OPTIMUM CYCLIC SOLVENT INJECTION (CSI) AND WATERFLOODING/GASFLOODING IN THE POST COLD HEAVY OIL PRODUCTION WITH SAND (CHOPS) RESERVOIRS

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Hongze Ma, candidate for the degree of Doctor of Philosophy in Petroleum Systems Engineering, has presented a thesis titled, *Optimum Cyclic Solvent Injection (CSI) and Waterflooding/Gasflooding in the Post Cold Heavy Oil Production with Sand (Chops) Reservoirs*, in an oral examination held on August 30, 2017. 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, the technical synergy of combining cyclic solvent injection (CSI) and waterflooding (WF) or gasflooding (GF) in a two-well configuration for the post-cold heavy oil production with sand (CHOPS) reservoirs was explored. In the experiments, the original heavy oil samples were collected from the Colony and McLaren formations in Alberta, Canada. The PVT data and viscosities of CH₄/CO₂/C₃H₈-saturated Colony/McLaren heavy oil were measured at different equilibrium pressures and Tₑ₀ₛ = 21 °C. A total of 17 sandpacked laboratory tests were conducted to examine the technical and economical merits of the combined CSI and WF/GF. Both the CSI + WF and CSI + GF recovered more heavy oil than the CSI or WF alone due to the extended foamy-oil flow. The combined CSI and WF outperformed the combined CSI and GF in terms of the heavy oil recovery factor (RF), heavy oil production rate, and cumulative gas–oil ratio (GOR) because gas channeling was hindered by the subsequently injected water. In addition, C₃H₈ was found to be a more dissolving and extracting solvent than CO₂ due to its more favourable PVT properties and larger heavy oil viscosity reduction. The intermediate pressure drawdown rate or CO₂ injection rate resulted in a higher heavy oil RF during the CSI or GF.

Theoretically, an analytical material balance model (MBM) was formulated to predict the cumulative heavy oil and gas productions and the average reservoir pressure during the primary production and subsequent CSI. The non-equilibrium phase behaviour and the foamy-oil properties were taken into account in this analytical MBM. Several unknown parameters were tuned and determined by best matching the theoretically predicted data and the experimentally measured data, such as the nucleation coefficient of
dissolved CH$_4$ in the heavy oil and the decay coefficient of dispersed CH$_4$ bubbles from the heavy oil. The predicted cumulative heavy oil productions and average reservoir pressures during the primary production and subsequent CSI agreed well with the measured data. However, there were large discrepancies between the predicted and measured cumulative gas productions in the CSI because of its gas channeling, which is a major technical issue encountered in the CSI. In addition, it was found that dissolved CH$_4$ in the heavy oil became the dispersed CH$_4$ bubbles more quickly when the nucleation coefficient was larger at a higher pressure drawdown rate or in a less viscous heavy oil. The foamy heavy oil with the dispersed CH$_4$ bubbles was more stable when the decay coefficient was smaller at an increased pressure drawdown rate or in a more viscous heavy oil.

Numerical simulations were undertaken to optimize the CSI, CSI + WF, and CSI + GF after the primary production in a representative and synthetic field-scale heavy oil reservoir by choosing the net present value (NPV) as an objective function. The steepest ascent (SA) method and the particle swarm optimization (PSO) were utilized to find the optimum well controls and maximize the NPV. Both the SA method and PSO efficiently determined nearly optimum NPVs for the CSI, CSI + WF, and CSI + GF in the heavy oil reservoirs with/without the wormholes. It was found in this study that the NPV of the CSI + GF was the highest in the post-CHOPS reservoir. The oil producer should be operated at the minimum allowable bottom hole pressure (BHP) during the entire reservoir life. The gas injector should be used to inject at the maximum allowable injection rate during the early cycles but shut in during the late cycles to control the gas channeling.
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NOMENCLATURE

Notations

- \( A \) calibration coefficient used in Eq. [3.2]
- \( b \) annual discount rate
- \( B \) calibration coefficient used in Eq. [3.2]
- \( B_{fo} \) foamy-oil formation volume factor, res \( \text{m}^3/\text{sc m}^3 \)
- \( B_g \) solvent formation volume factor, res \( \text{m}^3/\text{sc m}^3 \)
- \( B_o \) solvent-diluted heavy oil formation volume factor, res \( \text{m}^3/\text{sc m}^3 \)
- \( c_{fo} \) foamy-oil isothermal compressibility, kPa\(^{-1}\)
- \( c_{gi} \) gas injection cost, $/m^3
- \( c_o \) solvent-diluted heavy oil isothermal compressibility, kPa\(^{-1}\)
- \( c_w \) disposal cost of the produced water, $/m^3
- \( c_{wi} \) water injection cost, $/m^3
- \( E \) overall arithmetic average objective function
- \( E_g \) objective function defined as the time-weighted root-mean-squared absolute error between the measured and predicted cumulative gas production data
- \( E_o \) objective function defined as the time-weighted root-mean-squared absolute error between the measured and predicted cumulative oil production data
- \( E_p \) objective function defined as the time-weighted root-mean-squared absolute error between the measured and predicted average reservoir pressure data
- \( g_i \) gradient of the NPV with respect to the \( i \)th transformed control variable
- \( h \) height of the physical model, m
- \( h_{pp} \) nucleation coefficient of dissolved gas in the oil in the primary production, s\(^{-1}\)
$J$ objective function defined as the NPV in the entire reservoir life, $\$ 
$k$ permeability of the physical model, Darcy 
$k_{rg}$ gas relative permeability 
$k_{rgmax}$ maximum gas relative permeability 
$k_{ro}$ oil relative permeability 
$k_{romax}$ maximum oil relative permeability 
$l$ length of the physical model, m 
$L$ length of the capillary tubing, m 
$m_o$ mass of the produced oil in the GOR measurement by using the flash method, g 
$n_g$ exponential power of the gas relative permeability 
$n_o$ exponential power of the oil relative permeability 
$N$ total number of the simulation time steps 
$N_I$ total number of the injectors 
$N_P$ total number of the producers 
$p_g^k$ global best position of the particle found after the $k^{th}$ iteration of the particle 
swarm optimization 
$p_l^k$ local best position of the particle found after the $k^{th}$ iteration of the particle 
swarm optimization 
$P_{ave}$ average reservoir pressure in the primary production or CSI, kPa 
$P_{avec}$ predicted average reservoir pressure in the primary production or CSI, kPa 
$P_{avem}$ measured average reservoir pressure in the primary production or CSI, kPa 
$(P_{bn})_{pp}$ bubble-nucleation pressure in the primary production, kPa 
$P_e$ ending production pressure in the CSI, kPa
$P_{eq}$
equilibrium pressure, kPa

$P_f$
final production pressure in the primary production, kPa

$(P_i)_{pp}$
initial reservoir pressure in the primary production, kPa

$P_{inj}$
injection pressure, kPa

$(P_{pb})_{pp}$
pseudo bubble-point pressure in the primary production, kPa

$P_s$
final pressure in the soaking period, kPa

$q_g$
gas production rate at any time, sc m$^3$/s

$q_{g,ki}^n$
average gas injection rate of the $k$th injector over the $n$th time step of the numerical simulation, sc m$^3$/d

$q_{mix}$
mixture volume flow rate in the viscosity measurement, m$^3$/s

$q_o$
oil production rate at any time, m$^3$/s

$q_{o,j}^n$
average oil production rate of the $j$th producer over the $n$th time step of the numerical simulation, m$^3$/d

$q_{w,j}^n$
average water production rate of the $j$th producer over the $n$th time step of the numerical simulation, m$^3$/d

$q_{w,ki}^n$
average water injection rate of the $k$th injector over the $n$th time step of the numerical simulation, m$^3$/d

$Q_g$
cumulative gas production, sc m$^3$

$Q_{gc}$
predicted cumulative gas production, sc m$^3$

$Q_{gm}$
measured cumulative gas production, sc m$^3$

$Q_{gn}$
volume of the nucleated gas, sc m$^3$

$Q_o$
cumulative heavy oil production, m$^3$

$Q_{oc}$
predicted cumulative heavy oil production, m$^3$
\( Q_{\text{cm}} \) measured cumulative heavy oil production, \( \text{m}^3 \)

\( r \) wormhole diameter, m

\( r_1 \) random number between 0.0 and 1.0 used in Eq. [6.8]

\( r_2 \) random number between 0.0 and 1.0 used in Eq. [6.8]

\( r_{\text{eff}} \) effective radius of the capillary tubing, m

\( r_o \) oil price, \( \$/$m^3

\( R_s \) solution gas–oil ratio, \( \text{sc m}^3$/m^3$

\( R_{\text{si}} \) initial solution gas–oil ratio, \( \text{sc m}^3$/m^3$

\( s_i \) \( i \)th transformed control variable in the production optimization

\( s^k \) transformed control vector at the \( k \)th iteration of the optimization algorithm

\( S_{\text{fo}} \) foamy-oil saturation in the physical model, %

\( S_{\text{gi}} \) initial gas saturation in the physical model, %

\( S_o \) oil saturation in the physical model, %

\( S_{\text{oi}} \) initial oil saturation in the physical model, %

\( S_{\text{or}} \) residual oil saturation, %

\( S_{\text{wi}} \) irreducible or connate water saturation in the physical model, %

\( t \) production time, s

\( t_{\text{inj}} \) solvent injection time, s

\( t_j \) production time at the \( j \)th time step, s

\( t_n \) final production time for the CSI test or the production time at the end of the \( n \)th time step, s or day

\( t_{\text{pro}} \) production time, s

\( t_s \) soaking time, s
\( t_{\text{single}} \) end time of the single-phase flow during the primary production, s

\( T_{\text{res}} \) reservoir temperature, °C

\( u_i \) \( i^{\text{th}} \) control variable in the production optimization

\( u_i^{\text{low}} \) lower bound of the \( i^{\text{th}} \) control variable

\( u_i^{\text{up}} \) upper bound of the \( i^{\text{th}} \) control variable

\( v_i^k \) velocity of the \( i^{\text{th}} \) particle at the \( k^{\text{th}} \) iteration of the particle swarm optimization

\( V_{\text{dg}} \) dispersed gas volume, m³

\( V_g \) produced gas volume in the GOR measurement by using the flash method, m³

\( V_p \) pore volume of the physical model, m³

\( w \) width of the physical model, m

**Greek Symbols**

\( \alpha^{k+1} \) step size used in Eq. [6.5]

\( \beta_1 \) positive weight factor used in Eq. [6.8]

\( \beta_2 \) positive weight factor used in Eq. [6.8]

\( \Delta P_{\text{ave}} \) average reservoir pressure change during the pre-specified time step in the primary production or CSI, kPa

\( \Delta s_i \) change of the \( i^{\text{th}} \) transformed control variable

\( \Delta t_n \) \( n^{\text{th}} \) time step size, day

\( \varepsilon_f \) relative change termination criterion of the NPV, under which the production optimization is terminated

\( \varepsilon_u \) relative change termination criterion of the control vector, under which the production optimization is terminated
\[ \lambda \] weight factor used in Eq. [3.6]
\[ \lambda' \] weight factor used in Eq. [3.7]
\[ \lambda_{\text{CSI}} \] decay coefficient of the dispersed gas bubbles from the heavy oil during the CSI, \( \text{s}^{-1} \)
\[ \lambda_{\text{pp}} \] decay coefficient of the dispersed gas bubbles from the heavy oil during the primary production, \( \text{s}^{-1} \)
\[ \mu_{\text{do}} \] measured dead heavy oil viscosity, \( \text{mPa}\cdot\text{s} \)
\[ \mu_{\text{fo}} \] foamy-oil viscosity, \( \text{mPa}\cdot\text{s} \)
\[ \mu_{\text{mix}} \] viscosity of the solvent-diluted heavy oil, \( \text{mPa}\cdot\text{s} \)
\[ \rho_{\text{do}} \] measured dead heavy oil density, \( \text{g/cm}^3 \)
\[ \rho_{\text{g}} \] density of the gas, \( \text{kg/m}^3 \)
\[ \rho_{\text{mix}} \] density of the solvent-diluted heavy oil, \( \text{kg/m}^3 \)
\[ \tau \] oscillation period in the density measurement, \( \text{s} \)
\[ \phi \] porosity of the physical model, \( \% \)
\[ \chi \] solvent solubility, \( \text{g solvent/100 g heavy oil} \)
\[ \omega \] Pitzer acentric factor

**Subscripts**

ave average
avec average of the calculated data
avem average of the measured data
bn bubble nucleation
CSI cyclic solvent injection
dg dispersed gas

do dead oil

e ending

f final

fo foamy oil

g gas or global optimum

gc calculated gas

gi initial gas or gas injection

gm measured gas

gn nucleated gas

i initial or control variable index

inj injection

j time step index or producer index

J objective function

k injector index

l local optimum

n final production time or index of numerical simulation time steps

o oil

oc calculated oil

oi initial oil

om measured oil

or residual oil

p pressure or pore
pb  bubble point
pp  primary production
pro production
rg  gas relative permeability
rgmax maximum gas relative permeability
ro  oil relative permeability
romax maximum oil relative permeability
s   soaking or solution gas
si  initial solution gas
single single-phase flow
u   control vector
w   water
wi  irreducible water or water injection

**Acronyms**

BIP  binary interaction parameter
BOPD barrels of oil per day
BPR  back-pressure regulator
BT  breakthrough
CAPP Canadian Association of Petroleum Producers
CGI  continuous gas injection
CHOPS cold heavy oil production with sand
CMG  Computer Modelling Group Limited
CNRL Canadian Natural Resources Limited
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tr>
<td>CSI</td>
<td>cyclic solvent injection</td>
</tr>
<tr>
<td>CSS</td>
<td>cyclic steam stimulation</td>
</tr>
<tr>
<td>CWI</td>
<td>carbonated water injection</td>
</tr>
<tr>
<td>DLA</td>
<td>diffusion-limited aggregation</td>
</tr>
<tr>
<td>ECSP</td>
<td>enhanced cyclic solvent process</td>
</tr>
<tr>
<td>EHOR</td>
<td>enhanced heavy oil recovery</td>
</tr>
<tr>
<td>EOR</td>
<td>enhanced oil recovery</td>
</tr>
<tr>
<td>EOS</td>
<td>equation of state</td>
</tr>
<tr>
<td>GC</td>
<td>gas chromatography</td>
</tr>
<tr>
<td>GF</td>
<td>gasflooding</td>
</tr>
<tr>
<td>GOR</td>
<td>gas–oil ratio</td>
</tr>
<tr>
<td>IBP</td>
<td>initial boiling point</td>
</tr>
<tr>
<td>IOR</td>
<td>improved oil recovery</td>
</tr>
<tr>
<td>ISC</td>
<td>in-situ combustion</td>
</tr>
<tr>
<td>MBM</td>
<td>material balance model</td>
</tr>
<tr>
<td>MOPSO</td>
<td>multiple objective particle swarm optimization</td>
</tr>
<tr>
<td>MPZ</td>
<td>main pay zone</td>
</tr>
<tr>
<td>MW</td>
<td>molecular weight</td>
</tr>
<tr>
<td>NPV</td>
<td>net present value</td>
</tr>
<tr>
<td>OOIP</td>
<td>original oil-in-place</td>
</tr>
<tr>
<td>PP</td>
<td>primary production</td>
</tr>
<tr>
<td>PP-CSI</td>
<td>pressure pulsing-cyclic solvent injection</td>
</tr>
<tr>
<td>PSO</td>
<td>particle swarm optimization</td>
</tr>
<tr>
<td>Acronym</td>
<td>Definition</td>
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<tr>
<td>---------</td>
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<tr>
<td>PTRC</td>
<td>Petroleum Technology Research Centre</td>
</tr>
<tr>
<td>PV</td>
<td>pore volume</td>
</tr>
<tr>
<td>RF</td>
<td>recovery factor</td>
</tr>
<tr>
<td>RST</td>
<td>reservoir saturation tool</td>
</tr>
<tr>
<td>SA</td>
<td>steepest ascent</td>
</tr>
<tr>
<td>SAGD</td>
<td>steam-assisted gravity drainage</td>
</tr>
<tr>
<td>SF</td>
<td>oil-swelling factor</td>
</tr>
<tr>
<td>SOPSO</td>
<td>single objective particle swarm optimization</td>
</tr>
<tr>
<td>SOR</td>
<td>solvent–oil ratio</td>
</tr>
<tr>
<td>VAPEX</td>
<td>vapour extraction</td>
</tr>
<tr>
<td>VRR</td>
<td>voidage replacement ratio</td>
</tr>
<tr>
<td>WF</td>
<td>waterflooding</td>
</tr>
<tr>
<td>WOR</td>
<td>water–oil ratio</td>
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CHAPTER 1 INTRODUCTION

1.1 Heavy Oil Resources

According to the Canadian Association of Petroleum Producers (CAPP), the global demand for the crude oil has steadily increased from 60 to 88 million barrels per day over the past 20 years. With the increased demand and fast depletion of the conventional oil, much more attention has been diverted to the vast heavy oil resources. It has been estimated that there is approximately six trillion barrels of the original oil-in-place (OOIP) of heavy oil and bitumen resources, which are more than two thirds of the world oil resources (Alshmakhy and Maini, 2012a). Approximately 50% of the world resources of the heavy oil and bitumen are located in the western Canada. The Canadian heavy oil reservoirs have the main pay zones (MPZs) of 5–65 m with the porosities of 26–32% and the permeabilities of 1.2–7.5 D. (Dusseauult, 2001; James et al., 2007).

Heavy oil is characterized by its high viscosity, high specific gravity, low API gravity, and extremely low mobility under the actual reservoir conditions, in comparison with the conventional oil. For example, a dead crude oil with a viscosity in the range of 100 to 10,000 cP at the reservoir temperature is termed as heavy oil, whereas a dead crude oil with a viscosity higher than 10,000 cP at the reservoir temperature is considered to be bitumen (Bannerjee, 2012).

1.2 Heavy Oil Recovery Methods

The primary oil recovery, secondary oil recovery, and tertiary or enhanced oil recovery (EOR) processes are applied in sequence or selectively to exploit a heavy oil
Cold heavy oil production with sand (CHOPS) is a primary oil recovery method to effectively produce heavy oil by using the natural reservoir energy and encouraging sand production. Promoting production of the unconsolidated reservoir sand in turn contributes to an increased oil production rate due to the porosity and permeability increases, in conjunction with the foamy-oil flow. The heavy oil production rate of a typical CHOPS process can be 10–20 times higher than that predicted from the Darcy’s law (Smith, 1988). The heavy oil recovery factor (RF) of CHOPS can reach 15–20% with an oil production rate of 3.2–47.7 m³/day (Han et al., 2007). The reservoir pressure is maintained and the crude oil is displaced by injected water or gas in the secondary oil recovery. Waterflooding (WF) can be applied in the conventional and heavy oil reservoirs because it is relatively cheap and easy to apply (Smith, 1992; Mai and Kantzas, 2009). However, the oil recovery factors for heavy oil reservoirs during waterflooding are usually low because of the displacement instability, which is resulted from an unfavourable mobility ratio. The injected water can easily bypass the extremely viscous heavy oil and form water channels, which is known as the “viscous fingering” phenomenon. It was found that delayed waterflooding and variable voidage replacement ratio (VRR) were beneficial to 166 waterfloods in heavy and medium oil reservoirs in the Western Canada (Brice and Renouf, 2008). Gasflooding (GF) also suffers from severe viscous fingering and an early gas breakthrough (BT) due to an adverse mobility ratio.

The commonly used techniques for enhanced heavy oil recovery (EHOR) are summarized and compared in Figure 1.1. Thermal- and solvent-based oil recovery techniques are the two major EHOR methods for the heavy oil recovery. In
Figure 1.1 Enhanced heavy oil recovery methods (Lin et al., 2014b).
the thermal-based oil recovery techniques, the heavy oil viscosity is significantly reduced by heating an oil reservoir. As the first EOR technique, in-situ combustion (ISC) was experimentally studied in the 1940s and field tested in the 1950s (White, 1985). However, there is a large uncertainty in the application of the field-scale ISC (Moore et al., 1999; Kovscek et al., 2013). Cyclic steam stimulation (CSS) has been commercially successful in many field applications (Farouq Ali, 1994; Al-Qabandi et al., 1995). One limitation of the CSS process is that the driving force is not strong enough to move more heated fluids to the production well. Steam-assisted gravity drainage (SAGD) was proposed by Butler and co-workers to use gravity drainage in a pair of horizontal wells to recover steam-heated heavy oil (Butler et al., 1981). The horizontal wells have much larger contact area with the reservoir than the vertical wells and the gravity force is strong enough to achieve a high oil flow rate (Butler, 1994). As a mature and commercial technique, SAGD has been successfully applied in a number of oil fields for many years (Jimenez, 2008). Nevertheless, some reservoir characteristics and conditions may limit the field applications of the above-mentioned two major thermal-based methods, CSS and SAGD, including the thin pay-zone, bottom water, gas cap, and low rock thermal diffusivity. There are excessive heat losses to the overburden and underburden and/or the bottom water in these cases (Karmaker and Maini, 2003). Besides, large water and energy consumptions not only increase the operating costs but also cause the greenhouse gas emissions (Luhning et al., 2003).

An alternative way to reduce the heavy oil viscosity is to dissolve a solvent into the heavy oil, which is categorized as solvent-based heavy oil recovery methods. Solvent-based heavy oil recovery methods have some distinct advantages over the thermal-based
heavy oil recovery methods in terms of energy efficiency, cost effectiveness, produced oil quality, and environmental benefits (James et al., 2007). The energy consumption is reduced by 97% in a solvent-based heavy oil recovery process in comparison with that in a steam-based heavy oil recovery process (Singhal et al., 1996). Much less surface construction is required for the solvent injection process than that for the steam injection process. Therefore, the capital investment and operating cost will be much lower for a solvent-based heavy oil recovery process than those for a steam-based heavy oil process. Moreover, when enough solvent is dissolved into the heavy oil, asphaltene precipitation may occur so that the produced heavy oil is in-situ deasphalted and thus is of better quality. In addition, a solvent-based heavy oil recovery method is also more environmentally friendly, whereas a large amount of water is consumed and tremendous amounts of greenhouse gases are generated in a thermal-based heavy oil recovery process (Ma et al., 2017a).

1.3 Research Objectives

This thesis aims at studying the new enhanced heavy oil recovery methods, i.e., combined CSI and WF/GF, experimentally, theoretically, and numerically. The specific research objectives of this thesis are listed as follows:

- To explore the technical potential of combining CSI and WF/GF together in a two-well configuration as a hybrid EHOR process in the post-CHOPS reservoirs;
- To examine the joint EOR and IOR mechanisms in the combined CSI and WF/GF; and
- To identify an optimum combined CSI and WF/GF process with the highest heavy oil production rate, heavy oil recovery factor, and net present value (NPV).
1.4 Outline of the Thesis

This thesis is composed of seven chapters. Chapter 1 is an introduction to the research topic together with the purpose and scope of the thesis. Chapter 2 gives an updated literature review of the WF, GF, and CSI. The problem statement of this thesis is presented at the end of this chapter. Chapter 3 describes the laboratory tests of the combined CSI and WF, including the experimental materials, setup, preparation, procedure, and measured data. Several factors are investigated, such as the production scheme, pressure drawdown rate, solvent, soaking time, and heavy oil. Chapter 4 provides the experimental studies of the combined CSI and GF by measuring the cumulative heavy oil and gas productions as well as the injection and production pressures. Different production schemes are compared to identify the best production process. Chapter 5 formulates a material balance model to predict the cumulative heavy oil and gas productions and the average reservoir pressures in the primary production and the subsequent CSI. Chapter 6 presents the history matching of the laboratory tests and the production optimization of the field-scale CSI, CSI + WF, and CSI + GF. A synthetic field-scale heavy oil reservoir is constructed with/without the sand production. The steepest ascent (SA) method and particle swarm optimization (PSO) are used to optimize the well controls and obtain the maximum NPV. Chapter 7 summarizes the major scientific conclusions of this thesis and makes several technical recommendations for future studies.
CHAPTER 2   LITERATURE REVIEW

2.1 Waterflooding in Heavy Oil Reservoirs

2.1.1 Experimental studies and numerical simulations

More than 200 heavy oil waterflooding (WF) processes have been implemented in the Western Canada in the past 60 years as an economical secondary improved oil recovery (IOR) method (Miller, 2006; Kumar et al., 2008). Nevertheless, a typical waterflood in the post-CHOPS reservoirs recovers on average only 2–7% additional heavy oil because of severe viscous fingering and water channeling (Dong et al., 2006).

Mai and Kantzas (2009) conducted some WF tests in a sandpacked physical model with two different heavy oil samples at varying water injection rates. It was found that the capillary forces were responsible for the improved heavy oil production near the end. At low injection rates, water imbibition can cause a lower heavy oil recovery factor before water breakthrough (BT) but a higher ultimate heavy oil recovery factor at the end. Some empirical correlations were proposed on the basis of the experimental data obtained from the literature. The correlations can predict the heavy oil recovery factors before and after water BT by using the reservoir permeability, oil viscosity, and water injection rate.

Stephen et al. (1995) used numerical simulations to optimize the WF in the Buffalo Coulee field, Saskatchewan, Canada. The production and injection performances of 48 wells were history matched. It was found that the well spacing of 20 acres was adequate because the infill drilling could not recover any considerable incremental heavy oil. The
heavy oil recovery factor (RF) was increased by 20% as the water injection rate was increased by 50%.

Kumar et al. (2008) performed laboratory-scale and field-scale numerical simulations to predict the heavy oil WF performance. High mobility ratio, high mobile water saturation, and thin thief zones all reduced the heavy oil RF significantly. Heterogeneity was more detrimental to the WF in the heavy oil reservoirs than that in the light oil reservoirs. The heavy oil RF was the highest when water was injected above the reservoir fluid bubble-point pressure.

However, the numerical simulations can only provide a directional trend because the heavy oil recovery mechanisms are not completely modeled in the numerical simulations. For example, emulsification may happen during the heavy oil WF but are not included in the numerical simulations (Vittoratos, 2013). A more accurate description or consideration of the heavy oil recovery mechanisms during the heavy oil WF should be incorporated into the numerical models.

2.1.2 Pilot/field applications

Adams (1982) compared the measured and predicted WF production data in the heavy oil reservoirs in the Lloydminster area of the Western Canada. The dead heavy oil gravity and viscosity were in the ranges of 13–17 °API and 950–6,500 cP, respectively. The heavy oil RF during the primary production was estimated to be 3–8% by using the production decline analysis. The incremental heavy oil RF of the WF was expected to be only 1–2%. The field performance was worse than that predicted from the Buckley–Leverett model (Buckley and Leverett, 1942). The contributions of the solution-gas drive and rock compaction were believed to be important in the ultimate heavy oil
recovery. It is concluded that enhanced heavy oil recovery (EHOR) processes should be applied afterwards because of the low effectiveness of the WF in the Lloydminster area.

Miller (2006) presented the WF production performance in the Coleville Main Bekken field. The dead heavy oil gravity is 13.5° API and the dead heavy oil viscosity ranges from 1,200 to 1,600 cP. The Coleville Bekken reservoir was discovered in 1956 and WF was initiated in 1958. The reservoir was initially developed by using a 40-acre five-spot well pattern and a 80-acre nine-spot well pattern, respectively. During the 1970s, the water injection rate was increased in an attempt to build up the reservoir pressure, which resulted in severe water channeling. From 1993 to 1995, 19 horizontal and directional producers were added. Unexpectedly, however, the infill drilling did not consistently improve the field performance. The conversion of the producers and injectors and the introduction of a line drive and an edge drive increased the heavy oil production rates continuously in the mature WF.

Singhal (2009) compared the WF performance with three different water injection strategies in the heavy oil reservoirs of Alberta, Canada. In the Jenner Upper Mannville O reservoir, the heavy oil production rate and heavy oil cut were gradually decreased at a constant water injection rate. Water was injected in the Jenner Upper Mannville JJJ reservoir at steadily decreasing rates since 2001. The heavy oil production rate was lower but the heavy oil cut was relatively stable. From 1996 to 2006, the WF was applied in the Retlaw Mannville D8D reservoir with progressively increasing water injection rates. The increased water injection rates led to increased oil production rates with steeply decreased oil cuts.
Beliveau (2009) summarized some WF performances in the heavy oil reservoirs in order to provide benchmarks to newly found heavy oil reservoirs in India. A higher heavy oil RF was achieved with a larger water injection volume and a smaller well spacing. Moreover, the cumulative voidage replacement ratio (VRR) should be close to unity in order to have a higher heavy oil RF.

Vittoratos (2013) studied the optimum well controls during the heavy oil WF and concluded that the VRR should be less than unity. The solution-gas drive is activated and the emulsion flow forms when the VRR is less than unity. Experiments were performed by using the live oils with the respective gravities of 12 and 18 °API at the different VRRs. A large amount of the incremental heavy oil was recovered with the VRRs less than unity. The production data of an Alaskan heavy oil reservoir also proved that the VRR less than unity can improve the heavy oil production.

2.2 Gasflooding in Heavy Oil Reservoirs

Gasflooding (GF) or continuous gas injection (CGI) suffers from an adverse mobility ratio, strong viscous fingering, and an extremely early gas BT (Jha, 1986). The incremental heavy oil production usually cannot offset the high costs of gas acquisition, transportation, storage, compression and injection, which make the GF alone uneconomical for most post-CHOPS reservoirs (Sankur and Emanuel, 1983).

Sankur and Emanuel (1983) carried out seven coreflooding tests to investigate the potential of immisible CO₂ flooding to recover a Californian heavy oil reservoir with a high permeability and a high oil saturation. The effects of the CO₂ injection pressure and CO₂ purity were examined. It was found that the heavy oil RF is improved as the CO₂
injection pressure is increased. The addition of N₂ into CO₂ caused an earlier gas BT and a lower heavy oil RF.

Nguyen and Farouq Ali (1993) experimentally studied the effects of CO₂ injection pressure, CO₂ injection rate, and CO₂ purity on the production performance of the CO₂ flooding. The heavy oil RF was decreased with the increased CO₂ injection pressure if the asphaltene precipitation occurred. It is also found that CO₂ should be injected at a lower injection rate to increase its retention time so that more CO₂ can be dissolved into the heavy oil. In contrast, water should be injected at a higher injection rate to control the gravity segregation. A decrease of CO₂ partial pressure in the CO₂–N₂ mixture resulted in a decrease of the heavy oil RF.

In 1969, a field project of CO₂ flooding was commenced in the Richie field, Arkansas, USA (McRee, 1977). The reservoir is at a depth of 790 m with a MPZ thickness of 3 m, which has a reservoir permeability of 2.75 D, a reservoir porosity of 31%, and an initial water saturation of 20%. The dead oil has a gravity of 16 °API and a viscosity of 195 cP at the reservoir temperature of 52 °C. CO₂ was injected into three wells at 85,000–113,000 sc m³ for 78 d. The heavy oil production rate doubled from 10 m³/d to 20 m³/d for about one year with an estimated CO₂ utilization factor of 1,070 sc m³/m³.

An initially planned CO₂ huff-n-puff project was a successful immiscible CO₂ flood in the Bati Raman field, Turkey (Issever et al., 1993). The heavy oil gravity ranges from 9.7 to 15.1 °API and the heavy oil viscosity is between 450 and 1,000 cP. In 1986, CO₂ was continuously injected at 5.7–7.1 × 10⁵ sc m³/d in a 33-well pilot area. The gas BT was observed after CO₂ was injected for 3 to 6 months and the average GOR remained at
57–113 sc m³/m³. The heavy oil production rate of 1,699 m³/d was about 10 times higher than that before CO₂ flooding.

2.3 Cyclic Solvent Injection (CSI)

2.3.1 Experimental studies and numerical simulations

Solvent injection processes with propane, butane or solvent mixtures to dilute and extract heavy oil were patented in the 1970s (Allen et al., 1976; Allen, 1977). The same vertical well is used for the solvent injection and for the recovery of the heavy oil and injected solvent. Solvent is injected into a well, which is followed by shut-in (soaking) period for solvent dissolution into the surrounding oil bank. One cycle is completed by subsequently operating the same well as a production well for certain time. Feasibility of CO₂-cyclic solvent injection (CO₂-CSI) for enhanced heavy oil recovery was examined in the 1980s. Bardon et al. (1986) studied a CO₂ cyclic injection for enhanced heavy oil recovery in Turkey. Gondiken (1987) reported a pilot project of enhanced heavy oil recovery by injecting CO₂ in a reservoir with heavy oil of 11–12° API in Turkey. It was found that the oil production was increased by 2.5 times for two months, in comparison with that prior to the CO₂ injection. Experimental, simulation, and pilot results show the potential of the CSI or solvent huff-n-puff (Haskin and Alston, 1989; Gondiken, 1987; Lim et al., 1995; Qazvini Firouz and Torabi, 2012). Some experimental CSI studies have been summarized in Table 2.1. However, these processes may not be successfully applied in the oilfields because of the slow solvent diffusion in the heavy oil, which results in a low and uneconomical oil production rate (Das and Butler, 1998).
Table 2.1 Experimental studies of cyclic solvent injection (CSI) reported in the literature.

<table>
<thead>
<tr>
<th>Oil</th>
<th>Solvent</th>
<th>( \mu_o ) (cP(^\circ)C)</th>
<th>Model size (cm)</th>
<th>( \phi ) (%)</th>
<th>( k ) (D)</th>
<th>( T ) (°C)</th>
<th>cycle</th>
<th>Injection/production time (d/d)</th>
<th>Oil production rate (cm(^3)/d)</th>
<th>Produced GOR (std. cm(^3)/cm(^3))</th>
<th>( P ) (MPa)</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lloydminster</td>
<td>CH(_4)+CO(_2)</td>
<td>10.531@21.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Sayegh and Maini, 1984</td>
</tr>
<tr>
<td></td>
<td>CO(_2)</td>
<td>144@90</td>
<td>L=20, d=6.5</td>
<td>12–20</td>
<td>0.4×10(^{-6}) – 43×10(^{-6})</td>
<td>90</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Ravel and Anterion, 1985</td>
</tr>
<tr>
<td>Cold Lake</td>
<td>C(_3)H(_8)</td>
<td></td>
<td></td>
<td>32.8</td>
<td>80</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>C(_2)H(_6)</td>
<td>47×42×27</td>
<td></td>
<td>35</td>
<td>20</td>
<td>13</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Lim et al., 1995</td>
</tr>
<tr>
<td></td>
<td>CH(_4)</td>
<td></td>
<td></td>
<td>35</td>
<td>110</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td></td>
<td>CO(_2)</td>
<td>36.4</td>
<td>1.9</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Shi and Kantzas, 2008</td>
</tr>
<tr>
<td>Rush Lake</td>
<td>C(_3)H(_8)+CO(_2)</td>
<td>39.320@20</td>
<td>L=300, d=1–12</td>
<td>38</td>
<td>4.5</td>
<td>15–25</td>
<td>6</td>
<td>2.46–3.90</td>
<td>7.91–23.14</td>
<td>267–598</td>
<td>3</td>
<td>Ivory et al., 2013</td>
</tr>
<tr>
<td></td>
<td>C(_3)H(_8)</td>
<td>4.330@15</td>
<td>L=30.48, d=3.81</td>
<td>33.1–35.8</td>
<td>5.07–5.62</td>
<td>21</td>
<td>2</td>
<td>389.3–5330.0</td>
<td>0.8</td>
<td></td>
<td></td>
<td>Du et al., 2013</td>
</tr>
<tr>
<td></td>
<td>C(_2)H(_6)</td>
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<td>L=60.96, d=3.81</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>CO(_2)</td>
<td></td>
<td>L=30.48, d=15.24</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>CH(_4)+C(_2)H(_6)</td>
<td>2.246@22</td>
<td>101.3×4.9×3.2</td>
<td>39–40</td>
<td>42.9–43.6</td>
<td>22</td>
<td>6</td>
<td>460.2–3459.0</td>
<td>3.34</td>
<td></td>
<td></td>
<td>Yadali Jamaloei et al., 2013</td>
</tr>
<tr>
<td></td>
<td>C(_3)H(_8)</td>
<td>5.875@20.2</td>
<td>48.3×17.8×5.1</td>
<td>35.6–36.0</td>
<td>5.2–5.6</td>
<td>20.2</td>
<td>12</td>
<td>3</td>
<td>287</td>
<td>1.18×10(^3)</td>
<td>0.8</td>
<td>Jia et al., 2013</td>
</tr>
</tbody>
</table>
Shelton and Morris (1973) theoretically studied cyclic injection of a rich gas to recover heavy oil. It was concluded that only moderate viscosity reduction and soaking time were needed to achieve most of the benefits of the EOR mechanisms. The predicted results agreed well with the oil production performances of the actual well tests. Two series of phase behaviour measurements were conducted to simulate the pressure-decline process that occurred during a typical huff-n-puff process (Sayegh and Maini, 1984). It was found that CO\textsubscript{2} was a more efficient stimulating agent in heavy oil production than CH\textsubscript{4} due to its higher solubility and stronger oil-viscosity reduction ability. Moreover, six CO\textsubscript{2} corefloods were also performed to study the effects of soaking period and mobile water saturation on the longitudinal distribution of CO\textsubscript{2}. The results indicated that a longer soaking period was a more efficient way of promoting mass transfer and dissolving an adequate amount of CO\textsubscript{2}. The presence of a low mobile water saturation led to a more uniform longitudinal distribution of CO\textsubscript{2} along the core.

Lim et al. (1995) first experimentally investigated the efficiency and effectiveness of hydrocarbon solvent huff-n-puff process on enhancing heavy oil recovery. It was found that ethane was an effective solvent for deasphalting and producing bitumen. In addition, the well inflow mechanism dominated in the early cycles of production, whereas the gravity effect controlled the subsequent cycles. Furthermore, laboratory measured solvent effective diffusivity in bitumen was found to be 2 to 3 orders of magnitude higher than the solvent molecular diffusivity in bitumen. Shi and Kantzas (2008) performed two tests to study the potential of using methane and carbon dioxide injection as an oil recovery method for a heavy oil reservoir. A single cycle of CH\textsubscript{4} injection followed by a single cycle of CO\textsubscript{2} injection was conducted on a glassbeads model and a sandpacked model,
respectively. For the sandpacked model with a low permeability, CO₂ injection gave a higher additional oil recovery factor of 4.2%. The immiscible gas injection achieved only 8% incremental oil recovery for the glassbeads model, which was unfavourable in comparison with the high oil recovery factor of 22.2% for the primary oil production. Based on the GC analysis results, CO₂ was found to be much easier to dissolve into heavy oil and the solution-gas drive was the principal mechanism during CO₂ production. Qazvini Firouz and Torabi (2012) conducted fourteen huff-n-puff experiments to investigate the effects of the operating pressure, soaking time, and solvent composition. It was found that the highest oil recovery factor was obtained by injecting pure CO₂ at near-supercritical conditions. When the operating pressure was low, a longer soaking time did not noticeably increase the ultimate oil recovery factor. To inject a foaming agent prior to the foamy oil-assisted methane huff-n-puff (FOAM H-n-P) was proposed to enhance the sweep and/or displacement efficiency and strengthen the foamy-oil flow (Sun et al., 2015). Eight sandpacked tests showed that an average 43.29% incremental heavy oil was recovered in the FOAM H-n-P.

Alshmakhy and Maini (2012a) experimentally evaluated the potential of using cyclic CO₂ injection process to enhance heavy oil recovery from a depleted oil reservoir. The highest incremental oil recovery factor of 8.39% in five tests was obtained. Jia et al. (2013) introduced pressure pulsing cyclic solvent injection (PP-CSI) process as a variation of CSI. The traditional CSI process suffers from the solvent release/exsolution and viscosity regainment during its oil production period. In a PP-CSI, a three-step pressure control scheme was performed during the oil production period to elongate the foamy-oil flow and solvent flooding. The experimental results show that both oil
recovery factor and oil production rate of a PP-CSI process were much higher than those of a traditional CSI process. Feasibility of a CSI process as a post-CHOPS technique was studied by Du et al. (2013). It was found that wormholes improved the CSI performance, especially if they are located at the bottom of the oil reservoirs. Moreover, a relation between the oil production rate and the drainage height was determined by applying the power function regression. The length and diameter of a sandpacked model did not affect the experimental results. Yadali Jamaloei et al. (2013) proposed a new process, namely enhanced cyclic solvent process (ECSP). In the ECSP, a soluble solvent was injected after a volatile solvent is injected in a cyclic manner. Four tests were conducted to examine the impact of the solvent injection sequence. Higher oil recovery factor and production rate were achieved when a methane (volatile) slug was injected before ethane or propane (soluble) injection. The optimum solvent injection sequence was used to predict the Pelican oilfield production performance. The field-scale numerical simulations indicated that the ECSP scheme was especially effective to enhance oil recovery in thin heavy oil reservoirs.

Ravel and Anterion (1985) modified a compositional simulator to simulate the CO₂ huff-n-puff process. Four experiments were conducted to obtain the oil production data prior to the numerical simulations. The oil swelling, gravity drainage, and capillary imbibition were modeled in the simulations. In addition, an interfacial film theory was developed to represent the mass transfer. Ivory et al. (2009) not only conducted an experiment consisted of the primary oil production followed by six solvent injection cycles but also simulated the performance of the experiment. An excellent production history match confirmed that the numerical simulation model was effective. The
simulator included the non-equilibrium solvent-dissolving/releasing rate equation, which considered the delay for a solvent to reach its equilibrium concentration as it was dissolved into or exsolved from the oil. The sensitivity analysis results indicated that solvent injectivity was more sensitive to non-equilibrium rate, gas-phase diffusion coefficient, molar density of the oil phase, solvent solubility in oil, gas phase relative permeability, and capillary pressure. Qi and Polikar (2005) used the CMG GEM module to optimize the soaking time and well geometry in order to obtain the most effective viscosity reduction and the lowest solvent–oil ratio (SOR). An effective solvent mixture, whose dew-point pressure was slightly higher than the actual reservoir pressure, was determined. It was concluded that the optimum soaking time was related to both the injection rate and the solvent mixture and that the vertical distance between the horizontal injector and producer affected the oil recovery. It was also found that the molecular diffusion did not affect the solvent performance. Chang and Ivory (2012) scaled up the simulation study on the CSI as a post-CHOPS follow-up process from the laboratory scale to the field scale. Five different configurations of wormholes were proposed to simulate post-CHOPS reservoir characteristics. It was pointed out that the non-equilibrium phase behaviour of the heavy oil–solvent system should be considered or the oil production rate could be underestimated. The effective permeability and dual-permeability models showed better results in both history match of the primary oil production and prediction of the CSI performance. Shokri and Babadagli (2016) evaluated the CSI as a solvent-based post-CHOPS EOR process from the technical and economic points of view. A new modeling workflow was proposed and validated to simulate the CHOPS. In this workflow, a fractal wormhole growth model was
incorporated into the realistic reservoir model by using a partial-dual porosity approach. The use of heavier solvents gave higher heavy oil RFs but lighter solvents are more economically viable.

2.3.2 Pilot/field applications

Bardon et al. (1986) reported the pilot test of CO₂ huff-n-puff in the Camurlu heavy oil field in Turkey. Camurlu field reservoir is a thick, fractured, and low-permeability limestone reservoir bearing 10–12 °API crude oil. The primary oil recovery was very low because of the high oil viscosity and the gas coning. There is a CO₂-rich natural gas formation beneath the main pay zone. Consequently, the cyclic CO₂ injection process was used to enhance the heavy oil recovery. Three cycles were piloted in two wells. In the third cycle, the oil productivity and CO₂ injectivity were increased considerably during a short production time. However, considering the injection and soaking phases, the overall oil production rate (11.46 BOPD) was almost the same as that of the primary production (11 BOPD). It is suggested that the total time of one cycle should not be longer than 2 months with the injection period of 1 week, soaking period of 1 week, and production period of 6 weeks.

Karaoguz (1989) presented the field pilot application of the CO₂ huff-n-puff process in the Bati Raman field. The reservoir pressure was decreased rapidly during the primary recovery and the oil recovery factor was estimated to be 1.5%. A CO₂ reservoir, named Dodan, is near the heavy oil field. Therefore, CO₂ was injected cyclically to enhance the heavy oil recovery and increase the reservoir pressure. The oil production delay was observed because the gas in the fractures first flowed to the wellbore with the decline of the reservoir pressure. As a result, the oil production rate was increased in a short period
and reduced continuously afterwards. Finally, the CSI process was converted into the GF process because the offset wells showed considerable increase of the oil production.

Olenick et al. (1992) described the CO₂ huff-n-puff project applied in the Halfmoon field, Wyoming. Three cyclic CO₂ injection pilot tests were conducted after laboratory evaluation. The incremental oil rates ranged from 1.7 to 2.4 BOPD, which were far lower than that predicted from the experiments. Moreover, the oil production rate was only increased in a short period. It was observed that the oil production rates of the offset wells were also enhanced because of the flood response. Finally, the cyclic CO₂ injection was terminated due to the lack of the economic incentive. It should be noted that the coreflooding tests may overestimate the field response because the reservoir heterogeneity is not considered.

The Plover Lake CSI pilot was undertaken by Nexen in September 2002 (Morton et al., 2006). The heavy oil recovery factor of the CHOPS was 15% and the reservoir pressure was declined from 6.4 MPa to lower than 1 MPa. In the CSI pilot, three huff and puff cycles are conducted in a vertical well. Propane followed by methane was injected in the first cycle and butane followed by methane was injected in the second and third cycles. The propane and butane recovery factors were only 33 and 62.5%, respectively. It was probably because the production pressure was kept almost the same as the reservoir pressure and the gravity drainage was the major oil recovery mechanism. The injected solvents were found to stay near the wellbore and the solvent chamber was formed according to the reservoir saturation tool (RST) logs obtained in two observation wells. The water production was significantly reduced from 9 m³/d to less than 0.8 m³/d.
However, the oil production rate almost remained the same as that of 1.9 m$^3$/d prior to the solvent injection.

A CSI pilot test was implemented at the Bakken formation of the Luseland field by Nexen in the second quarter of 2004 (Nexen Inc., 2005). The heavy oil viscosity was in the range of 3,500–6,500 cP. The natural gas was injected into the five wells with high water cuts for only one cycle because the natural gas injection had small effects on the heavy oil and water productions. This may be attributed to the relatively short injection and soaking times, which are about 8 and 18 d, respectively.

A CSI pilot test was conducted at the Mervin field by Husky in March 2010 (Husky Inc., 2011). Carbon dioxide was injected at 3 MPa through three wells to the Colony formation with a 3.5 m thickness, 31% porosity, and 20% initial water saturation. The injection, soaking, and production times were equal to 5, 3, and 11 months, respectively. Although the CSI resulted in the incremental oil production, the large capital costs made the CSI process uneconomical.

### 2.4 Problem Statement

In the traditional CSI, the heavy oil viscosity regains due to the release of dissolved solvent from heavy oil during the pressure-depletion production process. In addition, the remaining foamy oil at the end of production period is pushed back from the producer by the subsequently injected solvent (Jia et al., 2015). In this study, new combined CSI and WF/GF processes are proposed to overcome the technical limitations of the traditional CSI. The injected water/gas can maintain the reservoir pressure to prevent the solvent release from the heavy oil. Moreover, the foamy-oil flow is maintained in the subsequent
WF/GF. These processes can effectively combine the enhanced microscopic displacement efficiency of CSI and the improved volumetric sweep efficiency of WF.

In the past, few theoretical/numerical studies have been conducted to predict the production performance of the CSI, especially in the post-CHOPS reservoirs. In this study, a material balance model (MBM) is formulated to predict the cumulative heavy oil and gas productions and the average reservoir pressures during the primary production and the subsequent CSI. The non-equilibrium phase behaviour and the foamy-oil properties are considered in this analytical MBM. The operating parameters impact greatly the revenue from the produced oil and gas. However, it is difficult to determine the optimum operating parameters intuitively and subjectively due to the complexity of the problem. The automatic optimization algorithms aim at finding the optimum or nearly optimum operating parameters under certain constraints and efficiently reducing the risks in making decisions. So far, the CSI optimization mainly relies on the parametric studies through the laboratory experiments or trial-and-error numerical simulations. However, those approaches cannot guarantee to find excellent operating parameters. Thus, it is of fundamental importance and practical interest to optimize the operating parameters of the CSI alone and hybrid CSI automatically by using the optimization algorithms to increase the net present value (NPV).
CHAPTER 3 EXPERIMENTAL STUDIES OF COMBINED CYCLIC SOLVENT INJECTION AND WATERFLOODING

3.1 Experimental Section

3.1.1 Materials

In this study, two heavy oil samples were collected from the oilfields of the Colony and McLaren formations in the Bonnyville area, Alberta, Canada, which are owned by the Canadian Natural Resources Limited (CNRL). The compositional analysis results of the Colony and McLaren heavy oils were obtained by using the standard ASTM D86 and are given in Tables 3.1(a) and 3.1(b), respectively. The carbon number distributions of the Colony and McLaren heavy oil are also plotted and compared in Figure 3.1. It can be clearly seen from this figure that the Colony heavy oil has a higher mole percentage of C_{9-20} and a lower mole percentage of C_{61+} than the McLaren heavy oil. The densities and viscosities of the Colony and McLaren heavy oils were measured by using a densitometer (DMA 512P, Anton Paar, USA) and a viscometer (DV-II+, Brookfield, USA) at different temperatures and the atmospheric pressure. The detail results are listed in Tables 3.2(a) and 3.2(b) for the Colony heavy oil and in Tables 3.3(a) and 3.3(b) for the McLaren heavy oil, respectively. The respective molecular weights of the Colony and McLaren heavy oils were measured to be 547.7 and 654.0 g/mol by using an automatic high-sensitivity wide-range cryoscopy (Model 5009, Precision Systems Inc., USA). The asphaltene contents of the Colony and McLaren heavy oils were measured by using the standard ASTM D2007–3 method and filter papers (Whatman No. 5, England)
Table 3.1  (a) Compositional analysis result of the Colony heavy oil collected from the Bonnyville area (Well No.: 16A-3-59-7) with the asphaltene content of 18.3 wt.% (n-pentane insoluble).

<table>
<thead>
<tr>
<th>Carbon no.</th>
<th>mol.%</th>
<th>wt.%</th>
<th>Carbon no.</th>
<th>mol.%</th>
<th>wt.%</th>
</tr>
</thead>
<tbody>
<tr>
<td>C_1</td>
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<td>0.00</td>
<td>C_32</td>
<td>1.46</td>
<td>1.61</td>
</tr>
<tr>
<td>C_2</td>
<td>0.00</td>
<td>0.00</td>
<td>C_33</td>
<td>1.32</td>
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<td>2.19</td>
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<td>C_53</td>
<td>0.40</td>
<td>0.74</td>
</tr>
<tr>
<td>C_23</td>
<td>2.54</td>
<td>2.02</td>
<td>C_54</td>
<td>0.53</td>
<td>0.99</td>
</tr>
<tr>
<td>C_24</td>
<td>2.47</td>
<td>2.05</td>
<td>C_55</td>
<td>0.47</td>
<td>0.89</td>
</tr>
<tr>
<td>C_25</td>
<td>2.21</td>
<td>1.91</td>
<td>C_56</td>
<td>0.53</td>
<td>1.03</td>
</tr>
<tr>
<td>C_26</td>
<td>2.22</td>
<td>2.00</td>
<td>C_57</td>
<td>0.40</td>
<td>0.78</td>
</tr>
<tr>
<td>C_27</td>
<td>2.24</td>
<td>2.09</td>
<td>C_58</td>
<td>0.44</td>
<td>0.88</td>
</tr>
<tr>
<td>C_28</td>
<td>1.89</td>
<td>1.83</td>
<td>C_59</td>
<td>0.39</td>
<td>0.79</td>
</tr>
<tr>
<td>C_29</td>
<td>1.97</td>
<td>1.98</td>
<td>C_60</td>
<td>0.35</td>
<td>0.72</td>
</tr>
<tr>
<td>C_30</td>
<td>1.68</td>
<td>1.74</td>
<td>C_61+</td>
<td>8.53</td>
<td>20.85</td>
</tr>
<tr>
<td>C_31</td>
<td>1.43</td>
<td>1.53</td>
<td>Total</td>
<td>100.00</td>
<td>100.00</td>
</tr>
</tbody>
</table>
Table 3.1 (b) Compositional analysis result of the McLaren heavy oil collected from the Bonnyville area oilfield (Well No.: 6C-3-59-7) with the asphaltene content of 20.2 wt.% \((n\text{-pentane insoluble})\).

<table>
<thead>
<tr>
<th>Carbon no.</th>
<th>mol.%</th>
<th>wt.%</th>
<th>Carbon no.</th>
<th>mol.%</th>
<th>wt.%</th>
</tr>
</thead>
<tbody>
<tr>
<td>C_1</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{32}</td>
<td>1.52</td>
<td>1.40</td>
</tr>
<tr>
<td>C_2</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{33}</td>
<td>1.34</td>
<td>1.27</td>
</tr>
<tr>
<td>C_3</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{34}</td>
<td>1.30</td>
<td>1.27</td>
</tr>
<tr>
<td>C_4</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{35}</td>
<td>1.23</td>
<td>1.24</td>
</tr>
<tr>
<td>C_5</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{36}</td>
<td>1.12</td>
<td>1.16</td>
</tr>
<tr>
<td>C_6</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{37}</td>
<td>1.01</td>
<td>1.07</td>
</tr>
<tr>
<td>C_7</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{38}</td>
<td>0.98</td>
<td>1.07</td>
</tr>
<tr>
<td>C_8</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{39}</td>
<td>0.97</td>
<td>1.08</td>
</tr>
<tr>
<td>C_9</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{40}</td>
<td>0.84</td>
<td>0.97</td>
</tr>
<tr>
<td>C_{10}</td>
<td>0.00</td>
<td>0.00</td>
<td>C_{41}</td>
<td>0.73</td>
<td>0.87</td>
</tr>
<tr>
<td>C_{11}</td>
<td>2.26</td>
<td>0.72</td>
<td>C_{42}</td>
<td>0.70</td>
<td>0.85</td>
</tr>
<tr>
<td>C_{12}</td>
<td>2.95</td>
<td>1.03</td>
<td>C_{43}</td>
<td>0.70</td>
<td>0.86</td>
</tr>
<tr>
<td>C_{13}</td>
<td>3.04</td>
<td>1.14</td>
<td>C_{44}</td>
<td>0.64</td>
<td>0.81</td>
</tr>
<tr>
<td>C_{14}</td>
<td>3.76</td>
<td>1.53</td>
<td>C_{45}</td>
<td>0.59</td>
<td>0.76</td>
</tr>
<tr>
<td>C_{15}</td>
<td>3.65</td>
<td>1.59</td>
<td>C_{46}</td>
<td>0.55</td>
<td>0.73</td>
</tr>
<tr>
<td>C_{16}</td>
<td>3.90</td>
<td>1.81</td>
<td>C_{47}</td>
<td>0.53</td>
<td>0.72</td>
</tr>
<tr>
<td>C_{17}</td>
<td>4.03</td>
<td>1.98</td>
<td>C_{48}</td>
<td>0.51</td>
<td>0.70</td>
</tr>
<tr>
<td>C_{18}</td>
<td>3.90</td>
<td>2.03</td>
<td>C_{49}</td>
<td>0.48</td>
<td>0.67</td>
</tr>
<tr>
<td>C_{19}</td>
<td>3.73</td>
<td>2.05</td>
<td>C_{50}</td>
<td>0.47</td>
<td>0.67</td>
</tr>
<tr>
<td>C_{20}</td>
<td>3.51</td>
<td>2.03</td>
<td>C_{51}</td>
<td>0.45</td>
<td>0.65</td>
</tr>
<tr>
<td>C_{21}</td>
<td>3.29</td>
<td>2.00</td>
<td>C_{52}</td>
<td>0.43</td>
<td>0.64</td>
</tr>
<tr>
<td>C_{22}</td>
<td>3.19</td>
<td>2.03</td>
<td>C_{53}</td>
<td>0.39</td>
<td>0.60</td>
</tr>
<tr>
<td>C_{23}</td>
<td>2.96</td>
<td>1.97</td>
<td>C_{54}</td>
<td>0.43</td>
<td>0.66</td>
</tr>
<tr>
<td>C_{24}</td>
<td>2.67</td>
<td>1.85</td>
<td>C_{55}</td>
<td>0.47</td>
<td>0.74</td>
</tr>
<tr>
<td>C_{25}</td>
<td>2.49</td>
<td>1.79</td>
<td>C_{56}</td>
<td>0.43</td>
<td>0.69</td>
</tr>
<tr>
<td>C_{26}</td>
<td>2.50</td>
<td>1.87</td>
<td>C_{57}</td>
<td>0.40</td>
<td>0.65</td>
</tr>
<tr>
<td>C_{27}</td>
<td>2.49</td>
<td>1.94</td>
<td>C_{58}</td>
<td>0.40</td>
<td>0.67</td>
</tr>
<tr>
<td>C_{28}</td>
<td>2.26</td>
<td>1.82</td>
<td>C_{59}</td>
<td>0.40</td>
<td>0.67</td>
</tr>
<tr>
<td>C_{29}</td>
<td>1.97</td>
<td>1.65</td>
<td>C_{60}</td>
<td>0.41</td>
<td>0.71</td>
</tr>
<tr>
<td>C_{30}</td>
<td>1.84</td>
<td>1.59</td>
<td>C_{61+}</td>
<td>17.46</td>
<td>39.18</td>
</tr>
<tr>
<td>C_{31}</td>
<td>1.73</td>
<td>1.55</td>
<td>Total</td>
<td>100.00</td>
<td>100.00</td>
</tr>
</tbody>
</table>
Figure 3.1  Carbon number distributions of the Colony and McLaren heavy oils.
### Table 3.2 (a) Densities of the Colony heavy oil at different temperatures and $P_a = 1$ atm.

<table>
<thead>
<tr>
<th>$T$ (°C)</th>
<th>$\rho_o$ (g/cm$^3$)</th>
</tr>
</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>
</tr>
<tr>
<td>50</td>
<td>0.9743</td>
</tr>
<tr>
<td>60</td>
<td>0.9681</td>
</tr>
</tbody>
</table>

### Table 3.2 (b) Viscosities of the Colony heavy oil 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>
</tr>
<tr>
<td>54</td>
<td>1,150</td>
</tr>
<tr>
<td>60</td>
<td>795.9</td>
</tr>
<tr>
<td>65</td>
<td>537.1</td>
</tr>
<tr>
<td>70</td>
<td>390.7</td>
</tr>
<tr>
<td>75</td>
<td>285.4</td>
</tr>
<tr>
<td>80</td>
<td>220.2</td>
</tr>
</tbody>
</table>
Table 3.3  (a) Densities of the McLaren heavy oil at different temperatures and $P_a = 1$ atm.

<table>
<thead>
<tr>
<th>T (°C)</th>
<th>$\rho_o$ (g/cm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>21</td>
<td>1.0042</td>
</tr>
<tr>
<td>30</td>
<td>0.9976</td>
</tr>
<tr>
<td>40</td>
<td>0.9918</td>
</tr>
<tr>
<td>50</td>
<td>0.9857</td>
</tr>
<tr>
<td>60</td>
<td>0.9793</td>
</tr>
</tbody>
</table>

Table 3.3  (b) Viscosities of the McLaren heavy oil 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>177,000</td>
</tr>
<tr>
<td>30</td>
<td>51,900</td>
</tr>
<tr>
<td>40</td>
<td>18,281</td>
</tr>
<tr>
<td>50</td>
<td>6,903</td>
</tr>
<tr>
<td>60</td>
<td>2,912</td>
</tr>
<tr>
<td>70</td>
<td>1,407</td>
</tr>
<tr>
<td>80</td>
<td>747.4</td>
</tr>
</tbody>
</table>
with a pore size of 2.5 μm and found to be 18.3 and 20.2 wt.% (n-pentane insoluble), respectively. The physicochemical properties of the Colony and McLaren brines at $T_{\text{res}} = 21$ °C and $P_a = 1$ atm are listed in Tables 3.4(a) and 3.4(b), respectively. The purities of methane, carbon dioxide, and propane (Praxair, Canada) used in this study were equal to 99.97 mol.%, 99.998 mol.%, and 99.5 wt.%, respectively.

3.1.2 PVT studies of heavy oil–solvent systems

A schematic diagram of the experimental set-up for measuring the viscosity and PVT data of the solvent-saturated heavy oil at a pre-specified equilibrium pressure and $T_{\text{res}} = 21$ °C is shown in Figure 3.2. CH$_4$/CO$_2$/C$_3$H$_8$-satureated live heavy oil was prepared by mixing the Colony/McLaren heavy oil and pure CH$_4$/CO$_2$/C$_3$H$_8$ in two stainless steel cylinders (500-10-P-316-2, DBR, Canada) at $T_{\text{res}} = 21$ °C. Each heavy oil–solvent system was considered to be at an equilibrium state once the daily pressure decay of the heavy oil–solvent mixture was less than 10 kPa, which was the accuracy of the pressure gauge used (PRI-PRO, Martel Electronics, USA). After the heavy oil–solvent system reached the equilibrium state, the viscosity ($\mu_{\text{mix}}$), density ($\rho_{\text{mix}}$), solvent solubility ($\chi$) in the heavy oil, and oil-swelling factor (SF) of the solvent-saturated heavy oil were measured by using the following experimental steps:

- The solvent-saturated heavy oil was pumped through several pieces of equipment in series at a constant volume flow rate by using a syringe pump (500 DX, ISCO Inc., USA). A back-pressure regulator (BPR-50, Temco, USA) was used to maintain the exit pressure above the equilibrium pressure so that the heavy oil–solvent mixture remained in a liquid phase all the time;
- The solvent-saturated heavy oil viscosity was measured by using a house-made
Table 3.4  (a) Physical and chemical properties of the Colony brine collected from the Bonnyville area (Well No.: 16A-3-59-7) at $P_a = 1$ atm.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature (°C)</td>
<td>21</td>
</tr>
<tr>
<td>Density (g/cm$^3$)</td>
<td>1.03</td>
</tr>
<tr>
<td>Viscosity (mPa·s)</td>
<td>1.2</td>
</tr>
<tr>
<td>pH @ 25.0 °C</td>
<td>7</td>
</tr>
<tr>
<td>Specific conductivity (µS·cm$^{-1}$)</td>
<td>57,143</td>
</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>
Table 3.4  (b) Physical and chemical properties of the McLaren brine collected from the Bonnyville area (Well No.: 6C-3-59-7) at $P_a = 1$ atm.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature (°C)</td>
<td>21</td>
</tr>
<tr>
<td>Density (g/cm$^3$)</td>
<td>1.04</td>
</tr>
<tr>
<td>Viscosity (mPa·s)</td>
<td>1.2</td>
</tr>
<tr>
<td>pH @ 25.0 °C</td>
<td>7.5</td>
</tr>
<tr>
<td>Specific conductivity (µS·cm$^{-1}$)</td>
<td>65,359</td>
</tr>
<tr>
<td>Refractive index @ 29°C</td>
<td>1.3398</td>
</tr>
<tr>
<td>Chloride (mg/L)</td>
<td>27,426</td>
</tr>
<tr>
<td>Sulphate (mg/L)</td>
<td>2.5</td>
</tr>
<tr>
<td>Total dissolved solids @ 180 °C (mg/L)</td>
<td>47,252</td>
</tr>
<tr>
<td>Potassium (mg/L)</td>
<td>65</td>
</tr>
<tr>
<td>Sodium (mg/L)</td>
<td>15,670</td>
</tr>
<tr>
<td>Calcium (mg/L)</td>
<td>1,050</td>
</tr>
<tr>
<td>Magnesium (mg/L)</td>
<td>442</td>
</tr>
</tbody>
</table>
Figure 3.2  Schematic diagram of the experimental set-up for measuring the viscosities and PVT data of the solvent-saturated heavy oil at different equilibrium pressures and $T_{res} = 21^\circ C$. 
capillary viscometer, which consisted of a 300 cm-long stainless-steel tubing (SS-T2-S-028-20, Swagelok, Canada) with an inner diameter of 0.175 cm and a wall thickness of 0.071 cm;

- The solvent-saturated heavy oil density was measured by using the densitometer (DMA 512P, Anton Paar, USA);

- The flash method was used to determine the solvent solubility in the heavy oil. Once the solvent-saturated heavy oil passed through the BPR, a quick separation of the heavy oil–solvent mixture occurred. The separated dead heavy oil was collected in a flask and weighed to be \( m_o \). The flashed gas was collected in a gas bubbler and its volume was measured to be \( V_g \);

- At the same time, the pumped solvent-saturated heavy oil volume \( V_{mix} \) was read from the syringe pump and recorded to determine the oil-swelling factor;

- Three different pumping rates of the solvent-saturated heavy oil were used to measure the viscosity and PVT data at each equilibrium pressure and \( T_{res} = 21 \text{ °C} \). The averages of the three measured data are reported as the measured viscosity and PVT data in this study;

- The pressure of the heavy oil–solvent system in the heavy oil cylinder was then reduced to a lower pre-specified equilibrium pressure by using the syringe pump; and

- The viscosity and PVT data measurements were repeated at the lower equilibrium pressure. In this study, the characterization of CH\(_4\)/CO\(_2\)-saturated Colony/McLaren heavy oil was conducted at five relatively high equilibrium pressures of 5.0, 4.0, 3.0, 2.0, and 1.0 MPa, whereas the characterization of C\(_3\)H\(_8\)-
saturated Colony/McLaren heavy oil was performed at five relatively low equilibrium pressures of 0.8, 0.7, 0.6, 0.4, and 0.2 MPa.

Prior to the solvent-saturated heavy oil viscosity measurements, a standard-viscosity silicone liquid of S8000 (Cannon Instrument Company, USA) with \( \mu = 33,583 \text{ cP} \) at \( T_{\text{res}} = 21 ^\circ \text{C} \) was injected through the capillary tubing at different constant volume flow rates of 0.1–0.5 cm\(^3\)/min to calibrate the capillary viscometer and determine the so-called “effective radius” of the capillary tubing. Then the Hagen–Poiseuille equation was applied to determine the solvent-saturated heavy oil viscosity:

\[
\mu_{\text{mix}} (P_{\text{eq}}, T_{\text{res}}) = \frac{\pi (r_{\text{eff}})^4 \Delta P}{8 q_{\text{mix}} L},
\]

where, \( \mu_{\text{mix}} (P_{\text{eq}}, T_{\text{res}}) \) is the viscosity of the solvent-saturated heavy oil at each pre-specified equilibrium pressure and \( T_{\text{res}} = 21 ^\circ \text{C} \); \( \Delta P \) and \( q_{\text{mix}} \) are the measured pressure drop between the two ends of the long capillary tubing and the preset constant heavy oil–solvent mixture volume flow rate of 0.1–5.0 cm\(^3\)/min; \( r_{\text{eff}} \) and \( L \) are the “effective radius” and the actual length of the capillary tubing. In addition, the densitometer was calibrated by using two standard liquids of S2000 and N7.5 (Cannon Instrument Company, USA) before the solvent-saturated live heavy oil density was measured. The respective densities of S2000 and N7.5 are equal to 0.8805 and 0.7996 g/cm\(^3\) at \( T_{\text{res}} = 21 ^\circ \text{C} \). The solvent-saturated heavy oil density was calculated by using the calibrated correlation:

\[
\rho_{\text{mix}} (P_{\text{eq}}, T_{\text{res}}) = A \tau^2 + B \tau,
\]
where, \( \tau \) is the oscillation period read from the densitometer; \( A \) and \( B \) are two calibration coefficients, which were determined in the calibration process and found to be equal to \( 6.32 \times 10^{-7} \) and \( 9.64 \), respectively.

The solvent solubility in the solvent-saturated heavy oil at a pre-specified equilibrium pressure and \( T_{\text{res}} = 21 \, ^\circ \text{C} \) was measured by using the above-mentioned flash method:

\[
\chi(P_{\text{eq}}, T_{\text{res}}) = \frac{V_g(1 \, \text{atm}, T_{\text{res}})\rho_g(1 \, \text{atm}, T_{\text{res}})}{m_o} \times 100\% ,
\]

where, \( \rho_g(1 \, \text{atm}, T_{\text{res}}) \) is the gaseous solvent density at \( P_a = 1 \, \text{atm} \) and \( T_{\text{res}} = 21 \, ^\circ \text{C} \), which was calculated by using the CMG WinProp module (Version 2014.10, Computer Modelling Group Limited, Canada). The swelling factor of the solvent-saturated heavy oil is defined as the ratio of the volume of the solvent-saturated heavy oil at a pre-specified equilibrium pressure and \( T_{\text{res}} = 21 \, ^\circ \text{C} \) to the volume of the dead heavy oil at \( P_a = 1 \, \text{atm} \) and \( T_{\text{res}} = 21 \, ^\circ \text{C} \):

\[
\text{SF}(P_{\text{eq}}, T_{\text{res}}) = \frac{V_{\text{mix}}(P_{\text{eq}}, T_{\text{res}})}{m_o / \rho_o(1 \, \text{atm}, T_{\text{res}})} .
\]

### 3.1.3 Combined CSI and waterflooding tests

A schematic diagram of the experimental set-up for conducting the primary production and CSI/CSI + WF/simultaneous CSI + WF/WF + CSI is shown in Figure 3.3. This experimental set-up was composed of three major operational units: a sandpacked physical model, a fluid injection unit, and a fluid production unit. The visual rectangular sandpacked physical model consisted of three plates. The rear plate was a stainless steel block with a rectangular cavity \((L \times W \times H = 40.0 \, \text{cm} \times 10.0 \, \text{cm} \times 2.0 \, \text{cm})\) for
Figure 3.3  Schematic diagram of the experimental set-up for the primary production, WF, CSI, CSI + WF, simultaneous (CSI + WF), and WF + CSI.
sandpacking. The front plate was a transparent acrylic glass plate so that the experimental process could be visualized. A thin transparent polycarbonate plate was placed in between to prevent the front plate from being scratched and corroded. In this study, the physical model was placed horizontally with the height of 2.0 cm to study a horizontal pay zone or slice of a heavy oil reservoir, which is perpendicular to the vertical well (injector or producer). For the primary production, the producer was located at the centre on the left-hand side of the physical model. The CSI injector and producer were positioned at the same location, whereas the WF injector was located at the centre on the right-hand side of the physical model.

The fluid injection unit included a solvent cylinder (Praxair, Canada) with a gas regulator (KCY Series, Swagelok, USA) and a gas flow meter (XFM17S, Aalborg, USA) for CSI. The gas regulator was set at a pre-specified injection pressure to regulate the continuous solvent supply from the solvent cylinder during the solvent injection period. In CSI + WF, simultaneous CSI + WF, and WF + CSI, the syringe pump was used to inject the reservoir brine from a brine cylinder into the sandpacked physical model during the WF.

The fluid production unit was comprised of a BPR (LBS4 Series, Swagelok, USA), a syringe pump (100DX, ISCO Inc., USA), a produced oil and water collector, a pair of gas bubblers for the produced gas, and a vacuum pump. The BPR was used to control the production pressure at a pre-specified pressure drawdown rate. It should be noted that the injection and production pressures were measured at the same time by using a pressure transducer (PPM-2, Heise, USA) and recorded in a personal computer automatically.
The procedure for preparing each sandpacked physical model is briefly described as follows. The physical model was packed with the Ottawa sands (Bell & Mackenzie, Canada) of mesh sizes of 60–80 and repeatedly hammered to ensure that the sands were uniformly settled, packed, and distributed. It was tested to be leakage-free up to 3.0 MPa by using methane for 24 h. Afterwards, its porosity was measured by using the imbibition method with water and found to be in the range of 37.5–38.9%. Next, its permeability was measured by using the Darcy’s law with water. Three different pressure drops of 4–10 kPa were applied at the two ends of the physical model and the corresponding water volume flow rates of $q_w = 4.8–15.0 \, \text{cm}^3/\text{min}$ were recorded. The measured permeabilities of the sandpacked physical model were in the range of 3.9–5.0 D. After the permeability was measured, the wet sands were dried with the high-pressure air for at least 24 h. Then the sandpacked physical model was saturated with the Colony/McLaren brine through the imbibition process. Finally, CH$_4$-saturated Colony/McLaren heavy oil was used to displace the brine at a constant injection pressure of 3.5 MPa and a constant production pressure of 3.0 MPa until the initial oil saturation ($S_{oi}$) and the irreducible water saturation ($S_{wi}$) were achieved. Table 3.5 summarizes the physical properties of the extracting solvents and the reservoir characteristics of the 2-D sandpacked physical model used in Tests #1–12.

The five improved and enhanced heavy oil recovery processes were investigated in Tests #1–12 after the primary production: WF, CSI, CSI + WF, simultaneous CSI + WF, and WF + CSI. The technical details are given in Table 3.6 and will be described below. In each test, the primary production started at the actual initial reservoir pressure of $P_i = 3.0 \, \text{MPa}$ and stopped at the final pressure of $P_f = 0.2 \, \text{MPa}$. A constant pressure
Table 3.5  Physical properties of the heavy oil, solvent, brine, and reservoir characteristics of the 2-D sandpacked physical model in Tests #1–12 at $T_{res} = 21$ °C.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Heavy oil</th>
<th>Solvent</th>
<th>Brine</th>
<th>$\mu_o \text{ @ 1 atm}$ (cP)</th>
<th>$\rho_o \text{ @ 1 atm}$ (g/cm$^3$)</th>
<th>$k$ (D)</th>
<th>$\phi$ (%)</th>
<th>$S_{oi}$ (%)</th>
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</thead>
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<td>-</td>
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<td>33,876</td>
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<td>98.9</td>
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<tr>
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<td>4.9</td>
<td>37.9</td>
<td>98.9</td>
</tr>
<tr>
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<td></td>
<td></td>
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<td>38.0</td>
<td>98.7</td>
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</tr>
<tr>
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<td>Colony</td>
<td>CO$_2$</td>
<td>Colony</td>
<td></td>
<td></td>
<td>4.9</td>
<td>38.0</td>
<td>99.0</td>
</tr>
<tr>
<td>6</td>
<td>McLaren</td>
<td>CO$_2$</td>
<td>McLaren</td>
<td></td>
<td></td>
<td>4.7</td>
<td>38.1</td>
<td>99.1</td>
</tr>
<tr>
<td>7</td>
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<td>C$_3$H$_8$</td>
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<td></td>
<td></td>
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<td>37.6</td>
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</tr>
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<td></td>
<td></td>
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<td>38.2</td>
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<td>38.3</td>
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</tr>
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<td>CO$_2$</td>
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<td>97.5</td>
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</tbody>
</table>
Table 3.6  Five improved and enhanced heavy oil recovery processes of Tests #1–12 after the primary production at $T_{res} = 21 \, ^\circ C$.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Production scheme</th>
<th>Primary production</th>
<th>CSI</th>
<th>WF</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$P_i$ (MPa)</td>
<td>$dP/dt$ (kPa/min)</td>
<td>$t_{pro}$ (min)</td>
<td>$P_f$ (MPa)</td>
</tr>
<tr>
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<td>WF</td>
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<td>5.0</td>
<td>560</td>
</tr>
<tr>
<td>2</td>
<td>CSI</td>
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<td>2.85</td>
</tr>
<tr>
<td>3</td>
<td>CSI</td>
<td></td>
<td>24×60</td>
<td>2.70</td>
</tr>
<tr>
<td>4</td>
<td>CSI</td>
<td>1.0</td>
<td>2800</td>
<td>60</td>
</tr>
<tr>
<td>5</td>
<td>CSI + WF</td>
<td></td>
<td>2.70</td>
<td>12.5</td>
</tr>
<tr>
<td>6</td>
<td>CSI + WF</td>
<td></td>
<td>2.70</td>
<td>6.8</td>
</tr>
<tr>
<td>7</td>
<td>S (CSI + WF)</td>
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<td>0.8</td>
<td>3.0</td>
</tr>
<tr>
<td>8</td>
<td>WF + CSI</td>
<td></td>
<td>2.70</td>
<td>12.5</td>
</tr>
<tr>
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<td>CSI + WF</td>
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<td>0.75</td>
<td>1.5</td>
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<tr>
<td>10</td>
<td>CSI + WF</td>
<td></td>
<td>60</td>
<td>3.0</td>
</tr>
</tbody>
</table>
drawdown rate of \( \frac{dP}{dt} = 5.0 \text{ kPa/min} \) was applied in the primary pressure-depletion process, except for a different pressure drawdown rate of \( \frac{dP}{dt} = 1.0 \text{ kPa/min} \) used in Test #4. In Test #1, 1.0 PV brine was injected at \( q_w = 0.5 \text{ cm}^3/\text{min} \) for 600 min post the primary production. At the end of the WF, the instantaneous WOR was already over 10 \( \text{cm}^3/\text{cm}^3 \). In Tests #2–4 and #12, CSI consisted of three periods: the injection, soaking, and production periods. In the CSI injection period, either \( \text{CO}_2 \) or \( \text{C}_3\text{H}_8 \) was continuously injected into the sandpacked physical model as an extracting solvent at \( P_{\text{inj}} = 3.0 \) or 0.8 MPa and \( T_{\text{res}} = 21 \text{ °C} \) for 40 min when no more solvent could be injected. Then the injected solvent was soaked or dissolved into the heavy oil until the reservoir pressure remained almost unchanged. In the CSI production period, the solvent injector was converted into the fluid producer. The production pressure was linearly reduced with time at a pre-set pressure drawdown rate from the ending pressure \( (P_s) \) of the CSI-soaking period to the prespecified ending pressure \( (P_e = 0.2 \text{ MPa}) \) of the CSI-production period.

In each cycle of Tests #5–7, #10, and #11 (CSI + WF), the WF was conducted after the CSI production period was completed. It should be noted that each cycle of the CSI + WF contains both CSI and WF. The reservoir brine was injected continuously from the WF injector to displace the remaining foamy heavy oil, which was generated during the previous CSI production period. In Test #8 (simultaneous CSI + WF), the reservoir brine was injected in the WF while the CSI production was underway at the same time. In Test #9 (WF + CSI), the WF was commenced after the primary production was terminated. The subsequent CSI was implemented after the WF, which had an opposite production sequence of CSI + WF. The water volume injection rate was equal to \( q_w = 0.5 \text{ cm}^3/\text{min} \) in CSI + WF, simultaneous CSI + WF, and WF + CSI. A total of 0.33 PV brine was injected
in each WF cycle of the above-mentioned three different production processes. Moreover, the residual heavy oil saturations at different locations of the sandpacked physical model were measured at the ends of Test #3 (CSI), Test #6 (CO₂-CSI + WF), and Test #10 (C₃H₈-CSI + WF). Each oily sand sample at a different location of the physical model was taken, heated in an oven (OMH 750, Fisher Scientific, Canada) at \( T = 110 \, ^\circ\text{C} \) and 1 atm for at least 10 h, and weighed when the oily sand sample was dried to remove the water. It is worthwhile to point out that no hydrocarbons were evaporated because the initial boiling point (IBP) of the Colony heavy oil was measured to be 156 \(^\circ\text{C}\). Then the dry oily sand sample was rinsed by using toluene as an extracting solvent to remove the residual heavy oil and weighed. It was assumed that the residual heavy oil was completely removed by toluene when the colour of the used toluene did not change. Finally, the cleaned sand sample was heated in the oven at \( T = 110 \, ^\circ\text{C} \) and 1 atm for at least 4 h to ensure that no toluene was left in the sand sample, which was weighed at the end. The residual heavy oil saturation was determined from the measured weight change (i.e., the oil weight), the weight and density of the dry cleaned sand sample, the heavy oil density, and the porosity of the sandpacked physical model.

3.2 Results and Discussion

3.2.1 Heavy oil PVT data

The measured viscosities and PVT data of CH₄/CO₂/C₃H₈-saturated Colony heavy oil and CH₄/CO₂/C₃H₈-saturated McLaren heavy oil as a function of the reduced pressure at \( T_{\text{res}} = 21 \, ^\circ\text{C} \) are plotted in Figures 3.4(a–d) and Figures 3.5(a–d), respectively. In this study, the reduced pressure is defined as the ratio of the equilibrium pressure (\( P_{\text{eq}} \)) to the saturation pressure (\( P_{\text{sat}} \)) for CO₂/C₃H₈ at \( T_{\text{res}} = 21 \, ^\circ\text{C} \) or to the critical pressure (\( P_c \)) for
(a) Measured viscosities of CH₄/CO₂/C₃H₈-saturated Colony heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_c = 4.599$ MPa for CH₄, $P_{sat} = 5.868$ MPa for CO₂, and $P_{sat} = 0.858$ MPa for C₃H₈) and $T_{res} = 21$ °C.
Figure 3.4  (b) Measured densities of CH$_4$/CO$_2$/C$_3$H$_8$-saturated Colony heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_c$ = 4.599 MPa for CH$_4$, $P_{sat}$ = 5.868 MPa for CO$_2$, and $P_{sat}$ = 0.858 MPa for C$_3$H$_8$) and $T_{res}$ = 21 °C.
Figure 3.4  (c) Measured solubilities of CH4/CO2/C3H8-saturated Colony heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_c = 4.599$ MPa for CH4, $P_{sat} = 5.868$ MPa for CO2, and $P_{sat} = 0.858$ MPa for C3H8) and $T_{res} = 21 ^\circ C$. 
Figure 3.4  (d) Measured oil-swelling factors of CH₄/CO₂/C₃H₈-saturated Colony heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_c = 4.599$ MPa for CH₄, $P_{sat} = 5.868$ MPa for CO₂, and $P_{sat} = 0.858$ MPa for C₃H₈) and $T_{res} = 21 ^\circ C$. 

Reduced pressure $P_{eq}/P_{sat}$ or $P_{eq}/P_c$
Figure 3.5  (a) Measured viscosities of CH$_4$/CO$_2$/C$_3$H$_8$-saturated McLaren heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_c = 4.599$ MPa for CH$_4$, $P_{sat} = 5.868$ MPa for CO$_2$, and $P_{sat} = 0.858$ MPa for C$_3$H$_8$) and $T_{res} = 21$ °C.
Figure 3.5  (b) Measured densities of CH₄/CO₂/C₃H₈-saturated McLaren heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_c = 4.599$ MPa for CH₄, $P_{sat} = 5.868$ MPa for CO₂, and $P_{sat} = 0.858$ MPa for C₃H₈) and $T_{res} = 21$ °C.
Figure 3.5  (c) Measured solubilities of CH₄/CO₂/C₃H₈-saturated McLaren heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_c = 4.599$ MPa for CH₄, $P_{sat} = 5.868$ MPa for CO₂, and $P_{sat} = 0.858$ MPa for C₃H₈) and $T_{res} = 21 \, ^\circ$C.
Figure 3.5  (d) Measured oil-swelling factors of CH$_4$/CO$_2$/C$_3$H$_8$-saturated McLaren heavy oil at different reduced pressures $P_{eq}/P_c$ or $P_{eq}/P_{sat}$ ($P_c = 4.599$ MPa for CH$_4$, $P_{sat} = 5.868$ MPa for CO$_2$, and $P_{sat} = 0.858$ MPa for C$_3$H$_8$) and $T_{res} = 21$ °C.
CH₄. Figure 3.4(a) and Figure 3.5(a) depict that C₃H₈-saturated heavy oil has the lowest viscosity in comparison with CH₄/CO₂-saturated heavy oil at $T_{\text{res}} = 21 \, ^\circ\text{C}$. The measured C₃H₈-saturated Colony heavy oil viscosity of 22 cP at the equilibrium pressure of 0.802 MPa and $T_{\text{res}} = 21 \, ^\circ\text{C}$ is close to that of a typical dead medium crude oil at 1 atm and $T_{\text{res}} = 21 \, ^\circ\text{C}$. The solvent-saturated heavy oil viscosity reduction is a major EOR mechanism in the solvent-based EHOR process. It is anticipated that C₃H₈-saturated heavy oil can be easily recovered due to its lowest viscosity and highest mobility by comparison. Accordingly, C₃H₈-CSI will be more effective than CO₂-CSI.

It was found from Figure 3.4(b) and Figure 3.5(b) that C₃H₈-saturated heavy oil has a much reduced density, whereas CH₄/CO₂-saturated heavy oil density is slightly decreased with the equilibrium pressure. The solvent-saturated heavy oil density reduction is the net result or effect of the solvent dissolution and the oil swelling. As shown in Figure 3.4(c) and Figure 3.5(c), CO₂/C₃H₈ solubility in the heavy oil is much higher than CH₄ solubility in the heavy oil at $T_{\text{res}} = 21 \, ^\circ\text{C}$. A high solvent solubility can appreciably enhance the microscopic displacement efficiency of CSI. This figure also indicates that C₃H₈ solubility is increased much more quickly at a higher equilibrium pressure, whereas CH₄/CO₂ solubility in the Colony heavy oil is increased almost linearly with the equilibrium pressure. Similar findings have also been reported in the literature (Chung et al., 1988; Luo and Gu, 2009). Figure 3.4(d) and Figure 3.5(d) show that the oil-swelling factor of the heavy oil–CH₄/CO₂ mixture is much smaller than that of the heavy oil–C₃H₈ mixture, the latter of which can swell about 50% of the dead heavy oil volume. The oil-swelling factor increases with the solvent solubility in the heavy oil at a given equilibrium pressure.
The solvent-saturated heavy oil viscosity is needed to design a successful solvent-based EHOR project in a heavy oil reservoir. In the literature, several empirical correlations are documented to predict the viscosity of the solvent-saturated light crude oil, whereas some are specially proposed for the solvent-saturated heavy crude oil.

According to Bloomfield and Dewan (1971), the classical Arrhenius equation was adopted:

\[ \mu_{\text{mix}} = \mu_{o}^{x_{o}} \mu_{s}^{x_{s}}, \]  

where, \( \mu_{\text{mix}} \) is the predicted viscosity of the oil–solvent system; \( x_{o} \) and \( x_{s} \) are the mole fractions of the oil and solvent in the oil–solvent system, respectively; \( \mu_{o} \) and \( \mu_{s} \) are the viscosities of the dead oil and solvent at the same temperature and pressure, respectively.

Shu (1984) proposed the following equation:

\[ \mu_{\text{mix}} = \mu_{o}^{f_{o}} \mu_{s}^{f_{s}}, \]  

where, \( f_{o} = 1 - f_{s} \) and \( f_{s} = \frac{c_{s}}{\lambda (1 - c_{s}) + c_{s}} \) are the weighted volume fractions of the oil and the solvent. Here, \( c_{s} \) is the volume fraction of the solvent in the oil–solvent system;

\[ \lambda = \frac{17.04 (\gamma_{o} - \gamma_{s})^{0.5237} \gamma_{o}^{3.2745} \gamma_{s}^{1.6316}}{\ln(\mu_{o}/\mu_{s})} \]  

is the weight factor; \( \gamma_{o} \) and \( \gamma_{s} \) are specific gravities of the dead heavy oil and the solvent at the same temperature and pressure, respectively.

Chung et al. (1988) obtained a modified weight factor, \( \lambda' \), to be used in the Shu equation for determining \( \text{CO}_{2} \)-saturated heavy oil viscosity:

\[ \lambda' = 0.255 \gamma_{o}^{-4.16} \left( \frac{1.87T}{547.57} \right)^{1.85} \left[ \frac{e^{7.36}}{e^{7.36(1-P/7384)} - 1} \right]. \]

Lobe (1973) developed a special mixing rule to calculate the viscosity of the solvent-diluted crude oil:
\[ v_m = c_s v e^{c_o \alpha_o} + c_o v e^{c_o \alpha_s}, \]  

where, \( \alpha_o = 0.27 \ln \left( \frac{V_o}{V_s} \right) + 1.3 \ln \left( \frac{V_o}{V_s} \right)^{0.5} \) and \( \alpha_s = -1.7 \ln \left( \frac{V_o}{V_s} \right) \); \( v \) is the kinematic viscosity, \( v = \frac{\mu}{\rho} \).

The measured and predicted viscosities of CH\(_4\)/CO\(_2\)/C\(_3\)H\(_8\)-saturated Colony heavy oil and CH\(_4\)/CO\(_2\)/C\(_3\)H\(_8\)-saturated McLaren heavy oil as a function of CH\(_4\)/CO\(_2\)/C\(_3\)H\(_8\) concentration at \( T_{res} = 21 ^\circ C \) are plotted and compared in Figures 3.6(a–c) and Figures 3.7(a–c), respectively. The relative errors between the measured and predicted CH\(_4\)/CO\(_2\)/C\(_3\)H\(_8\)-saturated Colony/McLaren heavy oil viscosities are also calculated. It was found that the Shu equation best predicts the viscosity of CO\(_2\)/C\(_3\)H\(_8\)-saturated heavy oil in comparison with the other three correlations. The Lobe equation gives the best predicted viscosities of CH\(_4\)-saturated heavy oil. The Chung equation always underestimates the viscosity of the solvent-saturated heavy oil. The Arrhenius equation predicts the viscosity of the solvent-saturated heavy oil with a relatively larger error.

### 3.2.2 Production scheme

In this study, four different production processes after the primary production were conducted to examine the effect of a different EHOR process on the heavy oil RF in the post-CHOPS reservoir: Test #3 (CSI), Test #6 (CSI + WF), Test #8 (simultaneous CSI + WF), and Test #9 (WF + CSI). The heavy oil RFs (in terms of the OOIP) of the primary production, WF, and CSI in Tests #1–12 are listed in Table 3.7. Test #6 (CSI + WF), Test #8 (simultaneous CSI + WF), and Test #9 (WF + CSI) give additional heavy oil RFs of
Figure 3.6    (a) Measured and predicted viscosities of CH$_4$-saturated Colony heavy oil as a function of CH$_4$ concentration at $T_{res} = 21$ °C.
Figure 3.6  (b) Measured and predicted viscosities of CO$_2$-saturated Colony heavy oil as a function of CO$_2$ concentration at $T_{res} = 21$ °C.
Figure 3.6  (c) Measured and predicted viscosities of C$_3$H$_8$-saturated Colony heavy oil as a function of C$_3$H$_8$ concentration at $T_{res} = 21$ °C.
Figure 3.7  (a) Measured and predicted viscosities of CH₄-saturated McLaren heavy oil as a function of CH₄ concentration at $T_{res} = 21$ °C.
Figure 3.7  (b) Measured and predicted viscosities of CO₂-saturated McLaren heavy oil as a function of CO₂ concentration at $T_{res} = 21 \, ^\circ C$. 
Figure 3.7  (c) Measured and predicted viscosities of C<sub>3</sub>H<sub>8</sub>-saturated McLaren heavy oil as a function of C<sub>3</sub>H<sub>8</sub> concentration at T<sub>res</sub> = 21 °C.
Table 3.7  Enhanced heavy oil recovery (EHOR) factors of Tests #1–12 (including the primary production) at $T_{res} = 21^\circ$C

<table>
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<th>Test No.</th>
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<th>$1^{st}$ cycle</th>
<th>$2^{nd}$ cycle</th>
<th>$3^{rd}$ cycle</th>
<th>$4^{th}$ cycle</th>
<th>$5^{th}$ cycle</th>
<th>$6^{th}$ cycle</th>
<th>Subtotal RFCSI (%)</th>
<th>Subtotal RFWF (%)</th>
<th>Total RF (%)</th>
</tr>
</thead>
<tbody>
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<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<td>-</td>
<td>-</td>
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5.8, 1.6, and 4.6%, in comparison with Test #3 (CSI). It should be noted that the WF alone as the subsequent IOR method after the primary pressure-depletion process in Test #1 has a heavy oil RF of 8.0%. These results show that the combined CSI and WF processes are effective EHOR methods because they have two distinct technical advantages over the traditional CSI. First, it is known that not all the foamy heavy oil can reach the oil producer at the end of the primary or CSI production (Jia et al., 2015). In the CSI + WF or WF + CSI, however, the foamy oil could be continuously and effectively displaced by the injected brine. Second, the reservoir pressure is maintained in the WF so that the heavy oil viscosity remains lower and the heavy oil mobility is higher in the combined CSI and WF. On the other hand, the combined CSI and WF can have some shortcomings. The injected reservoir brine prevents the subsequently injected solvent from further contacting the residual heavy oil, which is referred to as the waterblocking effect (Lu et al., 2016). Hence, the heavy oil RF of CSI in CSI + WF or WF + CSI is slightly lower than that in CSI alone. In the simultaneous CSI + WF, the well-maintained reservoir pressure substantially hinders the foamy-oil formation, which is one of the major EHOR mechanisms in CSI. This is why this EHOR process has a much lower heavy oil RF than CSI + WF or WF + CSI.

The variations of the measured heavy oil production rate, instantaneous GOR, pressure drop, and production pressure with the CSI production time of Cycle #1 in Test #6 (CSI + WF) are shown in Figure 3.8(a). In general, the CSI production period in each cycle can be roughly divided into three stages. First, the pressures at the two ends of the physical model were declined at the almost same rate of 12.5 kPa/min so that the pressure drop was small. At this stage, the heavy oil production rate was minimal and the
Figure 3.8  (a) Measured heavy oil production rate, instantaneous GOR, pressure drop, and production pressure during the CSI production period of Cycle #1 in Test #6 (CSI + WF).
instantaneous GOR reached its peak value because the gas mobility is much higher than the heavy oil mobility. In the second stage, the pressure drop started to increase gradually because the dispersed gas bubbles in the viscous foamy heavy oil grew quickly enough to maintain the reservoir pressure. The heavy oil production rate was increased quickly and the instantaneous GOR was reduced dramatically due to the increased pressure drop and the controlled gas mobility during the foamy-oil flow. In the final stage, the pressure drop continued to increase. More dispersed gas bubbles were coalesced continuously to become the so-called free gas, which had a detrimental effect on the foamy-oil flow. Accordingly, the heavy oil production rate was decreased and the gas (i.e., more free gas) production rate was increased at the end. It should be noted that the average reservoir pressure was much higher than the production pressure at the outlet even when the latter reached 0.2 MPa. Therefore, a considerable amount of the dissolved gas and/or dispersed gas bubbles still remained in the heavy oil even at the end of the CSI production.

Figure 3.8(b) shows the measured heavy oil production rate, instantaneous WOR, pressure drop, and production pressure versus the WF production time of Cycle #1 in Test #6 (CSI + WF). The measured pressure drops fluctuated considerably so that the smoothed pressure drops had to be plotted in Figure 3.8(b). At the beginning, the pressure drop reached a maximum and a small amount of oil was produced with no water production. Then the WOR rose rapidly and the pressure drop fell sharply, which indicates that water broke through relatively early in the post-CHOPS reservoirs. It is speculated that the injected reservoir brine first flowed quickly through the free gas-saturated and high-permeability channels. Both the heavy oil production rate and the instantaneous WOR fluctuated because the foamy-oil flow and free-gas flow dominated
Figure 3.8 (b) Measured heavy oil production rate, instantaneous WOR, pressure drop, and production pressure during the WF period of Cycle #1 in Test #6 (CSI + WF).
the fluid productions alternately. It should be noted that the new foamy oil formed during the WF and/or the residual foamy oil left at the end of the previous CSI production can be stable for several days in the porous medium (Sheng et al., 1997). At a later time, the heavy oil continued to be produced with a high but decreased instantaneous WOR. The growth of the dispersed gas bubbles due to the pressure decline and brine imbibition pushed the remaining heavy oil into the channels previously occupied by the brine (Li et al., 2012). Finally, it is worthwhile to point out that the WF in a post CHOPS reservoir differs considerably from the WF in a light oil reservoir, especially in WF Cycle #1 of CSI + WF. For the WF in a heavy oil reservoir, a relatively large amount of heavy oil can still be produced after the water breakthrough (BT), whereas only a minimal amount of light oil is recovered after the water BT in a light oil reservoir.

The measured average heavy oil production rates in CSI, cumulative GORs in CSI and the cumulative WORs in WF of Test #3 (CSI), Test #6 (CSI + WF), Test #8 (simultaneous CSI + WF), and Test #9 (WF + CSI) are plotted and compared in Figures 3.9(a–c). It was found from these three figures that the average heavy oil production rates are decreased and the cumulative GORs and WORs are increased in the late cycles of the combined CSI and WF processes. This is partially attributed to the reduced initial heavy oil saturation in each cycle of CSI or WF. Obviously, the oil relative permeability is reduced when the heavy oil saturation is reduced. At a high water saturation, the heavy oil becomes discontinuous ganglia trapped by the capillary force. In the late WF cycles, the gas channels were formed because of the free-gas flow in the previous CSI production period. The injected reservoir brine moved preferentially through the high-permeability gas channels, which leads to an earlier water BT and a higher WOR. Apparently, Test #8
Figure 3.9  Measured (a) average heavy oil production rates in CSI; (b) cumulative GORs in CSI; and (c) cumulative WORs in WF of different cycles in Test #3 (CSI), Test #6 (CSI + WF), Test #8 (simultaneous CSI + WF), and Test #9 (WF + CSI).
(simultaneous CSI + WF) has the highest average heavy oil production rate, lowest cumulative GOR and WOR. In this test, more solvent remained in the heavy oil due to the extended reservoir pressure maintenance and the solvent-diluted heavy oil viscosity remained low, though the total oil recovery factor was low.

### 3.2.3 Pressure drawdown rate

Three CSI + WF tests were carried out to investigate how a different pressure drawdown rate affects the production performance of CSI + WF. Tests #5–7 had three different pressure drawdown rates of 25.0, 12.5 and 6.8 kPa/min in the CSI production periods, respectively. The measured average heavy oil production rates and cumulative GORs and WORs of CSI + WF in different cycles of Tests #5–7 are compared and plotted in Figures 3.10(a–c) and the measured heavy oil RFs in different cycles of Tests #5–7 are listed in Table 3.7. The heavy oil production rate is higher and the cumulative GOR is lower with the increased pressure drawdown rate, as shown in Figures 3.10(a) and (b). A higher pressure drawdown rate induces faster bubble nucleation and more dispersed gas bubbles in the heavy oil, which results in a stronger foamy-oil flow and a lower gas mobility (Sheng et al., 1999a; Bera and Babadagli, 2016). Although a higher pressure drawdown rate causes a stronger foamy-oil flow, the CSI production period is much shortened. For example, the CSI production period in Test #5 was only half of that in Test #6 when the pressure drawdown rate was decreased from 25.0 to 12.5 kPa/min. Hence, Test #6 recovered the most heavy oil during the CSI production period with a moderate pressure drawdown rate of 12.5 kPa/min among the three tests. Both Table 3.7 and Figure 3.10(c) indicate that the heavy oil RF of WF is increased and that the cumulative WOR in the WF is decreased when the pressure drawdown rate in the CSI
Figure 3.10  Measured (a) average heavy oil production rates in CSI; (b) cumulative GORs in CSI; and (c) cumulative WORs in WF of different cycles in Tests #5–7 (CSI + WF) with the pressure drawdown rates of 25.0, 12.5, and 6.8 kPa/min, respectively.
production period is increased. In this case, more foamy oil is generated and fewer free gas-saturated channels exist at a higher pressure drawdown rate in the CSI production period (Wang et al., 2008). Then the remaining foamy oil is effectively displaced in the subsequent WF. As given in Table 3.7, the pressure drawdown rate of 12.5 kPa/min in Test #6 leads to the highest total heavy oil RF of 30.1% in CSI + WF due to the efficient foamy-oil formation and extended foamy-oil flow (Alshmakhy and Maini, 2012b; Zhou et al., 2016).

3.2.4 Solvent effect

In this study, four CSI + WF tests with two different solvents, CO$_2$ for Tests #6 and #7 and C$_3$H$_8$ for Tests #10 and #11, were performed and compared to differentiate CO$_2$-CSI + WF and C$_3$H$_8$-CSI + WF. Tests #6 and #10 had the respective CSI pressure drawdown rates of 12.5 and 3.0 kPa/min but the same CSI production periods of 200 min. Tests #7 and #11 had the respective CSI pressure drawdown rates of 6.8 and 1.5 kPa/min but the same CSI production periods of 366 min. The measured heavy oil RFs in Tests #6, #7, #10, and #11 are summarized in Table 3.7 and the measured average heavy oil production rates, cumulative GORs and WORs of CSI + WF in Tests #6, #7, #10, and #11 are plotted in Figures 3.11(a–c). As expected, C$_3$H$_8$ can displace more heavy oil because of its larger heavy oil viscosity and density reductions, higher solubility and larger oil-swelling factor, as shown in Figures 3.4(a–d). Specifically, CSI is repeated for at least four cycles with more than 1.0% heavy oil recovered during each CSI cycle of Test #10 or #11 (C$_3$H$_8$-CSI + WF). In contrast, the heavy oil RF of CSI Cycle #3 in Test #6 or #7 (CO$_2$-CSI + WF) is already lower than 1.0%. Obviously, C$_3$H$_8$-diluted heavy oil has a much higher mobility due to its lower viscosity, which leads to a higher heavy oil
Figure 3.11  Measured (a) average heavy oil production rates in CSI; (b) cumulative GORs in CSI; and (c) cumulative WORs in WF of different cycles in Test #6 (CO$_2$-CSI + WF and $t_{pro} = 200$ min), Test #7 (CO$_2$-CSI + WF and $t_{pro} = 366$ min), Test #10 (C$_3$H$_8$-CSI + WF and $t_{pro} = 200$ min), and Test #11 (C$_3$H$_8$-CSI + WF and $t_{pro} = 366$ min).
production rate, lower cumulative GOR and WOR, as shown in Figures 3.11(a–c). Moreover, Table 3.7 also indicates that the last three WF cycles of Test #11 (C₃H₈-CSI + WF) only produce a total of 0.7% heavy oil. The WF is not effective in the late cycles due to severe water channeling.

3.2.5 Residual oil saturation

In this study, the residual heavy oil saturations at 12–14 locations of the sandpacked physical model were measured at the ends of Test #3 (CO₂-CSI), Test #6 (CO₂-CSI + WF), and Test #10 (C₃H₈-CSI + WF), which had the same CSI production period of 200 min. Figures 3.12(a–c) show the digital images of the top surfaces of the sandpacked physical model in these three tests. The sampling locations in each test are marked by circles in the figures. It was found from Figure 3.12(a) that the measured residual heavy oil saturations range from 68.6 to 83.6% in Test #3 (CO₂-CSI). The residual heavy oil saturations at the two ends of the sandpacked physical model are slightly higher than those in the centre. Some foamy oil formed in the primary pressure-depletion production and the CSI production does not reach the CSI producer. The foamy oil formed far from the CSI producer is difficult to be mobilized and produced because of the lower pressure gradient (Zhou et al., 2016). It can be seen from Figure 3.12(b) that in Test #6 (CO₂-CSI + WF), the residual heavy oil saturations at the two ends of the sandpacked physical model become lower than those in the middle of the sandpacked physical model, which are in contrast to the residual heavy oil saturations in Test #3 (CO₂-CSI). This indicates that the WF substantially improves the heavy oil recovery in the post-CHOPS reservoirs. Figure 3.12(c) shows that more heavy oil is produced in Test #10 (C₃H₈-CSI + WF) than that in Test #6 (CO₂-CSI + WF) due to a stronger oil-swelling effect and a larger
Figure 3.12  Measured residual heavy oil saturations at different locations of the sandpacked physical model at the ends of (a) Test #3 (CO$_2$-CSI); (b) Test #6 (CO$_2$-CSI + WF); and (c) Test #10 (C$_3$H$_8$-CSI + WF).
viscosity reduction of C$_3$H$_8$-diluted heavy oil. Also there is a sharp displacement front between the WF injector and CSI producer. By means of the two-well configuration, the residual heavy oil near the WF injector after the CSI production period has been effectively displaced by the subsequently injected reservoir brine.

3.4 Chapter Summary

In this chapter, a total of twelve sandpacked laboratory tests are undertaken to explore the technical synergy of combining cyclic solvent injection (CSI) and waterflooding (WF). Three different production processes are compared to study the joint enhanced oil recovery (EOR) and improved oil recovery (IOR) mechanisms in CSI + WF, simultaneous CSI +WF, and WF + CSI. It was found that CSI + WF has the highest heavy oil recovery factor (RF) among the three hybrid production processes, CSI or WF alone. In this case, the remaining foamy oil at the end of the CSI production period is effectively displaced and produced in the subsequent WF. It is also found that a higher pressure drawdown rate in CSI helps to increase the heavy oil production rate and reduce the cumulative gas–oil ratio (GOR) in CSI or the cumulative water–oil ratio (WOR) in the WF. The highest heavy oil RF is achieved at a moderate pressure drawdown rate with a moderate production time. Furthermore, C$_3$H$_8$-CSI + WF has a higher heavy oil RF and a higher heavy oil production rate with better-controlled gas production and lower water consumption than CO$_2$-CSI + WF. This is because that C$_3$H$_8$-saturated heavy oil has the largest viscosity and density reductions and oil-swelling factor, in comparison with CH$_4$/CO$_2$-saturated heavy oil. Finally, the measured residual oil saturations at the end of CO$_2$/C$_3$H$_8$-CSI + WF are much lower than those at the end of CSI alone because of the extended solution-gas drive and foamy-oil flow in the WF.
CHAPTER 4 EXPERIMENTAL STUDIES OF COMBINED CYCLIC SOLVENT INJECTION AND GASFLOODING

4.1 Combined CSI and gasflooding tests

In this study, the experimental set-up for conducting the combined CO₂-CSI and GF after the primary production is schematically shown in Figure 4.1. This experimental set-up consisted of a sandpacked physical model, a fluid injection system, and a fluid production system. The combined CO₂-CSI and GF was carried out in a two-well configuration. The primary production and CSI were conducted by using the injection/production well at the centre on the left-hand side of the physical model, whereas CO₂ was injected from the well at the centre of the right-hand side of the physical model during the GF. One CO₂ cylinder was used to store and inject CO₂ during the combined CO₂-CSI and GF. The detailed experimental set-up and procedure for preparing the sandpacked physical model were described in the previous chapter. Table 4.1 summarizes the major physical properties of the 2-D sandpacked physical model used in Tests #13–17.

The specific production schemes of the primary production and subsequent EHOR processes in these five tests are summarized in Table 4.1. The same production scheme of the primary production as that described in Chapter 3 was used in each test, which started at an initial reservoir pressure of $P_i = 3.0$ MPa. A constant pressure drawdown rate of $dP/dt = 5.0$ kPa/min was used to model a pressure-depletion process in the actual CHOPS reservoir. The primary production process was terminated when the production pressure
Figure 4.1  Schematic diagram of the experimental set-up for conducting the primary production and subsequent combined CSI and gasflooding in Tests #13–17 at $T_{\text{res}} = 21^\circ\text{C}$. 
Table 4.1 Physical properties of the 2-D sandpacked physical model, heavy oil production schemes, gas injection rates ($q_{CO_2}$) in Tests #13–17 at $T_{res} = 21^\circ$C.

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<th>$S_{oi}$ (%)</th>
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<th>$q_{CO_2}$ (cm$^3$/min)</th>
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<tr>
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reached $P_f = 0.2$ MPa. In Tests #13–17, CO$_2$ was injected to repressurize the reservoir pressure to $P_{inj} = 3.0$ MPa during the CSI injection period. No more CO$_2$ could be injected into the physical mode at the end of the injection period of $t_{inj} = 40$ min. Then the injection well was shut in for CO$_2$ to dissolve into the heavy oil and restore the foamy-oil flow. The CSI soaking period was terminated at $t_s = 24$ h when the reservoir pressure reached an almost constant value of 2.7 MPa. The CSI production period was commenced at $P_s = 2.7$ MPa and terminated at $P_e = 0.2$ MPa with a constant pressure drawdown rate of $dP/dt = 12.5$ kPa/min. In Tests #13–15 (CSI + GF), the GF (CO$_2$-flooding) was started at the end of each CSI production period with a CO$_2$ injection rate of $q_{CO_2} = 0.05, 0.10, 0.20$ cm$^3$/min, respectively. In Test #16 (simultaneous CSI + GF) or Test #17 (GF + CSI), the GF was conducted simultaneously with each CSI production or prior to each CSI injection (Ma and Gu, 2017d).

4.2 Results and Discussion

4.2.1 Gasflooding versus waterflooding

This study examined three combined CSI and GF processes, i.e., CSI + GF (Test #14), simultaneous (CSI + GF) (Test #16), and GF + CSI (Test #17). Their measured heavy oil RFs are summarized in Table 4.2 and plotted in Figure 4.2(a), in comparison with three combined CSI and WF processes (Tests #6, #8, and #9). The incremental heavy oil RFs of the combined CSI and GF were larger than that of the WF alone (8.0%). The heavy oil RF of GF Cycle #3 was decreased to less than 1.0% because some gas/water channels were formed near the end. To inject CO$_2$ or gasflooding after each CO$_2$-CSI production period was found to be the best CO$_2$ injection timing in terms of the
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<th>3\textsuperscript{rd} cycle</th>
<th>Subtotal RF\textsubscript{CSI} (%)</th>
<th>Subtotal RF\textsubscript{GF} (%)</th>
<th>Total RF (%)</th>
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Figure 4.2  (a) Measured heavy oil RFs in the CSI + WF (Test #6), simultaneous (CSI + WF) (Test #8), WF + CSI (Test #9), CSI + GF (Test #14), simultaneous (CSI + GF) (Test #16), and GF + CSI (Test #17).
Figure 4.2 (b) Measured average heavy oil production rate ($q_o$) in the CSI + WF (Test #6), simultaneous (CSI + WF) (Test #8), WF + CSI (Test #9), CSI + GF (Test #14), simultaneous (CSI + GF) (Test #16), and GF + CSI (Test #17).
Figure 4.2  
(c) Measured cumulative GOR in the CSI + WF (Test #6), simultaneous (CSI + WF) (Test #8), WF + CSI (Test #9), CSI + GF (Test #14), simultaneous (CSI + GF) (Test #16), and GF + CSI (Test #17).
heavy oil RF. The simultaneous (CSI + GF) had the lowest heavy oil RF because the production time was the shortest. However, the average heavy oil production rate was the highest in this case, as shown in Figure 4.2(b). The reservoir pressure was maintained almost constant during the CSI production period due to the simultaneous CO$_2$ injection. It should be noted that the average heavy oil production rate was calculated by neglecting the CSI injection and soaking periods. Also, the cumulative GOR in the simultaneous (CSI + GF) is the highest because more gas is injected at a higher reservoir pressure, as shown in Figure 4.2(c).

Overall, the combined CSI and WF performed better than the combined CSI and GF in terms of the heavy oil RF, heavy oil production rate, and cumulative GOR, as shown in respective Figures 4.2(a–c), respectively. The mobility ratio of the injected water to heavy oil is much smaller than that of the injected CO$_2$ to heavy oil. The viscosity of CO$_2$ is calculated to be only 0.0153–0.0162 cP at 0.1–3.0 MPa and $T_{res} = 21$ °C by using the CMG WinProp module (Version 2014.10, Computer Modelling Group Limited, Canada). Therefore, the water displacement front was more stable due to less water channeling. In addition, the injected water was imbibed into the smaller pores because it is the wetting phase. Meanwhile, the heavy oil was displaced by the capillary force into the larger pores. The water imbibition is one of the heavy oil recovery mechanisms at the high water-cut case. Moreover, the injected water effectively controlled CO$_2$ mobility by blocking the high-permeability channels, which resulted in a higher macroscopic sweep efficiency. The gravity overriding of CO$_2$ was also minimized by the injected water so that more injected CO$_2$ entered the lower part of the heavy oil reservoir. On the other hand, the remaining heavy oil was surrounded by the injected water at the end and was difficult to
access and recover due to the so-called waterblocking effect. Hence, the heavy oil viscosity reduction and oil-swelling effect through CO$_2$ dissolution were weakened.

The heavy oil production rate, instantaneous GOR, pressure drop, and production pressure during the first cycle of the GF in Test #14 (CSI + GF) is shown in Figure 4.3. This figure indicates that the heavy oil production rate fluctuated around 5.0 cm$^3$/h, which was similar to that at the end of the CSI Cycle #1 in Test #14. This is because that the foamy-oil flow and free-gas flow alternate during the GF. The instantaneous GOR was about 160 sc cm$^3$/cm$^3$ during the GF and was higher than that near the end of the CSI Cycle #1 in Test #14. The injected CO$_2$ caused a stronger free-gas flow during the GF. It is also found from Figure 4.3 that the pressure drop was decreased slowly during the GF. The injected CO$_2$ might flow along the previously formed gas channels and break through quickly.

Unlike the quick gas BT in the GF of Test #14 (CSI + GF), water BT occurred slightly later when about 0.05 PV brine was injected during the first cycle of WF in Test #6 (CSI + WF), as shown in Figure 3.8(b). The WOR was increased rapidly and then decreased near the end. The heavy oil was produced at a high WOR due to the expansion of the dispersed gas bubbles and the water imbibition (Lu et al., 2016). The pressure drop was increased prior to the water BT and then decreased to reach a plateau. The reservoir pressure was maintained at a higher pressure than that in GF Cycle #1 of Test #14 (CSI + GF).

### 4.2.2 Foamy-oil flow versus free-gas flow

As the reservoir pressure declines during the CSI, gas is nucleated to become the small gas bubbles inside the heavy oil. The dispersed gas bubbles are transported through
Figure 4.3  Measured heavy oil production rate ($q_o$), instantaneous GOR, pressure drop ($\Delta P$), and production pressure ($P_{pro}$) during the GF of Cycle #1 in Test #14 (CSI + GF).
the porous media by the heavy oil, which is called the foamy-oil flow. As the reservoir pressure is further reduced, some dispersed gas bubbles coalesce and grow larger and larger so as to become a free-gas phase at certain time. Some dispersed gas bubbles become continuous free gas that flows along the gas channels. During the subsequent GF, the injected gas initially flows along the high-permeability channels and displace the remaining foamy-oil. The important differences between the foamy-oil flow and free-gas flow are the gas distribution and flow pattern. In the foamy-oil flow, the gas bubbles are formed through the nucleation at the widely distributed sites in the heavy oil reservoir. Thus, the gas bubbles can easily remain as a dispersed phase in the continuous heavy oil. In the free-gas flow, however, the gas preferentially flows as a separate phase through the low-resistance channels from the high-pressure zones to the low-pressure zones.

Figure 4.4 shows the measured heavy oil production rate, instantaneous GOR, pressure drop, and production pressure during the first cycle of the CSI production in Test #14 (CSI + GF). In the beginning of the CSI production, the oil production rate was extremely low because the foamy oil after the primary production was pushed away from the producer by the newly injected CO₂. A large amount of CO₂ was near the producer and the free-gas flow was dominant. Hence, the instantaneous GOR was high and the pressure drop was almost zero. As the reservoir pressure was depleted, the heavy oil production rate was increased and the instantaneous GOR was decreased, which indicates a stronger foamy-oil flow. The pressure drop became larger due to the high isothermal compressibility of the dispersed gas. At a later time, the dispersed gas bubbles coalesced continuously and became the free gas at the end. Therefore, the free-gas flow became dominant again, which resulted in a lower heavy oil production rate and a higher
Figure 4.4   Measured heavy oil production rate \( q_o \), instantaneous GOR, pressure drop \( \Delta P \), and production pressure \( P_{pro} \) during the CSI production of Cycle #1 in Test #14 (CSI + GF).

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instantaneous GOR. The foamy-oil flow and free-gas flow alternated during the subsequent GF, as described in the previous section.

The heavy oil RFs, heavy oil production rates, and cumulative GORs of the CSI and GF in Test #14 (CSI + GF) are compared in Figures 4.5(a–c). From the first cycle to the third cycle of the CSI or GF, the heavy oil RF and heavy oil production rate were decreased and the cumulative GOR was increased. The gas saturation became higher as more and more heavy oil was produced, which led to the dominant free-gas flow and severe gas channeling. In the first cycle, the CSI and GF had almost the same heavy oil RFs and heavy oil production rates. The foamy-oil flow was effective in the both processes. GF Cycle #2 gave a higher heavy oil RF, heavy oil production rate, and lower cumulative GOR than CSI Cycle #2. The free-gas flow was strong from the beginning of CSI Cycle #2. Most foamy oil was displaced during GF Cycle #2. The heavy oil RF and production rate were much lower and the cumulative GOR was far higher during GF Cycle #3. The gas channeling became so severe that most heavy oil was bypassed and thus remained untouched.

4.2.3 \( \text{CO}_2 \) injection rate

In this study, three different \( \text{CO}_2 \) injection rates of \( q_{\text{CO}_2} = 0.05, 0.10, 0.20 \text{ cm}^3/\text{min} \) were tested during the GF in Tests #13–15 (CSI + GF), respectively. The heavy oil RFs of the CSI + GF in Tests #13–15 are plotted and compared in Figure 4.6(a). The heavy oil RFs of the CSI + GF are slightly higher than that 12.9\% of the CSI alone (Test #3), which were equal to 13.8, 15.6, and 13.9\% in Tests #13–15, respectively. The remaining foamy oil after the previous cycle of the CSI production was recovered by the injected \( \text{CO}_2 \). During the CSI + GF, most heavy oil was produced in the first cycle, which helped
Figure 4.5  (a) Measured heavy oil RFs during the three cycles of the CSI and GF in Test #14 (CSI + GF).
Figure 4.5  (b) Measured average heavy oil production rates during the three cycles of the CSI and GF in Test #14 (CSI + GF).
Figure 4.5  (c) Measured cumulative GORs during the three cycles of the CSI and GF in Test #14 (CSI + GF).
Figure 4.6 (a) Measured heavy oil RFs of three cycles of the CSI + GF in Tests #13–15 with the respective CO₂ injection rates of $q_{CO_2} = 0.05, 0.10, \text{and} 0.20 \text{ cm}^3/\text{min}$. 
Figure 4.6  (b) Measured average heavy oil production rates ($q_o$) of three cycles of the CSI + GF in Tests #13–15 with the respective CO$_2$ injection rates of $q_{CO_2} = 0.05$, 0.10, and 0.20 cm$^3$/min.
Figure 4.6 (c) Measured cumulative GORs of Cycles #1 and #2 of the GF in Tests #13–15 with the respective CO$_2$ injection rates of $q_{CO_2} = 0.05$, 0.10, and 0.20 cm$^3$/min.
to increase the heavy oil production rate at the early stage. Only 3.1, 3.4, and 2.0% heavy oil were recovered during the second and third cycles of the CSI + GF in Tests #13–15, respectively. In general, the heavy oil RF of the CSI was quickly decreased with the cycle number in each test because the oil saturation became lower and lower in the late cycles. Less than 1% heavy oil was recovered in the third cycle of the CSI. Also, no light to intermediate hydrocarbons were extracted by CO₂ under the immiscible conditions in this study because the heavy oil does not contain any hydrocarbons under C₉ according to the gas chromatography (GC) analysis results (Ma et al., 2017b).

In the first cycle of the GF, the heavy oil RF is slightly increased when CO₂ injection rate is increased. A higher CO₂ injection rate leads to a higher pressure gradient, which accelerates the foamy-oil flow and heavy oil production. In addition, more CO₂ can be dissolved into the heavy oil at a higher reservoir pressure. Thus, the heavy oil viscosity is further reduced and the oil-swelling effect is stronger. During the second cycle of the GF, however, the lowest heavy oil RF was equal to 0.3% in Test #15 with the highest CO₂ injection rate of 0.20 cm³/min. This implies that more high-permeability channels were formed because of the gas BT at a high CO₂ injection rate. The subsequently injected CO₂ flowed through the established gas channels without displacing the foamy oil (Bera and Babadagli, 2016). During the third cycle of the GF, only 0.05, 0.03, and 0.3% heavy oils were recovered due to the severe gas channeling, corresponding to three respective CO₂ injection rates. In summary, the heavy oil was quickly produced at first but the total heavy oil RF was low when CO₂ injection rate is equal to 0.20 cm³/min. Test #14 gave the highest heavy oil RF of 15.6% with an intermediate CO₂ injection rate of 0.10 cm³/min.
The variations of the measured average heavy oil production rates of GF Cycles #1–3 in Tests #13–15 (CSI + GF) are plotted in Figure 4.6(b). During the first cycle of the GF, the average heavy oil production rate was slightly increased with the CO₂ injection rate. It reduced dramatically during the second cycle of the GF, especially in Test #5 with the highest CO₂ injection rate. Almost no heavy oil was produced during the last cycle of the GF. Figure 4.6(c) shows the measured cumulative GORs of GF Cycles #1 and #2 in Tests #13–15 (CSI + GF). Tests #13–15 had the lower cumulative GORs of 146–171 sc cm³/cm³ during GF Cycle #1 than 500–1,000 sc cm³/cm³ obtained from the field-scale CO₂ flooding projects (Dyer and Farouq Ali, 1989). The low cumulative GOR is mainly attributed to the foamy-oil flow during the GF and homogeneous physical model used in the laboratory tests. The dispersed gas bubbles were trapped in the viscous heavy oil, which effectively controlled the gas mobility. Besides, the foamy oil increased the oil saturation and also the oil relative permeability because the dispersed gas bubbles expanded when the reservoir pressure was declined. Also, the foamy oil swelled and occupied some gas channels so that the gas channeling was weakened. The cumulative GORs of the GFs were increased when more cycles were conducted. This is because that the gas saturation became higher and higher as the production proceeded, especially near the producer. The cumulative GORs in GF Cycle #3 were increased to 3,326, 6,556, and 1,157 sc cm³/cm³ in Tests #13–15, respectively. In GF Cycles #1 and #2, a higher CO₂ injection rate caused a higher cumulative GOR. More CO₂ was injected and the free-gas flow became stronger at a higher CO₂ injection rate.
4.3 Chapter Summary

In this paper, the gasflooding (GF) is applied to aid the CO₂-cyclic solvent injection (CO₂-CSI) in a post cold heavy oil production with sand (CHOPS) reservoir in a two-well configuration. The enhanced oil recovery (EOR) mechanisms are examined by conducting five experimental tests of the CSI + GF, simultaneous (CSI + GF), and GF + CSI, in which CO₂ is injected post, at the same time with, and prior to the CSI, respectively. The CSI + GF gives a higher heavy oil recovery factor (RF) than the simultaneous (CSI + GF) and GF + CSI due to the extended foamy-oil flow. The simultaneous (CSI + GF) has the highest average heavy oil production rate and gas–oil ratio (GOR). The production time of the simultaneous (CSI + GF) is only half of those of the CSI + GF and GF + CSI. The CSI + WF recovers more heavy oil than the CSI + GF due to the effective displacement of the foamy oil. The foamy-oil flow and free-gas flow alternate during the CSI and subsequent GF. The free-gas flow becomes dominant as the gas saturation is increased in the late cycles of the CSI and GF. A high CO₂ injection rate during the GF is detrimental to the heavy oil production as the free-gas flow becomes strong.
CHAPTER 5  ANALYTICAL PRODUCTION MODELS FOR PRIMARY PRODUCTION AND SUBSEQUENT CYCLIC SOLVENT INJECTION

5.1 Material Balance Model (MBM)

In this study, a material balance model (MBM) is developed to predict the cumulative heavy oil and gas productions and the average reservoir pressures in the primary production and subsequent CSI in the CHOPS reservoirs. In the MBM, the reservoir characteristics, reservoir fluid saturations and physical properties are assumed to be homogeneous but change with time.

5.1.1 Primary production

Single-phase flow

At the beginning of the primary production, CH₄-saturated live heavy oil in the reservoir is a single liquid phase. The average reservoir pressure is assumed to be same as the production pressure, which declines at the pre-specified pressure drawdown rate. As the average reservoir pressure declines to the bubble-nucleation pressure \((P_{bn})_{pp}\), the dissolved gas starts to nucleate and become small gas bubbles dispersed in the heavy oil. The dispersed small gas bubbles are assumed to flow along with the heavy oil at the same velocity to form the so-called foamy-heavy oil flow. During the single-phase flow, the dispersed gas bubbles are extremely small. Thus, the cumulative heavy oil production and the heavy oil production rate at the standard conditions in the single-phase flow period are obtained from the definition of the heavy oil isothermal compressibility:

\[ \text{...} \]
The cumulative gas production at the standard conditions in the single-phase flow period is equal to the product of the cumulative heavy oil production and initial solution gas–oil ratio, $R_{si}$:

$$Q_g(t) = Q_o(t)R_{si}. \quad [5.2a]$$

Thus, the gas production rate is easily obtained:

$$q_g(t) = \frac{dQ_g(t)}{dt} = q_o(t)R_{si}. \quad [5.2b]$$

The average reservoir pressure in the single-phase flow is assumed to be the same as the production pressure at any time:

$$P_{ave}(t) = (P_i)_{pp} - \int_0^t \left( \frac{dP}{dt} \right)_{pp} dt. \quad [5.3]$$

**Two-phase flow**

When the average reservoir pressure continues to decline to the pseudo bubble-point pressure $(P_{pb})_{pp}$, the dispersed gas bubbles are gradually coalesced and liberated from the heavy oil to form a separate free-gas phase and the single-phase flow becomes into a two-phase flow (Kraus et al., 1993; Chen et al., 2015). The two-phase flow starts when $P_{ave}(t)$ reaches the pseudo bubble-point pressure, $(P_{pb})_{pp}$. The cumulative heavy oil production at the standard conditions at any time in the two-phase flow is equal to:

$$Q_o(t) = \frac{V_p \left[ 1 - S_{wi} - S_o(t) \right]}{B_o(R_s)} + Q_o(t_{single}). \quad [5.4]$$
The cumulative gas production under the standard conditions at any time during the two-phase flow is found to be:

\[ Q_g(t) = \int_{t_{\text{avg}}}^{t} R(t)Q_0(t) \, dt + Q_g(t_{\text{single}}), \tag{5.5} \]

In this study, the two-phase flow is assumed to be one-dimensional (1-D) and in a semi-steady state. In addition, the foamy-oil viscosity at any time is assumed to be equal to the viscosity of the solvent-diluted heavy oil with the same solution gas–oil ratio (GOR) at the equilibrium state. In other words, the dispersed gas bubbles do not appreciably affect the foamy-oil viscosity. If the production pressure declines at a constant pressure drawdown rate, the average reservoir pressure is obtained from the Darcy’s law (Dake, 1998):

\[ P_{av}(t_{j+1}) = \frac{1}{t_{j+1} - t_j} \left[ \mu_{av}(R_s)B_{av}(R_s) \left( V_s(t_j) - V_s(t_{j+1}) \right) + \frac{1}{2 \mu_{av}(R_s)} \left( \frac{\partial P}{\partial P} \right)_{pp} \left[ (t_{j+1} - t_{\text{avg}}) - (t_j - t_{\text{avg}}) \right] \right] + (P_{ps})_{pp}. \tag{5.6} \]

Due to the non-equilibrium foamy-oil phase behaviour, the dissolved gas concentration in the heavy oil at any time is always higher than the solution GOR at the corresponding equilibrium state. On the other hand, the foamy-oil viscosity, \( \mu_{fo}[R_s(t)] \), and foamy-oil formation volume factor, \( B_{fo}[R_s(t)] \), in Eq. [5.6] are the functions of the non-equilibrium solution gas–oil ratio, \( R_s(t) \), which is derived as:

\[ R_s(t) = \frac{R_s(P_s)(1 - S_w)W_p - Q_{gn}(t)}{S_o(t)W_p}, \tag{5.7} \]

where, \( Q_{gn}(t) \) is the total nucleated gas volume at the standard conditions, which is determined from the difference between the non-equilibrium solution gas–oil ratio, \( R_s(t) \), and the equilibrium solution GOR at \( P_{\text{ave}} \), \( R_s(P_{\text{ave}}) \) (Shahvali and Pool-Darvish, 2009):
\[ Q_{\text{gen}}(t) = \int_{t_{\text{angk}}}^{t} h_{pp}[R_s(t) - R_s(P_{\text{ave}})]S_o(t)V_p dt. \quad [5.8] \]

In the above kinetic equation, \( h_{pp} \) is called the nucleation coefficient of the dissolved gas into the heavy oil during the primary production. Physically, it represents how quickly the dissolved gas (e.g., CH\(_4\)) is nucleated to become the dispersed gas bubbles still inside the heavy oil during the pressure-depletion primary production process.

The foamy-oil saturation, \( S_{fo}(t) \), and foamy-oil formation volume factor, \( B_{fo}(R_o) \), in Eq. [5.6] are larger than the solvent-diluted heavy oil saturation and formation volume factor because of the gas-in-oil dispersion, respectively:

\[ S_{fo}(t) = S_o(t) + \frac{V_{dg}(t)B_e(P_{\text{ave}})}{V_p}, \quad [5.9] \]
\[ B_{fo}(R_o) = B_o(R_o) + \frac{B_e(R_o)W_{dg}(t)B_e(P_{\text{ave}})}{S_o(t)V_p}, \quad [5.10] \]

where, \( V_{dg}(t) \) is the dispersed gas volume at the standard conditions, which is assumed to be an exponential function of the production time (Bikerman, 1973):

\[ V_{dg}(t) = \frac{S_o(t)}{1 - S_{wi}}Q_{\text{gen}}(t)e^{-\lambda_{pp}(t-t_{\text{angk}})}, \quad [5.11] \]

where, \( \lambda_{pp} \) is referred to as the decay coefficient of the dispersed gas bubbles from the heavy oil during the primary production. Physically, the decay coefficient describes how fast the dispersed gas bubbles in the heavy oil are coalesced and released from the heavy oil to become the free gas.

Both the average reservoir pressure and oil saturation, \( P_{\text{ave}}(t_{j+1}) \) and \( S_o(t_{j+1}) \) at \( t = t_{j+1} \), are unknown in Eq. [5.6]. A relation between them is derived on the basis of the
material balance equation, i.e., MBE (Craft and Hawkins, 1991). The average reservoir pressure at $t = t_{j+1}$ after the heavy oil saturation reduction of $\Delta S_o$ from $t_j$ to $t_{j+1}$ is given as:

$$P_{ave}(t_{j+1}) = P_{ave}(t_j) - \frac{S(t_{j+1})B_i(P_{ave})}{B_i(R_i)} \frac{\Delta R}{\Delta P_{ave}} + B_i(P_{ave}) \frac{S(t_{j+1})}{k_o(S_o)\mu_o(R_o)} \frac{\Delta B_i}{B_i(R_i) \Delta P_{ave}} \left[ S(t_{j+1}) - S(t_j) \right] \frac{\Delta B_i}{B_i(P_{ave}) \Delta P_{ave}} \left[ 1 - S(t_{j+1}) - S(t_j) \right]$$

[5.12]

Thus $P_{ave}(t_{j+1})$ can be determined through an iteration procedure until the difference between the two average reservoir pressures calculated from Eqs. [5.6] and [5.12] is smaller than a prespecified value, e.g., 1 kPa in this study.

5.1.2 Cyclic solvent injection (CSI) in post-CHOPS reservoirs

During the CSI injection period, a gaseous solvent (e.g., CO$_2$) is injected through an injector to increase the average reservoir pressure to a prespecified injection pressure. Then the injector is shut in for the solvent to dissolve into the heavy oil and further reduce its viscosity. The reservoir pressure is decreased due to the solvent soaking. The amount of the solvent dissolved into the heavy oil during the CSI soaking period can be calculated with the measured reservoir pressure reduction by using the Peng–Robinson equation of state (Peng and Robinson, 1976), for example. The dispersed CH$_4$ bubbles formed during the primary production are assumed to remain during the CSI soaking period because of the constraint of the pore wall in the porous media. The CSI production period has the same two heavy oil recovery mechanisms as those in the primary production: the heavy oil viscosity reduction through solvent dissolution and foamy-oil flow with the dispersed solvent bubbles.

However, the kinetic parameters during the CSI production period are different due to different heavy oil–solvent systems and pressure drawdown rates, which include the
nucleation coefficient of the dissolved solvent, $h_{CSI}$, the decay coefficient of the dispersed solvent, $\lambda_{CSI}$, and the pseudo bubble-point pressure, $(P_{pb})_{CSI}$. In this study, it is assumed that no new foamy oil is formed during the CSI production period so that the nucleation coefficient of the dissolved solvent, $h_{CSI}$, is equal to zero. This is because the amounts of the newly dissolved solvent (e.g., CO$_2$) and the remaining dissolved CH$_4$ after the primary production are rather small. The volume of the remaining dispersed gas is still assumed to be an exponential function of the production time but with a new decay coefficient ($\lambda_{CSI}$) of the dispersed solvent from the heavy oil during the CSI production period. The cumulative heavy oil and gas productions can still be calculated from Eqs. [5.4] and [5.5], respectively. The relation between the average reservoir pressure at $t = t_{j+1}$ and the heavy oil saturations at $t = t_j$ and $t = t_{j+1}$ becomes:

$$P_{av}(t_{j+1}) = \frac{1}{i_{j+1} - i_j} \left\{ \frac{\mu_{w}(R_t)B_{sw}(R_t)V_{r}S_{w}(t_j) - S_{r}(t_{j+1})}{3whkk_{sw}(S_{w})B_{w}(R_t)} - \frac{1}{2} \left( \frac{dP}{dt} \right)_{CSI} \left[ (t_{j+1} - t_j)^2 - (t_j - t_i)^2 \right] \right\} + (P)_{CSI}, \quad [5.13]$$

The relation between the pressure drop and heavy oil saturation derived from the MBE in Eq. [5.12] is also applicable in the CSI production period.

It is worthwhile to emphasize that the PVT data and the viscosities of different heavy oil–solvent systems at a given solvent concentration are determined by using the linear interpolation of the measured PVT data and viscosities at different equilibrium pressures and $T_{res} = 21$ °C. On the other hand, the Shu equation is applied to calculate the viscosity of the heavy oil–mixed solvent (CO$_2$ + CH$_4$) solvent system as it was found to be the most suitable (Shu, 1984). The foamy-oil isothermal compressibility is determined from the foamy-oil formation volume factor:

$$c_{fo} = -\frac{1}{B_{fo}} \left( \frac{\partial B_{fo}}{\partial P_{ave}} \right)_T. \quad [5.14]$$
The foamy-oil isothermal compressibility is much higher than the heavy oil isothermal compressibility due to the presence of the dispersed gas bubbles in the foamy heavy oil. In this study, the modified Brooks–Corey correlations (Brooks and Corey, 1964) are used to determine the foamy-oil and gas relative permeabilities:

\[
k_{wo}(S_{or}) = k_{romax} \left( \frac{S_{or} - S_{or}}{1 - S_{or} - S_{or} - S_{rg}} \right)^{n_o},
\]

\[
k_{wg}(S_{or}) = k_{rgmax} \left( \frac{1 - S_{or} - S_{or} - S_{rg}}{1 - S_{or} - S_{or} - S_{rg}} \right)^{n_g},
\]

where, \(n_o\) and \(n_g\) are the exponential powers of the foamy-oil and gas relative permeabilities, respectively. Finally, the heavy oil and gas production rates at any time, \(q_o(t)\) and \(q_g(t)\), can be readily obtained by differentiating the cumulative heavy oil and gas production data at any time, \(Q_o(t)\) and \(Q_g(t)\), with respect to time:

\[
q_o(t) = \frac{dQ_o(t)}{dt},
\]

\[
q_g(t) = \frac{dQ_g(t)}{dt}.
\]

5.2 Numerical Procedure

In the above-derived MBM, there are a total of nine unknown or to-be-determined parameters. They are the maximum oil and gas relative permeabilities at the end-point oil and gas saturations (\(k_{romax}\) and \(k_{rgmax}\)); the residual oil saturation (\(S_{or}\)); the exponential powers of the oil and gas relative permeabilities (\(n_o\) and \(n_g\)); the nucleation coefficient of the dissolved gas in the heavy oil in the primary production (\(h_{pp}\)); the decay coefficients of the dispersed gas from the heavy oil in the primary production (\(\lambda_{pp}\)) and in the subsequent CSI (\(\lambda_{CSI}\)); and the pseudo bubble-point pressure in the primary production
In this work, these nine parameters are adjusted so that the predicted and measured cumulative heavy oil and gas production data and average reservoir pressures are all best matched simultaneously. The time-weighted root-mean-squared absolute errors of the predicted cumulative heavy oil and gas productions and average reservoir pressures from the measured data are used as three respective objective functions:

\[ E_o = \sqrt{\frac{1}{T_o} \sum_{j=1}^{n} \left[ Q_{on}(t_j) - Q_{onm}(t_j) \right]^2 (t_j - t_{j-1})} \]  \hspace{2cm} [5.17a]

\[ E_g = \sqrt{\frac{1}{T_g} \sum_{j=1}^{n} \left[ Q_{gm}(t_j) - Q_{gm}(t_j) \right]^2 (t_j - t_{j-1})} \]  \hspace{2cm} [5.17b]

\[ E_p = \sqrt{\frac{1}{T_p} \sum_{j=1}^{n} \left[ P_{avem}(t_j) - P_{avem}(t_j) \right]^2 (t_j - t_{j-1})} \]  \hspace{2cm} [5.17c]

The Pareto optimal solutions are found by applying the multi-objective particle swarm optimization (MOPSO), which is a population-based stochastic optimization algorithm and has been successfully used to solve many nonlinear optimization problems (Coello et al., 2004). The MOPSO provides multiple solutions with a faster convergence rate, in comparison with the single objective particle swarm optimization (SOPSO). In this study, the optimum adjustable parameters are first selected from the Pareto optimal solutions and then determined by minimizing an overall arithmetic objective function:

\[ E = \frac{E_o}{Q_{on}(t_n)} + \frac{E_g}{Q_{gm}(t_n)} + \frac{E_p}{(P_i)_{pp}}. \]  \hspace{2cm} [5.18]

The numerical flowchart for determining the unknown nine parameters is given in Figure 5.1 and the detailed numerical procedure is described below:

1. The guessing values of the unknown parameters are specified for calculating the cumulative heavy oil and gas productions and average reservoir pressures;
During the primary production with the one-phase flow, the cumulative heavy oil and gas productions, \(Q_o(t)\) and \(Q_g(t)\), and the average reservoir pressure, \(P_{\text{ave}}(t)\), are calculated from Eqs. [5.1a], [5.2a], [5.3], respectively, when the average reservoir pressure is higher than the pseudo bubble-point pressure, \((P_{pb})_{pp}\);

As the average reservoir pressure declines below the pseudo bubble-point pressure, \((P_{pb})_{pp}\), and the two-phase flow starts, the average reservoir pressure, \(\bar{P}_{\text{ave}}(t_{j+1})\) at \(t = t_{j+1}\), is obtained from Eq. [5.6] with a pre-specified time step, \(\Delta t\), and a guessing value of \(\Delta S_o\);

The solution gas–oil ratio, \(R_s(t_{j+1})\), the foamy-oil saturation, \(S_{fo}(t_{j+1})\), and formation volume factor, \(B_{fo}(R_s)\), are calculated from Eqs. [5.7], [5.9], and [5.10], respectively;

The average reservoir pressure, \(\bar{P}_{\text{ave}}(t_{j+1})\), is calculated from Eq. [5.12] with the determined \(R_s(t_{j+1}), S_{fo}(t_{j+1}), B_{fo}(R_s)\), and the guessing value of \(\Delta S_o\);

Steps (3–5) are repeated until the difference between the two consecutive average reservoir pressures is smaller than 1 kPa in this study. Thus, the average reservoir pressure, \(\bar{P}_{\text{ave}}(t_{j+1})\), and the heavy oil saturation, \(S_o(t_{j+1})\), at \(t = t_{j+1}\) are determined;

The cumulative heavy oil and gas productions, \(Q_o(t_{j+1})\) and \(Q_g(t_{j+1})\) at \(t = t_{j+1}\), are calculated from Eqs. [5.4] and [5.5], respectively;

Steps (3–7) are repeated to calculate the cumulative heavy oil and gas productions, \(Q_o(t)\) and \(Q_g(t)\), and the average reservoir pressure, \(\bar{P}_{\text{ave}}(t)\), at the pre-specified time in the primary production with the two-phase flow when the average reservoir pressure is lower than the pseudo bubble-point pressure, \((P_{pb})_{pp}\).
Specify the unknown parameters in MOPSO

Calculate $Q_o(t_{j+1})$, $Q_g(t_{j+1})$, and $P_{ave}(t_{j+1})$ by using Eqs. [5.1a], [5.2a], and [5.3], respectively

$P_{ave}(t) > (P_{pb})_{pp}$

Yes

No

Calculate $Q_o(t_{j+1})$ and $Q_g(t_{j+1})$ by using Eqs. [5.4] and [5.5]

$t_{j+1} < t_n$

Yes

No

Calculate multiple objective functions by using Eqs. [5.17a–c]

$i = i + 1$

Yes

$i \leq 1,000$

Determine $k_{romax}$, $k_{rgmax}$, $S_{or}$, $n_o$, $n_g$, $h_{pp}$, $\lambda_{pp}$, $\lambda_{CSI}$, and $(P_{pb})_{pp}$, by minimizing the overall objective function defined in Eq. [5.18]

Update $\Delta S_o$

$j = j + 1$

Figure 5.1  Flowchart for determining the five mobility parameters, $k_{romax}$, $k_{rgmax}$, $S_{or}$, $n_o$, $n_g$, and four kinetic parameters, $h_{pp}$, $\lambda_{pp}$, $\lambda_{CSI}$, $(P_{pb})_{pp}$, in the MBM.
(9) During the CSI production period, the cumulative heavy oil and gas productions, \( Q_o(t) \) and \( Q_g(t) \), and the average reservoir pressure, \( P_{ave}(t) \), can be calculated similarly by following Steps (3–8). It should be noted that Eq. [5.13] becomes the relation between the average reservoir pressure, \( P_{ave}(t_{j+1}) \), and the heavy oil saturation at \( t = t_{j+1} \), \( S_o(t_{j+1}) \), which was derived from the Darcy’s law in this case;

(10) The multiple objective functions are determined from Eqs. [5.17a–c] after the cumulative heavy oil and gas productions, \( Q_o(t) \) and \( Q_g(t) \), and the average reservoir pressures, \( P_{ave}(t) \), in the primary production and subsequent CSI are predicted; and

(11) The new adjustable parameters are generated in the MOPSO and Steps (1–10) are repeated for the maximum iteration number of 1,000 when no new Pareto optimal solutions are found. The optimum unknown parameters are selected from the Pareto optimal solutions and determined by minimizing the overall average objective function defined in Eq. [5.18].

In this work, the measured cumulative heavy oil and gas production data and average reservoir pressures at different production times in Tests #2–4 and #12 are used to validate the theoretical MBM.

5.3 Results and Discussion

5.3.1 History matching

The measured and predicted cumulative heavy oil and gas productions and average reservoir pressures in Tests #2–4 and #12 are plotted and compared in Figures 5.2(a–d), respectively. It was found from Figures 5.2(a) and (b) that Tests #2 and #3 had similar
Figure 5.2  (a) Measured and predicted cumulative heavy oil and gas production as well as average reservoir pressure versus time data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of Test #2.
Figure 5.2  (b) Measured and predicted cumulative heavy oil and gas production as well as average reservoir pressure versus time data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of Test #3.
Figure 5.2 (c) Measured and predicted cumulative heavy oil and gas production as well as average reservoir pressure versus time data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of Test #4.

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Figure 5.2  (d) Measured and predicted cumulative heavy oil and gas production as well as average reservoir pressure versus time data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of Test #12.
production trends because the almost same production scheme was adopted in these two
tests. The only difference is that the soaking time in Test #3 was increased to 24 h,
instead of 1 h in Test #2. In Figure 5.2(c) for Test #4, more gas was produced and a lower
average reservoir pressure was reached at the end than those in Tests #2 and #3. This was
attributed to the lowest pressure drawdown rate of 1.0 kPa/min used in both the primary
production and the subsequent CSI in Test #4, which led to a much longer production
time. Figure 5.2(d) for Test #12 gave the lowest cumulative heavy oil production because
a much more viscous McLaren heavy oil was used in this test. It can be seen from these
four figures that overall, the predicted cumulative heavy oil production and average
reservoir pressure agree reasonably well with the measured data. However, the predicted
cumulative gas production was always much lower than the measured data because the
viscous fingering was severe and the high-permeability gas channels were formed during
the CSI.

5.3.2 Nucleation and decay coefficients

There are nine adjustable parameters to be determined in the present MBM, which can be
roughly categorized as five mobility parameters and four kinetic parameters. The five
mobility parameters, \( k_{\text{romax}} \), \( k_{\text{rgmax}} \), \( S_{or} \), \( n_o \), and \( n_g \), are used in the modified
Brooks–Corey correlations to determine the oil and gas relative permeabilities. The four
kinetic parameters are used to characterize the bubble nucleation and coalescence
processes. They are the nucleation coefficient of dissolved CH\(_4\) in the heavy oil in the
primary production, \( h_{pp} \), the decay coefficients of dispersed CH\(_4\) from the heavy oil in the
primary production and in the subsequent CSI, \( \lambda_{pp} \) and \( \lambda_{CSI} \), as well as pseudo bubble-
point pressure of the heavy oil-CH\(_4\) system in the primary production, \( (P_{pb})_{pp} \). The
determined mobility and kinetic parameters in Tests #2–4 and #12 are listed and compared in Table 5.1. It was found that the mobility parameters are in the same orders as those in the literature for a heavy oil reservoir (Tang and Firoozabadi, 2006; Akhlaghinia et al., 2013; Yadali Jamaloei et al., 2013). The kinetic parameters of Tests #2 and #3 are close to each other because of their almost same production scheme. The nucleation coefficients \( h_{pp} \) of the dissolved CH\(_4\) in the heavy oil in Tests #2–4 and #12 are plotted in Figure 5.3. During the nucleation, a few CH\(_4\) molecules form a cluster when the Gibbs free energy barrier is overcome. The Gibbs free energy barrier is decreased with the decreased surface energy of the CH\(_4\) bubbles and the increased solvent supersaturation, the latter of which is the driving force for the nucleation. The increased solvent supersaturation can be caused by increasing the pressure drawdown rate (Moulu, 1989). Therefore, the nucleation coefficient of the dissolved CH\(_4\) in the heavy oil is larger when the pressure drawdown rate is higher. In this case, the dissolved CH\(_4\) is nucleated more quickly in the heavy oil to form the dispersed small CH\(_4\) bubbles. It is noted from Figure 5.3 that the nucleation coefficient of CH\(_4\) in the more viscous McLaren heavy oil (Test #12) is much smaller than those in the less viscous Colony heavy oil (Test #2 or #3) at the same pressure drawdown rate. Also CH\(_4\) solubility in the more viscous McLaren heavy oil is much lower than that in the less viscous Colony heavy oil. The probability for CH\(_4\) molecules to be nucleated is decreased because much less CH\(_4\) is dissolved into the McLaren heavy oil under the same testing conditions.

Figure 5.4 shows the respective decay coefficients \( \lambda_{pp} \) and \( \lambda_{CSI} \) of the dispersed CH\(_4\) bubbles from the heavy oil during the primary production and subsequent CSI in Tests #2–4 and #12. The determined decay coefficients of the dispersed CH\(_4\) bubbles
Table 5.1  Five mobility parameters and four kinetic parameters used in the MBM for Tests #2–4 and #12.

<table>
<thead>
<tr>
<th>Test No.</th>
<th>( k_{\text{romax}} )</th>
<th>( k_{\text{rgmax}} )</th>
<th>( S_{\text{or}} ) (%)</th>
<th>( n_o )</th>
<th>( n_g )</th>
<th>( h_{\text{pp}} ) (s(^{-1}))</th>
<th>( \lambda_{\text{pp}} ) (10(^{-5}) s(^{-1}))</th>
<th>( \lambda_{\text{CSI}} ) (10(^{-5}) s(^{-1}))</th>
<th>( (P_{\text{pb}})_{\text{pp}} ) (kPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>1.0</td>
<td>0.01</td>
<td>35.2</td>
<td>3.3</td>
<td>3.5</td>
<td>0.093</td>
<td>9.5</td>
<td>1.0</td>
<td>2000</td>
</tr>
<tr>
<td>3</td>
<td>0.6</td>
<td>0.002</td>
<td>32.8</td>
<td>3.1</td>
<td>4.4</td>
<td>0.099</td>
<td>7.6</td>
<td>0.8</td>
<td>2017</td>
</tr>
<tr>
<td>4</td>
<td>1.0</td>
<td>0.03</td>
<td>15.3</td>
<td>2.0</td>
<td>6.0</td>
<td>0.035</td>
<td>824.1</td>
<td>824.1</td>
<td>2114</td>
</tr>
<tr>
<td>12</td>
<td>1.0</td>
<td>0.003</td>
<td>15.3</td>
<td>2.0</td>
<td>4.9</td>
<td>0.040</td>
<td>5.1</td>
<td>0.5</td>
<td>1800</td>
</tr>
</tbody>
</table>
Figure 5.3  Nucleation coefficients ($h_{pp}$) of dissolved CH$_4$ in the heavy oil in the primary production of Tests #2–4 and #12 with different pressure drawdown rates.
Figure 5.4   Decay coefficients of dispersed CH₄ from the heavy oil in the primary production ($\lambda_{pp}$) and subsequent CSI ($\lambda_{CSI}$) of Tests #2–4 and #12.
from the heavy oil are close to those published in the literature (Sheng et al., 1999b). The differences may be attributed to different heavy oils, production schemes and pressure drawdown rates used in this study. It can be concluded from Figure 5.4 that a higher pressure drawdown rate leads to a smaller decay coefficient of the dispersed CH$_4$ from the heavy oil and a more stable foamy oil. This is because the larger gas bubbles can break up into smaller gas bubbles when the pressure drawdown rate is high (Bora, 1998). The small gas bubbles can remain in the heavy oil for a long time because of a small total surface area or a low surface energy. The bubble breakup rate is also affected by the mechanical shear stress exerted by the surrounding liquid, which is proportional to the liquid velocity. The liquid velocity is generally higher at a higher pressure drawdown rate. Consequently, smaller gas bubbles are formed more quickly in a pressure-depletion test with a higher pressure drawdown rate.

Moreover, the decay coefficient of dispersed CH$_4$ from the heavy oil is decreased when the heavy oil viscosity is increased. As CH$_4$ bubbles approach each other, the thinning of the liquid films between the bubbles is important to the bubble stability. Obviously, the film thinning rate is decreased when the heavy oil viscosity is increased and the heavy oil flow rate is low. Besides, the flow resistance of the gas bubbles in the viscous heavy oil is high, which makes the foamy-oil system more stable (George et al., 2005; Wang et al., 2009b). The specific effects of the pressure drawdown rate and the heavy oil viscosity on the decay coefficient of the dispersed CH$_4$ bubbles found in this study are consistent with the experimental observations (Sheng et al., 1997).
5.3.3 Sensitivity analysis

In this study, the effects of some key mobility and kinetic parameters on the final cumulative heavy oil and gas productions and average reservoir pressure are examined by purposely increasing/decreasing an individual parameter by 20%. The detailed results of these sensitivity analyses by using Test #3 as a reference test are tabulated in Table 5.2. The cumulative heavy oil and gas productions and average reservoir pressure are affected substantially by the maximum oil relative permeability, \( k_{\text{romax}} \), whereas they are less sensitive to the kinetic parameters, i.e., \( h_{pp} \), \( \lambda_{pp} \), \( \lambda_{\text{CSI}} \), and \( (P_{pb})_{pp} \). The maximum oil relative permeability influences the final cumulative gas production more than the final cumulative oil production. Moreover, the final cumulative oil production changes more considerably with the kinetic parameters than the final cumulative gas production and average reservoir pressure. These findings also help to quickly determine the mobility and kinetic parameters by history matching the pressure-depletion processes in the primary production and subsequent CSI.

Table 5.2 indicates that a higher maximum oil relative permeability leads to a higher cumulative heavy oil production according to the Darcy’s law. When the pseudo bubble point-pressure is lower, the single-oil-phase flow during the primary production is longer. More foamy oil remains in the subsequent CSI production periods and less gas is produced during the subsequent CSI production period. The dissolved CH\(_4\) is nucleated more quickly to form the foamy oil if the nucleation coefficient is increased. However, the foamy-oil viscosity becomes higher after the nucleation of the dissolved gas (Bora, 1998). Therefore, the highest cumulative heavy oil production can be achieved at an intermediate or optimum nucleation coefficient by properly balancing the foamy-oil
Table 5.2  Sensitivity analysis results of the maximum gas relative permeability and four kinetic parameters, where Test #3 is used as a reference test.

<table>
<thead>
<tr>
<th>Reference test (Test #3)</th>
<th>Changed parameter</th>
<th>Relative change$^a$ of parameter (%)</th>
<th>$Q_{oc}(t_n)$ (cm$^3$)</th>
<th>Relative change of $Q_{oc}(t_n)$ (%)</th>
<th>$Q_{gc}(t_n)$ (cm$^3$)</th>
<th>Relative change of $Q_{gc}(t_n)$ (%)</th>
<th>$P_{ave}(t_n)$ (kPa)</th>
<th>Relative change of $P_{ave}(t_n)$ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parameter</td>
<td>Base value</td>
<td>-</td>
<td>0.0</td>
<td>69.6</td>
<td>0.0</td>
<td>2757</td>
<td>0.0</td>
<td>711</td>
</tr>
<tr>
<td>$k_{n_{\text{omax}}}$</td>
<td>0.60</td>
<td>0.72</td>
<td>20.0</td>
<td>75.7</td>
<td>8.8</td>
<td>3076</td>
<td>11.6</td>
<td>678</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.48</td>
<td>−20.0</td>
<td>61.3</td>
<td>−11.8</td>
<td>2417</td>
<td>−12.3</td>
<td>745</td>
</tr>
<tr>
<td>$(P_{pb})_{pp}$ (kPa)</td>
<td>2.017</td>
<td>2420</td>
<td>20.0</td>
<td>66.2</td>
<td>−4.8</td>
<td>2800</td>
<td>1.5</td>
<td>697</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1613</td>
<td>−20.0</td>
<td>74.7</td>
<td>7.4</td>
<td>2635</td>
<td>−4.4</td>
<td>741</td>
</tr>
<tr>
<td>$h_{pp}$ (s$^{-1}$)</td>
<td>0.099</td>
<td>0.120</td>
<td>20.0</td>
<td>66.2</td>
<td>−4.9</td>
<td>2749</td>
<td>−0.3</td>
<td>700</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.079</td>
<td>−20.0</td>
<td>70.3</td>
<td>1.1</td>
<td>2710</td>
<td>−1.7</td>
<td>714</td>
</tr>
<tr>
<td>$\lambda_{pp}$ &amp; $\lambda_{CSI}$ (10$^{-5}$ s$^{-1}$)</td>
<td>7.6 &amp; 0.8</td>
<td>9.1 &amp; 1.0</td>
<td>20.0</td>
<td>63.9</td>
<td>−8.1</td>
<td>2663</td>
<td>−3.4</td>
<td>693</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6.1 &amp; 0.7</td>
<td>−20.0</td>
<td>77.8</td>
<td>11.8</td>
<td>2817</td>
<td>2.1</td>
<td>745</td>
</tr>
</tbody>
</table>

Note: $^a$relative change $= \frac{x - x_{\text{base}}}{x_{\text{base}}} \times 100\%$
formation rate and viscosity regainment. The cumulative heavy oil production is increased and the average reservoir pressure is well maintained as the decay coefficient is decreased, which means that the foamy oil is more stable and lasts longer.

5.3.4 Foamy-oil isothermal compressibility and dispersed gas volume fraction

Figures 5.5(a–d) show the predicted foamy-oil isothermal compressibilities and dispersed gas volume fractions in the foamy oil versus time data in Tests #2–4 and #12. They depict that in the primary production of Test #2 or #3, the foamy-oil isothermal compressibility is suddenly increased at the beginning of the two-phase flow period due to the foamy-oil formation. It is decreased in the late primary production because more and more dispersed CH₄ bubbles are coalesced and liberated from the heavy oil to become the free gas. At the end of the primary production, it is increased again because of the larger dispersed gas volume at the lower reservoir pressure, which can be 1,000 times larger than the initial live-oil isothermal compressibility. At the beginning of the CSI production period, the foamy-oil isothermal compressibility is large because of some CO₂ dissolution, which has a stronger oil-swelling effect. Then it becomes smaller as the dispersed CH₄ bubbles are coalesced continuously to become the free gas. It is worthwhile to mention that the predicted foamy-oil isothermal compressibilities are in the same order as those reported in the literature (Shi et al., 2016). Moreover, the foamy-oil isothermal compressibility in Test #4 is much lower than that in Test #2 or #3 because the lowest pressure drawdown rate of 1.0 kPa/min was applied in this test, as shown in Figure 5.5(c). A lower foamy-oil compressibility does not help to maintain the reservoir pressure and heavy oil production rate. Figure 5.5(d) shows that the foamy-oil isothermal
Figure 5.5  Predicted foamy-oil isothermal compressibility and dispersed gas fraction in the foamy oil versus time data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of (a) Test #2; and (b) Test #3.
Figure 5.5  Predicted foamy-oil isothermal compressibility and dispersed gas fraction in the foamy oil versus time data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of (c) Test #4; and (d) Test #12.
compressibility in Test #12 is also lower than that in Test #2 or #3, which indicates that dissolved CH₄ is nucleated much more slowly in the more viscous McLaren heavy oil.

It can also be found from Figures 5.5(a–d) that there are not dispersed CH₄ bubbles in the heavy oil at the beginning when the average reservoir pressure is higher than the pseudo bubble-point pressure in Tests #2–4 and #12. The dispersed CH₄ volume fraction in the heavy oil is increased starting from the pseudo bubble-point pressure till the end of the primary production, which can be as high as 14 vol.% in Test #2. During the CSI production period, the dispersed CH₄ volume fraction in the heavy oil was decreased because the dispersed CH₄ bubbles were coalesced continuously to become the free gas and no more dissolved CH₄ was available to nucleate the dispersed gas bubbles and form the foamy oil. In addition, the dispersed CH₄ volume fraction in the heavy oil in Test #2 or #3 is larger than that in Test #4. This is because Test #2 or #3 has a larger nucleation coefficient of the dissolved CH₄ in the heavy oil and a smaller decay coefficient of the dispersed CH₄ bubbles from the heavy oil. Therefore, the dissolved CH₄ is nucleated more quickly to become the dispersed CH₄ bubbles, which tend to remain in the heavy oil for a longer time. The dispersed CH₄ volume fraction in the heavy oil in Test #12 is smaller than that in Test #2 or Test #3. In Test #12, the nucleation coefficient of the dissolved CH₄ is smaller so that dissolved CH₄ is nucleated more slowly to become the dispersed CH₄ bubbles.

5.3.5 Foamy-oil viscosity and solution CH₄–oil ratio

It can be seen from Figures 5.6(a–d) that the foamy-oil viscosity is increased and the solution CH₄–oil ratio is decreased during the primary production. The foamy-oil viscosity regainment is caused by the nucleation of the dissolved CH₄ in the heavy oil.
Figure 5.6  Predicted foamy-oil viscosity and solution CH₄–oil ratio versus time data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of (a) Test #2; and (b) Test #3.
Figure 5.6  Predicted foamy-oil viscosity and solution CH₄–oil ratio versus time data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of (c) Test #4; and (d) Test #12.
The foamy-oil viscosity is slightly lower during the CSI production period than that at the end of the primary production because of some CO₂ dissolution. The foamy-oil viscosity and solution CH₄–oil ratio remain almost unchanged during the CSI production period. The amount of dissolved CH₄ or CO₂ is so small that the dissolved gas cannot be nucleated in and released from the heavy oil during the CSI production period. At the end of the CSI, the foamy-oil viscosity is 45–64% of the dead heavy oil viscosity. The solution CH₄–oil ratio is 24–59% of the initial solution CH₄–oil ratio at the initial reservoir pressure of 3.0 MPa and temperature of 21 °C.

5.3 Chapter Summary

In this chapter, an analytical material balance model (MBM) is derived to predict the cumulative heavy oil and gas productions and average reservoir pressures in the primary production and subsequent cyclic solvent injection (CSI). The predicted cumulative heavy oil production and average reservoir pressure agree reasonably well with the measured data. Nevertheless, there are relatively large differences between the measured and predicted cumulative gas productions because the gas channeling in the solution-gas drive is not considered in the MBM, which requires some further studies. The dynamic gas nucleation and bubble coalescence processes are modeled by using two kinetic equations. The predicted nucleation coefficient of the dissolved CH₄ in the heavy oil to become the dispersed CH₄ bubbles was found to increase as the pressure drawdown rate is increased or the heavy oil viscosity is reduced. It was also found that the predicted decay coefficient of the dispersed CH₄ bubbles from the heavy oil to become the so-called free gas is smaller if the pressure drawdown rate or the heavy oil viscosity is increased. The foamy-oil isothermal compressibility and dispersed gas volume fraction
are increased considerably and quickly during the primary production, which is beneficial to the reservoir pressure maintenance. The foamy-oil viscosity and solution CH$_4$–heavy oil ratio remain almost constant during the subsequent CSI because CH$_4$ concentration in the heavy oil is so low that no dissolved CH$_4$ is released from the heavy oil.
CHAPTER 6  NUMERICAL SIMULATIONS OF COMBINED CYCLIC SOLVENT INJECTION AND WATERFLOODING/GASFLOODING

6.1  Laboratory-Scale History Matching

6.1.1  Laboratory-scale numerical simulation model

In this study, a numerical simulation model based on the laboratory sandpacked physical model was used in the CMG STARS module to simulate CSI (Test #3), CSI + WF (Test #6), simultaneous CSI + WF (Test #8), and WF + CSI (Test #9). A total of 40 × 5 × 1 grids were generated with the grid sizes of 1.0 × 2.0 × 2.0 cm³ in the x, y, and z directions, respectively. The ij cross section of this numerical model is shown in Figure 6.1. Since the physical model was sandpacked homogeneously, its porosity and permeability were assumed to be uniform everywhere. The reservoir conditions (P_res and T_res) and characteristics (k and φ) were set to be the same as those in the laboratory tests. The oil, gas, and water relative permeabilities were modeled by using the modified Brooks–Corey correlations (Brooks and Corey, 1964) with the end-point saturations and exponential powers. The oil, gas, and water relative permeabilities were adjusted and determined so that the simulated heavy oil, gas, and water production data can best history match the measured production data of three fluids: the oil, gas, and water (Ma and Gu, 2017e).
Figure 6.1  The ij cross section of the numerical simulation model for the homogeneous sandpacked physical model used in the experimental tests.
6.1.2 EOS modeling

A EOS model of the Colony heavy oil–CH$_4$/CO$_2$ system was generated by using the Peng–Robinson equation of state (P–R EOS) (Peng and Robinson, 1976) in the CMG WinProp module. Accurate characterization of the Colony heavy oil tested in this study is difficult because the heavy oil contains large amounts of heavy components. For example, the Colony heavy oil has 8.53 mol.% of C$_{61+}$. In practice, the heavy oil is assumed to consist of several pseudo-components with known properties, such as the critical pressure $P_c$, the critical temperature $T_c$, the Pitzer acentric factor $\omega$, and the molecular weight $MW$ (Chen et al., 2006; Lin et al., 2014). In this study, splitting and lumping were used to represent the compositional analysis result and divide the heavy oil into two pseudo-components. More specifically, the molecular weight and mole fraction of each component in the compositional analysis result, see Table 3.1(a), the apparent molecular weight and specific gravity of the Colony heavy oil were required to perform the splitting and lumping. The plus fraction splitting form was added into the WinProp module with the Gamma function and the Gaussian Quadrature as the splitting distribution function and the lumping method, respectively. Twu (1984) correlation was used to calculate the critical properties ($P_c$ and $T_c$) of each pseudo-component. The adaptive least-squares regression (Agarwal et al., 1990) was preformed to tune the EOS model. The critical pressure $P_c$, critical temperature $T_c$, molecular weight $MW$ of the heavier pseudo-component, and binary interaction parameter (BIP) between each of the two pseudo-components and CH$_4$/CO$_2$ were used as the adjustable parameters to best fit the measured CH$_4$/CO$_2$ solubilities in the Colony heavy oil, oil-swelling factors and densities of the Colony heavy oil–CH$_4$/CO$_2$ system at different equilibrium pressures and $T_{res} = 21 \ ^\circ$C.
Both the modified Pederson viscosity model (Pederson, 1987) and the Jossi–Stiel–Thodos viscosity correlation (Jossi et al., 1962) were tested and used to match the measured viscosities of the Colony heavy oil–CH₄/CO₂ system. It was found that the modified Pederson viscosity model can provide better regressed viscosities of the CH₄/CO₂-saturated heavy oil tested in this work, whereas the Jossi–Stiel–Thodos viscosity correlation was not suitable. Finally, the basic physicochemical properties (mole percentages, critical pressures, critical temperatures, Pitzer acentric factors, molecular weights, and BIPs) and K-values were generated for the CMG STARS module.

6.1.3 Foamy-oil model

In order to include the foamy-oil flow in the numerical model, the non-equilibrium dissolution processes of CH₄ and CO₂ into the heavy oil are represented by the following two kinetic equations with two reaction frequency factors, respectively (Ivory et al., 2009):

\[
\begin{align*}
(CH_4)_G + (CH_4)_L & \rightarrow 2(CH_4)_L, \quad [6.1] \\
(CO_2)_G + (CO_2)_L & \rightarrow 2(CO_2)_L, \quad [6.2]
\end{align*}
\]

where, L and G denote the solvent dissolved in the heavy oil phase and the solvent in the gas phase, respectively. Moreover, the non-equilibrium gas release processes of CH₄ and CO₂ from the heavy oil to form the foamy heavy oil are represented by (Ivory et al., 2009):

\[
\begin{align*}
(CH_4)_L & \rightarrow \text{Bub} \rightarrow (CH_4)_G, \quad [6.3] \\
(CO_2)_L & \rightarrow \text{Bub} \rightarrow (CO_2)_G, \quad [6.4]
\end{align*}
\]
where, Bub CH$_4$ and Bub CO$_2$ are CH$_4$ and CO$_2$ bubbles dispersed in the heavy oil phase, respectively.

### 6.1.4 Numerical simulation results

In the EOS modeling, the adaptive least-squares regression was performed to match the experimentally measured data. The predicted viscosities and PVT data of the Colony heavy oil–CH$_4$/CO$_2$ system are compared with the measured data in Figures 6.2(a–e), respectively. It can be seen from these five figures that fairly good agreements were obtained between the numerically predicted and experimentally measured data. After the adaptive least-squares regression, the physicochemical properties of the two pseudo-components are listed in Table 6.1. It is worthwhile to point out that the BIP between each pseudo-component and CH$_4$ is not listed in the table because it is approximately one order smaller than that between each pseudo-component and CO$_2$, which is given in the table. It should also be noted that the BIP between each pseudo-component and CO$_2$ is increased when the hydrocarbon component in the heavy oil becomes heavier. This fact indicates that a heavier hydrocarbon component with a larger carbon number has a stronger interaction with CO$_2$, in comparison with a lighter hydrocarbon component.

History matching of the cumulative heavy oil/gas/water production data was performed by using the CMG CMOST module for the CSI (Test #3), CSI + WF (Test #6), simultaneous CSI + WF (Test #8), and WF + CSI (Test #9). The history matching results are shown in Figures 6.3(a–d). It can be seen from these four figures that the predicted cumulative heavy oil and water production data from the CMG CMOST module well match those measured data for each test. The predicted cumulative gas
Figure 6.2  (a) Measured viscosities of CH₄/CO₂-saturated Colony heavy oil as a function of pressure at $T_{res} = 21^\circ$C.
**Figure 6.2**  (b) Measured and predicted saturation pressures of the Colony heavy oil–CH$_4$/CO$_2$ system as a function of CH$_4$/CO$_2$ concentration at $T_{res} = 21$ °C.
Figure 6.2  (c) Measured and predicted densities of CH₄/CO₂-saturated Colony heavy oil as a function of pressure at \( T_{\text{res}} = 21 \, ^{\circ}\text{C} \).
**Figure 6.2**  (d) Measured and predicted solubilities of CH$_4$/CO$_2$ in the Colony heavy oil as a function of pressure at $T_{res} = 21$ °C.
Figure 6.2  (e) Measured and predicted oil-swelling factors of CH₄/CO₂-saturated Colony heavy oil as a function of pressure at $T_{res} = 21 ^\circ C$. 
Table 6.1  Physicochemical properties of the two pseudo-components of the Colony heavy oil after the adaptive least-squares regression.

<table>
<thead>
<tr>
<th>Properties</th>
<th>Pseudo-components</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mole percentage (mol.%)</td>
<td>#1</td>
</tr>
<tr>
<td>Critical pressure $P_c$ (MPa)</td>
<td>2.21</td>
</tr>
<tr>
<td>Critical temperature $T_c$ (K)</td>
<td>674.8</td>
</tr>
<tr>
<td>Pitzer acentric factor $\omega$</td>
<td>0.526</td>
</tr>
<tr>
<td>Molecular weight $MW$ (g/mol)</td>
<td>160.7</td>
</tr>
<tr>
<td>Binary interaction parameter (BIP) with CO$_2$</td>
<td>0.09</td>
</tr>
</tbody>
</table>
Figure 6.3  (a) Measured and simulated cumulative heavy oil and gas production data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of Test #3 (CSI).
Figure 6.3  (b) Measured and simulated cumulative heavy oil, gas and water production data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of Test #6 (CSI + WF).
Figure 6.3  (c) Measured and simulated cumulative heavy oil, gas and water production data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of Test #8 (simultaneous CSI + WF).
Figure 6.3  (d) Measured and simulated cumulative heavy oil, gas and water production data in the primary production (PP) and subsequent CSI, including solvent injection (I), soaking (S), and oil production (P) periods of Test #9 (WF + CSI).
production data are slightly lower than the measured data due to the gas channeling. It is suggested that two sets of the oil and gas relative permeabilities should be used to consider the gas channeling in the future. The lower gas relative permeabilities are applied to calculate the dispersed-gas production because the dispersed gas is trapped in the heavy oil. The higher gas relative permeabilities are used to predict the free-gas production due to the gas channeling.

6.2 Field-Scale Production Optimization

6.2.1 Field-scale numerical simulation model

In this study, a synthetic field-scale heavy oil reservoir is used as an example for the production optimization. The reservoir model consists of a total of 20 × 20 × 5 grids with the grid sizes of 10 × 10 × 1 m³ in the x, y, and z directions. The reservoir permeability and porosity have the normal distributions with the respective average values of 3 D and 30%, as shown in Figures 6.4(a) and (b). The major reservoir characteristics are listed in Table 6.2. The EOS model, reaction frequency factors, and three-phase relative permeabilities are unknown but assumed to be the same as those used in the laboratory-scale numerical simulation of the CSI + WF. The heavy oil reservoir is assumed to be under the primary production for 10 years with four producers placed at the four corners, as shown in Figures 6.4(a) and (b). During the primary production, the bottom-hole pressures (BHPs) of the four producers are maintained at 0.2 MPa. The CSI/CSI + WF/CSI + GF is implemented as a follow-up EOR process. The CSI has the injection, soaking, and production periods of 1, 1, and 12 months. The CSI lasts for 6.5 years with 5.5 cycles. In the CSI + WF/GF, a new injector is drilled in the centre of the reservoir for the WF/GF with an inverse five-spot well pattern. The WF/GF lasts for 12 months in
Figure 6.4 Reservoir (a) permeability and (b) porosity normal distributions in the synthetic field-scale heavy oil reservoir.
Table 6.2  Major reservoir characteristics of the synthetic field-scale heavy oil reservoir.

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average reservoir permeability (D)</td>
<td>3</td>
</tr>
<tr>
<td>Effective permeability of the grid containing wormholes (D)</td>
<td>7,816</td>
</tr>
<tr>
<td>Average reservoir porosity (%)</td>
<td>30</td>
</tr>
<tr>
<td>Initial water saturation (%)</td>
<td>20</td>
</tr>
<tr>
<td>Initial reservoir pressure (MPa)</td>
<td>3.0</td>
</tr>
<tr>
<td>Reservoir temperature (°C)</td>
<td>21</td>
</tr>
</tbody>
</table>
each cycle. The CSI + WF/GF is repeated for 3 cycles with the same production life of 6.5 years. The BHPs of the four producers during the CSI and WF/GF and the water/gas injection rate of the injector during the WF/GF are optimized to maximize the NPV.

Wormholes are generated during the CHOPS and they are responsible for the high heavy oil production rate due to an extremely increased permeability. The wormhole growth is taken into account in the numerical simulation by using the diffusion-limited aggregation (DLA) model (Pan et al., 2010). The DLA model has been successfully applied to predict a broad variety of fractal branching-growth processes (Istchenko and Gates, 2014; Haddad and Gates, 2015). After the wormhole growth is determined at a prespecified time, the production performance is then predicted. Then the wormholes grow in a fractal pattern till the next prespecified time. The production performance is predicted on the basis of the updated or dynamic permeability field. This procedure is repeated until the reservoir production time reaches 3 years, when only a small amount of sand is produced from some actual CHOPS reservoirs (Liu and Zhao, 2005). In this study, the wormholes are assumed to grow longitudinally at a linear speed of 0.5 m/d in the middle layer of the synthetic field-scale heavy oil reservoir. The wormhole permeability is determined from the following equation:

\[ k = \phi r^2/8, \]  \[6.1\]

where, \( r \) is the wormhole diameter. The wormhole porosity and diameter are set to be 50% and 0.5 cm, respectively. An effective permeability of 7,816 D is assigned to the grids containing the wormholes. The reservoir permeability distributions (Layer #3) at different production times of 1 year and 3 years in the synthetic CHOPS reservoir are shown in Figures 6.5(a) and (b), respectively.
Figure 6.5  The reservoir permeability distributions (Layer #3) at different production times of (a) 1 year; and (b) 3 years in the CHOPS reservoir.
6.2.2 Two optimization algorithms

In the production optimization, an optimum control problem is solved to determine the optimum well controls, which maximize the NPV for the entire production life of the reservoir (Bao et al., 2010). In this study, the NPV is used as an objective function (Chen and Reynolds, 2016):

\[
J = \sum_{n=1}^{N} \left\{ \frac{\Delta t_n}{(1 + b)^{t_n/365}} \left[ \sum_{j=1}^{N_p} \left( r_o q_{o,j}^n - c_w q_{w,j}^n \right) - \sum_{k=1}^{N_i} \left( c_w q_{wi,k}^n + c_{gi} q_{gi,k}^n \right) \right] \right\},
\]

where, \( N \) is the total number of the simulation time steps; \( N_p \) and \( N_i \) are the total numbers of the producers and injectors, respectively; \( r_o \) is the heavy oil revenue; \( c_w, c_{wi}, \) and \( c_{gi} \) are the disposal cost of the produced water, water-injection cost, and gas-injection cost, respectively; \( q_{o,j}^n \) and \( q_{w,j}^n \) are the average oil and water production rates of the \( j^{th} \) producer at the \( n^{th} \) time step, respectively; \( q_{wi,k}^n \) and \( q_{gi,k}^n \) are the average water injection rate and average gas injection rate of the \( k^{th} \) injector at the \( n^{th} \) time step, respectively; \( \Delta t_n \) is the \( n^{th} \) time step size; \( t_n \) is the cumulative production time at the end of the \( n^{th} \) time step; \( b \) is the annual discount rate. The revenue and disposal cost of the produced gas are not included.

The objective function \( J \) is maximized by adjusting the control vector \( u = [u_1, u_2, u_3, \ldots, u_{N_u}]^T \), which contains all \( N_u \) control variables to be optimized. The control variables are the production control parameters, such as BHPs and fluid injection rate(s) at each control time step. In this study, the control vector is subject to the upper and lower bound constraints:

\[
u_{\text{low}} \leq u \leq u_{\text{up}}.
\]

[6.3]
One way to deal with the constrained optimization problem is to use a log transformation. For the $i^{th}$ control variable $u_i$, the transformed new variable $s_i$ is defined as:

$$s_i = \ln\left(\frac{u_i - u_{i,\text{low}}}{u_{i,\text{up}} - u_i}\right). \quad [6.4]$$

Thus the optimization is carried out in the transformed domain and the actual control variables are determined by using the inverse log transformation (Chen and Reynolds, 2016; Wang et al., 2009a).

**Steepest ascent (SA) method**

The SA method is used for the optimization problem because of its fast convergence rate (Boyd and Vandenberghe, 2009). The gradient is calculated by using the finite-difference method. The gradient of the NPV with respect to each transformed new variable $s_i$ is equal to:

$$g_i \approx \frac{J(s_i + \Delta s_i) - J(s_i)}{\Delta s_i}. \quad [6.5]$$

The transformed new control vector is updated by using the steepest ascent method:

$$s^{k+1} = s^k + \alpha^{k+1} g^k, \quad [6.6]$$

where, $\alpha^{k+1}$ is step size of the $(k + 1)^{th}$ iteration; $g^k$ is the gradient of the NPV with respect to the transformed new vector $s = [s_1, s_2, s_3, \ldots, s_{N_u}]^T$ evaluated at $s^k$ (Bangerth et al., 2006).

The termination criterion of the steepest ascent method is that a pre-specified maximum number of the simulation runs is exceeded or that the relative changes of both the NPV and the norm of the control vector are smaller than the pre-specified termination values (Chen and Reynolds, 2017):
\[
\left| \frac{J(u^{k+1}) - J(u^k)}{J(u^k)} \right| \leq \varepsilon_j, \quad [6.7a]
\]
\[
\left\| u^{k+1} - u^k \right\| \leq \varepsilon_u. \quad [6.7b]
\]

**Particle swarm optimization (PSO) method**

The PSO is a heuristic optimization algorithm, which was initially proposed by Eberhart and Kennedy (1995). The PSO is known to effectively solve the large-scale non-linear optimization problems because of its rapid convergence to the global optimum. Also, it does not require the calculations of the objective function gradients. The PSO employs a swarm of particles with certain positions and velocities in the search space. The position of the \( i^{th} \) particle in the \((k + 1)^{th}\) iteration is determined as follows:

\[
s_i^{k+1} = s_i^k + v_i^{k+1}, \quad [6.8]
\]

where, \( v_i^{k+1} \) is the velocity of the \( i^{th} \) particle in the \((k + 1)^{th}\) iteration and is equal to:

\[
v_i^{k+1} = v_i^k + \beta_1 r_1 (p_i^k - s_i^k) + \beta_2 r_2 (p_g^k - s_i^k), \quad [6.9]
\]

where, \( \beta_1 = 1.49618 \) and \( \beta_2 = 1.49618 \) are two positive weights and \( r_1 \) and \( r_2 \) are two random numbers between 0.0 to 1.0 with an uniform distribution. \( p_i^k \) and \( p_g^k \) are the local best position of the \( i^{th} \) particle and the global best position of the swarm found in the \( k^{th} \) iteration (del Valle et al., 2008).

The initial particle positions are evenly distributed and the initial particle velocities are set to be zero. Once the values of the objective function, i.e., Eq. [6.1], for different particles are obtained, the velocities are updated by using the new local best positions of the particles and the new global best position of the swarm. Then the particles positions
are updated to calculate the objective function. The iteration is continued until the desired termination criterion is satisfied:

$$\left| \frac{J(u^k) - J(u^{k-50})}{J(u^k)} \right| \leq \varepsilon_j . \quad [6.10]$$

The PSO finds the maximum NPV of the CSI/CSI + WF/CSI + GF if the relative change between the $k^{th}$ and $(k - 50)^{th}$ objective functions is smaller than a pre-specified value, $\varepsilon_j$.

In this study, the CSI/CSI + WF/CSI + GF project life is set to be 6.5 years. The control time step size is set to be 0.5 year. There are a total of 11 control time steps for the CSI and 12 control time steps for the CSI + WF/GF. The four producers are under BHP control with an upper bound of 3.0 MPa and a lower bound of 0.2 MPa. The control variable of the WF injector is the water injection rate with an upper bound of 20 m$^3$/d and a lower bound of 0 m$^3$/d. The gas injection rate is used as the control variable of the GF injector and is in the range of 0–1,000 sc m$^3$/d. The following parameters are used in Eq. [6.1] to optimize the NPV: $r_o = $503/m$^3$, $c_w = $31/m$^3$, $c_{wi} = $31/m$^3$, $c_{gi} = $0.05/sc m$^3$, and $b = 10\%$. The maximum numbers of the iterations in the SA method and PSO are equal to 500. The termination criteria of $\varepsilon_j$ and $\varepsilon_u$ are equal to $10^{-4}$ and $10^{-3}$, respectively.

6.2.3 CSI optimization

The effectiveness and efficiencies of the two different optimization algorithms, i.e., the SA method and PSO, are studied and compared by optimizing the CSI. In addition, two reservoir models with and without the wormholes are used to examine the effect of the wormholes. For the SA method, the initial BHPs of the four producers are set to be equal to 1.5 MPa. For the PSO, 20 particles with the evenly-distributed BHPs of the four producers are generated initially.
Figure 6.6 shows that the NPV changes with the number of the simulation runs in each case. The final NPV obtained from the SA method is slightly lower than that determined from the PSO. The SA method converges faster than the PSO when the wormholes are not taken into account. The two optimization algorithms converge with approximately 2,200 simulation runs in the presence of the wormholes. Moreover, the final NPV for the post-CHOPS reservoir with the wormholes is over 10 times higher than that for the heavy oil reservoir without the wormholes. The wormholes generated during the primary production greatly help to increase the NPV of the CSI in the post-CHOPS reservoirs. The solvent CO$_2$ is easily injected into the heavy oil reservoir with the wormholes. The contact area between the heavy oil and CO$_2$ is much increased. Hence, more CO$_2$ is dissolved into the heavy oil and the heavy oil viscosity is more reduced. In addition, the overall reservoir permeability is also increased because of the presence of the wormholes. Therefore, the mobility of the heavy oil is dramatically increased and more heavy oil is produced. More numerical simulations are run to optimize the CSI in the post-CHOPS reservoir than those for the heavy oil reservoir without the wormholes. The more heterogeneous the heavy oil reservoir is, the more simulation run is needed for the two optimization algorithms.

Figure 6.7 presents the final BHPs of the four producers obtained from the PSO during the CSI in the post-CHOPS reservoirs. The solution of the CSI optimization problem shows a bang-bang behaviour, which means that every control variable takes its maximum or minimum value (Sudaryanto and Yorsos, 2000). The four producers remain at the lower bound of the BHP during the entire reservoir life so that the pressure gradient
Figure 6.6  NPVs determined by using the SA method and PSO for the CSI in the heavy oil reservoir with/without the wormholes as a function of the number of the simulation runs.
Figure 6.7    Final BHPs of Producers #1–4 determined from the PSO during the CSI in the post-CHOPS reservoirs, which are all fixed at the lower bound of the BHP of 200 kPa.
in space and the pressure drawdown rate in time are high. More foamy oil can be formed and is more stable at a higher pressure drawdown rate, which is beneficial to control the gas mobility. Figure 6.8 shows the final BHPs of the four producers obtained from the SA method during the CSI in the post-CHOPS reservoir. The BHPs of Producer #2–4 determined from the final iteration are not equal to the lower bound because the gradient-based methods are designed to find a local optimum (Nocedal and Wright, 2006). In addition, the final BHPs of the four producers reach the lower bound of 200 kPa during the CSI in the heavy oil reservoir without the wormholes.

The oil and gas saturations at the end of the CSI in the heavy oil reservoir (Layer #3) without the wormholes are shown in Figure 6.9. A large amount of the heavy oil is not produced because of the high heavy oil viscosity, even though the four producers operate at the minimum BHP during the entire production life. Also, the gas only reaches the vicinities of the producers. The oil and gas saturations are symmetrically distributed due to the symmetrical well placements and almost uniform reservoir characteristics. The oil and gas saturations of the same layer in the presence of the wormholes are shown in Figure 6.10. More wormholes are generated near Producers #1–3 so that the remaining oil saturations are lower in the nearby regions. The gas saturation in the high-permeability area is high. The injected CO₂ easily flows along the wormholes and contacts with the heavy oil. Consequently, the wormholes are necessary for the follow-up CSI to recover more heavy oil and obtain a higher NPV.

Table 6.3 summarizes the final NPVs determined from the SA method and PSO, the cumulative heavy oil, water, and gas production data at the end of the CSI in the heavy oil reservoir with/without the wormholes. The cumulative heavy oil, water, and gas
Figure 6.8    Final BHPs of (a) Producer #1; (b) Producer #2; (c) Producer #3; and (d) Producer #4 determined from the SA method during the CSI in the post-CHOPS reservoirs.
Figure 6.9  (a) Oil saturations and (b) gas saturations at the end of the CSI in the heavy oil reservoir (Layer #3) without the wormholes.
**Figure 6.10**  (a) Oil saturations and (b) gas saturations at the end of the CSI in the post-CHOPS reservoir (Layer #3) with the wormholes.
Table 6.3 Final NPVs determined from the SA method and PSO, cumulative heavy oil, water, and gas production data at the end of the CSI in the heavy oil reservoirs with/without the wormholes.

<table>
<thead>
<tr>
<th>Wormholes</th>
<th>Optimization algorithm</th>
<th>Optimum NPV ($ \times 10^6$ $\dollar$)</th>
<th>$Q_o$ ($\times 10^3$ m$^3$)</th>
<th>$Q_w$ (m$^3$)</th>
<th>$Q_g$ ($\times 10^4$ sc m$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Absence</td>
<td>SA</td>
<td>0.30</td>
<td>2.5</td>
<td>8.0</td>
<td>4.9</td>
</tr>
<tr>
<td></td>
<td>PSO</td>
<td>0.30</td>
<td>2.5</td>
<td>8.0</td>
<td>4.9</td>
</tr>
<tr>
<td>Presence</td>
<td>SA</td>
<td>3.48</td>
<td>10.6</td>
<td>310.2</td>
<td>38.8</td>
</tr>
<tr>
<td></td>
<td>PSO</td>
<td>3.49</td>
<td>10.6</td>
<td>316.0</td>
<td>38.9</td>
</tr>
</tbody>
</table>
production data determined from the SA method are almost the same as those determined from the PSO. The SA method can give good estimates of the optimum NPVs for the CSI in the heavy oil reservoir with/without the wormholes. The cumulative oil, water, and gas production data in the post-CHOPS reservoir with the wormholes are much higher than those in the heavy oil reservoir without the wormholes. Although gas channeling in the post-CHOPS reservoir is more severe, more heavy oil is still produced and a higher NPV is achieved at the end.

### 6.2.4 CSI + WF optimization

Figure 6.11 shows the NPVs determined from the SA method and PSO versus the number of the numerical simulation runs for the CSI + WF in the heavy oil reservoir with/without the wormholes. The NPVs determined from both methods are increased rapidly in the first few numerical simulation runs and then do not change appreciably. The PSO performs better than the SA method for the CSI + WF optimization in terms of the final NPV and the number of numerical simulation runs. The PSO explores the objective function surface globally and converges to the global optimum NPV. The PSO searches faster in this case because an initial guessing control vector is close to the optimum solution vector, which will be explained later. The SA method needs more numerical simulation runs to converge for the CSI + WF optimization, in comparison with the CSI optimization. In the CSI + WF optimization, more control variables are optimized, which include the water injection rate. More simulation runs are required for the SA method as the dimension of the control vector is increased. A much higher NPV is achieved for the CSI + WF in the post-CHOPS reservoirs with the wormholes than that in the heavy oil reservoirs without the wormholes. The same trend holds for the CSI.
Figure 6.11  NPVs determined by using the SA method and PSO for the CSI + WF in the heavy oil reservoirs with/without the wormholes as a function of the number of the simulation runs.
Figure 6.12 depicts the final well controls of the four producers and one injector during the CSI + WF in the post-CHOPS reservoir, which are calculated from the PSO. The four producers operate at BHPs close to the minimum allowable value throughout the CSI + WF. The solution of the WF optimization is a bang-bang control if the BHP constraints are the upper and lower bounds (Zandvliet et al., 2007). The injector shuts in or injects at close to the minimum allowable water injection rate of zero m$^3$/d. The early water breakthrough leads to a high WOR, which makes the WF uneconomical. The final well controls of the four producers and the injector in the heavy oil reservoir without the wormholes are similar to those in the post-CHOPS reservoir. It should be noted that the final control variables and one set of the initial control variables are close. In this regard, the PSO converges faster for the CSI + WF optimization.

Table 6.4 gives the final NPVs, cumulative oil, water, and gas production data, and cumulative water injection data at the end of the CSI + WF calculated from the SA method and PSO, respectively. The results determined from the SA method and PSO are almost the same. In addition, the final NPV of the CSI + WF is similar to that of the CSI, though more CO$_2$ is injected during the 5.5 cycles of the CSI. The CSI + WF consists of three cycles only so that the foamy oil has more time to flow to the producers instead of being pushed back into the heavy oil reservoir by the injected CO$_2$.

### 6.2.5 CSI + GF optimization

Figure 6.13 presents the NPVs determined by using the SA method and PSO versus the numbers of the simulation runs for the CSI + GF in the heavy oil reservoir with/without the wormholes. The SA method and PSO yield almost the same final NPVs for the CSI + GF in the heavy oil reservoirs with/without the wormholes. A higher NPV
Figure 6.12  Final BHPs of (a) Producer #1; (b) Producer #2; (c) Producer #3; and (d) Producer #4, and final water injection rates of (e) Injector #5 determined from the PSO during the CSI + WF in the post-CHOPS reservoirs.
Table 6.4  Final NPVs determined from the SA method and PSO, cumulative heavy oil, water, and gas production data, and cumulative water injection data at the end of the CSI + WF in the heavy oil reservoirs with/without the wormholes.

<table>
<thead>
<tr>
<th>Wormholes</th>
<th>Optimization algorithm</th>
<th>Optimum NPV ((\times 10^6 \text{ $}))</th>
<th>(Q_o) ((\times 10^3 \text{ m}^3))</th>
<th>(Q_w) ((\text{m}^3))</th>
<th>(Q_g) ((\times 10^3 \text{ sc m}^3))</th>
<th>(Q_{wi}) ((\text{m}^3))</th>
</tr>
</thead>
<tbody>
<tr>
<td>Absence</td>
<td>SA</td>
<td>0.31</td>
<td>2.6</td>
<td>8.5</td>
<td>5.1</td>
<td>118.5</td>
</tr>
<tr>
<td></td>
<td>PSO</td>
<td>0.31</td>
<td>2.6</td>
<td>8.6</td>
<td>5.1</td>
<td>0</td>
</tr>
<tr>
<td>Presence</td>
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<td>PSO</td>
<td>3.50</td>
<td>10.7</td>
<td>395.3</td>
<td>38.4</td>
<td>163.6</td>
</tr>
</tbody>
</table>
Figure 6.13  NPVs determined by using the SA method and PSO for the CSI + GF in the heavy oil reservoirs with/without the wormholes as a function of the number of the simulation runs.
is achieved when the heavy oil is co-produced with the sands. The numerical results also show that the CSI + GF has a higher NPV than the CSI or CSI + WF.

Figure 6.14 illustrates the final control variables of the four producers and one gas injector during the CSI + GF in the post-CHOPS reservoir, which are determined from the PSO. The final BHPs are the minimum allowable BHP of 200 kPa or very close to 200 kPa. The gas injector operates at the maximum allowable gas injection rate of 1,000 sc m$^{3}$/d during the first two cycles of the GF but should be shut in during the last cycle. It is uneconomical to apply the GF during the last cycle when the gas saturation is too high. These simulation results show a bang-bang solution to the problem of the GF optimization. It is worthwhile to mention that the final control variables for the CSI + GF in the heavy oil reservoir without the wormholes have the minimum allowable values.

Figure 6.15 shows the oil and gas saturations at the end of the CSI + GF in the post-CHOPS reservoir (Layer #3) with the wormholes. The remaining heavy oil saturation is lower at the end of the CSI + GF than that at the end of the CSI, as shown in Figure 6.10. Although the oil and gas saturations at the end of the CSI + WF in the post-CHOPS reservoir (Layer #3) are not shown here, they are almost the same as those at the end of the CSI. The foamy oil near the gas injector is effectively swept to the boundaries of the reservoir during the CSI + GF. The gas saturation near the centre of the reservoir is higher due to CO$_2$ injection from the gas injector during the GF. The four producers and the gas injector are connected by the high gas-saturation channels at the end of the CSI + GF.

Table 6.5 provides the optimization results obtained from the SA method and PSO for the CSI + GF in the heavy oil reservoir with/without the wormholes. It can be seen
Figure 6.14  Final BHPs of (a) Producer #1; (b) Producer #2; (c) Producer #3; and (d) Producer #4, and final gas injection rates of (e) Injector #5 determined from the PSO during the CSI + GF in the post-CHOPS reservoir.
Figure 6.15  (a) Oil saturations and (b) gas saturations at the end of the CSI + GF in the post-CHOPS reservoir (Layer #3).
Table 6.5  Final NPVs determined from the SA method and PSO, cumulative heavy oil, water, and gas production data, and cumulative gas injection data at the end of the CSI + GF in the heavy oil reservoir with/without the wormholes.

<table>
<thead>
<tr>
<th>Wormholes</th>
<th>Optimization algorithm</th>
<th>Optimum NPV ($ \times 10^6$ $$)</th>
<th>$Q_o$ ($\times 10^3$ m$^3$)</th>
<th>$Q_w$ (m$^3$)</th>
<th>$Q_g$ (m$^3$)</th>
<th>$Q_{gi}$ ($\times 10^4$ sc m$^3$)</th>
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<tr>
<td>Absence</td>
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<td>8.6</td>
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<td>0</td>
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<tr>
<td></td>
<td>PSO</td>
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<td>8.6</td>
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<td>0</td>
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<td>45.9</td>
<td>73.6</td>
</tr>
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</table>
from the table that both the SA method and PSO give good estimates of the optimum NPV of the CSI + GF. The optimum CSI + GF recovers more heavy oil than the optimum CSI or CSI + WF. The injected CO$_2$ during the GF supplies the solvent, repressurizes the reservoir, restores the foamy-oil flow, and displaces the foamy oil. Accordingly, more CO$_2$ is injected and produced during the CSI + GF.

6.3 Chapter Summary

In this chapter, the field-scale CSI, CSI + WF, and CSI + GF in the heavy oil reservoir with/without the wormholes are optimized by applying the SA method and PSO, while the NPV is chosen as the objective function. Both the SA method and PSO are capable of finding the optimum NPVs of the CSI, CSI + WF, and CSI + GF. The PSO performs better than the SA method in terms of the final NPV because the PSO is a global search method. In addition, more computational effort is required for the SA method when the dimension of the control vector is increased. More numerical simulation runs are needed to optimize of the CSI, CSI + WF, and CSI + GF in the post-CHOPS reservoirs with the wormholes than those in the conventional heavy oil reservoirs without the wormholes. The reason is that the post-CHOPS reservoir is more heterogeneous. The wormholes are beneficial to the follow-up CSI, CSI + WF, and CSI + GF. The final NPV can be increased by over ten times in the presence of the wormholes. The optimum BHPs of the producers during the CSI, CSI + WF, and CSI + GF are at the minimum allowable value in the heavy oil reservoir with/without the wormholes. It is uneconomical to apply the WF immediately after the CSI production. To inject a gaseous solvent at the maximum allowable rate during the early cycles can increase both the
cumulative heavy oil production and the NPV. However, the gas injector should be shut in during the later cycles when the gas saturation becomes too high.
CHAPTER 7  CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

This Ph.D. thesis studies the technical potential of combined cyclic solvent injection (CSI) and waterflooding (WF) or gasflooding (GF) in the post-cold heavy oil production with sand (CHOPS) reservoirs. The major conclusions that can be drawn from this study are summarized as follows:

**Experimental studies of the combined CSI and WF/GF**

- The highest heavy oil recovery factor (RF) is obtained in the CSI + WF due to the improved volumetric sweep efficiency (WF) and enhanced microscopic displacement efficiency (CSI). The remaining foamy oil at the end of the CSI production period is effectively displaced and produced in the subsequent WF;
- The simultaneous (CSI + WF) has the highest average heavy oil production rate and the lowest cumulative gas–oil ratio (GOR) because of the well maintained reservoir pressure;
- The combined CSI and WF gives a higher heavy oil RF with a higher heavy oil production rate and a lower cumulative GOR than the combined CSI and gasflooding (GF). CO₂ mobility is effectively controlled and the gravity overriding is weakened because of the injected water;
- C₃H₈-CSI + WF has a higher heavy oil RF and a higher heavy oil production rate with a better-controlled gas production and a lower water consumption than CO₂-CSI + WF;
A higher pressure drawdown rate in the CSI helps to increase the heavy oil production rate and reduce the cumulative GOR in the CSI, and reduce the cumulative WOR in the WF;

A high CO\textsubscript{2} injection rate during the GF is detrimental to the heavy oil production because the free-gas flow becomes dominant in this case; and

The foamy-oil flow and free-gas flow alternates during the CSI and subsequent GF. The free-gas flow is dominant as the gas saturation is increased in the late cycles of the CSI and GF.

**Theoretical studies of the primary production and CSI**

- The predicted cumulative heavy oil production and average reservoir pressure agree well with the measured data. Nevertheless, there are relatively large differences between the measured and predicted cumulative gas productions because the gas channeling in the solution-gas drive is not considered in the material balance model (MBM);
- The predicted nucleation coefficient of the dissolved CH\textsubscript{4} in the heavy oil to become the dispersed CH\textsubscript{4} bubbles was found to increase as the pressure drawdown rate is increased or the heavy oil viscosity is reduced;
- The predicted decay coefficient of the dispersed CH\textsubscript{4} bubbles from the heavy oil to become the so-called free gas is smaller if the pressure drawdown rate or the heavy oil viscosity is increased;
- The foamy-oil isothermal compressibility and dispersed gas volume fraction are increased considerably during the primary production, which are beneficial to the reservoir pressure maintenance; and
• The foamy-oil viscosity is decreased due to the CO₂ dissolution and the solution CH₄–heavy oil ratio remains constant during the subsequent CSI because CH₄ concentration in the heavy oil is so low that no dissolved CH₄ is liberated from the heavy oil.

**Numerical studies of the combined CSI and WF/GF**

• Both the steepest ascent (SA) method and particle swarm optimization (PSO) can reliably find good solutions to the CSI, CSI + WF, and CSI + GF optimization problems. The PSO performs better than the SA method to more quickly find the global optimum net present value (NPV). In addition, the computational cost becomes higher as the dimension of the optimization problem is increased;

• The final NPVs of the CSI, CSI + WF, and CSI + GF in the post-CHOPS reservoir are significantly increased when the sands are allowed to be co-produced with the heavy oil; and

• The optimum NPVs of the CSI, CSI + WF, and CSI + GF are achieved when the bottom hole pressures (BHPs) of the producers are maintained at the lower bound. The WF is beneficial to the heavy oil production but reduces the final NPV due to the high water–oil ratio (WOR). For the CSI + GF, the gas injector should be allowed to inject the solvent at the upper bound of the gas injection rate during the early cycles but shut in during the later cycles to alleviate the gas channeling.

**7.2 Recommendations**

In this thesis, several new hybrid heavy oil recovery processes were studied as potential follow-up processes in the post-CHOPS reservoirs experimentally, theoretically,
and numerically. The following technical recommendations are made for the future studies:

- In the sandpacked laboratory tests, the sands can be allowed to be produced so that the wormholes are present in the physical model. The solvent can easily contact with more heavy oil far away from the production well through the wormholes. Meanwhile, the gas channeling becomes more severe because of the wormholes;

- The pressure drawdown rate in the actual heavy oil reservoir is about 0.1 kPa/min, which is much lower than those used in the sandpacked laboratory tests. Accordingly, a more realistic pressure drawdown rate can be applied in the experimental tests to examine its effect on the production performance of the combined CSI and WF/GF;

- Solvent mixtures, such as CO$_2$ + C$_3$H$_8$ instead of the pure solvent CO$_2$/C$_3$H$_8$, can be used as the extracting/displacing solvents during the combined CSI and WF/GF. CO$_2$ is much cheaper than C$_3$H$_8$, whereas C$_3$H$_8$ reduces the heavy oil viscosity much lower than CO$_2$. Thus, the solvent mixture of CO$_2$ + C$_3$H$_8$ can have a higher heavy oil RF with a lower capital cost;

- CO$_2$-saturated or carbonated water injection (CWI) or polymer flooding can be applied to control the mobility ratio of the injected water to the remaining heavy oil in the WF;

- Foaming agent may be injected with the solvent during the CSI injection period to maintain the foamy-oil stability and foamy-oil flow;

- In the production optimization, more operating parameters can be considered as the control variables to optimize the final NPV, in addition to the BHPs of the producers and the water/gas injection rate of the injector, such as the CSI soaking time. A longer
soaking time leads to a lower heavy oil viscosity and a higher heavy oil production rate. However, a longer soaking time also means a shorter CSI production time if the total time of the CSI is kept constant. Hence, the CSI soaking time is an important operating parameter to be optimized for the final NPV.
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