is measured and sampled with specialized syringes for posterior chromatographic analysis.

Figure 3-18: Schematic of the experimental set-up.

3.5. Experimental Procedures.

To conduct the experimental tests, the sandpack was first tested for leakage using nitrogen, then it was put under vacuum to remove trapped air, and lastly was CT scanned. Brine was then injected into the pack and pore volume and absolute permeability were determined. The pack was again scanned, and then approximately 1.9 PV of live Cold Lake formation oil, which has been previously saturated with CH₄ at 2,413 kPa was flooded from the top of the sandpack to establish the initial oil (OOIP) and connate water saturation (S_{wc}). All live oil mixing and flooding was run at a constant temperature of 21°C. Subsequently, the pack was set horizontally, and the primary production was started from the production end port with the other end of the core closed. The production fluids flowed to the top of the production piston cylinder, as the pump connected to the

bottom of the cylinder kept a constant rate of pressure decline. Periodic oil and gas samples were taken from the piston cylinder as a function of pressure and time. The primary depletion was ended when the outlet pressure reached a set pressure of 310 kPa.

During solvent injection, cores # 1 and # 2 were initially placed in a horizontal configuration for the first two cycles, and then they were flipped vertically for the following five cycles. In the case of core # 3, it was horizontally configured for the first four cycles and flipped vertically for the next 2 cycles. In all CSI cycles, the top of the core was closed, and injection and production were conducted from the bottom (base) of the core. For the horizontal cycle tests, the top and bottom ports correspond to the left and right of the sandpack respectively.

The solvent mixture was injected into the sandpack until the system reached its initial pressure (2,760 kPa). The gas source was disconnected, and core pressure drop was monitored during the diffusion process of the solvent into the oil. Injection and soaking stages lasted about 7 days during each cycle for three sandpack models.

The system was re-pressurized by injecting more solvent; this process was repeated until the system pressure reached the desired pressure and kept constant without the need of additional injection solvent. For the production stage, the bottom of the sandpack was again connected to the production cylinder and the pump was set at a fixed depletion rate (slow or fast) according to the objective of the experiment. The duration of the production stage depended on the depletion rate applied in every cycle, hence the production periods ranged between 1 to 10 days. The process described above represented one complete CSI cycle. Subsequently, the next cycle was commenced following the same procedure at the same laboratory conditions. All tests were

conducted at room temperature (23°C) with maximum fluctuations between 1°C to 2°C. The solvent mixture was kept at 2,760 kPa under which condition the mixture of propane and methane was in the vapor phase. During the test, pressure, volume, and temperature were constantly recorded with a data acquisition system (DAS).

The sandpack was also CT scanned after primary production and at the end of each CSI cycle to generate gas and liquid saturation profiles at every stage of the process. The data acquired from the CT images is essential for this study purposes since it can indicate how gas evolves and fluids redistribute along the sandpack when different pressure depletion rates and model positions are assessed during each CSI cycle. After completion of all cycles, a final step was to take measurements of the post-CSI cores and measure the residual oil saturation directly through Dean-Stark. Also, the viscosity of oil samples taken during every production stage was measured and compared with the viscosity of the original oil.

In total, twenty CSI cycles were completed for all three cores. All experiments were conducted using the same heavy oil sample and silica sand cores. The packing and saturation process were performed following the same procedure to assure similar properties for all cores. Sandpack properties of each core are presented in the following chapters.

Figure 3-16 shows the experimental methodology used for core #1 and #2. Seven cycles were conducted in each core using two different solvent concentrations to evaluate the effect of solvent in the heavy oil recovery. Horizontal and vertical core configurations were used for cycles 1 – 2 and 3 – 7 respectively to examine the effect of gravity forces. The effect of slow and fast depletion rates on the heavy oil recovery was also evaluated during horizontal and vertical cycles (124 kPa/h,

50 kPa/h, and 12.5 kPa/h). Core # 3 flooding was conducted to analyze the effect of high initial oil saturation, for this, the primary production was skipped, and 6 CSI cycles were run at fast depletion rates (Figure 3-17). The operative conditions for each test are explained in detail in the following chapters.

4. CHAPTER FOUR: SANDPACK MODEL ONE

4.1. Introduction

The first objective of this work is to study the role of gravity forces in CSI processes. For this purpose, the first sandpack model was saturated with live oil and then it was depleted under primary production to represent the void space that is left after primary production in real reservoirs. Solvent CSI cycles were run on the core at this depleted state.

A solvent mixture of propane and methane was prepared in a transfer cell with a mole ratio of 30% – 70% with a saturation pressure of 2,758 kPa at 21°C. Two CSI cycles were then conducted with the core horizontally positioned at two different depletion rates to study the effect of viscous forces. Subsequently, the core was flipped to a vertical position and five more CSI cycles were run. The objective of this change was to evaluate the effect of gravity. In addition, pressure was depleted at varying rates of 124 kPa/h, 50 kPa/h, and 12.5 kPa/h during the horizontal and vertical CSI cycles (similar to those applied in the field). This change in rate was studied to investigate the relative importance of viscous forces (pressure gradient) on a system where diluted oil was also able to drain through gravity. After completing each cycle, the core was CT scanned to determine from which region of the core the fluids were produced from, and how the fluids were distributed after every production stage. CT imaging also showed the gas distribution throughout the system and helped to identify gas overriding effects.

The asphaltene content in some of the produced oil samples was also measured to be compared with the original oil value. Finally, the core was removed from the core holder and the residual oil saturations along the post-flooded core were determined through the Dean-Stark method.

4.2. Properties Summary

Table 4-1 shows the dimensions of the core holder and the sand and fluid properties of the sandpack. Due to the sandpack length, oil viscosity, and low permeability, the saturation of the sandpack with live oil was a slow process. Live oil was injected until both water cut and the producing GOR were constant and very close to the original injected values. Around 1.85 pore volumes (PV) of live oil were injected in a period of 12 days.

Table 4-1: Sand and Oil Properties of Core # 1.

Core holder Dimensions		
Length (cm)	63	
Diameter (cm³)	10	
Sandpack Physical Properties		
Diameter (cm)	8.70	
Length (cm)	37.5	
Volume (cm³)	2,204	
Porosity (Fraction)	0.37	
Permeability (D)	1.5	
OOIP (cm³)	720	
S_o (fraction)	0.87	
S_{wi} (fraction)	0.13	
Fluid Properties Summary		
	<u>Dead Oil</u>	<u>Live Oil</u>
Density (g/cm³) at 21° C	0.9895	0.9840
Viscosity (mPa·s) at 21°	30,365	9,530
GOR (cm³/cm³) at 21° C	-	7.07
P_b (kPa)	-	2,413

The sandpack was CT scanned before and after being saturated with live oil. CT density values are converted into porosity and are plotted against the core length. Figure 4-1 (a) shows the CT porosity profile of the dry core, where 0 mm corresponds to the bottom, and the 375 mm to the top of the core. The mean CT porosity was about 38%. Although the core presents some heterogeneity,

the application of overburden stress helped to obtain a good porosity distribution with small porosity variations (<2%). It is important to highlight that during all production stages of the experiment (primary production and CSI cycles), there was no sand production, and hence, the porosity was assumed constant after every process.

Figure 4-1: a) CT porosity profile of dry core. b) CT density profile of dry and saturated core.

Figure 4-1 (b) shows the CT density profile of the core at three different stages of the process: dry core, core after water saturation, and core after live oil injection. As the porosity is constant during each saturation process, the density changes observed from the dry core scans to the water saturation and live oil saturation scans corresponds to the changes in liquid density (fluid saturation) at each scan stage. The changes of density after saturation with water and live oil are proportional in every region of the core, this indicates that fluids were uniformly distributed in the porous media.

4.3. Primary Depletion

Once the sandpack was saturated with live oil, it was horizontally aligned, and primary depletion was run from what was the bottom side which represents the zero length. The model pressure was decreased from 2,760 kPag to a minimum 310 kPag at a pressure depletion rate of 124 kPa/h. The expected duration of the cold production with this fast drawdown rate was about 20 hours. However, the test was extended for an additional 30 hours with the outlet fixed at 310 kPag, until the oil production plateau was reached. The results of the primary depletion are summarized in Table 4-2.

Table 4-2: Heavy Oil Primary Production Summary.

Post-primary production data	
Recovery Factor (%)	14.7
OOIP (cm ³)	720
Volume Oil Produced (cm ³)	105
S_o (fraction)	0.747
S_{wr} (fraction)	0.108
S_g (fraction)	0.145

Figure 4-2 shows the cumulative GOR, oil recovery factor, and pressure drop as a function of time during the primary production test. In the early stage of the depletion, the pressure had a fast-linear decline as the liquid was expanding and no gas was ex-solving. As pressure was reaching the bubble point (2,413 kPa), the gas supersaturation was evidenced as there was no contribution from gas to the pressure maintenance (0 to 7 hours). It was also noted that the pressure gradient within the sandpack was very small (~ 20 kPa). Once the gas started to nucleate, the core pressure slightly increased along with the oil production rate (8 to 13 hours). This was followed by a slowdown in the pressure decline rate while oil production continued increasing due to the foamy oil

mechanism. A clear sign of the effect of foamy oil at this time (14 to 20 hours) was the differential pressure, which was the highest pressure recorded during the process (roughly 112 kPa). The highest oil recovery was achieved during this period which was roughly 75% of the total primary production recovery factor (RF) (see Figure 4-3 (a)). The slow increment in the GOR confirmed that gas remained dispersed into the oil and the gas mobility was low.

When the gas bubbles became large enough, they started to coalesce and form a continuous gas phase, which resulted in a sharp increase in the GOR, and a decline in the oil recovery profile (21 – 25 hours). This trend was expected as there was less methane still in solution, thus oil viscosity increased, and mobility dropped. After this period, the oil recovery remained steady along with a rapid pressure drop. As the critical gas saturation had already been reached, the cumulative GOR increased linearly. At 30 days, the oil recovery factor and GOR became constant and remained this way until the end of depletion. The final oil recovery after 53 hours of primary production was 14.7 %.

Figure 4-2: Fast depletion primary production without sand.

Figure 4-3: a) Pressure drop and oil recovery vs. time during primary production. b) Density profile after live oil injection and primary production.

Once the primary depletion ended, the sandpack was again CT scanned. The output density values given by the CT are plotted along the length of the core, where 0 mm corresponds to the bottom base (injection and production port). Figure 4-3 (b) shows the CT density profiles obtained after live oil injection and primary production. As the primary depletion was conducted without sand production, the porosity is assumed constant after the process. Therefore, the density changes seen through the sandpack are attributed to lower overall fluid density, or the presence of a free gas phase, after primary production. The density profile shows how the density of the fluid decreased through the sandpack after the primary production, with higher decrements towards the bottom part of the core. This indicates that oil was produced along the whole sandpack, specially near the bottom end and there is free gas present throughout.

Table 4-3 shows the results of the material balance calculation for water and gas in the core after primary production. About 1,135 cm³ (22%) methane was left in the core after primary production,

from which 500 cm³ (44%) remained as free gas, and 635 cm³ remained in solution with oil (GOR = 1.03 cm³/cm³).

Table 4-3: Material balance of gas and water after primary production.

Material Balance from Primary Production	
Brine saturation volume (scm ³)	104.92
Volume brine produced (scm ³)	17.61
Brine recovered (%)	16.8
S_{wirr} (%)	10.8
Void space left in core (cm ³)	123.66
S_g (%)	14.5
Methane from live oil (scm ³)	5,089
Methane produced volume (scm ³)	3,954
Remaining methane after primary production (scm ³)	1,135
Remaining methane saturation (% initial gas)	22

4.4. Horizontal CSI Tests

Cycle 1 - Cycle 2: Fast depletion rate (124 kPa/h) – Slow depletion rate (50 kPa/h)

For the first two CSI tests, the sandpack was horizontally aligned and re-pressurized to 2,760 kPa by injecting the solvent mixture from the bottom end. Figure 4-4 shows the sandpack pressure variation and the solvent injection volume during the injection and soaking period of cycle 1. The solvent injection stage is made up of multiple solvent injections and soaking periods over 150 hours. Injection continued until no more pressure drop was observed in the system as a result of the solvent dissolution into the oil. The same injection methodology was applied for the rest of CSI tests. After the solvent injection, the sandpack was put into production at a fast depletion rate (cycle 1) and a slow depletion rate (cycle 2) from the bottom end. Table 4-4 summarizes the experimental conditions and production results from primary production to cycle 2. Note that

during the production period the core was depressurized to 310 kPa and the solvent was always in the vapor phase at the experimental conditions.

Figure 4-5 (a) (b) shows the pressure evolution with time during the production period of cycles 1 and 2. The maximum pressure drop between the top and bottom (inlet and outlet) of the sandpack for cycle 1 and cycle 2 was about 17 kPa and 12.5 kPa respectively. These differential pressures are much lower than the differential pressure present during primary production, which reached up to 110 kPa across the core (see Figure 4-6). After primary depletion, the whole sandpack was left with 15 % void space. Therefore, during the injection periods the vapour solvent could preferentially move and access the remaining oil but also stay as a free gas phase in the larger depleted pores. For this reason, when the production was resumed, the free gas could easily come out from the core without contributing to any driving force and pressure gradient to oil flow. As cycle 1 was rapidly depleted, it was expected to have large pressure gradients that allowed oil to flow before gas could leave solution. However, with the high free gas saturation content along the core, the gas flowed faster, and it was more difficult to create a pressure drop in the system.

Figure 4-4: Core pressure and injection gas volume during injection and soaking periods in cycle 1.

Figure 4-5: Pressure, oil recovery factor and GOR vs. time during the production phase: a) Cycle 1 at a fast depletion rate of 124 kPa/h. b) Cycle 2 at a slow depletion rate of 50 kPa/h.

Figure 4-6: Pressure drop and oil recovery vs. time: a) Cycle 1. b) Cycle 2.

As Table 4-4 shows, the oil recovery under horizontal CSI tests were 0.56% and 0.04 % OOIP for cycles 1 and 2 respectively. Oil recovery, GOR, and pressure as a function of time for cycle 1 are plotted in Figure 4-5 (a). It is observed that the core pressure drops almost linearly during the test without any indication of pressure maintenance. The negligible produced oil volume was achieved at early times (0 to 5 hours) when gas production was still very low. However, the oil production plateau is rapidly reached after 5 hours at the same time the GOR starts to increase linearly. As mentioned before, the absence of a pressure gradient and high free gas saturation led to a high large production of gas accompanied by a negligible volume of oil. In comparison to primary depletion, it is seen how gas production in cycle 1 starts at earlier times and reaches a much higher final value. The high gas mobility at premature times can be a sign of the absence of foamy oil flow (Kumar *et al*, 2000).

To evaluate the effect of pressure depletion during CSI horizontal tests, cycle 2 was conducted at a lower rate of 50 kPa/h. Figure 4-5 (b) shows a worse oil recovery scenario during this cycle. At this lower rate, there is an even smaller driving force for oil to flow so there is no delay in the GOR, but also no oil production as pressure linearly drops. The fact that free gas is present throughout the sandpack causes the gas to expand and flow through preferential paths as pressure declines. The slower depletion rate does not improve the oil recovery response since after cycle 1 there is still more void space and free gas saturation, which makes it even more complex to generate a differential pressure in the system. As the sandpack is horizontally positioned, the flow is governed only by viscous forces (pressure gradient), and therefore the test gives negligible production of oil.

Table 4-4: Experimental production data for primary depletion and horizontal CSI cycles.

Process	Sandpack position	Depletion rate (kPa/h)	Oil production (cm ³)	Oil saturation (fraction)	Oil Recovery (%)	Cumulative oil RF (%)
Primary depletion	Horizontal	124	105.42	0.745	14.65	14.65
Cycle 1	Horizontal	124	4.04	0.740	0.56	15.21
Cycle 2	Horizontal	50	0.30	0.740	0.04	15.25

Figure 4-7 shows the CT images taken at the end of primary production for cycle 1 and cycle 2. It is observed how the bulk density at three different positions along the sandpack (top, middle, and bottom) after cycles 1 and 2 remains almost unchanged compared to the primary production. As the produced oil volume was very small for the horizontal CSI tests, the fluids saturation does not significantly change from one cycle to another one. There is a region of lower density (blue-green tones) on the top walls of the core after cycle 1 and 2. This indicates that the gas fingering occurred at the upper part of the sandpack due to gravity segregation, and it remained there at the end of the production stage.

Figure 4-7: CT images after primary production and horizontal cycles 1 and 2.

4.5. Vertical CSI Tests

Cycle 3 - Cycle 5: Fast depletion rate (124 kPa/h)

For the three following tests, the sandpack was vertically oriented to study the combined effect of gravity and viscous flow on the cyclic solvent injection for recovering additional oil in depleted reservoirs. The injection and production stages were conducted from the bottom (base) port of the model, and the same injection pressure, soaking time, and depletion rate were applied for these tests. In contrast to the horizontal configuration, the vertical CSI tests gave significant incremental oil. The incremental oil recovery factor from vertical cycles 3, 4, and 5 was 3.9 %, 3.8 %, and 4.2% respectively. Figure 4-8 plots the oil recovery factor, GOR, and core pressure during the production phase of CSI cycle 3. Plots for cycle 4 and 5 are presented in Appendix C as production profiles behave pretty much the same for all the three tests. Two important observations were identified from these graphs: 1) the cumulative oil production significantly improved; 2) the produced GOR strongly decreased.

Figure 4-8: Core pressure, oil recovery factor and GOR vs. time during the production phase of cycle 3.

For comparative purposes, the oil RF (%) for the primary production, the two horizontal cycles, and the three vertical cycles were plotted as a function of the core outlet pressure in Figure 4-9. The oil recovery vs. pressure follows the same slope for each of the three vertical cycles, and the final recovery is repeatable for all them. In contrast, horizontal cycles show negligible oil recovery without any production response to the pressure drop in the system. The produced methane (C1) and propane (C3) gas composition during cycles 3, 4, and 5 as a function of pressure is given in Figure 4-10. This plot along with Figure 4-9 led to the definition of three ranges of how oil recovery could be responding against pressure, and possible reasons for this behavior.

At higher pressures (over 2,000 kPa), the pressure vs. oil recovery slope behaves the same for all three cycles. Since propane has a very high solubility in oil, at higher pressures the propane is still dissolved into the oil, and oil viscosity remains low. This is evidenced in Figure 4-10 which shows low propane gas composition in the produced gas at the start of the production period, and most production of methane. As pressure drops, the diluted oil is not viscous enough to trap the methane gas bubbles, thus methane comes out easier from solution contributing less to the pressure maintenance in contrast to its effect in foamy oil during the primary production.

This means that oil production during this pressure range is attributed to gravitational forces that allow for oil to flow through the large empty pores to the production end of the core, and viscous (pressure-driven) flow of solvent-diluted oil. When pressure drops from 2,000 kPa to 1,500 kPa, a reduction in the pressure vs. oil recovery slope is observed. This might be partially explained by the propane evolution and expansion that pushes oil out and increases the oil recovery rate. At pressures below 1,500 kPa, the propane production rate becomes faster, hence oil regains its viscosity and the oil recovery factor rapidly decreases. At these low pressures, propane ex-solution

from oil is clearly observed. The $C_3H_8 / (C_3H_8 + CH_4)$ ratio became very close to the injected propane molar fraction (70% CH_4 – 30% C_3H_8).

The presence of propane in solvent mixtures has shown to improve the solvent solubility and promote foamy oil flow in CSI (Ahadi and Torabi, 2018). However, the minimum DP observed during the vertical CSI depletions indicate the absence of supersaturation and foamy oil flow. Nevertheless, when samples were taken, foamy oil was visually identified as shown in Figure 4-11. It must be emphasized that this is evidence of slow-releasing solvent still present in the more viscous oil even at ambient conditions. The observation of foam in the produced oil does not indicate the presence of the foamy oil mechanism in the core. The low pressure vs. oil recovery slope of the primary production which equates to foamy oil production is not observed in the CSI tests. The sharp slope of oil pressure vs. oil recovery in all the CSI production profiles in Figure 4-9 would imply that the foamy oil mechanism is not present, regardless of the foam observed in the produced oil.

Figure 4-9: Oil recovery factor in function of core outlet pressure for primary production and CSI cycles 3 to 5.

Figure 4-10: Produced gas composition mole (%) in function of core outlet pressure for vertical CSI tests (cycle 3, 4, 5) run at a fast depletion rate of 124 kPa/h.

Figure 4-11: Foams in the solvent-saturated produced oil; taken from production phase during cycle 4.

At the end of every vertical cycle, the core was CT scanned to analyze the fluid's saturation profile.

Figure 4-12 (a) shows a comparison of the core density profile after primary production and at the end of cycle 5. The CT density profile shows a high contrast of density on the top of the core. It is

observed that the density was greatly reduced after the last vertical cycle compared to the original state (end of primary production). The decrease in density at the top of the core indicates the presence of a high free gas saturation region. This explains the reason why there was not any increase in the pressure drop in any of the vertical CSI cycles. On the other hand, at the bottom end (injection and production) of the core, an increase in the bulk density is seen after the end of cycle 5, compared to the core after primary production. This increment in liquid saturation at the lower region of the sandpack suggests the effect of gravity in draining and banking oil towards the production end of the core. This observation infers why during the injection stage for the vertical cycles, it took more time to generate a buildup in pressure and why a repeatable oil recovery factor was obtained for all of them. During each injection/soaking stage, solvent would dilute oil and this oil would drain via gravity to the bottom of the core. Then, during the following production stage, there was a high oil saturation of solvent-diluted oil already near the production end of the core, so repeatable production was obtained in each cycle.

Figure 4-12 (b) illustrates the CT images after the vertical cycle 5. The images taken along the sandpack confirm the theory of gas building up to the top and the oil pooling at the bottom of the core during vertical cycles.

Figure 4-12: CT fluid saturation analysis: a) CT density profile after primary production and cycle 5: b) CT images after primary production, cycle 1 and cycle 5.

The cumulative oil recovery factors are plotted in Figure 4-13. Approximately 15% of the OOIP was recovered after primary production and just 0.6% after horizontal CSI cycles. While during vertical CSI tests, repeatable incremental recovery factors were observed for the three cycles, with a cumulative oil recovery of 12% OOIP from all of them. During the horizontal mode production, the initial high free gas saturation inside the core inhibited a pressure drop between the inlet and outlet of the core that could flow the diluted oil. However, after the core was placed in a vertical position, the gravity segregation effect was advantageous for oil production since it helped to mobilize oil to the bottom end of the core and stabilized the fluid displacement. During the vertical CSI tests, the differential pressure between the two core ports was very small (8 –15 kPa) with few pressure peaks like the differential pressure measured during the horizontal experiments. Figure 4-14 shows the measured DP across the core during cycles 3 and 4. The experiments confirm that

a vertical displacement combined with a fast depletion rate works well for oil recovery in the CSI process, as compared to a poor recovery from the same rates in the horizontal core.

Figure 4-13: Ultimate recovery factor (% OOIP) of primary depletion and CSI cycles 1 to 5.

Figure 4-14: Pressure drop and oil recovery vs. time: a) Cycle 3. b) Cycle 4.

Cycle 6 - Cycle 7: Slow depletion rate (12.5 kPa/h)

By the end of CSI cycle 5, the cumulative oil recovery had reached 28.6 % of the OOIP, and the remaining oil saturation was 65.3%. Up to this point, gravity drainage appeared to affect the heavy oil recovery during CSI cycles when fast pressure depletions were applied. In field CSI operations, production cycles are run for weeks or even months, so pressure decline rates are much slower than what was run in cycles 3 to 5. Cycles 6 and 7 were run at pressure depletion rates 10 times slower than cycle 3 to 5 (12.5 kPa/h) to better represent the pressure depletion rates present in the field and investigate if this parameter would have any effect on improved oil recovery when gravity forces are acting.

Figure 4-15 plots the injection volume of the solvent mixture (30% C₃H₈ + 70% CH₄) and the core outlet pressure during the injection and soaking period of cycle 6. A similar injection and soaking behavior to that seen in previous cycles is observed. The volume of injected gas during these two last cycles did not increase significantly, although there was a larger void space present in the core. As observed in the CT fluid saturation analysis after vertical cycles 3, 4, and 5 there was a redistribution of fluids with mobile oil banking at the bottom of the core. This helped to block some of the open channels present during horizontal cycles, minimize gas fingering, and increase the solvent-heavy oil contact.

Figure 4-15: Core pressure and injection gas volume during injection and soaking periods in cycle 6.

Figure 4-16 (a) (b) shows the oil RF %, GOR, and core pressure curves for cycles 6 and 7. Since a slower pressure depletion rate was applied for these cycles, the system took close to 215 hours to reach its final set point value. As Figure 4-16 illustrates, the oil recovery factor for cycles 6 and 7 were 7.6% and 5.9% respectively. It is observed that the core pressure declined linearly during the test with a very low DP (9 – 12 kPa), same to the pressure range observed during the fast-vertical cycles. The GOR remained stable and low until oil production reached a plateau after about 150 h and 120 h for cycle 6 and 7 respectively. It is observed that the GOR is even lower for cycles 6 and 7 than what was obtained during cycles 3 to 5 where faster depletion rates were applied. This behavior might be attributed to the effect of slow pressure decline. Since the system pressure was not greatly reduced during the production stage, methane and propane gas bubbles released very slowly from the oil phase and hardly formed a continuous phase. This helped to keep the oil viscosity low and therefore, higher oil recovery factors were achieved.

Figure 4-17 (a) (b) presents the oil recovery factor and differential pressure (DP) versus time for the production phase of cycles 6 and 7 respectively. DP is the pressure difference between the inlet and outlet of the sandpack model. For cycles 6 and 7, DP only varied by about 7 – 12 and 8 – 14 kPa respectively which is almost the same as the average DP of cycles 1 – 5 as previously shown in Figure 4-6 and Figure 4-14. The absence of high-pressure gradients and pressure maintenance during cycles 1 – 7 suggests that the foamy oil mechanism is not present during these processes, thus not responsible for high oil recovery rates. This statement agrees with the experimental results of Soh *et al.*, (2018), who found that foamy behavior was reduced by adding propane to live oils saturated with methane. It is noteworthy that, for cycles 6 and 7 in which the highest oil recovery factors were obtained, the oil was produced under minimal pressure drop across the core. 7% OOIP incremental recovery was achieved under the absence of a pressure gradient. Oil flow under low-pressure gradients during vertical cycles might be attributed to the fact that the diluted oil was pooled at the bottom of the core. In other words, the length of the core was reduced to the length of the oil zone (0 – 10 cm, based on the CT density profile). Hence, under low oil viscosity and short length, large DP are not expected even if the flow is still governed by viscous forces.

Figure 4-16: Core pressure, oil recovery factor and GOR vs. time during the production phase: a) Cycle 6. b) Cycle 7.

Figure 4-17: Pressure drop and oil recovery vs. time: a) Cycle 6. b) Cycle 7.

Figure 4-18: Oil recovery factor in function of core outlet pressure for primary production and CSI cycles 3 to 7.

To analyze the effect of depletion rate, the oil RF (%) for the primary production test, the three fast depletion rate vertical cycles, and the two slow depletion rate vertical cycles were plotted as a function of the core outlet pressure in Figure 4-18.

The pressure vs. oil recovery factor profile for cycles 6 and 7 can be analyzed in three different zones according to the core outlet pressure. At high pressures (over 2,550 kPa), the pressure vs. oil recovery slope behaves the same for both cycles. Even in the absence of pressure drive, 50% (cycle 6) and 40% (cycle 7) of the final oil RF was obtained at these high system pressures. Same as during fast vertical cycles, in zone 1, propane remains dissolved into the oil keeping low oil viscosities values and therefore, high oil volumes are mobilized out of the core. When pressure drops to around 1,350 kPa (zone 2), the slope of the trend does not behave linearly anymore. At this pressure range, gas slowly starts evolving from solution, keeping the GOR relatively low; as pressure drops, gas expansion and release exponentially increases, while oil is being drained. It is

observed that this behavior is more pronounced in cycle 6 than cycle 7, resulting in higher oil recovery for the former. This could be attributed to the lower initial oil saturation at the start of cycle 7, where about 35% of the OOIP has already been produced.

The presence of more void space means that a major portion of the solvent tends to occupy the larger pores and leaves the system easily without contributing to oil viscosity reduction. Up to that point, more than 95% of the final oil recovery had been obtained. At pressures below 1,000 kPa, most of the solvent was released from solution, thus oil viscosity has increased, and very little oil is produced.

The slope of oil recovery vs. pressure from cycles 3 to 5 is clearly different from cycles 6 and 7. It is evident that during the slow depletion cycles considerably more oil is produced at all system pressures compared to the higher depletion rate cycles. This behavior might be due to a more stable displacement. Slower pressure depletion likely leads to less gas channeling and fingering through the core, and therefore, the sweep efficiency is higher. Consequently, oil drainage is more effective and oil recovery is improved compared to cycles 3 to 5.

Table 4-5 summarizes the experimental conditions and production results of primary production and all seven CSI cycles. Figure 4-19 shows that during cycles 3 to 5, the incremental oil recovery was repeatable with each subsequent cycle. When, the core was produced at slow depletion rates (12.5 kPa/h) the incremental oil recovery from CSI increased from 12.5 % to 26.01 %, bringing the cumulative oil recovery from primary production and 7 CSI cycles to 40.7 % OOIP.

It is important to highlight that although oil recovery for the vertical slow depletion cycles were higher than cycles 3 to 5, these cycles seem to be more efficient when they are analyzed in terms of pressure. This means that if recovery is analyzed as a function of time, cycles run at higher

depletion rates would be more effective as oil is recovered 10 times faster, hence, additional CSI cycles could be run in the same period of time. However, the results from slow depletion rates tests can be more representative of the behavior observed in the field, where CSI cycles can take anywhere from weeks to months to complete.

Figure 4-20 (a) plots the CT density profile of the final core (post-CSI Cycle 7) compared to the core after CSI Cycle 5. The density profiles follow the same trend in both states, but decrements in density are evident at the 80 – 340 mm interval of the core after cycle 7. This change reflects the fact that there was significant incremental production of oil from the slow depletion rate CSI cycles (13.5% OOIP). The lower density in the core after cycle 7 corresponds to a higher gas saturation since porosity is unchanged in this interval of the core. Towards the bottom end of the core (0 – 80 mm) the density contrast is negligible compared to the core state at the end of cycle 5 (i.e. at the end of the fast-vertical depletion). The similarity of the core density after cycle 5 and 7 at the bottom part indicates that oil saturation is still highest at this zone, as is expected by the continued production of oil in each cycle.

As previously discussed for high depletion rate CSI cycles, at the start of every cycle, there is more void space present in the core. Because of gravity segregation, gas tends to go to the upper side of the core and dissolve into the oil. Then, the diluted oil pools at the bottom end to fill the void space left by the produced oil from previous cycles. When the production phase is resumed, segregated oil at the bottom is produced, and the density at this region remains unchanged when it is compared to previous vertical cycles. This explanation can be supported by Figure 4-20 (b), which illustrates the final state of the core after cycle 7. It is observed that sands in the upper section of the core were cleaned, which means that the oil was mainly produced in this area. A dark section is seen at

the bottom end of the core which supports the pooling of the diluted oil at the bottom. This observation further confirms that gravity forces provide effective displacement and sweep of solvent-diluted oil during vertical systems.

Figure 4-19: Ultimate recovery factor (% OOIP) of primary depletion and CSI cycles 1 to 7.

Figure 4-20: Fluid density distribution: a) CT density profile along post-CSI cycle 5 and final CSI cycle. b) Core final state after conducting all seven CSI cycles.

Table 4-5: Experimental production data for primary depletion and CSI cycles.

Process	Period	Time (h)	Oil		Solvent composition		GOR (scm ³ /cm ³)	Oil Recovery %	Depletion rate (kPa/h)	Injection Pressure (kPa)
			Production (cm ³)	Solvent/gas (scm ³)	(scm ³)					
					CH ₄	C ₃ H ₈				
Depletion	Production	54	105	3,954	3,954	-	-	14.6	124	2,782
Cycle 1 Horiz.	Injection	139		16,080	11,256	4,824				
	Production	47	4.04	7,800	6,994	806	1,931	0.6	124	2,804
Cycle 2 Horiz.	Injection	145		13,503	9,452	4,051				
	Production	71	0.3	8,604	7,462	1,142	28,273	0.04	50	2,799
Cycle 3 Vertical	Injection	146		10,194	7,136	3,058				
	Production	28	28.1	9,119	7,381	1,738	324	3.9	124	2,799
Cycle 4 Vertical	Injection	170		14,667	10,267	4,400				
	Production	28	27.4	10,093	8,302	1,791	314	3.8	124	2,797
Cycle 5 Vertical	Injection	170		13,130	9,191	3,939				
	Production	30	30.1	11,021	8,964	2,057	366	4.2	124	2,827
Cycle 6 Vertical	Injection	188		12,674	8,872	3,802				
	Production	215	54.9	12,634	9,788	2,846	421	7.62	12.4	2,825
Cycle 7 Vertical	Injection	188		12,747	8,923	3,824				
	Production	214	42.4	12,823	10,364	2,459	301	5.89	12.4	2,825

Figure 4-21 compares the injection stage for cycles 1, 3, 5, and 7. It is observed that in early cycles (cycle 1 and 3) more injections were conducted compared to late cycles (cycle 5 and cycle 7). This is attributed to more propane dissolving into the oil during the early soaking steps. As propane is a slow releasing solvent, at later cycles, the oil around the injection port was already saturated with solvent, thus, fewer re-pressurization stages were required. The multiple pressure drops recorded during the horizontal injection cycles in Figure 4-21 (a) show that propane was effectively dissolved into the oil near the interface. Unfortunately, there is insufficient evidence to prove whether pressure traveled through oil compression or solvent dissolution.

Figure 4-21: Core pressure and injection gas volume during injection and soaking periods. a) Cycle 2. b) Cycle 3. c) Cycle 5. d) Cycle 7.

4.6. Dean-Stark Analysis

To determine the residual fluid saturations in the core after the CSI process, the core was measured using the Dean-Stark extraction method. For this, the core was cut in 25 parts, 1.5 – 1.9 cm in length.

Table 4-6 shows the core length at which each sample was taken and the respective fluid and sand mass measurements. Water and sand masses are directly measured through the Dean-Stark method. Oil mass is then calculated by the weight difference between the initial and dry sample minus the weight of the water removed and volumetrically measured during the process. The solids content is converted into solid volumes. Based on the measured residual oil and water volumes and pore volume, the residual oil and water saturations are obtained for each sample. The equations and procedure used to calculate the fluid saturations are presented in Appendix D.

Table 4-6: Core residual oil saturation after CSI cycles using Dean-Stark extraction.

Sample	Range cut (cm)		Fluid (g)	Sand (g)	Oil (g)	Vol water (cm ³)	Vol oil (cm ³)	Vol sand (cm ³)	Porosity (fract.)	PV (cm ³)	So (fract.)
1	0	1.3	27.7	181.3	21.5	6.2	21.7	68.4	0.38	28.7	0.76
2	1.3	2.9	31.6	185.4	25.4	6.2	25.7	70.0	0.38	34.8	0.74
3	2.9	4.5	32.3	183.9	26.8	5.5	27.1	69.4	0.38	34.6	0.78
4	4.5	6.1	32.7	146.3	27.3	5.4	27.6	55.2	0.37	34.6	0.80
5	6.1	7.5	27.5	147.1	21.7	5.8	21.9	55.5	0.37	30.6	0.72
6	7.5	9.1	34.8	199.3	27.7	7.1	28.0	75.2	0.37	34.9	0.80
7	9.1	10.8	25.5	153.5	20.5	5	20.7	57.9	0.37	37.4	0.55
8	10.8	12.4	22.6	152.4	17.7	4.9	17.9	57.5	0.38	35.1	0.51
9	12.4	13.9	15	119.5	11.3	3.7	11.4	45.1	0.37	33.2	0.34
10	13.9	15.5	28.7	185.7	21.9	6.8	22.1	70.1	0.37	35.7	0.62
11	15.5	17	20.9	139.3	17.9	3	18.1	52.6	0.37	33.1	0.55
12	17	18.5	20.2	145.2	17.2	3	17.4	54.8	0.37	33.4	0.52

Sample	Range cut (cm)		Fluid (g)	Sand (g)	Oil (g)	Vol water (cm ³)	Vol oil (cm ³)	Vol sand (cm ³)	Porosity (fract.)	PV (cm ³)	So (fract.)
13	18.5	20	17	148.2	14.6	2.4	14.8	55.9	0.37	33.3	0.44
14	20	21.5	15.2	132.6	12.7	2.5	12.8	50.0	0.37	33.2	0.39
15	21.5	23	11.8	95.9	10	1.8	10.1	36.2	0.37	32.8	0.31
16	23	24.6	16.9	148.7	12.4	4.5	12.5	56.1	0.38	35.5	0.35
17	24.6	26.1	12	127.7	8.5	3.5	8.6	48.2	0.38	33.0	0.26
18	26.1	27.4	14.5	151.6	11.8	2.7	11.9	57.2	0.37	28.8	0.41
19	27.4	28.6	17.2	133.8	12.9	4.3	13.0	50.5	0.37	26.3	0.50
20	28.6	30	15.3	135	11.6	3.7	11.7	50.9	0.37	30.3	0.39
21	30	31.5	15.4	153.4	11.2	4.2	11.3	57.9	0.37	31.8	0.36
22	31.5	33	8.8	126.9	6.5	2.3	6.6	47.9	0.37	32.0	0.21
23	33	34.5	11.4	103	9.2	2.2	9.3	38.9	0.37	32.9	0.28
24	34.5	36	18.3	147.3	14.2	4.1	14.3	55.6	0.37	33.2	0.43
25	36	37.5	18	139.8	13.6	4.4	13.7	52.8	0.38	33.3	0.41

Figure 4-22 shows a comparison between the residual oil saturations along the core length obtained through the CT and Dean-Stark methods respectively. The equations and procedure followed to calculate the saturation from CT data are explained in Appendix A. Saturation profiles obtained by CT are considered more accurate as measurements were taken at 5 mm-core intervals versus the 15-20 mm intervals using Dean-Stark measurements. Despite this, oil saturation profiles show a good match between the predicted CT values and the measured Dean-Stark values. Both curves verify previous observations (see Figure 4-20 (a)) of high gas saturation at the top and fluid pooling at the bottom. If the bottom part of the core is considered from 0 – 91 mm, the average oil saturation by Dean-Stark in this region is about 76%, while oil saturation at the top, from 230 – 375 mm is 35%. In the middle part of the core (91 – 230 mm) the average oil saturation was 47%. This further confirms the influence of gravity drainage on the volumetric sweep efficiency during vertical CSI tests: solvent-diluted oil drains from regions of high gas saturation, resulting in even fluid

displacement and low residual oil saturations. The average oil saturation obtained from the CT data was 52% against 50% from the Dean-Stark method. Note that the oil saturation distribution from CT had already been matched with the average residual oil saturation from the material balance at each cycle. As the cutting process were conducted by hand, it was found that the accuracy of the sample length cut was ± 3 mm.

Figure 4-22: Comparison of residual oil saturations along the core length after CSI cycles using CT and Dean-Stark methods.

As the CSI process was stopped at the 7th cycle, it was not possible to determine the true final oil recovery factor through this method. Therefore, measurements of residual oil saturation through Dean-Stark were primarily conducted to determine the residual fluids at the top of the core. On average, there was still a 50% oil left in the core after 7 CSI cycles, however, at the top (i.e. the well-swept zones) oil saturation dropped down to 30 – 40%. This value represents the endpoint residual oil saturation and the potential final oil recovery that could be obtained from the CSI at these experimental conditions.

5. CHAPTER FIVE: SANDPACK MODEL TWO

5.1. Introduction

Previous experimental studies (Jia, 2014; Qi, 2005; Ivory *et al.*, 2010) have pointed out propane as the most efficient solvent for enhanced heavy oil recovery. From experiments conducted in core # 1 (see Chapter 4), it was found that gravity forces played an important role on the oil recovery when a solvent mixture of 70% CH₄ – 30% C₃H₈ was cyclic injected. To better understand the impact of the solvent composition against the gravity effect on heavy oil recovery when CH₄ partially replaces C₃H₈, a poorer quality solvent mixture of 85% CH₄ – 15% C₃H₈ was used in another core following the same methodology that what was used for core #1 (see Figure 3-16). Primary production and 7 CSI cycles were conducted to perform comparison analyses with sandpack # 1.

In addition to CT and Dean-Stark analyses, produced oil viscosity was also measured and compared with the original oil sample used to saturate the core for all production cycles. The latter measurements provided further data to investigate the effect of solvent composition during CSI processes.

5.2. Properties Summary

Core #2 was packed following the sand packing procedure applied for core # 1 in order to obtain similar sandpack properties and perform comparative analyses between the two set of experiments. Table 5-1 shows a summary of the sand and fluid properties. Volume and sandpack porosity were found to be very close to core # 1 values. However, the measured absolute permeability to brine was about 50% of core # 1's permeability. Due to the low permeability, live oil saturation process took about 30 days to be completed in which 1.41 pore volumes (PV) were flooded through the core under a pressure drop of 1,000 – 2,700 kPa across the core. Figure 5-1 shows the pressure

difference between core inlet and outlet and live oil injection rate against live oil PV injected. The live oil injection was first run at a constant rate of 10 cm³/h. However, during this time period an abnormal pressure buildup was observed at the inlet of the core as live oil was being injected. Inlet pressure was continuously increasing so the pressure at the injection pump was constantly released before it reached its pressure limit. As the flow rate of 10 cm³/h was creating a rapid pressure buildup at the core inlet, the live oil injection was changed to a constant pressure mode after 0.5 PV injected. After several trials, the pump pressure was set at 4,820 kPa (800 psi) to accelerate the saturation process. The pressure behavior in the core was suggesting a possible plugging inside the core. Hence, the system was shut down several times to verify if the pressure transducers were correctly working. After 1.28 PV injected, the system was shut down and valves and lines from the pump to the core inlet were cleaned to remove any type of oil/sand plug. After this, the pressure at the inlet of the core continued increasing, and the saturation process was continued by keeping a pressure limit of 4,820 kPa until produced fluid samples indicated constant water cut and GOR.

Table 5-1: Sand and oil properties of core # 2.

Core holder Dimensions	
Length (cm)	63
Diameter (cm ³)	10
Sandpack Physical Properties	
Area (cm ²)	60.08
Average diameter (cm)	8.73
Length (cm)	36.8
Volume (cm ³)	2,211
Porosity (Fraction)	0.38
Permeability (D)	0.8
OOIP (cm ³)	705
S_o (fraction)	0.83
S_{wi} (fraction)	0.17

Figure 5-1: Differential pressure across the core during live oil saturation.

Figure 5-2: a) CT porosity profile of dry core. b) CT density profile of dry and saturated core.

Figure 5-2 (a) shows the porosity profile of the dry core after being CT scanned. Although the mean CT porosity was also same as core # 1 (~ 0.38 %), the CT porosity profile shows slight porosity variations through the core indicating a more homogenous packing compared to core # 1. The standard deviation of porosity for core # 2 was estimated in 0.0034 against 0.0051 for core # 1. Screen filters were also put at the inlet and outlet of the core to avoid solids production and being able to assume constant porosity through every CSI cycle. It is important to highlight that the improvement in the grain distribution of core # 2 was the result of adding two hours of vibration.

Figure 5-2 (b) shows core bulk density profile after brine and live oil saturation. The changes in liquid density at each stage follow the same trend with length compared to the initial core state (dry). However, bulk density is lower throughout the core, which means it was proportionally saturated with live oil.

5.3. Primary Depletion

Primary production was conducted following the same methodology and experimental conditions as core # 1. However, for this model, the pressure was decreased from 3,050 kPa to a minimum of 280 kPa at a fast drawdown rate of 124 kPa/h. The duration of this test was intended to be 20 hours, however, as the core was experiencing the same abnormal pressure gradient seen during the live oil saturation process, the primary depletion was completed in 203 hours after several attempts to find the cause of the plugging. Table 5-2 summarizes the fluids recovery after primary depletion.

Table 5-2: Heavy oil primary production summary.

Post-primary production data	
Recovery Factor (%)	18
OOIP (cm ³)	705
Volume Oil Produced (cm ³)	127
S_o (fraction)	0.683
S_{wr} (fraction)	0.134
S_g (fraction)	0.182

Figure 5-3 plots the pressure gradient, oil recovery factor, and cumulative GOR vs. time for the primary production. Unlike sandpack # 1, the core inlet and outlet pressures followed a different trend after 12 hours of testing, this indicated that both pressures in the core seemed to be falling at different rates. This behavior was attributed to the plugging in some part in the system. As it is observed, the core outlet pressure dropped linearly (0 – 25 hours) without any response even when the bubble point was reached. After 25 hours, pressure started to follow the same trend as the inlet pressure. However, high DPs (500 – 1,000 kPa) were still evidenced until the end of the test. While inlet pressure was following a typical primary production trend (same as core # 1), the outlet pressure at the production port (outlet) was falling at the same rate as the end pressure (withdrawal pump), this was translated in partial communication between both ports due to the plugging, and therefore, increments in the pressure gradient. Nevertheless, the pressure recorded at the core inlet allowed for the analysis of the production mechanisms during the test.

At the beginning of the primary production, the pressure declined at the pre-specified drawdown rate (124 kPa/h) as CH₄-saturated live oil was still in a single liquid phase. When the inlet pressure was at around 1,900 kPa, or 500 kPa below bubble point pressure (7 – 10 hours), pressure had linearly declined, which indicated the gas supersaturation influence. From 13 – 15 hours, the core pressure at the inlet end slightly increased as dissolved gas started to nucleate and form small gas bubbles. These bubbles promoted the foamy oil flow which was evidenced in the start of oil

production and a slight increase in the GOR. When pressure dropped below 1,800 kPa to 1,500 kPa, the pressure drop rate increased along with the oil recovery factor and GOR. The oil recovery factor from that pressure drop (15 – 22 hours) represented 60% of the total oil RF. This response is attributed to the foamy oil mechanism, which was previously observed in sandpack # 1 at a similar pressure range. Once gas bubbles became larger and started to gather together, the gas mobility increased, resulting in more rapid pressure decline rate, along with a GOR increment. From 25 to 30 hours, the GOR remained constant with a short increment in the oil recovery rate. When oil reached its production plateau of 17%, and the core outlet pressure reached the minimum set pressure (310 kPa), the test was practically finished. However, from 45 hours to 203 hours, the pump was brought down to atmospheric pressure to analyze the pressure response at both core sides. From this operation, both inlet and outlet pressures reached 280 kPa. This additional pressure drop produced a final oil RF of 18%. As it was expected, primary production was dominated by the foamy oil mechanism. Foamy oil kept oil viscosity low accompanied by a high-pressure gradient across the core that drives oil out of the core.

Figure 5-3: Fast depletion primary production without sand for core # 2.

After primary production, the core was again CT scanned. Figure 5-4 shows the comparison of live oil injection and primary production CT density profiles, where 0 mm corresponds the bottom base (injection and production port /outlet). Same as core # 1, the density of the fluid decreased through the sandpack after the primary production, which indicates the presence of free gas and lower oil saturation. The distribution of the remnant oil after primary production can be evaluated by using the density profiles after live oil saturation and primary production to estimate the oil saturation gradient. This will be further explained and compared to all sandpack results in Appendix A.

Table 5-3 summarizes the material balance for water and gas in the core after primary production.

Figure 5-4: Density profile after live oil injection and primary production.

Table 5-3: Material balance of gas and water after primary production of core # 2.

Material Balance from Primary Production	
Brine saturation volume (scm ³)	140.72
Volume brine produced (scm ³)	27.12
Brine recovered (%)	19.27
S_{wirr} (%)	13.4
Void space left in core (cm ³)	154.36
Free gas S_g (%)	18.2
Methane from live oil (scm ³)	4,986
Methane produced volume (scm ³)	4,256
Remaining methane after primary production (scm ³)	730
Remaining methane saturation (% initial gas)	15

5.4. Horizontal CSI Tests

Cycle 1 - Cycle 2: Fast depletion rate (124 kPa/h) – Slow depletion rate (50 kPa/h)

CSI cycle 1 and 2 follow the same injection and production procedure presented in the previous chapter (sandpack #1), and the same operative conditions such as pressure depletion rate, and injection pressure. At this pressure, the solvent mixture also met the requirement of being in the gaseous phase. The difference is that during the production of cycle 1, the core was depressurized to atmospheric pressure to clean the lines as a renewed attempt to unplug the system. After applying this strategy, the core was successfully unplugged, and the remaining CSI cycles were run normally.

Figure 5-5 (a) shows the core pressures and solvent injection volume during the injection and soaking period of cycle 1. Same as sandpack # 1, the injection was run by raising the core pressure to 2,760 kPa and then shutting in the system. Multiple solvent injections were done until no more pressure drops were recorded. The CSI soaking period was terminated at 163 h when the core

reached a stable pressure of 2,750 kPa. The differential pressure across the core and solvent injection volumes at standard conditions are shown in Figure 5-5 (b).

Figure 5-5: Injection and soaking stages during cycle 1, core # 2: a) Core pressure and injection gas volume. b) Differential pressure along the core and solvent injection volume at standard conditions.

Figure 5-6 (a) (b) plot the core pressures, oil RF, GOR vs. time. The trend of these plots reflects similar behavior previously observed during cycle 1 and 2 of sandpack # 1. However, this time, during cycle 1, significantly higher *DP* pressures were recorded. From 1,500 to 500 kPa, the differential pressure ranged between 11 – 200 kPa. Nevertheless, this pressure gradient seemed to be affected for the same plug described during primary production. As it is observed, the core outlet pressure dropped at a different decline rate than the inlet pressure, which indicates that the transducer located at the core outlet was recording the withdrawal pressure of the pump. Also, during this increment in the pressure gradient, neither oil production, which had already reached a plateau, showed any change nor the production gas that was coming out from the core. After 22 hours, the oil RF from cycle 1 was 0.53%, which corresponds to the same oil RF achieved during

cycle 1 of core # 1 at the same production time. This result suggests that under the conditions of large void space, free gas phase, and absence of pressure gradient, the increase in the concentration of more soluble solvents does not improve the oil recovery during horizontal CSI cycles run at fast depletion rates. Note that the cycle 1 was extended for an additional 24 hours to depressurize the core down to atmospheric pressure in a second attempt to unplug the system. The final oil recovery recorded for cycle 1 was 1.16%.

During cycle 2 a slower pressure depletion rate was applied (50 kPa/h). It was mainly observed that the total produced oil was obtained during the pressure range of 2,375 – 2,235 or only 260 kPa below the bubble point pressure. The highest differential pressure was observed during this production time which reached about 25 kPa. The linear pressure declination rate and continuous gas production during this pressure range indicated the absence of supersaturation and foamy oil flow compared to what was observed during primary production. As pressure continued declining, oil production quickly reached a plateau accompanied by high gas production volumes. At pressures below 2,235 kPa, the *DP* remained between 2 – 4 kPa, and the final oil RF from this cycle was 0.54%.

Same as cycle 2 in core # 1, the slow depletion rate did not improve the oil recovery response. At this point, there was already a 19% of void space left in the core, leading to high free gas saturation after the solvent injection, and therefore, low-pressure gradients to drive the oil out the core. Note that during cycle 2, core outlet and inlet pressures dropped at the same rate, which indicated a successful unplugging of the core after core pressure was dropped to atmospheric pressure during cycle 1. Table 5-4 summarizes the experimental conditions and production results from primary production to cycle 2.

Figure 5-6: Pressure, oil recovery factor and GOR vs. time during the CSI production phase of core # 2: a) Cycle 1 at a fast depletion rate of 124 kPa/h. b) Cycle 2 at a slow depletion rate of 50 kPa/h.

Table 5-4: Production data for primary depletion and horizontal CSI cycles in core #2.

Process	Sandpack position	Depletion rate (kPa/h)	Oil production (cm ³)	Oil saturation (fraction)	Oil Recovery (%)	Cumulative oil RF (%)
Primary depletion	Horizontal	124	127.24	0.682	18	18
Cycle 1	Horizontal	124	8.15	0.673	1.16	19.2
Cycle 2	Horizontal	50	3.79	0.669	0.54	19.7

Oil recovery from primary production and cycles 1 and 2 were higher in core # 2 than in core # 1, even when core permeability and propane content in the solvent mixture was lower. The higher recovery during primary production might be attributed to the much longer production time in core # 2 (253 hours against 54 hours). Furthermore, during cycle 1 in core # 2, the system was depressurized to atmospheric pressure, while in core # 1, the pressure was dropped down to 310 kPa.

Figure 5-7 illustrates the bulk density along the core length after cycles 1 and 2. In concordance with the material balance, CT density values indicated minor variations in the fluid saturation after cycle 1 to cycle 2. If curves from primary production and cycle 1 are compared, it is possible to observe a higher change in density at the top, which means higher gas saturation due to gravity segregation. The same behavior is observed after cycle 2, as gas has taken the preferential pathways to reach the top side of the core. It is important to emphasize that although the sandpack is marked to be positioned in the same position at every scanning, the core can be off ± 2 mm from the marked position.

Figure 5-7: CT density profile after primary production and horizontal cycles 1 and 2 in core #2.

5.5. Vertical CSI Tests

Cycle 3 - Cycle 5: Fast depletion rate (124 kPa/h)

During the vertical cycles conducted in sandpack # 1, an improvement in the heavy oil recovery factor was observed when gravity forces were acting. For sandpack # 2, vertical cycles were repeated at the same depletion rates but this time the concentration of propane in the solvent mixture was reduced by 50%. The main objective of these tests was to evaluate how the solvent composition could affect the oil RF when gravitational forces were present during the CSI process. The incremental oil recovery factor from vertical tests 3, 4, and 5 was 2.9 %, 2.1 %, and 3 % respectively. Again, the positive effect of gravity on the oil recovery factor compared to horizontal cycles was verified.

The recovery data of cycles 3, 4, and 5 is given in Figure 5-8 (a)(b)(c). All plots showed a smooth increasing oil recovery trend during the early stages (0 to 10 hours), during which the core pressure dropped from the initial core pressure to about 1,600 kPa. Below 1,600 kPa, the oil recovery reached the production plateau for all three cycles and the GOR increased. Meanwhile, in cycles 3 – 5 of core # 1, with the higher propane content, the average production rate was slightly higher, and the oil recovery plateau was reached at later times (18 hours) at pressures close to 800 kPa. Furthermore, the cumulative GOR for core # 1 vertical cycles was between 270 – 325 scm³/cm³, while in core # 2 tests, higher cumulative GOR ranged from 450 to 600 scm³/cm³. The cumulative GOR during vertical cycles in core # 2 dropped down about 27% compared to horizontal cycles. The highest *DP* was evidenced for all cycles between 5 to 8 hours of testing. For cycle 4 and 5, the *DP* at this time varied between 20 – 25 kPa, while for cycle 3 was between 300 – 430 kPa. Same to cycle 2, in cycle 3 the core outlet pressure was not trustworthy due to the plugging. However, during cycle 4 and 5, the core seemed to be unplugged as both inlet and outlet pressures

followed the same trend. Production for these two cycles is similar to that of cycle 3, so the higher differential pressure in Cycle 3 is a reflection of plugging, most likely at the core outlet, and is not an actual physical phenomenon within the core.

Figure 5-8: Core pressure, oil recovery factor and GOR vs. time: a) Cycle 3. b) Cycle 4. c) Cycle 5.

To better analyze the CSI response during fast depletion vertical cycle, oil recoveries and the produced methane (C1) and propane (C3) gas composition are plotted in Figure 5-9 and Figure 5-10 respectively as a function of the core inlet pressure. For all CSI cycles, the oil RF (%) vs. pressure followed a similar trend which can be visualized in two zones. From the initial pressure to 2,000 kPa, the recovery rate was significant, producing about 88%, 78% and 74% of the final recovery factor for cycle 3, 4, and 5 respectively.

From Figure 5-10 it is observed that above 2,000 kPa, CH₄ exhibited high mobility since the core was opened for production, while the mole % of propane remains constant in about 6%. This means that at this pressure range, a large volume of propane was still dissolved into the heavy oil which translates into low oil viscosity and high oil mobility, with free CH₄ acting as the carrier gas to provide energy to drive the solvent-diluted oil out of the core. When pressure fell below 2,000 kPa (Figure 5-9), the slope of oil recovery vs. pressure increased faster resulting in a reduction in the RF% until reaching the recovery plateau. From this pressure range, it was also evidenced how propane concentration in the gas effluent increased from 6% to the injected propane molar fraction (85% CH₄ – 15% C₃H₈). Therefore, the significant decrement in oil RF (%) during these pressure range is attributed to the propane exsolution from the diluted oil, which caused that oil regained its viscosity. Contrary to the primary production, from 2,000 kPa to 1,800 kPa there was no evidence of pressure maintenance, although a slight reduction in the pressure decline rate was seen. This indicates the inability of the diluted oil to trap the methane gas bubbles as pressure declines, so as observed previously there is no evidence of foamy oil acting as a production mechanism in these solvent-oil systems.

It was evidenced that the slope of oil RF (%) vs. inlet pressure at high pressures did not follow the same trend as cycle 4 and 5. However, this atypical tendency was attributed to the plugging since the measured DP , oil RF (%), propane and methane concentration in the gas effluent, and gas production from this cycle were in complete concordance with results obtained from cycle 4 and cycle 5. Also, it is worth mentioning that even though the core had certain plugging, this did not affect the oil recovery factor of cycle 3 since the following cycles (4 and 5) produced almost the same oil RF (%). Based on this, it is also possible to dismiss plugging effects on the negligible oil production obtained from cycles 1 and 2 (horizontal). It is also observed that during cycles 4 and 5, where the plug had already been removed, the slope at high pressures is not the same in none of the repeated tests. This is in contrast to core # 1, where early time response overlaid on the different CSI cycles. One reason for this behavior might be attributed to higher methane release in core # 2, which was 92 – 94% compared to 80 – 86% in core # 1. This response also meant lower oil recovery during this period compared to core # 1.

Figure 5-9: Oil recovery factor in function of core inlet pressure for primary production and CSI cycles 3 to 5 of core #2.

Figure 5-10: Produced gas composition mole (%) in function of core outlet pressure for vertical CSI tests (cycle 3, 4, 5) run at a fast depletion rate of 124 kPa/h.

Figure 5-11 shows the cumulative oil recovery factors of cycles 1 – 5. An ultimate oil recovery factor of 1.7 % was obtained from cycles 1 and 2, while 8% was recovered after three vertical CSI cycles. Oil RF (%) from cycles 3 to 5 exhibited nearly repeatable response as it was observed during CSI vertical cycles in core # 1. These results again confirm how gravity segregation during solvent injection promotes oil mobilization to the bottom (outlet) of the core after the gas is injected and left to soak for enough time to allow the diluted oil to drain and re-occupy the drained region at the bottom half of the core. Cycles 3 to 5 demonstrated that vertical displacements along with a fast depletion rate improve the oil recovery in the CSI process, as compared to horizontal CSI cycles where same and lower rates are applied.

Figure 5-11: Ultimate recovery factor (% OOIP) of primary depletion and CSI cycles 1 to 5, core # 2.

Figure 5-12 (a) shows the core density profile after primary production and after soaking time of cycle 3. The core was this time CT scanned before starting the production of cycle 3 to obtain more information about how fluids redistributed after the soaking time. After the vertical injection and soaking time of cycle 3, it is observed that density has dropped considerably from the 250 mm to the top of the core. Contrary, at the bottom of the core the bulk density has increased compared to the state after primary production. This confirms that the undissolved gas solvent (free phase) takes the preferential pathways towards the top of the core while the diluted-solvent oil drains down by gravity and occupy the empty volume left by the produced oil after primary production, resulting in oil pooling at the bottom end of the core. After production is resumed, the pooled oil flows as the gas phase on the top of the core expands. That is why at the end of the cycle 3, it is seen a significant reduction in the density at the bottom of the core which translates in lower residual oil saturation in that region.

Figure 5-12 (b) shows the density profile after cycles 3 – 5. It is evidenced that the bulk density at the top of the core decreases after every cycle while the bottom part remains almost unchanged. This explains why pressure took longer to build up in each injection cycle, and why all three vertical cycles gave similar oil recovery. Even after production of oil from each cycle, the density is still higher than that of the core after primary production, so liquid saturation is increased in the bottom region of the core, due to gravity drainage during solvent injection and soaking.

Figure 5-12: CT density profiles: a) After primary production and after soaking and production of cycle 3: b) After primary, cycle 3 to cycle 5.

Cycle 6 - Cycle 7: Slow depletion rate (12.5 kPa/h)

By the end of CSI cycle 5, the cumulative oil recovery had reached 27.6 % of the OOIP, and the remaining oil saturation was 60.3%. Up to this point, the residual oil saturation for sandpack # 2 was 5% lower than sandpack # 1. Hence, to evaluate the impact of depletion rate combined with gravity forces when the initial oil saturation is lower, two additional vertical cycles were run at the

same slow depletion rate applied for cycles 6 and 7 in sandpack # 1 (12.5 kPa). This means that the production period increased from about 20 hours (cycles 3 – 5) to 202 hours (cycles 6 – 7). On the other hand, injection and soaking periods were conducted following the same methodology previously explained.

The oil recovery factor for cycles 6 and 7 were 4.13 % and 4.15 % respectively. Very similar behavior of pressure and GOR was observed during these cycles compared to sandpack # 1 (see Figure 5-13). For both tests, pressure declined linearly with slight changes in the pressure decline rate. The GOR remain low and increased slowly as the oil recovery rate decreased. The cumulative GOR was slightly lower ($260 - 395 \text{ scm}^3/\text{cm}^3$) than GOR of cycles 3 to 5, which was 450, 600, $350 \text{ scm}^3/\text{cm}^3$ respectively. As mentioned before, this might be due to the slow drawdown rate of depletion that contributed to the slow release of gas from the oil phase, and therefore to higher oil recovery.

Figure 5-13: Core pressure, oil recovery factor and GOR vs. time during the production phase of core # 2: a) Cycle 6. b) Cycle 7.

For cycles 6 and 7, DP only varied about 2 – 18 kPa and 5 – 10 kPa respectively which was slightly lower than cycles 1 – 5 and significantly more to the primary production. These results coincide with Ivory *et al.*, (2010) and Alshmakhy (2011) who also recorded low-pressure drops during solvent cycles. It is believed that low oil viscosity (diluted oil) combined with high free gas saturation are responsible for low DP during solvent cycles. However, as previously mentioned, low-pressure gradients in vertical cycles might be due to oil pooling at the bottom of the core, and the smaller actual length of flow. During sampling it was observed small bubbles entrained in the crude oil. This observation was also detected during experiments in core # 1, which indicates that propane stays dissolved in the oil until low pressures.

Figure 5-14 plots the RF (%) in function of the core inlet pressure of all vertical cycles (fast and slow) and primary production. Same as cycles 3 – 5 analyses, the pressure vs. oil recovery factor profile for cycles 6 and 7 was divided into three regions based on the core inlet pressure. From the initial pressure to pressures over 2,300 kPa, the oil recovery and pressure ratio were the highest. Even when the pressure driving force across the core was negligible, 50% (cycle 6) and 60% (cycle 7) of the final oil recovery factor was obtained at only 500 kPa of pressure depletion.

Compared to cycles 3 – 5, region 1 was shorter in terms of pressure, this means that more oil was recovered during that pressure drop. Note that at these high pressures, it was measured a high production of propane in the gas effluent (GC measurements) which declined and stabilized until 1,000 kPa, when propane concentration started to increase again. Ivory *et al.*, (2010) also noted this response and they attributed it to the preferential solubility of propane in the oil at the bottom end of the core. Hence, when production was resumed, the first produced oil came from the closest region to the bottom end of the core which contained more propane dissolved. As pressure drops

around 1,200 kPa (zone 2), the slope of oil recovery vs. pressure was no longer linear. At this pressure range, a gradual increase in gas production (from material balance) was observed. The reason for this is due to the methane expansion and evolution from solution, which slowly increases as pressure drops. The gas expansion along with gravity forces maintained high oil mobility and therefore, high oil recovery factors. Up to that point, about 90% of the final oil RF has been already recovered. Hence, from pressures below 1,200 kPa to the final set pressure, propane has started to come out from solution which was evidenced in the exponential increase in the measured composition of the produced gas, resulting in the increase of oil viscosities and reduction of oil recovery.

It is noteworthy mentioning that both cycle 6 and 7 had virtually the same production profiles and RF, contrary to cycles 6 and 7 during core # 1 tests where recovery stopped faster after cycle 6. The repeatability of the results obtained from cycles 6 and 7 (core # 2) suggests that the higher homogeneity against core #1 combined with gravity forces increased the stability of solvent displacement, which in turn increased the sweep efficiency, and promoted a more stable oil drainage after each cycle.

Figure 5-14: Oil recovery factor in function of core outlet pressure for primary production and CSI cycles 3 to 7, core # 2.

Figure 5-15 compares the incremental oil recovery factor for all test's conditions. The incremental recovery from two slow (12.5 kPa) vertical cycles was 8.3 %, while for the three fast (124 kPa/h) vertical cycles was 7.9 %. A final oil recovery factor of 17.9 % was obtained from the CSI process, and a total recovery factor of 36 % including the primary production.

The oil RF from cycles 6 and 7 was 0.4 % higher than what was achieved from cycles 3 – 5, which indicates the efficiency of slow depletion rates on the heavy oil recovery. However, it is essential to note that the total running time for slow cycles was 481 hours which is equivalent to 6 times the total running time of three vertical fast cycles. However, the objective of running tests at very low depletion rates was to closely represent the CSI process as it is conducted in the field, where typical CSI cycles are run for months.

Table 5-5 provides more details about test conditions and production results of all experiments. An important observation must be made from the gas material balance. It is observed that the produced gas at every cycle is not always lower than the injected volume, this is because the core is not depressurized to atmospheric pressure. Thus, after every cycle, there is still gas remaining in the core that is accumulating. The total injected solvent volume was 74,213 scm^3 and the measured produced volume was 70,351 scm^3 . This difference (3,862 scm^3) could refer to the remaining gas volume after the last cycle, and the propane volume dissolved into the oil samples taken during the tests. However, as the remaining gas in the core and the dissolvent gas in oil sample was not measured, there is an uncertainty of the accuracy of the gas measurement method used in the experimental study.

Figure 5-15: Ultimate recovery factor (% OOIP) of primary depletion and CSI cycles 1 to 7, core # 2.

Table 5-5: Experimental production data for primary depletion and CSI cycles, core #2.

Process	Period	Time (h)	Oil		Solvent composition (scm ³)		GOR (scm ³ /cm ³)	Oil Recovery %	Depletion rate (kPa/h)	Injection Pressure (kPa)
			Production (cm ³)	Solvent/gas (scm ³)						
					CH ₄	C ₃ H ₈				
Depletion	Production	204	127	4,256	4,256			18	124	2,840
Cycle 1 Horiz.	Injection	163		12,883						
	Production	46	8	8,951	8,436	515	1,098	1.2	124	2,740
Cycle 2 Horiz.	Injection	168		10,135						
	Production	58	3.8	8,468	7,914	554	2,234	0.54	50	2,740
Cycle 3 Vertical	Injection	148		9,119						
	Production	24	20	9,246	8,506	740	456	2.9	124	2,835
Cycle 4 Vertical	Injection	188		9,739						
	Production	25	15	9,175	8,375	800	613	2.1	124	2,800
Cycle 5 Vertical	Injection	179		10,021						
	Production	24	21	11,500	10,542	958	552	3.0	124	2,820
Cycle 6 Vertical	Injection	172		10,706						
	Production	238	29.1	11,498	10,342	1,156	395	4.13	12.4	2,810
Cycle 7 Vertical	Injection	172		11,611						
	Production	244	29.29	11,514	10,363	1,151	393	4.15	12.4	2,800

Figure 5-16 (a) plots the CT density profile of the core after CSI cycles 5, 6, and 7. The density profiles follow the same trend in all states, but decrements in density are evident at the 80 mm – 300 mm of the core after cycle 7, more precisely from 200 mm – 300 mm where the average oil saturation decreased by 8% from cycle 6 to cycle 7. Towards the bottom end of the core (0 – 80 mm), it is observed an increment of density after cycle 7, which is equivalent to a rise by 2% in the average oil saturation.

The CT data confirm results obtained from the material balance and coincide with core # 1 observations: gas fingering to the top of the core, and oil pooling to the bottom end. Contrary to core # 1, in core # 2 the density at the bottom end did not remain unchanged after the last slow vertical cycle. This observation might be explained by

Figure 5-16 (b), which illustrates the final state of the core after cycle 7. It is observed that sands in the upper section of the core were cleaned, which supports the lower density values measured with the CT scanner. A dark section is seen at the bottom end of the core which demonstrates the oil pooling of the diluted oil at the bottom. Meanwhile, in the midzone of the core, there are intercalations of clean and saturated sand layers with less frequency to the upper side of the core. Therefore, it seems that after slow depletion CSI vertical cycles, where the system behaved more stable, more of these saturated layers are being cleaned by segregation of the oil to the bottom of the core. Although it was not possible to take pictures of the core after every cycle, the CT density profile verifies the effect of gravity forces and proper depletion rates in the stability of the displacement and swept efficiency of the fluids when the CSI is run in vertical configurations.

Figure 5-16: Fluid density distribution: a) CT density profile along post-CSI cycle 5, 6 and 7. b) Core final state after conducting all seven CSI cycles.

5.6. Dean-Stark Analysis

The Dean-Stark method was again used to measure the residual oil and water saturations after the primary production and the CSI process. The Dean-Stark yields highly reliable results. However, the extraction time can last at least 8 hours and sometimes reaches 48 hours depending on the volume of fluids. Therefore, for sandpack # 2, 8 samples were carefully selected from the core to be analyzed through this method (see Table 5-6). Appendix D shows a detailed explanation of the equations used to calculate the residual oil saturation.

Figure 5-17 plots the Post-CSI oil saturation in the system along the core length vs. the CT-predicted oil saturation profile. The green points joined by dotted lines represent the measured oil saturation from that section of the core. The length of the cuts varied from 1.7 to 2.5 cm. As the

cutting process was conducted by hand, it was found that the accuracy of the measurement was ± 3 mm. There is a good match between CT and Dean-Stark oil saturation results. The average oil saturation for the samples measured using the Dean-Stark was 52 %, while from the CT estimated one was 53 %, giving an error of 1%. The average saturation at the bottom (0 – 85 mm), middle (110 – 232 mm), and top (280 – 337 mm) of the core was 62%, 54% and, 35% respectively. It is worth mentioning that oil saturation values from the CT scanner were already matched with values obtained from the material balance. The Dean-Stark method also confirms the previous statements of lower oil saturation on the top and higher liquid saturation at the bottom. This result combined with images of core final state (Figure 5-16 (b)) demonstrates the effectiveness of the CSI vertical process on achieving low local residual oil saturation in well-swept parts of the reservoir.

Table 5-6: Core residual oil saturation after CSI cycles using Dean-Stark extraction, core #2.

Sample	Range cut (cm)		Fluid (g)	Sand (g)	Oil (g)	Vol water (cm ³)	Vol oil (cm ³)	Vol sand (cm ³)	Porosity (fract.)	PV (cm ³)	So (fract.)
1	4.5	6.2	30.94	192.61	24.67	6.20	24.93	510.42	0.38	38.86	0.64
2	6.5	8.5	33.38	210.35	27.31	6.00	27.60	557.43	0.38	45.59	0.61
3	11	13	32.84	213.74	26.57	6.20	26.85	566.41	0.37	44.54	0.60
4	13	15	28.82	200.16	23.16	5.60	23.40	530.42	0.37	44.79	0.52
5	17.5	19.5	31.25	219.95	25.18	6.00	25.44	582.87	0.37	44.91	0.57
6	21.5	23.2	22.59	193.01	17.33	5.20	17.51	511.48	0.37	37.71	0.46
7	28	29.7	19.16	193.57	13.70	5.40	13.84	512.96	0.38	38.67	0.36
8	32	33.7	18.83	189.55	13.37	5.40	13.51	502.31	0.37	38.23	0.35

Figure 5-17: Comparison of residual oil saturations along the core length after CSI cycles using CT and Dean-Stark methods.

Same than core # 1, the CSI was stopped at the 7th cycle for time concerns but not for low incremental recovery factor. Compared to core # 1, the average residual oil saturation in the core was 2% higher and 14% lower at the bottom of the core. However, it was observed that the top (the well-swept zones) oil saturation dropped down to 35% the same as core # 1. The fact that residual oil saturation at the top of the core # 1 and # 2 was the same, and that minor changes in oil density at that region were observed from cycle 6 to cycle 7 (see Figure 4-20 (a), Figure 5-16 (a)) indicates that 35% could be the lower residual oil saturation from the CSI process under this study's operative conditions. The differences in the residual oil saturation between core # 1 and # 2 at each part of the core can be analyzed from the solvent composition standpoint, however, this would be further discussed in chapter 7, where results from all cores will be compared.

6. CHAPTER SIX: SANDPACK MODEL THREE

6.1. Introduction

Experiments conducted in core # 1 and # 2 evaluated the effect of mechanisms such as gravity forces, drawdown pressure, and solvent composition on the oil recovery factor during CSI processes. The CSI performance from both cores was slightly different as a distinct solvent composition was used for each one. However, other factors such as absolute permeability and initial oil saturation at the start of the CSI process might have affected the oil recovery response. In both cores, CSI was run after primary production, which in the lab yielded 14 – 18% oil recovery, and significant void space. It is important to understand the impact of vertical vs. horizontal core CSI responses on systems that do not begin with this large void space.

CSI laboratory studies conducted without primary production (Du *et al.*, 2015; Qazvini Firouz and Toravi, 2012) have shown great efficiency on the final oil recovery factor (30-70%). This suggests that the fluctuation of the CSI performance between experiments could be also affected by another factor: the initial oil saturation. Hence, the objective of this set of experiments is to study the effect of initial oil saturation in CSI processes. For this purpose, the sandpack model # 3 was saturated with dead oil and the primary production was skipped. Then, a solvent mixture of mole ratio of 30% propane – 70% methane was injected following the same experimental procedures of cores # 1 and 2. Six CSI tests were conducted: four CSI cycles in horizontal alignment, and two in a vertical position, all of them at a fast depletion rate of 124 kPa/h. The core was horizontally run until no more incremental oil recovery was achieved. Then, the core was vertically aligned to verify the effect of gravity drainage on the heavy oil recovery enhancement.

Same as in previous core tests, the core was CT scanned after every CSI cycle, and the oil saturation evolution was analyzed. To evaluate the effect of solvent composition on the produced oil quality, oil viscosity of the produced samples was also measured and then compared to measurements from core # 2, where a higher propane concentration solvent was injected. Finally, the core was removed from the core holder and residual oil saturations were determined through the Dean-Stark method.

6.2. Properties Summary

The sandpack was also dry packed as cores # 1 and # 2 and CT scanned. Then, the porous medium was saturated with brine, and dead oil, and again CT scanned. Figure 6-1 shows a summary of measured sand and fluid properties. The sandpack porosity was found to be the same than core # 2 but the absolute permeability was two and four times the permeability of core # 1 and # 2 respectively. The saturation process with dead oil took about 8 days, which was much faster than for previous cores due to the higher core permeability and less operative arrangements due to gas absence. 1. Around 1.7 pore volumes (PV) of dead oil was injected until both water cut and the producing GOR was constant and very close to the original injected values.

Once the sandpack was saturated with dead oil, it was CT scanned before starting the first horizontal CSI cycle. The mean CT porosity was about 38% against 37.8% from the measured absolute permeability to brine. It is worth mentioning that the dry core and water saturated core was measured with a third-generation CT scanner that failed after the measurements. All subsequent scans were run using a different CT scanner. Hence, for core # 3, the baseline for the CT analysis started with the state of the core after dead oil saturation.

Table 6-1: Sand and oil properties of core # 3.

Core holder Dimensions	
Length (cm)	63
Diameter (cm ³)	10
Sandpack Physical Properties	
Area (cm ²)	59.9
Average diameter (cm)	8.73
Length (cm)	36.3
Volume (cm ³)	2,174
Porosity (Fraction)	0.38
Permeability (D)	3.3
OOIP (cm ³)	687.76
S_o (fraction)	0.84
S_{wi} (fraction)	0.16

6.3. Horizontal CSI Tests

Cycle 1 - Cycle 4: Fast depletion rate (124 kPa/h)

Before the first CSI test, the pore medium of the core was fully saturated with dead oil and irreducible water (84% and 16% respectively). For the injection stage, the sandpack was repressurized from an initial pressure 300 kPa up to a final injection and soaking pressure of 2,826 $\pm$ 10 kPa by injecting the solvent mixture from the bottom end (left side of the horizontal core). Figure 6-1 shows the sandpack pressure variation and the solvent injection volume during the injection and soaking period of cycle 1. As it is observed multiple injections were conducted during the process before the pressure stabilized. As there was not void space in the core, the core received just a small amount of solvent during multiple injections. Moreover, the limited amount of solvent was not large enough to diffuse into the large volume of heavy oil and reduce its viscosity to flow out the core. This resulted in a negligible produced oil in the first cycle (0.8 %). The produced oil from the first cycle, although it was small, left a void space in the core, which provided larger pore

volume for the solvent in the subsequent cycle. This increased the solvent diffusion/dispersion into the heavy oil and therefore, improved the cyclic oil recovery in the second and third cycle. The incremental oil recovery factor from horizontal tests # 1, # 2, and # 3 and # 4 was 0.8 %, 5.8 %, 5.9 %, and 1.7 % respectively.

Figure 6-1: Injection and soaking stages during cycle 1, core # 3.

Table 6-2 summarizes the injected solvent volume, the produced solvent composition and RF (%) for each horizontal cycle. Figure 6-2 plots the total pressure drop and the associated oil recovery as a function of time during CSI cycles 1 – 4. For cycles 1 and 2 oil recovery is obtained during late times, i.e. from the 20-hour of the production phase, while for cycles 3 and 4, production is observed from the 5th hour of production. However, for all cycles, the higher oil recovery happens from the 20-hour of the test during which there is the highest pressure drop present across the core. The highest DP were obtained during cycles 2 and 3, where DP reached peaks over 70 kPa. While for cycles 1 and 4, where lower oil recoveries were obtained, the average DP was about 10 kPa with peaks of 50 and 30 kPa respectively. This observation means that during CSI production, the

driving force for flow of diluted oil is partially related to the pressure gradient as the driving force for viscous (Darcy) flow of oil. The results of cycle 4 showed an abrupt drop in the incremental oil RF, primarily because at that point the gas channels present in the core were forming a continuous gas pathway through the system that affected the generation of high DP .

Figure 6-2: Pressure drop and oil recovery vs. time: a) Cycle 1. b) Cycle 2. c) Cycle 3. d) Cycle 4.

Table 6-2: Experimental production data for horizontal CSI cycles, core # 3.

Process	Oil	Injected	Produced	Solvent composition		GOR (scm ³ /cm ³)	Oil
	Production	Solvent/gas	Solvent/gas	(mole %)			Recovery
	(cm ³)	(scm ³)	(scm ³)	CH ₄	C ₃ H ₈		%
Cycle 1	6	2,106	696	77	23	121	0.8
Cycle 2	39.7	3,320	1,779	82	18	45	5.8
Cycle 3	40	5,335	5,229	81	19	130	5.9
Cycle 4	11	9,511	6,932	85	15	605	1.7

Figure 6-3 plots the CT density profile for all cycles. CT density values indicated significant variations in the fluid saturation from cycle 1 to cycle 2, especially, at the bottom part of the core as oil close to the production end is produced easily. After cycle 3, the major changes in density occurred in the middle part of the core with minor variations in the bottom. For cycle 4, the CT density profile remained almost unchanged compared to cycle 3. These results support the recovery results obtained from the material balance, and the low-pressure gradient during the production stage, which indicates the effect of continuous gas after preferential pathways have been formed.

Figure 6-3: CT density profiles after cycle 1 – 4 in core # 3.

Figure 6-4 (a) plots the oil RF (%) for the four horizontal cycles in function of the pressure gradient between the inlet and outlet of the core. Figure 6-4 (b) shows the DP values recorded at the moment of the sampling, for this reason, they are shown as discrete points. For a more detailed behavior of DP and oil RF, see Figure 6-2. It is observed that, during cycle 1, oil production started at pressures below 1,000 kPa, and more than 50% of the final oil recovery was obtained at pressures below 500 kPa when DP increased from 10 to 35 kPa.

For cycle 2, oil production started when the pressure reached 1,000 kPa. However, 83% of the final oil recovery was obtained at pressures below 500 kPa when DP increased from 20 kPa to 70 kPa. It was observed that the DP across the core dropped gradually until the core reached its predefined final pressure.

During cycle 3, oil production initiated at higher pressures (2,500 kPa), exhibiting 50% additional oil recovery factor compared to cycle 2 at the pressure range of 2,500 – 400 kPa. Below 400 kPa, about 66% of the final oil RF was obtained with also high DP . Finally, during cycle 4, at high pressures, a similar trend as cycle 3 is observed. However, the oil recovery stopped when pressure dropped below 500 kPa. This suggests that the presence of continuous gas pathways along the core at this point inhibited the generation of high DP at low pressures, which affected directly the driving force for oil to flow. High oil recoveries during cycle 2 and 3 are associated with the core's ability to have a pressure drawdown.

Figure 6-4: Oil recovery factor in function of core inlet pressure for primary production and CSI cycles 1 to 4 in core #3.

Figure 6-5: CT fluid saturation profile for horizontal CSI tests in core # 3.

Figure 6-5 illustrates the fluids (oil and water) saturation profile for cycles 1 to 4. Where fluid saturation refers to the residual oil and water remaining in the core after every CSI cycle. The core after the oil saturation is considered the baseline (fluid saturation = 1). It is observed minor variations in the fluid saturation after cycle 1, and most of this change occurred in the bottom part of the core near the injection/production end. Moreover, the produced C_3H_8 gas composition was

the highest compared to subsequent cycles as propane for being highly soluble in oil preferentially dissolved at the bottom end of the core during the injection stage. When the core was opened to production, the produced gas contained a higher propane concentration. For the next Huff-n-Puff cycle, the solvent/oil interface was gradually moving beyond the production port, and the fluid saturation profiles shifted to the left, mostly from the mid part to the bottom part of the core. At the end of cycle 3, a more homogenous decrement in the fluid's saturation along the core was observed, which indicated that the produced oil originated from higher zones in the core.

The saturation curve of cycle 4 showed a very low oil recovery response compared to cycle 3, which might be an indication of gas fingering, higher free gas saturation, and inefficient gas driving force as previously discussed in cycles 1 and 2 for cores # 1 and # 2. The significant decrease in oil recovery for CSI cycle 4 indicates that the system has lost the ability to mobilize solvent-diluted oil, much like the core state after primary production in the previous two tests. Any subsequent cycles will recover even less oil with each cycle.

Contrary to cores # 1 and # 2, CSI cycles in core # 3 were initiated with the core fully saturated with dead oil and irreducible water saturation. Other researches generally start with dead oil saturated cores and report total solvent recovery, which includes these early cycles. Some examples include works from Jia *et al.*, (2015) who reported 48.8 % oil RF from 29 cycles, Qazvini Firouz and Torabi (2012) who obtained 56% from 9 cycles and Du *et al.*, (2018) produced 34% RF from 35 cycles. These experimental studies also exhibited high depletion rates: 60 kPa/min, 500 kPa/min, and 12.5 kPa/min respectively.

Compared to these studies, only 14% OOIP was recovered in core # 3 from 4 cycles using a much slower depletion rate of 124 kPa/h (2 kPa/min). As previously mentioned, fast depletion rates have

been found to lead to higher production rates due to the presence of a greater pressure gradient in the core that promotes oil flow and low gas mobility under solution gas drive. Therefore, if CSI experimental studies are conducted at higher drawdown rates, better oil recoveries are obtained as was observed in the mentioned works from the literature. Furthermore, some of the high solvent recoveries reported by different researchers are attributed to the fact that the solvent is recovering oil while still forming continuous pathways through the core. Once, these pathways are formed like in CSI cycle 4 (core # 3), the recovery per cycle drops significantly.

Hence, the recoveries are supporting a growth of solvent pathways mechanism. In a non-CHOPS reservoir this analysis may be valid, but for post-CHOPS systems this is over-estimating the effect of CSI.

6.4. Vertical CSI Tests

Cycle 5 - Cycle 6: Fast depletion rate (124 kPa/h)

CSI cycles 1 – 4 resulted in 14.1 % of incremental oil recovery. Most of the oil production came from cycles 2 and 3. The horizontal mode flow was then interrupted after the 4th cycle as at this stage, there was already enough void space throughout the core that the incremental production of oil was dropped 30% compared to the previous two cycles (1.7% OOIP). Therefore, the sandpack was flipped to the vertical position to conduct two more CSI cycles at the same experimental conditions.

Figure 6-6 shows the ultimate oil recovered vertical cycle 5 is significantly higher than that obtained during the horizontal cycle 4. Also, despite even more void space present after cycle 5 production, the response from vertical cycle 6 was similar to that of cycle 5. These repeatable

vertical cycle results were also observed in the first two cores tested. Again, as previously observed during vertical cycles in core # 1 and # 2, the heavy oil recovery response was enhanced by the combination of gas solvent overriding during the injection, the formation of a mixing solvent/oil zone during the shut-in period, and the drainage of the diluted oil down to the production port by gravity forces during solvent injection and soaking. Thus, when the production stage starts, the pooled solvent-diluted oil is close to the production end of the core can easily drain without the requirement of a sustained pressure drop across the core, in contrast to the horizontal core tests.

The performance of CSI cycles was improved by applying vertical displacements when the residual oil saturation in the core was significantly low (higher void space through the core) to operate at the same solvent injection pressure and rates. The application of this concept increased the recovery rate, reduced GORs, and maintain the injection volumes close.

Figure 6-6: Ultimate recovery factor (% OOIP) of primary depletion and CSI cycles 1 to 6 in core # 3.

Figure 6-7 compares the oil RF (%) vs. pressure response for all horizontal and vertical cycles.

The oil recovery vs. pressure follows the same slope for both vertical cycles, but the oil recovery stops faster for the last cycle. Same as in vertical cycles for cores # 1 and # 2, the oil RF (%) vs. pressure followed a trend which can be analyzed in three zones respect to the pressure: 1) At high pressures (up to 2,000 kPa), oil is linearly recovered and it reaches 50% of the final oil RF, at this pressures, most of the propane is still dissolved into the oil which favors the low oil viscosity. 2) From 2,000 to 1,000 kPa, the oil recovery rate decreases with pressure as propane starts to exsolve from solution and oil gradually becomes more viscous. At pressures below 1,500 kPa, about 60 % of the injected solvent has been produced, hence oil regains its viscosity and oil recovery drops.

The pressure drop in the core during vertical cycles 5 and 6 was on average 6 kPa and 4 kPa, with peaks up to 28 kPa and 15 kPa (see Figure 6-8). Similar values to what was obtained during vertical cycles in core # 1 and # 2.

Figure 6-7: Oil recovery factor in function of core outlet pressure for all horizontal (1 – 4) and vertical (5 – 7) CSI cycles.

Figure 6-8: Pressure drop and oil recovery vs. time: a) Cycle 5. b) Cycle 6.

The effect of gravity is again observed in the CT density profiles plotted in Figure 6-9 (a). During cycles 5 and 6, the diluted oil drained down by gravity, and the solvent vapor occupied the space which was originally saturated with oil. This is the reason why the density at the bottom end of the core did not change from one vertical cycle to another one. As the density of the solvent in the gas phase is way lower than oil density, then, the bulk density at the top of the core decreased with time as it is observed from cycle 5 to cycle 6. In the case of cycles 3 and 4, where the CSI process was horizontally carried out, it is observed that density decreased faster near the bottom of the core, which is attributed to the faster expansion of solvent at that zone. However, the pressure gradient in the model was significant until cycle 4, where the effects of gas fingering affected the performance of the horizontal CSI tests.

Although the CSI process was stopped in the sixth cycle, there was still high oil residual oil saturation (64%) to be further recovered by vertical CSI cycles (see Table 6-3). In cores # 1 and # 2, the residual oil saturation after primary production and 7 CSI cycles was 52 % and 53 % respectively. However, in these cores, the CSI process was also stopped for time concerns but not

for low oil RF's. Figure 6-9 (b) illustrates the state of the core at the end of cycle 6. If this image is compared to images from core # 1 and # 2 it clearly shows that there is still a large volume of oil to be recovered but also to be pooled by additional vertical CSI tests.

Figure 6-9: Fluid density distribution: a) CT density profile along post-CSI cycle 1, 3, 5 and 6. b) Core final state after conducting all six CSI cycles.

Table 6-3: Experimental production data for primary depletion and CSI cycles, core #3.

Process	Period	Time (h)	Oil		Solvent composition (scm ³)		GOR (scm ³ /cm ³)	Oil Recovery %	Depletion rate (kPa/h)	Injection Pressure (kPa)
			Production (cm ³)	Solvent/gas (scm ³)						
					CH ₄	C ₃ H ₈				
Cycle 1 Horiz.	Injection	184		2,106	1,474	632				
	Production	30	6	696	534	163	121	0.8	124	2,707
Cycle 2 Horiz.	Injection	211		3,320	2,324	996				
	Production	41	39.7	1,779	1,464	315	45	5.78	124	2,711
Cycle 3 Vertical	Injection	162		5,335	3,734	1,600				
	Production	34	40	5,229	4,240	988	130	5.9	124	2,726
Cycle 4 Vertical	Injection	171		9,511	6,658	2,853				
	Production	27	11	6,932	5,871	1,062	605	1.7	124	2,772
Cycle 5 Vertical	Injection	163		9,011	6,308	2,703				
	Production	31	34	8,987	7,181	1,806	261	5.0	124	2,768
Cycle 6 Vertical	Injection	163		9,998	6,999	2,999				
	Production	35	29.4	10,810	8,648	2,163	368	4.27	124	2,779

6.5. Dean-Stark Analysis

At the end of cycle 6, eight samples were taken at atmospheric pressure at representative locations along the core. Then, the residual oil saturation was determined by Dean Stark analysis. The residual oil saturation measured from Dean-Stark and the CT saturation previously matched with the material balance is shown in Figure 6-10. For clarification, blue dashed lines connect the samples points to represent the oil average saturation of that length. From the saturation profile obtained through Dean Stark, it was found that the measured residual oil saturation varied from 52% to 71% (see Figure 6-10) along the whole core. The post-run oil average saturation was high (64%) at the bottom of the test (0 – 90 mm) compared to the top (260 – 330 mm) where the saturation was lower (57%). The average oil saturation in the middle of the sandpack (110 – 230 mm) was 67%. The higher density towards the mid and bottom part of the core is explained by the oil pooling and the gas overriding phenomenon product of the last two CSI cycles.

Figure 6-10: Comparison of residual oil saturations along the core length after CSI cycles using CT and Dean-Stark methods.

Table 6-4: Core residual oil saturation after CSI cycles using Dean-Stark extraction, core # 3.

Sample	Range cut (cm)		Fluid (g)	Sand (g)	Oil (g)	Vol water (cm ³)	Vol oil (cm ³)	Vol sand (cm ³)	Porosity (fract.)	PV (cm ³)	So (fract.)
1	0	2	34.8	207.8	28.2	6.50	28.5	550.8	0.37	46	0.62
2	2	4	31.6	178.9	25.3	6.20	25.6	474.2	0.37	40.9	0.63
3	7	9	36.9	203.8	29.9	7.00	30.2	540.1	0.37	44.9	0.67
4	11	13	35.5	199.6	28.4	7.00	28.7	528.9	0.37	45.1	0.64
5	16	18	36.0	203.6	28.9	7.00	29.2	539.5	0.36	43.9	0.67
6	21	23	39.8	225.7	32.2	7.50	32.6	598.2	0.36	45.6	0.71
7	26	28	33.1	191.0	26.6	6.50	26.8	506.1	0.37	44.1	0.61
8	31	33	30.3	212.2	23.4	6.80	23.6	562.5	0.39	45.2	0.52

Same as with cores # 1 and # 2, the CSI was stopped for time concerns but not for low incremental recovery factor. However, much higher residual oil saturation remained in the core as no primary production was conducted and only 6 CSI were run. Compared to core # 1 and # 2, the average oil saturation for the samples measured using the Dean-Stark was 63 %, 13% and, 11% higher than cores # 1 and # 2 respectively. It was observed that the residual oil saturation at the top region of the core was 22% higher than cores # 1 and # 2. Figure 6-9 (a) also shows significant changes in the bulk density from cycle 5 to cycle 6 at the top of the core. These two observations indicate that the number of vertical CSI cycles was not enough to drain and sweep the oil located on the top and to reach the potential residual oil saturation as observed in cores # 1 and # 2. The differences in the residual oil saturation between all cores will be discussed with more detail in chapter 7.

Figure 6-11 shows the average residual oil saturation (Dean-Stark measurements) at the end of the CSI process for all three cores. Data points linked by dotted lines represent the average oil saturation at selected locations of the core (bottom, middle and top). The residual oil saturation at the end of cycle 6 was around 50 – 60% at the top of the core, which is higher than what was obtained in cores # 1 and # 2. This indicates that additional CSI cycles could have been conducted to drain more oil and sweep the top region down to 35% like what was seen in the previous two tests, where 7 CSI cycles were run.

Figure 6-11: Average residual oil saturation at the top, middle and bottom of all three cores.

7. CHAPTER SEVEN: EXPERIMENTAL COMPARISON AND DISCUSSION

In this study, three different cores were utilized to test the effects of gravity drainage, pressure depletion rate, solvent composition, and initial oil saturation on the recovery factor during the CSI process. To fully analyze the effect of these variables on CSI, experimental results presented in previous chapters were compared to each other and with data from the literature. Since the data of the CSI test were collected under different operative schemes, the results obtained in this thesis were compared with the literature values in four distinct categories: 1) effect of gravity drainage; 2) effect of pressure depletion rate; 3) solvent composition; 4) effect of initial oil saturation.

Table 7-1 presents the results from cores # 1 – 3 with those chosen from the literature. The main parameters used for comparative purposes were: core position during the CSI process, length and core porosity, mobility ratio (k/μ), drawdown pressure, type of solvent, and initial oil saturation based on the inclusion of primary production before the CSI tests. The comparison and effect of these parameters will be discussed in the following sections.

Table 7-1: Comparison among different operating schemes of CSI

Authors	Core Position	Length (cm)	ϕ (%)	k (D)	μ_o (mPa·s)	$DP_{min-max}$ (kPa/h)	Solvent	Primary Prod.	RF (%)
Core # 1	H/V	37.5	38	1.5	30,365	12.4 -124	30% C ₃ + 70% C ₁	Yes	41
Core # 2	H/V	37	38	0.8	30,365	12.4 - 124	15% C ₃ + 85% C ₁	Yes	36
Core # 3	H/V	37	38	3.3	30,365	124	30% C ₃ + 70% C ₁	No	23
Ivory <i>et al.</i> (2010)	V	300	38	4.5	39,328	5	28% C ₃ + 72% CO ₂	Yes	50
Bryan <i>et al.</i> (2018)	V	108	39	4.5	37,517	8.3 - 50	CO ₂	Yes	32
Jamaloei <i>et al.</i> (2012)	H	3.2	38	41.8	1,086	566 -6,759	C ₁	Yes	6
		3.2	38	41.8	1,086		C ₁ and C ₃	Yes	40
Du <i>et al.</i> (2018)	H	30.4	36	5.48	2,700	750	40% C ₃ + 60% CO ₂	No	34
Qazvini Firouz and Toravi (2012)	H	30.4	24	1.8	1,423	830 -3,800	30% C ₃ + 72% CO ₂	No	56
Ahadi and Torabi (2018)	H	33.5	35	10.2	6,430	1,720	15% C ₃ + 85% C ₁	No	23
			32	9.7			30% C ₃ + 70% C ₁		29

Nomenclature: DP = Pressure depletion rate during production; H = Horizontal; V = Vertical

7.1. Effect of Gravity Drainage

The effect of gravity forces on the performance of CSI processes has been discussed earlier for each set of experiments. Favorable response of the heavy oil recovery factor was observed during vertical CSI cycles. This mechanism was further assessed by oil saturation distribution and density profiles using CT scanning and Dean-Stark analysis.

Table 7-2 summarizes the incremental oil recoveries from primary production and CSI cycles for all three cores. It also shows the remaining oil saturation in the core at the end of each production stage. The recovery factors from horizontal and vertical cycles are plotted in Figure 7-1.

For cores # 1 and # 2, the system was vertically aligned after no oil recovery was achieved through two horizontal cycles. It was found that during horizontal CSI tests, the system required a pressure gradient to promote oil flow. However, during these two cycles, it was difficult to create a pressure drop across the core due to the high free gas saturation in the system and preferential solvent pathways created after primary depletion. In the case of core # 3, as primary production was not conducted, oil production greatly declined after the 4th horizontal cycle. The system lost the ability to mobilize solvent-diluted oil like after primary production in cores # 1 and # 2 where high free gas saturation was present.

To evaluate the relative effect of viscous and gravity forces on the CSI performance, the core was then flipped to a vertical position. From five CSI cycles, oil recovery results were relatively repeatable even when high free gas saturation was already present at the start of each cycle. It is noteworthy to mention that vertical CSI cycles could have been continued to obtain a lower residual oil saturation in the cores, however, due to research time constraints, the process was finished at the 5th vertical cycle. Therefore, DS was conducted to measure the residual oil at the top drained part of the core (well-swept zone) and the potential maximum oil recovery was projected based on that value.

The final oil recovery factor of core # 1 and # 2 was enhanced by five vertical displacements from 15 % to 41% and 20% to 36% respectively. For core # 3, the final oil recovery went from 14% to 23% after two vertical cycles. The effect of gravity in core # 3 does not look as significant as in core # 1 (same solvent composition) because only two vertical cycles were conducted. However,

if the first two vertical cycles (run at 124 kPa) of both cores are compared, as shown in Figure 7-2, the higher incremental oil RF was obtained during cores # 3's cycles. This response might be attributed to the permeability of core # 3 as initial saturation at the start of vertical cycles was almost the same as in core # 1 (72% and 71% respectively).

Figure 7-1: Comparison of oil recovery factor during horizontal and vertical CSI cycles in all three cores.

Figure 7-2: Incremental oil recovery factor during first two vertical cycles in cores # 1, # 2, and # 3.

Table 7-2: Summary of production and experimental data of all three cores.

Core	Parameter	Primary Prod.	Cycle 1	Cycle 2	Cycle 3	Cycle 4	Cycle 5	Cycle 6	Cycle 7
1	Position	Horiz.	Horiz.	Horiz.	Vertical	Vertical	Vertical	Vertical	Vertical
	Depletion rate (kPa/h)	124	124	50	124	124	124	12.4	12.4
	S_o (fraction)	0.745	0.740	0.740	0.706	0.672	0.636	0.569	0.518
	RF (%)	14.6	0.56	0.04	3.9	3.8	4.2	7.6	5.9
	Avg. production rate (cm ³ /h)	-	0.09	0.01	0.99	0.98	1.02	0.14	0.20
	SOR (scm ³ /cm ³)		3,981	44,371	362	536	436	421	301
	Oil / Solvent	Live oil	70% CH ₄ - 30% C ₃ H ₈						
2	Position	Horiz.	Horiz.	Horiz.	Vertical	Vertical	Vertical	Vertical	Vertical
	Depletion rate (kPa/h)	124	124	50	124	124	124	12.4	12.4
	S_o (fraction)	0.683	0.674	0.669	0.645	0.627	0.603	0.568	0.534
	RF (%)	18	1.2	0.54	2.9	2.1	2.9	4.1	4.1
	SOR (scm ³ /cm ³)		1,580	2,674	450	650	481	368	396
	Avg. production rate (cm ³ /h)	-	0.18	0.07	0.83	0.61	0.86	0.12	0.12
	Oil / Solvent	Live oil	85% CH ₄ - 15% C ₃ H ₈						
3	Position	N/A	Horiz.	Horiz.	Horiz.	Horiz.	Vertical	Vertical	N/A
	Depletion rate (kPa/h)	N/A	124	124	124	124	124	124	N/A
	S_o (fraction)	N/A	0.830	0.781	0.732	0.718	0.676	0.641	N/A
	RF (%)	N/A	0.84	5.8	5.9	1.7	5	4.3	N/A
	SOR (scm ³ /cm ³)		365	84	133	830	262	340	N/A
	Avg. production rate (cm ³ /h)	-	0.195	0.975	1.192	0.431	1.125	0.847	N/A
	Oil / Solvent	Dead oil	70% CH ₄ - 30% C ₃ H ₈						

Figure 6-11 and Table 7-3 shows the average residual oil saturation (Dean-Stark measurements) at the end of the CSI process. Data points linked by dotted lines represent the average oil saturation at selected locations of the core (bottom, middle and top).

For cores # 1 and # 2, the residual oil saturation decreased from bottom to top of the core. These measurements were in complete agreement with the color of the sand. Figure 4-20 (b) and Figure 5-16 (b) showed much whiter sands at the upper part compared to the lower region of the core.

Even though C_3H_8 mole % concentration was 15% higher during core # 1 than in core # 2 tests, the residual oil saturation at the top of the core (well-swept zone) was the same. Besides, the overall MB S_{or} was within 2% of one another. This indicates that the residual oil saturation is not a strong function of the solvent composition. However, the higher oil saturation at the bottom of core # 1 and the lower value in the mid part of the core compared to core # 2, shows that higher propane concentration in the solvent mixture can increase the dilution and oil drainage during vertical cycles.

The Dean-Stark data was also used to estimate the potential oil recovery from the CSI process under these operating conditions based on the residual oil saturation at the top of the core. As previously mentioned, if the residual oil saturation at the middle and bottom part is assumed to drop down to 35% like in the well-swept zone (top of the core), it is estimated that an additional 16.7 % of OOIP could be recovered through the CSI process in core # 1, resulting in a final oil RF of 57.3%.

Table 7-3: Post-CSI average oil saturation at the bottom, middle and top regions of the core.

Core	Location	Core length (mm)	Oil saturation (fraction)
1	Bottom	0-91	0.76
	Middle	91-230	0.47
	Top	230-375	0.35
2	Bottom	0-85	0.62
	Middle	110-232	0.54
	Top	280-337	0.35
3	Bottom	0-90	0.64
	Middle	110-230	0.67
	Top	260-330	0.57

The volume of propane recovered during core # 1 tests was 6.7 % lower than what was measured in core # 2 CSI tests (46% and 52.7% respectively). This indicates that more propane was dissolved in the recovered oil samples, and likely in the residual oil within the core # 1, resulting in lower propane recovery. In the case of core # 3, although two CSI vertical cycles were not enough to sweep the top part of the core as in cores # 1 and # 2, the high oil saturation towards the bottom of the core, suggest the start of oil pooling at the bottom and mid part of the core due to gravity drainage.

During the vertical cycles, a decrease in the average SOR (cumulative solvent injection/cumulative oil production) was also observed compared to horizontal cycles. Gravity forces combined with diffusion and dispersion accelerated the development of a more stable mixing zone during the injection and soaking stage. Therefore, during the production phase, the gas fingering was minimized, and the sweep efficiency was enhanced, resulting in lower SOR.

Figure 7-3 plots the oil saturation at the end of every cycle normalized to the initial oil saturation (after oil saturation). This graph compares the oil saturation data reported by Ivory *et al.* (2010), Bryan *et al.* (2018), and Jamaloei *et al.* (2012) with the data obtained from cores # 1 and # 2 in

this study. Ivory *et al.* (2010) and Bryan *et al.* (2018) conducted CSI experiments at very similar conditions: high oil viscosity, moderate permeability, primary depletion prior to CSI, large sandpack length, vertical CSI configuration, and slow depletion rates during production (see Table 7-1). Although Ivory *et al.*, conducted two additional cycles, it is observed that Bryan *et al.*'s experimental work follows a very similar trend with slight attenuation in the slope of the curve. The fact that oil saturation is significantly reduced in each CSI cycle is evidence of oil pooling and gravity drainage. The difference in oil recovery efficiency between both experiments might be attributed primarily to the effect of the depletion rate, which was 10 times slower in Ivory *et al.*'s test. Secondly, to the effect of solvent type (CO_2 against $\text{CO}_2 + \text{C}_3\text{H}_8$ solvent mixture), and lastly to the length of the core which was three times longer. The data from cores # 1 and # 2 is consistent. Lower residual oil saturation was obtained from core # 1 due to its higher oil mobility (k/μ) and higher propane concentration. When these results are compared to Ivory *et al.*'s and Bryan *et al.*'s tests, the effect of gravity is not as pronounced as theirs. The core length was only 37.5 cm compared to 300 cm and 100 cm gravity head. Furthermore, the depletion rate applied for cores # 1 and # 2 experiments was much higher. This trend goes in agreement with the results from this study, in which slow depletion rates combined with gravity drainage enhanced the final oil recovery factor.

Jamaloei *et al.* (2012) conducted CSI tests in a horizontal configuration under high mobility conditions (high permeability core saturated with intermediate oil viscosity) and very high depletion rates. As it is observed, the final oil saturation at the end of six cycles was very close to core's # 1 residual oil saturation. This suggests that the process was dominated by a mobility effect and not by the gravity effect. The saturation plateau was reached at the last cycle, which also might

be attributed to the excess of void space and preferential gas pathways in the core that prevent the generation of high-pressure gradients as it was observed in the horizontal cycles of this study.

Figure 7-3: Comparison of oil saturation during CSI cycles obtained in this thesis with the data reported by different authors.

7.2. Effect of Pressure Drawdown Rate

Two sandpack models (core # 1 and # 2) were used to test the pressure drawdown rate on the CSI performance by applying slow and fast decline rates (12.4 kPa/h, 50kPa/h, and 124 kPa/h) under horizontal and vertical core alignments.

Table 7-2 shows the production data of all cores at each depletion rate. For cores # 1 and # 2, the core was horizontally positioned during the first two cycles and depleted at 124 kPa/h and 50 kPa/h respectively. Then, the core was vertically positioned and depleted at 124 kPa/h (cycle 3 to 5) and 12.4 kPa/h (cycle 6 and 7).

Figure 7-4 shows comparisons of the normalized recovery factor between core # 1 and # 2 with the pressure decline rate of 12.4 kPa/h, 50 kPa/h, and 124 kPa/h and sandpack orientation. The

normalized recovery factor was obtained by the cumulative recovery factor at each cycle over the recovery factor from primary production. Both cores show the same trend during vertical cycles; the ultimate oil recovery increased as pressure depletion rate decreased from 124 kPa/h to 12.4 kPa/h; however, with the fast depletion rate (124 kPa/h), the overall average oil production rate increased (see Table 7-2). Hence, in terms of overall average oil production rate, the optimal depletion rate was 124 kPa/h.

Figure 7-5 presents the pressure vs. cumulative oil RF during the CSI process under the pressure depletion rate of 124 kPa/h and 12.4 kPa/h (cycles 5 and 7 respectively) for cores # 1 and # 2. It is inferred that for both depletion rates, in the early phase of the depletion process, the gas bubble generation mostly comes from methane, as propane is more dissolved into the oil due to its higher solubility compared to methane. When pressure dropped below 2,500 kPa and 2,100 kPa in core # 1 and # 2 respectively, the propane started to nucleate and contribute to the oil flow. As pressure kept dropping, propane started to evolve from oil, resulting in oil viscosity regain and oil recovery decline. The foamy oil during CSI cycles was not significant as very low-pressure gradients were observed during the depletion. This observation supports the results of other researches (Soh *et al.*, 2018; Zhou *et al.*, 2016) in which the addition of propane reduced the foamy behavior.

Both cores followed the same trend of pressure vs. oil RF (%) at the two different depletion rates even when the solvent composition was not optimized for core # 2: 1) During slow depletion cycles (12.4 kPa/h), higher oil production is obtained at all system pressures compared to the fast depletion rate of 124 kPa/h. In vertical displacements, slow drawdown promotes a more stable displacement by reducing the gas channeling through the core. This leads to a more efficient oil

sweep and drainage compared to the fast depletion cycles. The higher C_3H_8 mole % solvent mixture exhibited a better performance in terms of oil RF during both slow and fast depletion rates. However, according to the residual oil saturation after all 7 CSI cycles (Figure 6-11), similar S_{or} was obtained from both solvents. This indicates that the highest C_3H_8 mole % solvent mixture can dilute and drain oil faster, which would be translated into less CSI cycles to obtain the same oil recovery than a mixture with lower C_3H_8 content.

Figure 7-4: Normalized oil RF for all seven CSI cycles in core # 1 and core # 2.

Figure 7-5: Oil recovery factor in function of core pressure for CSI cycles 4 and 7 of core # 1 and core # 2.

Several experimental studies have been conducted to evaluate the effect of pressure depletion in cold heavy oil production or methane-live oil systems. It had been observed by multiple researches (Maini, 2001; Shi and Kantzas, 2008; Alshmakhy and Maini, 2012; Jamaloei, 2013; Du *et al.*, 2018; Soh *et al.*, 2018; Sun *et al.*, 2016), that high-pressure depletion rates promote foamy oil flow and high oil RFs. However, as it was observed during CSI cycles, the effect of pressure depletion rate was the opposite. Hence, the rules of pressure decline rate cannot be generalized when high solubility solvents are added to the solvent mixture.

Figure 7-6 shows a plot of primary production from core # 1 and cycles 1 to 4 of core # 3. While core # 1 initiated with primary production (methane-saturated oil), the experiments in core # 3 were initiated with the CSI process by injecting 70% CH₄ and 30% C₃H₈. Both primary production and CSI cycles were conducted at a fast depletion rate of 124 kPa/h with the core horizontally

aligned. The differential pressures between the inlet and outlet of the core of CSI cycles 1 – 4 were much higher than was recorded in horizontal CSI cycles in core # 1 and # 2, but still lower than the DP during primary production in core # 1.

Figure 7-6: Oil recovery factor in function of core pressure for primary production (core # 1) and CSI cycles 1 – 4 core # 3.

In the absence of gravity drainage (cycle 1 and 2) in core # 1 and core # 2, the pressure depletion rate decrement from 124 kPa/h to 50 kPa/h did not have any impact of the heavy oil recovery factor. As previously discussed, the void space left after primary depletion led to high free gas saturation after the solvent injection, and therefore, low-pressure gradients to drive the oil out the core. Although this response was repeatable for both cores, previous studies have successfully obtained oil recovery from horizontal CSI tests (Qazvini Firouz and Torabi, 2012; Qazvini Firouz and Torabi, 2014; Jamaloei *et al.*, 2012) when very fast depletion rates are applied (500 kPa/min, and 9.4 – 112.6 kPa/min respectively). The difference between those studies and the horizontal tests of this study is primarily the depletion rate. During horizontal CSI tests, fast enough pressure

depletions are needed to generate a larger driving force for oil to flow before gas can leave solution and remove the energy from the system. As cycles 1 and 2 were run after primary production, the generation of a DP across the core at a drawdown rate of 124 kPa/h was even more complex due to the presence of continuous gas pathways through the core. Therefore, under these conditions, much faster depletion rates were required to obtain oil production as it was seen in the literature.

Figure 7-3 compares the residual oil saturation at each CSI cycle from Ivory *et al.* (2010) and Jamaloei *et al.* (2012). These experimental works are more comparable with core #1 and #2 tests as they primary depleted the core before the CSI process and they included C_3H_8 in their cyclic solvent injection. Ivory *et al.* (2010) conducted a 6-injection cycle experiment for long production times (roughly 60 days) and slow depletion rates (5 kPa/h). They used a stepped cone sandpack model vertically configured which successfully produced 43.6% OOIP. Under this slow pressure decline and 300 cm of gravity head, oil production was further dominated by the effect of gravity drainage compared to viscous forces. These results greatly support the outcomes from this study in which oil RFs from 16% to 25% were obtained by 5 CSI vertical cycles. However, Ivory *et al.* (2010) did not run CSI tests run with the model horizontally aligned to compare the results from horizontal tests of this study.

Jamaloei *et al.* (2012) introduced an enhanced CSI process in which CH_4 and C_3H_8 were sequentially injected in a rectangular sandpack horizontally aligned. Contrary to Ivory *et al.*'s physical model, the thickness was only 3.2 cm in which gravity forces could not rule oil production as in Ivory *et al.*'s experiments. Therefore, they applied much faster depletion rates (566 kPa/h –

6,759 kPa/h) to provide enough pressure gradient force. Through this methodology, they obtained successful incremental oil recovery of 34.3% from six ECSP and demonstrated the effect of high mobility (k/μ) and high DP on the recovery factor in CSI. Du *et al.* (2016) scaled down their pressure drawdown rates based on the scale ratio of Jamaloei *et al.*'s physical model thickness. In their study, they used a cylindrical sandpack of 30.48 cm length and 15.24 cm diameter to conduct CSI test with C_3H_8 at different pressure decline rates (750 kPa/h, 480 kPa/h, 300 kPa/h, 180 kPa/h and, 60 kPa/h). The final oil RFs from these tests were from 38.41% – 67.97%. If the same scale ratio is applied to the depletion rate of this study, based on the length of the sandpacks (37 – 37.5 cm), the depletion rate that should be applied during horizontal CSI cycles should be between 50 kPa/h – 585 kPa/h. These suggest that both depletion rates used in the horizontal tests (50 kPa/h and 124 kPa/h) were too slow to generate the required pressure gradient to produce the oil when the preferential pathways were already formed in the core (post-primary production).

7.3. Effect of Solvent Composition

Two solvent mixtures (solvent mixture # 1: 70% CH_4 – 30% C_3H_8 , solvent mixture # 2: 85% CH_4 – 15% C_3H_8) were investigated in this thesis. Since tests in this study were not performed in the same core (solvent mixture # 1 in core # 1, solvent mixture # 2 in core # 2), properties such as permeability varied between them, and therefore the datasets could not be compared directly. The recovery results are presented in Table 7-2. Oil recovery efficiencies (S_o/S_{oi}) of both solvent mixtures are compared in Figure 7-7.

Solvent mixture # 1 yielded a higher final oil recovery of 26% against 18% from solvent mixture # 2. This difference of 8 % OOIP is attributed to the higher concentration of propane in core # 1,

which supports previous results from Ahadi and Torabi (2018) in which additional 6% OOIP was recovered by increasing the propane concentration from 15% to 30% in the CH₄ stream (see Figure 7-7). One of the mechanisms contributing to higher oil recovery is the higher diffusion rate of propane in the heavy oil. The oil saturation at every cycle in Ahadi and Torabi experiments followed a more linear trend than the results from this study. This is attributed to the difference in the initial oil saturation due to the absence of primary production in their experiments. This effect will be further discussed in next section by comparing Ahadi and Torabi results with core # 3.

Figure 7-7: Comparison of oil recovery efficiency in terms of oil saturation for both solvent mixtures and with the data reported by Ahadi and Torabi (2018).

The solvent oil ratio (SOR) defined at the gas injected in scm³ divided by the volume of oil produced (cm³) at each cycle was higher for most of the vertical cycles during core # 2 tests (see Figure 7-8). It is worth mentioning that the SOR does not take into account the accumulated solvent at each cycle, only the injected volume. Also, higher propane was recovered during core # 2 tests

than core # 1 CSI cycles (52.7% against 46%). Higher propane concentration in the effluent gas meant that less propane was dissolved in the collected production oil samples and the remaining oil in the core, and therefore, lower oil viscosity reduction was achieved with the solvent mixture # 2.

As previously mentioned in Chapter 7.1, it was found that the S_{or} obtained from both mixtures did not significantly varied from each other (~ 2% from MB). This observation along with the residual oil saturation at each zone of the core indicated that the residual oil saturation is not a strong function of the solvent composition. However, higher propane content can enhance the dilution and drainage of oil, proving higher incremental RF per cycle. Hence, using the 15% propane concentration mixture means that more CSI cycles are required to obtain the same final saturation than the 30% propane mixture.

It is important to recall that core # 1 permeability was twice the permeability of core #2, which is another factor influencing the mobility oil rate during CSI. Hence, the higher final oil recovery obtained during core # 1 experiments is the result of combining a higher soluble oil mixture and a higher permeable core.

Figure 7-8: SOR data of vertical CSI cycles in core # 1 and # 2 tests (solvent mixture # 1 and # 2 respectively).

7.4. Effect of Initial Oil Saturation

Jamaloei *et al.* (2012) observed that after conducting several CSI cycles, the decreased in the available residual oil saturation caused an abrupt drop in the oil RF per cycle. In this study, the diluted oil was constantly pooled at the bottom of the core due to gravity drainage, which in turns maintained the oil saturation constant at the production end area. Therefore, significant decrements in the oil RF after vertical cycles were not observed. However, to study the effect of initial oil saturation, horizontal CSI cycles were initiated in core # 3 without primary production. This meant, 9% and 15% higher oil saturation than core # 1 and # 2 respectively at the beginning of the CSI process.

Figure 7-9 (a) shows the oil recovery efficiencies in terms of S_o/S_{oi} for all three cores. It is observed that core # 1 and core # 2 data points follow the same trend, with a slight attenuation on the slope

for core # 2 data due to the effect of solvent composition and core permeability as previously mentioned. Oil saturation per cycle in core # 3 behaves different than core # 1 (same solvent) and this trend can be analyzed in two sections: From the initial S_o/S_{oi} to about 0.87 (cycle 3), the oil saturation followed a linear trend. Once the core reached a $S_o/S_{oi} = 0.86$, close to the S_o/S_{oi} after primary production in core # 1, oil recovery abruptly declined, and that is observed in the S_o/S_{oi} plateau at the 4th cycle. At that point, the core was flipped vertically, and oil saturation started to respond similarly to cycles 3 – 5 of core # 1.

As the CSI process in core # 3 initiated at higher initial oil saturation, the first 4 cycles could be conducted with the core horizontally aligned keeping relative slow depletion rates (124 kPa/h). However, if primary production is included, the horizontal displacement does not work at this depletion rate as it was observed in core # 1 and # 2 horizontal tests. This observation suggests the primary production (initial oil saturation before CSI) as another variable that affects the final oil recovery and the operative schemes applied during CSI processes.

Figure 7-9 (b) compares core # 3 results with Ahadi and Torabi (2013) data. They conducted CSI cycles without primary production in a core horizontally positioned of 33.5 cm length and 9.4 D permeability. The core was saturated with heavy oil of 6,430 mPa·s viscosity. They injected two different solvent mixtures (same mixtures of this study) and depleted the core in 1 hour. The oil mobility ratio (k/μ) of their tests was much higher (~ 1.46) compared to core # 1 (0.05) and core # 2 (0.03) mobility ratios. Figure 7-9 (b) shows that their results using a solvent mixture of 30% propane exhibited the same trend and overlapped many S_o data points of core # 3 cycles. This suggests that during the CSI process, gravity forces can compensate for the limited oil mobility in the porous media. In other words, gravity forces can provide incremental oil recovery from

multiple CSI cycles under much smaller pressure depletion rates (closer to the field), even when there is already significant void space and free gas saturation across the core.

Figure 7-9: Effect of initial oil saturation in CSI tests: a) Comparison of oil saturation normalized to the initial oil saturation for cores # 1 and # 2 (primary depleted) and core # 3 without primary depletion. b) Comparison of oil saturation normalized to the initial oil saturation of core # 3 with Ahadi and Torabi (2018) tests.

7.5. Oil Viscosity Measurements

The viscosity of the oil samples taken during the production phase of all vertical cycles was also measured to be compared with the original oil properties. Unfortunately, only a few samples obtained from horizontal cycles were measured due to its limited volume. The viscosities of the samples were measured at atmospheric pressure and a temperature of 20°C using a Brookfield cone and plate viscometer with the spindle CPA-52Z, which covers the viscosity range of 3-92,000 mPa.s.

As the produced oil samples contained emulsified water, the viscosity measured by the viscometer corresponded to the viscosity of the emulsion. When emulsified drops of water are present in the

continuous phase (heavy oil), they create barriers for oil to flow, which is reflected in a change in the shear stress, and therefore a smaller change in shear rate. As a result, the volume of emulsified water leads to a viscosity increase (Pal *et al.*, 1992). To estimate the viscosity of the heavy oil, Einstein's theory of viscosity for emulsions was used:

$$n_r = 1 + 2.5 \varphi \quad (7.5-1)$$

Where n_r is the relative viscosity; the ratio between the emulsion viscosity to the oil viscosity, and φ is the dispersed water volume fraction.

This model proposes that the relative viscosity of emulsion increases linearly with the dispersed volume fraction. It also assumes that the emulsion is diluted, which means that the suspended particles are dispersed and that they are “hard spheres” (Pal *et al.*, 1996).

To determine the volume of the emulsified water, Nuclear Magnetic Resonance (NMR) spectroscopy was employed. The parameters were defined at an echo spacing of 0.34 ms, 7,395 echoes, 32 trains and a 12 s of repolarization time. The emulsion NMR relaxation distribution of the original dead oil is shown in Figure 3-13. The first peak corresponds to the oil and the following peaks to the water. Hence, the peak under 10 ms is viscous oil, and the other large peak at 400 ms is water in large emulsion droplets. The other peaks above 10 ms and below 200 ms are water in smaller emulsion droplets.

The NMR data was also used to calculate the relative hydrogen index (RHI) of the first oil peak. RHI is defined as the NMR amplitude per unit mass of oil, normalized to the known amplitude per unit mass of water. As previously mentioned in Chapter 3, this index can be used as a viscosity

indicator. As viscosity increases, the general trend is for RHI values to decrease (Bryan *et al.*, 2001).

The oil samples from core # 2 and # 3 tests had water fractions ranging from 0 – 26% and 0 – 18%. However, most of the samples taken during the CSI contained about 3 – 7% water. The samples with higher water fractions corresponded to the produced oil during primary production.

Figure 7-10 and Figure 7-11 present the measured viscosity of the emulsion, the estimated oil viscosity, and the RHI obtained from the NMR measurements at different stages of the process.

Figure 7-10 shows the viscosity measurements during core # 2 tests. It is observed that there was no reduction in the produced oil viscosity compared with the original oil viscosity. On the contrary, all samples presented higher oil viscosity values for both measured emulsion viscosity and the estimated oil viscosity. This difference was higher for the CSI cycles than for the primary production samples. The measured RHI for the produced samples was lower than the RHI of the original oil sample, except by primary production samples (1, 3 and 11). The decreasing trend correlates with the measured oil viscosity values as lower RHI translate into higher oil viscosities. This observation of produced oil viscosities being higher than the original oil viscosity might be attributed to the aging of the samples: the viscosity measurement of these samples was conducted almost 4 months after the first sample was taken. Loss of volatile compounds or evaporation damage could have affected the samples, which resulted in very high viscosities.

Jiang *et al.*, (2010) found that viscosity measurements of bitumen that had been previously in contact with solvents can be either higher or lower than the correct value due to evaporation of volatile compounds or remaining solvent in the samples.

The effect of aging has been also found to affect the viscosity of the emulsion. Upon aging, the water droplets coarsen due to coalescing and, therefore, the viscosity of the emulsion decreases (Pal, 1996). This statement might explain why the viscosity of the primary production samples, which had higher water fraction, was closer to the original oil viscosity value. However, according to this, the effect of losing volatiles might be stronger than the aging of the emulsion.

Figure 7-11 shows the viscosity measurements during core # 3 tests. Contrary to what was observed in the core # 2 results, the viscosity of the produced oil was closer to the original oil viscosity, and for few samples lower. It is evidenced that for both cores, the lower oil viscosities were measured in the last cycle. Which in the case of cycle 7 (core # 3), viscosity measurements were done just 20 days after their collection. This observation supports the theory of volatile compounds evaporation due to the aging of the samples, as samples in the early cycles exhibited much higher oil viscosities compared to the original oil viscosity. The measurements from core # 3 samples also showed that even when a higher propane concentration was present in the injected solvent mixture and aging was not long, oil viscosity improvements were not observed.

During CSI production, it was observed that the produced oil appeared to be foamy, and the propane content in the produced gas also often was less than the injected concentration (30% or 15%). These observations indicate that the produced oil initially still contained some residual propane even at ambient conditions. After leaving the samples for an extended period of time, there was no indication from either NMR or measured viscosity values that there was any residual solvent still in the oil. This shows that, even if propane is slow to exsolve from heavy oil, it does not remain stably trapped in the oil.

Previous authors (Lim *et al.*, 1995; Ahadi and Torabi, 2018) have reported that oil upgrading is obtained when enough oil is dissolved into the oil, and asphaltene separation occurs.

In this study, asphaltene content was measured in the original oil and two samples from cycles 5 and 7 with solvent mixture # 1 (30% C₃H₈ + 70% CH₄). The initial oil asphaltene content was measured to be 19.8 wt.%, and for cycles 5 and 7 was 19.7 wt.% and 20.2 wt.% respectively. These results indicated that there was no change in the asphaltene content on the produced oil, and therefore no asphaltene precipitation occurred at this propane concentration. These results match Ahadi and Torabi (2010) work, who observed asphaltene precipitation only when propane went beyond 50 mol% in the solvent mixture with methane, which is higher than what was used in this study. Yarranton *et al.*, (2008) also observed that solvent mixtures with propane and carrier gases are less likely to precipitate asphaltenes than pure C₃H₈.

Therefore, the absence of asphaltene precipitation at 30 mol% propane concentration tests coincide with the oil viscosity measurements from the viscometer and NMR, as oil viscosity improvement was not observed during these tests. Oil produced from CSI in the range of propane tested in this study comes from dilution, not from deasphalting within the sand.

Figure 7-10: RHI, measured emulsion and oil viscosity for different oil samples taken during core # 2 tests.

Figure 7-11: RHI, measured emulsion and oil viscosity for different oil samples taken during core # 3 tests.

8. CHAPTER EIGHT: CONCLUSIONS AND RECOMMENDATIONS

To further study the recovery mechanisms behind CSI processes, primary depletion and cyclic solvent injection of two different propane and methane ratios were performed in three cores of similar properties. CT scanning, NMR, and Dean-Stark were used to provide further understanding of how fluids distribute in the core and flow under different operating conditions during CSI. This chapter lists the major contributions of this thesis and the recommendations for future work in the same area.

8.1. Conclusions

1. In horizontal dead oil systems (no primary production), where initial oil saturation is high, the application of horizontal CSI lasted four cycles, before oil recovery decreased on a “per cycle” basis. Oil is recovered while the gas solvent is forming pathways across the core; once they are created, pressure communicates too quickly across the core and there is no significant pressure gradient and accordingly, oil recovery abruptly drops.
2. In the post-primary CSI horizontal tests, significant void space and free gas saturation are present throughout the system. Under these conditions, it was not possible to establish a pressure gradient across the core. Without this pressure gradient, even if solvent dilutes into oil, there is no driving force to mobilize the diluted oil, and therefore, negligible incremental oil recovery is obtained.
3. When significant void space is present in the core, horizontal CSI tests exhibited oil recovery factors below 2% per cycle, compared to per cycle oil RF on the order of 5% at high initial oil saturation conditions.

4. When the core is vertically aligned, during the injection and soaking periods, the gaseous solvent rises through the core and dissolves into the oil. Then, the diluted oil drains down to the bottom of the core. When the production stage is initiated, the pooled oil is produced from the bottom end of the core and improved incremental oil recovery factors are obtained (4% to 8% RF per cycle).
5. The analysis of CT images allows for an understanding of where in the core the oil comes from. During each vertical cycle, the void space left by the recovered oil is replaced by oil banking at the bottom of the core due to gravity drainage, and repeatable oil production is then achieved in the following cycles.
6. The analysis of the residual oil saturation from the Dean-Stark shows that gravity forces along with solvent oil dilution can sweep oil zones down to 35% residual oil saturation.
7. The oil recovery from vertical CSI tests in core # 1 was 25%. The total incremental production exceeds the recovery from primary production, so there is potential for considerable oil recovery from solvent CSI. This demonstrates that gravity drainage is playing a significant role in oil production from CSI even in a 37-cm length sandpack, and the favorable field response from the CSI could be partially attributed to its effect.
8. For both solvent mixtures, the ultimate oil recovery increased as pressure depletion rate decreased from 124 kPa/h to 12.4 kPa/h; oil recovery at slow depletion rates is more efficient as oil is recovered under higher system pressures. Slow depletion gave incremental oil recoveries of ~7% per cycle, compared to 4% per cycle under higher rates (30% C₃H₈ mixture). However, fast depletions were run an order of magnitude faster, so for the same time, the overall average oil production is higher at the fast depletion rate.

This means that slow depletion rates under gravity forces provide a more stable displacement but as a function of time it is better to deplete faster.

9. The solvent mixture with the composition of 30% C_3H_8 yielded an incremental RF of 26 % compared to 18% for the 15% C_3H_8 solvent mixture. However, at the top of the core (i.e. the well-drained zone), Dean-Stark measurements showed a residual oil saturation on the order of 35%. This indicates that the residual oil saturation is not a strong function of the solvent composition, but higher propane content can enhance the dilution and drainage of oil, resulting in higher final oil RFs for the same production time.
10. Both solvents exhibited a similar trend under the effect of gravity forces, however, this effect increases when slow depletion rates are applied. Incremental oil RF between the 30% C_3H_8 and 15% C_3H_8 solvent mixture increases from 25% to 50% when the drawdown rate drops from 124 kPa/h to 12.4 kPa/h.
11. There was no evidence of foamy oil acting as a production mechanism in the solvent-oil systems from this study, i.e. there was no region of an elevated pressure gradient across the core, like what was observed during primary production. However, foam in the produced oil indicates the slow-release of propane even at ambient conditions.
12. Measurements of oil viscosity and asphaltenes content indicated that the oil produced from CSI in the range of propane tested in this study comes from dilution, not from de-asphalting within the sand.
13. The data obtained from these experiments were compared with experimental works from the literature. Most of the trends observed under the effect of this study's variables fit the trends obtained from the literature.

8.2. Recommendations

Recommendations for future studies are as follows:

1. Modeling of gravity forces in the physical lab models could partially explain continuous oil production during multiple CSI cycles in the field. However, tests were run in the absence of wormholes, which is a phenomenon present in post-CHOPS reservoirs. Therefore, it is essential to evaluate if, under the effect of high permeable channels at the top of the reservoir, the solvent would still be able to dilute the oil and drain due to gravity. The evaluation of these parameters in 2-D or 3-D physical models would come closer to reservoir scale conditions.
2. Gravity forces were found to be an important mechanism for oil recovery in primary depleted systems where viscous forces (pressure gradient) do not provide enough drive for diluted oil flow. However, the effect of gravity forces was not studied in dead oil systems with low void space. An additional test starting with vertical CSI cycles in fully oil saturated cores would provide more data to compare the effect of this mechanism under different reservoir conditions.
3. The fast depletion rates applied in these experiments were not large enough to drive oil out of the core when large void space and preferential gas flow paths are present after primary production. Additional horizontal post-primary CSI cycle tests at higher depletion rates would show the minimum depletion rate required in the laboratory to generate a large enough driving force for oil to flow when gravity forces are absent. Final oil RFs could be compared with the available data in the literature at these experimental conditions.
4. Investigate the effect of the injection pressure during late CSI cycles where oil is already saturated. This accompanied by samplings at the other end of the core where the injection

is not occurring, would provide evidence of how far from the injection port the solvent is dissolving into the oil and whether pressure travels through oil compression or solvent dissolution.

5. The results of this experimental work showed the effect of different mechanisms present in the CSI process. However, it is necessary to apply numerical models to validate the experimental results and conduct a sensitivity analysis of the variables of this study.
6. Operational parameters during the solvent injection such as pressure and time might affect the CSI performance in field applications. Therefore, it is advisable to conduct additional CSI laboratory tests that evaluate the effect of short injection vs. long injection times when the same solvent volumes are injected.
7. Conduct the same experiments of this study using different solvent mixtures would provide further data to compare their effects on oil dilution and drainage, foamy oil behavior, and overall efficiency in terms of ultimate RFs when different depletion rates and gravity forces are applied.
8. Measuring the residual solvent of the remaining oil in the core and the solvent entrained in produced oil samples would offer a more accurate estimation of the gas material balance.
9. Using a flow rate controller during the injection period and a flow gas meter for the production phase would help to easily quantify the amount of solvent that is injected into the core and that is produced in each cycle.

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Appendix A: Core Packing and Saturation Assessment

Table A-1 compares the main core properties and fluid saturations after live oil/dead oil saturation of all three cores.

The highest initial oil saturation was obtained during the live oil saturation of core # 1. Although porosity for all cores was about 38%, the CT density profiles for each core after packing (dry state) showed different porosity distribution and heterogeneity. After primary production, the residual oil saturation varied 6% between cores # 1 and # 2.

Table A-1: Core properties and fluids saturation after oil saturation and primary production processes.

Core	Porosity (%)	Permeability (D)	Oil saturation		Primary Production		
			S_o (%)	S_{wi} (%)	S_o (%)	S_{wi} (%)	S_g (%)
Core # 1	37.4	1.5	87.3	12.7	74.7	10.8	14.5
Core # 2	38.3	0.8	83.4	16.6	68.3	13.4	18.3
Core # 3	37.8	3.3	83.7	16.3	83.7	16.3	0

To better analyze the saturation gradient thorough the core after primary depletion, the oil saturation distribution was determined using the CT bulk density of each slice at different stages (dry, saturated with oil, and post-primary production) as shown in Equation (A-1).

$$S_o = \frac{\rho_{post-primary\ depletion} - \rho_{dry}}{\rho_{oil\ saturated} - \rho_{dry}} \quad (A-1)$$

To determine the bulk density of each slide, first it was necessary to build a calibration curve using materials of known density and measuring the CT numbers as shown in Figure 3-4. Then, an

equation in function of both variables was obtained and was used to calculate the bulk density of the core from the respective CT numbers measured during the scanning:

$$Density = m * CT\ number + b \quad (A-2)$$

Where m corresponds to the slope of the line, and b to the y-intercept.

Then, by using a Java-based image processing program (Image J), the mean CT number and its respective standard deviation was determined for each standard. The density of each core slide and its standard deviation were calculated using Equation (A-2).

Table A-2 shows that the standard deviation increases for porous materials such rocks. Hence, for a porous medium saturated with water, oil and gas, the associated error to the CT measurements is even higher. Therefore, the overall oil saturation obtained from Equation (A-1) was matched with the average oil saturation determined by the material balance. From this, the CT provided the oil saturation distribution at the different stages (post-primary production and after each CSI cycle. For the oil saturation calculation, the S_w was assumed to be constant along the whole core and the value was the residual water saturation after every stage of the process (i.e. primary depletion and CSI cycles).

Table A-2: Standard deviation and error from CT density measurements.

Material	Mean CT number	True Density (kg/m ³)	SD CT number	Calculated Density (kg/m ³)	SD Density (kg/m ³)	Error (g/cm ³)
Acetone	-217.3	787.3	9.2	740.2	± 8.2	0.038
DI H ₂ O	13.8	997.5	7.9	947.4	± 7.1	0.043
Berea Sand	1198.0	2024.6	20.2	2008.7	± 18.1	0.0022
Grey Core	1406.4	2207.3	49.1	2195.6	± 44	0.032
Aluminum	2018.7	2695.7	27.7	2744.3	± 24.8	0.073
Air	-957.5	1.2	7.3	76.8	± 6.6	0.082

Figure A-1 (a) plots the cores density profiles after sand packing. Because the density profiles correspond to dry cores packed with a sand density of 2,650 kg/m³, cores bulk density falls between 1,500 to 1,700 kg/m³ based on their porosity. Toward the ends of the core the density contrast is higher than for other regions of the core. As the core bottom (i.e. length 0 mm) was the top of the original core pack, density was lower, and porosity was higher in this region of the core. There are variations in density along the cores, which corresponds to zones of higher or lower porosity (heterogeneity). It is observed that core # 2 was the less compact but the most homogeneous pack. Core # 2 had the lowest density, which is translated into the highest porosity. The fact of getting a looser packing means that there were more mobile grains, which could have caused the plugging of the outlet screens. That might be the reason of its low measured permeability.

Core # 1 was better packed than core # 3 (i.e. less variations in porosity along its length) and this is observed in its permeability which was 50% of core's # 3.

Figure A-1 (b) shows the oil saturation profile after primary depletion. As core # 2 was more uniformly packed (lower changes in overall bulk density), the oil saturation gradient after primary production was slightly lower than what was seen in core # 1. As it was expected, oil saturation at

the bottom part of all cores was lower than their tops regions, because oil close to the production end will be produced most easily during primary production. Overall, the mean CT porosity was around 38%, this shows that solids filled 62% of the total volume of the core, which is between simple cubing packing (52%) and cubic close packing (74%), which indicates that cores were uniformly packed with an exception of the two ends (inlet and outlet). To achieve a more uniform and compact sandpacks, wet packing is recommended.

Figure A-1: a) CT density profile of dry cores. b) Post-primary production oil saturation profile for cores # 1 and # 2 after.

Appendix B: Measurement of Brine Permeability

The absolute permeability to brine was determined by flowing brine through the sandpack using a constant water head pressure at the inlet of the core and recording its flow rate at the core outlet. Table B-1 shows the average velocity under different pressure gradients. The absolute permeability of the sandpack was determined from the slope of flow rate versus pressure gradient, as shown in Table B-1. The repeatability of the permeability measurement is expected to be ± 0.03 D.

Table B-1: Brine Permeability Measurements.

Water height (cm)	Pressure gradient (atm)	Flow rate (cm ³ /min)			Average velocity (cm/s)	Permeability (D)
53.2	0.0321	5.3	5.28	5.34	0.00152	1.56
61.1	0.0397	6.38	6.39	6.36	0.00183	
69.3	0.0477	7.48	7.48	7.45	0.00215	
78.3	0.0564	8.85	8.845	8.81	0.00254

Figure B-1: Absolute permeability to brine measurements.

Table B- 2 summarized the absolute permeability to brine of all three sandpacks. Three measurements were conducted for each pressure drop in order to confirm the repeatability of the measurements. Based on a 90% confidence interval, the repeatability was ± 0.03 D, ± 0.01 D, and ± 0.007 D respectively.

Table B- 2: Summary of brine permeability.

Sandpack No.	Permeability (D)
1	1.56
2	0.79
3	3.32

Repeatability Determination

The appropriate statistical distribution for determining the confidence interval based on a sample variance is the *t-distribution*. The formula used to calculate the confidence interval was:

$$\bar{x} - t_{\left(\frac{\alpha}{2}, v\right)} \frac{s}{\sqrt{n}} \leq \mu^* \leq \bar{x} + t_{\left(\frac{\alpha}{2}, v\right)} \frac{s}{\sqrt{n}} \quad (\text{B-1})$$

Where μ is the correct mean, n is the number of repeat measurements, s is the sample standard deviation, v is the degree of freedom which is equal to $n-1$, and $\alpha = 1 - (\% \text{ confidence interval}/100)$.

The parameter can $t_{\left(\frac{\alpha}{2}, v\right)}$ be found from t-test tables (McClave and Sincich, 2003).

Appendix C: Related Graphs of Production during CSI

Figure C-1: Pressure, oil recovery factor and GOR vs. time during the production phase at 124 kPa/h in core # 1: a) Cycle 4. b) Cycle 5.

Figure C-2: Pressure, oil recovery factor and GOR vs. time during the production phase at 124 kPa/h in core # 3: a) Cycle 1. b) Cycle 2.

Figure C-3: Pressure, oil recovery factor and GOR vs. time during the production phase at 124 kPa/h in core # 3: a) Cycle 3. b) Cycle 4.

Figure C-4: Pressure, oil recovery factor and GOR vs. time during the production phase at 124 kPa/h in core # 3: a) Cycle 5. b) Cycle 6.

Appendix D: Calculation of Post-CSI Fluid Saturations from Dean-Stark

Table 4-6 shows the data obtained from the Dean- Stark measurements in core # 1, which basically is: oil, water, and sand masses converted to volumes using their respective densities.

The pore volume (PV) of each cut section of the core is calculated using the volume and porosity of that section measured with the CT scanner when the core was in the dry state. Finally, the saturation of each fluid at each section is determined by dividing the volume of fluid obtained measured from the Dean-Stark and the PV.

The following equations show the procedure to calculate the residual fluid saturations after the CSI process:

$$V_{bulk} = A * L_{cut} \quad (D-1)$$

Where, V_{bulk} is the bulk volume, A is the average area of the cut cross section of the core, and L_{cut} is the length of each section of the core.

$$PV = V_{bulk} * \varphi \quad (D-2)$$

Where, PV is the pore volume of the section, and φ is the average porosity of the section measured with the CT scanner.

$$S_o = \frac{V_{oil}}{PV} \quad (D-3)$$

$$S_w = \frac{V_{water}}{PV} \quad (D-4)$$

$$S_g = 1 - S_o - S_w \quad (D-5)$$

Where, S_o is oil saturation, S_w is water saturation, and S_g is gas saturation at the volume of the cut section. V_{oil} is the volume of oil in cm^3 , and V_{water} is the volume of water.

Appendix E: CT images

The CT images were processed using the Image J software. Figure E-1, Figure E-2, and Figure E-3 show images of the core # 1 in the dry state, after primary production, after cycle 5, and after cycle 7. These images compare the core state after the main oil production stages to better visualize the changes in density of the images. The montage shows images of the core taken at every 5 mm, being the 5 mm the first image and the 37 cm the last image (from top to bottom and left to right). The first and last images (0 cm and 37.5 cm respectively) are not included as they were affected by the effect of the mandrels at the inlet and outlet of the core. The legend below the images represent the density in kg/m^3 , where the blue color is the lowest density and the red color is the highest density.

Figure E-1: CT density images of core # 1, legend represents the density in kg/m^3 . a) Core CT density at the dry state. b) Core CT density after live oil saturation.

Figure E-2: CT density images of core # 1after primary production, legend represents the density in kg/m³.

Figure E-3: CT density images of core # 1, legend represents the density in kg/m^3 . a) Core CT density after vertical cycle 5 (124 kPa/h). b) Core CT density after vertical cycle 7 (12.4 kPa/h).

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