CO_2-Based Heavy Oil Recovery Processes for Post-CHOPS Reservoirs

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Abstract

Cold Heavy Oil Production with Sand (CHOPS) is currently the process of choice for recovery from unconsolidated solution-gas rich heavy oil reservoirs. Compared to waterflood and thermal recovery processes, primary processes such as CHOPS have relatively low energy and emission intensities; in other words, they can be considered as relatively 'clean' fossil fuel energy recovery processes. However, with recovery factors between 5 and 15% at the end of its economic life, there is a search for follow-up processes that yield additional oil from these reservoirs with continued low energy and emission intensities. One option is CO_2-based enhanced oil recovery (EOR) processes – CO_2 can lower oil viscosity and if some fraction of the injected CO_2 is sequestered in the reservoir, then the process can be considered a CO_2 storage process in addition to an oil follow-up recovery process. Here, we evaluate the energy return and CO_2 sequestered in cyclic CO_2 and cyclic CO_2-hot water injection processes in a post-CHOPS heavy oil field. The results reveal that overall recovery factors can be raised through appropriate design of the CO_2 follow-up process. Cyclic CO2 injection achieves an incremental 2.4% recovery factor (over 4 years of operation) with high energy return ratio whereas CO2-hot water processes achieve higher recovery factors with lower energy return ratios. In these processes, the amount of CO_2 that remains sequestered in the reservoir is small, typically less than 5%. Thus, these EOR processes are not strong candidates for CO_2 sequestration.

Keywords: heavy oil; cold production of heavy oil with sand; post-CHOPS; CO_2 injection; follow-up recovery processes

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1. Introduction

Primary production of heavy oil resources, often referred to as cold production, is attractive due to low operating and capital costs of wells and surface equipment. Another key benefit of these heavy oil recovery processes is that their energy intensity (net energy consumed per unit oil produced, 4 GJ/m^3 oil), greenhouse gas (GHG) emissions intensity (typically less than 300-400 $kgCO_2eq/m^3$ oil), and water consumption (net gain of water) are all better than thermal extra heavy oil recovery processes such as Cyclic Steam Stimulation (CSS) and Steam-Assisted Gravity Drainage (SAGD) [32]. For example, in SAGD, the energy intensity is typically between 6-12 GJ/m^3 oil, GHG emissions intensity 500-1,500 kgCO2eq/m^3 oil, and water consumption is 100-250 kg/m^3 oil (assuming steam-to-oil ratio between 2 and 5 m^3/m^3 and 95% water recycle) [15]. Thus, on a per volume basis, heavy oil cold production processes have significant energetic and emissions advantages over that of thermal processes. In Western Canada, about 80% of heavy oil resources are found in reservoirs <5 m thick which due to its high viscosity (1,000-35,000 cP), low solution gas to oil ratio (GOR, ~8-15 m^3/m^3), and low initial reservoir pressures, have primary recovery factors from 3 to 8% [1]. In some cases, if the solution gas content is high enough and there are no neighbouring water zones, recovery factors reach as high as 15% [19]; 3 to 15% recovery factor is typical of primary production of heavy oil worldwide [27-29].

Several studies have been conducted to understand mechanisms of heavy oil production processes including experimental studies on sand production and foamy oil flow behavior, for example, Tremblay et al. [27-29], and Maini et al. [21, 22] among others. Also, due to sand production, as the process evolves, wormholes are created within the reservoir [29]. The wormholes are believed to be of order of a few tens of centimeters in diameter and they extend up to several hundred meters into the reservoir. There are several CHOPS wormhole models in the literature, for example [11, 18, 26]. The key challenge faced by operators after CHOPS has been done is that the reservoir is permeated with wormholes which often connect wells together. This means that injected fluid moves through the wormholes with little contact with the reservoir bypassing the heavy oil-laden reservoir between the wormholes. In heavy oil reservoirs where CHOPS has not been operated, currently secondary recovery process such as water and polymer flooding are used which work effectively in reservoirs where the heavy oil viscosity is less than ~5,000 cP [5, 9]. Water flooding and polymer flooding in post-CHOPS reservoirs suffer from the existence of the high permeability wormholes and gas-saturated zones that lead to low displacement and sweep efficiencies and thus low incremental recovery factor [1, 23, 25].

Another injectant that can be considered is carbon dioxide – it can act both as a solvent to lower the heavy oil viscosity as well as a swelling agent that expands the oil phase volume within pores [20]. Also, there are environmental benefits if some fraction of the CO_2 is sequestered within the reservoir. At this point, there are no detailed studies on the use of CO_2 as an injectant for post-CHOPS reservoirs for incremental recovery of oil and to evaluate the capability of the processes to sequester CO_2. In this study, we evaluate the use of CO_2 and CO_2-hot water mixtures for enhanced oil recovery from a post-CHOPS reservoir as well as the processes' ability to sequester CO_2.

For heavy oil reservoirs, waterflooding has shown very poor performance [1, 23]. Miller's study of different water flood operations in Western Canadian heavy oil reservoirs along with his theoretical investigations showed that waterflooding has very poor sweep efficiency due to the adverse mobility ratio, heterogeneity of the reservoirs, and presence of wormholes [23]. He found that by using horizontal wells, hot water injection, and steam stimulation may not consistently improve process performance. In polymer (aqueous polymer solution) injection, the mobility ratio of the water and oil is improved which prevents viscous fingering. This strategy is used by some companies in western Canadian heavy oil reservoirs e.g. in the Pelican Lake project operated by Canadian Natural Resources Limited and the Brintnell polymer flood operated by Cenovus. Laboratory studies of polymer flooding and alkaline/surfactant flooding reveal small increases of recovery factor from heavy oil reservoirs [3, 16, 20, 23]. However, field results have not confirmed this improvement in Western Canadian reservoirs [23]. Dong et al. [12] conducted laboratory experiments to produce heavy oil through an alkaline/surfactant recovery process which ended up with total recovery factors up to 20%.

Gates [14] investigated the application of solvent-aided SAGD in thin (8 m) oil sands reservoirs. The results revealed that lower steam usage and net injected energy-to-oil ratio are possible compared to the traditional SAGD process. SAGD and its derivatives are vulnerable to excessive heat losses to the overburden and understrata. Investigations on in situ combustion (ISC) have been performed through laboratory, modeling and pilot tests for heavy oil and oil sands thermal recovery, however, ISC has not yet enjoyed the success of other thermal methods such as SAGD and CSS due to complexity of reaction kinetics and control of the process [4]. Application of ISC as a follow-up process for CHOPS reservoirs was proposed recently by Chen et al. [8]. Their experiments show promising results (recovery factors >50%) at the laboratory scale. However, ISC has not been tested in the field in post-CHOPS reservoirs.

Solvent-based processes have been tested for oil sands reservoirs and demonstrated good recovery factors. These types of processes can be expanded to CHOPS reservoirs. Zhao et al. [32] conducted an optimization analysis for solvent-aided steam-flooding strategy for a 4 m thick heavy oil reservoir. Their results demonstrated that steam-solvent optimization can improve the process performance compared to injection pressure optimization only. They also performed a comparative simulation study to find a viable thermal recovery process for recovery in a thin (<5m) heavy oil reservoir [31]. Their investigation revealed that SAGD and steam flooding would not be efficient options for thin heavy oil reservoirs due to their high cumulative energy injected-to-oil ratio (cEOR >13.6 GJ/m^3). They concluded that hot water injection is possible with cEOR ranging from 8 to 14 GJ/m^3 although this is high relative to the cold production process. Recent studies suggest that there is potential for cyclic solvent injection for thin heavy oil reservoirs [25-28]. Chang and Ivory [7] used a specific well configuration for solvent injection (CO_2, CH_4, C_3H_8) as follow-up processes for CHOPS reservoirs. They used vertical injectors and a horizontal producer at lower depth below the bottom hole location of the CHOPS vertical wells. In these recovery processes, oil production mechanisms are dilution (lowers oil phase viscosity) and gravity-viscous flow. Different operation scenarios revealed how wormholes can increase the recovery factor or inappropriate design reduces the oil rate recovery due to solvent bypassing the reservoir through wormholes. Huerta et al. [17] performed an experimental study on the use of acid gas (CO_2/H_2S) as solvent for cyclic solvent injection in heavy oil reservoirs. They showed that a mixture of CO_2 and H_2S gives higher recovery factor and more gradual pressure decline during two-cycle test compared to that of pure CO_2. They also found that a mixture of CO_2-propane had the highest recovery and lowest pressure decline. The recovery mechanisms that contributed to production were oil swelling and oil mobilization.

Injection of CO_2 under miscible and immiscible condition has been investigated in the laboratory, field tests, and reservoir modeling [3, 24, 30]. In general, the results of these studies indicate an increase of recovery factor for heavy and light oils cases. Field and laboratory tests reported a successful immiscible CO_2 recovery in the Wilmington field (an unconsolidated sandstone reservoir) [24]. Heavy oil reservoirs in the Lloydminster area are unconsolidated low-pressure sandstone at depths typically between 300 and 700 m. Due to their shallow depths, miscibility between oil and injected CO_2 cannot be achieved.

2. Reservoir Simulation Model

In this study, CO_2-based processes are evaluated as a recovery strategy for a thin heavy oil reservoir. The viscosities of mixtures of the heavy oil, solution gas, and CO_2, displayed in Figure 1, is calculated from the log-linear mixing rule given by:

$$\ln \mu_{mix}(T) = x_{heavy\ oil} \ln \mu_{heavy\ oil}(T) + x_{CO2} \ln \mu_{CO2}(T) + x_{sg} \ln \mu_{sg}(T)$$

where $x_{heavy\ oil}$, x_{CO2}, and x_{sg} are mole fractions of heavy oil, CO2, and solution gas, respectively, and $\mu_{heavy\ oil}(T)$, $\mu_{CO2}(T)$, and $\mu_{sg}(T)$ are viscosities of the heavy oil, CO2 (liquid equivalent), and solution gas (liquid equivalent) at temperature T.

The reservoir model of the heavy oil formation is taken from the General Petroleum Formation in the Cold Lake area of Alberta, Canada; the history-matched model used in this study is described in detail in [26]. Table 1 lists properties of the reservoir model. Briefly, there are three rock types derived from the logs: 1. sandstone, 2. interbedded shale, siltstone and fine-grained sandstone, and 3. shale, minor siltstone and sandstone. Figure 2 displays the spatial distributions of the porosity, permeability and oil saturation for the General Petroleum Formation in the area of interest. The reservoir model consists of 118×147×50 gridblocks with dimensions of 20 m by 20 m in the horizontal directions and about 1 m in the vertical direction. A grid refinement study (halving the grid in each direction) produced a 0.5% difference of results (injection and production volumes) and thus the grid was considered sufficiently refined. Figure 3 displays the layout of the CHOPS wells. This reservoir was under primary production (CHOPS) for ~10 years.

Following Istchenko and Gates [18], the CMG STARS™ reservoir simulator is used [10]. A description of the governing equations (material balance, energy balance, diffusive and convection mass transfer, multiphase flow under Darcy's law, phase behaviour and equilibrium by using K-value correlations) and numerical method (finite volume method) is listed in [10]. The K-value correlation coefficient and other input data are listed in Table 1. The reservoir simulation model includes the effects of foamy oil flow (using pseudo reactions for conversion of dissolved gas to bubbles to free gas), solution gas drive, wormhole propagation, and sand production (see [18] for full details). Wormholes were evolved during the CHOPS stage and they are modeled as branched wells with a radius equals to 7.5 cm. The initial state of the reservoir for the post-CHOPS processes is the final state of the CHOPS operation after 10 years of production (see [18] for history-matched CHOPS operation). Each post-CHOPS simulation took between 10 and 15 hours to run on a quad core (3.4 GHz) workstation.

2.1 Post-CHOPS Cases

Five cases have been investigated. Cold and hot waterflooding cases are done to establish a baseline for comparison when carbon dioxide is added as an injectant to the recovery process.

Case 1: Waterflooding

In this process, four of the eight post-CHOPS wells are converted to injectors and the other four operated as producers as shown in Figure 3. The injectors were chosen as those that were perforated at relatively shallower depth to get potential benefits of gravity drainage. For operating conditions, the maximum injection pressure for the injectors is 3,500 kPa, and bottom hole pressure of the producers is set to 200 kPa. For the producers, an additional constraint of a maximum water cut of 95% is imposed. The temperature of the water is the same as the reservoir temperature (20°C).

Case 2: Hot Waterflooding

In this study, hot waterflooding is tested to enhance the mobility of the oil due to oil phase viscosity reduction. The operating conditions and well configuration were the same as that of cold waterflooding except the temperature of the injected water is equal to 200°C.

Case 3: Hot Water Alternating Gas (Hot WAG)

Water alternating gas injection may delay water breakthrough enabling greater oil recovery from the reservoir and in turn increase oil recovery factor. In this study this process is tested as another thermal recovery method hot water and carbon dioxide injected. The operating conditions and well configuration are the same as that of hot waterflooding. The ratio of the injection period of hot water to CO_2 is equal to 1. Over the first two years of the operation, injection periods for hot water and then CO2 were each 30 days duration. After the second year, the periods were raised to 45 days.

Case 4: Cyclic CO_2 Injection (CCI)

Here, CO_2 is introduced into the reservoir through cyclic injection and production – each well is operated cyclically (both injection and production occur in all wells). For Cyclic CO_2 Injection (CCI), all of the eight wells start at the same time for the injection and production periods. For operating conditions, the maximum injection pressure for cyclic processes is 4,500 kPa, and producers are set to 200 kPa bottom hole pressure. For this case, each cycle is as follows: 14 days of CO_2 injection, 4 days of soak time, and 14 days of production for the first year. In the second year, the injection and production intervals are enlarged to an injection interval of 30 days, and production period of 45 days.

Case 5: CO2-Hot Water Cyclic Injection

To improve the energy efficiency and oil recovery, CO_2-hot water cyclic injection is tested at different pressures and CO_2 volume fractions. Five tests are performed for low to high volume fraction of CO_2: 25%, 50%, 75%, 99%, and 99.5% volume fraction of CO_2 at surface conditions. The maximum injection pressure is equal to 4,500 kPa and the bottom hole pressure of the producers is set to 200 kPa.

The key difference between these cases and the Hot WAG case is that these processes are cyclic where the CO2-hot water mixture is injected into the well and then fluids are produced from the same well. In the Hot WAG case, slugs of each fluid are injected into the injectors and fluids are produced from the producers. The length of injection and production cycles were the same as that of the cyclic solvent injection case.

2.2 Energy Return Ratio

The performances of the different processes examined here are compared with respect to both incremental recovery factor and cumulative energy efficiency (for the follow-up process only) at the end of four-year post-CHOPS operation. The energy return ratio of each process (after four years of operation) is defined as the ratio of the energy of the produced oil with energy value of 42.7 GJ/m^3 to the sum of the required energy for compression (for CO_2 injection), pumping water (for injection), pumping produced fluids from bottom hole to the surface (water and oil), and energy requirement from burning natural gas to raise the temperature of water (for hot water injection):

$$\text{Energy Return Ratio} = \text{Chemical Energy of Produced Oil} / (W_p + W_c + H_{gas})$$

where W_p is the work of pumping water to the bottom hole and pumping liquids and sand from bottom hole to the surface, W_c is the work of compressors for injection of CO_2, and H_{gas} is the combustion energy of gas consumed to increase the temperature of water.

3. Results and Discussion

Table 2 lists a summary of the results of the cases described above. Prior to the follow-up process, the cumulative energy return ratio of the cold production process was equal to 10.5 GJ out per GJ invested in the recovery process. The recovery factor achieved by the cold production process was equal to 10.3%. The following subsections describe the results from the cases described above.

3.1 Waterflooding, Hot Waterflooding, and Hot Water-Alternating Gas

For the cold waterflooding case, 124,730 m^3 of water was injected into the formation and 32,167 m^3 of heavy oil is produced. Water breakthrough, defined where the water cut at the production wells reached 95%, did not occur in the four years of operation. As listed in Table 2, this process results in an incremental recovery factor of 2.1% at the end of four-year process with an energy return ratio of 3.8 GJ/GJ (GJ energy produced as chemical energy in the oil per GJ energy consumed in the recovery process). Recovery of this process is relatively low because of the high mobility ratio between the water and heavy oil phases.

Figure 4 compares the result of thermal and non-thermal waterflooding processes; the results reveal that the incremental oil recovery has remained almost the same among these cases. However, the energy return ratio of hot waterflooding is improved to 5.6 GJ/GJ from 3.8 GJ/GJ for the cold waterflooding process. The reason is first due to increasing oil mobility as a result of viscosity reduction due to heating. In the hot water injection case, the hot water at 200°C has lower viscosity (about 0.134 cP) compared to that of the cold water (at 20°C, viscosity is 1.02 cP) and thus it has a faster breakthrough time at about 900 days (defined when the water cut exceeded 95% at the production wells) than that of the cold water injection case.

The results of the Hot WAG case (water-to-gas ratio equal to 1), shown in Figure 5, reveal that Hot WAG did not improve process performance compared to hot waterflooding over the period of 4 years both with respect to recovery factor and energy efficiency. In the Hot WAG case, the energy return ratio is slightly worse than that of the hot water flood at 5.3 GJ/GJ. This is because of the lower amount of mobilized oil in the Hot WAG case as well as the additional energy required to compress the CO_2 for injection into the reservoir.

In general, the results suggest that flood type processes (waterflood, hot waterflood, hot WAG) are not good choices for post-CHOPS heavy oil reservoirs with high oil viscosity. This is due to the mobility ratio of the water to heavy oil and the relatively high conductivities of the wormholes that tend to convey the flooding fluid from the injector to the producer rather than allowing displacement from the unrecovered regions between the wormholes.

3.2 Cyclic CO_2 Injection (CCI)

As listed in Table 2, the results show 54.9 million m^3 (expressed at standard conditions, equivalent to ~101,900 tonnes) of CO2 was injected into the reservoir over four years of operation. As CO_2 diffuses into heavy oil, the viscosity of the oil drops and its mobility rises. Furthermore, the oil phase swells which can help move oil towards the production well. The results shown in Figure 5 show that for 2.4% incremental oil recovery over the four years of operation, the required CO_2 volume is 61 m^3/m^3 of produced oil (volumes expressed at surface conditions). Therefore, for the cyclic CO_2 injection design, the process requires a total CO_2 net volume of 2,370,900 m^3 (~4,405 tonnes) over four years of cyclic injection and up to 4.3% of the total amount of CO_2 injected by volume is sequestrated in the reservoir. Environmental benefits by having some part of the CO_2 stored in the reservoir is attractive; however, the amount sequestered within the reservoir is relatively small compared to the amount injected. The cumulative oil production profile is monotonic with no reduction of the overall slope.

Figure 6 shows the pressure around wells in two layers at different times, in which two of them have wormholes grown within these two layers. The results show that pressure depletion happens around the wormholes and the zone of depleted pressure enlarges as the recovery processes evolves. For the CCI process, the incremental recovery at the end of four years is 2.4% with energy return ratio of 9.9 GJ/GJ. Although the incremental recovery factor is low, the energy return ratio is much better than the other processes. This is because hot water is not used in this process.

3.3 CO_2-Hot Water Cases

The results for the cyclic CO_2 and hot water injection cases listed in Table 2 reveal that the incremental recovery factor ranges from 3 to 6.6% depending on the relative amounts of CO_2 and hot water. The energy return ratio for the processes range from 1.8 to 4.3 GJ/GJ with the lowest achieved at a ratio of 50% CO_2 and 50% hot water. As the amount of CO_2 is raised, the energy return ratio rises primarily due to the reduction of hot water injected in the process. The results suggest that there is an optimum value with respect to the CO_2-hot water ratio that balances the incremental recovery factor and the energy return ratio. Since the amount of oil produced in the 25% CO_2 and 75% hot water case is relatively large, its energy return ratio is slightly larger than that of the 50% CO_2/50% hot water case. As the hot water content drops, the energy invested in the process drops and thus for processes with greater than 50% CO_2, the energy return ratio rises despite the lower amount of oil produced.

The results shown in Figure 7 for the 25% CO_2-75% hot water and 99% CO_2-1% hot water cases reveal the net CO2 stored in the reservoir is relatively low. The lower the amount of water injected, the smaller is the cumulative oil produced. The cumulative oil profiles are monotonic and do not demonstrate a reduction of their slope which indicates that further operation beyond the four years evaluated here would yield significantly greater oil volumes. By increasing the CO_2 volume fraction, the total incremental recovery decreases but the energy efficiency of the processes increases. The best case among these CO_2-hot water cases reveals that about 4.1% of the CO_2 volume injected is sequestered in the reservoir. Again, similar to the CCI results, the relative amount of CO_2 stored is small.

Figure 8 displays the temperature distribution around the wells for the 25% CO_2-75% hot water case. The results show that for most of the wells, the temperature directly within the wormhole networks is partially heated due to the cyclic injection and production. The addition of CO_2 reduces the amount of heat convected into the reservoir. The largest heated zone surrounding a well occurs for Well 12 (leftmost, bottom well) – in this well, the size of the heated zone reaches about 90 m in diameter and the heated zone extends beyond the wormhole network.

3.4 Discussion: Energy Efficiency Analysis and Carbon Dioxide Storage

A comparison of the energy return ratios of the processes considered here is presented in Figure 9. The results show that the CCI process yields the greatest energy return ratio with hot water flood at about two-thirds of the CCI value. The reason that hot waterflooding yields a relatively high energy return ratio is due to due to the relatively small amount of hot water injected which leads to a relatively large mobilization of oil. CO_2 enables much more oil from the reservoir but with a reduction of the energy return ratio. Design of such processes with CO_2-hot water can decrease the viscosity of the oil far from the wormholes as hot water loses its heat at a larger distance away from the wellbore and swelled oil with reduced viscosity flows to the production wells in a post-CHOPS reservoir.

As presented in Table 2, the 25% CO_2-75% hot water process gives the highest incremental recovery factor for CO_2 -based processes for the reservoir in this study with final oil recovery of 102,150 m^3 after four years of post-CHOPS. However, its energy return ratio is not high.

The results suggest that CO_2 is a practical choice given its favourable energy efficiency. Among the proposed steam-CO_2-based processes, the CO_2-steam/hot water injection (case of 25% CO_2-75% hot water) has the highest recovery factor and acceptable energy efficiencies although its cumulative steam-to-oil ratio is relatively high (5.7 m^3/m^3). The CO_2-steam/hot water injection (case of 99% CO_2-1% hot water) has an energy efficiency of 3.0 (GJ out/GJ in) and lower cumulative hot water-to-oil ratio (4.1 m^3/m^3) which is favourable, it results in an incremental recovery factor of 3.6%.

The results reveal that the opportunity for CO_2 sequestration in the reservoir during the post-CHOPS oil recovery processes considered here is small, typically less than 10%. The reason for this is that the amount of water in the system is not large and thus the capability to store CO2 is small. Also, for cyclic processes, each production period is a blowdown step which largely produces back most of the injected CO_2 due to the pressure drop that occurs on production. Injecting hot water raises the temperature of the system which consequently lowers the solubility of CO_2 within the fluids in the reservoir and thus, co-injection of CO_2 and hot water does not provide optimal conditions for storage of CO_2 in the formation. This suggests that CO_2-based processes are not good candidates for CO_2 sequestration during oil recovery.

4. Conclusions

There is a potential to recover incremental oil from reservoirs that have been operated under primary production cold heavy oil production with sand (CHOPS) by using CO_2. CO_2 has a high injectivity value and it is used under immiscible conditions which enables its penetration into the reservoir through wormholes. It also yields a reduction of heavy oil viscosity and oil swelling within the reservoir.

Waterflooding and water alternating gas do not perform as well as CO_2 injection due to high viscosity of the oil for the post-CHOPS reservoir in this study. Therefore, CO_2 cyclic injection alone or with hot water can be optimized to improve recovery from the reservoir. With CO_2 cyclic injection, the incremental recovery factor at the end of four years of operation is 2.4% with relatively high energy efficiency; the energy return ratio is the highest of all of the processes evaluated here. Cyclic solvent injection with hot water appears to be a reasonable option with incremental recovery factor equal to 6.6% for the best case. However, the energy return ratio of CO_2-hot water injection for the reservoir is relatively low compared to the other cases examined here. The amount of CO_2 sequestered within the reservoir during the CO_2-based recovery processes is relatively small, usually less than 5%.

Acknowledgements

Authors would like to thank the financial support of the Petroleum Technology Research Centre Saskatchewan (PTRC) for this project, and Computer Modeling Group Ltd. for the use of their thermal reservoir simulation software CMG STARS^{TM}. We would also like to thank Jacky Wang for his help and comments on the modeling part of this study.

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Table 1: Properties of Cold-Lake CHOPS reservoir used in the simulation model. Source of data is Reference [26] unless otherwise noted.

Property	**Value**
Depth to reservoir top (m)	291
Net pay (m)	~6
Porosity	0.06-0.40
Oil saturation	0.4-0.8
Solution gas-to-oil ratio (m^3/m^3)	10
Horizontal rock permeability k_h (mD)	30-8500
k_v/k_h	0.8
Effective rock compressibility (1/kPa)	$5x10^{-6}$
Rock heat capacity (kJ/m^3 ºC)	2,600
Rock thermal conductivity (kJ/m day ºC)	660
Reference pressure (kPa)	2,500
Reference depth (m)	291
Initial reservoir temperature, ºC	20
Dead oil viscosity (cP)	See Figure 1
Water viscosity	Correlation listed in [10]
Liquid equivalent solution gas viscosity (cP) Correlation: $\mu = Ae^{\frac{B}{T}}$	See Figure 1
Gas phase viscosity (cP)	0.00864 (1.574 + 0.0044·T(ºC)) (from [10])
Oil phase density, kg/m^3	$\frac{920}{e^{0.0007\,(T-T_{ref})(^{o}C)\,+\,7x10^{-7}\,(P-P_{ref})(kPa)}}$, ($T_{ref}$ = 15.5 ºC and P_{ref} = 1 atm)
Water phase density	Correlation listed in [10]
Gas phase density	Redlich-Kwong equation of state with zero interaction coefficients [10]
Water thermal conductivity (kJ/m day ºC)	53.4
Gas thermal conductivity (kJ/m day ºC)	5
Oil thermal conductivity (kJ/m day ºC)	11.5
Foamy-oil kinetic parameters	N_1=1.44 1/day, N_2=0.288 $(gmol/m^3)^{-2}$/day, G_1=0 1/day, G_2=0.23 $(gmol/m^3)^{-2}$/day (from [18])
Liquid phase diffusion coefficient (carbon dioxide), m^2/s	1.9×10^{-9}
Liquid phase diffusion coefficient (methane), m^2/s	1.5×10^{-9}
K-values (methane) = $\frac{Kv1}{P} e^{\left(\frac{Kv4}{T(C)-Kv5}\right)}$	Kv_1=5.4547×10^5 kPa, Kv_4=-879.84°C, Kv_5=-265.99°C
K-values (carbon dioxide) = $\frac{Kv1}{P} e^{\left(\frac{Kv4}{T(C)-Kv5}\right)}$	Kv_1=8.6212×10^5 kPa, Kv_4=-3103.39°C, Kv_5=-272.99°C
Wormhole radius (m)	0.075
Number of gridblocks	118 × 147 (horizontal) × 50 (vertical)
Dimensions of gridblocks (m)	20 × 20 (horizontal) ×1 (vertical)
Oil-water relative permeability curves	S_w k_{rw} k_{row} 0.2000 0.0000 0.7000 0.3750 0.0000 0.2759 0.5500 0.0000 0.0658 0.5969 0.0014 0.0376 0.6125 0.0031 0.0303 0.6594 0.0148 0.0139 0.6750 0.0215 0.0101 0.7063 0.0402 0.0047 0.7531 0.0839 0.0007 0.7844 0.1252 0.0000 0.8000 0.1500 0.0000
Gas-Liquid relative permeability curves	S_l k_{rg} k_{rog} 0.4000 0.5000 0.0000 0.5000 0.2560 0.0000 0.6000 0.1080 0.0000 0.6563 0.0579 0.0046 0.6750 0.0456 0.0109 0.7125 0.0264 0.0369 0.7500 0.0135 0.0875 0.8063 0.0033 0.2275 0.8625 0.0000 0.4689

Table 2: Summary of results of cases investigated (after four years of operation). For the follow-up processes, the incremental RF and cumulative quantities are over the duration of the follow-up process (does not include initial cold production process).

Process	Cum. Oil Prod. (m3)	Cum. Water Inj. (m^3)	Cum. CO_2 Inj. (Sm^3)	RF%	Cum. Energy Return Ratio (GJ out/GJ in)	Cum. HWOR (m^3/m^3)
Cold Production	158,614	-	-	10.3	10.5	-
Follow-up Process	**Cum. Oil Prod. (m^3)**	**Cum. Water Inj. (m^3)**	**Cum. CO2 Inj. (Sm^3)**	**Increm-ental RF%**	**Cum. Energy Return Ratio (GJ out/GJ in)**	**Cum. HWOR (m^3/m^3)**
Waterflooding	32,167	124,730	-	2.1	3.8	-
Cyclic CO_2 Injection (CCI)	38,837	-	54,858,100	2.4	9.9	-
Hot Waterflooding	31,004	67,510	-	2.0	5.6	2.1
Hot WAG, ratio = 1	29,100	27,963	1,482,660	1.9	5.3	1.0
CO_2-Hot Water, Ratio 25:75	102,146	586,675	195,500	6.6	2.0	5.7
CO_2- Hot Water, Ratio 50:50	88,943	576,116	576,090	5.6	1.8	6.5
CO_2-Hot Water, Ratio 75:25	64,543	421,685	1,265,050	4.0	1.9	6.5
CO_2-Hot Water, Ratio 99:1	56,476	231,750	22,943,200	3.6	3.0	4.1
CO_2-Hot Water, Ratio 99.5:0.5	48,343	122,320	24,341,800	3.0	4.3	2.5

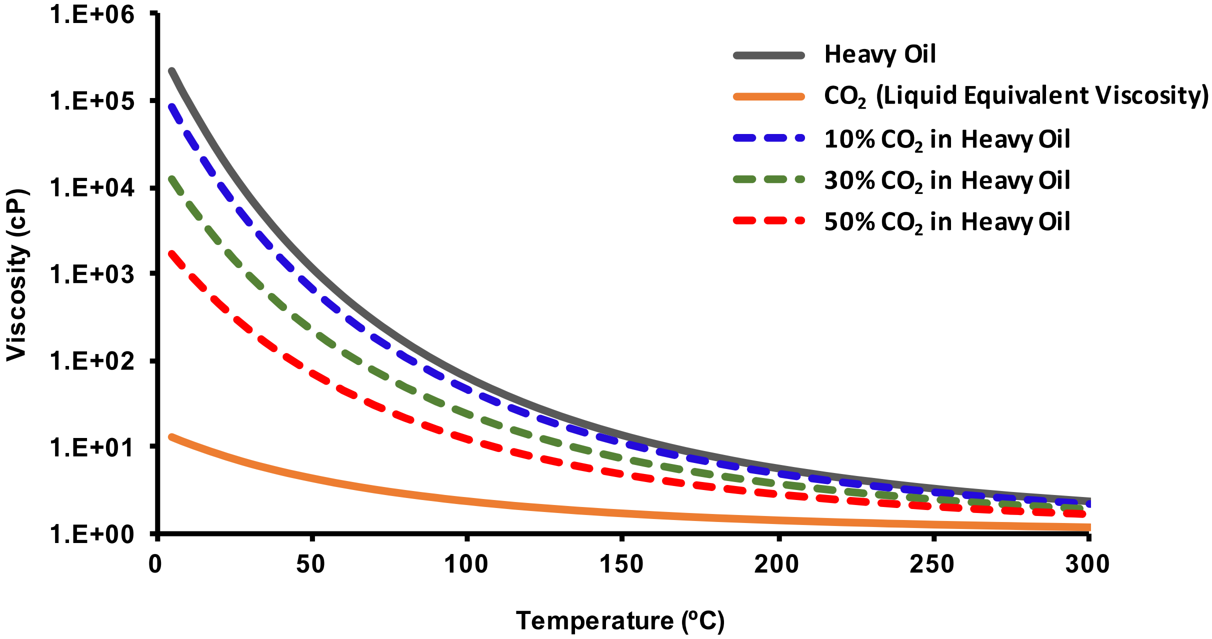

Figure 1: **Viscosity of heavy oil and CO_2 (as equivalent liquid phase, solution gas has same liquid equivalent viscosity) and their mixtures (mole percent) in the reservoir model.**

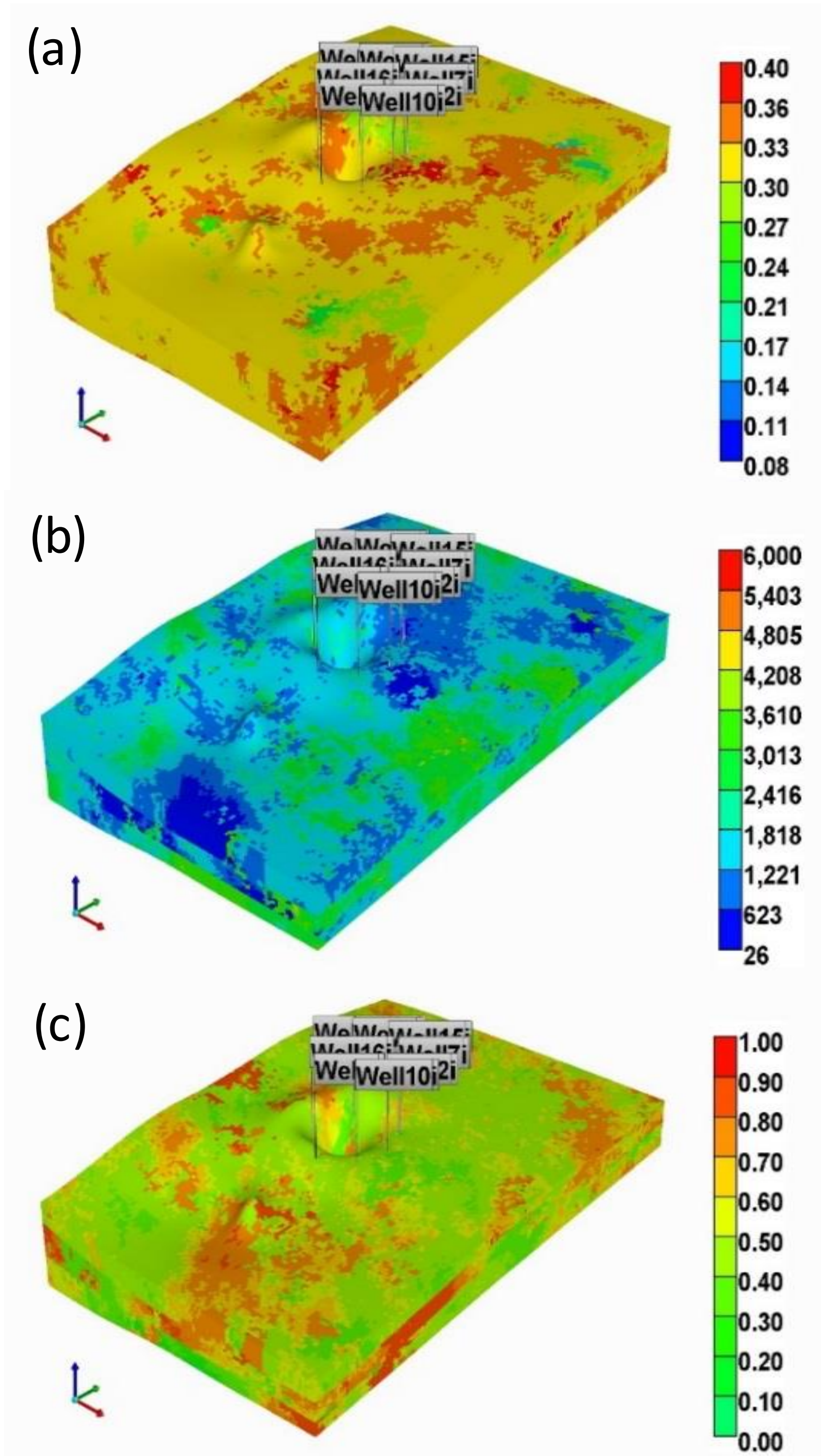

Figure 2: (a) Porosity, (b) permeability, and (c) oil saturation at the start of the post-CHOPS process. Average porosity is equal to 35% and horizontal permeability is between ~100 mD and ~8 D.

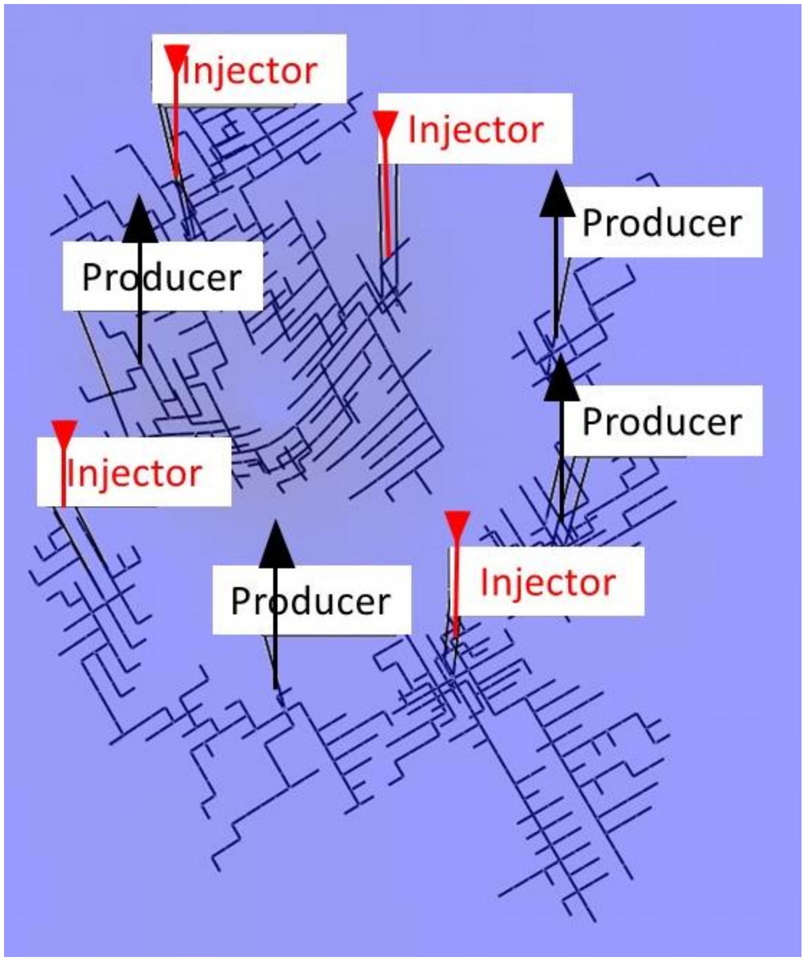

Figure 3: Arrangement of injector and producer wells used in waterflood, hot waterflood and hot WAG processes.

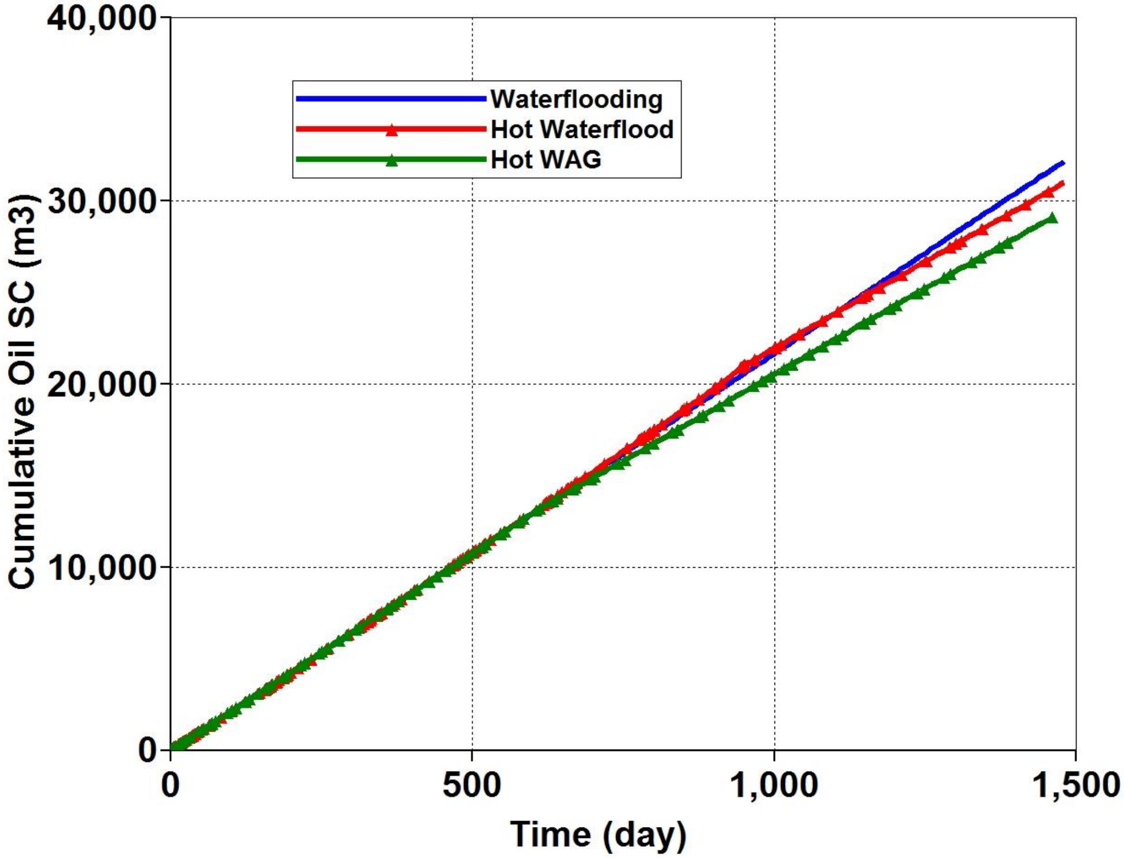

Figure 4. Performance of water flood and hot water alternating CO_2 (Hot WAG) cases.

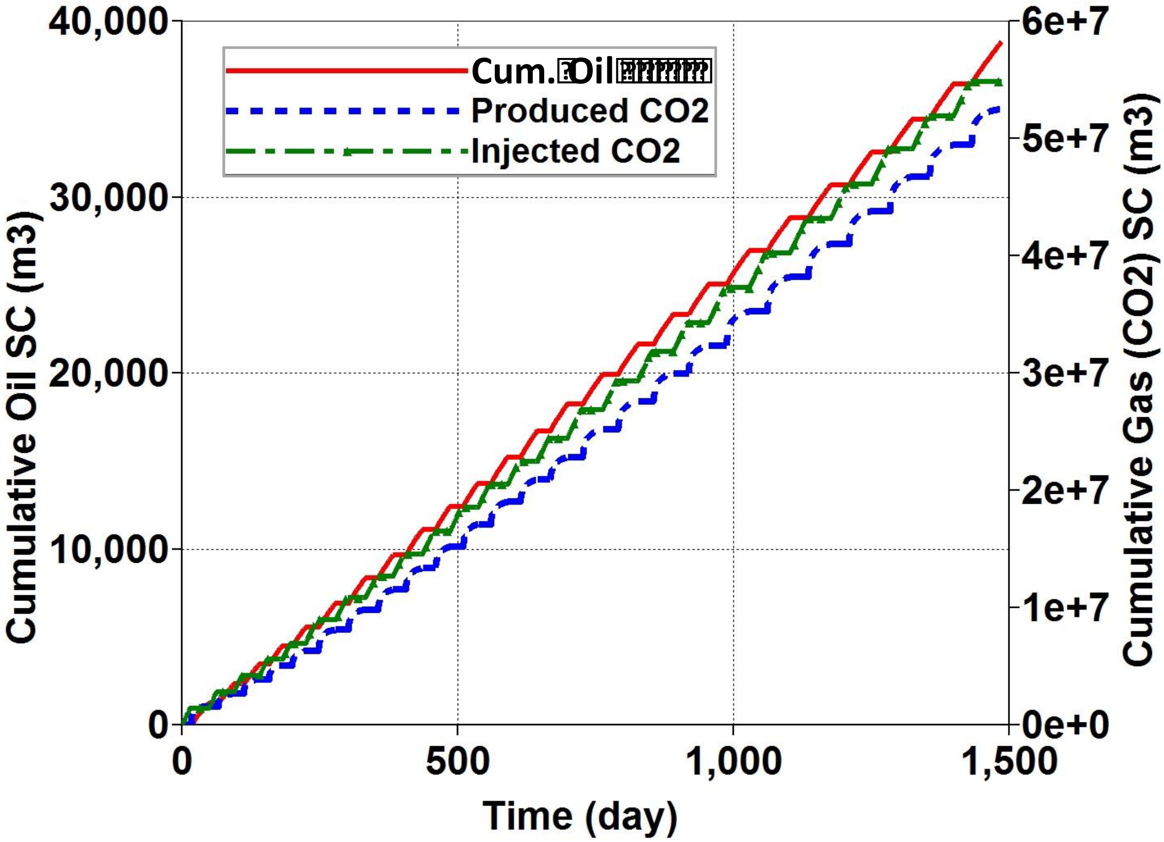

Figure 5. Cumulative oil recovered with CCI and the volume of injected and produced CO_2.

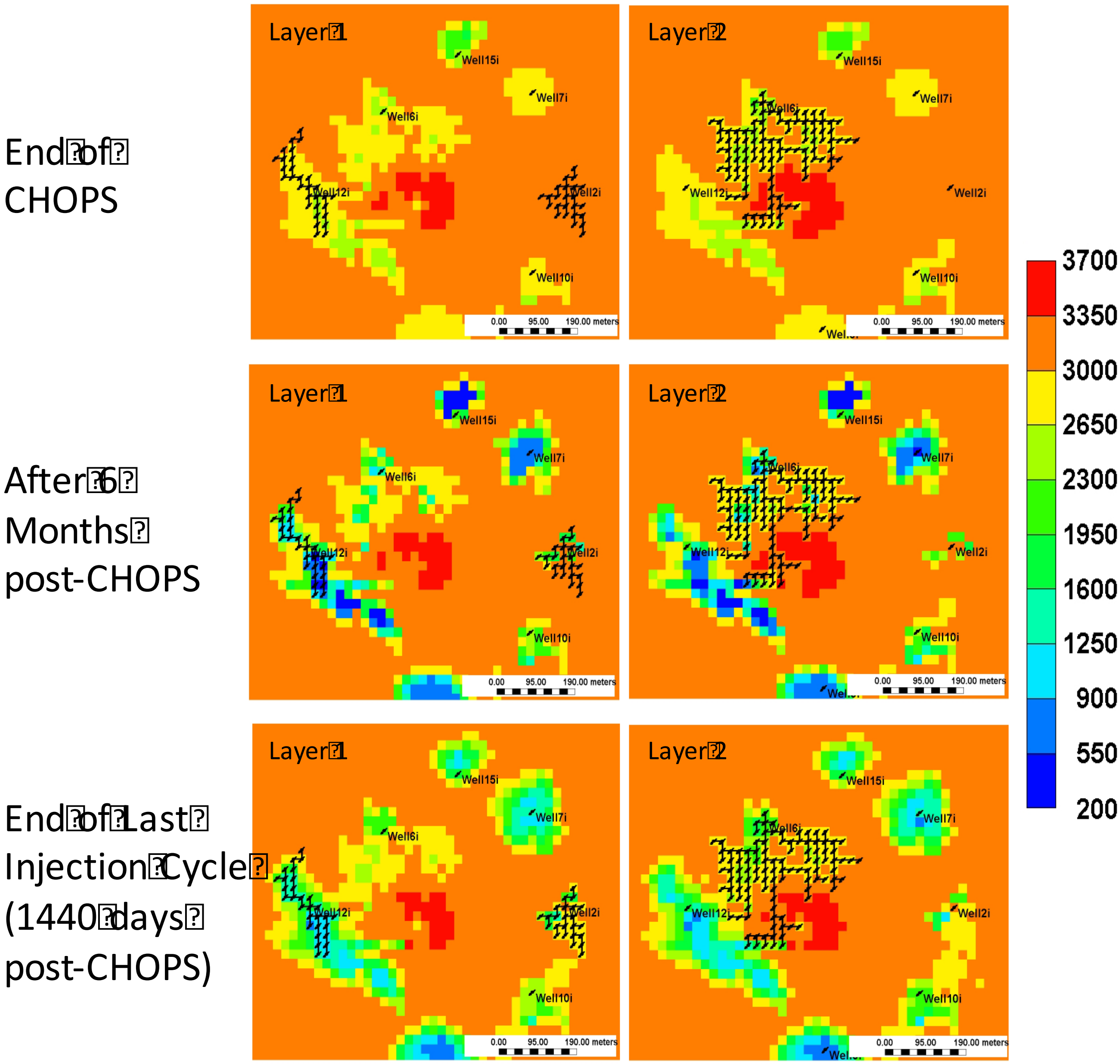

Figure 6. Pressure (kPa) distribution in two consecutive layers for the cyclic CO_2 injection process at start of post-CHOPS operation, after 6 months post-CHOPS operation, and end of last injection cycle (1440 days).

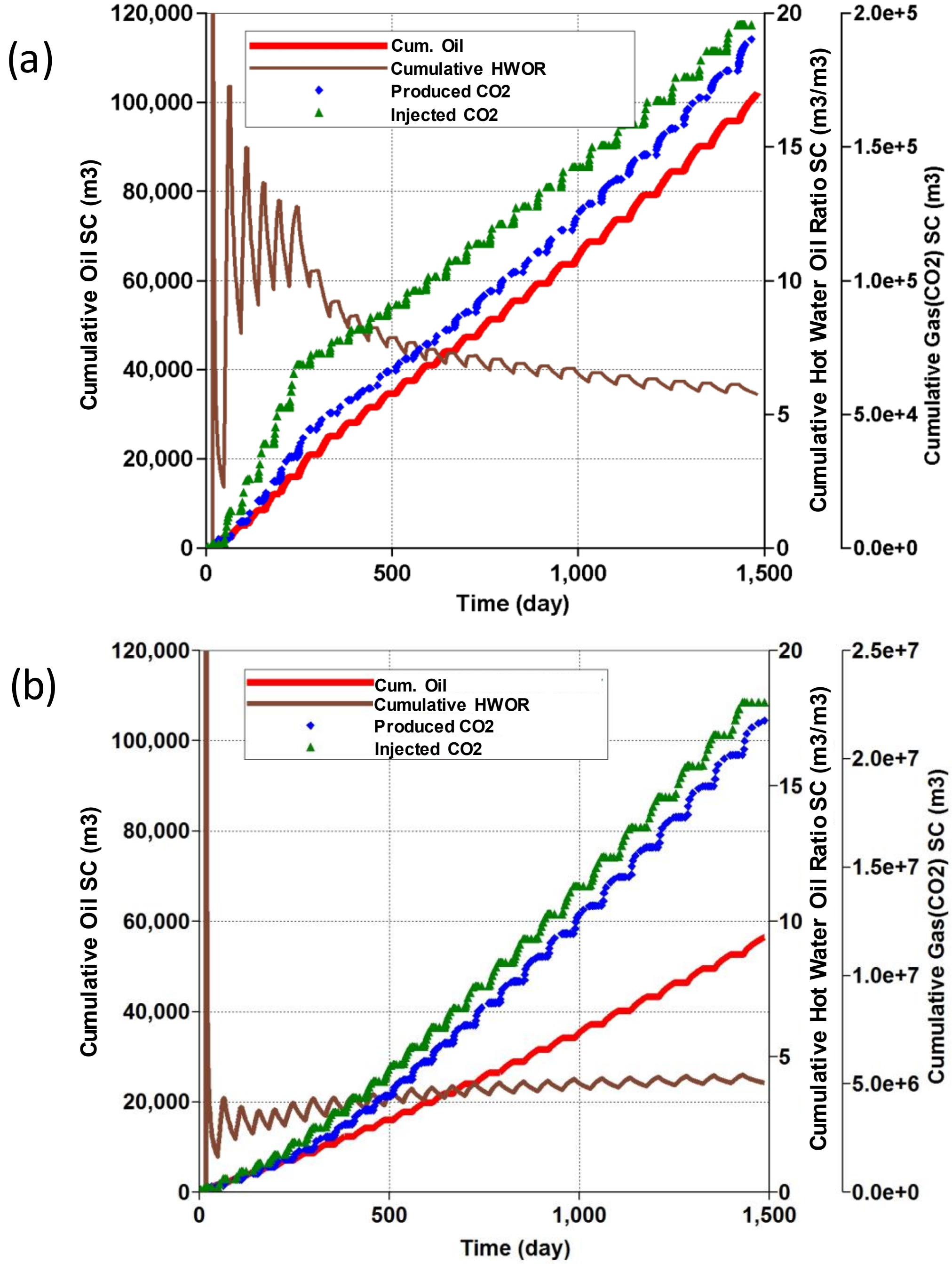

Figure 7. Cumulative oil recovered for cyclic CO2-Hot Water stimulation cases, hot water-to-oil ratio, and CO_2 injected and produced: (a) CO_2-Water ratio: 25:75 and (b) CO_2-Water ratio: 99:1.

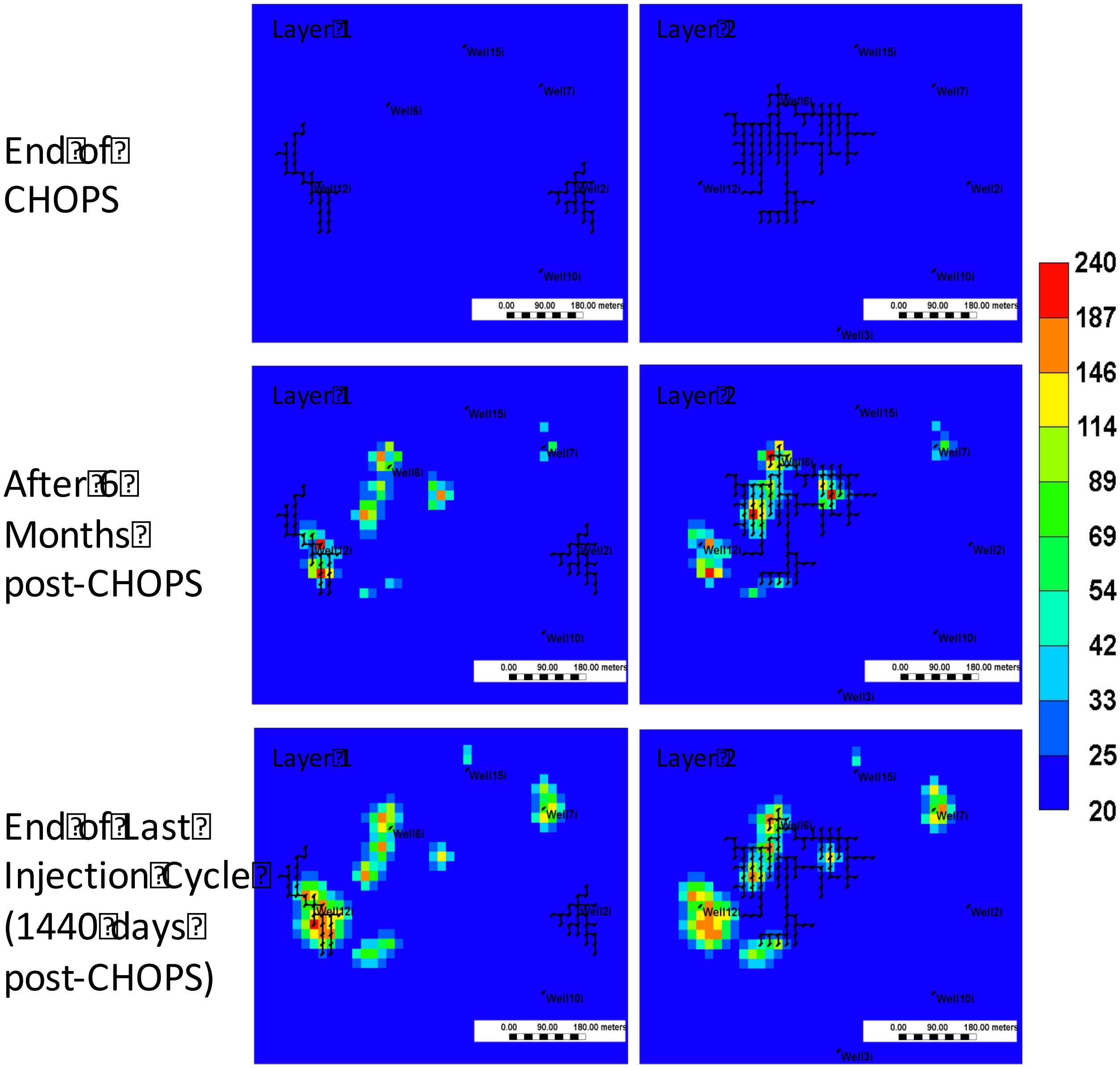

Figure 8. Temperature (°C) distribution in two consecutive layers for cyclic CO_2-hot water stimulation (CO_2-Water ratio: 25:75) at (a) start of post-CHOPS, (b) after 6 months, (c) end of last injection cycle (1440 days).

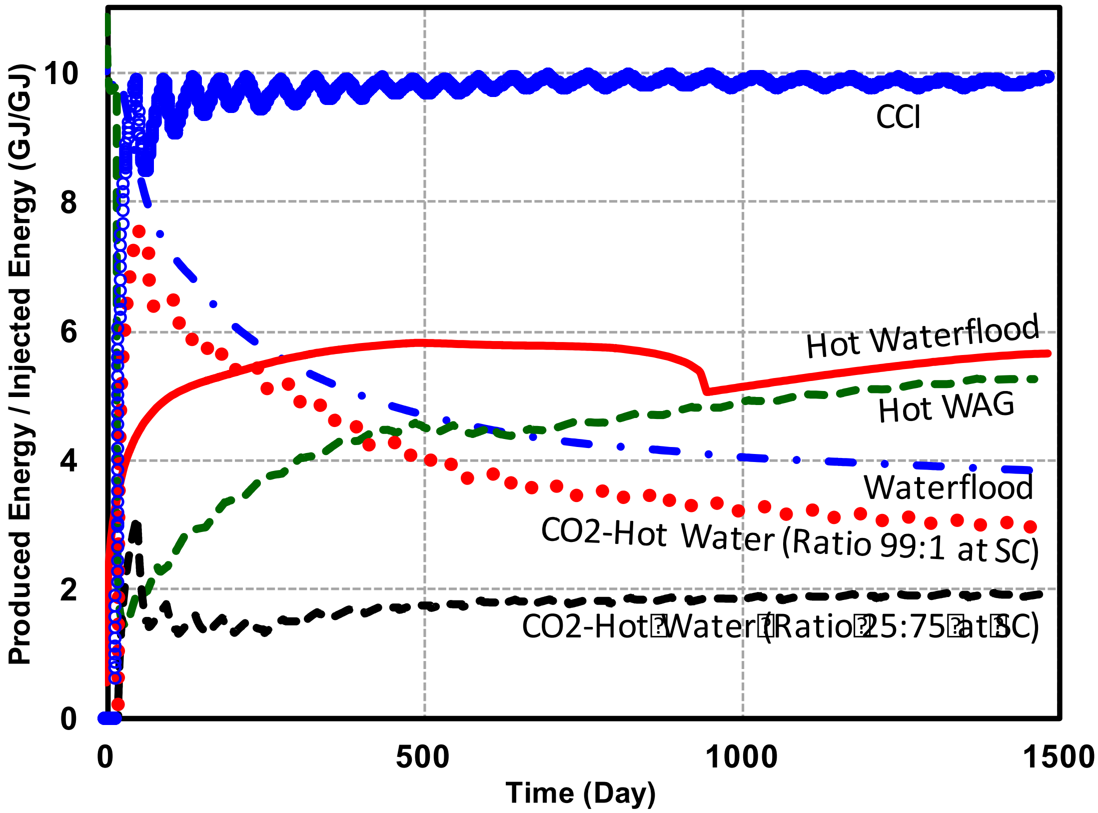

Figure 9. Energy return ratios of different post-CHOPS processes.