Gas Pressure Cycling (GPC) and Solvent-Assisted Gas Pressure Cycling (SA-GPC) Enhanced Oil Recovery Processes in a Thin Heavy Oil Reservoir

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Abstract: In this paper, gas pressure cycling (GPC) and solvent-assisted gas pressure cycling (SA-GPC) were developed as two new and effective enhanced oil recovery (EOR) processes. Eight coreflood tests were conducted by using a 2-D rectangular sandpacked physical model with a one or two-well configuration. More specifically, two cyclic solvent injection (CSI), three GPC, and three SA-GPC tests were conducted after the primary production, whose pressure was declined in steps from $P_i = 3.0\text{ MPa}$ to $P_f = 0.2\text{ MPa}$. It was found that the CSI tests had poor performances because of the known CSI technical shortcomings and an additional technical issue of solvent trapping found in this study. Quick heavy oil viscosity regainment resulted in the solvent-trapping zone. In contrast, $C_3H_8$-GPC test at a pressure depletion step size of $\Delta P_{EOR} = 0.5\text{ MPa}$ and $C_3H_8$-SA-CO$_2$-GPC test at $\Delta P_{EOR} = 1.0\text{ MPa}$ had the highest total heavy oil recovery factors (RFs) of 41.9% and 36.6% of the original oil-in-place (OOIP) among the two respective series of GPC and SA-GPC tests. The better performances of these two tests than $C_3H_8$- or CO$_2$-CSI test were attributed to the effective displacement of the foamy oil toward the producer in the two-well configuration. Thus the back-and-forth movements of the foamy oil in CSI test in the one-well configuration were eliminated in these GPC and SA-GPC tests. Furthermore, $C_3H_8$-GPC test outperformed $C_3H_8$-SA-CO$_2$-GPC test in terms of the heavy oil RF and cumulative gas-oil ratio (cGOR) because of the formation of stronger foamy-oil flow and the absence of CO$_2$, which reduced the solubility of $C_3H_8$ in the heavy oil in the latter test. In summary, different solvent-based EOR processes were ranked based on the heavy oil RFs as follows: $C_3H_8$-GPC > $C_3H_8$-SA-CO$_2$-GPC > CO$_2$-GPC > $C_3H_8$-CSI > CO$_2$-CSI.

Keywords: gas pressure cycling (GPC); solvent-assisted gas pressure cycling (SA-GPC); cyclic solvent injection (CSI); solution-gas drive; foamy-oil flow; thin heavy oil reservoirs

1. Introduction

The world’s heavy oil and oil sand resources are estimated to be approximately 5.6 trillion barrels [1,2]. Western Canada accounts for more than 70% of the world’s in-place oil sands [2,3]. It has been reported that the western Canadian sedimentary basin has a total proven oil sand reserves of about 162.3 billion barrels with majority of the accumulations located in Alberta [4]. Approximately 17.7 billion barrels of the heavy oil reserves are in Saskatchewan [3]. About 90% of the heavy oil deposits near the border between Alberta and Saskatchewan are in the thin heavy oil reservoirs with the main pay-zone thicknesses of 4–6 m [3,5,6]. The western Canadian heavy oil/oil sand resources and associated gas are accumulated in the shallow Lower Cretaceous fluvio-deltaic unconsolidated sands at depths of less than 3000 ft. Other additional reserves are accumulated in the Devonian and
Mississippian carbonates, which sub-crop the Cretaceous [7]. At present, only 12% of the heavy oil/oil sand resources in the western Canada can be recovered by using so-called open-pit mining technology. Thus majority of recoverable heavy oil/oil sands have to be produced by using the in situ enhanced oil recovery (EOR) processes [7]. An estimated recovery factor (RF) of about 10% of the original oil-in-place (OOIP) can be obtained in the Saskatchewan heavy oil reservoirs with the current EOR technologies and economic constraints.

Solvent-based EOR processes are excellent alternatives to thermal EOR processes in thin heavy oil reservoirs, the latter of which suffers from excessive heat losses to the surroundings, high capital and operating costs, large water consumption and treatments, and considerable greenhouse gas emissions [8]. A number of experimental studies have been published on the applications of solvent-based EOR processes in the heavy oil reservoirs [9–11]. For example, two series of laboratory PVT tests were conducted to model the pressure depletion process in the cyclic solvent injection (CSI) in a Lloydminster heavy oil reservoir [9]. The first series of tests showed that CO2 was a better extracting solvent than CH4 because of better heavy oil viscosity reduction even at low pressures. The second series of tests comprised the use of a CH4-CO2 solvent mixture with mole ratio of 1:3. It was observed that the efficiency of CO2 was reduced because of the presence of CH4. Afterwards, soaking-period effect and the mobile water saturation effect on the longitudinal distribution of CO2 were studied by using some coreflood tests. The results showed that CO2 had better distribution throughout the core because of the presence of the mobile water. A longer soaking period enhanced CO2 dissolution into the heavy oil.

On the other hand, a laboratory experiment was performed by utilizing C2H6-CSI to enhance heavy oil recovery in the Cold Lake oil sand, Alberta [12]. The experimental data showed that ethane (C₂H₆) was an effective extracting solvent to enhance the Cold Lake heavy oil production and also improve the produced heavy oil quality.

Some experimental results were presented for C3H8-CO2-CSI process in the Cold Lake and Lloydminster heavy oil reservoirs [13], which had been depleted during the cold heavy oil production with sand (CHOPS). During the CSI process, a solvent mixture of 28 mol.% C₃H₈ and 72 mol.% CO₂ was utilized and a total of six cycles were conducted. It was found that the primary production and the six cycles had the total heavy oil RF of 50%, which shows the potential feasibility of the CSI process. In another study, a total of fourteen CSI experiments were performed to investigate the operating pressure, soaking time, and solvent composition effects [11]. In each test, first, the Berea core was saturated with a Saskatchewan heavy oil. Then CO₂, CH₄, C₃H₈, and C₄H₁₀ were used as respective solvents under different operating conditions. It was found that CO₂ at near-supercritical conditions resulted in the highest heavy oil RF of 71%. The major EOR mechanisms included solution-gas drive, heavy oil viscosity reduction, light hydrocarbon extraction, and foamy-oil flow.

It has been found that CSI has some inherent technical drawbacks in thin heavy oil reservoirs: quick heavy oil viscosity regainment, reservoir energy depletion, and the so-called back-and-forth movements of the foamy oil near the producer [14,15]. As a result, more studies have been conducted to mitigate these shortcomings by modifying the CSI process. For example, a pressure pulsing cyclic solvent injection (PP-CSI) process was explored as a variation of the CSI process [16]. This process adopted a three-step pressure control scheme to enhance the performance of CSI. It included the model pressure reduction to initiate foamy oil flow, the model pressure re-increase to a preset value, and a certain pressure drop maintenance between the injector and producer for gas flooding, respectively. During the production period, the process was consecutively repeated. Although the oil production rate was decreased with increasing pressure pulse number in each cycle, it was found that the PP-CSI oil production rate was 4.37 times higher than that of the traditional CSI. On the other hand, four series of the enhanced cyclic solvent process (ECS) were studied in order to minimize the heavy oil viscosity regainment, which is often encountered during the traditional CSI [17]. This process comprised the cyclic injection of a CH₄ (a volatile gas) and C₂H₆ or C₃H₈ (a more soluble gas) in the heavy oil in sequence. CH₄ was utilized to cause the heavy oil to expand while C₂H₆ or C₃H₈ was injected to maintain a low heavy oil viscosity for a longer period during the heavy oil production. Each series of
ECSP tests had six cycles. The ECSP had a better heavy oil RF than the traditional CSI. The other CSI variations have been discussed in the literature [18].

In this paper, gas pressure cycling (GPC) and solvent-assisted gas pressure cycling (SA-GPC) were developed as novel respective solvent-based EOR processes in a thin heavy oil reservoir. These two processes were studied to mitigate or eliminate three known technical shortcomings of CSI: quick heavy oil viscosity regainment, back-and-forth movements of the foamy oil near the producer, and fast reservoir energy depletion during the CSI production period. Two CSI, three GPC, and three SA-GPC laboratory tests were conducted by using a sandpacked physical model to measure the heavy oil RFs and the instantaneous/cumulative gas-oil ratios (iGORs/cGORs) in different tests. In principle, GPC restores the foamy-oil flow and eliminates the movement of the foamy oil away from the producer. Moreover, SA-GPC is tested to effectively combine the EOR and improve the oil recovery (IOR) mechanisms. This second new solvent-based EOR process enhances the microscopic displacement efficiency (SA) and improves the volumetric sweep efficiency (GPC) in sequence.

2. Materials and Methods

2.1. Materials

The original heavy oil and brine sample used in this study were collected from the Colony formation in the Bonnyville area, Alberta, Canada. The compositional analysis of the Colony heavy oil was measured by using the standard ASTM D86 and can be found elsewhere [19]. The Colony heavy oil viscosity was measured by using a viscometer (DV-II+, Brookfield, WI, USA) to be \( \mu_o = 33,876 \text{ cP} \) at \( P_a = 1 \text{ atm} \) and \( T_{res} = 21 ^\circ \text{C} \) and the density was measured by using a densitometer (DMA 512P, Anton Paar, Ashland, VA, USA) to be \( \rho_o = 0.992 \text{ g/cm}^3 \) at \( P_a = 1 \text{ atm} \) and \( T_{res} = 21 ^\circ \text{C} \). The detailed physicochemical properties of the Colony heavy oil and brine were published in the previous paper [19].

The other materials included CH4 with a purity of 99.97 mol.%, CO2 with 99.998 mol.%, and C3H8 with 99.5 mol.%, all of which were purchased from Praxair, Saint-Laurent, QC, Canada.

2.2. Experimental Set-Up

The experimental set-up comprised five major operating units: a 2-D physical model, a solvent injection unit, a gas/brine/oil injection unit, a fluid production unit, and a data acquisition system (DAS). The 2-D physical model was made up of a rectangular stainless-steel plate with a rectangular cavity for holding the packed sand grains. The 2-D physical model was covered with a thick transparent acrylic plate for the experimental visualization and a thin transparent polycarbonate plate in between, which prevented scratches on the surface of the acrylic plate. The rectangular cavity has a dimension of \( L \times W \times H = 40 \text{ cm} \times 10 \text{ cm} \times 2 \text{ cm} \) with a chosen height-to-length ratio of 1:20, which models a typical thin heavy oil reservoir [15]. Figure 1 shows the schematic diagram of the experimental set-up for the primary production and the subsequent CSI/GPC/SA-GPC. A one-well configuration was utilized in the CSI experiments, whereas a two-well configuration was utilized in the GPC/SA-GPC experiments. The first well (A), which was located at the center of the left-hand side of the physical model, was used as a solvent injector and also as a producer in CSI and SA-GPC. The solvent injection unit included a solvent cylinder (Praxair, Mississauga, ON, Canada) with a two-stage solvent regulator (KCY Series, Swagelok, Solon, OH, USA). The solvent cylinder supplied solvent at a predetermined and regulated injection pressure during the solvent injection period. The second well (B) was located at the center of the right-hand side of the physical model and served as a gas injector in GPC/SA-GPC. The gas injection unit consisted of a gas cylinder (Praxair, Sherbrooke, QC, Canada) with a two-stage gas regulator (KCY Series, Swagelok, Solon, OH, USA). The solvent or gas injection pressure was measured during each injection process. The fluid production unit was composed of a high-precision back-pressure regulator (BPR) (LBS4 Series, Swagelok, Solon, OH, USA), which was used to set/adjust the production pressure by utilizing a pre-specified pressure depletion step size. Other equipment included a syringe pump (100DX, ISCO Inc., Lincoln, NE, USA), a produced oil and gas collector for separating the
produced oil-gas mixture and measuring the produced oil volume, a pair of gas bubblers for measuring
the produced gas volume, and a vacuum pump. Lastly, the DAS automatically measured and recorded
the differential pressure between the injection and production pressures. It included a digital pressure
indicator (PPM-2, Heise, Stratford, CT, USA) and a personal computer. Figure 1 also shows how the
above-described five major operating units were connected to acquire the experimental data in each
test consisting of the primary production and the subsequent CSI/GPC/SA-GPC.

**Figure 1.** Schematic diagram of the experimental set-up used for conducting the primary production
and the subsequent CSI/GPC/SA-GPC (cyclic solvent injection/gas pressure cycling/solvent-assisted gas
pressure cycling).

### 2.3. Experimental Preparation

The CH\(_4\)-saturated live heavy oil was prepared in two weeks and had a GOR of 9.6 sc cm\(^3\)/cm\(^3\)
at the saturation pressure of \(P_{\text{sat}} = 3.0\) MPa. Afterwards, the 2-D physical model was assembled
and tested for leakage by injecting CO\(_2\) at a pressure of 3.0 MPa into the model for 24 h. Then the
physical model was sandpacked in stages with the Ottawa sand grains (Bell & Mackenzie, Hamilton,
ON, Canada) of 60–80 mesh sizes and repeatedly hammered to ensure uniform sand distribution and eliminate the void spaces. The imbibition method was employed to measure its porosity, which was in the range of 38.7–40.0%. Also, the permeability of the sandpacked physical model was measured by using the Darcy’s law. Different water pressure drops of 6–12 kPa were applied at the two ends of the physical model and the corresponding volumetric water flow rates were measured to be 4–13 cm$^3$/min. Then the permeability was determined to be in the range of 3.8–4.7 D, which is close to typical heavy oil reservoir permeabilities in Canada. Subsequently, the sandpacked physical model was saturated with the Colony brine at a pressure of 3.0 MPa. Finally, an injection pressure of about 3.5 MPa and a production pressure of 3.0 MPa were applied to saturate the 2-D sandpacked model with CH$_4$-saturated live Colony heavy oil until the irreducible water saturation ($S_{wi}$) and initial oil saturation ($S_{oi}$) were achieved, noting that $S_{wi} + S_{oi} = 1$. The physical properties of the 2-D sandpacked physical model used in Tests #1–8 are listed on Table 1.

Table 1. The physical characteristics of the 2-D sandpacked physical model in Tests #1–8 at $T_{res} = 21.0$ °C.

| Test No. | $\phi$ (%) | $k$ (D) | $S_{oi}$ (%) |
|---------|------------|---------|--------------|
| 1       | 39.4       | 3.9     | 99.0         |
| 2       | 39.7       | 3.8     | 99.5         |
| 3       | 39.6       | 4.4     | 98.7         |
| 4       | 39.0       | 4.2     | 98.6         |
| 5       | 38.7       | 3.8     | 98.3         |
| 6       | 40.0       | 4.6     | 97.8         |
| 7       | 39.4       | 4.7     | 98.0         |
| 8       | 39.3       | 4.1     | 98.1         |

2.4. Experimental Procedures

A total of eight sandpacked tests were conducted: two CSI processes (Tests #1–2), three GPC processes (Tests #3–5), and three SA-GPC processes (Tests #6–8). Each process is briefly described below and more technical details are given in Table 2. In each test, the primary production was initiated at the initial reservoir pressure of $P_i = 3.0$ MPa and reservoir temperature of $T_{res} = 21$ °C. In the primary production, a constant production pressure depletion step size of $\Delta P_{PP} = 1.0$ MPa was applied in steps until the final production pressure of $P_f = 0.2$ MPa was obtained, in contrast to the constant pressure drawdown rate mostly used in the past studies. At each primary production pressure, fluids were continually produced until the volume of the produced heavy oil in every 15 min was less than 0.1% of the OOIP. This production criterion was also used to change to the next reduced production pressure in each cycle of the different EOR processes. Then $\Delta P_{pp} = 1.0$ MPa was applied and the primary production was continued at the next reduced production pressure. In this study, with the pre-specified $P_i = 3.0$ MPa and $P_f = 0.2$ MPa, a large pressure depletion step size of $\Delta P_{pp} = 1.0$ MPa was purposely chosen during the primary production in order to maintain a strong foamy-oil flow within the shortest primary production time of 18–20 h. After the primary production process, one of the following three EOR processes, CSI, GPC, and SA-GPC, was subsequently conducted as an EOR test and is described as follows.

More specifically, Tests #1–2 had the primary production and the subsequent CSI. The CSI process used a one-well configuration and consisted of several cycles. Each cycle had three periods, as shown in Figure 2a–c. Figure 2a shows the solvent injection period when either C$_3$H$_8$ or CO$_2$ was injected from the solvent injector (Well A) until a pre-specified final injection pressure of $P_{inj} = 0.8$ MPa for C$_3$H$_8$ or 3.0 MPa for CO$_2$ was reached in Test #1 (C$_3$H$_8$-CSI) or Test #2 (CO$_2$-CSI). Figure 2b shows the solvent soaking period when Well A was shut in to soak and dissolve the injected solvent into the heavy oil for 24 h with the ending pressure of $P_s = 0.7$ MPa in Test #1 or 2.1–2.4 MPa in Test #2. Figure 2c shows the fluids production period when the same well (Well A) was used as a producer and opened to produce fluids by applying $\Delta P_{EOR} = 0.5$ MPa in each CSI test until the ending production
production pressure of $P_e = 0.2$ MPa was achieved. Each CSI test was terminated once the heavy oil RF was less than 2% of the OOIP during one cycle after the first cycle.

**Table 2.** Technical details of Tests #1–8 (including the primary production) at $T_{res} = 21.0$ °C.

| Test No. | Process | Primary Production CSI/GPC/SA-GPC | Solvent Injection | Gas Injection | Soaking Production | Production |
|----------|---------|----------------------------------|-------------------|---------------|--------------------|------------|
|          |         | $P_i$ (MPa) $\Delta P_{PP}$ (MPa) $P_f$ (MPa) | $P_{inj}$ (MPa) Type | $P_{inj}$ (MPa) Type | $P_s$ (MPa)$\Delta P_{EOR}$ (MPa) $P_e$ (MPa) |
| 1        | CSI     | 3.0 1.0 0.2 $C_3H_8$ 0.8    | -                 | -              | 24 $\times$ 60 0.7 0.5 0.2 |
| 2        | CSI     | 3.0 1.0 0.2 $CO_2$ 3.0    | -                 | -              | 24 $\times$ 60 2.1–2.4 0.5 0.2 |
| 3        | GPC     | 3.0 1.0 0.2 -              | -                 | $C_3H_8$ 0.8  | 24 $\times$ 60 0.7–0.76 0.1 0.2 |
| 4        | GPC     | 3.0 1.0 0.2 -              | -                 | $C_3H_8$ 0.8  | 24 $\times$ 60 0.7–0.76 0.5 0.2 |
| 5        | GPC     | 3.0 1.0 0.2 -              | -                 | $CO_2$ 3.0    | 24 $\times$ 60 2.2–2.6 0.5 0.2 |
| 6        | SA-GPC  | 3.0 1.0 0.2 $C_3H_8$ 0.8  | $CO_2$ 3.0       | 24 $\times$ 60 2.2–2.7 0.1 0.2 |
| 7        | SA-GPC  | 3.0 1.0 0.2 $C_3H_8$ 0.8  | $CO_2$ 3.0       | 24 $\times$ 60 2.2–2.7 0.5 0.2 |
| 8        | SA-GPC  | 3.0 1.0 0.2 $C_3H_8$ 0.8  | $CO_2$ 3.0       | 24 $\times$ 60 2.2–2.7 1.0 0.2 |

**Figure 2.** Flow charts of three periods in each cycle of the cyclic solvent injection (CSI) process in a one-well configuration: (a) solvent injection from Well A; (b) solvent soaking; and (c) fluids production from Well A.

In Tests #3–5, each test had the primary production and the subsequent GPC. The GPC process utilized a two-well configuration and consisted of several cycles. Each cycle had three periods, as shown in Figure 3a–c. Figure 3a shows the gas injection period when either $C_3H_8$ or $CO_2$ was injected from the gas injector (Well B) and Well A was shut in until a pre-specified final injection pressure of $P_{inj} = 0.8$ MPa for $C_3H_8$ or 3.0 MPa for $CO_2$ was reached in Tests #3–4 ($C_3H_8$-GPC) or Test #5.
(CO\textsubscript{2}-GPC). Figure 3b shows the gas soaking period when both Well B and Well A were shut in to soak and dissolve the injected gas into the heavy oil for 24 h with the end pressure of \( P_s = 0.7-0.76 \) MPa in Tests #3–4 or 2.2–2.6 MPa in Test #5. Figure 3c shows the fluids production period when the producer (Well A) was opened to produce fluids by applying \( \Delta P_{\text{EOR}} = 0.1 \) and 0.5 MPa in Test #3 and Tests #4–5 respectively and Well B remained shut in until the ending production pressure of \( P_e = 0.2 \) MPa was achieved. Each GPC test was terminated once the heavy oil RF was less than 2% of the OOIP during one cycle after the first cycle.

Figure 3. Flow charts of three periods in each cycle of the gas pressure cycling (GPC) process in a two-well configuration: (a) gas injection from Well B; (b) gas soaking; and (c) fluids production from Well A.

In Tests #6–8, each test had the primary production and the subsequent SA-GPC. The SA-GPC process used a two-well configuration and consisted of several cycles. Each cycle had four periods, as shown in Figure 4a–d. Figure 4a shows the solvent injection period when solvent (C\textsubscript{3}H\textsubscript{8}) was injected from the solvent injector (Well A) at \( P_{\text{injs}} = 0.8 \) MPa and Well B was shut in until no more solvent could be injected. Figure 4b shows the gas injection period when gas (CO\textsubscript{2}) was injected from the gas injector (Well B) to pressurize the physical model to the final pressure \( P_{\text{injg}} = 3.0 \) MPa and Well A was shut in. Figure 4c shows the solvent and gas soaking period when both Well B and Well A were shut in so that the injected solvent and gas were soaked and dissolved into the heavy oil for 24 h with the ending pressure of \( P_s = 2.2-2.7 \) MPa in these three tests. Figure 4d shows the final fluids production period when Well A was opened as the production pressure was declined at the pre-specified \( \Delta P_{\text{EOR}} \) until
$P_e = 0.2$ MPa was reached and Well B remained shut in. In Tests #6–8, $\Delta P_{EOR} = 0.1$, 0.5, and 1.0 MPa were applied during the fluids production periods, respectively. Each SA-GPC test was terminated once the heavy oil RF was less than 2% of the OOIP during one cycle after the first cycle.

Figure 4. Flow charts of four periods in each cycle of the solvent-assisted gas pressure cycling (SA-GPC) process in a two-well configuration: (a) solvent injection from Well A; (b) gas injection from Well B; (c) solvent and gas soaking; and (d) fluids production from Well A.

3. Results and Discussion

3.1. CSI

Tests #1 and #2 were C$_3$H$_8$-CSI and CO$_2$-CSI processes, which are used for comparison purpose. Table 3 lists the heavy oil RFs of the primary productions and the subsequent cycles of the EOR processes in Tests #1–8. Tests #1 and #2 had the total heavy oil RFs of 27.6% and 22.7%. Consequently, Tests #1 and #2 had three cycles and two cycles. The experimental results show that C$_3$H$_8$-CSI outperformed CO$_2$-CSI in terms of the heavy oil RF. This is because C$_3$H$_8$ is a more soluble extracting solvent, has a stronger heavy oil viscosity reduction ability, and helps to form a stronger foamy oil [19]. The overall performances of Tests #1 and #2 were considered to be poor because they had low additional heavy oil RFs of 6.6% and 2.7% during the CSI process after the primary productions. This was attributed to the three major technical limitations of the traditional CSI [14,15].
Table 3. Heavy oil recovery factors during the primary production and each cycle of the CSI tests (Tests #1–2), GPC tests (Tests #3–5), and SA-GPC tests (Tests #6–8).

| Test No. | Primary Production | Cycle #1 | Cycle #2 | Cycle #3 | Cycle #4 | Cycle #5 | Cycle #6 | Total |
|----------|--------------------|----------|----------|----------|----------|----------|----------|-------|
| 1        | 21.0               | 2.0      | 3.3      | 1.3      | -        | -        | -        | 27.6  |
| 2        | 20.0               | 2.4      | 0.3      | -        | -        | -        | -        | 22.7  |
| 3        | 20.5               | 0.3      | 6.6      | 4.1      | 4.0      | 4.1      | 1.9      | 41.5  |
| 4        | 21.9               | 2.3      | 8.1      | 5.5      | 3.2      | 0.9      | -        | 41.9  |
| 5        | 21.0               | 4.0      | 5.0      | 0.3      | -        | -        | -        | 30.3  |
| 6        | 21.2               | 3.7      | 2.7      | 0.5      | -        | -        | -        | 28.1  |
| 7        | 20.1               | 5.9      | 1.4      | -        | -        | -        | -        | 27.4  |
| 8        | 21.5               | 6.1      | 2.1      | 2.9      | 2.6      | 1.4      | -        | 36.6  |

Figure 5a–c shows the overall trends of the measured heavy oil RFs and iGORs as well as production pressure ($P_{\text{prod}}$) with time in every 15 min in Cycles #1–3 of Test #1. During Cycle #1, the iGOR was low in the early period of the cycle because of the foamy-oil formation and production near the producer (Well A). Therefore, heavy oil production was largely controlled by foamy-oil flow. The iGOR increased steadily toward the late period of the cycle because of rapid solvent exsolution, which led to heavy oil viscosity regainment and weaker foamy-oil flow. The iGOR during Cycle #2 was low over the entire period of the cycle except near the end. This resulted in a stronger foamy-oil controlled production and better production pressure maintenance over a longer period in comparison with Cycle #1. Cycle #2 had a higher heavy oil RF because the injected solvent had contacted more heavy oil, which was due to the void space created during the first cycle. In Cycle #3, little amount of the foamy oil was produced because of the early solvent breakthrough (BT) and the increased back-and-forth movements of the foamy oil. The iGOR increased quickly because of rapid solvent exsolution, which led to quick heavy oil viscosity regainment and rapid pressure depletion. Figure 6a,b show the overall trends of the measured heavy oil RFs, iGORs, and $P_{\text{prod}}$ during Cycles #1 and #2 of Test #2. In Cycle #1, the iGOR increased sharply at the beginning due to the early solvent BT and the low solubility of CO$_2$ near the producer (Well A) at $P_1 = 3$ MPa and $T_{\text{res}} = 21$ °C. Afterwards, the iGOR decreased to moderate values because of the production of the foamy oil in the late period of the cycle. At this time, the heavy oil production was mainly controlled by the pressure difference. Cycle #2 of Test #2 had the same patterns as described for Cycle #3 of Test #1. The iGOR remained high and the final heavy oil RF was minimal.

3.2. GPC

3.2.1. Gas Effect

In this study, two C$_3$H$_8$-GPC processes at $\Delta P_{\text{EOR}} = 0.1$ and 0.5 MPa (Tests #3 and #4) and one CO$_2$-GPC process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #5) were tested and compared. Table 3 lists the heavy oil RFs of the cycles in each GPC test. Tests #3–5 had six, five, and three cycles, respectively. Two C$_3$H$_8$-GPC tests at $\Delta P_{\text{EOR}} = 0.1$ and 0.5 MPa had much higher total heavy oil RFs of 41.5% and 41.9%, in comparison with the heavy oil RF of 30.3% in CO$_2$-GPC test at $\Delta P_{\text{EOR}} = 0.5$ MPa. This is due to a much higher C$_3$H$_8$ solubility, which led to more effective heavy oil viscosity reduction and stronger foamy oil formation [19]. It is worthwhile to emphasize that a lower heavy oil viscosity and a stronger foamy oil are favorable conditions to increase the heavy oil RF and that CO$_2$-GPC test might perform better in an oil reservoir if its initial reservoir pressure is much higher than 3 MPa.

3.2.2. Pressure Depletion Effect

In this work, the pressure depletion effect was studied in the C$_3$H$_8$-GPC tests. The effect of $\Delta P_{\text{EOR}}$ is not obvious in Tests #3 and #4 if only the measured heavy oil RFs are compared. Nonetheless, the numbers of cycles completed in both tests show that a higher $\Delta P_{\text{EOR}}$ enhanced heavy oil recovery.
process with fewer cycles because of a stronger foamy-oil flow and a better microscopic displacement efficiency [20,21].

![Graphs showing heavy oil recovery factors, instantaneous gas-oil ratios (iGORs), and production pressures](image)

**Figure 5.** Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs) and production pressures ($P_{prod}$) in C$_3$H$_8$-CSI process at $\Delta P_{EOR} = 0.5$ MPa (Test #1) (a) Cycle #1; (b) Cycle #2; and (c) Cycle #3.
Figure 6. Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs), and production pressures ($P_{\text{prod}}$) in CO$_2$-CSI process at $\Delta P_{\text{EOR}} = 0.5$ MPa (Test #2) (a) Cycle #1; and (b) Cycle #2.

Figure 7a–e shows the overall trends of the measured heavy oil RFs, iGORs, and $P_{\text{prod}}$ due to the production pressure depletion effect during Cycles #1–5 in Test #4. In Cycle #1, the heavy oil RF was poor because of the following three major reasons. First, the foamy oil was mostly formed near the gas injector (Well B). Second, the production pressure depletion process created a path for the subsequent mobilization of the foamy oil near Well B toward the producer (Well A). Third, the entrained small gas bubbles had coalesced to form larger gas bubbles when the foamy oil was mobilized from Well B to Well A. As a result, the foamy-oil strength was reduced and the heavy oil RF was low. In Cycles #2–4, more heavy oil was produced during the production periods because an oil flow path had been formed during Cycle #1, which established effective well connectivity and foamy-oil mobilization between Well B and Well A. Moreover, during Cycles #2–4, the iGOR rose quickly to high values and then declined to moderate values throughout each production period. The lower iGOR was measured because most of the gas was utilized to form strong foamy-oil flow, which led to higher heavy oil RFs in these cycles in comparison with that in Cycle #1. In contrast, Cycle #5 in Test #4 had a severe gas BT from the beginning so that the iGOR rose quickly to high values and a low heavy oil RF was obtained. Cycles #1, #2–5 and #6 in Test #3 had similar heavy oil RF and iGOR trends to those of Cycles #1, #2–4, and #5 in Test #4, respectively.
Figure 8a–c shows the overall trends of the measured heavy oil RFs, iGORs, and $P_{\text{prod}}$ due to the production pressure depletion effect during Cycles #1–3 in Test #5. In Cycles #1 and #2, the heavy oil RFs were good because the reservoir pressure of lower than 1.5 MPa was maintained for a longer period so that more foamy oil was mobilized and produced. Consequently, the iGOR was maintained at a low value. Cycle #3 suffered from rapid reservoir pressure depletion, fast CO$_2$ exsolution, and early gas BT. Thus the iGOR rose quickly to a higher value.

3.3. SA-GPC

In Tests #6–8, three C$_3$H$_8$-SA-CO$_2$-GPC tests at $\Delta P_{\text{EOR}} = 0.1$, 0.5, and 1.0 MPa were performed after the primary production. As listed on Table 3, each test had the total heavy oil RFs of 28.1%, 27.4%, and 36.6%, respectively. Tests #6–8 had three, two, and five cycles, respectively. The SA-GPC at $\Delta P_{\text{EOR}} = 1.0$ MPa (Test #8) had the highest enhanced heavy oil RF of 15.1% because of the strongest foamy-oil flow formation. SA-GPC tests at $\Delta P_{\text{EOR}} = 0.1$ and 0.5 MPa (Tests #6 and #7) had the enhanced heavy oil RFs of 6.9% and 7.3%. More specifically, there is no large difference in the total heavy oil RF in SA-GPC at $\Delta P_{\text{EOR}}$ of less than or equal to 0.5 MPa. However, there is a significant increase in total heavy oil RF in SA-GPC at $\Delta P_{\text{EOR}} = 1.0$ MPa, which is attributed to stronger foamy oil formation and increased pressure difference across the 2-D physical model in Test #8.

![Figure 7](attachment:image1.png)
Figure 7. Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs), and production pressures ($P_{prod}$) in C$_3$H$_8$-GPC process at $\Delta P_{EOR} = 0.5$ MPa (Test #4) (a) Cycle #1; (b) Cycle #2; (c) Cycle #3; (d) Cycle #4; and (e) Cycle #5.
produced, a higher heavy oil RF and a shorter production time than Cycle #1 in Test #6 or #7. This is because the reservoir pressure of lower than 1.5 MPa was maintained for a longer period so that more foamy oil was mobilized and produced. Consequently, the iGOR was maintained at a low value.

In Cycles #1–5 in Test #8, Cycle #1 had a lower iGOR throughout the cycle until most foamy oil was produced. Thus, the iGOR rose quickly to a higher value.

In Tests #6 and #7, three C3H8-SA-CO2-GPC tests at ΔP = 1.0 MPa (Test #8) had the highest enhanced heavy oil RF of 15.1% because of the strongest foamy-oil flow formation. SA-GPC tests at ΔP = 1.0 MPa (Tests #6, #7) had the highest heavy oil RFs and iGORs trends. The iGOR was moderate almost throughout each cycle. In these cycles, little heavy oil was produced because the production was largely dependent on the pressure difference across the 2-D physical model rather than on the foamy-oil flow.

In Cycles #1, #2, and #3 had similar heavy oil RFs and iGORs trends. The iGOR was moderate almost throughout each cycle. In these cycles, little heavy oil was produced because most of the injected solvent and gas were utilized to form a stronger foamy-oil flow. Hence, production pressure depletion effect during Cycles #1–3 caused lower heavy oil RFs and iGORs. In Cycles #4 and #5 had solvent and/or gas BT from the beginning so that the iGOR increased steadily throughout each cycle. In these cycles, little heavy oil was produced because the production was largely dependent on the pressure difference across the 2-D physical model in Test #8.

In Tests #6 and #7, three C3H8-SA-CO2-GPC tests at ΔP = 0.5 MPa had the enhanced heavy oil RF of less than or equal to 0.5 MPa. However, there is a significant increase in total EOR of less than or equal to 0.5 MPa. Therefore, the foamy-oil flow was predominant during the production period as the production pressure was declined in steps. On the contrary, Cycles #4 and #5 had solvent and/or gas BT from the beginning so that the iGOR increased steadily throughout each cycle. In these cycles, little heavy oil was produced because the production was largely dependent on the pressure difference across the 2-D physical model in Test #8.

Figure 8a‒c shows the overall trends of the measured heavy oil RFs, iGORs, and production pressures (Pprod) in CO2-GPC process at ΔP_EOR = 0.5 MPa (Test #5) (a) Cycle #1; (b) Cycle #2; and (c) Cycle #3.

Figure 9a‒e shows the overall trends of the measured heavy oil RFs, iGORs, and Pprod during Cycles #1–5 in Test #8. Cycle #1 had a lower iGOR throughout the cycle until most foamy oil was produced, a higher heavy oil RF and a shorter production time than Cycle #1 in Test #6 or #7. This is...
because most of the injected solvent and gas were utilized to form a stronger foamy-oil flow. Hence, the heavy oil production in this cycle was mainly attributed to the strong foamy-oil flow. Cycles #2 and #3 had similar heavy oil RFs and iGORs trends. The iGOR was moderate almost throughout each cycle till the late period when it suddenly increased because of severe solvent and/or gas BT. In addition, the foamy-oil flow was predominant during the production period as the production pressure was declined in steps. On the contrary, Cycles #4 and #5 had solvent and/or gas BT from the beginning so that the iGOR increased steadily throughout each cycle. In these cycles, little heavy oil was produced because the production was largely dependent on the pressure difference across the 2-D physical model rather than on the foamy-oil flow.

3.4. Comparisons

3.4.1. CSI vs. GPC

Figure 10a shows the comparison of the heavy oil RFs during the primary production and every cycle of each CSI or GPC test. The experimental data indicate that two C₃H₈-GPC processes (Tests #3 and #4) had higher heavy oil RFs than C₃H₈-CSI process (Test #1). Likewise, CO₂-GPC process (Test #5) had a higher heavy oil RF than CO₂-CSI process (Test #2). Moreover, Figure 10b shows that the GPC process is better than the CSI process in terms of cGOR. This clearly indicates that the GPC process had superior foamy-oil strength and stability. Based on the heavy oil RFs, the GPC and CSI processes are ranked as follows: C₃H₈-GPC test (Test #4) > C₃H₈-GPC test (Test #3) > CO₂-GPC test (Test #5) > C₃H₈-CSI test (Test #1) > CO₂-CSI test (Test #2).

The performance of the CSI process was undermined by quick heavy oil viscosity regainment, rapid pressure depletion, back-and-forth movements of the foamy oil, as well as solvent-trapping effect. This is because a one-well configuration was utilized in the CSI tests. In contrast, the two-well configuration was utilized in each GPC test, which eliminated the back-and-forth movements of the foamy-oil encountered in the CSI process. The injector (Well B) placement allowed the injected gas to flow in the same direction as the produced foamy oil and helped to mobilize the foamy oil toward the producer (Well A). This resulted in an enhanced microscopic displacement efficiency, a larger heavy oil viscosity reduction, and a stronger foamy-oil flow.

Figure 11a is a digital photo of the 2-D physical model after the completion of the traditional CSI test in a one-well configuration. The arrows pointing to the right-hand side of the physical model represent the back movements of the foamy oil away from the solvent injector during the solvent injection. The arrows pointing to the left-hand side of the physical model represent the forward movements of the foamy oil during fluids production toward the producer. Obviously, not all the restored foamy oil was produced in each production period [15]. In the late stage of the production period of the CSI test, the heavy oil in Region A (bounded by the yellow lines) had quick heavy oil viscosity regainment, which led to some solvent being trapped in Region B (bounded by the red line). The solvent trapping observed in Region B is regarded as a new technical shortcoming of the traditional CSI process in the thin heavy oil reservoir.

Figure 11b is a digital photo of the 2-D physical model after the GPC test was completed in a two-well configuration. The arrows pointing to the right-hand side of the physical model represent the direction of the foamy-oil displacement toward the producer. Region A (bounded by the yellow lines) represents the areas where the heavy oil was bypassed. The bypassed heavy oil near the producer occurred as a result of the liberated gas BT, which prevented the foamy oil from reaching the producer and subsequently induced the heavy oil viscosity regainment in the late cycles of the GPC test. In summary, the flow patterns as shown in Figure 11a visually indicate the existence of the aforementioned technical shortcomings of the CSI process. The flow patterns as shown in Figure 11b visually reveal the effectiveness of the GPC process in utilizing a two-well configuration to eliminate the back-and-forth movements of the foamy oil in the CSI process.
Figure 9. Cont.
Figure 9. Measured heavy oil recovery factors (RFs), instantaneous gas-oil ratios (iGORs), and production pressures ($P_{prod}$) in SA-GPC process at $\Delta P_{EOR} = 1.0$ MPa (Test #8) (a) Cycle #1; (b) Cycle #2; (c) Cycle #3; (d) Cycle #4; and (e) Cycle #5.

3.4.2. GPC vs. SA-GPC

Figure 12a shows the comparison of the heavy oil RFs during the primary production and every cycle of each GPC or SA-GPC test. It is found that two C$_3$H$_8$-GPC tests (Tests #3 and #4) had higher heavy oil RFs than those in three SA-GPC tests (Tests #6–8). Also, Figure 12b compares the cGORs in every cycle of each GPC or SA-GPC test. C$_3$H$_8$-GPC process is better than SA-GPC process in terms of cGOR, as shown in Figure 12b. The GPC process had a stronger foamy-oil flow and a larger heavy oil viscosity reduction due to the superior solubility of C$_3$H$_8$ as an extracting solvent in the heavy oil.

In general, SA-GPC performed far below expectation. It was expected that the superior solubility of C$_3$H$_8$ would help to reduce heavy oil viscosity, while the injected CO$_2$ would raise the 2-D physical model pressure to $P_i = 3.0$ MPa and enhance the volumetric sweep efficiency. However, it was observed that the production performance of the solvent-gas mixture was more similar to that of CO$_2$ in terms of gas exsolution rate and foamy-oil strength. The solvent (C$_3$H$_8$) and gas (CO$_2$) injected into the physical model were estimated to be approximately 24 mol.% and 76 mol.%, respectively. With the composition of the mixed solvent and gas and their properties, the CMG WinProp module was used to construct the $P$-$T$ phase diagram of the mixed solvent and gas. It is found that at the initial reservoir
conditions, the C$_3$H$_8$-CO$_2$ mixture is in the gaseous phase. In addition, the saturation pressure of pure C$_3$H$_8$ is 0.8 MPa and above this pressure it will be in the liquid phase. Therefore, the injection of CO$_2$ into the physical model helped to vaporize C$_3$H$_8$ and thus reduced its solubility in the heavy oil. The performance of SA-GPC was undermined and the foamy oil formed during this EOR process was not strong enough to enhance heavy oil recovery, in comparison with C$_3$H$_8$-GPC. Based on the heavy oil RFs alone, GPC and SA-GPC processes are ranked as follows: C$_3$H$_8$-GPC test (Test #4) > C$_3$H$_8$-GPC test (Test #3) > SA-GPC test (Test #8) > CO$_2$-GPC test (Test #5) > SA-GPC test (Test #6) > SA-GPC test (Test #7).

\[\text{Figure 10. (a) Measured heavy oil recovery factors (RFs) during the primary productions (PPs) at the final primary production pressures of } P_f = 0.2 \text{ MPa and the different cycles in Tests #1–5. (b) Measured cumulative gas–oil ratio (cGORs) during Cycles #1–3 in C$_3$H$_8$-CSI process at } \Delta P_{\text{EOR}} = 0.5 \text{ MPa (Test #1); Cycles #1–2 in CO$_2$-CSI process at } \Delta P_{\text{EOR}} = 0.5 \text{ MPa (Test #2); different cycles in C$_3$H$_8$-GPC processes at } \Delta P_{\text{EOR}} = 0.1 \text{ and 0.5 MPa (Tests #3 and #4); and Cycles #1–3 in CO$_2$-GPC process at } \Delta P_{\text{EOR}} = 0.5 \text{ MPa (Test #5).}\]
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Figure 11. (a) A digital photo of the 2-D physical model after the CSI process was completed, which shows the directions of the back-and-forth movements of the foamy oil, Region A, where the heavy oil had regained its viscosity, and Region B, where some solvent was trapped. (b) A digital photo of the 2-D physical model after the GPC process was completed, which shows the direction of the foamy-oil displacement and the regions where the heavy oil was bypassed.

![Digital photo of the 2-D physical model after the CSI process](image1)

![Digital photo of the 2-D physical model after the GPC process](image2)

Figure 11. (a) A digital photo of the 2-D physical model after the CSI process was completed, which shows the directions of the back-and-forth movements of the foamy oil, Region A, where the heavy oil had regained its viscosity, and Region B, where some solvent was trapped. (b) A digital photo of the 2-D physical model after the GPC process was completed, which shows the direction of the foamy-oil displacement and the regions where the heavy oil was bypassed.

![Digital photo of the 2-D physical model after the CSI process](image1)

![Digital photo of the 2-D physical model after the GPC process](image2)

Figure 12. (a) Measured heavy oil recovery factors (RFs) during the primary productions (PPs) and in different cycles in Tests #3–8. (b) Measured cumulative gas–oil ratio (cGORs) in different cycles of C3H8-GPC processes at ∆P_{EOR} = 0.1 and 0.5 MPa (Tests #3 and #4); Cycles #1–3 in CO2-GPC process at ∆P_{EOR} = 0.5 MPa (Test #5); and in different cycles of SA-GPC processes at ∆P_{EOR} = 0.1, 0.5, and 1.0 MPa (Tests #6–8).

![Graph of heavy oil recovery factors](image3)

![Graph of cumulative gas–oil ratio](image4)
4. Conclusions

In this paper, a total of eight sandpacked coreflood tests were performed in the laboratory by using a 2-D physical model to study the production performances of two new different solvent-based enhanced oil recovery (EOR) processes and their abilities to restore foamy oil and enhance the heavy oil recovery. The two processes included gas pressure cycling (GPC) and solvent-assisted gas pressure cycling (SA-GPC), which were also compared with the traditional cyclic solvent injection (CSI). The following six conclusions can be drawn from this study:

- During the CSI, a new phenomenon termed the solvent-trapping effect was encountered in its late cycle, in addition to the known technical limitations of the back-and-forth movements of foamy oil, fast reservoir pressure depletion, and quick heavy oil viscosity regainment.
- The proposed GPC process could recover 41.9% of the original oil-in-place (OOIP) because an injector was utilized in a two-well configuration to inject gas and mobilize the foamy oil toward the producer. Thus, the microscopic displacement efficiency was increased to effectively enhance heavy oil production. C₃H₈-GPC test had higher heavy oil recovery factor (RF) in comparison with CO₂-GPC test. Although the heavy oil RF in C₃H₈-GPC test at ΔPₑₒᵣₑ = 0.1 MPa was similar to that in C₃H₈-GPC test at ΔPₑₒᵣₑ = 0.5 MPa, a higher ΔPₑₒᵣₑ meant a shorter production period.
- C₃H₈ is a much better extracting solvent than CO₂ in GPC process in terms of the heavy oil RF, production rate, and cumulative gas-oil ratio (cGOR). This was due to a high solubility of C₃H₈ and its ability to significantly reduce the heavy oil viscosity. Certainly, the production performance of CO₂-GPC is expected to be much better if a much higher solvent injection pressure is used.
- The proposed SA-GPC process could recover 36.6% of the OOIP, which was 9% more than the CSI heavy oil RF. This was attributed to the effect of the two-well configuration. Moreover, SA-GPC test at ΔPₑₒᵣₑ = 1.0 MPa had the highest heavy oil RF in comparison with the other two SA-GPC tests at ΔPₑₒᵣₑ = 0.1 and 0.5 MPa, respectively.
- GPC recovered more heavy oil than CSI because GPC utilized a two-well configuration to minimize or eliminate the major technical limitations associated with CSI. In addition, C₃H₈-GPC recovered more heavy oil than SA-GPC. This was because GPC utilized a higher solubility of C₃H₈ to reduce heavy oil viscosity, induce a stronger foamy-oil flow, and slow heavy oil viscosity regainment, in comparison with approximately 24 mol.% C₃H₈ + 76 mol.% CO₂ used in SA-GPC.
- Different solvent-based EOR processes were evaluated and ranked based on the heavy oil RFs as follows: C₃H₈-GPC > C₃H₈-SA-CO₂-GPC > CO₂-GPC > C₃H₈-CSI > CO₂-CSI. From an engineering point of view, nevertheless, an economic analysis of each solvent-based EOR process is required in order to find the best EOR choice on a field scale.

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Nomenclature

Notations

- $H$: Height of the 2-D physical model, m
- $k$: Absolute water permeability, D
- $L$: Length of the 2-D physical model, m
- $P_a$: Atmospheric pressure, atm
- $P_e$: Ending production pressure in each EOR process, MPa
- $P_f$: Final primary production pressure, MPa
- $P_i$: Initial reservoir pressure, MPa
- $P_{injg}$: Gas injection pressure, MPa
- $P_{injs}$: Solvent injection pressure, MPa
- $P_{prod}$: Production pressure, MPa
- $P_s$: Soaking pressure, MPa
- $P_{sat}$: Saturation pressure, MPa
- $S_{oi}$: Initial oil saturation, %
- $S_{wi}$: Initial water saturation, %
- $T_{res}$: Reservoir temperature, °C
- $W$: Width of the 2-D physical model, m

Greek symbols

- $\Delta P_{EOR}$: Pressure depletion step size during CSI/GPC/SA-GPC, MPa
- $\Delta P_{PP}$: Pressure depletion step size in the primary production, MPa
- $\phi$: Porosity, %

Subscripts

- $a$: Atmospheric
- $e$: Ending
- $EOR$: Enhanced oil recovery
- $f$: Final
- $i$: Initial
- $injg$: Gas injection
- $injs$: Solvent injection
- $oi$: Initial oil
- $PP$: Primary production
- $prod$: Production
- $res$: Reservoir
- $s$: Soaking
- $sat$: Saturation
- $wi$: Initial water

Acronyms

- BPR: Back-pressure regulator
- BT: Breakthrough
- cGOR: Cumulative gas-oil ratio
- CHOPS: Cold heavy oil production with sand
- CSI: Cyclic solvent injection
- DAS: Data acquisition system
- ECSP: Enhanced cyclic solvent process
- EOR: Enhanced oil recovery
- GOR: Gas-oil ratio
- GPC: Gas pressure cycling
- iGOR: Instantaneous gas-oil ratio
- IOR: Improved oil recovery
- OOIP: Original oil-in-place
- PP: Primary production
- PP-CSI: Pressure pulsing cyclic solvent injection
- $P-T$: Pressure vs. temperature
- RF: Recovery factor
- SA-GPC: Solvent-assisted gas pressure cycling
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