SOLVENT-ASSISTED WATER PRESSURE CYCLING (SA-WPC) IN
A THIN HEAVY OIL RESERVOIR

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By

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Olusegun Ajani Ojumoola, candidate for the degree of Master of Applied Science in Petroleum Systems Engineering, has presented a thesis titled, *Solvent-Assisted Water Pressure Cycling (SA-WPC) in a Thin Heavy Oil Reservoir*, in an oral examination held on December 11, 2019. 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

In this thesis, different sequences of solvent injection and/or water injection were explored to study their performances as an improved oil recovery (IOR) and/or enhanced oil recovery (EOR) processes in a thin heavy oil reservoir. In addition, the IOR/EOR processes were compared in terms of the heavy oil recovery factor (RF), cumulative gas–oil ratio (cGOR) and cumulative water–oil ratio (cWOR). In the experiments, the original heavy oil sample was collected from the Colony formations in Alberta, Canada. The colony heavy oil had a measured dead heavy oil viscosity and density of $\mu_o = 33,876$ cP and $\rho_o = 0.992$ g/cm$^3$ at $P_a = 1$ atm and $T_{res} = 21.0$ °C.

Five respective series of laboratory tests were conducted by using a rectangular sandpacked physical model with a height-to-length ratio of 1:20 to represent a thin heavy oil reservoir and can model a one- or two-well configuration process. These tests included two cyclic solvent injection (CSI) tests, three gas pressure cycling (GPC) tests, three solvent-assisted gas pressure cycling (SA-GPC) tests, three water pressure cycling (WPC) tests and four solvent-assisted water pressure cycling (SA-WPC) tests. Most test were initiated after the primary production pressure was reduced in steps of $\Delta P_{PP} = 1.0$ MPa from $P_i = 3.0$ MPa to $P_f = 0.2$ MPa. However, two of the three WPC tests were initiated after the primary production pressure was reduced from $P_i = 3.0$ MPa to $P_f = 2.0$ MPa and 1.0 MPa, respectively. Except two CSI tests that used a one-well configuration, every other test utilized a two-well configuration, where one well served as the producer/solvent injector and the other well served as the brine/gas injector.

In the traditional CSI process, an additional technical shortcoming known as gas trapping was observed. This was formed because the region before the gas-trapping zone
experienced quick heavy oil viscosity regainment. However, C$_3$H$_8$-GPC test at a pressure depletion step size of $\Delta P_{EOR} = 0.5$ MPa and SA-GPC test at $\Delta P_{EOR} = 1.0$ MPa had the highest heavy oil RFs of 41.9% and 36.6% of the original oil-in-place (OOIP), among the two series of GPC and SA-GPC tests. C$_3$H$_8$-GPC test and SA-GPC test outperformed the CSI test because the back-and-forth movements of the foamy oil in CSI was avoided by effectively displacing the foamy oil towards the producer in a two-well configuration. Also C$_3$H$_8$-GPC test was better than SA-GPC test in terms of the heavy oil RF and cGOR due to the formation of stronger foamy-oil flow and the absence of CO$_2$, which reduced the solubility of C$_3$H$_8$ into the heavy oil in the SA-GPC test.

Furthermore, the experimental results showed that the WPC test that was initiated at the final primary production pressure $P_f = 1.0$ MPa had the highest heavy oil RF of 29.2% of the OOIP in the series of WPC tests. However, its performance was undermined due to the lack of enough solvent in the physical model to reduce the heavy oil viscosity, severe water channeling and water breakthrough (BT). C$_3$H$_8$-SA-WPC test at $\Delta P_{EOR} = 0.5$ MPa had the highest heavy oil RF of 68.4% of the OOIP among all SA-WPC tests. In addition, the experimental data showed the existence of an optimum $\Delta P_{EOR}$ in C$_3$H$_8$-SA-WPC tests, above and below which the heavy oil RF was lower. It was also found that C$_3$H$_8$ was a far more effective extracting solvent than CO$_2$. Finally, C$_3$H$_8$-SA-WPC process was the best among all the IOR/EOR processes in this study because of its effective solvent dissolution to reduce the heavy oil viscosity, stronger foamy-oil flow, delayed water BT and combined EOR (SA) and IOR (WPC) mechanisms. As a result, the IOR/EOR processes were ranked based on the heavy oil RFs as follows: C$_3$H$_8$-SA-WPC > C$_3$H$_8$-GPC > SA-GPC > WPC > CO$_2$-SA-WPC > CO$_2$-GPC > C$_3$H$_8$-CSI > CO$_2$-CSI.
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DEDICATION

This work is dedicated to JESUS the author and the finisher of my faith, my wonderful wife Titilope Ifeoluwa Ojumoola for her prayers, understanding and encouragement throughout my studies, as well as to my parents and siblings for their unconditional support.
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**Figure 4.24(a)** Measured heavy oil recovery factors (RFs) during the primary productions (PPs) at the final primary production pressures of $P_f = 0.2$ MPa; the different cycles in SA-GPC processes at $\Delta P_{EOR} = 0.1$, 0.5, and 1.0 MPa (Tests #6–8); Cycles #1–4 in C$_3$H$_8$-SA-WPC processes at $\Delta P_{EOR} = 0.1$, 0.5 and 1.0 MPa (Tests #12–14); and Cycles #1–3 in CO$_2$-SA-WPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #15).

**Figure 4.24(b)** Measured cumulative gas–oil ratios (cGORs) during the different cycles in SA-GPC processes at $\Delta P_{EOR} = 0.1$, 0.5, and 1.0 MPa (Tests #6–8); Cycles #1–4 in C$_3$H$_8$-SA-WPC processes at $\Delta P_{EOR} = 0.1$, 0.5 and 1.0 MPa (Tests #12–14); and Cycles #1–3 in CO$_2$-SA-WPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #15).
NOMENCLATURE

Notations

\( H \)  Height of the physical model, m

\( k \)  Permeability, D

\( k_{RD} \)  Relative permeability of the displacing fluid

\( k_{ro} \)  Relative permeability of heavy crude oil

\( L \)  Length of the physical model, m

\( M \)  Mobility ratio

\( P_a \)  Atmospheric pressure, atm

\( P_{air} \)  Pressurized air pressure, MPa

\( P_c \)  Critical pressure, MPa

\( P_{e} \)  Ending production pressure, MPa

\( P_{eq} \)  Equilibrium pressure, MPa

\( P_f \)  Final primary production pressure, MPa

\( P_i \)  Initial reservoir pressure, MPa

\( P_{inj} \)  Injection pressure, MPa

\( P_{injg} \)  Gas injection pressure, MPa

\( P_{injs} \)  Solvent injection pressure, MPa

\( P_{injw} \)  Water injection pressure, MPa

\( P_{prod} \)  Production pressure, MPa

\( P_s \)  Soaking pressure, MPa

\( P_{sat} \)  Saturation pressure, MPa

\( q_{injw} \)  Water injection rate, cm\(^3\)/min
$S_{oi}$ Initial oil saturation
$S_{wi}$ Initial water saturation
$T$ Temperature, °C
$T_{res}$ Reservoir temperature, °C
$W$ Width of the physical model, m

Greek symbols

$\Delta P_{EOR}$ Pressure depletion step size during CSI, GPC, SA-GPC and SA-WPC, MPa
$\Delta P_{IOR}$ Pressure depletion step size in WPC, MPa
$\Delta P_{PP}$ Pressure depletion step size in the primary production, MPa
$\mu_D$ Viscosity of the displacing fluid, cP
$\mu_o$ Viscosity of the heavy crude oil, cP
$\rho_o$ Density of heavy oil, g/cm$^3$
$\phi$ Porosity, %

Subscripts

a Atmospheric
air Pressurized air
c Critical
D Displacing fluid
e Ending
EOR Enhanced oil recovery
eq Equilibrium
f Final
i Initial
inj Injection
injg Gas injection
injs Solvent injection
injw Water injection
IOR Improved oil recovery
o Oil
oi Initial oil
PP Primary production
prod Production
rD Relative displacing fluid
res Reservoir
ro Relative oil
s Soaking
sat Saturation
wi Initial water

Acronyms
ASP Alkali–surfactant–polymer
BBO Billion barrels of oil
BOPD Barrels of oil per day
BPR Back-pressure regulator
BT Breakthrough
cGOR Cumulative gas–oil ratio
CHOPS  Cold heavy oil production with sand
CPCSI  Cyclic production with continuous solvent injection
CSI  Cyclic solvent injection
CSI + WF  Combined cyclic solvent injection and waterflooding
CSS  Cyclic steam stimulation
cWOR  Cumulative water–oil ratio
DAS  Data acquisition system
ECSP  Enhanced cyclic solvent process
EHOR  Enhanced Heavy Oil Recovery
EOR  Enhanced oil recovery
ES-SAGD  Expanding-steam assisted gravity drainage
GA-CSI  Gas flooding-assisted cyclic solvent injection
GOR  Gas–oil ratio
GPC  Gas pressure cycling
iGOR  Instantaneous gas–oil ratio
IHOR  Improved heavy oil recovery
IOR  Improved oil recovery
ISC  In-situ combustion
LASER  Liquid addition to steam for enhancing recovery
MMbbl  Million barrels
OOIP  Original oil-in-place
PP  Primary production
PP-CSI  Pressure pulsing cyclic solvent injection
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>P‒T</td>
<td>Pressure vs. temperature</td>
</tr>
<tr>
<td>PVT</td>
<td>Pressure–volume–temperature</td>
</tr>
<tr>
<td>RF</td>
<td>Recovery factor</td>
</tr>
<tr>
<td>SAGD</td>
<td>Steam-assisted gravity drainage</td>
</tr>
<tr>
<td>SA-GPC</td>
<td>Solvent-assisted gas pressure cycling</td>
</tr>
<tr>
<td>SAP</td>
<td>Solvent-aided process</td>
</tr>
<tr>
<td>SA-WPC</td>
<td>Solvent-assisted water pressure cycling</td>
</tr>
<tr>
<td>THAI</td>
<td>Toe-to-heel air injection</td>
</tr>
<tr>
<td>VAPEX</td>
<td>Vapour extraction</td>
</tr>
<tr>
<td>WF</td>
<td>Waterflooding</td>
</tr>
<tr>
<td>WPC</td>
<td>Water pressure cycling</td>
</tr>
</tbody>
</table>
CHAPTER 1 INTRODUCTION

1.1 Heavy Oil Resources in Western Canada

The conventional crude oil had met the world energy demand until approximately 2007 when the crude oils from the conventional sources were not enough (Meyer et al., 2007). This led to a need to exploit the unconventional heavy oil and natural bitumen resources. Meyer and Attanasi (2003) reported that the estimated volumes of the technically recoverable heavy crude oil and natural bitumen are 434 billion barrels of oil (BBO) and 651 BBO respectively, which are listed in Table 1.1. Their total volume is approximately equal to the remaining conventional light crude oil resources (Meyer and Attanasi, 2003). The western hemisphere holds 69% and 82% of the world’s technically recoverable heavy crude oil and natural bitumen respectively, in contrast to 85% of the conventional light crude oil reserves in the eastern hemisphere.

In western Canada, most recoverable bitumen/heavy oil resources have to be produced by using the in-situ enhanced oil recovery (EOR) processes because only 12% can be recovered by using open-pit mining technology. Majority of the bitumen/heavy oil resources and associated gas are accumulated in the shallow Lower Cretaceous fluvio-deltaic sands at depths of less than 3000 ft (Beckie et al., 1988). Other additional reserves are accumulated in the Devonian and Mississippian carbonates, which sub-crop the Cretaceous (Beckie et al., 1988). According to BP (2019), Canada has a total proven natural bitumen reserves of about 162.3 BBO, which are mainly located in the western Canadian sedimentary basin. The majority of the in-place natural bitumen is located in Alberta, which accounts for 70% of the world’s in-place natural bitumen. Moreover, the heavy oil reserves in Saskatchewan was estimated to be about 17.7 BBO (Zhang et al., 2007). The heavy oil
Table 1.1 Estimated volumes of the technically recoverable heavy crude oil and natural bitumen by regions (Meyer and Attanasi, 2003).

<table>
<thead>
<tr>
<th>REGION</th>
<th>HEAVY CRUDE OIL</th>
<th>NATURAL BITUMEN</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Recovery factor (%)</td>
<td>Technically recoverable (BBO)</td>
</tr>
<tr>
<td>North America</td>
<td>19</td>
<td>35.3</td>
</tr>
<tr>
<td>South America</td>
<td>13</td>
<td>265.7</td>
</tr>
<tr>
<td>Western Hemisphere</td>
<td>13</td>
<td><strong>301.0</strong></td>
</tr>
<tr>
<td>Africa</td>
<td>18</td>
<td>7.2</td>
</tr>
<tr>
<td>Europe</td>
<td>15</td>
<td>4.9</td>
</tr>
<tr>
<td>Middle East</td>
<td>12</td>
<td>78.2</td>
</tr>
<tr>
<td>Asia</td>
<td>14</td>
<td>29.6</td>
</tr>
<tr>
<td>Russia</td>
<td>13</td>
<td>13.4</td>
</tr>
<tr>
<td>Eastern Hemisphere</td>
<td>13</td>
<td><strong>133.3</strong></td>
</tr>
<tr>
<td>World</td>
<td></td>
<td><strong>434.3</strong></td>
</tr>
</tbody>
</table>
deposits in Saskatchewan are located near the border between Alberta and Saskatchewan, 90% of which are in the thin heavy oil reservoirs with the main pay-zone thicknesses of 4–6 m (Zhang et al., 2007; Hutchence and Huang, 1999; Farouq-Ali, 1997). Based on the current EOR technologies and economic constraints, the Saskatchewan heavy oil reservoirs have an estimated recovery factor (RF) of about 10% of the original oil-in-place (OOIP). The viscosities of the heavy crude oils in the Saskatchewan heavy oil reservoirs are in the range of 2000–10,000 cP.

1.2 Enhanced Heavy Oil Recovery Processes

Improved oil recovery (IOR) includes processes such as waterflooding, gasflooding, as well as other processes that increases reservoir energy to stimulate oil production and increase oil RF. Meanwhile, EOR process involves the use of advanced techniques that alters the original properties of the oil to increase oil production and oil RF.

Heavy oil has some unique characteristics, such as its high viscosity, low mobility and low API gravity under the actual reservoir conditions. It is often characterized by its viscosity and API gravity. A crude oil with an oil viscosity of higher than 1,000 cP and an API gravity in the range of 10–15 ºAPI under the oil reservoir conditions is regarded as the heavy crude oil. Similarly, a crude oil with an oil viscosity of higher than 10,000 cP and an API gravity in the range of 5–10 ºAPI is regarded as the extra heavy crude oil or bitumen (Speight, 2000; 2014). The heavy oil viscosity is the major property and is often considered as the most important factor to affect the heavy oil production. Furthermore, the mobility ratio is defined as the ratio of the mobility of a displacing fluid to that of the heavy oil, which shows how change in a property of the displacing fluid/heavy oil can affect the heavy oil production.
\[ M = \frac{k_{rD}/\mu_D}{k_{ro}/\mu_o}, \]  

[1.1]

where \( M \) is the mobility ratio; \( k_{rD} \) and \( \mu_D \) are the displacing fluid relative permeability and viscosity in cP respectively; \( k_{ro} \) and \( \mu_o \) are the heavy crude oil relative permeability and viscosity in cP respectively.

A mobility ratio of less than unity (\( M < 1 \)) is desired for any enhanced heavy oil recovery (EHOR) process to be successful. In order to achieve this objective, most EHOR processes aim to reduce the oil viscosity \( \mu_o \), while the others aim to increase the displacing fluid viscosity \( \mu_D \). Some EHOR process aim to increase \( k_{ro} \) and decrease \( k_{rD} \) through other mechanisms, such as the interfacial tension (IFT) reduction and wettability alteration. It is more traditional to employ thermal-based EHOR processes and solvent-based EHOR processes due to their abilities to reduce the heavy oil viscosity and recover more heavy oil (Speight, 2013). In cold or offshore oilfields, however, polymer-augmented waterflooding could be the best option after the primary production (Speight, 2013). In general, the EHOR processes are categorized into four major different groups: thermal-based EHOR, solvent-based EHOR, chemical-EHOR and hybrid EHOR. The thermal-based EHOR processes include in-situ combustion (ISC), such as air injection or toe-to-heel air injection (THAI), cyclic steam stimulation (CSS), steam flooding, electrical heating, and steam-assisted gravity drainage (SAGD). The solvent-based EHOR processes include solvent flooding, solvent vapour extraction (VAPEX), warm VAPEX and cyclic solvent injection (CSI). Chemical-EHOR processes can be alkali, surfactant, polymer and alkali–surfactant–polymer (ASP) flooding. Lastly, the hybrid EHOR processes include expanding-SAGD (ES-SAGD), solvent-aided process (SAP) and liquid addition to steam for enhancing
recovery (LASER). These processes are outlined in Figure 1.1.

1.3 Research Objectives

The primary objective of this study is to explore different sequences of solvent injection and/or brine injection in order to develop new solvent- and/or water-based EHOR, which can considerably enhance the heavy oil recovery. The specific research objectives are summarized as follows:

- To explore gas pressure cycling (GPC) in a two-well configuration as an EHOR process in a thin heavy oil reservoir;
- To explore solvent-assisted gas pressure cycling (SA-GPC) in a two-well configuration as an EHOR process in a thin heavy oil reservoir;
- To study water pressure cycling (WPC) in a two-well configuration as an IOR process in a thin heavy oil reservoir;
- To maximize the technical synergy of the joint EOR and IOR mechanisms in the solvent-assisted water pressure cycling (SA-WPC); and
- To compare GPC, SA-GPC, WPC, SA-WPC processes with the CSI process and identify an optimum solvent- and water-based EHOR with the highest heavy oil RF.

1.4 Research Methodology

In this study, five series of laboratory experiments were conducted to examine the performances of different sequences of solvent and/or water injection, which include CSI, GPC, SA-GPC, WPC, and SA-WPC. Each series of experiments were conducted by using a 2-D rectangular sandpacked physical model to evaluate the heavy oil RFs, instantaneous gas–oil ratios (iGORs), which were measured every 15 min, cumulative gas–oil ratios
Figure 1.1 Enhanced heavy oil recovery (EHOR) processes (Lin et al., 2014).
(cGORs) and/or the cumulative water–oil ratios (cWORs). Some of the proposed new EHOR processes were compared with the traditional CSI. Furthermore, the pressure depletion step size ($\Delta P_{\text{IOR/EOR}}$) effect was also examined on the proposed new IOR/EOR processes.

1.5 Thesis Outline

There are five chapters in this thesis. Chapter 1 gives a brief introduction of the heavy oil resources in western Canada, EHOR processes, and the research objectives of this study. Chapter 2 provides some technical backgrounds of the foamy-oil phenomenon and an updated literature review of waterflooding, CSI and its variations in a heavy oil reservoir. Chapter 3 describes the experimental details of this study, including the materials used, experimental set-up, experimental preparation and procedure of each series of experiments. Chapter 4 presents and analyzes the results obtained in the experimental study. Chapter 5 summarizes the major scientific conclusions of this study and makes several technical recommendations for future studies.
CHAPTER 2 LITERATURE REVIEW

2.1 Primary Production

Most heavy oil reservoirs in western Canada are composed of unconsolidated sandstone grains with high permeabilities and produced in the primary production processes under the so-called solution-gas drive with low producing gas–oil ratios (GORs) and moderate oil production rates (Maini et al., 1993; Haddad and Gates, 2015). The cold heavy oil production with sand (CHOPS) is a special primary production process in such heavy oil reservoirs. As a result of the unconsolidated nature of the heavy oil reservoir, the foamy oil formed in the CHOPS fluidizes the sand grains and carries them along to the production well. Accordingly, there is some sand production at the beginning (Smith, 1988; Haddad and Gates, 2015). The primary heavy oil production rate is much higher than that predicted from the Darcy’s law due to foamy-oil flow and formation of wormholes (Maini, 2001). Most CHOPS reservoirs in western Canada have the main pay zone thicknesses of less than 5 m and often have typical primary heavy oil recovery RFs of 5–15%. Thus about 85–95% of the OOIP are still left in the heavy oil reservoirs to be recovered through the subsequent IOR and/or even EHOR (Maini, 2001).

As stated above, the foamy-oil flow is one of the major EOR mechanisms why the primary heavy oil production rate in a thin CHOPS reservoir is much higher than that predicted from the Darcy’s law. Maini et al. (1993) found at the wellheads of several heavy oil reservoirs in Alberta and Saskatchewan that the heavy oil produced was in the form of a thick oil-continuous foam, which was termed the “foamy oil”. Foamy-oil flow was defined as a non-Darcy two-phase flow of gas and oil, which is often encountered during the primary production in many Canadian and Venezuelan heavy oil reservoirs under the
solution-gas drive (Maini, 1999). Also Sheng (1997) called it a pseudo single-phase flow of heavy oil containing dispersed small gas bubbles. More importantly, foamy-oil stability is a key property of the foamy-oil flow, which causes the primary heavy oil production rate in the CHOPS reservoirs to be anomalously high. Sheng et al. (1997) defined foamy-oil stability as a measure of foaminess or the rates of destruction of foams. Only a few studies have been carried out on the foamy-oil stability, which were the experiments conducted by Sheng (1997) and Wu et al. (2011). Factors that affects the foamy-oil stability as studied by Sheng (1997) and Wu et al. (2011) are discussed below.

- Heavy oil viscosity effect: Both studies concluded that heavy oil viscosity is a major factor in determining the foamy-oil stability. It was found that a heavy oil with a higher viscosity had a slower growth of the dispersed bubbles and a reduced rate of bubble release from the oil phase. This implies that a higher heavy oil viscosity favours the foamy-oil stability. In addition, Sheng (1997) reported that the duration of the foamy oil increases linearly with the heavy oil viscosity.

- Effect of asphaltene content: Sheng (1997) inferred that the asphaltene content could improve the foamy-oil stability by hindering the coalescence of gas bubbles and creating more nucleation sites for the formation of more small bubbles. However, the experimental results suggested that asphaltenes do not significantly increase the foamy-oil stability (Sheng, 1997).

- Oil column height effect: The foamy-oil stability increased with increasing oil column height. This is because higher oil column induces a slower rate of drainage (ability of the entrained gas bubble to be liberated from the oil phase) and consequently causes increased foamy-oil stability. This phenomenon is called the
irrigation effect (Sheng, 1997).

- Pressure depletion rate effect: Some study of pressure depletion rate effect provides a better understanding of the competition between the bubble formation and bubble decay, which determine the foamy-oil stability. A higher pressure depletion rate causes more gas to come out of the heavy oil and also induces more bubble nucleation due to a high supersaturation (Sheng, 1997). Wu et al. (2011) confirmed this trend and explained that a higher pressure depletion rate maintains the foamy-oil flow characteristics, whereas a lower pressure depletion rate accelerates bubble decay and consequently reduces the foamy-oil stability.

- Effect of solution-gas concentration: The foamy-oil stability increased with increasing solution-gas concentration (Sheng, 1997). More gases dissolved into the heavy oil resulted in a higher supersaturation. Thus the bubble nucleation and foamy-oil stability were increased.

- Temperature effect: The bubble-point and pseudo-bubble point pressures of the heavy oil were increased due to the increase in temperature. However, the difference between the two pressures was decreased, which caused the dispersed gas to evolve and form the continuous free-gas phase quickly. This decreased the foamy-oil stability. However, Wu et al. (2011) noted that the temperature effect was negligible.

2.2 Waterflooding in Heavy Oil Reservoirs

A large number of heavy oil waterflooding (WF) projects have been applied in the heavy oil reservoirs in the world over the years (Oefelein and Walker, 1964; Jennings, 1966; Nelson, 1976; Adams, 1982; Smith, 1992; Yao, 1999; Jenkins et al., 2004; Miller, 2006;
Singhal, 2009). Heavy oil WF recovery factors (RFs) are low due to unfavourable mobility ratios. In fact, an average of 2–7% of the additional heavy oil is recovered during a typical WF in a post-CHOPS reservoir (Dong et al., 2006). However, WF is still often implemented in some oilfields because it is relatively cheap and easy. Also many field engineers have had some experiences over the years to optimize the WF projects (Mai and Kantzas, 2009). Kumar et al. (2008) found that only a few actual field-scale production data of heavy oil WF projects were published because most projects did not show any incremental oil recovery after the primary production. In addition, most oil was recovered at an extremely high water-cut. Highlighted below are some studies and field applications of WF in the heavy oil reservoirs in western Canada.

Adams (1982) published some results of the heavy oil WF projects in eight Husky’s heavy oil fields in the Lloydminster area, western Canada. The heavy oil reservoirs are relatively thin with net pay zone thicknesses of 11–25 ft. The heavy oil and reservoir characteristics include the API gravities of 13–17 ºAPI, heavy oil viscosities of 500–1500 cP and an average permeability of about 2 D. The flood patterns employed were 40-acre five-spot pattern and 80-acre inverted nine-spot pattern. The total heavy oil RF after WF was estimated to be of 3–8% of the OOIP, with an incremental heavy oil RF of 1–2% only for WF. The author concluded that the WF performance was not accurately predicted by the existing empirical correlations because the heavy oil production was worse than that predicted from the Buckley–Leverett theory but better than that predicted from segregated flow model. Moreover, the vertical sweep efficiency was lower because some of the less permeable sand units of the Mannville sands of the Lloydminster area were not flooded.

Smith (1992) published the WF studies in Husky’s Wainwright field near Wainwright
(Alberta) and Wildmere field west of Lloydminster (Alberta). The author believed that there were several other IOR mechanisms that contributes to the heavy oil production under WF other than the frontal displacement, which could be favourable or unfavourable. The IOR mechanisms include the pressure support, multi-phase (gas and oil) expansion and flow, GOR control, emulsification of oil at the interface of water, imbibition and gravity drainage. These heavy oil production mechanisms in heavy oil reservoirs under WF might be different from those proposed by the other researchers. However, the conclusions reached were in agreement with those published in the literature. The conclusions made by Smith (1992) are highlighted below.

- Changes in injection rates and production rates, conversions of injectors and producers, and addition of infill wells could be helpful since the heavy oil displacement is not frontal;
- Converting to line drive might be the only reasonable way to prevent severe short circuiting or water channeling; and
- If water injection rate is increased, the sweep efficiency is decreased.

Kasraie et al. (1993) reported the results of their WF projects in the moderately heavy oil reservoir of the Battrum Northeast pool, which is located at 45 km northwest of Swift Current, Saskatchewan. The heavy oil deposit at this location was discovered in 1955 and the oil production started under the solution-gas drive from 1963 to 1966. Afterwards, WF was applied to increase the declining reservoir pressure. They used numerical simulations to match the WF production history in the period of 1966–1968. The WF process was continued until 2000. It was reported that the total primary plus WF heavy oil RF was 20% of the OOIP and that the projected ultimate RF was 26–29% of the OOIP.
Ko et al. (1995) investigated infill drilling and additional WF by using numerical simulations in the Buffalo Coulee Bakken heavy oil pool, Saskatchewan (Canada). The heavy oil viscosity was estimated to be 350 cP and the flooding pattern employed was a 20–acre well spacing with nine-spot pattern. The published simulation data showed that the optimized water injection could lead to an additional heavy oil WF RF of up to 4% of the OOIP.

Forth et al. (1996) discussed the WF field data for Petro Canada’s Golden Lake heavy oil reservoir in the Lloydminster area, western Canada. They evaluated the very poor performance of WF in this heavy oil reservoir by statistically analyzing 140 variables from 372 wells and reached the following five conclusions:

- Heavy oil viscosity variation had strong influence on WF performance;
- The vertical sweep efficiency could be poor in thin heavy oil reservoirs;
- The primary CHOPS had a strong effect on the WF performance due to the formation of wormholes and the presence of free-gas saturation, which led to severe water channeling;
- It was suggested that the areal variations in the geology had a strong effect on the WF performance; and
- Only little additional heavy oil was produced and the net effect of WF was insignificant.

Kantzas and Brook (2004) conducted laboratory studies on the post-CHOP methods, which included waterflooding. Their results showed that the initial heavy oil WF had a poor performance. However, when the direction of the WF was reversed, the heavy oil RF was increased in comparison with the initial WF. This was due to the occurrence of viscous
fingering during the initial WF, which left the unswept zone behind to be swept when the WF direction was reversed. It was also observed that slow WF performed better on a laboratory scale.

Miller (2006) discussed the WF project in the Coleville Bakken reservoir, which was discovered in 1951. Its primary production peaked in 1956 and WF was initiated in 1958. The flooding patterns used during the initial WF were a 40-acre five-spot pattern and an 80-acre nine spot pattern, respectively. Continued expansion using a 20-acre well spacing resulted in sufficiently increased heavy oil production. However, severe water channeling occurred in the 1970s when the water injection rate was increased in order to raise the reservoir pressure. Also nineteen horizontal and directional producers were added between 1993–1995, which unexpectedly resulted in a poor performance. Meanwhile, the introduction of line drive using the vertical wells yielded better oil production during the late phase of the WF project.

Singhal (2009) compared WF performances in the Jenner Upper Manville O, Jenner Upper Manville JJJ, and Retlaw Manville D8D heavy oil reservoirs, which are located in Southern Alberta. Water injection rate was relatively steady since 1996 in the Jenner Upper Manville O reservoir, gradually decreased since 2003 in the Jenner Upper Manville JJJ reservoir, and increased between 1996–2006 in the Retlaw Manville D8D reservoir. In the Jenner Upper Manville O reservoir, the heavy oil production rate and heavy oil cut gradually decreased with no drastic changes. Also there were no noticeable changes in the heavy oil production rate and heavy oil cut in the Jenner Upper Manville JJJ reservoir, which indicated weak water channeling. However, the heavy oil production rate slowed
down and the heavy oil cut declined steeply in the Retlaw Manville D8D reservoir, which was an indication of severe water channeling.

2.3 Solvent-Based Enhanced Heavy Oil Recovery Processes

Thermal-based EHOR processes are not suitable for thin heavy oil reservoirs mainly because of excessive heat losses to the surrounding formations, high capital and operating costs, large water consumption and treatments as well as considerable greenhouse gas emissions (Lin et al., 2014). Thus solvent-based EHOR processes become excellent alternatives. However, VAPEX has had some limited success in the thin heavy oil reservoirs as a result of slow gravity drainage and low production rate (Upreti et al., 2007). Consequently, CSI becomes a more effective and realistic option for the thin heavy oil reservoirs because it is more economical, energy efficient and environmentally friendly (Chang and Ivory, 2013).

2.3.1 Cyclic solvent injection

The solvent injection processes were used as EHOR processes and were patented in the 1970s (Allen et al., 1976; Allen, 1977). CSI is considered as a direct alternative to CSS especially in a thin heavy oil reservoir, where the thermal-based processes are not suitable. CSI utilizes one well both as a solvent injector and as an oil producer. This EHOR process is also known as the huff and puff process. Each cycle comprises the solvent injection, soaking and production periods in sequence (Qazvini Firouz and Torabi, 2012). There are many studies published about the field applications of CSI in the light oil reservoirs. Meanwhile, only a few papers were about the possible applications of CSI in the heavy oil reservoirs (Sayegh and Maini, 1984; Simpson 1988; Qazvini Firouz and Torabi, 2012).

Shelton and Morris (1973) utilized rich-gas (CH$_4$ enriched with C$_3$H$_8$) CSI during their
study as an EHOR process in heavy oil reservoirs. The results of their field test showed that rich gas has the potential to recover heavy oil through heavy oil viscosity reduction and reservoir energy reinforcement. They also highlighted the important quantities in the application of the CSI process, which include the total volume of gas injected, soaking time and rate of gas injected, composition of the injected gas and reservoir heterogeneities, such as stratifications, water zones and gas caps.

Sayegh and Maini (1984) conducted a series of laboratory tests to evaluate the performance of CO\textsubscript{2}-CSI in a Lloydminster heavy oil reservoir. Two series of PVT tests were conducted to model the pressure depletion process in the CSI. In the first series of tests, it was observed that CO\textsubscript{2} had a higher solubility than CH\textsubscript{4} and was able to maintain reduced heavy oil viscosity even at low pressures. However, in the second series of tests, a CH\textsubscript{4}–CO\textsubscript{2} solvent mixture with mole ratio of 1:3 was utilized. It was found that CH\textsubscript{4} reduced the efficiency of CO\textsubscript{2}. Also some coreflood tests were performed to study the soaking-period effect and the mobile water saturation effect on the longitudinal distribution of CO\textsubscript{2}. The results showed that a longer soaking period enhanced mass transfer and dissolution of CO\textsubscript{2} into the heavy oil. Moreover, the presence of mobile water led to better distribution of CO\textsubscript{2} throughout the core.

Bardon et al. (1986) studied the performance of CO\textsubscript{2}-rich natural gas CSI as an EHOR process in the Carmulu oil field, Southeast Turkey. The reservoir contains 380 MMbbl of 10–12 °API OOIP and had a low primary heavy oil RF of 1%, which is due to the poor quality of the heavy oil, the reservoir heterogeneity and the presence of gas cap. It was found that the CO\textsubscript{2}-rich natural gas CSI had early production data that were 5 times higher than that recorded prior to the implementation of CSI.
Gondiken (1987) presented results of the CO$_2$-CSI field pilot project that was conducted in a heavy oil reservoir in Turkey. The reservoir contained a heavy oil with the oil gravity of 10–12 °API. It was found that the CO$_2$-CSI field pilot project increased the heavy oil production rate by 2.5 times for two months in comparison with that prior to CO$_2$-CSI injection.

Olenick et al. (1992) described the CO$_2$-CSI project that was conducted in Halfmoon field, Park County, North western Wyoming. The CSI project was proposed because the field was a poor WF candidate. A field CO$_2$ source was available and laboratory results showed that CO$_2$ could improve the recovery of the 17 °API heavy oil. However, the actual field data showed the incremental oil production rate of 1.7–2.4 BOPD, which was far lower than that predicted from the laboratory experiments. The project was eventually terminated because it was uneconomical.

Lim et al. (1995) presented the experimental studies on the use of light-hydrocarbon CSI to enhance heavy oil production in the Cold Lake oil sand, Alberta. A horizontal well was utilized both as the solvent injector and the oil producer. It was found that ethane (C$_2$H$_6$) was an effective solvent to enhance the production of the Cold Lake heavy oil and also improve the quality of the heavy oil. In addition, the results showed that the oil production rate was higher than that expected from the molecular diffusion rate of solvent into the heavy oil. Thus it was suggested that the EHOR mechanisms (e.g., solvent dispersion or fingering) other than the gravity-drainage drive mechanism must have aided the process.

Shayegi et al. (1996) conducted several series of experiments on the cyclic injection of CO$_2$, CH$_4$, N$_2$ and solvent mixtures of either CH$_4$ or N$_2$ with CO$_2$, respectively. The results showed that pure CO$_2$-CSI recovered about the same amount of heavy oil as CH$_4$-CSI,
whereas pure N₂-CSI recovered half the amount. However, CO₂–CH₄-CSI and CO₂–N₂-CSI had about 2–3 times higher RFs than pure CO₂-CSI. Peak heavy oil recovery was obtained when a solvent mixture containing 10–20% CO₂ was utilized.

Mohammed–Singh et al. (2006) reviewed the design and performance of 16 CO₂-CSI projects conducted in a number of wells in the Forest Reserves Oilfield, Trinidad and Tobago. The reservoirs had the heavy oils with gravities of 11–38 °API and heavy oil viscosities of 0.5–3000 cP. Also the reservoir properties include the porosities of 11–32%, main pay zone thicknesses of 2–67 m, and permeabilities of 0.01–2.5 D. It was reported that CO₂-CSI process helped to increase heavy oil recovery through the removal of some productivity damage, heavy oil viscosity reduction, oil-swelling effect, vapourization of lighter components and suppression of water production. Also in some cases, the project revealed other important findings, such as the injectivity and pressure communication with the adjacent formation, and drive mechanisms. The CO₂-CSI projects were largely successful due to the boosted heavy oil production and quick payout.

Ivory et al. (2010) summarized the numerical and experimental results obtained from the studies on the CSI process in the Cold Lake and Lloydminster reservoirs, which had been depleted during the CHOPS. The CSI process was composed of six cycles. A solvent mixture of 28 mol.% C₃H₈ and 72 mol.% CO₂ was utilized as the working solvent. The results indicated the total heavy RF of the primary production and the six cycles was 50%, which indicates the potential viability of the CSI process. Also a numerical model was developed to describe the trend pattern of the experimental results. Furthermore, the Alberta Innovates Technology Futures (AITF) foamy-oil model was used to history match the primary production and the six cycles, which was subsequently used to validate the
developed numerical model of the CSI process (Chang and Ivory, 2013).

Qazvini Firouz and Torabi (2012) performed a feasibility study on the CSI process to investigate the effects of the operating pressure, soaking time, and solvent composition. Fourteen CSI experiments were conducted by using CO$_2$, CH$_4$, C$_3$H$_8$ and C$_4$H$_{10}$ as solvents under different operating conditions. In all the tests, the Berea core, which had a permeability of 1.8 D and porosity of 24%, was saturated with a Saskatchewan heavy oil. It was found that injecting CO$_2$ at near-supercritical conditions yielded the highest heavy oil recovery RF of 71%. Also solution-gas drive, heavy oil viscosity reduction, extraction of light components and foamy-oil flow were regarded as the governing EOR mechanisms.

2.3.2 Variations

The traditional CSI seems to be a more feasible EHOR process in a thin heavy oil reservoir due to its cost-effectiveness, high energy efficiency and environmental friendliness. However, its performance in some cases is undermined due to quick heavy oil viscosity regainment, reservoir energy depletion during the CSI production period, and the so-called back-and-forth movement of the foamy oil near the producer (Jiang et al., 2014; Jia et al., 2015). As a result, some researchers have studied several variations of CSI in order to mitigate some of the major issues that undermine the performance of the traditional CSI.

Jia et al. (2013) presented a pressure pulsing cyclic solvent injection (PP-CSI) process as a modification of the CSI process. This process enhanced the performance of CSI by adopting a three-step pressure control scheme, which included reduction of the model pressure to induce foamy oil flow, re-increasing the model pressure to a preset value, and the maintenance of a certain pressure difference between the injector and producer for gas
flooding, respectively. This process was repeated consecutively during the production period. The results showed that the oil production rate of PP-CSI was 4.37 times higher than that of the traditional CSI. However, the oil production rate decreased with increasing pressure pulse number in each cycle.

Yadali Jamaloei et al. (2013) proposed enhanced cyclic solvent process (ECSP) to slow down the rate at which the oil regains its viscosity. The ECSP involved the injection of a volatile gas (methane) and a more soluble gas (ethane or propane) in a cyclic manner in the heavy oil. The volatile gas was injected to cause the heavy oil to expand while the soluble gas was introduced to keep the oil viscosity low for a longer period during production. Four series of ECSP tests were conducted with each test having six cycles and the results were used to determine the optimum solvent injection sequence for the Wabiskaw formation in the Pelican oilfield in northern Alberta. The results showed that ECSP had a better RF than the traditional CSI and that it was only effective during the early production stage.

Jiang et al. (2014) introduced cyclic production with continuous solvent injection (CPCSI). In CPCSI, a vapourized solvent at the conditions \((P, T)\) near its dew point was injected continuously into the model to maintain the reservoir pressure. Also an extra gas drive was supplied through an injector to mobilize the solvent-diluted heavy oil towards the producer. A relatively small pressure difference was maintained between the injector and the producer to control the dissolved solvent exsolution/liberation and heavy oil viscosity regainment. In this way, the major driving mechanism that contributed to more oil production was the continuous solvent injection. Although CPCSI seemed better than CSI, it lacked full incorporation of the solution-gas drive and foamy-oil flow, which are the major EOR mechanisms and require a large pressure depletion rate or step size to
Jia et al. (2015) also proposed gas flooding-assisted cyclic solvent injection (GA-CSI), which was designed to reduce the foamy-oil back-and-forth movement during each CSI cycle. In GA-CSI, gas flooding was applied after each CSI production period to further mobilize the residual foamy oil towards the producer. The heavy oil RF of this process was about three times higher than that of the traditional CSI. Meanwhile, an establishment of communication between the producer and the gas injector was required, which was both solvent and time consuming.

Ma et al. (2017) devised combined cyclic solvent injection and waterflooding (CSI + WF), during which the volumetric sweep efficiency of the traditional CSI was improved through the application of WF. Two different solvents (CO$_2$ and C$_3$H$_8$) and three different pressure drawdown rates (6.8, 12.5, 25.0 kPa/min) were applied and their effects on CSI + WF were determined. It was found that C$_3$H$_8$ was a much better extracting solvent than CO$_2$. The intermediate pressure drawdown rate of 12.5 kPa/min yielded the highest RF. In addition, the results also showed that CSI + WF performed much better than CSI or WF alone in the enhanced or improved heavy oil recovery.
CHAPTER 3  EXPERIMENTAL

3.1  Materials

In this study, the original heavy oil and brine samples were collected from the Colony formation in the Bonnyville area, Alberta, Canada. Ma (2017) reported the compositional analysis result of the Colony heavy oil measured by using the standard ASTM D86. The dead heavy oil had the measured density and viscosity of $\rho_o = 0.992$ g/cm$^3$ and $\mu_o = 33,876$ cP at $T_{res} = 21.0$ ºC and $P_a = 1$ atm. Also the densities and viscosities of the Colony heavy oil at various temperatures and the atmospheric pressure were measured by using a densitometer (DMA 512P, Anton Paar, USA) and a viscometer (DV-II+, Brookfield, USA), respectively. The detailed results are listed in Tables 3.1, 3.2(a) and 3.2(b), respectively. The molecular weight of the Colony heavy oil was measured to be 547.7 g/mol by using an automatic high sensitivity wide-range cryoscopy (Model 5009, Precision Systems Inc., USA). In addition, the asphaltene content of the Colony heavy oil was found to be 18.3 wt.% (n-pentane insoluble) by using the standard ASTM D2007-3 method and filter papers (Whatman No. 5, England) with a pore size of 2.5 μm. Table 3.3 summarizes the physicochemical properties of the Colony brine at $T_{res} = 21.0$ ºC and $P_a = 1$ atm. The other materials included CH$_4$ with a purity of 99.97 mol.%, CO$_2$ with 99.998 mol.%, and C$_3$H$_8$ with 99.5 mol.%, all of which were purchased from Praxair (Canada).

3.2  Experimental set-up

The experimental set-up comprised five major operating units: a fluid production unit; a physical model; a solvent injection unit; a brine/gas/oil injection unit; and a data acquisition system (DAS). The fluid production unit was composed of a high precision back-pressure regulator (BPR) (LBS4 Series, Swagelok, USA), which was connected to a
Table 3.1 The compositional analysis result of the heavy oil collected from the Colony formation in the Bonnyville area.

<table>
<thead>
<tr>
<th>Carbon no.</th>
<th>mol.%</th>
<th>wt.%</th>
<th>Carbon no.</th>
<th>mol.%</th>
<th>wt.%</th>
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</tr>
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<td>0.00</td>
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</tr>
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</tr>
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</tr>
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<td>C₅₅</td>
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</tr>
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<td>C₅₆</td>
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</tr>
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<td>0.78</td>
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<td>1.83</td>
<td>C₅₉</td>
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<td>0.79</td>
</tr>
<tr>
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<td>1.98</td>
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</tr>
<tr>
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<td>1.74</td>
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</tr>
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<td>C₃₁</td>
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<td>1.53</td>
<td>Total</td>
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Table 3.2(a) The Colony heavy oil densities at different temperatures and $P_a = 1$ atm.

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<tr>
<th>$T$ (°C)</th>
<th>$\rho_o$ (g/cm³)</th>
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</thead>
<tbody>
<tr>
<td>21</td>
<td>0.9920</td>
</tr>
<tr>
<td>30</td>
<td>0.9864</td>
</tr>
<tr>
<td>40</td>
<td>0.9804</td>
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<tr>
<td>50</td>
<td>0.9743</td>
</tr>
<tr>
<td>60</td>
<td>0.9681</td>
</tr>
</tbody>
</table>

Table 3.2(b) The Colony heavy oil viscosities at different temperatures and $P_a = 1$ atm.

<table>
<thead>
<tr>
<th>$T$ (°C)</th>
<th>$\mu_o$ (cP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>21</td>
<td>33,876</td>
</tr>
<tr>
<td>25</td>
<td>19,510</td>
</tr>
<tr>
<td>30</td>
<td>10,539</td>
</tr>
<tr>
<td>35</td>
<td>6,406</td>
</tr>
<tr>
<td>40</td>
<td>3,980</td>
</tr>
<tr>
<td>45</td>
<td>2,540</td>
</tr>
<tr>
<td>50</td>
<td>1,679</td>
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<tr>
<td>54</td>
<td>1,150</td>
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<td>65</td>
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<td>70</td>
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<td>75</td>
<td>285.4</td>
</tr>
<tr>
<td>80</td>
<td>220.2</td>
</tr>
</tbody>
</table>
Table 3.3 The physicochemical properties of the brine collected from the Colony formation in the Bonnyville area at $P_a = 1$ atm.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature (°C)</td>
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</tr>
<tr>
<td>Density (g/cm³)</td>
<td>1.03</td>
</tr>
<tr>
<td>Viscosity (cP)</td>
<td>1.2</td>
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<tr>
<td>pH @ 25 °C</td>
<td>7</td>
</tr>
<tr>
<td>Specific conductivity (μS·cm⁻¹)</td>
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</tr>
<tr>
<td>Refractive index @ 28 °C</td>
<td>1.3390</td>
</tr>
<tr>
<td>Chloride (mg/L)</td>
<td>22,999</td>
</tr>
<tr>
<td>Sulphate (mg/L)</td>
<td>2</td>
</tr>
<tr>
<td>Total dissolved solids (mg/L)</td>
<td>37,619</td>
</tr>
<tr>
<td>Potassium (mg/L)</td>
<td>50</td>
</tr>
<tr>
<td>Sodium (mg/L)</td>
<td>13,410</td>
</tr>
<tr>
<td>Calcium (mg/L)</td>
<td>766</td>
</tr>
<tr>
<td>Magnesium (mg/L)</td>
<td>349</td>
</tr>
</tbody>
</table>
syringe pump (100DX, ISCO Inc., USA) to control the production pressure by using a pre-specified pressure depletion step size. Other equipment included a produced oil and/or water collector, a pair of gas bubblers, a vacuum pump and an electric scale, which was used for measuring the weight of the produced oil and/or water. The pair of gas bubblers were used to collect and measure the produced gas, while the vacuum pump was used to evacuate the produced gas and allow for the subsequent measurement of the produced gas.

The physical model was a rectangular sandpacked model \((L \times W \times H = 40\, \text{cm} \times 10\, \text{cm} \times 2\, \text{cm})\) that was made up of a stainless-steel plate with a rectangular cavity for holding the packed sand grains. It was covered with a transparent acrylic plate for visualization of the experimental process and a transparent thin polycarbonate plate in between, which was used to prevent scratches on the surface of the acrylic plate. The height-to-length ratio of the physical model was chosen to be 1:20, which models a typical thin heavy oil reservoir, e.g., the main pay-zone thickness of 5 m and the horizontal well spacing of 100 m (Jia et al., 2015). In this study, a two-well configuration was utilized in all the experiments except a one-well configuration in the CSI experiments.

The first well (A) was located at the center of the left-hand side of the physical model and connected to the production unit and the solvent injection unit to act as a producer and a solvent injector, respectively. The solvent injection unit was a solvent cylinder (Praxair, Canada) with a two-stage gas regulator (KCY Series, Swagelok, USA). During the solvent injection period, the solvent pressure was regulated by using the two-stage gas regulator to gradually increase the injection pressure until the final solvent injection pressure was reached and no more solvent could be injected. On the other hand, the second well (B) was located at the center of the right-hand side of the physical model and connected to the
brine/gas/oil injection unit to serve as the brine/gas/oil injector. The brine/gas/oil injection unit was composed of brine and live-oil cylinders, a syringe pump (500D, ISCO Inc., USA) and a gas cylinder (Praxair, Canada) with a two-stage gas regulator (KCY Series, Swagelok, USA). In GPC and SA-GPC, the gas was supplied from the gas cylinder into the physical model. The gas pressure was regulated by using the two-stage gas regulator to gradually increase the gas injection pressure until the final gas injection pressure was reached and no more gas could be injected. In WPC and SA-WPC, the syringe pump was used to inject the reservoir brine from the brine cylinder into the physical model during the water injection period. Lastly, the DAS was used to automatically measure and record the injection and production pressures. It included a digital pressure indicator (PPM-2, Heise, USA) and a personal computer. Figure 3.1 shows the schematic diagram of the experimental set-up used in the primary production and subsequent CSI/GPC/SA-GPC/WPC/SA-WPC.

3.3 Experimental preparation
3.3.1 Live heavy oil preparation

CH₄-saturated live heavy oil was prepared by mixing the Colony heavy oil and pure CH₄ in two stainless steel cylinders (500-10-P-316-2, DBR, Canada) at $T_{res} = 21.0$ °C. One of the stainless steel cylinders was 75–80% filled with the Colony heavy oil and then CH₄ was injected into the cylinder at a pressure of about 1.5 MPa until no more CH₄ could be injected. Furthermore, the heavy oil–CH₄ mixture was transferred back and forth between the two cylinders by using two different syringe pumps (500D, ISCO Inc., USA) to set the pressures to 5 MPa at the sending cylinder and 3 MPa at the receiving cylinder. The heavy oil was assumedly saturated with CH₄ when the mixture volume no longer decreased at the
**Figure 3.1** Schematic diagram of the experimental set-up used for conducting the primary production and subsequent CSI/GPC/SA-GPC/WPC/SA-WPC.
receiving cylinder. The CH₄-saturated live heavy oil took about 2 weeks to prepare and had a GOR of 9.6 sc cm³/m³ at saturation pressure of $P_{\text{sat}} = 3.0$ MPa.

3.3.2 2-D physical model packing

The 2-D rectangular physical model was assembled and tested for leakage by injecting CO₂ into the physical model up to a pressure of 3 MPa for 24 h. Afterwards, the physical model was packed with the Ottawa sand grains of 60–80 mesh sizes (Bell & Mackenzie, Canada) and the model was hammered continuously to ensure a uniform distribution of the sand grains. The Ottawa sand grains of 60–80 mesh sizes were chosen because the measured porosity and permeability of the packed sand falls within the range of porosity and permeability of a typical thin heavy oil reservoir. Finally, a second leakage test was conducted by injecting pressurized air ($P_{\text{air}} = 0.8$ MPa) into the sandpacked physical model for 24 h in order to prevent future solvent/gas leakage during each experiment.

3.3.3 Porosity measurement

The porosity was measured by using the imbibition method in each experiment. First, the air in the pore spaces of the sandpacked physical model was vacuumed by using a vacuum pump. Second, the initial mass of the Colony brine was measured and recorded before the Colony brine was imbibed into sandpacked physical model. Lastly, the mass of brine imbibed into the pore spaces was determined and utilized to calculate the porosity of the sandpacked model. The porosities obtained during the experiments were found to be 37.9–40.1%.

3.3.4 Permeability measurement

The Darcy’s law was used to measure the permeability of the sandpacked physical
model. Different pressure drops of 6‒12 kPa were applied at the two ends of the sandpacked physical model and the corresponding volume flow rates of the brine were measured to be 4–13 cm³/min for all the experiments. Based on the measured pressure drops and volume flow rates, the permeability was determined from the Darcy’s law to be 2.1–4.7 D, which was close to the actual heavy oil reservoir permeability range in Canada.

3.3.5 Sandpacked model saturation with live oil

Prior to the saturation of the sandpacked model with the live heavy oil, the sandpacked model was pressurized with brine for two reasons. The first was to ensure that the sandpacked model was fully saturated with the brine. The second was to ensure that the initial reservoir conditions of \( P_i = 3.0 \) MPa and \( T_{res} = 21.0 \) °C for the Colony heavy reservoir were achieved. Afterwards, the live Colony heavy oil was injected to displace the brine by using the syringe pump. An injection pressure of about \( P_{inj} = 3.5 \) MPa and a production pressure of \( P_{prod} = 3.0 \) MPa were applied at the injector and the BPR respectively until the irreducible water saturation (\( S_{wi} \)) and initial oil saturation (\( S_{oi} \)) were reached. The physical characteristics of the sandpacked physical model used in the experiments are listed on Table 3.4.

3.4 Experimental Procedure

3.4.1 Primary production

In this study, all tests started from the primary production, after which the EOR, IOR and EOR/IOR processes were conducted, respectively. In each test, the primary production had an initial reservoir pressure of \( P_i = 3.0 \) MPa and reservoir temperature of \( T_{res} = 21.0 \) °C. In this study, the production pressure was depleted at a constant pressure depletion step size, in contrast to the constant production pressure depletion rates used in most previous
Table 3.4 The physical characteristics of the 2-D sandpacked physical model in Tests #1–15 at $T_{res} = 21.0 \, ^{\circ}C$.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Physical characteristics</th>
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<td>$\phi$ (%)</td>
<td>$k$ (D)</td>
<td>$S_{oi}$ (%)</td>
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</table>
studies. In Tests #1‒8 and #11‒15, a constant pressure depletion step size of $\Delta P_{pp} = 1.0 \text{ MPa}$ was applied during the primary production to decline the production pressure from $P_i = 3.0 \text{ MPa}$ in steps until the final production pressure of $P_f = 0.2 \text{ MPa}$ was reached. In Tests #9 and #10, however, $\Delta P_{pp} = 1.0 \text{ MPa}$ was applied during the primary production to reduce the production pressure from $P_i = 3.0 \text{ MPa}$ in steps until the final production pressures of $P_f = 2.0$ and $1.0 \text{ MPa}$ were reached, respectively. At each production pressure, fluids were continually produced until the volume of heavy oil produced was less than 1% of the OOIP. Then $\Delta P_{pp} = 1.0 \text{ MPa}$ was applied to move to the next production pressure. This criterion was also used during the production period of each EHOR process. Finally, given the $P_i = 3.0 \text{ MPa}$ and $P_f = 0.2 \text{ MPa}$ a large pressure depletion step size of $\Delta P_{pp} = 1.0 \text{ MPa}$ was chosen during the primary production to maintain a production time that is not longer than 18‒20 h.

3.4.2 Cyclic solvent injection

Tests #1–2 comprised C$_3$H$_8$-CSI and CO$_2$-CSI, respectively. Each test had the primary production + CSI and each CSI cycle had three periods: solvent injection, soaking and fluids production, as shown in Figure 3.2. In each CSI cycle, a one-well (Well A) configuration was utilized, in which Well A was employed as both the solvent injector and producer. In Test #1, C$_3$H$_8$ was injected from the solvent injector at $P_{inj} = 0.8 \text{ MPa}$ and $T_{res} = 21.0 \, ^\circ \text{C}$, whereas in Test #2, CO$_2$ was injected from the solvent injector at $P_{inj} = 3.0 \text{ MPa}$ and $T_{res} = 21.0 \, ^\circ \text{C}$. In both tests, the solvent was injected at the pre-specified conditions until no more solvent could be injected. Afterwards, this well was closed to soak and dissolve the solvent into the heavy oil for 24 h. After the soaking period was completed, the final injection pressure was reduced from $P_{inj} = 0.8 \text{ MPa}$ to $P_s = 0.7 \text{ MPa}$ in the different
Figure 3.2 Schematic diagrams of the (a) solvent injection; (b) soaking; and (c) fluids production periods during the cyclic solvent injection (CSI) process.
cycles of Test #1 and from $P_{injs} = 3.0$ MPa to $P_s = 2.1–2.4$ MPa in the different cycles of Test #2, respectively. This was a result of the dissolution and mass transfer of the solvent into the heavy oil. Finally, the producer was opened for the production of fluids. In addition, a constant pressure depletion step size of $\Delta P_{EOR} = 0.5$ MPa was applied to reduce the production pressure in steps to the final pressure of $P_e = 0.2$ MPa. The cycle was repeated in each test until the heavy oil RF of less than 2% in one cycle was obtained. The $\Delta P_{EOR} = 0.5$ MPa was utilized during each CSI production period for the purpose of comparison with the other proposed IOR/EHOR processes.

### 3.4.3 Gas pressure cycling

Tests #3–5 included two C$_3$H$_8$-GPC tests and one CO$_2$-GPC test. Each test had the primary production + GPC and each GPC cycle had three periods: gas injection, soaking, and fluids production, as shown in Figure 3.3. In each GPC cycle, a two-well configuration was utilized, where Well B served as the gas injector and Well A as the producer. In Tests #3–4, C$_3$H$_8$ was injected from the gas injector (Well B) at $P_{injg} = 0.8$ MPa and $T_{res} = 21.0$ ºC, whereas in Test #5, CO$_2$ was injected from the gas injector (Well B) at $P_{injg} = 3.0$ MPa and $T_{res} = 21.0$ ºC. In the tests, the gas was injected at the pre-specified conditions until no more gas could be injected. Afterwards, the wells were closed to allow for the dissolution of the gas into the heavy oil for 24 h in the soaking period. After the soaking period was completed, the final injection pressure was reduced from $P_{injg} = 0.8$ MPa to final soaking pressures of $P_s = 0.7–0.76$ MPa in the different cycles of Tests #3–4 and from $P_{injg} = 3.0$ MPa to $P_s = 2.2–2.6$ MPa in the different cycles of Test #5, respectively. Then Well A was opened for the fluids production. In Tests #3 and #4, $\Delta P_{EOR} = 0.1$ and 0.5 MPa were applied respectively during the C$_3$H$_8$-GPC production period to reduce the production pressure in
Figure 3.3 Schematic diagrams of the (a) gas injection; (b) soaking; and (c) fluids production periods during the gas pressure cycling (GPC) process.
steps to the final pressure of $P_e = 0.2$ MPa. These two $\Delta P_{EOR}$ values were chosen to study the $\Delta P_{EOR}$ effect. Also the difference between $P_s$ and $P_e$ was approximately 0.5 MPa. However, $\Delta P_{EOR} = 0.5$ MPa was utilized in Test #5 during each cycle for comparison purpose. The criterion employed for determining the final cycle in each GPC test was a heavy oil RF of less than 2% in one cycle after the first two cycles.

### 3.4.4 Solvent-assisted gas pressure cycling

Tests #6–8 consisted of three different SA-GPC tests. Each test had the primary production + SA-GPC and each SA-GPC cycle had four periods: solvent injection, gas injection, soaking and fluids production, as shown in Figure 3.4. A two-well configuration was employed in each SA-GPC cycle, where Well A was used as the solvent (i.e., a more soluble solvent) injector and the producer and Well B served as the gas (i.e., a volatile gas) injector. In each test, the solvent ($C_3H_8$) was injected from Well A at $P_{inj_s} = 0.8$ MPa and $T_{res} = 21.0^\circ C$, after which the gas ($CO_2$) was injected from Well B to pressurize the physical model to a final injection pressure of $P_{inj_g} = 3.0$ MPa. Afterwards, the soaking period was initiated by shutting in the two wells in order to allow the dissolution of the solvent and gas into the heavy oil for 24 h. Upon the completion of the soaking period, the final injection pressure was reduced from $P_{inj_g} = 3.0$ MPa to $P_s = 2.2–2.7$ MPa in the different cycles of Tests #6–8. Then Well A was opened for fluids production. In Tests #6–8, $\Delta P_{EOR} = 0.1, 0.5$ and 1.0 MPa were applied in the production period respectively to reduce the production pressure in steps to $P_e = 0.2$ MPa. The different $\Delta P_{EOR}$ depict low, intermediate and high pressure depletion step sizes respectively, and were chosen based on the $P_s$ and $P_e$ for each cycle of the SA-GPC tests to study the $\Delta P_{EOR}$ effect. In each test, the cycle was repeated until the heavy oil RF of less than 2% in one cycle was obtained.
Figure 3.4 Schematic diagrams of the (a) solvent injection; (b) gas injection; (b) soaking; and (c) fluids production periods during the solvent-assisted gas pressure cycling (SA-GPC) process.
3.4.5 Water pressure cycling

Tests #9–11 consisted of three different WPC tests. Each test had the primary production + WPC and each WPC cycle had two periods: brine injection and fluids production, as shown in Figure 3.5. A two-well configuration was employed in each WPC cycle, where Well A acted as the producer and Well B served as the brine injector. In Tests #9–11, the WPC process was initiated after the primary production pressure was reduced from $P_i = 3.0 \text{ MPa}$ to $P_f = 2.0 \text{ MPa}$, $1.0 \text{ MPa}$, and $0.2 \text{ MPa}$, respectively. Then the brine was injected from Well B at $q_{injw} = 0.5 \text{ cm}^3/\text{min}$ to pressurize the physical model to the final injection pressure of $P_{injw} = 3.0 \text{ MPa}$, after which Well A was opened for fluids production. During the production period, $\Delta P_{IOR} = 0.5 \text{ MPa}$ was applied in each test to reduce the production pressure in steps to $P_e = 0.2 \text{ MPa}$. In each WPC test, $\Delta P_{IOR} = 0.5 \text{ MPa}$ was utilized during each cycle in order to properly compare with the other proposed processes. The cycle was repeated in each test until the heavy oil RF of less than 2% in one cycle was obtained.

3.4.6 Solvent-assisted water pressure cycling

Tests #12–15 were composed of three $\text{C}_3\text{H}_8$-SA-WPC and one $\text{CO}_2$-SA-WPC tests. Each test had the primary production + SA-WPC and each SA-WPC cycle had four periods: solvent injection, brine injection, soaking and fluids production, as shown in Figure 3.6. A two-well configuration was utilized in each SA-WPC cycle, where Well A served as the solvent injector and producer and Well B functioned as the brine injector. In each test, the solvent ($\text{C}_3\text{H}_8/\text{CO}_2$) was injected from Well A at $P_{injS} = 0.8 \text{ MPa}$ and $T_{res} = 21.0 ^\circ\text{C}$, after which the brine was injected from Well B at $q_{injw} = 0.5 \text{ cm}^3/\text{min}$ to pressurize the physical model to $P_{injw} = 3.0 \text{ MPa}$. The soaking period was initiated by shutting in the two wells in order to allow the dissolution of the solvent into the heavy oil for 24 h. Then
Figure 3.5 Schematic diagrams of the (a) brine injection; and (b) fluids production periods during the water pressure cycling (WPC) process.
Figure 3.6 Schematic diagrams of the (a) solvent injection; (b) brine injection; (b) soaking; and (c) fluids production periods during the solvent-assisted water pressure cycling (SA-WPC) process.
Well A was opened for fluids production. In Tests #12–14 (C₃H₈-SA-WPC), $\Delta P_{\text{EOR}} = 0.1$, 0.5 and 1.0 MPa were applied during the production period respectively to reduce the production pressure in steps to $P_e = 0.2$ MPa. These three $\Delta P_{\text{EOR}}$ values were chosen to represent the low, intermediate and high pressure depletion step sizes, respectively. Also they were used to study the $\Delta P_{\text{EOR}}$ effect based on the final brine injection of $P_{\text{injw}} = 3.0$ MPa and the ending pressure of $P_e = 0.2$ MPa in each cycle of each SA-WPC test. In contrast, Test #15 was CO₂-SA-WPC, during which $\Delta P_{\text{EOR}} = 0.5$ MPa was applied in the production period to reduce the production pressure in steps to $P_e = 0.2$ MPa for comparison sake. In each test, the cycle was repeated until the heavy oil RF of less than 2% in one cycle was obtained. It is important to note that $P_{\text{inj}} = 0.8$ MPa was chosen in Tests #12–14 to avoid injecting liquid propane into the physical model because the saturation pressure of C₃H₈ is equal to 0.8 MPa at $T_{\text{res}} = 21.0 \degree C$. Also for comparison purpose, $P_{\text{inj}} = 0.8$ MPa was chosen in Test #15, even though the saturation pressure of CO₂ is equal to 5.9 MPa at $T_{\text{res}} = 21.0 \degree C$. The technical details of Tests #1–15 are listed in Table 3.5.
Table 3.5 Technical details of Tests #1‒15 (including the primary production) at $T_{res} = 21.0$ °C.

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<th>$\Delta P_{PP}$ (MPa)</th>
<th>$P_f$ (MPa)</th>
<th>CSI/GPC/WPC</th>
<th>WPC</th>
<th>Soaking</th>
<th>Production</th>
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<td></td>
<td></td>
<td></td>
<td>$P_i$</td>
<td>$\Delta P_{PP}$</td>
<td>$P_f$</td>
<td>$P_{inj}$</td>
<td>$P_{inj}/P_{inj}$</td>
<td>$t_s$ (min)</td>
<td>$P_s$ (MPa)</td>
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<td>–</td>
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<td>0.5</td>
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<td>CO$_2$</td>
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<td>–</td>
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<td>0.5</td>
<td>0.7–0.76</td>
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<td>–</td>
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<td>0.7</td>
<td>0.5</td>
<td>0.5</td>
</tr>
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<td>–</td>
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<td>0.5</td>
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</tr>
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<td>–</td>
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<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
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<td>CO$_2$</td>
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<td>0.5</td>
<td>0.5</td>
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<td>0.7</td>
<td>0.5</td>
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<td>CO$_2$</td>
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<td>CO$_2$</td>
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<td>0.7</td>
<td>0.5</td>
<td>0.5</td>
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<td>CO$_2$</td>
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<td>234×60</td>
<td>0.7</td>
<td>0.5</td>
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</tr>
<tr>
<td>12</td>
<td>SA-WPC</td>
<td>C$_3$H$_8$</td>
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<td>CO$_2$</td>
<td>–</td>
<td>234×60</td>
<td>0.7</td>
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<tr>
<td>13</td>
<td>SA-WPC</td>
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<td>0.8</td>
<td>CO$_2$</td>
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<td>234×60</td>
<td>0.7</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>14</td>
<td>SA-WPC</td>
<td>C$_3$H$_8$</td>
<td>0.8</td>
<td>CO$_2$</td>
<td>–</td>
<td>234×60</td>
<td>0.7</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>15</td>
<td>SA-WPC</td>
<td>C$_3$H$_8$</td>
<td>0.8</td>
<td>CO$_2$</td>
<td>–</td>
<td>234×60</td>
<td>0.7</td>
<td>0.5</td>
<td>0.5</td>
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CHAPTER 4    RESULTS AND DISCUSSION

4.1 Cyclic Solvent Injection

Tests #1 and #2 were the traditional CSI processes to be used for comparison purpose, during which two different solvents ($C_3H_8$ and $CO_2$) were utilized. Table 4.1 lists the heavy oil RFs of the primary productions and the subsequent cycles of the CSI in Tests #1 and #2. They had the total heavy oil RFs of 27.6% and 22.7%, respectively. The termination criterion for each of the traditional CSI test was a total heavy oil RF of less than 2% in one cycle. As a result, Tests #1 and #2 had three cycles and two cycles, respectively. Based on the experimental results, $C_3H_8$-CSI had a noticeably higher heavy oil RF than $CO_2$-CSI. Figures 4.1(a–c) show this is because $C_3H_8$ has a higher solubility, a more effective heavy oil viscosity reduction ability, and forms a stronger foamy oil than $CO_2$ (Ma et al., 2017). However, these two CSI tests were regarded to be poor because they had low additional heavy oil RFs of 6.6% and 2.7% after their primary productions, respectively. This was attributed to the technical limitations of the traditional CSI as described in Chapter 2 (Jiang et al., 2014; Jia et al., 2015).

Figures 4.2(a–c) show the overall trends of the measured heavy oil RFs, iGORs, which were measured every 15 min, and production pressure ($P_{prod}$) with time in Cycles #1–3 in Test #1, respectively. During Cycle #1 in Test #1, the iGOR remained low during the early period of the cycle due to the foamy-oil production near the producer (Well A) and increased steadily towards the late period of the cycle as a result of rapid solvent exsolution. Also during Cycle #2, the iGOR remained low as a result of more foamy-oil formation and production over a longer period of the cycle in comparison with Cycle #1. Cycle #2 had a higher heavy oil RF because the injected solvent had contacted more heavy oil, which was
Table 4.1 The heavy oil recovery factors (RFs) in the primary production and Cycles #1–3 in Tests #1 and 2.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Heavy oil recovery factor (%)</th>
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<tr>
<td></td>
<td>Primary production</td>
<td>Cycle #1</td>
<td>Cycle #2</td>
<td>Cycle #3</td>
<td>Total</td>
</tr>
<tr>
<td>1</td>
<td>21.0</td>
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<td>3.3</td>
<td>1.3</td>
<td>27.6</td>
</tr>
<tr>
<td>2</td>
<td>20.0</td>
<td>2.4</td>
<td>0.3</td>
<td>–</td>
<td>22.7</td>
</tr>
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Figure 4.1(a) Measured solubilities of CH$_4$/CO$_2$/C$_3$H$_8$-saturated Colony heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_{sat} = 0.858$ MPa for C$_3$H$_8$, $P_{sat} = 5.868$ MPa for CO$_2$, and $P_c = 4.599$ MPa for CH$_4$) and $T_{res} = 21.0$ °C (Ma et al., 2017).
Figure 4.1(b) Measured viscosities of CH$_4$/CO$_2$/C$_3$H$_8$-saturated Colony heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_{sat} = 0.858$ MPa for C$_3$H$_8$, $P_{sat} = 5.868$ MPa for CO$_2$, and $P_c = 4.599$ MPa for CH$_4$) and $T_{res} = 21.0$ °C (Ma et al., 2017).
Figure 4.1(c) Measured oil-swelling factor of CH\textsubscript{4}/CO\textsubscript{2}/C\textsubscript{3}H\textsubscript{8}-saturated Colony heavy oil at different reduced pressures \(P_{\text{eq}}/P_{\text{sat}}\) or \(P_{\text{eq}}/P_{c}\) (\(P_{\text{sat}} = 0.858\) MPa for C\textsubscript{3}H\textsubscript{8}, \(P_{\text{sat}} = 5.868\) MPa for CO\textsubscript{2}, and \(P_{c} = 4.599\) MPa for CH\textsubscript{4}) and \(T_{\text{res}} = 21.0\) °C (Ma et al., 2017).
Figure 4.2 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in C$_3$H$_8$-CSI process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #1) (a) Cycle #1; and (b) Cycle #2.
Figure 4.2 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in C$_3$H$_8$-CSI process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #1) (c) Cycle #3.
due to the void space created during the first cycle. In Cycle #3, however, the production was extremely poor because of severe gas channeling, early gas breakthrough (BT) and the back-and-forth movement of the foamy oil. As a result, only little amount of the foamy oil was produced. Moreover, iGOR increased quickly due to rapid solvent exsolution, quick viscosity regainment, and rapid pressure decline. The overall trends of the measured heavy oil RFs, iGORs, and \( P_{\text{prod}} \) during Cycles #1 and #2 in Test #2 are shown in Figures 4.3(a) and (b). In Cycle #1, iGOR increased sharply at the beginning due to the undissolved CO\(_2\) production near the producer (Well A). Then it decreased to moderate values because of the subsequent production of the foamy oil in the late period of the cycle. Similarly, Cycle #2 in Test #2 had the same pattern as described for Cycle #3 in Test #1. Thus iGOR remained high and the heavy oil RF was very low.

Table 4.2 lists the cumulative GOR (cGOR) in each cycle of Tests #1 and #2. A lower cGOR means that more gas was utilized to form a stronger foamy oil. Also Figure 4.4 shows some patterns formed in the physical model after the completion of each traditional CSI test. The arrows pointing to the right-hand side of the physical model represents back movements of the foamy oil during the solvent injection. Meanwhile, the arrows pointing to the left-hand side of the physical model towards the producer represents the forward movements of the foamy oil during fluids production. As a result, not all the restored foamy oil was produced (Jia et al., 2015). Moreover, at the late stage of the production period, the heavy oil in Region A had quick heavy oil viscosity regainment and as a result, some gas was trapped in Region B. This phenomenon is regarded as a new technical limitation of the traditional CSI process in the thin heavy oil reservoir.
Figure 4.3 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in CO$_2$-CSI process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #2) (a) Cycle #1; and (b) Cycle #2.
Table 4.2 Measured cumulative gas‒oil ratios during Cycles #1–3 in Tests #1 and 2.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Cumulative gas‒oil ratio (sc cm³/cm³)</th>
<th>Cycle #1</th>
<th>Cycle #2</th>
<th>Cycle #3</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td>361.74</td>
<td>441.21</td>
<td>1222.5</td>
</tr>
<tr>
<td>2</td>
<td></td>
<td>434.81</td>
<td>2246.04</td>
<td>–</td>
</tr>
</tbody>
</table>
Figure 4.4 A digital photo of the 2-D physical model, which shows the directions of the back-and-forth movements of the foamy oil, Region A, where the heavy oil had regained its viscosity, and Region B, where some gas was trapped.
4.2 Gas Pressure Cycling

In Tests #3–5, two C₃H₈-GPC tests and one CO₂-GPC were conducted after the primary production and they had the total heavy oil RFs of 41.5%, 41.9%, and 30.3%, respectively. The termination criterion for each test was the heavy oil RF of less than 2% in one cycle after the first two cycles. Consequently, Tests #3–5 had six, five, and three cycles, respectively. Table 4.3 lists the heavy oil RFs in the primary production and all the cycles in each test. These test results show that two C₃H₈-GPC tests had better heavy oil RFs than CO₂-GPC test because C₃H₈ is a better extracting solvent (Ma et al., 2017). The effect of ΔPₑₒᵣₑ is not clearly seen in Tests #3 and #4 if only the measured heavy oil RFs are compared. However, the numbers of cycles completed in both tests show that a higher ΔPₑₒᵣₑ enhances heavy recovery over a shorter period due to the formation of stronger foamy-oil flow and a much better microscopic displacement efficiency (Sheng, 1997; Wu et al., 2011).

Figures 4.5(a–f) show the overall trends of the measured heavy oil RFs, iGORs, and $P_{prod}$ during Cycles #1–6 in Test #3. In Cycle #1, the heavy oil RF was poor and could be attributed to the following three major reasons. First, the majority of the foamy oil was formed near the gas injector (Well B). Second, the energy generated during the production pressure depletion process was utilized to create a path for the subsequent mobilization of the foamy oil towards the producer (Well A). Third, the entrained small bubbles had coalesced to form larger bubbles before the foamy oil was mobilized from Well B to Well A. As a result, heavy oil RF was low and the iGOR was moderately high during the cycle. During Cycles #2–6, however, the iGOR rose quickly to high values until the production pressure was reduced below 0.4 MPa. Below 0.4 MPa, lower iGOR values were measured
Table 4.3 Heavy oil recovery factors in the primary production and Cycles #1–6 in Tests #3–5.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Heavy oil recovery factor (%)</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Primary production</td>
<td>Cycle #1</td>
<td>Cycle #2</td>
<td>Cycle #3</td>
<td>Cycle #4</td>
<td>Cycle #5</td>
<td>Cycle #6</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>20.5</td>
<td>0.3</td>
<td>6.6</td>
<td>4.1</td>
<td>4.0</td>
<td>4.1</td>
<td>1.9</td>
<td>41.5</td>
</tr>
<tr>
<td>4</td>
<td>21.9</td>
<td>2.3</td>
<td>8.1</td>
<td>5.5</td>
<td>3.2</td>
<td>0.9</td>
<td>–</td>
<td>41.9</td>
</tr>
<tr>
<td>5</td>
<td>21.0</td>
<td>4.0</td>
<td>5.0</td>
<td>0.3</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>30.3</td>
</tr>
</tbody>
</table>
Figure 4.5 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in $C_3H_8$-GPC process at $\Delta P_{\text{EOR}} = 0.1$ MPa (Test #3) (a) Cycle #1; and (b) Cycle #2.
Figure 4.5 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORS) and production pressures ($P_{prod}$) in $C_3H_8$-GPC process at $\Delta P_{EOR} = 0.1$ MPa (Test #3) (c) Cycle #3; and (d) Cycle #4.
Figure 4.5 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in $C_3H_8$-GPC process at $\Delta P_{\text{EOR}} = 0.1$ MPa (Test #3) (e) Cycle #5; and (f) Cycle #6.
because most of the remaining gas was utilized to form strong foamy-oil flow and a path was created for the mobilization of the foamy oil towards the producer (Well A). Also the same trends were observed during Cycles #1–4 in Test #4. The iGORs in these cycles were lower than those in Test #3 due to the stronger foamy-oil flow, which was induced at a higher $\Delta P_{EOR}$ (Sheng, 1997; Wu et al., 2011). In contrast, Cycle #5 in Test #4 had a severe gas BT from the onset so that the iGOR rose quickly to high values and a low heavy oil RF was obtained. The overall trends of the measured heavy oil RFs, iGORs, and $P_{prod}$ during Cycles #1–5 in Test #4 are shown in Figures 4.6(a–e).

Figures 4.7(a–c) show the overall trends of the measured heavy oil RFs, iGORs, and $P_{prod}$ during Cycles #1–3 in Test #5. In Cycles #1 and #2, the heavy oil RFs were good because the reservoir pressure of lower than 1.5 MPa was maintained for a longer period so that more foamy oil was mobilized and produced. Consequently, the iGOR was maintained at a low value. However, Cycle #3 suffered from rapid reservoir pressure decline, rapid CO$_2$ exsolution, and early gas BT. Thus the iGOR rose quickly to a high value. Table 4.4 lists the cGOR during each cycle in Tests #3–5. The measured cGOR was consistent with the above explanations for the cycles in each test. Foamy-oil stability was increased when liberated solution gas resulted in more bubble nucleation and formation of more microbubbles due to a higher supersaturation. Therefore, a lower cGOR implies the formation of stronger foamy-oil flow and leads to a higher heavy oil RF. Figure 4.8 shows the digital photo of the produced foamy oil during the GPC test, whereas Figure 4.9 shows the digital photo of the 2-D physical model after the GPC test was completed. The patterns shown in the 2-D physical model confirmed that the use of a two-well configuration in the GPC test can effectively prevent the back-and-forth movement of the foamy oil
Figure 4.6 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{prod}$) in C$_3$H$_8$-GPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #4) (a) Cycle #1; and (b) Cycle #2.
Figure 4.6 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in C$_3$H$_8$-GPC process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #4) (c) Cycle #3; and (d) Cycle #4.
**Figure 4.6** Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in $C_3H_8$-GPC process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #4) (e) Cycle #5.
Figure 4.7 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{prod}$) in CO$_2$-GPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #5) (a) Cycle #1; (b) Cycle #2.
Figure 4.7 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{prod}$) in CO$_2$-GPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #5) (c) Cycle #3.
Table 4.4 Measured cumulative gas–oil ratios during Cycles #1–6 in Tests #3–5.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Cumulative gas–oil ratio (sc cm³/cm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cycle #1</td>
</tr>
<tr>
<td>3</td>
<td>774.24</td>
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<tr>
<td>4</td>
<td>101.34</td>
</tr>
<tr>
<td>5</td>
<td>345.01</td>
</tr>
</tbody>
</table>
Figure 4.8 A digital photo of the produced foamy oil during the GPC test.
Figure 4.9 A digital photo of the 2-D physical model, which shows the direction of the foamy-oil displacement and the regions where the heavy oil was bypassed.
encountered in the traditional CSI test. In Figure 4.8, the arrows pointing to the left-hand side of the 2-D physical model represent the direction of the foamy-oil displacement towards the producer. Regions marked as A represent the areas where the heavy oil was bypassed. The bypassed heavy oil near the producer occurred as a result of the exsolved gas BT, which prevented the foamy oil from reaching the producer and consequently induced the heavy oil viscosity regainment in the late cycles of the GPC test.

4.3 Solvent-Assisted Gas Pressure Cycling

In Tests #6–8, three SA-GPC tests were conducted after the primary production. They had the total heavy oil RFs of 28.1%, 27.4%, and 36.6%, respectively. The termination criterion utilized for each test was the heavy oil RF of less than 2% in one cycle. Consequently, Tests #6–8 were able to complete three, two and five cycles respectively. Table 4.5 lists the heavy oil RFs in the primary production and cycles in each test. The experimental data show that SA-GPC at $\Delta P_{\text{EOR}} = 1.0 \text{ MPa}$ (Test #8) had the highest additional heavy oil RF of 15.1% due to the strongest foamy-oil flow formation. Meanwhile, SA-GPC tests at $\Delta P_{\text{EOR}} = 0.1$ and 0.5 MPa (Tests #6 and #7) had the additional heavy oil RFs of 6.9% and 7.3%, respectively. Although it was observed that a higher $\Delta P_{\text{EOR}}$ led to a higher heavy oil RF, SA-GPC generally had an unexpectedly poor performance.

Figures 4.10(a–c) show the overall trends of the measured heavy oil RFs, iGORs, and $P_{\text{prod}}$ during Cycles #1–3 in Test #6. Cycle #1 had a low foamy-oil production at the beginning. Thus the early stage iGOR was moderately high. Afterwards, more foamy oil was produced at a moderately low iGOR throughout the entire cycle as the production
Table 4.5 Enhanced heavy oil recovery (EHOR) factors of the primary production and Cycles #1–5 in Tests #6–8

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Heavy oil recovery factor (%)</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Primary production</td>
<td>Cycle #1</td>
<td>Cycle #2</td>
<td>Cycle #3</td>
<td>Cycle #4</td>
<td>Cycle #5</td>
</tr>
<tr>
<td>6</td>
<td>21.2</td>
<td>3.7</td>
<td>2.7</td>
<td>0.5</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>7</td>
<td>20.1</td>
<td>5.9</td>
<td>1.4</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>8</td>
<td>21.5</td>
<td>6.1</td>
<td>2.1</td>
<td>2.9</td>
<td>2.6</td>
<td>1.4</td>
</tr>
</tbody>
</table>
Figure 4.10 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in SA-GPC process at $\Delta P_{\text{EOR}} = 0.1$ MPa (Test #6) (a) Cycle #1; (b) Cycle #2.
Figure 4.10 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{prod}$) in SA-GPC process at $\Delta P_{EOR} = 0.1$ MPa (Test #6) (c) Cycle #3.
pressure was reduced in steps to the final pressure. In Cycle #2, the iGOR remained at a low value due to foamy-oil production. However, gas BT occurred when the production pressure was reduced below 1.0 MPa, after which the iGOR increased to a high value throughout the cycle. During Cycle #3, the heavy oil RF was very low due to early gas BT at the beginning. As a result, the iGOR increased moderately until the production pressure was reduced below 0.8 MPa. Afterwards, it further increased suddenly and then decreased to a lower value over the remaining period of the cycle. Similarly, the overall trends of the measured heavy oil RFs, iGORs, and \( P_{\text{prod}} \) during Cycles #1 and #2 in Test #7 are shown in Figures 4.11(a) and (b). Cycle #1 in Test #7 had the same trend as that during Cycle #1 in Test #6. However, Cycle #1 in Test #7 had a shorter production period and a higher heavy oil RF due to a larger \( \Delta P_{\text{EOR}} \), which led to a stronger foamy-oil flow. In Cycle #2, gas BT occurred once the production pressure reduction was commenced. Consequently, the heavy oil RF was low and the iGOR increased steadily over the entire period of the cycle as the production pressure was reduced in steps.

Figures 4.12(a–e) show the overall trends of the measured heavy oil RFs, iGORs, and \( P_{\text{prod}} \) during Cycles #1–5 in Test #8. Cycle #1 had low iGOR throughout the cycle until most foamy oil had been produced, a higher heavy oil RF and a shorter production time than Cycle #1 in Test #6 or #7. Cycles #2 and #3 had similar heavy oil RFs and iGORs. The iGOR was moderate almost throughout each cycle till the late period when it suddenly increased due to severe gas BT. Moreover, Cycles #4 and #5 had gas BT from the beginning so that the iGOR increased steadily throughout each cycle. Table 4.6 lists the cGOR values during all cycles in Tests #6–8, which agree well with the respective heavy oil RF trend in each SA-GPC test.
Figure 4.11 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in SA-GPC process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #7) (a) Cycle #1; and (b) Cycle #2.
Figure 4.12 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in SA-GPC process at $\Delta P_{\text{EOR}} = 1.0$ MPa (Test #8) (a) Cycle #1; and (b) Cycle #2.
Figure 4.12 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in SA-GPC process at $\Delta P_{\text{EOR}} = 1.0$ MPa (Test #8) (c) Cycle #3; and (d) Cycle #4.
Figure 4.12 Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in SA-GPC process at $\Delta P_{\text{EOR}} = 1.0 \text{ MPa}$ (Test #8) (e) Cycle #5.
Table 4.6 Measured cumulative gas–oil ratios during Cycles #1–5 in Tests #6–8.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Cumulative gas–oil ratio (sc cm³/cm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cycle #1</td>
</tr>
<tr>
<td>6</td>
<td>328.52</td>
</tr>
<tr>
<td>7</td>
<td>725.64</td>
</tr>
<tr>
<td>8</td>
<td>331.64</td>
</tr>
</tbody>
</table>
In general, the performance of SA-GPC was far below expectation. It was expected that the superior solubility of C\textsubscript{3}H\textsubscript{8} would be utilized to reduce heavy oil viscosity. Moreover, the injection of CO\textsubscript{2} into the physical model was intended to raise the pressure to $P_i = 3.0$ MPa and also improve the volumetric sweep efficiency. However, it was observed during the experiment that the behaviour of the gas mixture was closer to that of CO\textsubscript{2} in terms of gas exsolution rate and foamy-oil strength. In order to understand the SA-GPC low performance, the solvent (C\textsubscript{3}H\textsubscript{8}) and gas (CO\textsubscript{2}) injected into the physical model were estimated to be approximately 24 mol.% and 76 mol.%, respectively. Based on the mole percents and the gas properties, the CMG WinProp module was used to construct the $P$–$T$ phase diagram of the gas mixture. Figure 4.13 shows the $P$–$T$ phase diagram of 24 mol.% C\textsubscript{3}H\textsubscript{8} and 76 mol.% CO\textsubscript{2}. The red point represents the initial reservoir conditions of $P_i = 3.0$ MPa and $T_{res} = 21.0$ °C. This figure shows that at the initial reservoir conditions, the C\textsubscript{3}H\textsubscript{8}–CO\textsubscript{2} mixture was in the gaseous phase. In addition, the saturation pressure of pure C\textsubscript{3}H\textsubscript{8} is 0.8 MPa and above this pressure it will be in the liquid phase. Therefore, the injection of CO\textsubscript{2} into the physical model vapourized pure C\textsubscript{3}H\textsubscript{8} and thus reduced its solubility and heavy oil viscosity reduction ability. Consequently, the performance of SA-GPC was undermined and the foamy oil formed during the process was not strong enough to enhance heavy oil recovery, in comparison with C\textsubscript{3}H\textsubscript{8}-GPC.

4.4 Water Pressure Cycling

In Tests #9–11, three WPC tests were initiated at different primary production final pressures and they had the total heavy oil RFs of 23.0%, 29.4%, and 22.0%, respectively. The termination criterion of less than 2% heavy oil RF in one cycle was adopted in each test. Tests #9–10 were completed after two cycles. In contrast, Test #11 had only one cycle
Figure 4.13 P‒T phase diagram of 24 mol.% C₃H₈ + 76 mol.% CO₂ mixture at $T_{res} = 21.0$ °C, which was generated by using the CMG WinProp module.
due to its low heavy oil RF of 0.6% and its high cWOR of approximately 6.4:1. Table 4.7 lists the total heavy oil RF in each test. Based on the experimental data, Test #10 had the highest total heavy oil RF due to the following three major reasons. First, a reasonable amount of the foamy oil was produced during the primary production in Test #10. Second, a moderate amount of the brine was injected from Well B during the first WPC cycle. Therefore, the physical model was pressurized enough to dissolve some free gas (CH₄) into the heavy oil, reduce the heavy oil viscosity regainment, and mobilize the remaining foamy oil towards the producer (Well A). Lastly, the production pressure was maintained over a longer period during the primary production and WPC process in Test #10 in comparison with Tests #9 and #11.

The overall trends of the measured heavy oil RFs, iWCs, iGORs, and $P_{\text{prod}}$ during Cycles #1 and #2 in Test #9 are shown in Figures 4.14(a) and (b), respectively. In this test, the primary production had a very low heavy oil RF because of the rapid production pressure reduction from $P_i = 3.0$ MPa to $P_f = 2.0$ MPa in a short period. Therefore, only a small amount of foamy oil was produced, which contributed to the low measured total heavy oil RF in this test. During Cycle #1, the volume of the brine injected was too small to improve the volumetric sweep efficiency or have any effect on the dissolution of more free gas (CH₄) into the heavy oil. As a result, this cycle behaved more like the continuation of the primary production. The iGOR and the iWC were quite low until the production pressure declined to 0.5 MPa, during which both quantities increased and then decreased over the remaining period in the cycle. In addition, most of the foamy oil was produced in this cycle. During Cycle #2, water BT occurred from the start of the production period. Hence, the iWC increased steadily during the entire cycle. Also the production pressure depletion was
Table 4.7 Enhanced heavy oil recovery (EHOR) factors of the primary production and Cycles #1–2 in Tests #9–11

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Heavy oil recovery factor (%)</th>
<th>Primary production</th>
<th>Cycle #1</th>
<th>Cycle #2</th>
<th>Total</th>
</tr>
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<td>9</td>
<td>1.6</td>
<td>19.9</td>
<td>1.5</td>
<td></td>
<td>23.0</td>
</tr>
<tr>
<td>10</td>
<td>15.8</td>
<td>12.1</td>
<td>1.5</td>
<td></td>
<td>29.4</td>
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<td>21.4</td>
<td>0.6</td>
<td>–</td>
<td></td>
<td>22.0</td>
</tr>
</tbody>
</table>
Figure 4.14 Measured heavy oil recovery factors (RFs), instantaneous water cuts (iWCs), instantaneous gas–oil ratio (iGORs), and production pressures ($P_{\text{prod}}$) in WPC at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #9) (a) cycle #1; and (b) cycle #2.
rapid because the free gas had been produced with the foamy oil in the previous cycle.

Figures 4.15(a) and (b) show the overall trends of the measured heavy oil RFs, iWCs, iGORs, and \( P_{\text{prod}} \) during Cycles #1 and #2 in Test #10. During Cycle #1 in Test #10, iWC increased rapidly at the beginning of the production period when \( \Delta P_{\text{IOR}} \) of 0.5 MPa was applied. Afterwards, high iWC was continued until the production pressure declined to 1.0 MPa when the iWC declined to a moderate value throughout the remaining part of the cycle. This behaviour of the iWC trend was due to water channeling, which was caused by the rapid production pressure reduction at the early stage of the cycle. Moreover, the production pressure was maintained below 1.0 MPa for a longer period and consequently resulted in more heavy oil production and declined iWC. The iGOR was very low over the entire production period of Cycle #1 in Test #9 or Test #10 because the free gases contributed to the pressure maintenance in the physical model. Cycle #2 in Test #10 had similar trends to Cycle #2 in Test #9. Also WPC Cycle #1 in Test #11 had a low additional heavy oil RF because of rapid production pressure reduction, Most free gas had been produced along with the foamy oil during the primary production. The overall trends of the measured heavy oil RF, iWCs, and \( P_{\text{prod}} \) during Cycle #1 in Test #11 are shown in Figure 4.16. In addition, Tables 4.8(a) and (b) list the measured cGORs and cWORs during each cycle in Tests #9–11. Water channeling led to the high cWORs during Cycle #2 in Tests #9–10 and during Cycle #1 in Test #11, respectively. In general, WPC had some obvious shortcomings. They included large heavy oil viscosity regainment and poor production performances during the subsequent cycles after most foamy oil and free gases had been produced in the primary production or in the previous cycle(s). They also included water channeling, which prevented the remaining foamy oil from reaching the producer.
Figure 4.15 Measured heavy oil recovery factors (RFs), instantaneous water cuts (iWC) and production pressures ($P_{\text{prod}}$) in WPC at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #10) (a) cycle #1; and (b) cycle #2.
Figure 4.16 Measured heavy oil recovery factors (RFs), instantaneous water cuts (iWC) and production pressures ($P_{\text{prod}}$) in WPC at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #11) during Cycle #1.
Table 4.8(a) Measured cumulative gas‒oil ratios during Cycles #1‒2 in Tests #9‒11.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Cumulative gas‒oil ratio (sc cm³/cm³)</th>
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<tr>
<td></td>
<td>Cycle #1</td>
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<td>13.04</td>
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<tr>
<td>10</td>
<td>6.55</td>
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Table 4.8(b) Measured cumulative water‒oil ratios in Cycles #1–2 during Tests #9–11.

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<th>Cumulative water‒oil ratio (sc cm³/cm³)</th>
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<tr>
<td>10</td>
<td>0.6028</td>
</tr>
<tr>
<td>11</td>
<td>6.3572</td>
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</table>
4.5 Solvent-Assisted Water Pressure Cycling

In Tests #12–15, three different C₃H₈-SA-WPC tests at ΔPₑₒᵣₑₑᵣ = 0.1, 0.5, and 1.0 MPa and one CO₂-SA-WPC test at ΔPₑₒᵣₑₑᵣ = 0.5 MPa were conducted after the primary production, respectively. The termination criterion adopted for each test was the heavy oil RF of less than 2% in one cycle. However, the measured cGOR during Cycle #4 in Test #12 was too high and the test was terminated after the fourth cycle. Tests #13 and #14, which were C₃H₈-SA-WPC tests at ΔPₑₒᵣₑₑᵣ = 0.5 and 1.0 MPa respectively, were also terminated after the fourth cycle for comparison purpose. In contrast, CO₂-SA-WPC test lasted only three cycles because of a high cWOR and a low measured heavy oil RF of 0.7% in Cycle #3. Table 4.9 lists the heavy oil RFs in the primary production and cycles in each test. The results show that three C₃H₈-SA-WPC tests at ΔPₑₒᵣₑₑᵣ = 0.1, 0.5, and 1.0 MPa had much higher total heavy oil RFs of 62.0%, 68.4%, and 42.3%, respectively, than 29.2% in CO₂-SA-WPC test at ΔPₑₒᵣₑₑᵣ = 0.5 MPa. C₃H₈ was a much better extracting solvent in SA-WPC process than CO₂ under the same experimental conditions. C₃H₈ had a much higher solubility/capability to effectively reduce the heavy oil viscosity and generate a stronger foamy oil in C₃H₈-SA-WPC process.

Furthermore, the effect of ΔPₑₒᵣₑₑᵣ was also evident in three C₃H₈-SA-WPC tests. Sheng (1997) and Wu et al. (2011) reported in their studies that that the foamy-oil strength and stability can be enhanced by increasing ΔPₑₒᵣₑₑᵣ. The results listed in Table 4.9 indicate that C₃H₈-SA-WPC test at ΔPₑₒᵣₑₑᵣ = 0.5 MPa had the higher total heavy oil RF than that for C₃H₈-SA-WPC test at ΔPₑₒᵣₑₑᵣ = 0.1 MPa. However, the total heavy oil RFs measured in the first two C₃H₈-SA-WPC tests were significantly higher than that of C₃H₈-SA-WPC test at
Table 4.9 Enhanced heavy oil recovery (EHOR) factors in the primary production and Cycles #1–4 in Tests #12–15.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Heavy oil recovery factor (%)</th>
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<tr>
<td></td>
<td>Primary production</td>
<td>Cycle #1</td>
<td>Cycle #2</td>
<td>Cycle #3</td>
<td>Cycle #4</td>
<td>Total</td>
</tr>
<tr>
<td>12</td>
<td>21.6</td>
<td>12.9</td>
<td>12.9</td>
<td>8.8</td>
<td>5.8</td>
<td>62.0</td>
</tr>
<tr>
<td>13</td>
<td>21.8</td>
<td>13.1</td>
<td>12.5</td>
<td>10.4</td>
<td>10.6</td>
<td>68.4</td>
</tr>
<tr>
<td>14</td>
<td>19.9</td>
<td>11.3</td>
<td>4.5</td>
<td>3.1</td>
<td>3.5</td>
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</tr>
<tr>
<td>15</td>
<td>18.0</td>
<td>5.0</td>
<td>5.5</td>
<td>0.7</td>
<td>–</td>
<td>29.2</td>
</tr>
</tbody>
</table>
\[ \Delta P_{EOR} = 1.0 \text{ MPa.} \] This trend is in agreement with the finding of Zhou et al. (2016), where an optimum pressure depletion rate was found for the heavy oil–C$_3$H$_8$ system. The major reason why C$_3$H$_8$-SA-WPC processes at \( \Delta P_{EOR} = 0.1 \) and 0.5 MPa (Tests #12–13) had much higher total heavy oil RFs than C$_3$H$_8$-SA-WPC process at \( \Delta P_{EOR} = 1.0 \) MPa (Test #14) was because at a relatively lower \( \Delta P_{EOR} \), the bubble nucleation was slower and longer. In addition, the pressure in the physical model was maintained over a longer period at a lower \( \Delta P_{EOR} \) and the water BT was delayed (Ojumoola et al., 2019).

Figures 4.17(a–d) show the overall trends of the measured heavy oil RFs, iWCs, iGORs, and \( P_{\text{prod}} \) during Cycles #1–4 in Test #12. In Cycle #1, the foamy-oil production increased progressively as the production pressure was reduced in steps. Also most foamy oil was produced below 0.6 MPa because at this pressure, more bubbles were nucleated, which resulted in a stronger foamy-oil flow and a higher heavy oil mobility. In this cycle, the water BT was delayed until the production pressure was reduced below 0.6 MPa after most foamy oil was produced. Thus the iWC was increased and maintained at a high value throughout the rest of the cycle. In Cycle #2, most foamy oil was also produced below 0.6 MPa. Meanwhile, there were small fluctuations of the iWC because of the low foamy-oil production in the early period of the cycle. However, the water and gas BTs occurred simultaneously when the production pressure was reduced to 0.5 MPa. Thus both the iWC and the iGOR maintained high values throughout the remaining period in the cycle. Cycles #3 and #4 had similar trends to Cycle #2, except that the water and gas BTs occurred when the production pressure was declined to 0.2 MPa in Cycle #4.

The measured heavy oil RFs, iWCs, iGORs, in C$_3$H$_8$-SA-WPC process at \( \Delta P_{EOR} = 0.5 \) MPa (Test #13), which had four cycles, are shown in Figures 4.18(a–d). In each cycle,
Figure 4.17 Measured heavy oil recovery factors (RFs), instantaneous water-cuts (iWCs), instantaneous gas–oil ratios (iGORs), and production pressures ($P_{\text{prod}}$) in C$_3$H$_8$-SA-WPC process at $\Delta P_{\text{EOR}} = 0.1$ MPa (Test #12) (a) Cycle #1; and (b) Cycle #2.
Figure 4.17 Measured heavy oil recovery factors (RFs), instantaneous water-cuts (iWCs), instantaneous gas–oil ratios (iGORs), and production pressures ($P_{\text{prod}}$) in $C_3H_8$-SA-WPC process at $\Delta P_{\text{EOR}} = 0.1$ MPa (Test #12) (c) Cycle #3; and (d) Cycle #4.
Figure 4.18 Measured heavy oil recovery factors (RFs), instantaneous water-cuts (iWCs), instantaneous gas–oil ratios (iGORs), and production pressures ($P_{prod}$) in C$_3$H$_8$-SA-WPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #13) (a) Cycle #1; and (b) Cycle #2.
Figure 4.18 Measured heavy oil recovery factors (RFs), instantaneous water-cuts (iWCs), instantaneous gas–oil ratios (iGORs), and production pressures (\( P_{\text{prod}} \)) in \( \text{C}_3\text{H}_8\text{-SA-WPC} \) process at \( \Delta P_{\text{EOR}} = 0.5 \) MPa (Test #13) (c) Cycle #3; and (d) Cycle #4.
most foamy oil was produced after the production pressure was reduced to 0.5 MPa. The iWC trend during each cycle of Test #13 indicates that the water BT was delayed until the production pressure was reduced to 0.5 MPa. Afterwards, water channeling and BT occurred because most foamy oil had been produced and the iWC increased to its maximum. Similarly, the measured heavy oil RFs, iWCs, iGORs in C3H8-SA-WPC process at $\Delta P_{EOR} = 1.0$ MPa (Test #14), which had four cycles, are shown in Figures 4.19(a–d). In each cycle, most foamy oil was produced after the production pressure reached 1.0 MPa. The iWC trend during each cycle in Test #14 indicated that water channeling and BT occurred from the beginning of the production period because $\Delta P_{EOR}$ of 1.0 MPa was too large. However, the iGOR was low in each cycle because at $\Delta P_{EOR} = 1.0$ MPa, most gas was utilized to increase the foamy-oil strength. Figures 4.20(a–c) show the measured heavy oil RFs, iWCs, iGORs, in CO2-SA-WPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #15), which had three cycles. The iWC trend in each cycle shows that CO2-SA-WPC process had severe water channeling and BT due to low CO2 solubility. The low CO2 solubility and the early water BT in Test #15 had a more adverse effect on the performance of CO2-SA-WPC process than $\Delta P_{EOR}$. Consequently, CO2-SA-WPC test was only performed at $\Delta P_{EOR} = 0.5$ MPa. In addition, Tables 4.10(a) and (b) list the measured cGORs and cWORs during Cycles #1–4 in Tests #12–15. The measured results show that three C3H8-SA-WPC tests had higher cGORs than those in CO2-SA-WPC test because of more C3H8 dissolution, lower cWORs, and delayed water BTs in C3H8-SA-WPC tests. Thus C3H8-SA-WPC was much better than CO2-SA-WPC in terms of the heavy oil RF, cWOR, but not cGOR.
Figure 4.19 Measured heavy oil recovery factors (RFs), instantaneous water-cuts (iWCs), instantaneous gas‒oil ratios (iGORs), and production pressures ($P_{\text{prod}}$) in C$_3$H$_8$-SA-WPC process at $\Delta P_{\text{EOR}} = 1.0$ MPa (Test #14) (a) Cycle #1; and (b) Cycle #2.
**Figure 4.19** Measured heavy oil recovery factors (RFs), instantaneous water-cuts (iWCs), instantaneous gas–oil ratios (iGORs), and production pressures ($P_{\text{prod}}$) in C$_3$H$_8$-SA-WPC process at $\Delta P_{\text{EOR}} = 1.0$ MPa (Test #14) (c) Cycle #3; and (d) Cycle #4.
Figure 4.20 Measured heavy oil recovery factors (RFs), instantaneous water-cuts (iWCs), instantaneous gas–oil ratios (iGORs) and production pressures ($P_{\text{prod}}$) in CO2-SA-WPC process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #15) (a) Cycle #1; and (b) Cycle #2.
Figure 4.20 Measured heavy oil recovery factors (RFs), instantaneous water-cuts (iWCs), instantaneous gas–oil ratios (iGORs), and production pressures ($P_{\text{prod}}$) in CO2-SA-WPC process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #15) (c) Cycle #3.
Table 4.10(a) Measured cumulative gas–oil ratios during Cycles #1–4 in Tests #12–15.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Cycle #1</th>
<th>Cycle #2</th>
<th>Cycle #3</th>
<th>Cycle #4</th>
</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>168.12</td>
<td>291.49</td>
<td>810.03</td>
<td>1533.49</td>
</tr>
<tr>
<td>13</td>
<td>196.77</td>
<td>283.26</td>
<td>407.92</td>
<td>452.43</td>
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<td>14</td>
<td>29.45</td>
<td>88.27</td>
<td>174.97</td>
<td>125.63</td>
</tr>
<tr>
<td>15</td>
<td>43.33</td>
<td>48.27</td>
<td>116.18</td>
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</tbody>
</table>

Table 4.10(b) Measured cumulative water–oil ratios during Cycles #1–4 in Tests #12–15.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Cycle #1</th>
<th>Cycle #2</th>
<th>Cycle #3</th>
<th>Cycle #4</th>
</tr>
</thead>
<tbody>
<tr>
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<td>0.3931</td>
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<tr>
<td>13</td>
<td>0.3034</td>
<td>0.3891</td>
<td>0.9007</td>
<td>0.9099</td>
</tr>
<tr>
<td>14</td>
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<td>1.9959</td>
<td>3.4855</td>
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<td>15</td>
<td>3.2092</td>
<td>1.9346</td>
<td>14.7567</td>
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4.6 Comparison of Water- and/or Solvent-based EHOR Processes

Table 4.11 shows the physical characteristics of the sandpacked model, as well as the primary production and the combined incremental heavy oil RFs of Tests #1–15. The processes are compared as listed below.

4.6.1 CSI vs. GPC

Figure 4.21(a) compares the heavy oil RFs during the primary production and every cycle of each CSI or GPC test. The experimental data indicate that two C₃H₈-GPC processes (Tests #3 and #4) had much higher heavy oil RFs than C₃H₈-CSI process (Test #1). Similarly, CO₂-GPC process (Test #5) had a higher heavy oil RF than CO₂-CSI process (Test #2). In each GPC test, the two-well configuration helped to prevent the back-and-forth movements of the foamy-oil problem encountered in the traditional CSI process. This is because the injector (Well B) placement and the direction of injection of the gas helped to mobilize the foamy oil towards the producer (Well A). Also the gas had more contact with the heavy oil as a result of the injector placement. This also resulted in an enhanced microscopic displacement efficiency, a larger heavy oil viscosity reduction, and a stronger restored foamy-oil flow. Meanwhile, the performance of the CSI process was undermined by quick heavy oil viscosity regainment, rapid pressure depletion, back-and-forth movements of the foamy oil and gas-trapping effect. In addition, Figure 4.21(b) indicates that the GPC process is better than the CSI process in terms of cGOR, which is an indication of the foamy-oil strength and stability in both processes. Based on the heavy oil RFs, both the GPC and the CSI processes are ranked as follows: C₃H₈-GPC test (Test #4) > C₃H₈-GPC test (Test #3) > CO₂-GPC test (Test #5) > C₃H₈-CSI test (Test #1) > CO₂-CSI test (Test #2).
Table 4.11 The physical characteristics of the sandpacked model, the primary production, each EHOR process and total heavy oil RFs of Tests #1–15.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Physical characteristics</th>
<th>Heavy oil recovery factor (%)</th>
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<tr>
<td></td>
<td>φ (%)</td>
<td>k (D)</td>
<td>S_{oi} (%)</td>
<td>Primary production</td>
<td>CSI/GPC/SA-GPC/WPC</td>
</tr>
<tr>
<td>1</td>
<td>39.4</td>
<td>3.9</td>
<td>99.0</td>
<td>21.0</td>
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</tr>
<tr>
<td>2</td>
<td>39.7</td>
<td>3.8</td>
<td>99.5</td>
<td>20.0</td>
<td>2.7</td>
</tr>
<tr>
<td>3</td>
<td>39.6</td>
<td>4.4</td>
<td>98.7</td>
<td>20.5</td>
<td>21</td>
</tr>
<tr>
<td>4</td>
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<td>4.2</td>
<td>98.6</td>
<td>21.9</td>
<td>20</td>
</tr>
<tr>
<td>5</td>
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<td>3.8</td>
<td>98.3</td>
<td>21.0</td>
<td>9.3</td>
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<tr>
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<td>21.2</td>
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<tr>
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<td>95.3</td>
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<td>2.1</td>
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<td>99.3</td>
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<td>38.9</td>
<td>2.9</td>
<td>99.0</td>
<td>18.0</td>
<td>11.2</td>
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Figure 4.21(a) Measured heavy oil recovery factors (RFs) during the primary productions (PPs) at the final primary production pressures of $P_f = 0.2$ MPa; Cycles #1–3 in $C_3H_8$-CSI process at $\Delta P_{EOR} = 0.5$ MPa (Test #1); Cycles #1–2 in $CO_2$-CSI process at $\Delta P_{EOR} = 0.5$ MPa (Test #2); different cycles in $C_3H_8$-GPC processes at $\Delta P_{EOR} = 0.1$ and 0.5 MPa (Tests #3 and #4); and Cycles #1–3 in $CO_2$-GPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #5).
Figure 4.21(b) Measured cumulative gas–oil ratio (cGORs) during Cycles #1–3 in C₃H₈-CSI process at $\Delta P_{EOR} = 0.5$ MPa (Test #1); Cycles #1–2 in CO₂-CSI process at $\Delta P_{EOR} = 0.5$ MPa (Test #2); different cycles in C₃H₈-GPC processes at $\Delta P_{EOR} = 0.1$ and 0.5 MPa (Tests #3 and #4); and Cycles #1–3 in CO₂-GPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #5).
4.6.2 GPC vs. SA-GPC

Figures 4.22(a) compares the heavy oil RFs during the primary production and every cycle of each GPC or SA-GPC test, while Figure 4.21(b) compares the cGORs in every cycle of both processes. Figure 4.22(a) shows that two C₃H₈-GPC processes (Tests #3 and #4) had higher heavy oil RFs than those in three SA-GPC processes (Tests #6–8). The GPC process had a stronger foamy-oil flow and a higher heavy oil viscosity reduction due to the superior solubility of C₃H₈ as an extracting solvent. In the SA-GPC processes, however, the solubility of pure C₃H₈ was reduced due to the presence of injected CO₂ into the physical model. This resulted in a weaker foamy-oil flow and stability, as well as a lower heavy oil RF. Also the C₃H₈-GPC process is better than the SA-GPC process in terms of cGOR as shown in Figure 4.22(b). Based on the heavy oil RFs, both the GPC and the SA-GPC processes are ranked as follows: C₃H₈-GPC test (Test #4) > C₃H₈-GPC test (Test #3) > SA-GPC test (Test #8) > CO₂-GPC test (Test #5) > SA-GPC test (Test #6) > SA-GPC test (Test #7).

4.6.3 WPC vs. SA-WPC

The heavy oil RFs during the primary production and every cycle of each WPC or SA-WPC test are compared in Figure 4.23(a). The experimental data indicate that three C₃H₈-SA-WPC processes (Tests #12–14) had much higher total heavy oil RFs than those in three WPC processes (Tests #9–11). On one hand, the injected brine in each C₃H₈-SA-WPC process helped to dissolve more C₃H₈ into the heavy oil by pressurizing the physical model and improving the volumetric sweep efficiency. Consequently, foamy-oil flow was restored, the heavy oil viscosity was reduced, and the reservoir pressure was maintained. Hence, the heavy oil RF was enhanced under the foamy-oil flow and solution-gas drive
Figure 4.22(a) Measured heavy oil recovery factors (RFs) during the primary productions (PPs) at the final primary production pressures of $P_f = 0.2$ MPa; different cycles in $C_3H_8$-GPC processes at $\Delta P_{EOR} = 0.1$ and 0.5 MPa (Tests #3 and #4); Cycles #1–3 in CO$_2$-GPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #5); and the different cycles in SA-GPC processes at $\Delta P_{EOR} = 0.1, 0.5,$ and 1.0 MPa (Tests #6–8).
Figure 4.22(b) Measured cumulative gas–oil ratio (cGORs) during different cycles in $\text{C}_3\text{H}_8$-GPC processes at $\Delta P_{\text{EOR}} = 0.1$ and 0.5 MPa (Tests #3 and #4); Cycles #1–3 in CO$_2$-GPC process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #5); and the different cycles in SA-GPC processes at $\Delta P_{\text{EOR}} = 0.1$, 0.5, and 1.0 MPa (Tests #6–8).
Figure 4.23(a) Measured heavy oil recovery factors (RFs) during the primary productions (PPs) at the final primary production pressures of $P_f = 2.0$ and $1.0$ MPa in Tests #9 and #10, respectively, and $P_f = 0.2$ MPa in Tests #11–15; Cycles #1 and #2 in three WPC processes at $\Delta P_{IOR} = 0.5$ MPa (Tests #9–11); Cycles #1–4 in C$_3$H$_8$-SA-WPC processes at $\Delta P_{EOR} = 0.1$, 0.5 and 1.0 MPa (Tests #12–14); and Cycles #1–3 in CO$_2$-SA-WPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #15).
mechanisms. On the other hand, the WPC process alone suffered from a severe early water channeling and BT. Also lack of enough solvent for the heavy oil viscosity reduction and foamy-oil flow led to the low total heavy oil RFs. The cWOR and cGOR of every cycle in the WPC or SA-WPC process are compared in Figures 4.23(b) and (c), respectively. The very low cGOR during the WPC indicated the lack of enough solvent in the WPC process. In addition, the experimental data showed that C₃H₈-SA-WPC process is better than WPC process in terms of cGOR and cWOR. Based on the heavy oil RFs, both the WPC and the SA-WPC processes are ranked as follows: C₃H₈-SA-WPC test (Test #13) > C₃H₈-SA-WPC test (Test #12) > C₃H₈-SA-WPC test (Test #14) > WPC test (Test #10) > CO₂-SA-WPC test (Test #15) > WPC test (Test #9) > WPC test (Test #11).

4.6.4 SA-GPC vs. SA-WPC

Figure 4.24(a) shows the comparison of the heavy oil RFs during the primary production and every cycle of each SA-GPC or SA-WPC test. The experimental data show that three C₃H₈-SA-WPC tests had much higher heavy oil RFs than those in the three SA-GPC processes. Both processes (SA-GPC and SA-WPC) were intended to combine both the EOR and IOR mechanisms so as to increase the solubility of C₃H₈, further reduce the heavy oil viscosity, and enhance the heavy oil recovery. The SA-WPC process was able to achieve this goal but the SA-GPC process did not. This was due to C₃H₈ solubility reduction caused by the injected CO₂ during the SA-GPC, which led to a lower heavy oil RFs. In addition, Figure 4.24(b) shows that the SA-WPC process was also better than the SA-GPC process in terms of cGOR. Based on the heavy oil RFs, both the SA-GPC and the SA-WPC processes are ranked as follows: C₃H₈-SA-WPC test (Test #13) > C₃H₈-SA-WPC test (Test #12) > C₃H₈-SA-WPC test (Test #14) > SA-GPC test (Test #8) > CO₂-SA-WPC
Figure 4.23(b) Measured cumulative water‒oil ratios (cWORs); and (c) measured cumulative gas‒oil ratios (cGORs) during different cycles in the WPC processes (Tests #9‒11) and the SA-WPC processes (Tests #12‒15).
Figure 4.24(a) Measured heavy oil recovery factors (RFs) during the primary productions (PPs) at the final primary production pressures of $P_i = 0.2$ MPa; the different cycles in SA-GPC processes at $\Delta P_{EOR} = 0.1, 0.5$, and 1.0 MPa (Tests #6–8); Cycles #1–4 in $C_3H_8$-SA-WPC processes at $\Delta P_{EOR} = 0.1, 0.5$ and 1.0 MPa (Tests #12–14); and Cycles #1–3 in CO$_2$-SA-WPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #15).
Figure 4.24(b) Measured cumulative gas–oil ratios (cGORs) during the different cycles in SA-GPC processes at $\Delta P_{\text{EOR}} = 0.1$, 0.5, and 1.0 MPa (Tests #6–8); Cycles #1–4 in $\text{C}_3\text{H}_8$-SA-WPC processes at $\Delta P_{\text{EOR}} = 0.1$, 0.5 and 1.0 MPa (Tests #12–14); and Cycles #1–3 in CO$_2$-SA-WPC process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #15).
test (Test #15) > SA-GPC test (Test #6) > SA-GPC test (Test #7).
CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

In this study, the production performances of four different novel solvent- and/or water-based enhanced heavy oil recovery (EHOR) processes plus the traditional cyclic solvent injection (CSI) in a thin heavy oil reservoir were experimentally studied. Five series of experiments were conducted by using a 2-D rectangular physical sandpacked model. They include CSI, gas pressure cycling (GPC), solvent-assisted gas pressure cycling (SA-GPC), water pressure cycling (WPC), and solvent-assisted water pressure cycling (SA-WPC). The major technical conclusions are summarized as follows.

- The CSI had the gas-trapping effect during its late cycle, in addition to the known technical limitations of the back-and-forth movement of foamy oil, rapid reservoir pressure depletion, and quick heavy oil viscosity regainment.

- The proposed GPC process could recover 41.9% of the original oil-in-place (OOIP) because the two-well configuration was utilized to inject gas and mobilize the foamy oil towards the producer. Thus the microscopic displacement efficiency was increased to effectively enhance heavy oil production.

- \( C_3H_8 \)-GPC test at \( \Delta P_{EOR} = 0.5 \) MPa had the highest heavy oil recovery factor (RF) in comparison with \( C_3H_8 \)-GPC test at \( \Delta P_{EOR} = 0.1 \) MPa and \( CO_2 \)-GPC test at \( \Delta P_{EOR} = 0.5 \) MPa. Although the heavy oil RF in \( C_3H_8 \)-GPC test at \( \Delta P_{EOR} = 0.1 \) MPa was almost the same as that in \( C_3H_8 \)-GPC test at \( \Delta P_{EOR} = 0.5 \) MPa, a higher \( \Delta P_{EOR} \) meant a shorter production period to reach the same heavy oil RF.
The proposed SA-GPC process could recover 36.6% of the OOIP, which was 9% more than the CSI heavy oil RF. This was attributed to the effect of the two-well configuration. In addition, SA-GPC test at $\Delta P_{EOR} = 1.0$ MPa had the highest heavy oil RF in comparison with the other two SA-GPC tests at $\Delta P_{EOR} = 0.1$ and 0.5 MPa, respectively.

WPC test with the final primary production pressure of $P_f = 1.0$ MPa had the highest total heavy oil RF of 29.4% of the OOIP, in comparison with the other two WPC tests with $P_f = 2.0$ and 0.2 MPa, respectively.

The proposed SA-WPC process could recover as much as 68.4% of the OOIP because the brine injection increased the reservoir pressure and solvent dissolution into the heavy oil, which led to the heavy oil viscosity reduction and the foamy-oil flow restoration.

$C_3H_8$-SA-WPC at $\Delta P_{EOR} = 0.5$ MPa had the highest heavy oil RF, whereas $C_3H_8$-SA-WPC at $\Delta P_{EOR} = 0.1$ MPa had a much higher heavy oil RF than $C_3H_8$-SA-WPC at $\Delta P_{EOR} = 1.0$ MPa. Thus, the experimental results show the existence of an optimum $\Delta P_{EOR}$, above and below which the heavy oil RF is lower. Moreover, a higher $\Delta P_{EOR}$ resulted in a lower cGOR because of the restoration of strong foamy-oil flow. Meanwhile, a higher $\Delta P_{EOR}$ also led to a higher cWOR because of an early water BT.

$C_3H_8$ is a much better extracting solvent than $CO_2$ in GPC process in terms of the heavy oil RF, production rate, and cumulative gas‒oil ratio (cGOR), and also in SA-WPC process in terms of the heavy oil RF, production rate, and cumulative water‒oil ratio (cWOR), but not cGOR. This was due to a high solubility of $C_3H_8$
and its ability to significantly reduce the heavy oil viscosity. Also, water breakthrough (BT) during C₃H₈-SA-WPC was delayed due to the foamy-oil flow, whereas water BT occurred at the beginning of the production period during CO₂-SA-WPC.

- GPC recovered more heavy oil than CSI because GPC utilized a two-well configuration to minimize the major technical issues associated with CSI.

- C₃H₈-GPC recovered more heavy oil than SA-GPC. GPC utilized a higher solubility of C₃H₈ to induce a stronger foamy-oil flow, a reduced heavy oil viscosity, and a reduced quick heavy oil viscosity regainment, in comparison with approximately 24 mol.% C₃H₈ + 76 mol.% CO₂ used in SA-GPC.

- SA-WPC recovered much more heavy oil than WPC and SA-GPC because SA-WPC combined the enhanced oil recovery (EOR) and improved oil recovery (IOR) mechanisms. More specifically, SA-WPC had a much higher microscopic displacement efficiency (EOR) and a much higher volumetric sweep efficiency (IOR) due to the solvent injection and water pressure cycling, respectively.

- Different IOR/EHOR processes were ranked based on the heavy oil RFs as follows:
  
  C₃H₈-SA-WPC > C₃H₈-GPC > SA-GPC > WPC > CO₂-SA-WPC > CO₂-GPC > C₃H₈-CSI > CO₂-CSI.

### 5.2 RECOMMENDATIONS

In this thesis, four new solvent and/or water-based processes were experimentally studied as potential EHOR processes in a thin heavy oil reservoir. Four technical recommendations for future studies are summarized as follows:

- A mixed solvent of CO₂ and C₃H₈ with a reasonable amount of C₃H₈, instead of
Pure CO$_2$/C$_3$H$_8$ alone, can be used as the extracting solvents during GPC and SA-WPC. Although C$_3$H$_8$ is stronger in reducing the heavy oil viscosity than CO$_2$, CO$_2$ is much cheaper than C$_3$H$_8$. Thus, such a mixed solvent can have a high heavy oil RF and a low overall cost;

- Simultaneous (Gas + water) pressure cycling can also be studied as a potential EHOR process in a thin heavy oil reservoir;
- The proposed GPC, SA-GPC and SA-WPC processes can be experimentally studied to examine their potentials in the post-CHOPS reservoir; and
- Numerical simulation studies can be conducted to further study the proposed GPC, SA-GPC and SA-WPC, scale-up the laboratory studies, and explore their actual field applications in a thin heavy oil reservoir. Moreover, some important factors such as physical model dimension, well configuration, etc., must be considered in the scaling-up criteria.
- Economic analysis of each EHOR process can be conducted in order to determine which process is the most economically viable.
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