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Abstract

Low salinity water flooding is a field of science that is new and need more research to find a definite theory of what happens. There have not been done many modeling studies on this field.

The objective of my thesis is to evaluate whether existing commercial reservoir simulators can be used to translate laboratory results into field scale estimates.

The method of doing this was to simulate a core flooding using Schlumberger's "Eclipse 100" and Computer modeling group's "STARS". The model proposed by Omekeh et al. (2012) was attempted to be recreated in the simulators.

The "Eclipse 100" software uses a model proposed by Jerauld et al. (2008), which changes the relative permeability curves based on total salinity in the core or reservoir. And therefore is not able to recreate the ion exchange effect.

STARS also lacked the possibility to simulate the effect modeled by Omekeh et al. (2012), because it did not allow the interpolation of relative permeability curves to be based on a solid component that decreases due to desorption.

The STARS simulator can be able to reproduce the effect if they reprogram the software so that interpolating based on the concentration of solid components is possible.

Table of Contents

Acknowledgements	2
Abstract	3
Table of Contents	4
1. Introduction	6
2. Theory	8
2.1 Enhanced Oil Recovery	8
2.1.1 Primary Recovery	8
2.1.2 Secondary Recovery	8
2.1.3 Tertiary Recovery	8
2.2 Wettability	9
2.3 Cation exchange capacity	9
2.4 Conditions needed to have a positive low salinity effect	10
2.4.1 Clay present in the reservoir	10
2.4.2 Oil containing some polar component	10
2.4.3 Presence of connate brine with multivalent ions	10
2.5 Proposed mechanisms	11
2.5.1 MIE. Multi-component ion exchange	11
2.5.2 Chemical mechanism proposed by Austad et al.	11
2.5.3 EDL. Electrical double layer.....	12
2.5.4 pH increase.....	12
2.5.5 Clay dispersion / Fines migration	12
3. Modeling	13
3.1 Proposed modeling solutions	13
3.1.1 Ion exchange model by Omekeh et al.	13
3.1.2 Jerauld et al. model (“Eclipse 100” model)	15
4 Methods	17
4.1 Summary Eclipse	17
4.2 Summary STARS	19

5	Results	23
	5.1 Eclipse simulations	23
	5.1.1 Oil saturation.....	23
	5.1.2 Relative Permeability	24
	5.1.3 Salt Production Rate.....	25
	5.1.4 Oil Production	26
	5.2 STARS simulations	27
	5.2.1 Oil saturation.....	27
	5.2.2 Relative Permeability	28
	5.2.3 Salt Production Rate.....	29
	5.2.4 Salt concentration at rock surface	30
	5.2.5 Oil production	31
6	Discussion	32
	6.1 Evaluation of Eclipse	32
	6.2 Evaluation of STARS	33
	6.3 Recommendation for further work	33
7	Conclusions	35
	REFERENCES	36
	APPENDICES	37
	A1 Eclipse data file.....	37
	A2 STARS DATA FILE	43
	A3 Relative Permeability Curves	51

1. Introduction

Low salinity water flooding is a new enhanced oil recovery method. It is not completely understood yet, but many mechanisms have been proposed. There are a few people who have proposed different methods of modeling this effect. These will be presented.

The objective of this thesis is to evaluate whether existing commercial reservoir simulators can be used to translate laboratory results into field scale estimates with Low Salinity Water Flooding (LSWF).

An attempt to replicate the low salinity effect modeled by Omekeh et al. (2012) will be made, and check what possibilities there are in the existing commercial reservoir simulators “Eclipse 2010” and “CMG STARS”

Low salinity water flooding has with core experiments and field trials shown that it can have a positive effect on oil recovery. There have also been field trials where it has not had a clear positive effect (Skrettingland et al., 2011)

Field tests

BP has had some positive field test in Alaska.

4 SWCTT (Single Well Chemical Tracer Test) (McGuire et al., 2005)

3 SWCTT (Seccombe et al., 2008) showed that additional recovery by low salinity water (LoSal) had a correlation with the kaolinite concentration. There was a good agreement between core flooding results and SWCTT performed in the field.

BP tried low salinity water flooding at reservoir scale. (Lager et al., 2008) They used one injector and two nearby producers. The results clearly show an increased oil recovery by low salinity water injection, and also by testing brine composition after injection they showed results that are consistent with the MIE theory.

Statoil (Skrettingland et al., 2011) tested core flooding and one SWCTT in the Upper Statfjord formation. They had agreement between the core flooding experiments and the SWCTT performed. They did however show no or a very little increase of oil recovery. The results from this work indicate that the initial wetting condition is crucial to the low salinity flooding effect. The reason for the low potential in the Snorre field is believed to be because the wetting condition naturally is close to optimal.

Core tests

Lager et al. (2008) (Lager et al., 2008) reported low salinity effect at reservoir conditions as well. Previous Core experiments had been executed at sub reservoir conditions. They also concluded that generally end point water relative permeability data do not vary significantly between high and low salinity water flooding, in secondary or tertiary modes.

Core tests indicating that there is little or no effect with low salinity water injection.

Lager et al. (2006) performed core floods with connate water without divalent ions. These experiments should show no extra recovery by low salinity water flooding. And this was the case as well.

(Ligthelm et al., 2009) suggested that if you have low salinity formation water and inject water with higher salinity you will change the formation to more oil wet.

These tests are in line the theory that presence of multivalent ions in the connate water is needed to have a positive low salinity effect.

2. Theory

2.1 Enhanced Oil Recovery

Oil recovery can be divided into three different types, which are explained below. Low salinity water flooding is a tertiary recovery method.

2.1.1 Primary Recovery

Primary recovery is the natural depletion of the reservoir (Green and Willhite, 1998). This means that oil is recovered with the help of the natural energy present in the reservoir. Examples are solution-gas drive, gas-cap drive, natural water drive, fluid and rock expansion and gravity drainage. This form of production is used at the beginning of a reservoir's production period. Primary recovery is the least expensive method of extraction and typical recovery factors during this process is 5-15% of original oil in place (OOIP)

2.1.2 Secondary Recovery

Secondary recovery is the augmentation of natural energy with injection of water or gas (Green and Willhite, 1998). The mechanism is maintenance of pressure or a mechanical displacement of fluids. The most common secondary recovery method today is water injection, but gas injection is also used.

2.1.3 Tertiary Recovery

Tertiary recovery is often called "Enhanced Oil Recovery" or EOR for short. (Green and Willhite, 1998). This form of recovery affects the residual oil saturation to increase the oil recovery. Tertiary processes can be CO₂, surfactant, polymer or low salinity injection. The common denominator is that they change the interaction between the injected fluid and the reservoir fluid. Low salinity is the different from these methods since it only help to release more oil where the others change the miscibility and mobility of the displacement.

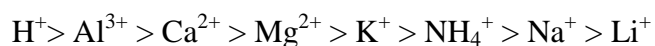
2.2 Wettability

When two immiscible phases are placed in contact with a solid surface, one phase is normally more attracted to the surface than the other (Green and Willhite, 1998). The phase that is more attracted is called the wetting phase. The wettability affects the relative permeability curve. The location of a phase in the pore space depends on the wettability, and therefore it is easy to see that wettability affects the relative permeability curves. A reservoir has heterogeneities and can and are often mixed wet. That means that the wettability can change over the course of the reservoir.

2.3 Cation exchange capacity

Cations are adsorbed onto clay because of the charge difference. Cations are positive while clay is often negatively charged. Cations that are adsorbed can be exchanged by other cations. The Cation exchange capacity (CEC) is reported in milliequivalents per 100 gram of dry clay (meq/100g).

The ions have different attractive forces and will normally replace each other in the following order:



This order can be changed with increasing temperature and concentration of the ions. This is a reason that it is important to have the different concentration of ions right in the injected low salinity water. (MI, 1998)

2.4 Conditions needed to have a positive low salinity effect

There are many proposed mechanisms for the low salinity effect. Tang and Morrow (1999) and Lager et al. (2006) have proposed certain conditions which are needed to see an effect.

2.4.1 Clay present in the reservoir

Clay is negatively charged and is acting as the base where the divalent ions are connected with the clay and the oil components.(Tang and Morrow, 1999)

2.4.2 Oil containing some polar component

If the oil is not polar or containing some polar component it will not be attracted to the clay and the divalent ions, which will mean that you will not have a positive low salinity effect. (Tang and Morrow, 1999)

2.4.3 Presence of connate brine with multivalent ions

You need to have connate brine present with multivalent ions to have a positive low salinity effect. The multivalent ion is acting as a bridge between the oil and the clay. Tang and Morrow (1999) reported that you needed connate brine for a positive effect. Lager et al. reported in 2006 that you don't see a low salinity effect if the connate brine was stripped of multivalent ion. (Lager et al., 2006)

2.5 Proposed mechanisms

In this chapter the different proposed mechanisms for improved low salinity effect are presented. There has not been an agreement on what the mechanism(s) of the low salinity water flooding effect is. It can be one of these or maybe a combination of these or some other. MIE is an accepted suggestion by some and that is also the mechanism that is the basis for the simulation in this thesis and the work done by Omekeh et al. (2012).

2.5.1 MIE. Multi-component ion exchange

MIE is a theory on what happens during low salinity water flooding (Lager et al., 2006). In this case there will be polar oil components that are connected to a negatively charged clay surface with the help of a positively charged multivalent ion. If this ion later is exchanged with a monovalent ion it will release the oil component since there will be an unbalance in the net of charge.

Lager et al. (2006) concluded that there will only be a low salinity effect if there are multivalent ions present on the clay surface. They did experiments where they flooded with high salinity water first and then with low salinity water, this resulted in a 5% OOIP extra recovery. This did not happen when they removed all the Ca^{2+} and Mg^{2+} before start of flooding. When this was performed it did not matter what salinity they flooded with, which indicates strongly that MIE is a valid mechanism. (Lager et al., 2006)

2.5.2 Chemical mechanism proposed by Austad et al.

Austad et al. (2010) proposed that when the reservoir have the initial equilibrium at a certain pH, pressure and temperature. Both basic and acidic organic materials are adsorbed onto the clay together with inorganic ions especially Ca^{2+} . When low salinity water is injected the equilibrium is disrupted and desorption of ions occur, which free up some of the adsorbed organic matter due to a local pH increase. The way this happens is that you have a reservoir in equilibrium at maybe around pH 5 because of the CO_2 and H_2S in the reservoir. When the low ionic water is injected the equilibrium is disturbed. As a result the Ca^{2+} and other multivalent ion are desorbed. To re-stabilize the equilibrium H^+ is adsorbed from the water (Austad et al. (2010)).

2.5.3 EDL. Electrical double layer

The electrical double layer theory is that there is a charged clay surface and an adsorbed layer which contains strongly bound ions (Lee et al., 2010). The other layer contains ions that are in Brownian motion, this layer is called the diffuse layer. Double layer thickness or Debye length, the length of the diffuse zone is dependent on electrolyte concentration. Low ionic strength leads to thicker double layer.

2.5.4 pH increase

McGuire et al. (2005) reported that an increase in pH can generate surfactants from the residual oil and believed this mechanism to be the major cause of the low salinity effect. The elevated pH comes from the injection of the low salinity water which has a higher pH value (McGuire et al., 2005). Before the paper by Lager et al. (2006) there had been some reporting where they got and believed that an increase in pH was the main reason for the increase in oil recovery. If this would have been the cause it should have a pH up towards 10, but this is not usually obtained in a reservoir due to proton buffering. The majority of petroleum reservoirs contain CO₂ which will act as a buffer, rendering an increase of pH up to 10 unlikely. So an increase of pH is most likely an effect of the low salinity enhanced recovery not the cause. (Lager et al., 2006)

2.5.5 Clay dispersion / Fines migration

Tang and Morrow (1999) explained that oil wet clay particles are mobilized during low salinity water floods. This result in exposure of underlying surfaces that leads to a more water-wet surface, and the release of more oil. BP have had during numerous low salinity water floods where they had an increased recovery, not had any fines migration. So this is not a definite mechanism (Lager et al., 2006).

3. Modeling

Low salinity water flooding is a fairly new field of science of EOR. This means that there have not been developed a lot of models of this phenomenon. As seen in the previous chapter there is a lot of proposed mechanisms for LSWF. Since there is not an agreement on what mechanism that is the correct one or correct ones, there have not been developed many models. Obviously it can be a lot of waste of time to develop a model based on a mechanism that may be discarded later. There may be uses for that model other places, but it may be difficult to get funding to a modeling project if it is based on a theory that is not widely accepted. Two models will be explained because they are essential for the simulation work done.

3.1 Proposed modeling solutions

3.1.1 Ion exchange model by Omekeh et al.

Omekeh et al. (2012) have proposed a model where they aim to link desorption of the divalent ions to improved flow functions. MIE (see chapter 2.5.1) is the chosen mechanisms and they link the amount of divalent ions released from the rock surface to a change of relative permeability curves so that more oil can be mobilized.

The low salinity effect is modeled on the results of desorption of divalent ions. The details of the cation exchange are not described in this thesis, since it is not really that relevant for this thesis. It can be checked out in the paper published by Omekeh et al. (2012)

The low salinity effect is implemented into the model with the help of a weighting function. (Omekeh et al., 2012). The function is 1 if there is no desorption and less than 1 if there is desorption. The relative permeability curves used in the model is chosen with interpolation with the help of the weighting function and the predetermined relative permeability functions for high and low salinity.

The amount divalent ion desorbed is given by:

$$m(\beta_{Ca}, \beta_{Mg}) = \max[(\beta_{Ca}(t = 0) - \beta_{Ca}(t > 0)), 0] + \max[(\beta_{Mg}(t = 0) - \beta_{Mg}(t > 0)), 0] \quad (1)$$

β adsorbed concentration,
 t time
 $\max[\dots]$ the maximum value of desorbed ions. It is calculated using the initial ($t = 0$) concentration minus the concentration after the initial condition ($t > 0$).

The weighting function is then:

$$F(\beta_{Ca}, \beta_{Mg}) = \frac{1}{1+r*m(\beta_{Ca}, \beta_{Mg})} \quad (2)$$

r constant
 $m(\beta_{Ca}, \beta_{Mg})$ function (1)

This weighting function is used to interpolate between the high and low salinity cases to find the permeability for each state:

$$k(S, \beta_{Ca}, \beta_{Mg}) = F(\beta_{Ca}, \beta_{Mg})k^{HS}(S) + [1 - F(\beta_{Ca}, \beta_{Mg})]k^{LS}(S) \quad (3)$$

k relative permeability value
 S Salinity
 HS High Salinity
 LS Low Salinity

3.1.2 Jerauld et al. model (“Eclipse 100” model)

Jerauld et al. (2008) proposed a modeling solution where they link the salinity of the brine in the reservoir to relative permeability curves. A high salinity set of curves and a low salinity set of curves are defined. It is modeled in such a way that the high salinity relative permeability curve is used if the salinity concentration is over a defined level. The low salinity curves are used for values of salinity below or at a defined level. For the values in between these two threshold values they interpolate the relative permeability curves. This is the model that is implemented into the “Eclipse 100” simulator. (Jerauld et al., 2008)

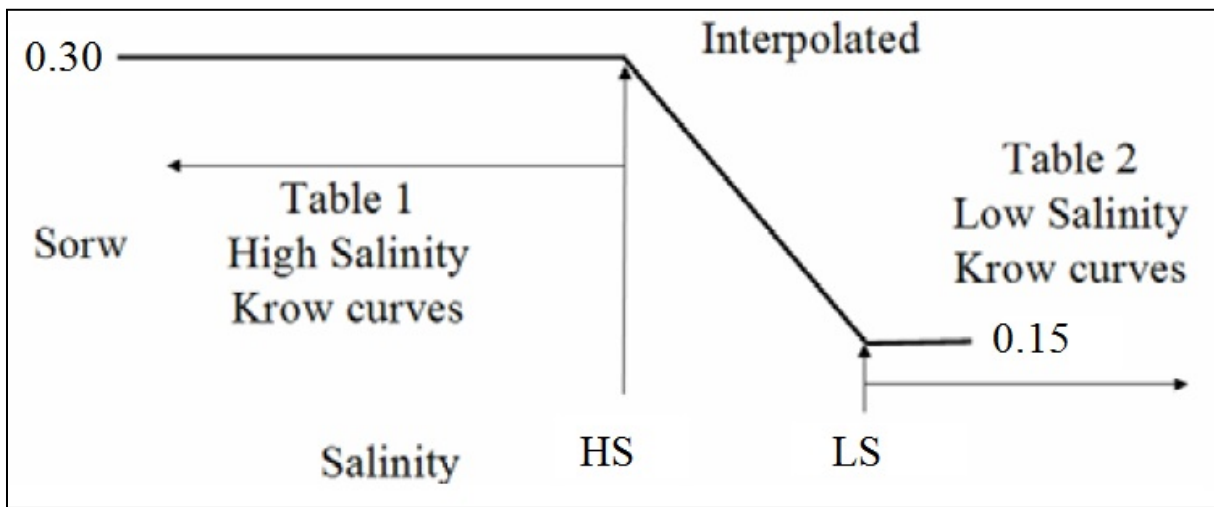


Figure 1: Saturation and relative permeability change with respect to salinity change. (Jerauld et al., 2008).

The shape of the relative permeability curves is assumed to linearly dependent between the high salinity (HS) and low salinity (LS) threshold values and constant beyond them. The following formulas are used to calculate the relative permeability values:

$$k_{rw} = \theta k_{rw}^{HS}(S^*) + (1 - \theta)k_{rw}^{LS}(S^*) \quad (4)$$

$$k_{row} = \theta k_{row}^{HS}(S^*) + (1 - \theta)k_{row}^{LS}(S^*) \quad (5)$$

k_{rw}, k_{row}	oil and water relative permeability
HS	High Salinity
LS	Low Salinity
S^*	normalized saturation
θ	dimensionless measure of low salinity versus high salinity

$$\theta = \frac{(S_{orw} - S_{orw}^{LS})}{S_{orw}^{HS} - S_{orw}^{LS}} \quad (6)$$

$$S^* = \frac{S_o - S_{orw}}{1 - S_{wr} - S_{orw}} \quad (7)$$

4 Methods

Two commercial simulators were chosen for this work. “Eclipse 100” and “STARS”. The experiment simulated on both was a core with only one salt in the brine. The choice of only using one salt was for simplistic reasons. It is not very difficult to add more salts to the simulations, but it takes more time and tuning. And the objective is to check the possibilities of these two programs. The simulation is going to be 8 days of injection of formation water (FW) and the injection low salinity water (LSW). The simulations on both had the following inputs:

Core length	8cm
Core width	1cm
Porosity	0.279
Permeability	150mD
Initial oil saturation	0.85
Relative permeability curves	“See Appendix (One for Low salinity and one for High salinity)”
Grids	40*1*1 (1D)
Pressure	68bar (not essential compressibility is neglected)
Injection velocity	6.323 cm/day
Oil viscosity	8cp
Mass of clay	0.529 kg/liter core
Ca ²⁺ Formation water	0.14794 moles/liter
Ca ²⁺ Low salinity water	0.00148 moles/liter

4.1 Summary Eclipse

Eclipse has a brine tracking function, which has a low salinity option. The low salinity option is based on the model described by Jerauld et al. (2008). This model relates the total salinity of the water to relative permeability curves. They defined a curve for low salinity water and one for high salinity water. For values between the curves they interpolate. This is also how the Eclipse model handles the low salinity water flooding.

Table 4.1: Essential functions and keywords in Eclipse for the brine and low salinity simulations (Schlumberger, 2012)

RUNSPEC	
BRINE	This let the simulator know that it has to deal with injected water with salinity values
LOWSALT	The activation keyword for the low salinity function of the eclipse simulator. This keyword also activates the BRINE keyword if it has not been written
ECLMC	Activates the multicomponent option. This is required if you are to use the multicomponent brine option.
TABDIMS	Sets the number of tables used. Need to be specified to allow to sets of relative permeability curves.
GRID	
IONROCK	Ion exchange capacity of the rock. This is entered in kg-moles/m ³ (METRIC). Needed it using multicomponent brine and want to have ion exchange simulated
PROPS	
LSALTFNC	Specify the low salinity fraction as function of the salt concentration in the grid block. Here you specify the concentration that is needed to be in either the low salinity, high salinity or in the interpolated area of the flow functions. See appendix for an example.
BDENSITY	It enables the brine surface density to vary with the salt concentration
PVTWSALT	PVT data of water with salt
IONXROCK	Activates ion exchange on rock surfaces and defines the ion exchange constant.
SOLUTION	
SALTVD	Salt concentration versus depth table
SUMMARY	
Don't have any essential keywords to the simulation here. There are some keywords that will show you the salt values in the simulation, but they are not needed to run the simulation. They are however interesting if you want to see how the salinity changes.	
SCHEDULE	
WSALT	Salt concentration for injection well

These are the essential keywords in the Brine and low salinity option in “Eclipse 100” (Table 4.1). See appendix for closer view of the other normal keywords used in the “Eclipse 100” simulation.

In table 4.2 there is listed the available salts in the “Eclipse 100” simulator. These salts contribute to the total salinity. And the characteristics of these have been implemented into the simulator.

Table 4.2: List of available salts to use in the multicomponent brine model.

Sodium Chloride	NaCl
Potassium Chloride	KCl
Calcium Chloride	CaCl ₂
Magnesium Chloride	MgCl ₂
Sodium Carbonate	Na ₂ CO ₃
Potassium Carbonate	K ₂ CO ₃
Calcium Carbonate	CaCO ₃
Magnesium Carbonate	MgCO ₃
Sodium Sulfate	Na ₂ SO ₄
Potassium Sulfate	K ₂ SO ₄
Calcium Sulfate	CaSO ₄
Magnesium Sulfate	MgSO ₄

4.2 Summary STARS

STARS is an advanced processes simulator for modeling the flow of three-phase, multi-component fluids. This simulator does not have a low salinity function, but have the possibility to model a similar effect modeled by Omekeh et al. (2012) and the modeling option of the Jerauld et al. (2008) model. In STARS there is an option where components can be defined and the reactions they take part of.

The method proposed is based on one salt, Calcium. It can be expanded to use all salts in the reservoir, but the workload and tuning will be much larger. For this thesis it was more essential to see if the software can simulate the effect, not the complexity of the simulations performed.

It is simulated with 4 components; WATER, OIL, CA2SOLID and CA2DIS.

CA2SOLID is the calcium in the solid phase, which means the calcium attached to the clay in the reservoir.

CA2DIS is the calcium dissolved in the water phase.

The relative permeability curves should be interpolated based on the concentration of CA2SOLID in the reservoir. Which means that if a lot of the CA2SOLID is dissolved i.e. desorbed from the surface, the reservoir will become more water wet and change the relative permeability curves to a defined curve that will give you an increased oil recovery this example. The problem here in STARS is that you can't integrate based on a component that is set as a solid component. This means that the simulation will be similar to the one done in "Eclipse 100". Since the interpolation component is then CA2DIS.

If STARS had the possibility to integrate based on a solid component it would have the possibility to simulate the no effects examples. Instead of only interpolating based on the total salinity concentration, it can show that no effect will be seen if the reservoir already has reached a wetting state that will not release any more oil. This seems like a very little effort to change in the STARS software. So if that is done the Stars simulator have good opportunities to simulate the low salinity effect as done by Omekeh et al. (2012).

The STARS simulation software has a graphical interface which is a good choice to use. It can also be programmed the way done with “Eclipse 100”, where the programming is in a data file using selected keywords. The keywords in Table 4.3 are the keywords you need to have in order to do the simulation the way done in this thesis. There are other keywords used as well, but these are the ones that are used in all sorts of simulations and are not included in this table. They can be looked up in the appendix if needed.

Table 4.3: Essential Keywords STARS (CMG, 2011)

INPUT/OUTPUT CONTROL	
Not any essential keywords in this part for the simulation that differ from any other simulation in STARS. See the appendix for the keywords used.	
GRID AND RESERVOIR DEFINITION	
Define grids, porosity and permeability in this section. There are not any essential keywords in this part for the simulation that differ from any other simulation in STARS. See the appendix for the keywords used.	
FLUID DEFINITIONS	
In this section you define the components and their properties. Reference conditions and the reactions you want to happen in the reservoir. See the appendix for the complete input of this section.	
MODEL	Indicate number of each type of component. I have “MODEL 4 3 3 2” which means 4 components, 3 in water, oil or gas phase, 3 in water or oil phase and 2 in water phase.
COMPNAME	Define the names of the components and the following keywords define the component properties: CMM (molecular weight), PCRIT(critical pressure), TCRIT(critical temperature) KVTAVBLIM(Liquid-liquid K value).
Reaction keywords:	
STOREAC	Defines the reacting component(s)
STOPROD	Defines the product of the reaction(s)
RPHASE	Defines the phase the reaction(s) is taking part in.
RORDER	Defines the order of the reaction(s)
FREQFAC	Reaction rate. Higher number means faster or more favorable to react this way.
RENTH	Reaction enthalpy, default is 0.

EACT	Activation energy. This can make the reaction(s) temperature dependent
ROCK-FLUID PROPERTIES	
Here you set the relative permeability curves for high and low salinity and what component they are supposed to interpolate on.	
INTCOMP	Define the component that should be taken into account and set the phase it is in.
INTLIN	Uses linear interpolation between the tables. This is the default
INTLOG	Uses Logarithmic interpolation. Not used in my simulations but is an option.
KRINTRP	The interpolation set number. Start at 1 for the first and increases by 1 for each additional set.
DTRAPW	Value of wetting phase interpolation parameter for current rock-fluid data set. Physical meaning of DTRAPW depends on interpolation option.
SWT	Water-Oil relative permeability table
INITIAL CONDITIONS	
Set the initial conditions like Saturation and concentration of the different components.	
MFRAC_WAT 'Component Name' CON	Sets the concentration of the water component(s) at initial conditions
MFRAC_SLD 'Component Name' CON	Sets the concentration of the solid component(s) at initial conditions
MFRAC_OIL 'Component Name' CON	Sets the concentration of oil component(s) at initial conditions
NUMERICAL CONTROL	
Default values used. See appendix for the plotted keywords and values used	
RECURRENT DATA	
Well data. Injection concentrations. Injection/Production rate.	
INJECTIOR UNWEIGHT 'well name'	Sets up the injection well for the following keyword.
INCOMP 'PHASE' 'VALUE(S)'	Injected composition of the set phase.

5 Results

The “Eclipse 100” simulations will be presented first, then the STARS. There will be a set of different parameters plotted to show the similarities and dissimilarities of these two simulators. Keep in mind that the low salinity injection started after 8 days.

5.1 Eclipse simulations

5.1.1 Oil saturation

Figure 5.1 show that the end point saturation for high salinity, 0.3 is reached after 2 days and stays stable until about 18 days. It should start to change after 8 days since the relative permeability value changes from 8 days. The reason for this is unknown at this point. Can be that the interpolation between the curves does not change the endpoint value until the salinity is close to the low salinity threshold.

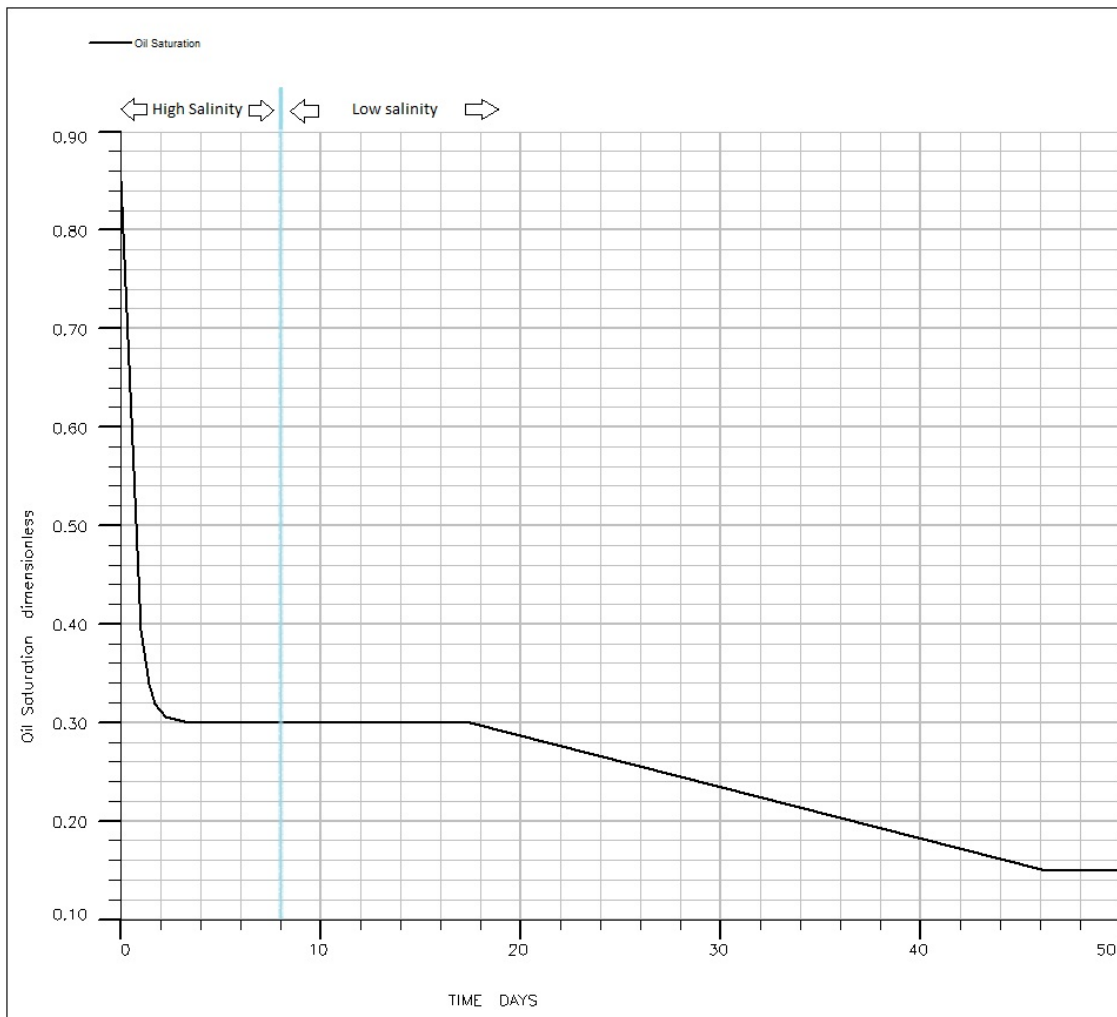


Figure 5.1 Oil Saturation versus time

5.1.2 Relative Permeability

Relative permeability changes the way expected. It reached stable values after about 2 days, and starts to change after 8 days when the low salinity water is injected. After about 18 days it starts to revert to the new endpoint values from the low salinity relative permeability curves.

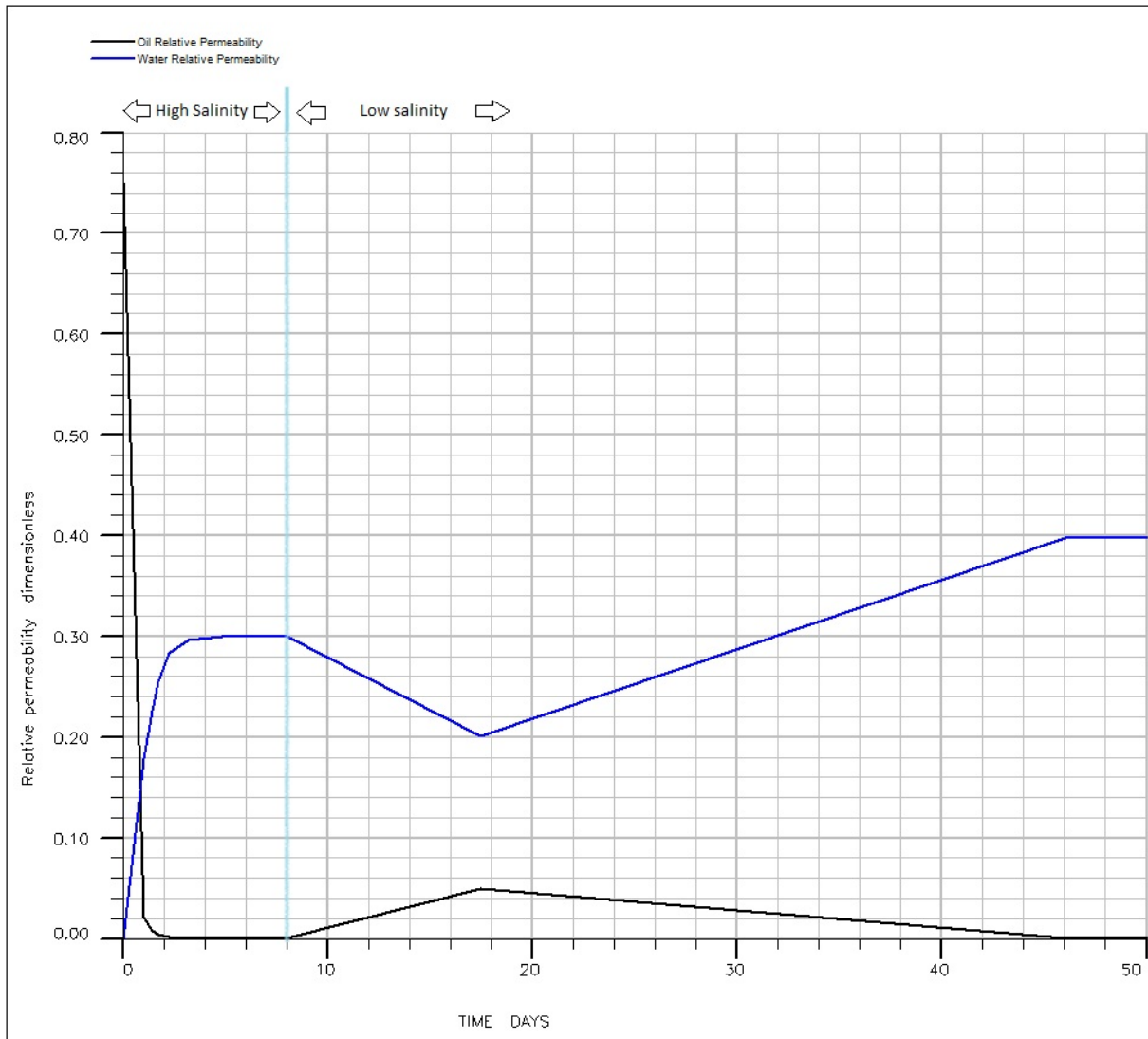


Figure 5.2: Relative permeability versus time

5.1.3 Salt Production Rate

Salt production clearly follows the injected values. There is a very little dip at approximately 18 days.

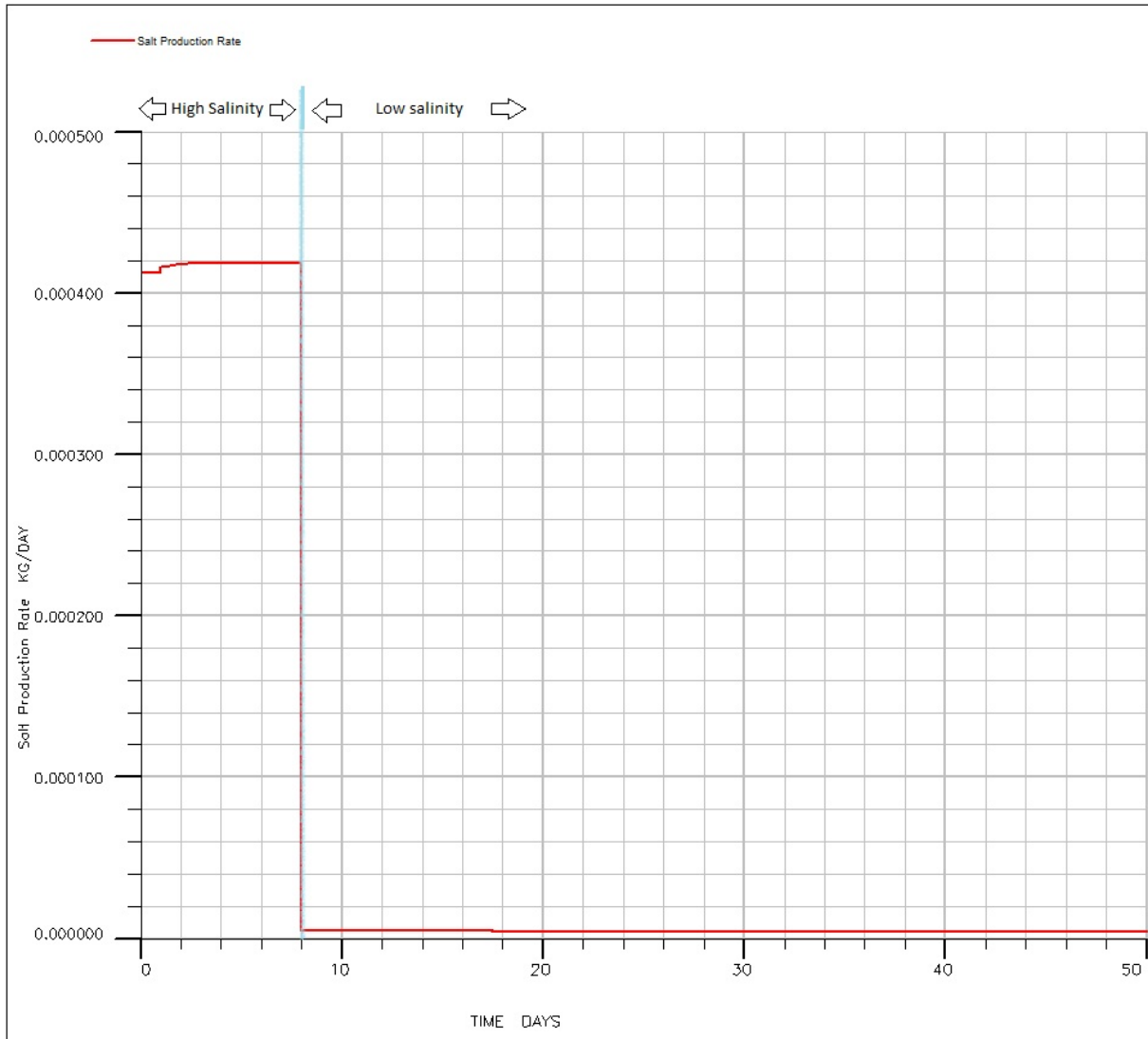


Figure 5.3: Salt Production Rate versus time

5.1.4 Oil Production

The rate used is right under one pore volume per day and you can see from the figure that after 2 days we have reached a plateau. This plateau is the saturation where the oil relative permeability has reached 0 with the FW (Formation Water) concentration in the reservoir. After 8 days we start to inject low salinity water into the core, and for some reason you don't see any extra oil production before about 20 days. The reason for this delay is unknown, but you see that you reach a new plateau after about 46 days. This extra increase in production is from right over 11ml to close to 12. This means an extra production of about 5-10% which is in agreement with the statement from Lager et al. as mentioned in chapter 2.5.1.

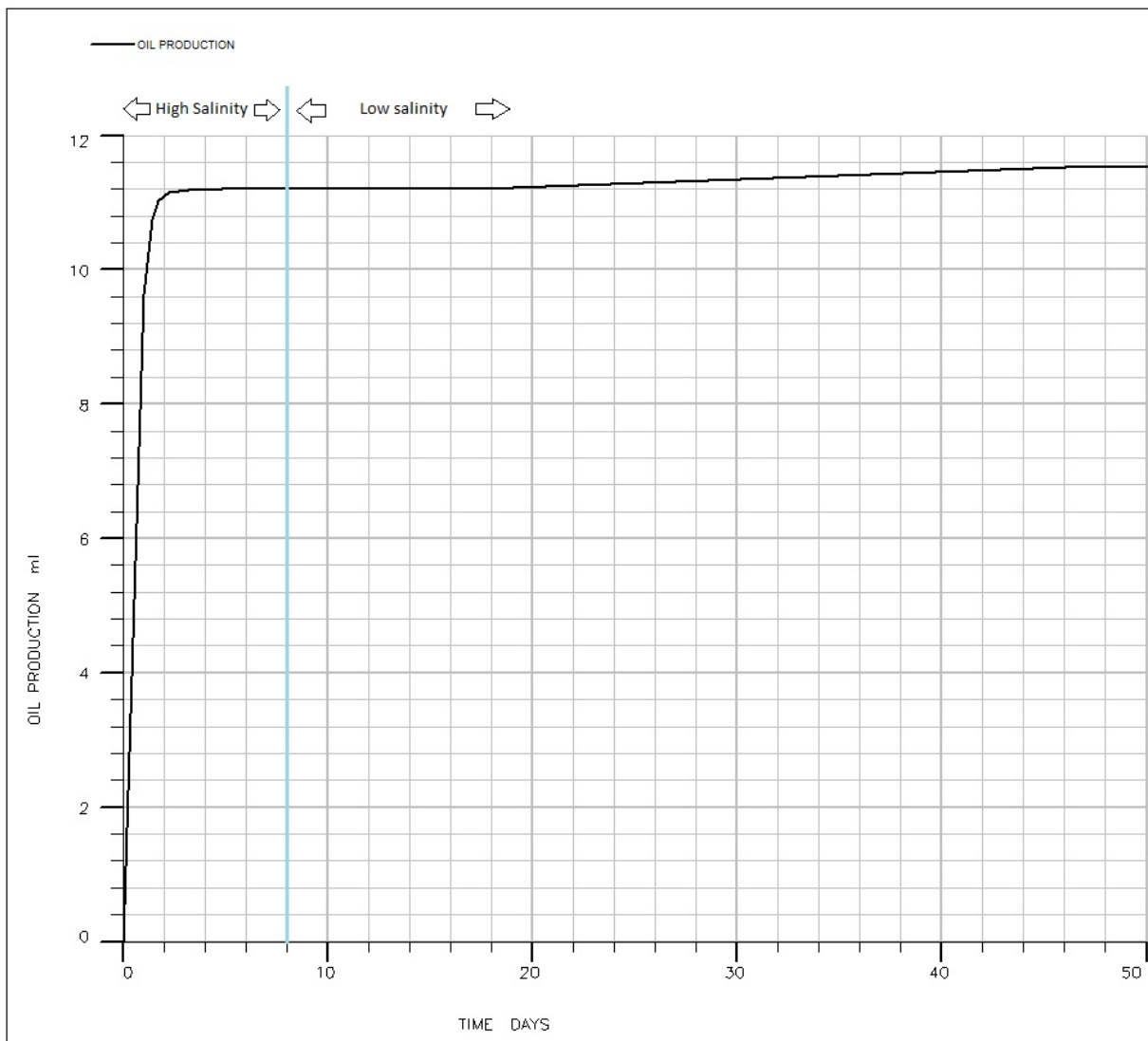


Figure 5.4 Oil Production versus time

5.2 STARS simulations

5.2.1 Oil saturation

This model reacts from the day the low salinity water is injected. It has the same endpoint that the “Eclipse 100” simulation at high salinity, but have a saturation that is a little bit lower than the endpoint with the low salinity relative permeability. This could probably be tuned to behave closer to the “Eclipse 100” simulations. STARS have for some reason an increased recovery after the breakthrough.

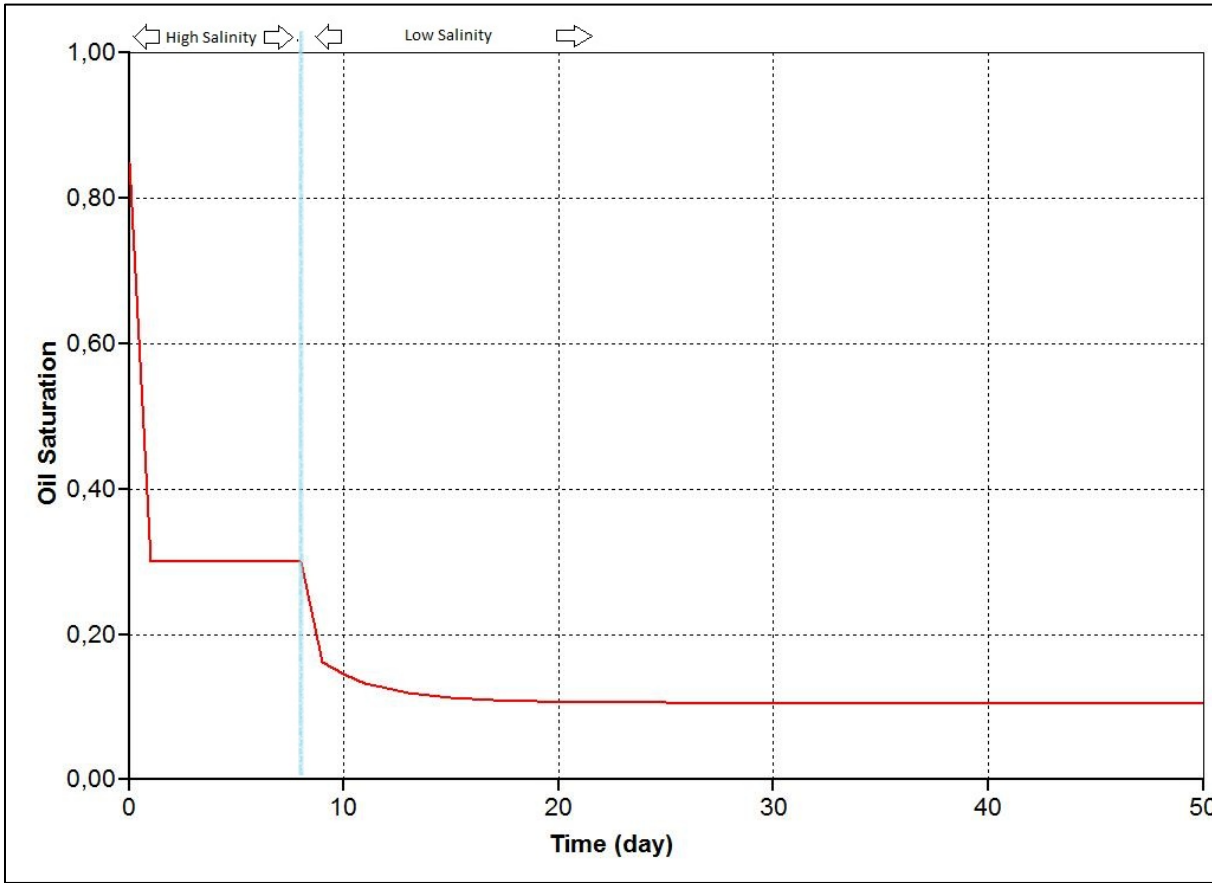


Figure 5.5: Oil Saturation versus time

5.2.2 Relative Permeability

The relative permeability behaves about the same way as in “Eclipse 100”. It does however change faster than in “Eclipse 100”. At 8 days the water relative permeability should go down and the oil relative permeability should go up. It does this if you study the simulation closer. I.e. decrease the time step and lower the viewing area. Then you will see a little spike in the relative permeability curves. This simulation will release the potential oil over very few time steps because of the injection rate, grid blocks and time steps chosen.

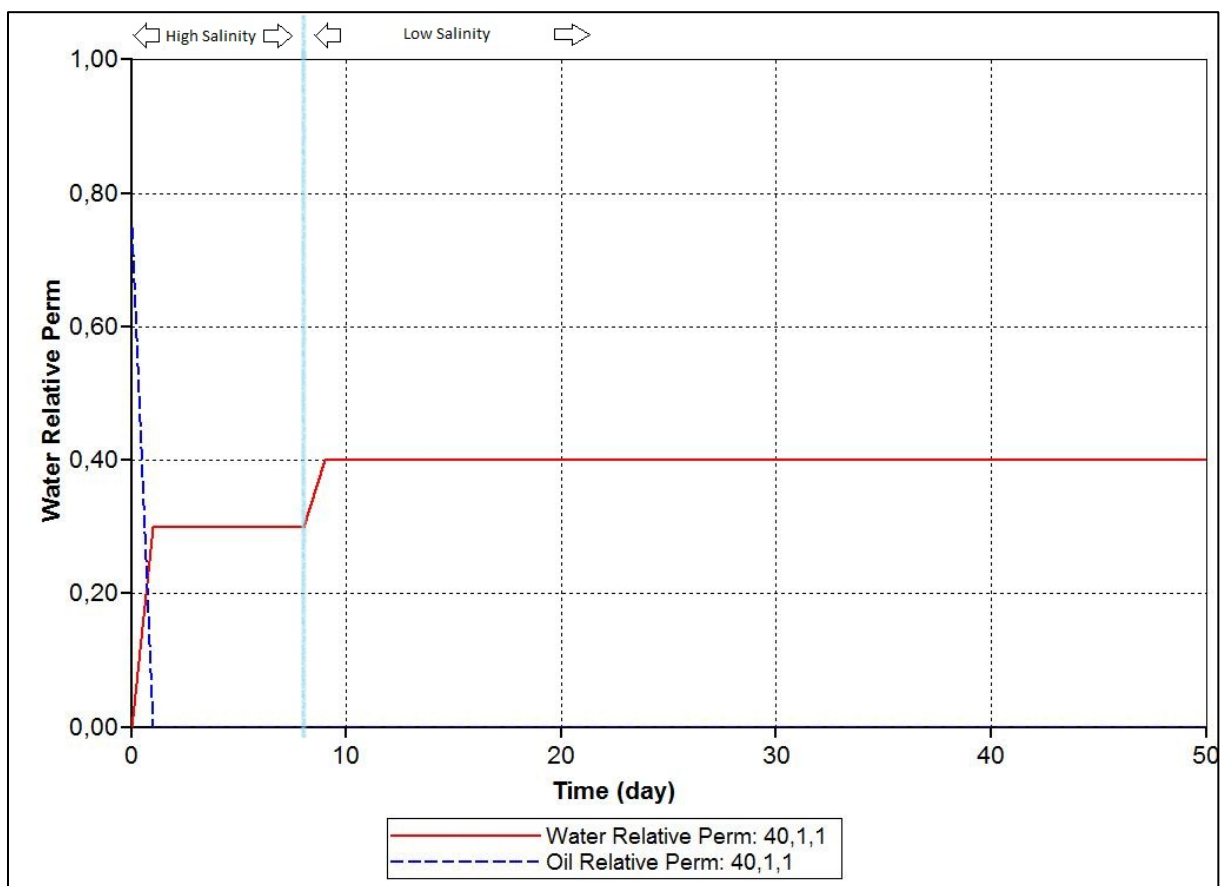


Figure 5.6: Water and oil relative permeability versus time

5.2.3 Salt Production Rate

The amount of salt produced behaves the way expected and in according to the simulation in “Eclipse 100” and the simulations done by Omekeh et al. (2012)

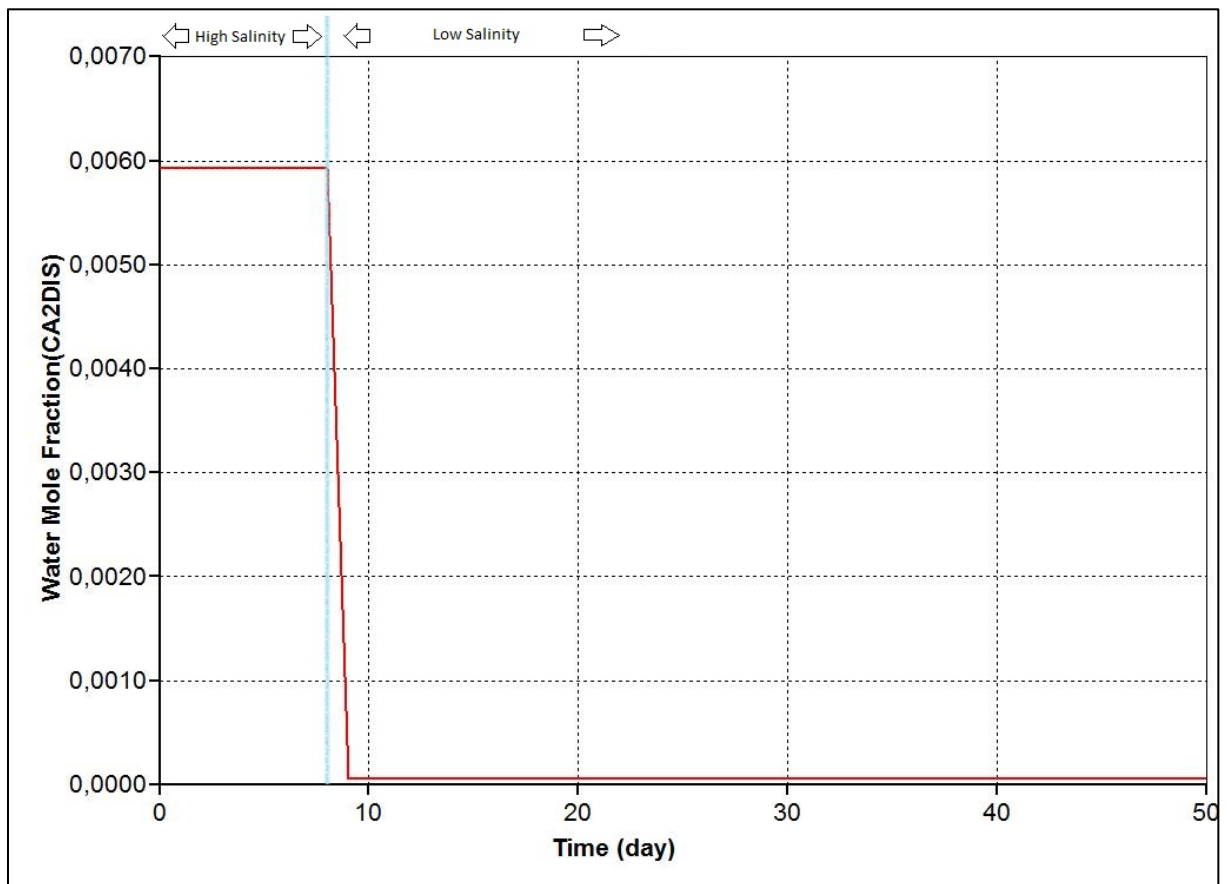


Figure 5.7: Mole fraction of CA2DIS produced versus time

5.2.4 Salt concentration at rock surface

The first 8 days the reactions from the simulation are reaching equilibrium. After 8 days when the low salinity water is injected the desorption starts, and the concentration goes down. If STARS had allowed the interpolation of the relative permeability curves to be based on a solid concentration you can see that we have a model here that can behave close to the model presented by Omekeh et al. (2012). It would also slow down the extra oil production to a more reasonable result.

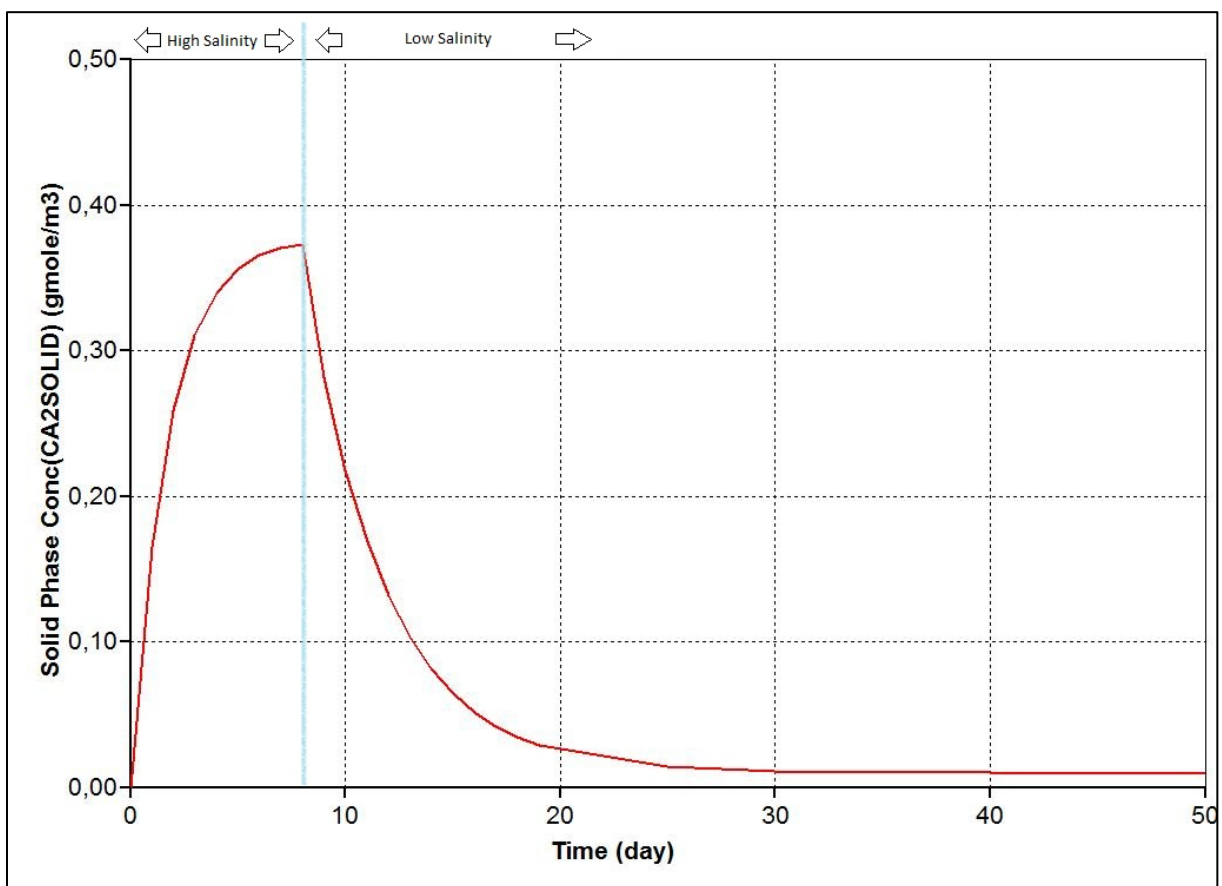


Figure 5.8: Concentration of calcium (CA2SOLID) on the rock versus time.

5.2.5 Oil production

The production behaves a bit different than the “Eclipse 100” simulation. After breakthrough you see an extended production until the low salinity effect comes in. The low salinity effect is faster than the one seen in “Eclipse 100”.

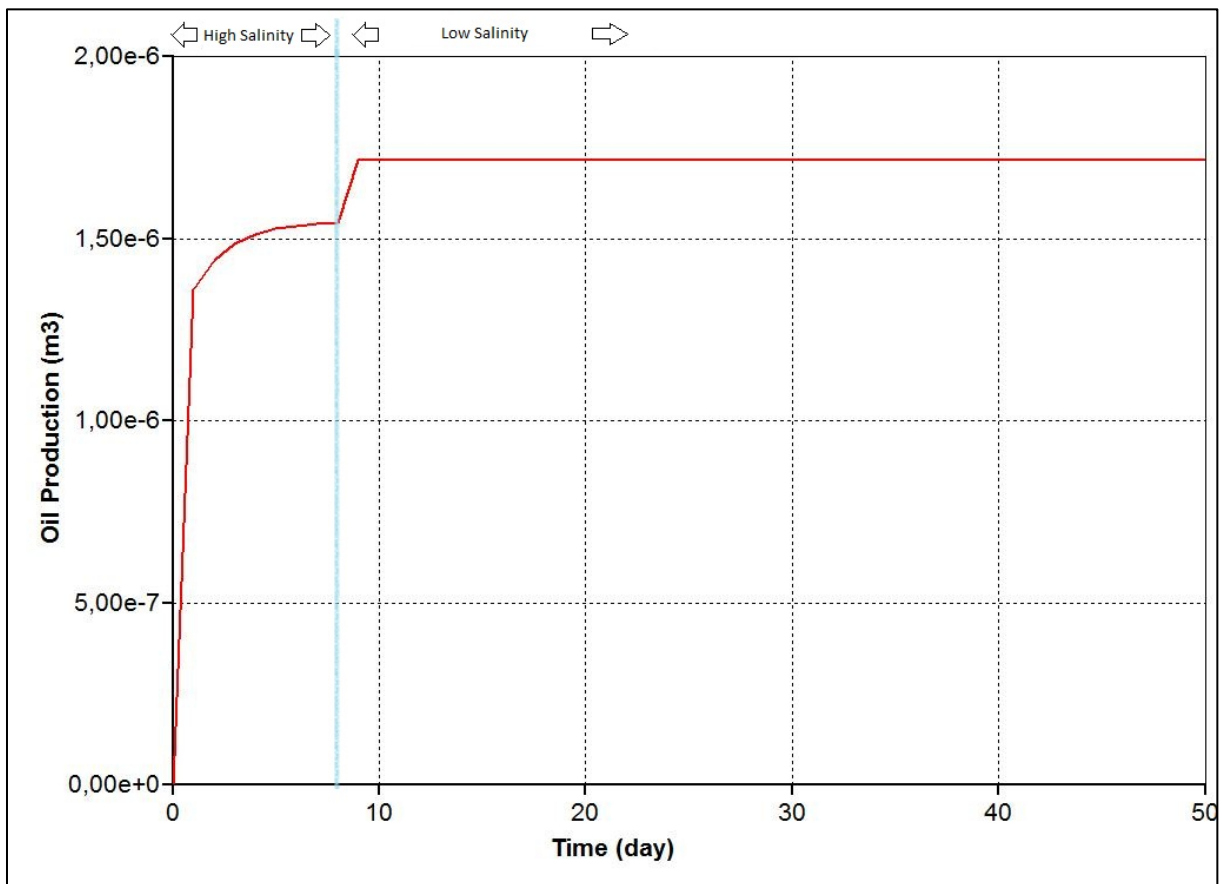


Figure 5.9: Oil production versus time

6 Discussion

6.1 Evaluation of Eclipse

Eclipse is a popular simulator and many oil companies use it. This means that a lot of people have knowledge and experience in the use of it. It would be easy to test current reservoir models with low salinity water flooding if Eclipse would integrate the new proposed method of modeling of the low salinity effect.

If the reservoir has characteristics that will make the Jerauld et al. model (2008) valid it will be a good choice for a simulator. This is because of the competency and widespread use of the simulator.

Interpolating and changing of relative permeability curves based on salt concentration is not the same as the model proposed by Omekeh et al. (2012). It should be fairly straight forward to integrate a model that changes relative permeability based on desorption of ion from the rock surface. Eclipse already has an ion exchange model in the software. They could make the change of relative permeability curves dependent on the ion exchange of certain ions. Then the model would be closer to the model by Omekeh et al. (2012).

A decrease in salinity does not mean that ion on the surface is desorbed. The composition of the low salinity water is also important. If the low salinity water has only Ca^{2+} in the composition then it can be that no Ca^{2+} and extra oil will be released from the clay. This is the weakness in having the change of relative permeability dependent on the salinity and not the ion exchange of the ions that trap the oil.

6.2 Evaluation of STARS

STARS have more options than Eclipse on custom reservoir simulation. In STARS you can define your own components and their characteristics. You can also define how they react. The STARS software has a good graphical interface to use when programming the simulations. This is a good assistant in the use of the simulation.

STARS is not as widespread as Eclipse. It is however used by a lot of people.

The use can be more complicated than Eclipse since it is based on a lot of custom design of effects. STARS uses less built in functions than Eclipse. This requires a deeper understanding of processes to set up simulations, which is not necessarily bad.

The STARS software was not able to interpolate based on a solid concentration. This should be easy for CMG to reprogram. If this change is done then STARS can base the change of relative permeability curves on the ion exchange instead of salinity.

6.3 Recommendation for further work.

Schlumberger (owner of Eclipse) should try to look into possibilities to create a low salinity function based on the modeling work of Omekeh et al. (2012). They do already have an ion exchange model included. I did not use it because I only used one salt. If they would allow for the interpolation to be based on the ion exchange of certain ion, you would have a good representation of the multicomponent ion exchange theory (MIE).

CMG should add the possibility to interpolate the relative permeability curves on the concentration of a solid component in STARS.

The following simulation work can be done on each of the simulators in the current editions:

- Simulate more core experiments to verify tuning.
- Include more ions.
- Simulate at larger scale when tuning at core scale is good and matches core experiments.
- They can be used if they can predict the results from Omekeh et al. (2012) model, core experiments or production history of a field.

7 Conclusions

Eclipse uses the Jerauld et al. (2008) model, which can be used if the model can predict results done with the Omekeh et al (2012) model. This can happen on some examples where the relative permeability curves change a way that makes the ion exchange and the change in salinity have the same effect in the interpolation of the relative permeability curves.

The work of using the desorption of ion to change the relative permeability curves was hindered in STARS due to the fact that it could not link it to the concentration of a solid component, only components in the oil, water or gas phase. STARS can also be used to simulate the same effect as the Jerauld et al. (2008) model.

“Eclipse 100” is not able to recreate the effect modeled by Omekeh et al. (2012) with the current software edition.

STARS was not either able to recreate the effect modeled by Omekeh et al. (2012) with the current software edition. It does however seem like a less effort for STARS to make a change so it can be done than it is for “Eclipse”.

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APPENDICES

A1 Eclipse data file

RUNSPEC =====

TITLE

Jari Kunnas thesis sim

OIL

WATER

BRINE

LOWSALT

METRIC

DIMENS

40 1 1 /

START

1 'JAN' 2012 /

-- Well dimensions

WELLDIMS

2 1* 1* 2 /

TABDIMS

2 2 /

GRID =====

INIT

DX

40*0.002 /

DY

40*0.01 /

DZ

40*0.01 /

PERMX

40*150 /

PERMY

40*150 /

PERMZ

40*150 /

PORO

40*0.279 /

TOPS

40*1 /

MINPV

0 /

PROPS =====

ROCK

68 0 /

/

LSALTFNC

--kg/m3

0.05931544 1.0 1*

5.929139 0.0 1* /

/

DENSITY

870 999 1* /

/

-- PVT data for oil. pressure [bar] - Bo [rm3/sm3]- viscosity [cp]

PVDO

0 1.01 8

68 1.0 8 /

/

-- PVT data for water with salt present

PVTWSALT

68 5.929139 /

5.929139 1 0 1 0 /

/

/

-- Saturation functions

SWOF

--Sw -Krw - Kro - Pcow

0.15 0 0.75 0

0.2 0.01 0.58 0

0.3 0.03 0.3 0

0.4	0.07	0.15	0
0.5	0.12	0.05	0
0.6	0.2	0.01	0
0.7	0.3	0	0 / --table 1 high salinity
0.15	0	0.9	0
0.2	0	0.78	0
0.3	0.01	0.55	0
0.4	0.025	0.35	0
0.5	0.05	0.2	0
0.6	0.1	0.1	0
0.7	0.2	0.05	0
0.85	0.4	0.0	0 / --table 2 low salinity

REGIONS =====

SATNUM

40*1 /

LWSLTNUM

40*2 /

SOLUTION =====

PRESSURE

40*68 /

SWAT

40*0.15 /

--Salt concentration versus depth table

SALTVD

0 5.929139

1 5.929139 /

SALT

--salt concentration initial(FW) kg/m3

40*5.929139 /

SUMMARY =====

-- Field salt production rates and totals

FSPR

FSPT

-- Field salt injection rates and totals

FSIR

FSIT

-- Field salt production and injection concentrations

FSPC

FSIC

-- Field salt in place

FSIP

-- Group salt production and injection rates

--GSPR

--'G' /

--GSIR

--'G' /

-- Well salt production and injection rates

WSPR

'PRODUCER' /

WSIR

'INJECTOR' /

-- Block salt concentration

--BSCN

--1 1 1 /

--/

FOPR

FOPT

FWPR

FWPT

FWIR

FWCT

BOSAT

1 1 1 /

40 1 1 /

/

FOSAT

BKRO
1 1 1 /
40 1 1 /
/

BKRW
1 1 1 /
40 1 1 /
/

SCHEDULE =====

-- Well specification data

WELSPECS

'PRODUCER' 'G' 40 1 1 'LIQ' /

'INJECTOR' 'G' 1 1 1 'WAT' /

/

COMPDAT

'PRODUCER' 40 1 1 1 'OPEN' 2* 0.001 /

'INJECTOR' 1 1 1 1 'OPEN' 2* 0.001 /

/

WCONPROD

'PRODUCER' 'OPEN' 'BHP' 5* 34 /

/

GCONINJE

'FIELD' 'WATER' 'RATE' 0.00007052841 /

/

WCONINJE

'INJECTOR' 'WATER' 'OPEN' 'GRUP' 2* 1000000 /

/

-- Salt concentration for injection well kg/m³

WSALT

'INJECTOR' 5.929139 /

/

-- Time-step data

TSTEP

1*8 /

-- Salt concentration for injection well kg/m³

WSALT

'INJECTOR' 0.059315 /

/

-- Time-step data

TSTEP
1*80 /

END

A2 STARS DATA FILE

```
** ===== INPUT/OUTPUT CONTROL =====  
** 2012-05-11, 10:55:07 AM, roman  
** 2012-05-11, 11:05:37 AM, roman  
** 2012-05-11, 11:14:12 AM, roman  
** 2012-05-11, 11:17:41 AM, roman  
** 2012-05-14, 11:05:29 AM, jaku1  
** 2012-05-21, 2:36:09 PM, jaku1  
** 2012-05-23, 10:46:50 AM, jaku1  
** 2012-06-01, 1:18:59 PM, jaku1  
** 2012-06-04, 3:54:33 PM, jaku1  
RESULTS SIMULATOR STARS 201110
```

```
INTERRUPT STOP  
TITLE1 'TEST'  
TITLE2 'Low salinity water flooding'  
TITLE3 'Jari Experiment #1'
```

```
*INUNIT *SI  
OUTPRN GRID FRCFLOW KRG KRO KRW PRES RFG SG SO SW VISG W  
      Y  
OUTPRN WELL WELLCOMP  
OUTPRN ITER NEWTON  
WRST 500  
WPRN GRID 500  
WPRN ITER 1  
WSRF GRID TIME  
WSRF WELL TIME  
OUTSRF GRID KRINTER KRO KRW PRES SG SO SW TEMP  
OUTSRF WELL DOWNHOLE
```

```
** ===== GRID AND RESERVOIR DEFINITION =====
```

```
*GRID *CART 40 1 1 ** One-dimensional grid
```

```
*DI *CON 0.002 **8cm  
*DJ *CON 0.01  
*DK *CON 0.01  
**$ Property: NULL Blocks Max: 1 Min: 1  
**$ 0 = null block, 1 = active block  
NULL CON      1
```

```
*POR *CON 0.279
```

```
*PERMI *CON 150 **150mD  
*PERMJ *EQUALSI
```

```

*PERMK *EQUALSI
**$ Property: Pinchout Array Max: 1 Min: 1
**$ 0 = pinched block, 1 = active block
PINCHOUTARRAY CON      1

*END-GRID
** ===== FLUID DEFINITIONS =====
** Two aqueous and two noncondensable gas components
**$ Model and number of components
MODEL 4 3 3 2
COMPNAME 'WATER' 'CA2DIS' 'OIL' 'CA2SOLID'
**      -----
CMM
0.018 0.209 0.209 .209
PCRIT
3140.0 480.0 144.0
TCRIT
374.0 -147.0 527.0
KVTABLIM 101.3 1001.3 60 300
**$ Gas-liquid K Value tables
KVTABLE 'WATER'
**$
      0      0
      0      0
** Reference conditions
PRSR 68.0
PSURF 500.0
TSURF 200.0
**$ Surface conditions
**$ Surface conditions
SURFLASH W W O
** Mass density
SOLID_DEN 'CA2SOLID' 0.16469 0 0
MASSDEN
1000 1000 700
AVISC
0 0 0.4
BVISC
0 0 0
**$ Reaction specification
**$ Reaction specification
STOREAC
0 0 0 1
STOPROD
0 1 0 0
RPHASE
0 0 0 4
RORDER
0 1 0 1
FREQFAC 0.3

```

```

RENTH 0
EACT 0
**$ Reaction specification
**$ Reaction specification
STOREAC
0 1 0 0
STOPROD
0 0 0 1
RPHASE
0 1 0 0
RORDER
0 1 0 1
FREQFAC 0.001
RENTH 0
EACT 0

```

```

*ROCKFLUID
RPT 1 WATWET
** ===== ROCK-FLUID PROPERTIES =====
INTCOMP 'CA2DIS' *WATER
*INTLIN
**SET 1 HIGH SALINITY
KRINTRP 1
DTRAPW 0.005929
** Water-oil relative permeabilities
**Sw Krw Kro
**$ Sw krw krow
SWT
  0.15  0  0.75
  0.2  0.01  0.58
  0.3  0.03  0.3
  0.4  0.07  0.15
  0.5  0.12  0.05
  0.6  0.2  0.01
  0.7  0.3  0 ** table 1 high salinity
**$ S1 krg krog
SLT
  0.15  1  0
  1  0  0.75
**SET 2 LOW SALINITY
KRINTRP 2
DTRAPW 0.00005929
** Water-oil relative permeabilities
**Sw Krw Kro
**$ Sw krw krow
SWT
  0.15  0  0.9
  0.2  0  0.78
  0.3  0.01  0.55

```

0.4	0.025	0.35
0.5	0.05	0.2
0.6	0.1	0.1
0.7	0.2	0.05
0.85	0.4	0.0 ** table 2 low salinity

**\$ SI krg krog

SLT

0.15	1	0
1	0	0.9

*INITIAL
VERTICAL OFF

INITREGION 1

** ===== INITIAL CONDITIONS =====

*PRES *CON 68.0 **68BAR
*TEMP *CON 80
**\$ Property: Water Saturation Max: 0.15 Min: 0.15
SW CON 0.15
**\$ Property: Oil Saturation Max: 0.85 Min: 0.85
SO CON 0.85
**\$ Property: Water Mole Fraction(CA2DIS) Max: 0.005929 Min: 0.005929
MFRAC_WAT 'CA2DIS' CON 0.005929
**\$ Property: Water Mole Fraction(WATER) Max: 0.994071 Min: 0.994071
MFRAC_WAT 'WATER' CON 0.994071
**\$ Property: Initial Solid Concentration(CA2SOLID) (gmole/m3) Max: 0.000148 Min:
0.000148
CONC_SLD 'CA2SOLID' CON 0.000148
**\$ Property: Oil Mole Fraction(OIL) Max: 1 Min: 1
MFRAC_OIL 'OIL' CON 1

*NUMERICAL

** ===== NUMERICAL CONTROL =====

*TFORM ZT
*ISOTHERMAL

*DTMAX 2.0
*SORDER *RCMRB

*RANGECHECK *OFF
NORM PRESS 10 ZO 0.05 ZNCG 0.4 ZAQ 0.4
CONVERGE PRESS 0.01 ZO 0.001 ZNCG 0.001 ZAQ 1e-005
*RANGECHECK *ON

*RUN

** ===== RECURRENT DATA =====

*TIME 0

*DTWELL .05
**
** *WELL 1 'INJTR' ** Well list
**\$
WELL 'INJTR'
** *WELL 2 'PRODN'
**\$
WELL 'PRODN'
PRODUCER 'PRODN'
OPERATE MAX BHL 5. CONT REPEAT
** LINEAR PRESSURE DROP
** I J K
**\$ rad geofac wfrac skin
GEOMETRY K 1. 1. 1. 0.
PERF TUBE-END 'PRODN'
**\$ UBA ff Status Connection
1 1 1 1. OPEN FLOW-TO 'SURFACE'
**
INJECTOR UNWEIGHT 'INJTR'
INCOMP WATER 0.994071 0.005929 0.
OPERATE MAX STW 7.05284e-005 CONT REPEAT
*GEOMETRY K 1 1 1 0 ** LINEAR PRESSURE DROP
** I J K WI
** WI?
PERF WI 'INJTR'
**\$ UBA wi Status Connection
40 1 1 4917.5 OPEN FLOW-FROM 'SURFACE'
TIME 1
TIME 2
TIME 3
TIME 4

** Obtain printouts and results at the following times

*TIME 5
TIME 6
TIME 7
TIME 8
**\$
WELL 'INJTR'

**
INJECTOR UNWEIGHT 'INJTR'
INCOMP WATER 0.999940334 5.96656377e-005 0.
OPERATE MAX STW 7.05284e-005 CONT REPEAT
TIME 9
TIME 10
TIME 11
TIME 12
TIME 13
TIME 14
TIME 15
TIME 16
TIME 17
TIME 18
TIME 19
*TIME 25
TIME 30
*TIME 50
*TIME 100
*TIME 150
*TIME 200
*TIME 250
*TIME 300
*TIME 350

*TIME 400.0
*STOP

RESULTS SPEC 'Initial Solid Concentration\$C' 'CA2SOLID'
RESULTS SPEC SPECNOTCALCVL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.000148
RESULTS SPEC SPECKEEMOD 'YES'
RESULTS SPEC STOP

RESULTS SPEC 'Oil Mole Fraction\$C' 'OIL'
RESULTS SPEC SPECNOTCALCVL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0

RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 1
RESULTS SPEC SPECKEEMOD 'YES'
RESULTS SPEC STOP

RESULTS SPEC 'Water Mole Fraction\$C' 'WATER'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.994071
RESULTS SPEC SPECKEEMOD 'YES'
RESULTS SPEC STOP

RESULTS SPEC 'Water Mole Fraction\$C' 'CA2DIS'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.005929
RESULTS SPEC SPECKEEMOD 'YES'
RESULTS SPEC STOP

RESULTS SPEC 'Permeability J'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC EQUALSI 0 1
RESULTS SPEC SPECKEEMOD 'YES'
RESULTS SPEC STOP

RESULTS SPEC 'Permeability K'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC EQUALSI 0 1
RESULTS SPEC SPECKEEMOD 'YES'
RESULTS SPEC STOP

RESULTS SPEC 'Oil Saturation'
RESULTS SPEC SPECNOTCALCVAL -100000
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.85
RESULTS SPEC SPECKEEMOD 'YES'
RESULTS SPEC STOP

RESULTS SPEC 'Water Saturation'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.15
RESULTS SPEC SPECKEEMOD 'YES'
RESULTS SPEC STOP

A3 Relative Permeability Curves

High Salinity		
sw	krw	kro
0,15	0	0,75
0,2	0,01	0,58
0,3	0,03	0,3
0,4	0,07	0,15
0,5	0,12	0,05
0,6	0,2	0,01
0,7	0,3	0

Low Salinity		
sw	krw	kro
0,15	0	0,9
0,2	0	0,78
0,3	0,01	0,55
0,4	0,025	0,35
0,5	0,05	0,2
0,6	0,1	0,1
0,7	0,2	0,05
0,85	0,4	0

