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Simulation Study of Enhanced Oil Recovery by ASP (Alkaline, Surfactant and Polymer) Flooding for Norne Field C-segment

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MASTER THESIS

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Abstract

This research is a simulation study to improve total oil production using ASP flooding method based on simulation model of Norne field C-segment. The black oil model was used for simulations.

Remaining oil in the reservoir can be divided into two classes, firstly residual oil to the water flood and secondly oil bypassed by the water flood. Residual oil mainly contains capillary trapped oil. Water flooding only is not able to produce capillary trapped oil so that there is a need for additional technique and force to produce as much as residual oil. One way of recovering this capillary trapped oil is by adding chemicals such as surfactant and alkaline to the injected water. Surfactants are considered for enhanced oil recovery by reduction of oil–water interfacial tension (IFT). The crucial role of alkali in an alkaline surfactant process is to reduce adsorption of surfactant during displacement through the formation. Also alkali is beneficial for reduction of oil-water IFT by in situ generation of soap, which is an anionic surfactant. Generally alkali is injected with surfactant together. On the other hand, polymer is very effective addition by increasing water viscosity which controls water mobility thus improving the sweep efficiency.

In the first place, ASP flooding was simulated and studied for one dimensional, two dimensional and three dimensional synthetic models. All these models were built based on C-segment rock properties and reservoir parameters.

Based on test runs, well C-3H was selected and used as a main injector in order to execute chemical injection schemes in the C-segment. Five studies such as polymer flooding, surfactant flooding, surfactant-polymer flooding, alkaline-surfactant and alkaline-surfactant-polymer flooding were considered in the injection process and important results from simulator were analyzed and interpreted. Sensitivity analyses were done especially focusing on chemical solution concentration, injection rate and duration of injection time.

The polymer flooding project in this study has shown a better outcome compared to water flooding project. Economically best ASP solution flooding case is the flooding with concentration of alkaline at 1.5kg/m³, surfactant at 15kg/m³ and polymer at 0.35 kg/m³ injecting for 5 years. AS flooding case for 4 years with alkali concentration at 0.5kg/m³ and surfactant concentration at 25 kg/m³ gave highest NPV value.

It was found that surfactant flooding has a promising effect and it is more profitable than polymer flooding for the C segment in terms of NPV. Economic sensitivity analysis (Spider diagram) for low case, base case and high case at different oil prices, chemicals prices, and discount rate were also presented. It was found that change in oil price has significant effect on NPV compared to other parameters while polymer price has the least effect on NPV for high and low cases.

Dedication

In the name of Allah, Most Gracious, Most Merciful

This work is dedicated to my respected parents and brother.

May Allah always bless you!

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Nomenclature

M	Mobility Ratio
R _s	Resistance Factor
R _k	Permeability Reduction Factor
R _{rr}	Residual Resistance Factor
λ_w	Water Mobility
λ_o	Oil Mobility
K _{rw}	Water Relative Permeability
K _{ro}	Oil Relative Permeability
μ_o	Oil Viscosity
μ_w	Water Viscosity
q _w	Water Flow Rate
q _o	Oil Flow Rate
ϕ	Porosity
K	Permeability
S _w	Water Saturation
S _o	Oil Saturation
C _p	Polymer Solution Concentration
EOR	Enhanced Oil Recovery
ASP	Alkaline, Surfactant and Polymer
AS	Alkaline and Surfactant
SP	Surfactant and Polymer
IFT	Interfacial Tension
N _c	Capillary Number
NPV	Net Present Value
P _{cow}	Capillary Pressure
S _{orw}	Residual Oil saturation after water flooding
μ_s	Surfactant Viscosity
C _a	Alkaline Concentration
T	Transmissibility
DF	Discount Factor
v	Pore Velocity

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1 Introduction

Oil production period mechanisms can be classified as primary, secondary and tertiary mechanisms. By the development of production time reservoir pressure is dropping, so different methods are used to control pressure and increase production. Most large oil fields are produced with some type of secondary pressure maintenance scheme, such as water flooding, gas flooding etc.

Oil recovery mechanisms and their classifications are shown in Figure 1.

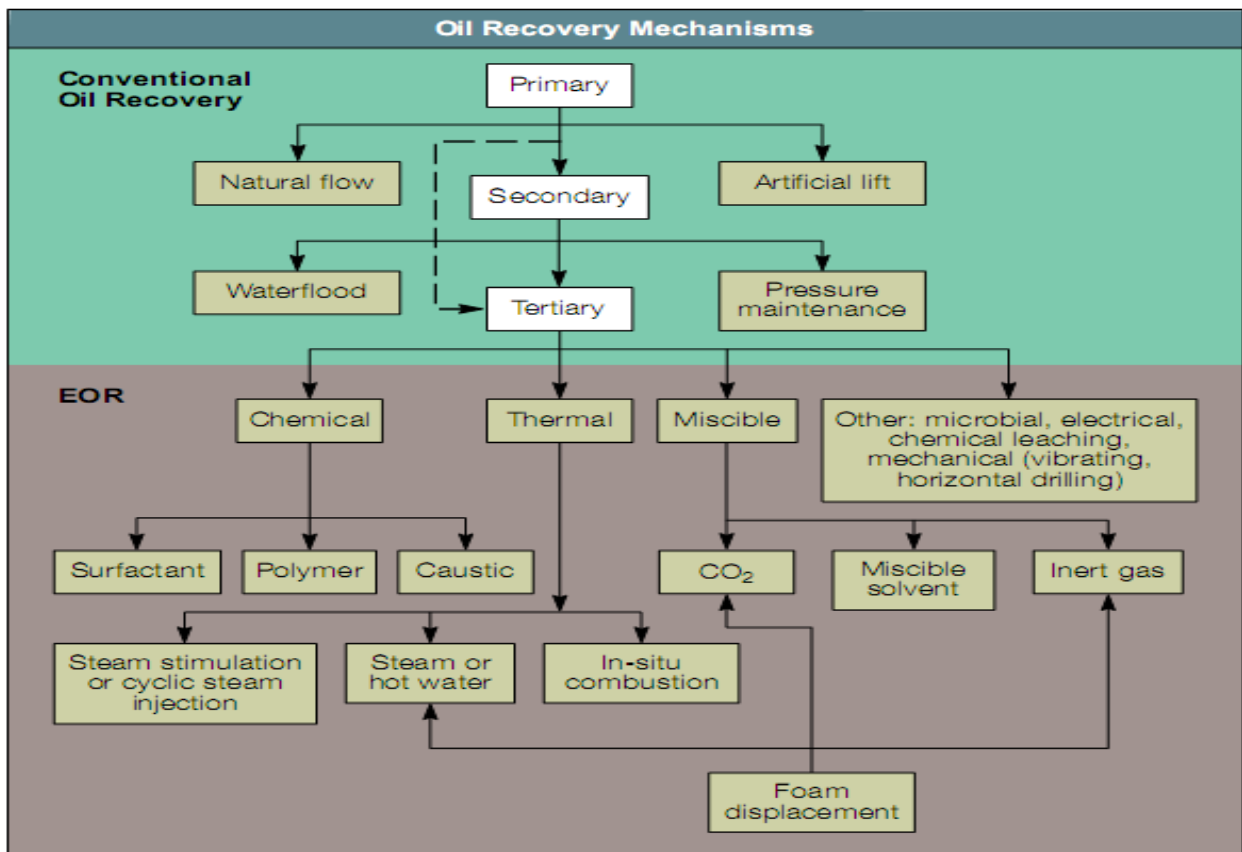


Figure 1: Oil recovery mechanisms (1)

1.1 Enhanced Oil Recovery Methods

EOR methods include two general titled methods of non-thermal and thermal with specific mechanisms for each one. Mainly, non-thermal production methods are widely used for conventional reservoirs.

When secondary oil recovery is not enough to continue adequate production tertiary recovery begins, but only when the oil can still be extracted profitably. This depends on the cost of the extraction method and the current price of crude oil. When prices are high, previously unprofitable wells are brought back into production; when they are low, production is curtailed. Tertiary oil recovery reduces the viscosity of the oil to increase oil production. Application of different kind of chemicals has been found profitable. Combinations of chemicals may be applied as premixed slugs or in sequence. The choice of the method and the expected recovery depend on many considerations, economic as well as technological. Methods for improving oil recovery, in particular those concerned with lowering the interstitial oil saturation, have received a great deal of attention both in the laboratory and in the field. (2)

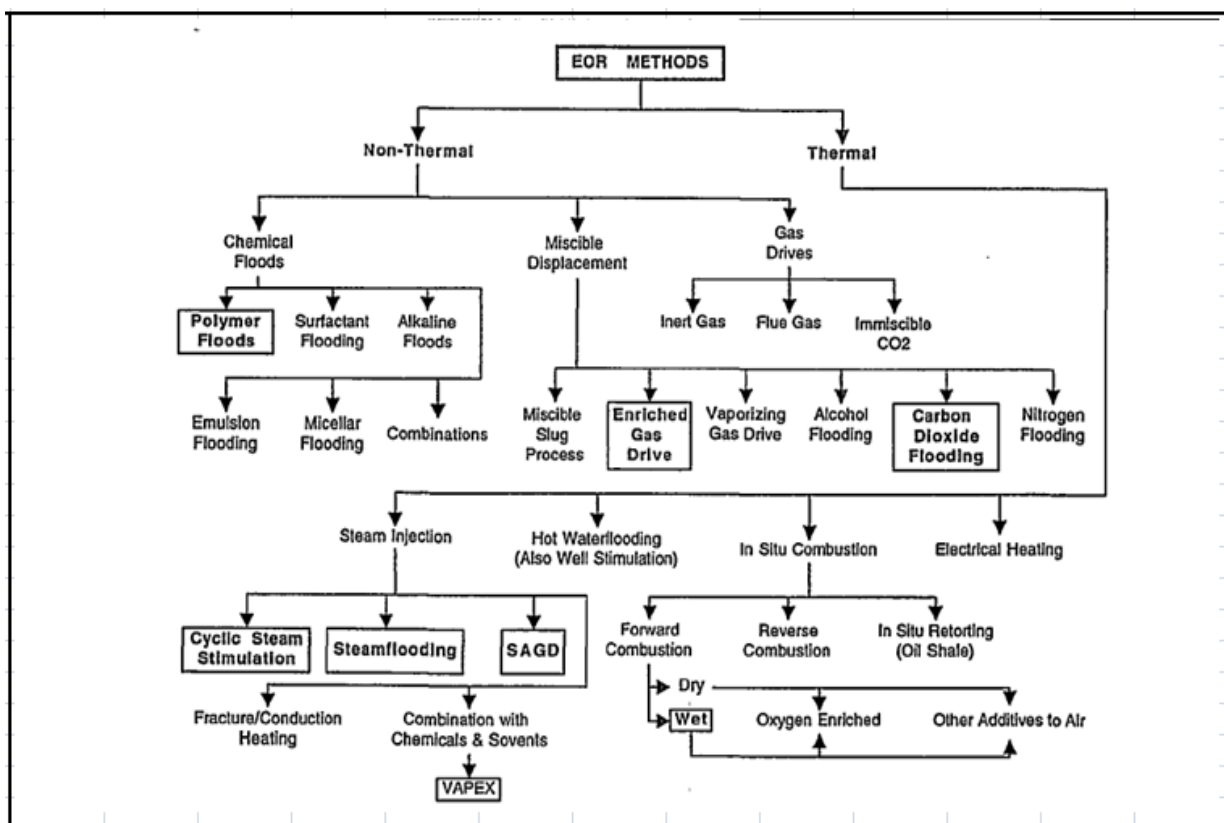


Figure 2: Categorization of EOR methods (3)

Recovery Process		Reservoir Lithology		
		Sandstone	Carbonate	Other ⁽¹⁾
Thermal Methods	Steam Injection ⁽²⁾	513	7	12
	Air Injection	27	10	1
	Hot water	17	-	-
Gas Injection ⁽³⁾	CO ₂	117	92	10
	Hydrocarbon	45	47	25
	N ₂	19	14	2
Chemical Methods ⁽⁴⁾	Alkaline (A)	22	-	-
	Polymer (P) ⁽⁵⁾	267	64	9
	Micellar Polymer (SP)	38	6	-
	S, AP, AS & ASP	27	-	-

(1) Include projects developed in combined lithology (sandstone-carbonate) as well as chalk, diatomite and turbiditic reservoirs.
(2) Include steam stimulation, steamfloods and SAGD projects.
(3) Include Water Alternating Gas (WAG) projects.
(4) Does not include well stimulation with surfactants.
(5) Does not include projects injecting biopolymers.
Source: U.S. DOE/NETL TORIS database, Oil and Gas Journal Bi-Annual EOR Surveys (1980-2004), publications and personal communications.

Figure 3: IOR methods implemented by lithology

1.2 Alkaline Flooding

Alkaline flooding is an enhanced oil recovery method in which an alkaline chemical such as sodium hydroxide, sodium orthosilicate or sodium carbonate is added to injected water. The alkaline chemical reacts with certain types of oils and forms surfactants inside the reservoir. Eventually, the surfactants play a big role to increase oil recovery by reducing interfacial tension between oil and water.

The alkaline agents lead to the displacement of crude oil by raising the pH of the flooding water. The reaction between alkaline and acidic components in crude oil forms in situ surfactant at the oil-brine interface. Then the crude oil is mobilized by the mixture and the mixture removes oil from the pore spaces in the reservoir. Normally, alkaline flooding has been used only in reservoirs containing specific types of high-acid crude oils.

The process can be modified by the addition of surfactant and polymer to the alkali which gives an alkaline-surfactant polymer (ASP) enhanced oil recovery method, essentially a less costly form of micellar-polymer flooding.

Chemical EOR is commercially available under limited conditions such as reservoir characteristics, depth, salinity, and pH level. The high cost of chemicals and reservoir characterization studies needs to be reduced to allow expanded use of chemical enhanced oil recovery methods before full implementation can take place. The addition of silicates is an enhancement to alkaline flooding. The silicates have two main functions:

- 1) It is as a buffer, maintaining a stable high pH level to produce a minimum interfacial tension
- 2) It improves surfactant efficiency through the removal of hardness ions from reservoir brines, thus reducing adsorption of surfactants on rock surfaces.

On the other hand, alkaline flooding is not recommended for carbonate reservoirs because of the profusion of calcium and the mixture between the alkaline chemical and the calcium ions can produce hydroxide precipitation that may damage the formation. (2)

The main profits of alkaline are lowering interfacial tension and reducing adsorption of anionic surfactants that decrease costs and make ASP a very smart enhanced oil recovery process provided the consumption is not too large. By numerical simulation process, the alkaline model can be planned and optimized to ensure the proper propagation of alkali, effective soap and surfactant concentrations to promote low interfacial tension and an encouraging salinity gradient.

Alkaline flooding is a complex process where interfacial tension reduction is not always the key mechanism. Depending on the rock and crude properties, emulsification and wettability alteration can play a major role in oil recovery from mixed-wet naturally fractured carbonates (Liu et al., 2006; Fathi et al., 2008; Zhang et al., 2008). (5)

1.2.1 Mechanisms of Alkaline

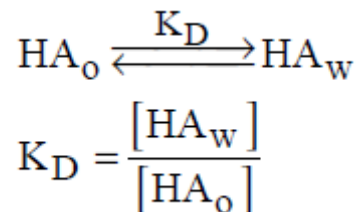
Application of alkaline flooding has four mechanisms

- “Emulsification and Entrainment” in which flowing alkali entrains the crude oil.
- “Wettability Reversal” (Oil-Wet to Water-Wet) in which change of wettability affects change in permeability that makes increase in oil production.
- “Wettability Reversal” (Water-Wet Oil-Wet to) in which we get low residual oil saturation through low interfacial tension.
- “Emulsification and Entrapment” in which movement of emulsified oil improves sweep efficiency.

Right alkali is chosen based on some factors such as price and availability at the flooding area, the PH level, the temperature and mineralogy of the reservoir and composition of the mixed water. (6)

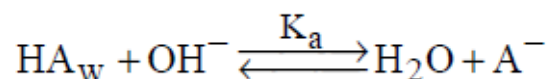
1.2.2 In-Situ Soap Generation

Eventually, soap in situ is generated by reaction of alkali agents such as sodium carbonate with acids in crude oil. Acid number is used as a measure for the possible amount of crude oil to produce soap. The acid number is the quantity of KOH to neutralize the acid in oil expressed in mg KOH/g oil. Fan and Buckley (2006) and Hirasaki (2007) discussed the new protocols for acid number measurements. The making of soap is modeled by the partitioning of acid in the crude oil (HA_o) to water according to the solubility as: (5)

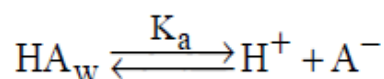


HA_w - the concentration of acid in water, K_D - the partition coefficient.

By the time the acid in water will separate in the aqueous phase to generate soluble anionic surfactant (A^-) referred to as soap according to the expression below:



The reaction above is one of the sources of alkaline consumption since the alkali uses hydrogen to generate soap by the following process:



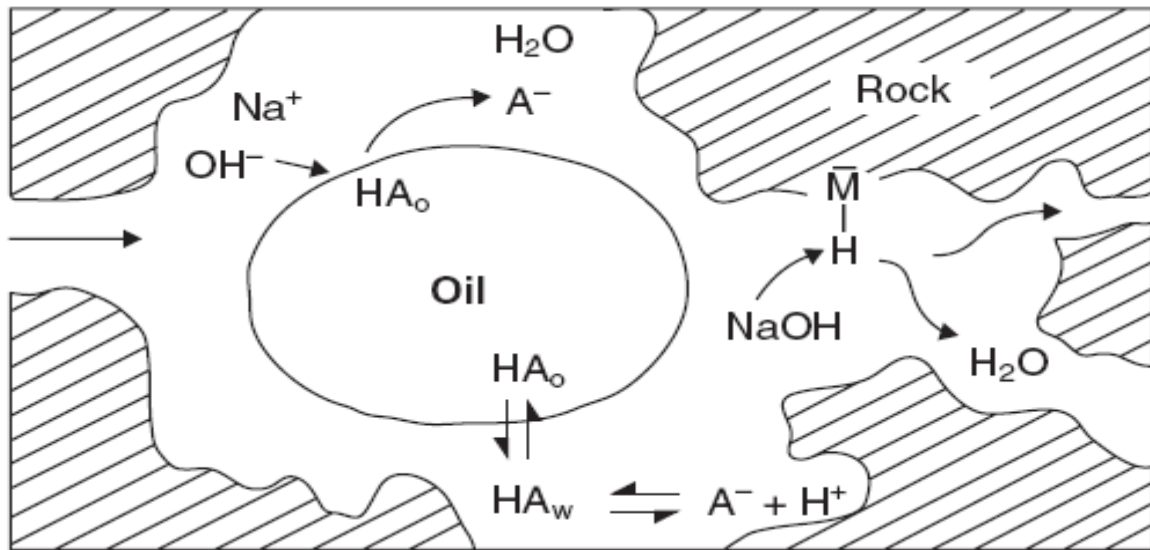
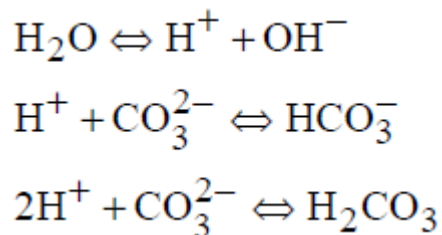


Figure 4: Schematic of alkaline recovery process (7)

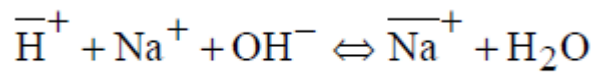
1.2.3 Aqueous Reactions

Buffered reactions can be shown as aqueous reactions. General example of the buffered reactions which are of interest to alkaline flooding process is the carbonate and bicarbonate buffered solutions. (5)



1.2.4 Ion Exchange Reactions with Clay

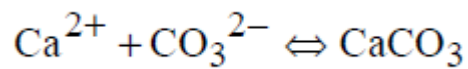
Ion exchange with clays in the rock causes a postponement in chemical breakthrough time where it has the same effect as adsorption. These reactions are relatively rapid reactions and are reversible. The hydrogen/sodium and sodium/calcium are example of key ion exchange reactions. The hydrogen/sodium ion replace can have a big impact on alkali consumption in proportion to the cat ion exchange capacity. (5)



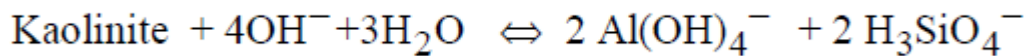
H+ and Na+ are the adsorbed ions on the rock.

1.2.5 Dissolution and Precipitation Reactions

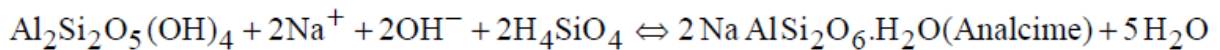
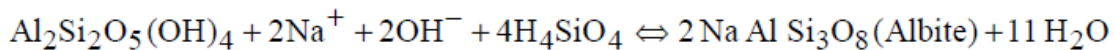
Dissolution and precipitation reactions constitute one of the most important reactions in alkaline flooding. Insoluble salt formation by reaction with hardness ions such as calcium and magnesium as a result of ion exchange from the rock surfaces is example of dissolution and precipitation reactions. These reactions can cause significant loss of alkaline over an extended period of time. (5)



As an example kaolinite, $\text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4$, is found in most sandstone formations. The dissolution of kaolinite at high pH can result in generation of aqueous types such as



Or dissolution of kaolinite can lead to precipitation of albite or analcime:



1.3 Surfactant Flooding

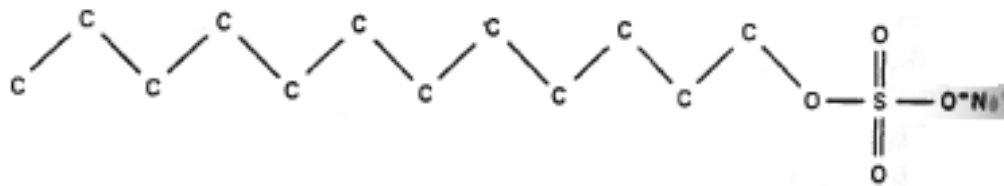
Surfactant flooding is an encouraging enhanced oil recovery method. After a long term water-flooding process, some amount of oil is left trapped in the reservoir due to a high capillary pressure. To get moveable oil, surfactant agents are introduced into the reservoir to increase oil recovery by lowering the interfacial tension between oil and water. Trapped oil droplets are mobilized due to a reduction in interfacial tension between oil. The coalescence of these drops leads to a local increase in oil saturation. An oil bank will start to flow, mobilizing any residual oil in front. Eventually, the ultimate residual oil is determined by interfacial tension between oil and surfactant solution behind the oil collection.

1.3.1 Interfacial tension

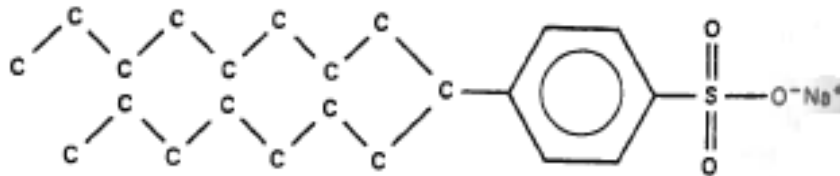
Low interfacial tension (IFT) between crude oil and water is significant for successful enhanced oil recovery by surfactant flooding. Generally, main requirement of alkaline/surfactant processes is targeting of ultralow interfacial tensions. For this purpose, the right surfactant should be selected and evaluated at low and economic concentrations. On the other hand, maintaining low IFT during the displacement process is a critical challenge because of dilution and adsorption effects in the reservoir. Consequently, oil displacement efficiency will be handled by IFT change from the static equilibrium value. The effect of changing IFT on the in-situ behavior of given oil/brine system was studied by carrying out IFT measurements with two surfactants using pre-equilibrated oil/brine/surfactant solutions. To have better understanding of the process, displacement was studied in reservoir and Berea cores. The parameters varied were type and concentration of injected surfactant, slug size and chase fluid. Through the use of the effective IFT concept, the oil displacement efficiency demonstrated good correlation with capillary number. The core flood experiments further suggest that other factors may affect the movement efficiency and should be included in the design of a cost-effective ASP flood. (8)

1.3.2 Structure of Surfactant

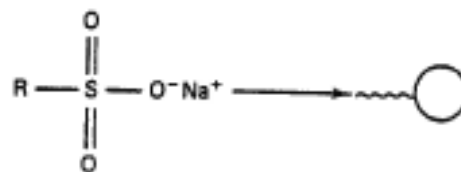
Hydrophilic head group and a lipophilic tail together contains surfactant molecule. The head refers to the solubilizing group – the lyophilic or hydrophilic group in aqueous systems and the tail refers to the lyophobic or hydrophobic group in water. The whole molecule is called an amphiphile telling a dual-nature which makes the surfactant reside at the interface between the aqueous and organic phases, lowering the interfacial tension. The molecular structure is shown in Figure 5. (9)



(a) Sodium dodecyl sulfate



(b) Texas no. 1 sulfonate



R = hydrocarbon group (nonpolar)

(c) Commercial petroleum sulfonates

Figure 5: Structure of molecular surfactant (10)

1.3.3 Surfactants types and some materials

During surfactant flooding process general types and some materials in use are follows:

- Anionic Surfactants
- Non-Ionic Surfactants
- Solubilizer
- Chelating Agent
- Cosolvents
- Polymer
- Large Hydrophobe Surfactants
- hydrophobes

1.3.4 Classification of surfactants

Surfactants are classified to some specific types in terms of Ionic nature of surfactants. These species are anionic, nonionic, cationic and amphoteric chemicals. Description for each group is given below.

Anionic

The charge on the molecular head group can be negative, positive and neutral. Anionic surfactants are defined due to negative charge on the head group. This kind of chemicals have some specifications such as stability, reducing IFT, low adsorption character. That is why they can be considered effective chemical EOR components. Some examples can be shown as anionic surfactants like carboxyl (RCOO^-) and sulfonate (RSO_3^-)

Cationic

Cationic surfactants have positive charge compared to anionic surfactants. Addition of cationic surfactants to polymer flooding can increase efficiency by changing wettability.

Nonionic

Due to neutral charge on the head group some surfactant types are called nonionic. For salinity stability analyses nonionic surfactants are highly used

Amphoterics

Amphoterics class consists of two or more of the other classes. The composition of these surfactants can be mixture of anionic, cationic and others.

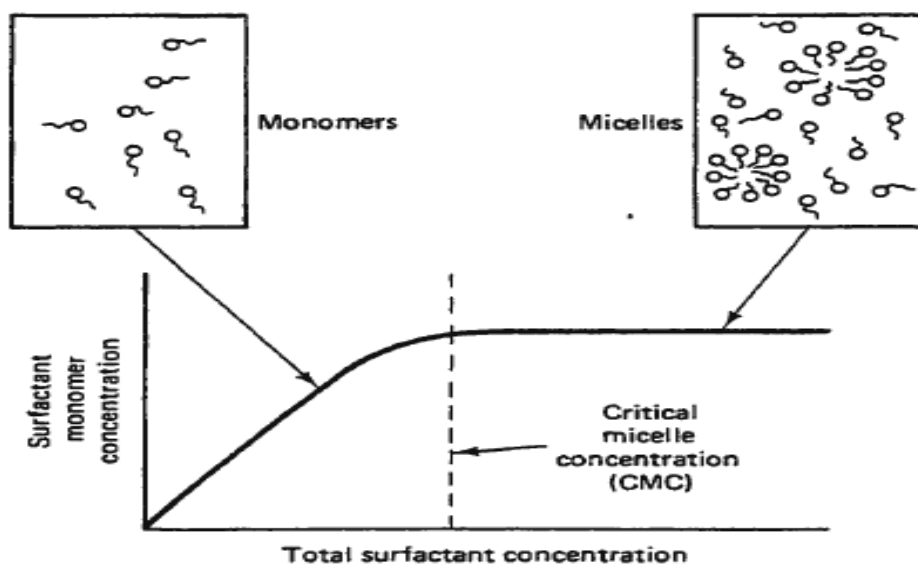


Figure 6: Critical Micelle Concentration (10)

1.3.5 Surfactant flooding potential in the North Sea

Implementing of surfactant injection in the North Sea has been discussed in the SPOR MONOGRAPH mainly for the fields like the Oseberg and Gullfaks. Based on analyses and studies implementing of surfactant project for the North Sea is encouraging and taking economic side for getting higher efficiency and profit it is recommended to inject surfactant early period of time before the reservoir is completely water-flooded. Improved Oil potential for surfactant flooding on the Norwegian continental shelf is estimated to be 100 million Sm³. (11)

1.4 Polymer Flooding

Polymer flooding is an enhanced oil recovery method that uses polymer solutions to increase oil recovery by increasing the viscosity of the displacing water to decrease the water/oil mobility ratio. During polymer flooding, a water-soluble polymer is added to the injected water in order to increase water viscosity. Depending on the type of polymer used, the effective permeability to water can be reduced in the swept zones to different degrees. It is believed that polymer flooding cannot reduce the S_{or} , but it is still an efficient way to reach the S_{or} more quickly or/and more economically. Adding a water-soluble polymer to the water-flood allows the water to move through more of the reservoir rock, resulting in a larger percentage of oil recovery. Polymer gel is also used to shut off high-permeability zones. In the process, the volumetric sweep is improved, and the oil is more effectively produced. Often, infectivity is one of the critical factors. The polymer solution should therefore be a non-Newtonian and shear thinning fluid, i.e., the viscosity of the fluid decreases with increasing shear rate. There are three potential ways in which polymer flooding makes the oil recovery process more efficient:

- Through the effects of polymers on fractional flow.
- By decreasing the water/oil mobility ratio.
- By diverting injected water from zones that have been swept.

The most important preconditions for polymer flooding are reservoir temperature and the chemical properties of reservoir water. At high temperature or with high salinity in reservoir water, the polymer cannot be kept stable, and polymer concentration will lose most of its viscosity. (12)

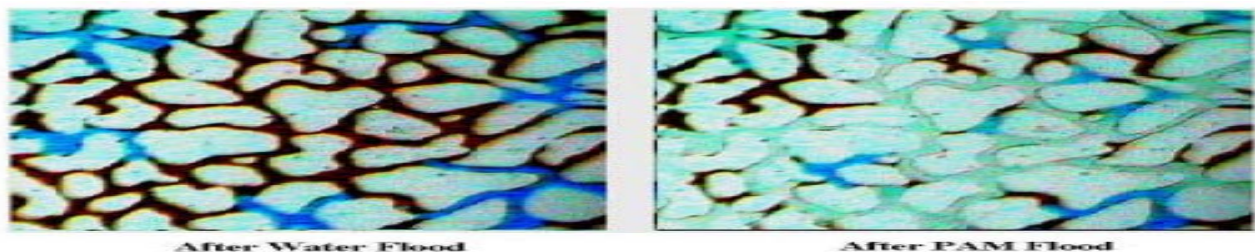


Figure 7: Comparison of oil saturation after polymer flooding and water flooding (13)

1.4.1 Polymer Types

Polymer is a term used to describe a very long molecule consisting of structural units and repeating units connected by covalent chemical bonds. The term is derived from the Greek words: polys meaning many, and “meros” meaning parts. The key feature that distinguishes polymers from other molecules is the repetition of many identical, similar, or complementary molecular units.

There are mainly two types of polymers which might be effective in reduction of mobility ratio:

Polyacrylamides- condensation polymers and their performance depend on the molecular weight and degree of hydrolysis. When partially hydrolyzed, some of the acryl amide is replaced by or converted into acrylic acid. This tends to increase the viscosity of fresh water but reduces the viscosity of hard waters. Polyacrylamides can absorb many times of its mass in water while ionic substances like salt cause the polymer to release some of its water.

They are relatively cheap, develop good viscosities in fresh water, and adsorb on the rock surface to give a long-term permeability reduction. The main disadvantages are their tendency to shear degradation at high flow rates, and their poor performance in high salinity brine.

Biopolymers- A biopolymers are derived from a fermentation process. It has a smaller molecular weight than polyacrylamide. Its molecular structure gives the molecule great-stiffness, a characteristic that gives the biopolymer excellent viscosifying power in high salinity water. However, they have less viscosifying power than polyacrylamide in fresh waters. They have good viscosifying power in high salinity water and good resistance to shear degradation. Also, they are not retained on the rock surface and thus easily propagate into the formation than polyacrylamide, which can reduce the amount of polymer required for a flood.

One of the key parameters which need to be considered in polymer selection are:

- Injectability into the reservoir
- Ability to move through the formation
- Provide required viscosity

(14)

1.4.2 Polymer Parameters

Polymer Solution Viscosity

The polymer solution viscosity is a key parameter to improve the mobility ratio between oil and water and adjust the water intake profile. As injection viscosity increases, the effectiveness of polymer flooding increases. The viscosity can be affected by a number of factors. First, for a given set of conditions, solution viscosity increases with increased polymer molecular weight. Second, increased polymer concentration leads to higher viscosity, and increased sweep efficiency. Third, as the degree of HPAM hydrolysis increases up to a certain value, viscosity increases. Fourth, as temperature increases, solution viscosity decreases. Polymer degradation can also decrease viscosity. Fifth, increased salinity and hardness in the reservoir water also decreases solution viscosity for anionic polymers.

The effectiveness of a polymer flood is directly determined by the magnitude of the polymer viscosity. The viscosity depends on the quality of the water used for dilution. A change in water quantity directly affects the polymer solution viscosity. Normally water quantity changes with the rainfall, ground temperature and humidity during the seasons. The concentrations of Ca^{2+} and Mg^{2+} in the water source are lower in summer and higher in winter. Consequently, the polymer viscosity is also relatively higher in summer and lower in winter.

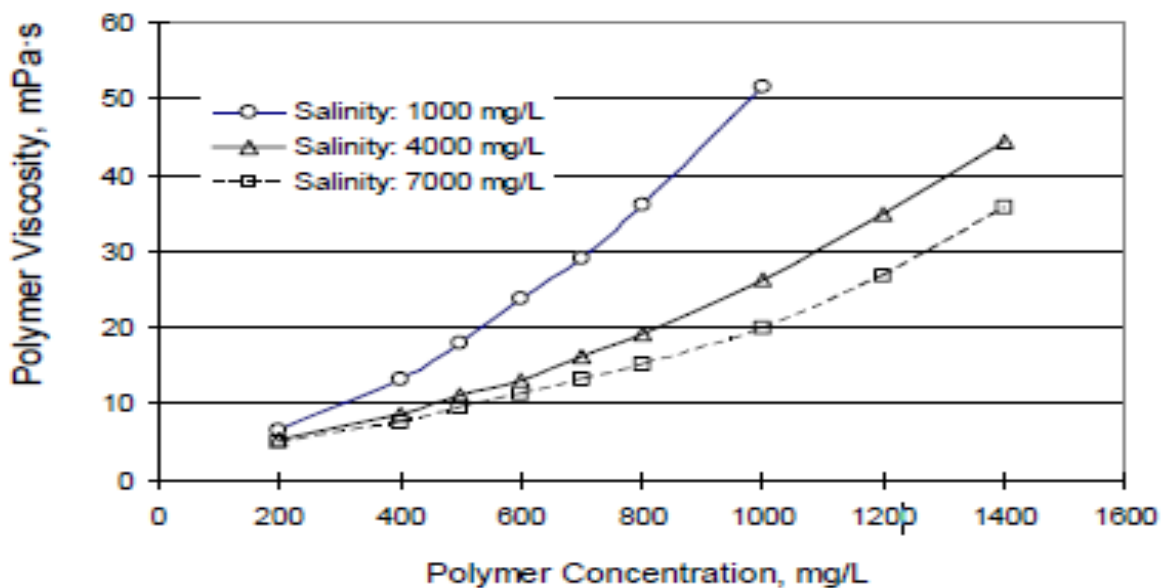


Figure 8: Viscosity versus concentration for different salinities

Two factors should be considered when choosing polymer molecular weight. First, the polymer with highest Mw is practical to minimize the polymer volume. Second Mw must be small enough so that polymer can enter and propagate effectively through reservoir rock. (12)

Polymer Molecular Weight

The effectiveness of a polymer flood is affected significantly by the polymer molecular weight (Mw). As illustrated in Figure 9, polymers with higher Mw provide greater viscosity. For many circumstances, larger polymer Mw also leads to improved oil recovery. Core flood simulation verifies this expectation for cases of constant polymer slug volume and concentration. (12)

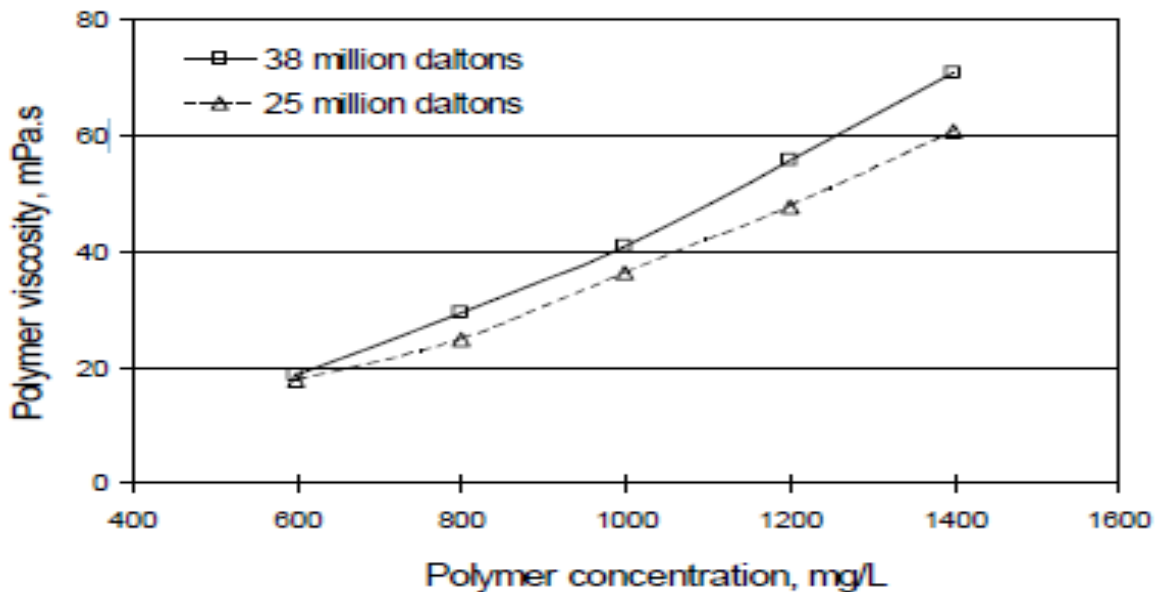


Figure 9: Viscosity versus concentration

Polymer Solution Concentration

The polymer solution concentration dominates every index that changes during the course of polymer flooding.

1) Higher injection concentrations cause greater reductions in water cut and can shorten the time required for polymer flooding. For a certain range, they can also lead to an earlier response time in the production wells, a faster decrease in water cut, a greater decrease in water cut, less required pore volumes of polymer, and less required volume of water injected during the overall period of polymer flooding. As polymer concentration increases, enhanced oil recovery increases and the minimum in water cut during polymer flooding decreases.

2) Above a certain value, the injected polymer concentration has little effect on the efficiency of polymer flooding. For a pilot project, the economics of injecting higher polymer concentrations should be considered. The polymer solution concentration has a large effect on the change in water cut. However, consideration should also be given to the fact that higher concentrations will cause higher injection pressures and lower injectivity. For individual wells, the concentration can be adjusted to meet particular conditions. (12)

1.4.3 Polymer Flooding Effects

Polymer Adsorption

The amount of polymer adsorbed depends on the nature of the polymer and the rock surface. Both physical adsorption of polymer on solid surfaces and polymer retention by mechanical entrapment appear to play a big role in total polymer retention in a reservoir. Generally, three phenomena have been observed regarding polymer adsorption: (1) laboratory tests often indicate higher adsorption than field performance; (2) adsorption is significantly less in consolidated cores than in sand packs; and (3) adsorption increases with increasing water salinity.

Typical field adsorption values range from 20 to more than 500lb/acre-ft. Laboratory adsorption values range from 30 to several hundred mg/gm.¹³ note that laboratory results often cannot be extrapolated to predict polymer adsorption in oil reservoirs, polymer retention is also important. (12, 15)

Polymer Retention

Retention of polymer in a reservoir can result from adsorption, entrapment or with improper application, physical plugging. Polymer retention tests are usually performed a polymer flood oil recovery test. If polymer retention tests are conducted with only water initially present in the core, a higher level of retention will result from the increased surface area available to the polymer solution in the absence of oil. Effluent samples from the core are collected both the polymer injection and a subsequent water flush. These samples are analyzed for polymer content. From a material balance, the amount of polymer retained in the core is calculated. Excessive retention will increase the amount of polymer that must be added to achieve the desired mobility control. The level of polymer retained in a reservoir depends on a number of variables:

permeability of the rock, surface area, nature of the reservoir rock (sandstone, carbonate, minerals, or clays), nature of the solvent for the polymer (salinity and hardness), molecular weight of the polymer, ionic charge on the polymer, and the volume of porosity that is not accessible to the flow of polymer solution. (12, 15)

Inaccessible Pore Volume

Polymer solutions propagate through porous media at a velocity different from that of water because of adsorption and inaccessible pore volume. Adsorption tends to move the front edge of a polymer slug at a slower velocity than the water bank, and inaccessible pore volume tends to move the polymer slug at a higher velocity than the water bank. The combination of the two effects results in a smaller slug that is shifted forward. The phenomenon of inaccessible pore volume was first reported by Dawson and Lantz. They showed that all the pore space may not be accessible to polymer molecules and that this allow be accessible to polymer molecules and that this allows polymer solutions to advance and displace oil at a faster rate than predicted on the basis of total porosity. They also concluded from laboratory

results that about 30% of the total pore volume in the rock samples used was not contacted by the polymer solution.

The inaccessible pore volume can have beneficial effects on field performance. The rock surface in contact with the polymer solution will be less than the total pore a volume, thus decreasing the amount of polymer adsorbed. More importantly, if connate water is present in the smaller pores inaccessible to the polymer, the bank of connate water and polymer-depleted injection water that precedes the polymer bank is reduced by the amount of inaccessible pore volume. However, movable oil located in the smaller pores will not be contacted by the polymer in some cases, and therefore it may not be displaced. (12)

Permeability reduction

Polymer reduces both the effective permeability of porous media and the mobility of displacing fluid the permeability reduction described by a reduction factor R_k :

$$R_k = \frac{K_w}{K_p}$$

Where K_w and K_p are the effective permeability of water and polymer. The mobility, change due to combined effect of increased viscosity and reduced permeability is the Resistance Factor R_r :

$$R_r = \frac{R_k * \mu_p}{\mu_w}$$

$$R_{rr} = \frac{\lambda_p}{\lambda_{p'}}$$

The effect of permeability reduction persists even after the polymer solution has gone through the porous media. This effect is described by the residual resistance factor R_{rr} . (12)

Where λ_p and $\lambda_{p'}$ are the motilities before and after polymer solution, respectively.

Dependence of Polymer behavior on shear rate

Both types of polymer solutions are known to exhibition non-Newtonian, shear-thinning fluid behavior. Shear thinning properties usually can be determined in the laboratory using Brookfield viscometer.

$$ShearRate = C v / \sqrt{K * \phi}$$

However, determination of the viscometric behavior of polymer solutions in reservoirs is more complex because shear rates are not well defined in the rock matrix.

At a given flow velocity or shear rate, the higher the polymer molecular weight is, the greater the mobility reduction will be, The degree of permeability reduction or residual resistance also increases with increasing polymer molecular weight. (12)

Displacing residual Oil in “Dead Ends”

Effect of polymer were studied in a laboratory using a glass etched core model with pore diameter of 250 μ m, the oil in the core was first flushed by water until the water cut was 100%, then glycerin with viscosity of 30cP until 100% water cut, and then finally by polyacrylamide fluid (viscosity 30 cp) until 100 % water cut. The results showed that viscosity alone cannot mobilize the residual oil as shown by the glycerin flooding. However, the polymer fluid mobilized 4 times the amount of residual oil out of the dead ends than the glycerin. The polymer “dragged” the residual oil from the dead ends because of its elastic properties, where the fluids in front can pull the fluid behind and beside it. The elastic properties are lacking in the water and glycerin.

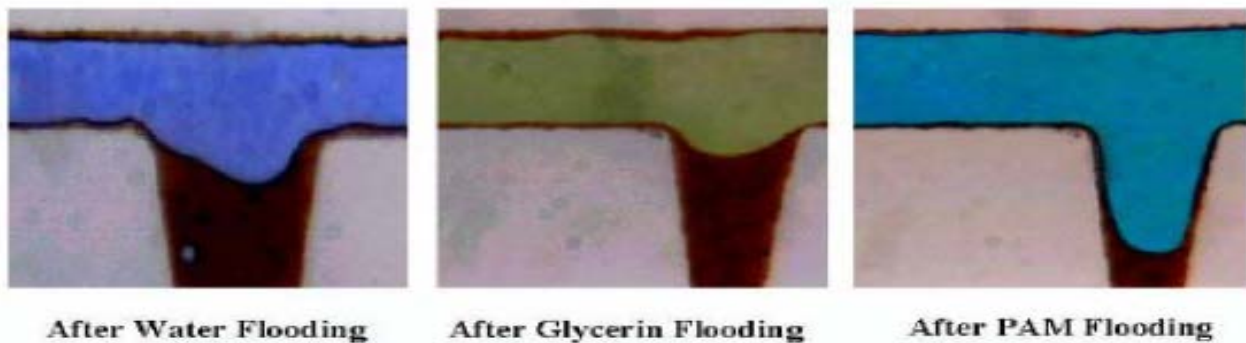


Figure 10: Residual oil in dead ends flushed by water, glycerin, and Polyacrylamide (13)

1.4.4 Mobility Control

During a standard water-flood the sweep efficiency achieved is usually not as good as desired. A fingering effect of the water flooding into the oil bank is usual problem (Figure 11). At the bottom (Figure 12) the use of a polymer has reduced the effect of fingering significantly, and as described above by avoiding fingering i.e. decreasing water saturation behind the front we are achieving piston like displacement and by that volumetric sweep can be improved.

Polymer is often added to the surfactant solution to increase its apparent viscosity giving potential to increase both volumetric sweep efficiency and displacement efficiency.

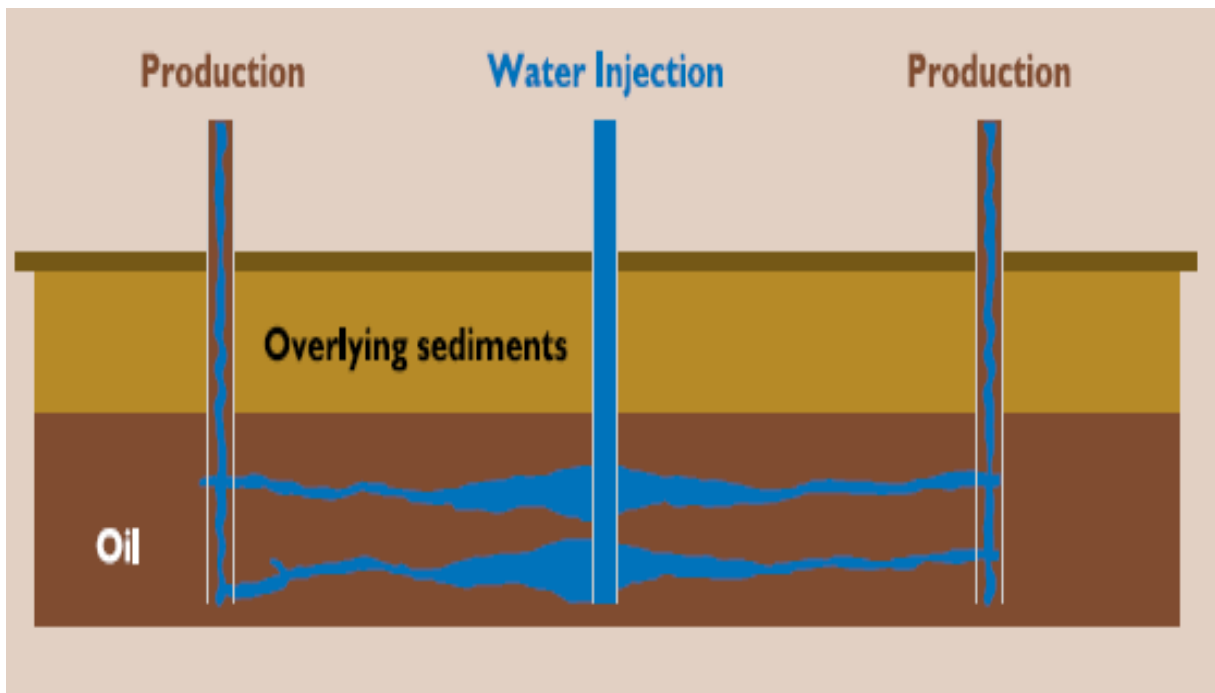


Figure 11: Fingering effect with water flooding

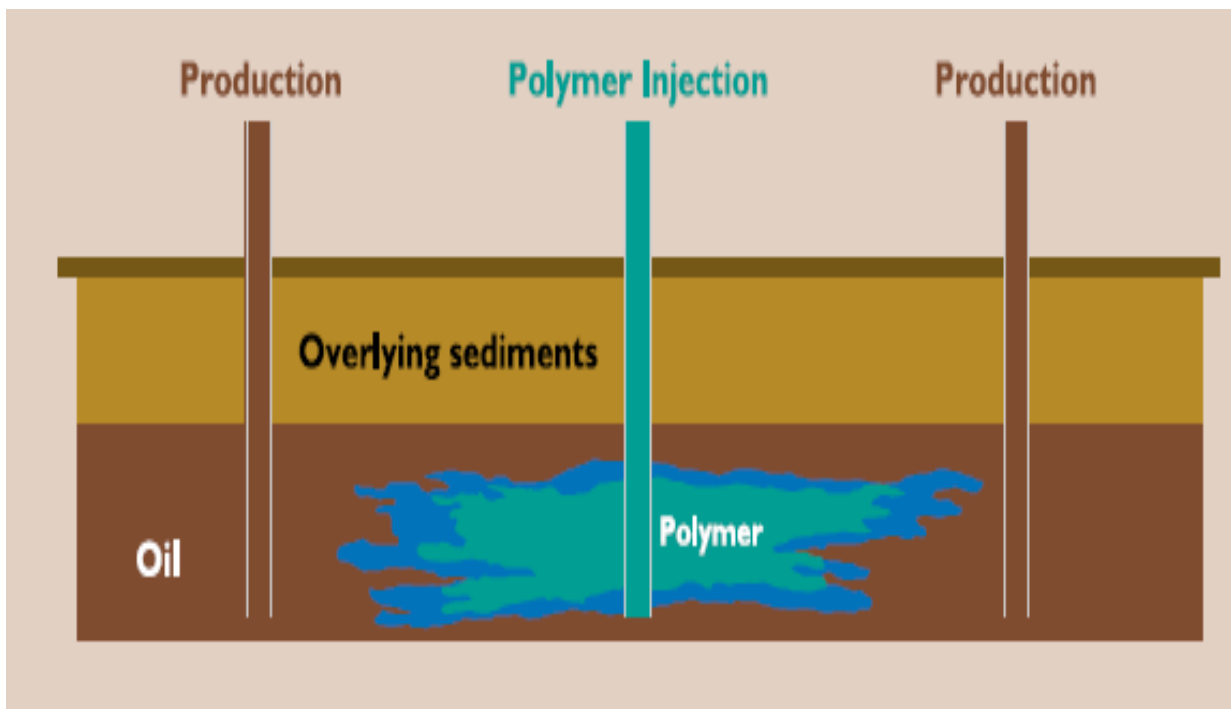


Figure 12: Decreased effect of fingering with polymer flooding

2 Norne Field

The Norne Field is situated approximately 200 km from the Norwegian coastline. It is located on the blocks 6608/10 and 6508/1 in the southern part of the Nordland II area. The water depth in the field zone is nearly 380 m. The main operator of the field is Statoil ASA and Eni Norge AS and Petoro are license partners.

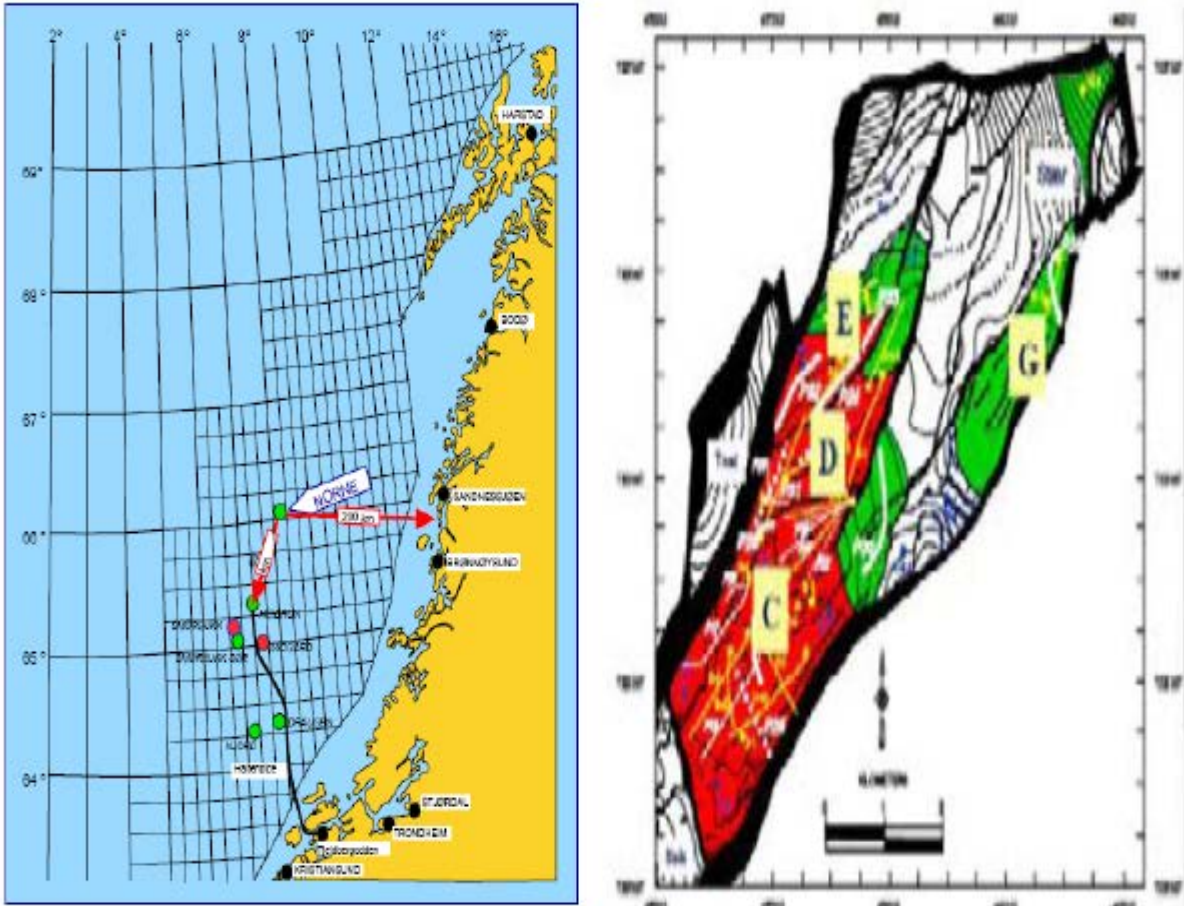


Figure 13: Location of the Norne Field and field segments (16)

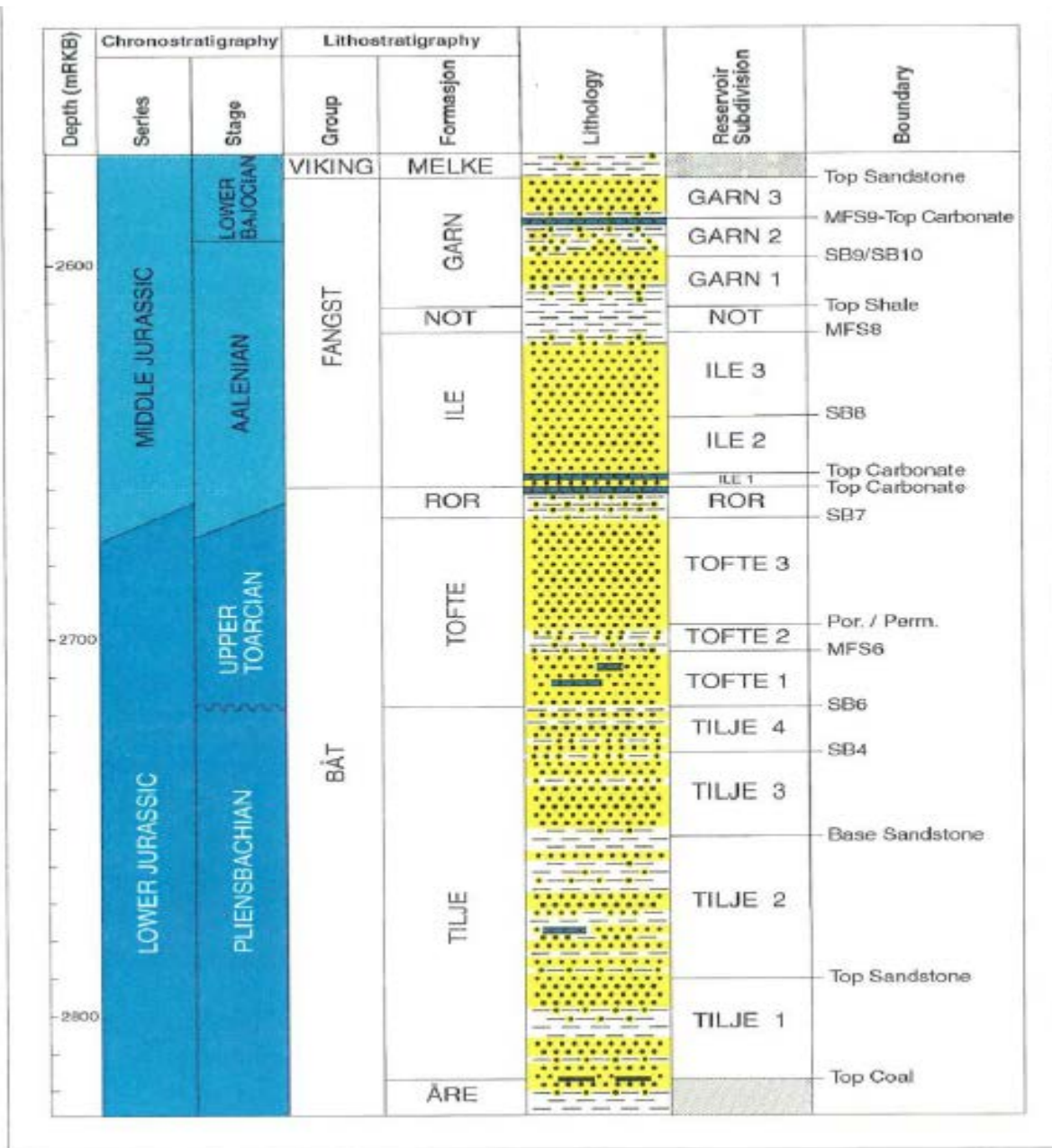


Figure 14: Stratigraphical sub-division of the Norne reservoir

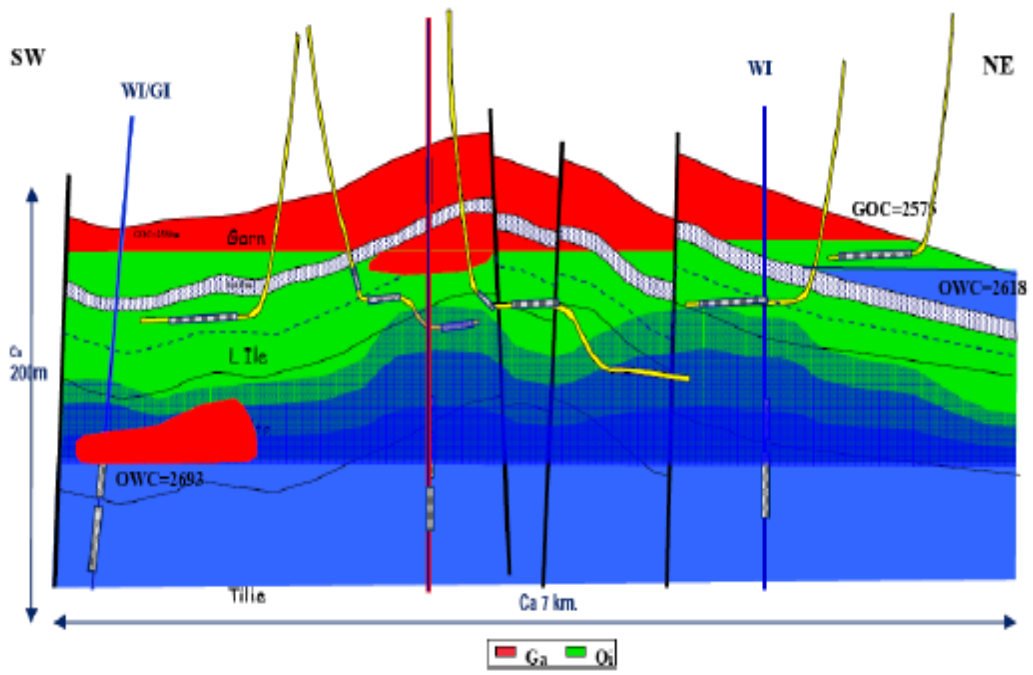


Figure 15: NE-SW cross-section of fluid contacts for the Norne Field (20)

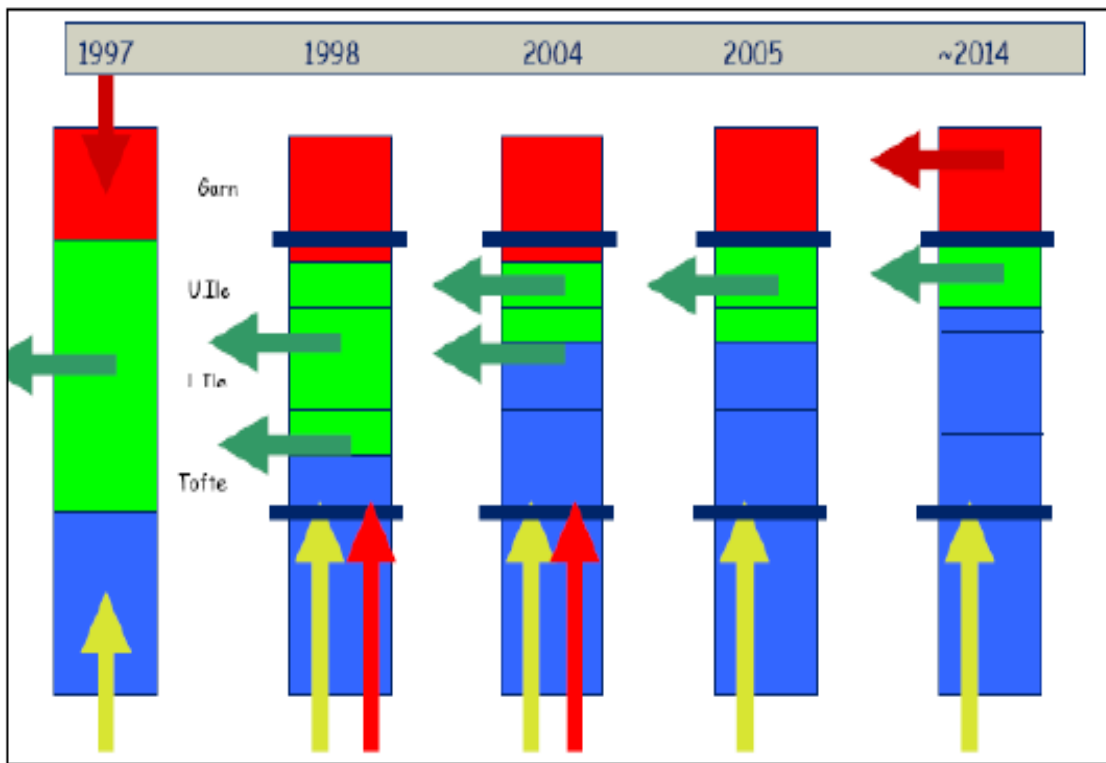


Figure 16: The drainage strategy for the Norne Field from pre-start to 2014 (20)

3 Simulation Results

ASP simulation was done for both synthetic models and for the field model. Three different synthetic models were built based on the field data. Before doing ASP study analyses for field model, simulation was applied to one dimensional, two dimensional and three dimensional models.

3.1 One Dimensional Model

One dimensional model contains 12 grid blocks with dimension of 50m. One producer and one injector were included to the model as shown in Figure 17. Simulation was run for approximately 13 months. Firstly, water was injected for 3 months then it was followed by particularly single chemical and chemical combination flooding for 10 months. In this model, concentration of chemicals is considered such as alkaline at 0.2 kg/m³, surfactant at 0.15 kg/m³ and polymer at 0.2 kg/m³.

As it can be seen from Figure 18 and Figure 19, flooding of two and three solution chemicals at the same time gives higher efficiency than flooding single chemical. Recovery factor is observed between 40% and 50% for AS and ASP solution flooding cases. In one dimensional flow efficiency of polymer seems lower than that of all other chemicals. When it comes to reservoir pressure it is evident that pressure is changing depending on the chemical type. Combination of chemicals leads to relatively higher pressure drop where ASP solution flooding causes lower reservoir pressure compared to highest pressure with surfactant case. Pressure is almost stable during polymer flooding. The main reason for change of pressure should be concentrations of typical chemicals.

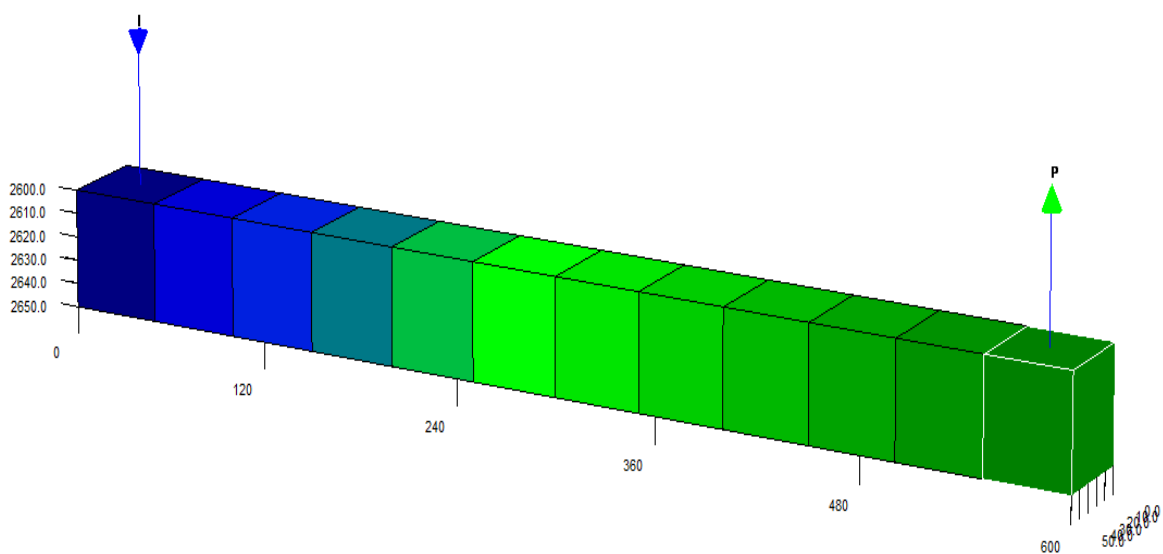


Figure 17: Overview of one dimensional Eclipse model

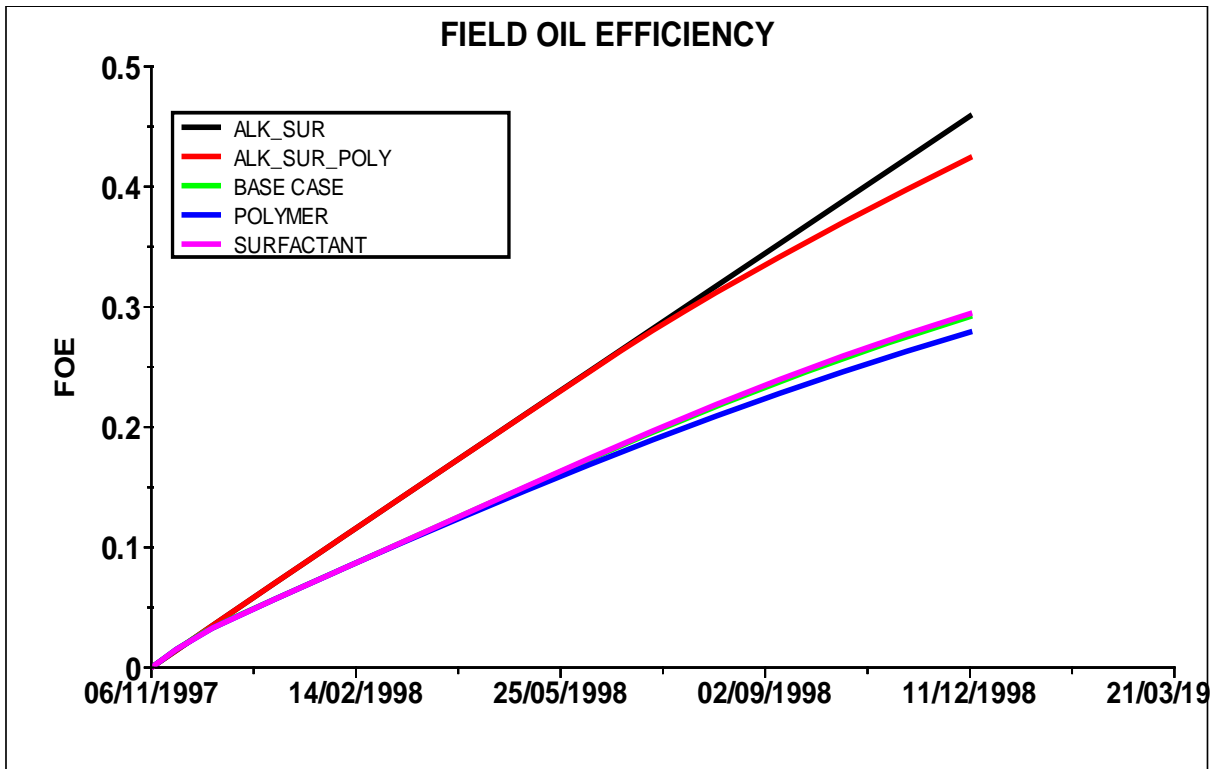


Figure 18: Field Oil efficiency for different chemicals

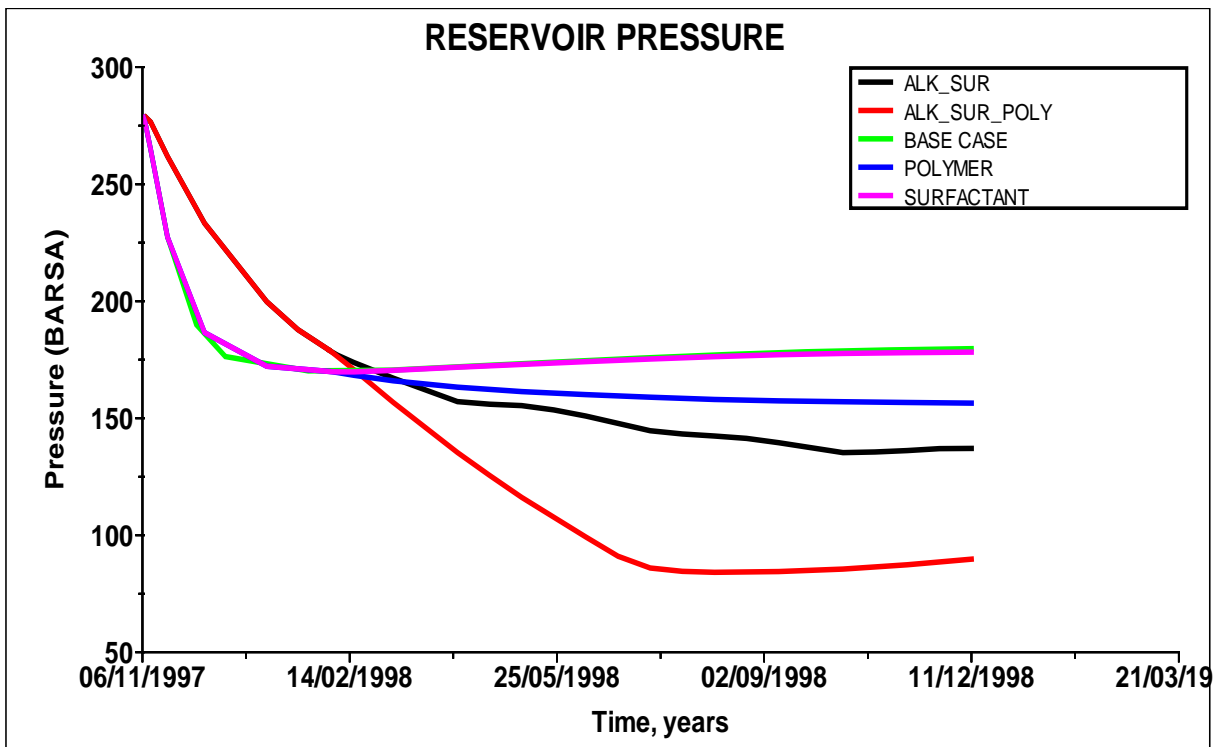


Figure 19: Reservoir pressure for different chemicals

3.2 Two Dimensional Model

Flooding process was investigated in two dimensional model with the same grid properties applied to one dimensional model which was taken from Norne C-segment field model. For new model six new grid blocks were added in Y direction.

From figure 21, ultimate recovery factor is highest for ASP and polymer cases while it is lowest for surfactant flooding case. All chemical together makes better sweep efficiency improving mobility ratio and attendance of surfactant and alkaline causes to produce trapped oil by decreasing interfacial tension (IFT).

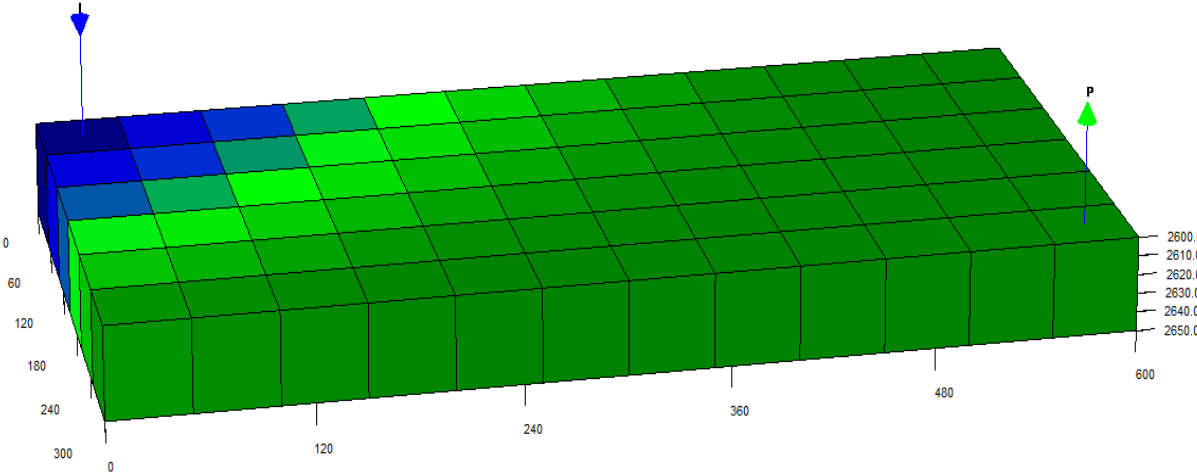


Figure 20: Overview of two dimensional Eclipse model

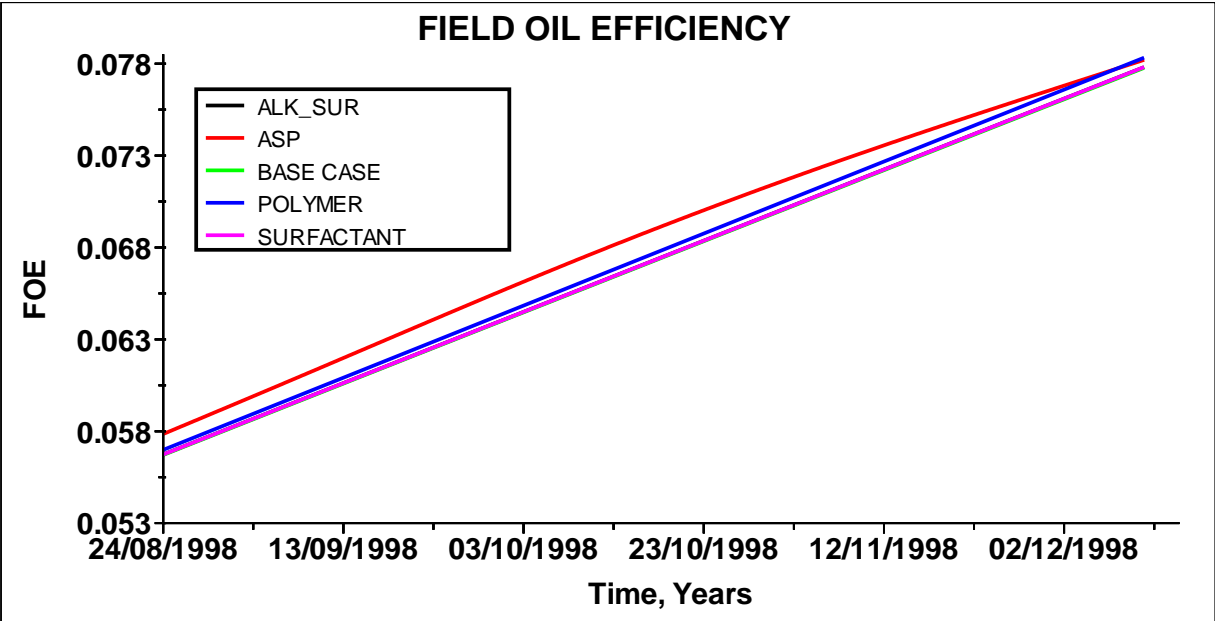


Figure 21: Field Oil Efficiency for different chemicals

3.3 Three Dimensional Model

The effect of ASP chemicals was analyzed for Cartesian synthetic model before applying EOR study for the field model. Purposefully, new Cartesian model was built which contains 12x12x3 grid blocks with the porosity of 0.30. The model is homogeneous in all directions.

Injection was controlled by injector bottom-hole pressure so the pressure was set to 325bar. Chemical cases such as surfactant, polymer, AS and ASP flooding for 10 months was simulated after 3 months' pre-water injection.

From simulation results, we can see that all chemical flooding cases perform efficiently in comparison to base case, but only polymer flooding case has lower efficiency in terms of oil recovery. Even based on one dimensional flow model analyses polymer was found poor effective chemical. ASP combination flooding leads to highest oil recovery and lowest water cut improving volumetric sweep efficiency and having less fingering effect.

These flooding cases carried out for the synthetic model gave general overview of how EOR works with different special chemicals' behavior. The application of ASP study on the field model will be discussed in details later.

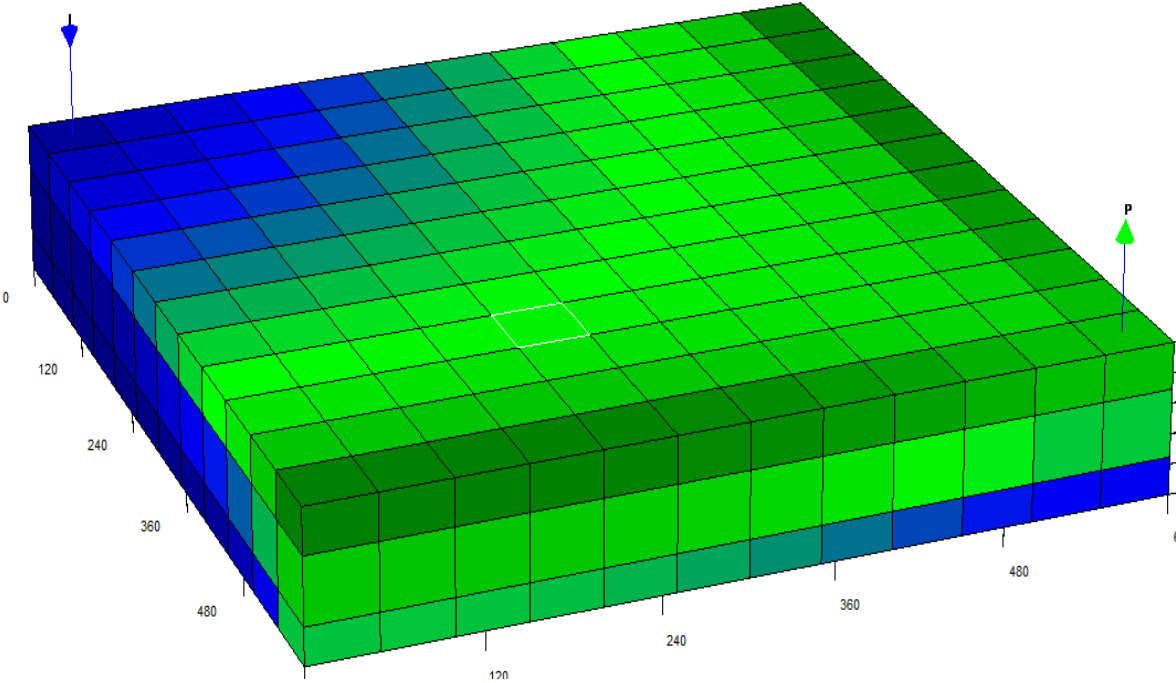


Figure 22: Overview of three dimensional Eclipse model

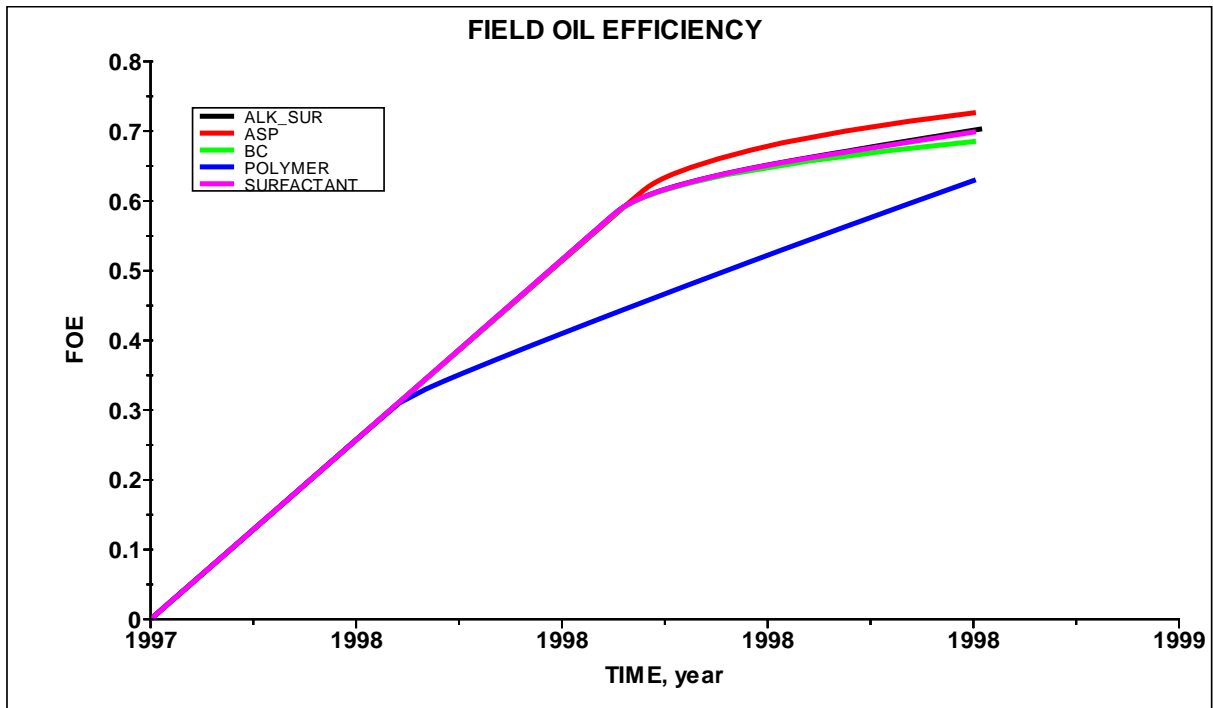


Figure 23: Field Oil Efficiency for different chemicals

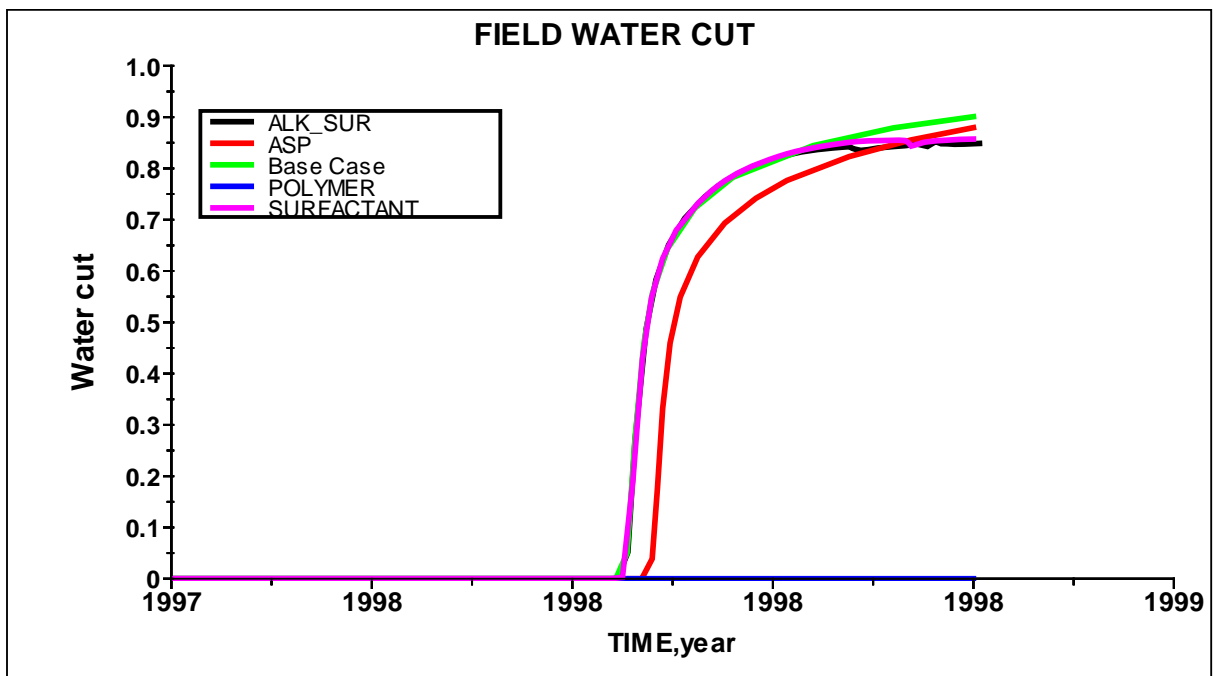


Figure 24: Waster-Cut for different chemicals

3.4 Simulation for C-Segment Field Model

Chemical studies and sensitivity analyses will be looked through to investigate ASP flooding method in the field scale. Firstly we need optimal injector for chemical injection. Since the injector has been chosen ASP will be applied with different parameter sensitivity analyses.

3.4.1 Injection Well Selection

Norne C-segment has 13 active wells including 9 producers and 4 injectors. Firstly, all these wells were combined using well grouping option in Eclipse simulator. Most amount of the oil reserve on the Norne main structure is located in the Ile and Tofte formations. For chemical EOR investigation we need proper injector between these wells. Evaluation cases for selection of injection well to implement future ASP project simulation study was applied to all injectors through flooding of surfactant and polymer with the same injection rate to make decision on optimal injector.

Producers	Year started to produce	Injectors
B-2H	desember 1997	C-1H
D-1H	november 1997	C-2H
D-2H	desember 1997	C-3H
B-4H	april 1997	C-4H
D-4H	juni 1998	
B-1H	april 1999	
D-1CH	november 2003	
B-4DH	juli 2004	
K-3H	oktober 2006	

Figure 25: C-Segment production and injection wells

As it can be seen from Figure 25 we have 4 injectors in C-segment, in the first place, surfactant properties and relevant keywords were included to eclipse data file and continuous surfactant was injected for 4 years through each injection well to compare well's effect based on filed simulation model's production performance. The wells were added in 2005 injecting surfactant with concentration of 15kg/m³ until the end of 2008, and then only water was injected for rest of simulation life.

Figure 26 indicates that surfactant mixture with water has positive effect with all injectors on oil recovery compared to base case performance. Obviously, injection through C-4H has smallest effect among other wells but production is higher and almost the same when C-2H and C-3H were used as a chemical injection well.

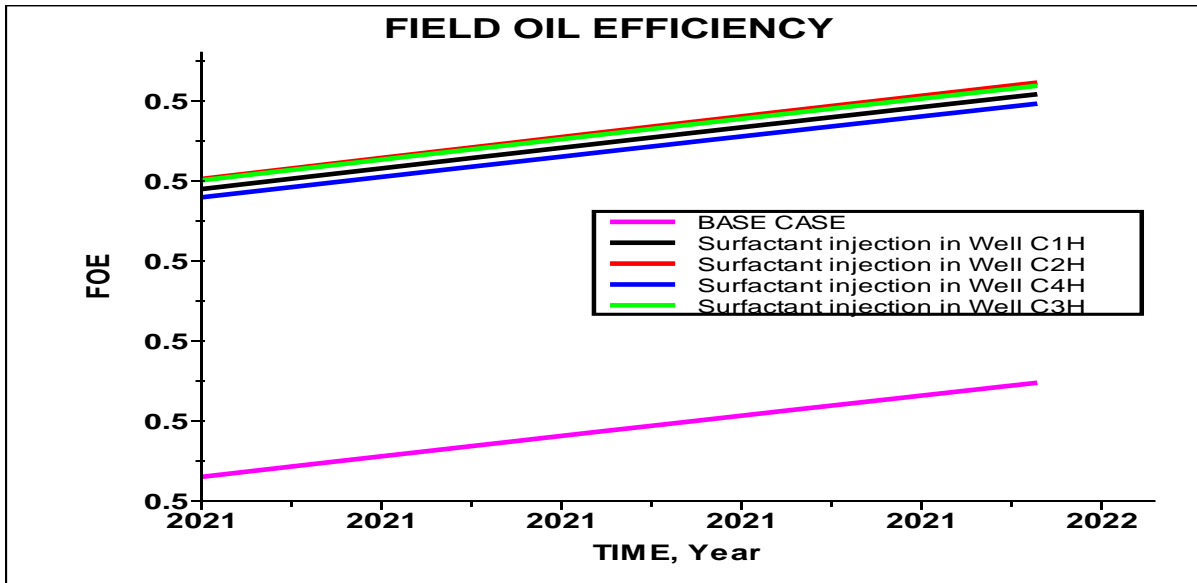


Figure 26: Recovery factor for different surfactant injection wells

When we look at surfactant adsorption and production plots, injection with C-3H leads to smallest adsorption in the formation and highest chemical production as a result of higher oil production. This can be because of area around Well C-3H is high permeable zone and certain amount of chemical reaches producers in a short time with low adsorption so we lose less chemical in the reservoir but recovery is high. Based on surfactant implementing on wells C-3H can be use as a main chemical injector.

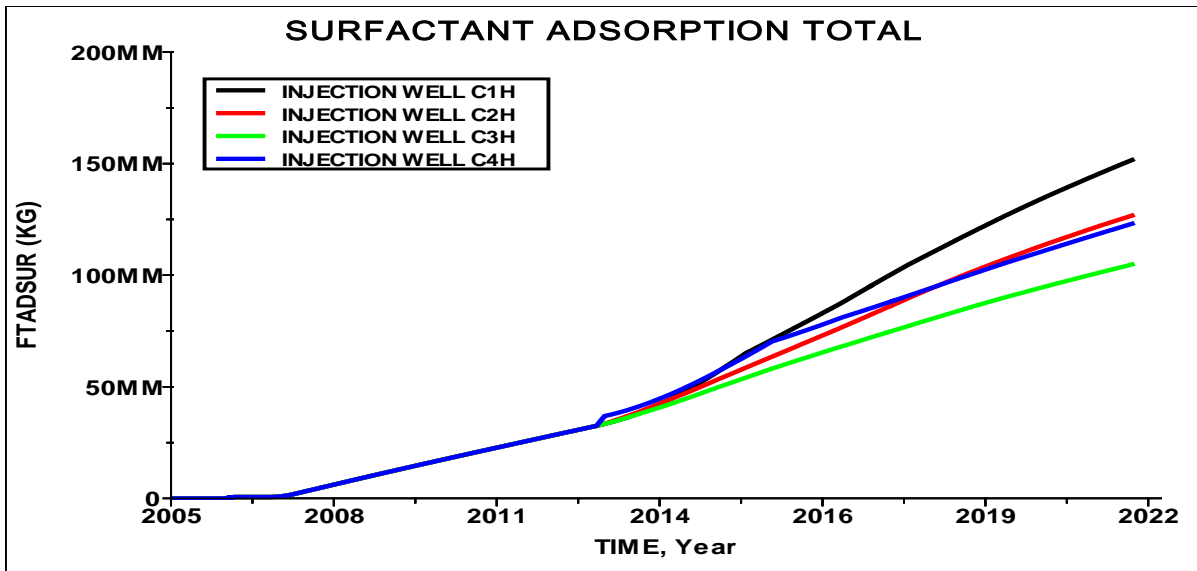


Figure 27: Surfactant Adsorption Total for different surfactant injection wells

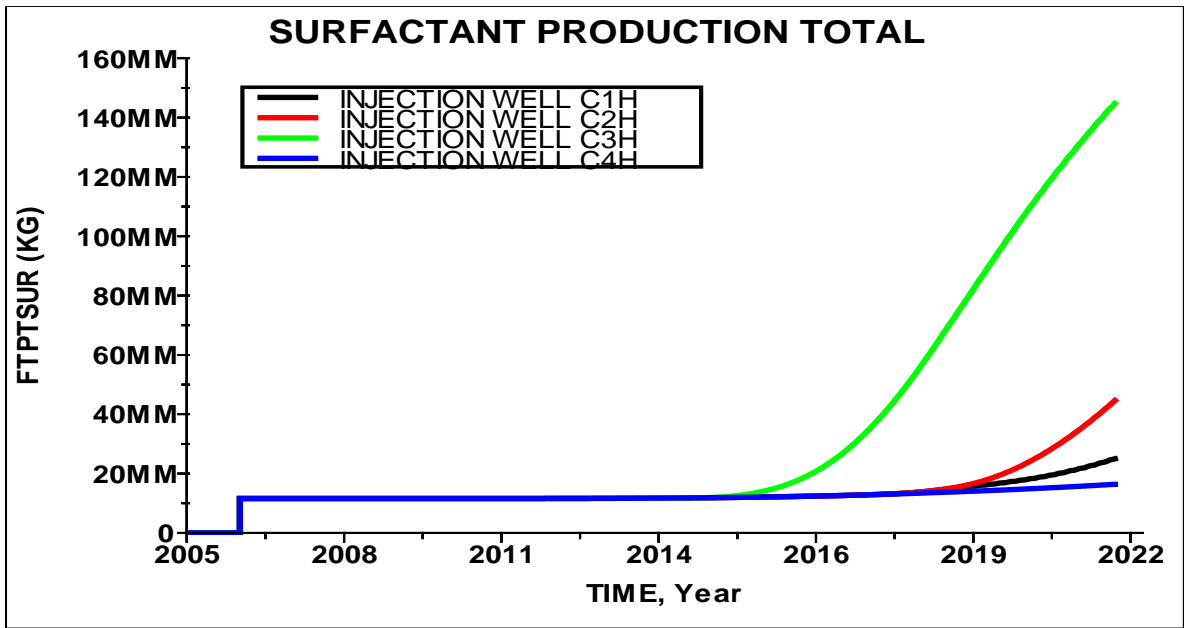


Figure 28: Surfactant Production Total for different surfactant injection wells

For optimal injection well selection polymer was used as well. Flooding was implemented starting in 2013 lasting 4 years with polymer solution concentration at 3kg/m³ through all 4 injection wells (C-1H, C-2H, C-3H, C-4H). From Figure 29 and Figure 30 we can see that polymer injection in well C-3H gives higher oil production compared polymer injection in other injection wells and in this case production of polymer is relatively higher.

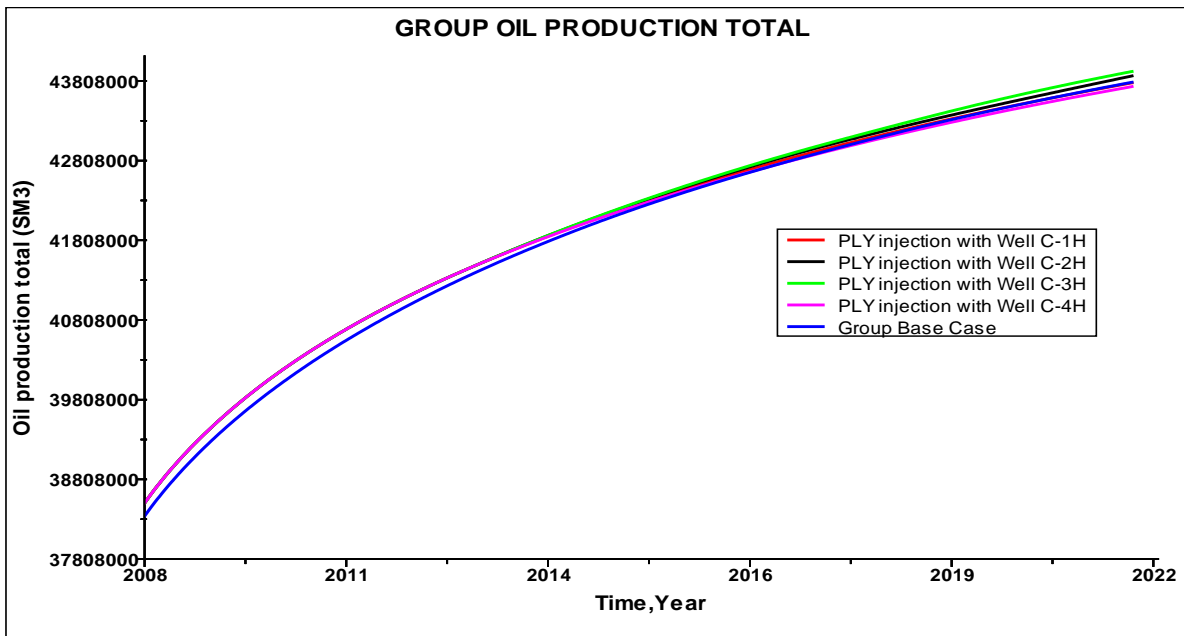


Figure 29: C-segment total oil production with different polymer injection wells

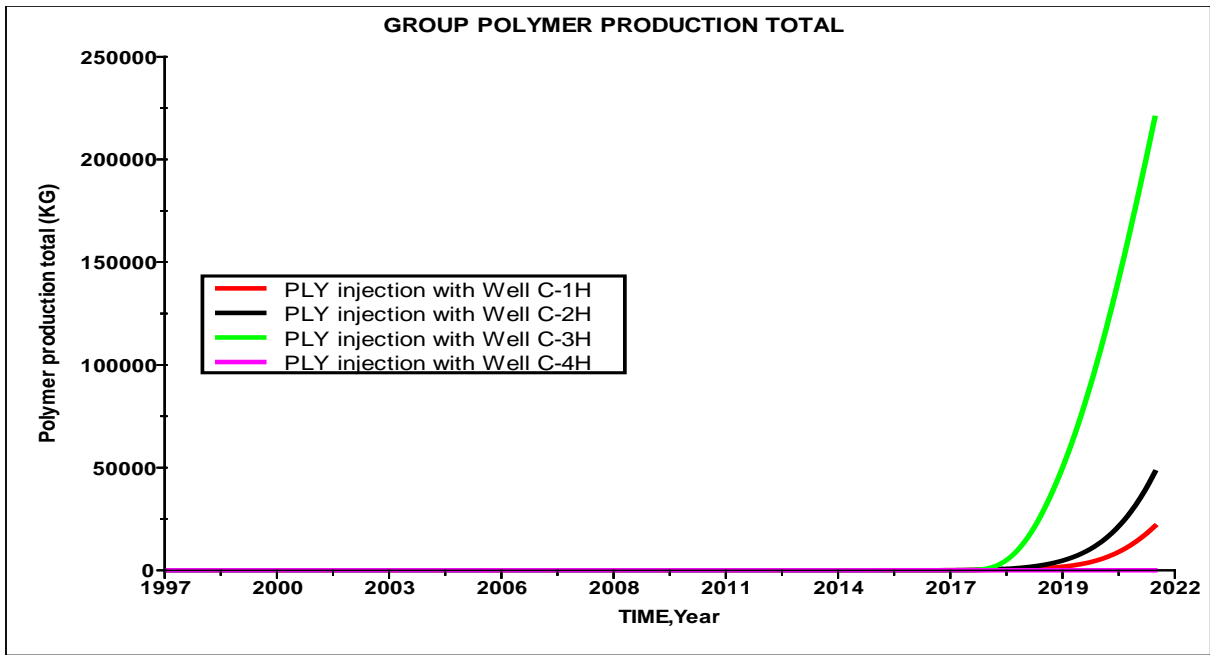


Figure 30: Polymer production with different polymer injection wells

Based on the proper well selection process in terms of surfactant and polymer flooding, well C-3H gave better results among all injectors and it was selected an optimal well in order to make all predictions, chemical sensitivity cases and ASP combination scenarios.

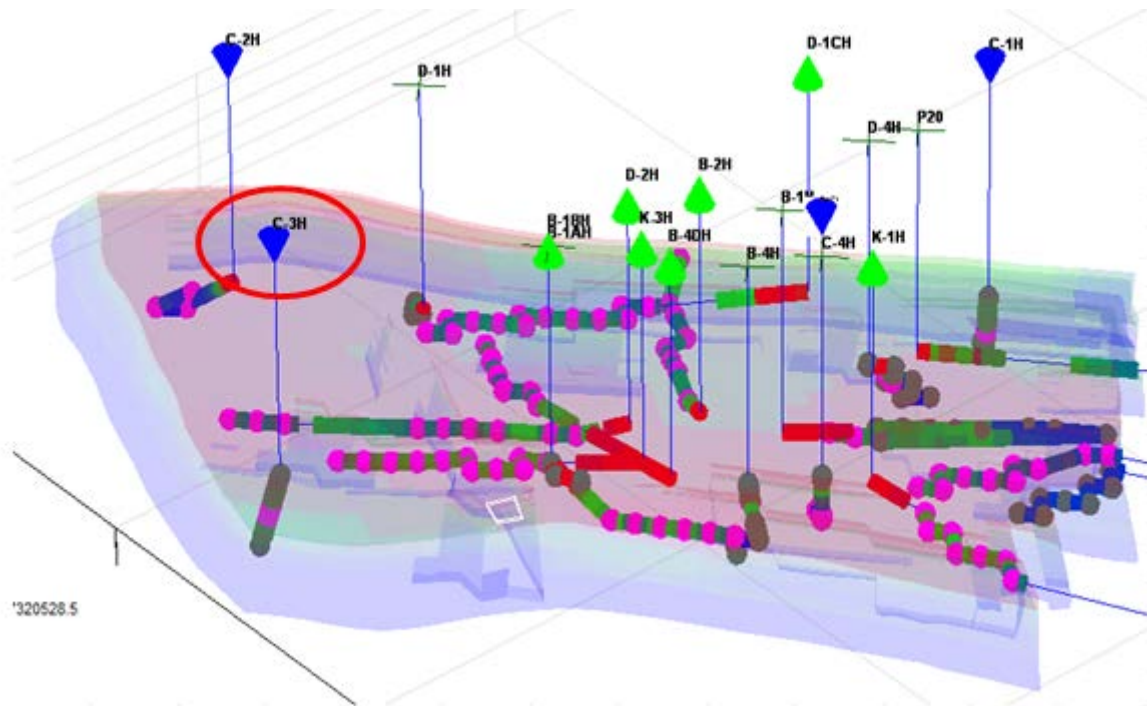


Figure 31: C-segment 3D view with production and injection wells

3.4.2 Plan for Chemical Simulation Cases

ASP (Alkaline, Surfactant and Polymer) flooding as Enhanced Oil Recovery (EOR) method was investigated through simulation study in different sensitivity cases. Main objective is to increase overall field oil recovery along with considering amount of total injected chemical in an economic way. Purposefully, three different chemicals both individually and their combinations for Alkaline -Surfactant (AS), Surfactant-Polymer (SP) and combination of all chemicals (ASP) were injected mixing with pure water with different solution concentrations. Typical studies with special cases as shown below will be discussed and cases will be evaluated economically in term of Net Present value (NPV).

Surfactant Study

- Case 1:** Surfactant flooding at concentration of 15kg/m³
- Case 2:** Surfactant flooding at concentration of 40kg/m³
- Case 3:** Continuous Surfactant flooding for 2 years
- Case 4:** Continuous Surfactant flooding for 3 years
- Case 5:** Continuous Surfactant flooding for 4 years
- Case 6:** Continuous Surfactant flooding for 6 years

Polymer Study

- Case 1:** Polymer flooding at concentration of 0.15kg/m³
- Case 2:** Polymer flooding at concentration of 0.3kg/m³
- Case 3:** Polymer flooding at concentration of 0.5kg/m³
- Case 4:** Polymer flooding at concentration of 0.8kg/m³
- Case 5:** Polymer flooding at injection rate of 5000kg/D
- Case 6:** Polymer flooding at injection rate of 8000kg/D
- Case 7:** Polymer flooding at injection rate of 11000kg/D

Alkaline –Surfactant (AS) Study

- Case 1:** AS flooding at concentration of 0.5kg/m³ and 25kg/m³ respectively
- Case 2:** AS flooding at concentration of 1.5kg/m³ and 25kg/m³ respectively
- Case 3:** AS flooding at concentration of 2.5kg/m³ and 25kg/m³ respectively

Surfactant -Polymer (SP) Study

- Case 1:** SP flooding at concentration of 15kg/m³ and 0.5kg/m³ respectively
- Case 2:** SP flooding at concentration of 40kg/m³ and 0.2kg/m³ respectively
- Case 3:** SP flooding at concentration of 15kg/m³ and 0.5kg/m³, following WI and PLY inj

Alkaline-Surfactant- Polymer (ASP) Study

- Case 1:** ASP flooding at concentration of 1.5kg/m³, 15kg/m³ and 0.35kg/m³ for 2yrs
- Case 2:** ASP flooding at concentration of 1.5kg/m³, 15kg/m³ and 0.35kg/m³ for 4yrs
- Case 3:** ASP flooding at concentration of 1.5kg/m³, 15kg/m³ and 0.35kg/m³ for 5yrs
- Case 4:** ASP flooding for 4 yrs-slug at concentration of 1.5kg/m³, 15kg/m³ and 0.35kg/m³
- Case 5:** ASP flooding for 2 yrs following by 1yr WI and following by 2yrs PLY inj.
- Case 6:** ASP flooding for 4 yrs following by 1yr WI and following by 2yrs PLY inj.

3.4.3 Surfactant Study

The effect of surfactant flooding in the reservoir has been analyzed with numerical simulation of concentration sensitivity and injection time period sensitivity cases. Firstly, the surfactant was modeled in Eclipse 100 where the assumption is that the surfactant exists only in the water phase and the solution concentration is specified at a water injector. The main effect of surfactant is reduction of oil–water interfacial tension (IFT).

3.4.3.1 Concentration Sensitivity

First surfactant case study is surfactant concentration sensitivity which contains of modeled input concentrations at 15kg/m³, 25kg/m³, 40kg/m³. Injection was set starting in the beginning of 2013 lasting till the end of 2016 with three mentioned concentration values. Total oil production, total water production, total production of surfactant and adsorption of surfactant for specific grid block around the injection well C-3H have been looked for discussion.

From oil production and water production plots it is observable that effect of concentration generally causes higher oil production compared single water injection which is base case, but increase in amount of surfactant leads to increase in oil production and decrease in water production. Because interfacial tension is reduced and trapped oil in the rock starts being swept. Very little difference on recovery between three cases makes it possible that 15kg/m³ could be better choice considering economic side to avoid wasting chemicals. Key observation from water production performance is that the same amount of water is produced at concentration of 15kg/m³ and 25kg/m³.

Plots for surfactant adsorption and production clearly indicate higher amount of chemical is produced in higher concentration. In Figure 35 for adsorption in the 18th layer at specific block (16, 23, and 18) which is close to well C-3H, big amount reaches to maximum adsorption level earlier than small amount, so concentration is different for the certain time interval in the grid block. From adsorption graph it is feasible that surfactant is adsorbed early when solution concentration is high, on the contrary it is low and takes time when the concentration is low.

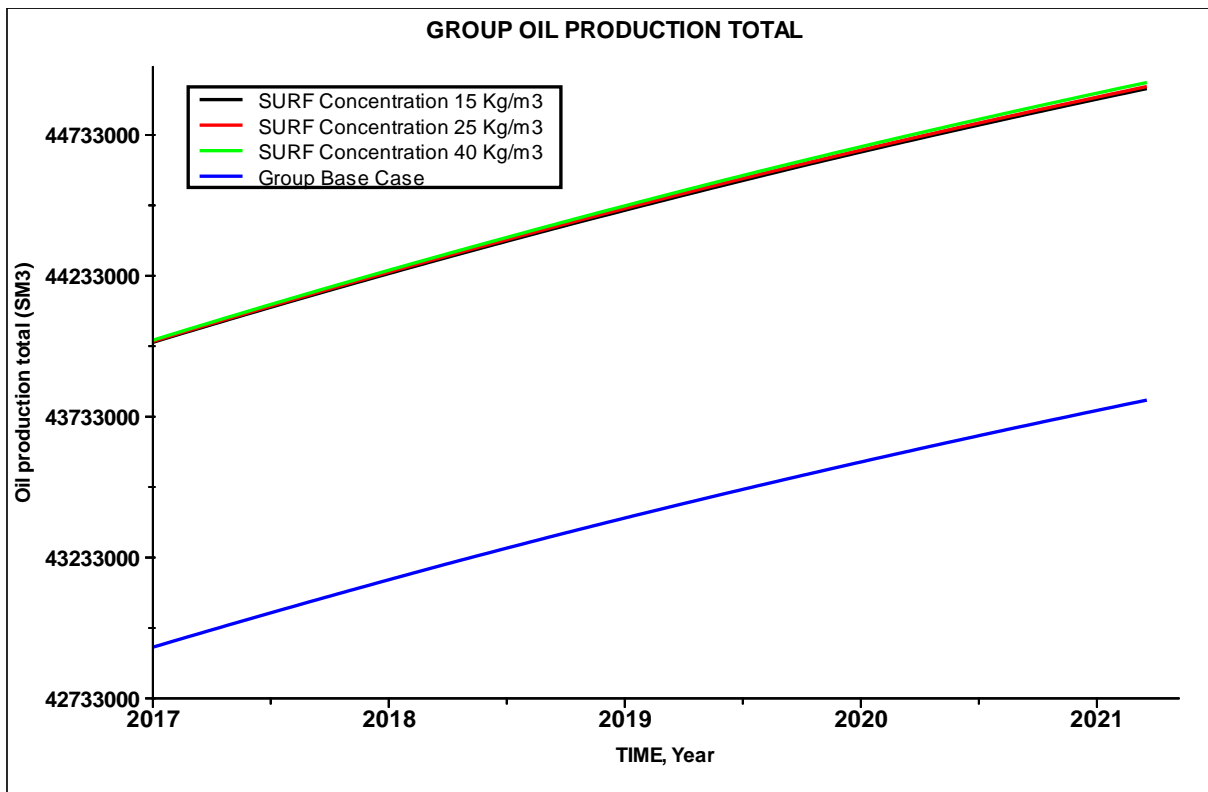


Figure 32: C-Segment oil production for different surfactant concentration

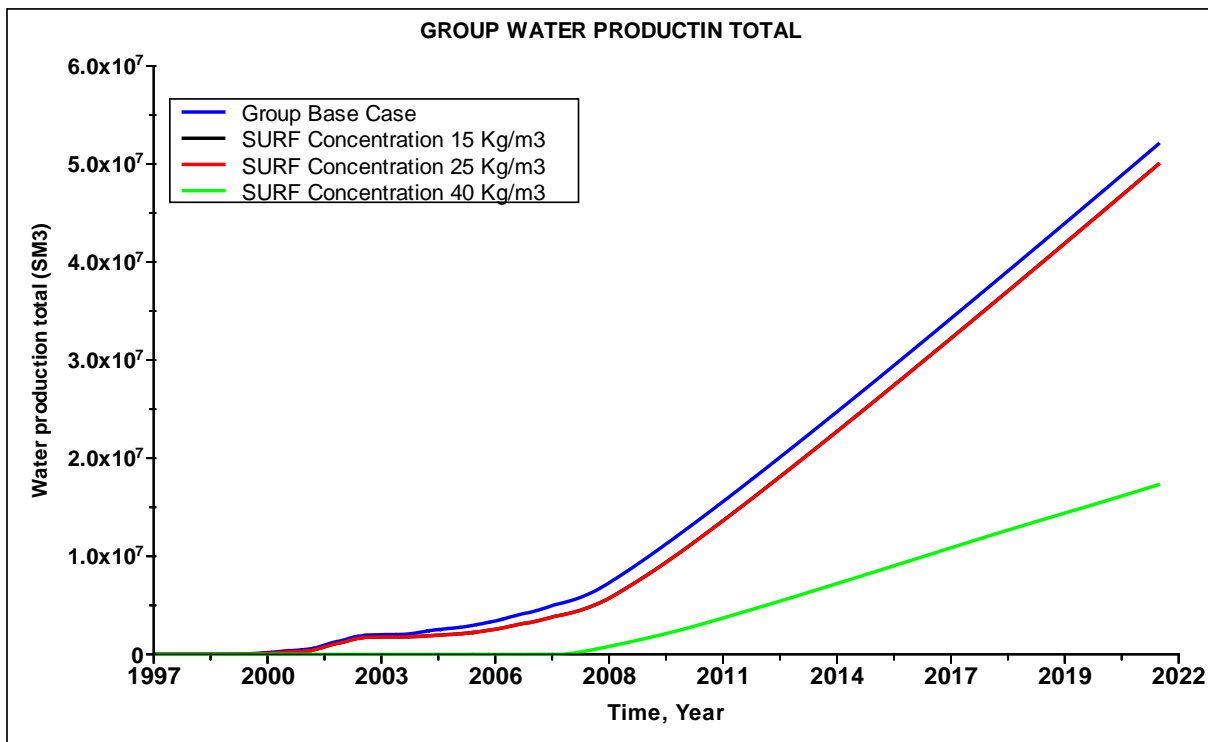


Figure 33: C-Segment water production for different surfactant concentration

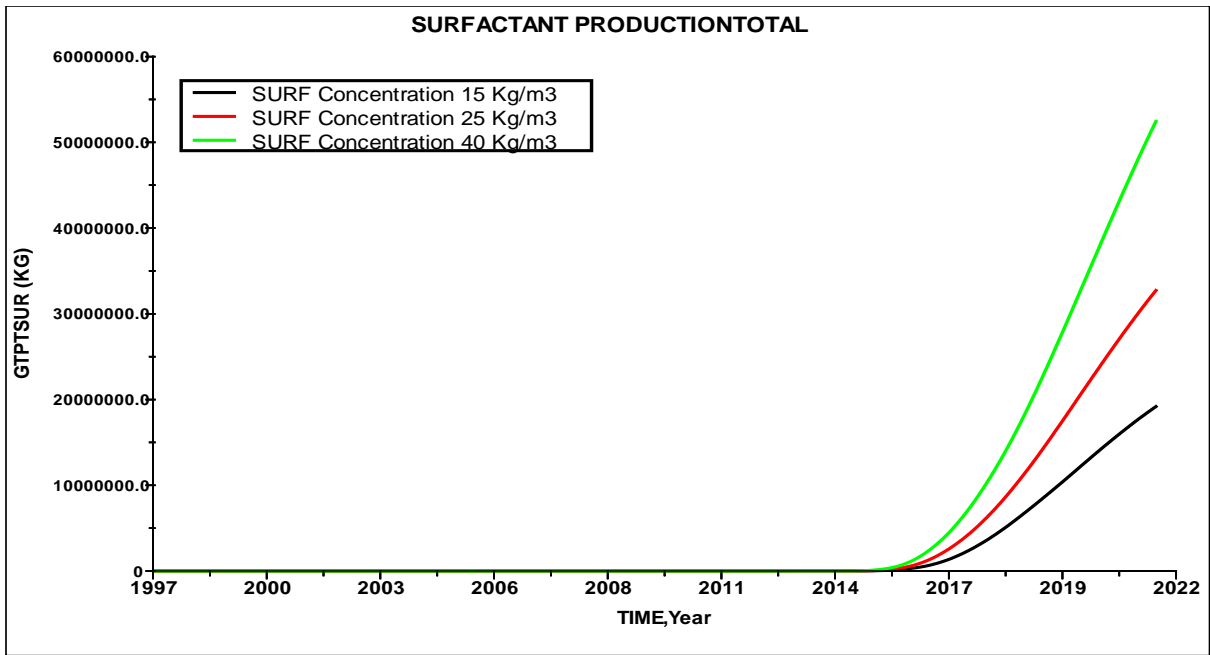


Figure 34: Surfactant production for different concentration

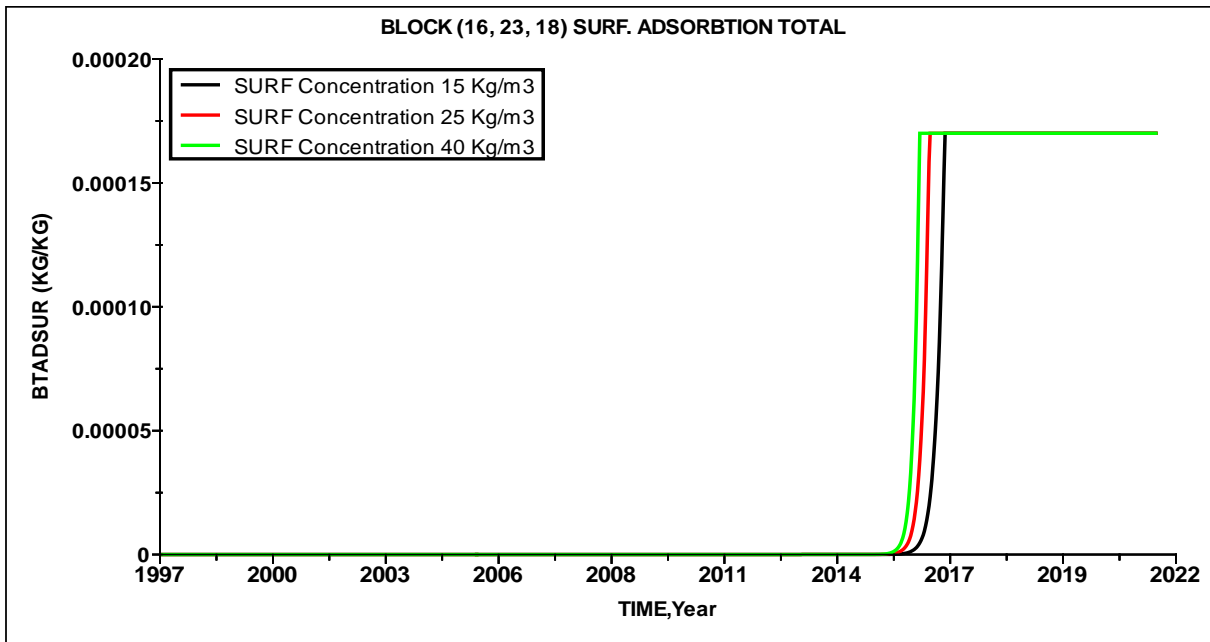


Figure 35: Surfactant adsorption in Block (16, 23, and 18) for different concentration

3.4.3.2 Injection Time Period Sensitivity

Analyzing of injection time period is important activity for EOR project. So injection time stage directly affects on reservoir behavior depending on early or later and how long surfactant injection goes on. Four cases have been run for the same injection rate and the same concentration but with different time period. These continuous cases includes: continuous injection for two years starting in 2015, continuous injection for three years starting in 2014, continuous injection for four years starting in 2016 and continuous injection for six years starting in 2013.

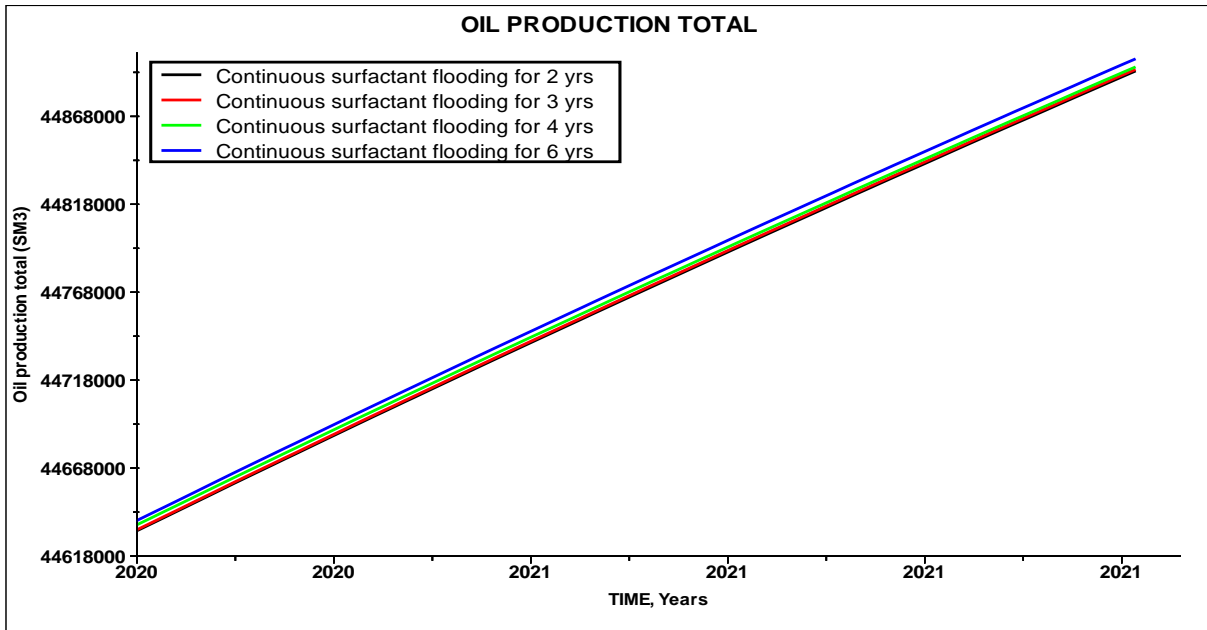


Figure 36: C-segment oil production for different continuous injection time period

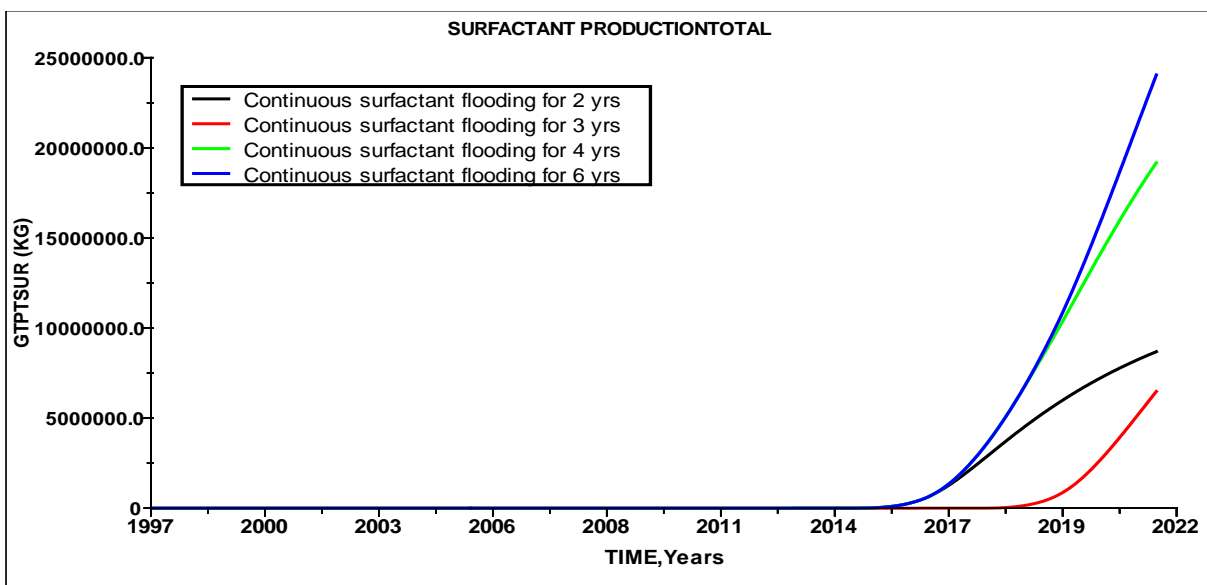


Figure 37: C-segment surfactant production for different continuous injection time period

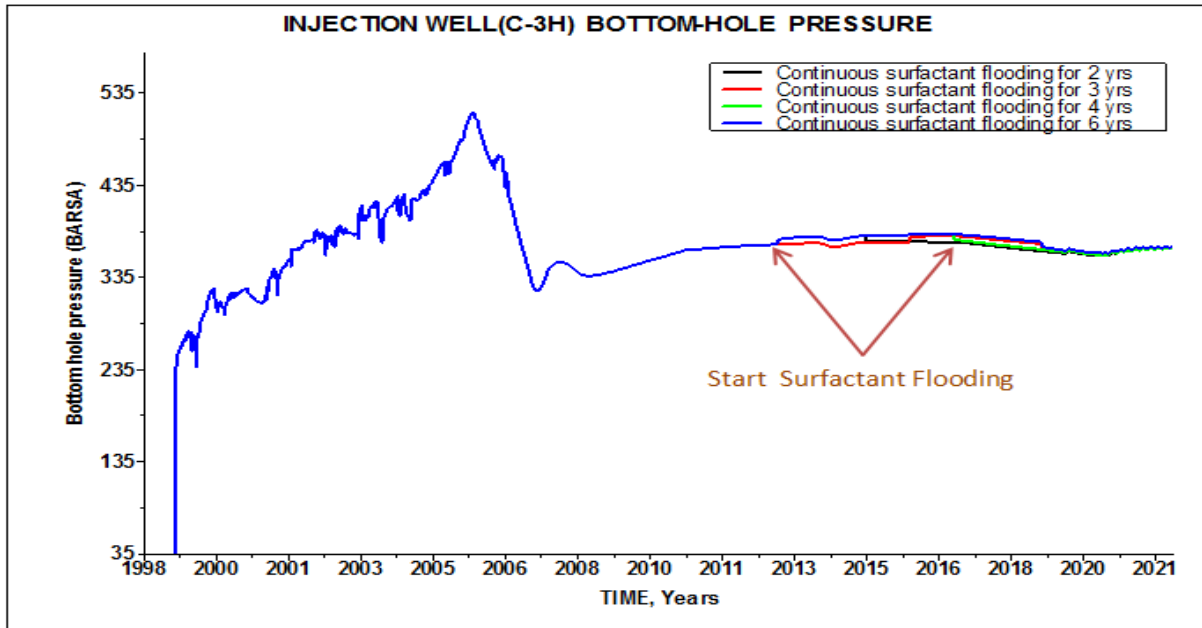


Figure 38: Well C-3H bottom-hole pressure for different continuous injection time period

From Figure 36 and Figure 37, it can be seen that longer injection period in early life of simulation leads to higher oil production and obviously higher chemical mixture in the flooding water. At different stages, injection for the period of 2, 3 and 4 years gave very close recovery values. Based on the analyses, to maximize production and at the same time to optimize the economic recovery long injection period is not profitable where injection for 2 or 3 years can be optimal choice. Even it can be wasteful injecting surfactant for 6 years when taking economic evaluation into consideration which will be discussed in details later. That is why better approach would be short term injection time period.

The injection well bottom-hole pressure is important parameter for EOR projects. There is a need for detailed analyzing of pressure around the injection well to keep the formation stability in the reservoir and avoid formation damage. Pressure graph demonstrates that with the same injection rate and the same solution chemical concentration injector bottom-hole pressure is going up a certain constant pressure limit for all injection time period sensitivity cases.

To sum up, surfactant flooding is recommended for the Norne C-Segment especially when the concentration is low and injection occurs in the early years. Injection of surfactant at a later time might not be profitable.

3.4.4 Polymer Study

As a part of ASP method, simulation study of polymer flooding is an important analyze. Advantages of polymer solution with water are improving mobility ratio and making better sweep efficiency. To investigate the polymer flooding in the C-Segment polymer properties such as viscosity, concentration and adsorption parameters were included to the base case model. To have better understanding of the flooding process sensitivity analyses have been done for solution concentration effect and injection rate effect. Important simulation results have been included to the report with comparison of different cases. Some assumptions have been considered for the process.

1. Isothermal conditions
2. No chemical, mechanical, and biological degradation is modeled
3. No chemical reactions between polymer and formation, oil and any other components in the water phase
4. Polymer exists in water phase only
5. Water density is not affected by polymer
6. Adsorbed polymer has no effect on pore volume
7. The adsorption of polymer on rock surface is assumed to be in equilibrium

3.4.4.1 Concentration Sensitivity

Choosing of proper polymer concentration should be detailed analyzed so concentration directly affects to polymer solution viscosity and defining the size of the required polymer injection slug whereas viscosity and injection slug causes big changes in oil production. To evaluate and optimize the injection according to concentration simulation has been run with concentrations at 0.15 kg/m³, 0.3 kg/m³, 0.5 kg/m³ and 0.8 kg/m³. For all these specific cases injection has been planned starting from 2013 to the end of 2016, and then continuing with only pure water injection.

In Figure 39, obviously, concentration at 0.8kg/m³ gives higher incremental oil production because of higher viscosity. On the contrary, concentration at 0.15kg/m³ gives lower incremental oil production. More importantly, higher injection concentrations cause greater reductions in water cut and can shorten the time required for polymer flooding and all are dealing increase in enhanced oil recovery. Polymer concentration directly reduces the mobility ratio by increasing the water phase viscosity and also effective on the water permeability to be decreased due to polymer adsorption, so the purpose of polymer concentration in slug is to control the water viscosity by adding polymer into injected water and improves the water driving efficiency. The polymer solution viscosity is a key parameter to improve the mobility ratio between oil and water, as concentration increases, viscosity increases and the effectiveness of polymer flooding increases.

As it can be seen from polymer production plot, the amount of produced polymer in the fluid is lower for higher concentration. The reason can be that higher concentration makes viscosity

to increase which causes improvement in mobility ratio that leads to flow spread in the reservoir by diverting injected water from zones that have been swept and widening the flow pattern zone by decreasing effect of fingering. As a result, more adsorption takes place because of wide sweeping area. Taking these concepts, production of polymer is lower for higher concentration in our case.

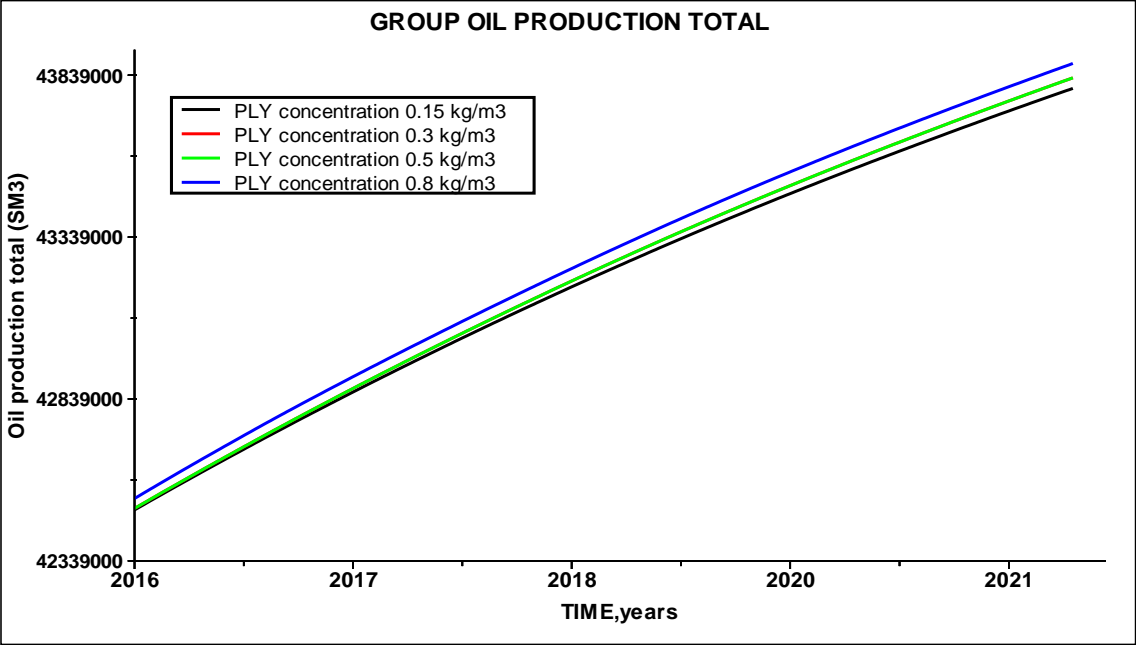


Figure 39: C-Segment oil production for different polymer concentration

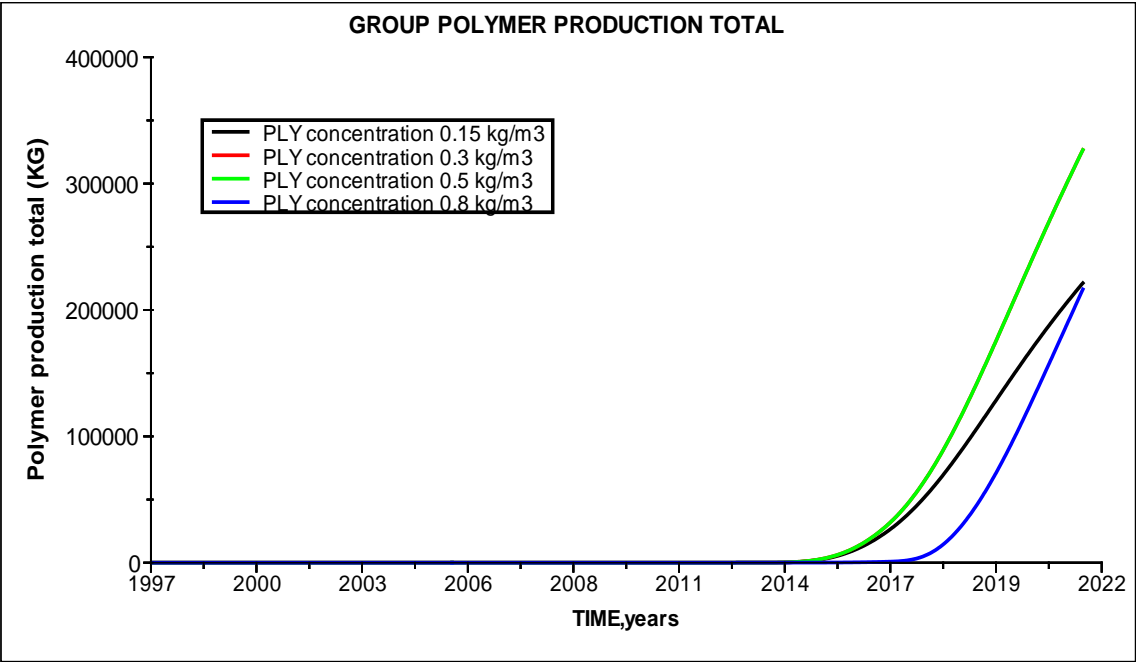


Figure 40: Polymer production total for different concentrations

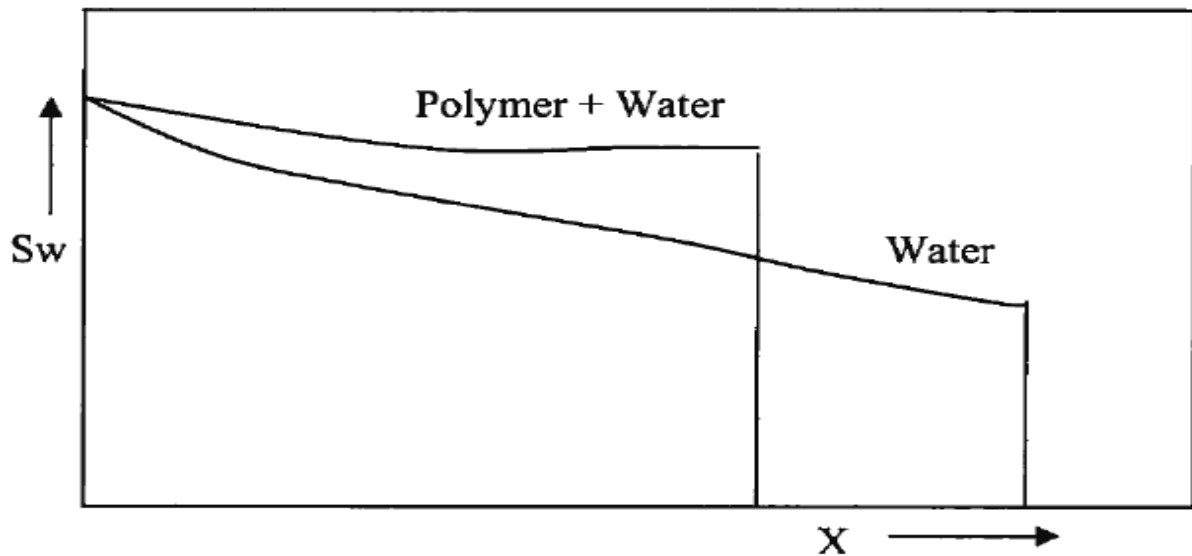


Figure 41: The overview of Polymer flooding to Buckley Leverett method

It is believed that polymer flooding cannot reduce the Sor, but it is still an efficient way to reach the Sor more quickly or/and more economically which is found in Buckley Leverett solution as described in figure BL.

The graphs in Figure 42 and Figure 43 shows how pressure near the injection well change due to polymer flooding at different concentrations. In the period of 4 years' continuous injection the incremental pressure is observed around injector but reservoir pressure starts to drop. Study of concentration effect shows the rate of reservoir pressure is opposite dependent with polymer concentration where concentration at 0.8kg/m³ leads to lower reservoir pressure. However, consideration should also be given to the fact that higher concentrations will cause higher injection pressures and lower injectivity. For the concentration at 0.8kg/m³ recovery is highest but highest bottom-hole pressure where incremental pressure is more than 50 bars makes it unfavorable case. Based on the analyses, the case at 0.8 kg/m³ is unfavorable though the case at 0.5kg/m³ can be optimal proposal.

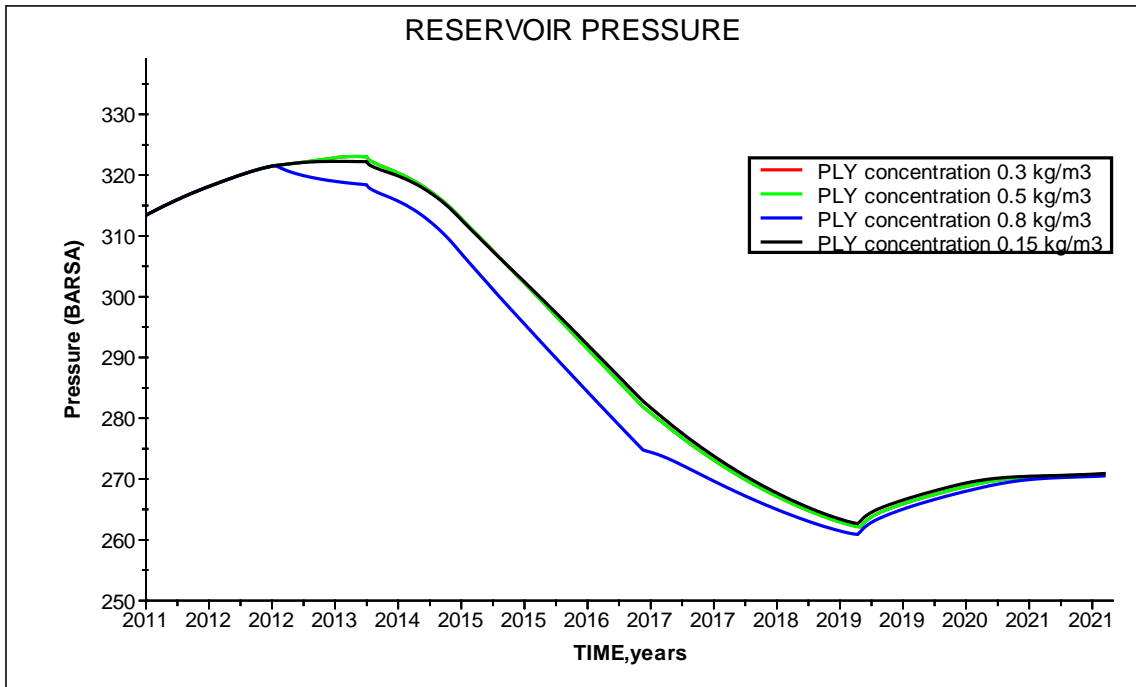


Figure 42: Field reservoir pressure for different polymer concentration

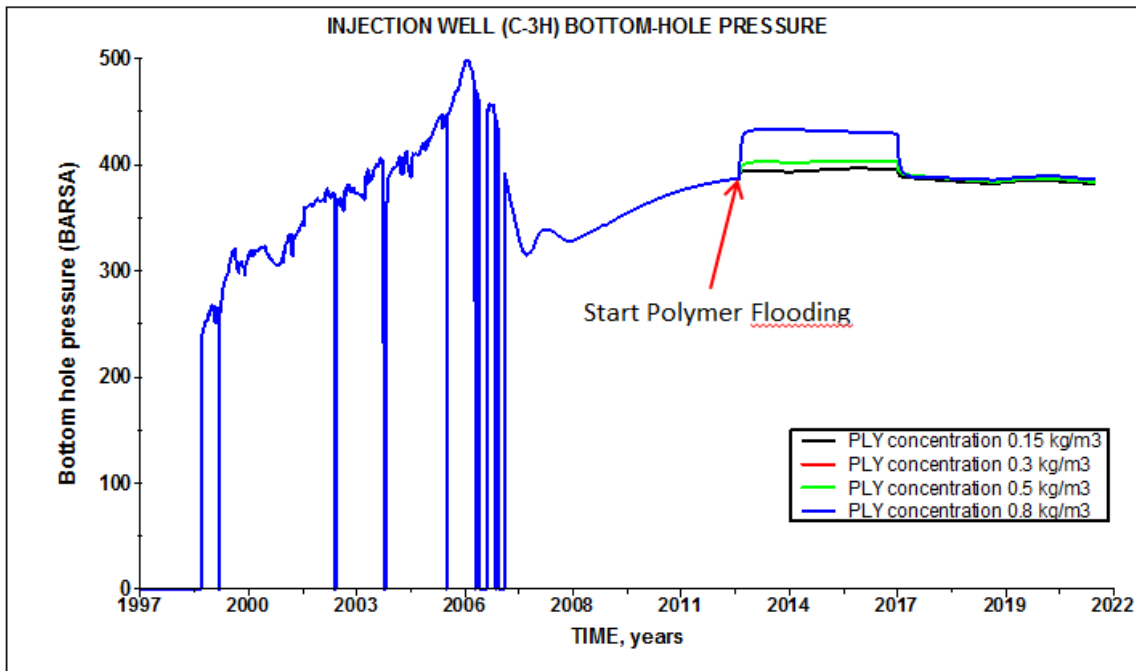


Figure 43: Well C-3H bottom-hole pressure for different polymer concentration

3.4.4.1 Rate Sensitivity

Injection rate is a parameter which can be controlled easily so rate sensitivity is applicable in most parametric studies. In this case rate sensitivity includes: polymer flooding for rate at 5000 Sm³/day, 8000 Sm³/day and 11000 Sm³/day. Injection rate for well C-3H was 8000sm³/D in the base case model. For sensitivity analyses this value was taken as medium value and concentration was kept constantly at 0.3kg/m³ during flooding process.

Figure 44 illustrates that oil production is getting lower when rate is going up. In fact, this point shows we need to be careful in rate control so rate should not be increased and simulator tells us that base case rate is almost at a critical point. Oil recovery is higher for the minimum tested rate at 5000sm³/D. The reason can be related to geological formation and early water breakthrough.

Minimum pressure drop down zone is appeared when injection rate is lowest. Reservoir pressure and injector well bore pressure (Figure 45 and Figure 46) are found with very similar behavior at rate of 8000Sm³/D and 11000Sm³/D. High injection pressure and lower recovery at higher rate tell us the possibility of fracturing in the reservoir. Based on simulation results, injection rate at 5000Sm³/D or below this value is found being optimal.

Analyses show that polymer injection as EOR method is more efficient than water injection because of improved mobility ratio, increasing the cumulative oil production and decreasing the total water production. Oil recovery factor increases with an increase in polymer solution concentration because of increase in displacing fluid's viscosity, but decreases with rate increase so lower injection rate causes much better volumetric sweep efficiency. More importantly, rate control should be investigated in detail especially in polymer study.

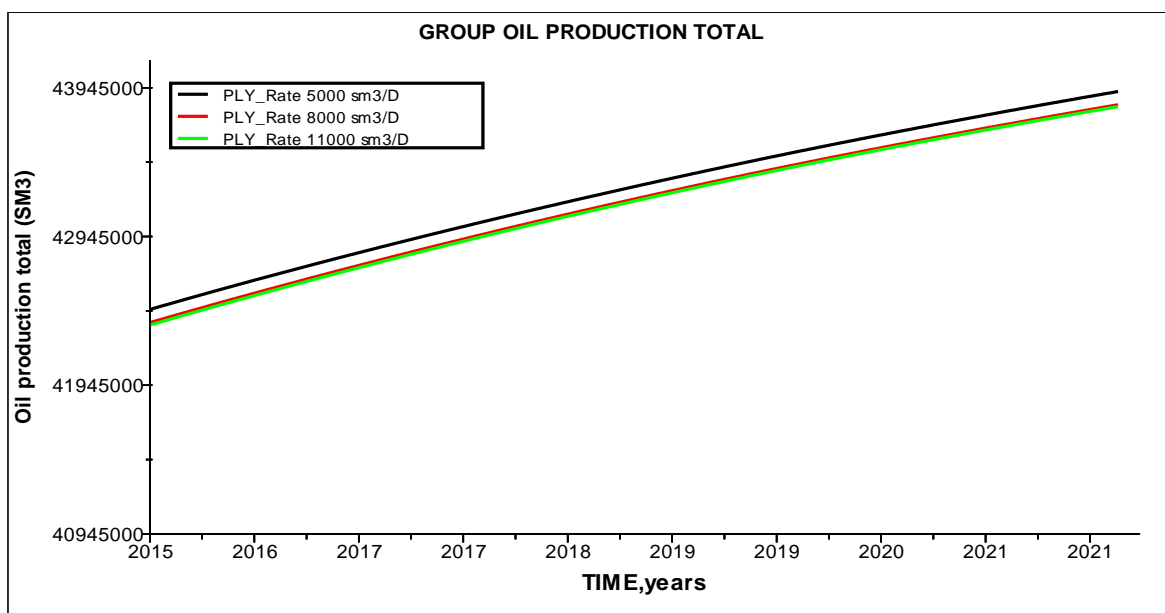


Figure 44: C-Segment oil production for different polymer injection rates

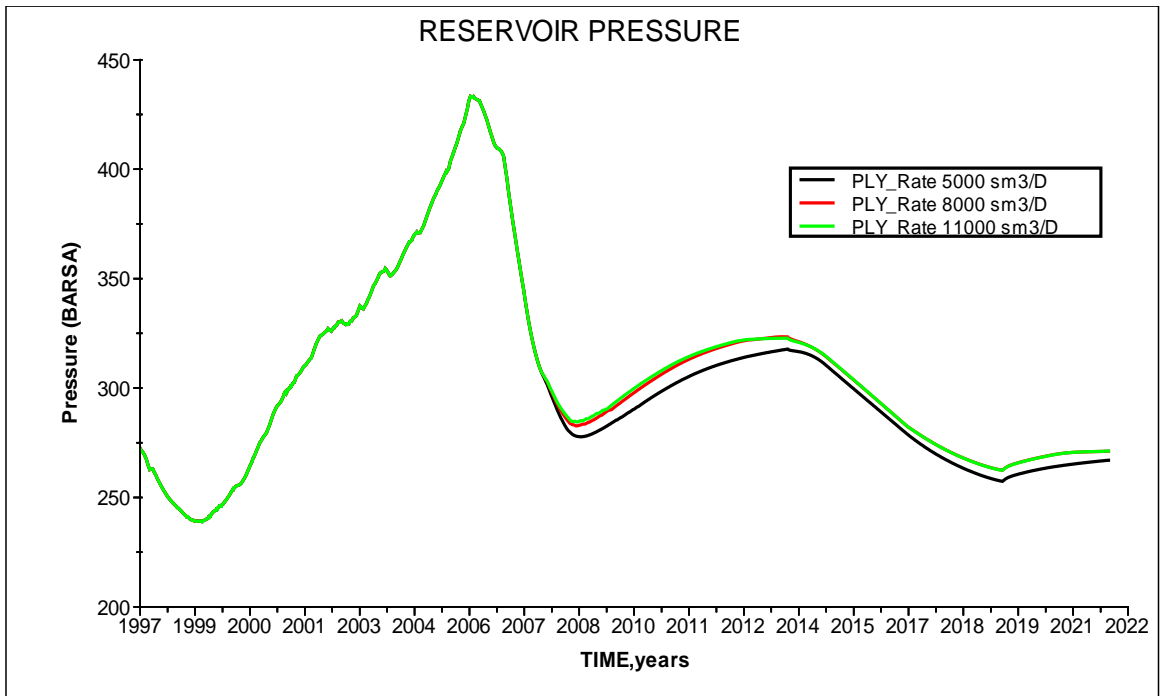


Figure 45: Reservoir pressure for different polymer injection rates

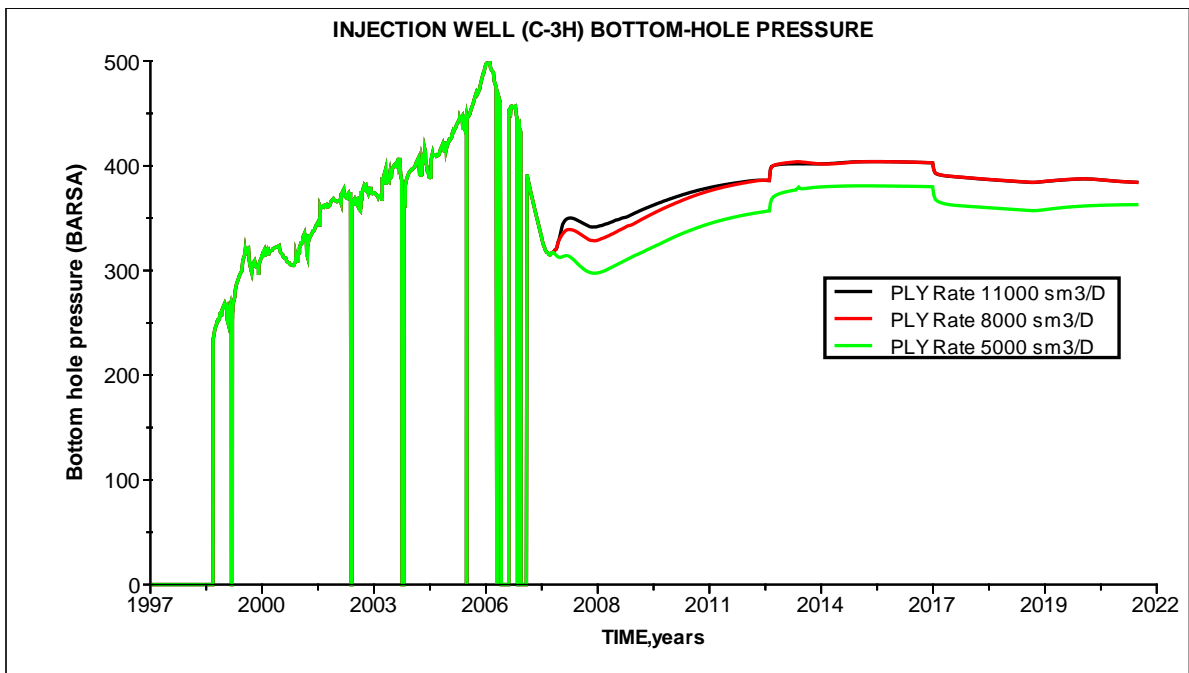


Figure 46: Injector bottom-hole pressure for different polymer injection rates

3.4.5 Alkaline-Surfactant Study

After analyzing effect of polymer and surfactant individually the combination of Alkaline-Surfactant (AS) was injected together into Well C-3H to get more incremental oil. Three cases were simulated at constant concentration of surfactant but with three different concentration of alkaline.

The cases are:

- AS flooding at concentration of 0.5kg/m³ and 25kg/m³ respectively
- AS flooding at concentration of 1.5kg/m³ and 25kg/m³ respectively
- AS flooding at concentration of 2.5kg/m³ and 25kg/m³ respectively

There are some benefits of alkali which is applicable most of the flooding process. The main concept of alkali surfactant flooding is the reduction of oil water Interfacial tension (IFT) and alkali plays a big role in an alkaline surfactant process to reduce adsorption of the surfactant during displacement. Important point is that AS reduces the amount of surfactant required and causes higher production in an economic way.

As it can be seen from Figure 47 simulator has produced lower oil production for the AS flooding with alkali at higher concentration. Obviously, production development is almost the same with alkali concentration at 1.5kg/m³ and 2.5kg/m³. Simulation with lower concentration at 0.5kg/m³ gives relatively better result. The reason can be that if alkali concentration is too much it can decrease viscoelasticity of AS solution which can reduce sweep efficiency. And we need to consider limit for alkali concentration due to the concept of minimum achievable value of IFT which is optimal value for most positive effect on movable oil. In our case, according to simulation result alkali is necessary for AS solution but high alkali concentration is not so effective. Figure 48 tells us that more alkali concentration more chemical production.

As a result, AS solution is an effective flooding process making more contribution with attendance of alkali but key observation from simulation results is that high alkali concentration low oil production. So Eclipse results for particularly alkali effect are matched with lab results discussed in literature part.

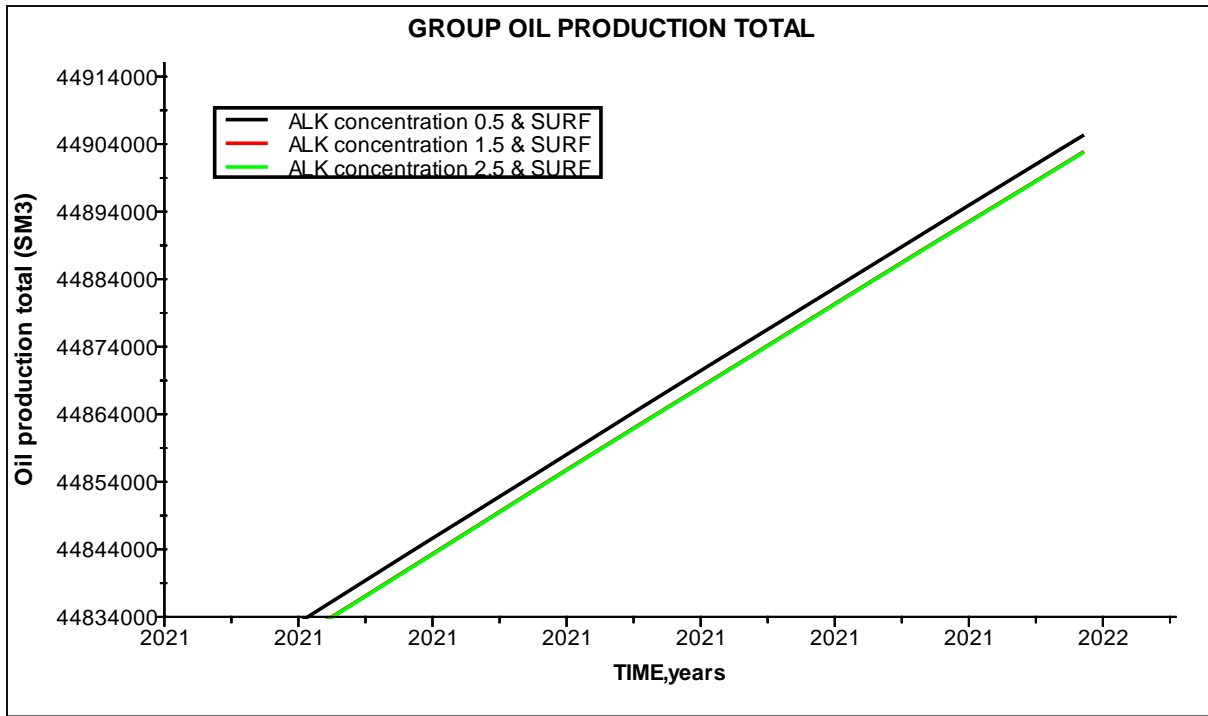


Figure 47: C-Segment oil production for different AS cases

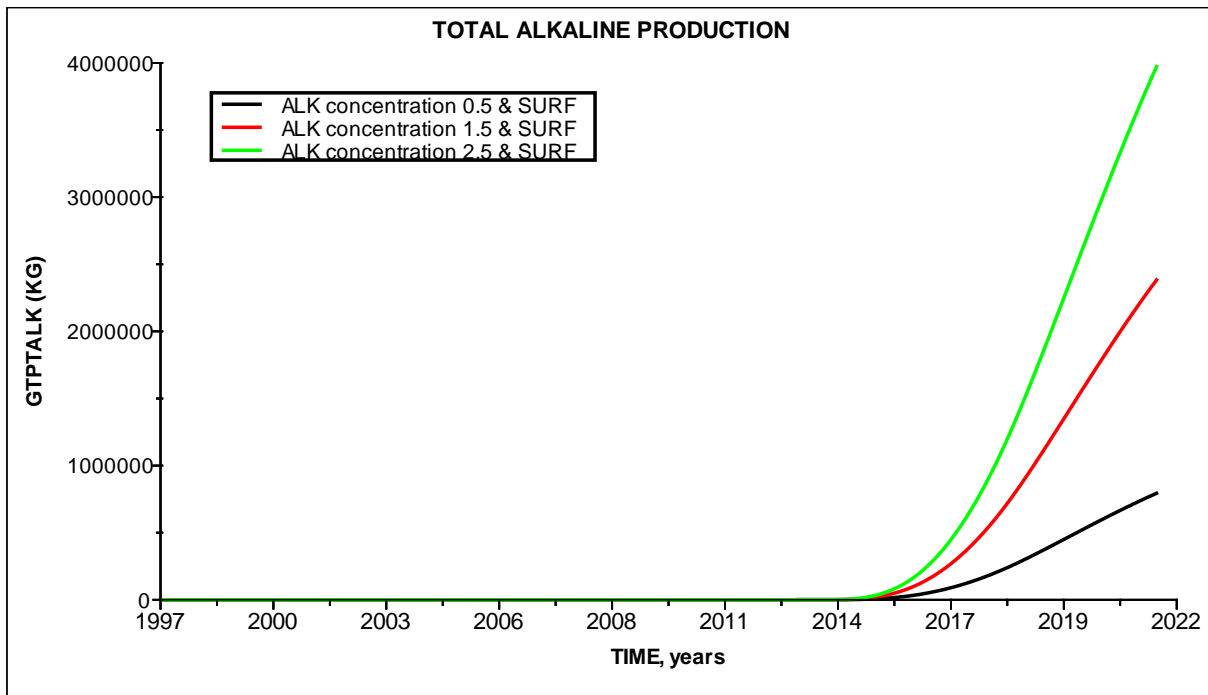


Figure 48: Alkali production for different AS cases

3.4.6 Surfactant-Polymer (SP) study

In this simulation study, the sequence of SP includes three cases such as combination of surfactant and polymer injected for 4 years from 2013 with different chemical concentrations. Additionally, in one case after 2 years' SP flooding water was injected for 1 year which was followed by polymer flooding during the next year, again WI occurred for rest of the simulation life period.

Simulated cases:

- SP flooding at concentration of 15kg/m³ and 0.5kg/m³ respectively
- SP flooding at concentration of 40kg/m³ and 0.2kg/m³ respectively
- SP flooding at concentration of 15kg/m³ and 0.5kg/m³, following by WI and PLY flooding

In Figure 49 SP solution with surfactant at 15kg/m³ and polymer at 0.5kg/m³ leads to better production efficiency and lower reservoir pressure (Figure 50) compared to SP with surfactant at 40kg/m³ and polymer at 0.2 kg/m³. The main impact is due to the amount of polymer in this solution so it makes better sweep efficiency. Higher polymer concentration means more polymers for the same injection rate. According to simulation results, the key fact in SP study is that injecting lower amount of surfactant in solution with higher amount of polymer is better than injecting sufficiently higher amount of surfactant in solution with lower amount of polymer.

As shown in Figure 51, during AS flooding period polymer effect is greater than surfactant effect on pressure around the injector. So polymer concentration demands more optimization analyses.

Conclusion is that SP solution causes higher oil production compared to single chemical flooding with positive sides that surfactant decreases IFT at the time polymer improves mobility by increasing fluid viscosity.

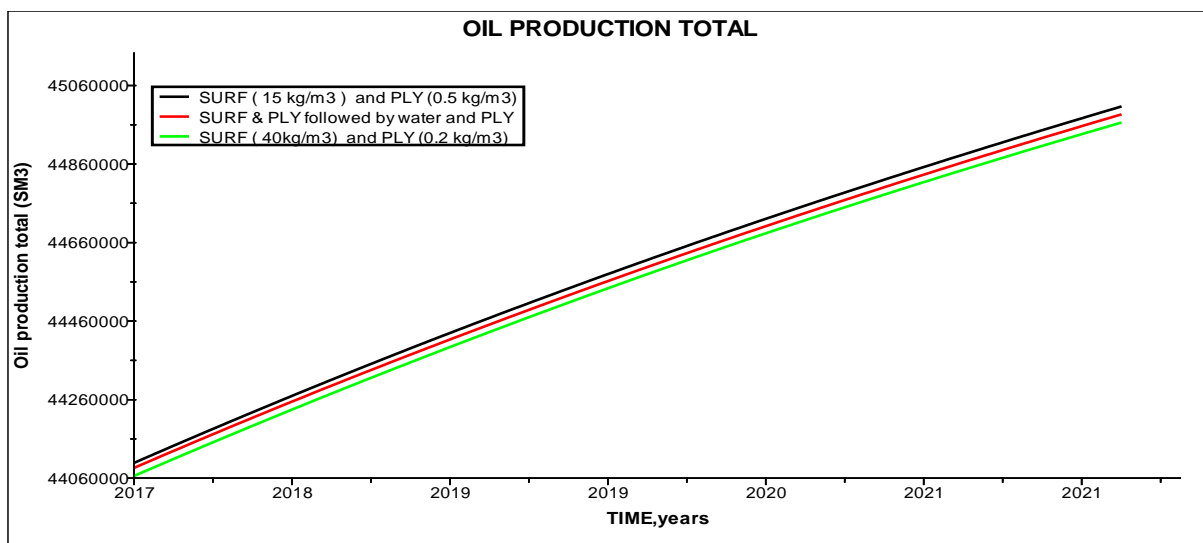


Figure 49: C Segment oil production for different SP cases

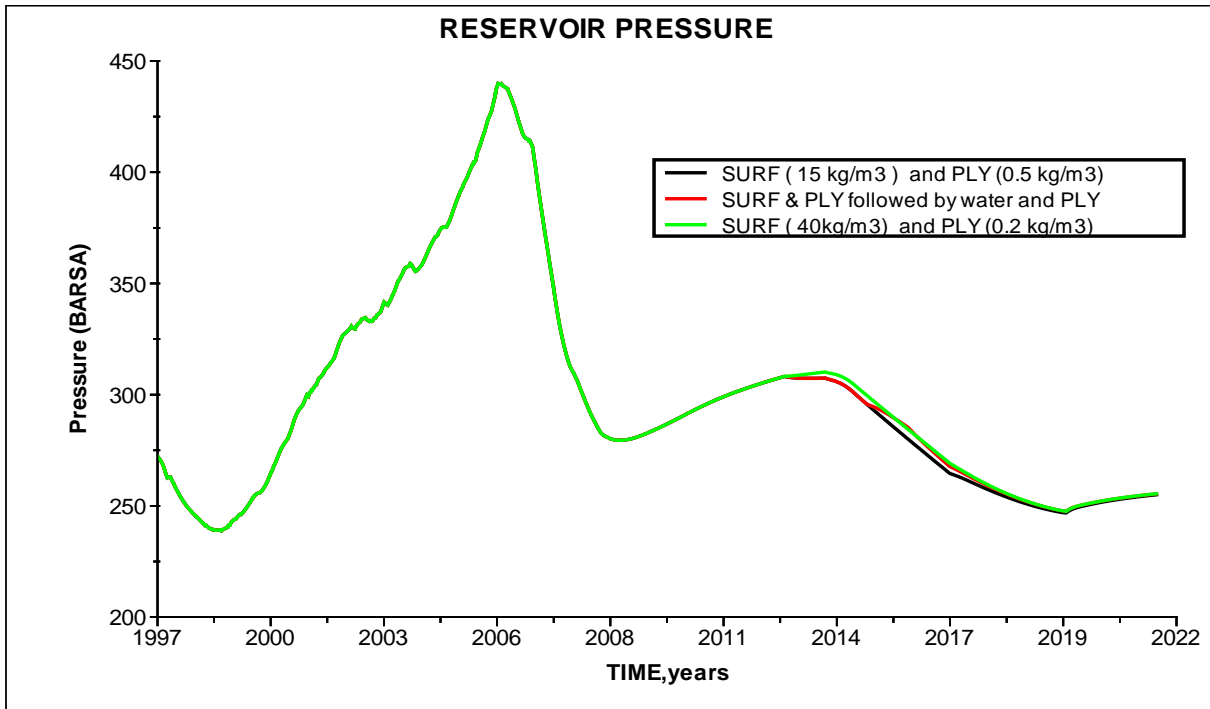


Figure 50: Field reservoir pressure for different SP cases

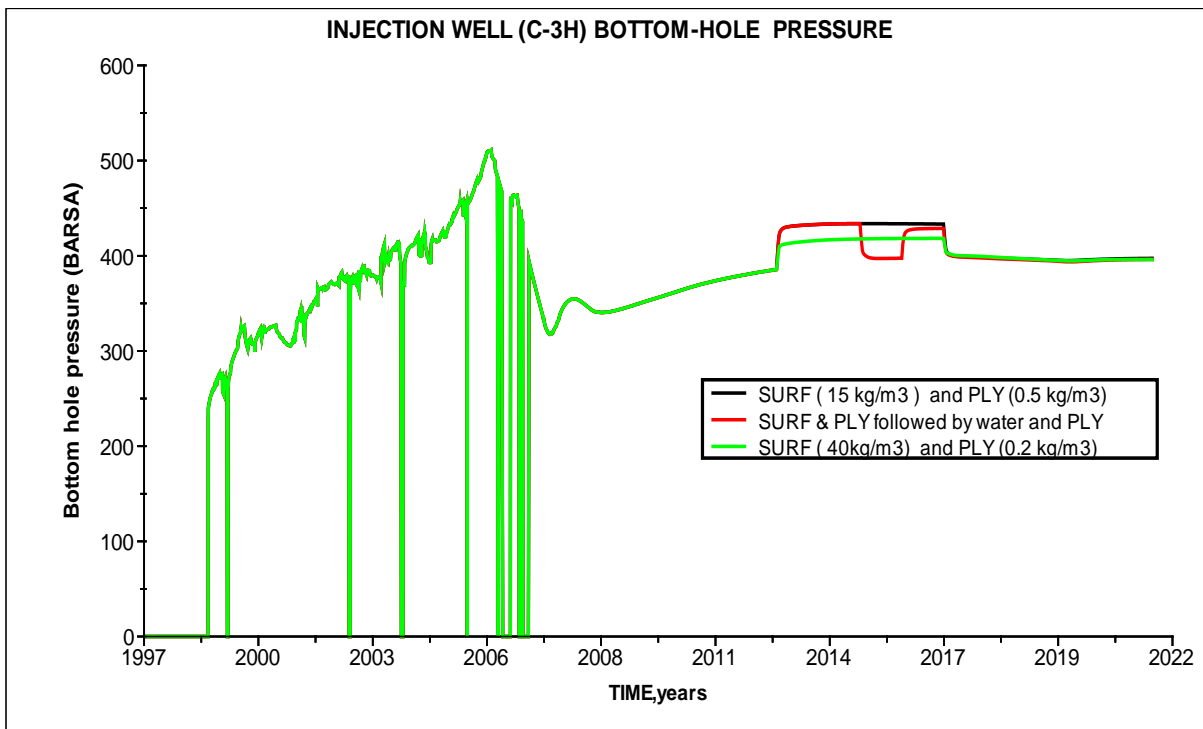


Figure 51: Well C-3H bottom-hole pressure for different SP cases

3.4.6 Alkaline-Surfactant- Polymer (ASP) Study

ASP flooding uses benefits of the three flooding methods simultaneously and recognized as a cost-effective chemical flooding process increasing capillary number, improving mobility and enhancing microscopic displacing efficiency. Field applications of alkali flooding often result in poor recovery due to alkali loss caused by reaction with rock, low acid content of oil and lack of mobility control. But, injecting a surfactant with alkali solution has been proven to be an effective process to both alkali loss and low acid content of oil, while co-injection of polymer with alkali or alkali/surfactant slugs considerably improves oil recovery. Observation is that the synergism of alkali and polymer results from a combination of improved sweep and mobilization of residual oil due to reduced interfacial tension and improved recovery by combined ASP slugs is explained by the same mechanisms as of AP slugs. The alkali is performing well in reducing the residual oil saturation by generating additional in-situ surfactant. Adding surfactant to AP slugs further reduces interfacial tension, and attains significantly higher recovery than AP slugs. (21)

For the duration of ASP flooding, the ASP solution initially moves quicker in the high-permeability layer than movement in the middle and low permeability layers because complex physicochemical reactions such as adsorption, retention and emulsion of the ASP solution cause the flow resistance and the pressure to increase. Therefore, the pressure difference in the high permeability layer becomes higher than those in the middle and low-permeability layers which results in the fluid changing flow direction from high permeability layer toward the middle and low permeability layers. (22)

Predominantly, the main use of this simulation study has been focused on time effect and chemical amount effect. Alkali, Surfactant and Polymer concentrations were set to 1.5kg/m³, 15kg/m³ and 0.35kg/m³ respectively for all cases. The cases can be grouped such as continuous ASP solution flooding for different years and one case in which simulation was done for ASP slug with injection period of 1 year. Considered cases are listed below:

- ASP flooding at concentration of 1.5kg/m³, 15kg/m³ and 0.35kg/m³ for 2yrs
- ASP flooding at concentration of 1.5kg/m³, 15kg/m³ and 0.35kg/m³ for 4yrs
- ASP flooding at concentration of 1.5kg/m³, 15kg/m³ and 0.35kg/m³ for 5yrs
- ASP slug inj. for 4 yrs at concentration of 1.5kg/m³, 15kg/m³ and 0.35kg/m³
- ASP flooding for 2 yrs following by 1yr WI and following by 2yrs PLY injection
- ASP flooding for 4 yrs following by 1yr WI and following by 2yrs PLY injection

From Figure 52 we can see that longer duration of ASP flooding gives better recovery. During this time residual oil saturation is decreased while long and continuities flooding leads to much trapped oil to move. As illustrated on the graph, periodical slug injection efficiency is very close to the efficiency of longer continuous injection where slug injection demands less chemical compared to continuous flooding. So the advantage of slug injection is to reduce chemicals costs by means of lower amounts of chemicals. Obviously, based on the last two cases injecting AS and polymer separately gives lower recovery. Considering this point, attendance of all chemicals in the solution is more beneficial and would be better choice.

We get higher incremental reservoir pressure and injector well pressure when followed polymer slug injection is used. But polymer in the solution with other chemicals does not have so big effect on pressure increase. Due to the constant concentration of each chemical, maximum injection pressure level while chemical flooding is stable for all cases since rate does not change as well.

From what have been discussed above, ASP as an effective chemical flooding process and it can be the potential EOR method for the C-segment.

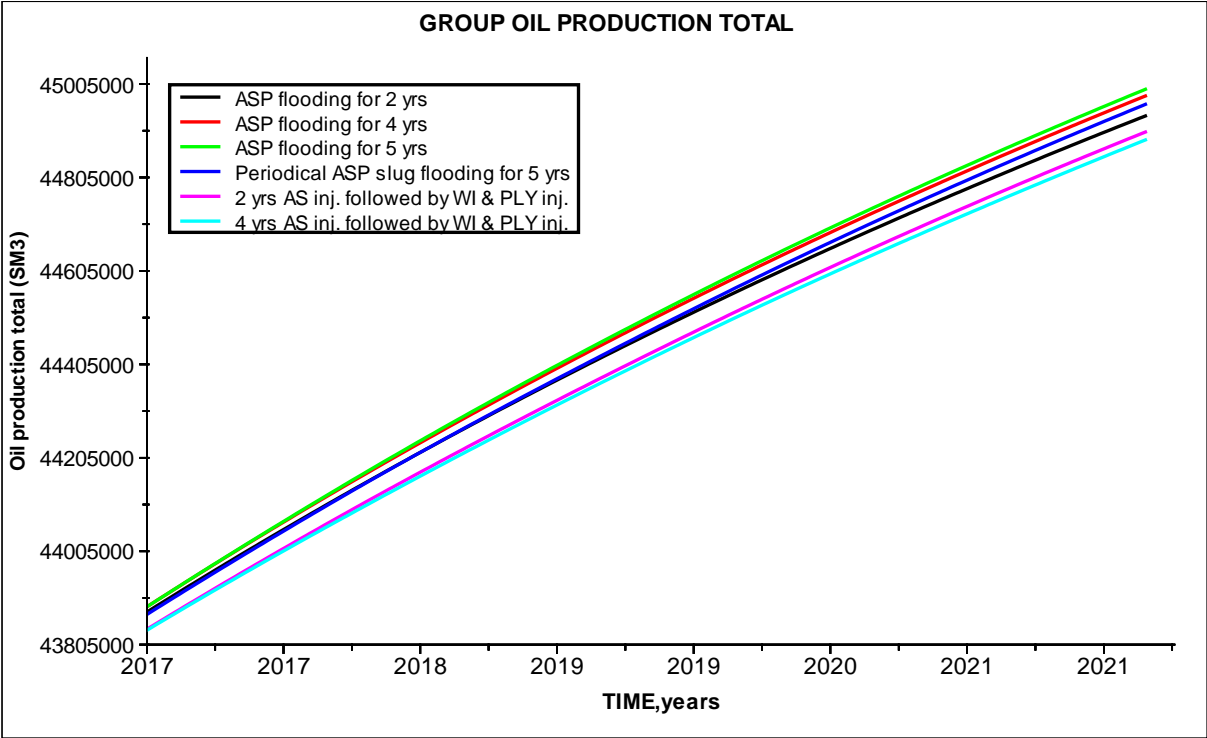


Figure 52: C-segment oil production for different ASP cases

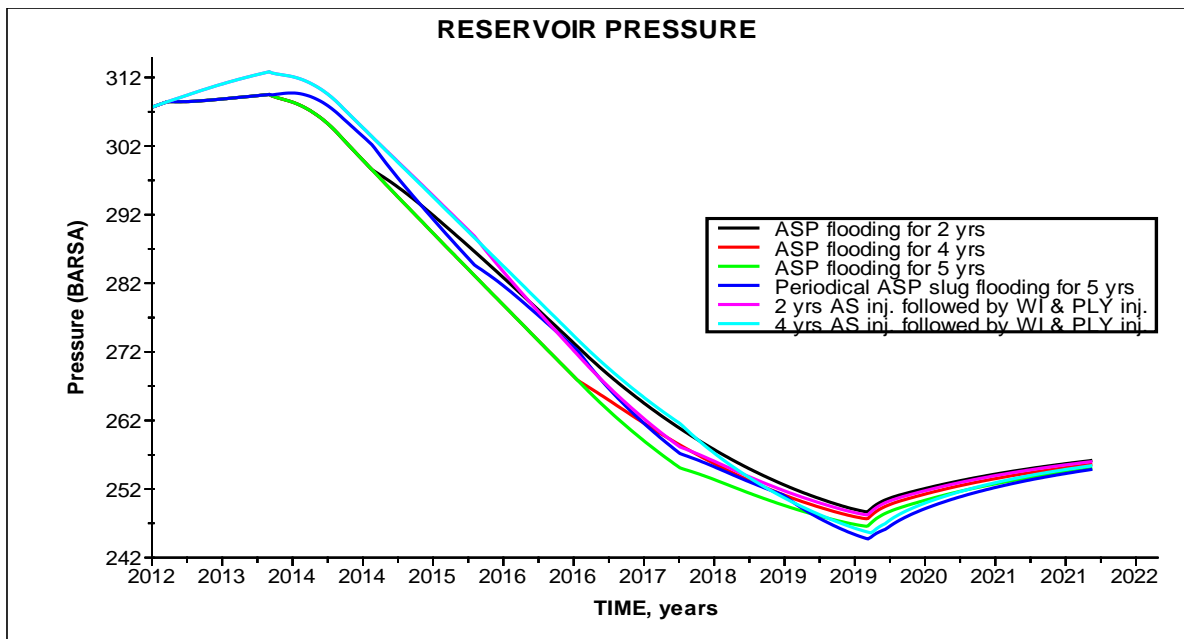


Figure 53: Reservoir pressure for different ASP cases

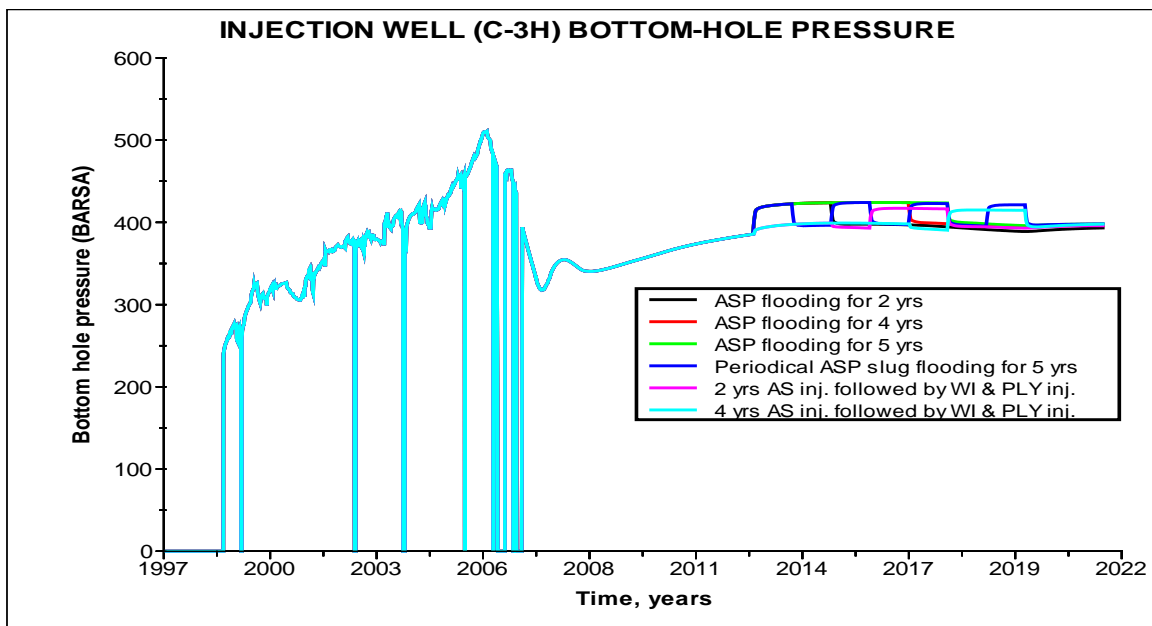


Figure 54: Injector bottom-hole pressure for different ASP cases

4 Economic Evaluation

Profitability analysis of the project is very important evaluation after the technical analysis is completed. This analysis is the basis for investment decision of the project. For this EOR project economic analysis and proper decisions have been done based on Net Present Value (NPV). NPV takes into consideration the value of cash earned in the future and converts the money to the present value. The equation below is used to calculate NPV.

$$NPV = \frac{Revenue - Expense}{(1 + r)^t} \quad DF(T) = \frac{1}{(1 + r)^T}$$

Where “r” represents discount rate and “t” represents projects year. In this simulation study implementation of ASP method started from 2013 and simulation lasted until 2022. The year 2013 is considered as a start year of the project therefore it is zero as a project year. So for economic evaluation years started from zero till nine which is 2021. DF is discount factor (for determining time value of money) that is taken to account in NPV formula.

A project is categorized as profitable when NPV is positive. And we are always encouraged to choose higher NPV when we have many alternatives with positive NPV. A high NPV indicates a high profitability from the project.

In our case, only revenue is got from selling of crude oil. It is assumed that expenses only include surfactant costs, polymer costs and alkali costs. For a specific case to calculate NPV and make decision, incremental revenue between chemical case and base case (no chemical, only water injection) has been used as a basis cash flow. For the estimation of income, annual total production data were taken from the Eclipse and included to excel.

The following prices for oil and chemicals were used. And conversion of units was done to get NPV with NOK.

The crude oil price for current year is referred to <http://www.oil-price.net/>

oil price	85	USD/bbl	3185.348767	NOK/Sm3
Alkaline price	1.5	USD/kg	8.937	NOK/kg
Surfactant price	3.3	USD/kg	19.6614	NOK/kg
Polymer price	4	USD/kg	23.832	NOK/kg

Discount rate	0.08
Inflation rate	0.03

Conversion		
1bbl =	0.1589873	m3
1m^3=	6.28981057	bbl
1USD=	5.958	NOK

Time	Project year	Base Case oil production	Oil production with Polymer	Incremental oil production	Oil Price	Incremental Revenue from oil	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.79E+09	3.32E+06	1.90E+04	6.30E+10	7.01E+05	1.67E+07	6.29E+10	1.00E+00	6.29E+10	6.29E+10
2014	1	1.80E+09	1.89E+09	8.60E+07	1.95E+04	1.68E+12	7.01E+05	1.67E+07	1.68E+12	9.26E-01	1.56E+12	1.62E+12
2015	2	1.82E+09	1.82E+09	1.63E+06	2.01E+04	3.29E+10	7.01E+05	1.67E+07	3.29E+10	8.57E-01	2.82E+10	1.65E+12
2016	3	1.83E+09	1.83E+09	1.37E+06	2.07E+04	2.83E+10	7.01E+05	1.67E+07	2.83E+10	7.94E-01	2.25E+10	1.67E+12
2017	4	1.84E+09	1.84E+09	1.37E+06	2.14E+04	2.93E+10	0	0	2.93E+10	7.35E-01	2.15E+10	1.69E+12
2018	5	1.85E+09	1.85E+09	1.83E+06	2.20E+04	4.02E+10	0	0	4.02E+10	6.81E-01	2.73E+10	1.72E+12
2019	6	1.86E+09	1.86E+09	8.64E+05	2.27E+04	1.96E+10	0	0	1.96E+10	6.30E-01	1.23E+10	1.73E+12
2020	7	1.87E+09	1.87E+09	1.51E+06	2.33E+04	3.52E+10	0	0	3.52E+10	5.83E-01	2.05E+10	1.75E+12
2021	8	1.88E+09	1.88E+09	1.60E+06	2.40E+04	3.85E+10	0	0	3.85E+10	5.40E-01	2.08E+10	1.77E+12

Table 1: NPV for Polymer flooding at concentration 0.3kg/m³ for 4 yrs

Table 1 represents the procedure how to calculate NPV for one of the polymer cases. Likewise, the procedure as described in the table was done for all chemical cases. Inflation affected only oil price while assuming chemical prices are constant for predicted years. We get present value by discounting net cash flow. Incremental oil production has been found by subtracting annual base case production from production with polymer flooding. NPV for each year was calculated cumulating of annual present value. We can see that cumulative incremental NPV is 1.77E+12 NOK in the end of simulation life which is key element for decision making of investment. Obviously, it is positive in this case and can make project being accepted.

Economic evaluation process demonstrated in the Table 1 was done for all typical chemical flooding cases and NPV values versus years were plotted in figure 55. By considering the following plots, it is evident that the highest NPV is from AS flooding for 4 years with alkali and surfactant at concentration of 0.5kg/m³ and 25 kg/m³ respectively. We have almost the same expected net present value at 1.09E+13 NOK for SP case with concentration of 15kg/m³ and 0.5kg/m³ respectively. The incremental NPV for polymer cases are lower than all other cases. Interesting observation is that in terms of NPV both AS and SP cases are better than ASP solution cases. Even adding only surfactant to water makes higher expected incremental NPV. Similarly, attendance of surfactant is visible in all high profitable cases.

As long as the expected net present value is positive, the project should be accepted but considering many alternatives, the cases with surfactant and its solution leads to much profit and based on the profitability evaluation and from investment point of view injecting only surfactant should be better than injecting combination of chemicals for C segment. Surfactant is very favorable chemical for the Norne C segment while polymer flooding is not encouraged to implement because that single polymer cases cause lower income. Purposefully, more analysis and studies are required to investigate surfactant effect for this field segment.

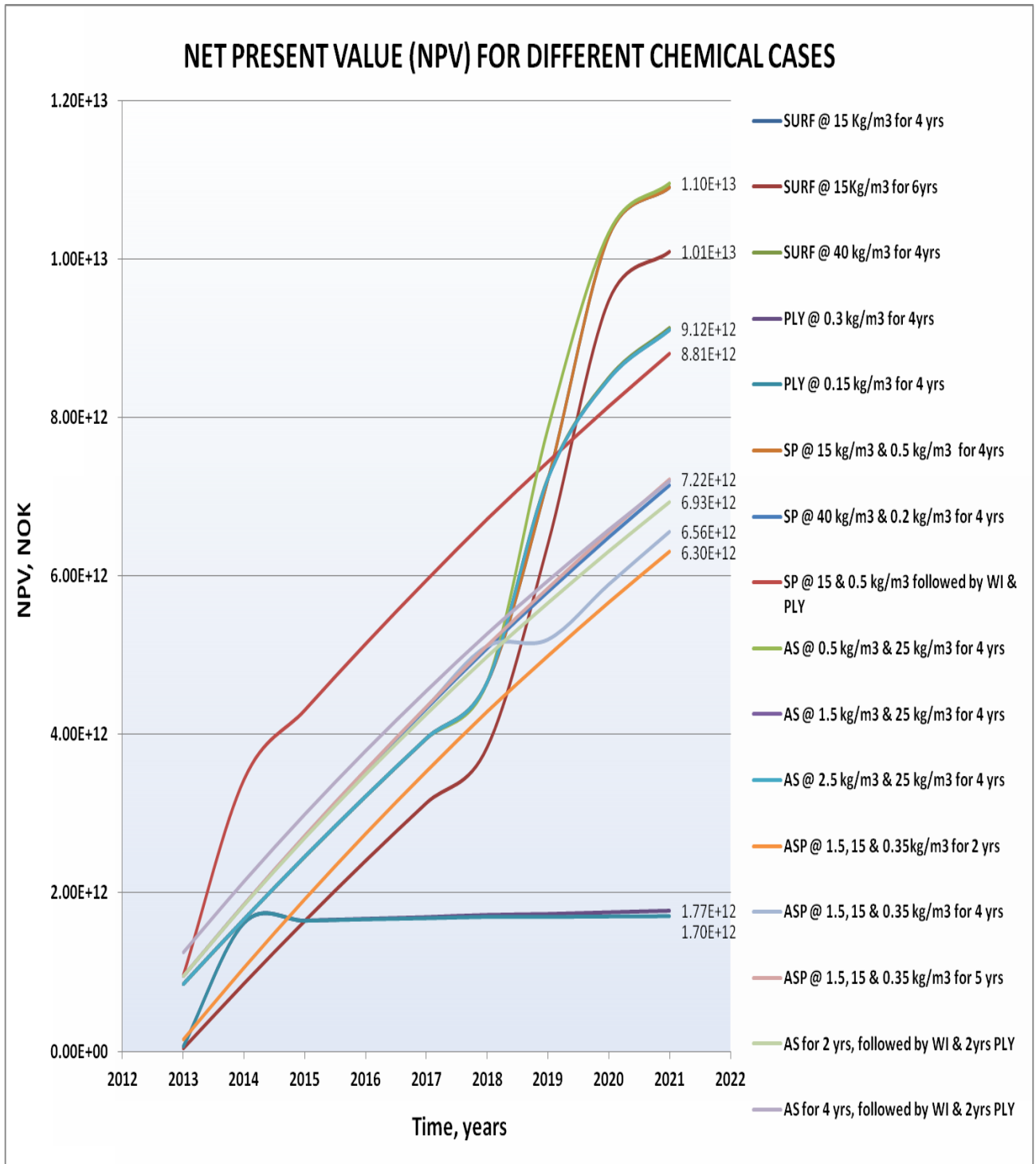


Figure 55: Net Present Value for Chemical Cases

4.1 Economic Sensitivity Analyses

For this project sensitivity analysis has been done to examine the effect of uncertainties in the predictions and assumptions on the profitability of the project. In our case five main parameters are uncertain and can be changed. These are oil price, alkaline price, surfactant price, polymer price and discount rate. These variables have effect on NPV. The analysis shows that how much the cumulative NPV is sensitive by changing each of these five variables. For this purpose, spider diagram has been used. To do sensitivity analysis, each of single parameter (oil price, alkaline price, surfactant price, polymer price and discount rate) was varied from low case to high case values while keeping all other base case parameters constant. The table below represents the range of assumed values for each parameter.

Variables	Low Case	Base case	High Case
Discount rate	0.11	0.08	0.05
oil price	75 USD/bbl	85 USD/bbl	95 USD/bbl
Alkaline price	1 USD/kg	1.5 USD/kg	2 USD/kg
Surfactant price	2 USD/kg	3.3 USD/kg	4.6 USD/kg
Polymer price	2.5 USD/kg	4 USD/kg	5.5 USD/kg

Table 2: Values for variables at low, base and high case

The graphs in Figure 57 were plotted based on change values (%) for each variable shown in Figure 56. From the results of the sensitivity analysis we can see that (+11.76) % and (-11.76) % change in oil price causes (+11.77) % and (-11.77) % change respectively in NPV. This means that change of oil price has a big effect on NPV value. Compared to chemical price effect, percentage change of discount rate has great effect on NPV where change of (-37.5) % and (+37.5) % in discount rate corresponds nearly (-9.44) % and (+11.31) % change in NPV respectively.

Chemical prices have much lower effect on NPV compared to oil price. Surfactant has highest impact of (+0.2/-0.2) % on NPV when it is deviated by (+39/-39) % from base case surfactant price.

From analyses and observations, it can be concluded that oil price has highest impact on NPV in terms of percentage change. On the contrary NPV is least sensitive to the polymer price.

OIL PRICE			
	Low Case	Base Case	High Case
Oil price (NOK/Sm3)	2810.601853	3185.348767	3560.095681
Change (%)	-11.76%	0.00%	11.76%
	i	k	L
NPV	6.37E+12	7.22E+12	8.07E+12
Change (%)	-11.77%	0.00%	11.77%
ALKALINE PRICE			
	Low Case	Base Case	High Case
Alkaline price (NOK/kg)	5.958	8.937	11.916
Change (%)	-33.33%	0.00%	33.33%
	i	k	L
NPV	7.22E+12	7.22E+12	7.22E+12
Change (%)	0.000779 %	0.000000 %	-0.000779 %
SURFACTANT PRICE			
	Low Case	Base Case	High Case
Surfactant price(NOK/kg)	11.916	19.6614	27.4068
Change (%)	-39.39%	0.00%	39.39%
	i	k	L
NPV	7.22E+12	7.22E+12	7.22E+12
Change (%)	0.020264 %	0.000000 %	-0.020264 %
POLYMER PRICE			
	Low Case	Base Case	High Case
Polymer price (NOK/kg)	14.895	23.832	32.769
Change (%)	-37.50%	0.00%	37.50%
	i	k	L
NPV	7.22E+12	7.22E+12	7.22E+12
Change (%)	0.000546 %	0.000000 %	-0.000546 %
DISCOUNT RATE			
	Low Case	Base Case	High Case
Discount Rate	0.11	0.08	0.05
Change (%)	37.50%	0.00%	-37.50%
	i	k	L
NPV	6.54E+12	7.22E+12	8.04E+12
Change (%)	-9.443865 %	0.000000 %	11.313196 %

Figure 56: Different variable changes and their impact on NPV

$$\text{Change} = (i - k) / K$$

$$\text{Change} = (L - k) / K$$

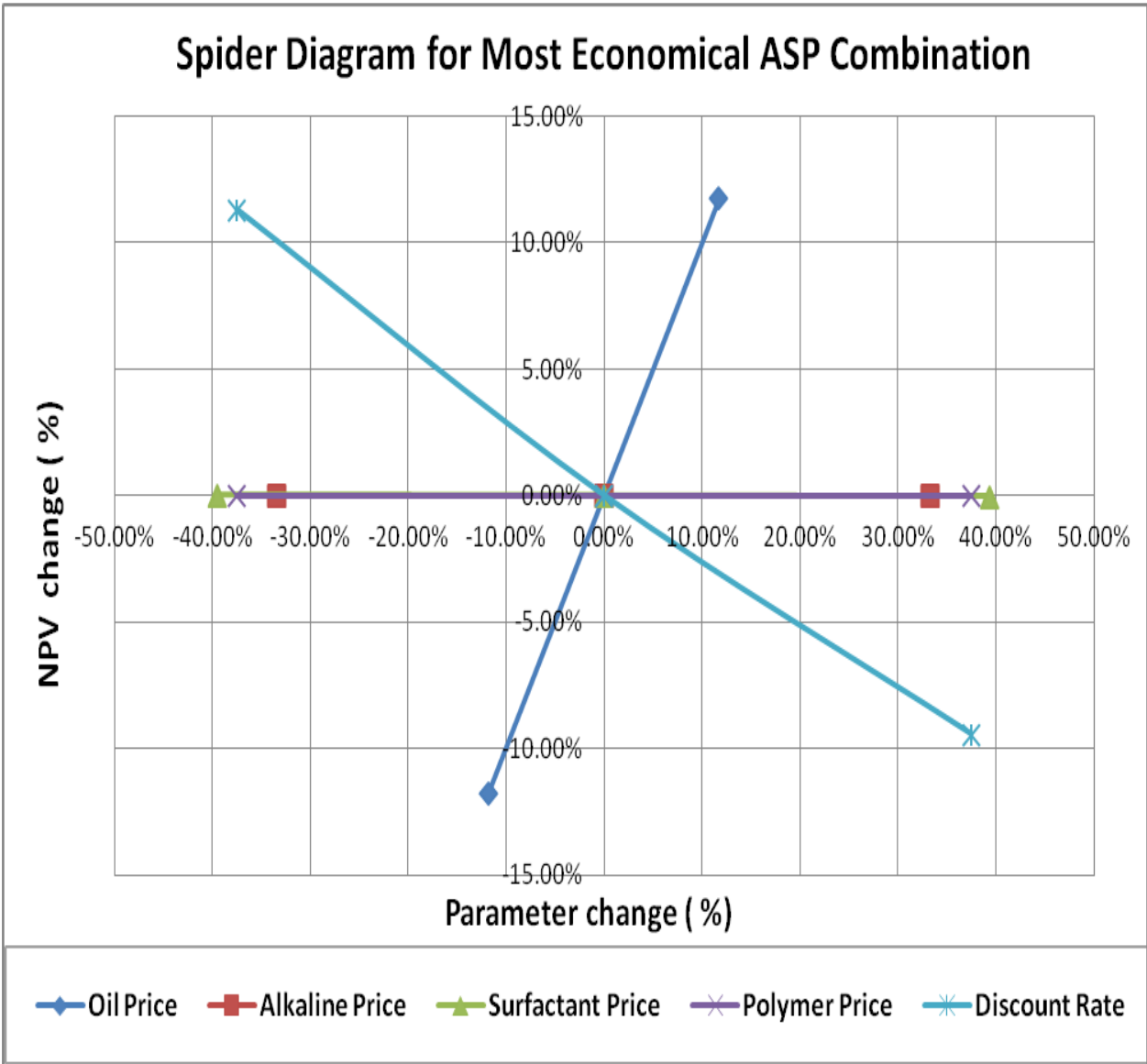


Figure 57: Spider diagram for ASP flooding case with ALK@1.5kg/m³,SURF@15kg/m³ &PLY@0.35 injecting for 5yrs

5 Discussion

In this project main purpose was to investigate ASP flooding as a tertiary recovering method in Norne field C segment through simulation study. The work was carried out using Eclipse simulation.

Norne C segment has 13 active wells including 9 producers and 4 injectors. We needed to choose one injection well to implement injection scheme and sensitivity analyses. Purposefully, the same chemical injection strategy was applied through each of injector and the impact on field production performance, chemical adsorption and production was studied. Finally, the well C-3H was selected as an optimal injector based on its location and numerical simulation results. This well was used as a chemical injector in the further ASP cases.

Firstly, only surfactant was added to water with different concentration and injection time period cases. It was discovered that, flooding is profitable when the concentration is low and injection occurs in the early years. Injection of surfactant at a later time might not be profitable. On the other hand, long injection period might not be profitable. So injection for 2 or 3 years can be optimal choice. From economic evaluation results, surfactant is very favorable chemical for the Norne C segment that all cases with surfactant gave high net present value.

The next step was polymer flooding study. Analyses showed that polymer injection as EOR method is more efficient than water injection because of improved mobility ratio, increasing the cumulative oil production and decreasing the total water production. Oil recovery factor increases with an increase in polymer solution concentration because of increase in displacing fluid's viscosity, but decreases with increase of rate so lower injection rate causes much better volumetric sweep efficiency. The incremental NPV for polymer cases are lower than all other cases which make polymer flooding as unfavorable method for C Segment.

Moreover, analyses were done for combination of 2 and 3 chemicals. From interpretations, AS solution was an effective flooding process with attendance of alkali. Main observation was that higher alkali concentration, lower oil production. SP solution caused higher oil production compared to single chemical flooding with positive sides that surfactant decreases IFT at the same time polymer improves mobility by increasing fluid viscosity. It was evident that the highest NPV value belongs to AS flooding case. SP case with concentration for surfactant at 15kg/m³ and polymer at 0.5kg/m³ was second best economical case. Simulation study showed that ASP as an effective chemical flooding process can be the potential EOR method for Norne C-segment by considering right chemical combinations with proper concentrations and duration of injection time.

Spider diagram clearly proved that oil price and discount rate has highest impact on NPV in terms of percentage change in price.

6 Conclusion

- The injector C-3H is optimal well for ASP flooding in Norne field C-segment.
- The ASP flooding is applicable EOR method for C segment.
- Economically, surfactant is very favorable chemical for C-segment.
- It is more profitable to inject surfactant for 2 and 3 years and it is wasteful injecting for 6 years.
- Polymer did not perform efficiently for both synthetic and field models.
- Change of chemical prices has lower effect on NPV compared to oil price.
- NPV was least sensitive to polymer price while it was highest sensitive to surfactant price.
- Production of polymer is lower for higher concentration in our case.
- Simulation with lower alkali concentration gives relatively better result.
- AS flooding for 4 years with alkali and surfactant at concentration of 0.5kg/m³ and 25 kg/m³ respectively gives highest NPV value.
- Polymer flooding at rate of 11000kg/D for 4 years gives lowest NPV which is most unfavorable case.
- Economically best ASP solution flooding case is the flooding with concentration of alkaline at 1.5kg/m³, surfactant at 15kg/m³ and polymer at 0.35 kg/m³ injecting for 5 years.

7 Recommendation

For more accurate and real results it is recommended detailed laboratory work focused on C-segment formation properties should be done considering ASP flooding. There is a need for up-scaling strategy to be development for our field model. Moreover, selection of proper time and duration of injection for chemical is important. Eclipse assumes that shear rate is proportional to the flow viscosity and does not show shear effect in the reservoir. Taking the possibility of share effect in the reservoir wide studies needs to be carried out.

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APPENDIX

A. Alkaline Properties

ALSURFST

--Alkaline --conc --Kg/m3	Water/oil Surface Tension Multiplier
0.0	1.0
6.0	0.5
15.0	0.3
20.0	0.1
30.0	0.0 /

ALPOLADS

--Alkaline --conc --Kg/m3	Polymer adsorption Multiplier
0.0	1.0
3.0	0.7
6.0	0.5
9.0	0.3 /
0.0	1.0
3.0	0.7
6.0	0.5
9.0	0.3 /

ALSURFAD

--Alkaline --conc --Kg/m3	Adsorption Multiplier
0.0	1.0
3.0	0.7
6.0	0.5
9.0	0.0 /
0.0	1.0
3.0	0.7
6.0	0.5
9.0	0.0 /

ALKADS

--Alkaline --conc --Kg/m3	Alkaline Adsorbed on rock (kg/kg)
0.0	0.000000
3.0	0.000005
6.0	0.000007
9.0	0.000008
10.0	0.000009 /
0.0	0.000000
3.0	0.000005
6.0	0.000007
9.0	0.000008
10.0	0.000009 /

B. Surfactant Properties

SURFVISC

--Surf conc	Water Viscosity
--Kg/m3	Centipoises
0.0 0.318	---0.42
5.0 0.449	
10.0 0.503	
15.0 0.540	
20.0 0.630 /	

SURFST

--Surf conc	Water/oil Turface Tension
--Kg/m3	(N/m)
0	30.0E-03
0.1	10.0E-03
0.25	1.60E-03
0.5	0.40E-03
1.0	0.07E-03
2.0	0.01E-03
3.0	0.006E-03
5.0	0.004E-03
10.0	0.006E-03
15.0	0.008E-03
20.0	0.01E-03 /

SURFADS

--Surf conc	Adsorbed mass
--Kg/m3	(kg/kg) = kg surf /kg rock
0.0	0.00000
1.0	0.00017
5.0	0.00017
10.0	0.00017 /
0.0	0.00000
1.0	0.00017
5.0	0.00017
10.0	0.00017 /

SURFCAPD

--Log10 (capillary	Miscibility
--number)	function 0 = immisible, 1= miscible
-8	0.0
-7	0.0
-6	0.0
-5.0	0.0
-2.5	1.0
0	1.0
5	1.0
10	1.0 /

SURFROCK

--Adsorption	Rock mass 1- reversible (desorption)
--index	density 2- irreversible
--	Kg/rm3
2	2650 /
2	2650 /

C. Polymer Properties

--Polymer shear thinning data

-- Wat. Velocity	Visc reduction
-- M/day	CP
--0.0	1.0
--2.0	1.0 /

-- Polymer solution Viscosity Function
PLYVISC

-- Ply conc.	Wat. Visc. mult.
-- Kg/m3	
0.0	1.0
0.1	1.55
0.3	2.55
0.5	5.125
0.7	8.125
1.0	21.2 /

-- Polymer Adsorption Function

PLYADS

-- Ply conc.	Ply conc.
--	Adsorbed by rock
-- Kg/m3	kg/kg
0.0	0.0
0.5	0.0000017
1.0	0.0000017 /
0.0	0.0
0.5	0.0000017
1.0	0.0000017 /

-- Todd-Longstaff Mixing Parameters

TLMIXPAR

1 1* /

-- Polymer-Salt concentration for mixing
-- Maximum polymer and salt concentration

PLYMAX

-- Ply conc.	Salt conc.
-- Kg/m3	kg/m3
1.0	0.0 /

--Polymer-Rock Properties

PLYROCK

--dead	residual	mass	Ads.	max.
--pore	resistance	density	Index	Polymer
--space	factor			adsorption
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /

RPTPROPS

'SURFVISC' 'PLYVISC' /

D. Excel tables from economic evaluation

Time	Project year	Base Case oil production	Oil production with surfactant	Incremental oil production	Oil Price	Incremental Revenue from oil	Surfactant injected	Surfactant expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.83E+09	4.48E+07	1.90E+04	8.50E+11	4.38E+07	8.61E+08	8.49E+11	1.00E+00	8.49E+11	8.49E+11
2014	1	1.80E+09	1.85E+09	4.54E+07	1.95E+04	8.87E+11	4.38E+07	8.61E+08	8.86E+11	9.26E-01	8.20E+11	1.67E+12
2015	2	1.82E+09	1.86E+09	4.58E+07	2.01E+04	9.22E+11	4.38E+07	8.61E+08	9.22E+11	8.57E-01	7.90E+11	2.46E+12
2016	3	1.83E+09	1.88E+09	4.62E+07	2.07E+04	9.58E+11	4.38E+07	8.61E+08	9.57E+11	7.94E-01	7.60E+11	3.22E+12
2017	4	1.84E+09	1.89E+09	4.65E+07	2.14E+04	9.92E+11	0	0	9.92E+11	7.35E-01	7.29E+11	3.95E+12
2018	5	1.85E+09	1.90E+09	4.71E+07	2.20E+04	1.04E+12	0	0	1.04E+12	6.81E-01	7.05E+11	4.65E+12
2019	6	1.86E+09	2.04E+09	1.80E+08	2.27E+04	4.07E+12	0	0	4.07E+12	6.30E-01	2.57E+12	7.22E+12
2020	7	1.87E+09	2.10E+09	2.25E+08	2.33E+04	5.26E+12	0	0	5.26E+12	5.83E-01	3.07E+12	1.03E+13
2021	8	1.88E+09	1.93E+09	4.74E+07	2.40E+04	1.14E+12	0	0	1.14E+12	5.40E-01	6.16E+11	1.09E+13

Table 3: Incremental NPV for Surfactant flooding at concentration of 15kg/m3 for 4 yrs

Time	Project year	Base Case oil production	Oil production with surfactant	Incremental oil production	Oil Price	Incremental Revenue from oil	Surfactant injected	Surfactant expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.79E+09	1.99E+06	1.90E+04	3.78E+10	4.38E+07	8.61E+08	3.70E+10	1.00E+00	3.70E+10	3.70E+10
2014	1	1.80E+09	1.85E+09	4.54E+07	1.95E+04	8.87E+11	4.38E+07	8.61E+08	8.86E+11	9.26E-01	8.20E+11	8.57E+11
2015	2	1.82E+09	1.86E+09	4.58E+07	2.01E+04	9.22E+11	4.38E+07	8.61E+08	9.22E+11	8.57E-01	7.90E+11	1.65E+12
2016	3	1.83E+09	1.88E+09	4.62E+07	2.07E+04	9.58E+11	4.38E+07	8.61E+08	9.57E+11	7.94E-01	7.60E+11	2.41E+12
2017	4	1.84E+09	1.89E+09	4.65E+07	2.14E+04	9.92E+11	4.38E+07	8.61E+08	9.91E+11	7.35E-01	7.29E+11	3.14E+12
2018	5	1.85E+09	1.90E+09	4.71E+07	2.20E+04	1.04E+12	4.38E+07	8.61E+08	1.04E+12	6.81E-01	7.05E+11	3.84E+12
2019	6	1.86E+09	2.04E+09	1.80E+08	2.27E+04	4.07E+12	0	0	4.07E+12	6.30E-01	2.57E+12	6.41E+12
2020	7	1.87E+09	2.10E+09	2.26E+08	2.33E+04	5.26E+12	0	0	5.26E+12	5.83E-01	3.07E+12	9.48E+12
2021	8	1.88E+09	1.93E+09	4.76E+07	2.40E+04	1.14E+12	0	0	1.14E+12	5.40E-01	6.18E+11	1.01E+13

Table 4: Incremental NPV for Surfactant flooding at concentration of 15kg/m3 for 6 yrs

Time	Project year	Base Case oil production	Oil production with surfactant	Incremental oil production	Oil Price	Incremental Revenue from oil	Surfactant injected	Surfactant expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm ³)	(Sm ³)	(Sm ³)	(NOK/Sm ³)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.83E+09	4.48E+07	1.90E+04	8.50E+11	1.17E+08	2.30E+09	8.48E+11	1.00E+00	8.48E+11	8.48E+11
2014	1	1.80E+09	1.85E+09	4.54E+07	1.95E+04	8.87E+11	1.17E+08	2.30E+09	8.85E+11	9.26E-01	8.19E+11	1.67E+12
2015	2	1.82E+09	1.86E+09	4.58E+07	2.01E+04	9.23E+11	1.17E+08	2.30E+09	9.21E+11	8.57E-01	7.89E+11	2.46E+12
2016	3	1.83E+09	1.88E+09	4.63E+07	2.07E+04	9.60E+11	1.17E+08	2.30E+09	9.57E+11	7.94E-01	7.60E+11	3.22E+12
2017	4	1.84E+09	1.89E+09	4.67E+07	2.14E+04	9.98E+11	0	0.00E+00	9.98E+11	7.35E-01	7.34E+11	3.95E+12
2018	5	1.85E+09	1.90E+09	4.76E+07	2.20E+04	1.05E+12	0	0.00E+00	1.05E+12	6.81E-01	7.12E+11	4.66E+12
2019	6	1.86E+09	2.04E+09	1.80E+08	2.27E+04	4.09E+12	0	0	4.09E+12	6.30E-01	2.58E+12	7.24E+12
2020	7	1.87E+09	1.96E+09	9.25E+07	2.33E+04	2.16E+12	0	0	2.16E+12	5.83E-01	1.26E+12	8.50E+12
2021	8	1.88E+09	1.93E+09	4.83E+07	2.40E+04	1.16E+12	0	0	1.16E+12	5.40E-01	6.28E+11	9.12E+12

Table 5: Incremental NPV for Surfactant flooding at concentration of 40kg/m³ for 4 yrs

Time	Project year	Base Case oil production	Oil production with Polymer	Incremental oil production	Oil Price	Incremental Revenue from oil	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm ³)	(Sm ³)	(Sm ³)	(NOK/Sm ³)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.79E+09	3.32E+06	1.90E+04	6.30E+10	7.01E+05	1.67E+07	6.29E+10	1.00E+00	6.29E+10	6.29E+10
2014	1	1.80E+09	1.89E+09	8.60E+07	1.95E+04	1.68E+12	7.01E+05	1.67E+07	1.68E+12	9.26E-01	1.56E+12	1.62E+12
2015	2	1.82E+09	1.82E+09	1.63E+06	2.01E+04	3.29E+10	7.01E+05	1.67E+07	3.29E+10	8.57E-01	2.82E+10	1.65E+12
2016	3	1.83E+09	1.83E+09	1.37E+06	2.07E+04	2.83E+10	7.01E+05	1.67E+07	2.83E+10	7.94E-01	2.25E+10	1.67E+12
2017	4	1.84E+09	1.84E+09	1.37E+06	2.14E+04	2.93E+10	0	0	2.93E+10	7.35E-01	2.15E+10	1.69E+12
2018	5	1.85E+09	1.85E+09	1.83E+06	2.20E+04	4.02E+10	0	0	4.02E+10	6.81E-01	2.73E+10	1.72E+12
2019	6	1.86E+09	1.86E+09	8.64E+05	2.27E+04	1.96E+10	0	0	1.96E+10	6.30E-01	1.23E+10	1.73E+12
2020	7	1.87E+09	1.87E+09	1.51E+06	2.33E+04	3.52E+10	0	0	3.52E+10	5.83E-01	2.05E+10	1.75E+12
2021	8	1.88E+09	1.88E+09	1.60E+06	2.40E+04	3.85E+10	0	0	3.85E+10	5.40E-01	2.08E+10	1.77E+12

Table 6: Incremental NPV for Polymer flooding at concentration of 0.3kg/m³ for 4 yrs

Time	Project year	Base Case oil production	Oil production with Polymer	Incremental oil production	Oil Price	Incremental Revenue from oil	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.79E+09	3.31E+06	1.90E+04	6.29E+10	4.38E+05	1.04E+07	6.29E+10	1.00E+00	6.29E+10	6.29E+10
2014	1	1.80E+09	1.89E+09	8.60E+07	1.95E+04	1.68E+12	4.38E+05	1.04E+07	1.68E+12	9.26E-01	1.56E+12	1.62E+12
2015	2	1.82E+09	1.82E+09	1.52E+06	2.01E+04	3.07E+10	4.38E+05	1.04E+07	3.06E+10	8.57E-01	2.63E+10	1.64E+12
2016	3	1.83E+09	1.83E+09	1.10E+06	2.07E+04	2.28E+10	4.38E+05	1.04E+07	2.28E+10	7.94E-01	1.81E+10	1.66E+12
2017	4	1.84E+09	1.84E+09	8.93E+05	2.14E+04	1.91E+10	0	0	1.91E+10	7.35E-01	1.40E+10	1.68E+12
2018	5	1.85E+09	1.85E+09	1.13E+06	2.20E+04	2.49E+10	0	0	2.49E+10	6.81E-01	1.69E+10	1.69E+12
2019	6	1.86E+09	1.86E+09	-4.14E+04	2.27E+04	-9.38E+08	0	0	-9.38E+08	6.30E-01	-5.91E+08	1.69E+12
2020	7	1.87E+09	1.87E+09	3.96E+05	2.33E+04	9.24E+09	0	0	9.24E+09	5.83E-01	5.39E+09	1.70E+12
2021	8	1.88E+09	1.88E+09	2.97E+05	2.40E+04	7.15E+09	0	0	7.15E+09	5.40E-01	3.86E+09	1.70E+12

Table 7: Incremental NPV for Polymer flooding at concentration of 0.15kg/m3 for 4 yrs

Time	Project year	Base Case oil production	Oil production with Polymer	Incremental oil production	Oil Price	Incremental Revenue from oil	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.79E+09	2.52E+06	1.90E+04	4.77E+10	1.20E+06	2.87E+07	4.77E+10	1.00E+00	4.77E+10	4.77E+10
2014	1	1.80E+09	1.89E+09	8.52E+07	1.95E+04	1.67E+12	1.20E+06	2.87E+07	1.67E+12	9.26E-01	1.54E+12	1.59E+12
2015	2	1.82E+09	1.82E+09	9.32E+05	2.01E+04	1.88E+10	1.20E+06	2.87E+07	1.87E+10	8.57E-01	1.61E+10	1.61E+12
2016	3	1.83E+09	1.83E+09	7.00E+05	2.07E+04	1.45E+10	1.20E+06	2.87E+07	1.45E+10	7.94E-01	1.15E+10	1.62E+12
2017	4	1.84E+09	1.84E+09	7.35E+05	2.14E+04	1.57E+10	0	0	1.57E+10	7.35E-01	1.15E+10	1.63E+12
2018	5	1.85E+09	1.85E+09	1.22E+06	2.20E+04	2.69E+10	0	0	2.69E+10	6.81E-01	1.83E+10	1.65E+12
2019	6	1.86E+09	1.86E+09	2.87E+05	2.27E+04	6.50E+09	0	0	6.50E+09	6.30E-01	4.10E+09	1.65E+12
2020	7	1.87E+09	1.87E+09	9.55E+05	2.33E+04	2.23E+10	0	0	2.23E+10	5.83E-01	1.30E+10	1.66E+12
2021	8	1.88E+09	1.88E+09	1.06E+06	2.40E+04	2.55E+10	0	0	2.55E+10	5.40E-01	1.38E+10	1.68E+12

Table 8: Incremental NPV for Polymer flooding at concentration of 11000kg/D for 4 years

Time	Project year	Base Case oil production	Oil production with SP	Incremental oil production	Oil Price	Incremental Revenue from oil	Surfactant injected	Surfactant expences	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.83E+09	4.48E+07	1.90E+04	8.50E+11	4.38E+07	8.61E+08	1.46E+06	3.48E+07	8.49E+11	1.00E+00	8.49E+11	8.49E+11
2014	1	1.80E+09	1.85E+09	4.54E+07	1.95E+04	8.87E+11	4.38E+07	8.61E+08	1.46E+06	3.48E+07	8.86E+11	9.26E-01	8.20E+11	1.67E+12
2015	2	1.82E+09	1.86E+09	4.58E+07	2.01E+04	9.22E+11	4.38E+07	8.61E+08	1.46E+06	3.48E+07	9.22E+11	8.57E-01	7.90E+11	2.46E+12
2016	3	1.83E+09	1.88E+09	4.62E+07	2.07E+04	9.58E+11	4.38E+07	8.61E+08	1.46E+06	3.48E+07	9.57E+11	7.94E-01	7.60E+11	3.22E+12
2017	4	1.84E+09	1.89E+09	4.65E+07	2.14E+04	9.92E+11	0	0	0	0	9.92E+11	7.35E-01	7.29E+11	3.95E+12
2018	5	1.85E+09	1.90E+09	4.71E+07	2.20E+04	1.04E+12	0	0	0	0	1.04E+12	6.81E-01	7.05E+11	4.65E+12
2019	6	1.86E+09	2.04E+09	1.80E+08	2.27E+04	4.07E+12	0	0	0	0	4.07E+12	6.30E-01	2.57E+12	7.22E+12
2020	7	1.87E+09	2.10E+09	2.25E+08	2.33E+04	5.26E+12	0	0	0	0	5.26E+12	5.83E-01	3.07E+12	1.03E+13
2021	8	1.88E+09	1.93E+09	4.74E+07	2.40E+04	1.14E+12	0	0	0	0	1.14E+12	5.40E-01	6.16E+11	1.09E+13

Table 9: Incremental NPV for SP flooding with SURF@15kg/m3 & PLY@0.5kg/m3

Time	Project year	Base Case oil production	Oil production with SP	Incremental oil production	Oil Price	Incremental Revenue from oil	Surfactant injected	Surfactant expences	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.84E+09	5.04E+07	1.90E+04	9.56E+11	1.17E+08	2.30E+09	5.84E+05	1.39E+07	9.53E+11	1.00E+00	9.53E+11	9.53E+11
2014	1	1.80E+09	1.85E+09	5.01E+07	1.95E+04	9.80E+11	1.17E+08	2.30E+09	5.84E+05	1.39E+07	9.78E+11	9.26E-01	9.05E+11	1.86E+12
2015	2	1.82E+09	1.87E+09	5.00E+07	2.01E+04	1.01E+12	1.17E+08	2.30E+09	5.84E+05	1.39E+07	1.00E+12	8.57E-01	8.61E+11	2.72E+12
2016	3	1.83E+09	1.88E+09	5.01E+07	2.07E+04	1.04E+12	1.17E+08	2.30E+09	5.84E+05	1.39E+07	1.04E+12	7.94E-01	8.22E+11	3.54E+12
2017	4	1.84E+09	1.89E+09	5.02E+07	2.14E+04	1.07E+12	0	0	0	0	1.07E+12	7.35E-01	7.89E+11	4.33E+12
2018	5	1.85E+09	1.90E+09	5.08E+07	2.20E+04	1.12E+12	0	0	0	0	1.12E+12	6.81E-01	7.60E+11	5.09E+12
2019	6	1.86E+09	1.91E+09	4.99E+07	2.27E+04	1.13E+12	0	0	0	0	1.13E+12	6.30E-01	7.12E+11	5.80E+12
2020	7	1.87E+09	1.92E+09	5.05E+07	2.33E+04	1.18E+12	0	0	0	0	1.18E+12	5.83E-01	6.88E+11	6.49E+12
2021	8	1.88E+09	1.93E+09	5.05E+07	2.40E+04	1.21E+12	0	0	0	0	1.21E+12	5.40E-01	6.56E+11	7.15E+12

Table 10: Incremental NPV for SP flooding with SURF@40kg/m3 & PLY@0.2kg/m3

Time	Project year	Base Case oil production	Oil production with SP	Incremental oil production	Oil Price	Incremental Revenue from oil	Surfactant injected	Surfactant expences	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.84E+09	5.05E+07	1.90E+04	9.58E+11	4.38E+07	8.61E+08	1.46E+06	3.48E+07	9.57E+11	1.00E+00	9.57E+11	9.57E+11
2014	1	1.80E+09	1.94E+09	1.37E+08	1.95E+04	2.67E+12	4.38E+07	8.61E+08	1.46E+06	3.48E+07	2.67E+12	9.26E-01	2.48E+12	3.43E+12
2015	2	1.82E+09	1.87E+09	5.07E+07	2.01E+04	1.02E+12	0	0.00E+00	0	0	1.02E+12	8.57E-01	8.74E+11	4.31E+12
2016	3	1.83E+09	1.88E+09	5.08E+07	2.07E+04	1.05E+12	0	0.00E+00	1.46E+06	3.48E+07	1.05E+12	7.94E-01	8.36E+11	5.14E+12
2017	4	1.84E+09	1.89E+09	5.11E+07	2.14E+04	1.09E+12	0	0	0	0	1.09E+12	7.35E-01	8.02E+11	5.94E+12
2018	5	1.85E+09	1.90E+09	5.17E+07	2.20E+04	1.14E+12	0	0	0	0	1.14E+12	6.81E-01	7.73E+11	6.72E+12
2019	6	1.86E+09	1.91E+09	5.07E+07	2.27E+04	1.15E+12	0	0	0	0	1.15E+12	6.30E-01	7.24E+11	7.44E+12
2020	7	1.87E+09	1.92E+09	5.13E+07	2.33E+04	1.20E+12	0	0	0	0	1.20E+12	5.83E-01	6.99E+11	8.14E+12
2021	8	1.88E+09	1.93E+09	5.14E+07	2.40E+04	1.24E+12	0	0	0	0	1.24E+12	5.40E-01	6.67E+11	8.81E+12

Table 11: SP flooding with SURF@15kg/m³ & PLY@0.5kg/m³ followed WI and PLYI

Time	Project year	Base Case oil production	Oil production with AS	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expences	Surfactant injected	Surfactant expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.83E+09	4.48E+07	1.90E+04	8.50E+11	4.38E+06	3.91E+07	7.30E+07	1.44E+09	8.49E+11	1.00E+00	8.49E+11	8.49E+11
2014	1	1.80E+09	1.85E+09	4.54E+07	1.95E+04	8.87E+11	4.38E+06	3.91E+07	7.30E+07	1.44E+09	8.85E+11	9.26E-01	8.20E+11	1.67E+12
2015	2	1.82E+09	1.86E+09	4.58E+07	2.01E+04	9.23E+11	4.38E+06	3.91E+07	7.30E+07	1.44E+09	9.21E+11	8.57E-01	7.90E+11	2.46E+12
2016	3	1.83E+09	1.88E+09	4.62E+07	2.07E+04	9.58E+11	4.38E+06	3.91E+07	7.30E+07	1.44E+09	9.57E+11	7.94E-01	7.60E+11	3.22E+12
2017	4	1.84E+09	1.89E+09	4.66E+07	2.14E+04	9.95E+11	0	0	0	0	9.95E+11	7.35E-01	7.31E+11	3.95E+12
2018	5	1.85E+09	1.90E+09	4.73E+07	2.20E+04	1.04E+12	0	0	0	0	1.04E+12	6.81E-01	7.08E+11	4.66E+12
2019	6	1.86E+09	2.04E+09	1.80E+08	2.27E+04	4.08E+12	0	0	0	0	4.08E+12	6.30E-01	2.57E+12	7.23E+12
2020	7	1.87E+09	1.96E+09	9.20E+07	2.33E+04	2.15E+12	0	0	0	0	2.15E+12	5.83E-01	1.25E+12	8.48E+12
2021	8	1.88E+09	1.93E+09	4.77E+07	2.40E+04	1.15E+12	0	0	0	0	1.15E+12	5.40E-01	6.20E+11	9.10E+12

Table 12: Incremental NPV for AS flooding with ALK@1.5kg/m³ & SURF@25kg/m³

Time	Project year	Base Case oil production	Oil production with AS	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expences	Surfactant injected	Surfactant expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.83E+09	4.48E+07	1.90E+04	8.50E+11	1.46E+06	1.30E+07	7.30E+07	1.44E+09	8.49E+11	1.00E+00	8.49E+11	8.49E+11
2014	1	1.80E+09	1.85E+09	4.54E+07	1.95E+04	8.87E+11	1.46E+06	1.30E+07	7.30E+07	1.44E+09	8.86E+11	9.26E-01	8.20E+11	1.67E+12
2015	2	1.82E+09	1.86E+09	4.58E+07	2.01E+04	9.23E+11	1.46E+06	1.30E+07	7.30E+07	1.44E+09	9.21E+11	8.57E-01	7.90E+11	2.46E+12
2016	3	1.83E+09	1.88E+09	4.62E+07	2.07E+04	9.58E+11	1.46E+06	1.30E+07	7.30E+07	1.44E+09	9.57E+11	7.94E-01	7.60E+11	3.22E+12
2017	4	1.84E+09	1.89E+09	4.66E+07	2.14E+04	9.95E+11	0	0	0	0	9.95E+11	7.35E-01	7.31E+11	3.95E+12
2018	5	1.85E+09	1.90E+09	4.73E+07	2.20E+04	1.04E+12	0	0	0	0	1.04E+12	6.81E-01	7.08E+11	4.66E+12
2019	6	1.86E+09	2.09E+09	2.24E+08	2.27E+04	5.08E+12	0	0	0	0	5.08E+12	6.30E-01	3.20E+12	7.86E+12
2020	7	1.87E+09	2.05E+09	1.81E+08	2.33E+04	4.23E+12	0	0	0	0	4.23E+12	5.83E-01	2.47E+12	1.03E+13
2021	8	1.88E+09	1.93E+09	4.78E+07	2.40E+04	1.15E+12	0	0	0	0	1.15E+12	5.40E-01	6.21E+11	1.10E+13

Table 13: Incremental NPV for AS flooding with ALK@0.5kg/m³ & SURF@25kg/m³

Time	Project year	Base Case oil production	Oil production with AS	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expences	Surfactant injected	Surfactant expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm3)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.83E+09	4.48E+07	1.90E+04	8.50E+11	7.30E+06	6.52E+07	7.30E+07	1.44E+09	8.49E+11	1.00E+00	8.49E+11	8.49E+11
2014	1	1.80E+09	1.85E+09	4.54E+07	1.95E+04	8.87E+11	7.30E+06	6.52E+07	7.30E+07	1.44E+09	8.85E+11	9.26E-01	8.20E+11	1.67E+12
2015	2	1.82E+09	1.86E+09	4.58E+07	2.01E+04	9.23E+11	7.30E+06	6.52E+07	7.30E+07	1.44E+09	9.21E+11	8.57E-01	7.90E+11	2.46E+12
2016	3	1.83E+09	1.88E+09	4.62E+07	2.07E+04	9.58E+11	7.30E+06	6.52E+07	7.30E+07	1.44E+09	9.57E+11	7.94E-01	7.60E+11	3.22E+12
2017	4	1.84E+09	1.89E+09	4.66E+07	2.14E+04	9.95E+11	0	0	0	0	9.95E+11	7.35E-01	7.31E+11	3.95E+12
2018	5	1.85E+09	1.90E+09	4.73E+07	2.20E+04	1.04E+12	0	0	0	0	1.04E+12	6.81E-01	7.08E+11	4.66E+12
2019	6	1.86E+09	2.04E+09	1.80E+08	2.27E+04	4.08E+12	0	0	0	0	4.08E+12	6.30E-01	2.57E+12	7.23E+12
2020	7	1.87E+09	1.96E+09	9.20E+07	2.33E+04	2.15E+12	0	0	0	0	2.15E+12	5.83E-01	1.25E+12	8.48E+12
2021	8	1.88E+09	1.93E+09	4.77E+07	2.40E+04	1.15E+12	0	0	0	0	1.15E+12	5.40E-01	6.20E+11	9.10E+12

Table 14: Incremental NPV for AS flooding with ALK@2.5kg/m³ & SURF@25kg/m³

Time	Project year	Base Case oil production	Oil production with ASP	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expences	Surfactant injected	Surfactant expences	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.80E+09	7.75E+06	1.90E+04	1.47E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.46E+11	1.00E+00	1.46E+11	1.46E+11
2014	1	1.80E+09	1.85E+09	5.02E+07	1.95E+04	9.81E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	1.02E+06	2.44E+07	9.80E+11	9.26E-01	9.07E+11	1.05E+12
2015	2	1.82E+09	1.87E+09	5.01E+07	2.01E+04	1.01E+12	0	0	0	0	0	0	1.01E+12	8.57E-01	8.65E+11	1.92E+12
2016	3	1.83E+09	1.88E+09	5.01E+07	2.07E+04	1.04E+12	0	0	0	0	0	0	1.04E+12	7.94E-01	8.24E+11	2.74E+12
2017	4	1.84E+09	1.89E+09	5.01E+07	2.14E+04	1.07E+12	0	0	0	0	0	0	1.07E+12	7.35E-01	7.87E+11	3.53E+12
2018	5	1.85E+09	1.90E+09	5.04E+07	2.20E+04	1.11E+12	0	0	0	0	0	0	1.11E+12	6.81E-01	7.55E+11	4.28E+12
2019	6	1.86E+09	1.91E+09	4.92E+07	2.27E+04	1.11E+12	0	0	0	0	0	0	1.11E+12	6.30E-01	7.02E+11	4.99E+12
2020	7	1.87E+09	1.92E+09	4.96E+07	2.33E+04	1.16E+12	0	0	0	0	0	0	1.16E+12	5.83E-01	6.75E+11	5.66E+12
2021	8	1.88E+09	1.93E+09	4.94E+07	2.40E+04	1.19E+12	0	0	0	0	0	0	1.19E+12	5.40E-01	6.42E+11	6.30E+12

Table 15: Incremental NPV for ASP with ALK@1.5kg/m³,SURF@15kg/m³ &PLY@0.35

Time	Project year	Base Case oil production	Oil production with ASP	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expences	Surfactant injected	Surfactant expences	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.84E+09	5.03E+07	1.90E+04	9.54E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	1.02E+06	2.44E+07	9.53E+11	1.00E+00	9.53E+11	9.53E+11
2014	1	1.80E+09	1.85E+09	5.02E+07	1.95E+04	9.81E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	1.02E+06	2.44E+07	9.80E+11	9.26E-01	9.07E+11	1.86E+12
2015	2	1.82E+09	1.87E+09	5.02E+07	2.01E+04	1.01E+12	4.38E+06	39144060	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.01E+12	8.57E-01	8.65E+11	2.73E+12
2016	3	1.83E+09	1.88E+09	5.04E+07	2.07E+04	1.05E+12	4.38E+06	39144060	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.04E+12	7.94E-01	8.29E+11	3.55E+12
2017	4	1.84E+09	1.89E+09	5.07E+07	2.14E+04	1.08E+12	0	0	0	0	0	0	1.08E+12	7.35E-01	7.96E+11	4.35E+12
2018	5	1.85E+09	1.90E+09	5.13E+07	2.20E+04	1.13E+12	0	0	0	0	0	0	1.13E+12	6.81E-01	7.68E+11	5.12E+12
2019	6	1.86E+09	1.87E+09	5.79E+06	2.27E+04	1.31E+11	0	0	0	0	0	0	1.31E+11	6.30E-01	8.27E+10	5.20E+12
2020	7	1.87E+09	1.92E+09	5.11E+07	2.33E+04	1.19E+12	0	0	0	0	0	0	1.19E+12	5.83E-01	6.95E+11	5.90E+12
2021	8	1.88E+09	1.93E+09	5.11E+07	2.40E+04	1.23E+12	0	0	0	0	0	0	1.23E+12	5.40E-01	6.64E+11	6.56E+12

Table 16: Incremental NPV for ASP with ALK@1.5kg/m³,SURF@15kg/m³ &PLY@0.35

Time	Project year	Base Case oil production	Oil production with ASP	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expences	Surfactant injected	Surfactant expences	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.84E+09	5.03E+07	1.90E+04	9.54E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	1.02E+06	2.44E+07	9.53E+11	1.00E+00	9.53E+11	9.53E+11
2014	1	1.80E+09	1.85E+09	5.02E+07	1.95E+04	9.81E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	1.02E+06	2.44E+07	9.80E+11	9.26E-01	9.07E+11	1.86E+12
2015	2	1.82E+09	1.87E+09	5.02E+07	2.01E+04	1.01E+12	4.38E+06	39144060	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.01E+12	8.57E-01	8.65E+11	2.73E+12
2016	3	1.83E+09	1.88E+09	5.04E+07	2.07E+04	1.05E+12	4.38E+06	39144060	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.04E+12	7.94E-01	8.29E+11	3.55E+12
2017	4	1.84E+09	1.89E+09	5.08E+07	2.14E+04	1.08E+12	4.38E+06	39144060	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.08E+12	7.35E-01	7.97E+11	4.35E+12
2018	5	1.85E+09	1.90E+09	5.15E+07	2.20E+04	1.13E+12	0	0	0	0	0	0	1.13E+12	6.81E-01	7.71E+11	5.12E+12
2019	6	1.86E+09	1.91E+09	5.07E+07	2.27E+04	1.15E+12	0	0	0	0	0	0	1.15E+12	6.30E-01	7.24E+11	5.85E+12
2020	7	1.87E+09	1.92E+09	5.15E+07	2.33E+04	1.20E+12	0	0	0	0	0	0	1.20E+12	5.83E-01	7.01E+11	6.55E+12
2021	8	1.88E+09	1.93E+09	5.17E+07	2.40E+04	1.24E+12	0	0	0	0	0	0	1.24E+12	5.40E-01	6.71E+11	7.22E+12

Table 17: Incremental NPV for ASP with ALK@1.5kg/m3,SURF@15kg/m3 &PLY@0.35

Time	Project year	Base Case oil production	Oil production with ASP	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expences	Surfactant injected	Surfactant expences	Polymer injected	Polymer expences	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.84E+09	5.03E+07	1.90E+04	9.54E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	1.02E+06	2.44E+07	9.53E+11	1.00E+00	9.53E+11	9.53E+11
2014	1	1.80E+09	1.85E+09	5.01E+07	1.95E+04	9.79E+11	0	0	0	0	0	0	9.79E+11	9.26E-01	9.06E+11	1.86E+12
2015	2	1.82E+09	1.87E+09	4.98E+07	2.01E+04	1.00E+12	4.38E+06	39144060	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.00E+12	8.57E-01	8.59E+11	2.72E+12
2016	3	1.83E+09	1.88E+09	4.99E+07	2.07E+04	1.03E+12	0	0	0	0	0	0	1.03E+12	7.94E-01	8.21E+11	3.54E+12
2017	4	1.84E+09	1.89E+09	4.99E+07	2.14E+04	1.07E+12	4.38E+06	39144060	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.07E+12	7.35E-01	7.83E+11	4.32E+12
2018	5	1.85E+09	1.90E+09	5.04E+07	2.20E+04	1.11E+12	0	0	0	0	0	0	1.11E+12	6.81E-01	7.55E+11	5.08E+12
2019	6	1.86E+09	1.91E+09	4.94E+07	2.27E+04	1.12E+12	4.38E+06	3.91E+07	4.38E+07	8.61E+08	1.02E+06	2.44E+07	1.12E+12	6.30E-01	7.05E+11	5.78E+12
2020	7	1.87E+09	1.92E+09	5.02E+07	2.33E+04	1.17E+12	0	0	0	0	0	0	1.17E+12	5.83E-01	6.83E+11	6.47E+12
2021	8	1.88E+09	1.88E+09	5.52E+06	2.40E+04	1.33E+11	0	0	0	0	0	0	1.33E+11	5.40E-01	7.17E+10	6.54E+12

Table 18: Incremental NPV for ASP flooding for 4 years' slug AIK1.5_SURF15_PLY0.35

Time	Project year	Base Case oil production	Oil production with ASP	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expenses	Surfactant injected	Surfactant expenses	Polymer injected	Polymer expenses	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.84E+09	5.02E+07	1.90E+04	9.52E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	0	0	9.51E+11	1.00E+00	9.51E+11	9.51E+11
2014	1	1.80E+09	1.85E+09	4.97E+07	1.95E+04	9.71E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	0	0	9.70E+11	9.26E-01	8.98E+11	1.85E+12
2015	2	1.82E+09	1.87E+09	4.91E+07	2.01E+04	9.89E+11	0	0	0	0	0	0	9.89E+11	8.57E-01	8.48E+11	2.70E+12
2016	3	1.83E+09	1.88E+09	4.87E+07	2.07E+04	1.01E+12	0	0	0	0	1.02E+06	2.44E+07	1.01E+12	7.94E-01	8.01E+11	3.50E+12
2017	4	1.84E+09	1.89E+09	4.84E+07	2.14E+04	1.03E+12	0	0	0	0	1.02E+06	2.44E+07	1.03E+12	7.35E-01	7.60E+11	4.26E+12
2018	5	1.85E+09	1.90E+09	4.86E+07	2.20E+04	1.07E+12	0	0	0	0	0	0	1.07E+12	6.81E-01	7.27E+11	4.99E+12
2019	6	1.86E+09	1.91E+09	4.73E+07	2.27E+04	1.07E+12	0	0	0	0	0	0	1.07E+12	6.30E-01	6.76E+11	5.66E+12
2020	7	1.87E+09	1.92E+09	4.78E+07	2.33E+04	1.12E+12	0	0	0	0	0	0	1.12E+12	5.83E-01	6.52E+11	6.31E+12
2021	8	1.88E+09	1.93E+09	4.78E+07	2.40E+04	1.15E+12	0	0	0	0	0	0	1.15E+12	5.40E-01	6.21E+11	6.93E+12

Table 19: Incremental NPV for AS for 2 yrs following by 1yr WI and 2yrs PLY

Time	Project year	Base Case oil production	Oil production with ASP	Incremental oil production	Oil Price	Incremental Revenue from oil	Alkaline injected	Alkaline expenses	Surfactant injected	Surfactant expenses	Polymer injected	Polymer expenses	Net Cash Flow	Discount Factor	Present Value	Net Present Value (NPV)
(Years)		(Sm3)	(Sm3)	(Sm3)	(NOK/Sm)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(kg)	(NOK)	(NOK)		(NOK)	(NOK)
2013	0	1.79E+09	1.85E+09	6.59E+07	1.90E+04	1.25E+12	4.38E+06	3.91E+07	4.38E+07	8.61E+08	0	0	1.25E+12	1.00E+00	1.25E+12	1.25E+12
2014	1	1.80E+09	1.85E+09	4.97E+07	1.95E+04	9.71E+11	4.38E+06	3.91E+07	4.38E+07	8.61E+08	0	0	9.70E+11	9.26E-01	8.98E+11	2.15E+12
2015	2	1.82E+09	1.87E+09	4.91E+07	2.01E+04	9.89E+11	4.38E+06	39144060	4.38E+07	8.61E+08	0	0	9.88E+11	8.57E-01	8.47E+11	2.99E+12
2016	3	1.83E+09	1.88E+09	4.87E+07	2.07E+04	1.01E+12	4.38E+06	39144060	4.38E+07	8.61E+08	0	0	1.01E+12	7.94E-01	8.00E+11	3.79E+12
2017	4	1.84E+09	1.89E+09	4.82E+07	2.14E+04	1.03E+12	0	0	0	0	0	0	1.03E+12	7.35E-01	7.57E+11	4.55E+12
2018	5	1.85E+09	1.90E+09	4.82E+07	2.20E+04	1.06E+12	0	0	0	0	1.02E+06	2.44E+07	1.06E+12	6.81E-01	7.22E+11	5.27E+12
2019	6	1.86E+09	1.91E+09	4.69E+07	2.27E+04	1.06E+12	0	0	0	0	1.02E+06	2.44E+07	1.06E+12	6.30E-01	6.69E+11	5.94E+12
2020	7	1.87E+09	1.92E+09	4.72E+07	2.33E+04	1.10E+12	0	0	0	0	0	0	1.10E+12	5.83E-01	6.43E+11	6.58E+12
2021	8	1.88E+09	1.93E+09	4.71E+07	2.40E+04	1.13E+12	0	0	0	0	0	0	1.13E+12	5.40E-01	6.12E+11	7.20E+12

Table 20: Incremental NPV for AS for 4 yrs following by 1yr WI and 2yrs PLY

E. Eclipse data file for specific ASP case

```
-- water injection rate of F-1, F-2, and F-3 by 50
-- Ny model July 2004 build by marsp/oddhu
-- New grid with sloping faults based on geomodel xxx
-----

RUNSPEC

--LICENSES
--'NETWORKS' /
--/

DIMENS
46 112 22 /

--NOSIM

--
-- Allow for multregt, etc. Maximum number of regions 20.
--
GRIDOPTS
'YES' 0 /

OIL
WATER
GAS

SURFACT
POLYMER
ALKALINE

DISGAS

VAPOIL

METRIC

-- use either hysteresis or not hysteresis
NOHYST
--HYST

START
06 'NOV' 1997 /

EQLDIMS
5 100 20 /

EQLOPTS
'THPRES' / no fine equilibration if swatinit is being used

REGDIMS
-- ntfip nmfipr nrfreg ntfreg
22 3 1* 20 /

TRACERS
-- oil water gas env
1* 10 1* 1* /

WELLDIMS
--ML 40 36 15 15 /
```

130 36 20 84 /

LGR

--MAXLGR MAXCLS MCOARS
0 0 848 /

--WSEGDIMS

-- 3 30 3 /

--mlLGR

-- maxlgr maxcls mcoars mamalg mxlalq lstack interp
-- 4 2000 0 1 4 20 'INTERP' /

TABDIMS

--ntsfun ntpvt nssfup nppvt ntfip nrpvt ntendp
107 2 33 60 16 60 /

-- WI_VFP_TABLES_080905.INC = 10-20

VFPIDIMS

30 20 20 /

-- Table no.

-- DevNew.VFP = 1

-- E1h.VFP = 2

-- AlmostVertNew.VFP = 3

-- GasProd.VFP = 4

-- NEW_D2_GAS_0.00003.VFP = 5

-- GAS_PD2.VFP = 6

-- pd2.VFP = 8 (flowline south)

-- pe2.VFP = 9 (flowline north)

-- PB1.PIPE.Ecl = 31

-- PB2.PIPE.Ecl = 32

-- PD1.PIPE.Ecl = 33

-- PD2.PIPE.Ecl = 34

-- PE1.PIPE.Ecl = 35

-- PE2.PIPE.Ecl = 36

-- B1BH.Ecl = 37

-- B2H.Ecl = 38

-- B3H.Ecl = 39

-- B4DH. Ecl= 40

-- D1CH.Ecl = 41

-- D2H.Ecl = 42

-- D3BH.Ecl = 43

-- E1H.Ecl = 45

-- E3CH.Ecl = 47

-- K3H.Ecl = 48

VFPPDIMS

19 10 10 10 0 50 /

FAULTDIM

10000 /

PIMTDIMS

1 51 /

NSTACK

30 /

UNIFIN
UNIFOUT

--RPTRUNSPEC

OPTIONS

77* 1 /

--
-- Input of grid geometry
--

GRID

NEWTRAN

GRIDFILE

2 /

-- optional for postprocessing of GRID

MAPAXES

0. 100. 0. 0. 100. 0. /

GRIDUNIT

METRES /

-- do not output GRID geometry file

--NOGGF

-- requests output of INIT file

INIT

MESSAGES

8*10000 20000 10000 1000 1* /

PINCH

0.001 GAP 1* TOPBOT TOP/

NOECHO

COARSEN

-- I1 I2 J1 J2 K1 K2 NX NY NZ --

6 9 43 92 1 3 1 1 1 /

10 12 45 96 1 3 1 1 1 /

13 18 48 100 1 3 1 1 1 /

19 19 58 90 1 3 1 1 1 /

20 25 49 70 1 3 1 1 1 /

26 30 50 90 1 3 1 1 1 /

31 41 65 91 1 3 1 1 1 /

31 38 61 64 1 3 1 1 1 /

31 34 56 60 1 3 1 1 1 /

38 41 92 100 2 3 1 1 1 /

31 33 54 55 1 3 1 1 1 /

31 32 53 53 1 3 1 1 1 /

35 36 59 60 1 3 1 1 1 /

39 39 63 64 1 3 1 1 1 /

35 37 93 98 2 3 1 1 1 /

36 37 99 99 2 3 1 1 1 /

33 34 94 96 2 3 1 1 1 /

30 34 93 93 1 3 1 1 1 /

30 37 92 92 1 3 1 1 1 /

39 41 102 102 2 3 1 1 1 /
19 19 48 57 1 3 1 1 1 /

6 9 43 92 5 10 1 1 1 /
10 12 45 96 5 10 1 1 1 /
13 18 48 100 5 10 1 1 1 /
19 19 58 90 5 10 1 1 1 /
20 25 49 70 5 10 1 1 1 /
26 30 50 90 5 10 1 1 1 /
31 41 65 91 5 10 1 1 1 /
31 38 61 64 5 10 1 1 1 /
31 34 56 60 5 10 1 1 1 /
38 41 92 100 5 10 1 1 1 /
31 33 54 55 5 10 1 1 1 /
31 32 53 53 5 10 1 1 1 /
35 36 59 60 5 10 1 1 1 /
39 39 63 64 5 10 1 1 1 /
35 37 93 98 5 10 1 1 1 /
36 37 99 99 5 10 1 1 1 /
33 34 94 96 5 10 1 1 1 /
30 34 93 93 5 10 1 1 1 /
30 37 92 92 5 10 1 1 1 /
39 41 102 102 5 10 1 1 1 /
19 19 48 57 5 10 1 1 1 /

6 9 43 92 11 18 1 1 1 /
10 12 45 96 11 18 1 1 1 /
13 18 48 100 11 18 1 1 1 /
19 19 58 90 11 18 1 1 1 /
20 25 49 70 11 18 1 1 1 /
26 30 50 90 11 20 1 1 1 /
31 41 65 91 11 19 1 1 1 /
31 38 61 64 11 19 1 1 1 /
31 34 56 60 11 19 1 1 1 /
38 41 92 100 11 19 1 1 1 /
31 33 54 55 11 19 1 1 1 /
31 32 53 53 11 19 1 1 1 /
35 36 59 60 11 19 1 1 1 /
39 39 63 64 11 19 1 1 1 /
35 37 93 98 11 19 1 1 1 /
36 37 99 99 11 19 1 1 1 /
33 34 94 96 11 19 1 1 1 /
30 34 93 93 11 19 1 1 1 /
30 37 92 92 11 19 1 1 1 /
39 41 102 102 11 19 1 1 1 /
19 19 48 57 11 20 1 1 1 /

6 9 43 92 19 22 1 1 1 /
10 12 45 96 19 22 1 1 1 /
13 18 48 100 19 22 1 1 1 /
19 19 58 90 19 22 1 1 1 /
20 25 49 70 19 22 1 1 1 /
26 30 50 90 21 22 1 1 1 /
31 41 65 91 22 22 1 1 1 /
31 38 61 64 21 22 1 1 1 /
31 34 56 60 21 22 1 1 1 /
38 41 92 100 22 22 1 1 1 /
31 33 54 55 21 22 1 1 1 /

```

31 32 53 53 21 22 1 1 1 /
35 36 59 60 21 22 1 1 1 /
39 39 63 64 21 22 1 1 1 /
35 37 93 98 22 22 1 1 1 /
36 37 99 99 22 22 1 1 1 /
33 34 94 96 22 22 1 1 1 /
30 34 93 93 22 22 1 1 1 /
30 37 92 92 22 22 1 1 1 /
39 41 102 102 22 22 1 1 1 /
19 19 48 57 21 22 1 1 1 /

```

```

31 31 52 52 1 22 1 1 1 /
35 35 58 58 1 22 1 1 1 /
37 37 60 60 1 22 1 1 1 /
40 40 64 64 1 22 1 1 1 /

```

```

/
/

```

```

-----
--
--      Grid and faults
--
-----

```

```

--
-- Simulation grid, with slooping faults:
--
-- file in UTM coordinate system, for importing to -----DecisionSpace
INCLUDE
'./INCLUDE/GRID/IRAP_1005.GRDECL' /
-- '/project/norme6/res/INCLUDE/GRID/IRAP_0704.GRDECL' /

```

```

--
INCLUDE
'./INCLUDE/GRID/ACTNUM_0704.prop' /

```

```

--
-- Faults
--
--

```

```

INCLUDE
'./INCLUDE/FAULT/FAULT_JUN_05.INC' /

```

```

-- Alteration of transmiscibility by use of the 'MULTFLT' -----keyword
--

```

```

INCLUDE
'./INCLUDE/FAULT/FAULTMULT_AUG-2006.INC' /
-- '/project/norme6/res/INCLUDE/FAULT/FAULTMULT_JUN_05.INC' /

```

```

-- Additional faults

```

```

--Nord for C-3 (forlengelse av C_10)

```

```

EQUALS
MULTY 0.01 6 6 22 22 1 22 /
/

```

```

-- B-3 water

```

```

EQUALS
'MULTX' 0.001 9 11 39 39 1 22 /
'MULTY' 0.001 9 11 39 39 1 22 /

```

```

'MULTX' 0.001 9 9 37 39 1 22 /
'MULTY' 0.001 9 9 37 39 1 22 /
/
-- C-1H
EQUALS
'MULTY' 0.001 26 29 39 39 1 22 /
/

-----
--
--      Input of grid parametres
--
-----

--
INCLUDE
'./INCLUDE/PETRO/PORO_0704.prop' /

--
INCLUDE
'./INCLUDE/PETRO/NTG_0704.prop' /

--
INCLUDE
'./INCLUDE/PETRO/PERM_0704.prop' /

-- G segment north
EQUALS
PERMX 220 32 32 94 94 2 2 /
PERMX 220 33 33 95 99 2 2 /
PERMX 220 34 34 95 97 2 2 /
PERMX 220 35 35 95 98 2 2 /
PERMX 220 36 36 95 99 2 2 /
PERMX 220 37 37 95 99 2 2 /
PERMX 220 38 38 95 100 2 2 /
PERMX 220 39 39 95 102 2 2 /
PERMX 220 40 40 95 102 2 2 /
PERMX 220 41 41 95 102 2 2 /
/

-- C-1H
MULTIPLY
PERMX 4 21 29 39 49 16 18 /
PERMX 100 21 29 39 49 19 20 /
/

COPY
PERMX PERMY /
PERMX PERMZ /
/

-- Permz reduction is based on input from PSK
-- based on same kv/kh factor
-- *****
-- CHECK! (esp. Ile & Tofte)
-- *****
MULTIPLY
'PERMZ' 0.2 1 46 1 112 1 1 / Garn 3
'PERMZ' 0.04 1 46 1 112 2 2 / Garn 2
'PERMZ' 0.25 1 46 1 112 3 3 / Garn 1
'PERMZ' 0.0 1 46 1 112 4 4 / Not (inactive anyway)
'PERMZ' 0.13 1 46 1 112 5 5 / Ile 2.2

```

```

'PERMZ' 0.13 1 46 1 112 6 6 / Ile 2.1.3
'PERMZ' 0.13 1 46 1 112 7 7 / Ile 2.1.2
'PERMZ' 0.13 1 46 1 112 8 8 / Ile 2.1.1
'PERMZ' 0.09 1 46 1 112 9 9 / Ile 1.3
'PERMZ' 0.07 1 46 1 112 10 10 / Ile 1.2
'PERMZ' 0.19 1 46 1 112 11 11 / Ile 1.1
'PERMZ' 0.13 1 46 1 112 12 12 / Tofte 2.2
'PERMZ' 0.64 1 46 1 112 13 13 / Tofte 2.1.3
'PERMZ' 0.64 1 46 1 112 14 14 / Tofte 2.1.2
'PERMZ' 0.64 1 46 1 112 15 15 / Tofte 2.1.1
'PERMZ' 0.64 1 46 1 112 16 16 / Tofte 1.2.2
'PERMZ' 0.64 1 46 1 112 17 17 / Tofte 1.2.1
'PERMZ' 0.016 1 46 1 112 18 18 / Tofte 1.1
'PERMZ' 0.004 1 46 1 112 19 19 / Tilje 4
'PERMZ' 0.004 1 46 1 112 20 20 / Tilje 3
'PERMZ' 1.0 1 46 1 112 21 21 / Tilje 2
'PERMZ' 1.0 1 46 1 112 22 22 / Tilje 1
/

-----
--
-- Barriers
--
-----

-- MULTZ multiplies the transmissibility between blocks
-- (I, J, K) and (I, J, K+1), thus the barriers are at the
-- bottom of the given layer.

-- Region barriers
--
--
INCLUDE
'/INCLUDE/PETRO/MULTZ_HM_1.INC' /
--
-- Field-wide barriers
--
EQUALS
'MULTZ' 1.0 1 46 1 112 1 1 / Garn3 - Garn 2
'MULTZ' 0.05 1 46 1 112 15 15 / Tofte 2.1.1 - Tofte 1.2.2
'MULTZ' 0.001 1 46 1 112 18 18 / Tofte 1.1 - Tilje 4
'MULTZ' 0.00001 1 46 1 112 20 20 / Tilje 3 - Tilje 2
-- The Top Tilje 2 barrier is included as MULTREGT = 0.0
/

-- Local barriers
--
INCLUDE
'/INCLUDE/PETRO/MULTZ_JUN_05_MOD.INC' /

-- 20 flux regions generated by the script Xfluxnum
--
INCLUDE
'/INCLUDE/PETRO/FLUXNUM_0704.prop' /

-- modify transmissibilities between fluxnum using MULTREGT
--
INCLUDE
'/INCLUDE/PETRO/MULTREGT_D_27.prop' /

```

NOECHO

MINPV
500 /

EQUALS

'MULTZ' 0.00125 26 29 30 37 10 10 / better WCT match for B-2H

'MULTZ' 0.015 19 29 11 30 8 8 / better WCT match for D-1CH

'MULTZ' 1 6 12 16 22 8 11 / for better WCT match for K-3H

'MULTZ' .1 6 12 16 22 15 15 / for better WCT match for K-3H

/

EDIT

-- modification related to HM of G-segment aug-2006

MULTIPLY

'TRANX' 0.1 30 46 72 112 2 2 /

'TRANX' 0.1 30 46 72 112 3 3 /

'TRANY' 5 30 46 72 112 2 2 /

'TRANY' 10 30 46 72 112 3 3 /

--

'TRANX' 10 29 29 67 70 1 3 /

'TRANY' 10 30 41 67 67 1 3 /

--

'TRANX' 0.05 34 34 76 95 1 3 /

'TRANY' 0.001 30 41 67 67 1 3 / Open against the main field

--

'TRANY' 0.5 30 30 90 93 1 3 / Increase TRANY against the well

'TRANY' 0.5 31 32 94 94 1 3 / Increase TRANY against the well

--

--

'TRANY' 0.5 31 31 87 93 1 3 /

--

--

'TRANY' 0.5 30 30 85 89 1 1 /

'TRANY' 2 30 30 72 82 1 3 /

'TRANY' 0.8 30 30 82 93 1 3 /

--

--

'TRANX' 10 34 34 92 95 1 3 / Increase TRANX trough the fault against the well

'TRANX' 0 34 34 90 91 1 3 /

'TRANX' 2 34 38 88 89 1 3 /

--'TRANX' 2 35 36 93 95 1 3 /

'TRANX' 0.1 35 36 90 91 1 3 /

'TRANX' 10 35 38 95 98 1 3 /

'TRANX' 5 31 31 91 92 1 3 / Increase TRANX against the well

--

--

'TRANX' 2 31 33 92 95 1 3 /

--

'TRANY' 2 30 31 79 86 3 3 /

'TRANY' 3 30 30 86 86 2 2 /

--

--

'TRANY' 0.7 34 41 72 80 1 3 /

```
'TRANX' 2 31 31 87 94 1 3 /
--
'TRANY' 0.0004 37 41 71 71 1 3 /
'TRANY' 2 30 31 87 93 2 3 /
'TRANX' 5 34 34 88 90 1 3 /
--
'TRANY' 1.5 33 35 94 96 2 3 /
--

'TRANX' 2 30 41 68 70 1 3 / Increase trans around F-4H
--
/
```

EQUALS

```
'TRANY' 20 31 31 85 85 1 3 / SET TRANY ulik 0 trough the fault
'TRANY' 30 30 30 93 93 2 2 /
'TRANY' 30 32 32 84 84 1 3 /
'TRANY' 30 30 30 93 93 3 3 /
--
--
'TRANY' 30 31 32 95 95 2 3 /
'TRANY' 30 31 32 94 94 1 1 /
'TRANY' 20 33 33 96 96 2 3 /
'TRANY' 20 34 34 97 97 2 3 /
--
--
'TRANX' 0 33 33 71 81 1 3 / set the fault tight
'TRANX' 0 34 34 76 85 1 3 /
--
'TRANY' 0 33 33 71 81 1 3 / Set the fault tigt
'TRANY' 0 34 34 76 85 1 3 /
--
'TRANY' 0 33 36 71 71 1 3 /
'TRANX' 0 34 41 71 71 1 3 /
--
'TRANY' 0 33 33 71 72 1 3 / Decrease TRANY trough the fault
--
'TRANX' 0 34 34 73 75 1 3 / Set the fault tight
'TRANY' 0 34 34 71 75 1 3 /
--
/
```

PROPS

```
--
-- Input of fluid properties and relative permeability
--
-----
```

NOECHO

```
-- Input of PVT data for the model
-- Total 2 PVT regions (region 1 C,D,E segment, region 2 Gsegment)
--
```

```
INCLUDE
'./INCLUDE/PVT/PVT-WET-GAS.DATA' /
```

```
INCLUDE
```

```

./INCLUDE/ASP.inc' /

TRACER
'SEA' 'WAT' /
'HTO' 'WAT' /
'S36' 'WAT' /
'2FB' 'WAT' /
'4FB' 'WAT' /
'DFB' 'WAT' /
'TFB' 'WAT' /
/

-----
--
-- initialization and relperm curves: see report blabla
--
-----

-- rel. perm and cap. pressure tables --

--
INCLUDE
'./INCLUDE/RELPERM/HYST/swof_mod4Gseg_aug-2006.inc' /
-- '/project/norne6/res/INCLUDE/RELPERM/HYST/swof.inc' /

--Sgc=10 0.000000or g-segment
--
INCLUDE
'./INCLUDE/RELPERM/HYST/sgof_sgc10_mod4Gseg_aug-2006.inc' /
-- '/project/norne6/res/INCLUDE/RELPERM/HYST/sgof_sgc10.inc' /

--
--INCLUDE
-- './INCLUDE/RELPERM/HYST/waghystr_mod4Gseg_aug-2006.inc' /
-- '/project/norne6/res/INCLUDE/RELPERM/HYST/waghystr.inc' /

--RPTPROPS
-- 1 1 1 5*0 0 /

-----

REGIONS

--
INCLUDE
'./INCLUDE/PETRO/FIPNUM_0704.prop' /

--
INCLUDE
'./INCLUDE/PETRO/SATNUM_0704.prop' /

EQUALS
'SATNUM' 102 30 41 76 112 1 1 /
'SATNUM' 103 30 41 76 112 2 2 /
'SATNUM' 104 30 41 76 112 3 3 /
/

MISCNUM
113344*1/

```

```

--
INCLUDE
 './INCLUDE/PETRO/IMBNUM_0704.prop' /

EQUALS
'SATNUM' 102 30 41 76 112 1 1 /
'SATNUM' 103 30 41 76 112 2 2 /
'SATNUM' 104 30 41 76 112 3 3 /
/

--
INCLUDE
 './INCLUDE/PETRO/PVTNUM_0704.prop' /

EQUALS
'PVTNUM' 1 1 46 1 112 1 22 /
/

INCLUDE
 './INCLUDE/PETRO/EQLNUM_0704.prop' /

-- extra regions for geological formations and numerical layers
INCLUDE
 './INCLUDE/PETRO/EXTRA_REG.inc' /

-----

SOLUTION

RPTRST
  BASIC=6 /

RPTSOL
  FIP=3 /

-----

-- equilibrium data: do not include this file in case of RESTART
--
--
INCLUDE
 './INCLUDE/PETRO/E3.prop' /

-- restart date: only used in case of a RESTART, remember to use SKIPREST
--RESTART
-- 'BASE_30-NOV-2005' 360 / AT TIME 3282.0 DAYS (1-NOV-2006)

THPRES
  1 2 0.588031 /
  2 1 0.588031 /
  1 3 0.787619 /
  3 1 0.787619 /
  1 4 7.00083 /
  4 1 7.00083 /
/

-- initialise injected tracers to zero
TVDPFSEA
1000 0.0
5000 0.0 /
TVDPFHTO
1000 0.0
5000 0.0 /

```



```
TVDPFS36
1000 0.0
5000 0.0 /
TVDPF2FB
1000 0.0
5000 0.0 /
TVDPF4FB
1000 0.0
5000 0.0 /
TVDPFDFB
1000 0.0
5000 0.0 /
TVDPFTFB
1000 0.0
5000 0.0 /
```

```
-----
SUMMARY
RUNSUM
SEPARATE
EXCEL
```

```
--
INCLUDE
'./INCLUDE/SUMMARY/summary.data' /
```

```
--
INCLUDE
'./INCLUDE/SUMMARY/extra.inc' /
```

```
--
INCLUDE
'./INCLUDE/SUMMARY/tracer.data' /
```

```
--
INCLUDE
'./INCLUDE/SUMMARY/gas.inc' /
```

```
--
INCLUDE
'./INCLUDE/SUMMARY/wpave.inc' /
```

```
-----
SCHEDULE
```

```
-- use SKIPREST in case of RESTART
--SKIPREST
```

```
-- No increase in the solution gas-oil ratio?!
```

```
DRSDT
0 /
```

```
-- Use of WRFT in order to report well perssure data after first
-- opening of the well. The wells are perforated in the entire reservoir
-- produce with a small rate and are squeesed after 1 day. This pressure
-- data can sen be copmared with the MDT pressure points collected in the
-- well.
```

NOECHO

-----Production Wells-----

--
INCLUDE
'./INCLUDE/VFP/DevNew.VFP' /
--
INCLUDE
'./INCLUDE/VFP/E1h.VFP' /
--
INCLUDE
'./INCLUDE/VFP/NEW_D2_GAS_0.00003.VFP' /
--
INCLUDE
'./INCLUDE/VFP/GAS_PD2.VFP' /
--
INCLUDE
'./INCLUDE/VFP/AlmostVertNew.VFP' /
--
INCLUDE
'./INCLUDE/VFP/GasProd.VFP' /

-- 01.01.07 new VFP curves for producing wells, matched with the latest well tests in Prosper. Imarr

--
INCLUDE
'./INCLUDE/VFP/B1BH.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/B2H.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/B3H.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/B4DH.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/D1CH.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/D2H.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/D3BH.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/E1H.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/E3CH.Ecl' /
--
INCLUDE
'./INCLUDE/VFP/K3H.Ecl' /

```

-----Production Flowlines-----
-----
--
-- 16.5.02 new VFP curves for southgoing PD1,PD2,PB1,PB2 flowlines -> pd2.VFP
--
INCLUDE
'/INCLUDE/VFP/pd2.VFP' /
--
-- 16.5.02 new VFP curves for northgoing PE1,PE2 flowlines -> pe2.VFP
--
INCLUDE
'/INCLUDE/VFP/pe2.VFP' /

-- 24.11.06 new matched VLP curves for PB1 valid from 01.07.06
--
INCLUDE
'/INCLUDE/VFP/PB1.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PB2 valid from 01.07.06
--
INCLUDE
'/INCLUDE/VFP/PB2.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PD1 valid from 01.07.06
--
INCLUDE
'/INCLUDE/VFP/PD1.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PD2 valid from 01.07.06
--
INCLUDE
'/INCLUDE/VFP/PD2.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PE1 valid from 01.07.06
--
INCLUDE
'/INCLUDE/VFP/PE1.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PE2 valid from 01.07.06
--
INCLUDE
'/INCLUDE/VFP/PE2.PIPE.Ecl' /

-----
-----INJECTION FLOWLINES 08.09.2005 -----
-----
-- VFPINJ nr. 10 Water injection flowline WIC
--
INCLUDE
'/INCLUDE/VFP/WIC.PIPE.Ecl' /

-- VFPINJ nr. 11 Water injection flowline WIF
--
INCLUDE
'/INCLUDE/VFP/WIF.PIPE.Ecl' /

-----
----- INJECTION Wells 08.09.2005 -----
-----

```

```

-- VFPINJ nr. 12 Water injection wellbore Norne C-1H
--
INCLUDE
'/INCLUDE/VFP/C1H.Ecl' /

-- VFPINJ nr. 13 Water injection wellbore Norne C-2H
--
INCLUDE
'/INCLUDE/VFP/C2H.Ecl' /

-- VFPINJ nr. 14 Water injection wellbore Norne C-3H
--
INCLUDE
'/INCLUDE/VFP/C3H.Ecl' /

-- VFPINJ nr. 15 Water injection wellbore Norne C-4H
--
INCLUDE
'/INCLUDE/VFP/C4H.Ecl' /

-- VFPINJ nr. 16 Water injection wellbore Norne C-4AH
--
INCLUDE
'/INCLUDE/VFP/C4AH.Ecl' /

-- VFPINJ nr. 17 Water injection wellbore Norne F-1H
--
INCLUDE
'/INCLUDE/VFP/F1H.Ecl' /

-- VFPINJ nr. 18 Water injection wellbore Norne F-2H
--
INCLUDE
'/INCLUDE/VFP/F2H.Ecl' /

-- VFPINJ nr. 19 Water injection wellbore Norne F-3 H
--
INCLUDE
'/INCLUDE/VFP/F3H.Ecl' /

-- VFPINJ nr. 20 Water injection wellbore Norne F-4H
--
INCLUDE
'/INCLUDE/VFP/F4H.Ecl' /

TUNING
1 10 0.1 0.15 3 0.3 0.3 1.20 /
5* 0.1 0.0001 0.02 0.02 /
--2* 40 1* 15 /
/

-- only possible for ECL 2006.2+ version
ZIPPY2
'SIM=4.2' MINSTEP=1E-6' /
/

--WSEGITER
--/

```

```
-- PI reduction in case of water cut
--
INCLUDE
'/INCLUDE/PI/pimultab_low-high_aug-2006.inc' /

-- History and prediction --
--
INCLUDE
'/INCLUDE/ASP4YRS.SCHEDULE' /

END
```