EXPERIMENTAL AND NUMERICAL INVESTIGATION OF CYCLIC SOLVENT INJECTION (CSI) PERFORMANCE IN HEAVY OIL SYSTEMS IN THE PRESENCE OF WORMHOLE NETWORKS

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By

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Nathan Abraham David, candidate for the degree of Master of Applied Science in Petroleum Systems Engineering, has presented a thesis titled, *Experimental and Numerical Investigation of Cyclic Solvent Injection (CSI) Performance in Heavy Oil Systems in the Presence of Wormhole Networks*, in an oral examination held on July 27, 2018. The following committee members have found the thesis acceptable in form and content, and that the candidate demonstrated satisfactory knowledge of the subject material.

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ABSTRACT

Cyclic Solvent Injection (CSI) technique has demonstrated great potential to improve oil production in thin post-CHOPS reservoirs (thickness < 10 m), which are characterized by wormhole networks; where thermal and gravity-dominated methods fail to sufficiently enhance oil production. Several investigations and considerable speculations have been made to understand the oil recovery mechanisms, optimum mixing ratio of hydrocarbon solvents/CO₂, as well as the cyclic injection scenarios of the process. In addition, the importance of wormhole coverage in the performance of CSI has been addressed in the literature; however, the studies on the effect of wormhole branching and networks in relation to the production performance are relatively limited.

In this study, the performance of cyclic solvent injection for a heavy oil (with viscosity of μₒ = 4440 mPa.s at T = 21°C) system is experimentally investigated in a 2D rectangular sand-packed model with different wormhole networks. Firstly, a series of cyclic injection tests with two solvent compositions of 15% C₃H₈ – 85% CO₂ and 50% C₃H₈ – 50% CO₂ were conducted in non-wormhole and linear wormhole porous media at the same operating pressure and temperature to determine the impact of the injection composition on the recovery efficiency of this process. Thereafter, similar tests were designed and carried out with the most feasible solvent composition (15% C₃H₈ – 85% CO₂) in a single-branched and double-branched wormhole networks porous media to determine the impact of the wormhole configuration on the performance of this process. The sand-pack model used in these tests had an absolute permeability and porosity ranging from 9 – 11 D and 31 – 34%, respectively. The performance of each wormhole configuration was investigated by measuring the heavy oil recovery factor (RF), solvent
oil ratio (SOR), foamy oil stability, solvent-produced oil asphaltene content, and residual oil saturation.

For the cyclic solvent injection tests (15% C₃H₈ – 85% CO₂ and 50% C₃H₈ – 50% CO₂) conducted at the same operating conditions, it was found that oil recovery increases with increased concentration of C₃H₈ in the solvent mixture. It was also observed that the presence of single-linear wormhole network promoted foamy oil flow in the system and consequently improved the performance of CSI (15% C₃H₈ – 85% CO₂) process by increasing the ultimate oil RF from 6.62% to 27.2%. Furthermore, adding a single wormhole increased the ultimate oil recovery to 36.04%, while the double-branched wormhole improved the ultimate oil recovery factor to 43.5%. Additionally, extending the pre-defined soaking period of 24 hours to 96 hours in the presence of double-branched wormhole significantly improved the cyclic oil recovery during the process. However, the longer soaking time did not noticeably change the ultimate oil recovery.

The solvent-produced oil asphaltene content was measured after each cycle, and the results showed that asphaltene molecules are deposited in the sand pack porous media during the process. The asphaltene precipitation made the remaining oil heavier and gradually caused the cyclic oil recovery to decrease.

Finally, the dispersion coefficient, reaction rate in the foamy oil model and relative permeability curve were examined by numerical simulation. It was found that the simulation results of dispersed gas foamy oil model have relatively more accurate predictions than those of the modified-fractional flow approaches.
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DEDICATION

First, I dedicate this thesis to Almighty God for granting me strength, confidence, and knowledge every day of my life.

Also, to my dearest parents Mr. and Mrs. Abraham David, and my dear siblings for their understanding, patience, endless love and their overwhelming support morally.

To my loving friends Ms. Bukola Yusuf, Mr. and Mrs. Essien, Enesoso Charles, Praise Koobee, Ola, and Mr. and Mrs. Babalola.
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NOMENCLATURE

Symbols

\( C_p \) Coefficient of variance

\( D_p \) Particle size

\( k \) absolute permeability (D)

\( MW \) molecular weight (g./mol)

\( P_{\text{inj}} \) injection pressure (kPa)

\( S_{wc} \) connate water saturation

\( S_{oi} \) initial oil saturation

\( S_{or} \) initial oil saturation

\( T \) temperature (°C)

Greek Letters

\( \rho_o \) crude oil density (kg/m\(^3\))

\( \rho_w \) water density (kg/m\(^3\))

\( \mu_o \) oil viscosity (mPa.s)

\( \mu_w \) water viscosity (mPa.s)

\( \phi \) porosity
Abbreviations

BPR Back Pressure Regulator

CHOPS Cold Heavy Oil Production with Sands

CT Computer Tomography

CSI Cyclic Solvent Injection

CPCSI Cyclic Production with Continuous Solvent Injection

DSP Dynamic Solvent Process

ECSP Enhanced Cyclic Solvent Process

EOR Enhanced Oil Recovery

FGSR Faculty of Graduate Studies and Research

GA-CSI Gasflooding-assisted Cyclic Solvent Injection

OOIP Original Oil in Place

PTRC Petroleum Technology Research Centre

RF Recovery Factor

SOR Solvent Oil Ratio

SRC Saskatchewan Research Council

VAPEX Vapor Extraction
SVX Solvent Vapor Extraction
CHAPTER 1: INTRODUCTION

1.1 Background

The Western Canadian Sedimentary Basin contains approximately two-thirds of heavy oil resources. The heavy oil in place found in less than 5 m thick reservoirs of the Lloydminster area, located on the Alberta-Saskatchewan border, is a significant portion of the total Canadian oil production (Alvarez and Coates, 2009; Zhang et al., 2014; Zhao et al., 2015). The vast liquid petroleum resources with an API gravity of below 20 in Western Canada, which are largely in unconsolidated sandstones with high porosity, have led to Cold Heavy Oil Production with Sands (CHOPS). CHOPS primary recovery successfully initiates continuous sand production along with oil through the perforated oil well, because of the huge pressure drawdown caused by a progressive cavity pump. It is a proven primary heavy oil production technology, that has manifested great economic advantage with an average ultimate recovery factor of 10% (Istchenko and Gates, 2012; Istchenko and Gates, 2014; Rangriz Shokri and Babadagli, 2014, 2015). Thus, approximately 90% of the oil remains untouched underground, which causes the process to be uneconomical in most cases. Therefore, an enhanced-oil-recovery (EOR) followed-up technique is necessary for CHOPS wells and fields to recover additional heavy oil.

The physical processes occurring in the reservoir during CHOPS is completely different from those that occurred during primary oil recovery in conventional oil reservoir (Dusseault, 2002). Some of the physical processes that explained the difference include foamy oil, massive stress redistribution, liquefaction of sands, and flow of a flour-slurry. Moreover, field experience shows that foamy flow in the reservoir condition results in oil production with a very low gas-oil ratio. Dusseault (2002) report for Alberta
Energy elaborates that the natural energy sources necessary for this new primary technology are from compressional energy, i.e., dissolution and expansion of gas and gravitational energy. In addition, the application of progressive cavity pump (PCP) in production wells for simultaneous flow of oil and sands to the wellbores, cold production has become an attractive primary technique for the development of thin (i.e. 2m to 10m) heavy oil formations (Rangriz Shokri and Babadagli, 2012; Tremblay, 2007). The aggressive sand production has improved oil production rates due to the generation of connected high permeable channels, i.e., wormholes network and dilated zones around the wellbore. These connected networks are believed to be of tens of centimeters in diameter and extended hundreds of meters within the reservoirs (Zhao et al., 2015). Field experience supports the idea that wormholes are one of the most significant mechanisms, which enhanced oil production rates in CHOPS. Squires (1993) reported that the communication of fluorescein dyes during the inter-well tracer test within a few hours after injection confirmed the existence of wormholes network. Therefore, the presence of wormholes network makes depleted CHOPS wells or fields unsuitable for conventional flooding processes to extract additional heavy oil (Tremblay, 2007; Zhao et al., 2015). Therefore, the search for a follow-up EOR or IOR processes that recovers heavy oil from a CHOPS reservoir beyond the mentioned recovery factor range has intensified.

Several researchers have proposed that wormholes can serve as flow paths for solvent or steam cyclic processes and gravity drainage-based processes (Du et al., 2015). However, the significant loss of heat due to thin net-pays of post-CHOPS reservoirs, limits the application of steam-based processes in terms of energy cost per unit volume of oil produced, environmental pollution, and in situ upgrading (Du et al., 2015; Yadali
Jamaloei et al., 2012; Zhao et al., 2015). In comparison, solvent-based processes are a better choice for recovering additional oil in a post-CHOPS reservoir, mainly because of their lower energy consumption, less environmental pollution, and lower capital costs (Qazvini Firouz and Torabi, 2012). Experimental studies show that solvent injection processes, such as vapor extraction (VAPEX) (Butler and Mokrys, 1998), Cyclic Solvent Injection (CSI) (Ivory et al., 2010), lateral SVX (Butler and Jiang, 2000; Zeng et al., 2008), and enhanced cyclic solvent process (ECSP) (Yadali Jamaloei et al., 2012), use a vaporized solvent to extract additional heavy oil during post-CHOPS operation. For the VAPEX process, literature explained that slow mixing of solvent and heavy oil and the lack of gravity drainage in thin reservoirs have limited the process. This will result in extremely low production rate at the early stage (Jiang et al., 2014). The presences of wormholes after CHOPS operation make the continuous injection of solvent to a breakthrough in a shorter time between injector and producer, so lateral SVX is not economical for post-CHOPS operation (Zeng et al., 2008). However, the existence of wormholes provides large contact area for solvent and heavy oil mixing and is utilized as conduits for diluted oil to flow back to the wellbore for CSI process. These phenomena make the solvent cyclic technique more efficient than other solvent-based methods in post-CHOPS reservoirs.

The CSI concepts are necessary to extract additional oil from thin wormhole reservoirs. The technique involves three stages; an injection of a solvent mixture, followed by a soaking period and finally a production period. It is analogous to the cyclic steam stimulation (CSS). This EOR process employs a single-well for both injection and production (Jia, et al., 2015). Figure 1.1 illustrates a schematic diagram of cyclic solvent
injection method. The solubility of solvent in oil, availability of solvent, and the cost of solvent are predominant criteria in solvent selection. The so-called solvent can be carbon dioxide (CO₂), flue gas, and light hydrocarbon gases such as natural gas, methane (CH₄), ethane (C₂H₆), propane (C₃H₈), and Butane (C₄H₁₀). The selected solvent/mixtures are injected into the reservoir at a pressure close to the dew point of the mixture; with the expectation of the pressure to approach initial reservoir pressure. Following injection, the solvent/mixture reduces oil viscosity as it dissolves in heavy oil via molecular diffusion and convective dispersion processes during the soaking period (Qazvini Firouz and Torabi, 2012). Following the solvent interaction, the well is returned to production until the pressure draw downs become minimum. The injection-soaking-production scheme is then repeated several times. However, the reservoir quality, net pays, inflow of water and many other conditions determine the strategy and solvent types.
Figure 1.1: A typical diagram of cyclic solvent injection method, retrieved from "goo.gl/rN9cZr" with some modification.

Solvent Swells the Oil and Reduces its Viscosity.
1.2 Research Scope and Objectives

This study is focused on providing valuable results on the performance of CSI under the effect of wormhole growth by considering different wormhole configurations in a lab-scaled physical model. Several experimental tests, as well as numerical simulation analysis, were carried out to model heavy oil production. The goal of this study was to evaluate the extent to which single-linear, single, and double branched wormholes affect the performance of post-CHOPS CSI process when applied in a lab-scaled model.

The initial performance potential of CSI was experimentally examined in a 2D rectangular model without wormhole using two selected solvent mixtures (15% C₃H₈ and 85% CO₂ and 50% C₃H₈ and 50% CO₂) to establish a baseline performance. Tests were performed at the same operating conditions for each solvent. With the same solvent mixtures and physical model incorporated with a single-linear wormhole, two tests were performed to investigate the effect of the wormhole on CSI performance as well as the solvent types. Furthermore, the effect of single and double-branched wormholes were investigated on the performance of CSI in extracting heavy oil using 15% C₃H₈ and 85% CO₂ as the solvent.

The measured properties (viscosity, density, and hydrocarbon composition) of the heavy oil sample were used to perform a complete PVT analysis for the simulation modeling in this project. The measured oil viscosity and density and their variation with temperature were imported to CMG WinProp™ software from the Computer Modeling Group (CMG. ver. 2013) to characterize the heavy oil fluid model. Finally, the CMG STARS™ stimulator (CMG. ver. 2013) with the prepared fluid model was used to conduct the simulation studies. A series of runs were conducted to validate the simulation
models and the results were compared with those obtained from the experimental tests. Then, an attempt was made to history match the experimental results with those obtained numerically using selected parameters such as reaction rate, relative permeability, and dispersion coefficient.

This study provides valuable results to the industry and shows how the branched wormhole networks generated during CHOPS affects the performance of CSI technique.

1.3 Organization of the Thesis

There are 5 chapters in this thesis. Chapter 1 provides a brief background to CHOPS, nature of post-CHOPS reservoirs, and some proposed EOR methods. Also, research scope and objective of this study were introduced. A comprehensive literature reviews regarding CHOPS process, the growth of wormholes, existing models for wormhole characterization, and post-CHOPS EOR processes were presented in Chapter 2. Specifically, the potential of cyclic solvent injection, its application experimental and numerical simulation were reviewed. Also, the knowledge gap in regard to the application of CSI technique in post-CHOPS reservoir was stated in this chapter. In Chapter 3, the experimental methodology and materials, and the experimental results were explained in detail. Chapter 4 deals with the lab-scaled simulation studies, including PVT analysis and history matching of experimental results. Finally, Chapter 5 draws the conclusions of this study and recommendations for future studies.
CHAPTER 2: LITERATURE REVIEW

2.1 Cold Heavy Oil Production with Sands (CHOPS) Process

The accumulated knowledge of Canadian heavy oil producers reveals that the key reservoir conditions for primary cold production include unconsolidated, clean sands, minimum oil viscosity, mobile oil, and a minimum initial gas-oil ratio (GOR). The term "unconsolidated" describes the high porosity sandstone reservoir, and in other words, it is conveying the notion that sandstones have no significant grain-to-grain cementation and that the tensile strength is close to zero (Dusseault, 2001). These reservoir conditions promote the widely deliberated mechanisms of CHOPS operation drive from foamy oil behavior and reservoir access generated from wormhole as the dominant recovery processes (Rangriz Shokri and Babadagli, 2014; Sawatzky et al., 2002). The large inflow performance of primary cold production resulting from sand production does not explain the mobility of a viscous fluid in the reservoir. The large fraction of solution gas released is trapped in the high viscous oil in the reservoir. These trapped gases appear to form a dispersed gas, which is different from gas phase flow in conventional oil reservoirs (B.Maini, 1999; Maini et al., 1993). Therefore, foamy oil suppressed and restricted liberated gas in the live heavy oil reservoir. To understand this mechanism, several researchers such as Maini et al., (1993) and Smith, (1988) have numerically and experimentally investigated the role of foamy oil behavior in the primary depletion of cold production.

The complexity of wormhole network in unconsolidated heavy oil reservoir results in different postulations by several researchers to explain how aggressive sand production improves oil recovery. Geilikman and Dusseault, (1999) and Metwally and
Solanki, (1995) explained that sand failures result in a dilated sand vicinity of the wellbores. Chugh et al., (2000) and Wong et al., (1994) followed the assumption that solid productions result in a dilated sand region limited to the wellbore by extending wormhole network into the formation. While Tremblay (2005) and Squires (1993) believed that wormholes only extend from the wellbore into the formation. Tracer injection tests performed by oil well operators to examine the connectivity of wormholes channel in the reservoir showed communication between certain wells. The investigation revealed the rapid flow of tracer dye injected in a cold production well reached another well at 400 m with an hour without concentration lost (Bani et al., 2004; Squires, 1993). Since the tracer dye could be easily absorbed on the sand matrix near the wellbore, it is very likely that wormhole only extends into the formations from the wellbore.

2.1.1 Wormhole Network Growth

The cold production of heavy oil from the unconsolidated sand formation in Lloydminster area created sharp pressure gradients in the reservoir. Following the sharp pressure gradient, sand matrix failures in areas of relative weak cohesive strengths occurred and the inflow of high viscous fluid dragged the failed sand to the wellbore. Thus, this will result in aggressive sand productions along with heavy oil in the initial stage of production. The simultaneous sand and oil productions from unconsolidated heavy oil reservoirs generate high permeability channels known as wormholes (Sawatzky et al., 2002). The wormholes extend from the wellbore and grow into the reservoir with different branching network, depending on the pressure distribution outside the wormholes and the inherent reservoir heterogeneity (Rangriz Shokri and Babadagli, 2014; Yuan et al., 1999). As stated in some literature (Bani et al., 2004), it is very likely
for wormhole channels to connect from different wells and established a connection as their bottom-hole pressure tends to equalize. However, this pressure equalization prevents further wormhole connections between these wells (Tremblay, 2007).

Experimental and theoretical studies have reached the conclusions that pressure gradient and cohesive strength or forces holding the sand grains together are the essential parameters that enhanced the development of high permeable channels (Tremblay et al., 1996, 1997, 1999). The existence of cementation or dirty sands results in an increase in the cohesive strength and it is unlikely for sands production to occur in such formations. This suggests that un-cemented heavy oil reservoirs of Lloydminster area have weak cohesive strength, which is critical to the growth of wormholes during cold production. On the other hand, observation of sand production from loosely packed sands in laboratory studies showed that generated short wormholes tend to collapse and, in some cases, form cavities (Sawatzky et al., 2002). Tremblay et al. (1996) performed a laboratory experiment using a horizontal sand pack to understand the effect of sand production on heavy oil recovery. The dead oil viscosity used for the test was approximately, 21,500 mPa.s. This experiment employed external drive mechanism since there was no dissolved gas in the heavy oil sample. They imaged the sand pack with an X-ray computed tomography (CT) to provide the variation of porosity after sand production. The CT images revealed the development of high-porosity channel or wormhole in the sand pack following sand production but did not confirm dilated regions around the wellbore (orifice in this case) as argued by several investigators (Metwally and Solanki, 1995; Smith, 1988). They concluded that wormhole development did not alter the remainder of the sand pack following the comparison of vertical porosity
profiles "before" and "after" sand production. In addition, they observed that pressure declined quickly in the sand pack as the wormhole started to form. Their experimental results showed that propagating wormhole phenomenon increased oil production rates during cold production.

To effectively characterize wormhole growth in cold production, Tremblay et al. (1999) visualized the formation and growth of a wormhole under solution gas drive using a CT scanner in the lab. In their experiment, the CT scanner tracks the wormhole tip as the growth advance into the sand pack during the pressure depletion test. They observed the significance of pressure gradient at the tip and along the wormholes when it reached the maximum length as gas bubbles grew. Their CT imaging and the production results showed that wormhole could develop under solution gas drive. They also revealed that gas evolution into bubbles during pressure depletion test reduced the pressure gradient and eventually destabilized sand grains at the wormhole tip. However, due to the lower pressure gradient along the wormhole, sands would not be transported, which caused the wormhole to stop growing.

A number of publications (Kantzas and Brook, 2004; Rangriz Shokri and Babadagli, 2014; Tremblay, 2007) revealed that wormholes could likely grow from well perforations as a consequence of sand production and extend into the formation in the weakest sand. Kantzas and Brooks (2004) discussed that a large number of perforations appears to be a factor in the development of wormholes. However, the significance of perforation in the growth and interaction of wormhole in a large sand pack were also addressed in the literature. Tremblay and Oldakowski (2003) discussed the development of wormholes from two vertically aligned orifices in a cylindrical sand pack under
solution gas drive. The pressure depletion resulted to sand, oil, and gas productions from the experiment and the development of two wormholes with different lengths at the orifices. Following the excavation of the sand pack at the end of the experiment, the estimated porosity of the channels was 50.5% and the initial porosity of the sand pack was 33.8%. Earlier to sand production, the calculated pressure gradient at the top orifice was slightly higher than the bottom orifice. This led to rapid wormhole growth at the top orifice, and subsequently decreased the pressure gradient at the bottom orifice, thus preventing the growth of wormhole. Therefore, it is unlikely for wormholes to develop out into the formation from every perforation of cold production wells. Accordingly, we can conclude that wormholes grow in regions of the weakest sand matrix, and towards the highest-pressure gradient in the formation.

Finally, a few numbers of publications (Sawatzky et al., 2002; Tremblay et al., 1998; Yuan et al., 1999) discussed the two possible stages of wormhole network development. These literatures have a similar description of the two categories of wormholes growth. The first stage corresponds to a period when the pressure difference is substantially large enough for the fast growth of the wormholes. The channels are filled entirely with failed sand; and the oil coupled with the loose sand flow through the channels. Moreover, this type of flow is similar to plug flow. The simultaneous productions of sands and heavy oil in this period have very high sand cuts. The flow of oil and lose sand in the second stage of wormhole development can be approximated as stratified flow. During this period, the increasing numbers of the wormhole with a constant bottom-hole pressure makes the pressures at the channels tip too small. Eventually, the presence of small pressure gradient stops the further growth of
wormholes. In this case, the sand cuts are very low compared to the initial period. This indicates that early stage of cold production has wormholes filled with failed sands predominantly. However, the mature stage of cold production has an increasing number of wormholes with oil eroded at the top (Tremblay et al., 1998).

2.1.2 Wormhole Growth Model

Many models have been developed to characterize the wormhole patterns generated inside the reservoir formation from sand productions and their contribution to oil recovery enhancement in CHOPS process. The mathematical model presented by (Vardoulakis et al., 1996) examined the hydro-mechanical aspect of the sand production problem. They based the model on the mass balance of the produced sands, flowing fluid, basic laws of particles erosion, and Darcy's law for fluid flow in porous media. Tremblay and Oldakowski (2003) presented a wormhole growth model composed of a fluid drainage equation and a sand fluidization equation. They validated this model with the measured values, such as oil, sand, and gas production, pressures distribution, final wormhole length, and diameter from wormhole growth experiments. Some developed coupled models, such as hydro-geomechanics (Coombe et al., 2001) and reservoir-geomechanics (Wang and Xue, 2002). These coupled models have provided informative results that assist with the understanding of cold production process. However, these coupled models could not describe the mechanism to predict wormhole growth and patterns in an unconsolidated formation.

Yuan et al. (1999) proposed that probabilistic active walker (PAW) model could describe the wormhole development pattern. The model assumed that wormhole diameter follows the power law, which slowly decreases with an increasing radial distance. The
application of the PAW model opens new possibilities in understanding wormhole growth and cold production of heavy oil. Furthermore, Liu and Zhao, (2005) proposed that the diffusion-limited aggregation (DLA) model could describe the wormhole growth in an unconsolidated formation. The DLA model employed the physics of the processes to relate to a wide variety of branching-growth patterns. They quantified the wormhole diameter distribution along the channels by using the area version of Gaussian function to analyze the experimental results published in the literature, which were set-up to study the wormhole dynamics using CT X-Ray scanner. They based the model on the assumption that the produced sand is solely from the paths of the wormholes. The results generated from the fractal wormhole model indicate proper characterization of wormhole structures and enhance the analyses of fluid flow in cold production process. Similarly, Rangriz Shokri and Babadagli, (2014) presented a DLA algorithm as wormhole domain with a partial dual-porosity and a systematic simulation technique to characterize the growth of wormhole networks. The growing nature of wormholes with this model depends on sand production data and reservoir properties. Therefore, at each time step, the wormholes grow according to the fractal pattern until the extended volumes equalize the sand production data for the second step. The generated results suggest that fractal pattern could be more reliable to represent wormholes in primary cold production.

A dynamic wellbore module (DWM) proposed by Istchenko and Gates, (2012; 2014) simultaneously captures the dynamic growth of individual wormholes as an extending production well. The model employed existing wellbore features in the commercial simulators, such as CMG software to model wormholes as a series of multilateral wells. With the limitation of growing the well/wormhole in the simulator,
DWM functions by continuously stopping and restarting the simulations and dynamically grow the wormhole based on a minimum fluidization velocity, a history-match parameter. However, a key limitation of the proposed model was the inability to capture sand-transport as a mobile solid phase through the wormhole. Similarly, a number of researchers, such as (Tremblay, 2007; Zeng et al., 2008; Zhang et al., 2014; Zhao et al., 2015) simulated wormhole network through the multi-lateral well model in commercial reservoir simulators. One recently proposed wormhole dynamic growth model by Fan and Yang, (2016) characterized wormhole growth for cold production. The proposed model employed geomechanics analysis attributed to collapsed pore and throat structure to quantify the sand production. In addition, the proposition of sand failure criterion and a four-direction pressure difference analysis determined the direction of wormhole development with the corresponding sand production rate. They validated the newly proposed wormhole dynamic growth model with a synthetic model and history-matched it with cold production wells.

Among the numerous wormhole growth models proposed to model the wormhole propagation mechanisms, there has been no agreement on which one is suitable for field applications (Fan and Yang, 2016). However, these models have provided informative results, which assisted with the understanding of this mechanism in unconsolidated formation.

2.2 Post – CHOPS EOR Processes

The presence of wormhole networks makes the CHOPS reservoirs complex and unique. These depleted reservoirs pose severe challenges for applying EOR follow-up processes to extract the remaining oil after CHOPS operations (Zhao et al., 2015).
Therefore, the optimal recovery of the post-CHOPS process remains unknown due to the nature of the reservoirs, which makes it least resistant to injected fluids. The injected fluids for mobilizing heavy oil often bypass most of the reservoir because of the extremely high connectivity of wormholes relative to the sand matrix of the reservoir (Zhao et al., 2015). This makes the application of traditional EOR techniques challenging (George Stosur, 1986) and the quest for reliable methods has intensified.

To date, several techniques have been evaluated for post-CHOPS reservoirs with the goal of recovering additional oil. Some of these methods include hot water flooding (Coskuner et al., 2015), solvent injection (Chang and Ivory, 2013; Coskuner et al., 2015; Du et al., 2015; Ivory et al., 2010; Kristoff et al., 2008; Zeng et al., 2008), in situ combustion (Chen et al., 2012), and CO₂ flooding (Alshmakhy and Maini, 2012; Derakhshanfar et al., 2012). One of the experimental post-CHOPS EOR processes was examined at both ambient and reservoir conditions, for example, gas injection and gas pulsing (Kantzas and Brook, 2004). In a recent publication (Rangriz Shokri and Babadagli, 2014), a fractal geostatistical method was used to model the propagation of wormhole network for a subsequent huff 'n' puff cycle of a hybrid combination of steam and solvent. However, the CSI process has become the focal point for post-CHOPS reservoir follow-up techniques. The history matching and preliminary evaluation of heavy oil production performance for CSI field trials have proved the technique to be feasible (Chang et al., 2015a, 2015b; Zhao et al., 2015). A detailed review of some relevant studies and modeling of solvent-based cyclic production are presented in the next section.
2.2.1 Cyclic Solvent Injection (CSI) Process

The CSI process is also known as huff-n-puff (Shelton and Morris, 1973) is a single well EOR technique in which a gas/solvent (or a mixture of solvent) slug is injected at a preferably appropriate pressure that causes the solvent to dissolve in oil (huff-cycle). Following the huff-cycle is a soaking period, where the well is shut-in for a period, allowing some portion of the solvent gas to dissolve in heavy oil (Yadali Jamaloei et al., 2012). This interaction between solvent and heavy oil occurs through molecular diffusion and convection processes, and the extent of the mixing time can be long enough for equilibrium condition to assure. Then, the same well is opened to production (puff cycle) and its bottom-hole pressure is drawn down continuously to induce the solution-gas drive and foamy oil flow, which produce solvent-diluted heavy oil (Alvarez and Coates, 2009; Jia, et al., 2015; Jia, et al., 2015; Qazvini Firouz and Torabi, 2012). The same operation is repeated for the next few cycles until the oil production rate reaches to an uneconomic level.

Some published literatures, such as Cuthiell et al., (2006); Ivory et al., (2010); Jiang et al., (2014); Lim et al., (1996); and Yadali Jamaloei et al., (2012) stated that solvent diffusion, oil swelling, solvent dispersion, interfacial tension reductions, solution-gas drive, and foamy oil flow are the production mechanisms involved in this solvent-based process. The selection of solvent or mixtures of solvent depends on the reservoir conditions, recovery mechanisms, and economic concerns. Carbon dioxide (CO$_2$), flue gas, and light hydrocarbons gases, such as natural gas, methane (CH$_4$), ethane (C$_2$H$_6$), propane (C$_3$H$_8$), and butane (C$_4$H$_{10}$) can be the solvent. The implementation of carbon
dioxide (CO$_2$) and other solvents (e.g. methane, ethane, etc.) as mixtures in huff-n-puff for heavy oil recovery have shown very promising results.

To provide a better understanding of this study and the extent of the generated results, we extended this literature review to cover the application of different gas/solvents in the CSI process. To be more specific, it sheds light on the experimental, numerical, and field investigations of CSI as a post-CHOPS recovery technique.

2.2.2 Experimental Studies on the CSI Process

Experimental evaluations of solvent-based cyclic production in unconsolidated heavy oil reservoirs are limited to those by Lim et al. (1995), Cuthiell et al. (2006), Jamaloei et al. (2012), Ivory et al. (2012), Qazvini Firouz and Torabi (2012), and Du et al. (2015). In their studies, an injection of a solvent mixture, followed by a soaking period, and a production period were the three stages considered. Lim et al. (1995) investigated the cyclic stimulation of cold lake oil sand with supercritical ethane. Their experiment included two parts, injection of sub-critical ethane (unheated ethane) and injection of supercritical ethane (heated ethane). Their experiments for cold lake oil sand recovery were performed in a 3D physical model, which had a horizontal injector/producer well located at the base, with a net confining pressure of about 1500 kPa on the model. For the first test, the unheated solvent was injected until the bottom-hole pressure exceeded the liquid-vapor equilibrium pressure of ethane. For the corresponding second test, the injected heated ethane was slightly above the supercritical temperature in the model. In order to examine the effect of supercritical ethane, the oil recovery factor, oil production rate, product quality, producing solvent/oil ratio, and solvent replacement ratio in the two cycles were presented and analyzed. They observed
that supercritical ethane can extract a greater number of heavy fractions in bitumen than the sub-critical ethane at a comparable solvent to bitumen mixing ratio. In addition, the production rate and recovery results were higher while the product quality was lower for supercritical ethane injection.

Ivory et al. (2010) conducted an experiment to evaluate the performance of a 28% C$_3$H$_8$ – 72% CO$_2$ solvent mixture in a post-CHOPS follow-up process. The experimental model design takes the shape of a stepped cone constructed from sections of pipe of about 3 m long. It captures a real-scale dimension and time, radial flow of fluids into and out of a 6 cm diameter wormhole during primary cold production and CSI follow-up processes. With the physical model configured in a vertical alignment with the narrow end down, the experiment consisted of primary production followed by six solvent injection cycles. The solvent mixture was injected via the narrow end of the model for about 62 – 80 days per cycles, and solvent diluted heavy oil production lasted for 22 days. The six cyclic solvent injections produced 40% oil recovery from the oil above the wormhole, which indicated the potential of CSI process in a post-cold production process in the presence of wormhole.

Qazvini Firouz et al. (2012) conducted a series of experiment in a Berea core placed vertically in a high-pressure core holder. They performed these experiments to evaluate the feasibility of solvent-based huff-n-puff method in enhancing heavy oil recovery. In their study, CO$_2$, CH$_4$, C$_3$H$_8$, and C$_4$H$_{10}$ were tested under different conditions. After four different tests for pure CO$_2$ injection near supercritical condition, they observed a recovery factor of 71%, which means pure CO$_2$ produced more oil at higher pressure. Similarly, their four sets of pure CH$_4$ huff-n-puff experimental results at
different operating pressures showed that the highest operating pressure yielded a recovery factor of 50%. Thus, the CO$_2$ huff-n-puff process was more efficient than the CH$_4$ based process. They also examined the efficiency of different mixtures of CO$_2$ – C$_3$H$_6$ and CO$_2$ – C$_4$H$_{10}$ huff-n-puff method at different compositions and concluded that addition of 19% hydrocarbon solvent to pure CO$_2$ increased the recovery factor by 10% at a specific operating pressure. With soaking time as one of their investigative parameters, they stated that longer soaking time had more effect on the cyclic injection process when operating at higher pressure.

In another study, Ahadi and Torabi (2018) investigated the optimum fraction of C$_3$H$_8$ and CH$_4$ that could be included in the CO$_2$ stream to maximize the recovery of cyclic injection processes. They performed series of huff-n-puff tests under various CO$_2$ operating pressures and hydrocarbon concentrations on heavy oil samples with viscosity of 1850 mPa.s to quantify the optimum solvent concentration. Furthermore, the optimum solvents were tested on heavier oil samples (6430 and 22,000 mPa.s) to examine the extent to which oil viscosity affects CSI performance. Their results revealed that there is an optimum injection pressure in cyclic CO$_2$ injection process in heavy oil systems and concluded that higher concentration of C$_3$H$_8$ in the CO$_2$ stream improved the oil recovery during cyclic injection. Although C$_3$H$_8$ plays an effective role in the performance of CSI, their experimental results indicated that increasing concentration of CH$_4$ in the CO$_2$ stream reduced the heavy oil production. Also, according to their findings, increasing the heavy oil viscosity from 1850 mPa.s to 6430 mPa.s lowered the recovery factor of cyclic 50% C$_3$H$_8$ – 50% CO$_2$ injection under similar operating pressure by 20%. In addition, no oil production was observed during the first cycle of
injecting the optimum quantified solvents when the heavy oil viscosity was increased to 22,000 mPa.s resulted in a lack of oil production.

Previous studies showed that viscosity regainment of solvent-diluted heavy oil and the associated loss of oil mobility due to solvent released during production period is the key technical challenge in CSI process. To overcome this technical shortcoming, Yadali Jamaloei et al. (2012), Jiang et al. (2014), and Jia et al. (2015) proposed new enhanced heavy oil recovery (EHOR) processes, such as ECSP, CPCSI, and GA-CSI respectively. Yadali Jamaloei et al. (2012) experimentally investigated hydrocarbon-based cyclic solvent process for heavy oil recovery in thin reservoirs. Their study consisted of two parts, methane cyclic solvent process (CSP) and methane and propane enhanced cyclic solvent process (ECSP). Applicability of both CSP and ECSP for thin heavy oil reservoir was evaluated by conducting a series of experiments in a sand-pack saturated with dead oil (with a viscosity of 1080.6 mPa.s at 22°C) and brine. The behavior and feasibility of methane-based huff-n-puff process were thus analyzed and examined from the six cyclic experimental results, through oil recovery factor, ultimate recovery, and oil recovery rate, pressure profiles of soaking and production period, and drawdown rate. For the ECSP part, methane and propane were cyclically injected in two separate slugs. With this injection strategy, methane provides solution-gas drive energy and most portion of propane stay in the oil to maintain low oil viscosity. Following a series of six ECSP cycles conducted in the same sand-pack, the experimental results suggested a relatively high recovery of oil (34.30% of OHOIP) compared to the six methane-based CSP cycles (4.27% of OHOIP). This comparison indicated that ECSP
improves heavy oil recovery in thin formations, by the use of viscosity reduction and solution-gas drive mechanisms during production cycles.

Jia et al (2015) proposed a new process, in which gas flooding-assisted cyclic solvent injection (GA-CSI) was utilized to enhance the performance of CSI. They conducted a series of experimental tests with two types of physical (two cylindrical and one rectangular) models saturated with dead oil (a viscosity of 5875 mPa.s at 20.2°C) and water, to evaluate the performance of conventional CSI process and the new proposed process. To examine the behavior of conventional CSI, oil production, solvent production, gross SOR, oil recovery factor, well configuration, and pressure profiles during re-pressurization and production in about 22 cycles were presented and analyzed. For the cylindrical model experimental results, they observed lower oil productivity with a conventional one-well configuration in comparison with a two-well configuration (solvent injector and oil producer set apart). Foamy oil was induced during the pressure drawdown process with the rectangular model, and the recorded digital images verified its back-and-forth movement in the solvent chamber during the cyclic production process. In the GA-CSI part, three cylindrical models with different length and one rectangular model were applied to evaluate the performance of the process through well spacing. With the solvent injector and oil producer set horizontally apart, the immediate application of gas flooding after the drawdown process enhanced heavy oil recovery by displacement of pre-induced foamy oil. The comparison of experimental results with the same physical model and cycle length suggested that the oil production rate of the newly proposed GA-CSI process is three to four times of that for a conventional CSI process.
It is apparent that wormholes developed in unconsolidated formation during cold production are one of the most significant mechanisms, contributing to oil production in CHOPS wells. Their existence would provide a fast conduit for the injected solvent to reach heavy oil far away from the injection well and channels that allow diluted-heavy oil to flow back. Thus, wormhole network would affect the performance of CSI. The current experimental studies of post-CHOPS reservoir did not consider the role of wormholes in the performance of CSI process, except the work of Du et al., (2015).

Du et al. (2015) investigated the role of wormholes on post-CHOPS CSI process with a series of experimental tests using three different cylindrical sand-pack models saturated with dead oil (viscosity of 2200 mPa.s at 21°C) and brine. In their study, a spring tube wrapped with filter gauze to prevent sand production was placed in the sand-pack model for each test mimicking a wormhole. They examined the effect of wormhole length, the vertical position of wormhole's, sand-pack model length, diameter, and orientation on the performance of CSI process. The experimental results obtained from the effect of wormhole length suggested that the wormhole coverage has a significant effect on the performance of CSI process. Thus, better CSI performance from larger wormhole coverage. Their results also indicated that wormhole developed at the bottom is more favorable for Post-CHOPS CSI process, because of the impact of gravity on oil recovery. In addition, the effects of model diameter and length on the oil recovery and oil production rate were insignificant. Therefore, the overall results were beneficial and assistive in understanding the performance of CSI process under the effect of wormholes.
2.2.3 Simulation Study on the CSI Process

In the past few years, several researchers have conducted solvent-based numerical simulation studies to history-match their experimental results. In this case, Ivory et al. (2010) developed a numerical model to history-match their radial drainage experiments. To simulate a CSI follow-up process, a total of three oil-phase components and one gas-phase component were used to determine the conditions at the end of primary production. In developing the CSI model, they included a representation of the non-equilibrium behavior of solvent solubility, solvent/oil mixtures, and the mixing parameters (diffusion, dispersion), into the reservoir fluid model. With the CMG-STARS simulator platform, they validated the model based on their experimental result by turning the K-values, capillary pressure, and relative permeability's. Their parametric study indicated that oil production is highly dependent on the rate of solvent dissolution and exsolution from the oil during injection and production, respectively.

In a recent work published by Chang and Ivory (2013), numerical simulation tool provided an avenue to optimized field-scale operation parameters of CSI and predictions of post-CHOPS reservoir characterizations. They used the CSI simulation model developed from their previous work (Ivory et al., 2010) to perform field-scale simulation of post-CHOPS reservoir characterizations with wormhole network region. The following represented the wormhole region: an effective high-permeability zone, a dual-permeability zone, a dilated zone around the well, extending wormholes from the well without branching (Spokes Model), and wormholes extending from the well with branching from the main wormhole (Spokes and branches Model). Their simulation study examined the impacts of solvent (60% methane and 40% propane) dissolution and
exsolution rate constant, injection strategy, grid size, and upscaling. The simulation results suggested that assumption of equilibrium solubility condition resulted in reduced oil production compared to non-equilibrium solvent-solubility behavior. In addition, the larger grid block reduced the predicted oil production by a factor of nine. They observed higher oil production during CSI process for the effective-permeability non-equilibrium simulations compared to the rest of the models that represented wormhole regions. Following this observation, wormhole network caused greater contact area for solvent penetration during CSI process in field-scale reservoir simulations.

In addition, Zhang et al. (2016) investigated the uncertainties in upscaling CSI process for post-CHOPS reservoirs through numerical simulation. They simulated a series of numerical models to correspond six CSI tests reported by Du et al. (2014) through comparison of predicted and experimental results. Key parameters such as relative permeability, reaction rate (in foamy oil model), dispersion coefficient, and capillary pressure were studied to history-match the recovery performance of CSI process. However, based on similar relative permeability, successful matched results were obtained only by tuning capillary pressure on the scale of physical models and wormhole locations. The sensitivity analysis performed indicated that capillary pressure played the greatest role in upscaling the CSI process. Thus, the larger the physical model, the smaller the required capillary pressure. Following the linking of experimental data to numerical simulation, a typical western Canadian heavy oil post-CHOPS reservoir was evaluated for CSI process at field-scale. The multilateral well model replicated the wormhole network generated during cold production, and the post-CHOPS reservoir conditions were obtained by history matching the field oil and water production. Their
performance evaluation of CSI follow-up process for ten years suggested additional oil recovery in the range of 13 – 16% of the remaining oil in the post-CHOPS reservoir.

Few studies show that during CSI process, the porous media is divided into two zones with different fluid properties, which are solvent chamber or gas zone and heavy oil zone (Du et al., 2015; Jia, et al., 2015). In this case, CSI process is mainly governed by the gas-oil flow, as the solvent chamber is predominated by free gas-oil flow and the heavy oil zone by dispersed gas, also known as foamy oil. On this note, Hong et al., (2017) investigated the characteristics of the gas-oil flow in CSI, specifically, the gas-liquid relative permeability curves. They focused on understanding the effect of the pressure depletion rate and solvent chamber on the fractional flow curves. To fulfill this goal, numerical simulations were carried out to history match seven lab-scale CSI tests conducted at different pressure depletion rates. They found that at low-pressure depletion rates, the gas-oil flow in CSI yielded the characteristics that have been observed in heavy oil solution gas drive. Furthermore, the pressure depletion rate affected the solvent injectivity due to the unproduced foamy oil in the solvent chamber during the previous production period.
2.3 Chapter Summary

From the above literature review, experimental and field studies have confirmed the development of wormhole network during the cold production of heavy oil in unconsolidated formation. It also highlighted the different models proposed by some researchers to replicate the presence of wormholes in numerical simulations of the post-CHOPS process. It can be seen that among other solvent-based techniques, CSI process has great potential to effectively recover additional heavy oil from cold production wells. The experimental, numerical simulation and field-scale studies on CSI process suggest that the presence of wormholes aids the process by significantly increasing the contact area between the injected solvent and the heavy oil, and the subsequent backflow of solvent-diluted oil to the cold production well.
CHAPTER 3: EXPERIMENTAL STUDY OF CYCLIC SOLVENT INJECTION (CSI)

The implementation of post-CHOPS CSI technique is considered expensive; therefore, a preliminary study in a 2D experimental model representing the actual reservoir seems crucial prior to field pilot tests. The running of the experiment at small scale will give a better understanding of the mechanisms involved in CSI process under the influence of wormholes networks. For this reason, this chapter presented a comprehensive study designed to investigate the effect of wormholes network and orientation on the performance of a different mixture of solvent-based cyclic injection and production. A general description of the experimental setup, materials, and procedures are detailed.

3.1 Experimental Methodology and Materials

3.1.1 Materials

The sand-pack model consisted of three plates; a rectangular stainless-steel frame (length: 24.5 cm, width: 20 cm and thickness: 5 cm) and two visual slabs made of thick Plexiglas plates for the top and bottom parts of the model. The visual model had four wells; single-well configuration was used for the tests to mimic the single well operation of CSI process. The visual model was placed horizontally with the height of 5.0 cm to investigate a thin slice of a heavy oil reservoir, which is perpendicular to the vertical (injector and producer). It is worthwhile to mention that the visual slabs limited the maximum operating pressure, as they were designed for pressures up to 1MPa which is typical pressure for some of the CHOPS reservoirs. The transparency of the slabs was
necessary and beneficial for visual observation of the CSI process. The visual model was used for another study by other researchers (Ahmadloo et al., 2013; Mohammadpoor et al., 2014) and the schematic of the physical model and its sand pack cavity is depicted in Figure 3.1.

Ottawa #530 silica sand (Bell and Mackenzie Co. Ltd., Canada) was used to pack the physical models. The white color sand has a rounded grain shape, 99.88% of silicon dioxide (SiO$_2$) and the density is $\rho_s = 2.3$ g/cm$^3$. Figure 3.2 illustrates the screen analysis for the sand sample.

Typical Saskatchewan heavy oil with an original viscosity of 110,000 mPa.s was synthetically prepared with kerosene at a ratio of 5:1. Using DV-II+ Brookfield Viscometer, the viscosity of the diluted crude was 4440 mPa.s at room temperature of $T = 21^\circ$C and atmospheric pressure. The crude oil sample viscosity and density at atmospheric pressure and various temperatures was measured and are listed in Table 3.1. The compositional analysis of the synthetic heavy oil sample is provided by Saskatchewan Research Council (SRC) and the results are presented in Figure 3.3. In addition, synthetic brine with 2 wt% NaCl concentration and density of $\rho_w = 1.0776$ kg/cm$^3$ was prepared to represent the reservoir brine.

Nitrogen with the purity of 99.99% and mixture of propane and carbon dioxide cylinders at various ratios were purchased from Praxair Canada. The compositions of the two mixtures used in this study were predefined to be 15% C$_3$H$_8$ and 85% CO$_2$ and 50% C$_3$H$_8$ and 50% CO$_2$. CMG-WinProp™ (Version 2013, Computer Modeling Group Ltd.) software was utilized to determine the phase behavior of the solvent mixtures. The
nitrogen gas was used for the backpressure line to maintain the desired pressure using the BPRs as well as pressure testing of the experimental setup.

Figure 3.1: Schematic diagram of the physical model and its sand pack cavity placed vertically (Mohammadpoor and Torabi, 2015)
Figure 3.2: Screen analysis for Ottawa sand #530
Table 3.1: Diluted-dead oil properties at 101.325 kPa at various temperatures

<table>
<thead>
<tr>
<th>Temperature, °C</th>
<th>Density, kg/m³</th>
<th>Viscosity, mPa.s</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>976.64</td>
<td>8490</td>
</tr>
<tr>
<td>21</td>
<td>973.02</td>
<td>4440</td>
</tr>
<tr>
<td>30</td>
<td>967.45</td>
<td>2060</td>
</tr>
<tr>
<td>50</td>
<td>954.64</td>
<td>462</td>
</tr>
</tbody>
</table>

Molecular Weight (MW) 460 g/mol.
Specific gravity (15.6°C/15.6°C) 0.948
Asphaltenes 23%
Figure 3.3: Compositional analysis result of dead oil with viscosity of 4440 mPa.s at 21°C
3.1.2 Experimental Setup

Figure 3.4a presents the schematic diagram of the CSI experimental setup. The CSI physical model is made up of the visual sand-pack model, pressure transducer (PPM-2, Heise, United States), and 1/8 in. inner diameter high-pressure stainless-steel pipes (Swagelok Company).

The transfer cells (solvent and crude oil), Teledyne ISCO Model 500HP Syringe Pump, and solvent injection valve made up of the fluid injection unit. The syringe pump was set up to inject brine, oil, and gas/solvent into the physical model. The fluids production unit included production control valve, BPR (LBS4 Series, Swagelok, USA), nitrogen gas cylinders, wet test meter (WTM) (Ritter Drum-Type Gas Meter, TG05/3-1 bar), and separator. The BPR was used to control the production pressure at pre-specified pressure drawdown rate. During the experiments, the separator collects the produced fluid and then separates the gas from the produced oil at atmospheric pressure. The volume of the produced solvent was recorded by the WTM and was observed through a personal computer, while the separated oil volume was obtained from the calibrated separator.

Figure 3.4b shows the schematic of the set up used to measure the asphaltene content of the produced-oil at room temperature. This set-up employed the standard ASTM D2007-03 method to calculate the produced-oil asphaltene content of each cycle and the precipitant utilized is n-pentane. The apparatus required for this test include a vacuum pump, Buchner flask, filter paper, Buchner funnel, an electric balance.

Prior to sand packing the physical model, the wormhole network was loaded to the well location of the sand-pack model. The wormholes are made up of 0.635 cm
diameter pipes, which was completely perforated and wrapped by filter gauze to prevent sand getting into the channels. The single-linear wormhole has a diameter of 0.635 cm with a length of 10.16 cm. For the single branched wormhole, the main wormhole is the same with the linear wormhole, and its branch (diameter: 0.635 cm) has a length of 2.35 cm. The double branched wormhole was made of the same material as the single-linear and single branched wormholes. There were two branches; each had different length and attached to the main wormhole at different angles (45° and 60°). The main wormhole and its branches were ~0.64 cm in diameter. Figure 3.5 depicts the top and side views of the sand-pack models used for this study and the configured wormhole networks.

It is worthwhile to mention that the performance of single-linear wormhole on CSI process has been studied by Du et al. (2015) and the study of hybrid cyclic solvent stimulation and hot water as solvent retrieval agent in the presence of branched wormholes was investigated (Rangriz Shokri and Babadagli, 2016).
Figure 3.4: (a) Schematic diagram of the experimental setup for the CSI tests, and (b) Schematic of the setup used to measure the asphaltene content of the oil samples.

Test: 1 and 2

Top view: W=20.0 cm
7
(Double-branched wormhole)
3.1.3 Experimental Procedure

The procedure for preparing each sand-pack model is briefly described as follows. The physical model was packed with Ottawa sands (Bell and Mackenzie Co. ltd., Canada) of mesh sizes of 40-200 and repeatedly hammered for proper compaction. It was pressure tested with nitrogen gas for 24 hours and then evacuated afterward using a vacuum pump (Maxima C Plus, Fisher Scientific) until a stabilized negative pressure of -84.81 kPa was obtained. Furthermore, the porosity of the sand-pack model was measured with brine using the imbibition method. Then, the permeability was measured by injecting the brine at various injection rates, recording the respective pressure drops across the model, and applying Darcy’s Law.

To establish initial oil saturation and connate water saturation, the sand-pack model was mounted vertically, and then oil from a high-pressure transfer cell connected to a syringe pump was injected through the bottom connections point. Because of the pressure constraints of the physical model, oil was injected at a constant rate of 0.1 cm$^3$/min to displace the brine out of the system. After 6 – 7 days, the sand-packed model was fully saturated, and the produced brine volume was considered as the original oil in place (OOIP). Then, the model was returned to the horizontal position and it was allowed for 24 hours to establish an equilibrium condition at room temperature. The obtained permeability values were confirmed by the equation proposed by Carmen-Kozeny and modified by Panda and Lake (Civan, 2015). This model treats porous media as bundles of capillary tubes of equal length and constant cross section (see Equation 3.1).
where $D_p$ is the particle size, $\phi$ is porosity, $\gamma$ is skewness, $\sigma$ is variance, $C_p$ is the coefficient of variance, and $\tau$ is tortuosity

\[
\gamma = \frac{1}{\sigma^3} \int_0^\infty (D_p - \bar{D}_p)^3 f(D_p) \, dD_p \quad \text{Equation 3.2}
\]

\[
\sigma^2 = \int_0^\infty (D_p - \bar{D}_p)^2 f(D_p) \, dD_p \quad \text{Equation 3.3}
\]

\[
C_p = \frac{\sigma}{\bar{D}_p} \quad \text{Equation 3.4}
\]

Thereafter, cyclic solvent injection (CSI) test was initiated. In the injection phase, the solvent ($15\%$ C$_3$H$_8$ – $85\%$ CO$_2$) was first transferred into a high-pressure transfer cell and its pressure was increased to 730 kPa. Then, water was running from the syringe pump (500D, Teledyne Isco Inc., United States) to the bottom of the transfer cell, and the solvent was subsequently displaced and injected at constant pressure from the top of the transfer cell to the CSI model at pre-specified constant pressure of 730 kPa. The solvent injection duration was set to 120 mins. Then, the sand-packed model was left for $t_{soaking} = 24$ hrs (soaking phase) to allow interaction between solvent and oil. After the soaking period, the system was opened by the same injection well to initiate the production phase. For the 1-hour production period, a backpressure regulator was applied to the production well, such that the producing pressure drop is close to the atmospheric pressure, yet no air entered the model. In this phase, once the produced oil and solvent passed through the BPR, they were collected in the separator. The volume of the produced solvent was measured by a WTM, while the volume of the produced oil was also measured separately. Therefore, each cycle lasted for 24 hrs and after the first cycle was completed; the second cycle proceeded with the same procedure as the first cycle.
The CSI continued till the cyclic oil recovery fell below 1% of the OOIP. Overall, each cycle lasts for 27 hours, including 2 hours of injecting period, 24 hours of soaking period, and 1 hour of production period; and this procedure was repeated for each CSI cycle.

After each CSI cycle, asphaltene content measurement experiment was carried out on the produced oil. For this purpose, we considered the standard ASTM D2007-03 method. The precipitant used for this test was n-pentane, which was added to the oil sample and stirred thoroughly. Then, the mixture was filtered through 0.2 µm Whatman No. 5 filter paper; this process was continued until clear liquid drainage was observed from the filter paper (Ahadi and Torabi, 2018; Mohammadpoor et al., 2014). Subsequently, the asphaltene precipitant left on the filter paper was placed in the air bath for a day to dry completely, and then the final weight of the asphaltene was measured.

Once each CSI test was completed, a digital image of the top surface and excavated surface thickness (2.5 cm) in the sand-pack model was captured using a high-quality camera. Afterward, the digital images were imported into the MATLAB image processing toolbox to achieve quantitative analysis of the saturation distributions.

Following the aforementioned procedure, a total of four CSI experimental tests were carried out. However, the fourth experimental test was conducted with an extended soaking period ($t_{soaking} = 96$ hrs) in a sand-pack model configured with double-branch wormhole under the same operating conduction with the previous three tests. Table 3.2 summarizes the experimental condition and the physical properties of the 2D sand-packed model of each CSI test.
Table 3.2: Review of each CSI test with its corresponding experimental conditions

<table>
<thead>
<tr>
<th>Test</th>
<th>Solvent mixtures</th>
<th>$P_{\text{inj}}$ (kPa)</th>
<th>Wormhole network</th>
<th>$\varphi$ (%)</th>
<th>$k$ (D)</th>
<th>$S_{\text{wc}}$ (%)</th>
<th>$T$ (°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>15% $\text{C}_3\text{H}_8$ – 85% $\text{CO}_2$</td>
<td>730</td>
<td>No</td>
<td>31.17</td>
<td>9.2</td>
<td>0.44</td>
<td>21.3</td>
</tr>
<tr>
<td>2</td>
<td>50% $\text{C}_3\text{H}_8$ – 50% $\text{CO}_2$</td>
<td>730</td>
<td>No</td>
<td>34.37</td>
<td>10.1</td>
<td>5.82</td>
<td>21.3</td>
</tr>
<tr>
<td>3</td>
<td>15% $\text{C}_3\text{H}_8$ – 85% $\text{CO}_2$</td>
<td>730</td>
<td>Single-linear</td>
<td>32.50</td>
<td>9.9</td>
<td>1.60</td>
<td>21.3</td>
</tr>
<tr>
<td>4</td>
<td>50% $\text{C}_3\text{H}_8$ – 50% $\text{CO}_2$</td>
<td>730</td>
<td>Single-linear</td>
<td>31.88</td>
<td>9.8</td>
<td>0.81</td>
<td>21.3</td>
</tr>
<tr>
<td>5</td>
<td>50% $\text{C}_3\text{H}_8$ – 50% $\text{CO}_2$</td>
<td>730</td>
<td>Single-branched</td>
<td>31.96</td>
<td>9.3</td>
<td>1.75</td>
<td>21.3</td>
</tr>
<tr>
<td>6</td>
<td>15% $\text{C}_3\text{H}_8$ – 85% $\text{CO}_2$</td>
<td>730</td>
<td>Double-branched</td>
<td>33.20</td>
<td>10.8</td>
<td>1.60</td>
<td>21.3</td>
</tr>
<tr>
<td>7</td>
<td>730</td>
<td>Double-branched</td>
<td>32.88</td>
<td>10.4</td>
<td>3.40</td>
<td>21.3</td>
<td></td>
</tr>
</tbody>
</table>
3.3 Results and Discussion

3.3.1 Effect of Solvent Types on CSI Performance

Two CSI tests were conducted on heavy oil sample with viscosity 4440 mPa.s at T = 21°C by injecting two different solvent mixtures of 15% C₃H₈ – 85% CO₂ and 50% C₃H₈ – 50% CO₂, namely Test 1 and Test 2, respectively. The experiments were performed at a similar operating pressure of 730 kPa and a constant temperature of 21.3°C. On this note, wormhole network was excluded in the sand-pack models and the results were compared to establish a baseline performance for the selected solvents. In this experiment, the ultimate recovery factor of 6.62% and 10.75% OOIP were obtained for the Test 1 and Test 2, respectively. The recovery factor (RF) for each set of huff-n-puff experiment is the cumulative oil production divided by the OOIP. Figure 3.6 compares the measured cumulative oil recovery factor versus cycle number for Test 1 and Test 2, conducted under the same operating conditions. The higher 4.13% incremental oil recovery observed in Test 2 is as a result of 35-mol% increase in C₃H₈ concentration in the stream of CO₂, and its increasing solubility. Thus, indicating that cyclic 50% C₃H₈ – 50% CO₂ injection improves the performance of CSI in Test 2 compared to the cyclic injection of 15% C₃H₈ – 85% CO₂ in Test 1. By analyzing the trend of cumulative oil recovery curve, it was observed that the slope of the curve was increasing during the first six cycles. However, the slope of the curve became smooth at the end of the sixth cycle and significantly decreased in the subsequent cycles. After the sixth cycle, though more solvent was introduced into the model, lesser oil was produced. This highlights the economic concern of continuing the CSI process in the last four
cycles. In the tenth cycle, the cyclic recovery fell below 1% and the process was terminated.

Figure 3.6: Effect of solvent types on oil recovery factor of CSI tests conducted under operating pressure of $P_{inj} = 730$ kPa
In addition, the arc-shaped behavior of this curve agreed with what Ahadi and Torabi (2018) obtained in their experimental studies of CSI performance.

Figure 3.7 shows cyclic oil recovery factor versus cycle number when the two mentioned solvents were tested at the same operating conditions. For Test 1, the sixth cycle yielded the highest incremental oil recovery and decreased in later cycles. Prior to CSI test, pore space of the model is fully saturated with oil and brine; thus, limiting the amount of solvent injected in the first cycle. Moreover, this small amount of solvent was not large enough to diffuse into the large quantity of heavy oil and reduce its viscosity to the extent of displacing it during production period. This result in a small amount of produced oil at the first cycle. The produced oil in the first cycle, though small in quantity created additional void space within the system, thus providing larger space for the solvent in the second cycle. Therefore, the diffusion/dispersion of solvent into the heavy oil system increased to some extent; and in turn, increased the cyclic oil recovery in the second cycle. As the cyclic production continued for subsequent cycles, higher quantities of solvent were injected, hence light components of the heavy oil were extracted leaving asphaltene components of the oil in the system. Meanwhile, the cyclic oil recovery started to decrease after the sixth cycle, indicating that more asphaltene components are precipitating in the model. Unlike Test 1, the highest cyclic oil recovery was observed at the eighth cycle during Test 2 while subsequent incremental oil recovery decreased gradually. Thus, the shift in the highest cyclic oil recovery factor can be attributed to the higher mole concentration of C₃H₈ in CO₂ stream. The conclusion that can be drawn from this comparison is that further increase in the mole concentration of C₃H₈ in CO₂ stream
can yield better performance of a huff-n-puff test on the same heavy oil sample as long as our mixture is remaining in the gas phase at operating pressure and temperature.
Figure 3.7: Effect of solvent types on the cyclic oil recovery factor of CSI tests conducted under operating pressure of $P_{\text{inj}} = 730$ kPa
The measured solvent oil ratio (SOR) values for Test 1 (15% C₃H₈ – 85% CO₂) and Test 2 (50% C₃H₈ – 50% CO₂) are compared in Figure 3.8. It is observed from the bar chart that SOR values increases as cycles increased. Moreover, higher SOR values correspond to Test 1, which indicates the tendency of CO₂ to evolve from the solvent/heavy oil mixture during production period. This is because of the lower fraction of propane, which is more soluble in heavy oil in comparison to CO₂. On the other hand, SOR values were very low for Test 2, which could be attributed to a high fraction of propane in the solvent mixture. As mentioned earlier, the injected solvent extracted lighter components of heavy oil and left asphaltene component of the oil in the model as the cycle number increased. As this continued to later cycle, the oil became heavier and the measured values for SOR increased. The precipitated asphaltene molecules blocked the reservoir pore space; thus, preventing the movement of the heavier oil in the model toward the production well. While the created large void space within the model from produced oil, allowed a higher quantity of solvent to be injected in later cycles. Therefore, the SOR data relieved the risk of continuing injecting in the last cycles since most of the injected solvents were produced.

It is worth mentioning that the main production mechanism in CSI process in a heavy oil system is the solution gas drive which is strongly dependent upon pressure, temperature, oil viscosity, and solvent solubility. This recovery mechanism was clearly observed in this study due to the foamy nature of the produced oil, especially during the seventh and eighth cycle for Test 2 (Figure 3.9). In the early cycles of production of this test, foamy oil was not observed in the produced oil; only oil and free gas were produced. The nature of this behavior demonstrated the minimal contribution of foamy oil
mechanism to the ultimate oil RF of 50% C\textsubscript{3}H\textsubscript{8} – 50% CO\textsubscript{2} cyclic injection. This is because of some quantity of the solvent dissolved in the heavy oil was produced with the oil as free gas and some portion were remained dissolved in unrecovered oil, even at low pressures. In subsequent cycles, the solvent was trapped in the porous system; thereby coalesce with the injected solvent to form a free gas. This implies that the foamy oil flow remained inside the porous system during the production period. Therefore, the reduced oil viscosity did re-increase significantly, which made the diluted oil to become heavier and more difficult to be produced. Furthermore, the back-and-forth movement of foamy oil in the sand-packed model was the reason behind the trapped foamy oil. This means that during the early stage of production period, the foamy oil flows toward the production well, and then it is pushed back by the injected solvent in the next cycle (Jia, Zeng, et al., 2015b). This movement continues in the system so that the dispersed solvent bubbles became larger and then coalesced to form a free gas in the model. Unlike the Test 2, observation of cyclic production for Test 1 showed no foamy oil behavior in the produced oil. One of the primary reasons is the smaller concentration of C\textsubscript{3}H\textsubscript{8} in the CO\textsubscript{2} stream; which significantly reduced the amount of dissolved solvent in the heavy oil. Therefore, a large portion of the injected solvent left the sand-pack model during the production as the pressure was reduced close to the atmospheric pressure.
Figure 3.8: Effect of solvent types on solvent oil ratio (SOR) for CSI tests conducted under operating pressure of $P_{\text{inj}} = 730$ kPa
Figure 3.9: Digital photographs of foamy behavior of the produced oil for Test 2
(a) 7th cycle produced oil and (b) 8th cycle produced oil
As a part of the observations and supporting results of the above conclusion, Figure 3.10a depicts the sudden increase of the sand-pack pressure during the repressurization by 15% C₃H₈ – 85% CO₂ and 50% C₃H₈ – 50% CO₂, pressure decay over the soaking period and the abrupt pressure drops during the CSI production cycles. For Test 1, the least efficient CSI cycles (Cycles 1 – 3) have low-pressure drops, and a small amount of oil was produced from the sand-pack model. Therefore, the accelerated diffusion of 15% C₃H₈ – 85% CO₂ in heavy oil occurs at the early cycles, and it was reduced after the sixth cycle due to asphaltene precipitation in the later cycles. One of the reasons behind this behavior is that the residual oil saturation near the injection well at the end of cycle six decreased significantly. Thus, a major portion of the injected solvent for the subsequent cycles tends to occupy the depleted space in the porous media (preferentially larger pores) and forms a trapped saturation. As the cycles proceed, solvent might coalesce into previous trapped solvents and forms free-gas phase within larger pores in the porous media, without contributing to the foamy oil flow during the production phase of CSI. In Cycle 1, the pressure behavior is like that of Cycle 2, and as shown in Figure 3.11b, they appear to have the lowest pressure drop over the soaking time. However, more oil was recovered in Cycle 2. This is due to the lower dissolution of solvent slug in heavy oil near the injection well for Cycle 2. As a result, its viscosity will be reduced to some extent. This observation showed higher apparent solubility of solvent in Cycle 2, compared to Cycle 1. Therefore, apparent solubility of solvent in porous media can be attributed to a large amount of injected solvent and a higher rate of diffusion. As for Test 2, the range of pressure decay observed in the sand-pack over the soaking time was more than that of Test 1. The reason behind this behavior is attributed
to higher concentration of C₃H₈ in the solvent mixture, which increased its solubility in the heavy oil in Test 2 compared to Test 1. It is possible that poor performance of CSI for Cycle 1 - 3 can be associated with the quantity of solvent that was introduced to the sand-packed model. Moreover, the effect of initial oil saturation, especially in the site of solvent injection limits the reduction of heavy oil viscosity to some extent; thereby resulting in a negligible amount of produced oil. As the CSI operation continued to Cycle 6, more oil was produced, which allowed more injected solvent to be dissolved in the heavy oil. This also decreased its viscosity and explained the reason behind the large recovery of oil through Cycle 8 compared to Cycle 1 with the same pressure drops (see Figure 3.10b). This indicated that initial oil saturation and amount of injected solvent are significant to the diffusion process of solvent in the heavy oil. In Cycles 9 and 10, the small pressure drop was also attributed to asphaltene molecules which were precipitated in the sand-packed model over the previous cycles. These heavy components tend to block the larger pores, and consequently reduce the dissolution of a large quantity of injected solvents.
Figure 3.10: Measured pressure profiles of the sand-packed for Test 1 and 2: (a) repressurizing + soaking + production period pressure profiles (b) pressure depletion during soaking period of CSI tests
At the end of Test 1 and 2, the residual oil saturation at representative locations was measured, and nomenclatures were assigned to sample locations based on the position of the injection/production well. Figure 3.11a – d shows the residual oil saturation profiles of the top surface and the middle surface of the sand-packed model. It was found from Figure 3.12a that the measured residual oil saturation varied from 74% to 98% (see Table B.2 in Appendix B) after completing Test 1. In contrast, the saturation profile at the middle of the sand-pack model varied from 85% to 93% (see Table B.1 in Appendix B) as shown in Figure 3.11b. This was because the injected solvent was severely affected by gas overriding phenomenon, which allowed the dissolution of solvent to occur at the top surface and the diluted heavy oil drained down the sand-packed model by gravity. Figure 3.11b shows that more diluted heavy oil was produced from the CSI process of Test 2 (50% C₃H₈ – 50% CO₂) than in Test 1(15% C₃H₈ – 85% CO₂) due to higher mole fraction of propane in Test 2; thereby contributing to higher oil swelling effect and viscosity reduction. In contrast, measured residual oil saturation of Figure 3.11c and d showed the effect of gas overriding phenomenon as discussed above in Test 1.
Figure 3.11: Digital photographs of the residual oil saturation distributions of sand-packed model at the end of CSI tests: (a) top surface Test 1, (b) middle surface Test 1, (c) top surface Test 2, and (d) middle surface Test 2
3.3.2 Effect of Wormholes on Solvent Types

In this section, a linear wormhole was added to the physical model before sand packing and then saturated the heavy oil sample (viscosity of 4440 mPa.s at \( T = 21^\circ C \)) to mimic the post-CHOPS reservoir conditions. The assumption was that after CHOPS process the amount of gas dissolved in the heavy oil is negligible prior to post-CHOPS operation. Based on the above assumption, the performance of cyclic solvent injection using two solvents with compositions of 15% \( C_3H_8 \) – 85% \( CO_2 \) (Test 3) and 50% \( C_3H_8 \) – 50% \( CO_2 \) (Test 4) were evaluated in terms of ultimate oil recovery factor, foamy oil phenomenon, pressure profile, and residual oil saturation.

Figure 3.12 shows the effect of increasing the concentration of \( C_3H_8 \) solvent in the stream of \( CO_2 \) gas on the recovery factor after utilizing CSI process in a wormhole-sand-pack model. As depicted, the recovery factor was significantly higher during Test 4 and the ultimate recovery factor was found to be about 35% of the original oil in place. On the other hand, Test 3 recorded an ultimate recovery factor of about 27% of the original oil in place. The arc-shape of the cumulative oil recovery curve agreed with the first part of this paper. It was observed that the slope of the curve was increasing in the first four cycles, and then it became smooth after the fourth cycle and decreased dramatically in the subsequent cycles for Test 4. This means that the introduced large amount of solvent to the model after the fourth cycle produced a small amount of oil and the test was terminated as the cyclic oil recovery fell below 1% of the original oil in place. A consistent trend was observed for Test 3; however, the slope began to decrease after the fifth cycle.
Figure 3.12: Effect of single-linear wormhole on oil recovery factor for different solvent type CSI tests
Figure 3.13 showed the cyclic oil recovery factor versus the cycle number for Test 3 and 4. Test 4 recorded its highest cyclic oil RF (7.28%) at the third cycle compared to Test 3, which the highest cyclic recovery was ascribed to the fifth cycle (5.84%). This behavior was attributed to the mole fraction of propane available in the solvent for dissolution at each cycle, which was caused by the high solubility of propane in heavy oil, even at low pressure (Tharanivasan et al., 2006). Prior to the CSI operation in Test 3 and 4, the incorporated wormhole in the sand-pack was filled with the saturated heavy oil without sand particles. Thus, more amount of injected solvent during the first cycle was dissolved into the heavy oil over the soaking time and reduced the viscosity to some extent. This resulted in increased produced oil for the first cycle. In comparison, the cyclic oil recovery in Test 4 was significantly higher than that of Test 3. The increased cyclic oil recovery for the first few cycles in Test 3 and 4 were attributed to the existence of wormholes, which increased the contact area of solvent and heavy oil and thereby allowed diluted oil to flow back to the well during the production phase (Du et al., 2015). Moreover, the initial oil saturation was drastically reduced after the fourth cycle. This implies that larger amount of solvent was required to re-pressurize the system. In turns, a small amount of produced oil was recorded. This means a major portion of the solvent was recovered, while some portions were retained in the porous system. In other words, SOR increased in the later cycles and obviously increased the cost of solvents. This indicates that large volume of solvent injections at last cycles was not efficient since its small portion diffused into the heavier oil due to asphaltene precipitation, and its larger portion formed a free gas. Additionally, we observed higher SOR values for Test 3 compared to Test 4, which agreed with the previous part of this study (Figure 3.14).
It is important to adduce here that once the production well valve was open at the end of the soaking period, the gas bubbles which are now dissolved in the heavy oil would be subjected to a great pressure difference. This pressure gradient applied a driving force on the gas to come out of the oil and be produced as a free gas since gas mobility was much higher than the oil. Moreover, this is considered as one of the challenging problems of CSI processes as the diluted heavy oil regains its viscosity during the production period (Jiang et al., 2014; Yadali Jamaloei et al., 2012). However, in extra heavy oils, the entrained gas is surrounded by viscous oil which delays gas ex-solution. The gas bubbles formed in moving oil can neither stay behind nor rush ahead, but instead move with oil; thereafter, these bubbles provide internal forces that push the slurry oil to the production well (Geilikman et al., 1995).
Figure 3.13: Effect of single-linear wormhole on the cyclic oil recovery factor for different solvent type CSI tests
Figure 3.14: Solvent oil ratio (SOR) for the CSI tests conducted with single-linear wormhole
Furthermore, the pressure profiles around the sand-pack model during CSI process is illustrated in Figure 3.15. Observation of the sand-pack pressure profile suggests that the pressure drop of each cycle decreased over the test duration. The main reason for this is that in Cycle 1, a small quantity of solvent slug was in contact with the original oil in place taking the advantage of wormhole existence, and dissolution of solvent gas occurred to some extent. The lower pressure drops observed in the later cycles can be logically explained by lower diffusion rate and the presence of asphaltene molecule left in the sand pack after the first few cycles, which trapped some portion of the solvent and resulted in lower oil-in-place remaining. It is believed that the pressure of the trapped solvent also caused a lower pressure drop in the system over the soaking time. It should also be noted that Test 4 followed a similar trend to Test 3; however, it had a lower pressure drop value. Figure 3.15b illustrates the pressure decay at the injection/production well of the sand-pack model during a soaking period of cyclic solvent injection tests.

The digital images of the foamy behavior of the produced oil for Test 3 and 4 are depicted in Figure 3.16. The obtained and illustrated images corresponded to the 2nd, 3rd, and 4th cycles' oil production. Observation of these pictures shows explosive foamy oil flow in Test 4 compared to that of Test 3. The higher diffusion rate of solvent could be the main reason for this behavior; however, the mole fraction of propane in the CO2 stream was the main dominant factor. In the 2nd cycles, the foamy oil in Test 3 was like that described in Test 4. There were thinning disperse gas bubbles in the produced oil and they were very negligible. Moreover, the explosive movement of foamy oil in the system resulted in more pronounced foamy oil produced in the 3rd cycle. As the test proceeded to
the 4th cycle, the foaminess of the produced oil increased as more amount of injected solvent diffused into the oil. In the early stage, the CSI tests showed an increasing cyclic oil recovery factor and in Test 4, the highest cyclic oil recovery factor ascribed to the 4th cycle corresponded to the highest foamy produced oil. In Test 3, the produced foamy oil and the highest cyclic oil recovery factor was achieved in the 5th cycle of CSI test. Nevertheless, as more quantity of solvent was injected in the subsequent cycles, the lighter components of the oil were being extracted while leaving the asphaltene molecules of the oil sample to be precipitated in the model. In addition, the foamy nature of the produced oil was more stable in the case of Test 4 as they lasted longer compared to the produced oil observations in Test 3. The foamy oil stability of these tests is illustrated in Figure 3.17. This indicates that foamy oil behavior played an important role in facilitating oil recovery in CSI performance, which agreed with the visualization studies of foamy oil flow during pressure reduction period in the dynamic solvent process (DSP) (Jia, et al., 2015a).
Figure 3.15: Measured pressure profiles of the sand-packed model for Test 3 and 4: (a) repressurizing + soaking + production period pressure profiles (b) pressure depletion during soaking period of CSI tests
Figure 3.16: Digital images of foamy behavior of the produced oil for CSI Test 3 and 4
Figure 3.17: Foam stability of the produced oil at atmospheric condition for CSI test 3 and 4
Figure 3.18(a) and (b) show the digital images of the top layer of the sand-pack model at the end of Test 3 and 4, respectively. Also, Figure 3.18(c) and (d) depict the images of the middle-layers, following excavation of the sand-pack model after Test 3 and 4, respectively. The circles in each of the images represent the sampling locations of the residual oil saturation measurements. According to the measured samples for both tests, the residual heavy oil saturation ranges from 9.9 to 44% (see Table B. 4 in Appendix B) at the top surface of the sand-pack model. Thus, the distributions of residual heavy oil saturation represent the solvent chamber (Du et al., 2015). The visual analysis of these sand-packed models shows that the distributions were not even, which indicated that the back and forth movement of foamy oil was significant. Meanwhile, at the middle-layers, the measured residual heavy oil saturation ranges from 23.4 to 46.7% (see Table B. 4 in Appendix B). It was found in Figure 3.18a - d that higher residual heavy oil saturation values were achieved for samples obtained on the same excavated level of the sand-pack model with the wormhole. The main reason behind these differences is that the injected solvent disperses upward due to gravity overriding effect, having a large contact area proportional to the wormhole. Thus, during production cycle the pressure difference and gravity drainage allowed the diluted heavy oil to travel and flow into the wormhole perpendicularly (Du et al., 2015). At the end of the production cycle, some portions of the induced foamy oil were left unproduced and then subjected to push back by the injected solvent in the next cycle. This indicates that pressure gradient was the dominant driving mechanism in CSI process and the gravity effect contributed to solvent chamber development and oil recovery factor.
Furthermore, Figure 3.18(a) – (d) suggests that beyond the area around the wormhole, the residual oil saturation increased from the tip of the wormhole as the distance increased. Du et al. (2015) obtained similar results and concluded that it was more difficult to produce heavy oil far away from the wormhole, as it took longer for the solvent to diffuse to further distances. This means that the heavy oil far away from the wormhole was partially diluted and during the production cycle, the drawdown pressure allowed the partially dissolved solvent to evolve and as a result, the diluted-heavy oil regained its viscosity. This implies that the performance of CSI process in post-CHOPS reservoir is significantly affected by wormhole coverage. Moreover, it is widely stated in the literature that the larger wormhole coverage, the better the performance of CSI. It was found that the residual oil saturation at similar locations is higher in Test 3 than those in Test 4. This shows that more heavy oil was produced in Test 4, which agreed with the achieved ultimate oil recovery factor for this test presented earlier. The reason for such a finding is the strong oil-swelling effect and higher heavy oil viscosity reduction by the increased mole fraction of C₃H₈ in the stream of CO₂ gas.
Figure 3.18: Digital photographs of the residual oil saturation distributions of the sand-packed model with single-linear wormhole at the end of CSI tests
3.3.3 Effect of Wormhole Configuration

In this section, four experimental tests were carried out to evaluate the effects of the single-linear, single-branched, and double-branched wormhole on the performance of CSI process. With the same solvent (15% C₃H₈ – 85% CO₂), each test was conducted under the same pressure of $P_{inj} = 730$ kPa and temperature of $T = 21°C$. The choice of this solvent mixture was based on the cost and environmental reasons. Performance of each wormhole configuration was investigated by measuring the incremental and cumulative oil recovery factor ($RF$), pressure drop, foamy oil phenomenon, SOR, asphaltene content, and the residual oil saturation. In addition, the fourth experimental test was performed to investigate how extended soaking period affect the performance of double-branched wormhole on CSI process.

Test 3, 5, and 6 were performed with the same sand-pack model with three different wormholes branching; single-linear, single-branched, and double-branched, respectively. Figure 3.19 and Figure 3.20 present the incremental and cumulative oil recovery factors for these three tests. As shown in Figure 3.19, the fifth cycle yielded the highest incremental oil recovery factor for Tests 3 and 6, while in Test 5 it was recorded at the fourth cycle. Moreover, it was observed that the cyclic recovery decreased as the cycle injection continued. Prior to CSI operation, the wormhole networks in the system were filled with saturated heavy oil without sand particles. Therefore, large portions of the injected solvent during the first cycle were dissolved in the heavy oil over the soaking period and reduced the oil viscosity to some extent. Thus, it resulted in a significant amount of produced oil for the first cycle. In comparison, Test 6 recorded higher incremental oil recovery factor than Tests 3 and 5. This is because of the larger contact...
area provided by the double-branched wormhole, which allowed a higher volume of solvent to be injected and therefore, increased the solvent-oil interaction during the first cycle. As the cycle number increased, the corresponding cyclic oil recovery factor maintained an increasing trend till the highest values in each test were obtained. Moreover, Test 5 showed highest incremental oil $RF$ during the third and fourth cycles compared to Tests 3 and 6. This increased incremental $RF$ dropped below the recorded values of Test 3 in subsequent cyclic production. Another observation, which was made from Figure 3.19, was the higher trend of incremental oil $RF$ obtained for each cycle of Test 6. The $RF$ values were above 3.5% except for the ninth cycle with the oil $RF$ of less than 2% compared to Tests 3 and 5. This was because of increasing the branch of the wormhole configured in Test 5 to double-branched increased the wormhole internal surface area. As a result, the volume of solvent that could possibly interact with oil was increased compared to the case in the non-wormhole domain.
Figure 3.19: Effect of wormhole configuration on cyclic oil recovery factor for cyclic 15% C$_3$H$_8$ - 85% CO$_2$ injection tests
Figure 3.20: Effect of wormhole configuration on oil recovery factor for cyclic 15% C₃H₈ - 85% CO₂ injection tests
Two observations can be made from Figure 3.20, in which the production performances of the tests were compared. On this note, the production performance was divided into two phases (1 and 2) as shown in Figure 3.20. First, the trends of the oil recovery factor curves for Tests 3 to 6 were increasing in Phase 1 and then almost remain as a constant value. At this phase, the oil recovery factor was mainly affected by the produced oil in the vicinity of the wormhole networks. This was because of the injected solvent was severely affected by gravity overriding effects and the solvent dispersion was proportional to the wormhole network coverage. This means that a large contact area has been established for the injected solvent to interact with the oil in the system. Therefore, the higher the wormhole coverage, the more oil was diluted and produced during the production phase. During Phase 1, the oil recovery was larger than the volume of recoverable oil available in the wormhole vicinity, which implies that the oil beyond the wormhole surroundings was also produced. This was as a result of the pressure difference between the ends of the sand-packed model that allowed the injected solvent to be dispersed beyond the wormhole regime. In Phase 2, a solvent chamber was observed, which indicated that solvent contact area had reached the walls of the sand-packed model. This showed that the solvent interaction with the remaining crude oil has become less compared to the early stages of CSI process in Phase 1. Thus, the oil recovery in Phase 2 dramatically decreased compared to the oil recovery in Phase 1. This also explained the reason that the oil recovery factor curve almost maintained constant during Phase 2.

Furthermore, it should be noted from Figure 3.20 that the ultimate oil recovery factor of Tests 3, 5, and 6 were 27.16%, 36.04%, and 43.46% of OOIP, respectively. Therefore, it is evident that increasing the branches of a linear wormhole can significantly
increases the ultimate oil recovery factor of the CSI process. Test 3 was conducted with a configured single-linear wormhole (length ~10.16 cm) in the sand-pack model. Then Test 5 was performed with a branched wormhole, such that a branch of 7.9 cm long was attached to the middle of the main wormhole (length ~10.16 cm) at an angle of 60°. Therefore, the attached branch contributed about 8.9% of OOIP to the performance of the main wormhole in Test 5. As for Test 6, adding a branch (~5.4 cm long) at an angle of 45°, about 2.54 cm from the base of the single-branched wormhole used in Test 5 significantly increased the ultimate oil RF by 7.4% of OOIP. It is obvious that the cumulative oil RF of Test 5 was like the values obtained in Test 6 at cycle number 4 and 5. This indicated that the branch at 60° angle dominated the performance of the double-branched wormhole network in the CSI process. Therefore, a well or reservoir with branching wormhole networks is more favorable for the application of post-CHOPS CSI process based on these findings.

The measured cumulative SORs in different cycles of Tests 3, 5 and 6, are compared and plotted in Figure 3.21. In the beginning, the recorded SOR values were very low which indicated higher cyclic oil recovery compared to the cyclic produced solvent. In the last stage, the SOR was increased significantly due to the lowered oil-solvent contact as a result of the reduction of remaining oil. Therefore, the larger volume of solvent formed free gas in the system and resulted in the reduced pressure drop across the system. Further observation disclosed that higher SOR values were achieved for Test 6 compared to Tests 3 and 6.
Figure 3.21: Effect of wormhole configuration on SOR for cyclic 15% C₃H₈ - 85% CO₂ injection tests
Figure 3.22 compares the pressure drops over the soaking period for Tests 3, 5, and 6. It is obvious that the trend of pressure decay in the sand-packed model over the soaking time decreases drastically with cycle number. This is due to the fact that in Cycle 1 the introduced solvent slug interacted with the original oil in place by taking the advantage of wormhole coverage and dissolution of the solvent occurred to some extent. As the time of interaction between oil and solvent increased, the concentration of the solvent in the system decreased due to diffusion and so did the pressure drop observed across the system. As cyclic injection continued, more volume of the solvent was introduced into the system and lower oil-in-place was remaining with asphaltene precipitation. This resulted in a low degree of solvent-oil contact and the trapped solvent pressure caused a lower pressure to drop in the system over the soaking time. It should also be noted from Figure 3.22 that Test 6 followed a similar trend to Test 3; however, the high-pressure drop was recorded for the later compared to the former after Cycle 4. This was as a result of higher volume of oil-in-place in Test 3 prior to the subsequent cycles.
Figure 3.22: Effect of wormhole configuration on the pressure depletion during the soaking period of cyclic 15% C₃H₈ - 85% CO₂ injection tests
3.3.4 Effect of Wormhole Configuration on Foamy Oil

In this section, the effect of wormhole configuration on the produced foamy oil behavior after each production phase of the performed CSI tests is studied. The foaminess of the produced oil is the height of the head of foam above oil after the production phase. The foam stability measurement, which is the length of time it takes a head foam to collapse, ranks the behavior of foamy oil in CSI process performed under different wormhole configurations. It is stated in the literature that foamy oil behavior is a function of viscosity, diffusion coefficient, and amount of gas dissolved in the oil. On this note, the tests were performed with the same oil viscosity; therefore, the foamy behavior which is illustrated in this study depends mainly on the diffusion coefficient and the amount of solvent dissolved in the oil.

Figure 3.23 depicts the digital images of the produced foamy oil for Tests 3, 5, and 6. The illustrated digital images as shown in Figure 3.23 correspond to the 4th, 5th, and 6th cycles' produced oil of the performed tests. The foam stability measurements for the performed tests are compared in Figure 3.24. It was observed that the higher the foam stability of the cyclic produced oil, the higher the incremental oil RF for the three performed tests. This indicated the role of foamy oil mechanism in the improved performance of cyclic solvent injection. The digital pictures show that lesser foaminess of the produced oil was obtained for Test 5 which had a single-branched wormhole compared to the foaminess obtained for Tests 3 and 6 with configured linear and double-branched wormholes, respectively. As mentioned in the previous section, adding a branch to the main wormhole (single-linear) to make a single branched wormhole increased the cyclic volume of solvent introduced into the sand-pack model of Test 5 compared to Test
3. Because of the higher solvent-oil interaction, the cyclic oil RF significantly increased in Test 5 compared to Test 3. Regardless of this performance, the observed foaminess and measured foam stability of the produced oil in the 5th cycle of Test 5 dramatically decreased compared to Test 3.

It should also be noted that in Figure 3.24, the effects of wormhole configurations (linear, single-branched, and double-branched wormholes) were less pronounced on the produced oil foaminess and stability during the early stages (Cycle 1 – 5) of the performed tests. During these cycles (1 – 5), the foam stabilities corresponding to the double-branched wormhole were minimal and they became more pronounced in the later stages of the test. The later stage foamy oil behavior was one of the main reasons behind the increased incremental oil recovery of Test 6.
**Figure 3.23:** Digital images of foamy behavior of the produced oil for Tests 3, 5 and 6
Figure 3.24: Effect of wormhole configuration on produced foamy oil stability
3.3.5 Effect of Wormhole Configuration on Residual Oil Saturation

Figure 3.25 compares the residual oil saturation distributions in the performed tests, in which the different wormhole configurations were in the middle of the rectangular sand-pack model. Figure 3.25 suggests that (1) the wormhole shapes affected the residual oil saturation distributions, which as well represent the solvent chamber shape at the top surfaces of the sand-pack model; (2) the uneven distributions of residual oil saturation indicated that the back and forth movement of foamy oil was significant in the oil recovery process; (3) more residual oil exists in the middle layer of the sand-packed model compared to the top surface at the end of the test, especially in the section further away from the wormhole surroundings; (4) increasing the branches of the linear wormhole significantly decreased the residual oil saturation in the middle layers of the sand-pack models after excavation; (5) more residual oil saturation exist at the top surface of the sand-pack models compared to the middle layers after excavation for Test 5 and 6; (6) for the three tests, sands in the section of the wormhole are much cleaner than the sands below the wormhole section of the model.
Figure 3.25: Effect of wormhole configuration on residual oil saturation profiles at the end of the tests
3.3.6 Effect of the Soaking Period on the Performance of Double-Branched Wormhole

In CSI operation, the duration after the injection phase is completed and before the production phase starts (which solvent is diffused and dispersed into the oil phase) is considered as the soaking time. It is one of the parameters that impact the performance of CSI process as the solvent-heavy oil interaction occurs in this phase through molecular diffusion and convection processes. Due to the importance of this parameter, one additional test was performed in the sand-pack model with the double-branched wormhole and this time, instead of the pre-defined soaking of 24 hours, a 96 hour's soaking time was applied.

Figure 3.26 shows a comparison between the ultimate oil RF results of above-mentioned test with the one previously obtained using 24 hours soaking time. The ultimate oil RF of Test 7 was raised by 3.6% when the soaking time was increased by 72 hours. Observation of Figure 3.26 indicated that the trends of the oil RF curves for Test 7 was increasing in Phase 1 and then almost maintained a constant value. At this phase, the oil RF was mainly affected by the soaking time in which the injected solvent-oil interaction was extended compared to Test 6 with pre-defined 24 hours soaking time. However, the oil recovery in Phase 2 significantly decreased and the curve almost maintained a constant value as the solvent chamber was achieved. Also, the effect of soaking time was more noticeable at the beginning of the process (e.g. first 3 cycles). This is because of the diffusion rate, which is a function of surface area, the amount of solvent and therefore, the presence of a higher quantity of heavy oil in the model (Qazvini Firouz and Torabi, 2012).
Figure 3.26: Effect of soaking period on the oil recovery of CSI test in the presence of double-branched wormhole network.
Longer soaking time raised the incremental oil RF by about 2.3% for the early process of Test 7 compared to Test 6 as illustrated in Figure 3.27. Also, Figure 3.27 indicated that the highest incremental oil recovery for Test 7 was achieved at Cycle 3, whereas Cycle 5 recorded the highest RF for Test 6. Furthermore, the lower cyclic oil recovery factors were observed after Cycle 5 for Test 7 compared to Test 6 as the cycle number increased. This suggested a lower rate of solvent diffusion due to the smaller surface area, the presence of heavier components (due to asphaltene molecule precipitations), and lower oil-in-place remaining in the sand-pack model. As depicted in Figure 3.28, the asphaltene content was measured, using standard ASTM D2007-03 method to be 19.3% after conducting the first cycle for Test 7. This obtained value was lower than the initial asphaltene content, which was found to be 23.1% using the same method. This indicated that asphaltene molecules are deposited in the sand-pack porous media during the process. Figure 3.28 shows a decreasing trend of the produced-oil asphaltene content measurements till the third cycle (11.4%) and then subsequent measurement resulted in increased with the cycle number in which 27.3% and 30.8% were found for the eighth and ninth cycles, respectively. This produced-oil asphaltene content trend is similar to the results obtained by Ahadi and Torabi (2018) in their attempt to investigate the optimum fraction of C\textsubscript{3}H\textsubscript{8} and CH\textsubscript{4} that could be included in the CO\textsubscript{2} stream to maximize the recovery of CSI.

As with other CSI tests, the pressure drop across the sand-pack model during the soaking time was more substantial during the first few cycles of Tests 6 and 7 (Figure 3.29). Observations of the performed tests show the negligible effect of soaking time on the pressure drop across this period. Following further analysis, it became evident that
additional investigations are required to evaluate the influence of soaking time during the cyclic process in the presence of branched wormhole networks.

Visual observation of the produced oil in both tests (6 and 7) confirmed the foamy oil flow as one of the production mechanism of CSI approach. Figure 3.30 depicts the digital image of the solvent-saturated produced oil foamy behavior. According to Figure 3.30, foamy oil flow contributed significantly to oil production in the early and middle processes of Test 7 and Test 6, respectively. Moreover, the early observation of foamy oil behavior in Test 7 was attributed to the extended soaking time, which allowed solvent solubility to occur. However, it caused the large molecules of the oil sample to deposit inside the model (as confirmed in Figure 3.28) and consequently reduced the heavier oil-solvent interaction in subsequent cycles. This decreased the cyclic oil recovery factor (as confirmed in Figure 3.27) and considerably, the foaminess of the solvent-saturated produced oil in subsequent cycles. The measured produced foamy oil stability for each cyclic production is plotted in Figure 3.31. As depicted, foamy oil stability data were in line with the trend of the cyclic oil recovery factor in which the injected solvent performance was reduced with cycle number after the third and fifth cycles of Test 6 and 7, respectively. As the stability of produced foamy oil increased, higher cyclic oil recovery was achieved and vice versa. In addition, the foamy oil flow was more stable in the first few cycles of Test 7 as the time for dispersed gas in the produced oil to coalesce lasted longer than those observed in Test 6. As the cycle number increased, foaminess of the produced oil decreased, and the stability dramatically reduced.
Figure 3.27: Effect of soaking period on the cyclic oil recovery factor of CSI tests in the presence of double-branched wormhole network
Figure 3.28: Solvent-produced oil asphaltene content (wt %) after each cycle injection of 15% C\textsubscript{3}H\textsubscript{8} - 85% CO\textsubscript{2} test for defined 96 hours soaking time
Figure 3.29: Effect of soaking period on pressure depletion across the sand-pack model with double-branched wormhole network
Figure 3.30: Effect of soaking period on produced foamy oil behavior in the presence of double-branch wormhole network
3.4. Chapter Summary

In this chapter, cycle number 0, 2, 4, 6, 8, and 10 produced foamy oil stability in minutes.

Test 6: 24 hrs soaking time
Test 7: 96 hrs soaking time

Figure 3.31: Effect of soaking period on the produced foamy oil stability in the presence of double-branched wormhole network.
CHAPTER 4: LAB-SCALE NUMERICAL SIMULATION STUDY

In addition to conducting laboratory experiments of cyclic solvent injection (CSI) under post-CHOPS reservoir conditions, performing a numerical simulation study is another way to study the effects of uncertain parameters such as relative permeability, foamy oil model, and solvent dispersion coefficient which might be difficult to study in the laboratory. With this intent, the numerical model assists in history matching analysis and visualization of the governing mechanisms involved in lab-scale CSI process. Also, validating the simulation model provides valuable information to further applicable studies in post-CHOPS development plans and optimizations.

This study employed CMG-STARS\textsuperscript{TM} from the Computer Modeling Group (Ver., 2013) to carry out history-match of seven lab-scale CSI tests conducted in rectangular sand-packed model with and without wormhole configurations. For an appropriate simulation model, a lab-scale model with the same properties and dimensions as the experimental model was built and history matching was performed to accurately predict the performance of CSI process in the presence and absence of wormhole configurations. The numerical simulations involved modeling the grid system, PVT properties, and uncertain parameters such as gas-liquid relative permeability curves, fractional flow model, and dispersion coefficients of propane and carbon dioxide in the oil phase.

4.1. Grid Block Systems

The 2D sand-pack experiments were simulated by developing the model’s rectangular shape out of a Cartesian grid. The dimension of the simulation model and the properties of numerical simulation model corresponding to each experimental test are
shown in Table 4.1. For experiments with wormhole network, the mimic wormhole was defined as two wells, injector, and producer, at the same location in a horizontal position for all the conducted tests. The single and double-branched wormholes were simulated through the multi-lateral well model. The sand-pack model was assumed to be homogenous in each CSI experiments, thus, constant porosity, permeability distributions in all direction, connate water saturation, and rock compressibility were set in the corresponding numerical simulation models. Figure 4.1 displays the grid system with mimic wormhole at the well location as an example. This was used to simulate Test 3.

The rock compressibility factor \( c_f \) is very important for reservoir modeling. For this study, Hall's rock compressibility correlation (Equation 4.1) as a function of only the porosity was used to determine the rock compressibility (DrillingFormulas.Com, 2016) for the simulation model. The unit of (Equation 4.1) is express in 1/psi, and converting this unit to 1/kPa changes Equation 4.1 to 4.2.

\[
c_f = 1.87 \times 10^{-6} (\phi)^{-0.415} \quad \text{Equation 4.1}
\]
\[
c_f = 2.71 \times 10^{-7} (\phi)^{-0.415} \quad \text{Equation 4.2}
\]

The pressure data recorded for the inlet and outlet ports during experiments were used as the well constraint or bottom-hole pressures for the injection and production wells. For the injection well, a maximum bottom-hole pressure was set close to the dew point of the solvent mixture at the experimental conditions. The constraint of the production well was the minimum bottom-hole pressure, which was close to atmospheric pressure. Appendix D presents the coordinates of the grid blocks as incorporated in the STARS data files.
**Table 4.1:** Characteristics of a proposed physical model for lab-scale simulation of the performed CSI tests

<table>
<thead>
<tr>
<th>Type</th>
<th>Cartesian</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity (%)</td>
<td>31.2*</td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>9200**</td>
</tr>
<tr>
<td>No. of the grid ((i \times j \times k))</td>
<td>16 \times 13 \times 3</td>
</tr>
<tr>
<td>Block width ((l, j, k))</td>
<td>1.531 cm, 1.539 cm, ((1.56, 1.88, \text{ and } 1.56)) cm</td>
</tr>
<tr>
<td>(S_{wc}) (%)</td>
<td>0.44***</td>
</tr>
<tr>
<td>Length (cm)</td>
<td>24.5</td>
</tr>
<tr>
<td>Width (cm)</td>
<td>20</td>
</tr>
<tr>
<td>Thickness (cm)</td>
<td>5</td>
</tr>
<tr>
<td>Rock compressibility ((1/kPa))</td>
<td>4.4 \times 10^{-7}</td>
</tr>
</tbody>
</table>

*Porosity is subject to change for each test (a value in the range of 31 – 34%)*  
**Permeability is subject to change for each test (a value in the range of 9000 – 1100 mD)*  
***\(S_{wc}\) is subject to change for each test (a value in the range of 0.44 – 5.82%)***
Figure 4.1: Grid system with wells' (mimic single-linear wormhole) locations
4.2. PVT Modeling

Viscosity and density of heavy oil directly affect the amount of solvent dissolved in it (Mohammadpoor and Torabi, 2015); therefore to accurately model and verify the experimentally measured data, the PVT analysis was performed using CMG-WinProp™ (ver. 2013) from the Computer Modeling Group. The diluted-dead oil viscosity and density at different temperatures obtained by Saskatchewan Research Council (SRC) (Table 3.1) were used to tune up the simulation PVT model. In addition, there are two types of viscosity correlation available in WinProp: Jossi-Stiel-Thodos (JST) correlation and the Pedersen corresponding states viscosity correlation. Among these correlations, the Modified Pedersen (1987) correlation is expected to give better liquid viscosity predictions for light and medium gravity oils than the JST model (WinProp User's Guide.). This model depends strongly on the critical pressure, critical temperatures, and molecular weights of the components. In this study, the viscosity model was constructed as a modified Pedersen model, and the comparison of the experimental values at various temperatures with those calculated through WinProp after the regression analyses are plotted in Figure 4.2. The result showed good qualitative and quantitative agreement between the experimental data and the simulated values after regression. Then, the validated PVT model was incorporated in the CMG-STARS to perform the lab-scale history-matching analysis.
Figure 4.2: Comparison between the experimental and simulated values of (a): crude density, and (b): crude oil viscosity after the regression.
4.3. Foamy Flow Model

The experimental data revealed that the recovery process of CSI is governed by the solvent chamber and the heavy oil zone. The free gas-oil flow dominates the solvent chamber while dispersed gas-oil (foamy oil flow) occupies the heavy oil zone (Hong et al., 2017). Studies show that heavy oil solution gas drive differs from the combined free gas flow and foamy oil in CSI. Therefore, understanding the foamy oil mechanism is a key factor in the production performance of CSI process (Bjorndalen et al., 2012). Dispersed gas (add one component), entrained gas (add two components), dispersed gas and entrained gas (add three components) foamy oil models are available in CMG-STARS. In this study, two foamy oil models i.e. modified fractional-flow approach and dispersed gas foamy oil model were applied separately, to history-match all 15% C₃H₈ – 85% CO₂ experimental tests. This resulted in ten lab-scale numerical simulation studies that were compared for characterizing the produced foamy oil behavior.

The modified fractional-flow approach is adopted to account for the delay of free gas flow due to foamy-oil flow in cyclic solvent injection recovery technique. In an attempt to match the production behavior, a lower gas relative permeability endpoint was assigned and was accompanied by higher irreducible gas saturation during the production stage. Thus, a separate set of relative permeability curves were incorporated for the injection stage. The Corey's correlations (Equation 4.3 and 4.4) were utilized to model the gas-liquid relative permeability curves, which were applied to model the foamy oil behavior of the produced oil.
\[ k_{rg} = k_{rgcl} \left( \frac{S_g - S_{g\text{crit}}}{1 - S_{g\text{crit}} - S_{o\text{lg}} - S_{w\text{con}}} \right)^{N_g} \]  

Equation 4.3

\[ k_{ro} = k_{ro\text{cg}} \left( \frac{S_l - S_{o\text{rg}} - S_{w\text{con}}}{1 - S_{g\text{crit}} - S_{o\text{lg}} - S_{w\text{con}}} \right)^{N_{o\text{g}}} \]  

Equation 4.4

Where, \( k_{rg} \): gas relative permeability; \( k_{rgcl} \): \( k_{rg} \) at connate liquid saturation; \( S_g \): gas saturation; \( S_{g\text{crit}} \): critical gas saturation; \( N_g \): gas relative permeability curve exponent; \( k_{ro} \): gas-oil oil relative permeability; \( k_{ro\text{cg}} \): \( k_{ro} \) at connate gas saturation; \( S_{o\text{rg}} \): gas-oil residual oil saturation; and \( N_{o\text{g}} \): gas-oil oil relative permeability curve exponent.

On the other hand, dispersed gas foamy oil model was applied for the selected performed tests to model the observed explosive foamy oil behavior. The sole purpose of applying these two proposed models for representing foamy oil behavior was to accurately simulate the lab-scale CSI processes and consequently to understand its performance under the influence of different wormhole network configurations. In this study, the non-equilibrium gas ex-solution which resulted in foamy oil changing to free gas was implemented in the CMG-STARS by two reaction equations. Thus, these reaction equations are represented as follows for CO\(_2\) and C\(_3\)H\(_8\) by:

\[ (C_3H_8)_L \rightarrow (C_3H_8)_G \]  

Equation 4.5

\[ (CO_2)_L \rightarrow (CO_2)_G \]  

Equation 4.6

where \((C_3H_8)_L\) is the dissolved \(C_3H_8\) in the oil phase, \((C_3H_8)_G\) is the \(C_3H_8\) in the gaseous phase, \((CO_2)_L\) is the dissolved \(CO_2\) in the oil phase, and \((CO_2)_G\) is the gaseous \(CO_2\).
4.4. History-Matching Results

Attempts were made to achieve a reasonable comparison between the production data of the simulation study with those obtained from the performed experiments. As a result, history-match analysis was conducted for all 15% C₃H₈ – 85% CO₂ experiments, which were operating at the same pressure. With the different foamy oil models mentioned in the previous section, the liquid-gas relative permeability curve was tuned to history-match the experimental results. Another matching parameter considered in this study was dispersion coefficient, which its effect will be evaluated in the next section. To avoid iteration failure and convergence issues, numerical control keywords such as time step control, solution methods, and linear solver, were adjusted in the simulation model. The same modified numerical controls were used for all the history-match study and they are listed in Table 4.2.

Figure 4.3 through Figure 4.7 depict the comparison of simulated ultimate RFs with the values obtained from experimental measurements for CSI tests with no-wormhole (Test 1), single-linear wormhole (Test 3), single-branched wormhole (Test 5), double-branched wormhole (Test 6), and double-branched wormhole plus extended soaking time of 96 hours (Test 7). The plots also compared the simulated results of the two implemented foamy oil flow models (modified fractional flow approach and dispersed gas flow model) to capture the foamy behavior of the produced oil. Although there was some difference between the simulation and experimental data, overall, the simulation results were in good qualitative and quantitative agreement with the experimental ones. In fact, in some cases, the experimental results were identical to the results obtained in the performed laboratory experiments.
Table 4.2: Numerical controls for the performed lab-scale simulation studies

<table>
<thead>
<tr>
<th>Numerical conditions</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>MAXSTEPS</td>
<td>99999</td>
</tr>
<tr>
<td>DTWELL</td>
<td>0.001 min</td>
</tr>
<tr>
<td>ISOETHERMAL</td>
<td>ON</td>
</tr>
<tr>
<td>NEWTONCYC</td>
<td>30</td>
</tr>
<tr>
<td>NCUTS</td>
<td>30</td>
</tr>
<tr>
<td>MAXPRES</td>
<td>1e+006 kPa</td>
</tr>
<tr>
<td>MINPRES</td>
<td>10 kPa</td>
</tr>
<tr>
<td>ITERMAX</td>
<td>300</td>
</tr>
<tr>
<td>NORTH</td>
<td>300</td>
</tr>
</tbody>
</table>
These differences are likely because of some laboratory operating conditions and phase behavior of rock-fluid(s) and fluid-fluid interaction could not be completely captured by the simulation process.

In addition, the estimated average absolute error between the experimental and simulated values of the cumulative oil recovery factor of the selected cyclic 15% C₃H₈ – 85% CO₂ injection tests are also shown in Figure 4.3 to Figure 4.7. It was found that the simulation results of dispersed gas foamy oil model have relatively more accurate predictions than those of the modified-fractional flow approaches in Tests 3, 5, 6, and 7. The only exception was Test 1, in which the modified fractional flow approach yielded an appropriate match to the experimental results. For Test 1, an average absolute error of 8.36% was obtained compared to the match obtained from the dispersed gas flow model which had an average absolute error of 28.04%. This could be attributed to negligible foamy oil flow, which agrees with the observation made at the production end during the laboratory CSI process of Test 1. This suggested that the modified-fractional flow model favors the gas-oil flow in CSI process, as two sets of two-phase relative permeability curves were incorporated separately for the injection and production stages and the only tuned variables are the fractional flows parameters. For Tests 3, 5, 6, and 7, average absolute errors for dispersed gas foamy oil model were 5.77, 3.33, 2.76, and 1.12%, respectively. Whereas the modified-fractional flow approaches yielded an average absolute error of 34.06, 34.03, 18.0, and 5.42%, respectively. Another matched parameter corresponding to the selected tests was the cumulative gas produced, and the plotted graphs and their percentage errors are listed in Appendix D.
Figure 4.3: (a): Comparison of simulated oil recovery factors with experimental ones, and (b): the experimental and simulated cumulative oil recovery factor after each cycle, for CSI Test 1, $P_{\text{inj}} = 730$ kPa
Figure 4.4: (a): Comparison of simulated oil recovery factors with experimental ones, and (b): the experimental and simulated cumulative oil recovery factor percentage relative error, for CSI Test 3 at $P_{\text{inj}} = 730$ kPa
Figure 4.5: (a): Comparison of simulated oil recovery factors with experimental ones, and (b): the experimental and simulated cumulative oil recovery factor after each cycle, for CSI Test 5 at $P_{inj} = 730$ kPa
Figure 4.6: (a): Comparison of simulated oil recovery factors with experimental ones, and (b): the experimental and simulated cumulative oil recovery factor after each cycle, for CSI Test 6, $P_{inj} = 730$ kPa
Figure 4.7: (a): Comparison of simulated oil recovery factors with experimental ones, and (b): the experimental and simulated cumulative oil recovery factor of each cycle, for CSI Test 7 at \( P_{\text{inj}} = 730 \text{ kPa} \).
4.5. Parametric Study on CSI process

As shown earlier through the experimental tests and numerical simulation, the presence of wormhole network had a significant influence on the performance of cyclic solvent injection process. It was illustrated that double-branched wormhole considerably improves the oil recovery during both 24 hours and 96 hours soaking time, with the later recording the highest ultimate oil RF. This improved oil production was attributed to the larger surface area created by the wormhole network for solvent-heavy oil interaction during the soaking phase of CSI process. Accordingly, the wormhole network served as a conduit for diluted-heavy oil to flow back to the production well during the production phase. It was also observed that introducing wormhole network promoted the foamy oil mechanism which was a key factor in determining how oil was produced in CSI process. On this note, it is important to study some parameters (e.g., reaction rate, gas-liquid relative permeability, gas dispersion coefficient in the oil phase, and soaking time) that may affect the efficiency of oil recovery during the cyclic injection process. Zeng (2008) stated that the relative permeability curve is one of the main fluid and formation uncertainties in numerical simulation. Thus, changing relative permeability curves in simulation model yield different production performances. As noted in the literature, gas-liquid relative permeability curve is of importance for cyclic solvent injection numerical simulation. And the foamy oil flow which is a significant mechanism in CSI process dramatically decreases the gas relative permeability. The tuned gas-liquid relative permeability curve that was inferred in the numerical simulation model for Test 3 are depict in Appendix C.
In this section, the effects of the above-mentioned parameters on oil recovery performance of cyclic 15% C$_3$H$_8$ – 85% CO$_2$ injection were determined through numerical simulation. Since the experimental phase behavior and cyclic injections of Test 6 were appropriately simulated using the dispersed gas flow model with an agreeable accuracy, simulations were carried out by varying only one parameter to examine its effect on the overall performance. Note that the water saturation in all the performed tests was very low in the model; therefore the water-oil relative permeability curve was insensitive to the performance of CSI. Thus, the following parameters such as gas-liquid relative permeability curve, reaction rate, dispersion coefficient, and soaking time were investigated by numerical simulation.

4.5.1. Effect of Reaction Rate

The main energy for foamy oil recovery mechanism is delaying the change of dispersed gas in the oil phase to free gas. This process was implemented in the simulation models through dispersed gas foamy oil model in which the dynamical solution gas transfers to free gas is based on the kinetic reaction. Zhang et al., (2014) stated that the reaction rate controls the changing process of foamy oil to free gas and calculated the reaction rates with Equation 4.7:

\[
Reaction \ rate = rrf \left[ e^{(-E_a/(T_{abs}R))} \right]
\]

where \(rrf\) is the reaction frequency factor; \(E_a\) is the activation energy, which provides the temperature dependence; \(T_{abs}\) is absolute temperature; and \(R\) is universal gas constant. In this study, different \(rrf\) values (2e-5, 2e-3, 0.2, and 20) were applied in the simulation models to calculate different reaction rates and to compare the simulated
results with the experimental data. Figure 4.8 shows the production performance of the various applied scenarios. It was found that decreasing the base case reaction rate constant (2e-3), which was the more accurate prediction by a factor of 100, had no significant effect on the production performance. Similar production response was obtained from increasing the reaction rate constant by the same factor. Further increase in the reaction rate constant (from 0.2 to 20) caused the ultimate oil RF to decrease from 43.2% to 40.8%.

As illustrated in Figure 4.8, the estimated percentage relative errors for each cycle number were very close for $rrf$ values of 2e-5, 2e-3, and 0.2, with an average absolute error of 2.6%, 3.4%, and 3.3%, respectively; whereas, $rrf$ values of 20 yielded 20.3% average absolute error. This suggested that $rff$ values between 2e-5 and 0.2 might result to a possible match with the obtained experimental data. Though the foamy oil mechanism is still new concept, which has not been completely understood; however, in this numerical study dispersed gas foamy oil model represented this mechanism based on kinetic reaction.
Figure 4.8: (a): Effect of reaction rate on the CSI process in Test 7, and (b): the cumulative oil recovery factor percentage relative error of reaction rate parametric study on the CSI process in Test 7
4.5.2. Effect of Dispersion Coefficient

The control of numerical dispersion is another parameter that affected the results obtained from the simulation of enhanced oil recovery processes. The grid blocks dimensions in simulation caused the numerical dispersion effects to vary. Therefore, setting an explicit dispersion modeled in the simulator was required in practice. Zhang et al., (2016) stated that in cyclic processes, the grid size/or time steps are hardly fine enough to reduce the numerical dispersion due to the availability of facility capacity and time. After history-matching, the base case dispersion coefficient values were 2.0e-3 cm²/min and 6.0e-3 cm²/min for C₃H₈ and CO₂, respectively. Three different dispersion coefficients were assigned in the input file (2e-2/6e-2, 2e-4/6e-4, and 2e-5/6e-5 cm²/min).

Error! Reference source not found. depicts the production scenarios and it was found that the results were very sensitive to the three assigned dispersion coefficients. It was found that decreasing the dispersion coefficient value (2e-3/6e-3 cm²/min) used for the base case resulted to lower oil RF and the average absolute errors were 22.7% and 39.5% for 2e-4/6e-4 and 2e-5/6e-5 cm²/min, respectively.
Figure 4.9: (a): Effect of dispersion coefficient on the CSI process in Test 7, and (b): the cumulative oil recovery factor percentage relative error of dispersion coefficient parametric study on the CSI process in Test 7
4.5.3. Effect of Soaking Time

As discussed in Chapter 3, an additional experimental test was carried out to investigate the effect of soaking time on the performance of cyclic solvent injection process in the presence of double-branched wormhole network. Instead of the pre-defined soaking time of 24 hours, the applied 96 hours soaking time increased the ultimate oil RF from 43.5% to 48.1%. The importance of this parameter requires more experimental tests involving different soaking scenarios; however, time constraint limits further laboratory investigation.

In this section, the validated numerical simulation model for Test 7 was used to further examine the effect of soaking time on the cyclic solvent injection process in the presence of double-branched wormhole network. Figure 4.10 shows that the investigated soaking times have very small impact on the oil recovery performance. It was found that the ultimate oil RF increased from $RF = 47.8\%$ with the soaking time of 96 hours to $RF = 48.5\%$ with the soaking time of 168 hours during the cyclic solvent injection process. Increasing the soaking time to 240 hours also resulted to an ultimate oil RF of 49.3%. Considering the simulation results, the ultimate oil RF is not noticeably improved when the soaking time was increased to 168 hours and 240 hours, indicating that there is an optimum soaking time for the cyclic solvent injection process. Regardless, as illustrated in Figure 4.10, the estimated percentage relative error between the experimental and simulated values of the cumulative oil RF showed that soaking time had more effect on the cyclic oil RF, especially for the first three cycles.
Figure 4.10: (a): Effect of the soaking period on the CSI process in Test 7, and (b): the cumulative oil recovery factor percentage relative error of soaking period parametric study on the CSI process in Test 7.
4.6. Chapter Summary

The lab-scale numerical simulation of cyclic solvent injection tests carried out in sand-packed model incorporated with different wormhole network configurations were conducted using the CMG software (ver., 2013). The simulation study consisted of three main parts. In the first part, the PVT analysis was performed using CMG-WinProp™ (ver. 2013) from the Computer Modeling Group. The dead oil viscosity and density at different temperatures were used to tune up the simulation PVT model. In the second part, simulation models with different wormhole configurations were built with CMG-Builder™ module and were employed as input reservoir models in the CMG-STARS™ simulator module. The last part consisted of history-matching process, which involved the comparison of the simulated data with the obtained experimental data and parametric studies were performed on CSI process. The history-matching process employed two different models to represent the foamy oil mechanism observed in the lab-scale studies of CSI operation.

The simulated results of the oil RF for cyclic 15% C₃H₈ – 85% CO₂ injections tests were conducted in sand-packed model with no-wormhole and sand-packed model with different wormhole configurations were appropriately matched with experimental ones. It was also observed that there existed a proper agreement between them with an average absolute percentage relative error less than 9% and 39% for dispersed gas foamy oil model and modified fractional flow model, respectively. In addition, a parametric study on the reaction rate, dispersion coefficient, and soaking time was carried out to determine the effect of these parameters on the oil recovery of cyclic 15% C₃H₈ – 85% CO₂ injection process. It was found that increasing the reaction rate constant to 20
decreased the oil recovery factor. The production performance scenarios were very sensitive to the differently applied dispersion coefficients. Also, the ultimate oil recovery factor was not noticeably improved by increasing the soaking time beyond 96 hours.
CHAPTER 5: CONCLUSIONS AND RECOMMENDATIONS

5.1. Conclusions

In this study, a series of experiments in a visual physical model and numerical simulation study was carried out regarding the performance of cyclic 15% \( \text{C}_3\text{H}_8 \) – 85% \( \text{CO}_2 \) and 50% \( \text{C}_3\text{H}_8 \) – 50% \( \text{CO}_2 \) injection processes in the presence of different wormhole network configurations under the same operating pressure. A total of seven tests were conducted experimentally to evaluate cyclic solvent injection technique for enhanced heavy oil recovery in lab-scale post-CHOPS porous media. The major conclusions that can be drawn from this study are summarized as follows:

1. The effect of \( \text{CO}_2/\text{C}_3\text{H}_8 \) mixture as an injected solvent in cyclic injection test was experimentally investigated in a 2D rectangular sand-packed model without wormhole network. It was found that higher concentration of \( \text{C}_3\text{H}_8 \) in the \( \text{CO}_2 \) stream has greater potential to recover the oil-in-place, and the ultimate oil recovery factor was 6.62% and 10.75% of the original oil in place for cyclic injection of 15% \( \text{C}_3\text{H}_8 \) – 85% \( \text{CO}_2 \) and 50% \( \text{C}_3\text{H}_8 \) – 50% \( \text{CO}_2 \), respectively.

2. It was observed that during the cyclic solvent injection of 15% \( \text{C}_3\text{H}_8 \) – 85% \( \text{CO}_2 \) and 50% \( \text{C}_3\text{H}_8 \) – 50% \( \text{CO}_2 \), a larger portion of the oil recovery was obtained through the 5\textsuperscript{th} to 9\textsuperscript{th} cycles. In the case of 50% \( \text{C}_3\text{H}_8 \) – 50% \( \text{CO}_2 \), the observed produced foamy oil corresponded to the 7\textsuperscript{th} and 8\textsuperscript{th} cycles, whereas the produced solvent-saturated oil obtained from cyclic 15% \( \text{C}_3\text{H}_8 \) – 85% \( \text{CO}_2 \) injection test showed absent of foamy oil.

3. It was observed that residual oil saturation at the top surface of the sand-packed models was very low for the two solvent mixtures. The measured residual oil
saturation ranged from 83.1% to 95.8% and 61.3% to 81.4% for 15% C₃H₈ – 85% CO₂ and 50% C₃H₈ – 50% CO₂, respectively. On the other hand, the highest residual oil saturation was observed in the middle of the physical models for the two solvents. It was found to vary from 89.6% to 95.6% and 71.9% to 87.3%. This suggested that gravity effects had a great impact on the recovery performance of CSI process.

4. The effect of linear wormhole incorporated on the oil recovery of the cyclic 15% C₃H₈ – 85% CO₂ and 50% C₃H₈ – 50% CO₂ injection tests were also determined. The results indicated that the performance of CSI process significantly improved in the presence of linear wormhole. In the case of 15% C₃H₈ – 85% CO₂ injection, the ultimate oil recovery factor increased from 6.62% to 27.16% of the original oil in place. On the other hand, after injecting 50% C₃H₈ – 50% CO₂, the ultimate oil recovery factor improved from 10.75% to 35.14%. Therefore, the performance of CSI process was improved by about 20% in the presence of linear wormhole.

5. The results of cyclic solvent injection tests in linear wormhole porous media also showed that the highest cyclic oil RF was gained in the early cycle numbers (i.e. 3rd and 5th). The linear wormhole played a key role in the performance of the selected solvent types.

6. Since foamy oil flow is a major mechanism of CSI process, it was found that wormhole network promoted the injection of enough solvent causing diffusion to occur to some extent and as a result initiating foamy oil flow in the recovery of heavy oil.
7. The measured oil RF during the cyclic 15% C₃H₈ – 85% CO₂ injection tests in a branched wormhole porous media revealed that adding branches to the linear wormhole significantly improved the oil recovery. The presence of wormhole(s) in the porous media increased the contact area between the injected solvent and the oil-in-place resulting in the diffusion of 15% C₃H₈ – 85% CO₂ into the larger portion of the porous media and a higher volume of crude oil can be produced.

8. It was found that the ultimate oil RF increased from 27.16% to 36.04% with single-branched wormhole porous media. On the other hand, the double-branched wormhole recorded the ultimate oil RF of 43.46% of OOIP. It suggested that a reservoir or well with multi-wormhole branching would favor post-CHOPS CSI process.

9. Nevertheless, the pre-defined soaking time of 96 hours did not significantly improve the ultimate oil recovery in the presence of double-branched wormhole. However, the incremental production of the early cycles increased considerably when the soaking time was extended.

10. The larger portion of the oil recovery was obtained through the 3rd to 6th cycles and these cycles corresponded to explosive produced foamy oil behavior. It was observed that the higher the foam stability of the cyclic produced oil, the higher the incremental oil recovery factor for the three performed tests. This indicated the role of foamy oil mechanism in the improved performance of cyclic solvent injection.

11. The wormhole shapes affected the residual oil saturation distributions, which as well represented the solvent chamber shape at the top surfaces of the sand-pack
model. It was observed that more residual oil existed in the middle layer of the sand-packed model compared to the top surface at the end of the test, especially in the section further away from the wormhole surroundings. Additionally, increasing the branches of the linear wormhole significantly decreased the residual oil saturation in the middle layers of the porous media.

12. The dead oil properties tests were used to regress and tune the PVT model for simulation studies. The lab-scale CSI process in a wormhole porous media was also simulated using the CMG software (ver., 2013), and the relative permeability curves together with dispersion coefficient of CO₂ and C₃H₈ in oil phase were employed to history-match the experimental data. In addition, modified fractional-flow approach and dispersed gas foamy oil model were used separately to represent the foamy oil behavior in the CSI process.

13. The selected experimental tests (1, 3, 5, 6, and 7) were simulated with different foamy oil models separately. It was found that the simulation results of dispersed gas foamy oil model had relatively more accurate predictions than those of the modified-fractional flow approaches in Test 3, 5, 6, and 7; except for Test 1 in which the modified fractional flow approach yielded an appropriate match to the experimental results.

14. The parametric study on reaction rate constant showed that varying the reaction rate frequency factor between 2e-5 and 0.2 had no significant effect on the production performance. However, increasing the reaction rate by a factor of 100 from 0.2 caused the ultimate oil recovery to decrease with an average absolute percentage relative error of 20.3%.
15. The production scenarios show that the results were very sensitive to the three assigned dispersion coefficients. It was found that decreasing the base case dispersion coefficient values resulted in lower oil recovery factors. Accordingly, sensitivity analysis of soaking time above 96 hours showed that the ultimate oil recovery factor was not noticeably improved when the soaking time was increased.

5.2. Recommendations

Based on the results of this research, the following are recommended for future studies:

1. The physical model used in this study had maximum injection pressure and temperature limitations of 1 MPa and 80°C, respectively. Therefore, evaluating the performance of CSI tests in the presence of wormhole network configurations at a higher injection pressure was not possible and is highly recommended; thus, requiring a new model with higher operating pressure tolerance.

2. As temperature is a key affecting parameter in phase behavior of the oil/solvent, diffusion rate, oil viscosity, etc., it is highly recommended to perform tests in temperature-controlled chamber.

3. To further investigate the role of different wormhole network configurations on foamy oil mechanism in CSI process, various pressure decline rates should be applied during the production period. In addition, it is also recommended to use a flow rate controller during injection period
to accurately quantify the amount of solvent that allied into the porous media in each cycle.

4. To obtain the amount of CO₂ or C₃H₈ in the solvent mixture that is dissolved in the oil-in-place during the soaking time, the produced gas should be properly characterized into different fractions.

5. Comprehensive phase behavior tests with dead oil-solvent mixture are required prior to a simulation study.

6. Performing CSI tests with low GOR live-oil is also recommended.

7. Up-scaling study may be useful as it provides a realistic picture of the experimental results when it is intended to be employed in real post-CHOPS reservoirs.
REFERENCE


https://doi.org/10.2118/05-09-03


APPENDIX A: EXPERIMENTAL SETUP

Figure A.1: Image of the experimental setup for CSI tests, (a): image of the visual sand-pack model, and (b): the image of the injection and production units
Figure A.2: (a): image of the transfer cell used for oil and solvent injection, and (b): image of the solvent-produced oil separator and wet gas meter
APPENDIX B: EXPERIMENTAL RESULTS

Results from the residual oil saturation tests performed at each CSI tests are presented in Table B.1 and B.1.

**Table B. 3:** Residual oil saturation for CSI Tests 1 and 2 at different locations of the sand-pack model

<table>
<thead>
<tr>
<th>No.</th>
<th>Layers</th>
<th>Location Name</th>
<th>( S_{or} ) (%)</th>
<th>Test 1</th>
<th>Test 2</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>Top Layer</td>
<td>R1</td>
<td>83.1</td>
<td>61.3</td>
<td></td>
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<tr>
<td>2</td>
<td>Top Layer</td>
<td>R2</td>
<td>86.2</td>
<td>70.3</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Top Layer</td>
<td>R3</td>
<td>91.9</td>
<td>73.3</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Top Layer</td>
<td>R4</td>
<td>97.6</td>
<td>79.1</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Top Layer</td>
<td>M1</td>
<td>76.0</td>
<td>60.5</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Top Layer</td>
<td>M2</td>
<td>73.5</td>
<td>65.0</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Top Layer</td>
<td>M3</td>
<td>76.9</td>
<td>72.8</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Top Layer</td>
<td>M4</td>
<td>92.6</td>
<td>77.6</td>
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<tr>
<td>9</td>
<td>Top Layer</td>
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<td>R2</td>
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<tr>
<td>15</td>
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<td>16</td>
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<tr>
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<td>Middle Layer</td>
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<td>92.3</td>
<td>72.3</td>
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<td></td>
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<tr>
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<td>Middle Layer</td>
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<td>95.4</td>
<td>87.3</td>
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Table B. 4: Residual oil saturation for CSI Test 3 and 4 at different locations of the sandpack model

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<th>Test 3 (%)</th>
<th>Test 4 (%)</th>
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</thead>
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<td>Top</td>
<td>R2</td>
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<td>18.8</td>
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<tr>
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<td>Top</td>
<td>R3</td>
<td>28.4</td>
<td>13.7</td>
</tr>
<tr>
<td>4</td>
<td>Top</td>
<td>R4</td>
<td>31.4</td>
<td>13.3</td>
</tr>
<tr>
<td>5</td>
<td>Top</td>
<td>M1</td>
<td>37.9</td>
<td>18.6</td>
</tr>
<tr>
<td>6</td>
<td>Top</td>
<td>M2</td>
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<td>13.5</td>
</tr>
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<td>Middle</td>
<td>R3</td>
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<tr>
<td>16</td>
<td>Middle</td>
<td>R4</td>
<td>55.8</td>
<td>18.6</td>
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<td>Middle</td>
<td>M1</td>
<td>36.2</td>
<td>19.7</td>
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<td>Middle</td>
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<td>56.8</td>
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<td>15.3</td>
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<td>10.0</td>
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</table>
In this appendix, the input data for the numerical simulation of cyclic solvent injection (15% C$_3$H$_8$ – 85% CO$_2$) of Test 3 are shown. It consists of the Cartesian grid block data, PVT model, and Gas-liquid relative permeability for both modified-fractional model approach and dispersed gas foamy oil model.

**C.1. Cartesian Grid Block**

************************************************************************
** Definition of fundamental Cartesian grid
************************************************************************

GRID VARI 16 13 3
KDIR DOWN
DI IVAR
  16*1.531
DJ JVAR
  13*1.539
DK ALL
  208*1.56 208*1.88 208*1.56
DTOP
  208*0
PERMI CON 9900
**0 = null block, 1 = active block
NULL CON 1
POR CON 0.325
PERMK EQUALSI
**0 = pinched block, 1 = active block
PINCHOUTARRAY CON 1
PERMJ EQUALSI
END-GRID
ROCKTYPE 1
PRPOR 101.325
CPOR 3.5e-7

**C.2. PVT Model**

************************************************************************
** THE FOLLOWING KEYWORDS CAN BE USED IN THE INITIALIZATION
SECTION IN STARS

************************************************************************
** MFRAC_OIL 'C3H8' CON  1.0401E-02
** MFRAC_OIL 'CO2' CON  2.1873E-02
** MFRAC_OIL 'Oil' CON  9.6773E-01
************************************************************************
********
** THE FOLLOWING SECTION CAN BE USED FOR THE COMPONENT
PROPERTY INPUT INTO STARS
************************************************************************
********
** PVT UNITS CONSISTENT WITH *INUNIT *SI
** Model and number of components
** Model and number of components
** Model and number of components
MODEL 5 5 5 1
COMPNAME 'WATER' 'C3H8' 'CO2' 'Oil' 'FREE_GAS'
**  --------  --------  --------  --------
CMM
0 0.0441 0.044 0.46 0.044
PCRIT
0 4245.52 7376.46 984.33 7376.46
TCRIT
0.00 96.65 31.05 685.46 31.05
KVTABLIM 101.32 2101.3 15 40
**  20.000
**  25.000
**  30.000
**  35.000
**  40.000
** Gas-liquid K Value tables
KVTABLE 'C3H8'
**
  11.761  0.78754
  13.091  0.86201
  14.508  0.94112
  16.01   1.0247
  17.597  1.1126
  19.268  1.2046
**  20.000
** 25.000
** 30.000
** 35.000
** 40.000

** Gas-liquid K Value tables

** KVTABLE 'CO2'

**

<table>
<thead>
<tr>
<th>Pressure, kPa</th>
<th>T, deg C</th>
<th>WinProp</th>
<th>STARS</th>
</tr>
</thead>
<tbody>
<tr>
<td>15.000</td>
<td>1.0132E+02</td>
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<td>&lt;W: L,S: L&gt;</td>
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<tr>
<td>20.000</td>
<td>2.1013E+03</td>
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<td>25.000</td>
<td>3.00000</td>
<td>&lt;W: LV,S: LV&gt;</td>
<td>&lt;W: L,S: L&gt;</td>
</tr>
<tr>
<td>30.000</td>
<td>3.50000</td>
<td>&lt;W: LV,S: LV&gt;</td>
<td>&lt;W: L,S: L&gt;</td>
</tr>
<tr>
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<td>4.50000</td>
<td>&lt;W: LV,S: LV&gt;</td>
<td>&lt;W: L,S: L&gt;</td>
</tr>
</tbody>
</table>

** Gas-liquid K Value tables

** KVTABLE 'Oil'

**

<table>
<thead>
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<th>WinProp</th>
<th>STARS</th>
</tr>
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<tr>
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<td>1.1372e-015</td>
<td>7.1165e-015</td>
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<td>1.6687e-014</td>
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<td>3.8166e-014</td>
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<tr>
<td>40.000</td>
<td>3.49465e-013</td>
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</tbody>
</table>
** 35.000
** 40.000
** Gas-liquid K Value tables
KVTABLE 'FREE_GAS'
**
11.761 0.78754
13.091 0.86201
14.508 0.94112
16.01  1.0247
17.597 1.1126
19.268 1.2046

**reference pressure, corresponding to the density
PRSR 101.325

**reference temperature, corresponding to the density
TEMR 21

**pressure at surface, for reporting well rates, etc.
PSURF 101.325

**temperature at the surface, for reporting well rates, etc.
TSURF 15.556

K_SURF 'Oil' 1.2859e-015
MOLDEN
0 0.01285 0.02094 0.002108 0.01285
CP
0 2.731e-006 4.303e-006 3.936e-007 2.731e-006
CT1
0 0.0003997 0.001378 3.039e-006 0.0003997
CT2
0 4.275e-006 4.417e-006 8.322e-007 4.275e-006
CPT
0 -3.159e-006 -4.412e-007 2.1e-010 -3.159e-006

** T, deg C        'WATER'      'C3H8'       'CO2'       'Oil'
**              ---------  ---------  ---------  ---------

** temp
VISCTABLE
*ATPRES 101.325

15  0  0.12319  0.12758  109870  0.12319
20  0  0.11857  0.12366  59488   0.11857
25  0  0.11381  0.11952  33285  0.11381
30  0  0.10934  0.11558  19263  0.10934
35  0  0.10523  0.11196  11514  0.10523
*ATPRES 2000

15  0   0.12323   0.12762   119380   0.12323
20  0   0.11861   0.1237     64751   0.11861
25  0   0.11431   0.12004     36439   0.11431
30  0   0.11031   0.11662     21218   0.11031
35  0   0.10659   0.11341     12753   0.10659
40  0   0.10312   0.11039    7893.5   0.10312

** Reaction specification
STOREAC
0 0 1 0 0
STOPROD
0 0 0 0 1
RPHASE
0 0 3 0 0
RORDER
0 0 1 0 0
EACT 23260
FREQFAC 2e-4
MTVEL 0 -1.5 0.000105833

** Reaction specification
STOREAC
0 1 0 0 0
STOPROD
0 0 0 0 1.001
RPHASE
0 3 0 0 0
RORDER
0 1 0 0 0
EACT 23260
FREQFAC 0.002
MTVEL 0 -1.5 0.000105833
C.3. Gas-Liquid Relative Permeability Tables

Test 3: RPT 1 WATWET

Figure C.1: Modified fractional flow model gas-relative permeability curves, (a): injection stage gas-liquid relative permeability curve, and (b): Production stage gas-liquid relative permeability curve
Figure C.2: Gas-liquid relative permeability curve used for dispersed gas foamy oil model
C.4. History-Matching Results

![Graph of cumulative produced gas and percentage error](image)

**Figure D.1:** (a): Comparison of simulated cumulative produced gas with experimental ones, and (b): the experimental and simulated cumulative produced gas percentage relative error after each cycle, for CSI Test 1, $P_{\text{inj}} = 730$ kPa
Figure D.2: (a): Comparison of simulated cumulative produced gas with experimental ones, and (b): the experimental and simulated cumulative produced gas percentage relative error after each cycle, for CSI Test 3, $P_{inj} = 730$ kPa
Figure D.3: (a): Comparison of simulated cumulative produced gas with experimental ones, and (b): the experimental and simulated cumulative produced gas percentage relative error after each cycle, for CSI Test 5, $P_{\text{inj}} = 730 \text{ kPa}$
Figure D.4: (a): Comparison of simulated cumulative produced gas with experimental ones, and (b): the experimental and simulated cumulative produced gas percentage relative error after each cycle, for CSI Test 6, $P_{\text{inj}} = 730 \text{ kPa}$
Figure D.5: (a): Comparison of simulated cumulative produced gas with experimental ones, and (b): the experimental and simulated cumulative produced gas percentage relative error after each cycle, for CSI Test 7, $P_{inj} = 730$ kPa