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CO_2 Low Salinity Water Alternating Gas: A New Promising Approach for Enhanced Oil Recovery

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Abstract

It has been recognized that there are significant advantages on combining low salinity waterflooding (LSW) with other enhanced oil recovery (EOR) techniques such as polymer or low tension surfactant flooding. This paper proposes a novel concept of low salinity water-alternating-CO_2 (CO_2 LSWAG) injection under CO_2 miscible displacement conditions. While LSW is an emerging EOR method based on alteration of wettability from oil-wet to water-wet conditions, WAG is a proven method for improving gas flooding performance by controlling the gas mobility. Therefore, LSWAG injection promotes the synergy of the mechanisms underlying these methods (i.e., ion-exchange, wettability alteration, and CO_2 miscible displacement and mobility control) that further enhances oil recovery and overcomes the late production problem frequently encountered in the conventional WAG. These features are demonstrated in this work based on a field case study.

To investigate the advantages of CO_2 LSWAG, a comprehensive ion exchange model associated with geochemical processes has been developed and coupled to the multi-phase multi-component flow equations in an equation-of-state compositional simulator. Laboratory core flood simulations of different CO_2 LSWAG schemes are conducted to understand the combined effects of solubility of CO_2 in brine, dissolution of carbonate minerals, ion exchange, and wettability alteration. CO_2 LSWAG performance is then evaluated on a field scale through an innovative workflow that includes geological modeling, multi-phase multi component reservoir flow modeling and process optimization. The simulation results indicate that CO_2 LSWAG has the highest oil recovery compared to conventional high salinity waterflood, high salinity WAG, and low salinity waterflood. A number of geological realizations are generated to assess the geological uncertainty effect, in particular clay distribution uncertainties, on CO_2 LSWAG efficiency. Finally, CO_2 LSWAG injection strategies are optimized by identifying key WAG parameters.

The proposed workflow demonstrates the synergy between CO_2 WAG and LSW. Built in a robust reservoir simulator, it serves as a powerful tool for screening, design, optimization, and uncertainty assessment of the process performance from laboratory to and field scales. CO_2 LSWAG is a promising EOR technique as it not only combines the benefits of CO_2 injection and low salinity water floods but also promotes the synergy between these processes through the interactions between geochemical reactions associated with CO_2 injection, ion exchange process, and wettability alteration. This paper demonstrates the merits of this process through modeling, optimization and uncertainty assessment.

Introduction

The modification of the injected brine composition could improve the oil recovery factor of conventional waterflooding up to 38% (Web et al., 2004), leading to a new concept of optimal injection brine composition for waterflooding. Other than using high salinity reservoir water, extensive laboratory experiments (Tang and Morrow, 1997; Morrow et al., 1998; Tang and Morrow, 1999a; Tang and Morrow, 1999b; Zhang and Morrow, 2006; Kumar et al., 2010; Lohardjo et al, 2010) and pilot tests (McGuire et al., 2005; Lager et al., 2008; Skrettingland et al., 2010; Thyne and Gamage, 2011) have confirmed the advantages of using low salinity brine as an injected fluid on the oil recovery for both secondary and tertiary modes. LSW has received increasing attention in the oil industry and is currently indentified as an important EOR technique as it shows more advantages than conventional chemical EOR methods in terms of chemical costs, environmental impact, and field process implementation.

Although the benefits of LSW have been realized, the mechanism for incremental oil recovery by LSW is still a topic for open discussions. Several mechanisms have been proposed during the last two decades including fines migration, wettability alteration, multi-component ionic exchange (MIE), saponification, pH modification, and electrical double layer effects. Dang et al. (2013b) provided a critical review and discussion of these mechanisms. Among the proposed hypotheses, wettability alteration towards increased water wetness during LSW is the widely accepted cause for enhanced oil recovery. The effects of low salinity brine on wettability modifications have been reported by many authors (Jadunandan and Morrow, 1995; Tang and Morrow, 1999a; Drummond and Isralachvili, 2002 and 2004; Vledder et al., 2010; Zekri et al., 2011). It has been experimentally found that the low salinity brine has a significant effect on the shape and the end points of the relative permeability curves (Webb et al., 2004; Kulkarni and Rao, 2005; Rivet, 2009; Fjelde et al., 2012), resulting in a lower water relative permeability and higher oil relative permeability. The mechanisms of wettability alteration due to ion exchange and geochemical reactions have been successfully implemented in a compositional simulator for modeling of LSW (Dang et al, 2013b). Excellent agreements between simulation results and important measurements from coreflood experiments and pilot observations were obtained with this modeling approach (Dang et al., 2013a).

Recently, novel EOR methods based on the synergy of LSW and other EOR approaches such as polymer flooding has been studied. Based on several coreflood experiments, Kozaki (2012) concluded that the use of low salinity polymer flooding has significant benefits because of considerably lower amount of required polymer for a target viscosity. Additionally, low salinity polymer flooding can also increase oil recovery by lowering residual oil saturation and achieve faster oil recovery by wettability alteration. These observations have been confirmed by Mohammadi and Jerauld (2012) based on numerical simulation. The simulation results show that low salinity polymer flooding gave about 5% incremental oil recovery over high salinity polymer flooding and a five times reduction in chemical costs per barrel of oil recovered could be obtained when polymer is added to low salinity brine. However, it was noted that an injectivity constraint can limit the synergy between polymer and LSW.

LSW could also have great benefits when combined with the water alternating miscible CO_2 injection (called CO_2 LSWAG). While LSW is an emerging EOR method based on modification of wettability and intrinsic permeability, WAG is a proven method for improving gas flooding performance by controlling the gas mobility. Therefore, LSWAG injection promotes the synergy of the mechanisms underlying these methods (i.e., ion-exchange, wettability alteration, and CO_2 miscible effects and mobility control) that further enhances oil recovery. CO_2 LSWAG can be used in oil production in two strategies.

1. As an effective IOR/EOR approach for green and brown oil fields by utilizing the advantages between them to overcome the current challenges associated with LSW and CO_2 WAG.
2. As an agent that improves the conformance control by blocking off the high conductivity zones and divert the injected fluid into unswept layers.

An unfavorable mobility of pure gas flooding results in viscous fingering and reduced volumetric sweep efficiency, and WAG helps overcome this problem and reduces the large amount of required gas for EOR projects, especially in offshore oil fields. However, oil production response is usually delayed in the WAG process compared with the single-slug CO_2 flooding. Although oil recovery is predicted to be higher in the WAG process, the economics may not be favorable because of the delayed production. LSW can accelerate the oil production in the early stage; whereas, CO_2 WAG can help promote the ion exchange and reservoir geochemical reactions, which are the favorable conditions for LSW itself. With this point of view, LSWAG promotes the synergy of the mechanisms between two technologies and can overcome the late production problem frequently encountered in the conventional WAG.

The second mode came from the idea that a drastic decrease in salinity gradient with sufficient amounts of Ca^{++} in the injected water (e.g., higher than 1/10 of the Na^+/Ca^{++} ratio, Jones, 1964) can mobilize clay minerals, plug the porous media and reduce the absolute permeability in the watered-out layers. The injected fluid is then diverted into low permeability zones, and provides additional oil recovery from these regions.

CO_2 LSWAG is a new EOR concept and one of the first publications in this area was by Kulkarni et al. (2004) and Jiang et al. (2010). They found that CO_2 WAG has a slightly better oil recovery with high salinity injection brine (CO_2 HSWAG) than with low salinity injection brine (CO_2 LSWAG) due to a decrease in CO_2 solubility. However, the entire core samples used in these experiments were strongly water wet sandstone cores with very low clay content, which are unfavorable conditions for LSW process. The presence of clay minerals for ion exchange has been addressed as one of the main requirements for achieving the additional oil recovery by LSW due to wettability alteration. Zolfaghari et al. (2013) reported that, CO_2 LSWAG gave an additional oil recovery up to 18% OOIP based on a series of coreflood experiments in the favorable conditions for LSW application. Interesting findings from their results are that CO_2 LSWAG is also highly effective for heavy oil and the ultimate recovery by LSW is even higher than that by CO_2 HSWAG. These positive results would encourage extending LSW and CO_2 LSWAG into heavy oil reservoirs in addition to light/medium oil reservoirs at this moment. Dang et al. (2013b) evaluated the potential of the novel concept of CO_2 LSWAG injection under CO_2 miscible displacement conditions using a 1D linear model. From their simulation results, CO_2 LSWAG has the highest oil recovery factor compared to CO_2 HSWAG, pure CO_2 flood, and LSW. However, the simulations were conducted only in the 1D homogeneous model that does not capture the effects of clay mineral distribution. Thus, a more realistic assessment of this process at larger scales is necessary.

Up to now, there is a lack of experimental evidences to conclude definitively that LSW induces water blockage. Thus most of projects have been focused on the first mode. However, the previous investigations were mainly limited to coreflood experiments in laboratory scale or simple 1D homogeneous simulation that were far from the reality of this hybrid process. This paper aims to overcome the gaps in the past evaluations of CO_2 LSWAG using an advanced and comprehensive simulation approach with a mechanistic LSW model in an equation-of-state compositional simulator. CO_2 LSWAG was first conducted in a 1D heterogeneous model for assessing the potential of this emerging technology, and then it was extended to field scale simulation for a comprehensive investigation of the propagation mechanisms and its benefits in large scales. CO_2 LSWAG is then optimized by injection brine composition and WAG parameters. An uncertainty assessment was carried out for evaluating of the geological effects on CO_2 LSWAG performance. The simulator GEM™ of Computer Modeling Group Ltd. is used to perform the simulation runs in this paper.

Modeling of CO_2 LSWAG

Methods modeling of CO_2 flooding and LSW are described in Nghiem et al. (2004) and Dang et al. (2013a). The key features are:

1. Geochemical reactions are fully coupled to the multiphase multicomponent flow equations and the equations for EOS flash calculations.
2. Ion exchange and wettability alteration during the course of LSW is considered as the main mechanism of the additional oil recovery.
3. The multiple ion exchanges were modeled based on chemical equilibrium between ions in the aqueous phase and clay minerals.
4. Various intra-aqueous reactions involved in LSW and WAG processes can be modeled.
5. Incorporation of various mineral dissolution and precipitation reactions can affect the ion exchange process.
6. Multiple relative permeability sets can be used to model the alteration of wettability.
7. The relative permeabilites of oil and water are altered by a scaled ion exchange equivalent fraction that represents the ion exchange and clay properties.

In the literature, LSW has been evaluated both in secondary and tertiary flooding modes and CO_2 LSWAG can be implemented either after waterflooding or LSW. Several prescreening conditions that are important for ensuring the highest efficiency on combing LSW and CO_2 WAG from experimental work and field observations are listed below and will be further examined in this paper:

Table 1: Prescreening Conditions for CO_2 LSWAG

Property	Preferred Condition
Reservoir	• Sandstones • Carbonates (possibility)
Crude Oil	• Must contain polar components (not effective with synthetic oil)
Clay Minerals	• Reservoir must contains sufficient amount of clay • High CEC and clays is preferred
Reservoir Minerals	• Calcite • Dolomite
Formation Water	• Presence of divalent ions such as Ca^{++} and Mg^{++} • Presence of connate water
Initial Wettability	• Oil Wet or Mixed Wet Reservoir • Small or ineffective in strong water wet reservoir
Reservoir Energy	• Sufficient high pressure for achieving miscibility condition.
Injected Fluid	• Lower salinity concentration than formation water • Must contain divalent ions • Sufficient CO_2 source for WAG implementation

Numerical Investigations of CO_2 LSWAG

Case Study 1 - One Dimensional Simulation

A one-dimensional model was developed in order to simulate this process. In this section, we reproduce a test by Dang et al. (2013b) in which the scaled ion exchange equivalent fraction was used as the interpolant value for wettability alteration in heterogeneity of porosity and permeability of the 1D model. The use of the scaled ion exchange equivalent fraction represents a more realistic relative permeability modification by considering both of the ion exchange and clay properties. The scaled ion-exchange equivalent fraction is defined as the equivalent fraction of Ca-X_2*CEC/CEC_{max}. Figure 1 shows the 1D linear model for simulation of CO_2 LSWAG with the main properties shown in Table 2. In this model, we considered the reversible ion exchange between Ca^{2+} and Na^+ as well as aqueous and mineral reactions. Relative permeability curves for oil wet and water wet conditions are shown in Figure 2.

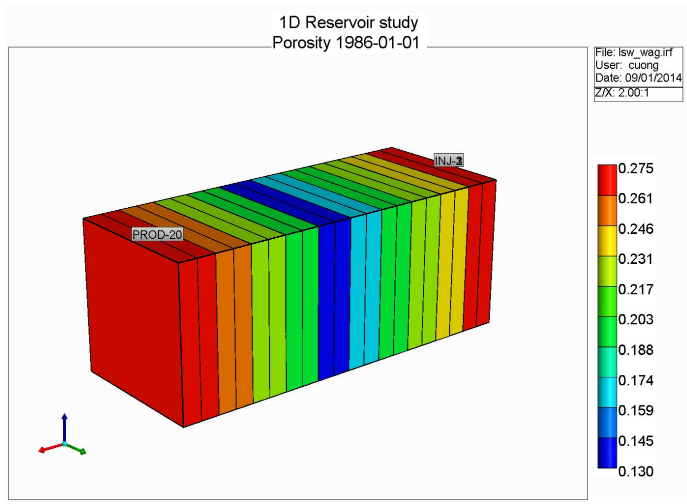


Figure 1 : 1D Linear Model of CO_2 LSWAG

Table 2: Basic Reservoir Properties for 1D Simulation

Parameter	Value for Base Case
Grid blocks system	20 x 1 x 1
Grid block sizes	Δx = 3.66 m, Δy = 30.48 m, Δz = 15.24 m
Horizontal permeabilities	2*2000 2*1900 2*1800 2*1700 2*1500 2*1200 2*1600 2*1850 2*2000 2*2100
Vertical permeabilities	Equals to Horizontal permeability
Porosity	2*0.265 2*0.24 2*0.22 2*0.2 2*0.16 2*0.13 2*0.19 2*0.23 2*0.26 2*0.275
Initial water Saturation	0.3
Selectivity coefficient	0.4 at 25°C (From Appelo, 1994)

The reactions that are modeled are:

$$CO_2(aq) + H_2O \leftrightarrow H^+ + HCO_3^- \tag{1}$$

$$H^+ + OH^- \leftrightarrow H_2O \tag{2}$$

$$\text{Calcite} + H^+ \leftrightarrow Ca^{2+} + HCO_3^- \tag{3}$$

$$\frac{1}{2}Ca^{2+} + Na - X \leftrightarrow \frac{1}{2}Ca - X_2 + Na^+ \tag{4}$$

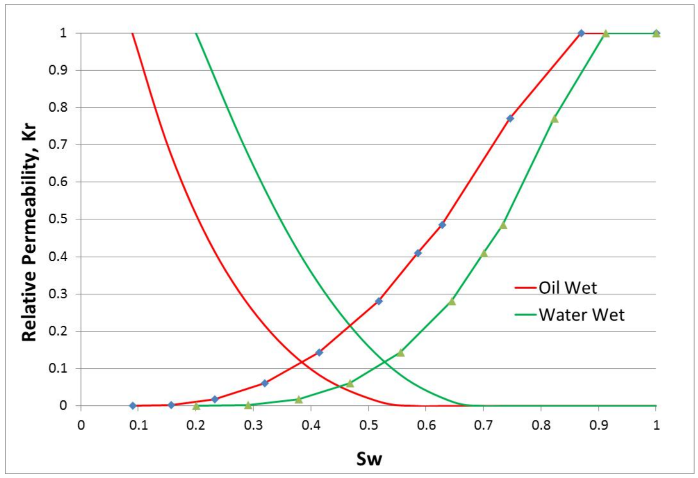


Figure 2: Relative Permeabilities for 1D CO_2 LSWAG Simulation

Various simulation scenarios were performed to compare CO_2 LSWAG with other recovery approaches such as conventional HSW, LSW, CO_2 HSWAG, and pure CO_2 flooding as shown in Table 3. The composition of formation water and injected brine is indicated in Table 4. Four cycles of CO_2 WAG were conducted after 0.4 injected pore volume of HSW or LSW with a WAG ratio of 1:1 (Figure 3).

Table 3: Injection Schemes for 1D Numerical Simulation

Run	**Water Injection (0.4 Pore Volume)**		**Water Alternating Gas (0.8 Pore Volume)**								**Chase Water (0.6 Pore Volume)**		
A													
B													
C													
D													
E								-	-	-	-			

	HSW
	LSW
	CO2

Table 4: Formation and Injected Brine Composition

	Formation	Injected Brine
Ca^{++}	0.024414	0.001892
Na^{+}	0.4892	0.01196

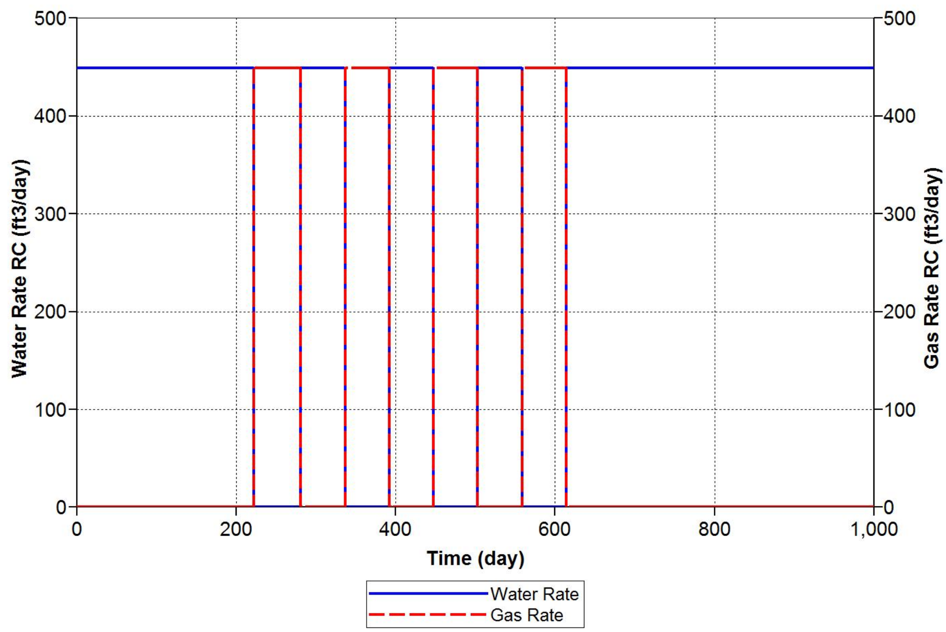


Figure 3: WAG cycling in 1D CO_2 LSWAG

First, we consider the effect of the conventional HSW (Run A) on the oil recovery compared to LSW (Run B). Figure 4 indicates that LSW has a great advantage on oil recovery. This benefit is due to ion exchange and mineral reactions, which were discussed in detail in Dang et al. (2013a). When the high salinity brine was injected, no wettability alteration occurred since the injected brine composition is similar to formation water composition. On the contrary, the adsorption of Ca^{++} during LSW altered the original mixed wetness to preferential water wetness, leading to a significant increase in the oil recovery.

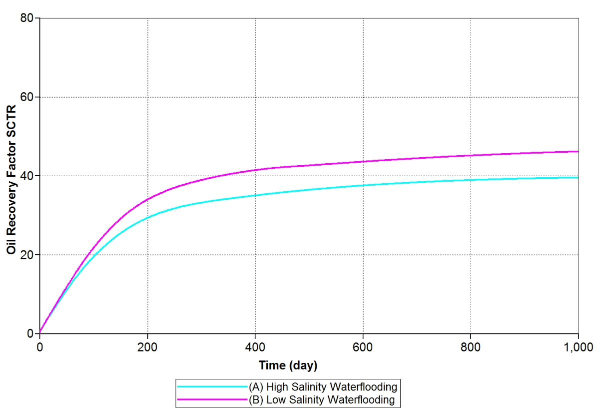


Figure 4: Cumulative Oil Recovery from Runs A and B

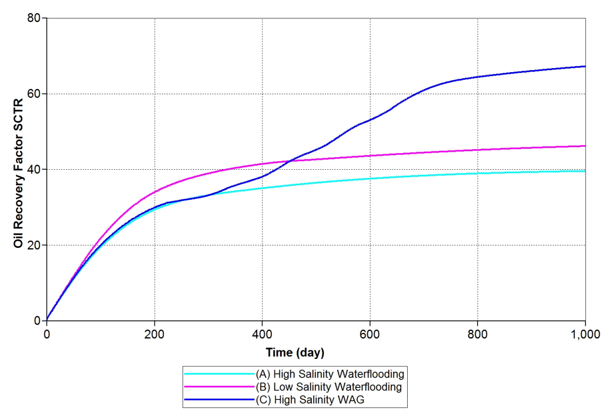


Figure 5: Cumulative Oil Recovery from Runs A, B and C

Although LSW has higher oil recovery than the conventional HSW, large amount of oil is still trapped in the reservoir. CO_2 HSWAG (Run C) was considered to increase oil recovery. In this run, about 0.4 and 0.6 pore volumes of high salinity brine were injected before and after four cycles of high salinity WAG, respectively. Figure 5 shows that oil recovery by high salinity WAG increases by 25.3% and 19.6% of the original oil in place (OOIP) compared to the HSW and LSW, respectively. The additional oil recovery comes from the effects of CO_2 miscible flooding.

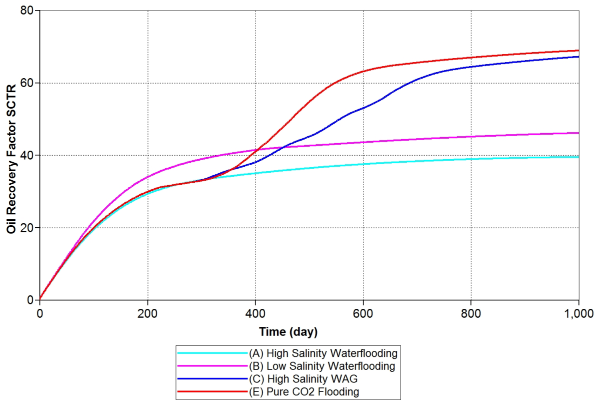


Figure 6: Cumulative Oil Recovery from Runs C and D

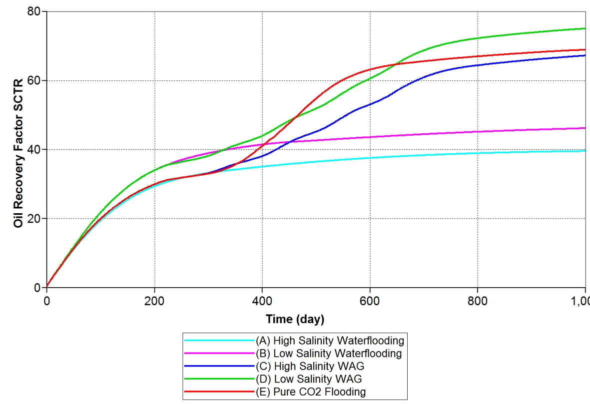


Figure 7: Cumulative Oil from Runs A, B, C and D

Figure 6 compared the oil recovery by four different recovery methods including HSW, LSW, CO_2 HSWAG, and pure CO_2 flooding. Although CO_2 HSWAG has a higher ultimate oil recovery factor than HSW and LSW and the final oil recovery factors by CO_2 HSWAG and pure CO_2 flooding are relatively similar, CO_2 HSWAG experiences with the problem of delayed production as indicated in the earlier discussions. It sometimes prevents the application of WAG in the field because of economic issues. However, this challenge can be overcome by using CO_2 LSWAG in which the ultimate oil recovery factor is maximized and oil is produced much faster compared to CO_2 HSWAG in the early stage of WAG cycles (Figure 7). These observations are clearly presented in Figures 8 and 9. The oil production rate continuously declines with time in HSW and LSW; however, CO_2 LSWAG keeps a high oil rate that is more sustainable than single slug CO_2 flooding and is higher than CO_2 HSWAG.

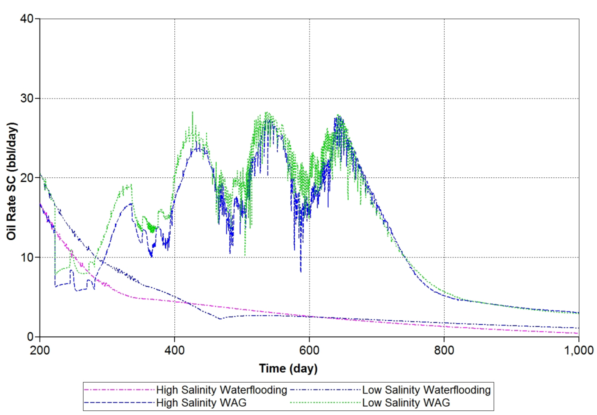


Figure 8: Comparative Oil Rate of HSW, LSW, CO_2 HSWAG, and CO_2 LSWAG

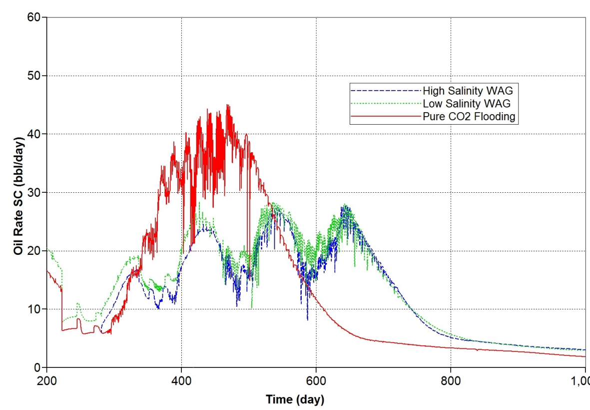


Figure 9: Comparative Oil Rate of CO_2 HSWAG, CO_2 LSWAG, and Pure CO_2 Flooding

The previous results confirm the advantage of CO_2 LSWAG on the oil recovery. This section aims to provide further insights into the role of geochemistry in CO_2 LSWAG. Generally, geochemical reactions play an important role in CO_2 LSWAG. The dissolution of Calcite can promote the wettability alteration by supplying the Ca^{2+} source for the ion exchange process. Figure 10 indicates the benefit of Calcite mineral dissolution on the oil recovery by CO_2 LSWAG. Oil is produced faster when the reaction involving Calcite (Eq. 3) is included. The dissolution of calcite increases the ion exchange level as shown in Figure 11.

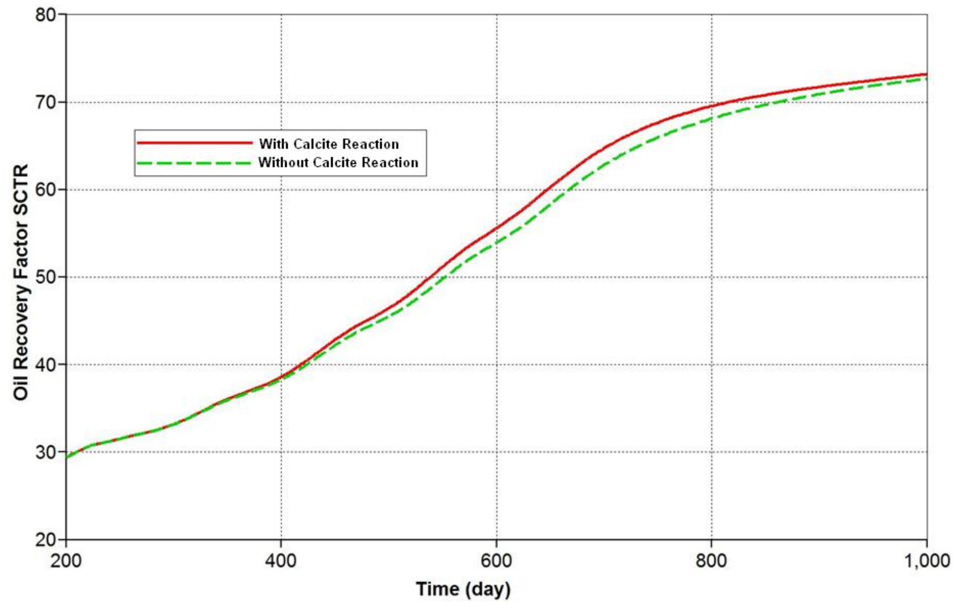
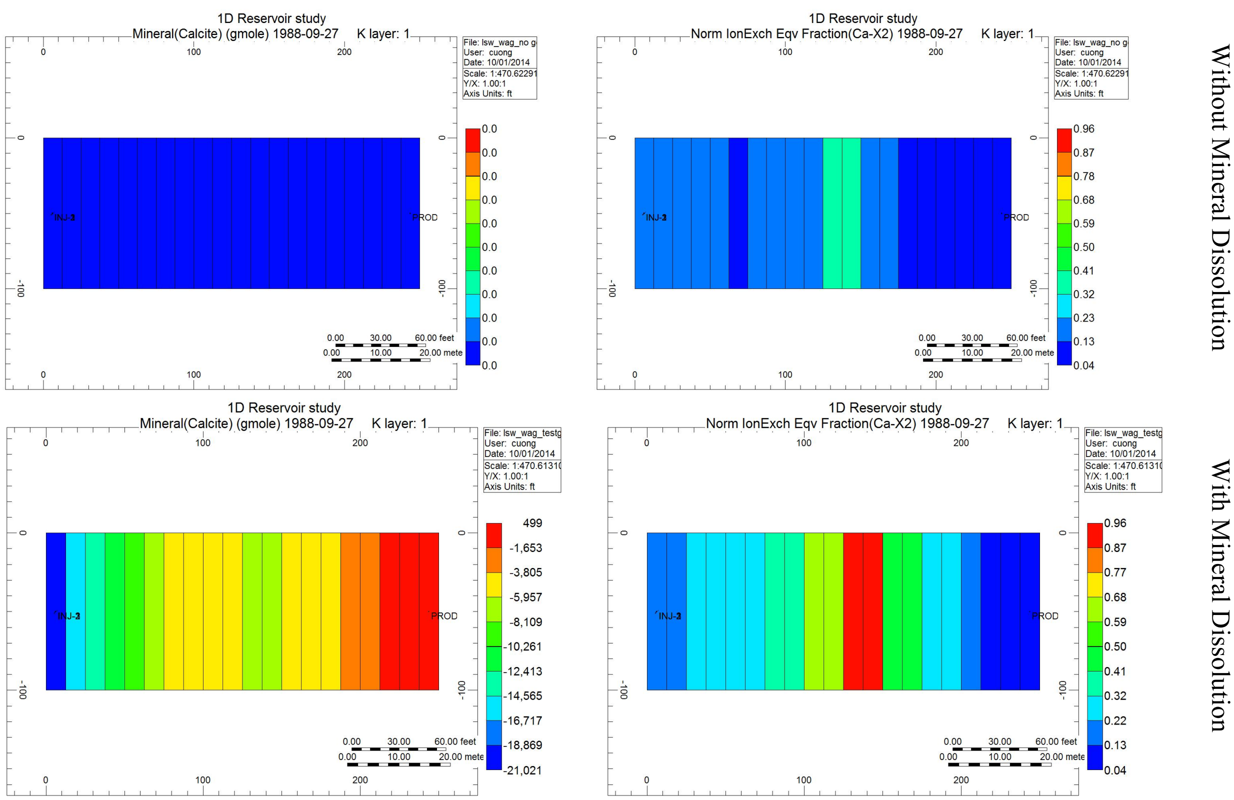


Figure 10: Effect of mineral dissolution on CO_2 LSWAG



Calcite Dissolution(-)/Precipitation(+) Scaled Equivalent Ion Exchange Fraction

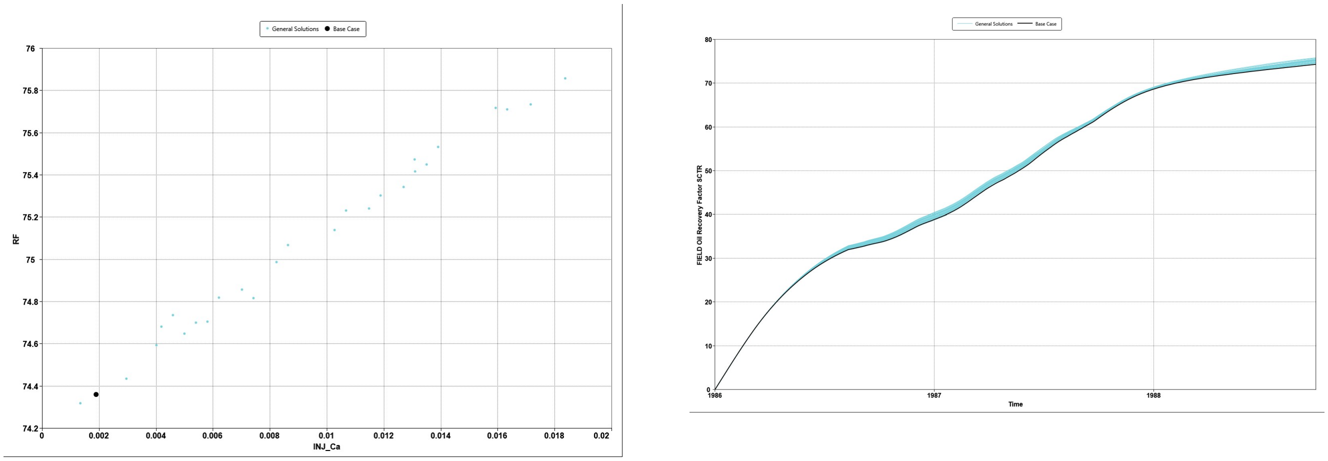
Figure 11: Comparative Ion Exchange with and without mineral reactions

There are four important aqueous and mineral reactions (Eqs. 1-4) that are involved in this process and the injection scheme can play an important role in the success of CO_2 LSWAG applications. A series of sensitivity analysis runs were conducted with the following observations:

- The oil recovery factor tends to increase with an increase of the injected Ca^{2+} concentration (Figure 12).
- Injected Na^{++} concentration must be lowered compared to the formation water to promote ion exchange and mineral

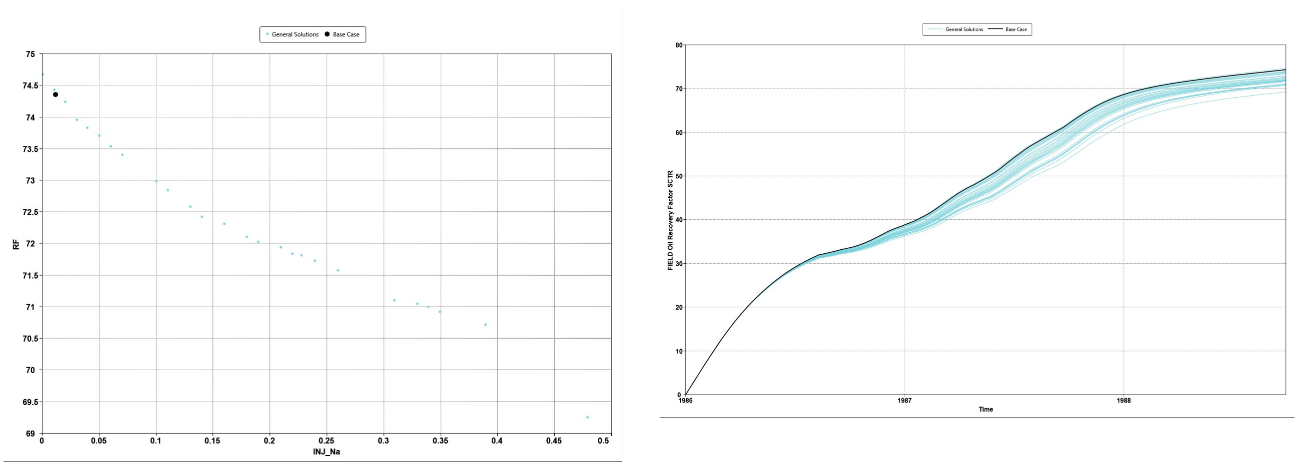
dissolution, resulting in a higher oil recovery factor (Figure 13).

- $HCO3^-$ in the injected brine has detrimental effects on CO_2 LSWAG performance as it may lead to the precipitation of Calcite, and consequently a decrease of ion exchange and wettability alteration (Figure 14).
- An increase in the amount of Calcite mineral leads to an increase in the ultimate recovery factor by CO_2 LSWAG (Figure 15).



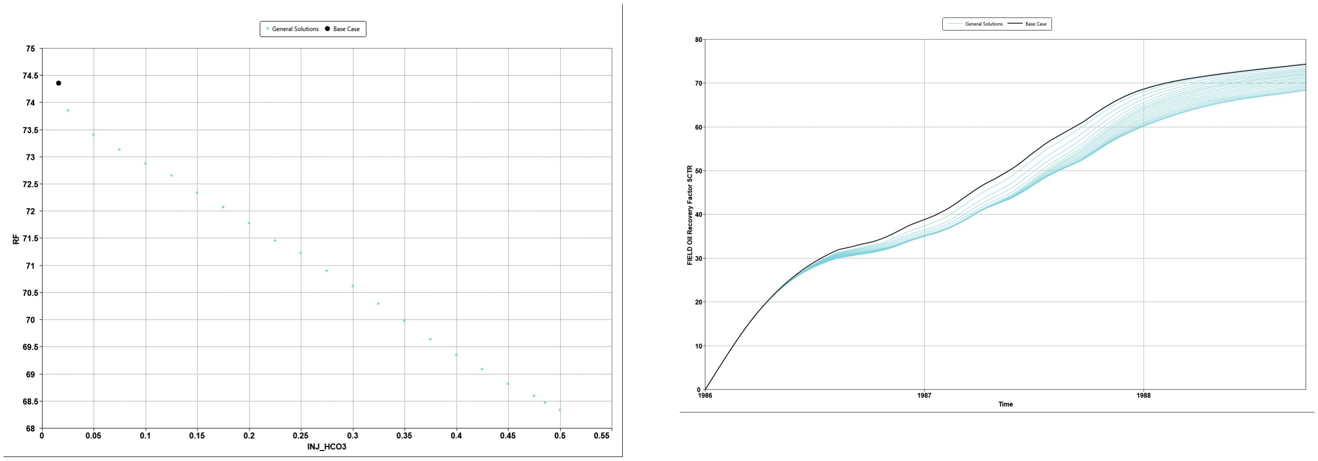
Recovery Factor Cumulative Oil

Figure 12: Effect of Injected Ca^{++} on CO_2 LSWAG



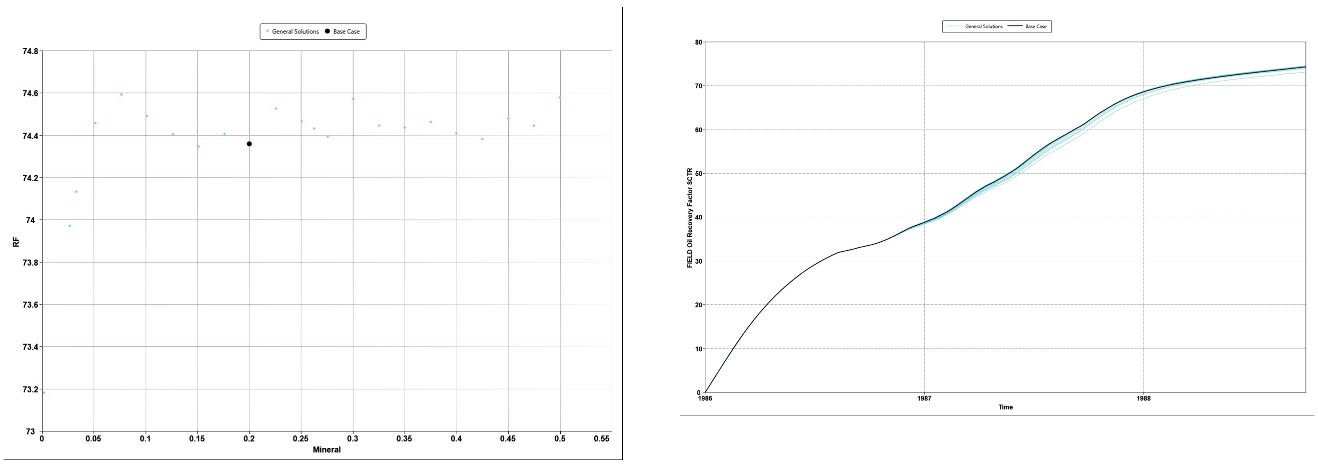
Recovery Factor Cumulative Oil

Figure 13: Effect of Injected Na^+ on CO_2 LSWAG



Recovery Factor Cumulative Oil

Figure 14: Effect of Injected $HCO3^-$ on CO_2 LSWAG



Recovery Factor Cumulative Oil

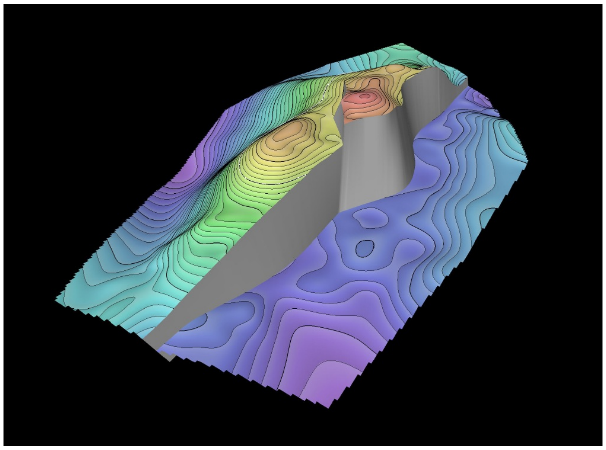
Figure 15: Effect of Mineral Quantity on CO_2 LSWAG

Case Study 2: Field Scale Simulation

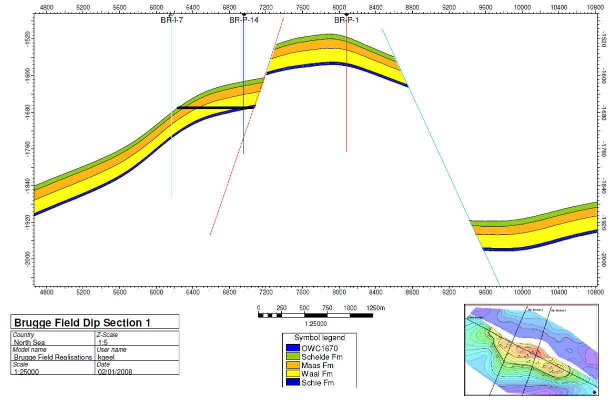
In this section, we extend the modeling and simulation of CO_2 LSWAG to the field scale. Although the advantages of CO_2 LSWAG have been confirmed by the 1D model, it is necessary to quantify the benefit of this process in a larger scale. CO_2 LSWAG was evaluated for a typical North Sea sandstone reservoir in a closed loop reservoir management. For this purpose, we use the Brugge field reservoir introduced by TNO (Peters et al., 2009) and populated it with geological properties including clay distribution for CO_2 LSWAG assessment. The geological model was first developed using the GOCAD™ software and served as the initial input data for the CO_2 LSWAG model in GEM™. Critical effects of clay mineral and important geochemistry processes like ion exchange and wettability alteration have been fully incorporated in this model. CO_2 LSWAG was compared with CO_2 HSWAG. Simulation sensitivity analysis and preliminary uncertainty assessments have been carried out in this study.

The Brugge field consists of an E-W elongated half-dome with a large boundary fault at its northern edge and one internal fault with a modest throw at an angle of some 20 degrees to the northern edge fault (Figure 16). The dimensions of the field are about 10 km x 3 km. From top to bottom, the Brugge field consists of nine layers of four main formations, namely Schelde, Maas, Waal, and Schie. The Waal formation has the greatest thickness, the highest average porosity and permeability and is the major producing reservoir zone. The Schelde formation corresponds to the top two layers (layers 1 and 2) of the simulation model; The Maas formation corresponds to layers 3, 4 and 5, the Waal formation corresponds to layers 6, 7 and 8, and the Schie formation corresponds to layer 9.

The original high-resolution model of the Brugge field consists of 20 million gridblocks. This high resolution model is upscaled to a simulation model with 44,550 active cells. The well logs and structure of this field were used as the "hard-conditioning" data and used as input to generate a number of geological realizations. The field has been developed by 14 vertical producers and 16 vertical water injectors.



3D view of the top structure map and faults of the Brugge Fiel



Dip section 1 across the Brugge Field (four formations, Northern Boundary Fault, Internal Fault, OWC, and nearby well trajectories)

Figure 5.16: Geological Properties of the Brugge Field from TNO

We model the effects of the dispersed clay in which the clay mineral fills the pore space between the sand grains. Three facies are included in the petrophysics model including: (1) Fine grained sandstone – FS facies has low porosity and low permeability with high clay content; (2) Coarse grained sandstone – CS with high porosity, high permeability and low clay content; (3) Medium grained sandstone MS which is the transition facies between FS and CS facies. The geological model is created with GOCAD™ and exported to GEM™. The reservoir model has 139 gridblocks in the *x*-direction, 48 gridblocks in the *y*-direction, and 9 gridblocks in the *z*-direction (Figure 17). All nine layers in the *z* direction follow the geological sequence of the Brugge field. The basic rock and fluid data were provided by TNO. The initial wettability is considered as a preferential mixed wet (or weak oil-wet) based on the relative permeability categorization by Honarpour et al. (1986). As discussed earlier, LSW changes the shape and endpoints of the relative permeability curves due to wettability changes toward more water wet rock. Since there is no reported result for modification of relative permeability corresponding to different salinities for Brugge's field reservoir rock, low salinity relative permeability is estimated from the original high salinity relative permeability based on our experience from similar low salinity EOR experiments and pilot tests. There is no relative permeability interpolation in the case of conventional CO_2 HSWAG.

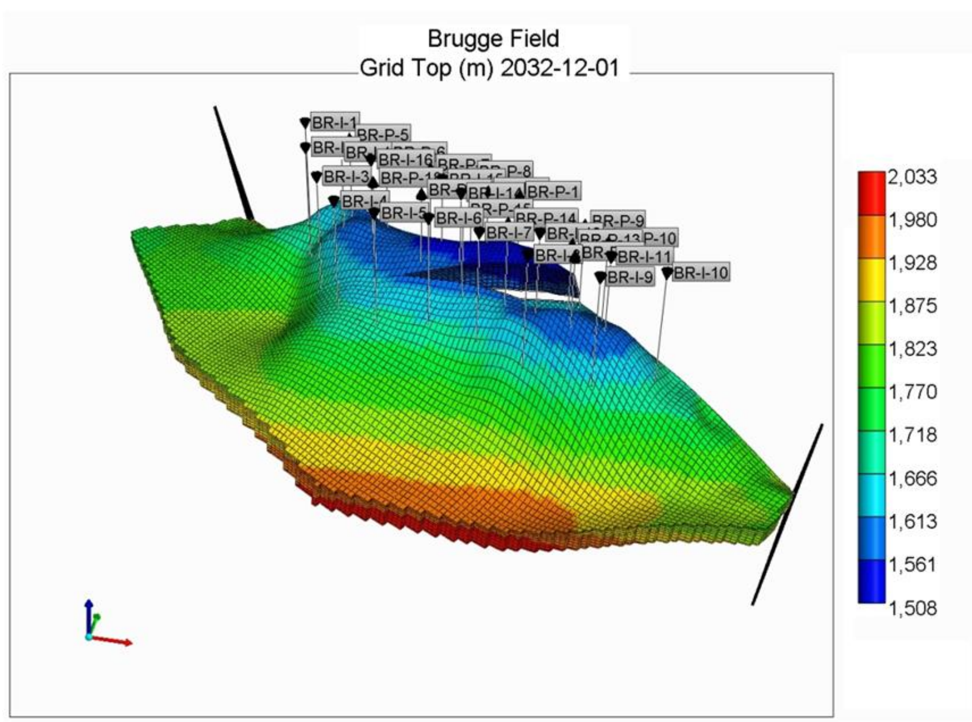


Figure 17: 3D Reservoir Model of Brugge Field

As the results from 1D simulation indicate, the secondary LSW followed by CO_2 LSWAG has the highest oil recovery factor. This injection scheme is, therefore, applied to the Brugge field. LSW is implemented for the first eight years, and then is followed by either CO_2 LSWAG or CO_2 HSWAG. For the base case of CO_2 LSWAG and CO_2 HSWAG, the WAG ratio is 1:1, the sizes of the alternate slugs is 90 days (about 0.7% HCPV) and the total slug sizes of CO_2 is approximately 13% HCPV at the end of the stage (Figure 18). All of the WAG processes are conducted under miscible conditions.

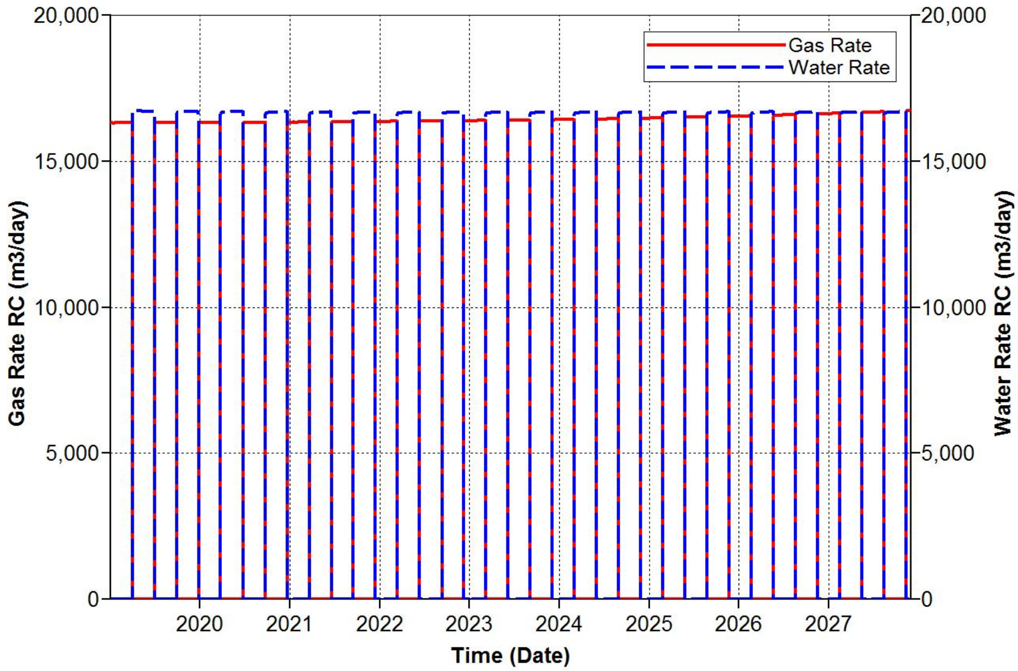


Figure 18: WAG Cycling in Brugge Field Model

Figure 19 shows that CO_2 LSWAG yields about 4.5% incremental OOIP compared to CO_2 HSWAG. By combining of the advantages of wettability alteration and miscible CO_2 WAG, this hybrid method is more effective than the conventional CO_2 HSWAG on decreasing of the remaining oil saturation for different formations in the Brugge field as shown in Figure 20.

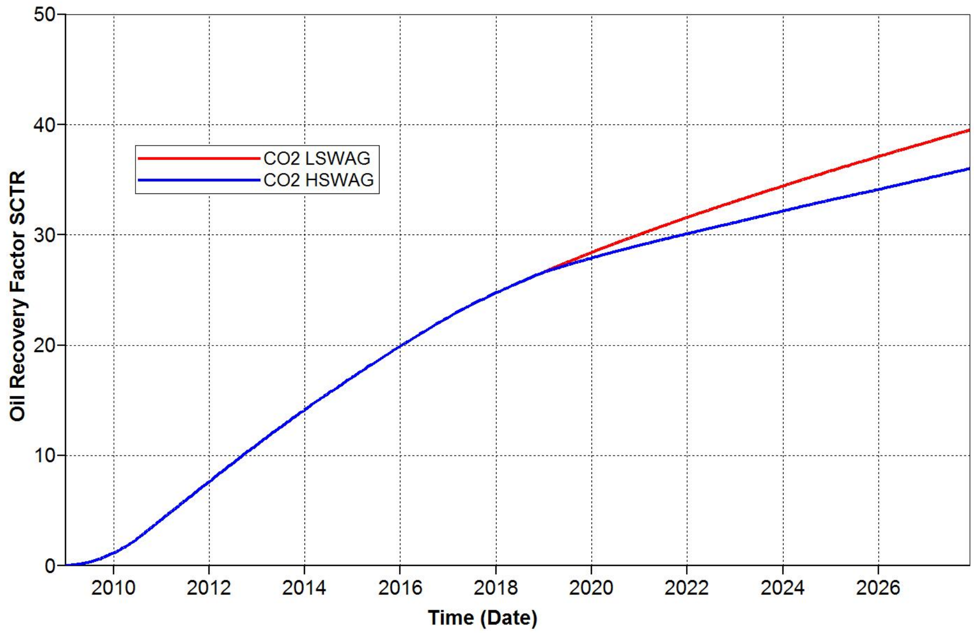
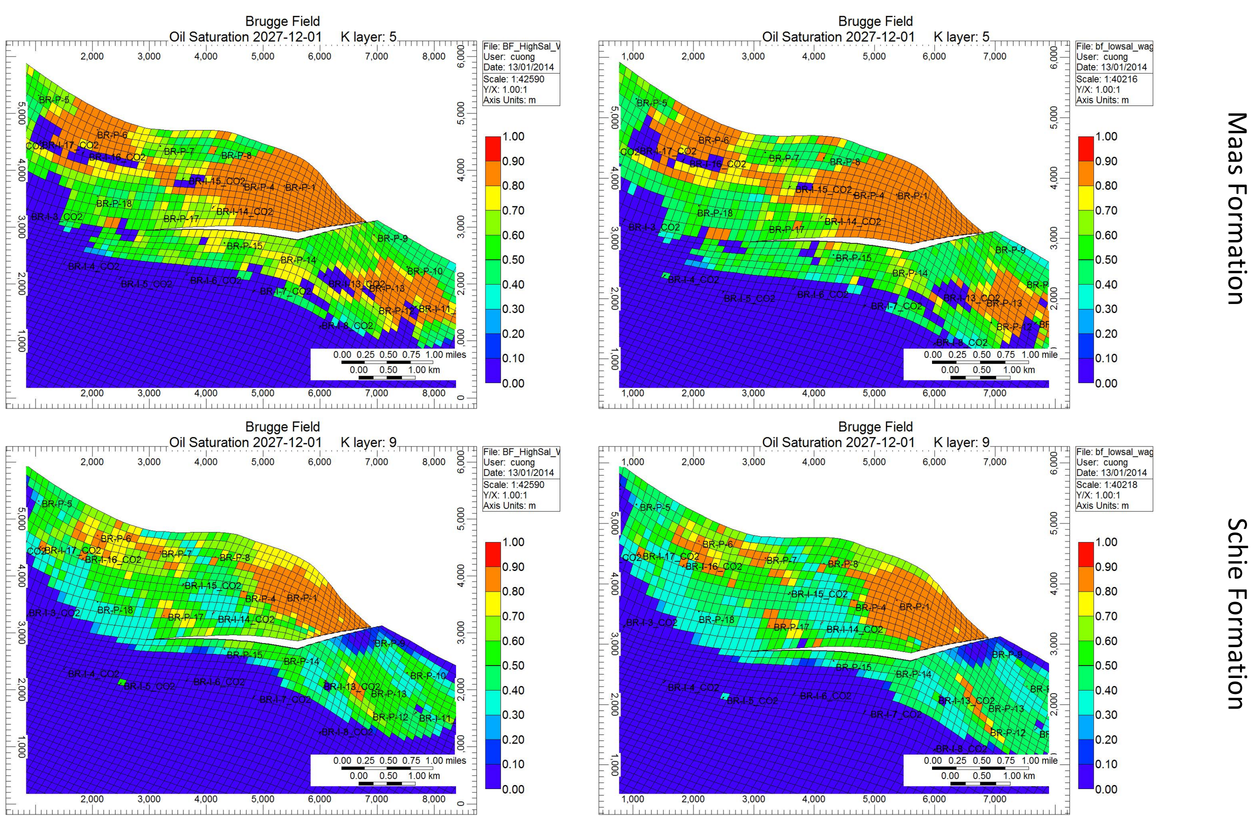


Figure 19: Comparative Oil Recovery by CO_2 HSWAG and CO_2 LSWAG



CO_2 HSWAG CO_2 LSWAG

Figure 20: Oil Saturation Map after CO_2 HSWAG and CO_2 LSWAG

Besides the injected brine composition which was discussed in the 1D model, this hybrid method can also be optimized by controlling of the WAG ratio and other injection scheme with the following important factors:

- The WAG ratio has a large effect on the ultimate oil recovery and the WAG ratio of 1:2 gave the highest oil recovery in this particular field (Figure 21). The WAG ratio can be varied for different reservoirs depending on the geological characterization, formation water and oil properties, and the source of CO_2. It is important to note that the solubility of CO_2 in the brine is higher when the injection brine salinity is lower and an amount of CO_2 will be lost in the aqueous phase. It thus needs to consider a make-up CO_2 for achieving the highest oil recovery factor.
- The longer CO_2 LSWAG cycling is applied, the higher the benefit (Figure 21).
- The shorter the water injection period in each WAG cycle is, the better the oil recovery is (Figure 23).

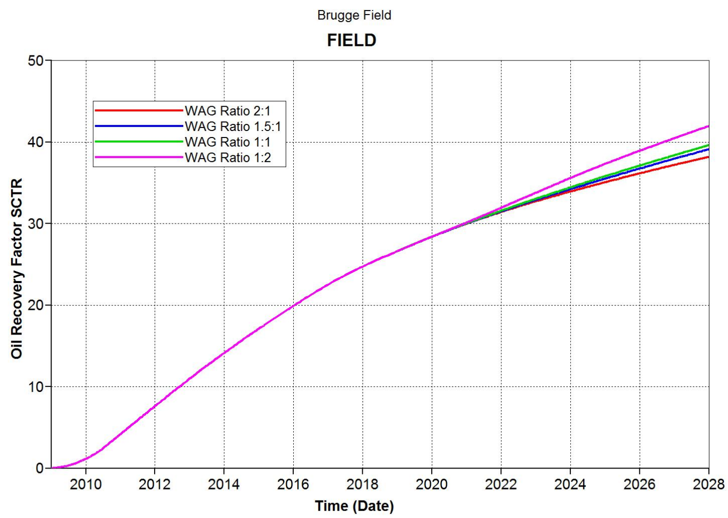


Figure 21: Effects of WAG ratio on CO_2 LSWAG

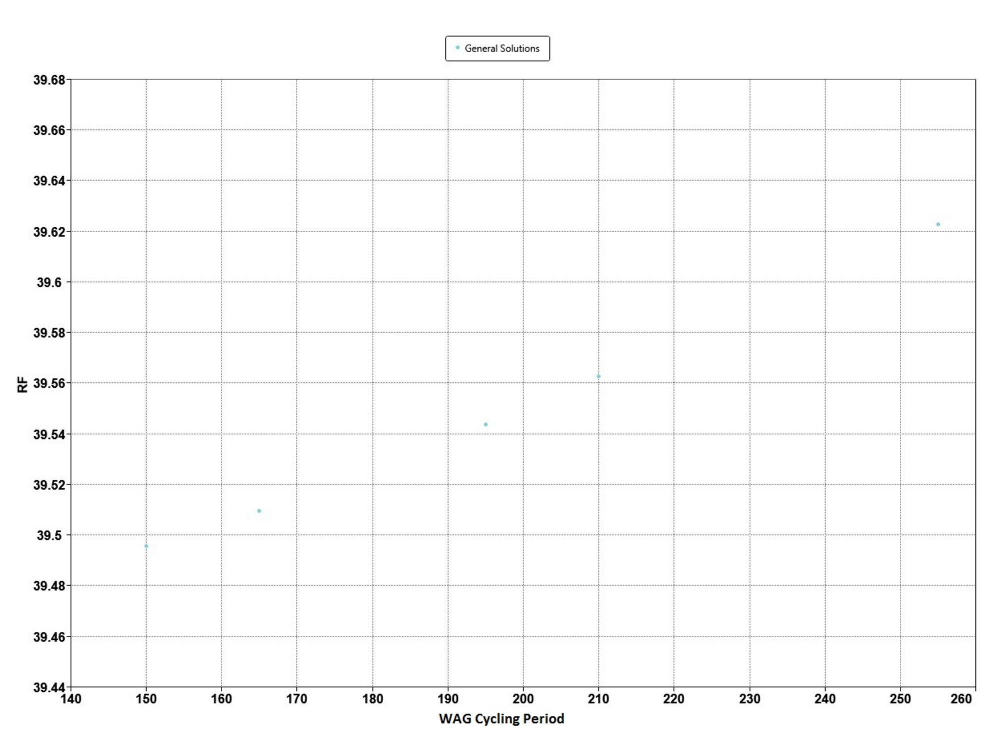


Figure 22: Effect of WAG Cycling Period on CO_2 LSWAG

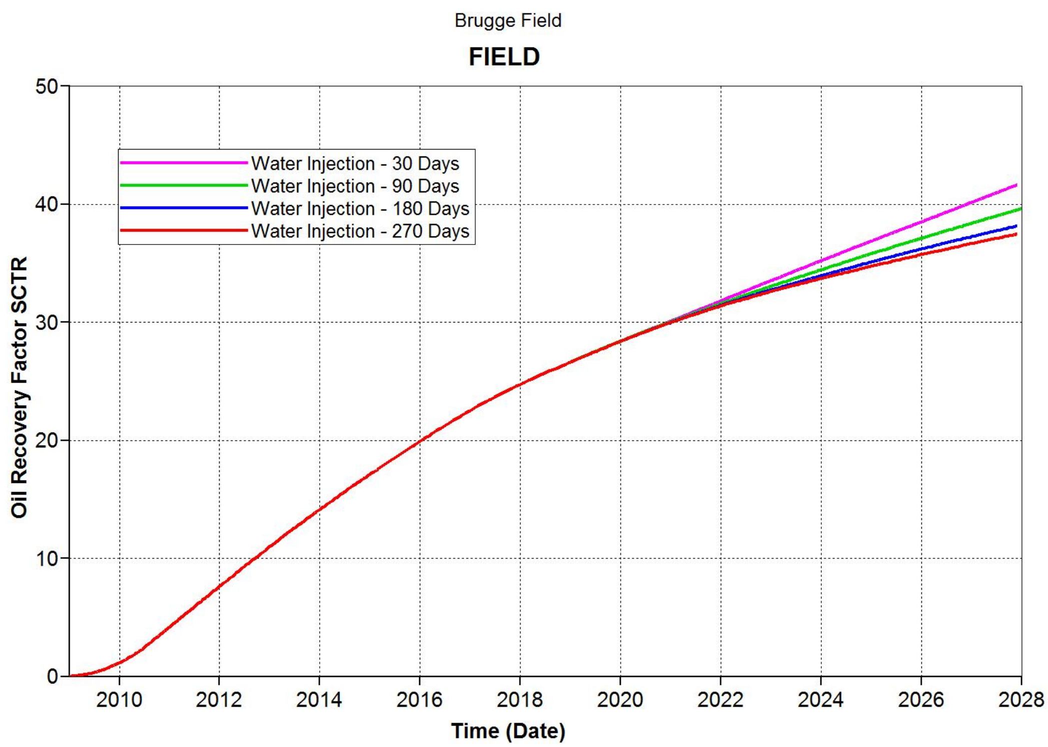


Figure 23: Effect of Water Injection Period in WAG Cycling on CO_2 LSWAG

Clay minerals distribution plays an important role in the CO_2 LSWAG performance since this process strongly depends on the ion exchange and wettability alteration. Clay minerals can be geostasitically distributed in the geological model and calibrated with well logs data. However, the distribution clay is an uncertain parameter, which will be studied below. Fifteen geological realizations with different facies and clay mapping have been generated from the base case. Figures 24 and 25 indicate the results of the uncertainty assessment of clay distribution on CO_2 LSWAG performance. The difference on the ultimate recovery factor between the best (realization # 31) and the worst (realization # 24) is approximately 2% OOIP.

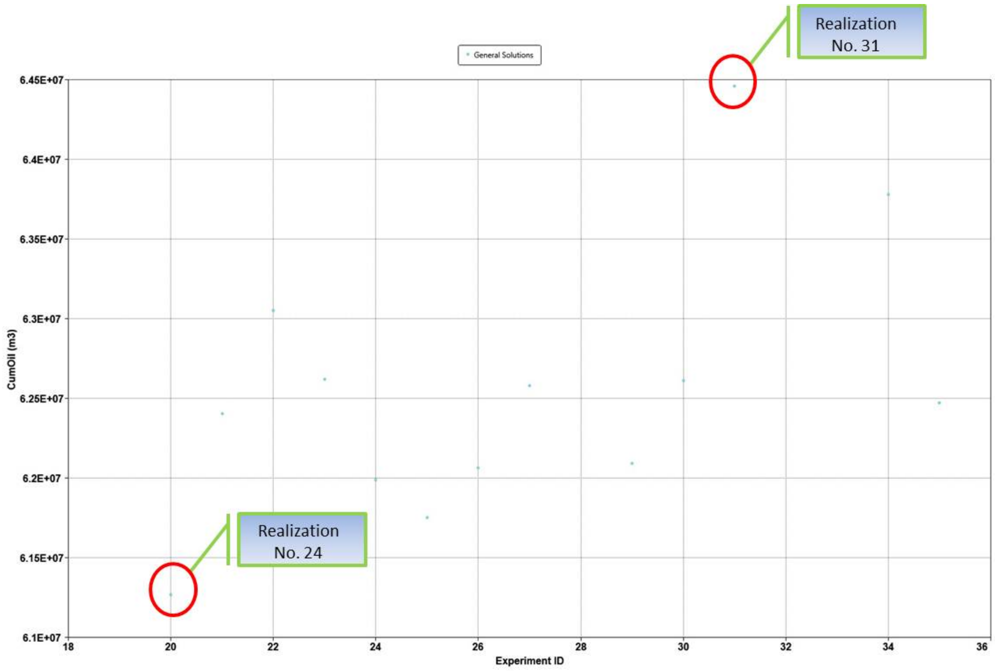


Figure 24: Summary of the Cumulative Oil Recovery from Fifteen Geological Realizations

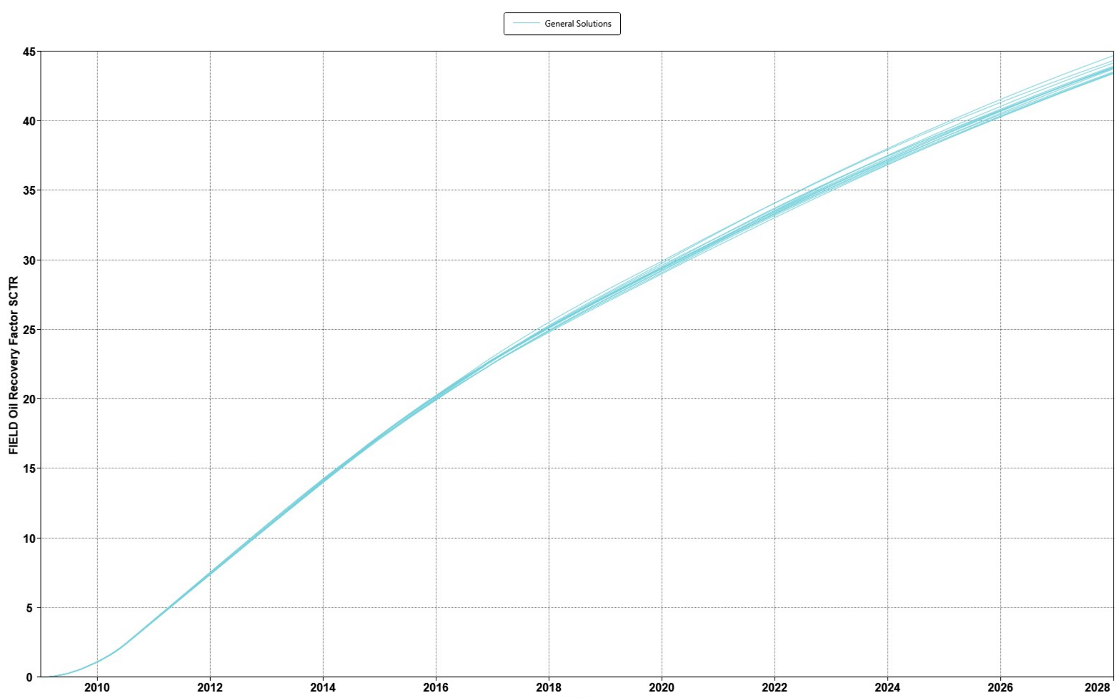
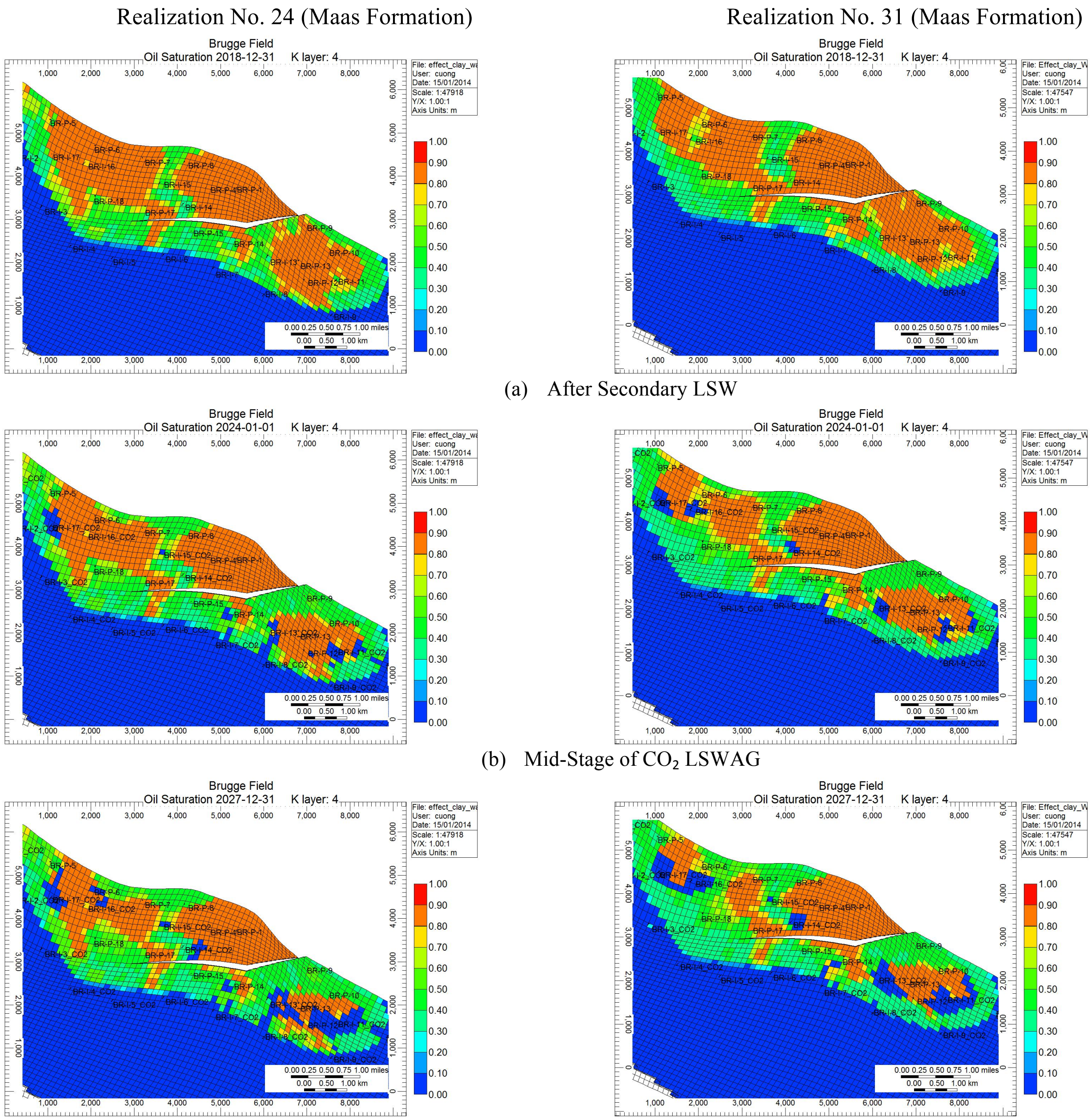


Figure 24: Effect of the Clay Distributions on the CO_2 LSWAG Recovery Factor

Figure 25 shows the comparative oil saturation at different injection periods after the secondary LSW, middle and final stages of CO_2 LSWAG implementation. It indicates that the geological realization 31 has a faster and higher oil production than the one in realization 24. One of the main reasons is the distribution of the clay mineral as represented by the porosity distribution in Figure 26. Similar to CO_2 HSWAG, this process is also sensitive to the reservoir heterogeneity. A high degree of reservoir heterogeneity may lead to low recovery. It is observed that the MS facies with average porosity and permeability and sufficient clay content has the highest benefit on promoting the CO_2 WAG as shown by realization 31. Another interesting observation is that there is only a slightly difference on the oil saturation map between these two realizations after the secondary LSW, but CO_2 WAG has shown a great advantage on enhancing oil recovery afterward. It is a good demonstration of the improvements with CO_2 LSWAG compared to the pure LSW.



(a) After Secondary LSW

(b) Mid-Stage of CO_2 LSWAG

(c) Final-Stage of CO_2 LSWAG

Figure 25: Comparative Oil Saturation Map of the Geological Realizations 24 and 31

Geological Realization No. 24 (Maas Formation) Geological Realization No. 31 (Maas Formation)

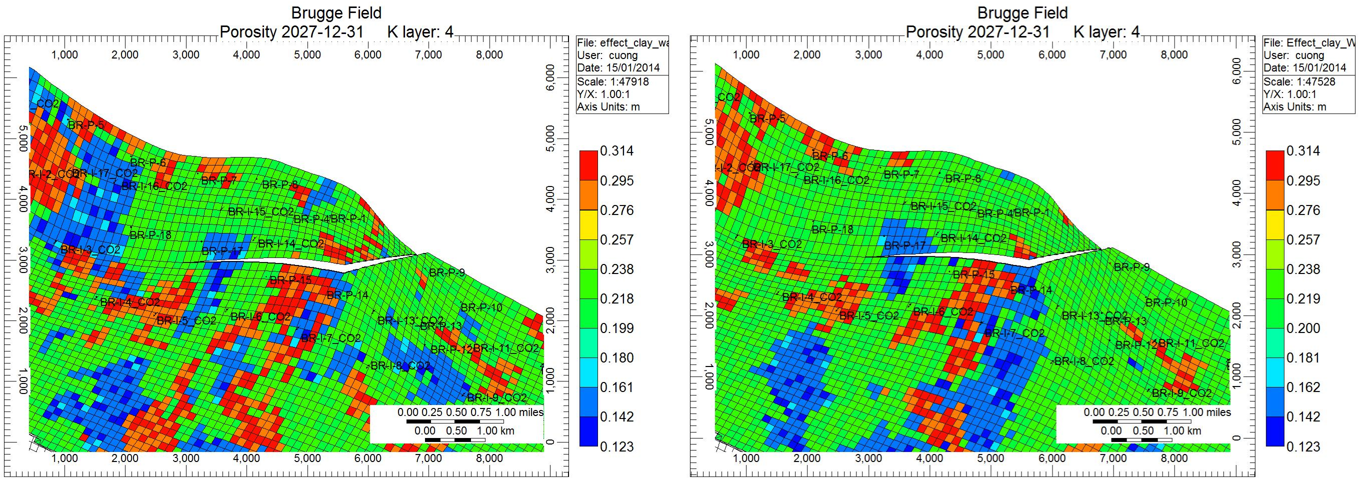


Figure 26: Porosity Distribution on the Geological Realizations 24 and 31

Conclusions

This paper presents a comprehensive evaluation of CO_2 LSWAG from a one-dimensional heterogeneous model into full field simulation. It shows that CO_2 LSWAG is a promising EOR technique as it not only combines the benefits of gas and low salinity water floods but also promotes the synergy between these processes through the interactions between geochemical reactions associated with CO_2 injection, ion exchange process, and wettability alteration. CO_2 LSWAG overcomes the late production problem frequently encountered in the conventional WAG. CO_2 LSWAG provides an incremental oil recovery of 4.5-9% OOIP compared to CO_2 HSWAG. The success of CO_2 LSWAG depends on: (1) type and quantity of clay; (2) initial reservoir wettability condition; (3) reservoir heterogeneity; (4) reservoir minerals such as calcite and dolomite; (5) composition of formation water and injected brine; (6) reservoir pressure and temperature for achieving CO_2 miscible condition; (7) WAG parameters.

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