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Surfactant Flooding of the Norne Field E-segment

Experts in Team

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Preface

The Experts in Team (EiT) course is a compulsory interdisciplinary project course for all master students at NTNU. This report has been prepared by group 4 in the Norne village spring 2010 at the Department of Petroleum Engineering. The Norne village is established by collaboration of Statoil and NTNU to create a conductive environment for students to work on real world problem. The tasks mainly deal with increasing the production of the oil and gas from the field, though other issues are also analyzed in the process. Though the topics are developed by Statoil, students are also motivated to come up with their own ideas. This will require substantial knowledge about the Norne field and Petroleum Engineering. It was quite acceptable to proceed with the topic provided to the group which is surfactant flooding to enhance oil recovery. The technical report examined the potential of surfactant flooding on oil recovery of the Norne field, E segment.

The purpose of the course is to experience what it is like to work with real projects from the industry. Each team consists of students with different backgrounds and different nationalities. EiT provides an opportunity to gain many new experiences and develop both academic and interaction skills. It was found hard for students from other disciplines to work in this area because they needed to do a lot of reading. It is still a conclusion that it is important to know how the oil being used every day is explored and produced.

We would like to thank our village leader professor Tom Åge Jelmert for his overall guidance, academic support and hospitality during the semester. Special thanks go to Nan Cheng and Lars Høier, the Experts from Statoil, for their professional advice. We owe Jan Ivar Jensen a lot for his support in running the Eclipse program and giving us supporting files that help run our project efficiently. Big thanks go also to the teaching assistants Jorunn Evandt and Nadine Halvorsen for assisting in the group process. Finally, special thanks to Statoil Harstad for their hospitality and support during our visit in Harstad and afterwards.

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LASHL Unit

Abstract

The group was assigned the task „Surfactant flooding' in the Norne field, in the E-segment. The task contains different parts. General knowledge on surfactant flooding and study of the impact of surfactant injection based on existing drainage pattern for producers and injectors was emphasized. In the case of suggesting SOR in the E-segment, it is wanted to find the optimized volume and injection time. An economic model used to calculate the cash flows associated with the simulation results, which gives us the net present value of the project, is calculated. The Eclipse simulator is a simulator that that has been used by simplification of the real life Several cases have been run, with different concentrations and injection times, re-opening and recompletion of a well. Regarding the results gained from simulation in Eclipse, it shows that surfactant flooding can not be a suitable alternative for enhanced oil recovery in the Norne field related to some issues, one of the issues deal with the small residual oil saturation after water flooding in the Norne field. That is due to high oil recovery before applying enhanced oil recovery methods. We hope and believe that Statoil will benefit from our project.

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1. **Enhanced Oil Recovery**

1.1 Introduction

Human beings have been using different forms of energy for their day to day activities in everyday life. The most important sources of energy are oil and gas. These forms of energy have been in use for quite some time and they are increasing in use due to their versatility and abundance. The total consumption of energy, mainly oil and gas, has been increasing exponentially for the last few decades. It is therefore inevitable to explore better methods for recovery. In addition to the increase in demand, the economic benefit makes the enhanced recovery of oil and gas more attractive and urgent, until other energy forms, such as wind, are made available in a way that the consumer requests.

The process of oil recovery can be broadly divided into three different methods depending upon the kind of oil displacement mechanisms employed to drive out the oil from its formation. Primary recovery is the natural process by which the oil is driven towards one or more wells due to pressure differences. However, the production obtained from this method is not sufficient enough to fulfill our economical need. It is therefore necessary to explore secondary recovery methods to boost the production. The most commonly used secondary recovery method is injecting fluids, often water or brine, into one or more injection wells to displace the oil from the formation and move it towards the production well.

Primary and secondary recovery techniques together are able to recover only about 35-50% of the oil from the reservoir [6]. A high recovery is desired both from the Norwegian Petroleum Directorate and the industry, and the consumers are increasing the demand for oil. It is therefore necessary to look into tertiary recovery, also called enhanced oil recovery, to extract the oil remaining in the reservoir.

The residual oil left after the water flooding is either from water swept part or area by-passed by the water flooding. The by-passed residual oil has a high interfacial tension with the water. By using chemicals it’s possible to reduce this force; it is possible to make the oil mobile and flood the free oil towards the production well. This kind of

tertiary oil recovery methods is called surfactant flooding and is a kind of chemical flooding. Its main purpose is to recover the residual oil by-passed by water flooding.
In this project surfactant flooding is studied in the E-segment of the Norne field as a case study substantiated by the presence of high residual oil saturation. As a first exercise a synthetic model is simulated using Eclipse with properties from the Norne field. The result, as will be presented below, shows a decrease in oil saturation after flooding.

1.2 Recovery Methods

In reservoir technology reservoir fluid flow modelling is done by a combination of several disciplines. These are geophysics, geology and petrophysics and are optimized by the help of observed production history to evaluate and optimize solutions for reservoir drainage [1].

"The life of an oil well in a reservoir goes through three distinct phases where various techniques are employed to maintain crude oil production at maximum levels. The primary importance of these techniques is to force oil into the wellhead where it can be pumped to the surface. Techniques employed at the third phase, commonly known as Enhanced Oil Recovery (EOR), can substantially improve extraction efficiency" [2]

1.2.1 Stages of Oil Field Development

Oil field recovery is divided into primary, secondary and tertiary recovery:

- In primary recovery oil is produced by a difference in pressure which moves the oil towards the wells.
- In secondary recovery the reservoir is subjected to water flooding or gas injection to maintain the pressure in the reservoir to continue the movement of oil.
- Tertiary recovery introduces fluids to the reservoir to improve the flow. These fluids are gases that are miscible with oil (e.g. CO_2), steam, air or oxygen, surfactant, polymer, gels or microorganisms [2].

Primary recovery typically provides access to only a small fraction; production is often limited to 15% of a reservoir's total oil capacity. Secondary recovery techniques can increase productivity to about 30% of original oil in place. Tertiary recovery (EOR) enables an extraction of up to half of a reservoirs' original oil content, depending on the reservoir and the EOR process applied [2].

1.2.2 Classification of EOR Processes

There are five categories of enhanced oil recovery:

1. Miscible Injection,
2. Chemical Process,
3. Thermal Recovery
4. Microbial Injection
5. Ultrasonic Simulation

Of the above five EOR processes, surfactant flooding will be assessed in this project. It targets the reduction of IFT between the displacing liquid and the oil.

One way of recovering the residual oil is by reducing the interfacial tension between oil and water. Thereby making it easier for oil to coalesce and flow to the production wells. This is achieved by the use of surfactants [3]. In this process, a solution which contains surfactants is pumped in to the reservoir.

2. Norne field Overview

2.1 Location

The Norne field is located in the Norwegian Sea, in the block 6608/10 and 6608/11, which is 200km from Norwegian Coast.

2.2 Tectonic Setting

The basin where the Norne field is located is a rift continental margin. It is formed by the succession of 2 tectonic events which can be divided in 3 episodes:

1st episode: The Caledonian orogeny from Silurian to early Devonian

2nd episode: the extension deformation with the continental separation between Eurasia and Greenland from Devonian to Paleocene

3rd episode: the seafloor spreading from Eocene to Present. [10]

2.3 The Norne field

The Norne filed is divided in different segments. On this part, our focus is the petroleum geology of Norne field particularly the E-segment (Figure1), associated to the extension deformation forming the basin.[11]

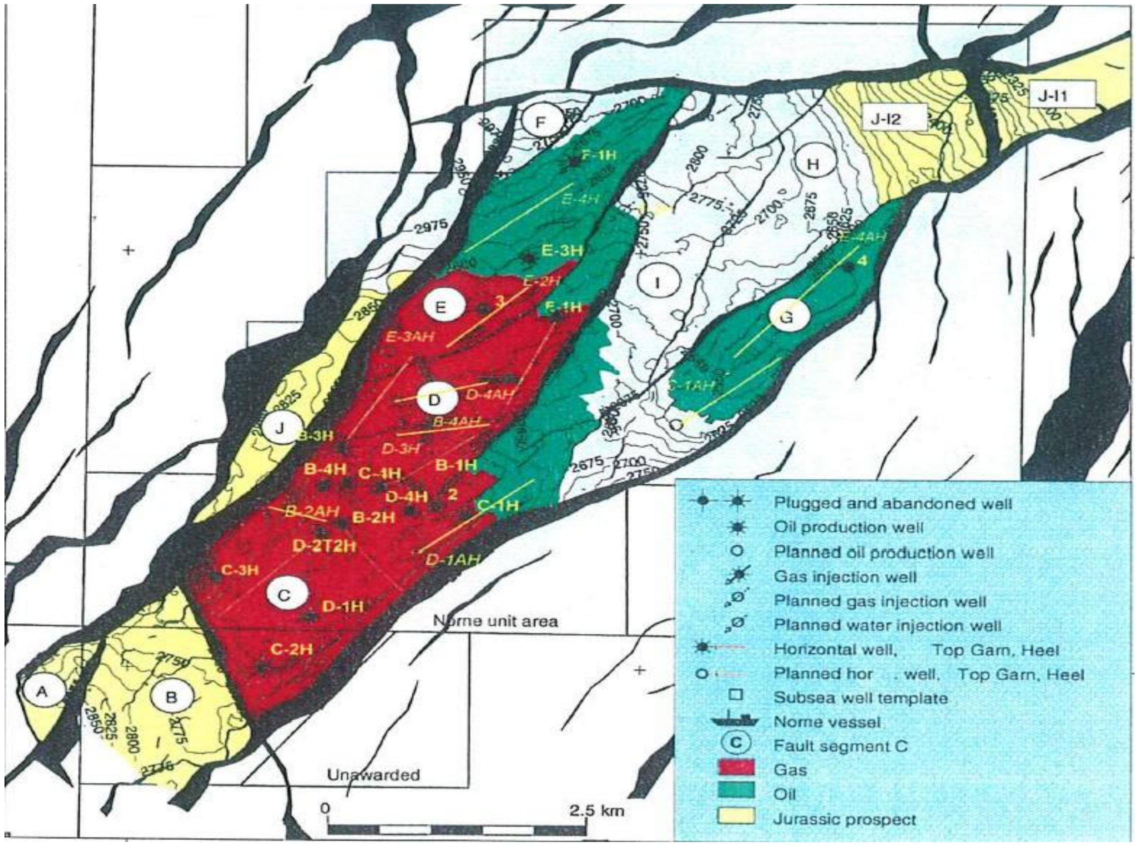

Figure 1: Map of Norne field [14]

2.3.1 Source rock

The source rock is defined by the alternation of sandstones and claystones with interbedded with coals and coaly claystones. It corresponds to Åre formation (Rhaetian to Pliensbachian). It is deposited in coastal plain to delta plain

2.3.2 Trap

Due to the tectonic event affecting the area, the trap is rotated fault block. The E-segment is situated on the horst part of the fault block with uplift.

2.3.3 Seal

On the top of the reservoir, a formation called Melke formation plays the role as a seal. It is constituted mainly by claystone with interbedded of siltstone and limestone.

2.3.4 Reservoir

The reservoir encompasses 3 types of formations. Two of them (Tofte and Ile formation) are oil reservoir and one is gas reservoir (Garn reservoir). These reservoirs are separated by sterile formation (Ror Formation at the base and Not Formation). Although, the 3 reservoir are interested, we only focused our study on the formations which contain oil based on the aim of the project.

2.3.4.1 The Tofte formation (Pliensbachian –Toarcian)[11]

This formation is an oil reservoir and the base of the reservoir. It is constituted by moderately to poorly coarse grained sandstone and contains 90% of arenite quartz cement. Therefore, the sediment is mineralogically immature. The sediments of that formation are mainly deposited by progradation fan delta, showing the uplift on the west part.

2.3.4.2 Ror formation (Pliensbachian –Toarcian)[11]

This formation is one of the main stratigraphic barriers between the Tofte formation and the Ile formation. It is formed by grey to dark grey mudstone with interbedded of silt.

2.3.4.3 Ile formation (late Toarcian –Aalenian)[11]

This formation is one of the oil reservoirs and mainly formed fine and medium standstone associated with thin lamination of siltstone and shales. Moreover, in this formation, we can notice the presence of carbonate cements. It is deposited in tidal environment with deltaic influence.

2.3.4.4 Not formation (Aalenian –Bajocian)[11]

It is a sterile formation associated with claystone and nodules of pyrite. The sediment is cemented by carbonate cements.

2.4 Reservoir characteristics

The formations are evaluated from wells data crossing the Norne fields starting from Garn formation to the Base of Tofte formation.

2.4.1 Thickness

The distribution of thickness is represented in the table1 below:

Wells	Top reservoir	Base reservoir	Thickness
6508/1-1s	2351	2530	179
6608/10-2	3061	3218	157
6608/10-3	2574	2720	146
6608/10-4	2567	2712	145
6608/10-5	2751	2791	40
6608/10-11s	3480	3695	215

Table 1: thickness from well data (source: NPD pagefacts)

Top depth(m)	Formation type
2578	GARN
2619	ILE
2668	TOFTE
2720	***TILJE***

Table 2: Top depth of Nornes formations

2.4.2 Reservoir facies presence [16]

The formations of the reservoir are associated with several facies distribution with mainly quartz, dolomite, sometimes pyrite, calcite as cements:

Transgressive deposit facies which is composed by very fine to very coarse sand relative to shallow to deep water conditions .

Lower Shoreface facies: this facies is dominated by cross bedded, sorted sand with bioturbation showing wide span energy (the homogenous interval is associated to low energy while the cross bedded interval associated with high energy.

Middle shoreface facies: it is characterized by fine grained and often homogenous sands. Sometimes, there is a presence of glauconite.

Upper shoreface facies: it consists of fine coarse sandstone with low mud content and with low angle lamination. The grain size and structure deposition show a high energy setting.

Amalgamated channels facies: this facies consists of fine to coarse grains, moderately sorted with cross bedding structures. Occasionally, thin mud rich beds are identified.

Due to facies variation, the formations of the reservoir are subdivided in different sub formations from the top to the base of reservoir:

Garn 3-2-1 formations

Not formation

Ile 3-2-1 formations

Tofte 3-2-1 formations

2.4.3 Reservoir quality [13]

In well 6608/10-3, the reservoir has a good porosity ranging from 16% to 33%. The Net to gross ratio varies from 41% to 100%. The water saturation varies from 11% to 36%. The permeability ranges from 39mD to 1971mD

Formations	Φ (%)	N/G (%)	Sw (%)	K (mD)
Garn 3	33	100	11	1099
Garn 2	27	99	-	1080
Garn 1	23	46	-	39
Not	-	0	-	-
Ile 3	25	64	-	70
Ile 2	28	100	15	950
Ile 1	27	91	17	810
Tofte 3	28	100	15	1354
Tofte 2	24	100	36	42
Tofte 1	16	41	25	1971

Table 3: porosity, N/G, Sw, permeability distribution

2.4.4 Connectivity within the reservoir

One of the challenges of E –segment filed is the connection between the reservoir. According to the lithologies and the depositional environments, the main barriers are the the Not Formation which is mainly constituted by claystone. Then, the Ror formation which is mudstone with silt and located between the Tofte formation on the base and the Ile formation on the top. In some reservoir, there is also, the challenge of the diagenesis effect like the presence of quartz cements and carbonates cements blocking the pores throats.

Therefore, when we are injecting surfactant, we will inject it in Tofte and Ile formation in order to avoid the Ror formation. The used of surfactant depends mainly on the connectivity between the reservoir.

The presence of quartz cements and carbonates cements is also one challenge of the used of surfactant.

2.4.5 Recoverable reserves calculation *[13]*

In order to analyze the different effects of the new recovery factors from the scenarios below on recoverable reserves, different geological parameters are used. Most of these parameters are obtained from the Norne field database.

The recoverable reserves are obtained from the formula

Recoverable reserves = $BV * N / G * \phi * S_o * trapfill * B_o * RF$

Where:

BV: bulk volume (m3)

N/G: Net to gross ratio

Φ: porosity

So: oil saturation

Bo: formation volume factor

RF: recovery Factor

Trap fill =1

[13]&[15]

	Recoverable reserve (10^6 Sm^3)		
RF	**P90**	**P50**	**P10**
S1: 0,648	15.1	17.3	19.9
S2: 0.6617	15.4	17.7	20.3
S3: 0.6614	15.4	17.7	20.3
S4: 0.6613	15.4	17.7	20.3
S5: 0.658	15.3	17.6	20.2

Table 4: probability of recoverable reserves in some scenarios

Using the different recovery factor obtained from scenarios, the recoverable oil reserves for E –segment are almost the same.

2.5 Recovery strategy

The oil is produced with water injection as drive mechanism. Gas injection ceased in 2005 and all of the gas is planned to be exported. [4].

Norne Field has the following features:

Recoverable = 94.9 MSm^3; Ultimate RF_o = 60.4%; Current RF_o = 53% [6].

3. Surfactant

3.1 Introduction

Surfactant is an abbreviation for surface active agents. Surfactants are wetting agents that lower the surface tension of a liquid, allowing for easier spreading. The interfacial tension between two liquids is also reduced. A surfactant is characterized by its tendency to absorb at surfaces and interfaces. „Interface' denotes a boundary between two immiscible phases.

Surfactant flooding is an enhanced oil recovery mechanism aimed at reducing the residual oil saturation in water swept zones [1]. The left over oil after the secondary recovery typically have a very low relative permeability. This is due to high interfacial tension and capillary pressure between the water and the oil phase. Injection of surfactants helps reduce these interfacial forces and thereby reduce the capillary pressure. The oil in the small pores can then easily be displaced and move into the production wells being pushed by injected water. However, it will still not be possible to extract all the left over oil after the secondary recovery method with the application of surfactants. It is necessary to study the effect of surfactant application to the particular geological formation to find out the effect of surfactant and the amount of surfactant required.

The surfactant injection can only be justified when oil prices are relatively high and if the residual oil saturation after water-flooding is high because they are expensive.

Different kinds of chemicals are used as surfactant. The application of each type depends on the type of rock formation we have and the required level of expected output. If an alkaline component is added it will react with the acid in the oil and reduce the absorption of the surfactants into the rock. The surfactant helps to release the oil from the rock and reduces the interfacial tension between the two phases. It might give a better result using both at the same place, but here only surfactant will be assessed.

3.2 Factors

3.2.1 Capillary Number

The capillary number is a measure of an EOR process' ability to produce oil. The only way to affect the capillary number is to reduce the interfacial tension. We can calculate the capillary number [4]:

$$N_c = \frac{v \cdot \mu}{\sigma}$$

Where:

N_c: The capillary number

V: The Darcy velocity of the displacement front

μ : Viscosity of the flowing fluid

σ : Interfacial tension

A favorable value for the capillary number is 10^{-3} or higher. The residual oil saturation decrease with an increase in capillary number as shown in the figure below [1]:

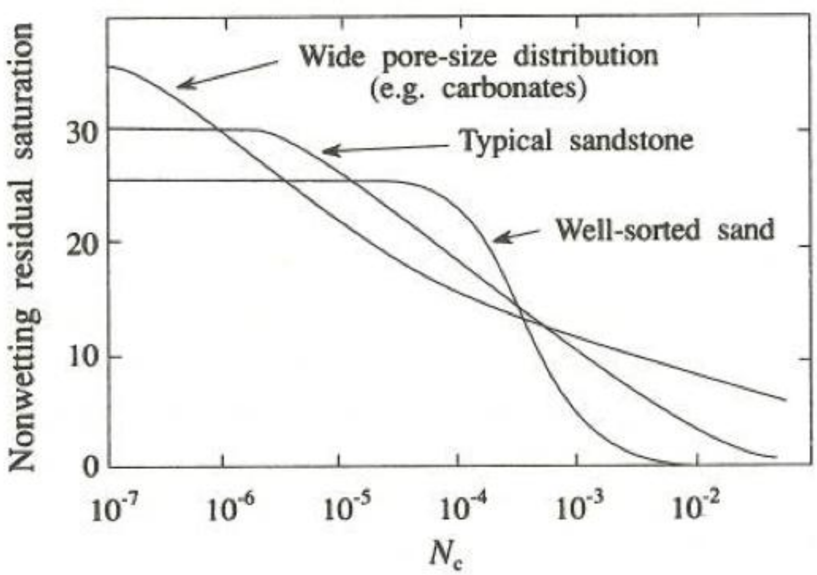

Figure 2: Capillary number Vs Residual saturation

3.2.2. Relative Permeability

Relative permeability is the ratio of effective permeability of a fluid at a given saturation to absolute permeability. If there is only one fluid present in a rock, its relative permeability is 1.0. By determining the relative permeability it is possible to find the ability of a fluid to flow while other fluids are present. This is in other words the permeability in the presence of more than one phase of fluid. The relative permeability reflects the capacity of a specific system to produce a combination of oil, water or gas more accurately than the absolute permeability, which is measured with a single-phase fluid, usually water [4]&[9].

A water flooded reservoir leaves a residual oil saturation of about 30%, this is the saturation at which the oil phase relative permeability value is zero [4]. This means that the oil doesn't move at this permeability, and it therefore necessary to increase the permeability by reducing the interfacial tension.

Relative permeability can be modelled either as immiscible relative permeability curves at low capillary numbers or as miscible relative permeability curves at high capillary numbers [4].

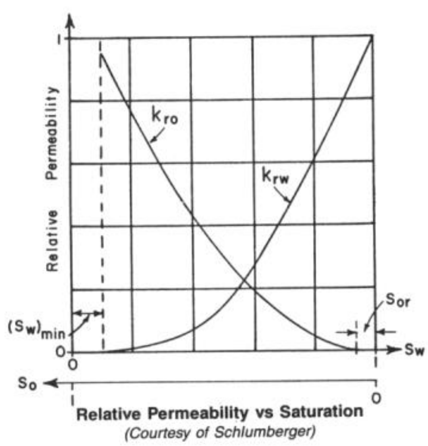

Figure 3: Relative permeability curves for an immiscible process

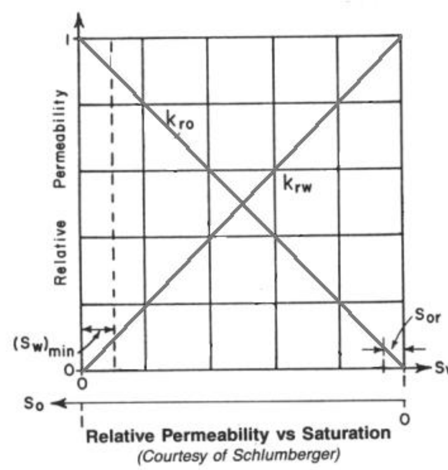

Figure 4: Relative permeability curves for a miscible process

It is essential to conduct relative permeability test at two stages, and it is expensive to conduct more than that. One of these points should preferably be around the critical saturation where we have the critical surfactant concentration for adsorption of the rock formation CMC. The other should be further from the CMC point where the residual oil saturation is very low.

3.2.3. Volumetric Sweep Efficiency

The volumetric sweep efficiency depends on the injection pattern selected, off-pattern wells, fractures in the reservoir, position of gas-oil and oil/water contacts, reservoir thickness, permeability and areal and vertical heterogeneities, mobility ratio, density difference between the displacing and the displaced fluid, and flow rate [9]. It is a measure of the effectiveness of injected fluid.

The mobility ratio, which is the ratio of permeability to viscosity, is especially important for the sweep efficiency. The mobility ratio of the surfactant slug needs to be very low to allow displacement of the oil bank.

3.2.4. Absorption of Surfactants

Retention of surfactant is caused by different factors such as precipitation, phase trapping and adsorption. While the first two can be prevented if there is a salt lenient surface, adsorption is very hard to prevent and can be very significant. It is therefore necessary to study the interaction between the rock and the surfactant in a laboratory before using the surfactant on site. It is also necessary to identify the right kind of surfactant which has less interaction with the rock. The adsorption is related to the economics of surfactant flooding, since it largely affects the volume necessary. The maximum adsorption for a surfactant is set to 0.5 mg per gram of rock [20]. This value has been set as the maximum value for a surfactant used in the simulation. It is reached at a concentration of 2 kg/m^3 assuming that no desorption of already adsorbed surfactant is possible.

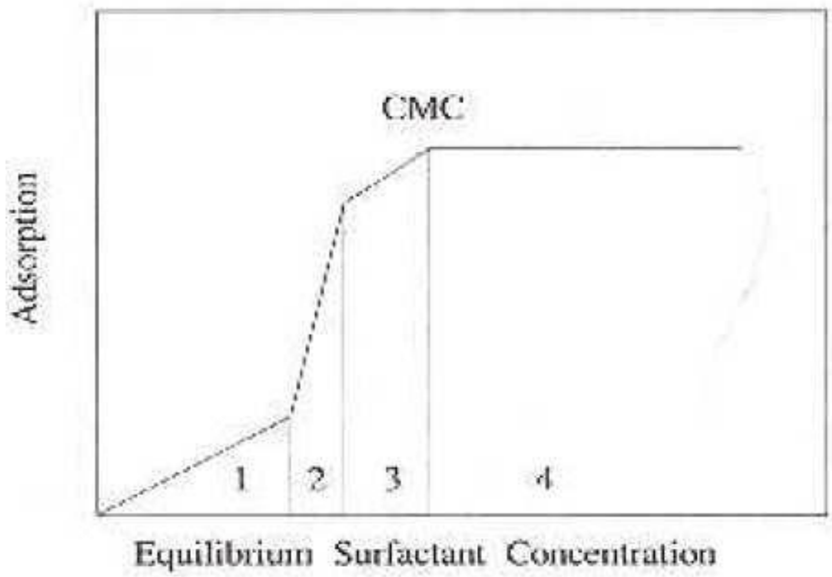

Figure 5: Stages of Adsorption [8]

The adsorption of surfactant to rock layer is generally categorized into four regions. In the first region the absorption is mainly due to anion exchange. The second region is characterized by increase in absorption as result of the reaction between the hydrophobic chains of surfactant adsorbed with the incoming surfactant. There is a decrease in adsorption of surfactant in region three as the initiation of adsorption requires overcoming the electrostatic repulsion already existing between the polymer and the rock. The last region is characterized by no further adsorption; the critical point is called critical micelle concentration (CMC).

The CMC level of adsorption corresponds to the critical concentration of surfactant at which we obtain low interfacial tension to make the residual oil mobile. It is however necessary to increase the concentration above this limit. The adsorption can be reduced by flushing with detergents that reduce hardness, increase the negative charges of the rock and reduce the interaction of the rock to adsorptions.

3.3 Process and Implementation

For effective oil recovery and environmental protection, it is advisable to follow the following aspects of surfactant modelling [6]:

1. Field history and status
2. Develop enhanced oil recovery chemicals or surfactant
3. Design the flooding
4. Implement flooding
5. Oil recovery

The first stage of the implementation process includes assessing the basic parameters for the simulating model. These are mainly related to the assessment of the field's history and its current status. We also need to determine the geological formation of the reservoir and the type of oil in the reservoir. In addition we need to asses the facilitations require in the extraction such as availability of water, equipment and surfactant. While the above assessment is applicable to any kind of recovery process, the assessment of surfactant is important to this project. We would have needed to make sure the availability and the economics of this before pursuing further on the implementation process.

The second stage deals mainly with identifying the right chemicals and their availability in the market. It also includes determining the interfacial tension and phase behaviour expected.

The third stage is where we plan the way we flood the field and decide on the drainage pattern to be followed. This relates to the flooding pattern and the injection plans to be followed. Water extraction, equipment usage design and the overall economics are studied at this stage. This is usually done by using modelling software such as Eclipse.

The fourth stage is where we implement the flooding of surfactants into our field. This can include training personnel, providing chemicals and other logistic and technical work.

The final stage is where we start recovering oil which includes demulsifying of oil from water and treating the water produced. The stages are summarized in the following flow diagram:

Figure 6: Various Aspects of Implementing Surfactant Flooding [6]

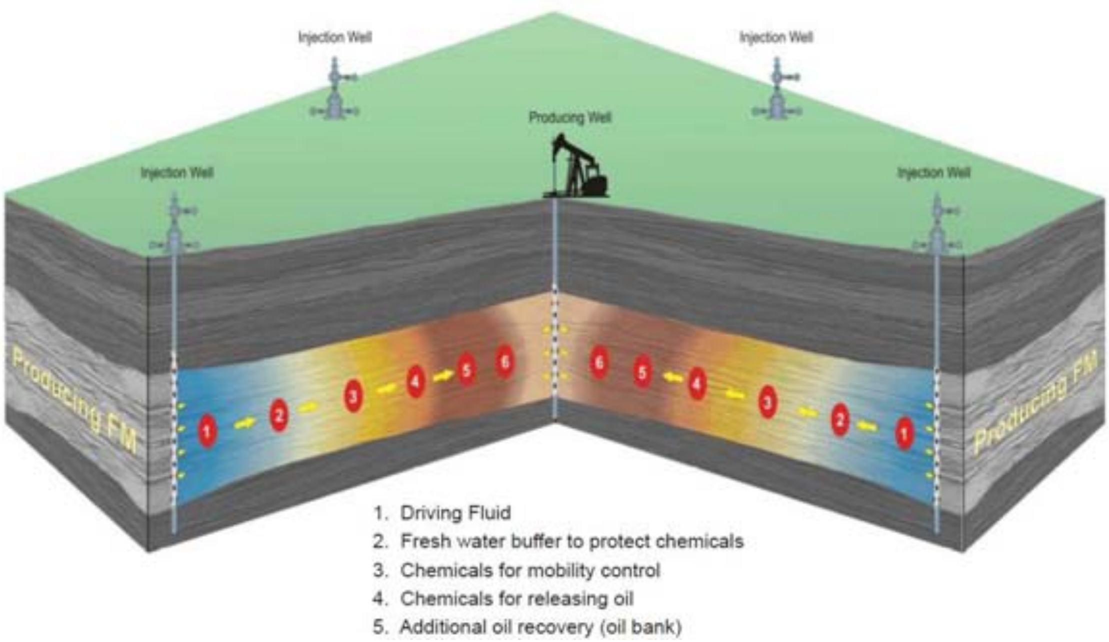

Figure 7: Surfactant Flooding Process [6]

3.4. Concentration

Because surfactants get adsorbed by the rock it is needed to find an optimal concentration to prevent this from happening. When a large amount of surfactant gets adsorbed the concentration in the solution decreases and the surfactants ability to reduce the interfacial tension is decreased.

When a surfactant is dissolved in water it splits into a cationic and an anionic monomer. When a certain concentration of the surfactant is reached, no more monomers are made. The monomers then go together to form a micelle and lowers the interfacial tension between water and oil in the reservoir. It's important that the concentration of the surfactant is greater than the CMC, this critical micelle concentration, to get a low IFT. If the concentration is lower than this the reduction in IFT stops.
The size of reservoir (pore volume), necessary water injection, excessive oil recovery due to surfactant flooding, concentration of the surfactant, cost of surfactant and maximum acceptable water-oil ratio needs to be determined. The concentration corresponding to the highest oil production is needed to optimize the excess oil produced with the surfactant injected.
Water cut must be considered before surfactant injection. If there is a high watercut in the production wells it might be better to inject surfactant with assistance from a nother chemical like a polymer or foam.

3.5 Volume of surfactant

Additional oil recover by chemical flooding can be obtained,

$$E_{RC} = (N_{PC} - N_{PW}) / N$$

Or can be calculated from,

$$E_{RC} = E_V \times E_{Dc} \times E_{MB} \times \frac{S_{orw}}{1 - S_{wi}}$$

Where E_v is the volumetric sweep efficiency, E_{Dc} is the microscopic displacement efficiency by chemical flooding. E_{MB} indicated the mobility buffer efficiency that depends on E_V and reservoir heterogeneity.

In order to calculate E_{Rc}, the other parameters should be defined as earlier. These parameters are depending on many factors that make them hard to evaluate. Most of these are determined for some fields in North Sea, for instance Statfjord, Gullfaks, Oseberg and

Snorre to about 0, 7. As the recovery of Norne is higher than those fields and the values are correlated with the recovery. E_v, E_{Dc}, E_{MB} are assumed for the Norne field regarding to previous calculations in the North Sea. By defining 4 different cases in calculating E_{RC} it is tried to take into account the uncertainty of assumptions. Also, it makes a range.

S_{wi} was evaluated from the simulation in Norne and it is about 0,2.

S_{orw} is assumed as 0,35.

1) E_v=0,6 , E_{Dc}=0,65, E_{MB}=0,6 $\Longrightarrow$ ERc= 0,10

2) E_v=0,5 , E_{Dc}=0,55, E_{MB}=0,5 $\Longrightarrow$ ERc= 0,06

3) E_v=0,45 , E_{Dc}=0,5, E_{MB}=0,45 $\Longrightarrow$ ERc= 0.04

The amount of surfactant needed to satisfy the retention of the reservoir is calculated as:

$$V_P * (\frac{1-\phi}{\phi}) E_V \Gamma \rho_r$$

Porosity is found in Statoils literature about the Norne field. Γ is the adsorption amount and be verified form our simulation; Γ =0,5 mg/g. ρ_r is the rock density , ρ_r =2650 kg/m^3. V_p is the pore volume needs to be determined. The best way is to calculate V_p is from OOIP. Since

OOIP=Vp* ϕ * (1-Swi). OOIP =157*10^6 *Sm3. The V_p is calculated to 7,2 *10^8 Sm^3

The amount of surfactant needed is calculated to 3,9*10^8 kg.

3.6 Timing of Surfactant Flooding

The efficiency of a surfactant flood is higher if it is implemented at the start of water injection than if it is implemented when the reservoir is already waterflooded. The Norne field was put on production in 1997, 13 years ago, so this is not a choice. The main task

of the project is to find out whether surfactant flooding is feasible after the E-segment have been waterflooded.
One thing which needs to be kept in mind is that the E-segment has had a MEOR injection from the start, which might have already decreased the IFT and increased the recovery by help of surfactant production.
The key question is how the efficiency will change depending on when we implement surfactant flooding.
As well as timing it a decision must be taken on where the surfactant should be injected.

3.7 Fields where surfactants have been injected

Surfactant flooding has mainly been implemented in onshore fields with low temperature and freshwater injection. Surfactant is usually not used alone but as assistance for polymers, alkaline solutions, foam, foam assisted wag, CO2 mobility control.
In China surfactant have been implemented on several fields like Gudong, where the ultimate recovery was increased by 13.4% OOIP due to alkaline-Surfactant-Polymer flooding during a pilot test, Karamay [22] and Daquing [23] where investigation show that by using surfactant-alkaline-polymer flooding the enhanced oil recovery is can increase by as much as 20% OOIP.
In USA a major surfactant implementation have been studied in the Powder River Basin in northeast Wyoming. The West Kiehl Minnelusa Field was implemented in 1987, and after 5 years it showed an incremental oil recovery of 11 %. Later 120 other Minnelusa fields have been evaluated for surfactant injection.
In Norway surfactant have not been emphasized, but have been used in the Snorre field in foam assisted WAG. It showed to be a success and the calculated incremental recovery is 5% [20]

4. Simulation

Eclipse is a reservoir simulation software used, worldwide, to simulate the behavior of petroleum reservoirs. Eclipse has the capability to simulate different processes such as In-situ combustion simulation and chemical simulation. In Eclipse it is possible to change and add new specifications to the code for different scenarios.

4.1 Model description

The model was prepared by Statoil. Flux over boundaries and the segments connection is an important part in chemical modeling. So the coarse grained model was used to study surfactant flooding potential. The impact of surfactant flooding in E-segment as an EOR option will be studied. In the first step was to predict the model until 2018 and modify it by surfactant injection by using specific keywords. There was a limitation on the number of simulated scenarios due to lack of time. The surfactant concentration and implementation time is changed in the schedule section for each scenario and the result is viewed in Office.

The surfactant distribution is modeled by solving the conservation equation for surfactant within the water phase. The surfactant concentration is calculated fully implicit at end of each time step, after the calculation of water, oil and gas is done. The input for surfactants to the reservoir is specified by concentration of the surfactant in the injected water and occur only in the water phase.[4]

4.2 Model modification

Model modification consists of different steps, first the model is extended to 2018, and then the surfactant model is activated. There are some necessary keywords to add in the RUNSPEC, PROPS and SUMMARY sections. In the below, the keywords will be explained.

4.3 Summary of keywords

4.3.1 SURFACT

It is located in the RUNSPEC section. Activates the surfactant model and it has no including data. [4]

4.3.2 SURFST

It supplies tables of water-oil surface tension as a function of surfactant concentration. The surfactant concentration in (Kg/m3) vs. surface tension in (cP). This keyword is added in the PROPS section. [4]

4.3.3 SURFVISC

SURFVISC is a keyword in the PROPS that contains the table of surfactant viscosity, which describes the effect of adding surfactant on the pure water viscosity. The surfactant concentration in (Kg/m3) vs. viscosity in (cP). [4]

4.3.4 SURFCAPDS

It is situated in the PROPS section.The capillary de-saturation function describes the transition between immiscible conditions (low surfactant concentration) and miscibility (high surfactant concentration) as a function of the dimensionless capillary number. The log of capillary number ($\log10\left(CAPN\right)$) vs. the number of relative permeability curve that is going to use. [4]

4.3.5 SURFADS

This PROPS section keyword describes the adsorption of surfactant by the rock. The right column refers to surfactant concentration in (Kg/m3) while the right column refers to the corresponding surfactant adsorption. [4]

4.3.6 SURFROCK

Another essential keyword in the PROPS section that specify the rock properties required for the surfactant model. The left value is the adsorption index in 1 or 2. The right value is indicated the mass density in (Kg/m3) that is used to calculate the surfactant loss due to rock adsorption. [4]

4.3.7 WSURFACT

Sets the concentration of surfactant in the injected water for each well, it is required that the well is defined as a water injection well. [4]

4.3.8 Summary

There are some keywords that control output data of the surfactant model, such as : FTPRSUR (Field total production rate of surfactant), FTIRSUR (Field total injection rate of surfactant)

5. Technical evaluation

According to the task description defined earlier an analysis has been carried out based on simulations in Eclipse. The main objective is to assess whether surfactant flooding is a profitable EOR method in the E-segment in the Norne field. The analysis is based on four scenarios with different volumes, timings and concentrations of a surfactant to detect a difference in efficiency, and to achieve a broader understanding for assessing the effectiveness of surfactant injection. The scenarios are connected to different simulation cases.

The four scenarios are based on water injection with and without surfactant, with different concentration and volumes and a combination of these. The various cases are described in more detail in chapter 5.1 to 5.7.

The simulations have been carried out over 21 years, from production start in November 1st 1997 to December 31st 2018. Surfactant has been injected in wells F-1H and F-3H which is perforated in the Tilje formation in the E-segment.

Name	Description	Data file	Compared by
S1	No surfactant (base case)	NORNE-COARSE2512	Volume
S2	***slug injection(ILE and TOFTE perforation)***	NORNE-COARSE251	Volume
S3	Continuous injection	NORNE-COARSE2513	Volume
S4	Concentration 5	NORNE-COARSE25142	Concentration
S6	Concentration 1	NORNE-COARSE25152	Concentration
S7	Concentration 100 11 years	NORNE-COARSE2516	Timing
S5	Concentration 100 2 separated injection periods of 8 and 3 years	NORNE-COARSE2517	Timing
S9	Wells flow at desired rate	NORNE-COARSE2519	Control keywords
S8	ILE formation potential(slug injection)	NORNE-COARSE2520	Formation type

Table 5: Description of scenarios

5.1 Effect of Surfactant Flooding

In this part, we investigate three different cases and compare them. In the first case, there is no surfactant injection (S2). This will be referred to as the base case. while in the two other cases we inject surfactant, first as a slug (S1) and then continuously for 21 years (S3). The surfactant slug was injected in a period of three years from 2005 to 2008.

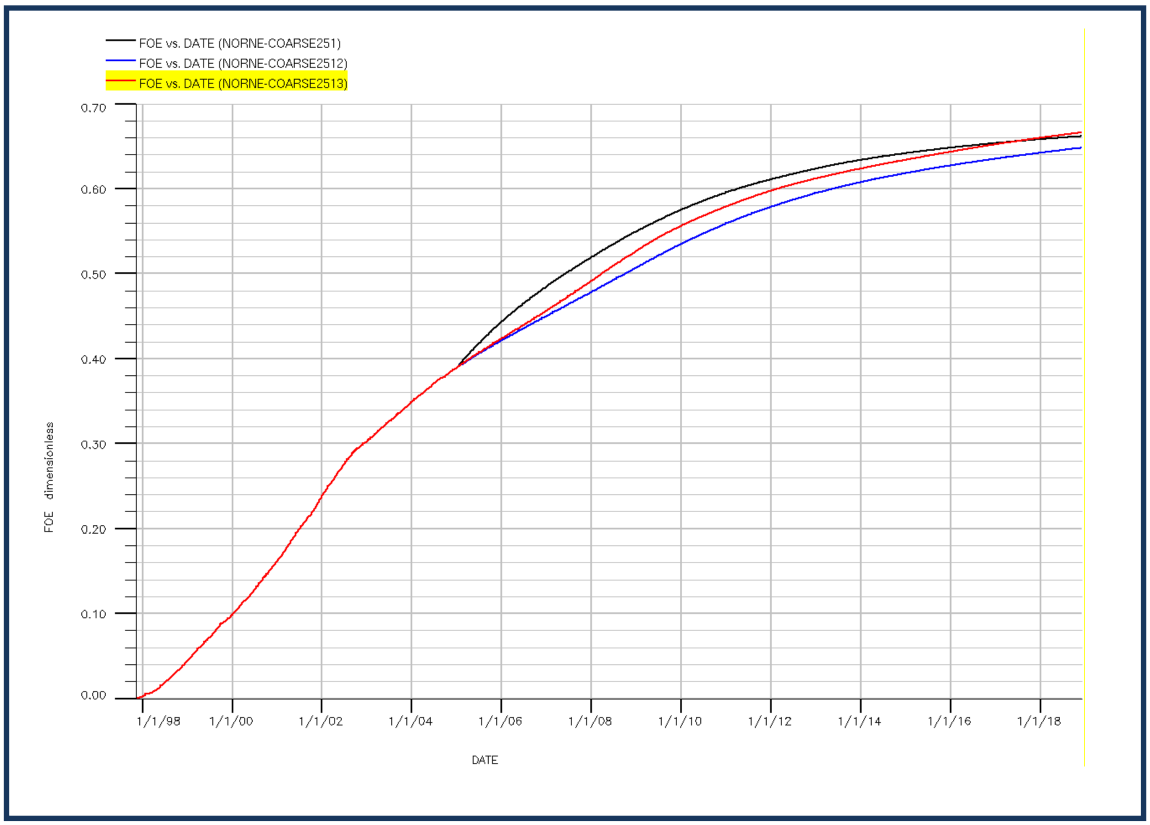

Figure 8: Oil recovery vs time with and without surfactant

The graph shows the effect of surfactant flooding on oil recovery. The blue line shows the Norne field recovery without surfactant, the black is with a slug injected, and the red is with a continuous injection. As we see from the figure, there is a significant increase in total oil production by usage of surfactants. By surfactant injection the total oil production is about $1.1112*10^8$ Sm^3, while in the case of no surfactant the total oil production is about $1.085*10^8$ Sm^3. Until 2005 the graphs will be equal because this is the point when surfactant injection is first implemented. With surfactant we hence get a recovery at the end of the simulation period of about 64.1%, while in the case of using surfactants the oil recovery increases to 66.15 which is an increase of 2% for the entire field.

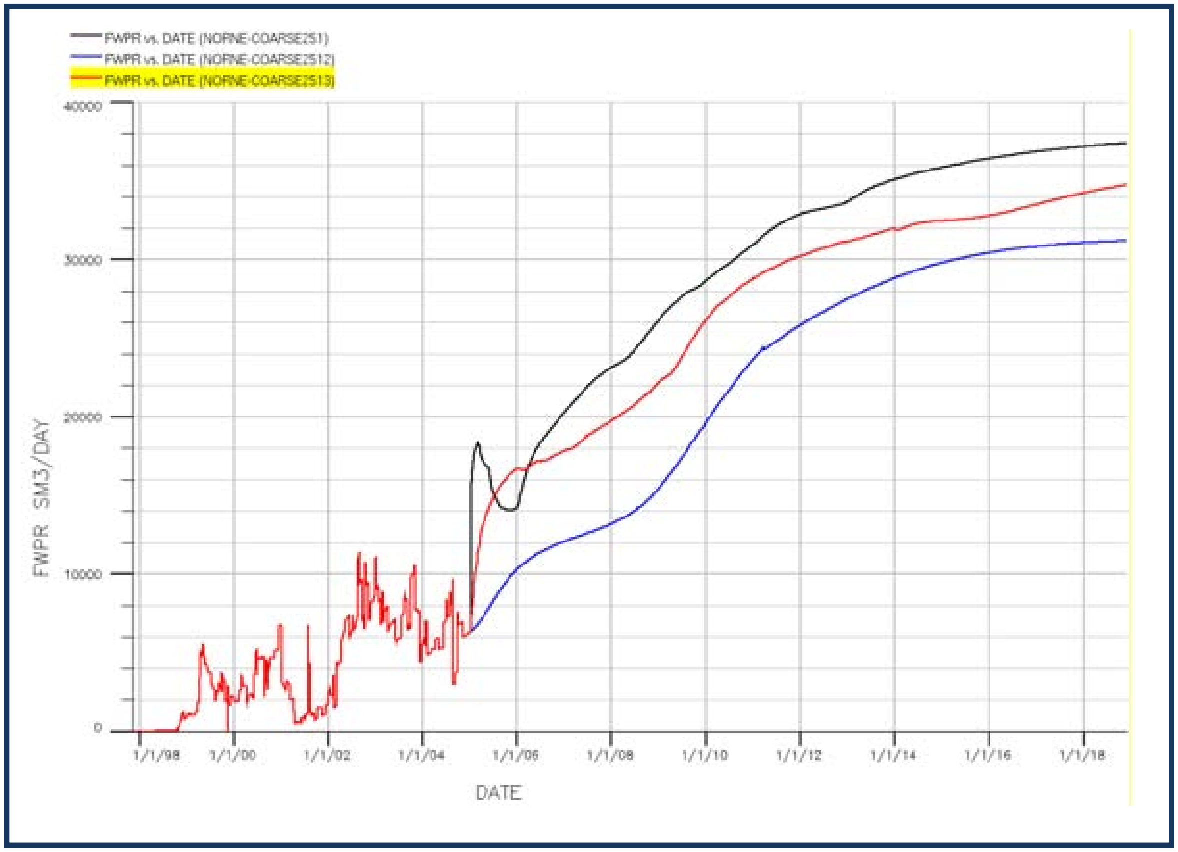

Figure 9: Water Production Rate vs time for S1, S2 and S3

From figure 11 it is seen that all of the cases will produce water. However, the water production rate has a decline after surfactant was injected, while in case of no surfactant there is a continuous increase in water production rate. This could be explained by the residual oil being mobilized and beginning to form an oil bank. Water starts to occupy the spaces released by the residual oil, thus causing a reduction in water production.

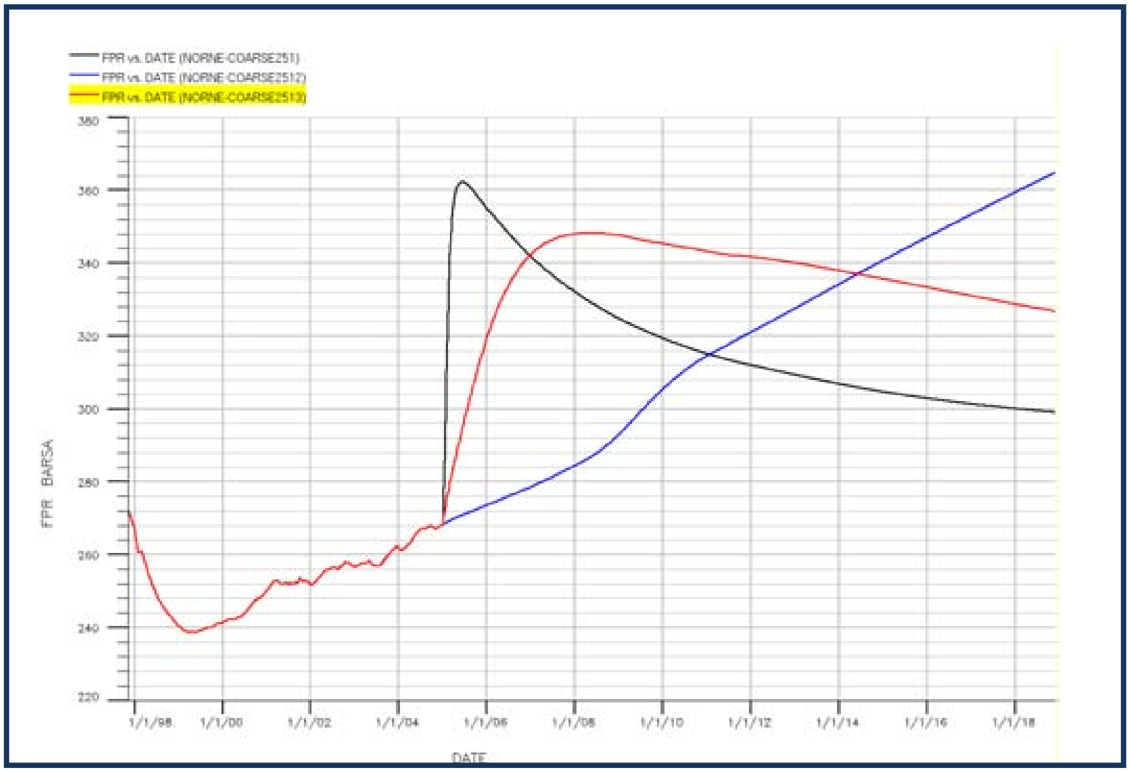

Figure 10: Pressure vs time for S1, S2 and S3

Figure 12 show the effect of continuous surfactant injection on reservoir pressure. Without surfactant there is a slowly increasing and stable pressure. The injection of a surfactant slug show a sharp increase in pressure right after injection, and then a decline in reservoir pressure later. Increased production from surfactant means more voidage in the reservoir, thus the decline in reservoir pressure.

5.2 Effect of timing

The effect of changing injection time is studied emphasizing recovery of the Norne field. Three cases are studied (S6) (S7) and the base case (S1)

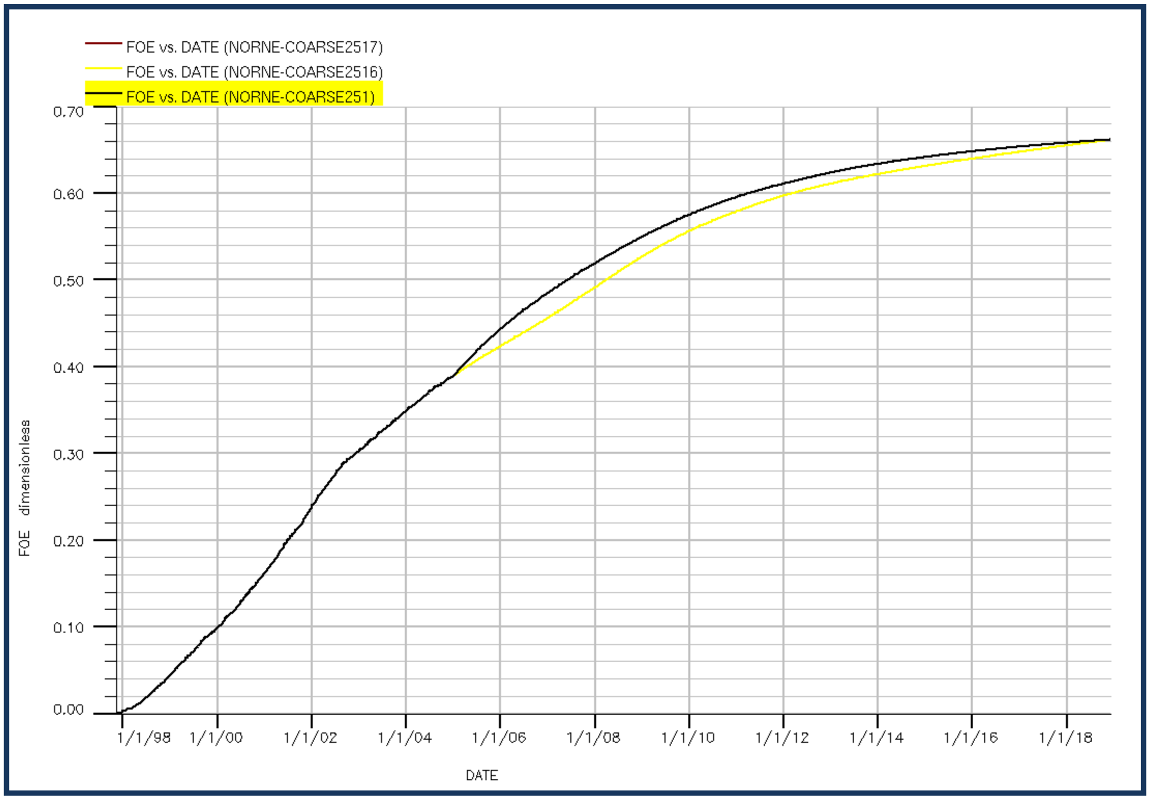

Figure 11: Oil recovery for different timing

From the figure it is seen that even though there is an increase in the surfactant injection time and concentration the oil production is slower than to the base case. The (S6) and (S7) cases are injected for half the time as the continuous case (S2), but with double the concentration of surfactant, and acts similar to it. The recoveries are the same at the end of the simulation. The effect of the timing of the process leads to a lower oil production at an early stage, but the final recovery is the same.

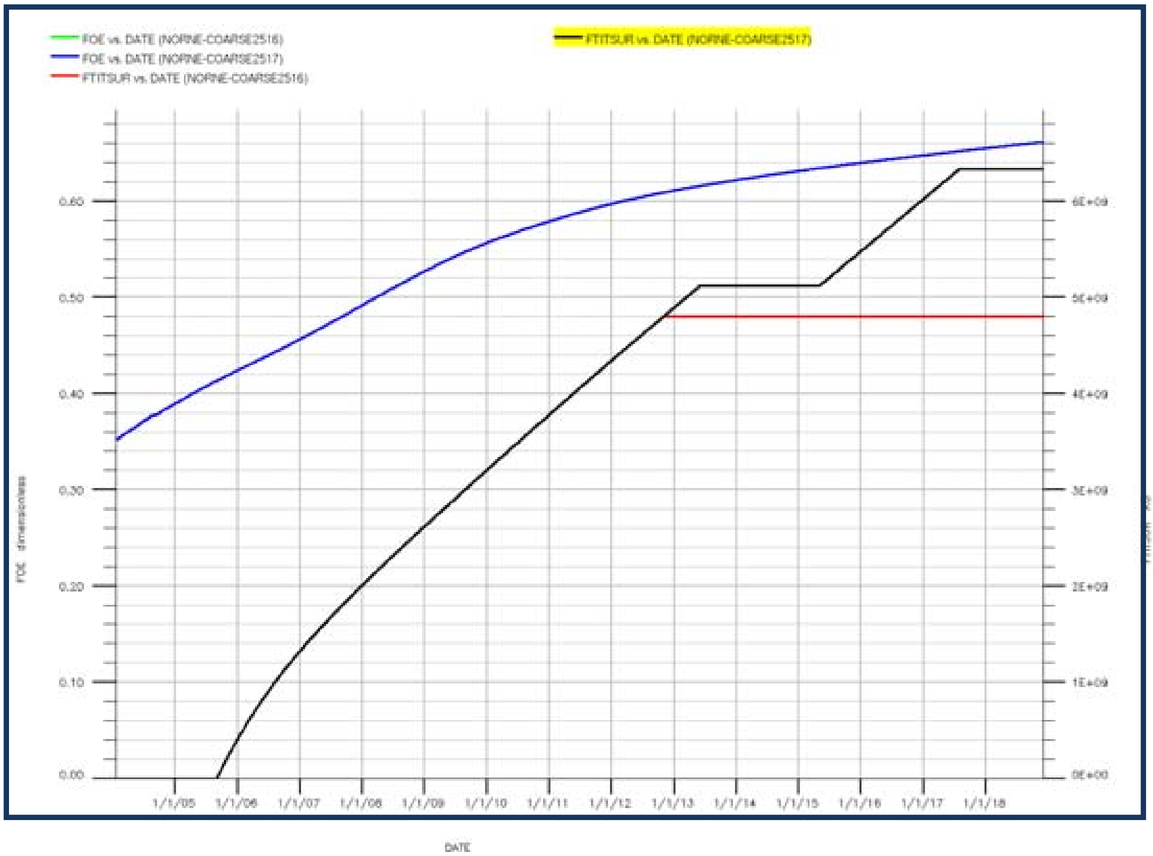

Figure 12: Oil Recovery compared with amount of surfactant injected

From the figure above it is seen that at a certain time the additional amount of surfactant does not improve recovery any more. This could be explained by the fact that both of these scenarios inject an amount of surfactant (5-6*10^9kg) which is far beyond the calculated requirements, and that the surfactant have already worked to its full potential.

5.3 Effect of concentration

By changing the concentration a change in the oil production rate is expected because of adsorpton effects. The graph below shows only minor differences. Four different cases are compared First it was tried to inject a slug of high concentration surfactant, followed by a period with lower concetration. The recoveries only differed with 0.45 %, the higher concentration producing the most.

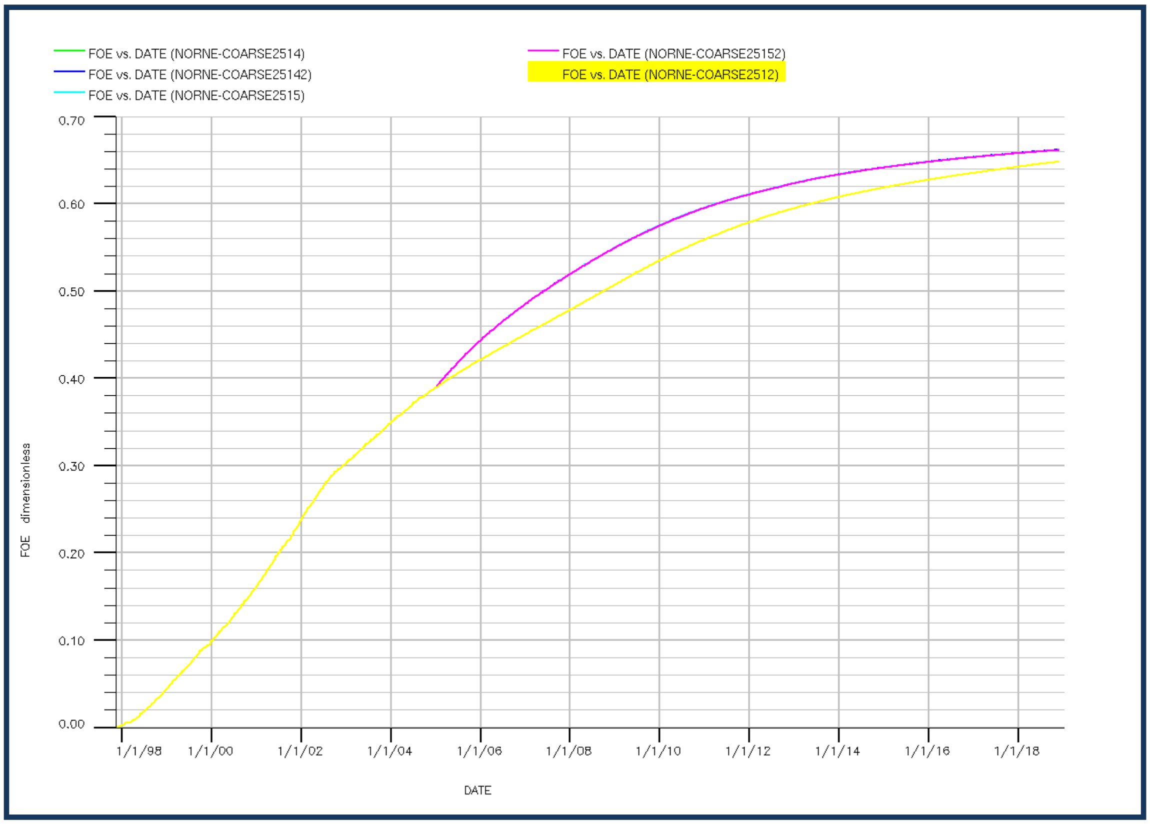

Figure 13: Oil recovery for different surfactant concentrations

The additional recovery from injection of high concentration surfactant corresponds to almost 68 000 bbl of oil.

5.4 Effect of no control keywords

In this section two different scenarios are compared: In the first scenario (S1) the control keywords WCONPROD and WCONINJE are used in the SCHEDULE section to control the production and injection rates and bottom hole pressure. In the second scenario (S9) the well is left to produce at its own desired pressure, which may lead to a decreased production because it is production below the bubble point of the oil.

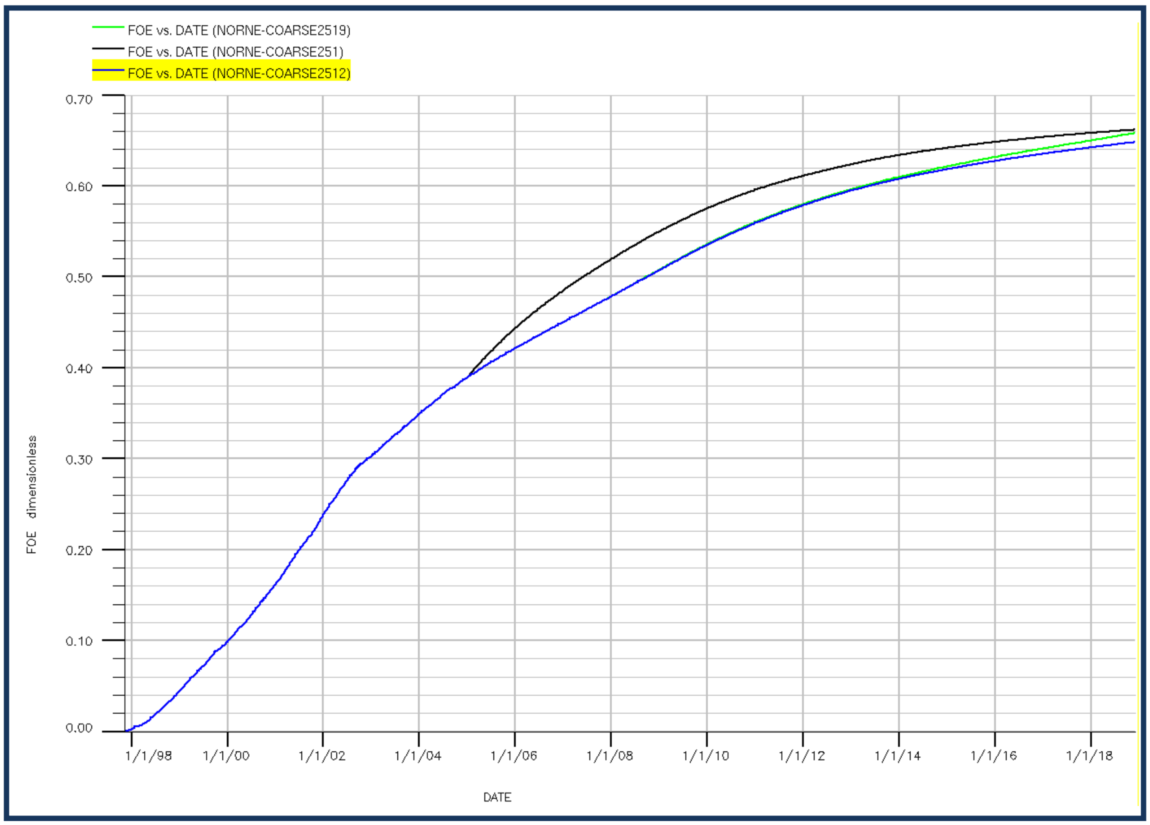

Figure 14: Oil recovery factor with and without control of the wells

There is no significant difference between the final oil recoveries in these three scenarios. The recovery factor for (S1) is 66.2 %, (S2) 64.8 % and without control of the wells the recovery reaches 65.8 %, so the recovery is higher with control over the wells. It is hard to know what would have happened if the simulation were run for an even longer period of time, because the (S9) case has a sharp increase right before the simulation ends.

As we can see from the figure, the amount of total oil produced in the (S1) case is bigger than in (S9). This means that the control keywords can control the pressure and the production rate and does not let the wells slow down, but keeps the rate or pressure values at the target value.

In (S2) and (S9) there is a constant increase in pressure, while in (S1) there is a peak and then pressure reduction, as seen in most of the scenarios with surfactant injection. This pressure reduction is related to the additional oil production which leads to a pressure reduction. The difference between the case (S1) and case (S9) is lack of control keywords don't keep the pressure above bubble point pressure in (S9).

In the absence of control keywords, the concentration of the surfactant remains constant over the three years injection period. This is because there is not any change in water injection rate, and the surfactant concentration in the water is constant.

In the base case (S1) there is a control keyword for water injection just after surfactant have been injected, and the concentration has to modify itself with the water rate and is reduced quickly.

5.5 Production and injection from Ile formation

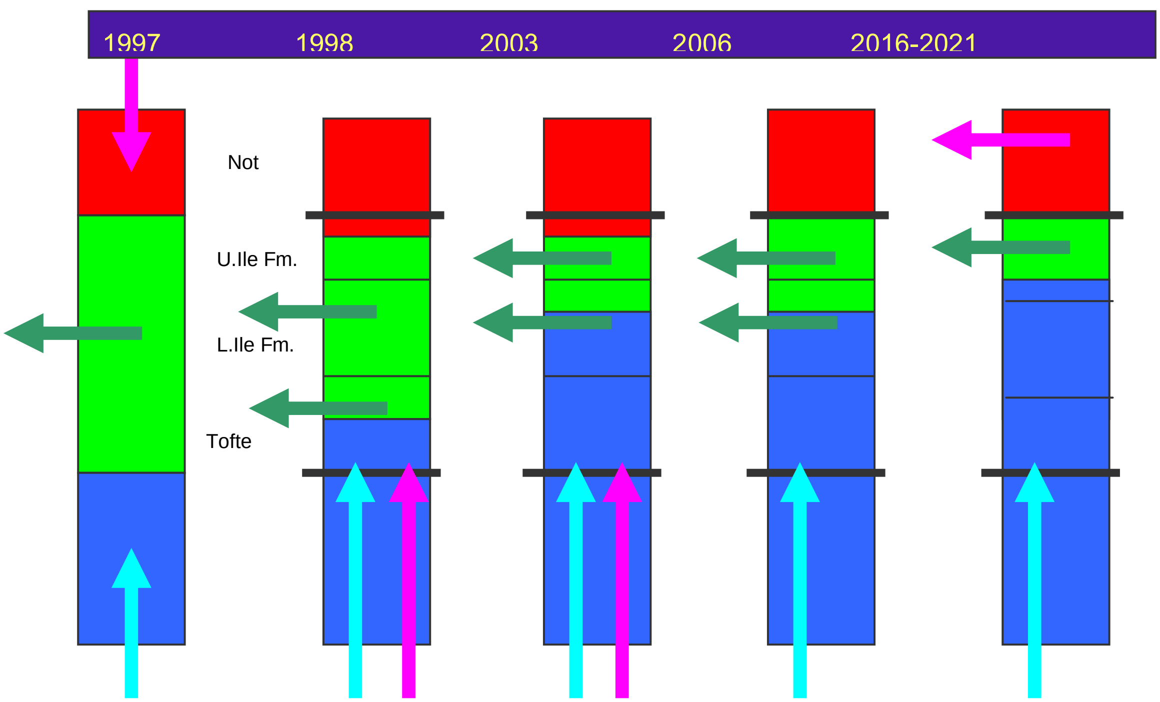

Figure 15: Statoils existing drainage pattern [22]

It is stated in the project definition that the production should be done according to Statoils existing drainage pattern. The pattern is described above. In the first years of development, it produced mostly from Ile and Tofte formation. As time goes the water-oil-contact (WOC) will move upwards and in 2006 it is only possible to produce from the Ile formation, mostly in the upper parts.

Both production and injection from the Ile formation is tried and compared with production from the Tofte formation. Ile formation is located between 2617 to 2657 meters depth, which refer to layers 9 to 14 in the Eclipse model. It is decided to inject from the well F-3H because the other injector, F-1H, is situated mostly in water contained layers and far from the producer E-2H and may lead to higher adsorption of surfactant. Due to less oil production rate from E-3AH and high water cut, it is decided to shut this well. It is possible to keep the water cut less than 90 % for the one producer. Well E-3AH is shut down and stops water injection from 2009 to 2014 and then start water injection again to maintain the pressure.

By applying these modifications, the recovery increase about 2% and reach 68 %. On the other hand, the oil production rate from the well E-2H increased with about 1000Sm3/day for about one year and then produced at plateau rate for about 3 years on 1500 Sm3/day. There is a small difference between S2 and S8. Water injection rate and surfactant concentration is kept constant to easier compare the results. The oil recovery is higher in S2 for 7 years, but in 2014 oil recovery of S8 starts to increase and the ultimate oil recovery of the field reaches to 68 % which is 4% more than the base case (S1). *See figure 19.*

Except from perforation location S2 and S8 have the same parameters. This is done to highlight the effect of formation producer. S8 only produce from Ile while S2 is producing from both Ile and Tofte. It is shown that, according to drainage pattern, it is best to produce and also inject in the Ile formation. The results from Eclipse prove the statement.

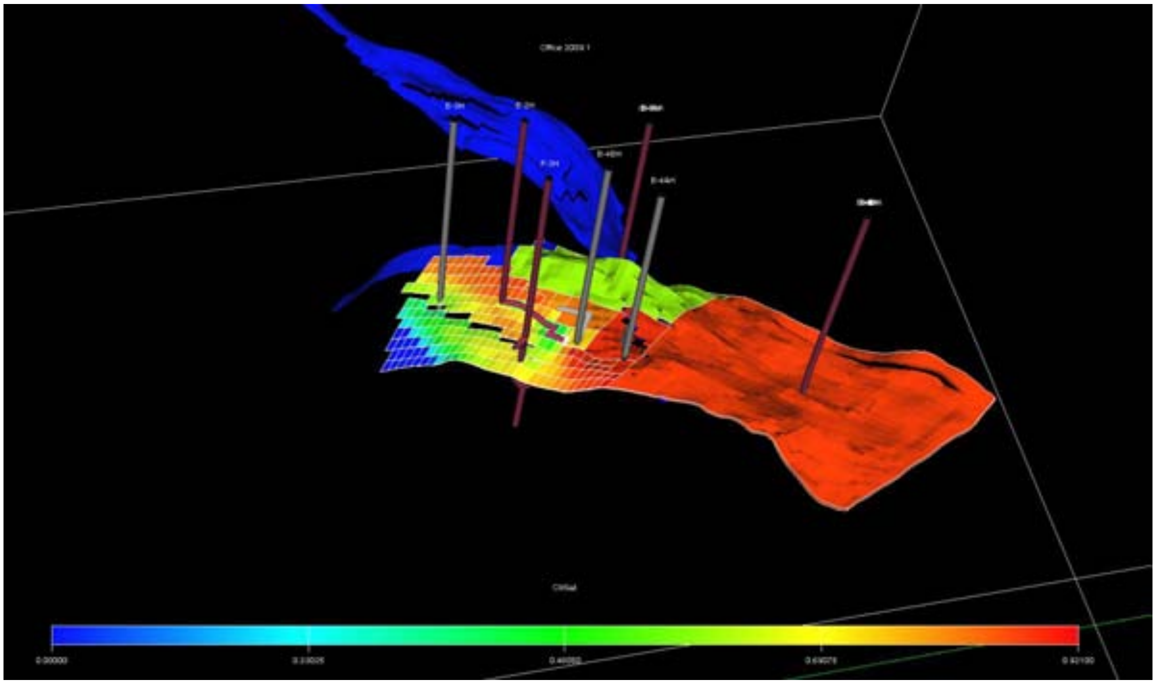

Figure 16: Layer 9- ILe formation in Nov 2004

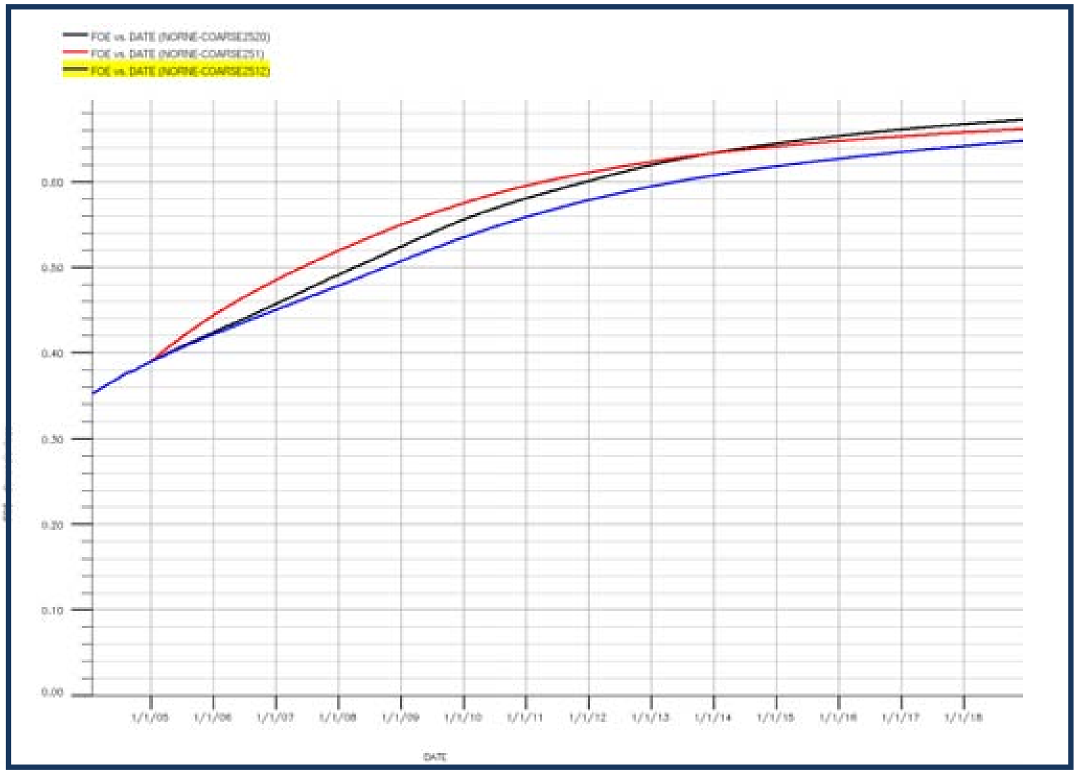

Figure 17: Oil recovery comparison of different scenarios

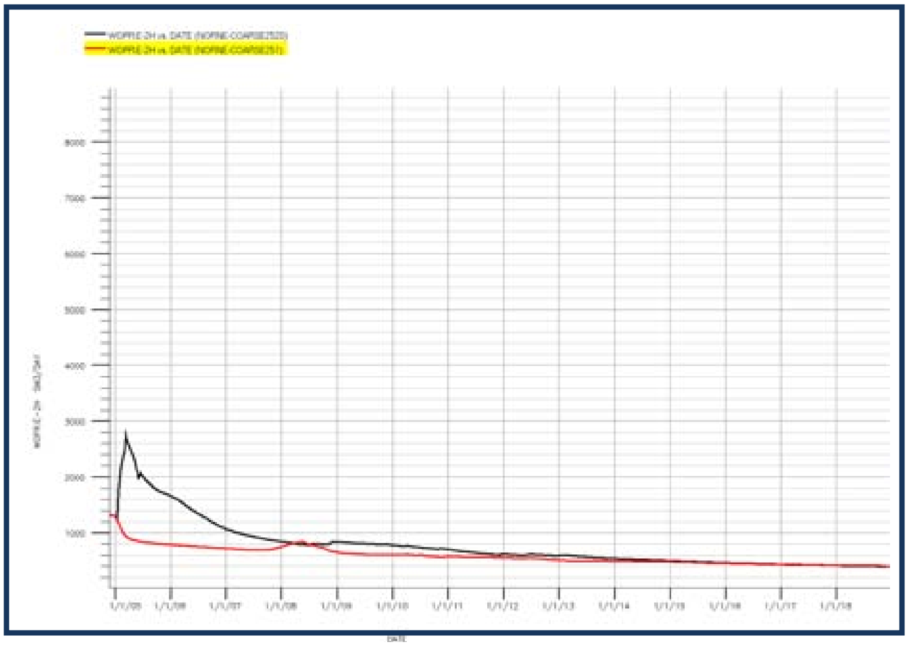

Figure 18: Oil production rate of E-2H in S2 and S8

5.6 Effect of injected volume of surfactant

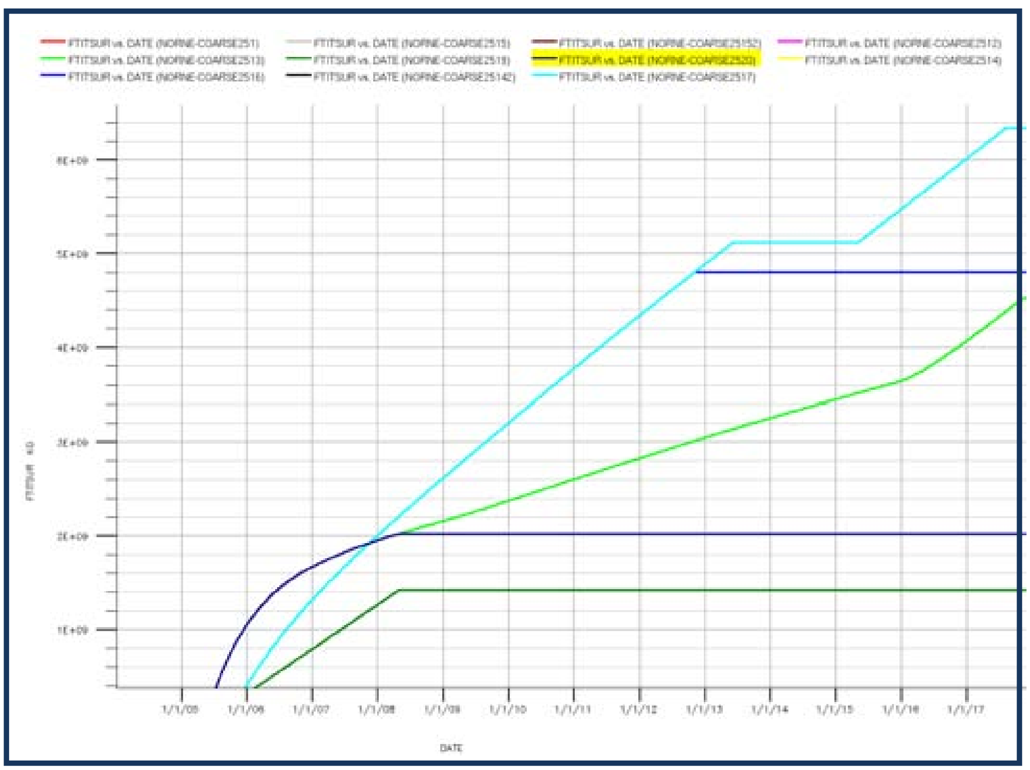

Figure 19: Total amount of surfactant injected

From the different scenarios that have been simulated four of the cases have injected more than the calculated requirement of surfactant. In the remaining seven cases there have been injected less than this amount. The results in the oil recovery do not seem to be dependant on the injection amounts. As seen in the figures the two cases with the highest surfactant injection produce only 6^{th} and 7^{th} most. The continuous injection result in the highest recovery, but injecting this amount of surfactants will be uneconomical. By injecting surfactant into the Ile formation the recovery is high, but this is mainly due to a high injection. It would be preferable to simulate more scenarios with injection in the Ile formation, but due to time shortage this is left for later work. In the economical part it is crucial to include the costs for plugging and re-perforating one of the injection wells for this scenario.

By not controlling the well, so that the pressure is kept above bubble point, the amount injected is to no extent important; this case yields a low recovery even though the injection is far above the calculated required amount.

The slug injection, which is used as base case, give good results. The amount of surfactant injected is below the calculated requirement, but still returns a good recovery.

Changing the concentration does not seem to have a constant influence on the recovery. The differences are small from case to case.

5.7 Effect of surfactant injection on water production

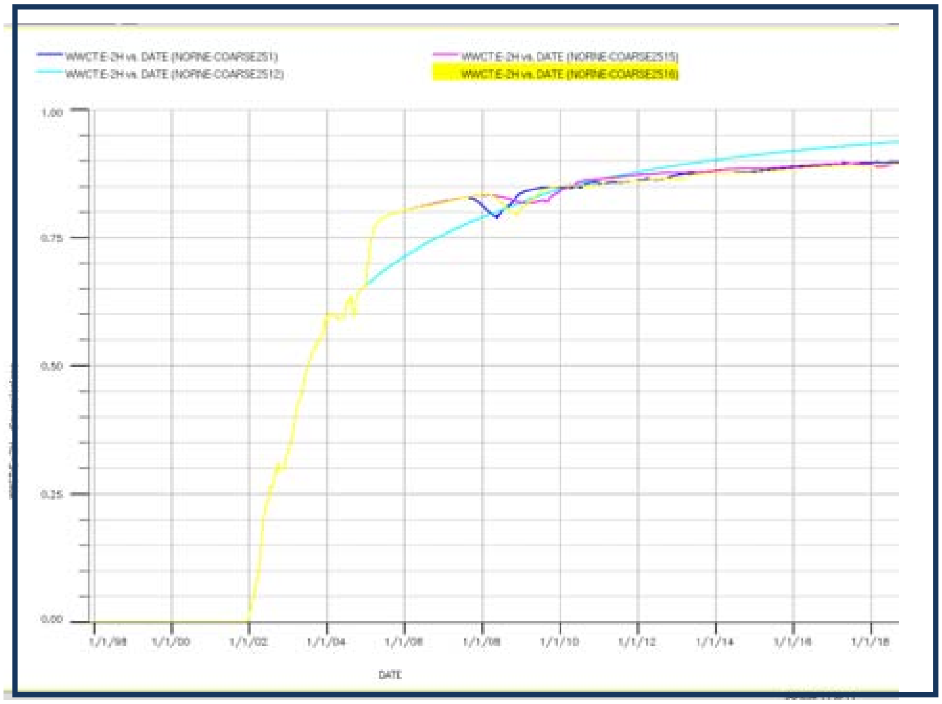

Figure 20: Water cut in the production wells

The more surfactant injected, the higher amount of water is needed to solve it and, subsequently, the water production decrease. The same effect will be seen for watercut. Directly after the surfactant injection there is a rapid increase in watercut, probably due to the pressure increase by injection. When the injection is stopped the watercut go down, and after a short period start a slow increase. The end result is a lower watercut than in the case with no surfactant.

5.8 Annual Comparison

The annual production for the different scenarios is obtained from technical evaluation done above. All output for each scenario is compared with the scenario with no surfactant injection. According to figure 23, in most years, S3 and S8 have the highest field oil recovery. S3 is injecting continuously while S8 is just producing from the Ile formation. As expected, the difference is not significant. Considering field oil recovery, field oil production and field surfactant injection with economical evaluation, it is concluded that surfactant flooding can not be recommended for Norne field. It is a high risk investment.

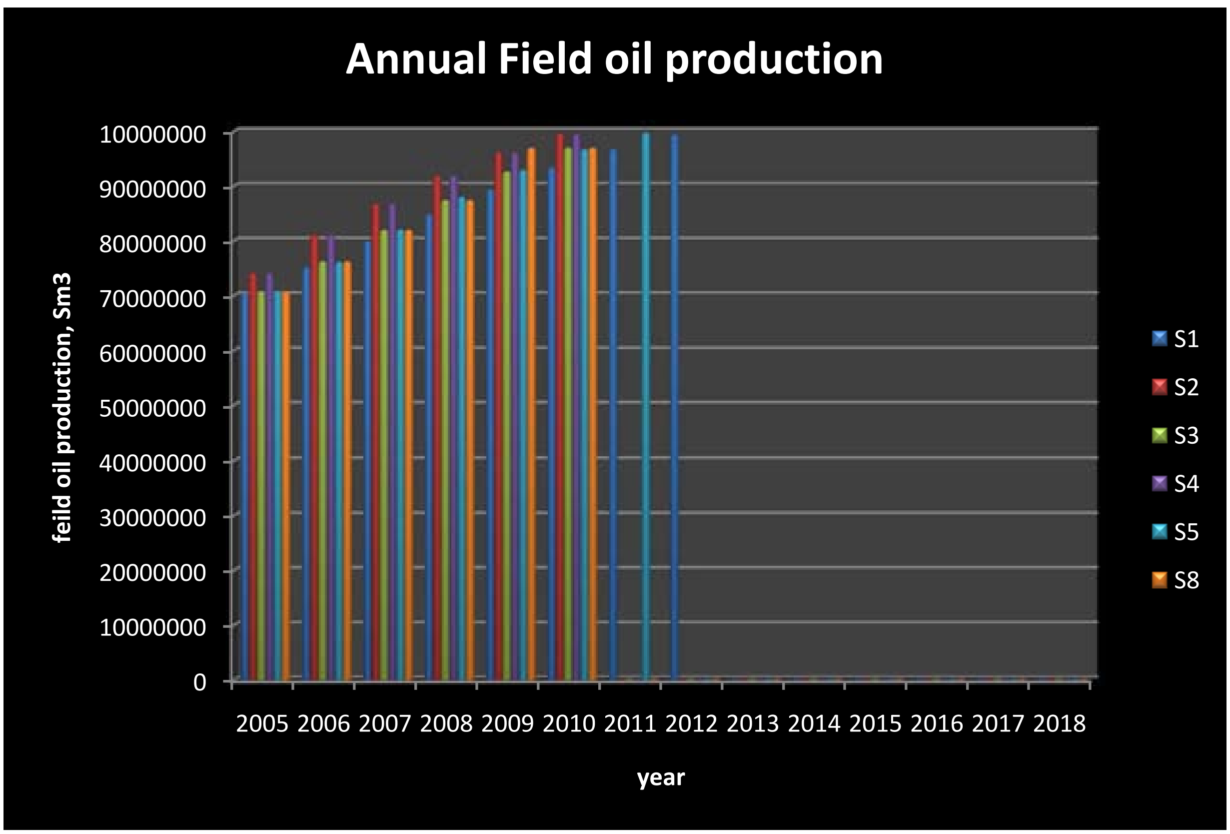

Figure 21: Annual production of E-segment for different scenario

Field oil production						
year	S1 2512	S2 251	S3 2513	S4 25142	S5 2517	S8 2520
2005	70408856	74083832	70763712	74083568	70800144	70763712
2006	75225624	81049392	76302112	81050056	76174064	76302112
2007	79947520	86783648	82052648	86781672	82121184	82052648
2008	84791144	91910080	87466784	91863800	88025088	87466832
2009	89415016	96135704	92689712	96083592	92991032	97041272
2010	93433032	99559656	97040528	99503296	96731304	97041272
2011	96720536	1.0213253E+8	1.0038834E+8	1.0208014E+8	99809920	1.003879E+8
2012	99428560	1.0428814E+8	1.0335973E+8	1.0424465E+8	1.0212238E+8	1.033583E+8
2013	1.0159274E+8	1.0597169E+8	1.0591371E+8	1.0594687E+8	1.0394742E+8	1.0590814E+8
2014	1.0338005E+8	1.0730062E+8	1.0784938E+8	1.0727062E+8	1.0554004E+8	1.0784125E+8
2015	1.0488136E+8	1.0838313E+8	1.0936725E+8	1.0835257E+8	1.0694222E+8	1.0935751E+8
2016	1.0620371E+8	1.092919E+8	1.1055242E+8	1.0926377E+8	1.082471E+8	1.1054007E+8
2017	1.073755E+8	1.100537E+8	1.1152285E+8	1.1002778E+8	1.094934E+8	1.1150384E+8
2018	1.0838387E+8	1.1067612E+8	1.1234184E+8	1.1064962E+8	1.105877E+8	1.1231006E+8

Table 6: Annual production of E-segment for different scenario

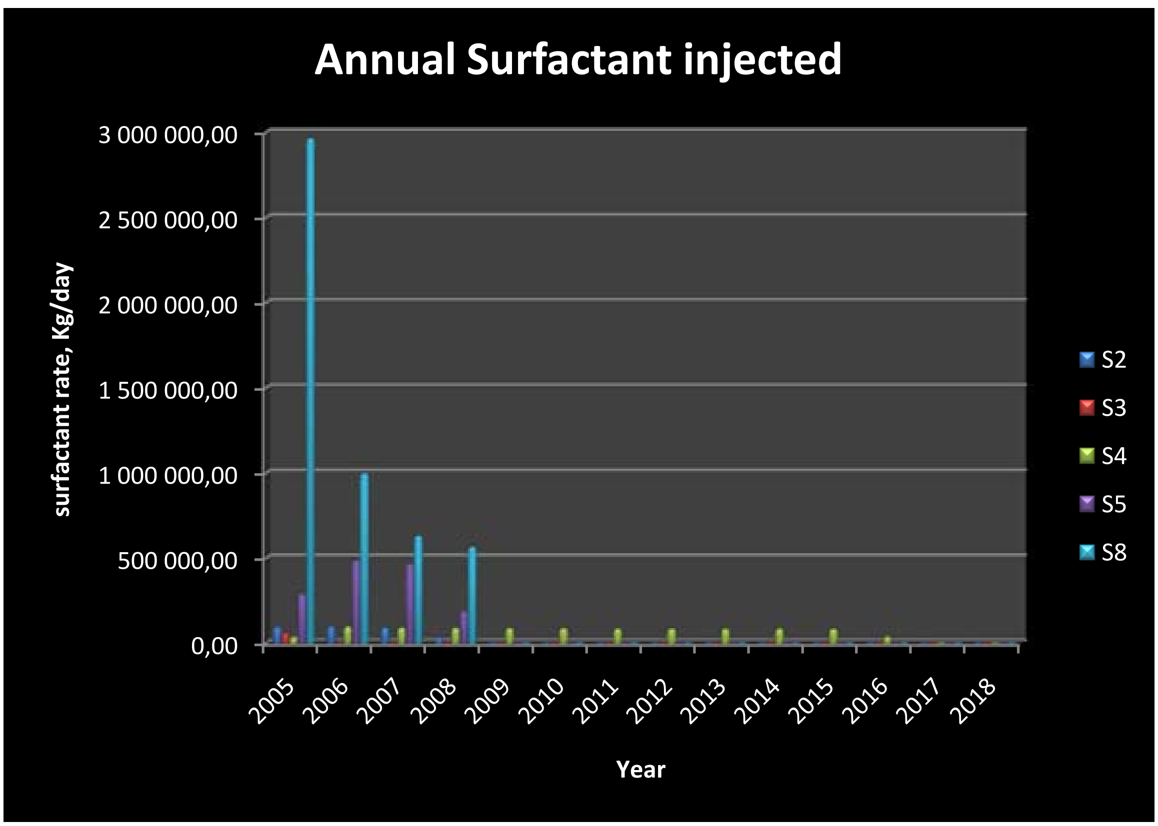

Figure 22: annual injection of surfactant for different scenarios

Field surfactant injected(Kg/day)					
year	**S2**	**S3**	**S4**	**S5**	**S8**
2005	**93 126,13**	**57 983,57**	**35 852,57**	**289189,70**	**2963957,00**
2006	**96 978,85**	**1 939,26**	**96 937,40**	**484690,80**	**997600,19**
2007	**90 705,72**	**1 813,44**	**90 674,89**	**465781,50**	**631541,37**
2008	**31 708,40**	**632,66**	**90 142,14**	**187099,00**	**565925,06**
2009	**0,00**	**0,00**	**88 262,80**	**0,00**	**0,00**
2010	**0,00**	**0,00**	**87 512,20**	**0,00**	**0,00**
2011	**0,00**	**0,00**	**85 523,60**	**0,00**	**0,00**
2012	**0,00**	**0,00**	**85 295,20**	**0,00**	**0,00**
2013	**0,00**	**0,00**	**84 613,40**	**0,00**	**0,00**
2014	**0,00**	**0,00**	**85 477,50**	**0,00**	**0,00**
2015	**0,00**	**0,00**	**83 994,50**	**0,00**	**0,00**
2016	**0,00**	**0,00**	**36 626,40**	**0,00**	**0,00**
2017	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**
2018	**0,00**	**0,00**	**0,00**	**0,00**	**0,00**

Table 7: Annual injection of surfactant for different scenarios

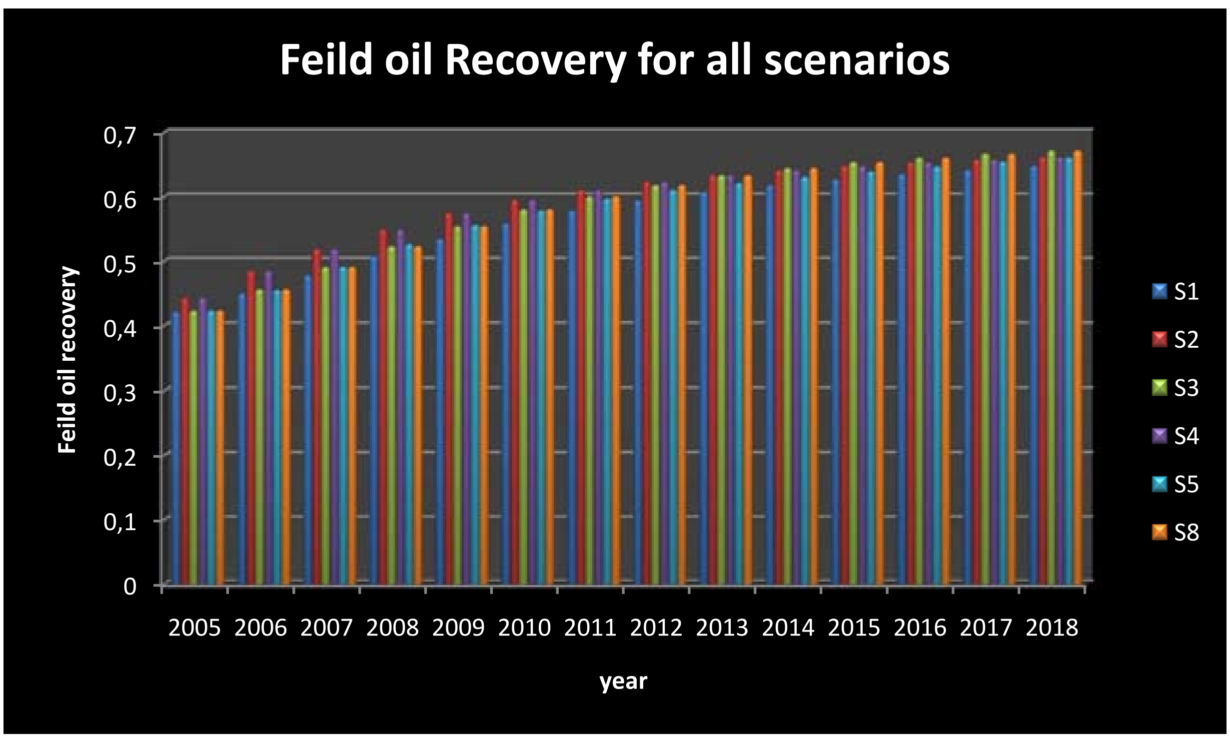

Figure 23: Annual field oil recovery for all scenarios

FOE						
year	S1	S2	S3	S4	S5	S8
2005	0,42105874	0,443042255	0,42328903	0,44304007	0,42351422	0,42328903
2006	0,44985598	0,48468655	0,45641044	0,48468015	0,45564282	0,45641044
2007	0,47808778	0,51892436	0,49078572	0,51890051	0,4911983	0,49078572
2008	0,50704688	0,54957223	0,52310538	0,54926723	0,5264954	0,5231055
2009	0,53467309	0,57483572	0,55432063	0,574485	0,55618483	0,55432802
2010	0,5587095	0,59530544	0,58031625	0,59491545	0,5785464	0,58032089
2011	0,57835793	0,61068708	0,60030031	0,61031193	0,59695226	0,60030299
2012	0,59453475	0,623568	0,61805111	0,62324184	0,61077756	0,6180535
2013	0,60747075	0,63363349	0,63331586	0,63341916	0,62168872	0,63329434
2014	0,61815476	0,64157867	0,64488816	0,64133334	0,63121039	0,64485127
2015	0,62712878	0,64805049	0,65396291	0,64780182	0,63959348	0,6539163
2016	0,63503313	0,65348363	0,66104686	0,65324944	0,6473949	0,66098785
2017	0,64203835	0,65803814	0,66684872	0,65781713	0,65484613	0,66674984
2018	0,64806587	0,66175938	0,67174524	0,66153485	0,66138852	0,67157006

Table 8: Annual field oil recovery

6. Economy

To evaluate the economy of surfactant injection in the E-segment for the different scenarios listed above, a comparison of Net Present Value (NPV) is done. Different assumptions are needed. Calculation is done by using Norwegian Kroner (NOK) as currency. Because of uncertainty in some parameters, they are assumed according to Statoils plan. They might be change in time.

6.1 Assumptions

6.1.1 Oil price forecast

The oil price has fixed from 2005 to 2009, extract from economy. After 2009, the oil price is obtained by assuming the constant value of 75 USD/bbl up to 2018.

Years	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Oil price forecast (USD/bbl)	55.47	62.65	66.97	91.77	53.92	75	75
Years	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Oil price forecast (USD/bbl)	75	75	75	75	75	75	75

Table 9: oil price forecast during the times

6.1.2 Other parameters

In order to calculate the Net Present values, some other economical parameters are assumed:

Discount rate: 7%

Inflation rate: 2.5%

Tax: 74%

Current rate: 1 USD = 6 NOK

6.1.2 Cost of surfactant

The cost of surfactant is based on the amount of surfactant needed per year for different scenario and the price of surfactant. This cost is defined as Capex in our budget.

Price of surfactant: 20.9 NOK /kg [17]

year	scenario 2		scenario 3	
	Amount (kg)	Cost (MNOk)	Amount (kg)	Cost (MNOk)
2005	93 126,13	1,946	57 983,57	1,212
2006	96 978,85	2,027	1 939,26	0,041
2007	90 705,72	1,896	1 813,44	0,038
2008	31 708,40	0,663	632,66	0,013
2009	0,00	0,000	0,00	0,000
2010	0,00	0,000	0,00	0,000
2011	0,00	0,000	0,00	0,000
2012	0,00	0,000	0,00	0,000
2013	0,00	0,000	0,00	0,000
2014	0,00	0,000	0,00	0,000
2015	0,00	0,000	0,00	0,000
2016	0,00	0,000	0,00	0,000
2017	0,00	0,000	0,00	0,000
2018	0,00	0,000	0,00	0,000

Table 10: Amount of injected surfactant scenario 2 and 3

year	scenario 4		scenario 5	
	Amount(10^3kg)	Cost (MNOk)	Amount(10^3kg)	Cost (MNOk)
2005	35,852.57	757.21	289,189.70	6,107.69
2006	96,937.40	2,047.32	484,690.80	10,236.67
2007	90,674.89	1,915.05	465,781.50	9,837.31
2008	90,142.14	1,903.80	187,099.00	3,951.53
2009	88,262.80	1,864.11	0.00	0.00
2010	87,512.20	1,848.26	0.00	0.00
2011	85,523.60	1,806.26	0.00	0.00
2012	85,295.20	1,801.43	0.00	0.00
2013	84,613.40	1,787.04	0.00	0.00
2014	85,477.50	1,805.28	0.00	0.00
2015	83,994.50	1,773.96	0.00	0.00
2016	36,626.40	773.55	0.00	0.00
2017	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00

Table 11: Amount of injected surfactant scenario 4 and 5

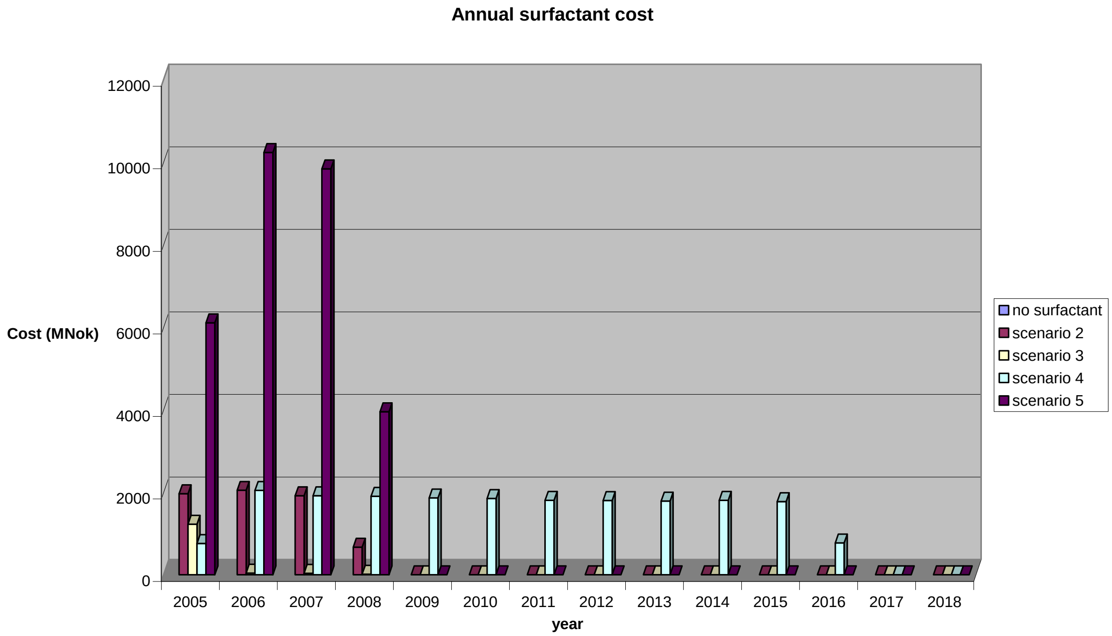

Figure 24: Annual Cost of surfactant for different scenarios

6.2 Net Present Value

After calculation, the NPV for the different scenarios before tax and after tax are

Scenario	Technical case	NPV (MNOK)	
		Before Tax	After Tax
Scenario 1: No surfactant	(S2)	93,503	24,311
Scenario 2	(S1)	95,270	24,699
Scenario 3	(S5)	99,923	25,965
Scenario 4	(S6)	87,155	22,493
Scenario 5	(S9)	69,292	17,693

Table 12: Net present value

6.3 Economical evaluation

Economically speaking, in that case that we consider that the scenarios are mutually exclusive, the best alternative is the scenario with the highest NPV after tax which is the scenario 3.

Scenario 5 is the worst alternative, because the injection of surfactant without well control results in a NPV less than the NPV without using surfactant.

7. Discussion

For chemical flooding, the analysis done indicates that only the most favorable fields might have an economic potential with the present status of chemical performance and price on the Norwegian continental shelf. [19]

Surfactant flooding as a process is sensitive to brine salinity, temperature and clay content. Adsorption, which determines the total amount of surfactants needed for an efficient displacement process, is closely related to the type and content of clay. Fault locations play an important role in surfactant injection. The reason that the geological part of the Norne has been studied is to determine the target formation for surfactant implementation and oil production.

As Surfactant flooding is dependent on geometrical factors, completion of the injectors is taken care about. If the injectors are located in the aquifer then a large portion of surfactants may be lost without contacting the residual oil. In this project, surfactant has been injected in the Tofte and Ile formations.

The potential for surfactant flooding is strongly related to the remaining oil saturation after water flooding. Due to high oil recovery from the Norne field and less residual oil saturation. It seems hard to extract more oil via Enhanced oil Recovery methods such as surfactant flooding.

North Sea reservoirs frequently have a favorable mobility ratio between water and oil, which may reduce the need for polymers; hopefully this will be the case in the Norwegian Sea as well. [19]

Compared to the NPV of no surfactant, most of the scenarios NPV are increased, except for the scenario 5 (S9) which is less than the NPV of no surfactant. This is caused by the high concentration of surfactant injected in the first four years. The total cost of that surfactant is almost 30,133 Billion NOKs, a huge amount of money.

The difference in NPV from the scenario with no surfactant injected to the best case is approximately 6 million NOKs. Costs for solving logistics problems and injection modifications are not included. Several uncertainties were mentioned about the model, and they should be considered before a possible implementation.

Another constraint is related to limited storage capacity on platforms that create problems for the daily injection of large quantities of surfactant. Injection at 3000 m^3/day of a 2% surfactant solution, implies the handling of around 6o tons of chemical per day. [8]. Also a large well spacing is needed on the offshore fields.

Analysis of some factors not considered in this project is necessary, such as rock absorption and the type surfactant polymer to be used. The potential of surfactant flooding on the oil recovery of the Tofte formation is assessed, but lack of time made it difficult to study the object in detail.

The topic is an interesting study but it needs more time, and all aspects of surfactant flooding must be taken into account.

8. Conclusions

In surfactant flooding of oil reservoirs, surfactant products are added to the injection water to reduce the oil-water interfacial tension and thereby mobilize the residual oil.
This project studied the potential of surfactant flooding on increasing the oil recovery in the Norne field, E-segment. The model was simulated by Eclipse simulator. Several case studies have been carried out. Surfactant was injected in different concentrations and different times, in order to find the optimum volume and time of surfactant injection. The upper extreme is the case with continuously surfactant injection that gains the highest oil recovery. The simulations show that different concentration does not affect the recovery significantly. The same result is seen for different injection times. This might be due to small residual oil saturation in the Norne field left to be extracted with Enhanced Oil Recovery methods. To overcome this problem, it is decided to change the well perforations and produce only from the Ile formation. This scenario obtains more oil recovery compared to previous cases. It is reasonable according to drainage pattern of Norne field. Another simulated case was related to simulate the model without control keywords. The results show that only small variations from the other scenarios.
From the simulation model the Norne fields recovery is about 64% without surfactant, while in the cases of continuously injection the recovery reaches 68%. The probability of additional recoverable oil, as well as the high cost of field development and production, increases the financial risk of implementing surfactant in the Norne as an alternative EOR method for Statoil.

9. References

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For more detail on which surfactant to choose please see the SPE paper "*Identification and Evaluation of High-Performance EOR Surfactants*" by David B. Levitt, SPE, Adam C. Jackson , SPE, Christopher Heinson, SPE, and Larry N. Britton, The University of Texas at Austin; Taimur Malik, and Varadarajan Dwarakanath, SPE, Intera; and Gary A. Pope, SPE, The University of Texas at Austin, April 2009

Appendix: 3D map of the Norne field

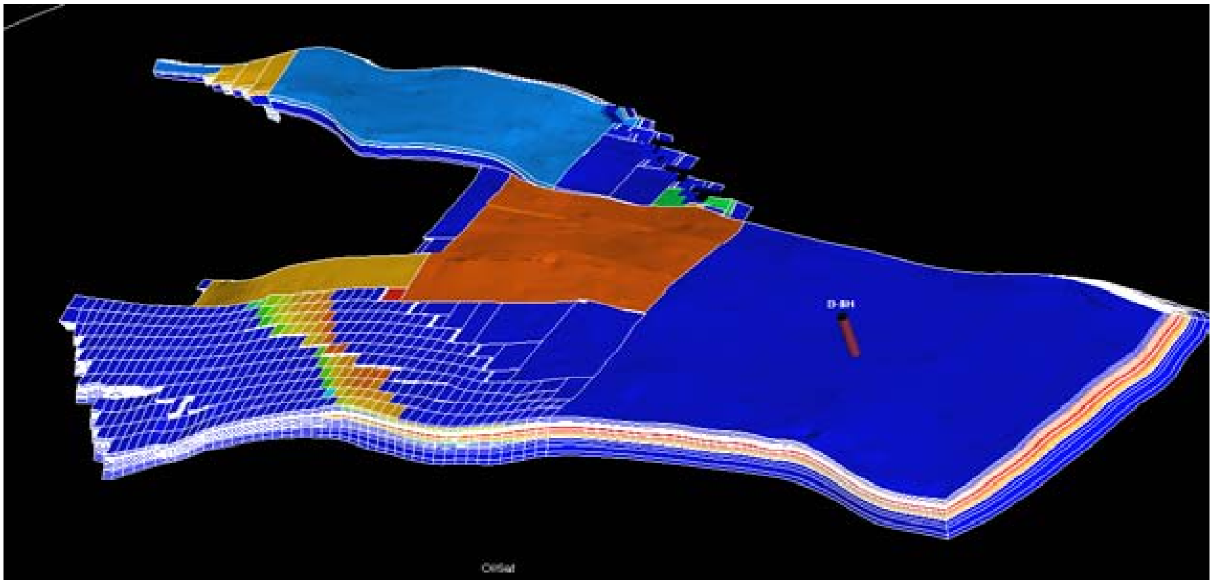

Figure 25: 3D visualization of Norne field in Nov 1997(same for all the cases)

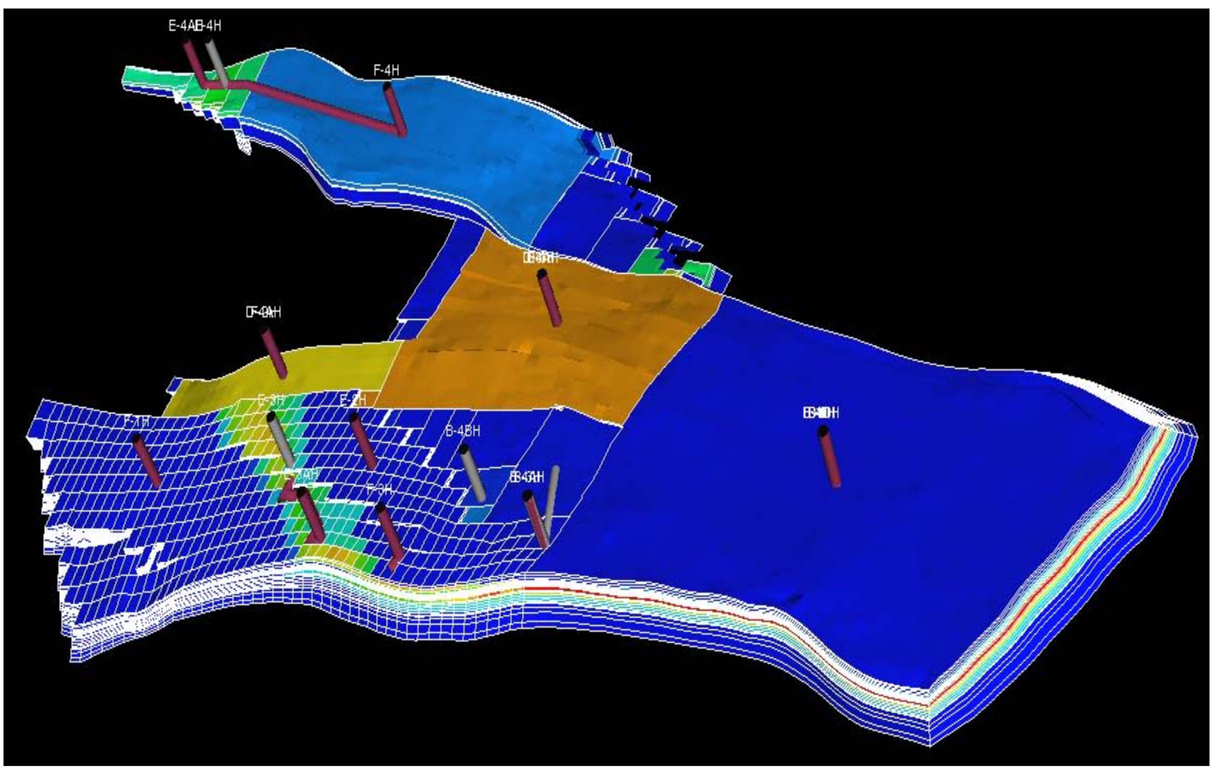

Figure 26: 3D visualization of Norne field in Dec2004 (same for all the cases)

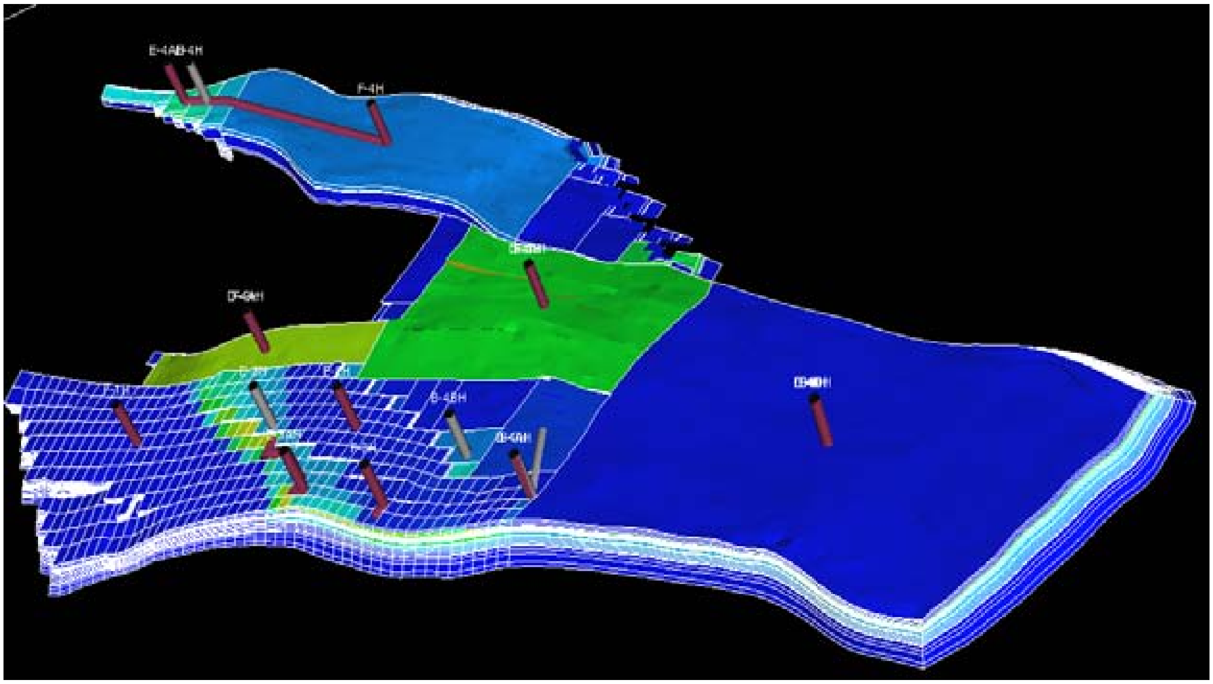

Figure 27: 3D visualization of Norne field in Dec2018

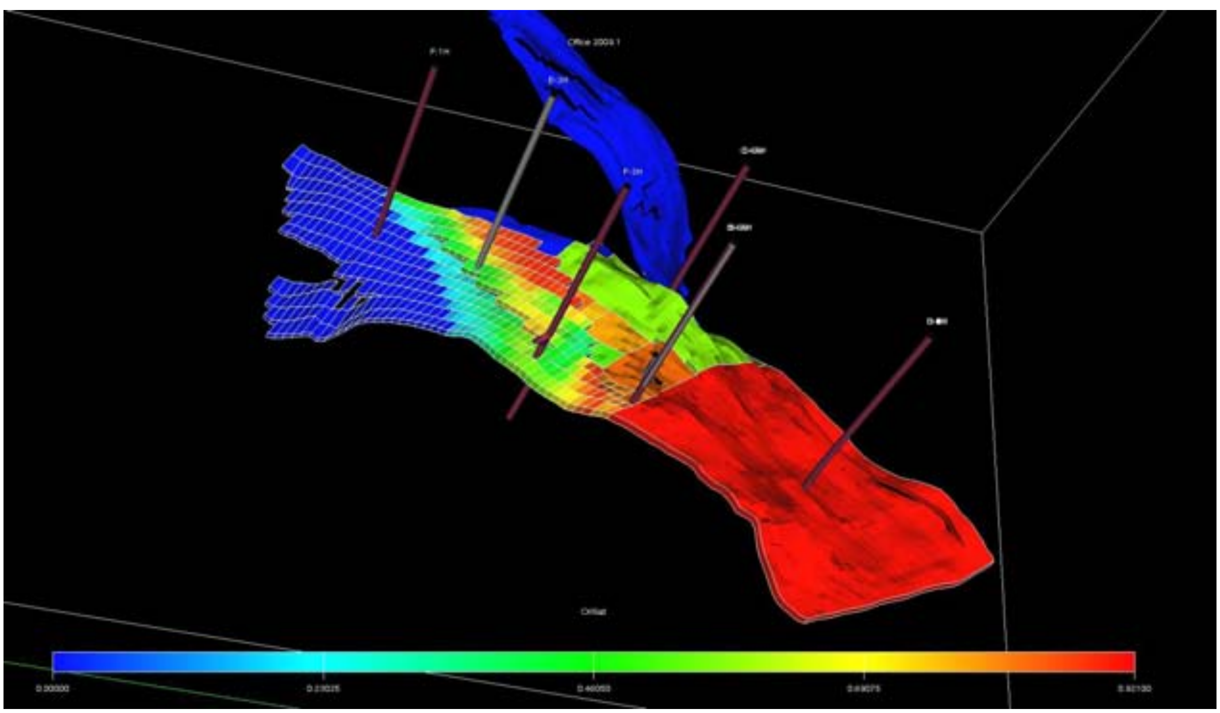

Figure 28: Layer 10-Ile formation Nov 2004